

# Achieving “Peak” Drilling Performance Through Optimized Wellbore Hydraulics

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## Abstract

In well planning and construction, design engineers often give limited or even cursory attention to well bore hydraulics, frequently delegating the calculations to a service company. In part this is due to other demands on time and lead times on capital goods, and in part is due to imperfect understanding and accuracy of traditional models.

During drilling operations, well bore hydraulics are not often improved as drilling proceeds but are used as originally designed.

Simple methods to ensure hydraulics start on a firm foundation, and straightforward real-time optimization techniques are presented that can improve overall well economics by:

- Improving rate of penetration
- Minimizing downtime due to poor hole cleaning and stuck pipe
- Reducing environmental loading by reduction of fuel usage
- Prolonging bit life, permitting in most cases, a more aggressive bit to be used
- Maximizing rig equipment life, especially related to mud pumps, thus making these improvements “win-win” for both the operator and the drilling contractor.

Additionally, the combined effects of well bore hydraulics and drilling rates on bottom hole circulating pressures will be examined—of extreme importance to critical wells where the window between pore pressure and fracture pressure may be extremely narrow and difficult to navigate.<sup>1</sup>

## Introduction

Broadly speaking, the subject of hydraulics may be broken down into two closely related divisions. The first of those divisions is referred to as well bore hydraulics, that relates flow rate, fluid density, geometry, bit nozzles, fluid viscosities and other factors’ effects on total pressure needed to circulate.

The second category of the issues relates to hole cleaning. Hole cleaning is perhaps the number one preventable cause of trouble in drilling operations today.

We will consider these two items in reverse order.

## Hole Cleaning Issues

Poor hole cleaning in vertical wells, from whatever root cause problem, can lead to a plethora of costly well problems, ranging from inefficiencies and slow drilling to total loss of the hole. Vertical wells have a different set of challenges than deviated ones to overcome. While not as much of a technical problem in vertical holes as in deviated ones, the consequences may be just as severe in either well type.

### Vertical Hole Sections

For years drillers have focused on two primary factors when faced with vertical hole cleaning problems: Drilling fluid viscosity and annular velocity. Standard ways of “listening to the well” for indicators of hole cleaning effectiveness have related primarily to examination of the size, shape, and quantity of cuttings returning to the surface.

When cuttings were reporting to the surface in the correct quantities (approximating the volume of rock drilled), were visually sharp-edged, and were reasonable sizes corresponding to different bit types, then hole cleaning was acceptable.

In contrast, if the shaker screens had little or no cuttings, either at all or from time to time, the volume was too low. Smaller and or rounded cuttings indicated excessive recirculation of the cuttings in the annulus and correspondingly poor hole cleaning.

Depending on the well, this poor hole cleaning may or may not have been critical. A relatively short duration and shallow well can tolerate some amount of cuttings buildup without experiencing overt problems such as lost returns or stuck pipe. However, even in these forgiving situations, the absence of proper hole cleaning results in a poor mud system performance (often indicated by a very high plastic viscosity), and less drilling efficiency.

In more critical wells, perhaps such as deep, hot wells or those with very narrow fracture pressure by pore pressure windows, the results of poor hole cleaning could be catastrophic.

Other problems associated with poor mud performance and poor hole cleaning might include:

- Slow drilling ROP

- Premature bit failure and wear
- Premature mud pump wear
- Poor filter cake performance
- Poor cementing

Further, poor mud properties and high plastic viscosity (fundamentally caused by grinding and pulverizing and degrading of cuttings before they are removed by the surface solids control equipment), has been blamed for poor well productivity and shorter economic life. In today's competitive environment, risk of such issues or even simply poor drilling efficiency cannot be long tolerated.

Importantly, if good hole cleaning was not being achieved, it has historically been and in some operations continues to be a somewhat inexact art as to how the mud engineer might attempt remedy the problem. Raising the viscosity is an obvious solution along with higher flowrates, but the inexact nature of how this is done often results in overshooting on viscosity, flowrates, or both, along with a corresponding waste of expensive chemicals and pumping resources.

### CCI and Transport Ratio

Two of the more important concepts worth brief review are the Sifferman's Transport Ratio<sup>2</sup> and Robinson's Carrying Capacity Index<sup>3</sup> (CCI).

The Transport Ratio is a measure of how cuttings settle or recirculate in the annulus relative to a unit of drilling fluid traveling up the wellbore. 100% perfect hole cleaning, or a Transport Ratio of 1.0, would indicate that the cuttings traveled at the same speed as the bulk annular fluid velocity. Put another way, there would be zero slippage or recirculation of the cuttings relative to the mud.

$$\text{Transport Ratio} \stackrel{\text{def}}{=} \frac{V_C}{V_A} \quad \text{Eq. 1}$$

Where  $V_C$  is the velocity of the cuttings and  $V_A$  is the velocity of the bulk drilling fluid. If the Transport Ratio may be thought of as a measure of perfection, then the CCI may be thought of as a measure of how much hole cleaning is enough to stay out of trouble from well problems such as stuck pipe. It was developed as a practical tool for rig-site and office personnel alike to quickly use and monitor.

$$\text{CCI} \stackrel{\text{def}}{=} \frac{K \times AV \times MW}{400,000} \quad \text{Eq. 2}$$

Where:

$K$  is the low-shear rate viscosity, equivalent cP,  $AV$  is annular velocity, feet per minute, and  $MW$  is mud weight, pounds per gallon. 400,000 is simply a normalizing constant and is not a conversion factor. It was found that by simply multiplying the three numerator terms together, if the resulting value was 400,000 or greater, hole problems related to hole cleaning were unlikely. Putting the 400,000 in the denominator

forces the CCI to be 1.0 at the no-hole-problem level. A value less than 1.0 indicates a higher risk of hole cleaning related hole problems, with higher risk associated with lower values below 1.0.

Though slightly more complex than the Transport Ratio, all variables relate to standard information found on nearly all drilling morning reports. (See Nomenclature section for more

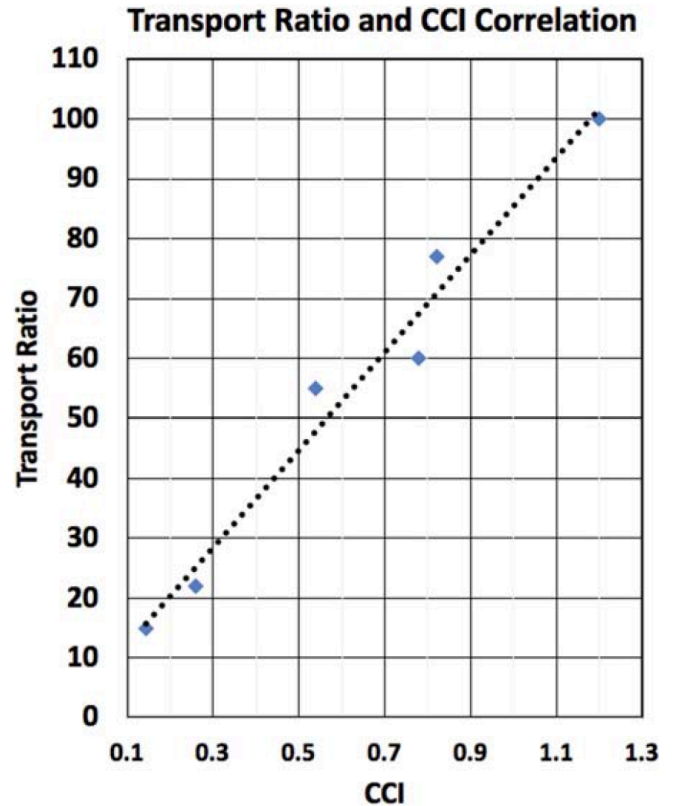


Figure 1 - Correlation between Transport Ratio and CCI

details). Though the Transport Ratio and the CCI were examining different aspects of hole cleaning, there is a tight correlation between the two as shown in figures 1 and 2 nearby.<sup>4</sup>

Robinson's CCI sets a practical goal of 1.0 in order to minimize hole cleaning related trouble costs, while Sifferman's Transport Ratio effectively sets an upper limit on hole cleaning efforts ( $TR=1$ ) corresponding to a CCI of approximately 2.5. Any additional viscosity or velocity above that point is, frankly, wasted and does not improve hole cleaning.

Conversely, since increasing viscosities and flow rates both increase annular pressure losses, down hole pressure and the overbalance at the bottom of the hole increase, leading to both lower rates of penetration and higher risk of lost returns and differentially stuck pipe. Further, formation damage can be increased due to bottom hole pressure being higher than necessary.

### "Cuttings Block"

Examination of equation 2 shows that as annular velocity increases in the numerator, the CCI value increases. Decreasing velocity in the annulus decreases the CCI value. This leads to an interesting problem in rugose wellbores where the enlarged hole section may be 50-100% or more diameter than the as-drilled hole diameter.

The success of the CCI also yields potential insight into real world cases where good hole cleaning eludes the well-construction team even though design and execution seem adequate or even robust.

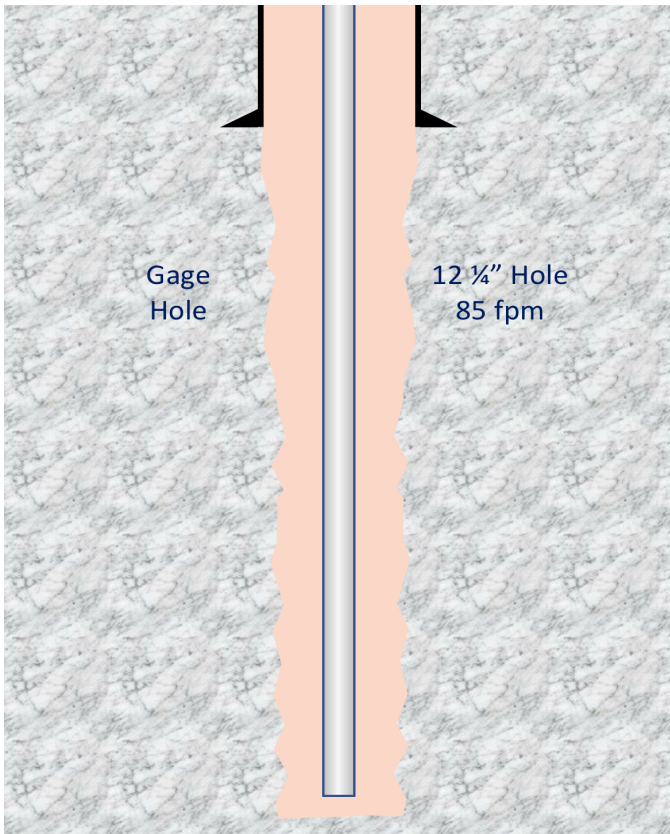


Figure 2 - Relatively Gage Borehole, CCI = 2.4

Calculations with CCI are ordinarily done assuming a gage or gun-barrel hole. However, if the mud viscosity and mud weight remain constant (which they effectively do over short hole intervals) while the diameter expands dramatically, then the CCI value can plummet over a limited section of the well bore.

For example, assume that we are drilling a 12.25 in. hole with a 5 in. drill string. We have computed the AV to be 85 ft/minute and know that the MW is 13.2 ppg and the K viscosity is 850 cP. With these parameters, we calculate the CCI value to be 2.4. We are having no hole-cleaning problems.

After drilling a few hundred more feet, cuttings coming back across the shaker decrease and then stop completely. Parameters show that full mud returns are still reporting to the surface and flow rate, drilling rate and mud properties are the same.

What happened?

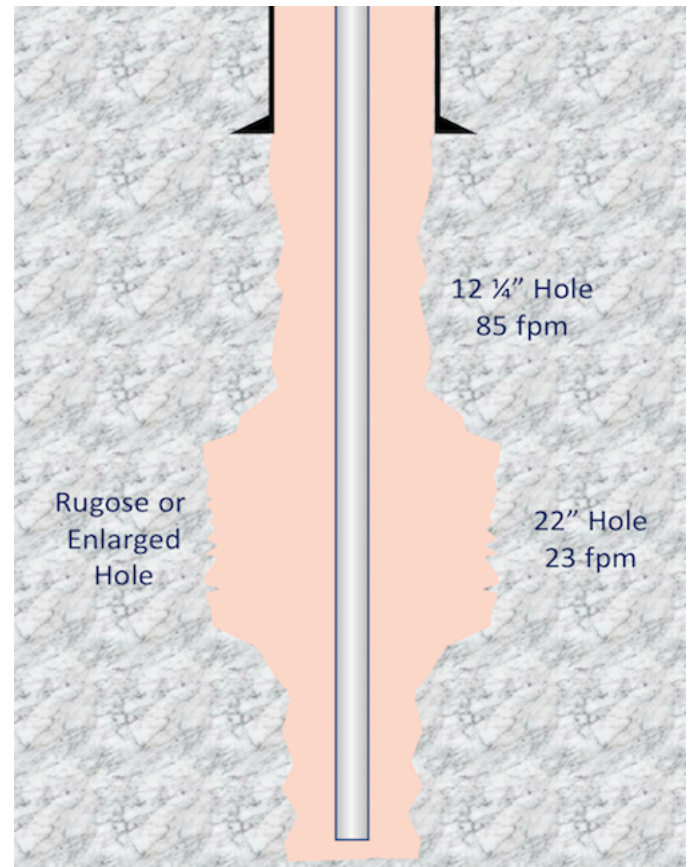


Figure 3 - Rugose or "Washed out" Hole Enlargement, CCI = 0.6

An enlarged wellbore may be the culprit. Let us assume the wellbore for 50 ft or so has enlarged (usually due to either unconsolidated rock or the more common case of a "chemical attack" on the formation rock by the water in the mud) to about 22 in. from the original 12.25 in. This raises the cross-sectional flow area in that 50-ft length enlarged wellbore section by a factor of 3.7, which in turn reduces the CCI value for that section to 0.6! While the CCI in the 12.25 in. section is robust, the ability of the mud to lift cuttings through and past the 22 in. enlarged section is very poor.

In extreme cases of hole enlargement, this can lead to a *de facto* "cuttings block" effect where cuttings will have accumulated and tumbled and degraded until small enough to be lifted out of the wellbore.<sup>5</sup>

In cases where the cuttings cannot be carried past the low velocity rugose or "washed out" hole section, they will accumulate and degrade until either they can be carried out, or trouble occurs, or the problem is recognized, and remedial action is taken.

The remedial action is a matter of choice by the rig site and office based personnel. Typically this includes raising the annular velocity by speeding up the pump as a first response, followed by viscous pills or sweeps. Thickening the mud over the next few hours as the mud engineer can accomplish this with

the mud system being used and the pore pressure/fracture pressure constraints of the well.

In the cuttings block example situation above, the initial CCI was quite robust. However, if the original gage hole CCI had been 1.0, then the resulting CCI in the enlarged section would be a mere 0.27, certainly insufficient to clean the hole reliably.

### Deviated Hole Sections

In wellbores with deviation from vertical greater than 30 degrees, additional care must be taken to ensure adequate hole cleaning. The cautions regarding CCI must still be honored, as essentially all wells still have a vertical section in them. However, due to Boycott Settling<sup>6</sup> and related issues, additional practical parameters should be monitored.

In Boycott settling, heavier cuttings and weighting material can fall to the low side of the wellbore. Once the solids of both types are on the low side wall of the well, it is nearly impossible to get those particles moving and suspended in the mud without physical stirring of some sort. Viscous pills do not work, largely due to the shear-thinning nature of most of our drilling muds. That is, the highest shear rate (described as the flow streamline velocity difference divided by the distance between the streamlines) the mud sees is at the surface of the topmost solid particle of the cuttings bed. Since the mud is shear thinning, its effective viscosity drops very low at the very instant that it needs to be high to lift the cutting. Rather than lifting the particle back into the flow stream, the viscous pill will simply deform around the particle as demonstrated by M-I and others.<sup>7</sup>

Some success has been realized by low viscosity pills followed by viscous pills, or high-density pills followed by viscous pills, or some other combination. (High density pills work by providing higher buoyancy factors, and correspondingly lower forces needed to pick up the cutting and get it back into the circulating system, with a viscous pill to carry it out once lifted.)

Interestingly, increasing the pump rate itself may not help in the absence of other hole cleaning tools at our disposal.

The tried and true method of ensuring good deviated well hole cleaning is to rotate the drill string itself, though some tension exists on the proper RPM needed to accomplish this. Some maintain that the rotary speed should be around 150-180 RPM, but others contend this is too high and leads to premature MWD/LWD and other downhole tool failures due to higher vibration levels. Regardless of the speed, the mechanical rotation provides sufficient energy to physically stir the cuttings. When this stirring action is supplemented by sufficiently viscous mud or occasional pills, the hole cleaning can be straightforward.

### Trend Analysis

Interestingly, the relative inability of most muds to clean the hole in the absence of pipe rotation has led to a powerful trend analysis tool. This tool utilizes the simple fact that a drilling fluid with a high cuttings concentration will have a higher density than a drilling fluid with a lower cuttings concentration, since the rock particles are slightly more dense than the drilling fluid is.

The technique consists of using a PWD tool, or in its absence the stand pipe pressure, to carefully monitor the bottom hole or circulating pressure respectively, as it changes when the pipe is rotated.

If there is a cuttings bed on bottom, the cuttings bed will be stirred up when the pipe is rotated. This stirring of the cuttings bed will be reflected as a higher pressure on bottom.

Practically speaking, most inclined boreholes will have some cuttings on bottom if the pipe is not rotated. A minimal amount may usually be tolerated. Perfect hole cleaning, at least in a theoretical sense, is not generally possible nor necessary. Hence there will be an increase in the bottom hole or standpipe pressure when pipe rotation is initiated.

The key to the trend analysis is to monitor the level of this difference in pressure over time and as the wellbore is deepened. If the difference is relatively constant with time and depth, no action may be needed. However, if the pressure difference increases, that is a clear signal to the observant driller. The well is talking. It is telling you that the cuttings bed is growing!

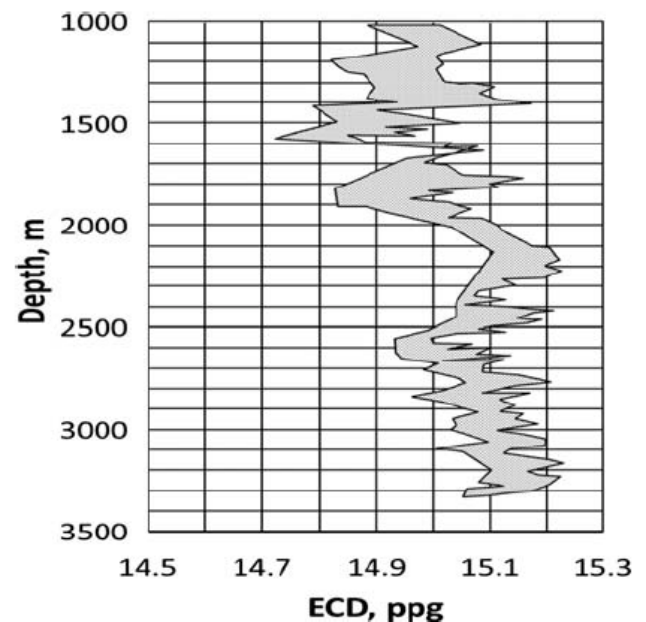


Figure 4 - Delta ECD Between A Rotating and Non-Rotating Drill String

In Figure 4 we see data from a near-horizontal well in the North Sea. ECD, as measured by a PWD tool is plotted vs. depth of the well. The reason for the PWD tool in the first place was to monitor bottom hole pressure closely in order to minimize the chance of breaking the formation down, a situation that in this field could lead to catastrophic lost returns and many days of down time.

However, a second and not as widely recognized use of the PWD data is to monitor the cuttings bed buildup in the build

section—the worst section for hole cleaning problems due to both Boycott Settling and potential avalanching of a cuttings bed.

The left most edge of the grayed area in Figure 4 is the ECD while the drill string was static. The right most edge of the grayed area is the ECD when the drill string was rotating. The difference between the rotating and static ECDs is caused by the stirring up of the cuttings bed.

If there were no cuttings bed, there would be no difference, a condition rarely if ever met 100%, but nearly met at about 1620 meters depth, and to a lesser extent around 2350 meters and 2530 meters. Conversely, if the cuttings bed is relatively deep, the difference between the two conditions may be relatively high, such as around 1400 meters, 1770 meters, 2150 meters, 2420 meters, and other depths.

Some ask if there were other factors contributing to the difference between rotating and non-rotating values. The short answer is no. While some parameters were slightly different at different depths, the values at the same depths were the same—the same mud weights, the same flowrates, and the same viscosities.

What is then done is again up to those drilling the well. But clearly when the trend is to higher and higher pressures as the well is deepened, action must be taken. Commonly used remedial actions include:

- Running the pumps faster,
- Rotation of the drill string, especially when coupled with thin or weighted or viscous pills, or some combination of two or all three,
- Backreaming

Depending on well conditions, some operators now avoid backreaming, since the pressure spikes that can be caused by it could exacerbate wellbore instability issues in known troublesome formations.

### **Flow Rate and Annular Velocity**

Worth mentioning is that for fluid mechanics calculations and even rules of thumb, annular velocity is the correct parameter for fluid movement. While in the drilling industry we commonly refer to the flow rates involved, it is the fluid velocity that actually matters.

### **Annular Pressure Drop with Annular Velocity**

With annular velocity being the key parameter or variable (and not volumetric flow rate, per se), and interesting paradox may be cleared up. The paradox may occur in highly deviated wells, especially those being drilled in sliding mode. The paradox is how the pump rate may be increased with very little increase in standpipe pressure.

“In horizontal and nearly horizontal wellbores, a curious discovery was made by Henry Nickens of Amoco Production Research Company in Tulsa, Oklahoma. Dr. Nickens was investigating pressure drops through annuli, particularly at high

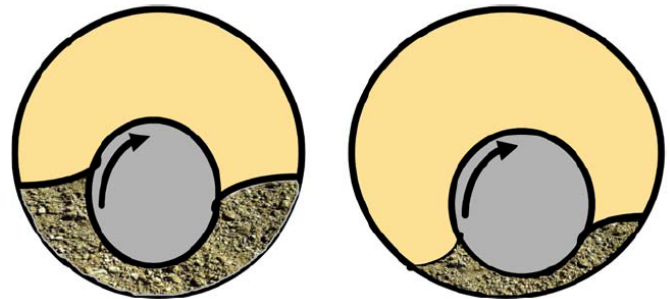
angles in simulated wellbores and flow loops.<sup>8</sup>

He found that, counterintuitively, it was possible at times to change the flow rate in the horizontal test section without appreciably changing the pressure drop through that test section. In some flow rate comparison cases, the relationship between flow rate and pressure drop was actually negative—the faster he pumped, the less pressure drop he got!

In terms of conventional fluid mechanics, this was not possible.

Increasing flow rate, implying higher velocities, should result in higher pressure losses. In fluid mechanics terms, the link between fluid velocity pressure losses is a well-established part of the physics of fluid flow.

The solution to this apparent paradox found by Dr. Nickens lies in the behavior of the cuttings beds themselves as shown in Figure 5. Fluid velocity itself was changed by the cuttings beds and vice versa.



*Figure 5 - Poor and improved hole cleaning (left and right, respectively), as seen by cuttings bed thickness in a horizontal wellbore section.*

Dr. Nickens found that the cuttings beds acted as a regulator on pressure drop or, more accurately, on fluid velocity which controls that pressure drop. When the pumps were run faster, the cuttings bed would erode as shown on the right drawing. This erosion of the bed resulted in a larger cross-sectional area above the bed and the pipe, resulting in a lower velocity and hence lower pressure drop.

Conversely, if the pumps were slowed, more cuttings would fall out of the slurry to the low side of the hole as shown on the left side of the drawing, reducing the cross-sectional area resulting in a higher velocity and hence higher pressure drop.

Once equilibrium was reached after a pump rate change, the equilibrium velocity of the fluid was essentially unchanged, and hence the pressure drop itself was unchanged!

Effectively, the cuttings bed buildup served to adjust the flow velocity to match the fluid's ability to transport cuttings.”<sup>9</sup>

### **Practical Wellbore Hydraulics Issues**

Practical Wellbore Hydraulics is a broad subject encompassing many facets. The most basic and relevant ones relate to pumping rates, geometries, fluid viscosities, and how

those tie to pressure losses through the inside of the drill string, through the bit nozzles, and back up the annulus.

Make no mistake, the sum of the pressure losses through the drill string, across the bit, and up the annulus is equal to the standpipe pressure. The energy stored by the pumps in the drilling fluid (via compression) is completely depleted or used up when the mud returns to the atmospheric pressure flowline.

It is a zero-sum game. Using more of the energy (we generally refer to as pressure) to get the drilling fluid to the bit and/or up the annulus reduces the amount of stored energy (pressure) that is available for other uses such as MWD tools, mud motors, or across the bit.

### Wellbore Fluid Sections and Use of Energy

The next step in our journey of understanding wellbore hydraulics as related to bit nozzle selection is to consider the different parts of the wellbore that consume the pressure stored in the drilling fluid. Generically, they consist of four classic divisions:

- surface equipment;
- drill string (inside, including both drill pipe and the BHA);
- bit pressure drop; and
- annulus [including all different geometry annuli as the outside diameter (OD) of the drill string changes and the hole diameter (or inside casing diameter or riser inside diameter (ID)) changes.

In Figure 6 below, operational limits of flow rates and pressures are shown on a log-log plot. It also includes an upwardly sloped line from roughly the lower left to the upper right. This upwardly sloped line represents all of the above pressure losses, except the bit pressure drop. For bit nozzle

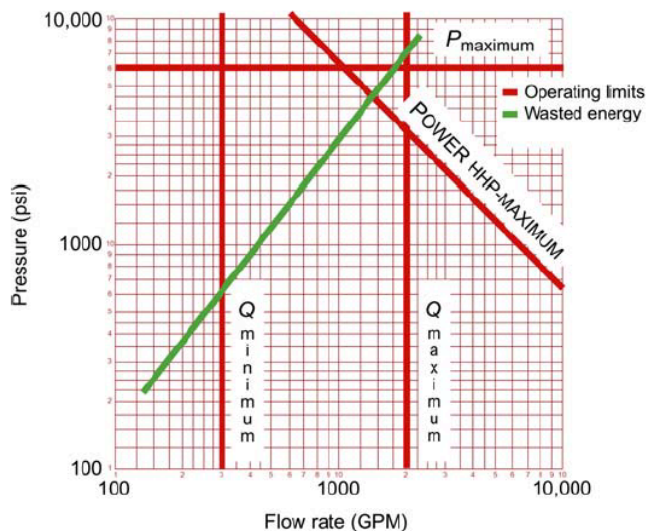


Figure 6 - Operational limits (red) and  $P_{CIRC}$  (green) shown on Log-Log plot of Pressure vs. Flow rate<sup>10</sup>

selection and understanding hydraulics, we will refer to this

upwardly sloped line as the circulating-system pressure losses,  $P_{CIRC}$ .

More memorably perhaps, we will refer to this as the “wasted energy” or “wasted pressure” line, since pressure losses spent flowing through the surface equipment, the drill string, and back up the annulus do not contribute appreciably to drilling rate and may actually slow the ROP.

That being said, there are valid uses of the pressure in these areas, primarily

- To simply move the drilling fluid from the surface to the bit and back to the surface again.
- To power downhole “jewelry” such as mud motors, MWD, and LWD equipment. All such equipment losses (or valid uses of hydraulic energy as you may prefer) are included in the upwardly sloping  $P_{CIRC}$  line.

The slope of the green line ( $P_{CIRC}$ ) in Figure 6 must lie between 1.0 and 2.0. A slope value of 1.0 would represent fully laminar flow down the drill string and up the annulus, while a slope value of 2.0 would represent fully turbulent flow. In practice, neither fully laminar nor fully turbulent flow is likely, so the slope, which corresponds to the exponent  $u$  in the proportionality

$$P \sim Q^u \quad \text{Eq. 3}$$

That slope value or exponent  $u$  is used in numerous pressure/flow equations. It was given the symbol  $u$  to denote that it is often the “unknown” exponent when designing wellbore hydraulics, and thus must be measured for the as drilled well and associated geometry and drilling fluid.

Since flow through an increased length of pipe increases the pressure drop through the pipe, the  $P_{CIRC}$  line moves up the page vertically as the well is deepened. Similarly, as the drilling fluid density or rheologies increase, the  $P_{CIRC}$  line also moves up the page. Hence, the line represents the  $P_{CIRC}$  or wasted pressure at a particular point in the wellbore.

Over time and changes in the wellbore, the line’s vertical position changes, and its slope may change slightly, though always remaining in the range between 1.0 and 2.0.

It is important to reiterate that the positive-sloped line represents the physics of the fluid mechanics. Its vertical position and slope at a given point (or time) in the wellbore cannot be easily or quickly changed, if at all. If a driller pumps faster, the pressure required to pump, without a bit even screwed onto the bottom of the drill string (which is, in essence, what this  $P_{CIRC}$  line represents), is going to go up accordingly.

The only available pressure that can be used across the bit nozzles is the difference between the upper horizontal  $P_{MAXIMUM}$  line (or perhaps the -1 sloped  $POWER_{MAXIMUM}$  line at the upper right if not at the triple limit point), and this wasted energy or  $P_{CIRC}$  line. Inspection of the graph quickly shows that as flow rate is increased more and more, correspondingly less and less pressure drop is available to dedicate to the bit nozzles and hence bottom hole cleaning. In the extreme, when the  $P_{CIRC}$  line reaches

the -1 sloped  $P_{\text{MAXIMUM}}$  line or upper horizontal  $P_{\text{MAXIMUM}}$  limit line, zero pressure is available to expend across the bit and the driller increasing the speed control setting for the pump will have no effect. As the pressure drop across the bit reduces toward zero, drilling rate can plummet in the case of tri-cone bits, and torque can escalate in the case of PDC bits. In both bit types, efficiency is sacrificed, and bit life will likely suffer accordingly.

### Flow Rate vs. Pressure

Inspection of Figure 6 clearly shows that as flow rate is increased, pressure losses through the circulating system increase. In extreme cases, there may be little or even no pressure loss available for bit nozzles—a condition that is deleterious to the rate of penetration.

### Drill Pipe Size

Drill pipe size affects not only the pressure losses required to move the fluid from the surface to the BHA and bit, but also the cross-sectional area of the return annulus. A larger pipe size will have less pressure drop inside the pipe but result in a higher velocity outside of the pipe in the annulus. This latter increases in velocity assists in hole cleaning, and has led some operators, especially in shale play areas, to drill with larger than standard pipe sizes.

### Bit Nozzles

Given that most of the hydraulic parameters of a particular well are difficult or impossible to practically change—the hole diameters, casing diameters, drill string inner and outer diameters, and bottom hole assembly geometries and mud-powered downhole tools—the well designer must optimize remaining hydraulic energy through the judicious selection of bit nozzle sizes.

Bit nozzle pressure drop is given by

$$\Delta P_{\text{BIT}} = \frac{MW \times Q^2}{12775 \times \text{TNFA}^2} \quad \text{Eq. 4}$$

Note that for this version of the equation, a pressure recovery factor of around 15% has been assumed. Other primitive forms of the equation, not accounting for the pressure recovery factor, were commonly expressed as

$$\Delta P_{\text{BIT}} = \frac{MW \times Q^2}{10868 \times \text{TNFA}^2} \quad \text{Eq. 5}$$

Modern PDC bits, or tricone bits with extended or mini-extended nozzles, may have a pressure drop between that of Equation 4 and Equation 5.

Note that to find the nozzles, Equation 4 may be rearranged

to solve for the Total Nozzle Flow Area, TNFA, as

$$\text{TNFA} = \sqrt{\frac{MW \times Q^2}{12775 \times \Delta P_{\text{BIT}}}} \quad \text{Eq. 6}$$

Many other papers have addressed how to size the nozzles properly, some with better results than others. In general, the procedure is to

1. determine the position of the green  $P_{\text{CIRC}}$  line on the log-log plot, preferably by taking measurements on the rig site,
2. Determining the optimum circulating rate,
3. Determining how much pressure is available to use across the bit nozzles at that circulating rate,
4. Compute the total nozzle flow area based on 2 and 3 above, using the equation 6 (or the primitive alternative),
5. Choose the best combination of standard-sized nozzles to achieve the desired TNFA.

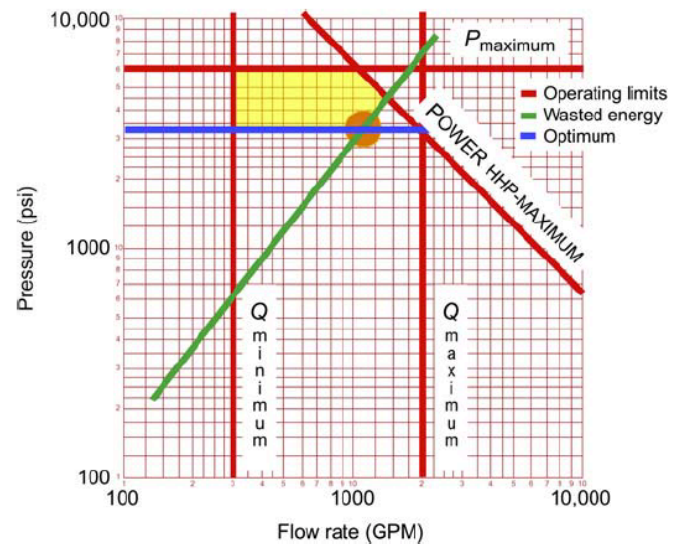


Figure 7 - Log log plot of Figure 6, with optimum line (blue) defining optimum flowrate, and available bit pressure loss shown (yellow)<sup>10A</sup>

When it is not possible to measure parameters at the rig site, a less complicated, but less optimal method is to determine the flow rate that will be used (perhaps as required by downhole MWDs, mud motors, or other downhole tools), compute their use of pressure along with an estimate of drill string and annulus parasitic losses, and use the remaining amount for the bit.

Caution: Experience teaches that the vast majority of wells pump too hard. This excessive flow rate, while cleaning the hole well, results in purely wasted energy as pressure used to pump

the mud down the drill string and up the annulus. In most cases, optimizing the wellbore hydraulics will result in decreased flow rate without loss of hole cleaning.

Note that with very long bit runs common today, the well designer must take this into account when sizing nozzles, or risk either imperfect hydraulics optimization or worse, running out of pump pressure at the end of the bit run. Taking this into account is discussed in prior papers and in the new book *Practical Wellbore Hydraulics and Hole Cleaning*.<sup>11</sup>

### Combined Effects On Bottom Hole Pressure

When the strength of a weak zone in the open hole is of concern, it is worth noting that both drilling rate and pumping rate have profound effects on the bottomhole pressure. In Figure 7, each curve represents a drilling rate in a particular geometry annulus. The solid dot on each curve is the optimum flow rate to achieve minimum bottom hole pressure for that drilling rate. Inspection of Figure 7 clearly shows that

1. The standard practice of reducing drilling rate will decrease the bottom hole pressure if flow rate and other parameter are held constant, but
2. The standard practice of slowing the pump rate may or may not decrease bottom hole pressure for a given drilling rate. In some cases, increasing the pump rate

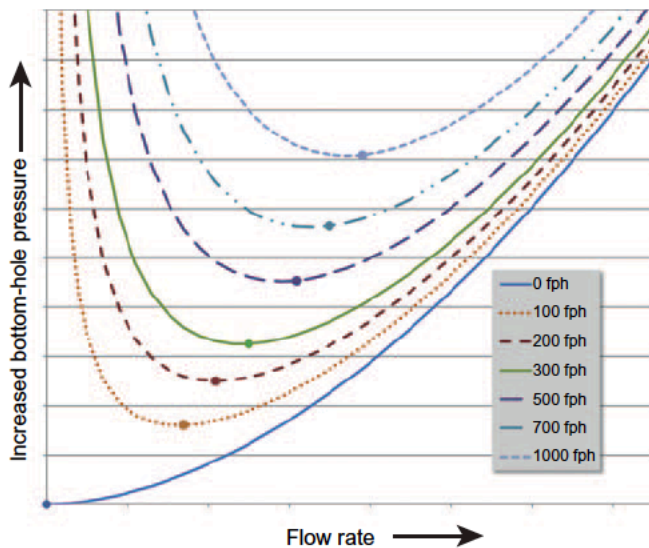


Figure 8 - Combined effect of drilling rate and flow rate on bottom hole pressure<sup>12</sup>

may lead to lower bottom hole pressures.

### Costs and Efficiencies

In terms of drilling hydraulic efficiencies—slightly different than Dupriest's Mechanical Specific Energy—the best way to determine this is to measure the energy used to drive the mud pumps. Hydraulic power is given by

$$HHP = \frac{P \times Q}{1714} \quad \text{Eq. 7}$$

Comparing this equation to Figure 1 reveals that in terms of

the  $P_{CIRC}$  portion of the graph, reducing the flow rate but still using maximum stand pipe pressure results in a reduced power being required.

An excellent measure of this power usage is found in measuring the diesel fuel used by the rig, specifically to power the mud pumps. While most rigs today are not equipped to easily measure this, it is not difficult.

By comparing the diesel used by the pumps under different hydraulic conditions, one can see if the extra power is needed or not. The diesel used to produce that extra power is either useful or is, in essence wasted.

Nearby Figure 8 shows the result of such a multi-day measurement of the diesel usage for pumps, normalized to reflect different hours per day usage of the pumps, over about 22 days.

During the first portion of the measurements, hydraulics parameters were not optimized—typical nozzle sizing, 16-16-16's in this case, along with pumping to reach the maximum standpipe pressure were the standard operating conditions. Note that the rig, a relatively small land rig, was using about 2100 gallons per day of diesel to power the mud pumps.

Starting at about day 16, nozzles were reduced to 13-13-13s on the next bit run. Penetration rate (not shown) remained constant at depths that usually would have been slowing down as stronger rock was encountered. In other words, there was no slowing of ROP, and perhaps in comparison with what would have normally been expected, there was an improvement, even though pumps were running slower (and pressure drop across the bit nozzles was higher). Diesel fuel used to run the pumps was observed to drop to about 1500 gallons per day.

Field personnel were encouraged, and nozzle sizes were again reduced at the next bit change on day 21, this time to 11-11-11s. As with the partial optimization, drilling rates remained approximately constant where they normally would have been slowing. Diesel fuel used dropped to just over 900 gallons per day.

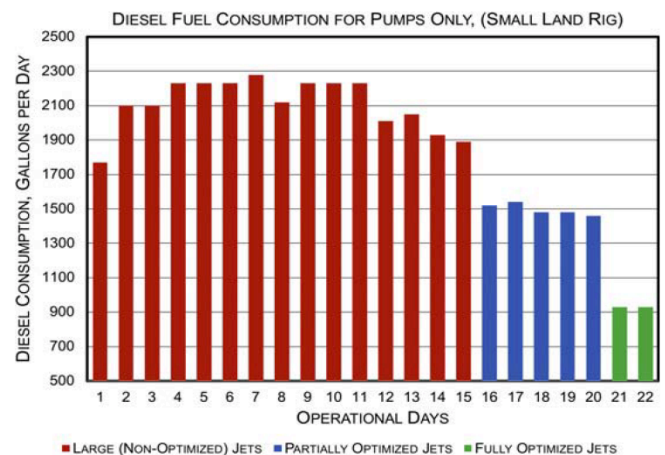


Figure 9 - Diesel fuel used to run mud pumps during non-optimized, partially-optimized, and fully optimized operations (normalized for 24 hour/day usage)<sup>13</sup>

In short, from the normal non-optimized to fully optimized operations, a savings of approximately 1200 gallons per day was realized, a savings of over 57%!

Notably in today's culture and carbon awareness, this 1200 gallons of diesel saved, also resulted in saving 26,856 pounds (over 12.2 metric tons) of CO<sub>2</sub> production.

For a full discussion on MSE, please refer to the Driller's Knowledge Book (another in the IADC Technical Publication Committee series) by Robinson and Garcia,<sup>14</sup> or the original papers by Koederitz<sup>15</sup> or Dupriest.<sup>16</sup>

For operators, optimized hydraulics offers clear benefits in terms of drilling efficiencies. For drilling contractors, the benefits may be more tangible. The best way to measure maintenance intervals for heavy machinery is to monitor the amount of work done by the machine. This can be somewhat complex, so a reasonable proxy, at least for diesel engines, is to monitor the amount of diesel burned in that engine. Less diesel used equals less work performed equals less wear-and-tear equals less maintenance and longer equipment life. In the case of the full pumping system, the components are in series, such that by monitoring the diesel used by the prime movers is tantamount to monitoring the work done by all the components—prime movers, generators, motors, mechanical end of pumps, and fluid end of pumps—in storing energy (pressure) in the drilling fluid.

Referring again to Figure 8, optimized hydraulics used 57% less diesel. To connect the dots, this would result in more than double the equipment life or less than half of the wear-related maintenance!

Yet another way that optimized hydraulics affects drilling efficiency is more subtle. As evidenced by both Figure 7 and Figure 8, in many cases pumps are routinely run faster than they need to be in order to clean under the bit, power downhole tools, and lift the cuttings out of the hole. This extra pumping, which in turn results in additional velocity, higher turbulence (and hence a higher  $u$  exponent value) and higher-pressure losses in both the drill string and the annulus and less energy available for the bit. The higher losses in the annulus raise the ECD at the bottom of the hole—the effective differential pressure at the bottom of the hole increases.

As most drillers know, the closer the bottom hole pressure is to balanced then the faster drilling will be. The converse is also true—as bottom hole pressure increases, drilling rate will decrease as shown in Figure 9 below.

A well where the drilling fluid was close to balanced when static, would experience slower drilling rate as ECD increased.

## Conclusions

Time and space do not permit getting into the details of the above items, but perhaps they can be summarized in the list below.

1. Hole cleaning can be achieved without extensive modeling through good well design, execution, monitoring of key parameters for vertical and deviated sections, and trend analysis.

2. In high angle regions, changing the pump rate may not affect the steady state annular pressure drop. The cuttings bed will serve as an automatic regulator of that pressure loss by regulating the velocity of the

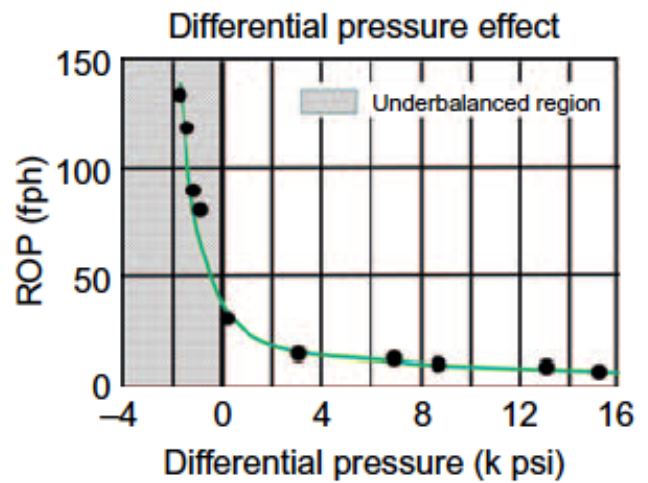


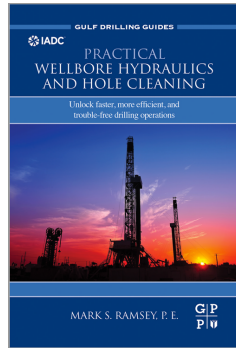
Figure 10 - Effect of overbalance on drilling rate. This is sometimes referred to as a "fear and greed" plot!<sup>17</sup>

- annular fluid.
3. Hole cleaning in vertical sections of the well is a completely different technical issue from that of highly deviated wells, due primarily to the Boycott effect and the potential avalanching of cuttings beds.
4. Robinson's CCI and Sifferman's Transport Ratio are very useful in monitoring hole cleaning for vertical and near vertical sections of a well.
5. Close monitoring of trends of the delta between rotating and non-rotating bottom hole pressure are very useful in highly deviated sections of a well, due to the cuttings bed being on the low side of the hole or suspended in the drilling fluid. (In the absence of downhole pressure readings, the same effect may be seen on standpipe pressure gages, albeit somewhat attenuated.)
6. Even when hole cleaning parameters are optimum, an enlarged hole section can radically reduce annular velocity in a section of the wellbore and thus create a de facto "cuttings block".
7. Highly deviated wells with cuttings beds can exhibit constant annular pressure loss not a function of flow rate due to the regulation effect of the cuttings bed itself on annular velocity.
8. Pump energy (pressure) may be partially or wholly wasted without optimized hydraulics.
9. Bit nozzles should be sized to use whatever remaining energy (pressure) is available and doing so can have significant improvements in ROP.
10. In wells with narrow pore pressure by fracture pressure windows, the combined effects of drilling rates and pump rates on bottom hole pressures should be carefully evaluated or measured.

11. Significant savings of diesel fuel (and associated CO<sub>2</sub> production) can be realized by optimizing wellbore hydraulics.
12. Significant equipment maintenance savings (or extended equipment life) can be realized by optimizing wellbore hydraulics.

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I would like to thank everyone who made this work possible over my career thus far, (far too numerous to mention individually, but especially members of the IADC Technical Publications committee), and all those who will help build on this and distribute it further. Additional details on these and other aspects of both hydraulics and hole cleaning may be found in the newly published book, **Practical Wellbore Hydraulics and Hole Cleaning**.<sup>18</sup> The author may be contacted at [markramsey@texasdrillingassociates.com](mailto:markramsey@texasdrillingassociates.com).



$Q$	=	Flow rate
$Q_{crit}$	=	Flow rate where the two operating limits of maximum pressure and maximum available hydraulic power intersect
$Q_{opt}$	=	Optimum flow rate for optimized hydraulics across the bit
$\rho$	=	Rho - density
$t$	=	Time
$u$	=	“Unknown” exponent of flow rate in the power law equation, and, slope of best fit line on logarithmic paper when plotting pressure vs. flow rate
$v$	=	Velocity
$V_C$	=	Velocity of cuttings, fpm
$V_A$	=	Velocity of bulk drilling fluid, fpm

## Nomenclature

$BHA$	=	Bottom hole assembly
$BHA$	=	Bottomhole assembly
$CCI$	=	Cuttings Carrying Index or Carrying Capacity Index
$PV$	=	Plastic Viscosity, cP
$ROP$	=	Rate of Penetration, ft per hour
$ECD$	=	Equivalent Circulating Density, ppg
$PWD$	=	Pressure While Drilling
$\Delta P_{bit}$	=	Pressure drop across the bit, psi
$\Delta P_{bit\ opt}$	=	Optimum pressure drop across the bit, psi
$E_m$	=	Mechanical Efficiency
$E_v$	=	Volumetric Efficiency
$F$	=	Force
$GPM$	=	Gallons Per Minute
$HP$	=	Horsepower
$HHP$	=	Hydraulic Horsepower
$M$	=	Mass
$MW$	=	Mud Weight, ppg
$P_{bit}$	=	Pressure drop across the bit
$P_{circ}$	=	Pressure drop through rig circulating system exclusive of the pressure drop through the bit
$Power_{MAXIMUM}$	=	-1 sloped rig power limitation line on a log log plot of pressure vs flowrate
$Psi$	=	pounds per square inch
$P_{max}$	=	$P_{MAXIMUM}$ , Maximum surface pressure available on a rig
$PPG$	=	Pounds Per Gallon
$ppg$	=	Pounds Per Gallon
$P_{surf\ opt}$	=	Standpipe pressure at the surface under optimum conditions

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