STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

FORM 3

AMENDED REPORT ☐
(highlight changes)

APPLICATION FOR PERMIT TO DRILL

5. MINERAL LEASE NO: ML-47061
6. SURFACE: State

1A. TYPE OF WORK: DRILL ☑ REENTER ☐ DEEPEN ☐

7. IF INDIAN, ALLOTTEE OR TRIBE NAME:

B. TYPE OF WELL: OIL ☐ GAS ☐ OTHER Water Disp SINGLE ZONE ☐ MULTIPLE ZONE ☑

8. UNIT or CA AGREEMENT NAME:

2. NAME OF OPERATOR: Enduring Resources, LLC

9. WELL NAME and NUMBER: Rock House 10-22-31-36WD

3. ADDRESS OF OPERATOR: 475 17th St., Ste 1500 CITY Denver STATE CO ZIP 80220
PHONE NUMBER: (303) 350-5114

10. FIELD AND POOL, OR WILDCAT: ~~Undesignated~~ Natural Buttes

4. LOCATION OF WELL (FOOTAGES)
AT SURFACE: 1164' FNL - 1633' FEL
638136X 39.909443
4418746Y -109.383937
AT PROPOSED PRODUCING ZONE: Same

11. QTR/QTR, SECTION, TOWNSHIP, RANGE, MERIDIAN: NWNE 36 10S 22E

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE: 42.4 Miles South of Bonanza, UT

12. COUNTY: Uintah
13. STATE: UTAH

15. DISTANCE TO NEAREST PROPERTY OR LEASE LINE (FEET): 1164'
16. NUMBER OF ACRES IN LEASE: 640
17. NUMBER OF ACRES ASSIGNED TO THIS WELL: 40 acres

18. DISTANCE TO NEAREST WELL (DRILLING, COMPLETED, OR APPLIED FOR) ON THIS LEASE (FEET): 25'
19. PROPOSED DEPTH: 4,565
20. BOND DESCRIPTION: RLB0008031

21. ELEVATIONS (SHOW WHETHER DF, RT, GR, ETC.): 5298' RT-KB
22. APPROXIMATE DATE WORK WILL START: 1/31/2007
23. ESTIMATED DURATION: 20 days

24. **PROPOSED CASING AND CEMENTING PROGRAM**

SIZE OF HOLE	CASING SIZE, GRADE, AND WEIGHT PER FOOT			SETTING DEPTH	CEMENT TYPE, QUANTITY, YIELD, AND SLURRY WEIGHT			
20"	14"	line pipe		40	3 yards	Ready Mix		
12-1/4"	8-5/8"	J-55	24#	250	Premium Lead	129sxs	3.50	11.1
7-7/8"	5-1/2"	J-55	15.5#	4,581	Class G	813 sxs	1.15	15.8

25. **ATTACHMENTS**

VERIFY THE FOLLOWING ARE ATTACHED IN ACCORDANCE WITH THE UTAH OIL AND GAS CONSERVATION GENERAL RULES:

☑ WELL PLAT OR MAP PREPARED BY LICENSED SURVEYOR OR ENGINEER
☑ EVIDENCE OF DIVISION OF WATER RIGHTS APPROVAL FOR USE OF WATER
☑ COMPLETE DRILLING PLAN
☐ FORM 5, IF OPERATOR IS PERSON OR COMPANY OTHER THAN THE LEASE OWNER

NAME (PLEASE PRINT) Alvin R. (Al) Arlian TITLE Landman - Regulatory Specialist

SIGNATURE Evette Bissett for Al Arlian DATE 1/22/2007

(This space for State use only)

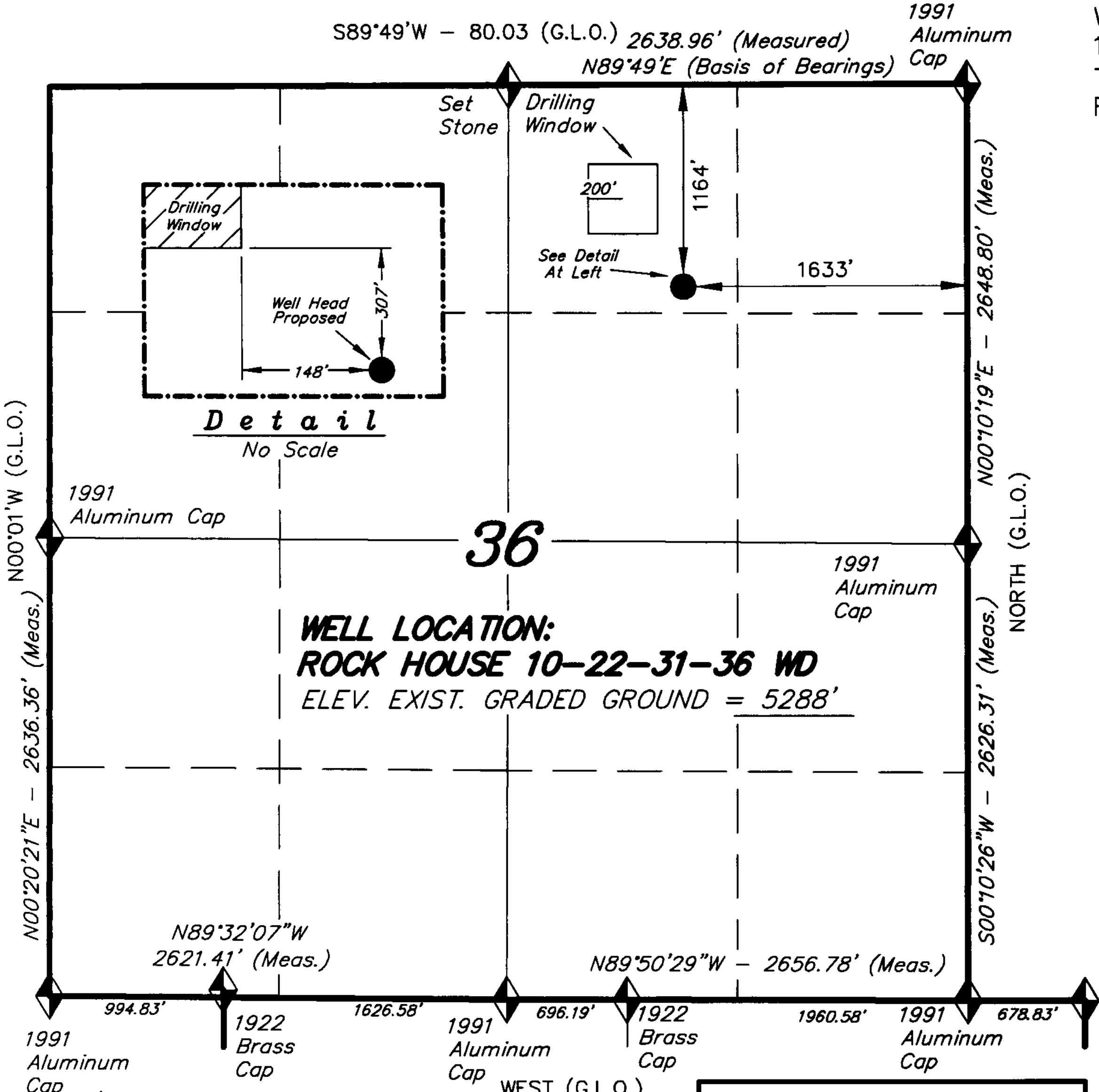
API NUMBER ASSIGNED: 43-047-38993 APPROVAL:

RECEIVED
JAN 2 6 2007
DIV. OF OIL, GAS & MINING

(11/2001)

(See Instructions on Reverse Side)

T10S, R22E, S.L.B.&M.



◆ = SECTION CORNERS LOCATED

BASIS OF ELEV; U.S.G.S. 7-1/2 min QUAD (ARCHY BENCH)

10-22-31-36
(Surface Location) NAD 83
LATITUDE = 39° 54' 33.81"
LONGITUDE = 109° 23' 04.88"

ENDURING RESOURCES

WELL LOCATION, ROCK HOUSE 10-22-31-36 WD, LOCATED AS SHOWN IN THE NW 1/4 NE 1/4 OF SECTION 36, T10S, R22E, S.L.B.&M. UINTAH COUNTY, UTAH.

THIS IS TO CERTIFY THAT THE ABOVE PLAT WAS PREPARED FROM FIELD NOTES OF ACTUAL SURVEYS MADE BY ME OR UNDER MY SUPERVISION AND THAT THE SAME ARE TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

REGISTERED LAND SURVEYOR
REGISTRATION No. 189377
STATE OF UTAH

REGISTERED LAND SURVEYOR No.189377 STACY W. STEWART STATE OF UTAH

TRI STATE LAND SURVEYING & CONSULTING
180 NORTH VERNAL AVE. – VERNAL, UTAH 84078
(435) 781-2501

DATE DRAWN: 01-09-07	SURVEYED BY: K.G.S.	SHEET 2 OF 10
REVISED:	DRAWN BY: F.T.M.	
NOTES:	SCALE: 1" = 1000'	

Enduring Resources

475 17[TH] Street Suite 1500 Denver Colorado 80202
Telephone 303 573-1222 Fax 303 573 0461

January 22, 2007

Ms. Diana Whitney
Utah Division of Oil, Gas and Mining
1594 West North Temple, Suite 1210
P. O. Box 145801
Salt Lake City, Utah 84114-5801

RE: Enduring Resources, LLC
Rock House 10-22-31-36WD
NWNE 36-10S-22E
State Lease: ML-47061
Uintah County, Utah

RECEIVED
JAN 2 6 2007
DIV. OF OIL, GAS & MINING

Dear Ms. Whitney:

Enclosed are two original applications to drill concerning the above-referenced proposed well. This information was also submitted to SITLA.

Enduring Resources, LLC ('ERLLC') plans to drill the above-referenced well from an exception location (on an existing well pad) to limit surface impact. This water disposal well will be drilled on the Rock House 2D-36 well pad.

ERLLC and its Partners are the only leasehold interest owners within 460 feet of any part of the above-referenced proposed well's proposed well bore, therefore,

A. *ERLLC also grants itself permission for an exception well location.*

Enduring Resources, LLC is requesting the Utah Division of Oil, Gas and Mining to hold this application and all future information as confidential.

If any questions arise or additional information is required, please contact me at 303-350-5719

Very truly yours,

Evette Bissett

Evette Bissett
Regulatory Affairs Assistant

Enclosures
cc: SITLA w/ attachments

Enduring Resources, LLC
Rock House 10-22-31-36 WD
NWNE 36-10S-22E
Uintah County, Utah
State Lease: ML-47061

ONSHORE ORDER 1 - DRILLING PLAN

In addition to DOG&M rules and regulations and the drilling plan set forth below, this well will be drilled, completed, and operated pursuant to EPA Underground Injection Control Program Permit No. UT21059-07147, attached hereto and made a part hereof by this referenced. This well is also subject to a water disposal agreement between Enduring and SITLA concerning off-lease water disposed of in this well.

1. **Estimated Tops of Geological Markers:**

Formation	Depth **(K.B.)**
Uinta	Surface
Wasatch	3516

2. **Estimated Depths of Anticipated Water, Oil, Gas or Other Minerals:**

Substance	Formation	Depth **(K.B.)**
	KB-Uinta Elevation: 5298'	
Oil /Gas	Wasatch	3516
	Estimated TD	4565

A 12-1/4" hole will be drilled to approximately 250 feet and surface casing will be set.

3. **Pressure Control Equipment: (3000 psi schematic attached)**

A. Type: Eleven (11) inch double gate hydraulic BOP with eleven (11) inch annular preventer on 3,000 psi casinghead, with 3,000 psi choke manifold equipped per the attached diagram. BOPE as specified in *Onshore Oil & Gas Order Number 2.* A PVT, stroke counter and flow sensor will be installed to check for flow and monitor pit volume.

B. Pressure Rating: 3,000 psi BOPE

C. Kelly will be equipped with upper and lower Kelly valves.

D. Testing Procedure: Annular Preventer

At a minimum, the annular preventer will be pressure tested to 50% of the stack rated working pressure for a period of ten (10) minutes or until provisions of the test are met, whichever is longer.

At a minimum, the above pressure test will be performed:

1. When the annular preventer is initially installed;
2. Whenever any seal subject to test pressure is broken;
3. Following related repairs; and
4. At thirty (30) day intervals.

In addition to the above, the annular preventer will be functionally operated at least weekly.

Blow-Out Preventer

At a minimum, the BOP, choke manifold, and related equipment will be pressure tested to the approved working pressure of the BOP stack (if isolated from the surface casing by a test plug) or to 70% of the internal yield strength of the surface casing (if the BOP is not isolated from the casing by a test plug). Pressure will be maintained for a period of at least ten (10) minutes or until the requirements of the test are met, whichever is longer.

At a minimum, the above pressure test will be performed:

1. When the BOP is initially installed;
2. Whenever any seal subject to test pressure is broken;
3. Following related repairs; and
4. At thirty (30) day intervals.

In addition to the above, the pipe and blind rams will be activated each trip, but not more than once each day. All BOP drills and tests will be recorded in the IADC driller's log.

E. Miscellaneous Information:

The blowout preventer and related pressure control equipment will be installed, tested and maintained in compliance with the specifications in and requirements of *Onshore Oil & Gas Order Number 2*.

4. Proposed Casing & Cementing Program:

A. Casing Program: All New

Hole Size	Casing Size	Wt./Ft.	Grade	Joint	Depth Set (MD)
20"	14" O.D.				40' (GL)
12-1/4"	8-5/8"	24#	J-55	ST&C	0 – 266' (KB) est.
7-7/8"	5-1/2"	15.5#	J-55	LT&C	4581 ' (KB)

Casing string(s) will be pressure tested to 0.22 psi/foot of casing string length or 1500 psi, whichever is greater (not to exceed 70% of the internal yield strength of the casing), after cementing and prior to drilling out from under the casing shoe.

B. Casing Design Parameters:

Depth (MD)	Casing	Collapse(psi)/SF	Burst (psi)/SF	Tension(mlbs)/SF
40' (GL)	14" OD			
266' (KB)	8-5/8", 24#/ft, J-55, STC	1370/1.52(a)	2950/3.28(b)	244/5.81(c)
4581' (KB)	5-1/2", 15.5#/ft, J-55, LTC	6350/2.68 (d)	7780/3.57 (e)	223/4.90(f)

(a.) based on full evacuation of pipe with 8.6 ppg fluid on annulus
(b.) based on 8.6 ppg gradient with no fluid on annulus
(c.) based on casing string weight in 8.6 ppg mud
(d.) based on full evacuation of pipe with 10.0 ppg fluid on annulus
(e.) based on 9.2 ppg gradient, gas to surface, with no fluid on annulus, no gas gradient
(f.) based on casing string weight in 9.2 ppg mud

PROPOSED CEMENTING PROGRAM

Surface Casing (if well will circulate)-Cemented to surface

CASING	SLURRY	FT. of FILL	CEMENT TYPE	SXS	EXCESS (%)	WEIGHT (ppg)	YIELD (ft^3/sx)
8-5/8"	Lead	250	Premium cement + 0.25 pps celloflake and 2% calcium chloride	129	25%	11.1	3.50

A cement top job is required if cement fallback is greater than 10' below ground level. Top job (weight 15.8 ppg, yield 1.15 ft^3/sx) cement will be premium cement w/ 3% $CaCl_2$.+0.25 pps celloflake. Volume as required

Surface Casing (if well will not circulate) - Cemented to surface

CASING	SLURRY	FT. of FILL	CEMENT TYPE	SXS	EXCESS (%)	WEIGHT (ppg)	YIELD (ft^3/sx)
8-5/8"	Lead	250	Premium cement + 0.25 pps celloflake and 2% calcium chloride	129	25	15.8	1.15
8-5/8"	Top job	As req.	Premium cement + 0.25 pps celloflake and 3% calcium chloride	As Req.		15.8	1.15

Production Casing and Liner - Cemented TD to surface

CASIN G	SLURRY	FT. of FILL	CEMENT TYPE	SXS	EXCESS (%)	WEIGHT (ppg)	YIELD (ft^3/sx)
5-1/2"	Lead and Tail	TD to Surface	50/50 Poz Class G cement w/ 2% gel extender, 6% Halad-322, 2% Super CBL, 5% salt and .25#/sack flocele.	813	25	14.3	1.47

Cement volumes for the 5-1/2" Production Casing will be calculated to provide a top of cement to surface. Cement volumes are approximate and were calculated under the assumption that a gauge hole will be achieved. Actual cement volumes may vary due to variations in the actual hole size and will be determined by running a caliper log on the drilled hole. Actual cement types may vary due to hole conditions and cement contractor used.

All waiting on cement (WOC) times will be adequate to achieve a minimum of 500 psi compressive strength at the casing shoe prior to drilling out.

5. Drilling Fluids (mud) Program:

Interval (MD)	Mud Weight	Fluid Loss	Viscosity	Mud Type
0' – 266' (KB)		No cntrl		Air/mist
266'-4581' (KB)	8.8-9.8	8 - 10 ml	32-42	Water/Gel

Sufficient mud material(s) to maintain mud properties, control lost circulation and contain a blowout will be available at the well site during drilling operations.

6. Evaluation Program:

Tests: No tests are currently planned.

Coring: No cores are currently planned.

Samples: No sampling is currently planned.

Logging

- Dual Induction–SFL /Gamma Ray/Caliper/SP/TDLT/CNL/ML
  TD to Base Surface Casing
- Cement Bond Log / Gamma Ray:
  TD to Base of Surface Casing or Top of Cement if below Base of Surface Casing

7. **Abnormal Conditions:**

No abnormal temperatures or pressures are anticipated. No H_2S has been encountered or known to exist from previous wells drilled to similar depths in the general area.

Maximum anticipated bottom hole pressure equals approximately 2374 psi (calculated at 0.50 psi/foot of hole) and maximum anticipated surface pressure equals approximately 1370 psi (anticipated bottom hole pressure minus the pressure of a partially evacuated hole calculated at 0.22 psi/foot of hole).

8. **Anticipated Starting Dates:**

- Anticipated Commencement Date- Within one year of APD issue.
- Drilling Days- Approximately 10 days
- Completion Days - Approximately 10 days
- Anticipate location construction within 30 days of permit issue.

9. **Variances:**

None anticipated

10. **Other:**

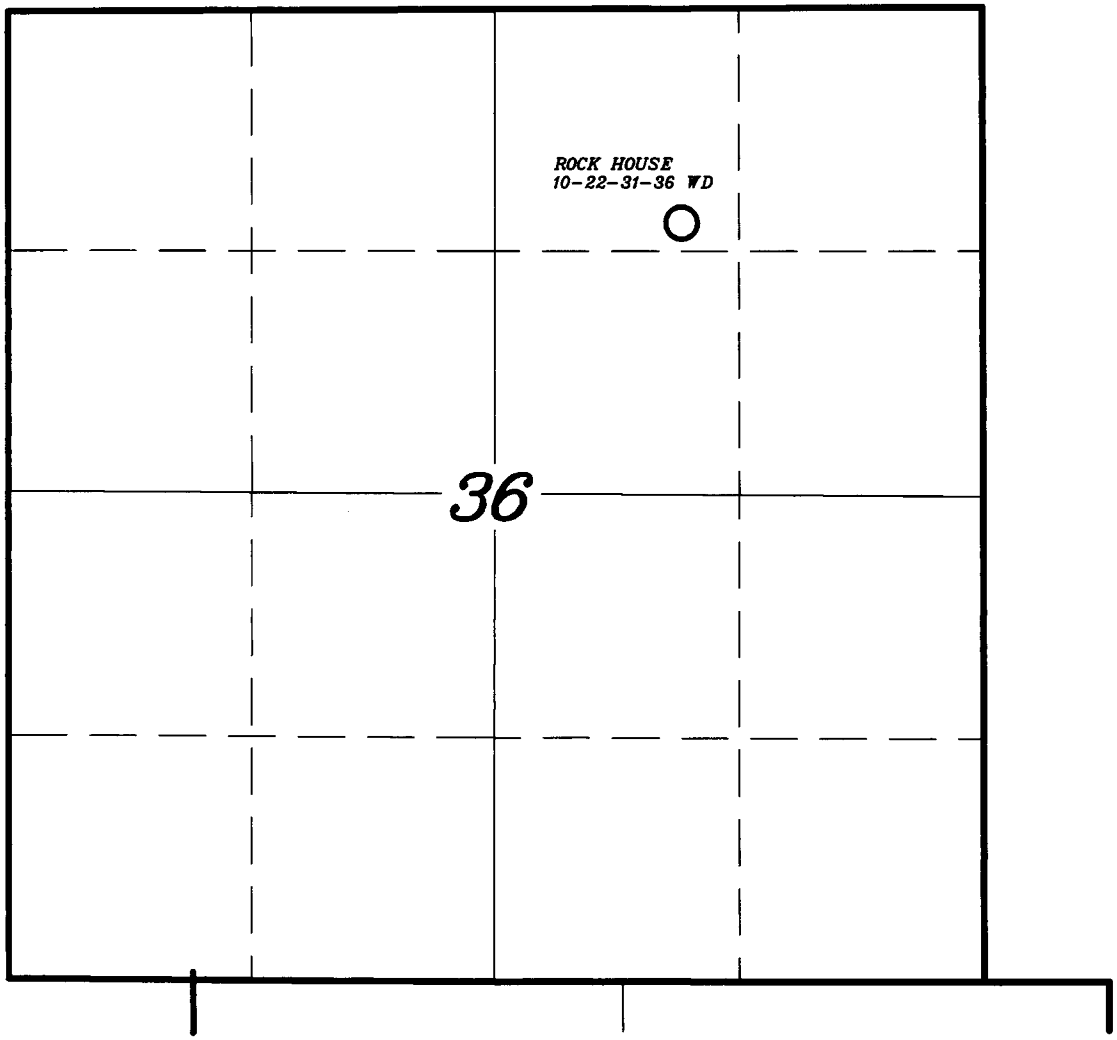
A Cultural Resource Inventory and Paleontology reconnaissance shall be conducted for the well location, access route and pipeline.

Single Shot directional surveys will be dropped every 2000 feet to monitor hole angle.

T10S, R22E, S.L.B.&M.

ENDURING RESOURCES

SECTION DRILLING MAP
ROCK HOUSE 10-22-31-36 WD



LEGEND

○ = Vertical Well

⊙ = Directional Well (Bottom Hole)

TRI STATE LAND SURVEYING & CONSULTING 180 NORTH VERNAL AVE. – VERNAL, UTAH 84078 (435) 781-2501		
DATE DRAWN: 01-09-07	SURVEYED BY: K.G.S.	SHEET 1 OF 10
REVISED:	DRAWN BY: F.T.M.	
NOTES:	SCALE: 1" = 1000'	

Directions to the Rock House 10-22-31-36 WD Well Pad

Beginning at the city of Bonanza, Utah. Leave the city of Bonanza heading south on state highway 45 for a distance of approximately 5.7 miles where the there is a turn-off to the right. Turn right, leaving state highway 45, and proceed southwest for a distance of approximately 5.1 miles (3.2 + 1.9 as shown on Topo "A"). The road then turns to the west; proceed northwesterly along said road for a distance of approximately 3.7 miles. Said road then turns to the southwest; proceed southwesterly then westerly for a distance of approximately 3.2 miles where the road forks. Turn left and bear southerly along the Asphalt Wash road for a distance of 3.0 miles where the road forks near a landing strip. Stay right, and continue heading south along the West Fork road for a distance of approximately 6.5 miles where the there is a turn-off to the right. Turn right and bear westerly for a distance of approximately 1.7 miles. The road then turns to the north; proceed northerly along said road for a distance of approximately 3.8 miles where there is a turn-off to the left. Turn left and bear northwest for a distance of approximately 1.4 miles where there is a fork in the road near a landing strip. Turn right and bear northerly for a distance of approximately 2.1 miles where the said road turns and bears southwest. Continue along said road as it turns and bears southwest and continue bearing southwest for a distance of approximately 1.5 miles. The road then turns to the north; proceed northerly for a distance of approximately 0.3 miles where there is a turn-off to the left. Stay to the left and proceed northerly for approximately 4.4 miles to the Rock House 10-22-31-36 WD Well Pad.

Enduring Resources, LLC

Rock House 10-22-31-36 WD
NWNE 36-10S-22E
Uintah County, Utah
State Lease: ML-47061

MULTI-POINT SURFACE USE & OPERATIONS PLAN

1. Existing Roads:

Beginning at the city of Bonanza, Utah, head south on state highway 45 for a distance of approximately 5.7 miles where the there is a turn-off to the right. Turn right, leaving state highway 45, and proceed southwest for a distance of approximately 5.1 miles (3.2 + 1.9 as shown on Topo "A"). The road then turns to the west; proceed northwesterly along said road for a distance of approximately 3.7 miles. Said road then turns to the southwest; proceed southwesterly then westerly for a distance of approximately 3.2 miles where the road forks. Turn left and bear southerly along the Asphalt Wash road for a distance of 3.0 miles where the road forks near a landing strip. Stay right, and continue heading south along the West Fork road for a distance of approximately 6.5 miles where the there is a turn-off to the right. Turn right and bear westerly for a distance of approximately 1.7 miles. The road then turns to the north; proceed northerly along said road for a distance of approximately 3.8 miles where there is a turn-off to the left. Turn left and bear northwest for a distance of approximately 1.4 miles where there is a fork in the road near a landing strip. Turn right and bear northerly for a distance of approximately 2.1 miles where the said road turns and bears southwest. Continue along said road as it turns and bears southwest and continue bearing southwest for a distance of approximately 1.5 miles. The road then turns to the north; proceed northerly for a distance of approximately 0.3 miles where there is a turn-off to the left. Stay to the left and proceed northerly for approximately 4.4 miles to the Rock House 10-22-31-36 WD Well Pad.

2. Planned Access Roads:

This proposed water disposal well is located on an existing well pad. No improvements are needed to the access road.

Surface disturbance and vehicular traffic will be limited to the pad location and the access route. Any additional area needed will be approved in advance. All construction shall be in conformance with the standards outlined in the BLM and Forest Service publication: *Surface Operating Standards for Oil and Gas Exploration and Development. 1989.*

The road surface and shoulders will be kept in a safe usable condition and will be maintained in accordance with the original construction standards. All drainage ditches will be kept clear and free flowing and will be maintained according to original construction standards. The access road surface will be kept free of trash during operations. All traffic will be confined to the approved disturbed surface. Road drainage crossings shall be designed so they will not cause siltation or accumulation of debris in the drainage crossing nor shall the drainages be blocked by the road bed. Erosion of drainage ditches by runoff water shall be prevented by diverting water off at frequent intervals by means of cutouts. Upgrading shall not be allowed during muddy conditions. Should mud holes develop, they shall be filled in and detours around them avoided. When snow is removed from the road during the winter months, the snow shall be pushed outside of the borrow ditches and the turnouts kept clear so that snowmelt will be channeled away from the road.

3. **<u>Location of Existing Wells within a One-Mile radius (See "Topo" Map "C" attached):</u>**

The following wells are wells located within a one (1) mile or greater radius of the proposed location:

a. None: Water Wells:
b. None: Injection Wells:
c. (10): Producing Wells:
   1. Rock House 10-22-21-36, NENW 36
   2. Rock House 10-22-32-36, SWNE 36
   3. Rock House 10-22-14-36, SWSW 36
   4. Rock House 10-22-13-36, NWSW 36
   5. Rock House 10-22-33-36, SWNE 36
   6. Rock House 10-22-42-36, NWNE 36
   7. Rock House 4-36, NWNW 36
   8. Rock House 11-36, NESW 36
   9. Rock House 10-22-41-36, NENE 36
   10. State 1022-36E, SWNW 36
d. None: Drilling Wells:
e. None: Shut-in Wells:
f. None: Temporarily Abandoned Wells:
g. None: Disposal Wells:
h. (2): Abandoned Wells:
   1. Sharples-Texaco State 1, NESW 36
   2. NBU 61-25B, SWSW 25
i. None: Dry Holes:
j. None: Observation Wells:
k. (25): Pending (staked) Wells:
   1. There are twenty-five other wells staked in this section.

4. **<u>Location of Existing and/or Proposed Facilities:</u>**

The water disposal facilities will be located on the disturbed portion of the well pad and at a minimum of 25 feet from the toe of the back slope or the top of the fill slope.

A dike will be constructed completely around those water disposal facilities which contain fluids (i.e. water tanks and/or injection pumps). These dikes will be constructed of compacted subsoil, be impervious, hold 100% of the capacity of the largest tank and be independent of the back cut.

All permanent (on site for six months or longer) above the ground structures constructed or installed, will be painted a flat, non-reflective, earth tone color to match one of the standard environmental colors, as determined by the Rocky Mountain Five State Inter-Agency Committee.

All facilities will be painted within 6 months of installation. The color shall be designated by SITLA. Facilities required to comply with the Occupational Safety and Health Act (OSHA) will be excluded.

Any necessary pits will be properly fenced to protect livestock and prevent wildlife entry.

There will be no Gas Gathering Pipeline for this well.

5. **Location and Type of Water Supply:**

Whenever practical, water will be obtained from Enduring Resources LLC Water Right Number 49-2215 or Water Right Number 49-2216 (*See Townships of permitted Use below). If those sources are not available, a new water source shall be submitted prior to commencing operations. (These permits have one-year terms and then must be renewed.)

*Enduring Water Permits' Townships of Use:

T10S-R22E	T11S-R22E	T12S-R22E
T10S-R23E	T11S-R23E	T12S-R23E
T10S-R24E	T11S-R24E	T12S-R24E

Water will be hauled to the location over the roads marked on "Topo" Maps "A" and "B."

No water (source) well is to be drilled on this lease.

6 **Source of Construction Materials:**

This well will be drilled on an existing well pad and no new construction materials will be needed.

7. **Methods of Handling Waste Materials:**

Drill cuttings will be contained and buried in the reserve pit.

Drilling fluids, including salts and chemicals, will be contained in the reserve pit will be removed and disposed of at an approved waste disposal facility within 120 days after drilling is terminated.

The reserve pit will be constructed on the location and will not be located within natural drainage, where a flood hazard exits or surface runoff will destroy or damage the pit walls. The reserve pit will be constructed so that it will not leak, brake or allow discharge of liquids.

The reserve pit will be lined with ¼ felt and a minimum of 16 mm plastic with sufficient bedding used to cover any rocks. The liner will overlap the pit walls and be covered with dirt and/or rocks to hold it in place. No trash or scrap that could puncture the liner will be disposed of in the pit.

A chemical portable toilet will be furnished with the drilling rig. The toilet will be replaced periodically utilizing a licensed contractor to transport by truck the portable chemical toilet so that its contents can be delivered to the Vernal Wastewater Treatment Facility in accordance with state and county regulations.

Garbage, trash and other waste materials will be collected in a portable, self-contained, fully enclosed trash cage during operations. No trash well is burned on location.

All debris and other waste material not contained in the trash cage will be cleaned up and removed from the location immediately after removal of the drilling rig.

Any open pits will be fenced during the operations. The fencing will be maintained until such time as the pits are backfilled.

No chemicals subject to reporting under SARA Title III (hazardous materials) in an amount greater than 10,000 pounds will be used, produced, stored, transported or disposed of in association with the drilling, completion or testing of this well. Furthermore, no extremely hazardous substances, as defined in 40 CFR 355, in threshold planning quantities, will be used, produced, stored, transported or disposed of in association with the drilling, completion or testing of this well.

Produced oil will be stored in an oil tank and then hauled by truck to a crude purchaser facility. Any produced water from the proposed well will be contained in a water tank and will then be hauled by truck to an approved disposal site.

8. <u>Ancillary Facilities:</u>

During drilling operations, approximately 10 days, the site will be a manned camp. Three or four additional trailers will be on location to serve as the crews' housing and eating facilities. These will be located on the perimeter of the pad site within the topsoil stockpiles. Refer to Sheet 4.

9. **<u>Well Site Layout: (Refer to Sheets #2, #3, and #4)</u>**

The attached Location Layout Diagrams described drill pad cross-sections, cuts and fills and locations of the mud tanks, reserve pit, flare pit, pipe racks, trailer parking, spoil dirt stockpile(s) and surface material stockpiles(s).

Please see the attached diagram for rig orientation and access roads.

The top soil will be windrowed rather than piled. It will be reseeded and track walker at the time the location is constructed. Seeding will be with the determined during the onsite. (Refer to "Seed Mixture for Windrowed Top Soil Will included:" following herein.

The top soil removed from the pit area will be store separately and will not be reseeded until the pit is reclaimed.

All pits shall be fenced to the following minimum standards:

a. 39 inch net wire shall be used with at least one strand of barbed wire on top of the net wire. Barbed wire is not necessary if pipe or some type of reinforcement rod is attached to the top of the entire fence.
b. The net wire shall be no more than 2 inches above the ground. The barbed wire shall be 3 inches over the new wire. Total height of the fence shall be at least 42 inches.
c. Corner posts shall be cemented and/or braced in such a manner to keep the fence tight at all times.
d. Standard steel, wood or pipe posts shall be used between the corner braces. Maximum distance between any two fence posts shall be no greater than 16 feet.
e. All wire shall be stretched by, using a stretching device, before it is attached to corner posts.
f. The reserve pit fencing will be on three sides during drilling operations and on the fourth side when the rig moves off location. Pits will be fenced and maintained until cleanup.
g. Location size may change prior to drilling the well due to the current rig availability. If the proposed location is not large enough to accommodate the drilling, the location will be re-surveyed and a Form 9 will be submitted.

10. **<u>Plans for Surface Reclamation:</u>**

Producing Location:

a. Immediately upon well completion the location and surrounding area will be cleared of all unused tubing, equipment, materials, trash and debris not required for injection operations.
b. Immediately upon well completion any hydrocarbons in the pit shall be removed

in accordance with 40CFR 3162.7.

c. Before any dirt work associated with location restoration takes place, the reserve pit shall be as dry as possible. All debris in it will be removed. Other waste and spoil materials will be disposed of immediately upon completion of operations.
d. The reserve pit and that portion of the location not needed for production facilities/operations will be re-contoured to the approximated natural contours. The reserve pit will be reclaimed within 90 days from the date of well completion, weather permitting.
e. To prevent surface water(s) from standing (ponding) on the reclaimed reserve pit area, final reclamation of the reserve pit will consist of "mounding" the surface 3 feet above surrounding round surface to allow the reclaimed pit area to drain effectively.
f. Upon completion of back filling, leveling and re-contouring, the stockpiled topsoil will be spread evenly over the reclaimed area(s).

Dry Hole/Abandoned Location:

(When the last well on this pad is plugged)

a. Abandoned well sites, roads and other disturbed areas will be restored as nearly as practical to their original condition. Where applicable, these conditions include the re-establishment of irrigation systems, the re-establishment of appropriate soil conditions and re-establishment of vegetation as specified.
b. All disturbed surfaces will be re-contoured to the approximated natural contours with reclamation of the well pad and access road to be performed as soon as practical after final abandonment. If necessary, re-seeding operations will be performed after completion of other reclamation operations.

Seed Mixture for Windrowed Top Soil Will Included:

To be provided by the SITLA

11. Surface Ownership: Location, Access and Pipeline Route:

Wellsite: SITLA

Access: SITLA

Pipeline: N/A

12. Other Information

On-site Inspection for Location, Access and Pipeline Route:

The on-site may be scheduled by DOG&M (on existing pad).

Special Conditions of Approval:

- Tanks and Disposal Equipment shall be painted pursuant of SITLA request.
- **SITLA AND ENDURING HAVE A WATER DISPOSAL AGREEMENT CONCERNING ANY WATER THAT IS DISPOSED OF IN THIS WELL WHICH IS NOT PRODUCED FROM WELLS LOCATED IN THIS SECTION.**

Archeology:

a. A copy of the Cultural Resource Inventory Report prepared prior to this pad being built is attached.

Paleontology:

a. If a Paleontology Reconnaissance Report was prepared prior to this pad being built, it is attached.

If, during operations, any archaeological or historical sites, or any objects of antiquity (subject to the Antiquities Act of June 8, 1906) are discovered, all operations which would affect such sites will be suspended and the discovery reported promptly to the surface management agency.

13, Lessee's or Operator's Representatives:

Representatives:

Alvin R. (Al) Arlian
Landman – Regulatory Specialist
Enduring Resources, LLC
475 17th Street, Suite 1500
Denver, Colorado 80202
Office Tel: 303-350-5114
Fax Tel: 303-573-0461
aarlian@enduringresources.com

Teme Singleton
Drilling Engineer
Enduring Resources, LLC
475 17th Street, Suite 1500
Denver, Colorado 80202
Office Tel: 303-573-5711
Fax Tel: 303-573-0461
tsingleton@enduringresources.com

All lease and/or unit operations will be conducted in such a manner that full compliance is made with all applicable laws, regulations, Onshore Oil and Gas Orders, the approved plan of operations, and any applicable Notice to Lessees. The operator is fully responsible for the actions of his/her/its subcontractors. A copy of these conditions will be furnished the field representative to insure compliance.

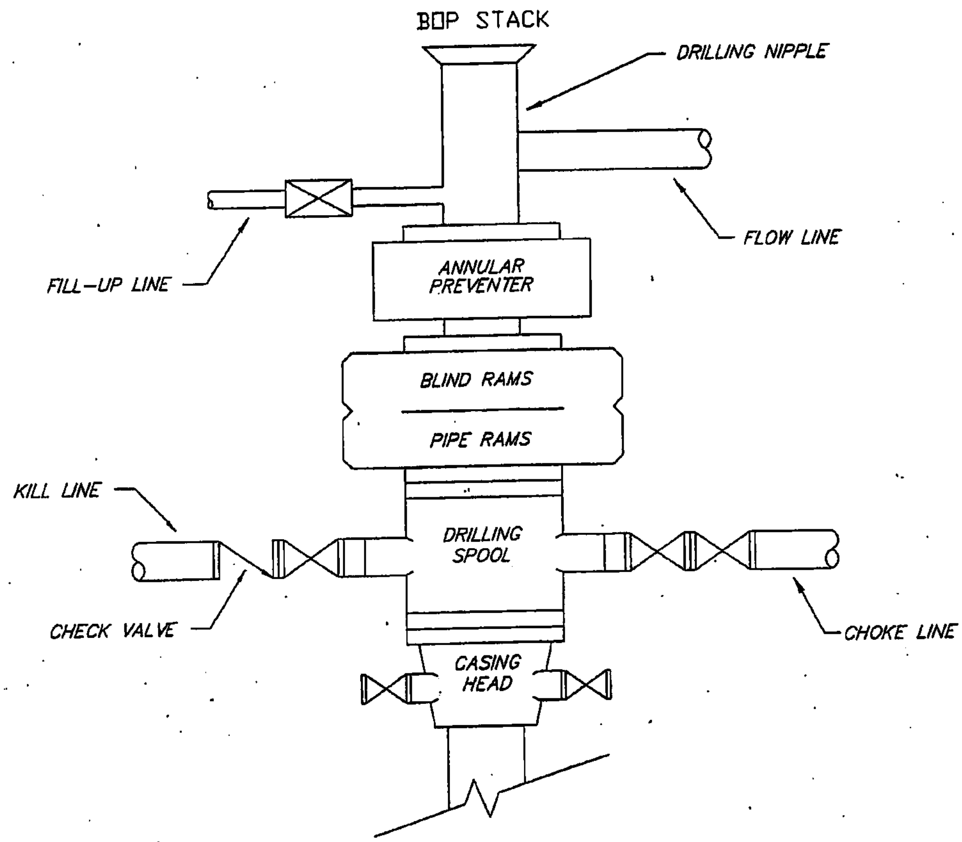
A complete copy of the approved APD and ROW grant, if applicable, shall be on location during construction of the location and drilling activities.

The operator or his/here/its contractor shall contact the DOG&M forty-eight (48) hours prior to construction activities.

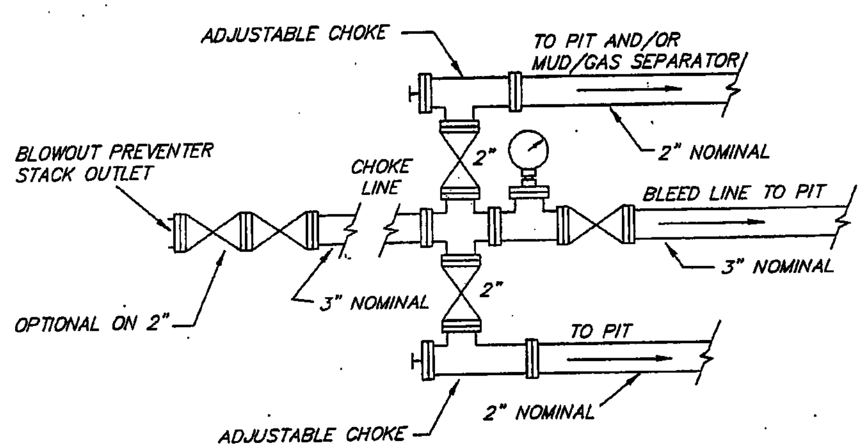
DOG&M shall be notified upon site completion prior to moving on the drilling rig.

ENDURING RESOURCES, LLC

TYPICAL 3,000 p.s.i.
BLOWOUT PREVENTER SCHEMATIC



TYPICAL 3,000 p.s.i.
CHOKE MANIFOLD SCHEMATIC



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
http://www.epa.gov/region08

Ref: 8P-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Alex Campbell
Enduring Resources, LLC
475 17th Street Suite 1500
Denver, CO 80202

Re: Underground Injection Control Program
Permit for the Rock House 10-22-31-36 WD Well
Uintah County, UT
EPA Permit No. UT21059-07147

Dear Mr. Campbell:

Enclosed is your copy of the FINAL Underground Injection Control (UIC) Permit for the proposed Rock House 10-22-31-36 WD injection well. A Statement of Basis, which discusses development of the conditions and requirements of the Permit, also is included.

The Public Comment period ended on JAN 17 2007. There were no comments on the Draft Permit received during the Public Notice period, and therefore the Final Permit becomes effective on the date of issuance. All conditions set forth herein refer to Title 40 Parts 124, 144, 146, and 147 of the Code of Federal Regulations (CFR) and are regulations that are in effect on the date that this Permit becomes effective.

Please note that under the terms of the Final Permit, you are authorized only to construct the proposed injection well, and must fulfill the "Prior to Commencing Injection" requirements of the Permit, Part II Section C Subpart 1 and obtain written Authorization to Inject prior to commencing injection. It is your responsibility to be familiar with and to comply with all provisions of the Final Permit.

The Permit and the authorization to inject are issued for the operating life of the well unless terminated (Part III, Section B). The EPA will review this Permit at least every five (5) years to determine whether action under 40 CFR § 144.36(a) is warranted.

If you have any questions on the enclosed Final Permit or Statement of Basis, please call Patricia Pfeiffer of my staff at (303) 312-6271, or toll-free at (800) 227-8917, ext. 6271.

Sincerely,

Deb H Thomas

for Stephen S. Tuber
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

enclosure:
Final UIC Permit
Statement of Basis
Form 7520-7 Application to Transfer Permit
Form 7520-11 Monitoring Report
Form 7520-14 Plugging Plan
Form 7520-12 Well Rework Record
Groundwater Section Guidance 34
Groundwater Section Guidance 35
Groundwater Section Guidance 37
Groundwater Section Guidance 39

cc:
Maxine Natchees, Acting Chairperson
Uintah & Ouray Business Committee
Ute Indian Tribe
P.O. Box 190
Fort Duchesne, UT 84026

Chester Mills, Superintendent
BIA - Uintah & Ouray Indian Agency
P.O. Box 130
Fort Duchesne, UT 84026

Mr. Jack Watson
Senior Geologist
Enduring Resources
475 Seventeenth Street, Suite 1500
Denver, CO 80202

Shaun Chapoose
Director of Land Use Department
Ute Indian Tribe
P.O. Box 460
Fort Duchesne, UT 84026

Brad Hill
Technical Services Manager
Utah Division of Oil, Gas, and Mining
1594 West North Temple - Suite 1220
Salt Lake City, UT 84114-5801

Fluid Minerals Engineering Office
BLM - Vernal Office
170 South 500 East
Vernal, UT 84078

Lynn Becker, Director
Energy and Minerals Department
Ute Indian Tribe
P.O. Box 70
Ft. Duchesne, UT 84026

UNDERGROUND INJECTION CONTROL PROGRAM

PERMIT

PREPARED: October 2006

Permit No. UT21059-07147

Class II Salt Water Disposal Well

Rock House 10-22-31-36 WD
Uintah County, UT

Issued To

Enduring Resources LLC
475 17th Street, Suite 1500
Denver, CO 80202

Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Permit,

Enduring Resources LLC
475 17th Street, Suite 1500
Denver, CO 80202

is authorized to construct and to operate the following Class II injection well or wells:

Rock House 10-22-31-36 WD
1164 ft FNL & 1633 ft FEL, NWNE S36, T11S, R22E
Uintah County, UT

EPA UIC permits regulate the injection of fluids intoinjection wells so that injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences are not discussed in this document. Under 40 CFR §144.35, issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other federal, state or local laws or regulations. EPA UIC permits may be issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR §§144.39, 144.40 and 144.41, and may be reviewed at least once every five (5) years to determine if action is required under 40 CFR §144.36(a).

This Permit is issued for the life of the well or wells unless modified, revoked and reissued, or terminated under 40 CFR 144.39 or 144.40. This Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for this program is delegated to an Indian Tribe or a State. Upon the effective date of delegation, all reports, notifications, questions and other compliance actions shall be directed to the Indian tribe or State Program Director.

Issue Date: JAN 17 2007 Effective Date JAN 17 2007

for Stephen S. Tuber
Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

(a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:

(i) on the injection tubing; and

(ii) on the tubing-casing annulus (TCA); and

(c) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure specified in APPENDIX C is reached at the wellhead; and

(d) a non-resettable cumulative volume recorder attached to the injection line.

4. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

5. Postponement of Construction or Conversion

The Permittee shall complete well construction within one year of the Effective Date of the Permit, or in the case of an Area Permit within one year of authorization of the additional well. Authorization to construct and operate shall expire if the well has not been constructed within one year of the Effective Date of the Permit or authorization and the Permit may be terminated under 40 CFR 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. Workovers and Alterations

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

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

(b) There is no significant fluid movement into an underground source of drinking water throught vertical channels adjacent to the injection well bore (Part II).

1. *Demonstration of Mechanical Integrity (MI).*

The operator shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in Appendix B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. *Mechanical Integrity Test Methods and Criteria*

EPA-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from EPA and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. *Notification Prior to Testing.*

The Permittee shall notify the Director at least 30 days prior to any scheduled mechanical integrity test. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. *Loss of Mechanical Integrity.*

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION

INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. Requirements Prior to Commencing Injection.

Well injection, including for new wells authorized by an Area Permit under 40 CFR 144.33 (c), may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

(a) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-10 or 7520-12; all applicable logging and testing requirements of this Permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to 40 CFR 146.8 and Part II Section B of this Permit has been demonstrated; and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.

Injection is permitted only within the approved injection interval, listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. Injection Pressure Limitation

(a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs. In no case shall injection pressure cause the movement of injection or formation fluids into a USDW.

(b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permitee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

4. *Injection Volume Limitation.*

Injection volume is limited to the total volume specified in APPENDIX C.

5. *Injection Fluid Limitation.*

Injected fluids are limited to those which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, pursuant to 40 CFR 144.6(b). The well also may be used to inject approved Class II wastes brought to the surface such as drilling fluids and spent well completion, treatment and stimulation fluids. Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved. This well is NOT approved for commercial brine or other fluid disposal operation.

Fluid sources are listed in Appendix C of the Permit No. UT 21059-07147.

6. *Tubing-Casing Annulus (TCA)*

The tubing-casing annulus (TCA) shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. *Monitoring Parameters, Frequency, Records and Reports.*

Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

(a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;

(b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;

(c) the analytical techniques or methods used for analysis.

2. *Monitoring Methods.*

(a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

(b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

(c) Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.

(d) Pressures are to be measured in pounds per square inch (psi).

(e) Fluid volumes are to be measured in standard oil field barrels (bbl).

(f) Fluid rates are to be measured in barrels per day (bbl/day).

3. Records Retention.

(a) Records of calibration and maintenance, and all original strip chart 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 shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

(b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(c) The Permittee shall retain records at the location designated in APPENDIX D.

4. Annual Reports.

Whether the well is operating or not, the Permittee shall submit an Annual Report to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D. The report of fluids injected during the year must identify each new fluid source by well name and location, and the field name or facility name.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-11 may be copied and shall be used to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Section E. PLUGGING AND ABANDONMENT

1. *Notification of Well Abandonment, Conversion or Closure.*

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. *Well Plugging Requirements*

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with 40 CFR 146.10 and other applicable federal, State or local law or regulations. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.6 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. *Approved Plugging and Abandonment Plan.*

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. *Forty Five (45) Day Notice of Plugging and Abandonment.*

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abanonment plan.

5. *Plugging and Abandonment Report.*

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or

(b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. *Inactive Wells.*

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

(a) Provides written notice to the Director;

(b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and

(c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other 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 may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by 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. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 144.41. The filing of a request for modification, revocation and reissuance, 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 condition of this Permit.

2. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address.

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data.

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging , or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section 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.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, 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:

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

Section E. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. *Duty to Reapply.*

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

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 (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. *Permit Actions.*

This Permit may be modified, revoked and reissued or teminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. *Property Rights.*

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. *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. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. *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 must be 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 purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements.

All applications, reports or other information submitted to the Director shall be signed and certified according to 40 CFR 144.32. This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

(a) Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.

(b) 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.

(c) Monitoring Reports. Monitoring results shall be reported at the intervals specified in this Permit.

(d) 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 30 days following each schedule date.

(e) Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

(ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall 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, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

(g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

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

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

DRILLING OPERATIONS

At a minimum, the well will be cased and cemented. The cement will behind pipe will be adequate and protect USDWs. The drilling operations below have estimated depths and minor changes may occur due to field conditions.

Two strings of casing will be set and cemented to the surface. The surface casing will be 8-5/8" 24#/ft J-55 set at approximately 250 ft inside a 12-1/4" hole.

Cement will be circulated to surface using 129 sacks Premium cement with .25#/sack flocele and 2% Calcium Chloride. A top cement job will be pumped down the annulas thru 1" in the event the cement fallback is below ground level. If required, the top cement job will be Premium cement w/3% calcium chloride and .25#/sack flocele.

The injection casing will be 5-1/2" 15.5 #/ft J-55 set at approximately 4225 ft inside a 7-7/8" hole. Cement will be circulated to surface using 813 sacks 50/50 Poz Class G cement with 2% gel extender, 6% Halad-322, 2% Super CBL, 5% salt and .25#/sack flocele. A cement bond log will be run from plug back total depth to top of cement.

MUD PROGRAM

Surface to 250', spud mud, fresh water/lime, 8.4-8.8 lb/gal

Base surface casing to 3500', fresh water/lime, 8.4-8.8 lb/gal

3500' to total depth of 4565', low solids non-dispersed, 8.6-9.5 lb/gal
Use high viscosity gel sweeps as necessary to keep hole clean.

LOGGING PROGRAM

Operator will run FDC-CNL-PE-DIL-GR-Caliber from final total depth to the base of the surface casing.

Other

Deviation surveys will be made at least every 500' using a single shot survey.

Detailed drilling plans will be set forth on the APD.

COMPLETION OPERATIONS

The injection casing will be perforated across the injection zones. A string of 2-7/8" 6.5 lb/ft J-55 tubing will be used as the injection string. A packer will be run and set above the top perforation.

The annulas fluid between the tubing string and the 5-1/2" casing will be fresh water containing corrosion inhibitors and oxygen scavengers.

A mechanical integrity test will be conducted on the annular space between the tubing string and the 5-1/2" casing.

PROPOSED INJECTION SCHEMATIC

WELL NAME: ROCK HOUSE 10-22-31-36WD DATE: 6-Oct-06

LOCATION: NWNE SECTION 36-T10S-R22E, 1164' FNL & 1633' FEL, UINTAH CTY, UTAH

Lat 39 54' 33.81", Long 109 23' 4.88"

API #:

SPUD DATE: COMPLETIONS DATE:

RIG RELEASED:

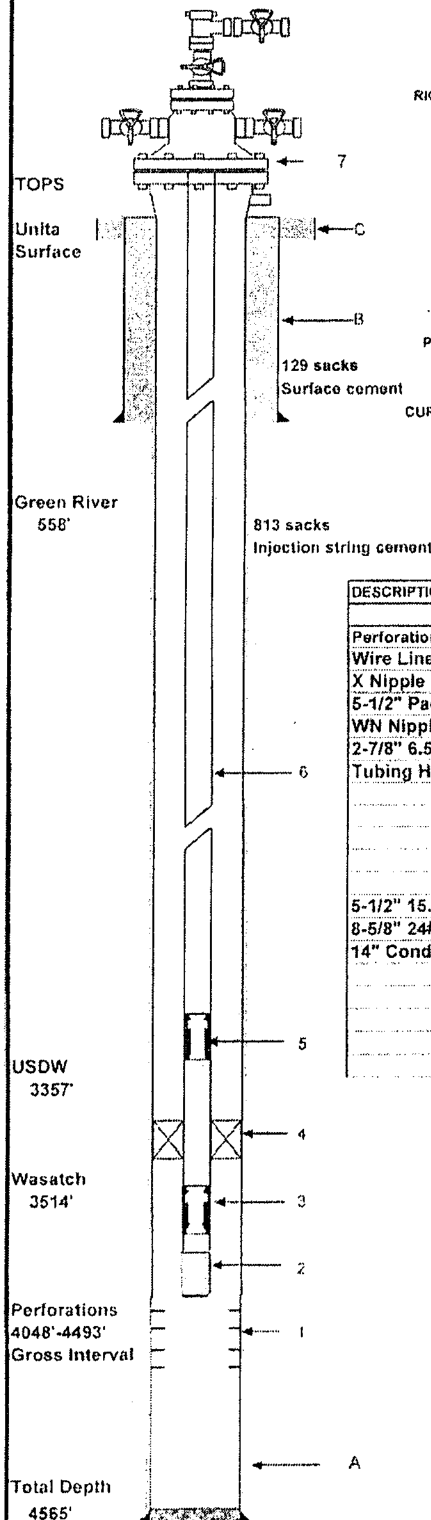
KB ELEV: Ft

GL ELEV: 5281.5 Ft

TD: 4565 Ft PBTD: 4525.00 Ft

TUBULARS:	SIZE inch	WEIGHT #/ft	GRADE	THREAD	DEPTH	OTHER
Conductor:	14				40	
SURFACE:	8-5/8	24	J-55	ST&C	250	
PRODUCTION:	5-1/2	15.5	J-55	ST&C	4565	
TUBING:	2-7/8	6.5	J-55	EUE	4000	

CURRENT ZONE: Wasatch
4048-62', 4088-97', 4103-46' & 4478-93'



DESCRIPTION (starting at the bottom)	LENGTH (ft)	DEPTH (ft)	#
BOTTOM OF TOOL STRING →		4000.00	#
Perforations 4048-62', 4088-97', 4103-46' & 4478-93'			1
Wire Line Re-Entry Guide			2
X Nipple			3
5-1/2" Packer			4
WN Nipple			5
2-7/8" 6.5 #/ft J-55 EUE lined tubing			6
Tubing Hanger			7
5-1/2" 15.#/ft J-55 ST&C		4565.00	A
8-5/8" 24# J-55 ST&C		250.00	B
14" Conductor		40.00	C

DIAGRAM NOT TO SCALE

Rock House 10-22-31-36 WD.jpg

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Logs.

Logs will be conducted according to current UIC guidance. It is the responsibility of the permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

WELL NAME: Rock House 10-22-31-36 WD

TYPE OF LOG	DATE DUE
TEMP	1 year after injection operations, 3 years after injection operations, then to be determined
Porosity	Prior to running casing
CBL/VDL/GAMMA RAY	Prior to injection and after casing is set

Tests.

Tests will be conducted according to current UIC guidance. It is the responsibility of the permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

WELL NAME: Rock House 10-22-31-36 WD

TYPE OF TEST	DATE DUE
Step Rate Test	Within 30 days of injection operations
Radioactive Tracer Survey (2)	If CBL shows insufficient cement behind pipe, then test shall be ran prior to authorization to inject and at least once every 5 years thereafter
Pressure Fall-Off Test	1 year after injection operations, 3 years after injection operations, then to be determined
Injection Zone Water Sample	Prior to injection; swab testing on formation: conductivity to be monitored for consistency prior to sample collection; salinity profile on completion fluids to be submitted
Standard Annulus Pressure	Prior to injection and at least once every 5 years thereafter
Pore Pressure	Prior to injection

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
Rock House 10-22-31-36 WD	1,165

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

Well Name	TDS (mg/L)
Rock House 2D-36	25,487
Rock House 3-32	30,746
Rock House 4-36	31,853
Rock House 6D-32	30,064
Rock House 7-32	33, 632
Rock House 11-31	29,622
Rock House 12D-32	24,922

WELL NAME: Rock House 10-22-31-36 WD

FORMATION NAME	APPROVED INJECTION INTERVAL (KB, ft) TOP	BOTTOM	FRACTURE GRADIENT (psi/ft)
Wasatch Formation	4,025.00 -	4,510.00	0.730

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

There is no limitation on the number of barrels per day (bbls/day) of water that shall be injected into this well, provided further that in no case shall injection pressure exceed that limit shown in Appendix C.

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

OBSERVE WEEKLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)

ANNUALLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH

ANNUALLY	
REPORT	Each month's maximum and averaged injection pressures (psig)
	Each month's maximum and averaged annulus pressure(s) (psig)
	Each month's averaged injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year

Records of all monitoring activities must be retained and made available for inspection at the following location:

Enduring Resources
475 Seventeenth Street, Suite 1500
Denver, CO 80202

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

All depths listed are an estimate. Actual depths will be reported after plugs are placed.

Operator will file and obtain approval for a detailed P&A plan for approval prior to initiating any P&A operations. Typical P&A operations may be as follows:

1. Set wireline bridge plug above the injection interval at approximately 4000 ft. Pressure test the casing string and the bridge plug. Dump 5 sacks cement on top of the bridge plug.

2. Go in hole with tubing and pump five 100 ft cement plugs from 3564' to 3464' across Wasatch top at 3514', from 3407' to 3307' across the USDW at 3357', from 608' to 508' across the Green River top at 558', from 300' to 200' across base of surface casing and from 100' to surface. Cement will be Class G with additives. Each 100' plug will be 12 sacks of cement.

3. Remove wellhead. Install plug and abandon marker. Remove fencing material and reclaim location.

A plugging procedure will be submitted and approval obtained with the appropriate regulatory agencies before any plugging operations are conducted.

ROPOSED PLUG AND ABANDON SCHEMATI

WELL NAME: ROCK HOUSE 10-22-31-36WD DATE: 6-Oct-06

LOCATION: NWNE SECTION 36-T10S-R22E; 1164' FNL & 1633' FEL, UINTAH CTY, UTAH

Lat 39 64' 33.81", Long 109 23' 4.88"

API #:

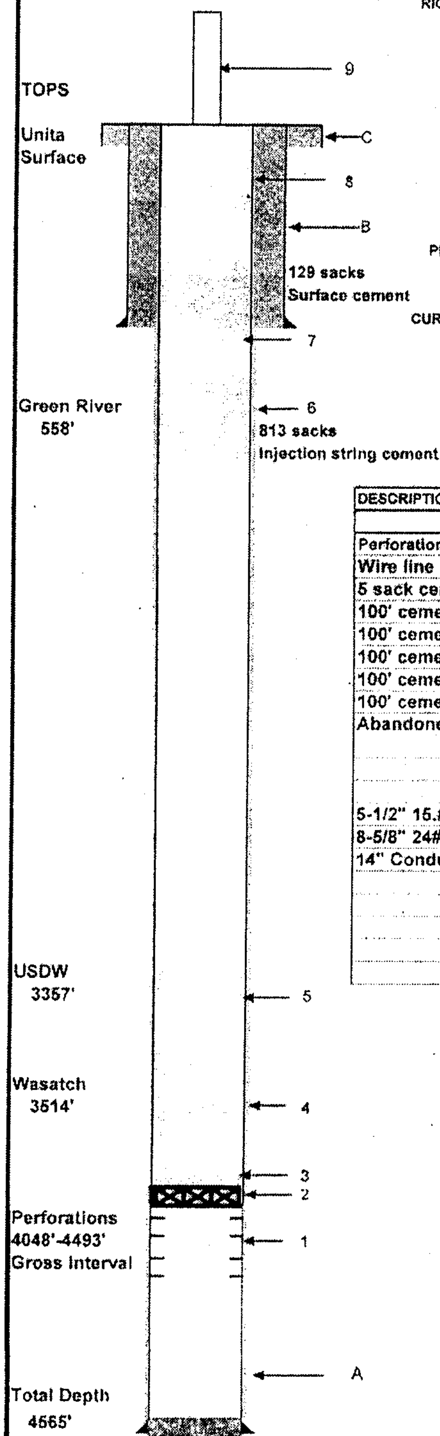
SPUD DATE: COMPLETIONS DATE:

RIG RELEASED:

KB ELEV: Ft

GL ELEV: 5281.5 Ft

TD: 4565 Ft PBTD: Ft



TUBULARS:	SIZE inch	WEIGHT #/ft	GRADE	THREAD	DEPTH	OTHER
Conductor:	14				40	
SURFACE:	8-5/8	24	J-55	ST&C	250	
PRODUCTION:	5-1/2	15.5	J-55	ST&C	4565	
TUBING:	2-7/8	6.5	J-55	EUE	4000	

CURRENT ZONE:

DESCRIPTION (starting at the bottom)	LENGTH (ft)	DEPTH (ft)	#
BOTTOM OF TOOL STRING →		4000.00	#
Perforations 4048-62', 4088-97', 4103-46' & 4478-93'			1
Wire line set bridge plug			2
5 sack cement plug, dumped with wire line bailer			3
100' cement plug from 3564' to 3464'			4
100' cement plug from 3407' to 3307'			5
100' cement plug from 608' to 508'			6
100' cement plug from 300' to 200'			7
100' cement plug from 100' to surface			8
Abandoned Well Marker			9
5-1/2" 15.#/ft J-55 ST&C		4565.00	A
8-5/8" 24# J-55 ST&C		250.00	B
14" Conductor		40.00	C

DIAGRAM NOT TO SCALE

Rock House 10-22-31-36 WD P&A.jpg

APPENDIX F

CORRECTIVE ACTION REQUIREMENTS

No corrective action is deemed necessary for this project.

STATEMENT OF BASIS

ENDURING RESOURCES LLC
ROCK HOUSE 10-22-31-36 WD
UINTAH COUNTY, UT

EPA PERMIT NO. UT21059-07147

CONTACT: Patricia Pfeiffer
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-GW
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 6271

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other federal, state or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR 144.36(a).

PART I. General Information and Description of Facility

Enduring Resources LLC
475 17th Street, Suite 1500
Denver, CO 80202

on

Resubmitted on September 20, 2006

April 3, 2006

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

Rock House 10-22-31-36 WD
1164 ft FNL & 1633 ft FEL, NWNE S36, T11S, R22E
Uintah County, UT

Regulations specific to Uintah-Ouray Indian Reservation injection wells are found at 40 CFR 147 Subpart TT.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Ute Indian Tribe or the State of Utah unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1

WELL STATUS / DATE OF OPERATION

NEW WELLS

Well Name	Well Status	Date of Operation
Rock House 10-22-31-36 WD	New	N/A

Hydrogeologic Setting

The Uinta Basin is a major sedimentary basin of the western-central Rocky Mountain province. The basin is both a structural and a topographic basin located in northeastern Utah and northwest Colorado. The surface terrain is high mountain desert in the central part of the basin, and elevations vary from approximately 5,600 feet to over 11,000 feet above sea level. The topographic basin extends about 200 miles west to east and 173 miles north to south and has an area of about 10,000 square miles. It is strongly asymmetric, bounded by the Uinta Mountain uplift on the north and by the Wasatch Mountain uplift and the eastern faulted margin of the Wasatch Plateau on the west. Dip on the southwest and southeast flanks range from a few degrees to up to 15°. The north flank is highly complex, with major faulting and steep to overturned beds. The basin is considered to be a major producer of gas for the United States. The greatest portion of the energy resources are hydrocarbons, in the forms of coal, oil and gas, bituminous sandstone and limestone, and some gilsonite. The Uintah & Ouray Indian Reservation comprises just over 4 million acres of this area, reaching from the Utah-Colorado border west to the Wasatch Mountain Range.

Groundwater hydrology of the Uinta Basin is controlled primarily by the geologic structure of the region. Recharge of groundwater is greatest near the northern edge of the basin. On the south flank of the basin, most recharge is in the areas of highest altitude where precipitation is greatest. However, because of the low dip of the south flank, few formations except the Green River Formation are exposed to recharge. The major direction of ground water flow in this portion of the Uinta Basin is predominantly toward the White River. Bitter Creek is a tributary of the White River. The White River is located approximately 3 miles to the north of the proposed well location. Bitter Creek is approximately 2.5 miles to the west.

During the Eocene time, large amounts of sediment form adjacent higher areas were deposited in various lacustrine and fluvial environments in the basin. These sediments total more that 15,000 feet thick in the center of the basin and contain important mineral resources. During the Sevier/Laramide mountain building episode, deformation (thrust faulting and downwarping) occurred in the basin. The basin had several lakes that accumulated large amounts of organic material, and later heat and pressure of burial changed the organic-rich sediment into the thick oil shale of the middle and upper Green River Formation. The geologic formations of interest for this well, in descending order, are the Uinta and Green River Formations and the Wasatch Group.

The Uinta Formation is exposed at the surface in the area of the proposed well. The Uinta is comprised of thinly bedded calcareous shale, siltstone, and fine-grained sandstone. Hydraulic conductivity of the Uinta may be greatly enhanced by naturally occurring fractures.

The Green River Formation is comprised of sandstones, limestone and shale beds that were deposited along the edges and on the broad level floor of Lake Uinta as it expanded and contracted through time. Deposition in and around Lake Uinta consisted of open to marginal lacustrine sediments that make up the Green River Formation. The cyclic nature of deposition in the southern shore area resulted in numerous stacked deltaic deposits. Distributary mouth bars, distributary channels, and near shore bars are the primary producing sandstone reservoirs in the area (Ref: "Reservoir Characterization of the Lower Green River Formation, Southwest Uinta Basin, Utah Biannual Technical Progress Report, 4/1/99 9/30/99", by C. D. Morgan, Program Manager, November 1999, Contract DE AC26 98BC15103). Intervals in which porous sandstones occur are comprised of tight sandstone and interbedded shale forming the confining layers to the individual sandstone lenses. In some areas there is complex intertonguing between the sediments of the underlying Wasatch and the Green River Formation. In the eastern portion of the basin, the

Green River thins to about 1000 ft as the lower part pinches out. Gilsonite, a naturally occurring solid amorphous asphaltic bitumen originated by solidification of petroleum, occurs in veins that fill the vertical tensional fractures in this area that are rooted in the upper Green River oil shale.

The Wasatch Group, in descending order, is divided into the Colton, Flagstaff, and North Horn Formations. The Flagstaff Formation is not present at the proposed well location. The Colton is described as being primarily sandstone with mudstone (shale) and minor limestone. The sandstone units are characterized by mud chips, mud clasts, and discontinuous finer-grained beds. The Colton displays complex reservoir geometry, and heterogeneity is typical. The North Horn consists of conglomerate, sandstone, siltstone, and lacustrine limestone and shale. The basal unit consists of thin lacustrine shale and lime wackestone overlain by variegated floodplain mudstones and fine-grained fluvial sandstones.

Geologic Setting (TABLE 2.1)

TABLE 2.1
GEOLOGIC SETTING
Rock House 10-22-31-36 WD

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Uinta Formation	0.00	558.00	0.00 - 3,000.00	calcareous shale, some limestone, claystone, and sandstone
Green River Formation	558.00	3,514.00	0.00 - 3,000.00	greensih-gray shales with interbedded sandstone, marlstone, limestone, oil-shale and trona
Wasatch Formation	3,514.00	5,507.00	3,000.00 - 35,000.00	shale and claystone with interbedded conglomerate and sandstone
Mesaverde Formation	5,507.00	8,172.00	10,000.00 - 35,000.00	interbedded sandstone, siltstone, and shale with minor coal beds

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

The Wasatch is the proposed injection zone. EPA has evaluated the capacity of the proposed injection zone to accept fluids, using porosity data and the effective height from the Rock House 10-22-31-36 production well located approximately 235 feet to the northwest. The portion of the Wasatch Formation proposed for injection was calculated to have a cumulative volume capacity of approximately 11,328,013 barrels within the quarter mile area of review.

An Injection Profile Survey, using either a spinner or tracer test, will be required prior to injection. Along with a profile of fluid loss versus depth, these data provide an indication of the absence of fluid channeling away from the well bore, and also can be used to determine an accurate volume that the formation can receive should an aquifer exemption be necessary. Other data to be collected includes temperature, caliper, and casing collar locator logs.

Formation fluid sampling and analysis of the injection zone will be required during drilling and completion of the well. Swab testing will be conducted, with conductivity monitored for consistency before the sample is collected. The operator will also provide a salinity profile on the completion fluids.

If the injection zone is shown to contain fluids of less than 10,000 mg/l total dissolved solids (TDS), an aquifer exemption will be required prior to approval for injection.

TABLE 2.2

INJECTION ZONES

Rock House 10-22-31-36 WD

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Wasatch Formation	4,025.00	4,510.00	3,000.00 - 35,000.00	0.730		N/A

* **C - Currently Exempted**
E - Previously Exempted
P - Proposed Exemption
N/A - Not Applicable

Confining Zone(s) (TABLE 2.3)

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

Impermeable intervals of the Wasatch are identified as the confining zones that will prevent migration of fluid outside of the injection zone. The following estimated depths are based on wireline logs of the Rock House 10-22-31-36 production well, located approximately 153 feet to the northeast.

1. The upper confining zone, a 385 foot section of shale and claystone, is estimated at between 3625-4010 feet below ground surface.

2. The lower confining zone, a 107 foot section that consists primarily of shale and claystone, is estimated at between 4593-4700 feet below ground surface.

Gilsonite veins in the Uinta Basin vary in width from fractions of an inch to almost 18 feet, and average about 3 to 6 feet. These veins can be vertically continuous for hundreds to approximately 2,000 feet and more. Because there is concern that the fractures associated with these gilsonite veins could act as conduits for the fluid migration out of the proposed injection zone, a pressure falloff test and temperature survey will be required after 1 year and after 3 years of operation to evaluate continuing confinement of injection fluid within the injection zone. If confinement is not confirmed, EPA may consider limiting injection rates or prohibiting injection, if necessary to protect underground sources of drinking water.

TABLE 2.3
CONFINING ZONES
Rock House 10-22-31-36 WD

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Wasatch Formation-Upper	primarily shale and claystone	3,625.00	4,010.00
Wasatch Formation-Lower	primarily shale and claystone	4,593.00	4,700.00

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

Based on the Technical Publication No. 92, Utah Department of Natural Resources, the base of USDWs at the proposed well location is found at 3,356 feet below ground surface. However, according to published information, water in the Uinta, Green River, and Wasatch aquifers has been found to range from fresh to briny. Therefore, unless water samples are collected and prove otherwise, these will be considered to be USDWs.

The Douglas Creek-Renegade aquifer, consisting of the Douglas Creek Member of the Green River Formation and the Renegade Tongue of the Wasatch Formation, is a basin-wide aquifer underlying the Duchesne River-Uinta aquifer. The Douglas Creek-Renegade aquifer is thick, and has a hydraulic conductivity ranging from 0.05 to 0.25 ft/d in the southeastern part of the Uinta Basin (Holmes and Kimball, 1983).

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
Rock House 10-22-31-36 WD

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Uinta Formation	calcareous shale, some limestone, claystone, and sandstone	0.00	558.00	0.00 - 3,000.00
Green River Formation	greenish-gray shales with interbedded sandstone, marlstone, limestone, oil-shale and trona; USGS Pub No. 92 places base of USDW at 3356 ft bgs	558.00	3,514.00	0.00 - 3,000.00
Wasatch Formation	shale and claystone with interbedded conglomerate and sandstone	3,514.00	5,507.00	3,000.00 - 35,000.00

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
Rock House 10-22-31-36 WD

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
surface	12.25	8.63	0.00 - 250.00	0.00 - 250.00
longstring	7.88	5.50	0.00 - 4,565.00	0.00 - 4,565.00

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)

The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of Part II (External) mechanical integrity.

Tubing and Packer

Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)

The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

Monitoring Devices

The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
Rock House 10-22-31-36 (2D-36)	Producer	No	8,250.00	1,830.00	Yes
Rock House 10-22-32-36	Producer	No	7,760.00	1,300.00	No
Rock House 10-22-41-36	Producer	No	7,850.00	1,110.00	No
Rock House 10-22-42-36	Producer	No	7,840.00	2,605.00	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

Area Of Review

Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

After reviewing the State of Utah, Division of Water Rights web page, it was determined that there are no water wells in the AOR.

The Rock House 10-22-31-36 production well is located approximately 253 feet to the northwest of the proposed well location. A CBL must be analyzed for this well prior to authorization for injection. If inadequate cement is found behind the pipe, then corrective action will be required prior to authorization for injection.

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

PART V. Well Operation Requirements (40 CFR 146.23)

Enduring Resources will be the sole operator of the proposed Rock House 10-22-31-36 WD injection well. To monitor and record injection pressures, each well head will be equipped with a pressure chart that will be read by an approved Enduring Resources employee (pumper) on a weekly basis. Electronic data from the pressure chart will be checked daily for accuracy and compliance with system requirements.

Enduring Resources is requiring truck drivers hauling disposable water to the wells to be pre-qualified and be identified with a truck number and driver number. No driver will be able to enter the site without pre-authorization. No water will be accepted from any industrial process or from fracture fluids, or from any source other than those pre-screened and pre-approved by Enduring Resources and approved by the EPA. Enduring Resource will be maintaining chain of custody documentation.

The Rock House 10-22-31-36 WD injection well will be enclosed inside a chain link fence. All fence gates will be locked and keys or entrance codes will only be provided to authorized Enduring Resources employees or contractors.

TABLE 5.1
INJECTION ZONE PRESSURES
Rock House 10-22-31-36 WD

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Wasatch Formation	4,025.00	0.730	1,160

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to 40 CFR § 144.6(b). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, is prohibited.

Well Name	TDS (mg/L)
Rock House 2D-36	25,487
Rock House 3-32	30,746
Rock House 4-36	31,853
Rock House 6D-32	30,064
Rock House 7-32	33, 632
Rock House 11-31	29,622
Rock House 12D-32	24,922

Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

A step rate test will be required for the proposed injection zone to determine the fracture gradient for the zone. The initial Maximum Allowable Injection Pressure (MAIP) of 1,165 psi, based on an estimated fracture gradient of 0.73 psi/ft, will initially be approved until results of the step rate test are evaluated.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit,

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Mechanical Integrity (40 CFR 146.8)

An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

If the cement bond log shows adequate casing cement of at least eighteen (18) feet of effective 80% bond index cement bond across or through the upper Confining Zone, Part II (External) mechanical integrity is considered to be demonstrated. If the new, centralized CBL is not able to identify adequate casing cement, a radioactive tracer survey (RTS) will be required within a 90day period following commencement of injection, and the Part II MI demonstration, using a temperature log, noise log, or RTS, is required at least once every five years thereafter.

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, injection flow rate and cumulative fluid volume, and the maximum and average value for each must be determined for each month. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with other applicable federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.6 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

Surety Bond, received October 10, 2006

Evidence of continuing financial responsibility is required to be submitted to the Director annually.

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SUBJECT: **GROUND WATER SECTION GUIDANCE NO. 34:** ***Cement bond logging techniques and interpretation***

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

These procedures are to be followed when running and interpreting cement bond logs for injection and production (area of review) wells.

PART I - PREPARE THE WELL

Allow cement to cure for a sufficient time to develop full compressive strength. A safe bet is to let the cement cure for 72 hours. If you run the bond log before the cement achieves its maximum compressive strength, the log may show poor bonding. Check cement handbooks for curing times.

Circulate the hole with a fluid (either water or mud) of uniform consistency. Travel times are influenced by the type of fluid in the hole. If the fluid changes between two points, the travel times may "drift," causing difficulty in interpretation and quality control.

Be prepared to run the cement bond log under pressure to reduce the effects of micro-annulus. Micro-annulus may be caused by several reasons, but the existence of a micro-annulus does not necessarily destroy the cement's ability to form a hydraulic seal. If the log shows poor bonding, rerun the log with the slightly more pressure on the casing as was present when the cement cured. This will cause the casing to expand against the cement and close the micro-annulus.

PART II - PARAMETERS TO LOG

Amplitude (mV) - This curve shows how much acoustic signal reaches a receiver and is an important indicator of cement bond. Record the amplitude on the 3 foot spaced receiver.

Travel time (µs) - This curve shows the amount of time it takes an acoustic signal to travel between the source and a receiver. For free pipe of a given size and weight, the travel time between points is very predictable although variable among different company's tools. Service companies should be able to provide accurate estimates of travel times for free pipe of a given size and weight. Travel time is required as a quality control measurement. Record the travel time on the 3 foot spaced receiver.

Variable density (VDL) - Pipe signals, formation signals, and fluid signals are usually easy to recognize on the VDL. If these signals can be identified, a practical determination for the presence or absence of cement can be made. VDL is logged on the 5 foot spaced receiver.

Casing collar locator (CCL) - Used to correlate the bond log with cased hole logs and to match casing collars with the collars that show up on the VDL portion of the display.

Gamma ray - Used to correlate the bond log with other logs.

PART III - LOGGING TECHNIQUE

Calibrate the tool in free pipe at the shop, prior to, and following the log run. Include calibration data with log.

Run receivers spaced 3 feet and 5 feet from transmitter.

Run at least 3 bow-type or rigid aluminum centralizers in vertical holes, 6 centralizers in directional holes. A CCL is not an adequate centralizer.

Complete log header with casing/cement data, tool/panel data, gate settings and tool sketch showing centralizers.

Set the amplitude gate so that skipping does not occur at amplitudes greater than 5 mV.

Record amplitude with fixed gate, and note position on log.

Record amplified amplitude on a 5X scale for low amplitudes.

Record amplitude and travel time on the 3 foot receiver.

Record travel time on a 100 μs scale (150 - 250, 200 - 300).

Logging speed should be approximately 30 ft/min.

Log repeat sections.

PART IV - QUALITY CONTROL

Compare the tool calibration data to see if the tool "drifts" during logging. Differences in the calibration data may require you to re-log the well to obtain reliable data.

Compare repeat sections to see if logging results are repeatable.

Check the logged free pipe travel times with the service company charts for the specific tool and casing size used. Since the travel times depend on such factors as casing weight, type of fluid in the hole, etc., these charts should be used only as guidelines. When you are confident of the free-pipe travel times as seen on the log, use them.

When interpreting the log, a decrease in travel time (faster times) with simultaneous reduction of amplitude may show a de-centered tool.

A 4 to 5 micro-second (μs) decrease in travel time corresponds to about a 35% loss of amplitude. A decrease in travel time more than 4 to 5 μs is unacceptable.

PART V - LOG INTERPRETATION

Do not rely on the service company charts for amplitudes corresponding to a good bond. These amplitudes depend on many factors: type of cement used, fluid in the hole, etc.

To estimate bond index, choose intervals on the log that correspond to 0% bond and 100% bond. Read the amplitude corresponding to 100% bond from the best-bonded interval on the log (NOTE: the accuracy of this amplitude reading is very critical to the bond index calculations). Next, find the amplitude corresponding to 0% bond. Some bond logs may not include a section with free pipe. In this instance, choose the appropriate free-pipe travel time from the service company charts for your specific tool, or from the generalized chart (TABLE 2) at the end of this guidance. To calculate a bond index of 80%, use the following equation:

Where: A_{80} = Amplitude at 80% bond (mV)

$$A_{80} = 10^{[(0.2)\log(A_0)+(0.8)\log(A_{100})]}$$

A_0 = Amplitude at 0% bond (mV)
A_{100} = Amplitude at 100% bond (mV)

EXAMPLE:

As an example, consider a bond log showing the following conditions:

- Free pipe (0% bond) amplitude at 81 mV
- 100 % bond amplitude at 1 mV.

Substituting the above values into the equation results in:

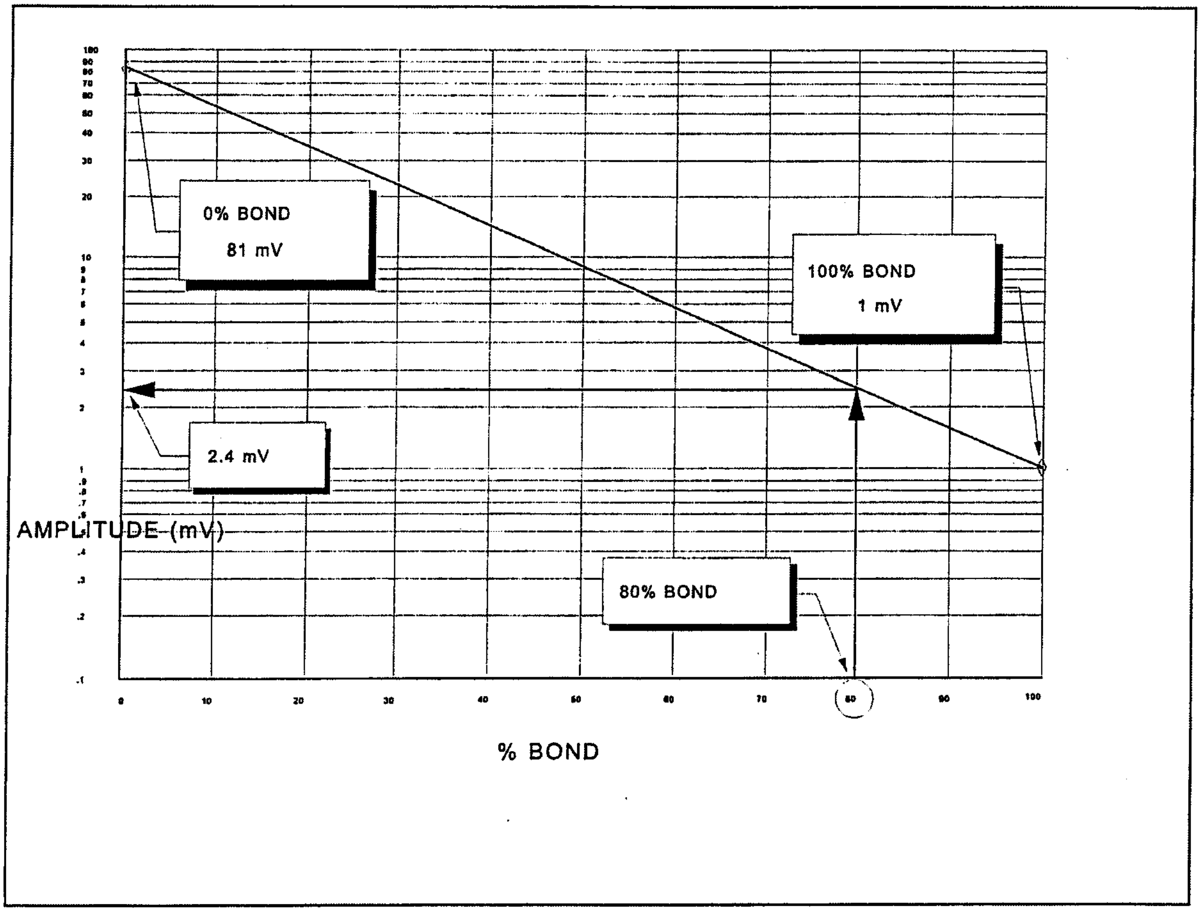
$$A_{80} = 10^{[(0.2)\log(81)+(0.8)\log(1)]}$$

$$A_{80} = 2.41mV$$

Another way to calculate the amplitude at 80% bond is by plotting these same log readings on a semi-log chart.

Plot the values for 0% Bond and 100% Bond vs. their respective Amplitudes on a semi-log chart - amplitudes on the log scale (y-axis), and bond indices on the linear scale (x-axis). Then, connect the points with a straight line. To estimate the amplitude corresponding to an 80% Bond Index, enter the graph on the x-axis at 80% bond. Draw a straight line upward until you reach the diagonal line connecting the 0% and 100% points. Continue by drawing a horizontal line to the y-axis. This point on the y-axis is the amplitude corresponding to an 80% Bond Index.

Using the values from the example above, your chart will look like that shown below:



In this example, 80% bond shows an amplitude of 2.4 mV.

A convenient way to evaluate the log is to draw a line on the bond log's **amplified** amplitude (5X) track corresponding to the calculated 80% bond amplitude. Whenever the logged **amplified** amplitude (5X) curve drops below (to the left of) the drawn line, this indicates a bond of 80% or more.

PART IV - CONCLUSIONS – REMINDERS

Different pipe weights and cement types will affect the log readings, so be mindful of these factors in wells with varying pipe weights and staged cement or squeeze jobs.

Collars generally do not show up on the VDL track in well- bonded sections of casing.

Longer (slower) travel time due to cycle skipping or cycle stretch usually suggests good bonding.

Shorter (faster) travel times indicate a de-centered tool or a fast formation and will provide erroneous amplitude readings that make evaluation impossible through that section of the log. Fast formations do not assure that the cement contacts the formation all around the borehole.

Although the bond index is important, you should not base your assessment of the cement quality on that one factor alone. You should use the VDL to support any indication of bonding. Also, you must know how each portion of the CBL (VDL, travel time, amplitude, etc.) influences another.

Most 3'-5' CBL's cannot identify a 1/2" channel in cement. Therefore, you also need to consider the thickness of a cemented section needed to provide zone isolation. For adequate isolation in injection wells, the log should indicate a continuous 80% or greater bond through the following intervals as seen in TABLE 1, below:

TABLE 1 - INTERVALS FOR ADEQUATE BOND

PIPE DIAMETER (in)	***CONTINUOUS INTERVAL WITH BOND $\geq$ 80% (ft)***
4-1/2	15
5	15
5-1/2	18
7	33
7-5/8	36
9-5/8	45
10-3/4	54

<u>Adequately bonded cement by itself will not prevent fluid movement</u>

If the bond log shows adequate bond through an interval where the geology allows fluid to move (permeable and/or fractured zones), fluids may move around perfectly bonded cement by traveling through the formation.

<u>Always</u> cross-check your bond log with open hole logs to see that you have adequate bonding through the proper interval(s).

TABLE 2 - TRAVEL TIMES AND AMPLITUDES FOR FREE PIPE (3 FT RECEIVER)

CASING SIZE (in)	*CASING WEIGHT (lb/ft)*	*TRAVEL TIME (µs)* *1-11/16" TOOL*	*TRAVEL TIME (µs)* *3-5/8" TOOL*	*AMPLITUDE (mV)*
4-1/2	9.5	252	233	81
	11.6	250	232	81
	13.5	249	230	81
5	15.0	257	238	76
	18.0	255	236	76
	20.3	253	235	76
5-1/2	15.5	266	248	72
	17.0	265	247	72
	20.0	264	245	72
	23.0	262	243	72
7	23.0	291	271	62
	26.0	289	270	62
	29.0	288	268	62
	32.0	286	267	62
	35.0	284	265	62
	38.0	283	264	62
7-5/8	26.4	301	281	59
	29.7	299	280	59
	33.7	297	278	59
	39.0	295	276	59
9-5/8	40.0	333	313	51
	43.5	332	311	51
	47.0	330	310	51
	53.5	328	309	51
10-3/4	40.5	354	333	48
	45.5	352	332	48
	51.0	350	330	48
	55.5	349	328	48

UNITED STATES
ENVIRONMENTAL
PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 300

SUBJECT: **GROUND WATER SECTION GUIDANCE NO. 35**
Procedures to follow when excessive annular pressure is observed on a well.

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

The following procedure is intended as an aid to UIC field inspectors when they encounter excessive annular pressure on a well. Excessive annular pressure is defined as 100 psi or 10% of the tubing pressure, whichever is less.

Usually, annular pressure is a direct indication of a loss of mechanical integrity. In some instances, recurring annular pressure may be caused by fluctuations in the temperature of the injected fluid. These temperature fluctuations may cause the annular pressure to increase when a hot fluid is being injected and decrease as the temperature of the injected fluid cools. The presence of temperature-induced pressure on the annulus does not indicate a malfunction in the casing/tubing/packer system and is not considered a loss of mechanical integrity. Wells exhibiting recurring temperature-induced annular pressure may be allowed to continue injecting if a temperature monitoring program is approved and followed.

This guidance was written to help determine the cause of annular pressure. When the procedures in this guidance are followed, any major mechanical integrity problems (a breech in the casing/tubing/packer system) will become apparent quickly. A quick determination will allow the operator to begin follow-up procedures immediately to prevent contamination to USDWs.

Use Section Guidance No. 35 to determine <u>if</u> the well has experienced a loss of mechanical integrity. If you find that there <u>is</u> a loss of mechanical integrity, use *Headquarters Guidance No. 76. - Follow-up to loss of Mechanical Integrity for Class II Wells* to bring the well back into compliance. The use of Section Guidance No. 35 is not to be confused with, nor does it supersede any provision of Headquarters Guidance No. 76. Instead, the two guidance documents are meant to work together to identify and to remedy any potential mechanical integrity failure.

A flowchart for Section Guidance No. 35 is included for quick reference in the field.

PROCEDURES TO FOLLOW WHEN EXCESSIVE ANNULAR PRESSURE IS OBSERVED

During field inspections, the following procedures should be followed when excessive annular pressure is observed. Excessive annular pressure is defined as 100 psi or 10% of the tubing pressure, whichever is less.

Note Conditions at the Well	Note tubing and annular pressure readings, and the operating status of the well (injecting, shut-in, etc.) on the UIC inspection form.	
See If Annulus Pressure Will Bleed-off	Attempt to bleed the pressure from the annulus by having the operator open the annulus (for a maximum of sixty seconds). It is the operator's responsibility to collect and dispose of any fluids bled from the annulus.	
Did the Annular Pressure Bleed to 0 Psi Within Sixty Seconds?	YES Have the operator close the annulus. On your inspection form note the volume of fluid (or gas) bled from the annulus during the sixty seconds, and the tubing and annulus pressures.	NO Have the operator close the annulus. On your inspection form note the volume of fluid (or gas) bled from the annulus during the sixty seconds, and the tubing and annulus pressures. Have the operator shut the well in for 2 hours, and if possible, bleed pressure from the injection tubing. Record the tubing and annulus pressure after two hours. Bleed off the annulus for 60 seconds. Record the tubing and annulus pressures after bleed-off, and estimate the volume bled off. INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES. **END PROCEDURE.**

See If Pressure Returns Within 15 Minutes	Continue to monitor the well for annulus pressure return for at least 15 minutes after the annulus valve is closed.	
Does Pressure Return to the Annulus after 15 Minutes?	YES On your inspection form, note the annulus and tubing pressures recorded after 15 minutes.	NO Require the operator to monitor and report to EPA with the annulus and tubing pressures for at least 14 days to see if pressure returns to the annulus.

	Have the operator shut the well in for 2 hours, and if possible, bleed pressure from the injection tubing. Record the tubing and annulus pressure after two hours. Bleed off the annulus for 60 seconds. Record the tubing and annulus pressures after bleed-off, and estimate the volume bled off. INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES. **END PROCEDURE.**	Instruct the operator to contact EPA as soon as any pressure returns to the annulus.
<u>DOES PRESSURE RETURN TO THE ANNULUS WITHIN 14 DAYS?</u>	<u>YES</u> EPA Technical Expert will design a proper Mechanical Integrity test. Compliance officer will require the operator to conduct the test within 14 days.	<u>NO</u> The well is considered to have mechanical integrity. **END PROCEDURE.**

<u>Does the Well Pass the MIT?</u>	<u>YES</u> Require the operator to monitor and report to EPA with the annulus and tubing pressures for at least 14 days to see if pressure returns to the annulus. Instruct the operator to contact EPA as soon as any pressure returns to the annulus.	<u>NO</u> INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES.**END PROCEDURE.**
<u>Does Pressure Return to the Annulus Within 14 Days?</u>	<u>YES</u> EPA Technical Expert will design a proper Monitoring Program to determine the cause of recurrent annular pressure. Compliance officer will require the operator to begin the Monitoring program within 14 days. Conduct unannounced inspections at the	<u>NO</u> The well is considered to have mechanical integrity. **END PROCEDURE.**

	well during the Monitoring Program.	
Is the Annulus Pressure Caused by Temperature?	YES EPA Technical Expert will design a proper Temperature Monitoring Program that allows injection to continue while tracking relationship between temperature and recurrent annulus pressure. Compliance officer will require the operator to cease injection immediately if the operator fails to follow the Temperature Monitoring Program. Compliance officer will require the operator to cease injection immediately if recurrent annular pressures cannot be explained by the results of the Temperature Monitoring Program. Compliance officer will require annual Mechanical Integrity Tests using the standard pressure method.	NO INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES. **END PROCEDURE.**

14-DAY PRESSURE MONITORING

Please use this form to report data for a 14-day period after pressure is bled from the tubing-casing annulus. Please telephone EPA in Denver as soon as possible when/if pressure returns to the annulus. This data will be used to determine the cause(s) of recurrent annular pressure.

NOTE: DO NOT BLEED PRESSURE FROM ANNULUS DURING THE 14-DAY MONITORING PERIOD.

	DATE	TIME	ANNULUS PRESSURE (psi)	TUBING PRESSURE (psi)	WELL INJECTING (YES/NO)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					

WELL NAME: ______________________________

OPERATOR: ______________________________

SIGNATURE: ______________________________ DATE: ____________________

UNITED STATES
ENVIRONMENTAL
PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 300

SUBJECT: **GROUND WATER SECTION GUIDANCE NO. 37**
Demonstrating Part II (external) Mechanical Integrity for a Class II injection well permit.

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

During the review for a Class II injection well permit, consideration must be given to the mechanical integrity (MI) of the well. MI demonstrates that the well is in sound condition and that the well is constructed in a manner that prevents injected fluids from entering any formation other than the authorized injection formation.

A demonstration of MI is a two part process:

PART I - **INTERNAL MECHANICAL INTEGRITY** is an assurance that there are no significant leaks in the casing/tubing/packer system.

PART II - **EXTERNAL MECHANICAL INTEGRITY** demonstrates that after fluid is injected into the formation, the injected fluids will not migrate out of the authorized injection interval through vertical channels adjacent to the wellbore.

A Class II injection well may demonstrate Part II MI by showing that injected fluids remain within the authorized injection interval. This may be accomplished as follows:

1) Cement bond log showing 80% bond through the an appropriate interval (Section Guidance 34),

2) Radioactive tracer survey conducted according to a EPA-approved procedure, or

3) Temperature survey conducted according to a EPA-approved procedure (Section Guidance 38).

For each test option above, the operator of the injection well should submit a plan for conducting the test. The plan will then be approved (or modified and approved) by EPA. EPA's pre-approval of the testing method will assure the operator that the test is conducted consistent with current EPA guidance, and that the test will provide meaningful results.

Part II MI may be demonstrated either before or after issuing the Final Permit. However, if Part II is to be demonstrated after the Final Permit is issued, a provision in the permit will require the demonstration of Part II MI. The well will also be required to pass Part II MI prior to granting authorization to inject.

Radioactive tracer surveys and temperature surveys require that the well be allowed to inject fluids as part of the procedure. In these cases, a well that has shown no other demonstration of Part II MI will be allowed to inject only that volume of fluid that is necessary to conduct the appropriate test.

After the results of the test proves that the well has passed Part II MI, the well will be given authorization to begin full injection operations.

If any of the tests show a lack of Part II MI, the well will be repaired and retested, or plugged (See Headquarters Guidance #76).

UNITED STATES
ENVIRONMENTAL
PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 300

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

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

Introduction

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

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

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

Definition: Mechanical Integrity Pressure Test for Part I. A pressure test used to determine the integrity of all the down hole components of an injection well, usually tubing, casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer. Pressure tests must be run at least once every five years. **If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the attached form or an equivalent form containing the necessary information. A pressure recording chart documenting the actual annulus test pressures must be attached to the form.**

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or packer). The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region VIII Primacy programs; and 4) to provide a

<u>procedure which can be easily administered and is applicable to all class I and II wells.</u> Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region VIII's procedure for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

Pressure Test Description

Test Frequency

The mechanical integrity of an injection well must be maintained at all times. Mechanical integrity pressure tests are required <u>at least</u> every five (5) years. **If for any reason the tubing/packer is pulled, however, the injection well is required to pass another mechanical integrity test prior to recommencing injection regardless of when the last test was conducted. <u>The Regional UIC program must be notified of the workover and the proposed date of the pressure test.</u> The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate.** Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells).

Region VIII's criteria for well testing frequency is as follows:

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

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

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

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

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

6. Class III uranium extraction wells; initially.

Test Pressure

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

Test Criteria

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

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

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

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

Recordkeeping and Reporting

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

Procedures for Pressure Test

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

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

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

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

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

Following steps are at the well:

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

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

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

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

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

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

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

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

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

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

16. Return to office and prepare follow-up.

Alternative Test Option

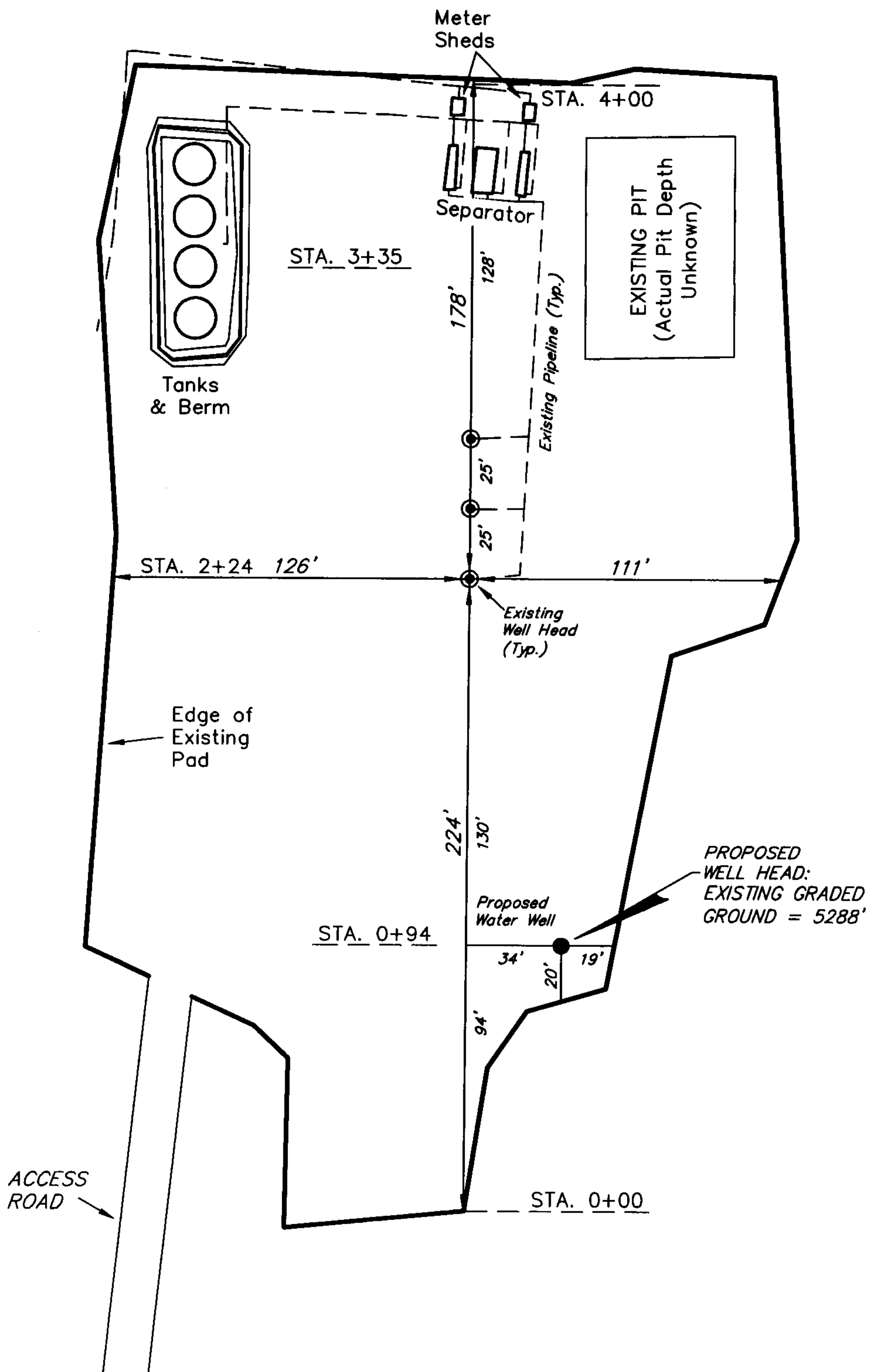
While it is expected that the test procedure outlined above will be applicable to most wells, the potential does exist that unique circumstances may exist for a given well that precludes or makes unsafe the application of this test procedure. In the event that these **exceptional or extraordinary** conditions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

Attachment

ENDURING RESOURCES

ROCK HOUSE 10-22-31-36 WD

Pad Location: NWNE Section 36, T10S, R22E, S.L.B.&M.



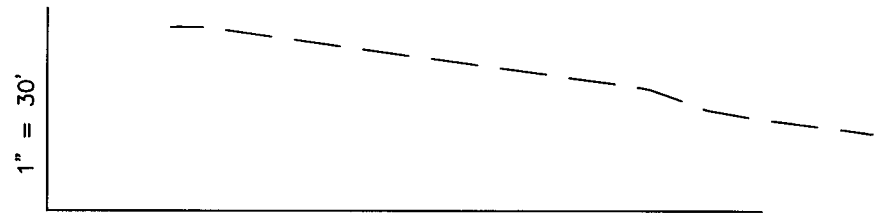
SURVEYED BY: K.G.S.	DATE DRAWN: 01-09-07	Tri State Land Surveying, Inc. (435) 781-2501 180 NORTH VERNAL AVE. VERNAL, UTAH 84078	SHEET 3 OF 10
DRAWN BY: F.T.M.	SCALE: 1" = 60'		
NOTES:			

ENDURING RESOURCES

CROSS SECTIONS

ROCK HOUSE 10-22-31-36 WD

Pad Location: NWNE Section 36, T10S, R22E, S.L.B.&M.



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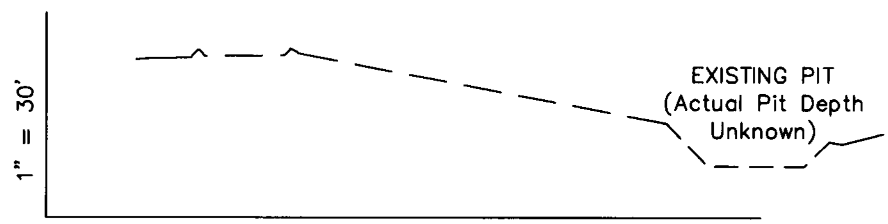

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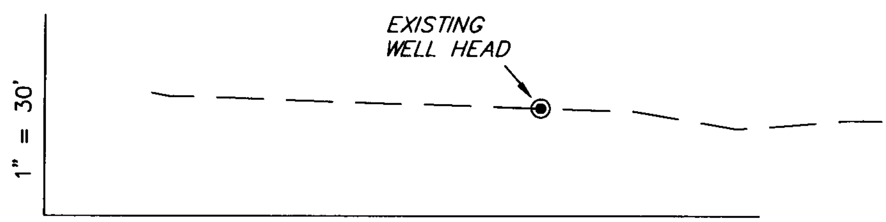

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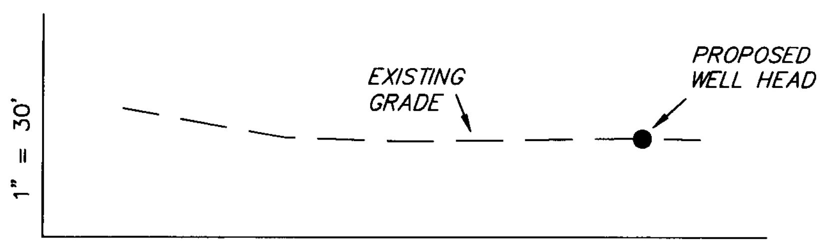

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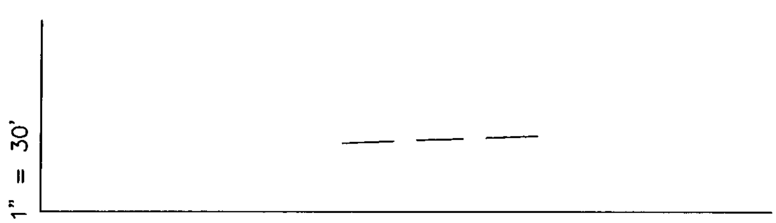


1" = 60'   STA. 0+00

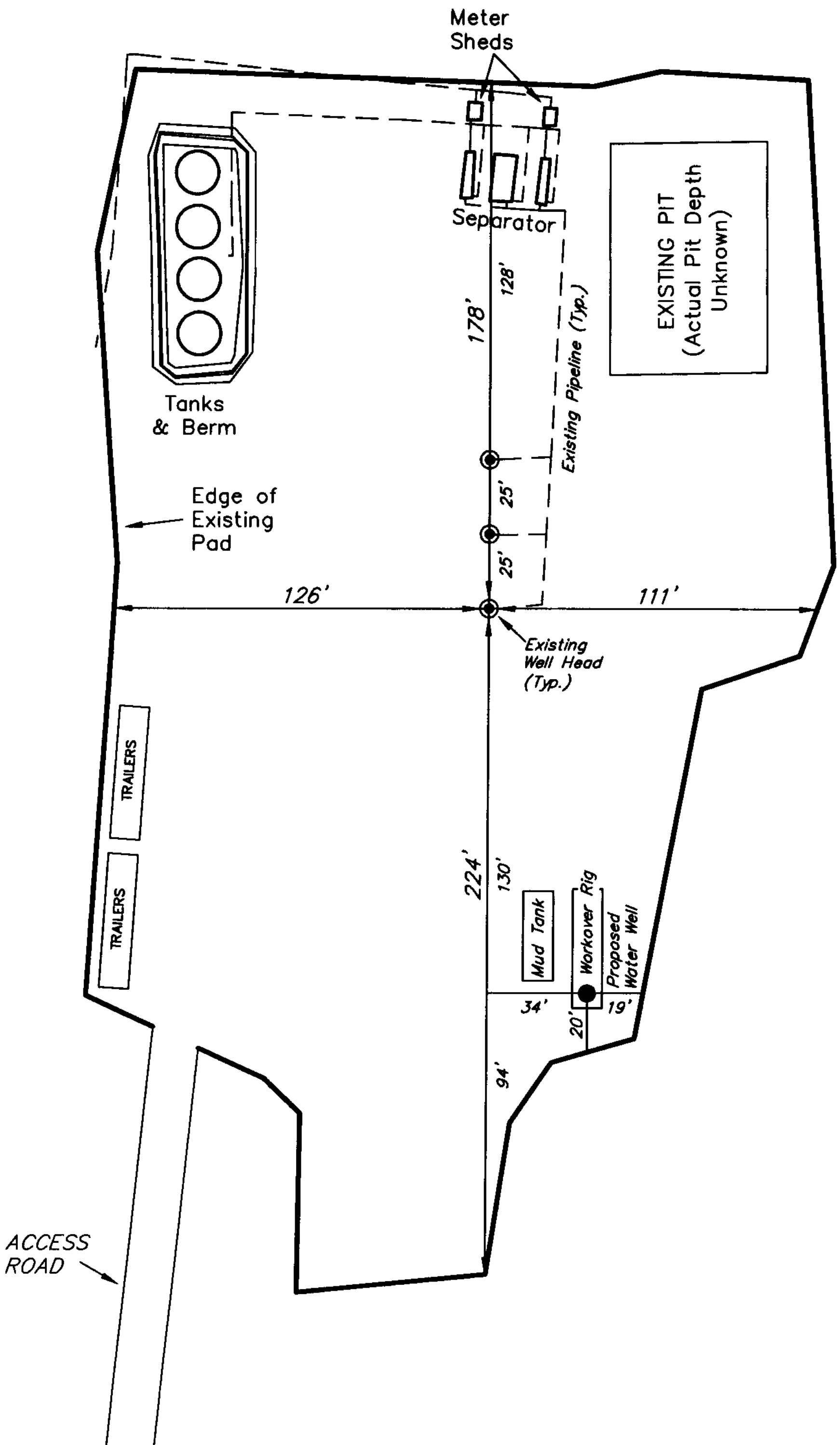
SURVEYED BY:	K.G.S.	DATE DRAWN:	01-09-07	Tri State Land Surveying, Inc. (435) 781-2501 180 NORTH VERNAL AVE. VERNAL, UTAH 84078	SHEET 4 OF 10
DRAWN BY:	F.T.M.	SCALE:	1" = 60'		
NOTES:					

ENDURING RESOURCES

TYPICAL RIG LAYOUT

ROCK HOUSE 10-22-31-36 WD

Pad Location: NWNE Section 36, T10S, R22E, S.L.B.&M.



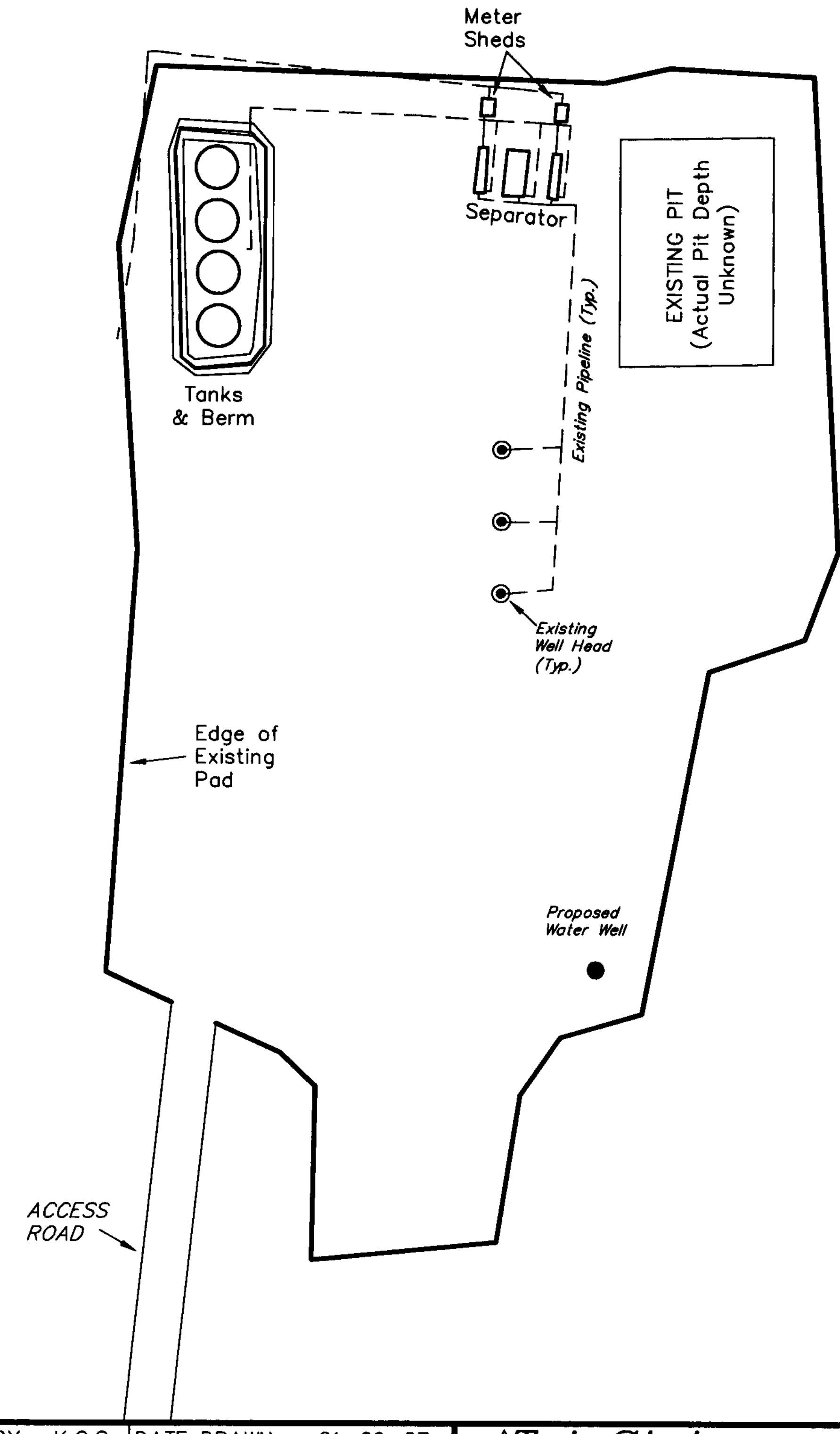
SURVEYED BY: K.G.S.	DATE DRAWN: 01-09-07	Tri State Land Surveying, Inc. (435) 781-2501	SHEET
DRAWN BY: F.T.M.	SCALE: 1" = 60'	180 NORTH VERNAL AVE. VERNAL, UTAH 84078	5
NOTES:			OF 10

ENDURING RESOURCES

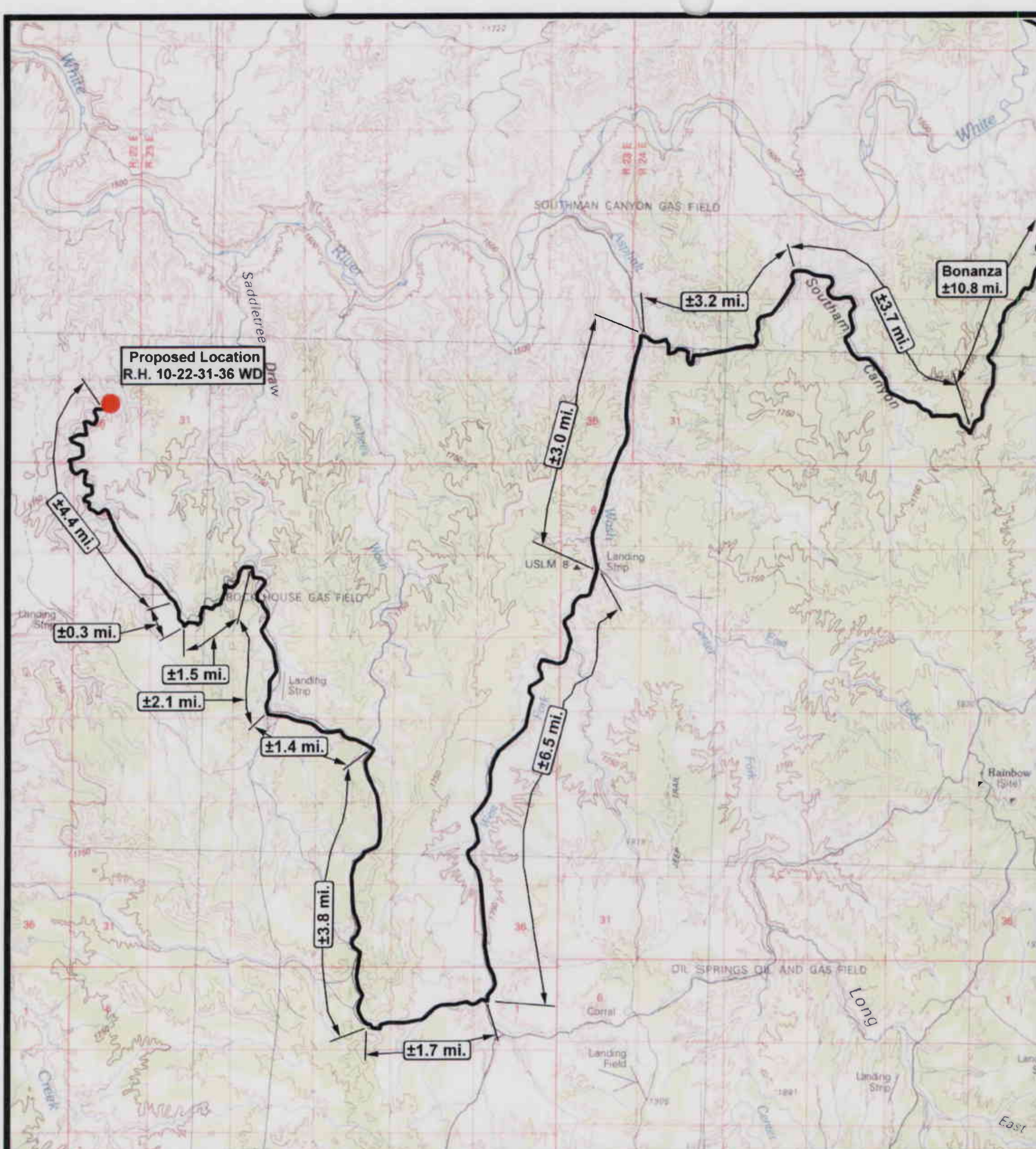
PRODUCTION SCHEMATIC

ROCK HOUSE 10-22-31-36 WD

Pad Location: NWNE Section 36, T10S, R22E, S.L.B.&M.



SURVEYED BY: K.G.S.	DATE DRAWN: 01-09-07	Tri State Land Surveying, Inc.	(435) 781-2501		SHEET 6 OF 10
DRAWN BY: F.T.M.	SCALE: 1" = 60'	180 NORTH VERNAL AVE.	VERNAL, UTAH 84078		
NOTES:					



ENDURING RESOURCES

Tri-State Land Surveying Inc.
(435) 781-2501
180 North Vernal Ave. Vernal, Utah 84078

Legend

Existing Road

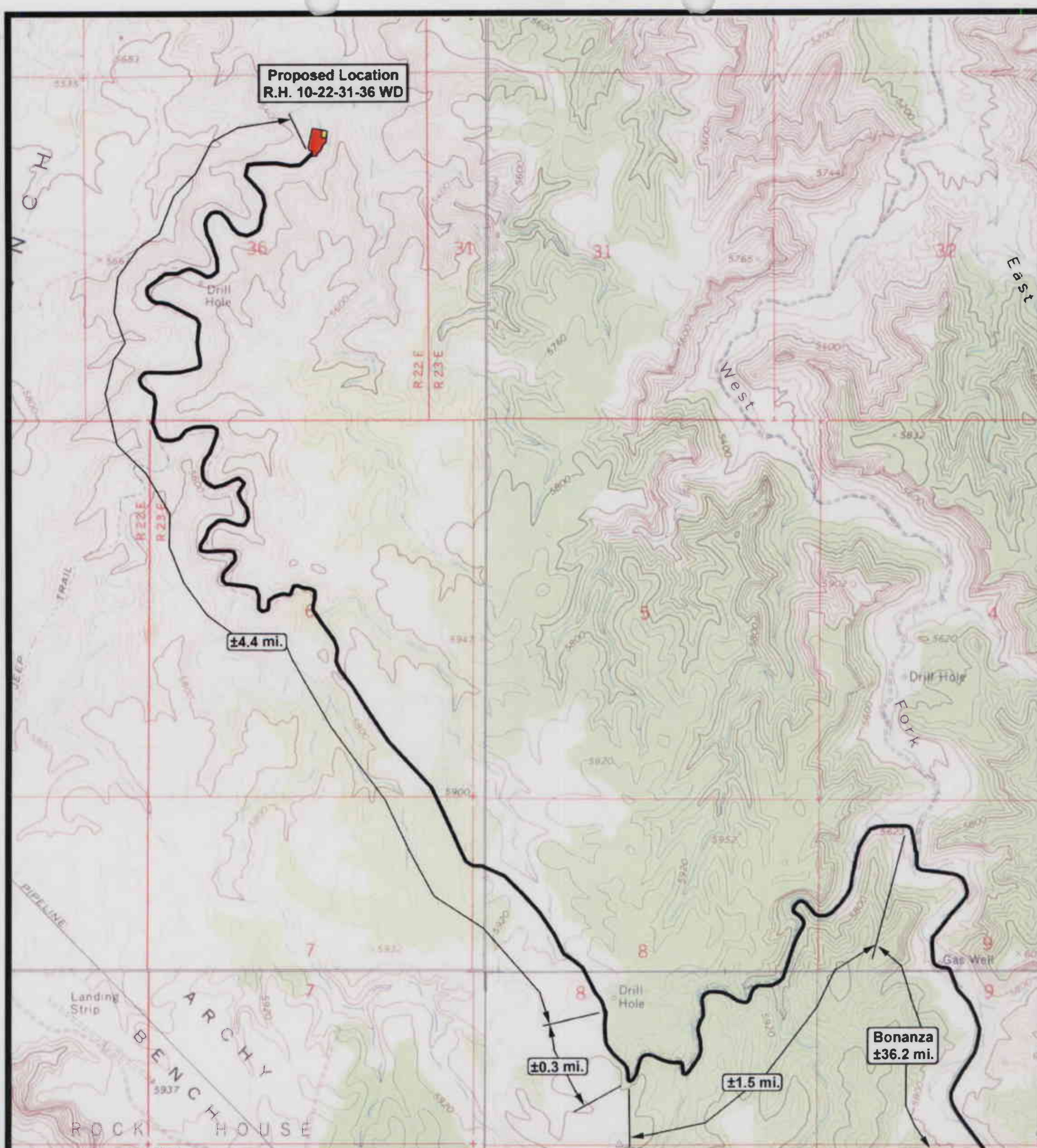
Rock House 10-22-31-36 WD
Sec. 36, T10S, R22E, S.L.B.&M.

N

SCALE: 1" = 100,000'
DRAWN BY: mw
DATE: 01-09-2007

TOPOGRAPHIC MAP "A"

SHEET 7 OF 10



ENDURING RESOURCES

Rock House 10-22-31-36 WD
Sec. 36, T10S, R22E, S.L.B.&M.

N

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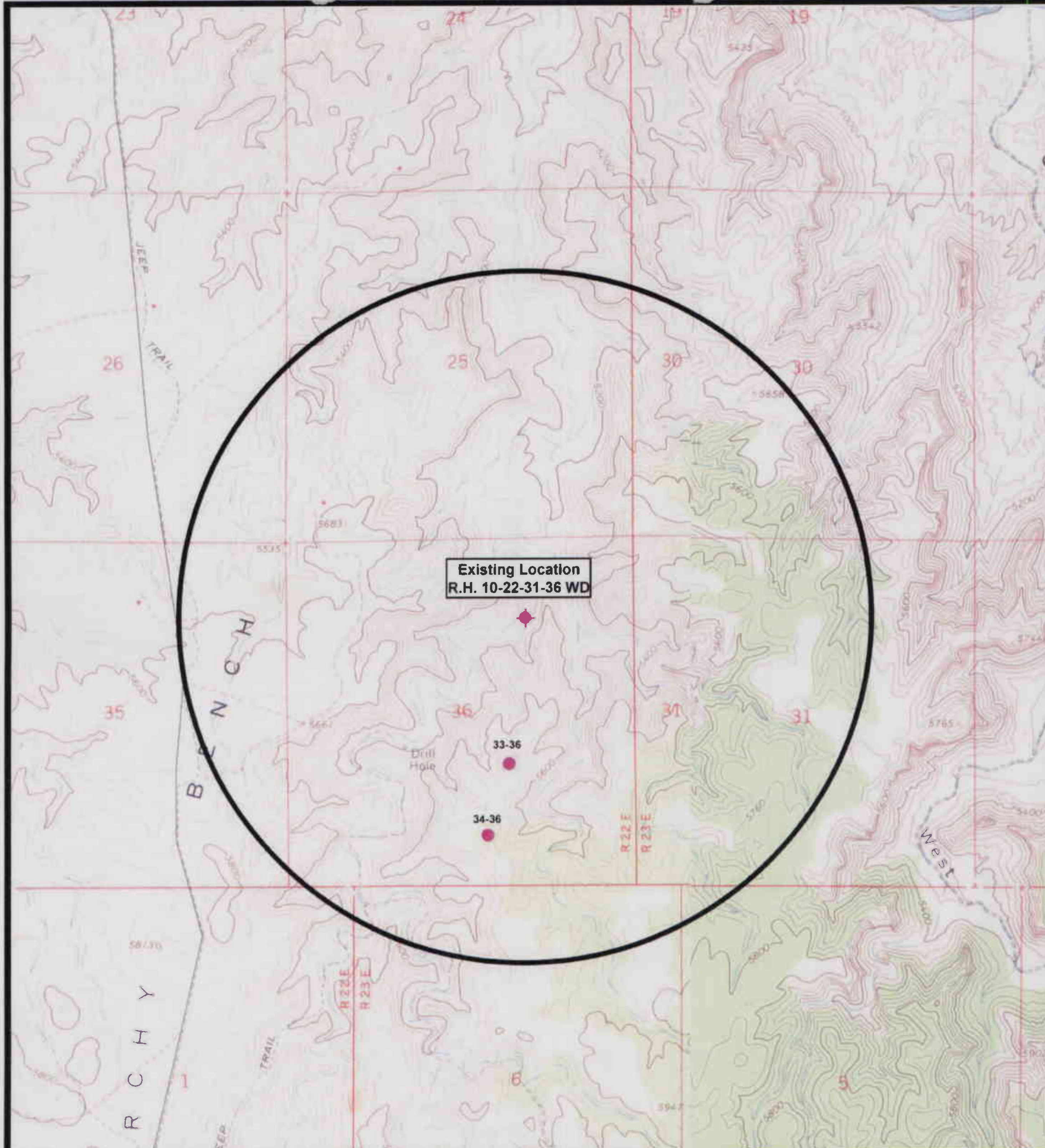
SCALE: 1" = 2,000'
DRAWN BY: mw
DATE: 01-09-2007

Legend
Existing Road
Proposed Access

TOPOGRAPHIC MAP "B"

SHEET 8 OF 10



ENDURING RESOURCES

Rock House 10-22-31-36 WD
Sec. 36, T10S, R22E, S.L.B.&M.

N

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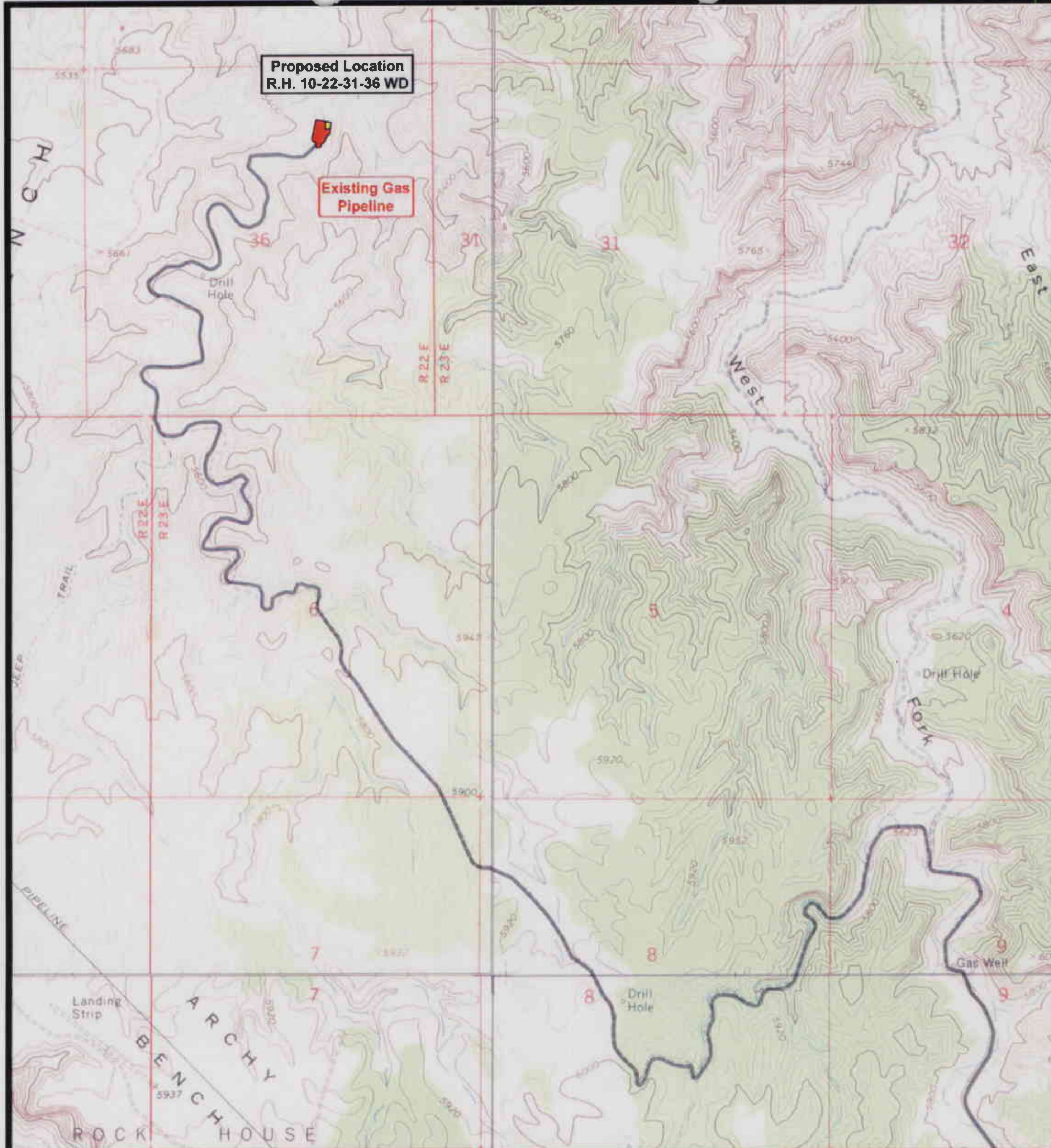
Legend

- Location
- One-Mile Radius

SCALE: 1" = 2,000'	TOPOGRAPHIC MAP	SHEET
DRAWN BY: mw	"C"	9
DATE: 01-09-2007		OF 10



ENDURING RESOURCES

Rock House 10-22-31-36 WD
Sec. 36, T10S, R22E, S.L.B.&M.

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180 North Vernal Ave. Vernal, Utah 84078

SCALE: 1" = 2,000'
DRAWN BY: mw
DATE: 01-09-2007

Legend
Roads

TOPOGRAPHIC MAP
"D"

SHEET 10 OF 10

WELL PAD

ENDURING RESOURCES

R.H. 10-22-31-36 WD

Date Photographed: 01/08/2007
Date Drawn: 01/09/2007
Drawn By: mw

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ACCESS