BIT SELECTION - THE CENTER OF A GOOD DRILLING PROGRAM

BILL GREAVES
Oilfield Products Division, Dresser Industries, Inc.

As America's energy demands increase, major new responsibilities are placed on the industry to find new reserves. Hundreds of thousands of dollars, sometimes even millions, are spent on a single well. These high costs, coupled with limited equipment sources, make it critical that we use drilling equipment, especially rock bits, efficiently.

Several years ago the cost and importance of the rotary rock bit were considered relatively insignificant to the overall cost of drilling an oil well. However, with the development of tungsten carbide inserts and sophisticated lubrication and bearing designs the rock bit has become expensive. Even though these bits can now drill through thousands of feet of rock, selection of each bit has become a very important factor in the cost of drilling operations.

The proliferation of bearing designs and cutting structures since 1967 caused the International Association of Drilling Contractors (IADC) to adopt in 1973 a standard coding for rotary rock bits. This coding is summarized in Fig. 1. the new classification system was initiated to help eliminate some of the confusion among contractors and operating company personnel arising from different coding systems of the various manufacturers.

The IADC selected a three-digit numerical system which classifies:

1. Cutting structure (milled tooth or insert)
2. Formation hardness, and
3. Design features.

The first digit relates to the cutting structure of the bit. Series 1, 2 and 3 in this position describe milled tooth bits for soft, medium, and hard formations, respectively. Series 5, 6, 7, and 8 describe insert bits for soft, medium, hard, and extremely hard formations respectively. The second digit is a formation hardness subclassification with numbers 1 through 4 designating formation hardness. The final digit, the bit feature classification, indicates mechanical or design features such as gauge inserts, sealed or friction-type bearings. The IADC classification of 1-1-4, for example, refers to a milled tooth bit (1) used to drill the softest formation (1) and having a standard mechanical feature of the sealed bearing (4). The IADC classification of 7-4-7 indicates an insert bit (7) designed to drill hard formation (4), and having friction bearing and gauge inserts (7).

PLANNING THE PROGRAM

Every well-executed drilling project has a drilling program. It will vary from operator to operator, but the objective is always the same—to drill a safe and usable hole to the desired depth at the minimum cost. The plan will consider casing, formation tops, anticipated trouble zones, deviation, hydraulic data, bit type, recommended bit weight, rotary speed, drilling fluid and drilling rig requirements. The good drilling program considers all these factors prior to well spudding.

The operator, contractor, or service company representative should also gather pertinent information concerning drilling performance on offset wells. This should include bit records, well logs and formation tops, mud recaps, and geolograph records, if available.

However, before this information is sorted, rearranged, and deciphered, the operating company engineer should carefully consider his casing program versus the available bit selection. The availability of bit types may be limited (even with major manufacturers) if an unusual size is required to pass through thick or high-drift casing. When bit size is dictated by other elements of the drilling program, the operator's selection of rock bit cutting structure and bearing-type

CLASSIFICATION OF ROTARY ROCK BITS

(as adopted by the IADC, February, 1972)

Series	Classification	Types	SECURITY Standard (1)	SECURITY T Gauge (2)	SECURITY Gauge Insert (3)	SECURITY Sealed Bearing (4)	SECURITY Sealed Bearing & Gauge (5)	SECURITY Friction Sealed Bearing (6)	SECURITY Friction Bearing & Gauge (7)	SECURITY Directional (8)	HUGHES Standard (1)	HUGHES T Gauge (2)	HUGHES Gauge Insert (3)	HUGHES Sealed Bearing (4)	HUGHES Sealed Bearing & Gauge (5)	HUGHES Friction Sealed Bearing (6)	HUGHES Friction Bearing & Gauge (7)	REED Standard (1)	REED T Gauge (2)	REED Gauge Insert (3)	REED Sealed Bearing (4)	REED Sealed Bearing & Gauge (5)	REED Friction Sealed Bearing (6)	REED Friction Bearing & Gauge (7)	SMITH Standard (1)	SMITH T Gauge (2)	SMITH Gauge Insert (3)	SMITH Sealed Bearing (4)	SMITH Sealed Bearing & Gauge (5)	SMITH Friction Sealed Bearing (6)	SMITH Friction Bearing & Gauge (7)
1	MILLED TOOTH SOFT	1	S3S			S33S				S3SJD	OSC-3A			X3A				Y11			S11		F11		DS						
		2	S3	S3T	S3TG	S33				S3JD	OSC-3			X3				Y12	Y12T		S12		F12		DT	DTT		SDT			
		3	S4	S4T	S4TG	S44					OSC-1G	C1C	ODG	X1G	XDG			Y13	Y13T		S13	S13G			DG	DGT	DGH	SDG	SDGH		
		4	S6	S6T	S6TG	S66				DS/DSS	OSC												F14		K2		K2H				
2	MILLED TOOTH MEDIUM	1	M4N		M4NG	M44N					OWV/OW4		ODV/OD4	XV	XDV			Y21		Y21G	S21	S21G	F21		V1		V1H				
		2	M4								WO							Y22					F22		V2		V2H	SV	SVH		
		3	M4L		M4LG	M44L				DM	OWC			XC				Y23		Y23G	S23	S23G			T2		T2H	ST2			
		4																													
3	MILLED TOOTH HARD	1	H7	H7T	H7TG	H77					W7		WD7	X7	XD7	J7		Y31		Y31G	S31	S31G		F31G	L4		L4H	SL4	SL4H		
		2	H7U		H7UG	H77U					W7R-2							Y32		Y32G											
		3			H7SG		H77S											Y33													
		4				H77C		H77CF			WR		WDR	XWR		J-8	JDB	Y34		Y34G	S34	S34G	F34	F34G	WC		WCH	SWC	SWCH	FWC	
4																															
5	INSERT SOFT	1					S84		S84F								J22							F52/FP52							
		2					S86		S86F								J33					S53		F53/FP53					2JS		F2
		3			S8		S88		S88F	D588																			3JS		F3
		4																						F54/FP54							
6	INSERT MEDIUM	1							M84F				A44		X44		J44												4JS		F4/F45
		2			M8		M88		M88F						X55R		J55R					S62		F62/FP62					47JS		F47
		3							M89F				A55		X55		J55					S63		F63/FP63					5JS		F5
		4																				S64		F64/FP64					57JS		F57
7	INSERT HARD	1																													
		2			H8		H88		H88F				A88		RG7XJ		J88			Y72		S72		F72/FP72					6JS		F6
		3																		Y73		S73		F73/FP73					7JS		F7
		4			H9		H99		H99F		R1				RG1XJ		J99			Y74		S74		F74/FP74					8JS		F8
8	INSERT EXTRA HARD	1																													
		2																													
		3			H10		H100		H100F						RG28XJ					Y83		S83		F83/FP83					9JS		F9
		4																													

NOTE: Bit classifications are general and are to be used only as simple guides. All bit types will drill effectively in formations other than those specified. This chart shows the relationship between the specific bit types.

FIG. 1

combinations may also be limited, thereby affecting other factors of the drilling operation. This happened in the Lone Star Baden No. 1, when the specially made string of 96-lb/ft, 13-3/8 in. casing required a customized 11-7/8 in. bit program.

Of course, each bit manufacturer can make any size bit desired and probably has numerous sizes and type combinations readily available; but the unusual sizes may not be in inventory when needed. Table 1 shows 42 bit sizes available from various manufacturers. Many are available only on special order. Of the 16 standard designs, only about seven are judged as optimum sizes, developed through extensive design and field research. These seven sizes offer a great range of performance features such as cutting structures and bearing configurations, and provide high drilling efficiency.

In planning a bit program, the offset bit records from nearby wells can be used as a reference datum line to select bit type and operating practices. These accumulated drilling data and results of dull bit grading identify base operating parameters (weight, speed, hydraulics, stabilization, etc.) that can lead to improved

TABLE 1—BIT SIZES FROM ALL MANUFACTURERS

AVAILABLE SIZES	STANDARD SIZES	OPTIMUM SIZES
3-3/4	3-3/4	
3-7/8		
4-1/8	4-1/8	
4-1/4		
4-1/2		
4-5/8		
4-3/4	4-3/4	
5-5/8	5-5/8	
5-3/4		
5-7/8		
6	6	
6-1/8		
6-1/4		
6-1/2	6-1/2	6-1/2
6-5/8		
6-3/4		
7-3/8		
7-5/8	7-5/8	
7-7/8	7-7/8	7-7/8
8-3/8		

AVAILABLE SIZES	STANDARD SIZES	OPTIMUM SIZES
8-1/2	8-1/2	8-1/2
8-5/8		
8-3/4	8-3/4	
9		
9-1/2	9-1/2	9-1/2
9-5/8		
9-7/8	9-7/8	9-7/8
10-5/8	10-5/8	
11		
12		
12-1/4	12-1/4	12-1/4
13-1/2		
14-3/4	14-3/4	
15		
17-1/2	17-1/2	17-1/2
18-1/2		
20		
22		
23		
24		
26		

drilling performance for a given interval. Figure 2 shows a typical bit record. Bit selection and operating conditions look fine on this record to a depth of 7767 ft. Dull grading confirms that bit selection was good and that operating practices were proper. Tooth and bearing wear are about equal. However, on run 12 the bit type was changed from a soft to a hard cutting structure. Correspondingly, the penetration rate slowed from 10 to 6 ft/hr. Although this change may be questionable, review of the electric log on a nearby well confirms that a change in formation was anticipated at this depth (see Fig. 3). Because the formation change was anticipated, the previous bit (run 11) was used about 50% longer than normal to reach the harder formation. Once reached, it took three hard-formation bits to get through the thin streak of hard formation.

Analysis of these data suggested that this interval could be drilled quite successfully with softer type, steel tooth and insert bits. There appeared to be enough sand in this formation to permit the use of long-tooth insert-type bits quite successfully. In fact, the entire section was later drilled successfully with more economical insert bits (Fig. 4). Note that the bits on this record have not been graded. Because of this, future improvement will be quite difficult. Analyzing the performance of bit 9, for example, is quite difficult without the previous grading information. Bit 9 lasted only 31-1/2 hours; this is probably low for a journal-type bearing. The same is true for run 10, with only 40 hours' life at a lower penetration rate. However, without data it is virtually impossible to determine what could be improved; i.e., whether the cutting structure failed early due to a hard

CONTRACTOR: RIG NO:	DRAWORKS:	D.C.: (O.D. x I.D. x LENGTH) 10 x 3 x 166	SPUD: (MO / DAY / YEAR) __/__/__	T.P. DRILLERS:
COMPANY: FIELD:	DEPTH & H.P. RATING:	8 x 2 7/8 x 270	U.S.: __/__/__	
WELL NAME: WELL NO:	PUMP MAKE 1:	__x__x__	INTER: __/__/__	
STATE: COUNTY:	PUMP MAKE 2:	DRILL PIPE:	T.D.:	WATER SOURCE:
SEC: T.SHIP RANGE:	MUD TYPE:	T.J. TYPE:	TOTAL DAYS: TOTAL ROT HRS:	FUEL SOURCE:

RUN NO.	SIZE	TYPE	SERIAL NO.	JETS-32nds REG. R or RO 1	2	3	DEPTH OUT	FEET	HOURS	FEET PER HOUR	WT. 1000 LBS.	R.P.M.	PUMP PRESS.	PUMP NO. 1 LINER	SPM	MUD PROPERTIES WT	W.L.	F.V.	PV/YP	% SOL.	VER. DEV.	DULL COND. 1/4 1/8 T	B	G	RG*	REMARKS	DATE	DEPTH
1	22	111					2235	2235	30																			
2	15	111		16	16	16	3708	1473	17 1/2	84	30-35	180	3400	6	240	H.O.						7	5	I	L			
3	15	111		16	16	16	4674	966	16 3/4	58	30	180	3400	6	✓	8.9			6/6	5		6	5	I	L			
4	15	111		16	16	16	5264	590	16 1/4	36	30-50	150	3400	6	✓	9.1			11/7	5		6	7	I	L			
5	15	111		16	16	16	5820	556	18 1/4	30.5	30-35	150	3400	6	✓	9.2			15/14	7		6	6	I	L			
6	15	121		16	16	16	5867	47	2	23.5	30	160	3400	6	✓	9.1			12/12	7						Nozzle w.o.		
7	15	111		16	16	16	6455	588	20	29	40-45	160	3300	6	✓	9.1			13/14	6		3	5	I	L			
8	15	111		16	16	16	6882	427	19 1/4	22	40-45	160	3300	6	✓	9.1			18/16	7		4	4	I	L			
9	15	121		16	16	18	7075	193	14	14	50	150	3400	6	✓	9.2			8/4	7		3	3	I	L	w.o.-D.C.		
10	15	111		16	16	16	7393	318	28	11	30-40	150	3400	6	✓	9.3			11/8	6		3	4	I	L			
11	15	121		16	16	16	7767	374	36	10	30-40	150	3400	6	✓	9.6			11/6	6		7	7	I	M			
12	15	311		16	16	18	7838	71	11 3/4	6	35-40	120	3400	6	✓	9.2			11/8	6		5	5	I	M			
13	15	311		16	16	18	7924	86	14 1/4	6	35-50	110	3400	6	✓	9.2			13/11	5		6	5	I	L	Well kicked		
14	15	311		16	16	18	7998	74	13 3/4	5.4	70	50	3400	6	✓	10.4			13/11	10		5	5	I	L	w.o.-D.C.		
15	15	211		16	16	18	8154	156	22 3/4	7	50	150	3400	6	180	10.5			22/10	11		4	5	I	M	Lost 2 STAB BLD		
16	15	211		18	18	18	8288	134	21	6	45	140	3400	6	✓	10.5			21/13	11	1 1/4	6	6	I	L			
17	15	121		18	18	18	8320	32	5	6.4	40	125	3400	6	✓	10.5			20/14	12								
18	15	211		18	18	18	8453	133	18 1/4	7	50	120	3400	6	✓	10.5			20/13	12	1 1/4	6	6	I	L			
19	15	211		18	18	18	8636	183	15 3/4	11.6	30-40	130	3400	6	✓	10.5			21/6	12		5	8	I	L			
20	15	211		18	18	18	8776	140	21 1/4	6.6	40-50	120	3400	6	✓	10.5			32/10	12		5	5	I	L			
21	15	211		18	18	18	8893	117	20	5.9	30-50	130	3400	6	✓	10.5			21/7	12	3/4	6	5	I	L			
22	15	121		18	18	18	9028	135	20 3/4	6.5	25-45	130	3400	6	✓	10.5			18/8	12		4	7	I	L			
23	15	211		16	16	18	9036	58	8	7.3	30-40	120	3400	6	✓	10.5			19/8	12		4	4	I	L			
24	15	211		18	18	18	9125	89	15 3/4	5.7	40-45	120	3400	6	✓	10.5			25/7	12		6	6	I	L			
25	15	231		18	18	18	9310	135	19 1/2	6.9	50	140	3400	6	✓	10.5			28/10	12								

*DENOTE BY (N)-NO, (L)-LIGHT, (M)-MEDIUM OR (H)-HEAVY ROUNDING OF GAGE

FIG. 2—TYPICAL BIT RECORD

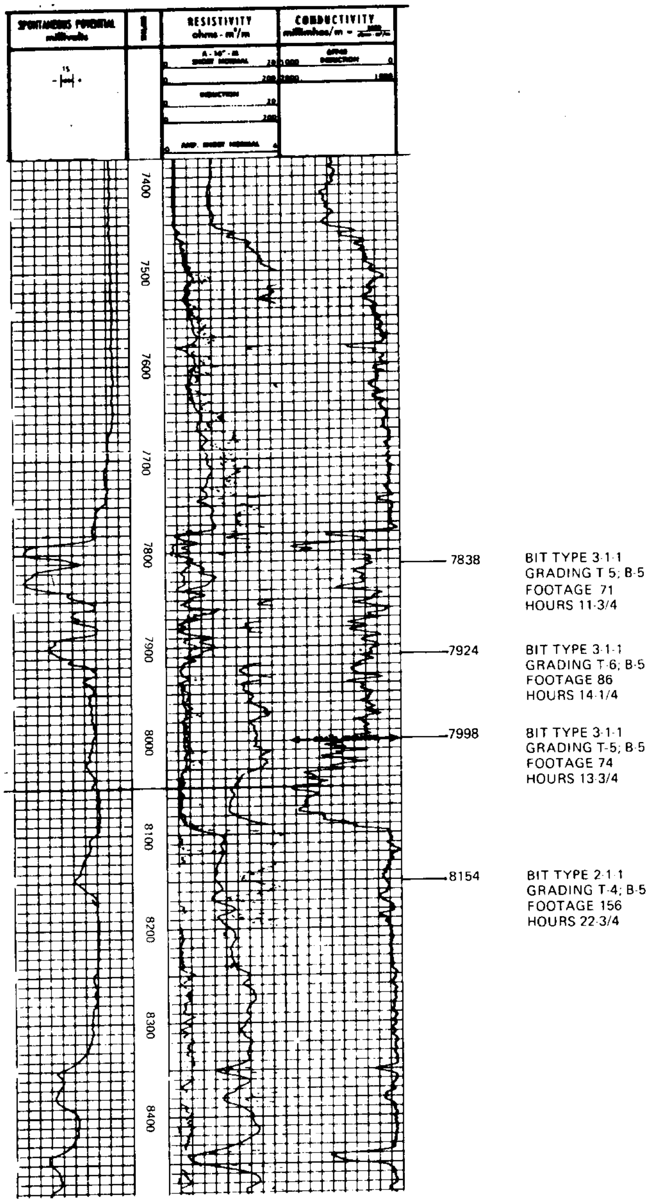

FIG. 3

formation or improper operation (high energy levels or torqueing). In order to improve any drilling operation the data must be recorded.

The IADC has set up a system of grading dull bits by tooth wear, bearing wear, and gauge wear. Entered on the bit record with remarks regarding the bit's overall condition or the reason the bit was pulled, bit grading is a valuable tool in improving drilling operations on the next well.

BIT RUN COST

Another important tool for improvement of a well program is the process of analyzing the cost of each bit run. That is, how much did it cost to drill each foot of hole? Table 2 illustrates a typical cost analysis for bit runs such as those indicated in Fig. 2. This type of analysis is one of the most important factors in evaluating bit performance and application. It permits a realistic evaluation of all factors affecting drilling operations costs. Such factors include relationships between penetration rate, bit footage, rig cost, trip time and bit cost. With a wide variety of rock bit types available over a wide range of prices and capabilities, the cost-per-foot is one of the most important factors in evaluating bit performance. Cost-per-foot analysis also quickly identifies problems or trends that might be overlooked in a quick glance at the bit record. Cost-per-foot related to previously mentioned variables can be determined by the equation:

$$C = \frac{B + R(T+t)}{F} \qquad (1)$$

Where
- C = drilling cost per foot, \$
- B = bit cost, \$
- R = rig operating cost, \$/hr
- T = rotating or drilling time, hr
- t = round trip time, hr
- F = hole drilled by bit, ft

INSERT VERSUS MILLED TOOTH

Referring to Table 2 cost per foot column, it is normally assumed that each succeeding foot drilled in a well will be more expensive than the previous foot. However, any radical change from a normal trend line should highlight a possible improvement interval. Such an interval might exist on bit run 6 or 9, where cost-per-foot of drilling increased appreciably. However, the bit record shows in both instances that the reason is mechanical failure—a washout in each case. Likewise, the cost of drilling intervals 12, 13, and 14 increased dramatically. This indicates that the bit selection might be improved. The question becomes, "Is it economically feasible to use an insert-type rock bit?" Here, a break-even calculation is necessary. This involves calculating the performance required by another type of bit to obtain the same cost-per-foot. Use the equation:

CONTRACTOR: RIG NO: DRAWORKS:

COMPANY: FIELD: DEPTH & HP RATING:

WELL NAME: WELL NO: PUMP MAKE 1:

STATE: COUNTY: PUMP MAKE 2:

SEC: T'SHIP RANGE: MUD TYPE:

D.C.: OD x I.D. x LENGTH ___x___x___ ___x___x___ ___x___x___

DRILL PIPE: ______ T.J. TYPE: ______

MO / DAY / YEAR SPUD: ___/___/___ U.S.: ___/___/___ INTER: ___/___/___

T.D.: TOTAL DAYS: TOTAL ROT HRS:

T.P. DRILLERS: WATER SOURCE: FUEL SOURCE:

RUN NO	SIZE	TYPE	SERIAL NO	JETS-32nds REG. R or RO 1	2	3	DEPTH OUT	FEET	HOURS	FEET PER HOUR	WT 1000 LBS	R.P.M.	PUMP PRESS	PUMP NO1 LINER	SPM	MUD PROPERTIES WT	W.L.	F.V.	PV/YP	% SOL	VER DEV	DULL COND ¼ ⅛ T	B	G	* RG	REMARKS	DATE	DEPTH
1	15	111		14	14	14	2800	2800	38	73	15	150	1500	6¾	64													
2	9⅞	111		13	13	13	4575	1775	20½	86	30	130	2000	"	56													
3		124		12	12	12	5837	1268	23½	54	30	135	"	"	52	9.2												
4		111		13	13	13	6412	575	13½	42	30	130	"	"	54	9.4												
5		114		13	13	13	6979	567	16	35	40	120	"	"	58	9.3												
6		114		13	13	13	7450	471	19	24	40	130	"	"	54	9.4												
7		517		13	13	13	8471	1021	73½	14	20	50	"	"	56	9.4												
8		517		13	13	13	9975	1504	135	11	30	50	"	"	45	9.8												
RR #7		517		13	13	13	10253	253	31	8	30	52	"	"	52	9.8												
9		527		13	14	14	10611	358	31½	11	30	52	1800	"	48	9.8												
10		527		13	14	14	10875	264	40	6	36	52	1700	"	45	9.8												
CORE	8½"						10931	51	8½	6	15	50	750	"	28													
11	9⅞	315		14	14	13						50	1800	"	46	9.8										REAMED		
CORE	8½"													"														
12	9⅞	234		13	14	14	11270	273	32	8	44	60	2000	"	46													

*DENOTE BY (N)-NO, (L)-LIGHT, (M)-MEDIUM OR (H)-HEAVY ROUNDING OF GAGE

FIG. 4

TABLE 2

THE FOLLOWING CALCULATIONS ARE BASED ON THE FOLLOWING DATA:
RIG COST PER HOUR = $ 150.00 TRIP TIME (HOURS/1000 FT) = 0.70

BIT NO	BIT TYPE	DEPTH OUT	FEET DRLD	DRILLING HOURS	DRILLING RATE	CUM HOURS	RUN COST	COST PER FT	CUM COST
INITIAL HOLE SIZE IS 22.000 INCH.									
1	111	2235	2235	30.00	74.5	30.00	12735	5.70	12735
BIT SIZE CHANGE TO 15.00									
2	111	3708	1473	17.50	84.2	47.50	4063	2.76	16798
3	111	4674	966	16.75	57.7	64.25	4052	4.19	20850
4	111	5264	590	16.25	36.3	80.50	4039	6.85	24890
5	111	5820	556	18.25	30.5	98.75	4398	7.91	29287
6	121	5867	47	2.00	23.5	100.75	1965	41.81	31252
7	111	6544	588	20.00	29.4	120.75	4727	8.04	35979
8	111	6882	427	19.25	22.2	140.00	4659	10.91	40638
9	121	7075	193	14.00	13.8	154.00	3892	20.17	44350
10	111	7393	318	28.00	11.4	182.00	6025	18.75	50555
11	121	7767	374	36.00	10.4	218.00	7265	19.42	57820
12	311	7838	71	11.75	6.0	229.75	3634	51.19	61454
13	311	7924	86	14.25	6.0	244.00	4019	46.73	65473
14	311	7998	74	13.75	5.4	257.75	3951	53.40	69424
15	211	8154	156	22.75	6.9	280.50	5318	34.09	74742
16	211	8288	134	21.00	6.4	301.50	5069	37.83	79811
17	121	8320	32	5.00	6.4	306.50	2673	83.52	82484
18	211	8453	133	18.25	7.3	324.75	4674	35.14	87158
19	231	8636	183	15.75	11.6	340.50	4318	23.60	91476
20	211	8776	140	21.25	6.6	361.75	5158	36.84	96634
21	211	8893	117	20.00	5.8	381.75	4983	42.59	101617
22	121	9028	135	20.75	6.5	402.50	5109	37.85	106726
23	211	9086	58	8.00	7.3	410.50	3203	55.22	109929
24	211	9175	89	15.75	5.7	426.25	4375	49.16	114304
25	231	9310	135	19.50	6.9	445.75	4952	36.68	119255

THE TOTAL COST OF BITS = $ 33176
THE AVERAGE DRILLING RATE IS 20.89 FT/HR.
THE AVERAGE COST PER FOOT IS 12.81
FOOTAGE THROUGH THIS INTERVAL IS 9310 FEET

$$T_2 = \frac{B_2 + R(t)}{C(F/T) \cdot R} \quad (2)$$

Where
- T_2 = Rotating hours for replacement bit to give break-even cost
- B_2 = Replacement bit cost, $
- R = Rig operating cost, $/hr
- t = Round trip time, hr
- C = Drilling cost-per-foot for prior bit, $
- (F/T) = Penetration rate for prior bit, ft/hr

Once break-even hours are found, footage can be determined by the equation:

$$F_2 = (F/T)\,(T_2) \quad (3)$$

The break-even calculation determines exactly the hours and footage required by other bits to match performance being achieved with current bits. The calculations assume that replacement bits can equal penetration rates currently obtained. To illustrate this, refer to Table 2. For bit run 12 perhaps a more expensive sealed insert should be used to reduce drilling cost in this interval. Tables 3 and 4 show the combined cost of several bit runs divided by the total footage for those bit runs, the average cost-per-foot for that particular interval. By substituting the cost of a more expensive sealed-bearing insert bit (or a friction-bearing insert bit) into Eqs. (2) and (3), a break-even footage and the run time can be determined for that interval. Of course, this is based on the average penetration for the insert bit. In reality, insert bits often penetrate at a lower rate than milled tooth bits; therefore, it is appropriate to calculate new break-even costs using the lower penetration rate normally achieved with the insert bit. If expected penetration rates are not known, several random rates may be selected to develop information, as shown in Table 3. This shows new drilling rate, footage, and hours required if the higher priced bit penetrated at 60% of the original rate, and in increments of 10% up to 120%. With this information a logical set of parameters can be determined for that particular bit in that particular area. Assuming that the number falls within a reasonable range, it may become economically feasible to use the higher priced bit.

TABLE 3—SUMMARY OF BITS 12 THROUGH 14

THE TOTAL COST OF BITS = $ 3147
THE AVERAGE DRILLING RATE IS 5.81 FT/HR
THE AVERAGE COST PER FOOT IS 50.24
FOOTAGE THROUGH THIS INTERVAL IS 231 FEET

DO YOU WANT TO TRY A DIFFERENT PRICED BIT THROUGH THIS INTERVAL?
ENTER: BIT COST, MINIMUM, MAXIMUM DRILLING RATE %4800, 60, 120

PERCENT DR RATE	NEW DRLG RATE	FEET REQD	HOURS REQD	COST $/FT
60.0	3.487	781.6	224.2	50.24
70.0	4.068	422.1	103.8	50.24
80.0	4.649	313.8	67.5	50.24
90.0	5.230	261.6	50.0	50.24
100.0	5.811	230.9	39.7	50.24
110.0	6.392	210.7	33.0	50.24
120.0	6.974	196.3	28.2	50.24

A RATE OF PENETRATION OF 5.81 FT/HR WOULD BE REQUIRED TO MAINTAIN A COST OF $ 50.24 FOOT THROUGH THIS 231 FOOT INTERVAL.

TABLE 4—SUMMARY OF BITS 12 THROUGH 18

THE TOTAL COST OF BITS = $ 7343
THE AVERAGE DRILLING RATE IS 6.43 FT/HR
THE AVERAGE COST PER FOOT IS 42.77
FOOTAGE THROUGH THIS INTERVAL IS 686 FEET

DO YOU WANT TO TRY A DIFFERENT PRICED BIT THROUGH THIS INTERVAL?
ENTER: BIT COST, MINIMUM, MAXIMUM DRILLING RATE % 6000,60,120

PERCENT DR RATE	NEW DRLG RATE	FEET REQD	HOURS REQD	COST $/FT
60.0	3.856	1782.7	462.4	42.77
70.0	4.498	731.1	162.5	42.77
80.0	5.141	506.8	98.6	42.77
90.0	5.784	409.2	70.8	42.77
100.0	6.426	354.6	55.2	42.77
110.0	7.069	319.7	45.2	42.77
120.0	7.711	295.4	38.3	42.77

A RATE OF PENETRATION OF 4.58 FT/HR WOULD BE REQUIRED TO MAINTAIN A COST OF $ 42.77 PER FOOT THROUGH THIS 686 FOOT INTERVAL.

FRICTION VS. ROLLER BEARINGS

The friction-bearing insert bit is considered a longer life bit than the roller-bearing insert bit. When should a roller-bearing insert bit be selected? Generally speaking, the roller-bearing bit will be selected when records show the cutting structure is breaking or being destroyed before the bearings are beginning to take a great deal of wear. In such cases, where the cutting structure life will not match the increased bearing life, the additional cost of a friction bearing is not justified. Nor is this additional cost warranted when an intermediate casing point (requiring a bit size change) or final depth is anticipated prior to the expected end of the bearing life.

PROGRAM PREPARATION

Well programming has always been done to varying degrees of detail by operator personnel and, to a lesser extent, by the more progressive contractor. For some time there has been a tendency to look to the rock bit industry for this service. The small contractor or operator may do this because his technical staff is limited. Some operators may request outside assistance to double check their own efforts.

Rock bit suppliers may have information about a particular area that is not readily available to his customers. His rock bit program will be based on the best data available, and will include detailed studies of:

1. Geology—lithology, drillability, structure, and competency of zones to be penetrated
2. Possible downhole conditions. These include high pressure zones, lost circulation, water intrusion, temperature.
3. Offset well data. Offset well data in the form of electric logs, bit records, and other pertinent material should be collected and evaluated. Any information concerning drilling problems, including lost circulation, deviation, doglegs, key seats, high pressures, sticking problems, and water flows should be investigated so that preventive measures can be included in the drilling program.
4. Hole and casing program. Though this is a contractor/operator responsibility, it is necessary to have this information for planning bit selection and for developing the hydraulics program.

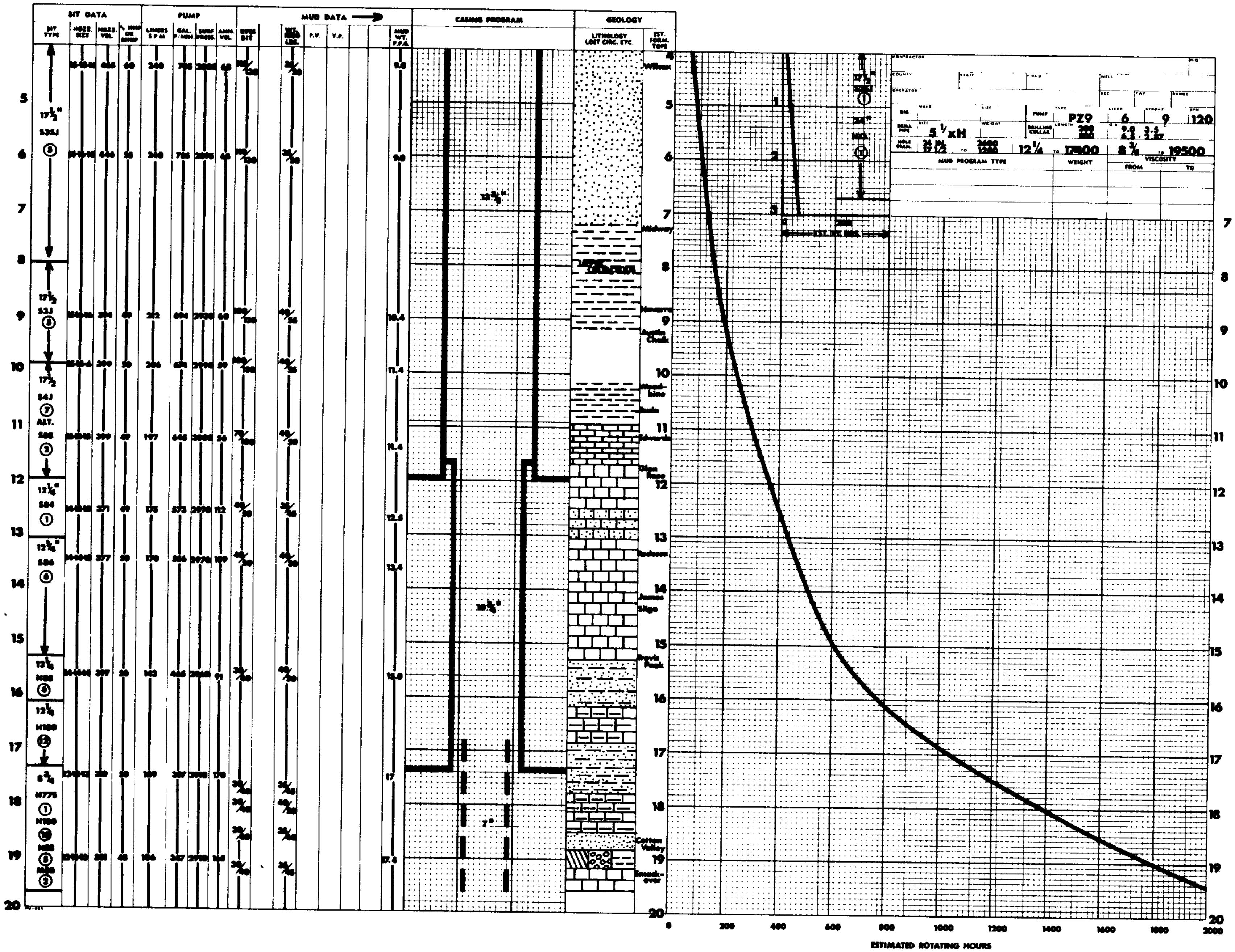

FIG. 5—SUGGESTED DRILLING PROGRAM

5. Mud program. The drilling fluid density will have a direct effect on the hydraulic program as well as the expected life and performance of the rock bits.
6. Rig specifications. These parameters enter the picture in one of two ways. The program may be completed with all details of the operation spelled out and a rig selected that will meet the demands; or a program must be designed for optimum results considering all limitations of a specified rig.

Once all the supporting data and information are acquired, it is necessary to decide how comprehensive the plan will be and what form it will take. This depends largely on the needs of the user drilling that particular area. The plan and its results should be linked in a way that will expedite evaluation and improvement of subsequent programming. Consequently, the program should not be considered complete until the well is documented. Figure 5 shows a program presentation which defines bit, mud, and time requirement information, and involves a reasonably detailed study of operator and contractor requirements. It presents a datum reference line from which the progress of the well can be recorded as the well program is implemented. With other documented data it serves as an excellent basis for evaluation and improvement. Figure 6 shows a preliminary program. Such a minimum-effort program is usually used when objectives are limited to estimation of associated costs.

The forces of business today dictate that we drill at increasingly lower cost-per-foot. This becomes more difficult to achieve as more difficult requirements are placed on the industry. As a result, we must consider very carefully numerous factors (bit weight/speed relationship, bit selection, the drilling mud, hydraulics, and drilling equipment limitations) that lead to a cost-effective drilling program.

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Suggested Bit Program

FOR: ______________________ COUNTY: ______________________

LOCATION: ______________________ STATE: ______________________

LEGAL DESCRIPTION: ______________________ HOLE SIZE: 24" to 2600'; 17-1/2" to 12000'; 12-1/4" to 17400'; 8-3/4" to 19500'

APPROXIMATE DEPTH		BIT	REMARKS			
FROM	TO	TYPE	FEET	HOURS	RPM	WEIGHT
0	60	(Use Dry Hole Digger to Set Conductor)				
60	2,600	1-17-1/2" S3SJ	2,600'	22	110/150	30
60	2,600	1-24" Hole Opener	2,600'	20	30	10/15
2,600	8,000	5-17-1/2" S3SJ	5,400'	110	110/130	35/50
8,000	9,800	5-17-1/2" S3J	1,800'	90	100/130	40/55
9,800	12,000	7-17-1/2" S4J	2,200'	125	100/130	40/55
		Set 13-3/8" Pipe				
12,000	13,100	1-12-1/4" S84	1,100'	70	40/50	35/40
13,100	15,300	6-12-1/4" S86	2,200'	300	40/50	40/50
15,300	16,000	6-12-1/4" H88	700'	240	30/40	40/50
16,000	17,400	12-12-1/4" H100	1,400'	440	30/40	45/55
		Set 10-3/4" Pipe				
17,400	19,500	1-8-3/4" H77S			30/40	35/45
		10-8-3/4" H100			30/40	40/50
		5-8-3/4" H88			30/40	35/45
		2-8-3/4" M88	2,100'	625	30/40	35/45

	AVERAGE RATE OF PENETRATION
TOTAL BIT COST $ 142,782	INTERVAL 60-2600 118.2 FT/HR.
TOTAL ESTIMATED DRILLING TIME 2042 HRS.	INTERVAL 2600-12000 28.9 FT/HR.
TOTAL ESTIMATED TRIP TIME 864 HRS.	INTERVAL 12000-17400 5.1 FT/HR.
TOTAL TIME 2906 HRS.	INTERVAL 17400-19500 3.3 FT/HR.
ALTERNATE INTERVAL 9,800-12,000; 2-S88	

FIG. 6