Form 3160-3
(June 2015)

OCD – HOBBS
02/11/2019
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FORM APPROVED
OMB No. 1004-0137
Expires: January 31, 2018

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No.
NMNM0006531

6. If Indian, Allotee or Tribe Name

7. If Unit or CA Agreement, Name and No.

1a. Type of work: ☑ DRILL ☐ REENTER

1b. Type of Well: ☑ Oil Well ☐ Gas Well ☐ Other

1c. Type of Completion: ☐ Hydraulic Fracturing ☑ Single Zone ☐ Multiple Zone

8. Lease Name and Well No.
LEA UNIT [302802]
103H

2. Name of Operator
LEGACY RESERVES OPERATING LP [240974]

9. API Well No.
30-025-45575

3a. Address	3b. Phone No. *(include area code)*	10. Field and Pool, or Exploratory
303 West Wall St., Ste 1800 Midland TX 79701	(432)689-5287	LEA / UPPER WOLFCAMP 98247

4. Location of Well *(Report location clearly and in accordance with any State requirements.*)*
At surface NENE / 140 FNL / 1065 FEL / LAT 32.594493 / LONG -103.5257874
At proposed prod. zone SENE / 2310 FNL / 430 FEL / LAT 32.5740103 / LONG -103.5237209

11. Sec., T. R. M. or Blk. and Survey or Area
SEC 11 / T20S / R34E / NMP

14. Distance in miles and direction from nearest town or post office*	12. County or Parish	13. State
26 miles	LEA	NM

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any)	16. No of acres in lease	17. Spacing Unit dedicated to this well
140 feet	40	2559.68

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft.	19. Proposed Depth	20. BLM/BIA Bond No. in file
50 feet	11300 feet / 18397 feet	FED: NMB001015

21. Elevations (Show whether DF, KDB, RT, GL, etc.)	22. Approximate date work will start*	23. Estimated duration
3666 feet	10/16/2018	45 days

24. Attachments

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No. 1, and the Hydraulic Fracturing rule per 43 CFR 3162.3-3 (as applicable)

1. Well plat certified by a registered surveyor.
2. A Drilling Plan.
3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO must be filed with the appropriate Forest Service Office).
4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above).
5. Operator certification.
6. Such other site specific information and/or plans as may be requested by the BLM.

25. Signature	Name *(Printed/Typed)*	Date
(Electronic Submission)	Kayley Thurber / Ph: (405)289-9326	08/17/2018

Title
Permitting Specialist

Approved by *(Signature)*	Name *(Printed/Typed)*	Date
(Electronic Submission)	Cody Layton / Ph: (575)234-5959	01/30/2019

Title	Office
Assistant Field Manager Lands & Minerals	CARLSBAD

Application approval does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.
Conditions of approval, if any, are attached.

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

GCP Rec 02/11/2019

APPROVED WITH CONDITIONS
Approval Date: 01/30/2019

KZ
02/11/2019

(Continued on page 2)

*(Instructions on page 2)

PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	Legacy Reserves Operating LP
LEASE NO.:	NMNM0006531A
WELL NAME & NO.:	Lea Unit 103H
SURFACE HOLE FOOTAGE:	140'/N & 1065'/E
BOTTOM HOLE FOOTAGE	2310'/N & 430'/E
LOCATION:	Section 11, T.20 S., R.34 E., NMPM
COUNTY:	Lea County, New Mexico

Potash	◉ None	○ Secretary	○ R-111-P
Cave/Karst Potential	◉ Low	○ Medium	○ High
Variance	○ None	◉ Flex Hose	○ Other
Wellhead	◉ Conventional	○ Multibowl	
Other	☐4 String Area	☒Capitan Reef	☐WIPP

A. Hydrogen Sulfide

1. A Hydrogen Sulfide (H2S) Drilling Plan shall be activated 500 feet prior to drilling into the **Yates - Seven Rivers** formation. As a result, the Hydrogen Sulfide area must meet Onshore Order 6 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.

B. CASING

1. The **13 3/8** inch surface casing shall be set at approximately **1785** feet (a minimum of 25 feet into the Rustler Anhydrite and above the salt) and cemented to the surface.

    a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.

    b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater (This is to include the lead cement).

    c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength,

Approval Date: 01/30/2019

whichever is greater.

d. If cement falls back, remedial cementing will be done prior to drilling out that string.

2. The minimum required fill of cement behind the **9 5/8** inch intermediate casing is:

<u>Option 1:</u>

- Cement to surface. If cement does not circulate see B.1.a, c-d above. **Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to Capitan Reef.**

<u>Option 2:</u>

Operator has proposed DV tool at depth of 3900', but will adjust cement proportionately if moved. DV tool shall be set a minimum of 50' below previous shoe and a minimum of 200' above current shoe. Operator shall submit sundry if DV tool depth cannot be set in this range. If an ECP is used, it is to be set a minimum of 50' below the shoe to provide cement across the shoe. If it cannot be set below the shoe, a CBL shall be run to verify cement coverage.

a. First stage to DV tool: Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.

b. Second stage above DV tool:
   - Cement to surface. If cement does not circulate, contact the appropriate BLM office. **Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to Capitan Reef.**

<u>Option 3:</u>

Operator has proposed DV tool at depth of 3900' and 1900', but will adjust cement proportionately if moved. DV tool shall be set a minimum of 50' below previous shoe and a minimum of 200' above current shoe. Operator shall submit sundry if DV tool depth cannot be set in this range. If an ECP is used, it is to be set a minimum of 50' below the shoe to provide cement across the shoe. If it cannot be set below the shoe, a CBL shall be run to verify cement coverage.

a. First stage to DV tool: Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.

b. Second stage above DV tool:

    - Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with third stage cement job.

c. Third stage above DV tool:

    - Cement to surface. If cement does not circulate, contact the appropriate BLM office. **Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to Capitan Reef.**

❖ **Special Capitan Reef requirements.** If lost circulation (50% or greater) occurs below the Base of the Salt, the operator shall do the following:

- Switch to fresh water mud to protect the Capitan Reef and use fresh water mud until setting the intermediate casing. The appropriate BLM office is to be notified for a PET to witness the switch to fresh water.

- Daily drilling reports from the Base of the Salt to the setting of the intermediate casing are to be submitted to the BLM CFO engineering staff via e-mail by 0800 hours each morning. Any lost circulation encountered is to be recorded on these drilling reports. The daily drilling report should show mud volume per shift/tour. Failure to submit these reports will result in an Incidence of Non-Compliance being issued for failure to comply with the Conditions of Approval. If not already planned, the operator shall run a caliper survey for the intermediate well bore and submit to the appropriate BLM office.

3. The minimum required fill of cement behind the **7** inch intermediate liner is:

    - Cement to top of liner. Operator shall provide method of verification.

<u>Operator will utilize a 7" tie back casing and cement to surface.</u>

4. The minimum required fill of cement behind the **4 1/2** inch production liner is:

    - Cement should tie-back at least **100 feet** into previous string. Operator shall provide method of verification.

C. PRESSURE CONTROL

1. Variance approved to use flex line from BOP to choke manifold. Manufacturer's specification to be readily available. No external damage to flex line. Flex line to be installed as straight as possible (no hard bends).

2. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **5000 (5M)** psi.

3. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **9 5/8** inch intermediate casing shoe shall be **10,000 (10M)** psi. **Variance is approved to use a 5M Annular which shall be tested to 5000 psi.**

D. SPECIAL REQUIREMENT(S)

Commercial Well Determination
A commercial well determination will need to be submitted after production has been established for at least six months.

Unit Wells
The well sign for a unit well shall include the unit number in addition to the surface and bottom hole lease numbers. This also applies to participating area numbers. If a participating area has not been established, the operator can use the general unit designation, but will replace the unit number with the participating area number when the sign is replaced.

MHH 01102019

GENERAL REQUIREMENTS

The BLM is to be notified in advance for a representative to witness:

a. Spudding well (minimum of 24 hours)
b. Setting and/or Cementing of all casing strings (minimum of 4 hours)
c. BOPE tests (minimum of 4 hours)

☒ Chaves and Roosevelt Counties
Call the Roswell Field Office, 2909 West Second St., Roswell NM 88201.
During office hours call (575) 627-0272.
After office hours call (575)

☒ Eddy County
Call the Carlsbad Field Office, 620 East Greene St., Carlsbad, NM 88220, (575) 361-2822

☒ Lea County
Call the Hobbs Field Station, 414 West Taylor, Hobbs NM 88240, (575) 393-3612

1. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval.

    a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
    b. When the operator proposes to set surface casing with Spudder Rig
        - Notify the BLM when moving in and removing the Spudder Rig.
        - Notify the BLM when moving in the 2nd Rig. Rig to be moved in within 90 days of notification that Spudder Rig has left the location.
        - BOP/BOPE test to be conducted per Onshore Oil and Gas Order No. 2 as soon as 2nd Rig is rigged up on well.

2. Floor controls are required for 3M or Greater systems. These controls will be on the rig floor, unobstructed, readily accessible to the driller and will be operational at all times during drilling and/or completion activities. Rig floor is defined as the area immediately around the rotary table; the area immediately above the substructure on which the draw works are located, this does not include the dog house or stairway area.

3. The record of the drilling rate along with the GR/N well log run from TD to surface (horizontal well – vertical portion of hole) shall be submitted to the BLM office as well as all other logs run on the borehole 30 days from completion. If available, a digital copy of the logs is to be submitted in addition to the paper copies. The Rustler top and top and bottom of Salt are to be recorded on the Completion Report.

A. CASING

1. Changes to the approved APD casing program need prior approval if the items substituted are of lesser grade or different casing size or are Non-API. The Operator can exchange the components of the proposal with that of superior strength (i.e. changing from J-55 to N-80, or from 36# to 40#). Changes to the approved cement program need prior approval if the altered cement plan has less volume or strength or if the changes are substantial (i.e. Multistage tool, ECP, etc.). The initial wellhead installed on the well will remain on the well with spools used as needed.

2. <u>Wait on cement (WOC) for Potash Areas:</u> After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi for all cement blends, 2) until cement has been in place at least <u>24 hours</u>. WOC time will be recorded in the driller's log.

3. <u>Wait on cement (WOC) for Water Basin:</u> After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi at the shoe, 2) until cement has been in place at least <u>8 hours</u>. WOC time will be recorded in the driller's log. See individual casing strings for details regarding lead cement slurry requirements.

4. Provide compressive strengths including hours to reach required 500 pounds compressive strength prior to cementing each casing string. Have well specific cement details onsite prior to pumping the cement for each casing string.

5. No pea gravel permitted for remedial or fall back remedial without prior authorization from the BLM engineer.

6. On that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test shall be performed before drilling more than 20 feet of new hole.

7. If hardband drill pipe is rotated inside casing, returns will be monitored for metal. If metal is found in samples, drill pipe will be pulled and rubber protectors which have a larger diameter than the tool joints of the drill pipe will be installed prior to continuing drilling operations.

8. Whenever a casing string is cemented in the R-111-P potash area, the NMOCD requirements shall be followed.

B. PRESSURE CONTROL

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in Onshore Oil and Gas Order No. 2 and API RP 53 Sec. 17.

2. If a variance is approved for a flexible hose to be installed from the BOP to the choke manifold, the following requirements apply: Check condition of flexible line from BOP to choke manifold, replace if exterior is damaged or if line fails test. Line to be as straight as possible with no hard bends and is to be anchored according to Manufacturer's requirements. The flexible hose can be exchanged with a hose of equal size and equal or greater pressure rating. Anchor requirements, specification sheet and hydrostatic pressure test certification matching the hose in service, to be onsite for review. These documents shall be posted in the company man's trailer and on the rig floor.

3. 5M or higher system requires an HCR valve, remote kill line and annular to match. The remote kill line is to be installed prior to testing the system and tested to stack pressure.

4. If the operator has proposed a multi-bowl wellhead assembly in the APD. The following requirements must be met:

   a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
   b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
   c. Manufacturer representative shall install the test plug for the initial BOP test.
   d. Operator shall perform the intermediate casing integrity test to 70% of the casing burst. This will test the multi-bowl seals.
   e. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.

5. The appropriate BLM office shall be notified a minimum of 4 hours in advance for a representative to witness the tests.

   a. In a water basin, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. The casing cut-off and BOP installation can be initiated four hours after installing the slips, which will be approximately six hours after bumping the plug. For those casing strings not using slips, the minimum wait time before cut-off is eight hours after bumping the plug. BOP/BOPE testing can begin after cut-off or once cement reaches 500 psi compressive strength (including lead when specified), whichever is greater. However, if the float does not hold, cut-off cannot be initiated until cement reaches 500 psi compressive strength (including lead when specified).

b. In potash areas, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. For all casing strings, casing cut-off and BOP installation can be initiated at twelve hours after bumping the plug. However, **no tests** shall commence until the cement has had a minimum of 24 hours setup time.

c. The tests shall be done by an independent service company utilizing a test plug not a cup or J-packer. The operator also has the option of utilizing an independent tester to test without a plug (i.e. against the casing) pursuant to Onshore Order 2 with the pressure not to exceed 70% of the burst rating for the casing. Any test against the casing must meet the WOC time for water basin (8 hours) or potash (24 hours) or 500 pounds compressive strength, whichever is greater, prior to initiating the test (see casing segment as lead cement may be critical item).

d. The test shall be run on a 5000 psi chart for a 2-3M BOP/BOP, on a 10000 psi chart for a 5M BOP/BOPE and on a 15000 psi chart for a 10M BOP/BOPE. If a linear chart is used, it shall be a one hour chart. A circular chart shall have a maximum 2 hour clock. If a twelve hour or twenty-four hour chart is used, tester shall make a notation that it is run with a two hour clock.

e. The results of the test shall be reported to the appropriate BLM office.

f. All tests are required to be recorded on a calibrated test chart. A copy of the BOP/BOPE test chart and a copy of independent service company test will be submitted to the appropriate BLM office.

g. The BOP/BOPE test shall include a low pressure test from 250 to 300 psi. The test will be held for a minimum of 10 minutes if test is done with a test plug and 30 minutes without a test plug. This test shall be performed prior to the test at full stack pressure.

h. BOP/BOPE must be tested by an independent service company within 500 feet of the top of the Wolfcamp formation if the time between the setting of the intermediate casing and reaching this depth exceeds 20 days. This test does not exclude the test prior to drilling out the casing shoe as per Onshore Order No. 2.

C. DRILLING MUD

Mud system monitoring equipment, with derrick floor indicators and visual and audio alarms, shall be operating before drilling into the Wolfcamp formation, and shall be used until production casing is run and cemented.

D. WASTE MATERIAL AND FLUIDS

All waste (i.e. drilling fluids, trash, salts, chemicals, sewage, gray water, etc.) created as a result of drilling operations and completion operations shall be safely contained and disposed of properly at a waste disposal facility. No waste material or fluid shall be disposed of on the well location or surrounding area.

Porto-johns and trash containers will be on-location during fracturing operations or any other crew-intensive operations.

PECOS DISTRICT
SURFACE USE
CONDITIONS OF APPROVAL

OPERATOR'S NAME:	LEGACY RESERVES
LEASE NO.:	NMNM0006531
WELL NAME & NO.:	103H:LEA UNIT
SURFACE HOLE FOOTAGE:	140'/N & 1065'/E
BOTTOM HOLE FOOTAGE	2310'/N & 430'/E
LOCATION:	T-20S, R-34E, S11. NMPM
COUNTY:	LEA, NM

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Standard Conditions of Approval (COA) apply to this APD. If any deviations to these standards exist or special COAs are required, the section with the deviation or requirement will be checked below.

Approval Date: 01/30/2019

I. GENERAL PROVISIONS

The approval of the Application For Permit To Drill (APD) is in compliance with all applicable laws and regulations: 43 Code of Federal Regulations 3160, the lease terms, Onshore Oil and Gas Orders, Notices To Lessees, New Mexico Oil Conservation Division (NMOCD) Rules, National Historical Preservation Act As Amended, and instructions and orders of the Authorized Officer. Any request for a variance shall be submitted to the Authorized Officer on Form 3160-5, Sundry Notices and Report on Wells.

II. PERMIT EXPIRATION

If the permit terminates prior to drilling and drilling cannot be commenced within 60 days after expiration, an operator is required to submit Form 3160-5, Sundry Notices and Reports on Wells, requesting surface reclamation requirements for any surface disturbance. However, if the operator will be able to initiate drilling within 60 days after the expiration of the permit, the operator must have set the conductor pipe in order to allow for an extension of 60 days beyond the expiration date of the APD. (Filing of a Sundry Notice is required for this 60 day extension.)

III. ARCHAEOLOGICAL, PALEONTOLOGY & HISTORICAL SITES

Any cultural and/or paleontological resource discovered by the operator or by any person working on the operator's behalf shall immediately report such findings to the Authorized Officer. The operator is fully accountable for the actions of their contractors and subcontractors. The operator shall suspend all operations in the immediate area of such discovery until written authorization to proceed is issued by the Authorized Officer. An evaluation of the discovery shall be made by the Authorized Officer to determine the appropriate actions that shall be required to prevent the loss of significant cultural or scientific values of the discovery. The operator shall be held responsible for the cost of the proper mitigation measures that the Authorized Officer assesses after consultation with the operator on the evaluation and decisions of the discovery. Any unauthorized collection or disturbance of cultural or paleontological resources may result in a shutdown order by the Authorized Officer.

IV. NOXIOUS WEEDS

The operator shall be held responsible if noxious weeds become established within the areas of operations. Weed control shall be required on the disturbed land where noxious weeds exist, which includes the roads, pads, associated pipeline corridor, and adjacent land affected by the establishment of weeds due to this action. The operator shall consult with the Authorized Officer for acceptable weed control methods, which include following EPA and BLM requirements and policies.

V. SPECIAL REQUIREMENT(S)

Timing Limitation Stipulation / Condition of Approval for lesser prairie-chicken: Oil and gas activities including 3-D geophysical exploration, and drilling will not be allowed in lesser prairie-chicken habitat during the period from March 1st through June 15th annually. During that period, other activities that produce noise or involve human activity, such as the maintenance of oil and gas facilities, pipeline, road, and well pad construction, will be allowed except between 3:00 am and 9:00 am. The 3:00 am to 9:00 am restriction will not apply to normal, around-the-clock operations, such as venting, flaring, or pumping, which do not require a human presence during this period. Additionally, no new drilling will be allowed within up to 200 meters of leks known at the time of permitting. Normal vehicle use on existing roads will not be restricted. Exhaust noise from pump jack engines must be muffled or otherwise controlled so as not to exceed 75 db measured at 30 feet from the source of the noise.

Timing Limitation Exceptions:
The Carlsbad Field Office will publish an annual map of where the LPC timing and noise stipulations and conditions of approval (Limitations) will apply for the identified year (between March 1 and June 15) based on the latest survey information. The LPC Timing Area map will identify areas which are Habitat Areas (HA), Isolated Population Area (IPA), and Primary Population Area (PPA). The LPC Timing Area map will also have an area in red crosshatch. The red crosshatch area is the only area where an operator is required to submit a request for exception to the LPC Limitations. If an operator is operating outside the red crosshatch area, the LPC Limitations do not apply for that year and an exception to LPC Limitations is not required.

Ground-level Abandoned Well Marker to avoid raptor perching: Upon the plugging and subsequent abandonment of the well, the well marker will be installed at ground level on a plate containing the pertinent information for the plugged well. For more installation details, contact the Carlsbad Field Office at 575-234-5972.

VI. CONSTRUCTION

A. NOTIFICATION

The BLM shall administer compliance and monitor construction of the access road and well pad. Notify the Carlsbad Field Office at (575) 234-5909 at least 3 working days prior to commencing construction of the access road and/or well pad.

When construction operations are being conducted on this well, the operator shall have the approved APD and Conditions of Approval (COA) on the well site and they shall be made available upon request by the Authorized Officer.

B. TOPSOIL

The operator shall strip the top portion of the soil (root zone) from the entire well pad area and stockpile the topsoil along the edge of the well pad as depicted in the APD. The root zone is typically six (6) inches in depth. All the stockpiled topsoil will be redistributed over the interim reclamation areas. Topsoil shall not be used for berming the pad or facilities. For final reclamation, the topsoil shall be spread over the entire pad area for seeding preparation.

Other subsoil (below six inches) stockpiles must be completely segregated from the topsoil stockpile. Large rocks or subsoil clods (not evident in the surrounding terrain) must be buried within the approved area for interim and final reclamation.

C. CLOSED LOOP SYSTEM

Tanks are required for drilling operations: No Pits.

The operator shall properly dispose of drilling contents at an authorized disposal site.

D. FEDERAL MINERAL MATERIALS PIT

Payment shall be made to the BLM prior to removal of any federal mineral materials. Call the Carlsbad Field Office at (575) 234-5972.

E. WELL PAD SURFACING

Surfacing of the well pad is not required.

If the operator elects to surface the well pad, the surfacing material may be required to be removed at the time of reclamation. The well pad shall be constructed in a manner which creates the smallest possible surface disturbance, consistent with safety and operational needs.

F. EXCLOSURE FENCING (CELLARS & PITS)

Exclosure Fencing
The operator will install and maintain exclosure fencing for all open well cellars to prevent access to public, livestock, and large forms of wildlife before and after drilling operations until the pit is free of fluids and the operator initiates backfilling. (For examples of exclosure fencing design, refer to BLM's Oil and Gas Gold Book, Exclosure Fence Illustrations, Figure 1, Page 18.)

G. ON LEASE ACCESS ROADS

Road Width
The access road shall have a driving surface that creates the smallest possible surface disturbance and does not exceed fourteen (14) feet in width. The maximum width of surface disturbance, when constructing the access road, shall not exceed twenty-five (25) feet.

Surfacing
Surfacing material is not required on the new access road driving surface. If the operator elects to surface the new access road or pad, the surfacing material may be required to be removed at the time of reclamation.

Where possible, no improvements should be made on the unsurfaced access road other than to remove vegetation as necessary, road irregularities, safety issues, or to fill low areas that may sustain standing water.

The Authorized Officer reserves the right to require surfacing of any portion of the access road at any time deemed necessary. Surfacing may be required in the event the road deteriorates, erodes, road traffic increases, or it is determined to be beneficial for future field development. The surfacing depth and type of material will be determined at the time of notification.

Crowning
Crowning shall be done on the access road driving surface. The road crown shall have a grade of approximately 2% (i.e., a 1" crown on a 14' wide road). The road shall conform to Figure 1; cross section and plans for typical road construction.

Ditching
Ditching shall be required on both sides of the road.

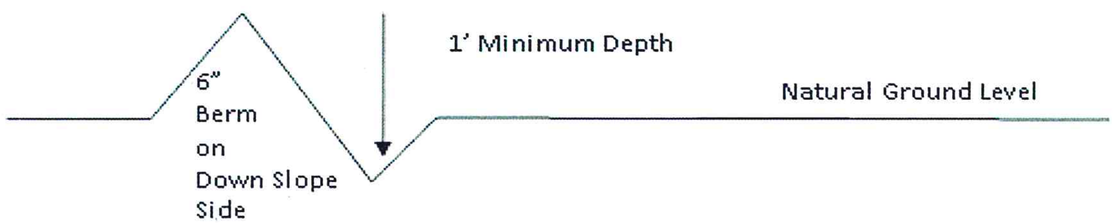
Turnouts
Vehicle turnouts shall be constructed on the road. Turnouts shall be intervisible with interval spacing distance less than 1000 feet. Turnouts shall conform to Figure 1; cross section and plans for typical road construction.

Drainage

Drainage control systems shall be constructed on the entire length of road (e.g. ditches, sidehill outsloping and insloping, lead-off ditches, culvert installation, and low water crossings).

A typical lead-off ditch has a minimum depth of 1 foot below and a berm of 6 inches above natural ground level. The berm shall be on the down-slope side of the lead-off ditch.

Cross Section of a Typical Lead-off Ditch



All lead-off ditches shall be graded to drain water with a 1 percent minimum to 3 percent maximum ditch slope. The spacing interval are variable for lead-off ditches and shall be determined according to the formula for spacing intervals of lead-off ditches, but may be amended depending upon existing soil types and centerline road slope (in %);

Formula for Spacing Interval of Lead-off Ditches

Example - On a 4% road slope that is 400 feet long, the water flow shall drain water into a lead-off ditch. Spacing interval shall be determined by the following formula:

$$\text{400 foot road with 4\% road slope: } \frac{400'}{4\%} + 100' = 200' \text{ lead-off ditch interval}$$

Cattle guards

An appropriately sized cattle guard sufficient to carry out the project shall be installed and maintained at fence/road crossings. Any existing cattle guards on the access road route shall be repaired or replaced if they are damaged or have deteriorated beyond practical use. The operator shall be responsible for the condition of the existing cattle guards that are in place and are utilized during lease operations.

Fence Requirement

Where entry is granted across a fence line, the fence shall be braced and tied off on both sides of the passageway prior to cutting. The operator shall notify the private surface landowner or the grazing allotment holder prior to crossing any fences.

Public Access

Public access on this road shall not be restricted by the operator without specific written approval granted by the Authorized Officer.

Construction Steps

1. Salvage topsoil
2. Construct road
3. Redistribute topsoil
4. Revegetate slopes

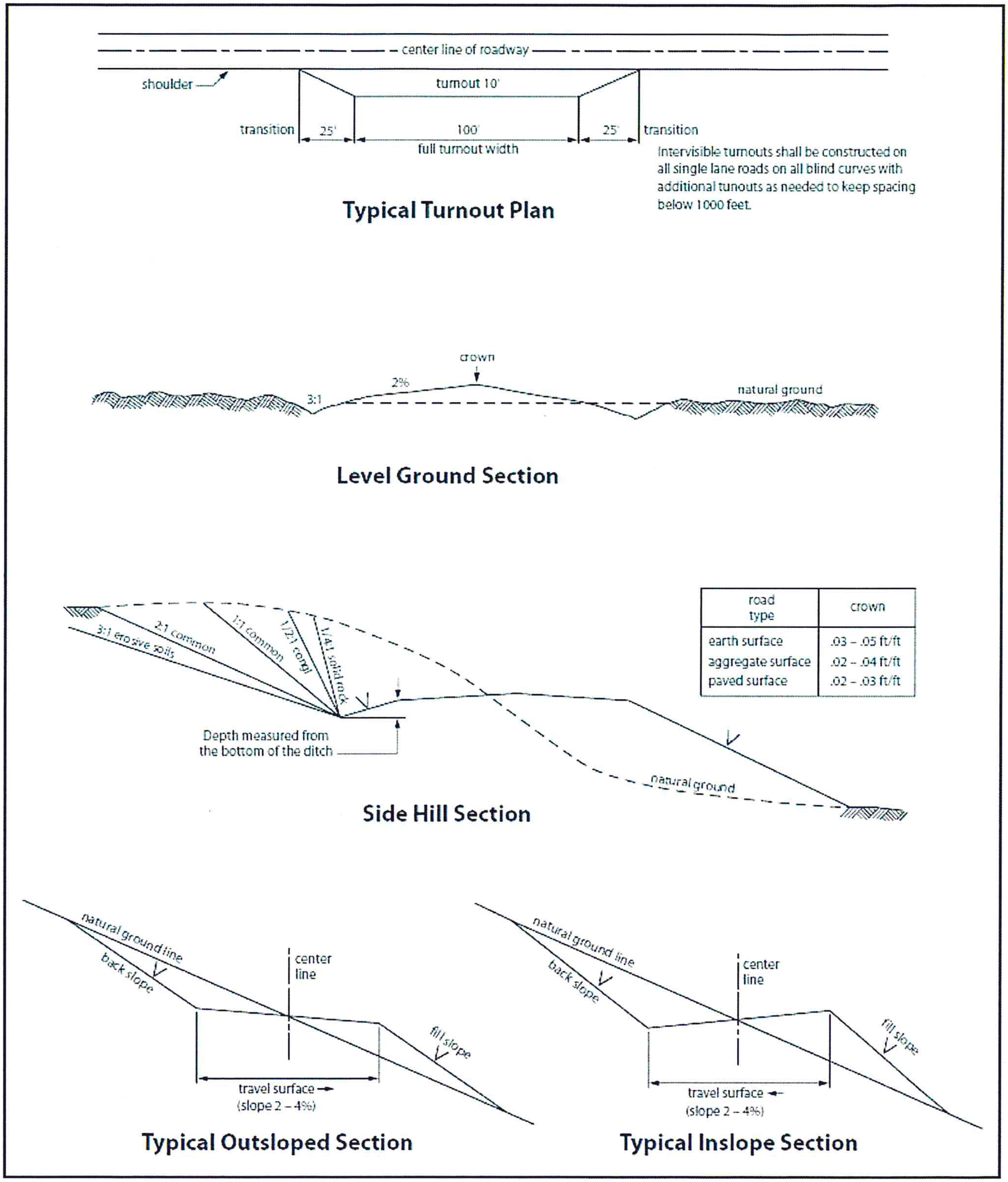


Figure 1. Cross-sections and plans for typical road sections representative of BLM resource or FS local and higher-class roads.

VII. PRODUCTION (POST DRILLING)

A. WELL STRUCTURES & FACILITIES

Placement of Production Facilities
Production facilities should be placed on the well pad to allow for maximum interim recontouring and revegetation of the well location.

Exclosure Netting (Open-top Tanks)
Immediately following active drilling or completion operations, the operator will take actions necessary to prevent wildlife and livestock access, including avian wildlife, to all open-topped tanks that contain or have the potential to contain salinity sufficient to cause harm to wildlife or livestock, hydrocarbons, or Resource Conservation and Recovery Act of 1976-exempt hazardous substances. At a minimum, the operator will net, screen, or cover open-topped tanks to exclude wildlife and livestock and prevent mortality. If the operator uses netting, the operator will cover and secure the open portion of the tank to prevent wildlife entry. The operator will net, screen, or cover the tanks until the operator removes the tanks from the location or the tanks no longer contain substances that could be harmful to wildlife or livestock. Use a maximum netting mesh size of 1 ½ inches. The netting must not be in contact with fluids and must not have holes or gaps.

Chemical and Fuel Secondary Containment and Exclosure Screening
The operator will prevent all hazardous, poisonous, flammable, and toxic substances from coming into contact with soil and water. At a minimum, the operator will install and maintain an impervious secondary containment system for any tank or barrel containing hazardous, poisonous, flammable, or toxic substances sufficient to contain the contents of the tank or barrel and any drips, leaks, and anticipated precipitation. The operator will dispose of fluids within the containment system that do not meet applicable state or U. S. Environmental Protection Agency livestock water standards in accordance with state law; the operator must not drain the fluids to the soil or ground. The operator will design, construct, and maintain all secondary containment systems to prevent wildlife and livestock exposure to harmful substances. At a minimum, the operator will install effective wildlife and livestock exclosure systems such as fencing, netting, expanded metal mesh, lids, and grate covers. Use a maximum netting mesh size of 1 ½ inches.

Open-Vent Exhaust Stack Exclosures
The operator will construct, modify, equip, and maintain all open-vent exhaust stacks on production equipment to prevent birds and bats from entering, and to discourage perching, roosting, and nesting. (*Recommended exclosure structures on open-vent exhaust stacks are in the shape of a cone.*) Production equipment includes, but may not be limited to, tanks, heater-treaters, separators, dehydrators, flare stacks, in-line units, and compressor mufflers.

Containment Structures

Proposed production facilities such as storage tanks and other vessels will have a secondary containment structure that is constructed to hold the capacity of 1.5 times the largest tank, plus freeboard to account for precipitation, unless more stringent protective requirements are deemed necessary.

Painting Requirement
All above-ground structures including meter housing that are not subject to safety requirements shall be painted a flat non-reflective paint color, **Shale Green** from the BLM Standard Environmental Color Chart (CC-001: June 2008).

VIII. INTERIM RECLAMATION

During the life of the development, all disturbed areas not needed for active support of production operations should undergo interim reclamation in order to minimize the environmental impacts of development on other resources and uses.

Within six (6) months of well completion, operators should work with BLM surface management specialists (Jim Amos: 575-234-5909) to devise the best strategies to reduce the size of the location. Interim reclamation should allow for remedial well operations, as well as safe and efficient removal of oil and gas.

During reclamation, the removal of caliche is important to increasing the success of revegetating the site. Removed caliche that is free of contaminants may be used for road repairs, fire walls or for building other roads and locations. In order to operate the well or complete workover operations, it may be necessary to drive, park and operate on restored interim vegetation within the previously disturbed area. Disturbing revegetated areas for production or workover operations will be allowed. If there is significant disturbance and loss of vegetation, the area will need to be revegetated. Communicate with the appropriate BLM office for any exceptions/exemptions if needed.

All disturbed areas after they have been satisfactorily prepared need to be reseeded with the seed mixture provided below.

Upon completion of interim reclamation, the operator shall submit a Sundry Notices and Reports on Wells, Subsequent Report of Reclamation (Form 3160-5).

IX. FINAL ABANDONMENT & RECLAMATION

At final abandonment, well locations, production facilities, and access roads must undergo "final" reclamation so that the character and productivity of the land are restored.

Earthwork for final reclamation must be completed within six (6) months of well plugging. All pads, pits, facility locations and roads must be reclaimed to a satisfactory revegetated, safe, and stable condition, unless an agreement is made with the landowner or BLM to keep the road and/or pad intact.

After all disturbed areas have been satisfactorily prepared, these areas need to be revegetated with the seed mixture provided below. Seeding should be accomplished by drilling on the contour whenever practical or by other approved methods. Seeding may need to be repeated until revegetation is successful, as determined by the BLM.

Operators shall contact a BLM surface protection specialist prior to surface abandonment operations for site specific objectives (Jim Amos: 575-234-5909).

Ground-level Abandoned Well Marker to avoid raptor perching: Upon the plugging and subsequent abandonment of the well, the well marker will be installed at ground level on a plate containing the pertinent information for the plugged well.

Company: Legacy Reserves
Lease #: NMNM 0006531
Well name: Lea Unit 101H, 102H, and 103H

Seed Mixture for LPC Sand/Shinnery Sites

Holder shall seed all disturbed areas with the seed mixture listed below. The seed mixture shall be planted in the amounts specified in pounds of pure live seed (PLS)* per acre. There shall be no primary or secondary noxious weeds in the seed mixture. Seed will be tested and the viability testing of seed shall be done in accordance with State law(s) and within nine (9) months prior to purchase. Commercial seed shall be either certified or registered seed. The seed container shall be tagged in accordance with State law(s) and available for inspection by the Authorized Officer.

Seed will be planted using a drill equipped with a depth regulator to ensure proper depth of planting where drilling is possible. The seed mixture will be evenly and uniformly planted over the disturbed area (smaller/heavier seeds have a tendency to drop the bottom of the drill and are planted first). Holder shall take appropriate measures to ensure this does not occur. Where drilling is not possible, seed will be broadcast and the area shall be raked or chained to cover the seed. When broadcasting the seed, the pounds per acre are to be doubled. Seeding shall be repeated until a satisfactory stand is established as determined by the Authorized Officer. Evaluation of growth may not be made before completion of at least one full growing season after seeding.

Species to be planted in pounds of pure live seed* per acre:

Species	lb/acre
Plains Bristlegrass	5lbs/A
Sand Bluestem	5lbs/A
Little Bluestem	3lbs/A
Big Bluestem	6lbs/A
Plains Coreopsis	2lbs/A
Sand Dropseed	1lbs/A

*Pounds of pure live seed:

Pounds of seed **x** percent purity **x** percent germination = pounds pure live seed

Approval Date: 01/30/2019

Operator Certification

I hereby certify that I, or someone under my direct supervision, have inspected the drill site and access route proposed herein; that I am familiar with the conditions which currently exist; that I have full knowledge of state and Federal laws applicable to this operation; that the statements made in this APD package are, to the best of my knowledge, true and correct; and that the work associated with the operations proposed herein will be performed in conformity with this APD package and the terms and conditions under which it is approved. I also certify that I, or the company I represent, am responsible for the operations conducted under this application. These statements are subject to the provisions of 18 U.S.C. 1001 for the filing of false statements.

NAME: Kayley Thurber **Signed on:** 08/16/2018

Title: Permitting Specialist

Street Address: 1219 Classen Drive

City: Oklahoma City **State:** OK **Zip:** 73103

Phone: (405)289-9326

Email address: kthurber@rsenergysolutions.com

Field Representative

Representative Name:

Street Address:

City: **State:** **Zip:**

Phone:

Email address:

AFMSS

U.S. Department of the Interior
BUREAU OF LAND MANAGEMENT

Application Data Report
02/07/2019

APD ID: 10400033195

Submission Date: 08/17/2018

Highlighted data reflects the most recent changes

Show Final Text

Operator Name: LEGACY RESERVES OPERATING LP

Well Name: LEA UNIT

Well Number: 103H

Well Type: OIL WELL

Well Work Type: Drill

Section 1 - General

APD ID: 10400033195

Tie to previous NOS?

Submission Date: 08/17/2018

BLM Office: CARLSBAD

User: Kayley Thurber

Title: Permitting Specialist

Federal/Indian APD: FED

Is the first lease penetrated for production Federal or Indian? FED

Lease number: NMNM0006531

Lease Acres: 40

Surface access agreement in place?

Allotted?

Reservation:

Agreement in place? NO

Federal or Indian agreement:

Agreement number:

Agreement name:

Keep application confidential? YES

Permitting Agent? YES

APD Operator: LEGACY RESERVES OPERATING LP

Operator letter of designation: Authorization_Letter_for_Reagan_Smith_Lea_103H_20180817124846.pdf

Operator Info

Operator Organization Name: LEGACY RESERVES OPERATING LP

Operator Address: 303 West Wall St., Ste 1800

Zip: 79701

Operator PO Box:

Operator City: Midland

State: TX

Operator Phone: (432)689-5287

Operator Internet Address:

Section 2 - Well Information

Well in Master Development Plan? EXISTING

Mater Development Plan name: Lea Unit Master Dev Plan

Well in Master SUPO? NO

Master SUPO name:

Well in Master Drilling Plan? NO

Master Drilling Plan name:

Well Name: LEA UNIT

Well Number: 103H

Well API Number:

Field/Pool or Exploratory? Field and Pool

Field Name: LEA

Pool Name: UPPER WOLFCAMP

Is the proposed well in an area containing other mineral resources? USEABLE WATER,NATURAL GAS,OIL

Operator Name: LEGACY RESERVES OPERATING LP

Well Name: LEA UNIT **Well Number:** 103H

Describe other minerals:

Is the proposed well in a Helium production area? N **Use Existing Well Pad?** YES **New surface disturbance?** N

Type of Well Pad: MULTIPLE WELL **Multiple Well Pad Name:** LEA UNIT **Number:** 7

Well Class: HORIZONTAL **Number of Legs:** 1

Well Work Type: Drill

Well Type: OIL WELL

Describe Well Type:

Well sub-Type: INFILL

Describe sub-type:

Distance to town: 26 Miles **Distance to nearest well:** 50 FT **Distance to lease line:** 140 FT

Reservoir well spacing assigned acres Measurement: 2559.68 Acres

Well plat: Lea_Unit_103H_Signed_C102_04_10_18_20180817124834.pdf

Agency_Lease_Plat___Lea_Unit_103H_20180817153140.pdf

Well work start Date: 10/16/2018 **Duration:** 45 DAYS

Section 3 - Well Location Table

Survey Type: RECTANGULAR

Describe Survey Type:

Datum: NAD83 **Vertical Datum:** NAVD88

Survey number:

	NS-Foot	NS Indicator	EW-Foot	EW Indicator	Twsp	Range	Section	Aliquot/Lot/Tract	Latitude	Longitude	County	State	Meridian	Lease Type	Lease Number	Elevation	MD	TVD
SHL Leg #1	140	FNL	1065	FEL	20S	34E	11	Aliquot NENE	32.594493	-103.5257874	LEA	NEW MEXICO	NEW MEXICO	F	NMNM 0006531	3666	0	0
KOP Leg #1	140	FNL	420	FEL	20S	34E	11	Aliquot NENE	32.293964	-103.523725	LEA	NEW MEXICO	NEW MEXICO	F	NMNM 0006531	-7156	10865	10822
PPP Leg #1	816	FNL	422	FEL	20S	34E	11	Aliquot NENE	32.592651	-103.523725	LEA	NEW MEXICO	NEW MEXICO	F	NMNM 0006531	-7633	11600	11299

Operator Name: LEGACY RESERVES OPERATING LP

Well Name: LEA UNIT **Well Number:** 103H

	NS-Foot	NS Indicator	EW-Foot	EW Indicator	Twsp	Range	Section	Aliquot/Lot/Tract	Latitude	Longitude	County	State	Meridian	Lease Type	Lease Number	Elevation	MD	TVD
PPP Leg #1	1320	FNL	421	FEL	20S	34E	11	Aliquot SENE	32.591269	-103.523725	LEA	NEW MEXICO	NEW MEXICO	F	NMNM 0006531A	-7634	12100	11300
PPP Leg #1	1320	FNL	424	FEL	20S	34E	14	Aliquot SENE	32.576747	-103.523721	LEA	NEW MEXICO	NEW MEXICO	F	NMNM 0080262	-7634	17400	11300
PPP Leg #1	0	FNL	423	FEL	20S	34E	14	Aliquot NENE	32.580369	-103.523722	LEA	NEW MEXICO	NEW MEXICO	F	NMNM 0053434	-7634	16100	11300
EXIT Leg #1	2310	FNL	430	FEL	20S	34E	14	Aliquot SENE	32.5740103	-103.5237209	LEA	NEW MEXICO	NEW MEXICO	F	NMNM 0080262	-7634	18397	11300
BHL Leg #1	2310	FNL	430	FEL	20S	34E	14	Aliquot SENE	32.5740103	-103.5237209	LEA	NEW MEXICO	NEW MEXICO	F	NMNM 0080262	-7634	18397	11300

LEGACY
RESERVES
303 W. Wall, Suite 1800 - Midland, Texas 79701
(432) 689-5200

March 20, 2018

Bureau of Land Management
Division of Oil and Gas
620 E. Greene Street
Carlsbad, NM 88220-6292
Attn: Land Law Examiner

Re: Legacy Reserves Operating, L.P.
Designation of Agent
Lea Unit 103H
11-20S-34E NMPM
Lea County, NM

To whom it may concern:

Legacy Reserves Operating, L.P. has contracted with Reagan Smith Energy Solutions, Inc. to assist in regulatory compliance associated with the Lea Unit 103H. Reagan Smith Energy Solutions, Inc. has the authority to act as Legacy Reserves Operating, L.P.'s agent to maintain regulatory compliance for the Lea Unit 103H. This includes the submittal of an APD, Communitization Agreement, Designations of Operator, Sundry Notices, and any other regulatory documents on behalf of Legacy Reserves Operating, L.P. in order to maintain regulatory compliance with the Bureau of Land Management in regard to the above referenced project.

Sincerely,

Matthew Dickson
Legacy Reserves Operating, L.P.

Drilling Plan Data Report

02/07/2019

APD ID: 10400033195

Submission Date: 08/17/2018

Highlighted data reflects the most recent changes

Operator Name: LEGACY RESERVES OPERATING LP

Well Name: LEA UNIT

Well Number: 103H

Show Final Text

Well Type: OIL WELL

Well Work Type: Drill

Section 1 - Geologic Formations

Formation ID	Formation Name	Elevation	True Vertical Depth	Measured Depth	Lithologies	Mineral Resources	Producing Formation
1	RUSTLER	1965	1700	1704	SANDSTONE,SILTSTONE	NONE	No
2	YATES	241	3424	3443	LIMESTONE,SANDSTONE,DOLOMITE,ANHYDRITE,SILTSTONE	NONE	No
3	SEVEN RIVERS	-144	3809	3831	DOLOMITE,SALT,ANHYDRITE,GYPSUM,SILTSTONE	NONE	No
4	QUEEN	-967	4632	4662	MUDSTONE,SANDSTONE,DOLOMITE,ANHYDRITE,GYPSUM	NONE	No
5	BELL CANYON	-1923	5588	5626	LIMESTONE,SHALE,SANDSTONE	NONE	No
6	CHERRY CANYON	-2806	6471	6514	LIMESTONE,SHALE,SANDSTONE	NONE	No
7	BRUSHY CANYON	-3442	7107	7150	LIMESTONE,SHALE,CHERT,CONGLOMERATE	NONE	No
8	BONE SPRING	-4526	8191	8234	LIMESTONE,SANDSTONE	USEABLE WATER,NATURAL GAS,OIL	No
9	UPPER AVALON SHALE	-5117	8782	8825	SHALE,SILTSTONE	USEABLE WATER,NATURAL GAS,OIL	No
10	BONE SPRING 1ST	-5839	9504	9547	LIMESTONE,DOLOMITE	USEABLE WATER,NATURAL GAS,OIL	No
11	BONE SPRING 2ND	-6376	10041	10084	SANDSTONE	USEABLE WATER,NATURAL GAS,OIL	No
12	BONE SPRING 3RD	-7034	10699	10742	SHALE,SANDSTONE	USEABLE WATER,NATURAL GAS,OIL	No
13	WOLFCAMP	-7344	11009	11056	LIMESTONE,SHALE	USEABLE WATER,NATURAL GAS,OIL	Yes

Section 2 - Blowout Prevention

Operator Name: LEGACY RESERVES OPERATING LP

Well Name: LEA UNIT **Well Number:** 103H

Pressure Rating (PSI): 5M **Rating Depth:** 11300

Equipment: Ten thousand (10M) psi working pressure Blind Rams and Pipe Rams and a five thousand (5M) psi Annular Preventer will be installed on all casing. Three (3) chokes; two (2) hydraulic and one (1) manual, will be used.
Requesting Variance? YES

Variance request: A variance is requested to use a 5M annular on the 10 M BOP. A variance to the requirement of a rigid steel line connecting to the choke manifold is requested. Specifications for the flex hose are provided with BOP schematic in exhibit section.
Testing Procedure: A third party testing company will conduct pressure tests and record prior to drilling out below 13-3/8s" casing. The BOP, Choke, Choke Manifold, Top Drive Valves and Floor Safety Valves will be tested to 5000 psi prior to drilling below the 13-3/8s" surface casing shoe and to 100% of full working pressure (10,000 psi) prior to drilling below the 9-5/8s" intermediate casing shoe. The Annular Preventer will be tested to 2500 psi prior to drilling below the 13-3/8s" surface casing shoe and to 100% of working pressure (5,000 psi) prior to drilling below the 9-5/8" intermediate casing shoe. In addition, the BOP equipment will be tested after any repairs to the equipment as well as drilling out below any casing string. Pipe rams, blind rams, and annular preventer will be activated on each trip, and weekly BOP drills will be held with each crew. Floor Safety Valves that are full open and sized to fit Drill Pipe and Collars will be available on the rig floor in the open position when the Kelly is not in use.

Choke Diagram Attachment:

McVay_2_Choke_Manifold_Diagram_20180817131908.pdf

BOP Diagram Attachment:

McVay_2_BOP_Diagram_20180817131914.pdf

Section 3 - Casing

Casing ID	String Type	Hole Size	Csg Size	Condition	Standard	Tapered String	Top Set MD	Bottom Set MD	Top Set TVD	Bottom Set TVD	Top Set MSL	Bottom Set MSL	Calculated casing length MD	Grade	Weight	Joint Type	Collapse SF	Burst SF	Joint SF Type	Joint SF	Body SF Type	Body SF
1	SURFACE	17.5	13.375	NEW	API	N	0	1800	0	1796			1800	J-55	54.5	BUTT	1.42	3.5	DRY	4.3	DRY	4.3
2	INTERMEDIATE	12.25	9.625	NEW	API	N	0	5600	0	5562			5600	HCL-80	47	BUTT	1.97	1.34	DRY	2.99	DRY	2.99
3	INTERMEDIATE	8.5	7.0	NEW	API	N	0	10700	0	10657			10700	HCP-110	32	BUTT	2.31	1.98	DRY	2.31	DRY	2.31
4	PRODUCTION	6	4.5	NEW	API	N	10200	18397	10200	11300			8197	P-110	13.5	BUTT	1.89	1.26	DRY	1.91	DRY	1.91

Casing Attachments

Operator Name: LEGACY RESERVES OPERATING LP

Well Name: LEA UNIT **Well Number:** 103H

Casing Attachments

Casing ID: 1 **String Type:** SURFACE

Inspection Document:

Spec Document:

Tapered String Spec:

Casing Design Assumptions and Worksheet(s):

Lea_Unit__103H_Drilling_Program_20180817145128.pdf

Casing ID: 2 **String Type:** INTERMEDIATE

Inspection Document:

Spec Document:

Tapered String Spec:

Casing Design Assumptions and Worksheet(s):

Lea_Unit__103H_Drilling_Program_20180817145218.pdf

Casing ID: 3 **String Type:** INTERMEDIATE

Inspection Document:

Spec Document:

Tapered String Spec:

Casing Design Assumptions and Worksheet(s):

Lea_Unit__103H_Drilling_Program_20180817145226.pdf

Operator Name: LEGACY RESERVES OPERATING LP

Well Name: LEA UNIT **Well Number:** 103H

Casing Attachments

Casing ID: 4 **String Type:** PRODUCTION

Inspection Document:

Spec Document:

Tapered String Spec:

Casing Design Assumptions and Worksheet(s):

Lea_Unit__103H_Drilling_Program_20180817145234.pdf

Section 4 - Cement

String Type	Lead/Tail	Stage Tool Depth	Top MD	Bottom MD	Quantity(sx)	Yield	Density	Cu Ft	Excess%	Cement type	Additives
SURFACE	Lead		0	1600	1300	1.72	13.5	2236	100	Class C cement	4%Bentonite, 0.4 pps Defoamer, 0.125 pps Cellophane, 9.102 H2O GPS
SURFACE	Tail		1600	1800	200	1.32	14.8	264	60	Class C Neat	6.304 H2O GPS
INTERMEDIATE	Lead		0	5000	1700	1.94	12.6	3298	180	35:65 POZ-Class C	6% Bentonite, 0.5% Fluidloss, 0.15% Retarder, 0.4pps Defoamer, 10.542 H2O GPS
INTERMEDIATE	Tail		5000	5600	350	1.18	15.6	413	140	Class H	0.3% Fluidloss, 5.216 H2O GPS
INTERMEDIATE	Lead		0	5300	820	1.18	15.6	968	15	Class H	0.2% Retarder, 6.3 H2O GPS
INTERMEDIATE	Tail		5300	10700	550	1.62	12.6	891	30	PVL	1.3% Salt, 5% Expanding Cement, 0.5% Fluidloss, 0.3% Retarder, 0.1% Antisettling, 0.4 pps Defoamer, 8.621 H2O GPS
PRODUCTION	Lead		10200	18397	700	1.34	14.2	938	30	50:50 Poz (fly ash) Class H	5% Salt, 2% Bentonite, 0.5% Fluidloss, 0.2% Retarder, 0.2% Dispersant, 0.4pps

String Type	Lead/Tail	Stage Tool Depth	Top MD	Bottom MD	Quantity(sx)	Yield	Density	Cu Ft	Excess%	Cement type	Additives
											Defoamer, 6.088 H2O GPS

Section 5 - Circulating Medium

Mud System Type: Closed

Will an air or gas system be Used? NO

Description of the equipment for the circulating system in accordance with Onshore Order #2:

Diagram of the equipment for the circulating system in accordance with Onshore Order #2:

Describe what will be on location to control well or mitigate other conditions: In the event that circulation is lost (> 50%) while drilling the 12-1/4" intermediate hole in the Capitan Reef at +/-4000', we will plan to install a DV tool and external casing packer within 200' of the top depth where lost circulation occurred and will pump a two-stage cement job with the potential to add an additional DV tool for a three-stage cement job. If there is no lost circulation a single stage cementing procedure will be followed. Legacy plans to cement to surface regardless of whether a single stage, 2-stage or 3-stage procedure is implemented.

Describe the mud monitoring system utilized: A Pason PVT system will be rigged up prior to spudding this well. A volume monitoring system that measures, calculates, and displays readings from the mud system on the rig to alert the rig crew of impending gas kicks and lost circulation. In order to effectively run casing, the mud viscosity and fluid loss properties may be adjusted.

Circulating Medium Table

Top Depth	Bottom Depth	Mud Type	Min Weight (lbs/gal)	Max Weight (lbs/gal)	Density (lbs/cu ft)	Gel Strength (lbs/100 sqft)	PH	Viscosity (CP)	Salinity (ppm)	Filtration (cc)	Additional Characteristics
5600	10700	OTHER : Cut brine	9	9.2							
1800	5600	OTHER : Brine	10	10							
0	1800	OTHER : Fresh Water	8.5	9							
10700	11300	OIL-BASED MUD	10.5	11							

Operator Name: LEGACY RESERVES OPERATING LP

Well Name: LEA UNIT **Well Number:** 103H

Section 6 - Test, Logging, Coring

List of production tests including testing procedures, equipment and safety measures:

Mud logging, H2S plan, BOP and choke plans all in place for testing, equipment, safety

List of open and cased hole logs run in the well:

CBL,GR,MWD,MUDLOG

Coring operation description for the well:

No coring planned

Section 7 - Pressure

Anticipated Bottom Hole Pressure: 5880 **Anticipated Surface Pressure:** 3394

Anticipated Bottom Hole Temperature(F): 200

Anticipated abnormal pressures, temperatures, or potential geologic hazards? YES

Describe:

Capitan Reef

Contingency Plans geoharzards description:

If lost circulation (50% or greater) occurs below the Base of the Salt, the operator shall switch to fresh water mud to protect the Capitan Reef and use fresh water mud until setting the intermediate casing. The appropriate BLM office is to be notified for a PET to witness the switch to fresh water.

Contingency Plans geohazards attachment:

Hydrogen Sulfide drilling operations plan required? YES

Hydrogen sulfide drilling operations plan:

H2S_Contingency_Plan_Briefing_Areas_Alarm_Loc._Legacy_Lea_Unit_103H_20180817142654.pdf

Section 8 - Other Information

Proposed horizontal/directional/multi-lateral plan submission:

Lea_Unit__103H_Plot_Plan_1_20180817142802.pdf

Lea_Unit__103H_Planning_Report_Plan_1_20180817142812.pdf

Other proposed operations facets description:

Other proposed operations facets attachment:

Lea_Unit__103H_AC_Report_Plan_1_20180817142823.pdf

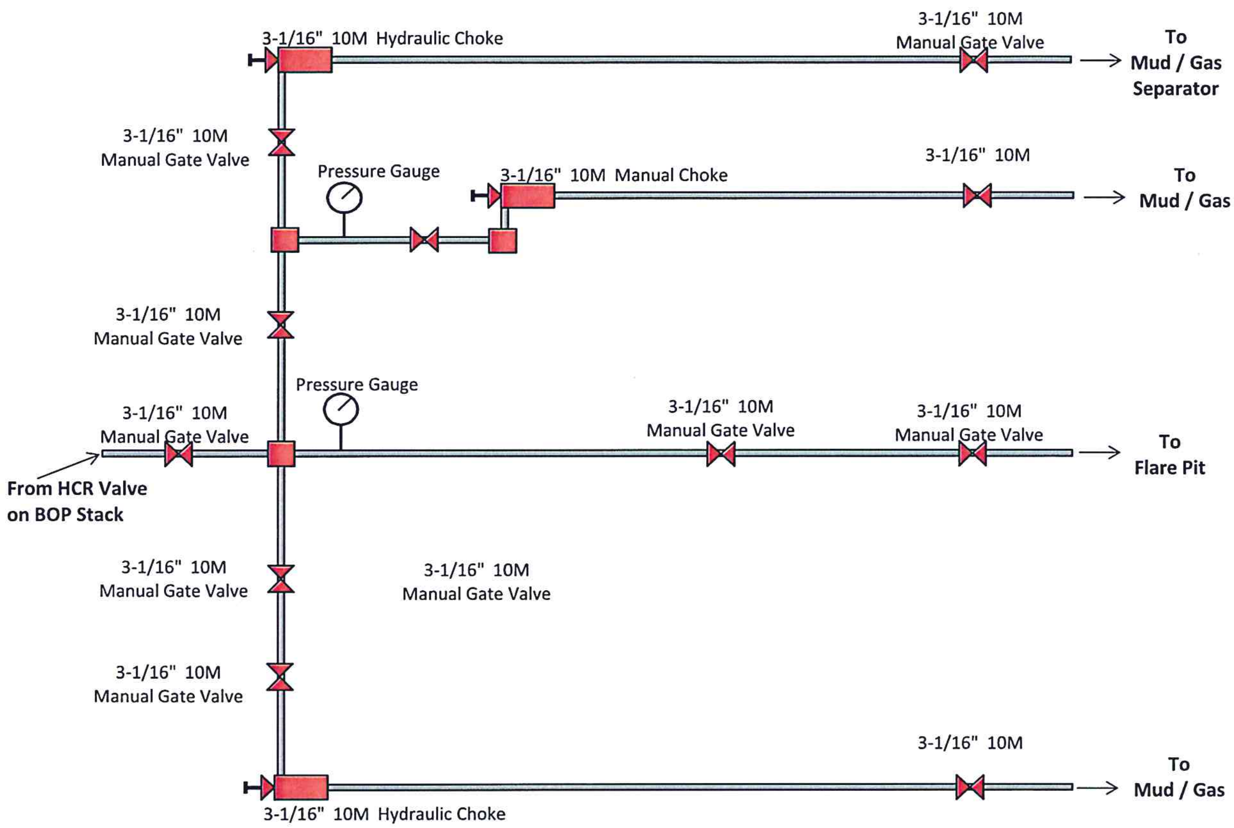
Flex_Hose_Specs_20180817142832.pdf

McVay_Rig2_Schematic_20180817142839.pdf

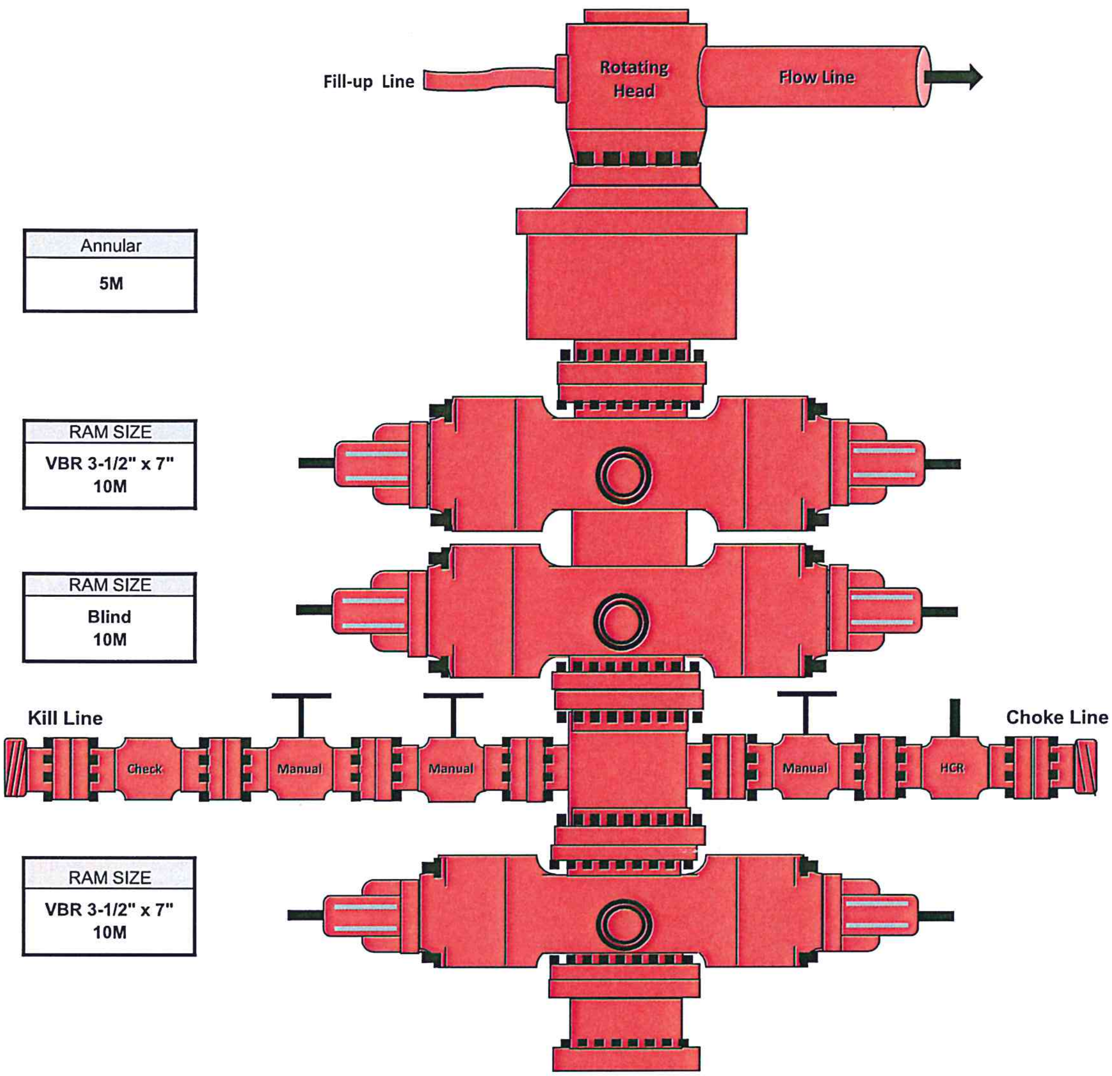
Lea_Unit_103H_GasCapturePlanFormAPD_20180817142854.pdf

Other Variance attachment:

Choke Manifold (10M)



13-5/8" BOP Stack (10M)



DRILLING PROGRAM

Operator:
LEGACY RESERVES OPERATING LP

Project Name:
LEA UNIT 103H

Project Location:
Lea County, New Mexico

Prepared By:
Matt Dickson
Drilling Engineer

Submitted To:
Bureau of Land Management
Carlsbad Field Office

Please address inquiries, questions, scheduling of meetings and deficiency statements, if any, to Scott St. John and/or Monica Smith Griffin at the address shown below:

Reagan Smith Energy Solutions, Inc.
1219 Classen Drive
Oklahoma City, OK 73103
405-286-9326

sstjohn@rsenergysolutions.com msmith@rsenergysolutions.com

1.0 Drilling Program

1.1 Estimated Formation Tops

FORMATION	*TVD @ Surface Loc*	*TVD @ KB*	*TVD @ TD*
Rustler	1,700'	1,728'	1,728'
Yates	3,424'	3,452'	3,452'
Seven Rivers	3,809'	3,837'	3,837'
Queen	4,632'	4,660'	4,660'
Bell Canyon	5,588'	5,616'	5,616'
Cherry Canyon	6,471'	6,499'	6,499'
Brushy Canyon	7,107'	7,135'	7,135'
Bone Spring	8,191'	8,219'	8,219'
Avalon Shale	8,782'	8,810'	8,810'
1st BS	9,504'	9,532'	9,532'
2nd BS	10,041'	10,069'	10,069'
3rd BS	10,699'	10,727'	10,727'
Wolfcamp	11,009'	11,037'	11,085'
Upper Wolfcamp	11,212'	11,240'	11,300'

Target Formation and Total Depth:

The total depth of the proposed well is approximately 18,397.2' MD located in the Upper Wolfcamp.

According to New Mexico EMNRD 19.15.15.9 NMAC a well shall be located no closer than 330' feet to a boundary of the unit.

1.2 Estimated Depths of Anticipated Fresh Water, Oil, and Gas

Substance	**Depth**
Fresh Water	0' to 250'
Base of Treatable Water	1100'
Hydrocarbons	8,219' to TD

1.2.2 State Water Protection Compliance

Bureau of Land Management requires surface casing to be set at a minimum of 25' into the Rustler Anhydrite and above the salt section. Operator proposes to set the surface casing at a depth of 1800' (measured from the surface) and use 13-3/8" casing.

Special Capitan Reef requirements
If lost circulation (50% or greater) occurs below the Base of the Salt, the operator shall switch to fresh water mud to protect the Capitan Reef and use fresh water mud until setting the intermediate casing. The appropriate BLM office is to be notified for a PET to witness the switch to fresh water.

1.3 Pressure Control Equipment

Ten thousand (10M) psi working pressure Blind Rams and Pipe Rams and a five thousand (5M) psi Annular Preventer will be installed on all casing. Three (3) chokes; two (2) hydraulic and one (1) manual, will be used.

A variance to the requirement of a rigid steel line connecting to the choke manifold is requested. Specifications for the flex hose are provided with BOP schematic in exhibit section.

A third party testing company will conduct pressure tests and record prior to drilling out below 13-3/8s" casing. The BOP, Choke, Choke Manifold, Top Drive Valves and Floor Safety Valves will be tested to 5000 psi prior to drilling below the 13-3/8s" surface casing shoe and to 100% of full working pressure (10,000 psi) prior to drilling below the 9-5/8s" intermediate casing shoe. The Annular Preventer will be tested to 2500 psi prior to drilling below the 13-3/8s" surface casing shoe and to 100% of working pressure (5,000 psi) prior to drilling below the 9-5/8" intermediate casing shoe.

In addition, the BOP equipment will be tested after any repairs to the equipment as well as drilling out below any casing string. Pipe rams, blind rams, and annular preventer will be activated on each trip, and weekly BOP drills will be held with each crew.

Floor Safety Valves that are full open and sized to fit Drill Pipe and Collars will be available on the rig floor in the open position when the Kelly is not in use.

1.4 Proposed Casing and Cementing Program

1.4.1 Proposed Casing Program

Interval	Depth	Size	Weight/ft	Grade	Thread	Condition	Hole size
Conductor	120'	20"	94.00#	H-40		New	26"
Surface	1,800'	13-3/8"	54.50#	J-55	BTC	New	17-1/2"
Intermediate	5,600'	9-5/8"	47#	HCL-80	BTC	New	12-1/4"
Intermediate Liner	10,700	7"	32.00#	P-110HC	BTC	New	8-1/2"
Production	18,397'	4-1/2"	13.5#	P-110	BTC	New	6"

<u>Conductor</u>: 20", H-40# line pipe to a depth of 120'.
Wall thickness of 0.250".

<u>Surface Casing</u>:

Top	Bottom	Size	Weight/ Ft	Grade	Thread	Collapse psi	Internal Yld psi	Body Yld Strength	Joint Strength
Surface	1,800'	13-3/8"	54.50	J-55	BTC	1130	2730	853,000	909,000

<u>Intermediate Casing</u>:

Top	Bottom	Size	Weight/Ft	Grade	Thread	Collapse psi	Internal Yld psi	Body Yld Strength	Joint Strength
Surface	5,600'	9-5/8"	47#	HCL-80	BTC	5,740	6,870	1,086,000	1,122,000

<u>Intermediate Liner</u>:

Top	Bottom	Size	Weight/Ft	Grade	Thread	Collapse psi	Internal Yld psi	Body Yld Strength	Joint Strength
Surface	10,700	7"	32#	P-110HC	BTC	11,890	12,450	1,025,000	1,053,000

<u>Production Casing</u>:

Top	Bottom	Size	Weight/Ft	Grade	Thread	Collapse psi	Internal Yld psi	Body Yld Strength	Joint Strength
10,200	18,397.2	4-1/2"	13.5#	P-110	BTC	10,690	12,420	422,000	443,000

1.4.2 Proposed Cement Program

Conductor: Grout to Surface (est. 8 cu. yds on backside)

13-3/8" Surface:

Surface Casing String	
LEAD	
Top of MD	0
Bottom of MD	1600
Cement Type	Class C
Additives	4%Bentonite, 0.4 pps Defoamer, 0.125 pps Cellophane, 9.102 H2O GPS
# of SKS	1300
Yield (ft3/sk)	1.72
Density (lbs/gal)	13.5
Volume (ft3)	2236
Excess (%)	100%
TAIL	
Top of MD	1600
Bottom of MD	1800
Cement Type	Class C Neat
Additives	6.304 H2O GPS
# of SKS	200
Yield (ft3/sk)	1.32
Density (lbs/gal)	14.8
Volume (ft3)	264
Excess (%)	60%

9-5/8" Intermediate (No DV Tool):

Intermediate Casing String	
LEAD	
Top of MD	0
Bottom of MD	5000
Cement Type	35:65 POZ-Class C
Additives	6% Bentonite, 0.5% Fluidloss, 0.15% Retarder, 0.4pps Defoamer, 10.542 H2O GPS
# of SKS	1700

Yield (ft3/sk)	1.94
Density (lbs/gal)	12.6
Volume (ft3)	3298
Excess (%)	180%
TAIL	
Top of MD	5000
Bottom of MD	5600
Cement Type	Class H
Additives	0.3% Fluidloss, 5.216 H2O GPS
# of SKS	350
Yield (ft3/sk)	1.18
Density (lbs/gal)	15.6
Volume (ft3)	413
Excess (%)	140%

9-5/8" Intermediate (With 1 DV Tool):

Intermediate Casing String	
***Stage 1**	
LEAD	
Top of MD	0
Bottom of MD	5000
Cement Type	35:65 POZ-Class C
Additives	6% Bentonite, 0.5% Fluidloss, 0.15% Retarder, 0.4pps Defoamer, 10.542 H2O GPS
# of SKS	1700
Yield (ft3/sk)	1.94
Density (lbs/gal)	12.6
Volume (ft3)	3298
Excess (%)	180%
TAIL	
Top of MD	500
Bottom of MD	5600
Cement Type	Class H
Additives	0.3% Fluidloss, 5.216 H2O GPS
# of SKS	350
Yield (ft3/sk)	1.18
Density (lbs/gal)	15.6
Volume (ft3)	413
Excess (%)	140%
***Stage 2**	

Stage Tool Depth	+/- 3900'
LEAD	
Top of MD	0
Bottom of MD	3500
Cement Type	35:65 POZ-Class C
Additives	6% Bentonite, 0.5% Fluidloss, 0.15% Retarder, 0.4pps Defoamer, 10.543 H2O GPS
# of SKS	1200
Yield (ft3/sk)	1.94
Density (lbs/gal)	12.6
Volume (ft3)	2328
Excess (%)	200%
TAIL	
Top of MD	3500
Bottom of MD	3900
Cement Type	Class H
Additives	0.3% Fluidloss, 5.216 H2O GPS
# of SKS	200
Yield (ft3/sk)	1.18
Density (lbs/gal)	15.6
Volume (ft3)	236
Excess (%)	100%

9-5/8" Intermediate (With 2 DV Tools):

Intermediate Casing String	
***Stage 1**	
LEAD	
Top of MD	0
Bottom of MD	5000
Cement Type	35:65 POZ-Class C
Additives	6% Bentonite, 0.5% Fluidloss, 0.15% Retarder, 0.4pps Defoamer, 10.542 H2O GPS
# of SKS	1700
Yield (ft3/sk)	1.94
Density (lbs/gal)	12.6
Volume (ft3)	3298
Excess (%)	180%
TAIL	
Top of MD	5000
Bottom of MD	5600
Cement Type	Class H

Additives	0.3% Fluidloss, 5.216 H2O GPS
# of SKS	350
Yield (ft3/sk)	1.18
Density (lbs/gal)	15.6
Volume (ft3)	413
Excess (%)	140%
***Stage 2**	
Stage Tool Depth	+/- 3900'
LEAD	
Top of MD	0
Bottom of MD	3500
Cement Type	35:65 POZ-Class C
Additives	6% Bentonite, 0.5% Fluidloss, 0.15% Retarder, 0.4pps Defoamer, 10.543 H2O GPS
# of SKS	1200
Yield (ft3/sk)	1.94
Density (lbs/gal)	12.6
Volume (ft3)	2328
Excess (%)	200%
TAIL	
Top of MD	3500
Bottom of MD	3900
Cement Type	Class H
Additives	0.3% Fluidloss, 5.216 H2O GPS
# of SKS	200
Yield (ft3/sk)	1.18
Density (lbs/gal)	15.6
Volume (ft3)	236
Excess (%)	100%
***Stage 3**	
Stage Tool Depth	+/- 1900'
TAIL	
Top of MD	0
Bottom of MD	1900
Cement Type	Class C Neat
Additives	6.304 H2O GPS
# of SKS	700
Yield (ft3/sk)	1.32
Density (lbs/gal)	14.8
Volume (ft3)	924
Excess (%)	30%

7" Intermediate Liner:

Intermediate Casing String	
LEAD	
Top of MD	0
Bottom of MD	5300
Cement Type	Class H
Additives	0.2% Retarder, 6.3 H2O GPS
# of SKS	820
Yield (ft3/sk)	1.18
Density (lbs/gal)	15.6
Volume (ft3)	968
Excess (%)	15%
TAIL	
Top of MD	5300
Bottom of MD	10,700
Cement Type	PVL
Additives	1.3% Salt, 5% Expanding Cement, 0.5% Fluidloss, 0.3% Retarder, 0.1% Antisettling, 0.4 pps Defoamer, 8.621 H2O GPS
# of SKS	550
Yield (ft3/sk)	1.62
Density (lbs/gal)	12.6
Volume (ft3)	891
Excess (%)	30%

4-1/2" Production Liner:

Production Casing String	
LEAD	
Top of MD	10,200
Bottom of MD	18,397
Cement Type	50:50 POZ-Class H
Additives	5% Salt, 2% Bentonite, 0.5% Fluidloss, 0.2% Retarder, 0.2% Dispersant, 0.4pps Defoamer, 6.088 H2O GPS
# of SKS	700
Yield (ft3/sk)	1.34
Density (lbs/gal)	14.2

Volume (ft3)	938
Excess (%)	30%

Cement volumes are based on bringing cement to surface on all strings and TOC to ~10,200' (top of liner) on production.

Operator reserves the right to change cement designs as hole conditions may warrant.

1.5 Proposed Mud Program

Top TVD	Bottom TVD	Type	Max Mud Weight for Hole Control Design	Viscosity (sec/qt)
SURFACE	1,800	Fresh Water	9.0	28-38
1800	5,600	Brine	10.0	28-30
5,600	10,700	Cut Brine	9.2	28-30
10,700	TD	OBM	11.0	55-65

The operator must include the minimum design criteria, including casing loading assumptions and corresponding safety factors for burst, collapse, and tensions (body yield, and joint strength).

1.6 Casing Design

1.6.1 Drilling Design Analysis

Interval	Max TVD (ft)	Anticipated Mud Weight (ppg)	Estimated Max Pore Pressure (psi)	Internal Yield Strength (psi)	Collapse Strength (psi)	Joint Strength (lbs)	Body Strength (lbs)	Burst Safety Factor (Min 1.25)	Collpase Safety Factor (Min 1.25)	Tensile Safety Factor (Min 1.6)
Surface	1,800	8.5	780	2,730	1,130	909,000	853,000	3.5	1.42	4.3
Interm.	5,600	10	2,420	6,870	5,740	1,122,000	1,086,000	1.34	1.97	2.99
Tie-Back	10,700	9.0	4,730	12,450	11,890	1,053,000	1,025,000	1.98	2.31	2.31
Prod.	11,300	10.5	5,880	12,420	10,690	443,000	422,000	1.26	1.89	1.91

Surface Casing Design Notes:

- **Burst Design Assumptions: Calculations assume complete evacuation behind pipe.**
- **Collapse Design Assumptions: Calculations assume complete evacuation inside pipe.**
- **Tension Design Assumptions: Calculations include 100,000 lb. max over-pull and do not consider the effects of buoyancy, with string held in tension.**

Intermediate Casing Design Notes:

- **Burst Design Assumptions: Calculations assume a .7psi/ft shoe test, and 0.22 psi/ft gas gradient.**
- **Collapse Design Assumptions: Calculations assume complete evacuation inside pipe.**
- **Tension Design Assumptions: Calculations include 100,000 lb. max over-pull and do not consider the effects of buoyancy, with string held in tension.**

Intermediate Liner w/ Tie-Back Design Notes:

- **Burst Design Assumptions: Calculations assume a .7psi/ft shoe test, and 0.22 psi/ft gas gradient.**
- **Collapse Design Assumptions: Calculations assume complete evacuation inside pipe.**
- **Tension Design Assumptions: Calculations include 100,000 lb. max over-pull and do not consider the effects of buoyancy, with string held in tension.**

Production Design Notes:

- **Burst Design Assumptions: Calculations assume surface frac pressure of 9500 psi along with a fluid gradient of 0.49psi/ft, with an external force equivalent to 0.44 psi/ft.**
- **Collapse Design Assumptions: Calculations assume complete evacuation inside pipe.**
- **Tension Design Assumptions: Calculations include 100,000 lb. max over-pull and do not consider the effects of buoyancy, with string held in tension.**

*Notes:

1) Collapse DSF: If < 1.125 calculations are required.
2) Burst DSF: If < 1.0 calculations are required.
3) Body Tensile DSF: If < 1.6 (dry) or < 1.8 (buoyant) calculations are required.
4) Joint Tensile DSF: If < 1.6 (dry) or < 1.8 (buoyant) calculations are required.
5) Will an offset pressure variance request be requested to meet safety factors? Max. 0.22 psi/ft. Please indicate offset pressure variance requested.

Mud weight increases at shoe depths are for pressure control. Mud weight increases in the curve and lateral sections of the hole are for hole stability, not pressure control. Mud weight assumptions for casing load designs exceed anticipated maximum mud weight for balanced drilling in all hole sections. Expected mud weights in the Upper Wolfcamp Horizontal will be 0.5 to 1.0 ppg greater than formation pressure (i.e. overbalanced drilling.)

The Mud System will run as a closed loop system with PVT monitoring. All drill cuttings and liquid mud will be hauled to an approved NMOCD site for disposal or soiled farmed upon receiving appropriate approval.

1.7 Completion Program and Casing Design

Hydraulic fracturing will occur through the production casing. The burst design calculation assumes TOC at surface and therefore, the backside of the production casing is not evacuated. The maximum pumping pressure is 10,000 psi with a maximum proppant fluid weight of 9.5 ppg. The design safety factor for burst is 1.25.

Upon request, operator will provide proof of cement bonding by bond log. Operator is responsible for log interpretation and certification prior to frac treatment.

Upon request, operator will provide estimated fracture lengths, flowback storage, volumes of fluids and amount of sand to be used, and number of stages of frac procedure. Furthermore, a report of the annulus pressures before and after each stage of treatment may be requested by the BLM. The report may include chemical additives (other than proprietary), dissolved solids in frac fluid, and depth of perforations.

1.8 Evaluation Program

Required Testing, Logging, and Coring procedures noted below:

- Mud Logging/Gamma Ray/MWD.
- Cased hole CBL on production casing.

1.9 Downhole Conditions

Zones of possible lost circulation:	Capitan Reef
Zones of possible abnormal pressure:	Upper Wolfcamp
Maximum bottom hole temperature:	200° F
Maximum bottom hole pressure:	5,880 psi or less.

1.10 Overview of Drilling Procedure

- Drill 17.5" surface hole to 1,800'; run 13.375" casing to 1,800' and cement to surface; install 10M stack, set isolation plug and test BOPE and casing independently to regulatory requirements.
- Drill 12.25" intermediate hole to 5,600', run 9.625" casing and cement; set isolation plug and test BOPE and casing independently to regulatory requirements.
- Drill 8-1/2" intermediate hole to approximately 10,700' and run 7" liner with a tie-back sleeve, and cement to top of liner set at +/- 5,300'.
- Drill 6" production hole to +/- 18,500'; run 4.5" liner from TD to +/- 10,200' and cement per cement program and test.
- Run 7" tie-back string from +/- 5300' to surface and cement per cement program, circulate cement to surface.

1.11 Overview of Completion for Equipment Sizing

- A Sundry Notice will be submitted with the proposed completion procedure prior to the job.