PLANNING, THE CRITICAL FACTOR IN HORIZONTAL DRILLING

Kendall Manning
SMITH INTERNATIONAL

ABSTRACT

Problems inherent in drilling horizontally make planning particularly critical in such projects. Reaction time for the ever-changing formation are much shorter than when drilling a conventional directional well. A medium radius horizontal well with build rates ranging from 15-deg/100 ft to 30-deg/100 ft can go awry quickly.

This paper discusses the specific information required to produce a detailed wellplan that will help ensure a successful horizontal project, such as build rates, horizontal extensions, formation evaluation, drillstring components, pump restrictions and drilling fluid requirements.

Several medium radius case histories are described briefly to illustrate the importance of planning.

WELL PLAN

In drilling a medium radius horizontal well, factors taken for granted in drilling vertical or directional wells take on added importance.

When selecting a casing program for a horizontal well, the build rate must first be determined. Table 1 provides the maximum build rates allowed for typical hole sizes under normal drilling conditions. Once hole size and build rate have been determined, a kickoff point can be selected.

One of the primary advantages of a medium radius well is the short radius of curvature, which also keeps the measured depth and the departure-from-vertical short. This allows the vertical portion of the well to be drilled deeper, reducing the cost of the well by starting the time-consuming directional drilling further downhole. And upon completion of the well, the production equipment can be placed closer to the pay zone.

The well profile shown in Figure 1 is representative of most medium radius applications. The initial build section is from the kickoff point to ±45-degrees inclination. Forty-five degrees is used because current measurement-while-drilling (MWD) systems are positioned approximately 45 ft back from the bit, and in order to obtain an accurate bit location survey and bottomhole assembly (BHA) build rate, it is necessary to drill about 90 ft further along the wellpath.

Once the actual build rate of the BHA is evaluated for the initial build section, the specifics can be determined for completing the tangent section and drilling the second build section on to the target zone. The tangent section provides the ability to compensate for any difference between the designed and actual build rates of the well. Since there is little margin for error with medium radius wells, the tangent section is critical. However, should the actual build rate coincide with the predicted rate, the driller simply rotates through this section to the second build section.

Several important parameters regarding the target zone should be determined in the planning stages, such as thickness and formation dip. Today's steerable motors and MWD survey tools enable the drilling system to stay inside narrow, restricted formations. Should a long extension be required through formations with high dip angles (5-degrees or more), it would not take much measured depth to drill completely out of the pay zone. The steerable motor is capable of building to plus or minus 90-degrees to achieve maximum pay zone exposure.

It is the horizontal extension that is the goal of the well. The location and length of this section are based upon the particular reservoir characteristics. Horizontal extensions in medium radius applications range from approximately 500 to 3,000 ft. The length is affected primarily by torque and drag limitations, as well as possible lease line restrictions. The maximum horizontal length may well be less than the desired length for optimum production because of irreconcilable restrictions.

FORMATION EVALUATION

The most critical aspect of any medium radius well design is selection of the proper BHA that will produce accurate and consistant build rates and will hold the build through the horizontal extension. Computerized bottomhole assembly programs have been developed that predict the performance of medium radius assemblies (Table 2). Input parameters include:

- Hole size;
- Stabilizer placement and clearance;
- Mud weight;
- Weight-on-bit;
- Drill collar and MWD specifications;
- Dip angle and direction and
- Formation class.

Formation class measures the ratio of the rates at which the bit drills perpendicular to versus parallel to the bedding planes, allowing for hole angle with respect to dip angle. In areas where hole washout is a problem, the computer can be programmed to compensate for the resulting oversized hole - an important feature since overgauge holes tend to decrease the designed build rate. Rapidly changing hole conditions make this program particularly helpful because a 20-deg/100 ft build rate allows very little margin for error.

However, it is important to remember that the program is only as good as the information input, and providing all required information enables the program to design the optimum bottomhole assembly for the horizontal project. Specifics include:

- o Bit records;
- o Daily reports from offset directional wells;
- o Mud logs;
- o Caliper logs;
- o Electric logs and
- o Dip meter readings.

MUD MOTOR DESIGN

The heart of any medium radius well design is the downhole mud motor. Medium radius horizontal wells would not be possible without today's steerable motors. Typically, medium radius wells are drilled with slow-speed, high torque motors. Their 80-160 rpm range makes them suitable for use with either roller cone or fixed head bits. The bend point in the housing of these motors is much closer to the bit than in bent sub/motor combinations, allowing much smaller angle changes to produce higher build rates and less bit offset.

In most medium radius applications, a "double bend" assembly completes the build sections of the well. This assembly, appropriately called an angle build assembly, comprises a motor with an oversized bent connecting-rod housing aligned with a bent sub placed above the motor (Figure 2). The purpose of the oversized con-rod housing is:

- o to serve as a fulcrum point for the bit;
- o to act as a stabilizer to push the bit against the high side of the hole and
- o to increase the structural integrity of the overall tool.

The build assembly drills exclusively in the oriented (sliding) mode, with the power of the downhole motor only advancing the BHA. Drill-string rotation of this assembly would result in hole problems due to the high bit offset.

The tangent and horizontal extension sections are drilled using a steerable motor system, or hold assembly, which consists of a stabilized bent housing motor with two additional stabilizers in the drillstring (Figure 3). The hold assembly has the ability to drill using either the motor only (sliding mode) or the motor and rotary table (rotary mode). It is designed to be used in the rotary mode as much as possible to provide hole agitation for cuttings removal and to reduce sticking problems. The assembly is rotated as the motor continues to run, turning the bend through 360-degrees which negates the bent housing affect so that a straight wellbore is drilled. Should course adjustments become necessary, the tool can be shifted into the sliding mode and make the required corrections quickly to keep the wellbore on course.

TORQUE/DRAG ANALYSIS

Torque and drag computer models are typically used to plan medium radius horizontal wells (Table 3). The programs provide a number of outputs regarding bottomhole assemblies, including:

- o Maximum pick-up load;
- o Surface slack-off load and
- o Maximum drilling torque.

This data is critical when selecting the optimum well profile and the size and weight of the drillstring, as well as the proper placement of the string components. Upon completion of the well, comparison between predicted and actual results have shown the benefits of these torque and drag computer models.

DRILLSTRING SELECTION

Drillstring selection is another important factor in planning a medium radius well due to the inherent drilling problems. It is important to determine the type of drillstring required and whether the necessary tubulars are available on the drilling rig.

Table 4 displays a typical drillstring for a medium radius horizontal well, although each well must be studied separately to optimize the drillstring design. In this case, a reverse tapered drillstring has been selected, with drill collars above the heavy-weight and standard drill pipe.

Although standard drill pipe can withstand a high level of compressive loading due to the support provided by the low side of the hole, heavy-weight drill pipe often is run throughout the entire curved section of the wellbore to counteract the forces imposed through this highly deviated area (Figure 4). It is important to keep drill collars well above the kickoff point to minimize the drilling torque. Detailed planning of the drillstring accomplishes the following:

- o Allows sufficient weight-on-bit;
- o Minimizes buckling tendencies in the drill pipe;
- o Prevents over-torquing of connections;
- o Prevents over-pulling of connections and
- o Minimizes casing wear.

HYDRAULICS AND MUD SYSTEMS

Possibly the most critical drilling parameter in a horizontal well is cleaning the hole, so it is important to work-up a complete hydraulic inventory prior to rig selection. Short trips are made often to wipe the hole clean. Penetration rates should always be of secondary concern. Triplex pumps are generally required, with standpipe pressures ranging from 2,000 to 3,000 psi.

And selecting an effective mud system contributes to a successful horizontal well. However, it is generally not necessary to make significant changes from normal drilling procedures in a given area. Typically, mud systems that work well in vertical holes will work well in horizontal holes.

CASE HISTORY #1

The first case history shows the importance of planning to prevent the loss of time and money. A 6 1/2-in. hole was drilled using a 4 3/4-in. mud motor with a 2 1/4-degree oversized connecting-rod housing and a 1/2-degree bent sub. The assembly was designed with a computerized BHA program to build angle at 20 deg/100 ft.

A tangent section was not feasible because of lease line restrictions. Hole erosion was a possibility in the area. However, computer analysis indicated that the predicted build rate would be achieved if hole washout remained less than 3/4-in. (Table 5). The kickoff went well with the build assembly. Dogleg severity over the first 90 ft averaged 19.21 deg/100 ft. At this point a sandstone section was unexpectedly encountered and dogleg severity dropped to 14.26 deg/100 ft over the next 90 ft (Table 6). It was determined that hole enlargement through this sand section was the cause of the unexpected drop in build rate.

Since there could be no tangent section to correct the wellpath, the borehole was plugged back to a higher kickoff point to offset the sand section (Figure 5). Upon entering the sand section once again, the flow rate was reduced by 35 gpm which caused the build rate to decrease slightly, but not as much as in the original wellbore. Study of existing mud logs could have prevented the time-consuming plug back.

CASE HISTORY #2

This well also was designed for a 20 deg/100 ft build rate. A 2.5 degree bent housing with a 8.5-in. oversized con-rod housing was utilized on a 6.5-in. slow-speed, high torque mud motor to drill the 9 7/8-in. hole. The operator had extensive knowledge of the geology of the area.

Again, the BHA was designed using the computerized bottomhole assembly program. As can be seen by the survey results, the actual build rate stayed consistently close to the planned rate (Table 7). The predicted torque and drag figures are compared to the actual results in

Figures 6, 7 and 8. Proper planning contributed greatly to the success of this medium radius horizontal well.

CONCLUSION

Medium radius horizontal wells can be drilled successfully, with standard equipment, if properly planned before the drilling rig is brought on location. Parameters change downhole very quickly and it is particularly important to be able to react to those changes just as swiftly...in-depth planning can provide the necessary edge for a successful project.

REFERENCES

1.) Williamson, J.S. and Lubinski, A., "Predicting Bottom Hole Assembly Performance," SPE 14764 presented at 1986 IADC/SPE Drilling Conference, Dallas, February 10-12.

2.) Dawson, R. and Paslay, P.R., "Drill Pipe Buckling in Inclined Holes," SPE 11167 presented at 1982 SPE Fall Technical Conference and Exhibition, New Orleans, September 26-29.

3.) Johancsik, C.A., Friesen, D.B. and Dawson, R., "Torque and Drag in Directional Wells - Prediction and Measurement", JPT (June 1984) 987-992.

4.) Maurer Engineering, Inc., "Project to Determine The Limitations of Directional Drilling", Report No. TR88-4, January 4, 1988.

5.) Kerr, D. and Odell, A., "Here's How to Plan a Horizontal Well", **Drilling Contractor** (December 1988/January 1989) 23-26.

Table 1
Estimated Maximum Build Rates
Versus Hole Size

Hole Size, in.	Motor OD, in.	Build Rate, °/ft	Radius, ft
6⅛	4¾	18/100	318
6½	4¾	20/100	286
6¾	4¾	22/100	260
7⅞	4¾	22/100	260
8½	6½	16/100	358
8¾	6½	17/100	337
9½	6½	20/100	286
9⅞	6½	20/100	286

NOTE: Build rates possible under normal drilling conditions. Parameters may change due to high dip angles, hole enlargement or other adverse conditions.

Table 2
Bottomhole Assembly Computer Program Worksheet

CASE	ASY	UNKN./	HOLE	HOLE	DIP	FORM	MUD	STAB	OR 2ND	BEND	DRILL STRING				WOB	DEG/	BEND	BEND
NO.	NO.	RESULT	SIZE	ANGL	ANG	CLAS	WT.	LGTH	CL	RXN	OD	ID	DENS	LGTH	KIPS	100 FT	ANGLE	POSITION
1		CH	8.8	20.0	1.	38.0	6.	20.27	2.250	4238.	6.50	4.65	.460	5.6	20.000	16.769	2.25	8.73
		16.77									7.50	5.75	.282	3.1			.75	11.54
											6.50	4.65	.460	11.5				
											6.25	2.25	.282	999.9				
2		CH	8.8	40.0	1.	38.0	6.	20.27	2.250	5334.	6.50	4.65	.460	5.6	20.000	17.083	2.25	8.73
		17.08									7.50	5.75	.282	3.1			.75	11.54
											6.50	4.65	.460	11.5				
											6.25	2.25	.282	999.9				
3		CH	8.8	60.0	1.	38.0	6.	20.27	2.250	5889.	6.50	4.65	.460	5.6	20.000	18.219	2.25	8.73
		18.22									7.50	5.75	.282	3.1			.75	11.54
											6.50	4.65	.460	11.5				
											6.25	2.25	.282	999.9				
4		CH	8.8	80.0	1.	38.0	6.	20.27	2.250	5939.	6.50	4.65	.460	5.6	20.000	20.057	2.25	8.73
		20.06									7.50	5.75	.282	3.1			.75	11.54
											6.50	4.65	.460	11.5				
											6.25	2.25	.282	999.9				

Table 3

TORQUE & DRAG CALCULATIONS FOR DIRECTIONAL WELLS RESULTS SUMMARY

DRILL STRING DATA:

ELEMENT NUMBER	EFFECTIVE DIAMETER (INCHES)	ADJUSTED WEIGHT (LBS/FT)	ELEMENT LENGTH (FEET)	DEPTH TOP-BOTTOM (FEET)
1	5.667	18.5	7502.0	0 - 7502
2	6.500	99.3	350.0	7502 - 7852
3	5.670	41.0	1000.0	7852 - 8852
4	5.667	18.5	800.0	8852 - 9652
5	6.500	99.3	114.7	9652 - 9767
6	6.500	70.6	23.8	9767 - 9791

WELL DESIGN INFORMATION:

WEIGHT ON BIT = 20,000.0 LBS
OVERPULL AT BIT = 0.0 LBS
ESTIMATED BIT TORQUE = 500.0 FT-LBS
MUD WEIGHT = 8.80 LBS/GAL
TOP FRICTION FACTOR = 0.26 (APPLIES FROM SURFACE TO 7913 FEET)
BOTTOM FRICTION FACTOR = 0.40 (APPLIES FROM 7913 TO TD)

RESULTS:

MAXIMUM PICK-UP LOAD (LESS TRAVELING ASSEMBLY WT.) = 189,588.3 LBS
SURFACE SLACK-OFF LOAD (LESS TRAVELING ASSEMBLY WT.) = 133,289.8 LBS
ROTATING OFF-BOTTOM LOAD (LESS TRAVELING ASSEMBLY WT.) = 164,422.1 LBS
MAXIMUM TORQUE (WHILE DRILLING) = 7739.1 FT-LBS

Table 4
Drillstring Configuration at Total Depth

Component	Length, ft
Bit	0.86
PDM	23.80
Float Sub	2.00
MWD Pulser Collar	12.00
Crossover/Muleshoe	3.00
Non-mag Stabilizer	5.00
Non-mag Drill Collar	30.00
Non-mag Stabilizer	5.00
Non-mag Drill Collar	30.00
4½" Drill Pipe	820.00
4½" Heavy-Weight Drill Pipe	1000.00
6½" Drill Collars	350.00
4½" Drill Pipe	To Surface

Table 5
Predicted Build Rate vs Hole Enlargement
(Deg/100 ft.)

Weight-On-Bit: 15,000 lbs
Wellbore Inclination: 30 Degrees
Formation Anisotropy: Mild to Moderate

Hole Dia., in.	Build Rate
6.5	21.32
6.75	20.85
7.0	20.38
7.25	19.90
7.5	19.42
7.75	18.93
8.0	18.44
9.0	16.42
10.0	14.84

Table 6
Well Survey Data - Case History No. 1

MEASURED DEPTH (FT)	INCL ANGLE (DEG)	COURSE LENGTH (FT)	TOTAL VERTICAL DEPTH	DOGLEG SEVERITY (DEG/100')
4377	3.29	132.00	4375.58	2.66
4408	8.97	31.00	4406.39	18.80
4438	14.97	30.00	4435.72	20.59
4469	20.56	31.00	4465.23	18.23
4501	25.29	32.00	4494.70	14.78
4532	29.54	31.00	4522.21	13.94
4564	33.68	32.00	4549.43	14.07
4610	42.00	46.00	4585.67	18.05

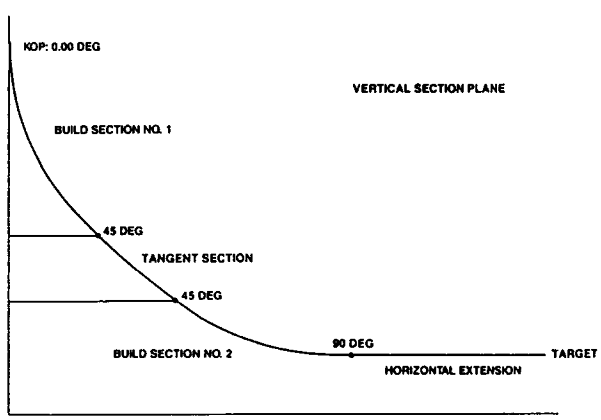

Figure 1 — Typical medium radius well profile

Table 7
Well Data Survey

MEASURED DEPTH (FT)	INCL ANGLE (DEG)	COURSE LENGTH (FT)	TOTAL VERTICAL DEPTH	DOGLEG SEVERITY (DEG/100')
0.00	0.00	0.00	0.00	0.00
1270.00	1.10	1270.00	1269.92	.09
1300.00	3.00	30.00	1299.90	6.44
1312.00	4.70	12.00	1311.87	14.21
1329.00	7.30	17.00	1328.78	15.30
1360.00	12.50	31.00	1359.31	16.78
1374.00	15.20	14.00	1372.90	19.32
1390.00	18.10	16.00	1388.23	18.13
1422.00	23.90	32.00	1418.09	18.17
1451.00	30.40	29.00	1443.88	22.42
1482.00	36.30	31.00	1469.76	19.08
1513.00	42.20	31.00	1493.76	19.03
1543.00	48.20	30.00	1514.89	21.14
1574.00	54.30	31.00	1534.28	19.84
1604.00	60.00	30.00	1550.55	21.00
1634.00	66.10	30.00	1564.14	21.97
1664.00	71.90	30.00	1574.89	19.46
1695.00	77.60	31.00	1583.04	19.13
1724.00	83.60	29.00	1587.77	21.58
1754.00	89.00	30.00	1589.71	18.59
1783.00	90.00	29.00	1589.96	8.02

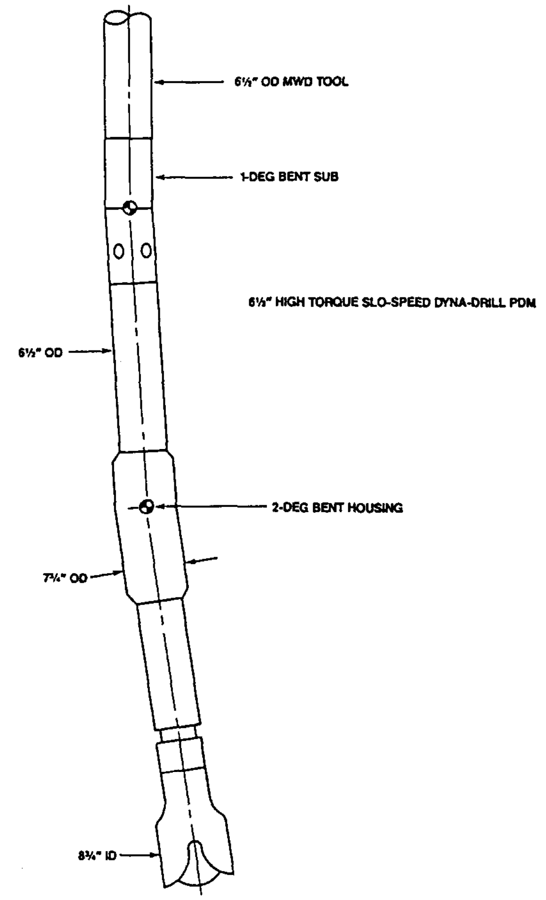

Figure 2 — Medium radius angle build assembly

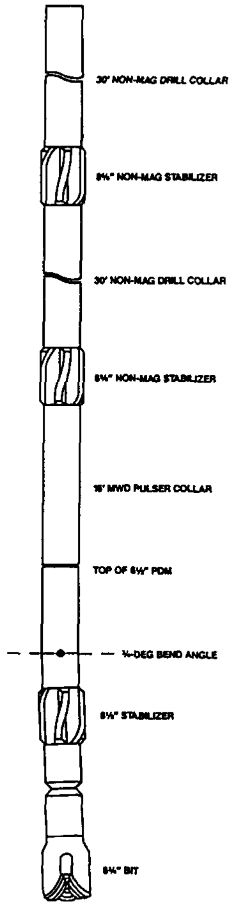

Figure 3 — Steerable system

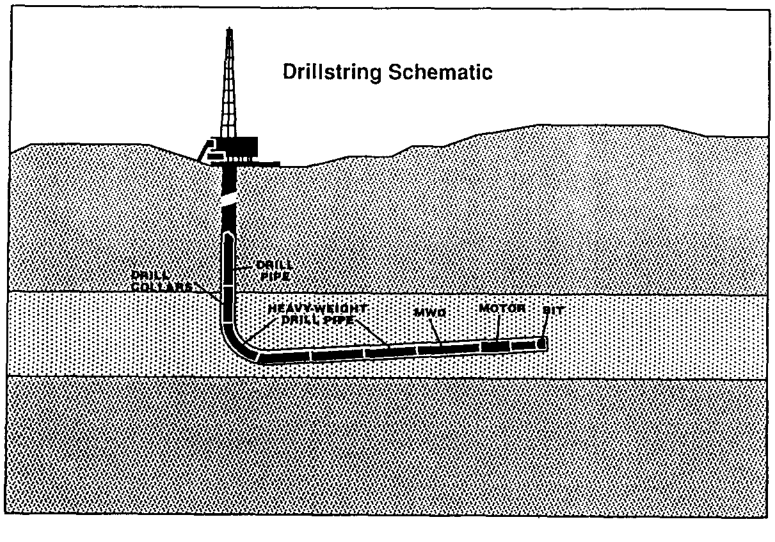

Figure 4

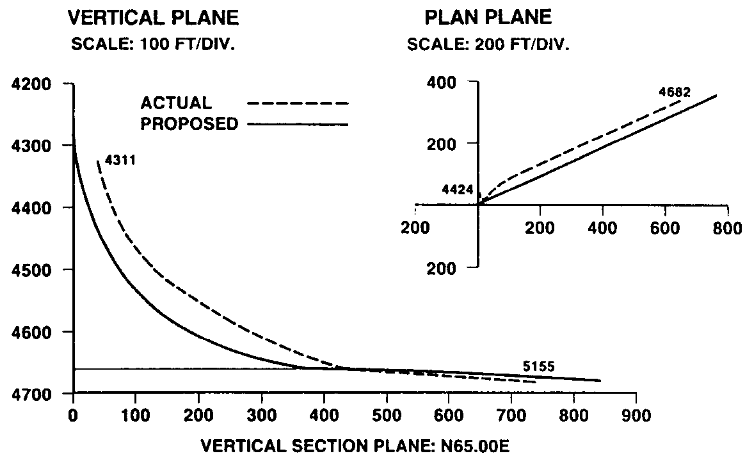

Figure 5 — Case History No. 1

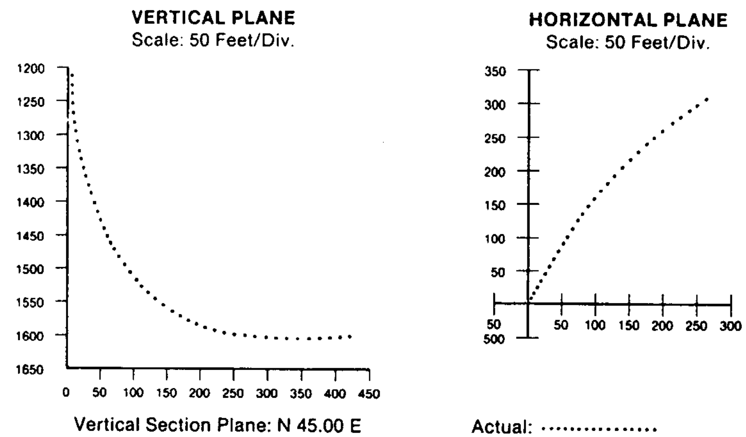

Figure 6 - Case History No. 2

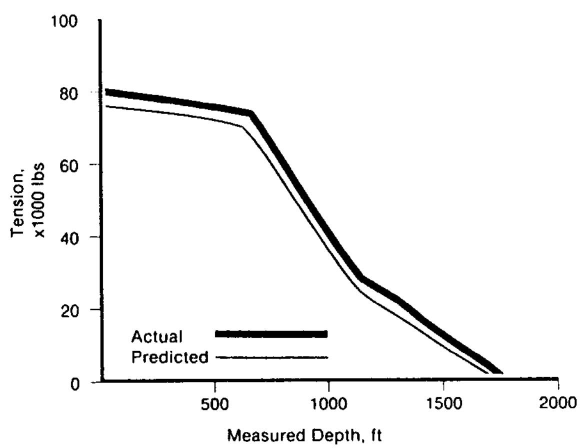

Figure 7 — Torque and drag calculations of pick-up tension (actual vs predicted)

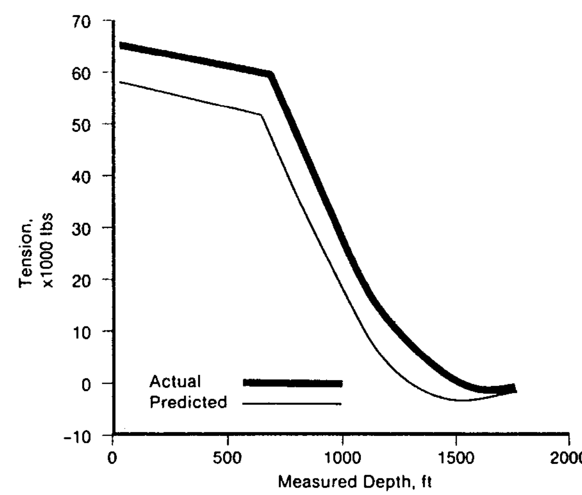

Figure 8 — Torque and drag calculations of slack-off tension (actual vs predicted)