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Case History : New Drills Off Old Platforms In EI 338/339 Field

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Abstract

This paper will summarize the challenges that were faced and the lessons learned in trying to drill both new wells and sidetracks off of several 30 year old platforms.

Since there were no empty slots on the platforms the first challenge was to reclaim slots without a rig in 260' of water to help keep the project's costs down. The next hurdle was to design directional and drilling plans so the new wells would not collide with the 27+ wells that had been drilled from each 18 slot platform. The third challenge was correctly picking intermediate casing depths. This was complicated by drilling thru partially pressure depleted sands above a rapid, shallow pressure transition zone in a field where sands are not uniformly deposited across the field and are difficult to correlate. Also, most wells were drilled with 45+ degrees of inclination so hole cleaning had to be factored into the drilling procedures. Last, the decision had to be made to use water or oil based mud to drill the wells with. While oil based mud would help with ROP, torque, drag and handling the massive gumbo attacks that the EI 339 area is known for, most of these wells would require 16+ ppg mud at TD. 16+ ppg oil based mud would greatly increase the chance of losing complete mud returns into a shallower, weaker zone while drilling a high perm 15+ ppg oil sand near TD.

The lessons learned :

1) Importance of setting intermediate casing 1 stand shallower rather than 1 stand too deep.
2) Can save $ 500,000 by drilling high angle, high pressure S shaped directional wells with modern water based mud(even thru a depleted sand) vs an oil based mud.
3) Well slots can be efficiently and economically reclaimed before the drilling rig arrives.
4) Divers have a hard time knowing which way is North in 260' of water.
5) With proper planning a 30 year old platform can be safely drilled from, even new wells, if the right drilling plan is used.

The prize at the end of it all : 2 platforms that had been producing 2,000 BOEPD now produce 10,000 BOEPD.

Introduction

ChevronTexaco set several 18 slot platforms in the 1970s in Eugene Island blocks 354, 338 and 339. They have been prolific producers over the years as part of the largest field in the Gulf of Mexico, Eugene Island 300. In recent years though the production has declined substantially to about 1,000 BOPD per platform. Some previous attempts to revitalize the area thru drilling new wells off the older platforms were not financially successful. Our challenge was to not only drill new wells off these old platforms, but also take what ever steps were necessary to ensure it was done profitably.

1 Rigless P&As/T&As

The first key is to plan to do as little pipe recovery and handling as possible during rigless T&As and P&As. This takes some advance planning and discussions with the MMS and your selected contractor so that the abandonment procedures are efficient and contain pre-approved backup plans for the things that are most likely to go wrong. Such as having the wording in your MMS Sundry that if you are unable to inject into the old perforations you will set a thru tubing bridge plug +/- 100' above the perfs and then spot a 500' long balanced cement plug within 1,000' of the perfs.

It is also best to plan and award the work to the contractor at least 2 weeks in advance. This allows the contractor to plan the abandonment work for several wells as batch processes that can minimize everyone's costs. By doing this it allows the contractor to bring their eline and cementing equipment out to the platform once to set the cement plugs and do most of the eline work together in all the wells at once. Then they can bring out the BOPs and casing cutters and casing jacks to retrieve the tubing and casing strings from all the wells. This also minimizes equipment on location, making for a more organized and safer working environment.

One typical P&A procedure for a well with drive pipe, surface and production casing would be :

a) Have a qualified 3rd party company fully inspect the platform crane before it's used at all. We have found this greatly increases the safety of the P&A operations.

b) Set up office buildings and some times living quarters if it is an unmanned platform.
c) Lock open tubing SSSV. Establish injection into perforations down tubing. Fill and pressure test production casing to 1,000 psi. Pressure test surface casing to 500 psi. Circulate tubing and casing clean of hydrocarbons.
d) Cement off old perforations by bull-heading +/- 50 cubic feet of cement down the tubing. Wait on and then tag the top of the cement.
e) Cut the tubing at +/- 3,000'. Circulate a 500' long balanced cement plug in place. Wait on, then tag, then pressure test cement to 1,000 psi on tubing and annulus.
f) Cut tubing +/- 300' BML.
g) ND tree. NU and test BOPs. POOH and lay down tubing. Set CIBP in production casing at +/- 300' BML.
h) Cut production casing +/- 250' BML. Spear, pull and LD casing with casing jacks.
i) TIH and spot cement plug from 300' BML to 100' BML. Pressure test cement to 1,000 psi.
j) Set CIBP in surface casing at +/- 100' BML.
k) TIH and cut surface casing at +/- 35' BML. Try to pull with casing jacks. If cannot pull surface casing free, TIH and cut drive pipe at +/- 35' BML.
l) Pull surface casing and drive pipe free and POOH with casing jacks.

We have found rigless P&As to be a safe and cost efficient method. We can P&A a well rigless for an average cost of $ 250,000.

2 Collision Avoidance

One look at Figure 1, a spider plot of the wells drilled off of Eugene Island Block 339 platform B, will show why collision avoidance is an intricate part of the well planning process. Between the wells drilled from the original 18 slots, plus full slot reclamations and redrills, plus major sidetracks there are now 30 wellbores drilled below this 18 slot platform.

The first challenge is to find which directional company has a full, up to date set of surveys for all the wells drilled in the field. Then we check them for accuracy versus our records and resolve any discrepancies. Once we have a basic directional plan for a new well the directional company runs their collision avoidance program versus all offset wells in the field(not just wells drilled from the same platform). From their report we come up with a list of wells we are concerned about colliding with. As Figure 2 shows, at EI blocks 338/339 the list usually includes 8 to 15 wells whose closest distance to our projected well path is less than 1 % of the MD. We then group the offset problem wells by depth and tackle them one depth group at a time, from shallowest to deepest. If possible, we redesign the new well's directional plan so that the closest the new well comes to any of the offset wells is at least 1 % of the MD at which the 2 wells pass closest to each other. If we can accomplish that then we will be willing to drill the well with mud motor BHAs. If we can not get at least 1% of the MD away from an offset well, we will drill that part of the well with a rotary jetting BHA.

We will set 2 way positive plugs in all offset wells that the new well will pass < 2% of the MD at which they will be closest together. The plugs will be set in the tubing below the depth at which the new well will pass the existing well. Then we bleed down most of the pressure off the tubing and casing annuluses. Then we monitor the offset wells for any changes in tubing and/or casing pressure while we drill the new well past them. We pull the plugs once the new well is cased deeper than the depth the plug was set at.

The shallowest problems usually occur from +/- 350' to 750' MD. It usually involves finding a big enough open space at or just below the sea floor to fit in one more string of drive pipe. With an increasing number of slot reclamations on these platforms this is getting harder and harder to find. We have recently had to resort to removing some of the smaller structural braces supporting the lowest level of bell guides to create a space for the EI 338 A- well. We have also had to resort to trying to pull the new string of drive pipe across a 12" diameter structural beam, which did not work. But we did then successfully pull it across a 10" member to run new 22" drive pipe. But we had to cut away part of the 3rd from bottom bell guide as well as the 2nd one from the sea floor to free the pipe up enough to bend it across that 10" diameter member while applying 20,000 lbs of side force with 2 subsea come alongs.

Even with all this work with the drive pipe, we still usually have 3 to 5 wells within 2' to 10' of our new well at the drive pipe's shoe at +/- 750' MD plus another 2 to 4 wells 10' to 20' away at 1,500' MD. Since some of these wells are usually closer than 1% of the well's MD we usually exit the drive pipe shoe with a jetting rotary bha. We believe, coupled with control drilling the conductor hole, it allows us to feel any minor bumps or collisions in time to minimize the damage done where as a mud motor bha can drill right thru a well before you know it's happened. We have had a lot of success jetting our conductor holes around other wells. We normally can average 1.5°/100' build rates with the bha listed in Figure 3. One other idea we are doing is to drill with the smallest bit we can for our planned conductor casing size, for instance using a 17.5" bit for 16" casing or a 16" bit for 13-3/8" Buttress casing. We count on the hole washing out to get the casing down while physically minimizing our chances of hitting offset wells by using smaller bits.

Once the conductor casing is set we still usually have 1 to 3 wells to avoid while drilling the surface hole. At this stage we usually can plan the well so that we are 1% of the MD away from offset wells. This allows us to use mud motor bhas to drill our surface holes, which is good since we normally have to build to 40° to 60° in our surface hole to hit our well's targets. One other idea we try to employ in our surface holes is to plan to drill shallower than or deeper than all the offset well paths our well will cross in the surface casing hole. That way if you plan to be shallower than the offset wells, the directional driller knows if he is on or ahead of the planned line you are safe. Like wise if you plan to drill deeper than the offsets, the directional driller knows if he is on or below the planned line you are safe. It's just an easy way for everybody to know at a glance while you are drilling the well if everything is going okay or not.

3 Run New Drive Pipe

While the jackup rig was preloading, rigging up and starting to run the new drive pipe divers using saturated air would cut a section away from the 2nd bell guide above the sea floor. The divers would also rig up a subsea come along anchored to one of the platform jacket legs. Once the new pipe was lowered to a few feet above the 1st bell guide above the sea floor the divers would place the come along's sling around it. Then as the rig lowered the pipe the divers used the rig's air hoist attached to the subsea come along to pull the drive pipe outside of the 1st bell guide above the sea floor(as illustrated in Figures 4 thru 6). After that the pipe was slacked off into the mud until it could support it's own weight.

One thing we learned was doing this in +/-260' of water does not always go smoothly. Once on the EI 338 A-7 ST and again on the EI 339 B-3 ST one of the new drive pipe's collars got hung up on a lip left on the 2nd bell guide from bottom and both times divers had to go back down and cut more metal off of that belle guide. Another time on the EI 338 A-6 ST 3 we could not slack off the drive pipe into the sea floor due to all the trash on the sea floor. Again the divers had to go back down and literally clean up the sea floor. Also, on the EI 338 A platform we had already done this type of slot reclamation on several wells and there was not an open space available to run the new drive pipe in. After consulting with the Facilities Engineering department we determined we could have the divers cut and remove a small brace from the bottom belle guide deck to create room to run the drive pipe for the EI 338 A-7 ST.

All of the complications listed above are usually fixed by divers. Usually the dive company will bring 6 divers out to do this type of slot reclamation work. But on several wells this was not enough and the rig ended up waiting on divers to get enough rest so they could dive again or on more divers being flown out to the rig to finish the work. Our experience shows you would be money ahead if you bring out 6 to 8 divers when they first mob to the rig and then fly out 2 to 4 more the day they start working. Their salaries will be more than paid for by the rig downtime they will save you.

Next we hangoff the drive pipe with padeyes and slings to support it's weight. Then we TIH with a jetting bha and wash out under the drive pipe to 280' BML(see Figure 7) while utilizing a surface read out gyro to orient ourselves. We do this because we have 100% success in having full returns while drilling the conductor hole in this field if our drive pipe has at least 275' of penetration. It also helps our well avoid colliding with the other 24+ wells previously drilled from these 18 slot platforms. It is vital to the safety of the operation to ensure the company designing, supplying and installing the padeyes and slings is told they will need to support the entire weight of the drive pipe in air from +/- 300' BML back to and above the rig floor. After the hole is drilled to 280' BML we slack off the drive pipe to bottom until it can support it's own weight. Then we rig up the casing hammer and drive the pipe to refusal(see Figure 8).

While this is a mechanically complex way of reclaiming slots, we have found it fits our program due to it's reasonable costs. Our average cost for performing these steps with the jackup rig on location is $ 285,000.

On the EI 338 A-6 ST 3 we had an unexpected problem. Instead of the divers pulling the drive pipe to the North of the bottom bell guide the divers mistakenly pulled it to the West. This happened even though we were on the Northern most row of slots and the instructions given to the divers were to pull the pipe to the North, namely away from all the other wells on the platform. The mistake was discovered after we washed out the drive pipe and ran a gyro survey but before we jetted out to 280' BML. The gyro survey showed our new well was on course to collide with the EI 338 A-7 ST well at +/- 800' MD, which we had just finished drilling and completing 1 month earlier and was flowing in excess of 1,000 BOPD. We attempted to jet drill the well to the North, but the well continued to go to the Southwest. We ran and drove the drive pipe to refusal at 722' MD. After a long night of running close to 25 different directional plans, we agreed on one that we thought gave us a good chance of missing the A-7 ST well. We set a plug in the A-7 ST well at 3,000' MD and locked it's SCSSV closed at 650' MD. Then we control drilled out of the A-6 ST 3 drive pipe shoe at 30'/hour with a rorary jetting bha and slowly drilled our way down underneath the A-7 well until we were sure we would not hit it. We used a surface read out gyro and took surveys every 15' to 30'. By doing this we dropped the angle in the A-6 well until it's angle was less than A-7s and A-6s azimuth matched the A-7 well's azimuth, except we were 3' below it. After paralleling the A-7 well for one joint we slowly turned the A-6 well to the South to move it away from the A-7 well. After that the EI 338 A-6 ST 3 was drilled to TD with no more wellbore collision problems.

4 Intermediate Casing Point

A constant challenge on most of the old as well as the new wells drilled from these platforms is picking the correct depth at which to set our intermediate casing. It would be important to set intermediate casing at the proper depth in any field in which you encountered high pressure sands as shallow as you do in the EI 338/339 area. Figures 9 and 10 show the rapid pore pressure increase along with the requisite mud weight increase versus depth for the EI 339 B-3 ST and EI 339 B-17 ST respectively. Careful observation of the graphs reveal that we have to weight up from 10 ppg to 16 ppg mud in as little as 3,000' of TVD.

Figure 9 further illustrates another problem, which is that the B-3 ST had to drill thru the partially pressure depleted 4500' Sand in it's intermediate hole. The 4500' Sand is a well developed sand that is 300' TVD thick. It's reduced pressure raised concerns about how large a kick could it take plus would we stick the intermediate casing before it reached bottom if we used a water based mud. The sticking concern was addressed by sizing and adding some LCM additives to the mud to bridge off the 4500' Sands pore throats to ensure a continuous filter cake across the sand. We also centralized the casing from TD to the top of the 4500' Sand. The kick size concern was addressed by pushing the surface casing shoe down to 3,700' TVD and by paying special attention to staying slightly ahead of our mud weight plan to minimize the possibility of a kick. The hole section was drilled without any kicks and the casing went to bottom as planned.

What makes it hard to get the intermediate casing set at the correct depth, even after 60+ wells have been drilled is the fact that the sands are not uniformly deposited across the field and are very difficult to correlate. Another complicating factor is that the top of abnormally high pressure changes across the field. In one part of the field the EI 338 A-7 ST drilled thru the 5700' Sand with 12.5 ppg mud and then set intermediate casing. However in another part of the field the EI 339 B-3 ST was up to 13.1 ppg mud above the 5700' Sand and had to set intermediate casing and weight up to drill thru the 5700' Sand. One part of EI block 338 has one area that is highly faulted by faults with less than 150' of throw. Yet thru drilling a few wells in this area we have learned that the top of abnormally high pressure changes across these small faults that are hard to see on 3D seismic.

All these problems taken together has caused a lot of time and energy being devoted in each well's planning process to determining the correct TVD depth to set intermediate casing. But the EI 338 A-7 ST showed that even with what was thought to be good planning regarding the intermediate casing depth combined with real time GR/resistivity LWD wasn't enough to avoid trouble. Our plan was to test our surface casing seat to 13.2 ppg emw, drill to 7,660' TVD with 12.4 ppg mud and set casing. But at 6,960' TVD our mud was seriously gas cut and we weighted up to 12.6 ppg. The gas dropped out of the mud, we checked our correlations versus offset logs and we resumed drilling because we believed we were still quite a ways above casing depth. At 7,187' tvd our mud was seriously gas cut again and we weighted up the mud to 12.8 ppg. Again the gas dropped out of the mud as the heavier mud reached the surface, we checked our correlations again and started to doubt them. What the well was telling us did not agree with what the log was telling us. After involving the drilling superintendent and geologist in the decision we decided to drill one more stand to help clear up which sand we were in at TD. We almost finished drilling that stand.

At 7,271' tvd we were gas cut again and this time weighting up to 12.9 ppg did not get rid of the gas. We knew from our PWD tool and hydraulic programs that our surface casing seat had already held a 13.5 ppg emw. So we weighted up to 13.1 ppg at a reduced pump rate, but the gas did not go away. We then slowly weighted up to 13.2 and then 13.3 ppg but we still had gas cut mud. We shut down the pumps to observe the well and it flowed a 2" stream and had visible gas bubbling out of the mud in the bell nipple. To kill the well we mixed and spotted 600 bbls of 14.5 ppg mud in the open hole at a slow pump rate and left 13.3 ppg mud inside the surface casing for a 13.9 ppg emw at TD. Once this heavier mud was in place the well was dead and we POOH and ran and cemented our intermediate casing on bottom.

The bottom line was we ended up setting casing almost 400' tvd shallower than the offset wells had. We also had drilled one stand too deep and spent 2 rig days and $ 250,000 because of it. Ever since the EI 338 A-7 ST I have spent more time on planning my intermediate casing depth. But I also constantly remind myself to believe what the new well is telling me while it is being drilled more than I believe my offset data or correlations. My goal on all the wells I have drilled after the EI 338 A-7 ST has been to set intermediate casing one stand too shallow rather than one stand too deep.

5 Water or Oil Based Mud

During earlier drilling programs the wells intermediate and production liner hole sections were almost entirely drilled with synthetic oil or diesel based muds. The oil based muds showed off several of their benefits in the EI

338/339 field. They eliminated the problems we had had in the past with massive gumbo attacks. They also allowed us to drill basically as fast as we wanted to. A third benefit was a reduction in torque and drag not only while drilling but also while running casing. This drag reduction helped us get some casing strings down that might not have reached bottom without the oil based muds.

Over time though some negatives of oil based muds became apparent. The faster ROPs in combination with larger cuttings and more gauge holes caused significant hole cleaning problems. The compressibility of oil based muds leads to a higher equivalent circulating density than with water based muds. These higher ecds led to losing partial to full mud returns in a lot of wells, either while drilling or if not while drilling then while trying to run or cement casing strings. The bottom line turned out to be that oil based muds worked great, as long as you didn't lose returns. The problem was that when you lost full mud returns with obm we found that no LCM product that we tried allowed us to resume drilling with zero mud losses. The only effective method to eliminate mud losses was to cut the mud weight. This reduced our ecd below the emw necessary to frac the formation that was taking our mud. Unfortunately this solution was not available to us on most of our wells due to our high pore pressures which increased along with our depth. This left us with a choice of drilling with partial to no returns, which we did several times, or setting a liner to cover up the formation taking the mud or stopping the well short of TD. None of them are particularly attractive nor profitable options. Also, losing returns with oil based mud was so expensive it ruined the profitability of a number of our wells that otherwise would have been financially successful.

To help our well's profitability we decided to try to find a water based mud that would give us some of the advantages of oil based muds without it's encumbent problems. We settled on a low lime water based mud with a glycol additive. The first test of it's effectiveness was how well would it prevent gumbo attacks. On the first well we used it we lost 3 rig days fighting off gumbo attacks. While this was disappointing the attacks were handled and some lessons were learned. The lessons, detailed in Figure 11, were implemented on the second well and resulted in only 12 hours of rig time being spent dealing with gumbo, and almost all of that time was spent in the surface casing hole. So that showed that our chosen mud could handle our gumbo problems just fine.

One thing that some people might find some what surprising is that we actually drilled our wells from surface casing shoe to TD as fast as the earlier wells drilled with oil based muds. This is shown in Figure 12 which compares the last well drilled with oil based mud to the first 2 drilled with water based mud. While it's tempting to sing the praises of wbm due to it's higher average amount of footage per day, it's also tempting to discount the higher average daily footage numbers for the wbm wells due to the troubles encountered by the obm well. Therefore I removed trouble time from all three wells for a fair, apples to apples comparison. All three wells drilled 12-1/4" intermediate holes. All three wells set 9-5/8" 53.5# P-110 casing. All three wells also drilled 8-1/2" production holes and had final mud weights at TD from 16.2 to 16.5 ppg. Considering the level playing field it is impossible to ignore the wbm wells daily footages being very competitive with the obm well on a trouble free days calculation. Also hard to ignore is the fact that the mud bill for wbm wells was $ 500,000 lower than the bill for the last obm well.

A further common sense explanation for the success of the wbm in the EI 338/339 field has to do with the types of wells drilled. Oil based mud earns it's keep when you have at least one long mostly tangential hole section to drill, preferably > 9,000' md, that doesn't require high mud weights. Then you can concentrate on maximizing your ROP and not have to worry about losing returns. The typical EI 338/339 well is completely different from that. The length of our typical hole sections are seldom longer than 4,500' md. Plus during that 4,500' of md we are probably building and/or dropping angle and/or changing the well's azimuth by at least 70 degrees as well as weighting up the mud several ppg while trying to determine what the correct casing setting depth is.

The bottom line is that our choice of using a wbm helped us to have a profitable drilling program whose average cost of finding, developing and completing our 4 wells was less than $ 4.70 per BOE.

6 Hole Cleaning

As mentioned earlier in this paper the faster ROPs, along with larger cuttings and more gauge holes caused by obm in combination with high angle directional wells caused us significant hole cleaning problems. Over the years we as a company and the oil industry as a whole have come a long way in identifying ahead of time when a well could be expected to have hole cleaning problems as well as numerous best practices for combating those problems. Figures 13 and 14 show the directional plans for two typical wells for this field, namely the EI 339 B-17 ST and EI 339 B-9 ST respectively. From them you can easily see that our average wells include from 40° to 75° of deviation from vertical with or without 80° to 120° of azimuth change. A number of our wells also usually include dropping angle at TD and all of our wells are routinely drilled for 100' to 150' radius targets.

Now while the hole cleaning problems encountered in our wells at EI 338/339 field are by no means world class; what they are are one more problem added onto what is already a challenging well to drill and case safely. Due to the typically short lengths of our hole sections we are unable to economically justify using rotary steerable bhas. This leaves us using mud motor bhas to usually drill several build, turn and drop sections in our wells by slide drilling. This combined with our high angles all but guarantees we cannot efficiently clean a couple sections of our hole while we are drilling them. We have our mud vendor run their hole cleaning prediction program for our wells ahead of time to pin down where in the well we will have trouble cleaning the hole. This then allows us to plan to use the appropriate sweeps of appropriate sizes and make ups to aid us in cleaning these difficult hole sections. We also plan in at least one and usually two short trips in our typical 4,500' md 12-1/4" intermediate hole to find out if we are in fact handling our hole cleaning well enough or not.

The complexity of this only becomes apparent when you combine your hole cleaning plan in with the rest of your drilling procedure. Such as in the wells we drilled since we switched back to using a wbm, does a smooth short trip mean we have our hole cleaning problems under control or does it mean our wbm is washing out the hole enough that it is temporarily masking a real hole cleaning problem ? In the wells we have drilled to date with wbm : following modern hole cleaning practices has been sufficient to efficiently clean our hardest hole sections as evidenced by our being able to POOH with our mud motor bhas slick from our intermediate casing and production liner setting depths. Another point to consider is do you push your directional drilling company to rotate their motors at their limit to help with hole cleaning in a particularly difficult section of the hole to clean even though you know it will shorten the life of the motor and possibly cost you a rig day or worse to replace the motor ? We have had good reliability of our mud motors being able to finish our hole sections, perhaps due to their short lengths, therefore we have pushed the motors to their rpm limits in the hardest hole sections to clean without seeing an increase in mud motor failures. Also, if you have been successfully drilling wells by making short trips every 1000' to 1500' of md but in your next well that spacing puts you right in the middle of a 400' thick pressure depleted sand or maybe it would be 400' from your planned intermediate casing depth. Do you extend your short trip interval to below the sand or to the casing point to try to save the rig time and $ the short trip will cost or do you make the short trip and ensure the hole is in good shape for a key part of the well ? Our philosophy has been that the downside is too expensive to try to save these few $. Specifically the cost of potentially fracturing the pressure depleted sand, losing returns and sticking pipe due to cuttings packing off around the bha can easily cost $ 1.0 to 1.5 million to recover from. Like wise trying to drill to a difficult to pin down intermediate casing depth where drilling 50' too deep can result in a kick and going to a slow pump rate would allow any cuttings bed to slide downhole, potentially sticking the pipe and requiring a sidetrack that could again end up costing $ 1.5 million.

Conclusions

1) Plugging and abandoning wells can be done safely and inexpensively on offshore platforms prior to the drilling rig arriving.
2) With a lot of preplanning and attention to detail, along with a little good fortune, new wells can be drilled from old platforms without colliding with any of the up to 30 previously drilled wellbores.
3) Slot reclamation by cutting out bell guides and pulling new strings of drive pipe beside the bottom most bell guide maybe a mechanically complicated method, but we have found it to be a cost effective way of getting the work done.
4) Setting intermediate casing at the correct depth has been and will continue to be one of the chief challenges of drilling wells in the EI 338/339 field.
5) Profitably drilling, casing and completing the EI 339 B-17 ST, B-3 ST and B-9 ST wells with a low lime wbm with a glycol additive proves that obm is not needed to drill wells at EI 338/339 field.
6) The hole cleaning problems inherent in drilling our typical wells complicate but do not over whelm our drilling procedure and can be handled by modern hole cleaning practices.
7) 30 year old platforms in 260' of water on the GOM shelf can be profitably drilled from if the proper drilling plan is assembled and implemented properly.

Nomenclature

BHA = bottomhole assembly
BOE = barrel oil equivalent
BOP = blowout preventer
BML = below mud line
CIBP = cast iron bridge plug
ECD = equivalent circulation density
EI = Eugene Island
EMW = equivalent mud weight
GOM = Gulf of Mexico
GR = gamma ray
LD = lay down
LWD = logging while drilling
perfs = perforations
P&A = permanently plug and aband
PWD = pressure while drilling
RKB = rig floor kelly bushing elevation
ROP = drilling rate of penetration
rpm = revolutions per minute
T&A = temporarily plug and abandon
TD = total depth
TIH = trip in hole
TVD = true vertical depth

WOB = weight on bit

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FIGURE 1

Typical spider diagram of wells drilled from a platform at EI 338/339 field.

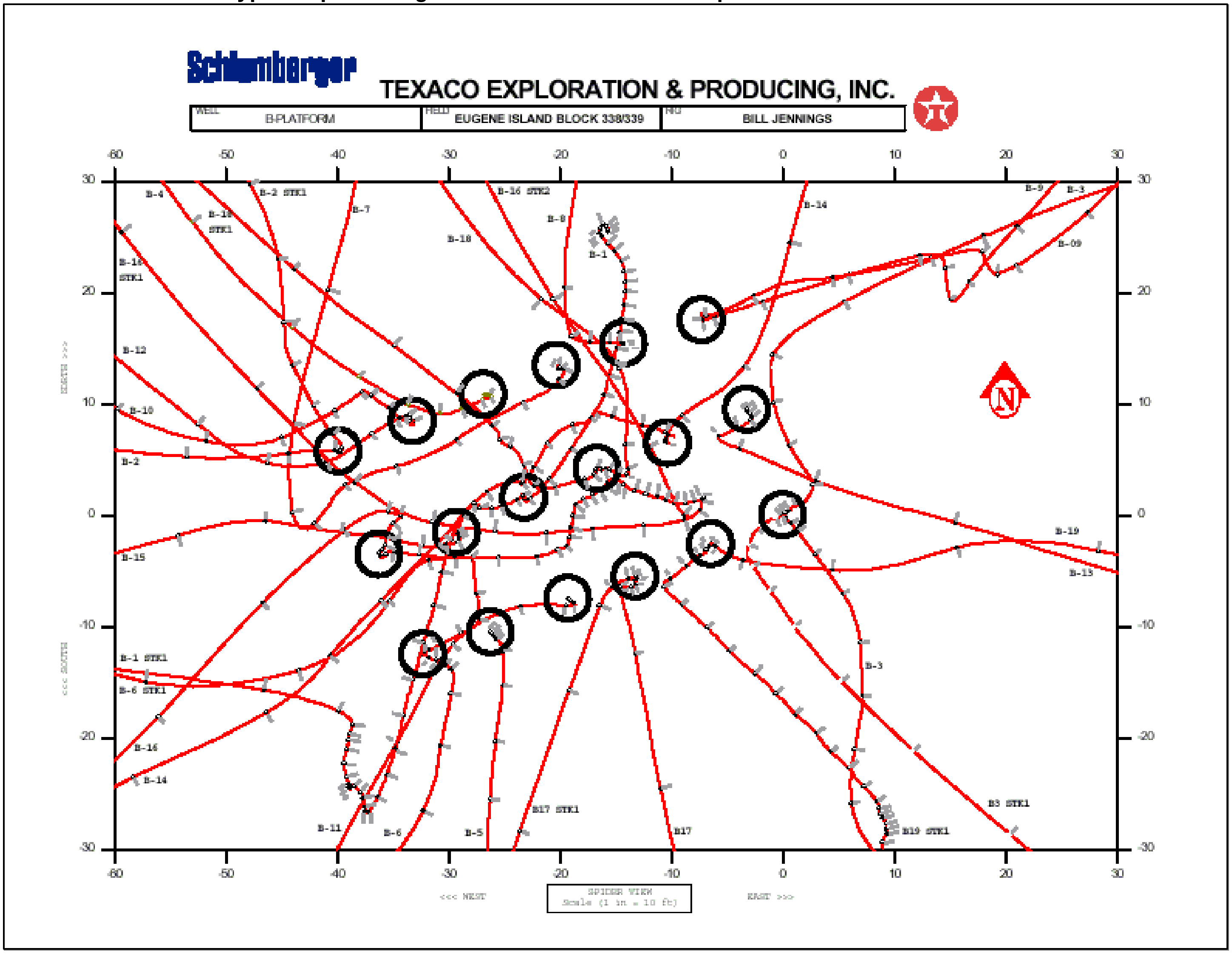


FIGURE 2

Typical list of wells we need to avoid colliding with in drive pipe and conductor hole.

WELLS	DEPTH	DISTANCE
B-14 ST	0' - 1000'	< 12'
B-14 OH	750'	9'
B-17 OH	650' - 875'	4'
B-18 OH	650' - 850'	7'
B-19 OH	350' - 650'	7'
B-19 ST1	350' - 1500'	5' - 20'
B-11 OH	650'	8'
B-16 ST1	850'	8'

FIGURE 3

Jetting rotary bha :

1 17-1/2" bit 10/10/24 nozzles, 1 float sub, 1 mule shoe sub, 1 drill collar,
1 22" sidewinder, 11 drill collar, 1 cross over, 27 heavy weight drill pipe.

FIGURE 4

Original configuration of wells on the EI 339 B platform.

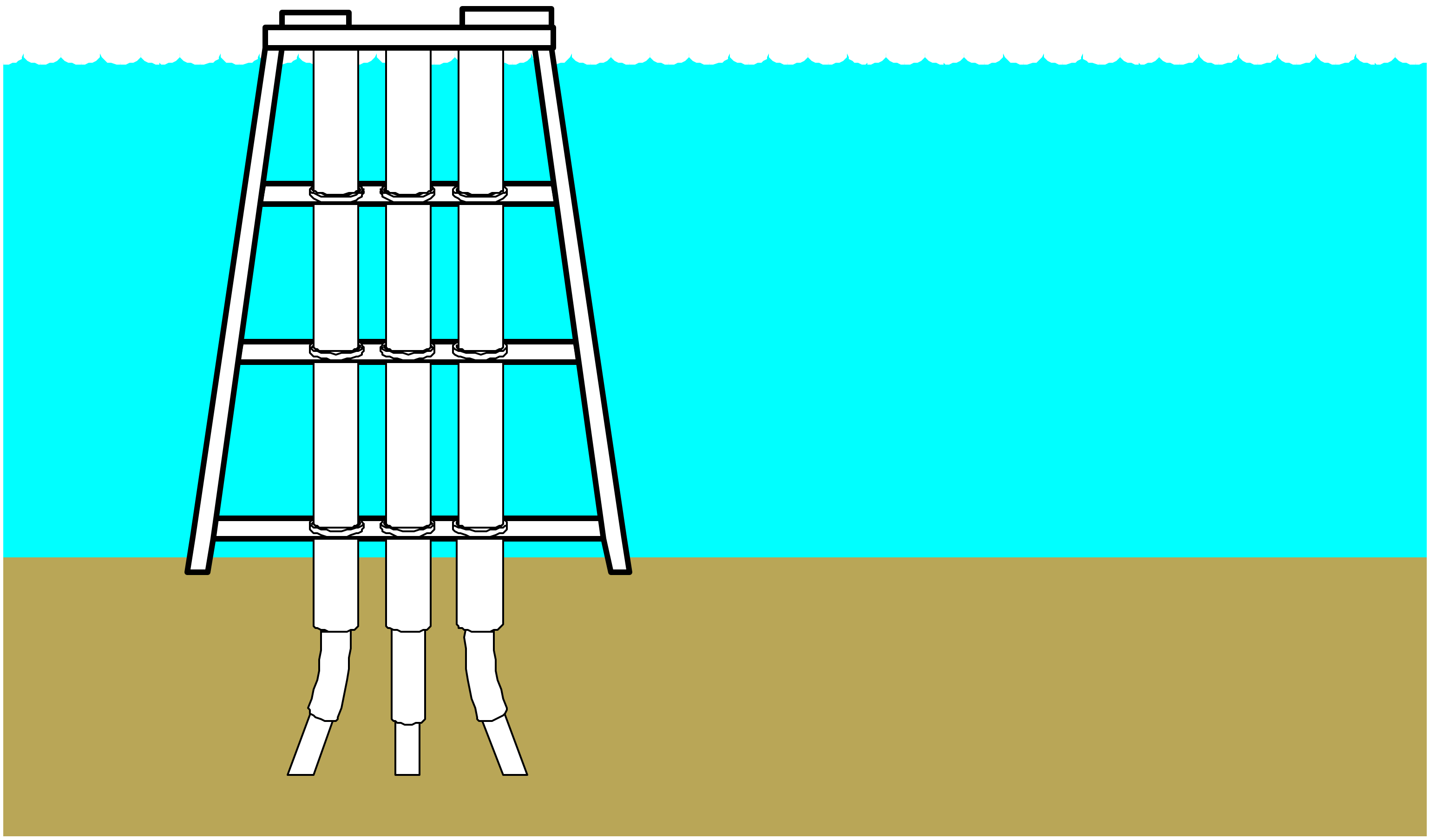


FIGURE 5

A view of the EI 339 B platform after a rigless P&A.

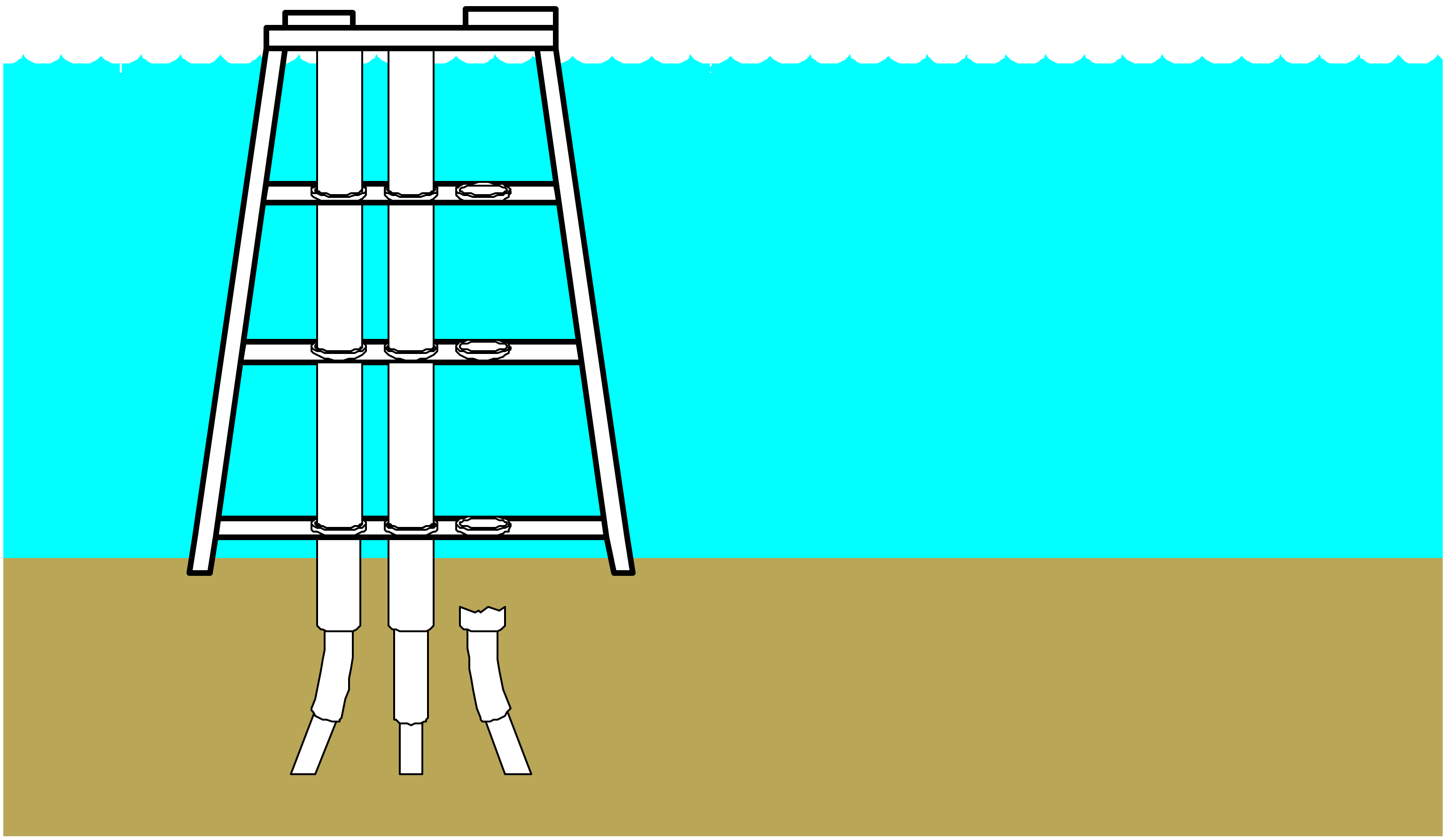


FIGURE 6

Divers pull new drive pipe outside of bottom belle guide using a subsea come along.

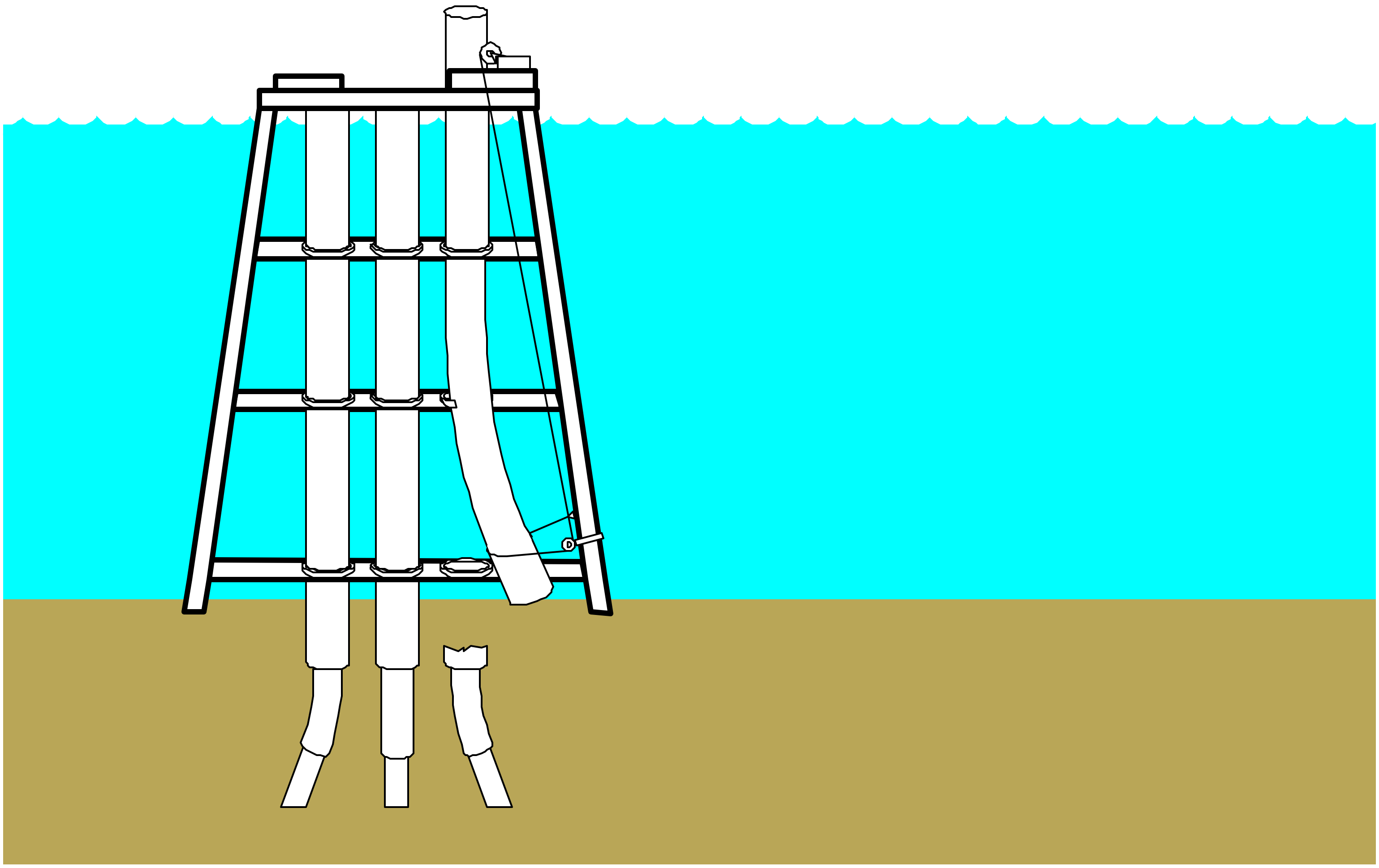
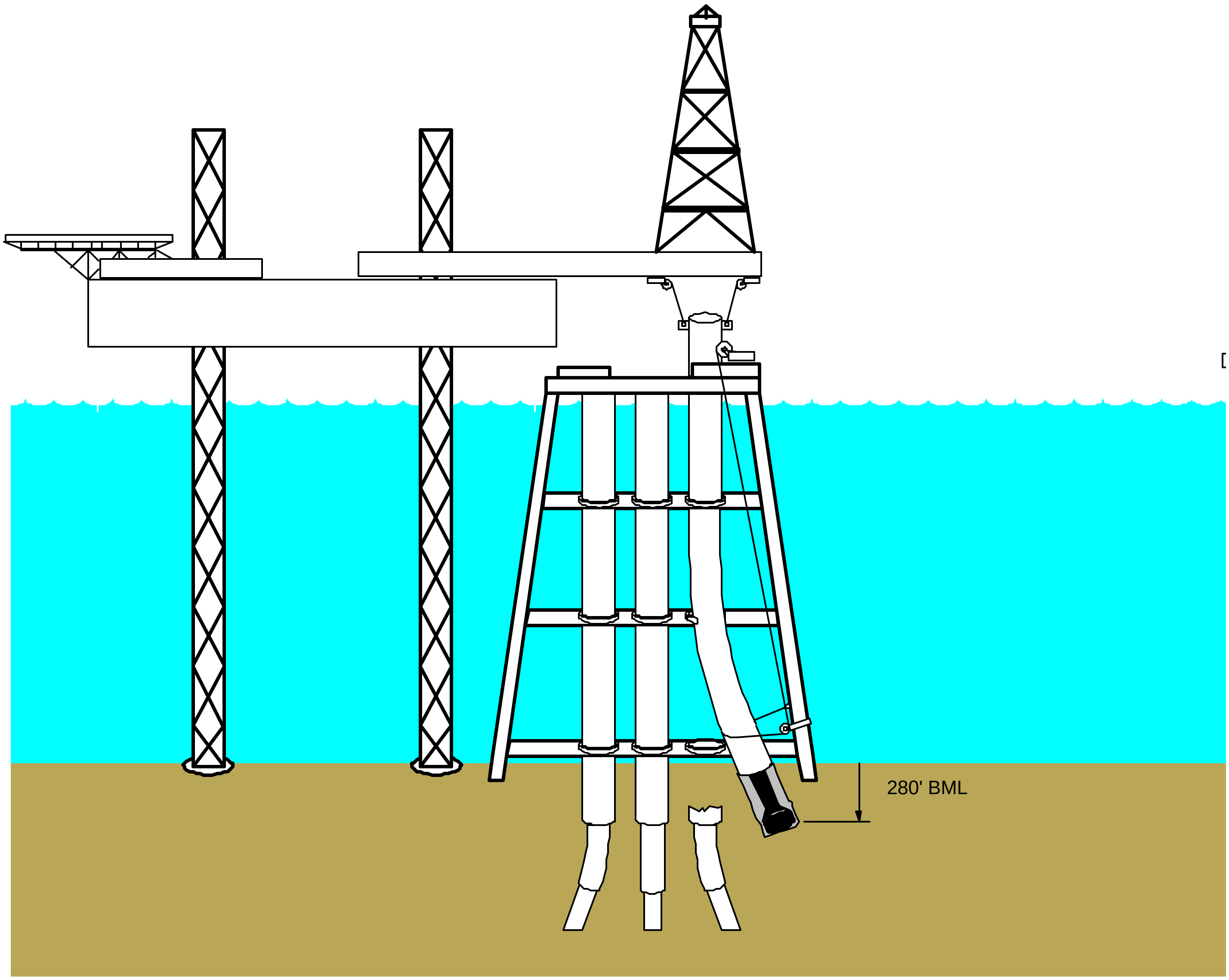
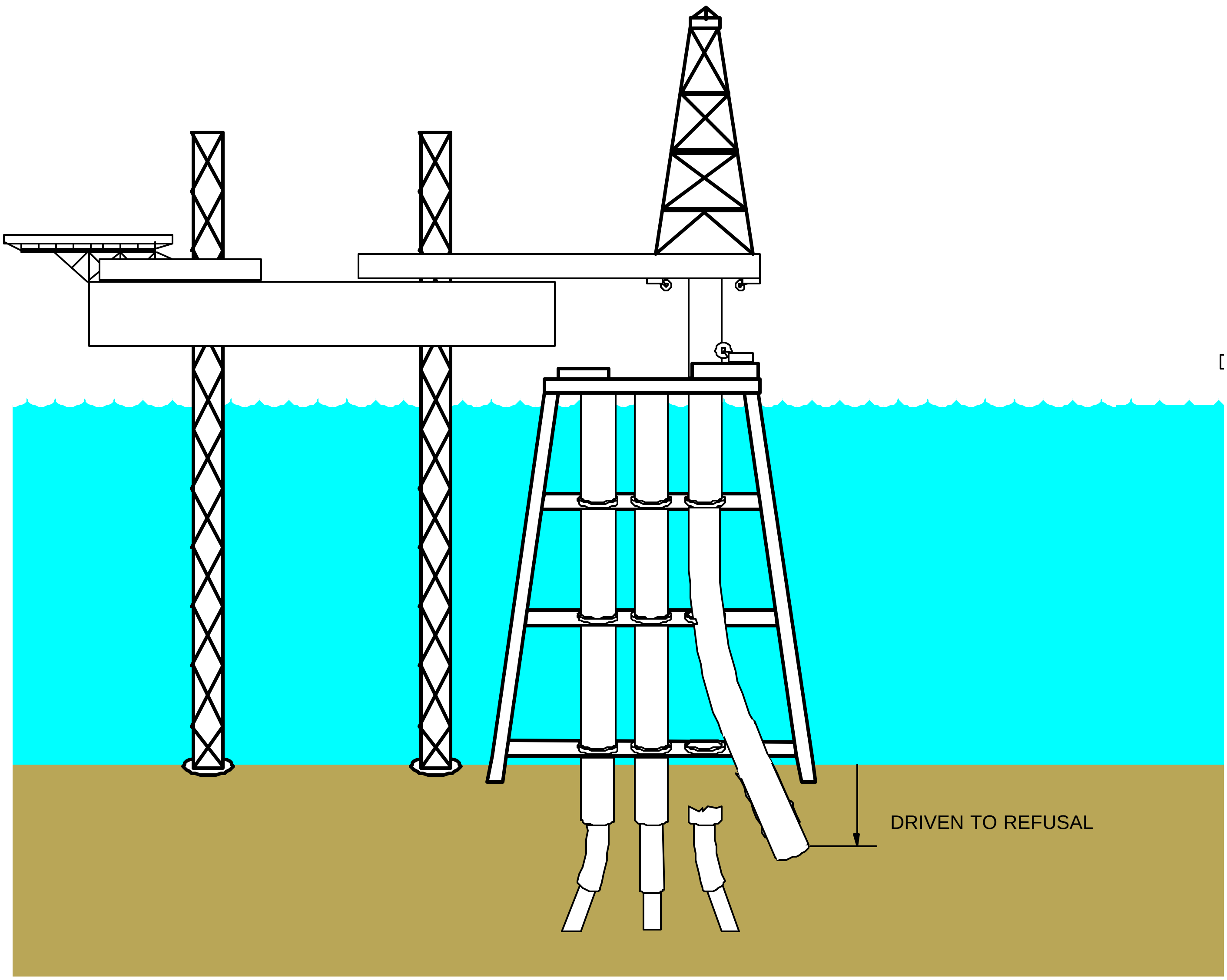


FIGURE 7



Drill out below new drive pipe with rotary jetting bha to 280’ BML without NU a diverter.

FIGURE 8



Final view of new string of drive pipe.

FIGURE 9

Pore pressure and mud weight plot for typical well in EI 338/339 field.

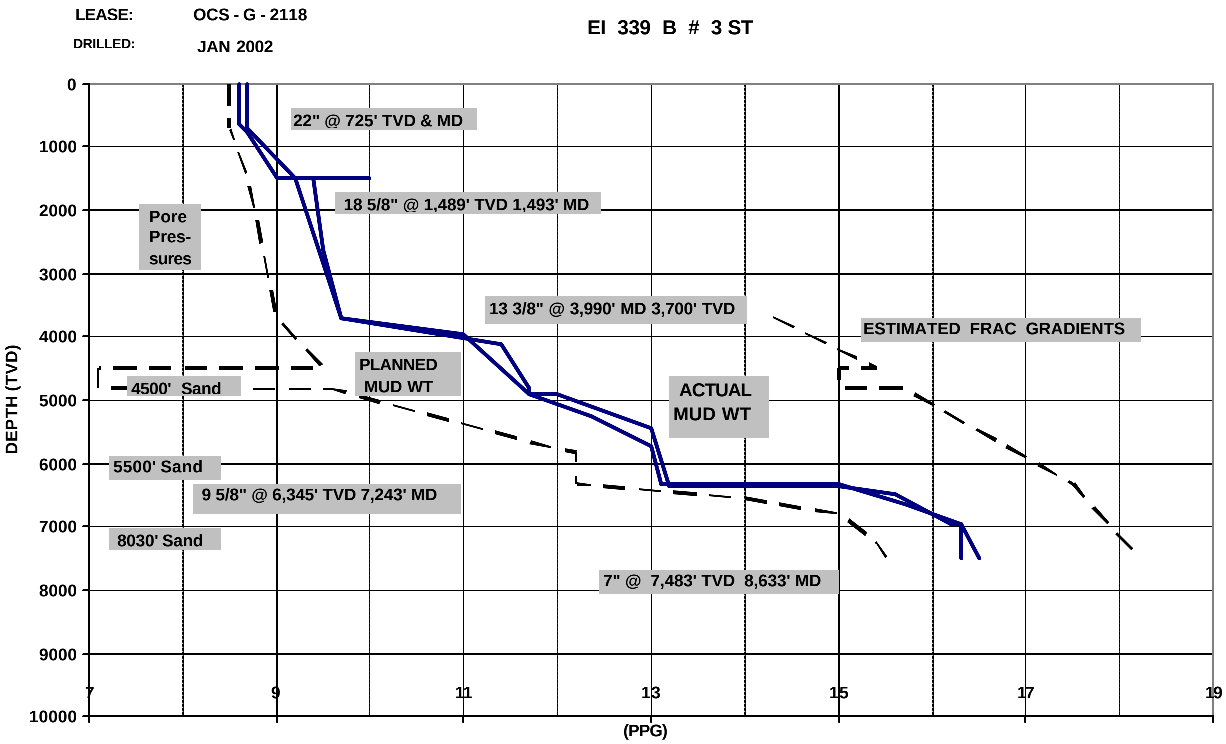


FIGURE 10

Pore pressure and mud weight plot for EI 339 well B-17 ST.

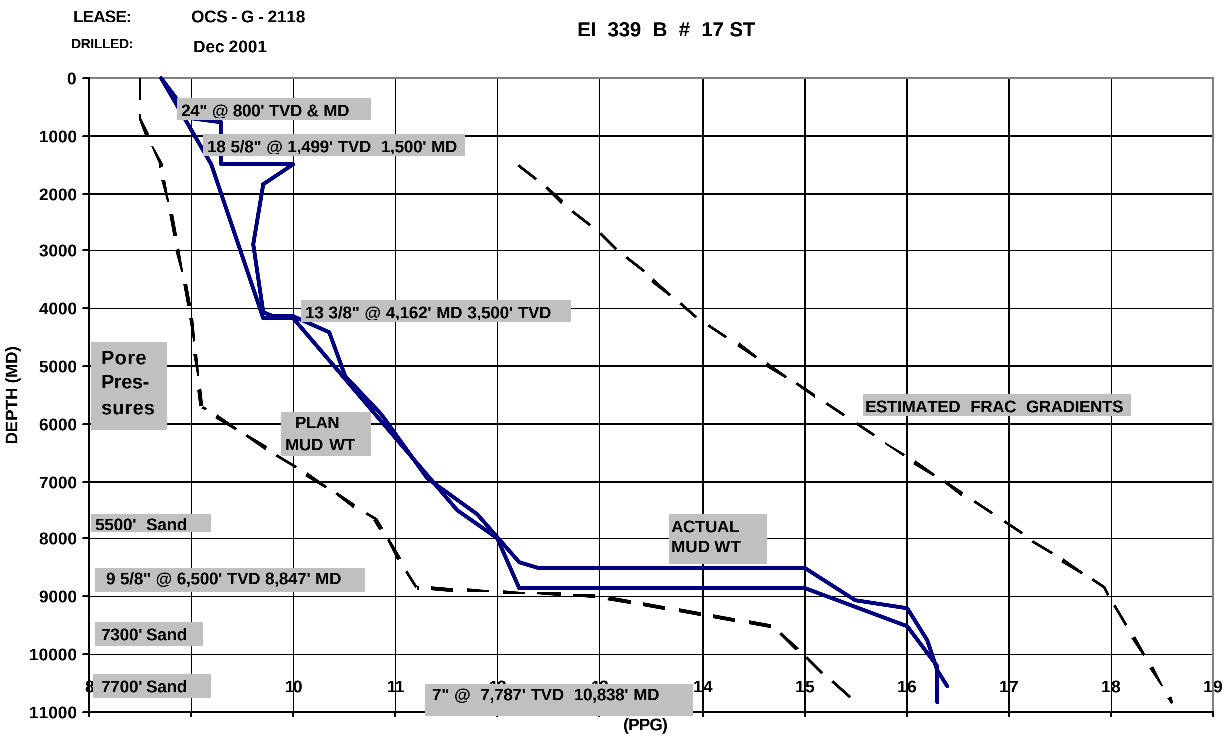


FIGURE 11

Water based mud lessons learned for dealing with gumbo :

1) Start spud mud off with a higher chlorides count of +/- 25,000.

2) Minimize, aka try to eliminate the use of caustic completely.

3) Dump half our rig pits mud volume after surface casing is set. Rebuilding half of our volume from scratch helped reduce mud's CECs.

4) Break the mud over before we drill out of surface casing and have our full % of glycol in the mud instead of waiting until we are drilling deeper in the intermediate hole to break mud over and add glycol.

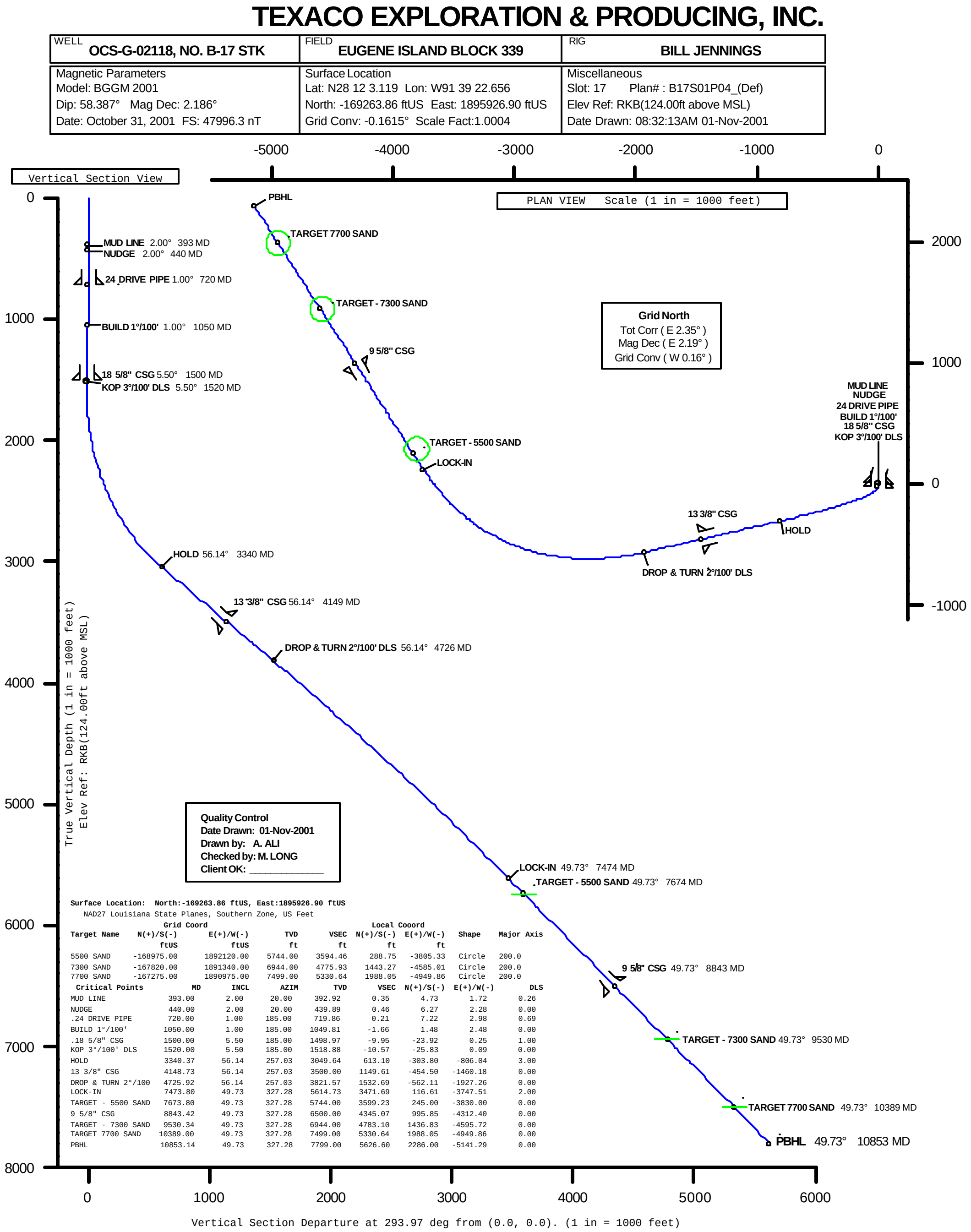
FIGURE 12

Comparison of recent wells drilled with wbm to last well drilled with obm.

WELL	EI 338 A-7 ST	EI 339 B-17 ST	EI 339 B-3 ST
Type of mud used.	Oil based	Water based	Water based
Days from surface casing shoe to intermediate hole TD.	5.0 days 4,430' md	6.0 days 4,372' md	4.7 days 3,253' md
Days to run, set, cement, weight up and drill out of intermediate casing.	4.5 days	2.5 days	3.2 days
Days to drill from inter-mediate casing shoe to the well's TD.	4.5 days 822' md	4.0 days 2,042' md	2.0 days 1,390' md
Total days from surface casing shoe to the well's TD.	14.0 days 5,252' md	12.5 days 6,414' md	9.9 days 4,643' md
Average md feet per day from surface casing shoe to the well's TD.	375'	513'	469'
Trouble days.	4.5 days	0.9 days	0.8 day
Average md feet per trouble free day.	553'	553'	510'

FIGURE 13

Typical directional plan for a newly drilled well from a reclaimed slot in the EI 338/339 field.

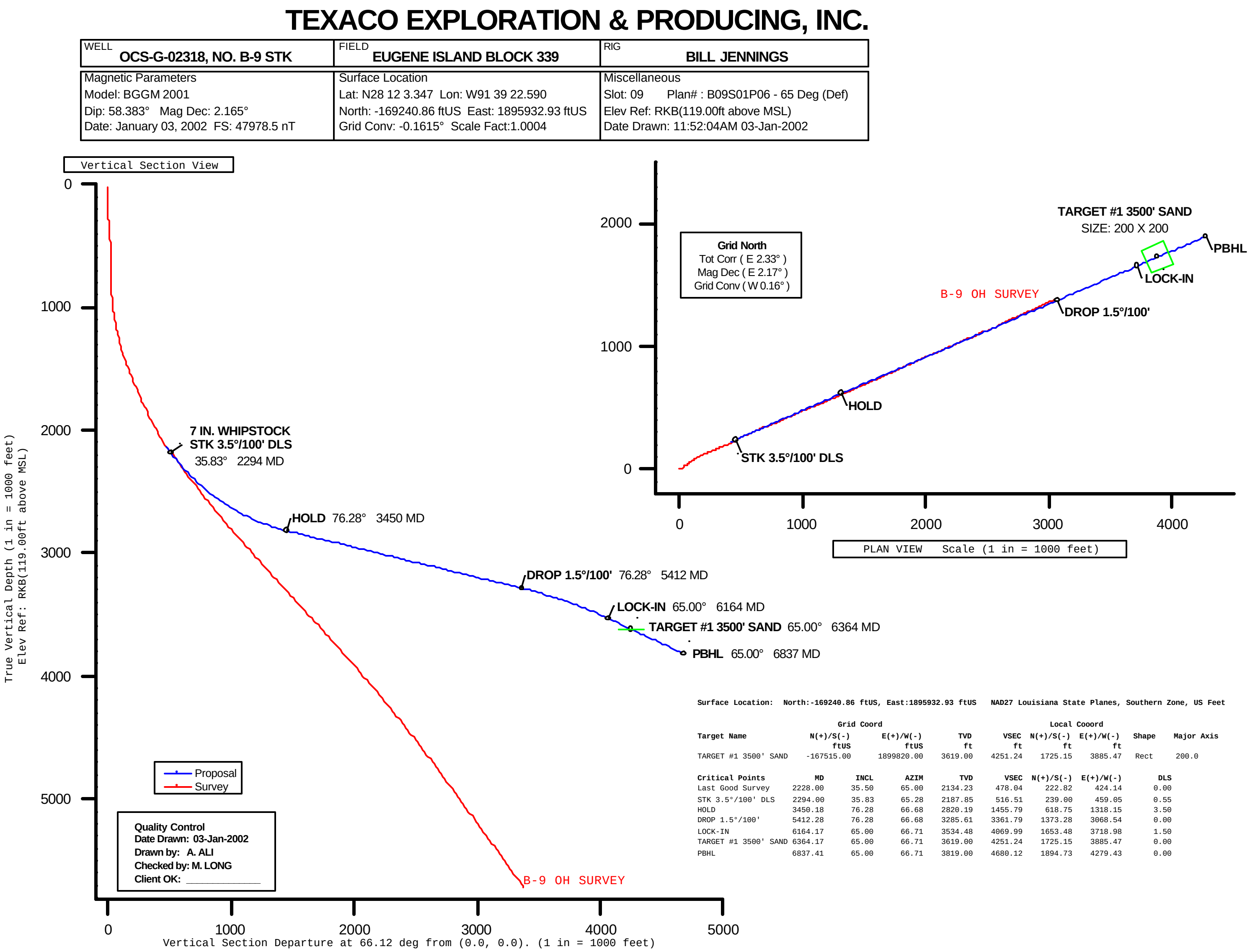


Target Name	Grid Coord N(+)/S(-) ftUS	Grid Coord E(+)/W(-) ftUS	TVD ft	VSEC ft	Local Coord N(+)/S(-) ft	Local Coord E(+)/W(-) ft	Shape	Major Axis
5500 SAND	-168975.00	1892120.00	5744.00	3594.46	288.75	-3805.33	Circle	200.0
7300 SAND	-167820.00	1891340.00	6944.00	4775.93	1443.27	-4585.01	Circle	200.0
7700 SAND	-167275.00	1890975.00	7499.00	5330.64	1988.05	-4949.86	Circle	200.0

Critical Points	MD	INCL	AZIM	TVD	VSEC	N(+)/S(-)	E(+)/W(-)	DLS
MUD LINE	393.00	2.00	20.00	392.92	0.35	4.73	1.72	0.26
NUDGE	440.00	2.00	20.00	439.89	0.46	6.27	2.28	0.00
.24 DRIVE PIPE	720.00	1.00	185.00	719.86	0.21	7.22	2.98	0.69
BUILD 1°/100'	1050.00	1.00	185.00	1049.81	-1.66	1.48	2.48	0.00
.18 5/8" CSG	1500.00	5.50	185.00	1498.97	-9.95	-23.92	0.25	1.00
KOP 3°/100' DLS	1520.00	5.50	185.00	1518.88	-10.57	-25.83	0.09	0.00
HOLD	3340.37	56.14	257.03	3049.64	613.10	-303.80	-806.04	3.00
13 3/8" CSG	4148.73	56.14	257.03	3500.00	1149.61	-454.50	-1460.18	0.00
DROP & TURN 2°/100	4725.92	56.14	257.03	3821.57	1532.69	-562.11	-1927.26	0.00
LOCK-IN	7473.80	49.73	327.28	5614.73	3471.69	116.61	-3747.51	2.00
TARGET - 5500 SAND	7673.80	49.73	327.28	5744.00	3599.23	245.00	-3830.00	0.00
9 5/8" CSG	8843.42	49.73	327.28	6500.00	4345.07	995.85	-4312.40	0.00
TARGET - 7300 SAND	9530.34	49.73	327.28	6944.00	4783.10	1436.83	-4595.72	0.00
TARGET 7700 SAND	10389.00	49.73	327.28	7499.00	5330.64	1988.05	-4949.86	0.00
PBHL	10853.14	49.73	327.28	7799.00	5626.60	2286.00	-5141.29	0.00

FIGURE 14

Typical directional plan for a shallow sidetrack in the EI 338/339 field.



Surface Location: North:-169240.86 ftUS, East:1895932.93 ftUS NAD27 Louisiana State Planes, Southern Zone, US Feet

	Grid Coord				Local Cooord			
Target Name	N(+)/S(-) ftUS	E(+)/W(-) ftUS	TVD ft	VSEC ft	N(+)/S(-) ft	E(+)/W(-) ft	Shape	Major Axis
TARGET #1 3500' SAND	-167515.00	1899820.00	3619.00	4251.24	1725.15	3885.47	Rect	200.0

Critical Points	MD	INCL	AZIM	TVD	VSEC	N(+)/S(-)	E(+)/W(-)	DLS
Last Good Survey	2228.00	35.50	65.00	2134.23	478.04	222.82	424.14	0.00
STK 3.5°/100' DLS	2294.00	35.83	65.28	2187.85	516.51	239.00	459.05	0.55
HOLD	3450.18	76.28	66.68	2820.19	1455.79	618.75	1318.15	3.50
DROP 1.5°/100'	5412.28	76.28	66.68	3285.61	3361.79	1373.28	3068.54	0.00
LOCK-IN	6164.17	65.00	66.71	3534.48	4069.99	1653.48	3718.98	1.50
TARGET #1 3500' SAND	6364.17	65.00	66.71	3619.00	4251.24	1725.15	3885.47	0.00
PBHL	6837.41	65.00	66.71	3819.00	4680.12	1894.73	4279.43	0.00