Hilcorp Energy Company
State of Colorado 24-33BH
SHL: 625’ FSL 2,065’ FWL (SE/4 SW/4)
BHL: ±600’ FNL ±1,980’ FWL (NE/4 NW/4)
Sec. 33 T14S R63W
El Paso County, Colorado
Surface: Fee
Mineral Lease: State

CONFIDENTIAL

DRILLING PROGRAM

Please contact Mr. John McKnight with Hilcorp at 713-289-2755, if there are any questions or concerns regarding this Drilling Program.

WELL OBJECTIVES
(1) Drill and case each wellbore with no health, safety, or environmental impact.
(2) Optimize drilling efficiency by utilizing best drilling practices and input from entire drill team. Communicate best practices to Hilcorp so they can be included in the design of future wellbores.

SURFACE ELEVATION – 5,918’ (Un-graded ground elevation)

SURFACE FORMATION – Arapahoe

ESTIMATED FORMATION TOPS (PILOT HOLE)

	(TVD)	(Subsea est.)
Arapahoe	20’	5,912’
Laramie	500’	5,432’
Fox Hills	800’	5,132’
Pierre Shale	1,050’	4,882’
Niobrara	5,220’	712’
Niobrara B	5,375’	557’
Niobrara C	5,525’	407’
Fort Hays	5,640’	292’
Codell	5,680’	252’
Carlile Shale	5,690’	242’
TOTAL DEPTH	**5,940’**	**-8’**

ESTIMATED DEPTHS OF ANTICIPATED WATER, OIL, GAS, OR MINERAL BEARING FORMATIONS (PILOT HOLE)

	(TVD)	(MD)	
Arapahoe	20’	20’	Fresh Water
Laramie	500’	500’	
Fox Hills	800’	800’	Fresh Water
Pierre Shale	1,050’	1,050’	
Niobrara	5,220’	5,220’	Water, Oil & Gas
Niobrara B	5,375’	5,375’	Water, Oil & Gas
Niobrara C	5,525’	5,525’	Water, Oil & Gas
Fort Hays	5,640’	5,640’	
Codell	5,680’	5,680’	
Carlile Shale	5,690’	5,690’	

ESTIMATED FORMATION TOPS (PRODUCTION HORIZONTAL HOLE)

	(TVD)	(Subsea est.)
Arapahoe	20’	5,912’
Laramie	452’	5,460’
Fox Hills	752’	5,160’
Pierre Shale	1,002’	4,910’
Niobrara	5,172’	740’
Niobrara B	5,327’	585’
Niobrara C	5,477’	435’

ESTIMATED DEPTHS OF ANTICIPATED WATER, OIL, GAS, OR MINERAL BEARING FORMATIONS (PRODUCTION HORIZONTAL HOLE)

	(TVD)	(MD)	
Arapahoe	20’	20’	Fresh Water
Laramie	452’	452’	
Fox Hills	752’	752’	Fresh Water
Pierre Shale	1,002’	1,002’	Water & Gas
Niobrara	5,172’	5,194’	Water, Oil & Gas
Niobrara B	5,327’	5,402’	Water, Oil & Gas
Niobrara C	5,477’	5,736’	Water, Oil & Gas

All fresh water and prospectively valuable minerals encountered during drilling will be recorded by depth and protected.

HORIZONTAL DRILLING PROGRAM

A) Kick-Off-Point (KOP) is estimated to be at 4,780’ TVD.

B) A non-productive test for evaluation purposes will be run in the pilot hole (vertical portion) from 5,000’ – 5,940’ TVD. After the pilot hole is tested a cement plug will be set.

C) The horizontal portion of the well will kick off at 4,780' TVD, the curve and lateral will be drilled, and production casing will run the distance of the horizontal leg +/- 4,070 ft.

CASING PROGRAM

Total Measured Depth (MD)	Hole Diameter	Casing Diameter	Casing Weight and Grade	Cement
0 – 40'	17 1/2"	16" w/ 3/8" WT	Conductor Casing	Redimix to surface
Surface 0' – 1,600'	13-1/2"	10-3/4"	K-55 40.50 lbm/ft	Lead: ±335 sks Swiftcem B2 Tail: ±215 sks Swiftcem B2*
Horizontal Production 0' – 9,260'	8-1/2"	5-1/2"	L-80 20 lbm/ft	Lead: ±620 sks Extendacem Tail: ±800 sks Extendacem)**

* *Cement volume calculated based on gauge hole plus 100%.*

** *Cement volume calculated based on gauge hole plus 35%.*

Yields:	Surface:	Lead:	Swiftcem B2 =	2.42 ft^3/sk (12.0 ppg) 14.36 gal/sk
		Tail:	Swiftcem B2 =	1.72 ft^3/sk (13.5 ppg) 9.09 gal/sk
	Production:	Lead:	Extendacem =	2.4 ft^3/sk (11.3 ppg) 13.81 gal/sk
		Tail:	Extendacem =	1.67 ft^3/sk (13.8 ppg) 7.75 gal/sk

DRILLING SEQUENCE

Prior to Spud

1. Prior to rig move, the following should be completed:
    a. Have conductor pre-set at 40' below ground level. Run and cement 16" w 3/8" WT casing in 17-1/2" hole.
    b. Drill mouse and rat hole per rig layout.
2. Visually inspect BOP elastomers for wear or defects.
3. Have BHA component connections inspected (DCs, XOs, HWDP).
4. Cut conductor per rig requirement.
5. Install flow-line, flow-line jet. Install fill-up line; install drains on conductor below final cut depth.
6. Make all necessary regulatory notifications at least 24 hrs. prior to spudding well.
7. Construct location for zero discharge. No reserve pit will be constructed. All mud will be hauled back to vendor and cuttings hauled to most economic commercial disposal facility.

Surface Hole Section

1. P/U 13-1/2" BHA. Ensure all components have been inspected previously. Ensure to drift all components prior to P/U.
2. Wash out to bottom of conductor.
3. Drill 13-1/2" hole to casing point as specified by the waterboard letter.
    a. Spud with fresh water. Utilize soap, liquid PHPA (Shale Stabilizer), & SGA-10 for hole cleaning & gumbo control.
    b. Keep pH low, max 7.5.
    c. Add large amounts of water to keep the gel concentration where it needs to be. Consider pumping a gel sweep at TD, although gel usage should be kept to a bare minimum.
    d. Add a small quantity of Desco the last several hundred feet for thinning as the temp starts to thicken mud.
    e. Take surveys every 1000' minimum, more often if necessary.
    f. Circulate at reduced rates for first couple stands out of the shoe, gradually go to full circulating rate to avoid broaching around the conductor.
    g. Do not allow MW to reach 10 ppg, stop drilling and add large volumes of water if the weight reaches 10 ppg. Continuously monitor MWs.
4. Once casing point is reached, circ B/U and ensure the surface hole is not TD'd in sand.
5. Circ B/U and sweep hole clean. Make a short trip back to the shoe. Circ and sweep hole clean. POOH and handle BHA as appropriate.
6. No open hole logs planned on the surface hole.
7. R/U casing tools for 10-3/4" surface casing.
8. Run 10-3/4" casing as follows:
    a. Centralizers: One each joint on first 4 joints (installed mid tube across SCs), One each joint for next 3 joints across couplings, one across couplings on every 4th joint to surface. Ensure to leave last 3 joints below surface w/o a centralizer so that top out tbg can be run if necessary.
    b. Thread-lok the casing shoe, shoe joints, and FC.
    c. Install cement baskets as appropriate. Normal practice is 1 at ~120', another @ ~160'.
    d. Witness the loading of cement plugs in cmt head.
    e. Down jet double-valve float shoe (inspect and caliper OD and ID prior to running, verify that the float is operational).
    f. 1 joint of casing
    g. Float collar
    h. 10-3/4" casing to surface.
    i. Utilize fill up line to keep casing full at all times. Fill up each joint as it is being run. Ensure proper displacement of mud observed in pits. Note on wellview report if any mud is lost while running casing.
    j. Tag bottom and verify depth, set casing 1ft off bottom in full tension.
9. Circ with rig pumps. Monitor returns and reduce rate if full returns are not observed. Circ the greater of 1 x casing cap or B/U.

10. Observe loading of plugs in cement head.
11. Prior to beginning surface casing cement job:
    a. Notify regulatory authority of upcoming cmt job. They may elect to come out and witness the job.
    b. Check cement lab test for sufficient pump time, free water, and fluid loss.
    c. Discuss job with the cementer, double check calculations, additives, availability of M/U water.
12. Mix and pump the surface casing cement job per the cement program:
    a. Utilize top and bottom plug.
    b. Displace cement with WBM using the cement unit.
    c. Continue reciprocating casing until signs of sticking are observed.
    d. Bump plug with 500 psi over final pump pressure. Release pressure and check to ensure floats are holding. If the plug does not bump, recheck displacement calculations and volumes pumped during the displacement. Do not over displace by more than ½ the shoe joint volume.
    e. Report on the wellview report amount of cement returns to surface and whether or not full circulation was observed during the cement job.
    f. Keep an independent written account of volumes pumped and pressures experienced throughout the job. File Hilcorp pipe record and cementing report forms with the wellview morning report.
13. WOC a minimum of 4 hrs. N/D flowline and begin cleaning pits while WOC.
14. If no cement returns to surface, organize a temp log to be run between 8 – 12 hours of bumping the plug. Call the regulatory authority to determine necessary remedial steps.
15. Cut and remove 16" & excess 10-3/4". Make final cut on 10-3/4". Pre-heat and install "A" section of wellhead.
    a. Control cool the wellhead after installation to prevent cracking. Weld baseplate to conductor.
    b. Test wellhead to 1000 psi.
    c. Witness caliper of critical dimensions on the wellhead and verify they are all within spec prior to acceptance of the wellhead for installation.
16. N/U 13-5/8" 5M BOP stack as follows from top to bottom:
    a. Rotating head
    b. 13-5/8" 5M Hydril annular BOP
    c. 13-5/8" 5M Cameron type "U" double ram.
    d. 2 x 4-1/16" outlets below blind rams for choke and kill operations.
    e. 13-5/8" 5M Cameron type "U" single ram.
    f. Test BOPs to 250 / 5000 psi (250 / 3500 psi for annular for each test after initial R/U or after change out). Chart record all pressure tests at choke manifold cross. Record tests and pressure on IADC report and maintain record of tests for well file. The BOP test should be performed with water and tests should be held for 5 min. Document and sign the BOP test per DNR regulations.
    g. Run a gyro survey inside the 10-3/4" while N/U BOPs.
    h. Install flowline and drip pan.

Pilot Hole Section

1. M/U 8-1/2" PDC bit and directional drilling assy.
2. TIH and tag TOC. Break circ and test casing to 1500 psi for 30 min. There must be no more than a 10% reduction in pressure over 30 min for the test to be successful.
3. Circulate through choke manifold (both chokes, one at a time) to ensure flow path is clear and record SCRs through same (min of 2 rates with each pump). Open up well and record SCRs through bell nipple. Note rates and pressures on IADC report.
4. Drill cement and ½ of the shoe track. Retest casing to 1500 psi, no chart necessary.
5. Drill the remainder of the shoe track and 5' of new formation.
6. Circ B/U to ensure recovery of formation cuttings.
7. Conduct FIT to 14 ppg EMW using WBM.
8. Drill 8-1/2" hole section to pilot hole TD.
    a. Ensure to have mud loggers R/U by 1500'.
    b. Record SCRs through bell nipple at the following points:
        i. Beginning of each tour.
        ii. MW change.
        iii. BHA change.
        iv. 1000' of new hole.
9. A copy of the kill sheet, updated for current hole conditions, drill string and wellbore configuration is to be maintained on the rig floor at all times.
10. At Pilot hole TD, circ and cond mud for logging operations.
11. TOH, handle BHA as appropriate.

Logging Program / Wellbore Plug Back

1. R/U and run open hole logs per logging program issued by geology. R/D logging equipment.
    a. Ensure to monitor wellbore at all times while logging.
    b. Ensure detailed drawings are available including all ODs, FNs, etc.
2. R/U 3-1/2" tubing handling equip and RIH w/ the following cementing string to (TD will be confirmed by geology based off GR log, estimated PH TD is 5,940'):
    a. 3-1/2" diffuser sub
    b. +/- 1000' of 3-1/2" PH-6 tubing.
    c. XO
    d. 5" DP to surface
3. Circ & cond mud for spotting balanced barite plug, ensure to rotate & reciprocate string while circulating. Pump at max flow rate.
4. Prior to spotting balanced barite plug:
    a. Discuss job with the mud engineer, double check calculations.
5. Spot balanced plug.
6. Pull up and position bottom of stinger at planned depth to ensure the top of the cmt plug is +/- 300' above planned KOP.
7. Prior to spotting kick-off plug:
    a. Discuss job with the cementer, double check calculations, ensure availability of makeup water & additives.
    b. Ensure calculated TOC is a minimum of 500' above planned kick off point.

c. Ensure a side entry pump in swivel is utilized to make string rotation during displacement possible.

8. R/U and pump spacer & cmt per plug back procedure. Ensure the R/U of surface cmt equipment will allow the string to be rotated while displacing cement.

9. Displace cement using cmt unit, pump as fast as cmt unit will allow (min 8 bpm). Rotate the string @ 40 rpm while displacing. String rotation and high pump rates are critical to getting a good cement plug!!!

10. TOH slowly (~3 min/std) to ~500' above calculated TOC. Drop DP wiper ball, circ and cond mud @ max loss free rate. Ensure to rotate / reciprocate string while pumping.

11. TOH, L/D 3-1/2" tubing.

Production Hole Section

1. M/U 8-1/2" PDC bit and directional drilling assy.

2. TIH to TOC.

3. Dress off cmt until firm cmt is found. Ensure to wait a minimum of 24 hrs. before drilling cement.

4. If the top +/- 200' of cement is not hard, consider additional WOC time.

5. Time drill only if the bit continues to follow the original wellpath and the current depth is less than 50' from planned KOP.

6. Drill curve per the directional plan @ 10°/100'. Send updated GR logs to geologist beginning at 400' above KOP. Continue sending logs every 30' until landing well. Send updated logs every 100' while drilling lateral.

7. Run the centrifuge as often as possible to keep dilution to a minimum. Ensure shakers are in good working order and run the finest screens possible. Check that there are no holes in the screens on each connection.

8. When drilling lateral, hole cleaning becomes much more difficult as cuttings will tend to pile up on the low side of the hole.

a. Maintain 6 rpm at or above 8.
b. Utilize hi-vis or weighted sweeps as necessary.

9. At TD, circ B/U and condition mud for running 5-1/2" production casing.

a. Minimize mud viscosity & flatten gels as much as possible. Treat mud to avoid progressive gels.

10. Make a short trip to the top of the curve.

11. Circ and condition mud again at TD.

12. TOH, L/D drill pipe.

13. R/U & run 5-1/2" production casing.

a. Ensure CRT is on location and ready in the event it is required.
b. Ensure XO to DP is available on rig floor with a TIW M/U and in the open position.
c. Circulate through float equipment while running casing to ensure proper operation of same. Break circulation periodically while RIH.
d. Utilize fill-up / circulating tool to keep string full while RIH. Do not stop the pipe once in open hole, except to stab and M/U the next joint.
e. Do not stop to circulate the well unless absolutely necessary.

f. Report the amount of mud lost while running casing (if any) on wellview report.
g. Centralization: 1 x solid body straight blade centralizer (8-1/4" x 4-1/2") @ 10' above shoe. 1 x solid body straight blade centralizer every 3rd joint to 1,000' above KOP. One below surface casing shoe, one above surface casing shoe, 2 below wellhead.
h. Overpull on the casing in stuck conditions is 100k.
i. Calculate space out of casing to land shoe as close to TD as practical.

14. With shoe at TD, circ with rig pumps. Monitor returns and reduce rate if full returns are not observed. Circ the greater of 2 x casing cap or B/U.

15. Prior to beginning production casing cement job:

a. Check cement lab test for sufficient pump time, free water, and fluid loss.
b. Discuss job with the cementer, double check calculations, additives, availability of M/U water. Use 15% OH excess in volume calculations. Ensure top of tail reaches KOP.
c. The company rep should insure that all calculations are reviewed and discrepancies corrected. Agreement should be reached on all pumped volumes and pumping rates on all stages prior to cementing.
d. Recheck mud/spacer/cement compatibility test prior to beginning job.
e. Observe loading of plugs in cement head. Verify proper operation of cmt head.

16. Mix and pump the production casing cement job per the cement program:

a. Utilize top and bottom plug.
b. Pump spacer per cement company's recommendation. Ensure spacer is 0.5 ppg above current MW.
c. Ensure bulk cement contains CaCO3 so that it is acidizeable.
d. Displace cement with clayfix / water.
e. Quality and density of cement are critical. Pump rate can be reduced to ensure density is correct.
f. Bump plug with 1000 psi over final pump pressure. Release pressure and check to ensure floats are holding. If the plug does not bump, recheck displacement calculations and volumes pumped during the displacement. Do not overdisplace by more than ½ the shoe track volume. If the floats are not holding, cement will have to be held in place using final pressure obtained when the plug was bumped.
g. Reciprocate casing until signs of sticking are observed. Land casing 1 ft off bottom with full hanging weight.
h. Report on the wellview report amount of cement returns to surface and whether or not full circulation was observed during the cement job.
i. Keep an independent written account of volumes pumped and pressures experienced throughout the job. File Hilcorp pipe record and cementing report forms with the wellview morning report.
j. Pump rates during cementing are guidelines only. Pump spacers and cement at the highest rates possible. But care should be taken not to obtain a rate resulting in excessive ECD and subsequent lost returns.
k. Ensure cement company provides a graphical and tabular record of the job.

l. Send in the cement pressure plot to Hilcorp Drilling Engineer after completion of job.

17. Flush BOP and flowline.
18. N/D & raise BOP. Set slips on 5-1/2" casing. Note weight set down on slips on wellview report.
19. Cut and remove casing.
20. Set back BOP. Remove spacer spool and DSA.
21. Install "B" wellhead section. Test void to 5000 psi. N/U dry hole tree or temporary abandonment cap.
22. Pump out & clean mud pits.

Release rig. Note rig release time & date on wellview report.

PRESSURE CONTROL

- See attached blowout preventer diagram.

BOPs and choke manifold will be installed and pressure tested before drilling out of surface casing (subsequent pressure test will be performed whenever pressure seals are broken), and then will be checked daily as to mechanical operating condition. BOPs will be pressure tested at least once every 30 days. Ram type preventers and related pressure control equipment will be pressure tested to related working pressure of the stack assembly if a test plug is used. If a plug is not used, the stack assembly will be tested to the rated working pressure of the stack assembly or 70% of the minimum internal yield of the casing, whichever is less. Annular type preventers will be pressure tested to 50% of their working pressure. All casing strings will be pressure tested to 0.22 psi/ft or 1,500 psi, whichever is greater, not to exceed 70% of the internal yield. If a 5M system or greater is used, the casing shoe will be tested by drilling 5-20' out from under the shoe and pressure tested to a maximum expected mud weight equivalent as shown in the mud program listed below.

A manual locking device (i.e. hand wheels) or automatic locking devices shall be installed on the BOP stack. Remote controls capable of both opening and closing all preventers shall be readily accessible to the driller.

The choke manifold and accumulator will meet or exceed Onshore Order No. 2 (OSO #2) standards. The BOP equipment will be tested after any repairs to the equipment. Pipe rams, blind rams and annular preventer will be activated on each trip and weekly BOP drills will be conducted with each crew. All tests, maintenance, and BOP drills will be documented on rig "tower sheets".

Statement of Accumulator System and Location of Hydraulic Controls

The drilling rig has not been selected for this well. Selection will take place after approval of this application is granted. Manual and/or hydraulic controls will be in compliance with OSO #2 for 5,000 psi system.

A remote accumulator will be used. Pressures, capacities, location of remote hydraulic and manual controls will be identified at a later time.

MUD PROGRAM

0’	-	1,600’	Spud Mud w/ LCM material, if necessary M.W.: <9.0 ppg
1,600’	-	TD	Water Based Mud w/ calcium carbonate, barium sulfate, and LCM material, if necessary M.W.: <9.0 ppg

Sufficient mud materials to maintain mud properties, control lost circulation and to contain a “kick” will be available on location.

AUXILIARY EQUIPMENT

A. Upper Kelly cock; lower Kelly cock will be installed while drilling and tested with 5,000 psi BOP.
B. Inside BOP or stabbing valve with handle (available on rig floor).
C. Safety valve(s) and subs to fit all string connections in use.
D. Mud monitoring will be with a flow sensor, pit level indicator, and visually observation.

LOGGING, CORING TESTING PROGRAM

A. Gamma Ray, Resistivity, Neutron/Density Porosity, Quad combo, Crossed Dipole Sonic.
B. Coring: Possible 200’ core.
C. Testing: None planned – Drill Stem tests may be run on shows of interest.

ABNORMAL CONDITIONS

A. Pressures: No abnormal conditions are anticipated.
Anticipated BHP gradient: 0.45 psi/ft
B. Temperatures: No abnormal conditions are anticipated.
C. H_2S: None Anticipated.
D. Estimated bottom hole pressure: 2,673 psi

ANTICIPATED START DATE

May 14, 2012