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AK-3 Drilling Procedure

Draft 10 Aug 16

August 2016

Introduction

A small diameter well will be drilled into the conceptualized resource outflow of the Akutan geothermal system. This will be the third exploration well drilled in HSBV. The goals of the project are:

- Identify a drilling target and well site within the hot springs area of HSBV
- Construct drilling site improvements and establish a base camp
- Drill and test a resource confirmation well at the approved target location
- Assess the probability of producing commercial quality geothermal resources from production wells
- Prepare a bankable feasibility study to support development investment/financing

To achieve these goals, a well was designed to intersect the resource at a depth that the flow test and injection test is possible for resource characterization. All equipment and personnel will be transported by helicopter, limiting the rig size and, therefore, capability.

Site selection for the new well is based on data collected since 2009, including the data from the 2010 drilling campaign. Through reexamination of the data and reports, including reprocessing of the 2012 gravity survey data and building a 3D visualization in GOCAD software, the target site was selected close to the hot springs in lower HSBV located 450' southwest of TG-2 drilled in 2010.

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Planned Wellhead Coordinates

WGS84 Zone 3 coordinates: 443969E 6000805N

Alaska State Base Plane Coordinates: NAD 27 Zone 7 x-126726.1 y-78180.6

Ground Elevation: 41' ASL (UTM)

Planned Drilling Equipment

Drilling Contractor: Major Drilling

Equipment List:

1. One (1) unitized heliportable LF-90 core drilling rig
2. One (1) supply pump with 3,000' waterline
3. One (1) light plant
4. One (1) substructure
5. One (1) mud circulation unit
6. One (1) mud mixing unit and tank
7. One (1) mud pump
8. 1,700 feet each of PQ and HQ size core rods and 850' BQ size core rods.

Planned Well Construction[1]

Hole (“)	Casing (“)	Weight (ppf)	Grade	Connection	Depth (‘)
10-3/4	8-5/8 (8” line pipe .332 wall)	28.55	A53B	WELD (ERW)	± 40
7-1/2	5-1/2	15.5	K55	VFJ	± 220
PQ (4.834)	4-1/2	11.6	K55	VFJ	± 800
HQ (3.789)	3-1/2	7.7	HQ Rod or NW casing (blank and perforated)	Q rod or WT	±700 - ±1,700 (100’ blank liner lap)

Summary of Geologic Prognosis, Significant Depths, and Directions

Stratigraphy

The expected stratigraphy of AK-3 is based on the stratigraphy found in TG-2, located about 500’ northeast of the proposed site, and TG-4, also located in Hot Springs Bay Valley.

Depth Interval (ft.)	Rock type/Characteristics
0-25	Ash fall, unconsolidated till, clay, scoria
25-50	Volcanic breccia weakly consolidated
50-325	Andesite/basalt flows with minor overprint of propylitic (minor calcite, chlorite) and some argillic alteration at top of section
325-410	Basaltic conglomerate with interlayered tuff toward bottom of section tuff
410-800	Andesite/basalt with some alteration minerals calcite, chlorite minor epidote, prenite (plus adularia deeper in section)
800-1500	Alternating andesite, basalt, basaltic conglomerate, tuff layers. Expect alteration minerals to become more evident deeper near expected fault zone. Likely to encounter thin <10’ dacite flow somewhere below 1050 ft.

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Expected Well characteristics

The expected well characteristic for the top part of the hole are based on the experience of the offset well TG-2 located northeast of the proposed site. TG-2 was drilled with a core rig in 2010.

Depth (ft.)	Description
0-50	Controllable flowing zones through shallow saturated intervals, could be 120°F
50-150	Possibility of flowing zones, elevated temperature
150-400	Elevated temperature
400-800	Possibility of flow zones/loss of circulation at 420’to 800’ (strat contacts? alteration at flow margins?), edges of reservoir, elevated temperature
800-1500	Encounter fault zone in reservoir, expect lost circulation

[1] All depths in this plan are MD from RKB (5’ AGL) unless specified otherwise

Reservoir fluid chemistry is expected to be a neutral NaCl brine, with TDS of ±5000 ppm. TDS values are variable in previous samples and likely diluted by meteoric waters.

Projected Fault Zone

The target of the AK-3 well is a northwest striking fault zone with an estimated 60°+ dip to the SW. The surface location is about 450' from the surface projection of the fault (Figure 3). The table below shows the estimated depth of fault intersection with varied dip angles.

Fault angle	Intersection depth
60	779
65	965
70	1236

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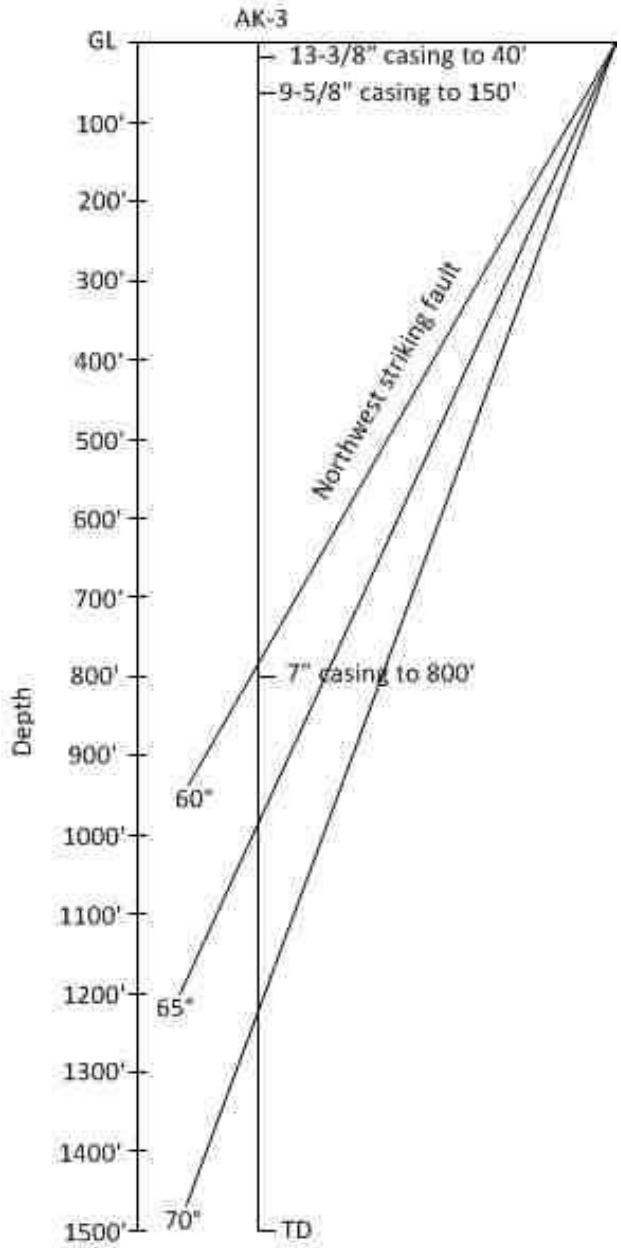

Figure 1: Proposed well AK-3 with projected fault intersections based on distance of 450' from surface trace of fault.

Agency Notifications

Well Permit Information:
AGOCC Permit No: 215-080
Exploratory well, Hot Springs Bay Valley AK-3
City of Akutan

Notify the Alaska Oil and Gas Conservation Commission engineer Guy Schwartz 48 hours prior to spud, 48 hours prior to BOP testing (Step 15 and Step 19) and Leak-off Testing (Step 16 and Step 20). Contact: Guy Schwartz guy.schwartz@alaska.gov, (907) 793-1226. Please copy mary@geothermalresourcegroup.com on all correspondence with the AOGCC.

BOP and LOT test must be recorded with pressure transducer provided by Prospect Geotech, results graphed, and sent to AOGCC contact. Please document testing with notes, photos, and the requested pressure data over the time of the test. Send reports to billrickard@geothermalresourcegroup.com, mary@geothermalresourcegroup.com, and ozgur@geothermalresourcegroup.com, and guy.schwartz@alaska.gov.

Send pdf of daily drilling summary report with cost suppressed from Rimbase to AOGCC contact as well.

Reporting

Daily, send completed .wex file to billrickard@geothermalresourcegroup.com , mary@geothermalresourcegroup.com, and ozgur@geothermalresourcegroup.com each morning with summary of activities in body of the e-mail. GRG will distribute the completed report to other parties to start.

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Daily, send pdf of daily drilling summary report with cost suppressed from Rimbase to AOGCC contact Guy Schwartz guy.schwartz@alaska.gov. Please copy mary@geothermalresourcegroup.com on all correspondence with the AOGCC.

Daily, send daily geological report to mary@geothermalresourcegroup.com, billrickard@geothermalresourcegroup.com , and wosborn@geothermalresourcegroup.com and ozgur@geothermalresourcegroup.com each morning with summary in body of the e-mail. Please match report number with the Drilling Supervisors Report number. GRG will distribute report to outside parties.

Rig site layout

The rig site is layout as planned is shown below. During site preparation ensure that cellar is large enough to accommodate side outlets and planned attachments to side outlet. Please confer with Major team leader on location and orientation of cellar.

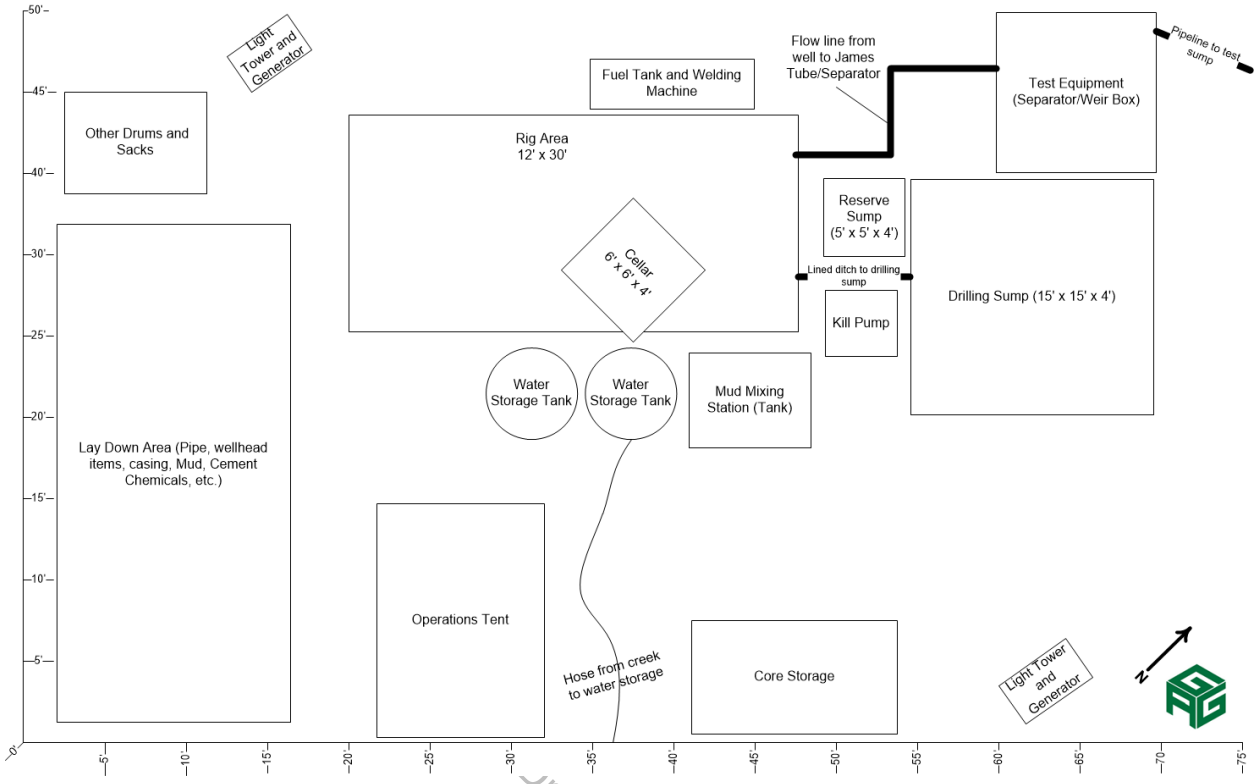

Figure 1: Proposed site layout AK-3.

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AK-3 Well Drilling Plan

1. Set up base camp. Mobilize materials, equipment, services, and personnel.
2. Build location with cellar and site sump to suit core drilling activities and personnel camp.
3. Secure water and fuel sources.
4. Move in and rig up drilling rig. Notify or ensure that AOGCC is notified of spud 48 hours in advance.
5. Install water and fuel pumps and lines.
6. Hold pre-spud safety and operations meeting. **Continue safety and operations meetings for each tour and operation as necessary.**
7. Drill 10-3/4" diameter hole to ±40 ft from bottom of cellar. Take returns to the mud pit using a suitable pump. Collect cuttings samples every 10 ft.
8. Rig up and run ±40 ft of 8" ID, .322" WT, API 5L X-42 conductor pipe with the top joint 3-6" above the cellar basement. Weld connections.
9. Cement conductor.

10. WOC (wait on cement) until surface grab samples are set.
11. Drill 7-1/2” diameter surface hole from ±40 ft to ±220 ft:
    - 11.1. Notify AOGCC and provide an estimate for completing the section, casing, and BOP testing,
    - 11.2. Drill section to fit the casing and follow the mud program while drilling,
    - 11.3. Take returns to the mud pit using a suitable pump,
    - 11.4. Note lost circulation and intervals and drilling breaks and immediately report lost circulation to the drilling supervisor,
    - 11.5. Be prepared for artesian flow throughout rotary drilled interval:
        - 11.5.1. If artesian flow occurs, mix weighted mud using $CaCl_2$. Use Barite if necessary weight to kill the well cannot be reached or maintained,
        - 11.5.2. If weighting mud is insufficient to kill the well, mix and spot neat cement across zone.
    - 11.6. Collect cuttings samples every 10 feet.
    - 11.7. Run a drift shot with MRT at section TD,
    - 11.8. Circulate and condition hole for casing,
    - 11.9. Measure out of the hole and lay down pipe.
12. Rig up and run ±220 ft, 5-1/2”, 15.5 ppf (drifted to 4.84”), K-55, VFJ (Valley Flush Joint) surface casing and the float shoe:
    - 12.1. Install centralizers with stop rings, placed as necessary,
    - 12.2. Make joints up per the torque value to be provided by the drilling supervisor,
    - 12.3. Bakerlock the first 2 joints and the float shoe,
    - 12.4. Wash string down to bottom if necessary,
    - 12.5. The stick-up should be 6-9” above the cellar basement (3-6” above the conductor). Use the 5-1/2” VFJ pup joint to bring the top of the casing string above the cellar basement level if necessary.
13. Cement using 100% excess per cementing program below.
    - 13.1. Pump contaminated returns from cellar basement to a reserved section in the sump.
    - 13.2. Displace cement inside the casing to 50’ above the section TD (~170’),
    - 13.3. Check the float and keep pressure on casing if not holding,
    - 13.4. WOC until surface grab samples are set,

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13.5. Perform top job, if needed. Run tremie pipe (NQ) and mix and displace cement into the 8-5/8” x 5-1/2” annulus through the tremie pipe,

13.6. WOC (wait on cement) until surface grab samples are set.

14. Make up wellhead and BOPE assembly:

14.1. Thread on 5-1/2” VFJ x 6” Fig 206 Hammer Union (HU) cross over adapter,

14.2. Install 5-1/2” 2M casing head with 6” Fig 206 HU top / bottom connections with 2 ea. 2" side outlet nipples and 2M NPT threaded gate valves,

14.3. Install 6” 600 master valve (slab gate) with 6” Fig 206 HU top / bottom connections

14.4. Install 5” 1,000 psi annular type preventer, riser, and flow line,

14.5. Install 2” kill line from 2” side outlet valve to a suitable pump.

15. Test casing, wellhead, BOPE, and lines to 750 psi:

15.1. Notify AOGCC 48 hours in advance

15.2. Function test annular preventer, master valve, and kill line valve.

15.3. Line up one mud pump to the kill line

15.4. RIH with a plugged PQ rod joint and snub bottom of joint to bottom of the annular preventer

15.5. Close the annular preventer and pressure test annular preventer, casing head, master valve, kill line valve, and diverter line valve to 200 psi and 750 psi and hold 5 minutes each. Record test data, including time to pressure up, and forward to AOGCC for approval.

15.6. While drilling the PQ section, the BOPE must be function tested every 7 days subsequent to the first test. Test the annular preventer against the master valve, pumping through a single PQ rod joint.

16. Pick up PQ rods and core hole from 220 ft to +/-800 ft. Rig up 1,500 psi hydraulic wireline stripper and FOSV.

16.1. Notify AOGCC and provide an estimate for completing the section, casing, and BOP testing.

16.2. Perform formation integrity test:

16.2.1. Drill out shoe track and clean out cement.

16.2.2. Drill ahead making 5 feet of new hole.

16.2.3. Apply surface pressure to annulus to a maximum of 1 psi/ft gradient. Apply pressure at 0.1 bbl/1 minute increments. Follow the attached ‘LOT’ procedure.

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16.3. Drill section to fit the casing and follow the mud program while drilling,

16.4. Take returns to the mud pit via flow line,

16.5. Monitor flowline temperatures constantly.

16.6. Note lost circulation intervals and drilling breaks and immediately report to the drilling supervisor. Maintain water on the backside to prevent flashing, if deemed necessary.

16.7. Be prepared for artesian flow or steam kicks:

16.7.1. If artesian flow occurs, mix weighted mud using $CaCl_2$. Use Barite if necessary weight to kill the well cannot be reached or maintained,

16.7.2. If a steam kick is suspected, pump cold mud in the hole and start weighting mud up if cooling the well does not stop the flow.

16.7.3. If weighting mud is insufficient to kill the well, mix and spot neat cement across zone

16.8. Collect and box 10-foot core samples per geologist's instructions.

16.9. Run 3 drift shot surveys with MRT at approximately 400, 600, and 800 ft.

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17. Rig up and run ±800 ft, 4-1/2", 11.6 ppf (drifted to 3.89"), K-55, VFJ (Valley Flush Joint) production casing with the float shoe:

17.1. Fabricate and install poor boy centralizers if necessary,

17.2. Make joints up per the torque value to be provided by the drilling supervisor,

17.3. Bakerlock the first 3 joints and the float shoe,

17.4. Wash string down to bottom if necessary,

17.5. The stick-up should be above the side outlet valves while cementing (~25" above cellar basement).

18. Cement using 100% excess per running and cementing program below:

18.1. Take returns through 2" side outlet on casing head,

18.2. Displace cement inside the casing to 150' above the section TD (~650'),

18.3. Check floats and keep pressure on casing if not holding,

18.4. WOC until surface grab samples are set,

18.5. Find top of cement. Perform top job, if needed. Follow 'Top fill and Top Squeeze' method attached.

18.6. WOC until surface grab samples are set.

19. Test casing, wellhead, BOPE, and lines to 750 psi.
    - 19.1. Notify AOGCC 48 hours in advance
    - 19.2. Function test annular preventer, master valve, and kill line valve
    - 19.3. Line up one mud pump to the kill line
    - 19.4. RIH with a plugged PQ rod joint and snub bottom of joint to bottom of the annular preventer
    - 19.5. Close the annular preventer and pressure test annular preventer, casing head, master valve, kill line valve, and diverter line valve to 200 psig and 750 psig and hold 5 minutes each. Record test data, including time to pressure up, and forward to AOGCC for approval.
    - 19.6. While drilling the HQ section, the BOPE must be function tested every 7 days subsequent to the first test. Test the annular preventer against the master valve, pumping through a single PQ rod joint.
20. Pick up HQ rods and wireline core from +/-800 ft to 1,500 ft +/-200 (TD). Rig up 1,500 psi hydraulic wireline stripper and FOSV.
    - 20.1. Notify AOGCC and provide an estimate for completing the section, casing, and BOP testing.
    - 20.2. Perform formation integrity test.
        - 20.2.1. Drill out shoe track and clean out cement.
        - 20.2.2. Drill ahead making 5 feet of new hole.
        - 20.2.3. Apply surface pressure to annulus to a maximum 1 psi/ft gradient. Apply pressure at 0.1 bbl/1 minute increments. Follow the attached 'LOT' procedure.
    - 20.3. Follow the mud program while drilling.
    - 20.4. Monitor flowline temperatures constantly.
    - 20.5. Note lost circulation intervals and drilling breaks and immediately report lost circulation to the drilling supervisor. Maintain water on the backside to prevent flashing.
    - 20.6. If a steam kick is suspected, pump cold mud in the hole and start weighting mud up if cooling the well does not stop the flow.
    - 20.7. Collect and box 10 feet core samples as per geologist's instructions.
    - 20.8. Run a drift shot and MRT or other Temperature log at ~200 foot intervals and at TD. (Drift shot regulatory requirement, MRT, use your judgement)

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20.9. Whenever required, follow pressure / temperature logging or injection test procedures.

20.10. If torque or wellbore stability becomes a problem, cut the HQ string and continue coring with NQ.

21. Completion:

21.1. Upon reaching TD, follow pressure / temperature logging or injection test procedures.

21.2. Cut HRQ (or NRQ) rod string at 100’ above the 4-1/2” casing (or HQ rod) and squat on bottom:

21.2.1. POH coring rods,

21.2.2. Kill the well thoroughly using cool water or weighted mud and keep dead with a steady stream of water from the backside,

21.2.3. RIH to bottom and squat blank and perforated liner string. Perforated interval TBD by the drilling supervisor and the wellsite geologist,

21.2.4. RIH with rod cutter and cut string 100’ above the 4-1/2” or HQ rod sting,

21.2.5. POH laying down pipe.

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22. Lay down the riser, flow line, and annular preventer.

23. Install the 6” x 6” x 4" flow tee, equipped as follows:

23.1. 6" Fig206 HU top and bottom connections,

23.2. 4" 2M side outlet with 4" Fig206 HU upstream x Companion Flange downstream 4" 2M gate valve for flow test discharge (landing shoulder profile is machined inside the flow tee).

24. Install the 6" Fig206 HU x 2" FNPT threaded Shooting Flange and the 2” 2M crown valve (gate).

25. Install the 2” lubricator.

26. Close the side outlet valves, master valve, and the crown valve.

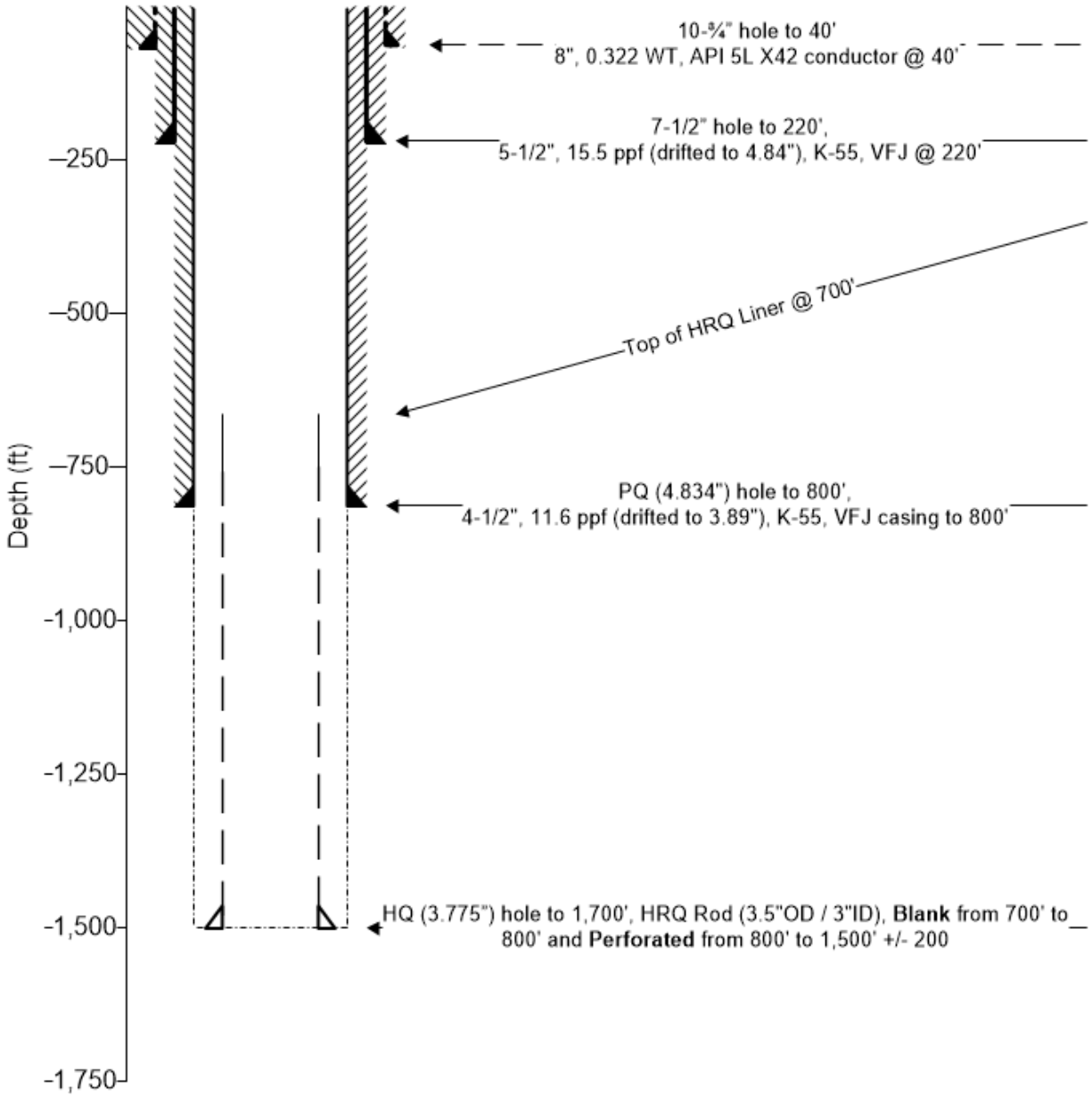
27. Rig down, release rig, and move off.

28. Pressure/Temperature logging is planned either prior to move-off or after move-off, pending results of drilling.

AK-3

Planned Well Schematic

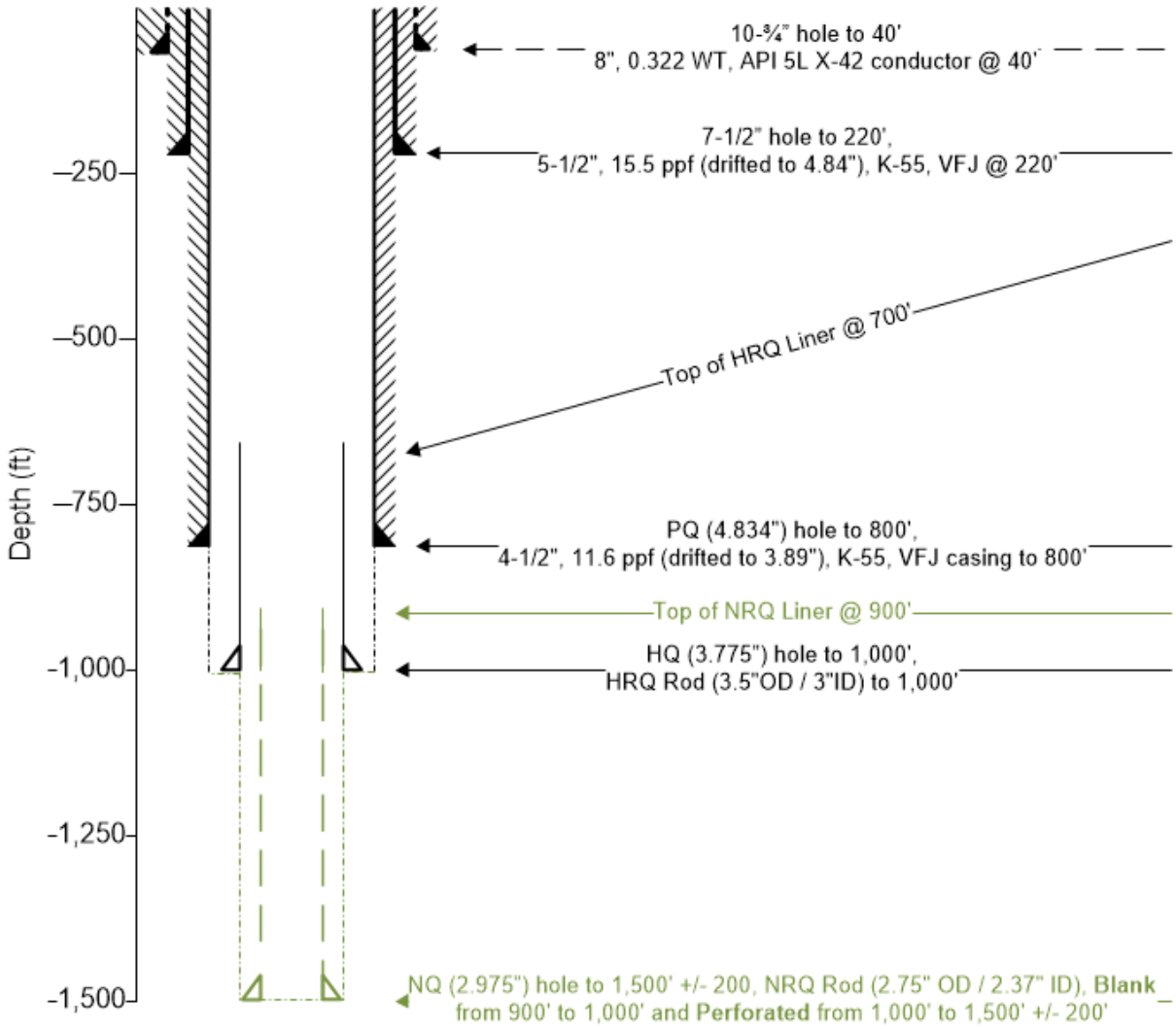
Drawn by GRGI 8-July-2016 – Not To Scale



AK-3

Planned Well Schematic (with contingency liner assuming hole problems at 1,000')

Drawn by GRGI 8-July-2016 – Not To Scale



AK-3

BOP / Drilling 10-¾"

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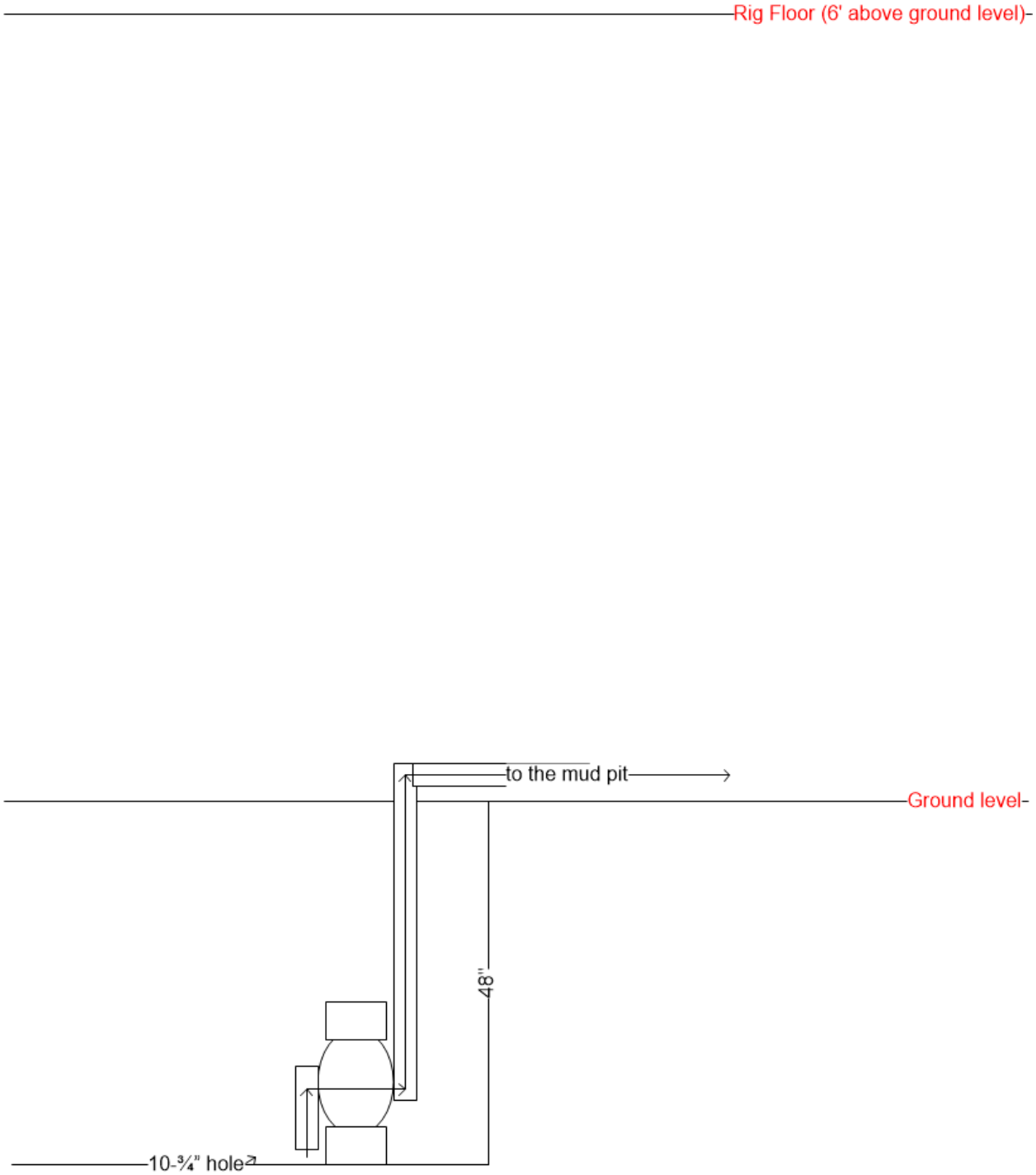

AK-3

BOP / Drilling 7-½"

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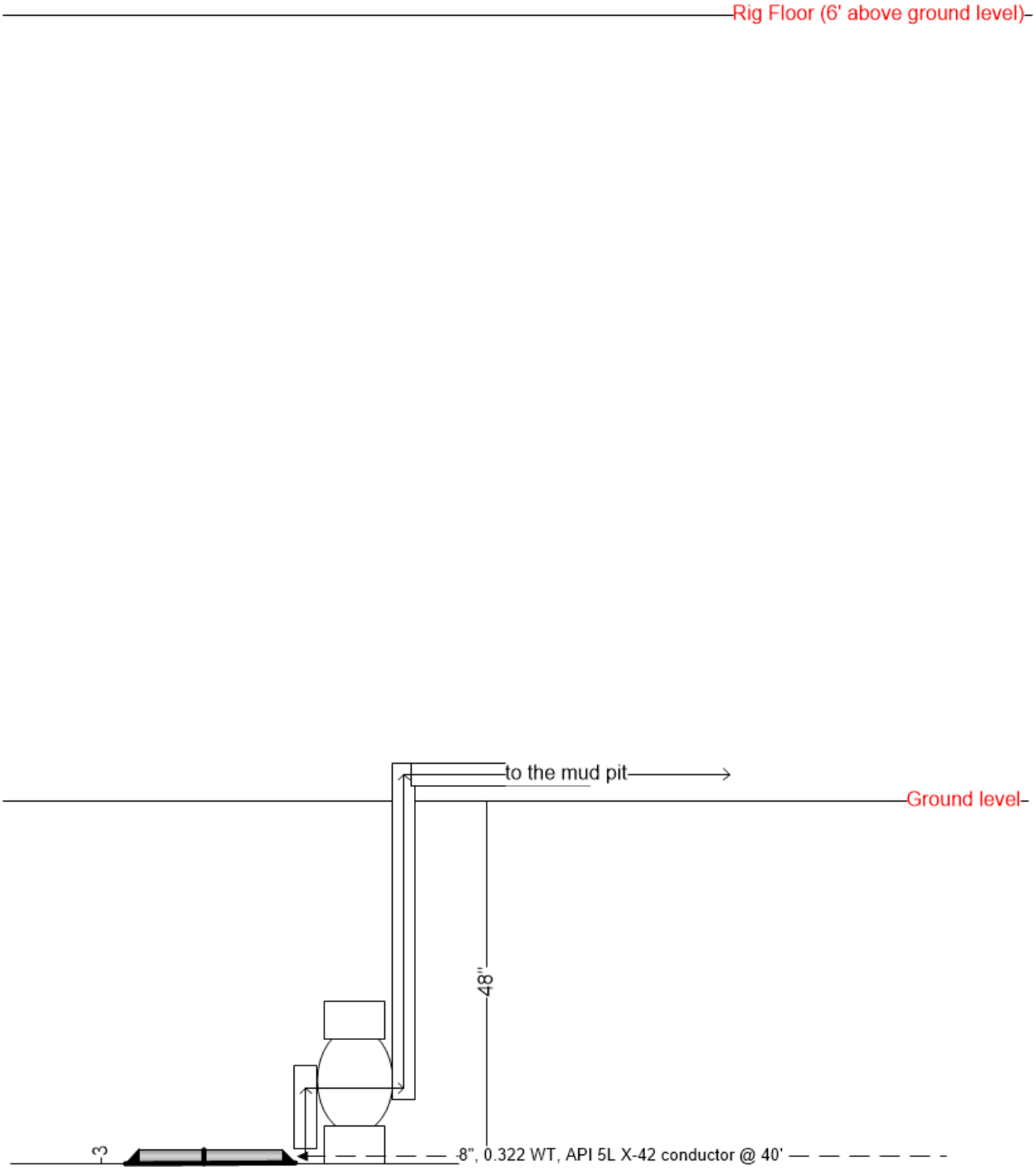
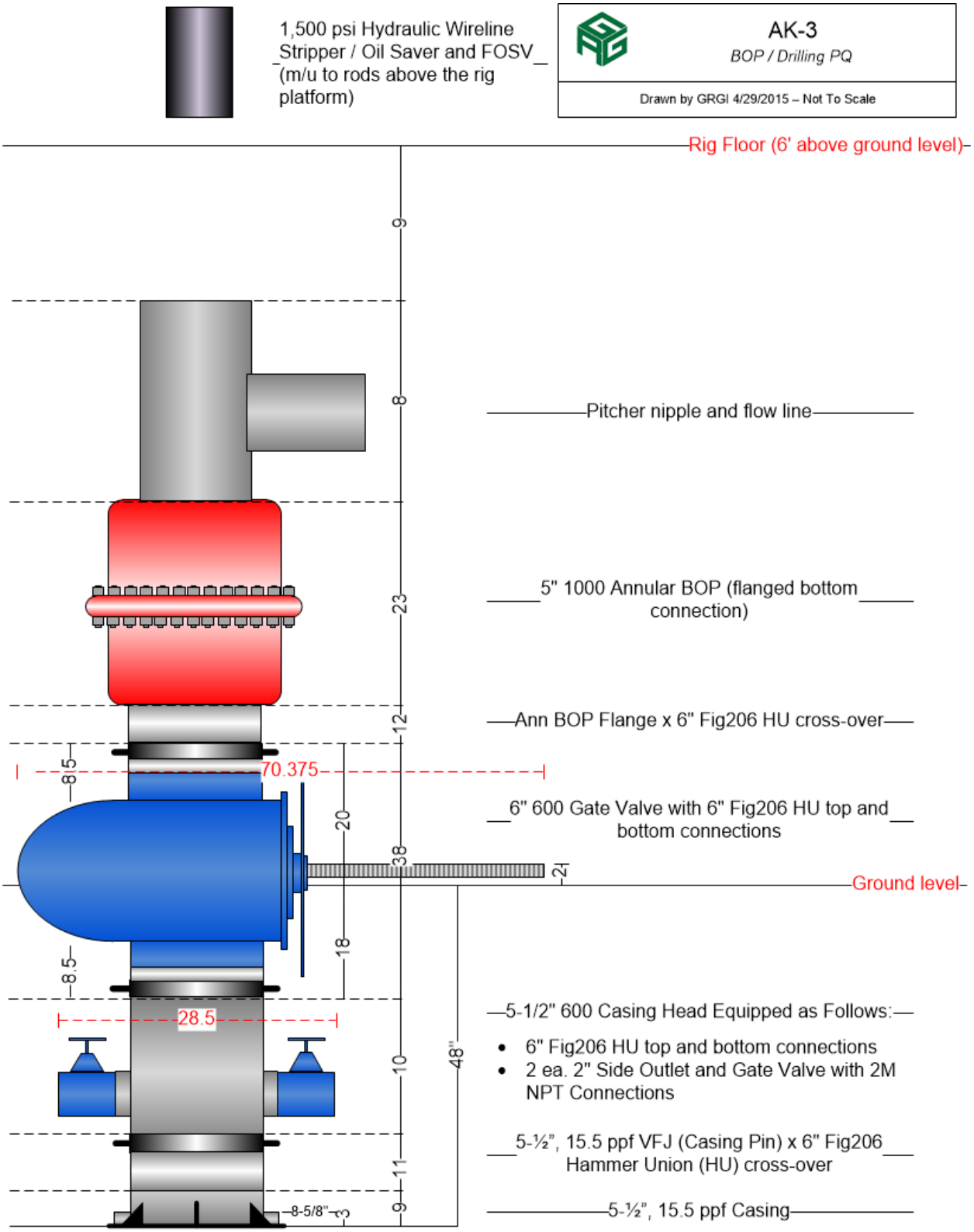
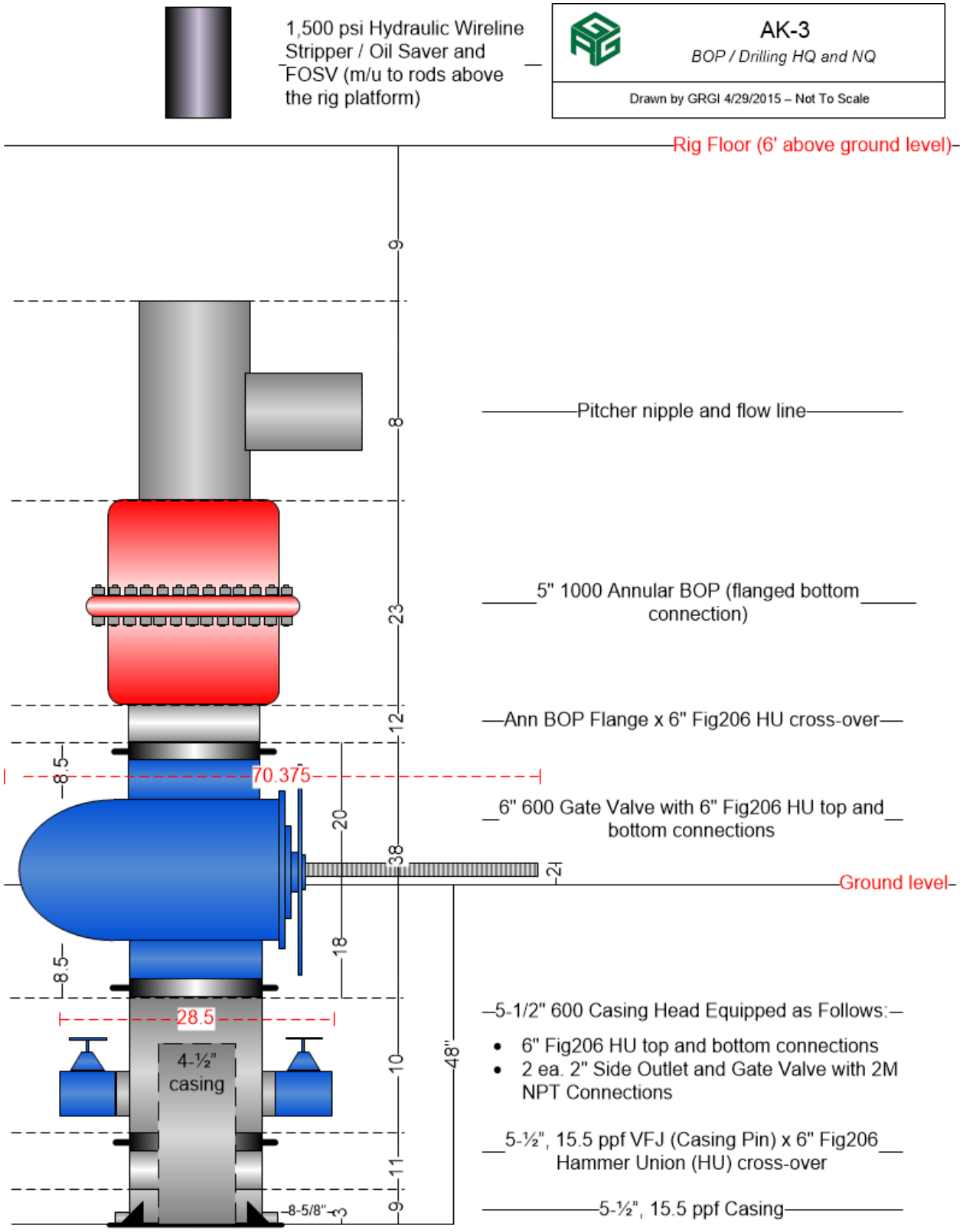



1,500 psi Hydraulic Wireline Stripper / Oil Saver and FOSV (m/u to rods above the rig platform)
AK-3
BOP / Drilling PQ
Drawn by GRGI 4/29/2015 – Not To Scale
Rig Floor (6' above ground level)
Pitcher nipple and flow line
5" 1000 Annular BOP (flanged bottom connection)
Ann BOP Flange x 6" Fig206 HU cross-over
6" 600 Gate Valve with 6" Fig206 HU top and bottom connections
Ground level
5-1/2" 600 Casing Head Equipped as Follows:
6" Fig206 HU top and bottom connections
2 ea. 2" Side Outlet and Gate Valve with 2M NPT Connections
5-½", 15.5 ppf VFJ (Casing Pin) x 6" Fig206 Hammer Union (HU) cross-over
5-½", 15.5 ppf Casing
70.375
28.5
8.5
8.5
8-5/8"
9
8
23
12
20
38
2
18
10
11
9
48"


1,500 psi Hydraulic Wireline Stripper / Oil Saver and FOSV (m/u to rods above the rig platform)
AK-3
BOP / Drilling HQ and NQ
Drawn by GRGI 4/29/2015 – Not To Scale
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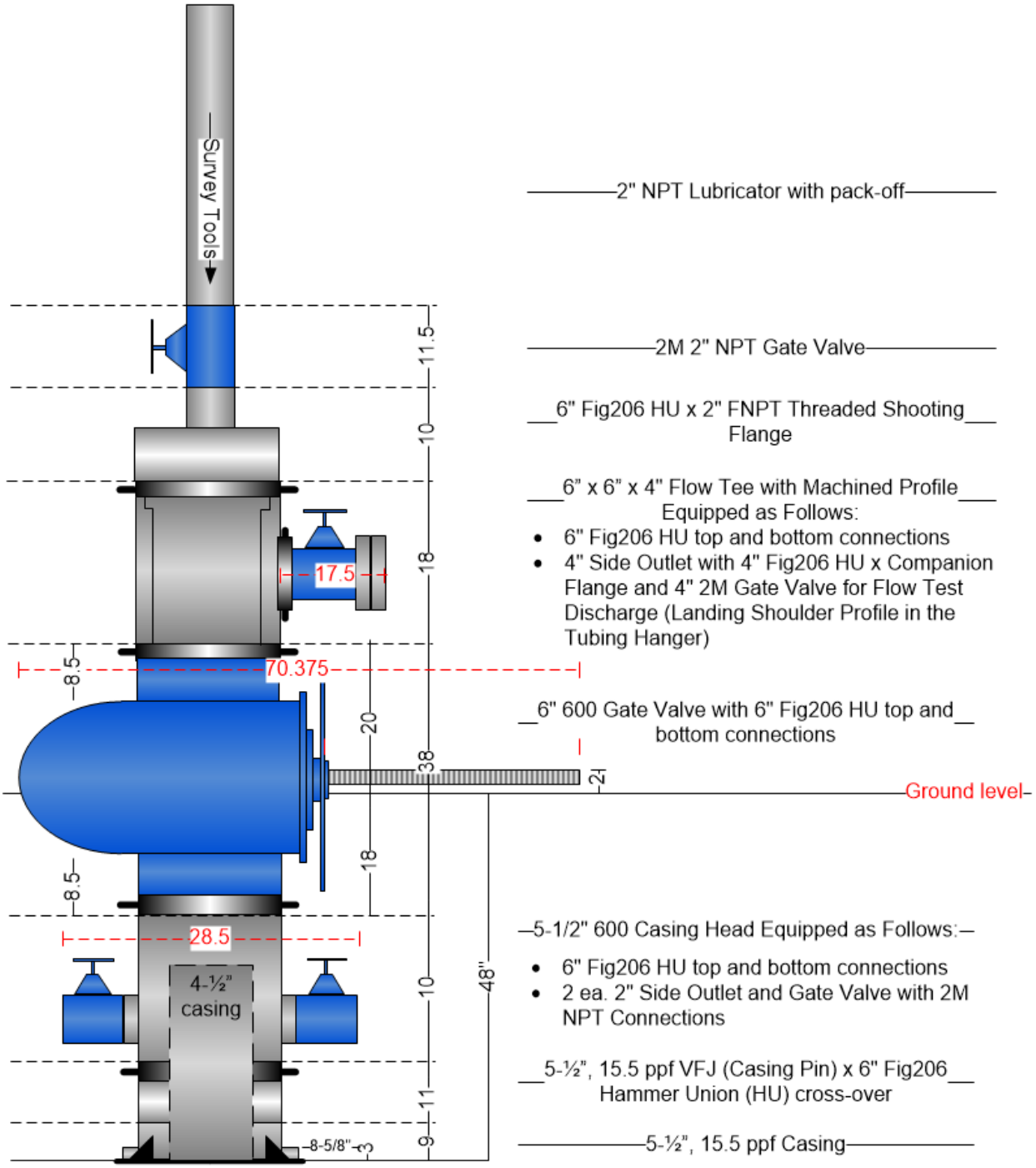
5-½", 15.5 ppf Casing
70.375
28.5
4-½" casing
8-5/8"
9
8
23
12
8.5
20
38
2
18
8.5
10
48"
11
9
3

AK-3

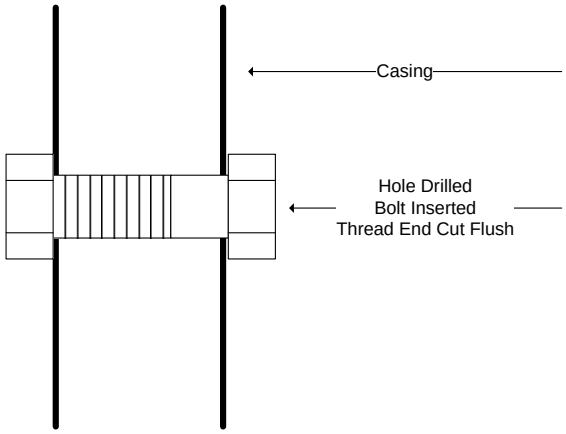
Survey / Permanent Wellhead

Drawn by GRGI 4/29/2015 – Not To Scale



Procedure for Running and Cementing 5-1/2" Casing

1. Break off coupling (box end) from 6-5/8" conductor. Tape threads heavily using duct tape to protect threads.
2. Prepare lead joint of casing by running a bolt to act as a plug stopper.



3. Run 4.5" double-wall core casing.
4. Circulate hole to condition for cement.
5. Rig up cementing head with wiper plug.
6. Pump 1 bbl of fresh water ahead of 12.2 cu ft of Class G cement w/30% silica flour and 2% CaCl2.
7. Drop wiper plug and displace with mud. Bump plug.
8. Clean cement out of annulus to below threads on conductor.
9. WOC
10. Perform top job if needed.
11. Cut off casing to below top of conductor threads.
12. Tack-weld straps between the 4-1/2" casing and the 6-5/8" conductor.
13. Make up coupling (box end) on conductor casing.
14. Make up Teflon Seal, wellhead, master valve and BOPE. Function Test BOPE.

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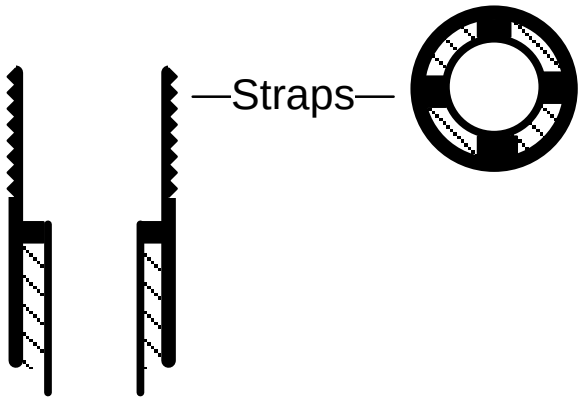

Procedure for Running and Cementing 4-1/2" Casing

1. Prepare lead joint of casing by "orange-peeling" end to act as a bull nose and plug stopper.

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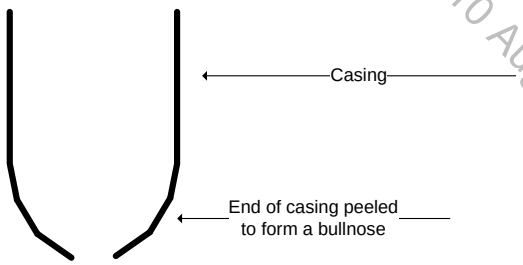

2. Run 3.5" double-wall core casing.
3. Circulate hole to condition for cement.
4. Rig up cementing head with wiper plug.
5. Pump 1 bbl of fresh water ahead of 33.4 cu ft of Class G cement w/30% silica flour, 0.75% Halad-322, and .05% CFR-6L. Take returns through 4-1/16" Diverter
6. Drop wiper plug and displace with mud. Bump plug.

7. Flush wellhead by pumping fresh water through 3-1/8” side outlet
8. WOC
9. Nipple down annular preventer, master valve, and wellhead. Remove and clean Teflon seal.
10. Perform top job if needed.
11. Cut off casing even with 4-1/2” casing.
12. Make up Teflon Seal, wellhead, master valve and BOPE.
13. RIH with NQ rod and bit and test annular preventer and side outlet valves to 300 psi.
14. Drill out bullnose and cement, pull core barrel and clean out junk.
15. Drill ahead.

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Drilling Fluid Recommendations

AK-3 / DRILLING FLUID RECOMMENDATIONS									
Operation	Depth		Weight		Funnel Viscosity		Filtrate		Comments
	From	To	between		between		between		
Core PQ	0	40	8.5	9.2	38	50	<15		Freshwater - Gel system to drill surface holes for setting surface casing; High Yield Gel for viscosity and good hole cleaning, Soda Ash for pH 9-10. Note possible artesian flow through this interval. Use Calcium Chloride for increasing mud weight as needed. Maintain a stock of barite for emergency.
Open to 10-3/4"	0	40							
Core PQ	40	220							
Open to 7-1/2"	40	220							
Core PQ	220	800	8.5	9	32	38	5	15	Mix Gel/polymer coring fluid. Maintain 8-20 ppb Gel (always add Gel first), with 0.5-1.0 lb/1,000 gallon liquid polymer and 0.5-1.0 ppb Pac LV. Add 0.5-0.75 ppb Soda Ash for pH 9-10. Maintain viscosity at 32-38 sec/qt with Gel and polymers as needed; this will also provide lubricity for coring. Lubricators may be used for additional lubricity/rod chatter. Mix thinner if needed, and Defoamer, again, if needed. If artesian conditions are encountered, consider increasing mud weight with Calcium Chloride. Keep a stock of barite for emergency. If whole mud losses are encountered, try to keep fluid level and cool the wellbore by pumping water down the annulus and sweeping hole with high viscosity pills as needed.
Core HQ	800	1,700	8.34	8.7	32	38	5	15	Continue coring with water / polymer system, as above but without Gel, using Pac LV and Polyvis as needed for fluid loss and viscosity. Consider using <4 ppb gel premix only if polymers don't mix properly. Keep a stock of barite for emergency.

Notes:
Baroid additives may be substituted with generic products after cross referencing.
Artesian Conditions – Artesian conditions are possible during this project. Calcium Chloride can be premixed if desired, and stored for potential use. Barite or Calcium Chloride can both be mixed into the coring fluid.

Draft 10 Aug 16

Cement Volume Calculations

RESOURCE CEMENTING

Volume Calculations

AK-3: Sacked Geothermal Cement

5-1/2" Surface Casing

Previous Casing:	**8-5/8" 24 lb/ft Conductor**	Equiv. ID:	10.044 in	Annular Fill Factor:	0.1926 ft3/ft	0.0343 bbl/ft
Depth:	**40.00 ft**			w/ Excess:	0.3852 ft3/ft	0.0686 bbl/ft
Previous Casing OD:	8.625 in					
Previous Casing ID:	8.097 in					
Excess:	100%					
Open Hole ID:	**7.500 in**	Equiv. ID:	9.069 in	Annular Fill Factor:	0.1418 ft3/ft	0.0253 bbl/ft
Excess:	100%				0.2836 ft3/ft	0.0505 bbl/ft
Casing Size:	**5-1/2" 15.5 lb/ft Casing**			Capacity Factor:	0.1336 ft3/ft	0.0238 bbl/ft
Depth:	**220.00 ft**					
Casing OD:	5.500 in					
Casing ID:	4.950 in					
Shoe Track Length:	40.00 ft					
AHV inside Casing:	7.70 ft3	1.37 bbl				
AHV inside Open Hole:	25.53 ft3	4.55 bbl				
Total AHV:	**33.23 ft3**	**5.92 bbl**				
Annular Excess:	33.23 ft3	4.55 bbl				
Shoe Track Volume:	5.35 ft3	0.95 bbl				
Total Cement Volume:	**71.80 ft3**	**11.42 bbl**				
Casing Volume:	24.06 ft3	4.28 bbl	**(Displacement Volume)**			
Cement: RC-ThermaLite HT (66.7-lb Bag)		**Calculated Top of Cement:**		**0 ft**		
Lead Cement Density:	13.50 lb/gal					
Lead Cement Yield:	1.00 ft3/bag					
Lead Cement Water Req:	4.14 gal/bag					
Lead Mix Water Volume:	298.08 gals	7.10 bbl				
Lead Cement Volume:	**71.80 ft3**	**12.79 bbl**		**72 bags**		
50-ft Top Out Cement:	9.12 ft3	1.62 bbl		10 bags		

4-1/2" Production Casing

Previous Casing:	**5-1/2" 15.5 lb/ft Casing**	Equiv. ID:	5.362 in	Annular Fill Factor:	0.0232 ft3/ft	0.0041 bbl/ft
Depth:	**220.00 ft**				0.0464 ft3/ft	0.0083 bbl/ft
Previous Casing OD:	5.500 in					
Previous Casing ID:	4.950 in					
Excess:	100%					
Open Hole ID:	**4.820 in**	Equiv. ID:	5.120 in	Annular Fill Factor:	0.0163 ft3/ft	0.0029 bbl/ft
Excess:	100%			w/ Excess:	0.0325 ft3/ft	0.0058 bbl/ft
Casing Size:	**4-1/2" 11.6 lb/ft Casing**			Capacity Factor:	0.0873 ft3/ft	0.0155 bbl/ft
Depth:	**800.00 ft**					
Casing OD:	4.500 in					
Casing ID:	4.000 in					
Shoe Track Length:	40.00 ft					
AHV inside Casing:	5.10 ft3	0.91 bbl				
AHV inside Open Hole:	9.43 ft3	1.68 bbl				
Total AHV:	**14.54 ft3**	**2.59 bbl**				
Open Hole Excess:	14.54 ft3	1.68 bbl				
Shoe Track Volume:	3.49 ft3	0.62 bbl				
Total Cement Volume:	**32.57 ft3**	**4.89 bbl**				
Casing Volume:	66.32 ft3	11.81 bbl	**(Displacement Volume)**			
Cement: RC-ThermaLite HT (66.7-lb Bag)		**Calculated Top of Cement:**		**0 ft**		
Lead Cement Density:	13.50 lb/gal					
Lead Cement Yield:	1.00 ft3/bag					
Lead Cement Water Req:	4.14 gal/bag					
Lead Mix Water Volume:	136.62 gals	3.25 bbl				
Cement Volume:	**32.57 ft3**	**5.80 bbl**		**33 Bags**		
50-ft Top Out Cement:	1.16 ft3	0.21 bbl		2 bags		

Planned Days vs. Depth

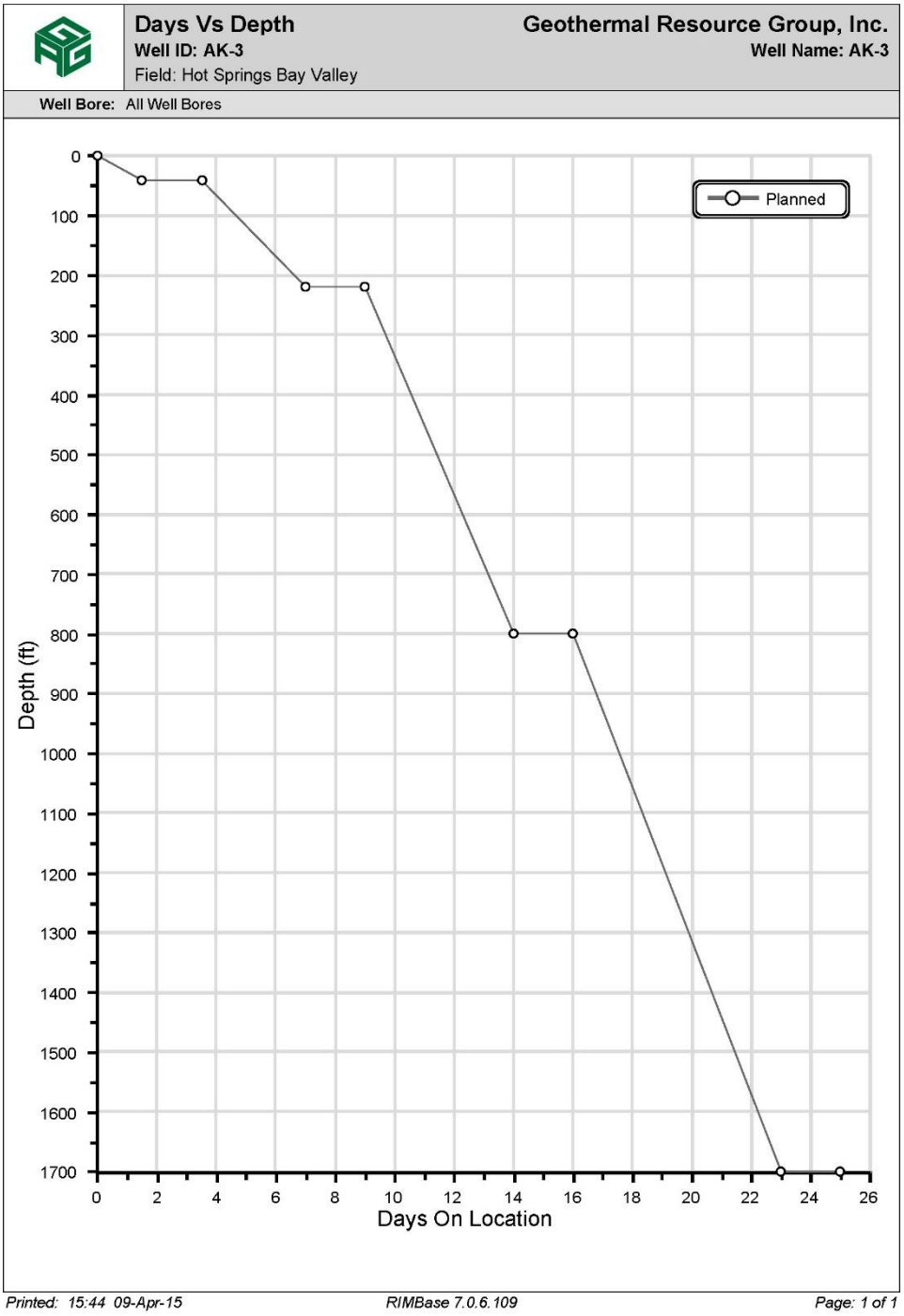

Figure 6: Days vs Depth estimation for well AK-3.

Recommended Make-up Torque

VALLEY FJ by Valley Perforating Company — Effective 2014

Recommended Make-UP torque — BOL 2000 recommended — REV 3

PIPE OD	WT/FT	Grade	MIN/FT LBS	OPT FT LBS	MAX FT LBS
2-3/8"	4.43#	J55	480	660	780
		NL80	580	800	950
2-7/8"	6.16#	J55	600	750	1000
		NL80	700	900	1200
3-1/2	8.81#	J55	1300	2000	3000
		NL80			
4" &4-1/2"	11.35#	J55	1400	1800	2800
		LN80	1500	2000	3000
5"	15-18#	J55	1500	2000	3000
		NL80	1500	2200	3200
	20#	P110	1800	3000	5000
5-1/2"	15.5#	J55	1400	2000	3200
		NL80	1400	2000	3200
	17#	J55	1400	2000	3400
		NL80	1400	2200	3400
6-5/8"	24-28#	J55	1800	2400	3600
		NL80	1800	2600	3600
7"	23-26#	J55	1600	2000	3400
		NL80	1600	2200	3400
8-5/8	32-36#	J55	2800	3500	4000
		NL80	3500	4200	4800
9-5/8	36#	J55	3400	4000	4800
		NL80	4200	4800	5800
10-3/4	38.88	J55	5000	6000	7000
		NL80	5500	6500	7500

NOTES:

The torque values listed above are recommendations only. The standard allowable value variance is 25%.
Optimum makeup may vary with field conditions. API accepted thread compounds are recommended.
This thread is designed for shallow well conditions and a safety factor of 1.5 is recommended depending on application
We expect all thread compounds to be clean and free from any debris as the thread has a close tolerance from root to crest.
A light coating of thread compound is recommended as compounds can be "trapped" with any acme thread form.
A visual makeup is always necessary and once shouldered the torque is expected to spike.
Please call if there are any question: 661 324 4964

Well Control

There is no Inside Blowout Prevention (float) when core drilling. Core drilling is true slim-hole drilling – the area of the annulus in a core hole is almost always smaller than the area of the inside of the core rod (drill pipe). This is opposite of conventional rotary drilling, where the area of the annulus is almost always greater than the area of the inside of the drill pipe. As a result, the inside of the core rod represents the path of least resistance for fluids to travel up the well bore. It is essential when handling pipe or any other operation where the core barrel is not inside the pipe to use FOSV's, along with stuffing boxes, lubricators, or the circulating pin to act as an Inside BOP. Always handle the core rod using FOSV's.

There are several types of well control issues when drilling core holes into geothermal reservoirs. These are:

Artesian Flow – flow occurs due to geo-pressured fluids entering the wellbore. This will occur both up the pipe and around the annulus. Artesian flow may or may not be associated with lost circulation, depending on the mud weight.

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Single-phase Flow – large volumes of super-heated steam exit the wellbore both through the annulus and up the drill pipe. This type of flow is always associated with a lost circulation event.

Two-phase Flow – this is a combination of boiling water and steam. Flow occurs due to high temperature combined insufficient hydrostatic pressure in the wellbore. This will occur both up the pipe and around the annulus. Two-phase flow is usually associated with a lost circulation event.

Well Bore Flashing – steam is emitted from the annulus due to boiling in the wellbore. This will not occur inside the pipe as long as the pipe remains below the static water level and fluid is circulated down the pipe.

Well Kill Plan:

1. Close the annular preventer and FOSV
2. Record SIDP, SICP, and mud temperature (if available),
3. Close the 2" side outlet valve,
4. Begin pumping fresh water through the 2" side outlet valve to cool the well,
5. Stop after pumping 1-1/2 x hole volume and check for flow,

6. If the flow continues, start mixing $CaCl_2$ and increasing mud weight,
7. Continue increasing mud weight with Barite if $CaCl_2$ added mud weight is not sufficient.

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Handling Core

The driller's helper will know how to box the core. It is important to emphasize to him that he let the core drain really well before boxing. Otherwise, the box will be full of polymer.

Have a bucket of clean water and a sponge (a bunch of sponges, actually) on hand to wipe the slime off the core.

A box of core will read just like a book – left to right and top to bottom. As you look at the core from the top-down, mark each individual piece with a black line on the right and a red line on the left. Number the broken sections from top to bottom. The more altered it is, the more broken up the pieces will be.

Describing Core

Make as through descriptions as possible, chip off samples every 10 feet or more often if warranted and reserve 2 sets of samples in the chip trays. In upper part of the hole when rotary drilling clean and reserve 10 foot samples in envelopes. The core will be preserved in the Major provided core boxes, labeled properly in the tent at the rig site. The intent is to move the comple core to the City and eventually to the State repository in Anchorage, but there is not the will or means to do this at this time. At the end of the drilling project the core should be reserved in a weather resistant location in the Hot Springs Bay Valley, the Harbor, or in the City.

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Describe:

- Rock Type.
- Color. (Use a GSA or another standard color chart.)
- Texture.
- Hardness and Induration. A trick to determining induration is to hit the core with a hammer. Highly indurated or silicified rock will "ring" and poorly indurated or argillic altered rock will "thud." Everything in between is more or less a judgement call.
- Fractures, veining, vugularity and other physical features. Use a protractor for a rough orientation.
- Hydrothermal alteration.
- Hydrothermal mineralization.

Make up a small placard with the following information:

- Core Box Number;
- Depth from and to;
- Estimated Percent of Recovery.

Photographing Core

Take digital pictures of the entire core box at a high resolution. Include the placard in the photograph. Photograph it using a consistent method.

Take additional pictures of significant features in the core, being sure to include the depth of the feature.

Either photograph the core in natural light or photograph it using proper photography lighting.

Don't photograph it under fluorescent lights – the color will look weird.

Set the white balance prior to beginning the photographing.

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Run an egg timer – set it for one hour. Reset the white balance on an hourly basis.

Photograph in oblique sunlight, not in direct sunlight. Direct sunlight will create glare.

Use a Tiffen (FKA Kodak) Color separation chart.

Photograph the chart each time the white balance is reset and try to include the color chart in each photograph.

Buttoning Up the Core

If you plan only to do a more detailed description later, then the core may be sent in as-is. Keep in mind that some minerals like Gypsum or Anhydrite may hydrate during the interim and crumble away.

Driller's responsibilities

The driller's helper will box and label core, and stack the boxes on a pallet. Don't let them skimp on boxes – "one barrel, one box." It is important to emphasize that they let the core drain really well before boxing. Otherwise, the box will be full of polymer.

The driller (or helper) will prepare daily drilling logs, core reports, weekly situation reports, serious incident reports, as required, and end of well reports. Rate of penetration and mud returns will be

obtained from the driller. The driller will need to log drilling times on his worksheet, and note intervals where there are "drilling breaks". He will also need to note if he is losing (or gaining) fluid. These numbers will be entered manually into the logging software by the wellsite geologist.

The driller will take drift measurements at 200 foot intervals while drilling to determine deviation from true vertical. At the same time, the driller will run an MRT to take bottom hole temperature (use judgement if this is needed). The driller will note the drift and MRT reading on his tour report and the geologist will log the bottom hole temperature from the MRT on the mud log.

Core Logging Procedures

1. Wipe the slime off the core (polymer and mud, etc.) using a bucket of clean water and sponges/towels. Can use the provided spray nozzle and water hose. But don't get too energetic and scub the core itself away!
2. A box of core will read just like a book – left to right and top to bottom. On each cut of core, put a red line on top of each section and a black line on bottom. This orients each core section relative to top and bottom.
3. Mark a section number – if broken into 12 pieces, mark 1-12. Include any pieces that appear to be ready to fall apart.
4. Do gross description. If need to see a fresh surface, whack w/rock hammer. Note the following:
   4.1. Rock Type.
   4.2. Color. Use a GSA color chart.
   4.3. Texture.
   4.4. Hardness and Induration. A trick to determining induration is to hit the core with a hammer. Highly indurated or silicified rock will "ring" and poorly indurated or argillic altered rock will "thud." Everything in between is more or less a judgment call.
   4.5. Fractures, veining, vugs and other physical features. Use a protractor for a rough angle.
   4.6. Hydrothermal alteration. Describe suite (argillic, propylitic, etc.)
   4.7. Hydrothermal mineralization.
   4.8. Contact or contact zone, and whatever length interval it's over (use a tape measure)
5. Fill out placard with the following information:
   5.1. Core Box Number;
   5.2. Depth from and to;

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5.3. Estimated Percent of Recovery. (I print out batches of these on blank 3x5 index cards and fill in the blanks.)

6. After taking the photo, tuck the card underneath a piece of the core. This will help to identify the core if the lid to the box should be lost.
7. Take a high-resolution digital photo of the core box:
   7.1. Pay attention to color. Be consistent – always photo either in natural light (set light balance) or copper photo lights – don't try to photograph in incandescent light. Run an egg timer and set it for an hour, set light balance over course of the day. Photograph in oblique light so no glare. Kodak color separation chart. Set white balance.
   7.2. Make sure it's from the same fixed distance each time (use tripod w/ piece of string to measure distance)
   7.3. Include placard as well as core box
   7.4. Photograph anything else significant.
   7.5. Photograph the chart each time the white balance is reset and try to include the color chart in each photograph.
8. Transpose descriptive data from worksheet into LogPlot
9. Enter other data (rate of penetration, PT info, circulation information, etc… into LogPlot.
10. Maintain a 10 ft sample chip set for Alaska Oil and Gas.

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Supplies: Core Logging

- Bucket of clean water
- Sponges and towels
- Water hose w/ spray nozzle
- Black and red permanent markers
- GSA color chart
- Rock hammer
- Hand lens and/or magnifying glass
- Blank index cards
- Pre-printed index cards ("placards") w/ info given above

- Digital camera and tripod
- Kodak color index
- Egg timer
- Copper photo lights?
- Laptop w/ LogPlot software

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Akutan Account Codes

99.01 Mob/Demob

99.02 Rig Footage

99.03 Rig Hourly

99.04 Rig and Camp Fuel

99.05 Location Cost

99.06 Communications

99.07 Camp Services

99.11 Drilling Supervision

99.12 Drilling Engineering

99.13 Geology

99.14 Logistics

99.15 Roustabouts

99.16 Travel Expense

99.17 Vehicles

99.21 Helicopter Daily

99.22 Helicopter Fly Time

99.23 Helicopter Fuel

99.31 Conductor & Casing

99.32 Cement

99.33 Bits & Tools

99.34 Drilling Fluids

99.35 BOPE

99.36 Wellhead & Tubing

99.37 Small Parts & Supplies

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99.41 Rental Equipment

99.42 Drift & Directional Tools

99.43 Logging & Well Testing

99.44 Other Services

99.45 Shipping

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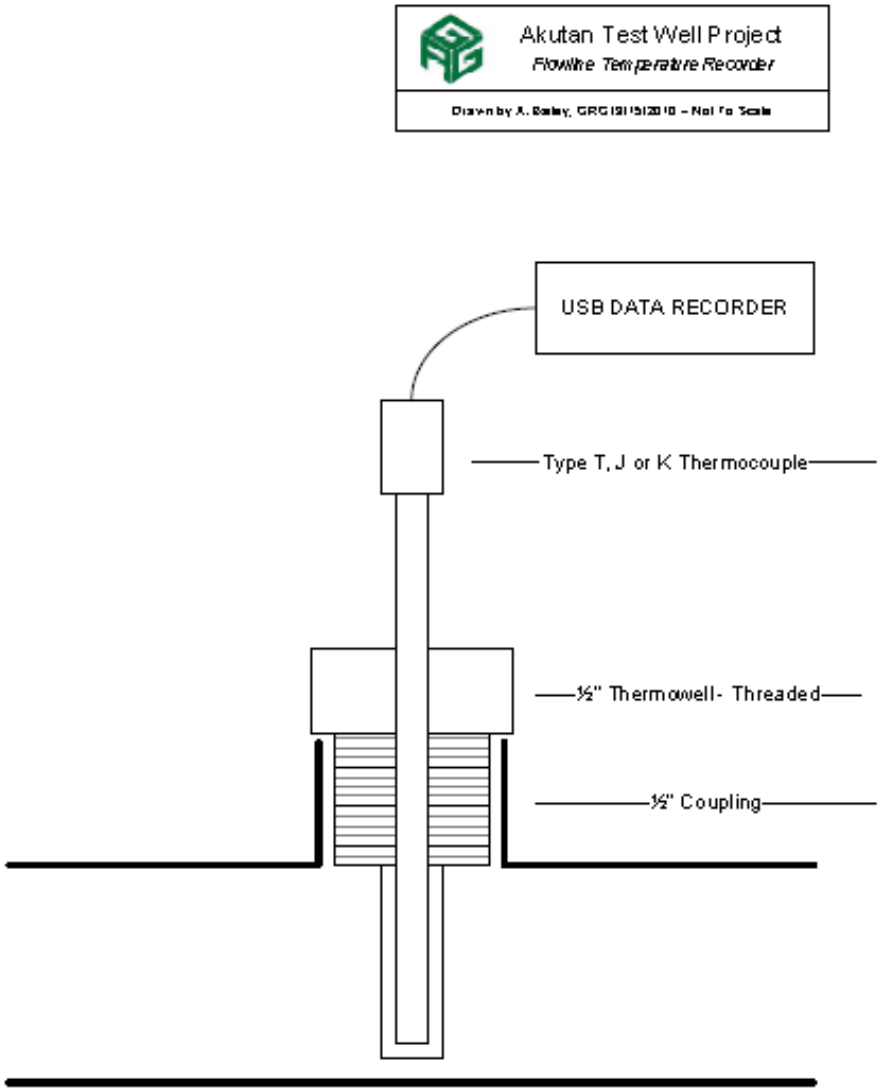

Schematic of Flow Line Data Recorder

Leak-Off Test Procedure

Important: Never test formation to greater than 1.0 psi/ft fracture gradient.

Prior to Testing

Drill out the casing shoe. Clean out cement below the shoe. Make 20 feet of new hole. Spot a high viscosity pill with low water loss on bottom.

Use a sheet of linear graph paper to plot pressure on the vertical axis versus volume of fluid pumped on the horizontal axis. Don't begin this test without graph paper in hand! There is a sheet included at the end of this procedure. Record your name, well name, date and time, the mud weight and casing size on the graph paper. Mark the 1.0 psi/ft gradient on the graph paper and mark an estimated leak-off so you have the upper limit and some idea of where to expect leak-off.

During the leak-off test, graph the volume pumped versus the corresponding pressure. Use a straight edge to connect data points. Record all liquid pumped.

In general, the shoe formations in geothermal wells are brittle and weak. Therefore, it is necessary to find the leak-off pressure without breaking down the formation directly beneath the casing shoe.

Test Procedure

Draft 19 Aug 16

Fill the stack and close the rams. Pump until pressure begins to register on pressure gauge. The starting point should be 0 psig starting pressure on the y-axis and 0 barrels injected on the x-axis. Graph the start pressure (Figure1).

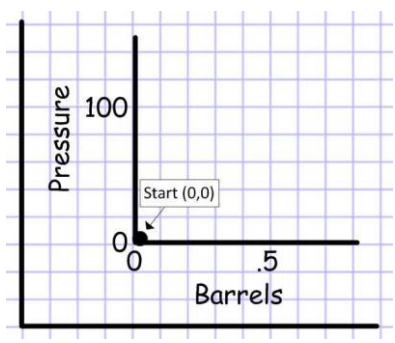

Figure 1. Log your volume pumped and start pressure before looking for leak-off. It will take some volume pumped before the pressure will come off zero.

Now you can begin pumping incremental volumes. All of the volumes should be the same size. In the following example the volume is 2/10ths of a barrel. It will take some volume pumped before a pressure greater than zero is recorded, but it is still necessary to record these volumes. Pump until a pressure is recorded, and start recording the pressure at the even increments subsequent to that. Between each incremental pumping, stop and graph the pressure on your graph paper and record the values (Figure 2).

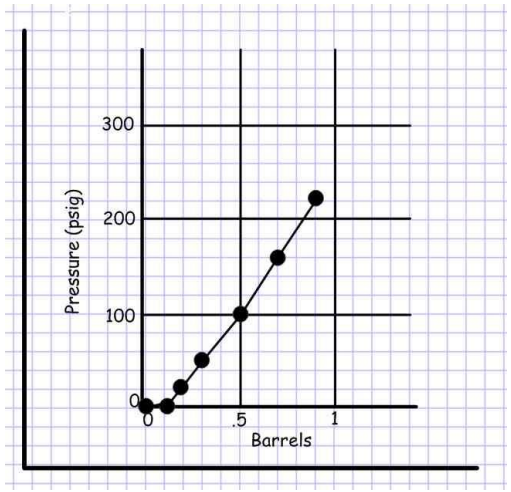

Figure 2. Initially, the pressure curve grows steeper with each pumping.

At first, the pressure vs. volume curve will grow steeper with each pumping. This is <u>not</u> what we are looking for. Instead, what we are looking for is a constant increase in pressure with each pumping increment. So instead of the pressure vs. volume curve growing steeper, it will appear as a constant slope – a straight line from point to point:

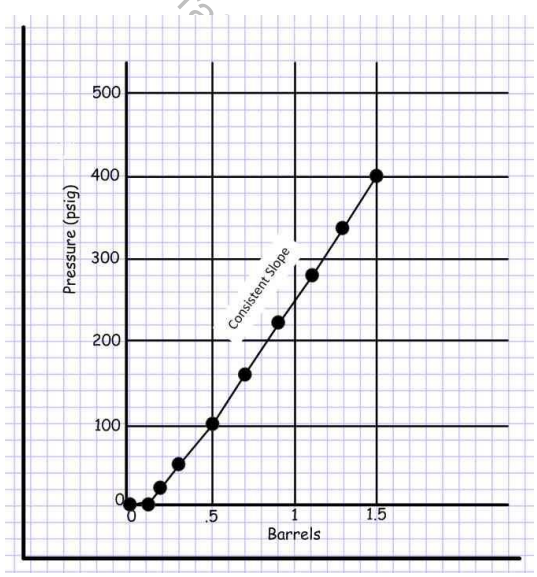

Figure 3. The slope becomes constant.

You are now looking for the most important part of the leak-off test –a decrease in the slope of pressure vs. volume curve (where the slope becomes less steep). This is the leak-off pressure and the point at which you want to stop pumping fluid. After reaching the leak-off pressure, the slope will change (Figure 4).

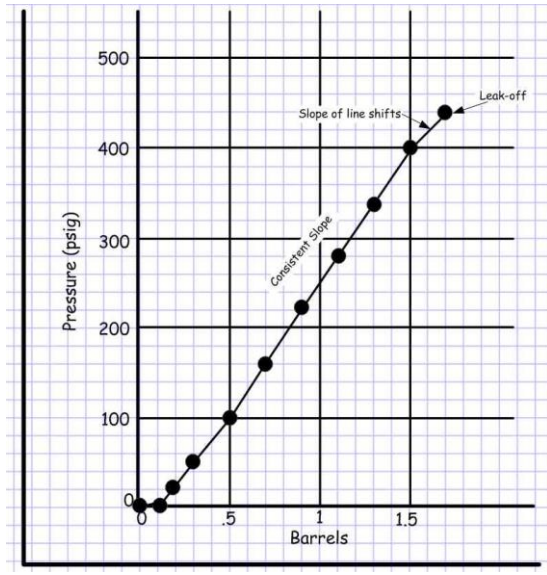

Figure 4. The slope has shifted. Leak-off has occurred!

Figure 4 suggests that leak-off occurred at 1.7 barrels and 440 psig. The actual leak-off was somewhere between 400 psig and 440 psig. The slow way we do the leak-off gives a very conservative leak-off pressure and the top of that change in slope is closer to the real leak-off than the lower part. Sometimes the change is very dramatic and easy to find. Other times it is more subtle, and more fluid has to be pumped to make sure leak-off has occurred.

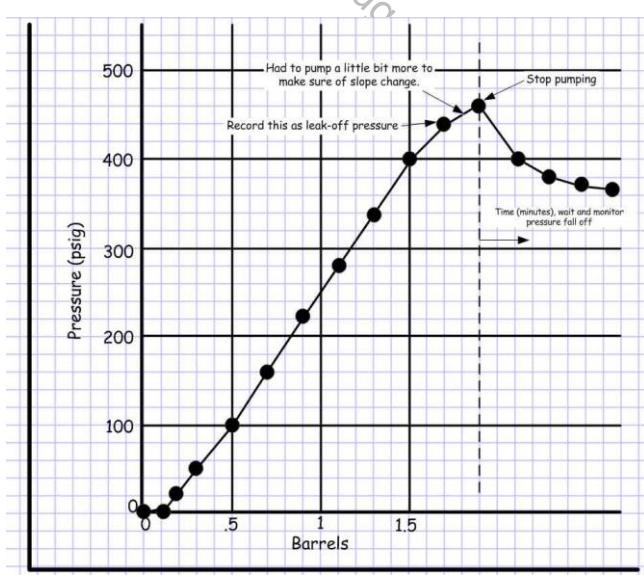

Figure 5. Record the pressure bleed-off in even time increments after stopping pumping. Record the fall off until it starts to level out.

Quite often the curve doesn't build up as neatly and you have to pump an extra increment or two to make sure you have a change of slope (Figure 5). The recorded leak-off still is the point at which the slope of the pressure vs. volume curve first started to decrease. Always record the bleed-off pressure in even time increments from the time you stop pumping until it starts to level out. The bleed-off pressure is helpful in interpreting the test results and integrity.

Calculation of Results

To determine the fracture gradient, we must know the following:

- True vertical depth of the well
- Weight in pounds per gallon of the fluid in the well bore
- Leak-off pressure

Using this information, we will calculate the fracture gradient using the following formulas:

a) **Hydrostatic Pressure = Weight of Fluid in Wellbore (ppg) x 0.052 x TVD**
b) **Fracture Gradient = (Hydrostatic Pressure of the Fluid + Leak-off Pressure) / True Vertical Depth**
c) **Equivalent Mud Weight = (Fracture Gradient / 0.433) x 8.33**

For this example, we'll use 2,000' as the TVD and 9.0 ppg as the weight of the fluid. We have already determined the leak-off pressure as being 490 psig. The results of this calculation are:

a) Hydrostatic Pressure = 9.0 x 0.052 x 2000 = 936 psig
b) Fracture Gradient = (936 psig + 490 psig) / 2000 ft = 0.71 psi/ft
c) Equivalent Mud Weight = (0.71/0.433) X 8.33 = 13.66 ppg

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Well Number:

Date:

Time:

Casing Size:

Mud Weight:

TVD:

Top Fill and Top Squeeze Procedure

This procedure can be used on any casing string that is run with a previous cemented casing string in place. The wellhead must have an annular preventer and a side outlet with a pressure gauge installed. The main purpose of this procedure is to keep the casing-by-casing annulus free of trapped water while cementing the inner casing.

1. At TD, condition hole for casing, spot LCM pill at bottom if necessary, and rig up and run casing.
   1.1. Take care not to surge hole by dropping casing fast while running.
   1.2. Stop and circulate casing periodically while running casing, to break mud gel strength.
2. Cement casing as per cementing program.
   2.1. Use appropriate excess cement volumes.
   2.2. Pump the recommended mud flush and NaSiO2 / CaCl2 pre-flush (if available, as necessary).
   2.3. Measure displacement from tanks and count displacement pump strokes. Bump plug if possible. Do not displace more than 1/3 of shoe track volume to bump plug.
   2.4. Do not forget to collect at least three samples (start, middle, and towards the end of job) and measure weight of returns while cementing to determine contamination.
   2.5. Check floats. Hold pressure from surface if floats do not hold. If floats leak, do not pump and bleed; but hold constant pressure until cement takes an initial set.
3. Close annular preventer as soon as cement is in place.
4. If good cement (weighting 0.2-0.3 ppg less than pumped weight) returns to surface and stays at surface, keep annular preventer closed to prevent any water out of casing by casing annulus and wait on cement (WOC) until samples are cured and proceed directly to Step 7.
5. If good cement returns to surface but then falls away, proceed with top-fill:
   5.1. WOC for 4 hours (or until the cement takes an initial set). Make sure all water is kept out of annulus while WOC.
   5.2. Fill annulus with cement from surface through side outlet valves
      5.2.1. Use accelerated cement slurry.
      5.2.2. Open both valves and run a cement line to one valve, but do not connect line.
      5.2.3. Mix and pump cement until good cement slurry comes out of cement line.
      5.2.4. Hook line to one side outlet valve and take returns through other side outlet valve.

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5.2.5. Pump until annulus fills with cement (good cement returns are observed from the outlet).

5.2.6. Do not forget to collect samples while cementing.

5.2.7. Pump excess cement to surface to remove any contamination from the annulus.

5.2.8. Close valves and break lines to wash up. Do not displace cement.

5.2.9. Leave annular preventer closed, WOC until cement samples are cured.

5.2.10. Proceed with Step 7.

6. If good cement doesn't return to surface, IMMEDIATELY flush the casing-by-casing annulus with water, WOC, and proceed with top squeeze:

6.1. Close the annular preventer and one side outlet valve.

6.2. Pump at least one casing-by-casing annulus volume of water through a side outlet valve. It is recommended to pump some extra volume in order to make sure that it is possible to pump through the annulus into the formation. It is important that this is done before the cement in the annulus takes an initial set.

6.3. WOC for 4 hours (or until the cement takes an initial set). Be prepared to pump at least twice the volume of casing-by-casing annular volume of cement.

6.4. Flush casing annulus with at least one casing-by-casing annular volume of water before mixing any cement. This is to ensure that cement can be pumped out of the casing shoe before any is pumped into the annulus.

6.5. Open one side outlet valve and connect a cement line. If practical, install a pressure gage on the other side outlet and open it to the annulus.

6.6. Start pumping to squeeze cement through the annulus

6.6.1. Use accelerated cement slurry.

6.6.2. Pump at least 100% of the cement required to fill the casing annulus, or until a squeeze is obtained. Any backpressure at the well head that doesn't drop off to zero is usually considered adequate. Hesitation (stutter) squeeze method may be employed; but only after one full casing by casing annular volume has been pumped. Do not wait longer than 15 minutes between pumping intervals. Once you fill the annulus with cement, the hydrostatic of the cement column may be much greater than the initial pumping pressure with water.

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6.6.3. Do not forget to collect at least three samples (start, middle, and towards the end of job) while cementing.

6.6.4. More cement can be used, especially if there are indications of a loss zone.

6.6.5. Cut job short if constant good squeeze pressure is observed after the casing-by-casing volume has been pumped. It is considered best practice to pump at least one casing by casing annular volume of cement slurry to ensure that no water is left in the casing by casing annulus.

6.6.6. Do not displace cement. Close valve and break off line to wash up. WOC until cement samples are cured.

6.6.7. If no squeeze has been achieved after pumping all of the planned volume, the cement top falls away in the annulus, leave annular preventer closed, WOC, and proceed to the top fill procedure (Step 5 above). This is a common occurrence; a top fill is required about half the time after a top squeeze.

6.7. After the squeeze has been achieved, leave the annular preventer closed (and leave any pressure on the annulus), until cement takes an initial set. Pressure may be kept until cement samples are set, if necessary.

6.8. Proceed with Step 7.

7. If cement top falls after completing steps 4, 5, or 6 and the cement samples are cured, keep annular preventer closed to keep all water out of annulus and use the top fill procedure (Step 5 above) however many times necessary to fill the whole annulus and complete the top job. If the cement is not too far below from the surface (< 20’), it can be top filled manually (without the pumping unit) mixing and dumping in the cellar. Make sure to keep all surface water out of annulus.

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