Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

HOBBS OCD
JUN 16 2014
RECEIVED

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-025-25785

5. Indicate Type of Lease STATE ☐ FEE ☒

6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name
MARK

1. Type of Well: Oil Well ☒ Gas Well ☐ Other

8. Well Number 10

2. Name of Operator
CHEVRON U.S.A. INC.

9. OGRID Number 4323

3. Address of Operator
15 SMITH ROAD, MIDLAND, TEXAS 79705

10. Pool name or Wildcat
PENROSE; SKELLY GRAYBURG

4. Well Location
Unit Letter: H 1650 feet from NORTH line and 340 feet from the EAST line
Section 3 Township 22S Range 37E NMPM County LEA

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☐	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER: CLEANOUT & ACIDIZE				OTHER:			

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

CHEVRON U.S.A. INC. INTENDS TO CLEANOUT AND ACIDIZE THE GRAYBURG FORMATION.

PLEASE FIND ATTACHED, THE INTENDED PROCEDURE.

DURING THIS PROCESS WE PLAN TO USE THE CLOSED LOOP SYSTEM WITH A STEEL TANK AND HAUL TO THE REQUIRED DISPOSAL, PER THE OCD RULE 19.15.17.

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Denise Pinkerton TITLE REGULATORY SPECIALIST DATE 06/12/2014

Type or print name DENISE PINKERTON E-mail address: leakejd@chevron.com PHONE: 432-687-7375

For State Use Only

APPROVED BY: Maley Brown TITLE Dist. Supervisor DATE 6/16/2014

Conditions of Approval (if any):

JUN 17 2014

WELL NAME: Mark #10

API #: 30-025-25785 CHEVNO: EP9821

OPERATOR: Chevron Midcontinent, L.P.

LOCATION: 1650' FNL & 340' FEL Sec.3 TwnShp: 22S Range: 37E

COMPLETION: 7/1/2006

The purpose of this project is acidize the vertical section of wellbore in Grayburg, and to coil tubing CO the horizontal section of Grayburg and acidize. This procedure is meant to be a guide only. It is up to the WSM, Workover Engineer and Production Engineer to make the decisions necessary to do safely what is best for the well. PLEASE REFER TO THE H2S SHEET AND TAKE ALL NECESSARY PRECAUTIONS TO MITIGATE THAT AND ANY OTHER RISKS.

Contacts: John Taxiarchou (PE) 432-687-7208, 210-848-8284 (C)
Danny Hunt (OS) 575-394-1242, 817-526-2322 (C)
Bobby Hill (PTTL) 575-394-1245, 575-631-9108 (C)
Clarence Fite (ALCR) 575-394-4001, 575-390-9084 (C)
Kevin Jones(WE) 432-687-7388, 575-631-4407 (C)
Victor Bajomo (DS) 432-687-7953, 432-202-3767 (C)
Gabriel Garcia (LWSM) 575-390-7220 (C)
Darryl Ruthardt (LWSM) 575-390-8418 (C)

Wellbore Information:

Surface Casing –9 5/8" 36# J-55 set @ 1132' TOC Surf.
Intermediate Casing – 7" 23# @ 7571' TOC Surf.
Casing Window – 4 ½" 3620-28 OH Horizontal
PBTD – 6515' CIBP
PERFS – 3650' to 3817' (Grayburg)

LONG TUBING set at 3,969.6ftKB on 7/15/2008 00:00

Tubing Description	Run Date	String Length (ft)	Set Depth (MD) (ftKB)
LONG TUBING	7/15/2008	3,959.15	3,969.6

Item Des	Jts	OD (in)	Wt (lb/ft)	Grade	Len (ft)	Btm (ftKB)
TUBING	113	2 7/8	6.50	J-55	3,540.00	3,550.5
ANCHOR CATCHER		2 7/8	0.00	0	2.70	3,553.2
TUBING	11	2 7/8	6.50	J-55	347.32	3,900.5
BLAST JOINT	1	2 7/8	6.50	J-55	32.56	3,933.1
SEATING NIPPLE		2 7/8	0.00	0	1.10	3,934.2
PERFED SUB		2 7/8	6.50	J-55	4.02	3,938.2
MUD JOINT	1	2 7/8	6.50	J-55	31.45	3,969.6

Rod Strings

Short Rod on 7/15/2008 00:00

Rod Description	Run Date	String Length (ft)	Set Depth (ftKB)
Short Rod	7/15/2008	3,949.00	3,949.0

Item Des	Jts	OD (in)	Wt (lb/ft)	Grade	Len (ft)	Btm (ftKB)
POLISHED ROD		1 1/2			26.00	26.0
PONY ROD		1			20.00	46.0
ROD	56	1			1,400.00	1,446.0
ROD	85	7/8			2,125.00	3,571.0
SINKER BAR	14	1 1/2			350.00	3,921.0
PONY ROD	14	7/8			4.00	3,925.0
ROD PUMP	14	2			24.00	3,949.0

Chevron

WELL NAME: Mark #10

API #: 30-025-25785 CHEVNO: EP9821

OPERATOR: Chevron Midcontinent, L.P.

LOCATION: 1650' FNL & 340' FEL Sec.3 TwnShp: 22S Range: 37E

COMPLETION: 7/1/2006

PRE-WORK:

1. Complete the rig move checklist.
2. Ensure location is in appropriate condition, anchors have been tested within the last 24 months, and power line distance has been verified to determine if a variance and RUMS are necessary.
3. When NU anything over and open wellhead (EPA, etc.) ensure the hole is covered to avoid dropping anything downhole.
4. Review H2S calculations in H2S tab included.
5. Any equipment installed at the wellbore, including wellhead (Inside Diameter), is to be visually inspected by the WSM to insure no foreign debris or other restrictions are present.
6. DO NOT! Flow back CO2 to non CO2 rated vessels.
7. Have horse head removed from well.
8. Ensure that at least 1,000 feet of production yellow band tubing is available to CO well.

PROCEDURE:

1. Verify that well does not have pressure or flow. If the well has pressure, note tubing and casing pressures on Wellview report. Bleed down well; if necessary, kill with cut brine fluid (8.6 ppg).
2. MIRU pulling unit and surface equipment.
3. Remove stuffing box and lay down polish rod.
4. Unseat pump and POOH LD rods and inspecting for pitting and shoulder damage.
5. Ensure well is dead. ND WH. Release TAC.
6. NU Chevron Class III configured 7-1/16" 5M remotely-operated hydraulically-controlled BOP, 2-7/8" pipe rams over blind rams. NU EPA pan.
    - Keep the charted test of the BOP supplied by the vendor for the entire job.
7. RU Floor, unset TAC and POOH w/1 Jnt. 2 7/8" tubing. PU 7" 23# cup test packer, RIH w/ PKR +/- 25' and test BOPE to 250/500 psi. Note testing pressures in Wellview. Release and LD packer.
    - **Caliper elevators and tubular EACH DAY prior to handling tubing/tools. Note in JSA when and what items are callipered within the task step that includes that work.**
8. POOH scanning and LD 2-7/8" production tubing and BHA. Keep Yellow tubing, send bad tubing to 1788.

- **Strap production pipe out of hole to verify depths and note them in Wellview. Send Tubing scan report to KJCY@chevron.com.**
- **Order replacement production tubing. You should already have 1,000 feet available.**

9. PU 6" bladed junk mill, four 3-1/2" DC and 2-7/8" tubing. RIH till tag fill.
   - **Begin tripping in the hole with production tubing. If necessary SD while you wait for remaining new 2-7/8 production tubing.**
10. MIUL new 2-7/8 tubing and continue to RIH.
11. MIRU Foam/ Air Unit, Flowback Manifold, and Blowdown Tank w/Gas Buster.
12. Clean out fill to **4300'**. **(See Supplemental SOG for Foam Air operations)**
13. POOH w/ tubing standing back, LD BHA.
14. PU 7" 23# Arrow Set 10K treating packer in tandem with 7" RBP on 2-7/8 production tubing.
15. RIH hydrotesting to **5000** psi. Set RBP @ 3870'. POOH one joint and set treating packer. Test RBP against treating packer to 500 psi for 5 minutes.
    - **If the RBP test fails POOH and fix or replace then repeat test.**
16. PU packer to 3635'.
17. MIRU Pretroplex acid contractor. Install Petroplex plug valve to tubing instead of frac. Valve. Pressure test surface lines and plug valve to **6000** psi and pop offs to **5000** psi. Spot 750 gallons of X-25 across perfs. Once X-25 hits bottom of tubing set packer @ 3,635'. Pump 17 bbls of X-25 followed by 2 bbls of flush.
    - **Ensure that the proper number of strokes has been calculated to allow the packer to be set at the right time.**
    - **Allow X-25 to soak for 24 hours.**
18. Flowback the full load of X-25.
    - **If needed swab back.**
    - **Discuss with RE when to stop flowback or swabbing.**
19. MIRU Petroplex Acidizing. Install Petroplex plug valve to tubing instead of Frac Valve. Pressure test surface lines and plug valve to **6000** psi and set mechanical pop offs to **5000** psi. Acid Frac Blinebry @ 13BPM w/Max Surface Psi of **5000**psi from 3,650'-3,817' with 2,650 gals 15% HCl slurry and 2,500# of rock salt as follows

Additive	Amount
I-3	5 gal.
Acetic-G	13 gal.
FENX	92 lbs
EP-3	5 gal
P-3 Low Surface Wetting Agent	7 gal.
I-10	1 gal

20. Record ISIP, 5-Min, 10-Min, 15-min. RD & release Petroplex.

21. Leave well SI for 2hr to allow acid to spend. Open well and flow back/swab back spent treatment fluids to open top tank. Test reactivity of recovered acid load of fluid, If acid is not spent shut well in 1 additional hour to allow acid to spend. Recover 100% of load if possible or swab until return indicate formation fluid and not spent acid. *Record oil cut recovered, fluid volumes, and swabbing depths in Wellview.*

22. Release PKR, RIH washing down with fresh water to retrieve RBP @ 3870'. POOH and LD 2-7/8" WS, PKR and RBP.

23. PU 7" 23# Arrow Set 10K treating packer with a 1.43" 'F' stainless steel profile nipple in tandem with 7" RBP on 3-1/2 L-80 9.3# 8 round frac string.

24. RIH Hydrotesting tubing to **7000**psi and set RBP at **3,635'**. PU and set treater packer at 3,630'.

25. Test RBP against treating packer to **500** psi for 5 minutes.

    - **If RBP fails notify RE.**

26. Unset packer and PU to 3,615'. Set packer and test the casing to surface **500** psi for 5 minutes.

    - **If test fails notify RE.**

27. RU, run in and set profile plug using slick line.

28. RD BOP. RU WH.

29. RDMO workover rig.

30. Procedure to move in coil tubing pre work is as fallows

    - **See CT company proposal on back to verify additives are on location and added to the system.**
    - **Set up an exclusion zone on coiled tubing operations and discuss in the JSA. The area from the wellhead to the unit (essentially the area below the goose neck and coil) to ensure we do not have people in these areas when the coil is being run in or out of the well. Record mitigation steps on the wellview report.**

1. MIRU coil unit. (referenced from Coil Tubing Unit Drillout SOP) Coil unit will be contracted that has lubricator support built into the truck instead of a crane lift. This setup puts less stress on the 1" 8rd connection.
    a. Prior to CT RU shut in well. Spot CTU along with acid tanks for X-25 avoiding placement of equipment where evacuation routes are obstructed. Ensure that CTU gooseneck placement is in accordance with MCA SWP electrical line policy.
    b. The wellhead should consist of a B1 flange, IPC nipple, and 2" gate valve. The CT stack should be as follows: 2" 8RD X Bowen connection swedge, flowcross, BOP (blind, shear, slip, and pipe), lubricator, and injector head. From the flowcross, run a line to a dual choke manifold w/ a minimum rating of 5M. The downstream line of the choke should run to a half frac. Manifold a second half frac to the first with a 4" equalizing line on the bottom of the backside. The first pit will serve as a settling pit and the pumps will suck water off the top of the second pit. Setup equipment to monitor backside pressure.
    c. Ensure that there is a sufficient distance between the top of the BOP blind rams and the top of the lubricator to contain the entire CT BHA. Verify that there is enough room to close the blind rams with 16 inches of clearance.
    d. Perform hydraulic function test of the BOP rams and inspect all components.
    e. Inspect the CT BOP. Ensure proper sized rams are installed and that sealing elements are appropriate for the environment. Ensure BOP shear rams are rated for the tubing being used. Verify that vendor has tested BOP's within last 14 days and supplies stump test chart.
    f. Perform a mechanical function test of the BOP. Record precharge and charge pressures along with bottle volume and ram volume requirements to comply with Chevron BOP requirements.
    g. Connect lubricator to the injector and run tubing through the lubricator.
    h. Cut the end of the coiled tubing with a manual rotary pipe cutter and affix a tubing connector. Check manufacturing specs for load requirements in order to determine pull test ratings.
    i. Perform pull test by installing a pull plate in bottom box of the CTU connector. Pull test against the bottom of the lubricator. Pull test to recommended value based on coil connector.
    j. Pump fresh water through coil using dye as needed to load the coil and determine capacity. Makeup bull plug with needle valve to CTU connector. Establish an exclusion zone and hydro test CT to no more than 80% of yield
    k. Install bottom hole assembly (BHA should be slick 1.25" OD):
        - back pressure valve
        - ~4' straight pipe
    l. Pump through BHA to surface function test.
    m. Rig up CT injector, lubricator, and BOP's to wellhead. Leave the crane block connected to the injector lift bail to stabilize the unit. Secure the injector frame to deadman anchors with CTU guywires on the backside of the injector head. Secure the the front side of the injector frame back to the reel trailer with chain and ratcheting boomer. Guying back to the wellhead is not considered a secure rig up. The wellhead is not an anchor point; use ground anchors previously installed.
    n. Verify that all wellhead and pressure control components have working pressures of at least 3000 psi. Perform pressure test at 500 psi low and 3000 psi high (or 80% of lowest rated component) for 5 minutes each against closed gate valve to test pump iron, CT, wellhead, stripper, flow back

lines, and manifold. During pressure test, bleed off the low pressure prior to attempting the high pressure test (do not step pressures up). Bleed test pressure off.

o. Activate CT Data Acquisition system. Zero the weight indicator and check the analogue gauge is zero. Check that speed, depth, tubing pressure, wellhead pressure, and rate/total readouts are set on zero. Ensure that emergency engine kill switch is present and working.

2. RU wireline. PU and POOH with profile plug. RD wireline.
3. Equalize pressure across the gate valve, open well, and RIH with sonic hammer.
4. RIH to ~500' (no greater than 50 ft/min), perform weight check by pulling up at least 50'. Perform weight checks every additional 2000' in the tubing and after exiting the tubing, unless a tag occurs. If tag occurs, perform weight check before washing through fill. Slow to 20 ft/min within 200' of PN/packer (packer set at 3,630') and continue at reduced speed while below the end of tubing.
   - **Consult Sonic Hammer rep for pumping rates and treatment details. Normal rate is .8 bbls/min at ~4000 psi w/ 12,000' of coil. Circulate the entire time the CT is below the gate valve, but circulate at a reduced rate through the tubing.**
   - **Use FW.**
5. Once the CT reaches casing window, wash out 50' intervals with ~10 bbl gel pills in between. Pull CT up out of casing as needed to assist with clearing cuttings. Shut in switch to X-25 and wash pulling back through the window.
6. Wash out fill using fresh water to PBTD if possible. Notify WOE if PBTD is not reached. Circulate bottoms up from final clean-out depth.
   - **Backside pressure should not exceed #3000. Slow pump rate if necessary.**
7. **If wash tool was unsuccessful to wash perforations, discuss with Engineering.**
8. POOH pumping rate equal or greater than the displacement of the coil volume being pulled from the hole, displace coil with fresh water to flowback tank containing soda ash to neutralize acid. Monitor choke pressure and volume in/out so that the acid is not allowed to flow back into the tubing.
31. RDMO coiled tbg unit. Flow well back to open top tanks after allowing 24 hours for the X-25 to spend.
32. Flowback the full load of X-25.
    - **If needed swab back.**
    - **Discuss with RE when to stop flowback or swabbing.**
33. **Contact WOE prior to pumping acid.**
34. MIRU Petroplex Acidizing. Install Petroplex plug valve to tubing instead of Frac Valve. Pressure test surface lines and plug valve to **7000** psi and set mechanical pop offs to **6000** psi. Acid Frac Blinebry @ **13BPM w/Max Surface Psi of 6000**psi window from 3,620'-3,628' with XXXX gals 15% HCl slurry and XXXX# of rock salt as follows

Additive	Amount
I-3	5 gal.
Acetic-G	13 gal.
FENX	92 lbs
EP-3	5 gal
P-3 Low Surface Wetting Agent	7 gal.
I-10	1 gal

35. Record ISIP, 5-Min, 10-Min, 15-min. RD & release Petroplex.

36. Leave well SI for 1hr to allow acid to spend. Open well and flow back/swab back spent treatment fluids to open top tank. Test reactivity of recovered acid load of fluid, If acid is not spent shut well in 1 additional hour to allow acid to spend. Recover 100% of load if possible or swab until return indicate formation fluid and not spent acid. *Record oil cut recovered, fluid volumes, and swabbing depths in Wellview.*

37. Unset packer and POOH LD 3-1/2 tubing and packer.

38. PU production tubing with on/off tool, TIH and retrieve RBP.

39. POOH with tubing, on/off tool and RBP, LD same.

40. PU Production BHA and RIH hydrotesting production tubing to **5000** psi. ***(Space out per ALCR Recommendations)***

41. NDBOPE, NUWH.

42. RIH w/Pump and Rods per ALCR Rod design.

    - **Contact appropriate Field Specialist to remove locks**.

43. Check pump action with pumping unit.

44. Clean location, RDMO, Notify ALCR and production, Complete Wellwork Ownership Form,Turn well back to Production. (contacts on first page).***Send copy of Wellwork Ownership Form to KJCY@Chevron.com when completed.***

STANDARD GUIDELINES

Maximum Anticipated H2S Exposures (RRC H9 / NM Rule 36)

All personnel on location must be made aware of each of the following values (values vary by field):

Maximum anticipated amount of H2S that an individual could be exposed to is 11000 ppm
at the maximum anticipated escape volume (of wellbore gas) of MCF/D
100 ppm Radius of Exposure is 138 feet.
500 ppm Radius of Exposure is 63 feet.

Elevators

At every tubing size change, the elevators must be calipered and all lifting equipment must be visually inspected for the correct sizing, and rechecked daily. The elevators must also be checked for proper sizing by placing a pony sub in the elevators. Prior to picking up power swivel, caliper and visually inspect elevators and bail on swivel. Checks are to be documented in the JSA and elevator log.

ND/NU

Prior to N/D, N/U operations, if only one mechanical barrier to flow will be in place, visual monitoring of well condition by the WSM is necessary for 30 minutes or more to ensure that the well is static ***before*** removing or replacing well control equipment. For all deviations to 2B policy, check that MOC for exemption from 2B policy is in place and applicable. During ND/NU operations with only one barrier to flow in-place, constant visual monitoring of well condition ***during ND/NU*** by the WSM is necessary.

Installed Equipment

Any and all equipment installed at the surface on the wellbore is to be visually inspected (internally) by the WSM prior to N/U to the wellhead by the service provider to ensure no debris or other potential restrictions are present. During any NU ops over an open wellhead (BOP, EPA, etc.), ensure the hole is covered to avoid dropping anything downhole.

Hazard ID

Identify hazards with the crew as they come up during the job. Stop and review and discuss JSAs.

Scale and Paraffin Samples

When removing rods and/or tubing from a well, collect samples of any paraffin and/or scale.

When drilling, note, report and sample significant returns of scale or paraffin, or anything other significant returns. Assume that samples that come from different areas/environments in the well are different and require a different sample; e.g. top/bottom of well, inside outside of tubing. Always collect enough sets of samples for both Production and D&C Chemical Reps. Send any samples to Chemical Reps., both for

1) Production (many times Baker), as well as for
2) D&C (many times PetroPlex).

Discuss D&C's Chemical Rep's recommendations with Engineering, or simply implement as practical.

Trapped Pressure

Recognize whether the possibility of trapped pressure exists, check for possible obstructions by:

- Pumping through the fish/tubular – this is not guaranteed with an old fish as the possibility of a hole above the obstruction could yield inconclusive results
- Dummy run – make a dummy run through the fish/tubular with sandline, slickline, e-line or rods to verify no obstruction. If unable to verify that there is no obstruction above the connection to be broken, or if there is an obstruction:
- Hot Tap at the connection to check for pressure and bleed off
- Observe and watch for signs / indicators of pressure as connection is being broken. Use mud bucket (with seals removed) and clear all non-essential personnel from the floor.

Wireline

For all wireline and slickline jobs (except in new, cemented, tested and unperforated casing) install wireline packoff and lubricator. Follow Standard Guideline for installing equipment over wellhead. Test to 250 on the low end, and test on the high end based on SITP or max. anticipated pressure. Establish exclusion zone around wellhead area. Observe and enforce radio silence as needed for explosives. All wireline tools are to be calipered and documented on a diagram prior to PU and RIH. This is critical information in the event of fishing operations.

Foam clean out hazard mitigation

1 Install flowback manifold with two chokes. All components on flowback manifold must be rated to at least 5,000 psi. If possible, flowback manifold components should be hydrotested before delivery.

2 Run dart type float in bit sub bored for a float. Install open top flowback tank downwind from rig.

3 NU stripper head with **NO Outlets** (Check stripper cap for thread type - course threads preferred). Stripper head to be stump tested to 1,000 psi before use for foam operations.

4 Clear floor of all personnel while breaking circulation and anytime they are not required.

5 Pump high quality foam at all times. Do not pump dry air at any time. Fluid injection rates will generally be above 12 gallons per minute

6 Whenever there is pressure on the stripper head, have a dedicated person continuously monitor pressure at choke manifold and have a dedicated person at accumulator ready to close annular BOP in case stripper leaks.

7 Do not allow pressure on stripper head to exceed 500 psi. If pressure cannot be controlled below 500 psi, stop pumping, close BOP and bleed off pressure.

8 Ensure that high quality, stiff foam is pumped while circulating in lateral. Stiff foam is required to prevent segregation while circulating along lateral. Monitor flow and pressures carefully when cleaning out the lateral as well will begin to unload very rapidly when foam "turns the corner".

9 Before rigging up power swivel to rotate, carefully inspect Kelly hose to ensure that it is in good condition. Ensure that swivel packing is in good condition. Visually inspect and caliper elevators and bail on swivel.

10 POOH LD workstring & bit. Pump kill fluid down tubing to put tubing on vacuum to help eliminate trapped pressure before breaking out string floats. Have foam-air hand on location during this process. He should employ a special tool to check for pressure under floats.