Petroleum Engineering

DRILLING AND WELL COMPLETIONS

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Chapter 8 . . .

Factors Affecting Penetration Rate

8.1 Introduction

Contract drilling prices have remained essentially constant over the last ten or fifteen years despite the fact that the greatest inflationary period in United States history has occurred during the same time. This unique price stability has been due, largely, to the highly competitive and resourceful nature of the drilling industry in general, and to the rig floor, desk, and laboratory thinking and experimentation which has resulted in improved techniques and equipment for making hole faster.

The factors which affect rate of penetration are exceedingly numerous and certainly are not completely understood at this time. Undoubtedly, influential variables exist which are as yet unrecognized. A rigorous analysis of drilling rate is complicated by the difficulty of completely isolating the variable under study. For example, interpretation of field data may involve uncertainties due to the possibility of undetected changes in rock properties. Studies of drilling fluid effects are always plagued by the difficulty of preparing two muds having all properties identical except the one under observation. These and other complexities will become more apparent in later sections.

While it is generally desirable to increase penetration rate, such gains must not be made at the expense of over-compensating, detrimental effects. The fastest *on-bottom* drilling rate does not necessarily result in the lowest cost per foot of drilled hole; other factors such as accelerated bit wear, equipment failure, etc., may raise cost. These restrictions should be kept in mind during the following discussion, which deals largely with *on-bottom* drilling rate.

Some of the more recognizable variables which affect penetration rate are the following:

1. Personnel efficiency
   a. Competence
      (1) experience
      (2) special training
   b. Psychological factors
      (1) company-employee relations
      (2) pride in job
      (3) chance for advancement
2. Rig efficiency
   a. State of repair, preventive maintenance
   b. Proper size
   c. Ease of operation, degree of automaticity, and power equipment
3. Formation characteristics
   a. Compressive strength
   b. Hardness and/or abrasiveness
   c. State of underground stress (overburden pressure, etc.)
   d. Elasticity — brittle or plastic
   e. Stickiness or *balling* tendency
   f. Permeability
   g. Fluid content and interstitial pressure
   h. Porosity
   i. Temperature
4. Mechanical factors
   a. Weight on bit
   b. Rotating speed
   c. Bit type
5. Mud properties
   a. Density
   b. Solid content
   c. Flow properties
   d. Fluid loss

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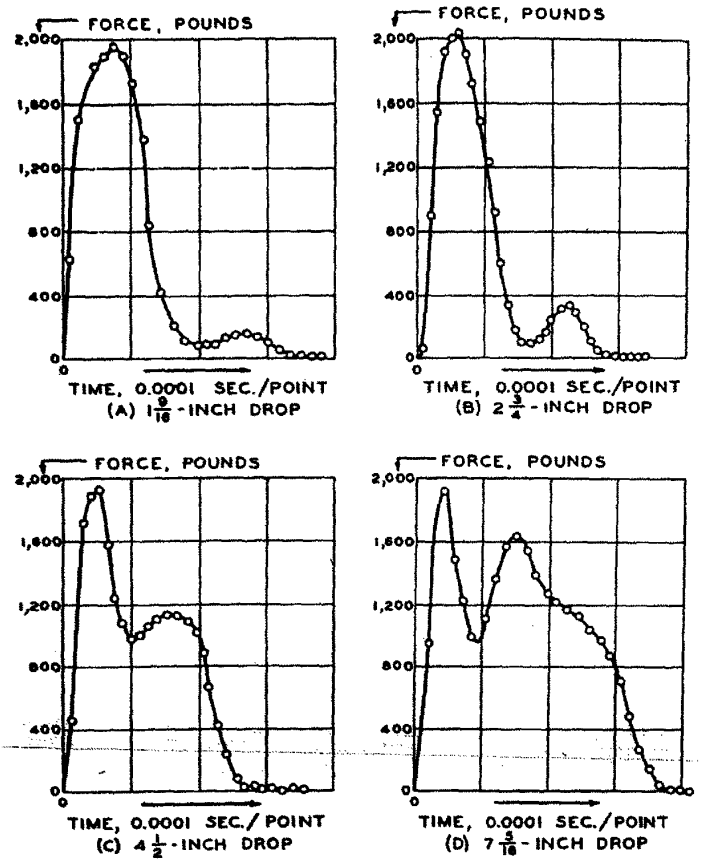

Fig. 8.1. Tracings of typical force waveforms for various heights of drop with an 0.03-in. bit and weight of 15 lb for single blows on Indiana limestone. After Pennington,[1] courtesy API.

e. Oil content
f. Surface tension—wettability

6. Hydraulic factors—essentially bottom hole cleaning

8.2 Fundamentals of Rock Failure

For drilling purposes, rocks may be classified into three general types, namely:

(1) Soft rocks: soft clays and shales, unconsolidated to moderately cemented sands
(2) Medium rocks: some shales, porous limestones and dolomites, consolidated sands, gypsum
(3) Hard rocks: dense limestones and dolomites, highly cemented sands, quartzite, and chert.

As mentioned in our earlier discussion of bits, soft rocks may be drilled by the scraping-cutting action of drag-type bits, or by the combined grinding-scraping action of offset cone-angle, rolling cutter bits. The harder formations are drilled mostly by the crushing penetration of the bit teeth. Since it is in the latter type of formation that penetration rates are lowest, let us further consider the failure mechanism of these rocks.

Experiments on the failure of elastic rocks conducted by Battelle Memorial Institute for Drilling Research, Inc. are of considerable fundamental interest.[1-3] In part of these studies a drop tester, consisting of a weighted bit on a rod, was dropped from various heights, striking the rock specimen below. Strain gauges close to the bit allowed the force waveforms to be recorded by an oscilloscope camera. Four such patterns for single blows at various drop heights are shown in Figure 8.1. Note that the first force peak is 2000 lb for all cases, with the magnitude of the second peak increasing with drop height. Figure 8.2 shows the first energy peak with an expanded time scale. The curve between O and A corresponds to the bit crushing small surface irregularities on the rock. Between A and B, the constant steep slope denotes that elastic deformation is being undergone by the rock. If the impact force is not above point B, the rock does not fail and only a

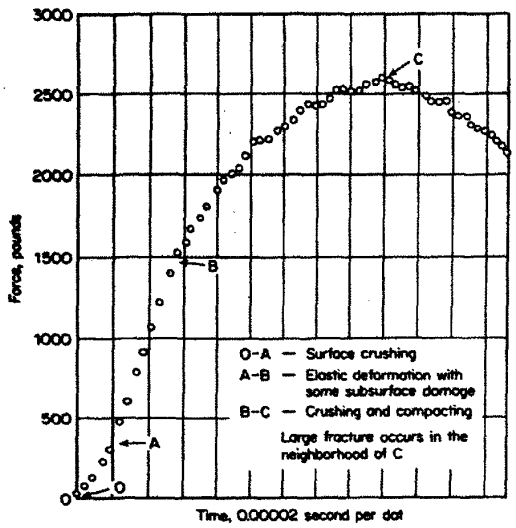

Fig. 8.2. Expanded first force pulse of a force waveform for a single blow with an 0.03-in. bit on Indiana limestone. After Pennington,[1] courtesy API.

surface mark is left. Between points *B* and *C*, the narrow wedge of rock beneath the bit is crushed, and the blow energy is transmitted to the rock around the wedge, and chips are formed. Beyond point *C*, the energy level drops until the bit once again contacts solid rock. If sufficient energy is left, another peak occurs, etc. It was found that the amount of rock removed was linearly related to the blow energy. Other experiments with static rather than impact loading gave similar results, except that a lower energy level was required to fracture a given amount of rock. The results in Figures 8.1 and 8.2 are exactly analogous to cable tool drilling (or any percussive device) in brittle rocks.

The sequence of pictures in Figure 8.3 shows the drilling action of a rolling cutter bit in sandstone at atmospheric conditions.[4] Cuttings are removed by air circulation. In the first picture, a force is applied to the center tooth as the cone rolls. The rock does not fail until the fourth picture, when the applied load finally exceeds the rock's strength. The failure is a small explosion, with chips flying in all directions. This continues as the tooth sinks deeper and is complete, in the eleventh picture. It may thus be surmised that the rotary drilling mechanism is not too basically different from the straight percussive (cable tool) method.

8.3 Rock Characteristics

The rock properties which govern drilling rate are not completely understood. Furthermore, correlation is lacking between strength and elastic properties as measured at laboratory conditions, and those which exist at the depths of interest to the oil industry. Considerable data and an extensive bibliography on rock properties has been published by Wuerker.[5] Other investigations concerned with the effect of pressure on rock drillability are also available.[6,7]

In general, penetration rate varies inversely with the compressive strength of the rock being drilled. The related property of hardness or abrasiveness enters the picture because of its effect on bit life. The hardest and also the strongest sedimentary rocks are chert (a form of quartz, SiO_2) and various quartzites which offer severe drilling problems when encountered.

The elastic properties of various formations are greatly influenced by the state of stress at which they exist. The behavior of most shales is typical of this effect, because they become increasingly difficult to drill at greater depths. For explanation of this behavior, consider Figure 8.4 which shows a thin impermeable element of formation directly below the bit. If the hole is filled with liquid, the upper surface of the element is subjected to a pressure which is dependent on mud density and depth. Practically speaking, this pressure tends to prevent removal of the element much as though the rock's strength were increased by the applied pressure. Therefore it may be expected that the effect of such superimposed stresses will be more pronounced in weak (soft, relatively compressible) rocks than in stronger, more competent beds [see Figure 8.5(A)]. Note that drilling rate reaches an essentially minimum value at some confining pressure, with little change occurring at subsequent higher pressures. This is particularly evident for the soft shale shown in Figure 8.5(C). Also note that the effect of confining pressure on drilling rate is greater at higher bit weights, as is shown in Figure 8.6.

Payne and Chippendale[8] have reported test results which lend further insight into the mechanism of rock failure at high vs. atmospheric pressures. In these experiments, crushing loads were applied to rocks with a round (5 mm diameter) tungsten carbide penetrator, the size and type of indentation being the object of study. Typical results are shown in Figure 8.7. The letters *A* and *H* denote imposed hydrostatic pressures of atmospheric and 5000 psi; the numbers refer to the applied load in pounds. In the atmospheric tests visible cracks appeared, and the chips around the indentation were separate, easily removable flakes. Under 5000 psi, however, the failure was more plastic, as evidenced by the extruded material which piled up around the depression and could not easily be removed. Hence, the sandstone was brittle at low pressure and plastic at high pressure. Not all rocks behaved in this manner. Quartzite, granite, and dolomite experienced the same type of failure at the higher pressure; however, the

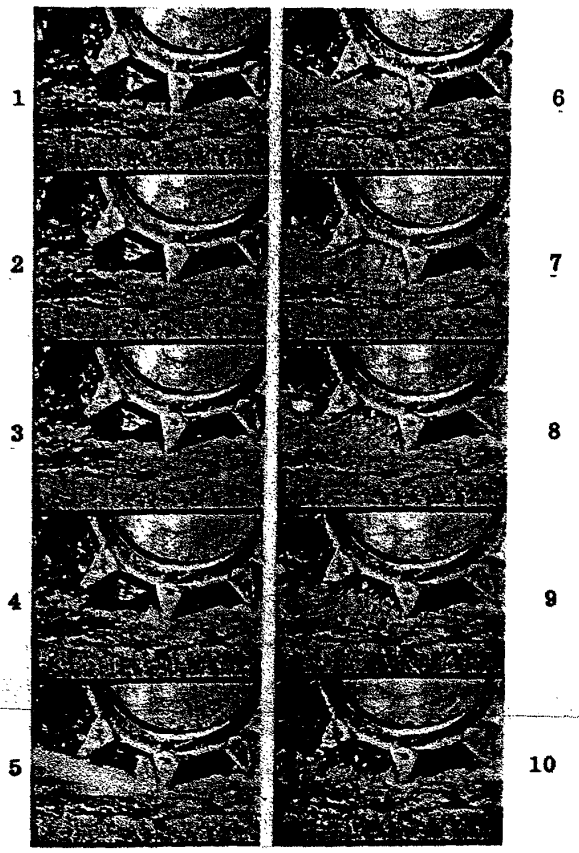

Fig. 8.3. Elastic rock failure as caused by rolling cutter bit. Conditions are atmospheric pressure with cuttings being blown away by air. Starting in picture 1, a tooth starts to apply pressure to the rock as the cone rolls forward. The rock does not break immediately. Then in picture 4, the pressure of the tooth exceeds rock strength and failure starts. The failure is practically an explosion of rock. Chips continue to fly as the tooth sinks deeper. Finally, by picture 10 particle discharge diminishes and then ceases. Filmed by Hughes Tool Company with a 9⅞-in. O.S.C. bit cutting Berea sandstone. After Murray and MacKay,[4] courtesy Hughes Tool Company.

loads necessary to produce the fracture were 50 to 100% higher than at atmospheric conditions.

The balling tendency of a formation is primarily dependent on its mineral composition. Hydratable clays, bentonite in particular, form a sticky, pasty mixture with water which becomes imbedded between bit teeth and surrounds the cones and the entire bit. This reduces tooth penetration and, consequently, drilling rate.

Permeability affects the drillability of rocks through its effect on the relief of imposed pressures. Consider again the rock element shown in Figure 8.4. If this rock were sufficiently permeable to the drilling fluid, no appreciable pressure differential would exist across a thin element; hence the pressure effect would be minimized. This is the conclusion of Bredthauer,[9] and Murray and Cunningham,[7] and is in agreement with their experimental evidence, i.e., that permeable rocks which allowed pressure equalization ahead of the bit showed no appreciable change in drillability with pressure. From these data, it may be concluded that any other factors facilitating more rapid pressure relief will also decrease the effect of pressure on drilling rate. A rock completely saturated with incompressible fluids (water, oil) should be less sensitive to borehole pressure effects than one containing a gas, since in the former a small quantity of mud filtrate is sufficient to equalize pressure for a substantial distance.

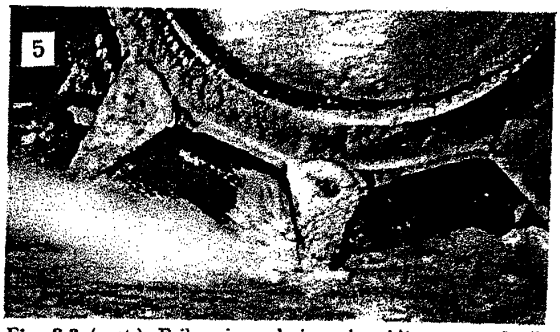

Fig. 8.3 (cont.). Failure is explosive when bit pressure finally exceeds strength of rock.

A porous zone drills faster than a dense section of the same rock. This fact has long been used by drillers and geologists for detecting the presence of such zones. A major portion of this effect is probably due to the lower compressive strength of porous zones.

The effect of temperature (in the range of our interest) on rock properties is not generally considered. However, rock failure becomes more plastic as temperature

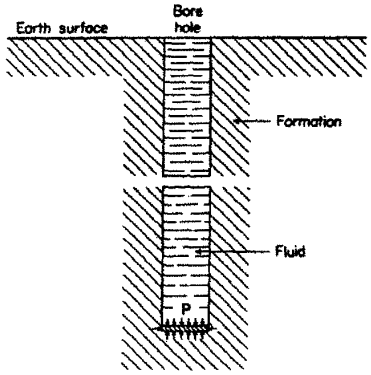

Fig. 8.4. Element of formation beneath rock bit. After Murray and Cunningham,[7] courtesy AIME.

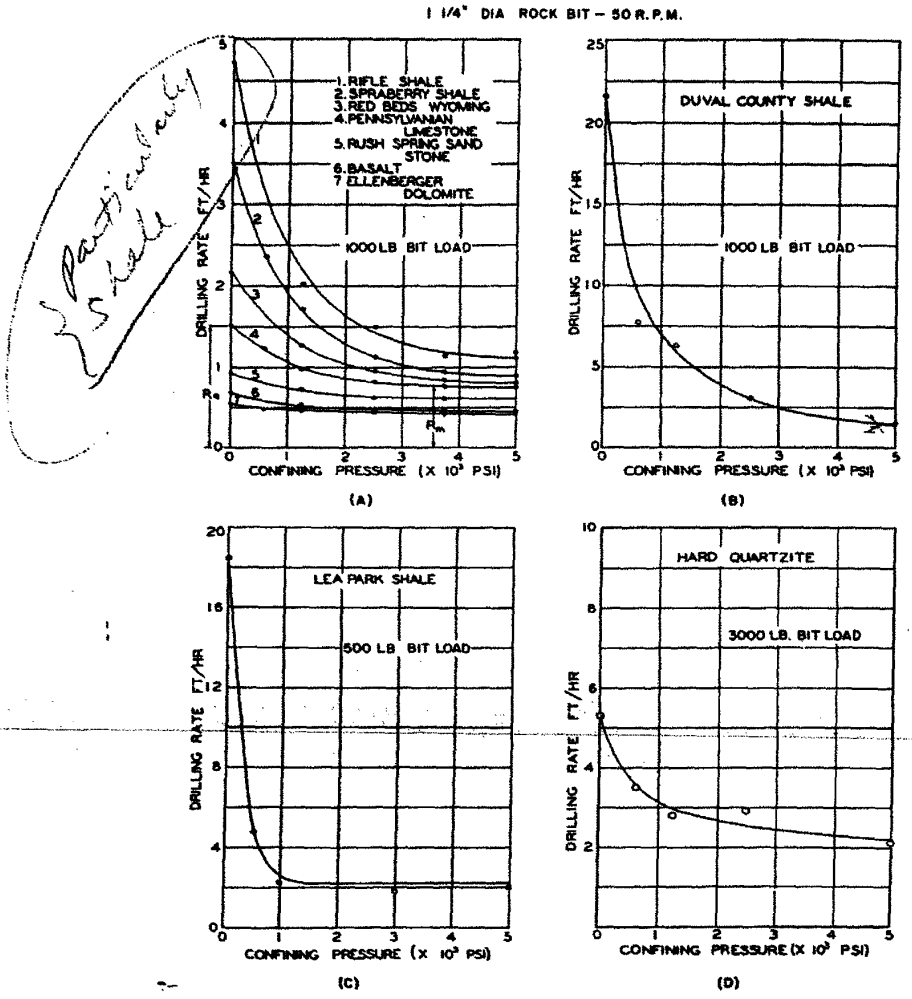

Fig. 8.5. Penetration rate vs. confining pressure for various rock types. After Murray and Cunningham,[7] courtesy AIME.

increases; such effects may be of interest in the future, as drilling goes deeper.

No mention has been made of such properties as grain size, Poisson's ratio, modulus of elasticity, modulus of resilience, or other more involved measurements of strength and elastic behavior.[5] These properties are, in general, unknown for sedimentary rocks at the conditions of interest in this field. A knowledge of these factors could lead to a more thorough knowledge of the mechanics of rock failure.

It might seem to the reader that too much space has been allotted to rock properties, which are beyond human control. It should be realized, however, that it is these rock properties which completely govern drilling practices in different geologic areas. Hole size, bit type, drilling fluid selection, and general operating procedures are all dictated by the nature of the rocks to be drilled. Consequently, rock characteristics are of prime importance, with operational procedures being secondary.

8.4 Mechanical Factors

In all areas, penetration rate is governed by the weight on the bit and/or the rotary speed which may be applied. Normally, these limits are imposed by either crooked hole, equipment, and/or hydraulic considerations. Let us postpone our discussion of crooked hole problems until Chapter 9, and deal with the latter factors in this chapter. Other variables will be considered constant or of no consequence, except as noted.

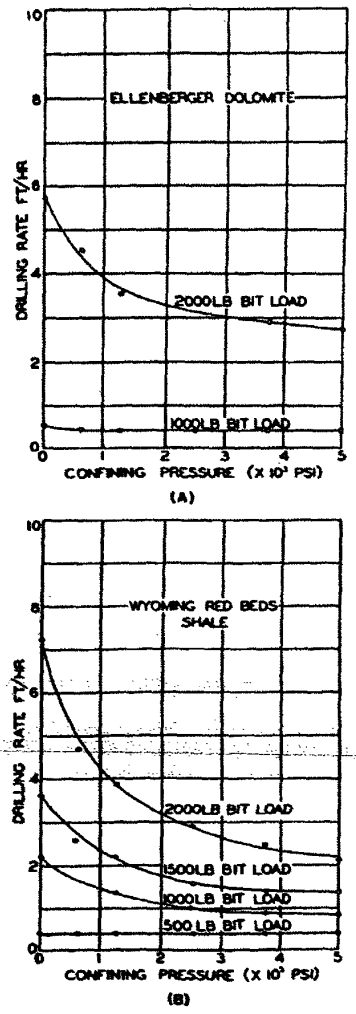

Fig. 8.6. Drilling rate vs. confining pressure, variable bit load. After Murray and Cunningham,[7] courtesy AIME.

Weight on Bit

The general effect of this variable on rate of penetration is shown in Figure 8.8.[16] Note that there are two distinct drilling regions:

(1) drilling at bit loads below the compressive strength of the rock — out to approximately 30,000 lb, for the pink quartzite.

(2) drilling at bit loads above this critical weight. Obviously bit weights in region (2) are desirable and are applied if possible. This principle is well illustrated by Figure 8.9, which shows the increase in penetration rate and footage when sufficient bit weight to overcome the rock's compressive strength was applied.

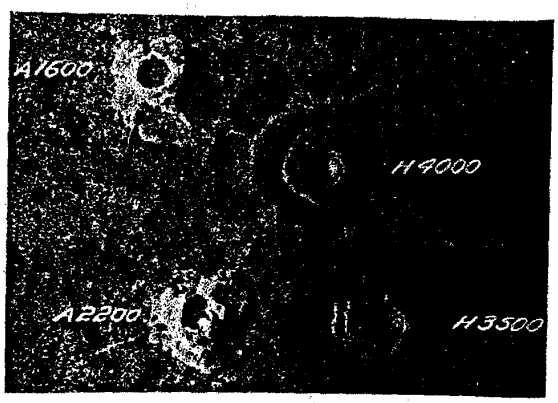

Fig. 8.7. Rock failure under different imposed pressures. Letters *A*, *H* denote atmospheric and 5000 psi pressure, respectively. Numbers indicate applied load, lbs. After Payne and Chippendale,[8] courtesy Hughes Tool Company.

From Figure 8.8 it is evident that for each rock type the points above the critical load lie on approximately straight lines:[11]

(8.1) $$R_p = a + bW$$

where R_p = instantaneous or *on bottom* penetration rate, ft/hr

W = weight on bit, lb

a, b = intercept and slope respectively, which are dependent on rock properties, bit size and type, drilling fluid properties, etc.

Other data, both field[12–14] and laboratory [15,16] tend to substantiate the linearity of R_p versus W over reasonable ranges of bit loading. This relation will hold true only if other factors are constant. In particular, adequate cleaning and cutting removal must be maintained. This does not necessarily mean constant circulation rate or constant nozzle velocity, since at higher values of W more and probably larger cuttings are being generated. Consequently, circulation inadequacies will affect this relationship, unless the flow rate is high enough to perform its function equally well at all W's of interest. This will be further emphasized in a later section devoted to hydraulic factors.

Rotational Speed

The effect of this variable on penetration rate is not too well established. In general, on bottom drilling rate increases with increased rotary speed. Figures 8.10 and 8.11 are typical of the rotary speed effect and suggest that the following relationship exists:

(8.2) $$R_p = f(N)^n$$

where f = some function

N = rotary speed, rpm

$n < 1$

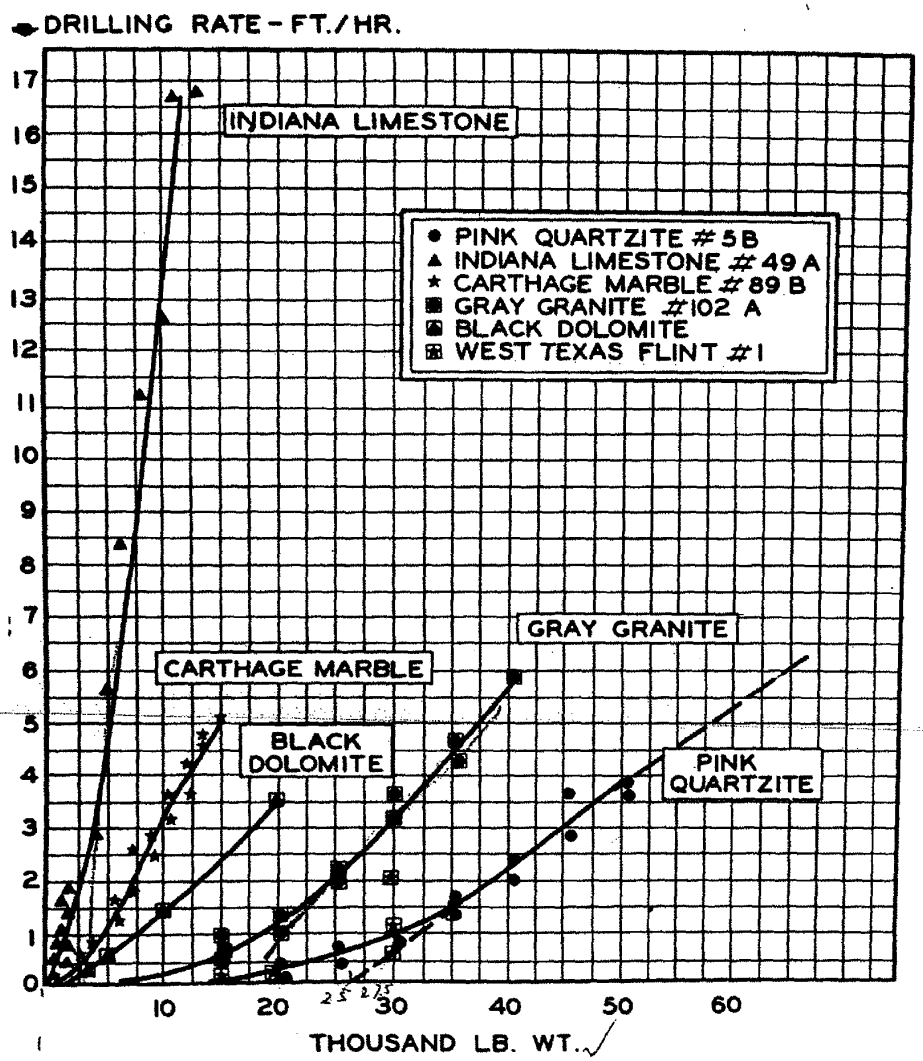

Fig. 8.8. The effect of bit loading on penetration rate for various rocks. Laboratory data — atmospheric pressure. Courtesy Hughes Tool Company.[10]

Again, the true relationship may be obscured by the hole cleaning variable. A satisfactory nozzle velocity at 100 rpm may not be adequate at 200 rpm, since at the latter speed a cutting has only half as much time to clear bottom prior to the next tooth impact.

The Battelle Institute study[2,3] set forth a formula for a rate of advance predicting linearity between R_p and N. It was assumed that each tooth impact removes essentially the same amount of rock. Fundamentally, this would seem logical; however, available data do not confirm this analysis for rotary (roller bit) drilling. Turbodrill data to be cited later confirms Eq. (8.2) for rotating speeds up to 750 rpm.[17]

Combined Effect of W and N

An empirical combination of Eq. 8.1 and 8.2 indicates:

$$R_p = e + fWN^{1/2} \tag{8.3}$$

where e, f = constants for a given set of conditions.

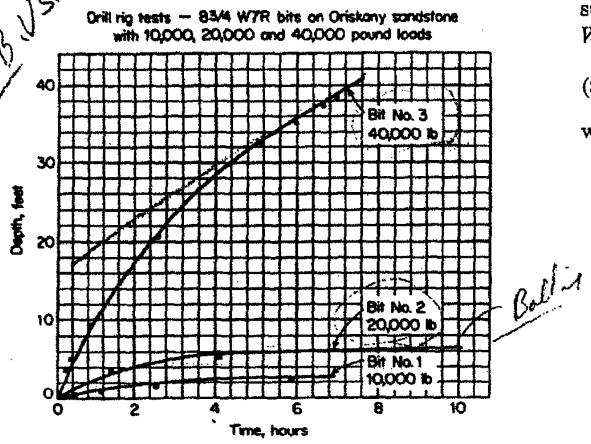

Fig. 8.9. Increased penetration facilitated by proper bit weight application. Laboratory data — atmospheric pressure. Courtesy Hughes Tool Company.[10]

Figure 8.12 is a replot of Figure 8.10, except that W and N have been combined. Other laboratory[15] and turbodrill field data[17] exhibit essentially the same value of n.

The compressive strengths of many rocks encountered in oil well drilling are low enough that little error is involved by assuming R_p to be directly proportional to W, that is, that $a = 0$ in Eq. 8.1. It is also generally considered that the effect of bit size may be eliminated by substituting the applied weight per inch of diameter[7] for W in the equations, with the following result:

$$R_p = f\frac{W}{d}(N)^n = fwN^{1/2} \tag{8.4}$$

where d = bit diameter, in.

w = lb/in. of bit diameter

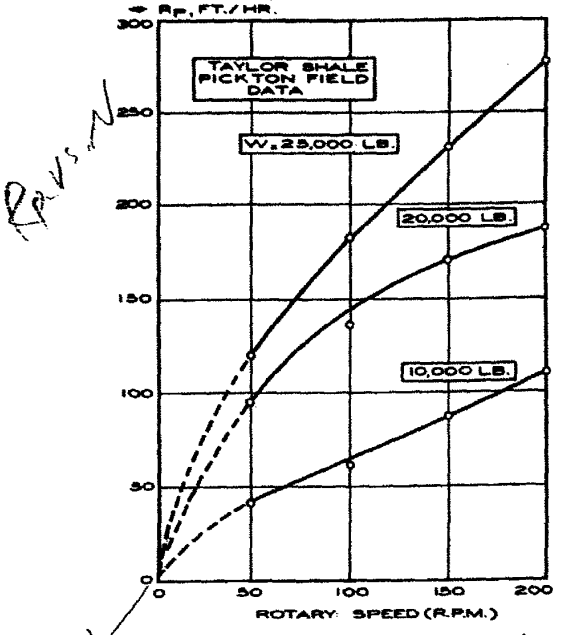

Fig. 8.10. Effect of rotary speed on penetration rate at various bit weights. Replotted from data of Bielstein and Cannon,[13] courtesy API.

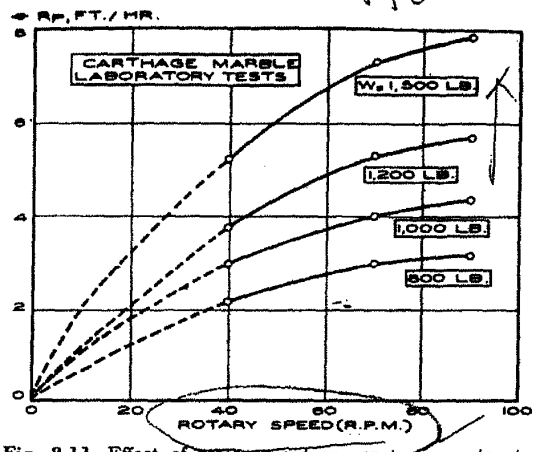

Fig. 8.11. Effect of rotary speed on penetration rate at various bit weights. Replotted from data of Wardroup and Cannon,[16] courtesy API.

Equation (8.4) may be considerably in error for extremely hard rock drilling. Analysis of West Texas field tests showed the effect of bit weight to be expressible as a power function:[18]

$$R_p = f'W^m N^{1/2} \tag{8.5}$$

where $m \simeq 1.2$.

Eqs. 8.3, 8.4, and 8.5 are purely empirical, and may not fit all situations. Certainly, these equations are not valid for W's too small to cause rock failure; however, such values are of little practical importance.

Practical Limitations on W and N

These factors must, of course, be held within the operational limits imposed by economic drill string and bit life. Over-all penetration rate is greatly affected by increased trip frequency, caused by accelerated bit wear due to operating at excessive W and/or N values. The practical limitation on bit weight is primarily governed by the allowable tooth stress of the bit itself, and the current maximum which has been applied to some bit types is about 10,000 lb/in. Recall that crooked hole considerations are ignored at this time. Rotational speed also affects bit performance, primarily through bearing and tooth wear, and through the severity of vibrational loads.

Most drill string failures are attributed to material fatigue which has been aggravated by corrosion and/or

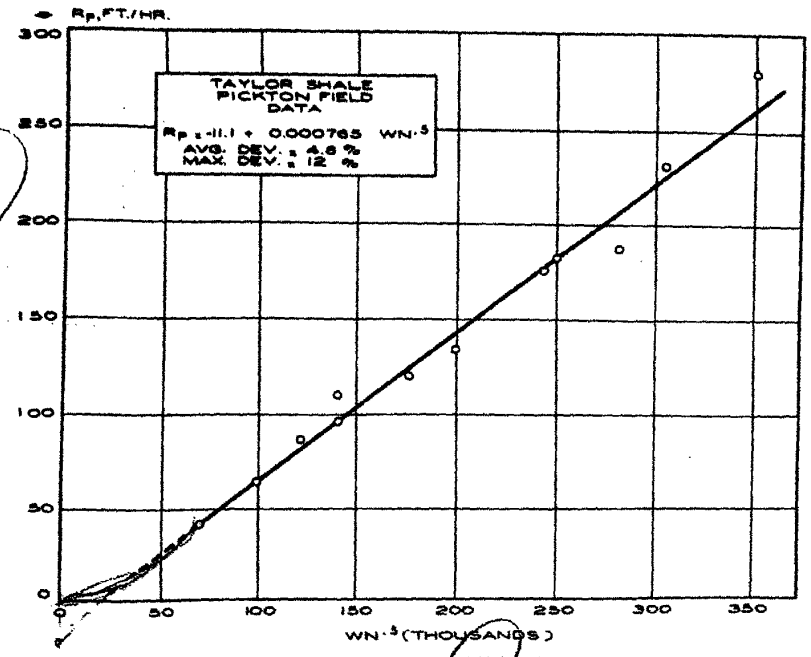

Fig. 8.12. Rate of penetration vs $WN^{1/2}$. Data of Fig. 8.10.

improper care and handling.[19,20] Since fatigue failures are related to both the number of stress reversals and the magnitude of the stress, it should be expected that both table speed and weight on bit will affect the frequency of such failures. Of the two, table speed seems to be the more critical, provided that excessive drill collar-hole clearance is avoided. The drill collars and the adjacent sections of drill pipe receive the worst punishment from vibrational loads; it is in these sections that most failures occur.

Theoretically, every drill string has a natural frequency at which vibrational effects are maximum. It is generally agreed that table speeds in resonance with this will result in severe vibrations and accelerated failure frequency. Main[21] has presented Eq. 8.6 for computing this critical speed range, based on certain simplifying assumptions. This formula has not, however, been widely applied.

$$N_c = \frac{258{,}000}{L} \tag{8.6}$$

where N_c = critical rotational speed at which vibratory effects are maximum, rpm

L = length of drill string, ft

Note: Higher order harmonic vibrations will also occur at $4N_c$, $9N_c$, etc.

Crane[22] has suggested a drilling practice based on a constant weight-times-speed factor. This criterion is in qualitative agreement with field practices: as weight is increased, the rotating speed is decreased. But the question arises, what is the limiting value which should be applied: WN = ?

A satisfactory solution in one area will not necessarily apply to another where conditions are different. It is, however, possible to estimate this factor from standard operating practices. For example, Figure 8.13 shows common operating weight-speed ranges for various bit sizes. Constant WN curves added to these approximate the operating trend with a reasonable degree of accuracy. The WN values shown were chosen arbitrarily in an attempt to approximate the indicated maxima. Speer[23] has also derived a similar solution for an *optimum* WN value; however, his curve falls above that suggested in Figure 8.13, and is not quite symmetrical. This approach will be shown later. If one assumes that these or similar data represent the current limiting conditions, then a constant WN factor appears to be a reasonable solution to the problem of allowable table speed–bit weight combinations. Other evidence indicates, however, that the constant weight-speed product approach may be used for determining an *optimum* N at a *given* W; however, it may be unsatisfactory for determining the proper W for a given N.[24]

Bit size may be eliminated as a factor from the suggested WN values of Figure 8.13 by again expressing bit loading as lb/in. of diameter:

$$wN = K \tag{8.7}$$

where $K \cong 5 \times 10^5$ lb-rpm/in., from Figure 8.13.

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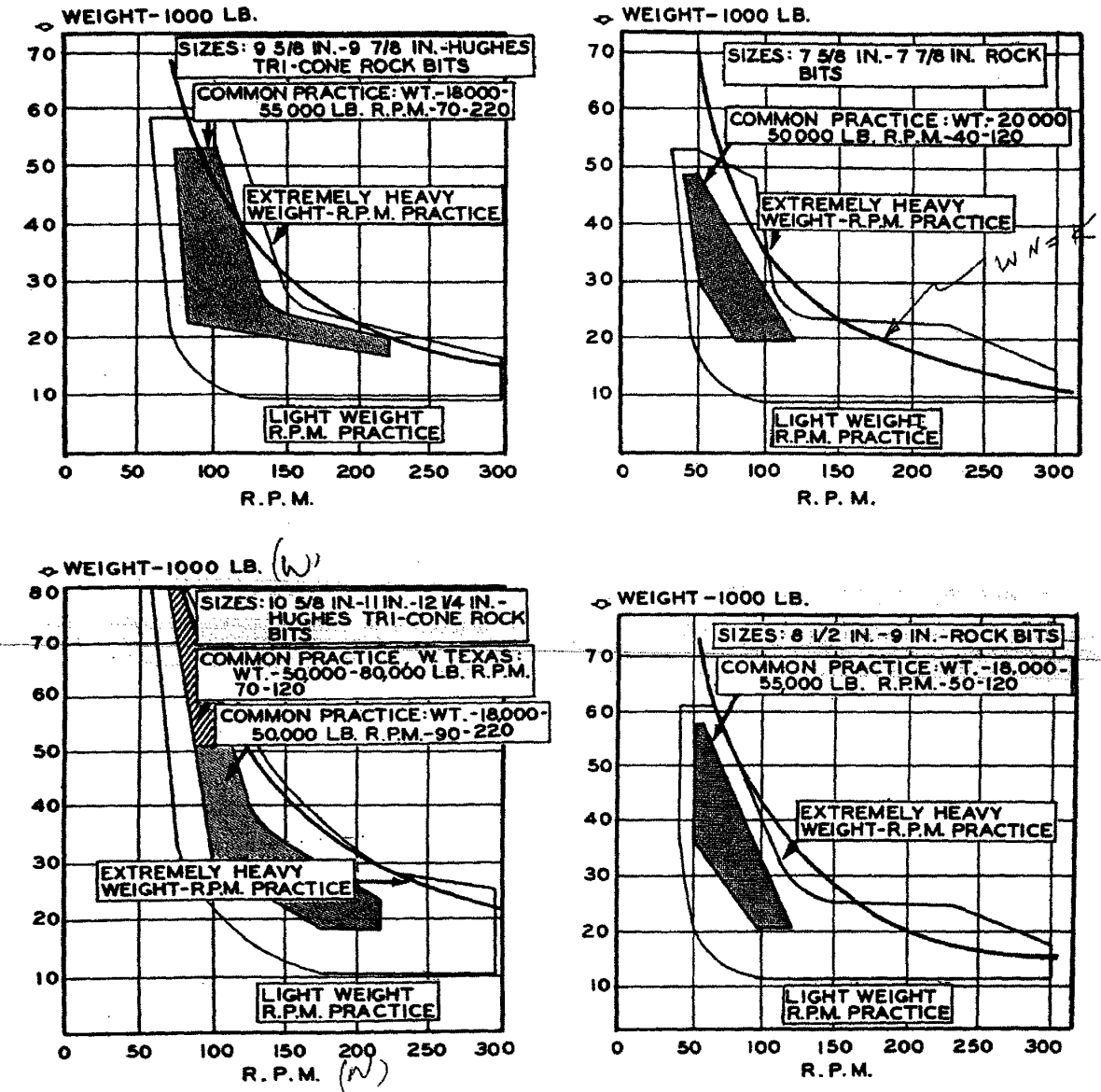


Fig. 8.13. Drilling practice curves showing applied range of weight and rotary speed combinations. Courtesy Hughes Tool Company. Curves of constant weight-speed product have been added as follows:

Bit size (in.)	WN
$7\frac{7}{8}$ to $7\frac{7}{8}$	3.6×10^6 lb-rpm
$8\frac{1}{2}$ to $9\frac{7}{8}$	4.0×10^6
$9\frac{1}{2}$ to $9\frac{7}{8}$	4.8×10^6
$10\frac{5}{8}$ to $12\frac{1}{4}$	6.4×10^6

Acceptable values of K will, in general, vary with bit size, since the smaller bits will not tolerate unit loadings as high as will the larger sizes. For the size range shown, however, there appears to be little difference in field practices.

Using Eq. (8.7) as a means of relating w and N, we may now alter Eq. (8.4) to

$$R_p = \alpha w^{1/2} = \beta N^{-1/2} \tag{8.8}$$

where $\alpha = fK^{1/2}$

$\beta = fK$

This relationship shows that penetration rate increases proportionally with $w^{1/2}$ and $N^{-1/2}$ if the product wN is restricted to a constant value. It must be realized that this entire treatment is empirical, and like most empirical equations, has a limited scope of applicability. The drilling practice curves indicate a range of applicability of $50 < N < 300$.

The uniformity with which the force W is applied to the bit is normally dependent on the driller's handling of the brake. The drilling line should be payed out smoothly so that the bit weight is constant. The ideal operation, if achieved, requires the full attention of the driller or another crew member. The use of an automatically controlled feed to insure constant bit loading has increased drilling rates by over 10% in hard rock areas.[16]

Bit Type

The precise nature of the drilling action of roller bits is quite involved and, is not, apparently, completely understood. As was mentioned in Chapter 5, soft formation roller bits have longer, widely spaced teeth with considerable cone offset. These impart a *drag bit cutting action* along with *nearly static percussive* effects. Thus the drilling action is a complex combination of two mechanisms. Hard rock roller bits have zero cone offset; thus they approach true roll, and hence drill by an essentially percussive process. Tooth stresses prohibit utilization of any large degree of shovelling or cutting action in hard rocks.

Numerous factors affect bit performance, such as tooth geometry (tooth type, wedge angle, spacing, row to row patterns, etc.), cone offset, number of cones, bearing designs, metallurgical control, etc. An informative paper concerning bit design factors is that by H. G. Bentson,[25] to which the reader is referred for detailed study.

Drag bits are little used for oil well drilling at this time. This decline in usage is not due to these bits' unsatisfactory cutting action; the drag bit is an efficient drilling tool, and is still widely used in the mining industry for small hole work. It seems logical that any rock which behaves plastically could best be drilled by this type of bit. For example, one can pound on modelling clay with a hammer and merely deform it; however, it is readily cut with a knife. Since at high confining pressures even the harder rocks may behave plastically, it again would seem that percussive bit action would be a poor choice, and that cutting or shovelling should be more efficient. The real problem has been to design a drag bit or an offset cone angle roller bit capable of standing the stresses and abrasive wear necessary for employing cutting action in hard, high strength rocks.

Diamond bits drill in much the same manner as drag bits, each stone acting as an individual tooth. Large stone, widely spaced patterns are used on relatively soft rocks; the hardest drilling requires smaller stones and more closely spaced designs. Usage of diamond bits is, of course, largely restricted to hard rock areas and/or deep wells where reduction in trip frequency is a prime aim.

8.5 The Effect of Drilling Fluid Properties on Penetration Rate

In Chapter 6 it was intimated that a drilling fluid property desirable for one function might be undesirable for other reasons, and that the mud selected was generally a compromise based on the considerations most critical to the area in question. This will become more apparent as we consider the effect of mud properties on the rate of penetration.

The effect of mud density has already been covered since it governs the pressure imposed on the hole bottom. This is probably the main factor contributing to the success of air drilling in such areas as depicted by Figure 8.14.[26] The effect of mud density is probably not completely expressed in terms of the pressure exerted by the mud column. Rather, it should be considered in terms of the pressure differential between the interstitial fluid pressure in the rock and the imposed pressure.[27] All rocks are porous, although some are so slightly porous that we consider them non-porous. Therefore, reconsider Figure 8.4 for the case where no mud column pressure is exerted. In this case, internal pressures

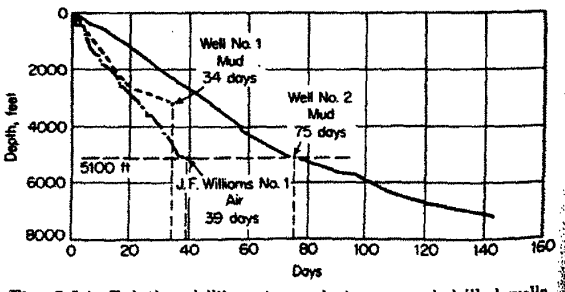


Fig. 8.14. Relative drilling times of air vs. mud drilled wells in Atoka County, Oklahoma. After Adams,[26] courtesy API.

within the rock will help remove the small element below the bit, and thus increase drillability.

Rapid removal of cuttings from below the bit allows each successive tooth impact to attack new rock; this, of course, leads to faster drilling. Research has shown that highly turbulent flow conditions at the hole bottom are desirable for this purpose.[28] Since density appears in the Reynolds number expression, it follows that, if all other factors are constant, an increase in density will decrease the bottom clearance time of cuttings. This is a minor effect as far as density is concerned, and does not warrant specific attention.

Solid Content

Many properties of a mud vary with its solid content and it is thus difficult to isolate data which relate specifically to this factor. It has long been observed in West Texas that very small amounts of clay solids in the drilling fluid greatly reduce the drilling rates obtainable by use of water. Such decreases are completely beyond those expected from the relatively small density increase, and it is apparent that other factors must be involved. More recently, it has been found that low-solids muds in which small quantities of CMC are wholly or partially substituted for larger quantities of bentonite allow increased drilling rates,[29] despite the fact that all other mud properties remain the same. It is then logical to assume that the solid content may itself be a separate factor. Perhaps the solid particles cushion the bit tooth-rock contact such that a clean, sharp impact is not obtained. At any rate, it is the opinion of many experts that the percentage of solids in muds exerts a separate and distinct effect on drilling rate.

Flow Properties

The same pumps are normally used for drilling the entire hole. This means that the available hydraulic horsepower must be essentially constant. An increase in yield point and viscosity increases system frictional losses thereby reducing the pressure drop (and velocity) which can be applied across the bit. Chip clearance time is thus increased and penetration rate decreased. Viscosity influences bottom hole turbulence in the same way; its effect on the Reynolds number is much more drastic than that of density, due to its wider range of values. For example, viscosity at bottom hole conditions commonly ranges from 0.50 cp for water to 50 cp for colloidal muds, a ratio of 100. Density variation for this same viscosity range might be from 8 to 16 lb/gal, or a ratio of 2. Therefore viscosity exerts a considerable effect on the attainment of turbulent flow.

Results from the laboratory experiments of Eckel[30] are shown in Figure 8.15. Here the relative drilling rate (based on the rate obtained using water as drilling fluid) is shown as a function of Stormer viscosity. Other variables including per cent solids and filtration rate were also involved, so that viscosity is not the only factor influencing results. For normal muds, viscosity and solid content are so interrelated that isolation of either factor is difficult. From the standpoint of lubrication between bit teeth and the rock, high viscosity causes high film pressures, and hence reduces the chances of having rock-to-tooth friction. Surface tension also enters these considerations.

The bit teeth must shear and displace drilling fluid before contacting the rock. The energy expended for this purpose is dependent on viscosity; very high viscosity muds may provide an effective viscous cushion which softens bit teeth impact. Yield point effects may be considered in regard to their contribution to apparent or equivalent Newtonian viscosity.

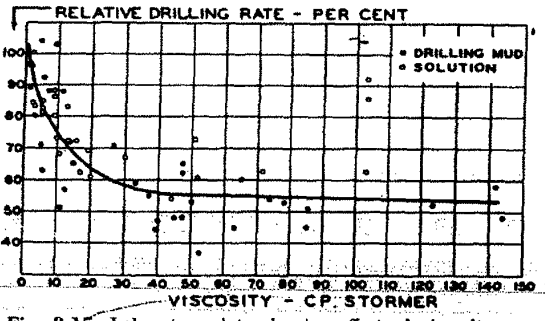


Fig. 8.15. Laboratory data showing effect of viscosity on drilling rate. After Eckel,[30] courtesy API.

Filtration Loss

The effect of filtration on the drillability of permeable rocks has been explained by Murray and Cunningham[7] in conjunction with their studies on hydrostatic pressure effects. They found that penetration rate was not affected by imposed borehole pressures if such pressures were equalized ahead of the bit. Water, for example, may readily enter a permeable rock ahead of the bit so that no pressure differential exists across the thin element being drilled. Low water loss muds, however, almost instantaneously deposit a tough, low permeability filter cake on the hole bottom, allowing a definite pressure differential to exist. This has two detrimental effects: the dynamic filtration pressure effect already discussed, and the requirement that the bit tooth penetrate the filter cake prior to contacting the rock. Also, the loosened cuttings are trapped in the pasty filter cake mixture and require longer bottom clearance times.

Figure 8.16 shows the observed effect of water loss on the penetration rate in shale. As stated by Cunningham and Goins,[31] it is difficult to explain this effect in almost impermeable rocks; however, even the extremely low

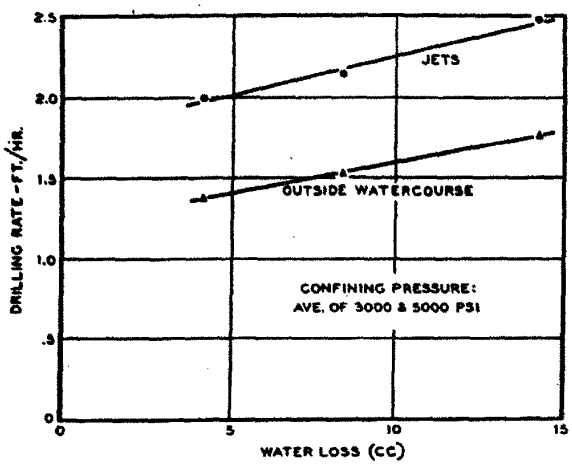


Fig. 8.16. Effect of water loss on drilling rates when drilling a Wilcox shale with a 1½-in. bit in a lime base mud. Laboratory data: bit weight — 750 lb; speed — 50 rpm. Each point is average of 24 tests. After Cunningham and Goins,[31] courtesy *Petroleum Engineer*.

permeability of shales may allow some pressure equalization effect. Also, the increased starch content used to reduce water loss could conceivably cause the observed behavior. Thus the low fluid loss which is desirable from the formation damage standpoint is undesirable from the standpoint of penetration rate.

Oil Content

It has long been observed in the field that the addition of oil to water base muds almost always improves penetration rate in virtually all types of rocks.[32,33] The largest increases appear to occur in the soft rock areas, with smaller increases being noted in hard rock

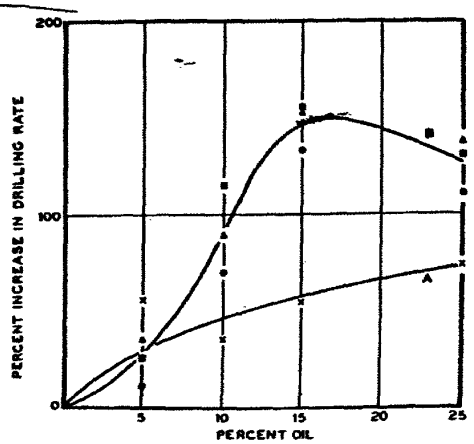


Fig. 8.17. Increase in drilling rate vs. oil concentration. Curve (A) is for a Vicksburg shale; curve (B) is for a Miocene shale (laboratory data). After Cunningham and Goins,[31] courtesy *Petroleum Engineer*.

drilling. Generally, these increases have been attributed to better lubrication (increased bit life), better bore-hole conditions (less enlargement, minimum heaving shale troubles, less hole-pipe friction and drag), and less bit balling by hydratable clays and shales. At present, it is considered that prevention of balling is the most important factor in soft rock areas.

Increased bit life means that less non-productive rig time is expended in making trips; thus the over-all penetration rate is increased. It has also been observed that increases in *on bottom* drilling rate are also obtained, despite the conflicting facts that oil additions to water base muds generally decrease water loss and increase apparent viscosity. Therefore, other factors exist

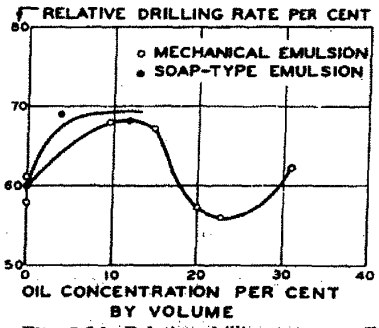


Fig. 8.18. Relative drilling rate vs. oil content — West Texas field data. After Eckel,[30] courtesy API.

which more than compensate for the latter detrimental effects. Density and solid content decreases may be compensating factors in some instances.

Laboratory test results showing the effect of oil percentage on the drillability of two Gulf Coast shales are shown in Figure 8.17. Note the optimum oil concentration for shale *B* which is not evident for shale *A*. This optimum percentage (shale *B*) compares very closely with the West Texas field data of Figure 8.18. Figure 8.19 shows the variation of drilling rate in Miocene shale (*B*) as a function of both oil content and jet velocity. This suggests that the optimum oil percentage may vary slightly with hydraulic conditions. In these tests much of the increased drilling rate was due to the decrease in balling shown in Figure 8.20. The presence of oil is thought to reduce balling by virtue of its preferential wetting of steel resulting in less clay-steel adhesion. A similar effect on the powdered, paste forming, shale particles may also contribute to reduced balling. Additional tests performed on powdered shale showed that the interstitial water content of the shale was insufficient to form a paste and that additional water was required for balling conditions. It should be noted that balling is evidently not the only factor involved, since penetration rate decreased above 15% oil content despite the

continued decrease of balling. Part of the increased drilling rate may be due to deeper tooth penetration for a given bit load when an oil film is present to reduce the rock-steel frictional coefficient.

Just why penetration rate does decrease at oil contents above an optimum value in some cases, or why it doesn't in others, is unknown at this time. Other factors apparently become dominant under proper conditions, and cause irregular drilling rate behavior. Available evidence shows that oil concentrations of 15 to 20% are optimum in many cases.

Surface Tension

Russian authors have reported that certain electrolytes and surface active agents act as rock hardness reducers with 30 to 60% increase in drilling rate being obtained by their proper use. Presumably, these

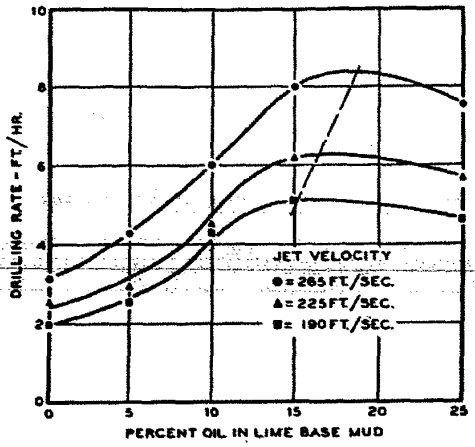


Fig. 8.19. Drilling rate vs. percent oil in a Miocene shale from Louisiana. Laboratory data: bit was 1¼-in., 2-cone jet, with 500 lb weight and 50 rpm. Hydrostatic pressure was 5000 psi. Each point is average of 16 tests. After Cunningham and Goins,[31] courtesy *Petroleum Engineer*.

materials act to produce more complete wetting of the rock by the liquid. This suggests that microscopic cracks, which tend to heal themselves after the bit load is released, may be held open by the wetting film of liquid; this would facilitate chipping by the next tooth impact.[28] Friction between bit tooth and rock would be reduced, also. Tests conducted by the Battelle group using sodium hydroxide solutions confirmed the results claimed by the Russian scientists.

The use of emulsifying agents in emulsion muds appears to affect drilling rate, in some cases. Lignites, salts of higher fatty acids, and other detergents or surfactants are common chemical emulsifiers. Hard rock drilling rates using fresh water have sometimes shown marked increases when surfactants were added

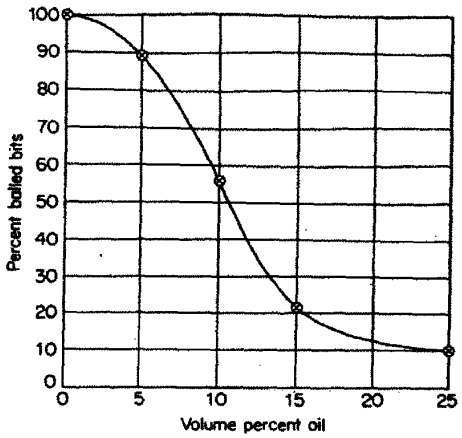


Fig. 8.20. Effect of oil content on the incidence of balled bits in laboratory drilling of Miocene shale. After Cunningham and Goins,[31] courtesy *Petroleum Engineer*.

to the water.[16] These increases were due to both increased bit life and higher on-bottom penetration rates. Both the type of detergent and the character of the rocks govern the effect obtained. It then appears that alterations in wettability and surface tensions play some part in rock drillability. This subject warrants further investigation and may offer some economic promise.

8.6 Hydraulic Factors

In this section we will be primarily concerned with the rapidity of cutting or chip removal from below the bit. Instantaneous removal of these particles is of course impossible; however, proper application of available hydraulic energy can minimize regrinding and increase penetration rate. This is the principle which has been stated earlier as pertaining to the widespread acceptance of jet bits. The jets themselves do not drill the hole but merely expedite cutting removal.

The effect of hydraulic factors on the drilling rate of drag-type bits has been rather extensively studied.[34–36] The principal conclusions from these studies were the following:

(1) Rate of penetration is directly proportional to nozzle velocity (at constant circulation rate)
(2) Rate of penetration is directly proportional to circulation volume (at constant nozzle velocity).

The direct proportionalities noted were due, essentially, to increases in the allowable weight on the bit resulting from better hole cleaning at the higher volumes and velocities. It should be noted that these results applied to soft rocks and drag-type bits. This type of drilling is carried on at relatively low bit loads, with penetration rate being almost entirely dependent on the drilling

fluid's ability to remove large cutting volumes and prevent bit balling.

The effects of hydraulic factors on rock bit drilling rates have also been investigated.[18,16,23,31,37–40] In soft and medium rocks, increases in penetration rate have generally resulted from increased hydraulic horsepower. Some question exists as to whether these increases correlate best with the impact of the jet stream as indicated by drag-bit experience, or with the hydraulic horsepower expended across the bit. *Impact force* depends on flow rate times velocity:

$$F = Mv = \frac{\rho_m q v}{60g} \tag{8.9}$$

where F = continuous force on bottom exerted by jet streams, lb

M = mass rate of flow, lb-sec/ft

ρ_m = mud density, lb/gal

q = mud flow rate, gal/min

v = nozzle velocity, ft/sec

g = 32.2 ft/sec^2.

Field data on penetration rate in soft and medium strength rocks are largely manifestations of increased weight on bit made possible by improved bit and bottom hole cleaning. Figure 8.21 shows the typical increases in bit weight facilitated by increased nozzle velocity, as experienced in California drilling. The curvature of the lines indicates balling, which becomes more severe as bit weight is increased.

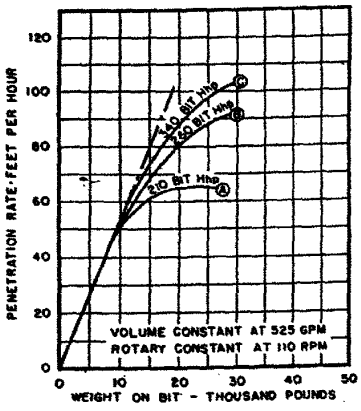


Fig. 8.21. Combined hydraulic and bit weight effect on penetration rate in California drilling. After Thompson,[38] courtesy API.

In hard rock drilling, the maximum bit weights applied are dependent on equipment considerations, rather than on bit balling. Consequently, it appears that increased nozzle velocity aids drilling rate by minimizing regrinding, with this effect disappearing as soon as no appreciable regrinding occurs. Nozzle velocities above this latter maximum effective value will result in no further increase in penetration rate. From results in West Texas, Bromell[39] has concluded that bit horsepower is an unimportant variable below penetration rates of 14 ft/hr, as long as adequate bottom hole cleaning is provided. Total pump horsepower may be reduced with no reduction in penetration rate resulting, if the circulation volume is cut down and the nozzle size is decreased, as shown in Table 8.1. The reductions are, of course, limited by the minimum annular velocity which may be tolerated.

TABLE 8.1

ILLUSTRATION OF CONSTANT PENETRATION RATE AT ESSENTIALLY CONSTANT BIT HORSEPOWER AND REDUCED CIRCULATION VOLUMES*

Surface pressure	*q, gal/min*	*Nozzle area, in.^{2}*	*Nozzle velocity, ft/sec*	*Required engine horsepower*	*Bit horsepower*	*Drilling rate, ft/hr*
1150	410	0.620	215	440	95	41.9
1125	345	0.488	230	340	90	41.3
1025	295	0.359	265	260	100	41.7

*After Bromell[39], courtesy API.

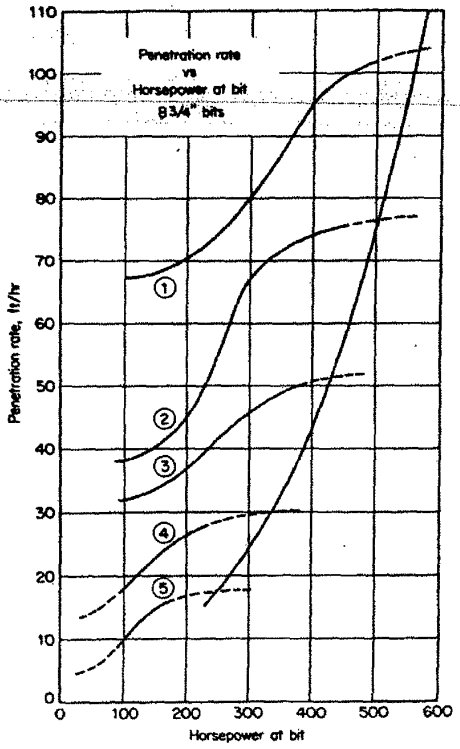


Fig. 8.22. *S* curve relationship between bit horsepower and penetration rate — Texas Gulf Coast area. After Keating,[40] courtesy API.

Considerable attention has been focused on the determination of minimum nozzle velocities which must be applied to make the use of jet bits advantageous over conventional types. It has been consistently demonstrated that penetration rate undergoes a sharp increase as jet velocity is increased through some critical range. Maximum benefit is obtained above the critical range, while lower velocities may prove less effective than normal circulation through conventional watercourse bits. Such relationships may be seen in Figure 8.22 which shows an S curve relationship between horsepower and drilling rate.[40] At low horsepowers, little cleaning is done, and little penetration benefit is obtained by increasing jet velocity. However, at some intermediate value, sharp rate increases are achieved from relatively small velocity increases. This effect diminishes as maximum cleaning is obtained, as indicated by the second slope reduction at the top of the S.

Minimum nozzle velocities of 200 to 250 ft/sec appear to be necessary in order to obtain substantial drilling rate increases in most rocks. Maximum nozzle velocities are not so well defined and have probably not been attained for soft rock drilling. The practical limit is imposed by available horsepower and nozzle erosion. Maximum values proposed for any case must depend on the bottom cleaning required; this is a function of bit type, the nature of the rocks being drilled, the rotary speed, and the weight on the bit.

It is apparently not possible to develop any general mathematical relationship between drilling rate and bit hydraulics which will fit all situations. The best operation will, in most cases, be a program which utilizes maximum bit horsepower at all times. In general, the available pump horsepower is constant; therefore, since the drill string losses increase with depth, the available bit horsepower decreases with depth:

$$\text{(1)} \qquad HP_B = HP_t - HP_x$$

where HP_B = bit horsepower

HP_t = total pump horsepower

HP_x = system horsepower exclusive of bit

Since

$$\text{(2)} \qquad HP_t = \frac{q\Delta p_t}{1714}$$

$$\text{(3)} \qquad q\Delta p_t = \text{constant}$$

The circulating rate, q, is governed by hole size and minimum allowable annular velocity, and is often treated as a constant in a given case. Thus for these operational restrictions, the total pressure drop, Δp_t, must also be constant. Example 8.1 illustrates this approach.

Example 8.1

Constant HP, Minimum q
Hole size = 8¾ in.
Drill pipe = 4½ in., 16.6 lb, IF.
Drill collars = 500 ft long, 6¾ in. o.d., 2¼ in. bore
Bit = 3 cone, jet type, rolling cutter rock bit
Pump capacity = 400 HP (output)
Required annular velocity = 150 ft/min (from experience)

Calculate (1) Operating conditions for utilization of 400 HP, (2) Nozzle size at 6,000 ft depth, (3) Nozzle size at 11,500 ft depth.

Solution:

In lieu of more specific data we will assume the mud properties of the Hughes charts in Chapter 7.

(1) $$q = 2.45(d_h^2 - d_p^2)\bar{v}_A$$
$$= 2.45[(8.75)^2 - (4.5)^2](150/60)$$
$$= 350 \text{ gal/min}$$

Since

$$HP = \frac{q\Delta p_t}{1714}$$

$$\Delta p_t = \frac{(1714)(400)}{350} = 1960 \text{ psi}$$

These are then the imposed operating limits for circulating volume and pressure.

(2) Calculating hydraulic losses,

Δp_s = 20 psi (Figure 7.3, #3)
Δp_p = 220 psi (Figure 7.5, #7)
Δp_c = 100 psi (Figure 7.7, 2¼ in.)
Δp_{ac} = 26 psi (Figure 7.11, 6¾ in.)
Δp_{ap} = 55 psi (Figure 7.11, 4½ in.)
Δp_x = 421 psi
Δp_b = 1960 − 421 = 1540 psi

From Figure 7.9,

A_N = 0.260 in.² = total area of 3 nozzles;

hence

$$d_N = \left(\frac{4A_N}{3\pi}\right)^{1/2} = 0.332 \text{ in.}$$

The nearest larger stock nozzle size would normally be selected.

(3) At 11,500 ft,

Δp_s = 20 psi (same as above)
Δp_p = 440 psi (twice)
Δp_c = 100 psi (same as above)
Δp_{ac} = 26 psi (same as above)
Δp_{ap} = 110 psi (twice)
Δp_x = 696 psi
Δp_b = 1960 − 696 = 1264

Hence,

A_N = 0.290 in.²
d_N = 0.351

Note that nozzle size is relatively insensitive to depth changes under these conditions.

We now consider a second approach in which total pressure loss, Δp_t, is held constant at some maximum value as dictated by pump and/or surface connection ratings.[34,41,42] The flow rate q will be treated as a restrained variable free to vary above some minimum value, i.e., $q \geq q_{min}$; where q_{min} depends on the necessary annular velocity and hole-pipe clearance.

Assuming turbulent flow and that annular losses are relatively small, we may write:

$$\Delta p_x = K_1 q^{1.86} \tag{4}$$

where K_1 is dependent on pipe length, size, tool joint, and mud properties, but is constant for a given set of operating conditions. The power expenditure is

$$HP_x = \frac{q\Delta p_x}{1714}$$

$$\therefore \quad HP_x = \frac{K_1 q^{2.86}}{1714} \tag{5}$$

Also,

$$HP_t = \frac{q\Delta p_t}{1714} \tag{6}$$

Substituting Eqs. (5) and (6) into Eq. (1), we arrive at an expression for bit horsepower:

$$HP_B = \frac{q\Delta p_t}{1714} - \frac{K_1 q^{2.86}}{1714} \tag{7}$$

Differentiating (7) with respect to q, noting that Δp_t = constant, and solving for maximum Δp_B which is the desired operating condition:

$$\Delta p_x = 0.35\Delta p_t \tag{8.10}$$

or

$$\Delta p_b = 0.65\Delta p_t \tag{8.10a}$$

This shows that bit horsepower is maximum when approximately 65% of the total pressure drop occurs across the bit, pump pressure being constant. It is generally desirable to operate with maximum bit HP, if feasible. We must now determine some rational expression for the corresponding value of q. This is readily obtained from Eq. (8.10), since Δp_t is known from pump rating, etc.

$$\Delta p_x = K_1 q^{1.86} = 0.35\Delta p_t$$

from which

$$q_0 = 0.57\left(\frac{\Delta p_t}{K_1}\right)^{0.54} = \text{optimum } q \tag{8.11}$$

This expression allows calculation of the corresponding nozzle size, since from Chapter 7,

$$\Delta p_b = \frac{\rho q_0^2}{7430 C^2 d_e^4} \tag{7.13}$$

where ρ = mud density, lb/gal

C = nozzle coefficient = 0.95 for jet bits

d_e = hydraulically equivalent single nozzle diameter, in.

Substituting $\Delta p_b = 0.65\ \Delta p_t$, $C = 0.95$, and solving for d_e

$$d_e = 0.123\, q_0^{1/2}\left(\frac{\rho}{\Delta p_t}\right)^{1/4} \tag{8.12}$$

Example 8.2 Constant Pressure Operation

Let us rework Example 8.1 assuming the same pipe sizes, etc., and a depth of 6000 ft. This time we will let $\Delta p_t = 2000$ psig and q vary, according to our recent discussion. Immediately we see that $\Delta p_x = 700$, and $\Delta p_b = 1300$ psig.

Solution:

$$q_0 = 0.57\left(\frac{2000}{K_1}\right)^{0.54}$$

To determine K_1 we must consider both the drill pipe and drill collar section.

It can be shown (see Problem 6b) that

$$\Delta p_p + \Delta p_c = \Delta p_p\left[1 + \frac{L_c}{L_p}\left(\frac{d_p}{d_c}\right)^{4.86}\right]$$

where L_c, L_p = length of drill collars and pipe, respectively, ft

d_c, d_p = internal diameters of same, in.

Since

$$\Delta p_p = \frac{0.58 q^{1.86} L}{1000 d^{4.86}} = \text{turbulent pressure loss inside pipe, psi, according to Hughes charts (see Problem 6)}$$

It can be shown (see Problem 6b)

$$K_1 = \frac{0.58 L_p}{1000 d_p^{4.86}}\left[1 + \frac{L_c}{L_p}\left(\frac{d_p}{d_c}\right)^{4.86}\right]$$

Substitution of values yields

$$K_1 = \frac{(0.58)(5.5)}{(3.83)^{4.86}}\left[1 + \frac{0.5}{5.5}\left(\frac{3.83}{2.75}\right)^{4.86}\right] = 0.00682$$

Solving for q_0:

$$q_0 = 0.57\left(\frac{2000}{0.00682}\right)^{0.54} = 507 \text{ gal/min}$$

The corresponding nozzle size is

$$d_e = 0.123(507)^{1/2}\left(\frac{9.5}{2000}\right)^{1/4} = 0.728 \text{ in.}$$

Assuming 3 equal size nozzles, the actual size of each should be:

$$d = \frac{0.728}{\sqrt{3}} = 0.42 \text{ in.}$$

It is interesting to compare this solution to that of Example 8.1.

Ex. 8.1	$\Delta p_b = 1540$ psi,	$HP_b = 314$
Ex. 8.2	$\Delta p_b = 1300$ psi,	$HP_b = 384$

We note that the bit pressure loss has dropped 240 psi, but due to the increased flow rate (and total input HP), the bit power has been increased by 70 HP. Actually, Example 8.1 is the more efficient, in terms of per cent of input power utilized at the bit; however, bit HP is less.

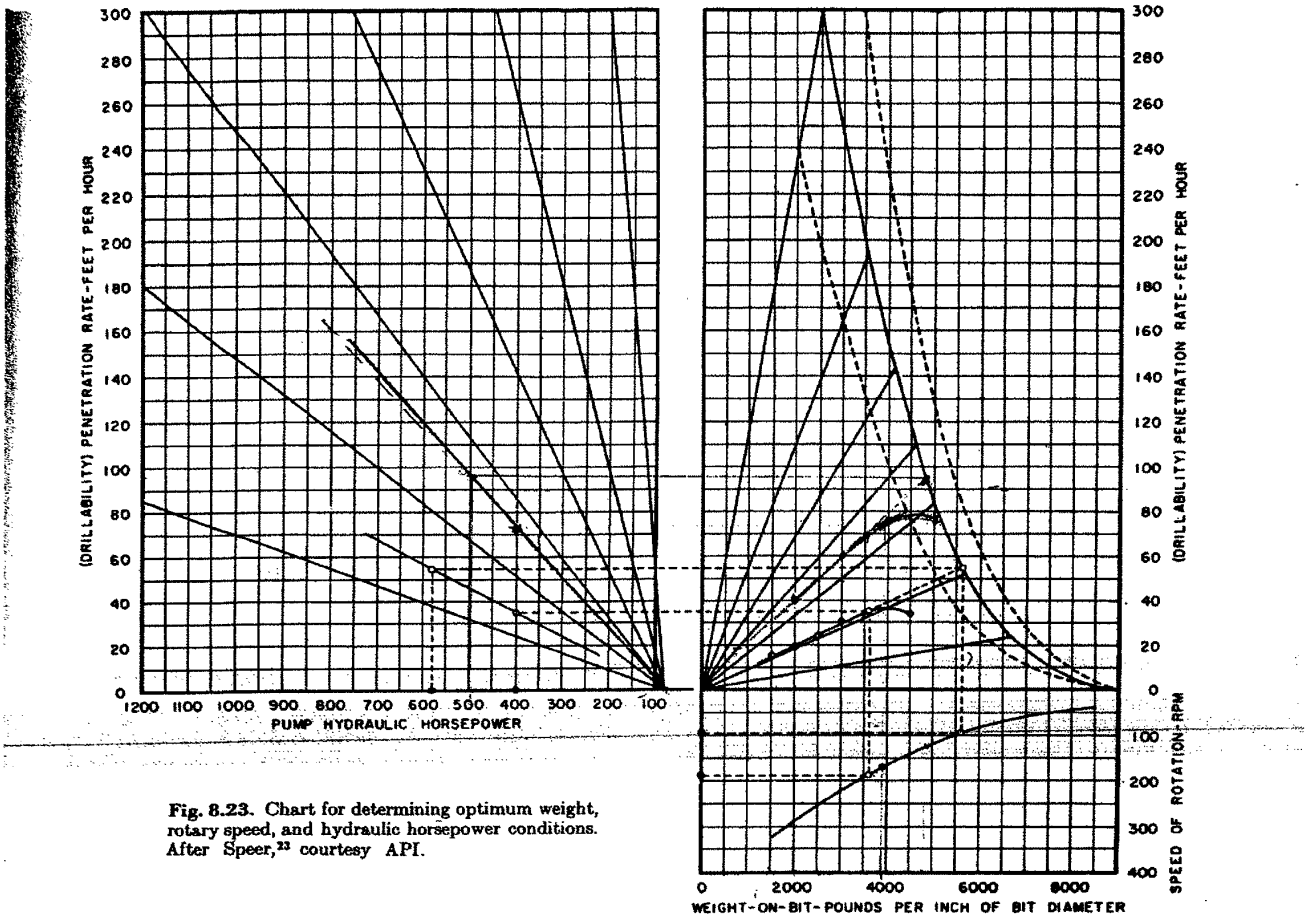


Fig. 8.23. Chart for determining optimum weight, rotary speed, and hydraulic horsepower conditions. After Speer,[23] courtesy API.

Depending on the situation, rig equipment, etc., either approach may be desirable. In some cases constant pressure operation (variable q and HP) may be permissible to some particular depth at which point the optimum rate may become less than the minimum value permissible for hole cleaning. If this occurs, the operation necessarily changes to that for constant HP case. The article by Colebrook[42] contains a number of useful curves illustrating the effect of certain variables on constant pressure operation.

Neither of these approaches may be desirable in hard rock drilling where maximum benefit from bottom cleaning may be obtained at a lower hydraulic level than that predicted by either method. This is well illustrated by Bromell's data in Table 8.1.

An over-all approach to selection of optimum drilling conditions has been developed by John Speer[23] who has presented a comprehensive analysis of a large number of data. This method is illustrated by Example 8.3 which is solved graphically with Figure 8.23.

Example 8.3 (After Speer[23])

A certain rig is available to drill a 1,000-ft homogeneous shale section. It is desired to determine: (a) optimum operating conditions for the available rig; and (b) the equipment required to drill the shale section most economically. The given parameters are as follows:

1. 400 HP pump
2. 4½-in. drill pipe
3. 9⅞-in. hole
4. three ½-in. bit nozzles

When the shale section is drilled, short-duration tests of weight vs. penetration rate are made (1) to establish a drillability index for the formation and (2) to determine at what weight the bit begins to ball up with the available pump (a tentative index must first be established to select an appropriate rotary speed). These test values are plotted on the weight vs. penetration rate chart (upper righthand section) and an

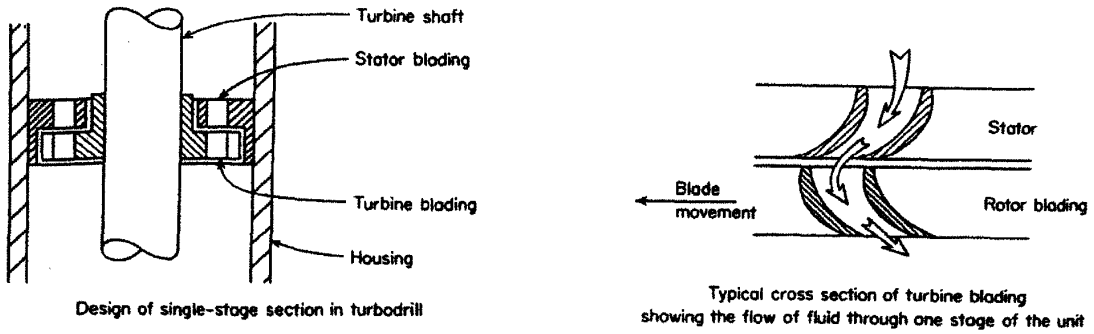


Fig. 8.24. Elementary diagram of turbine components. After LeVelle,[44] courtesy *Petroleum Engineer*.

appropriate curve is drawn through them. The low weight section of this curve should be linear until the bit begins to ball up. From the point on this curve where the bit begins to ball up, a horizontal line is drawn left to intersect with 400 HP. The single point thus obtained is sufficient; a linear relationship can now be drawn between hydraulic horsepower and penetration rate for this shale section. It will be noticed that this index is in a sense dimensionless, inasmuch as it includes hole size, type of bit, drillpipe size, etc. As a next step, a vertical line is drawn from the weight where the bit begins to ball up downward, to intersect with the *optimum* W vs N curve. The intersection shows that this formation would be most economically drilled with a weight of 3600 lb/in. of bit diameter (35,000 lb) and 190 rpm rotary speed, with the 400 HP pump.

Now return to the weight vs. penetration rate index, and extend the linear section of the curve to intersect the optimum weight on bit curve. From this point, a horizontal line is drawn left to intersect the hydraulic horsepower index curve already established for this formation. This intersection gives the hydraulic horsepower required to maintain sufficient bottom-hole cleaning to permit use of optimum weight. A vertical line is also drawn downward to determine optimum speed of rotation for the new weight. These manipulations show that minimum footage cost could be achieved in this formation with a 580 HP pump, used in conjunction with a weight of 5,600 lb/in. of bit diameter (55,000 lb) and 95 rpm. By working backwards from the hydraulic horsepower index curve, the best weight and rotary speed practices for any hydraulic horsepower can also be determined in the same way.

Inspection of Figure 8.23 shows this method to be based on the linear relationship of hydraulic horsepower and penetration rate. This premise has been questioned by Moore[43] who, among others, feels that hydraulic effects are best expressed by impact force (Eq. 8.9).

The reader should not infer that any of the various empirical expressions presented in this chapter are infallible. They are presented as means of estimating the effect of certain factors; the refinement of various parameters must be attained under individual well conditions.

8.7 Other Drilling Methods

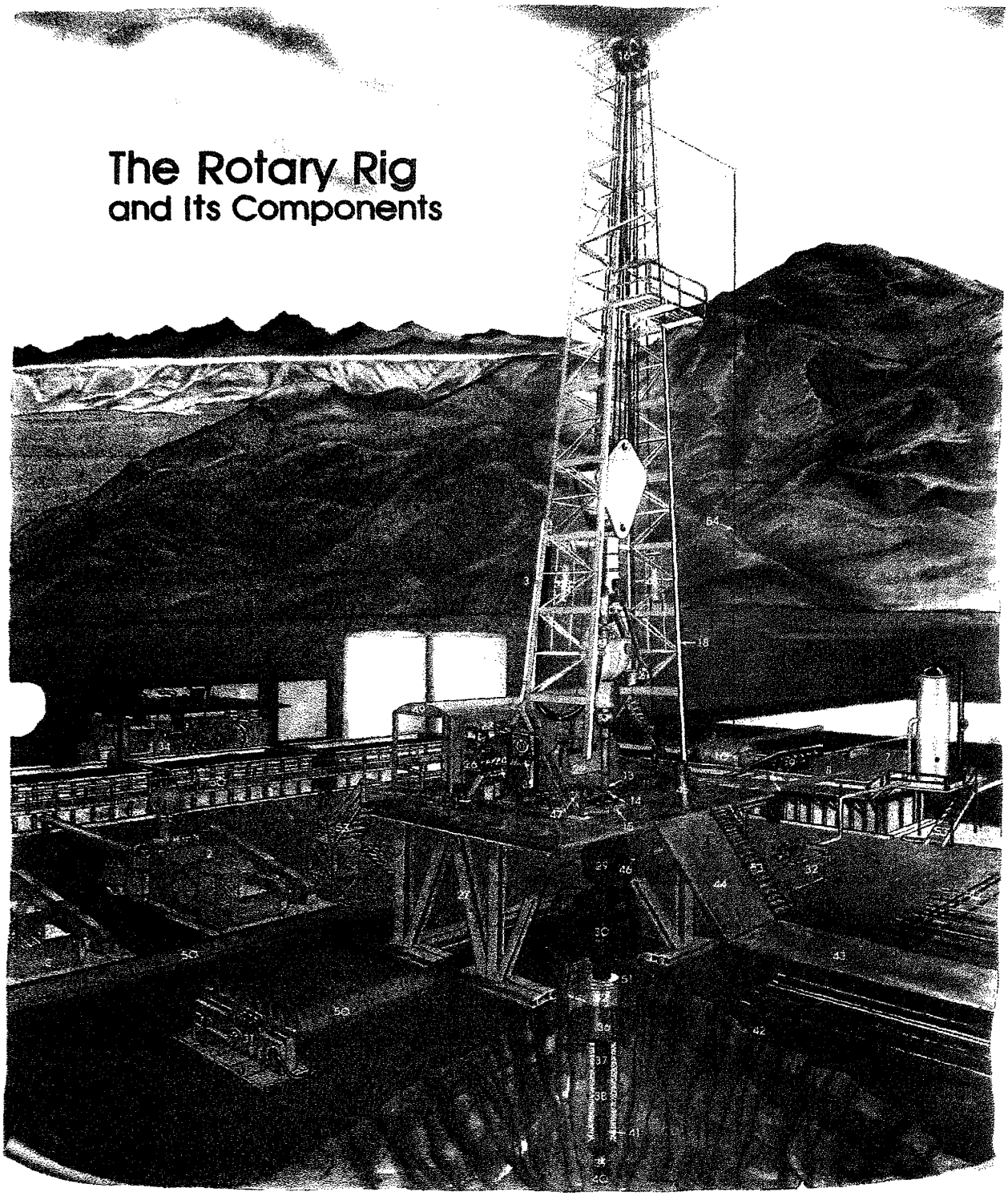
While considerable effort has been exerted to increase conventional drilling rates, the possibility of developing other drilling methods has not been ignored. These range from mere variations of the conventional rotary technique to radical departures from basic methods. The future application of any new technique will depend on the standard American question: can it do the job more efficiently?

8.71 The Turbodrill

The turbodrill is a rotary drilling device employing the same basic mechanism as the conventional method. The principal difference is that the bit's rotation is provided by a down hole multistage turbine which is powered by the drilling fluid; thus rotation of the drill string is eliminated. The turbine section contains matching sets of stators and rotors, each pair being referred to as one stage. Current models utilize 100 or more stages. Drilling mud is deflected by the stator and strikes the rotor blades, causing them to rotate (see Figure 8.24).[44] The design principles governing nozzle and blade angles are the same as in other types of turbines. Variations in these factors allow the design of turbines with different operating characteristics as dictated by different applications. Figure 8.25 is a cutaway view of the French (Neyrpic) model which has had considerable success in European tests.[45]

Turbodrills are not new as far as the idea of their application to drilling is concerned. The first patent relating to turbodrilling was issued to C. G. Cross in 1873, almost thirty years before the use of rotary tools in oil well drilling. Subsequent development in this country was sporadic; although various turbodrill designs were developed and field tested, they are generally unsuccessful.[46,47] The main failing of American designs

The Rotary Rig
and Its Components



ULATING SYSTEM

Mud pits
Mud pumps
ipe
hose
ad components
s
return line
Shale shaker
Desilter
Desander
Degasser
Reserve pits

ROTATING EQUIPMENT

12. Swivel
13. Kelly
14. Kelly bushing
15. Rotary table

HOISTING SYSTEM

16. Crown block and water table
17. Monkeyboard
18. Mast
19. Traveling block
20. Hook
21. Elevators
22. Drawworks
23. Cathead
24. Brake
25. Weight indicator
26. Driller's console
27. Substructure
28. Drilling line

WELL-CONTROL EQUIPMENT

29. Annular blowout preventer
30. Ram blowout preventers
31. Accumulator unit
32. Choke manifold
33. Mud-gas separator

POWER SYSTEM

34. Power-generating plant
35. Fuel tanks

PIPE AND PIPE-HANDLING EQUIPMENT

36. Conductor pipe
37. Surface casing
38. Drill pipe
39. Drill collars
40. Drill bit
41. Annulus
42. Pipe racks
43. Catwalk
44. Pipe ramp
45. Rathole
46. Mousehole
47. Tongs
48. Tong counterweights

MISCELLANEOUS

49. Doghouse
50. Walkways
51. Cellar
52. Casinghead
53. Stairways
54. Hoisting line
55. Gin pole

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