

## Improved Method of OCHO™ Hydraulics Optimization Including Long Bit Run Predictive Considerations

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### Abstract

Many techniques exist to pre-plan the best use of available hydraulic energy on a particular rig. Often when these pre-planning tools are used, optimum hydraulics are not achieved due to a variety of factors. Pressure loss through a pipe is proportional to the flow rate if the flow is laminar and proportional to the square of the flow rate if the flow is turbulent. Most current software planning programs use an exponent of 1.82 or 1.86 to estimate the pressure loss. From surface measurements made before tripping a drill bit, the exponent can be determined for the specific flow pattern, down hole tools, well bore size, fluid rheology, and temperature effects found in the well being drilled. The exponent can not be predicted with any degree of reliability. The exponent has a unique value for each well and changes with depth and drilling fluid properties.

With today's mud systems and bit technology, a significantly different hydraulics regime may exist at the end of the bit run compared to the conditions existing at the beginning of the bit run. A straightforward and accurate predictive technique will be presented which modifies the exponent to account for these longer bit runs and anticipated drilling fluid property changes.

### Introduction

The optimization of bit hydraulics has been the subject of much discussion over the years. Unfortunately, due to the inability to understand the various flow regimes, coupled with the lack of knowledge about the values of variables important to calculating pressure (or energy) losses. Further, drilling fluids are notoriously non-Newtonian in nature, and their particular shear stress vs. shear rate curves are difficult to predict and expensive to measure, and do not extrapolate easily to other well bores and drilling fluid systems.

Broadly speaking, the energy stored in the drilling fluid as pressure via the triplex pumps is used up in three broad areas:

- Drill string components (including mud motors, MWD/LWD equipment, etc.)
- Return well bore, casing, and riser annuli, and
- Bit nozzles

Of these three categories, the only one that directly affects drilling rate, good or bad, is the bit nozzle pressure drop. For the purposes of hydraulics optimization, the other two can be

thought of as necessary, yet wasted, energy or pressure.

Properly planned and field calibrated OCHO hydraulics optimization maximizes the use of available hydraulic energy across the bit.

### Discussion

To illustrate the concepts, we will handle the discussion in several parts, including:

- Review current technologies
- Extrapolations for depth
- Extrapolations for mud weight
- Combined effects

### Review

First, imagine running in the hole open ended with all of the normal components in the drill string present. By normal components, include the BHA, stabilizers, drill collars, heavy weight, drill pipe, and MWD/LWD and/or motors and associated directional survey instrument packages. Everything is in place and run to bottom, except the drill bit and associated jet nozzles.

If circulation is established through this imaginary bit-less drill string, the standpipe pressure will read some amount. It will be the same as if the bit was there, too, except in this imaginary case it will be lower by exactly the amount that the bit nozzles would consume.

When the bit and bit nozzles are added to our imaginary rig, pressure losses go up accordingly, but the non-bit portion, which might be thought of as wasted energy in terms of drilling enhancement, remains the same.

As an example, if our rig was drilling with 4 ½" drill pipe at a depth of 5314 feet with an 12 ¼" tri-cone bit with a 24/32 and two 12/32 inch nozzles (0.6627 square inches total nozzle flow area [TNFA]). The drill pipe specifications are taken to be:

Weight=16.6 ppf  
 Grade E-75  
 NC46 tool joints (X-Hole), with a TJ ID of 3.25 inches  
 Equivalent ID of 3.78 inches diameter

Mud weight was 11.8 ppg (water base mud, PV=8, YP=16). According to standard calculations, the standpipe

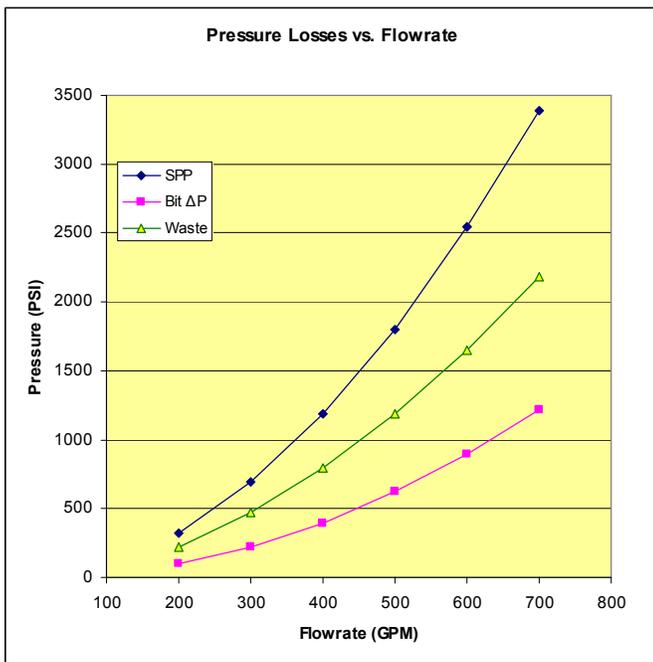
pressure for this arrangement flowing at 300 gpm would be, 693 psi, with the bit representing 223 psi or 32% of the total. The remainder of the pressure loss was consumed by surface equipment getting to the drill string, the drill string components, and the return annuli.

If the driller on this same system increased or decreased the pump rate, pressure losses at the bit and the rest of the system would increase or decrease accordingly. For our well, the following results were obtained at various pump rates, using the ReedHycalog bit hydraulics software package.

**Table 1: Pressure Loss Distribution for Various Flow rates**

GPM	SPP	Bit DP	Bit %	Waste	Waste %
200	325	99	30.5	226	69.5
300	693	223	32.2	470	67.8
400	1187	396	33.4	791	66.6
500	1804	619	34.3	1185	65.7
600	2540	891	35.1	1649	64.9
700	3394	1213	35.7	2181	64.3

These data are plotted on standard Cartesian coordinates in Figure 1.



**Figure 1-Pressure vs. Flow (standard coordinates)**

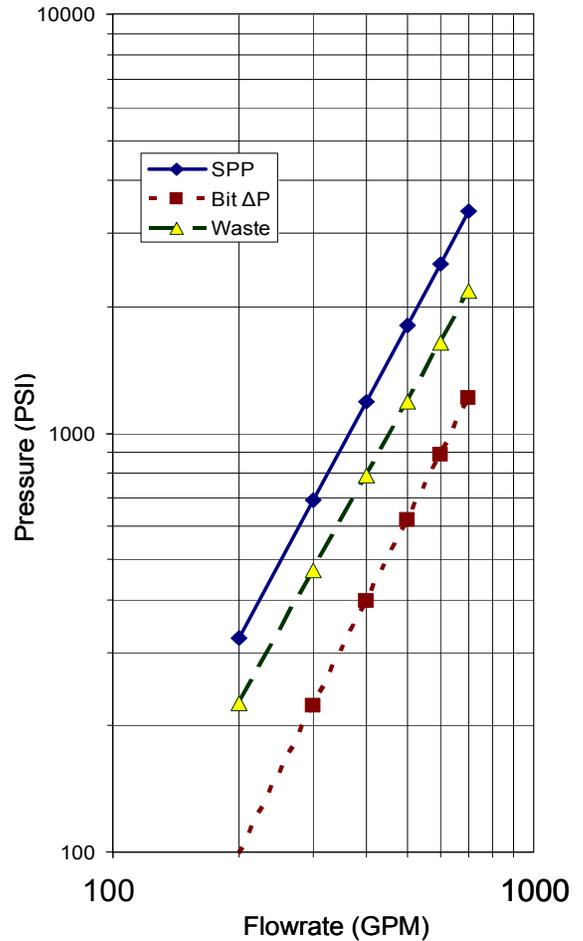
An exponential fit to the data, of the form:

**Equation 1**

$$\Delta P = k Q^u,$$

yields an exponent “u” of 2 on the bit pressure drop and an exponent of 1.8 on the wasted energy curve. The identical data are plotted on logarithm (log-log) coordinates in Figure 2.

**Pressure Loss vs. Flowrate**



**Figure 2-Logarithmic plot of data in Figure 1**

Though difficult to visually see at the small physical size of Figure 2, the slope of the bit pressure drop line (lower line), measured linearly (i.e. with a ruler) is slightly steeper than the slope of the wasted energy line (middle line). The slope of the standpipe pressure line is a combination of the two parts, and hence has a midrange slope to it.

Hydraulic optimization can mean many things to many different drilling personnel. It can refer to maximizing annular flow rate, maximizing the force with which the fluid strikes the bottom of the hole (impact), or maximizing the

power expended through the nozzles in the drill bit (hydraulic power). This development will focus on an attempt to maximize cuttings removal beneath a drill bit. Better cuttings removal will result in elevated bit founder points and promote faster drilling.<sup>1, 2</sup> Equations are derived in reference 1 to maximize this cuttings removal based on either hydraulic impact or on hydraulic horsepower.

Referring back to Figure 2 and our imaginary bit-less well bore, the line representing the wasted energy (i.e. what is not being used for cuttings removal at the bottom of the hole), should be minimized, leaving more available energy to be “spent” across the bit. If flow rate is too high, most of the pressure is expended in transporting the fluid. If flow rate is too low, not enough total energy is transported to the bit to effectively remove chips from the bottom or transport them to the surface.

While the calculations of these pressure losses have been known since the post World War II era, the accuracy of various parts of the numerical modeling have been questioned. It is well-known that the annulus calculations are not very accurate in some situations, and the inside drill string calculations are better but not perfect. More recently, even the bit pressure drop calculation has been shown to suffer by a varying amount up to around 30%, believed by this author to be closely tied to the plastic viscosity PV and the mud weight.

These inaccuracies are largely due to the numerous assumptions one must make in order to calculate the pressure losses. In short the variables that are used to predict pressure losses are not known.

For example: A fluid is flowing at 45 gallons per minute inside of a 2” inside diameter, 100 ft long pipe. What is the pressure loss in the pipe? In this simple example, the fluid description is absent from the problem specifications. Would it make a difference if the fluid were water, alcohol, or honey? Why? Obviously, the viscosity of the fluid would have a big impact on the pressure loss. On a drilling rig, the rheological properties of a drilling fluid are measured at either 120°F or sometimes at 150°F or more for an oil-based drilling fluid in a hot hole. Unfortunately, rheological properties cannot be predicted accurately at other temperatures (and pressures) from measurements made at one temperature.

Second, the flow regime is unknown in a well bore. When fluid is flowing in fully laminar flow in a pipe, the pressure drop in a pipe is proportional to the flow rate. When fluid is flowing in fully turbulent flow, the pressure drop in a pipe is proportional to the *square* of the flow rate. Within a drill string, tool joints disrupt the flow profile between each joint. In a very viscous drilling fluid, very little turbulence may be experienced; in a very low viscosity fluid, much turbulence may be experienced. The induced turbulence would not necessarily continue throughout the pipe joint. So the pressure drop through drill pipe should be proportional to flow rate raised to some exponent between 1 and 2, inclusive. These values cannot be predicted with any certainty before the well is drilled.

Many hydraulic programs assume an exponent (on flow rate) of around 1.80 to 1.9. This range of values is based on

measurements made shortly after the Second World War with pipe and mud technology of the time. A better solution would be to measure the effect at the rig site and use the well bore itself as a rheometer. This “rig-measured exponent” will include all of the unusual features within the circulating system (large diameters, small diameters, changes in viscosity with pressure and temperature, changes in flow regimes, etc.)

### How to Utilize the Well bore as Calibration Device

Rather than continually make educated guesses at the variables involved, if we look back at Figures 1 and 2, we realize that if we can accurately identify what the wasted energy line looks like, then we can effectively calibrate all of the uncertainties out of the problem. The only thing that stops us from doing so is that we do not ordinarily have an imaginary open ended drill string in the hole. Instead, we have a drill string with a bit. However, since the wasted energy line is the same with or without a bit, if we can reasonably calculate the bit pressure drop (thought to be one of the more accurate calculations), then we can obtain the wasted energy line and then optimize accordingly.

Fortunately, the OCHO™ (Onsite Continuous Hydraulic Optimization) is an eight-step plan for doing exactly that. It enables one to tailor the hydraulics program to the well bore as it is being drilled. The eight steps are:

1. Calibrate rig pumps. Measure the rate of liquid level drop in the slugging tank while pumping down hole through the drill bit. Account for air in the drilling fluid to calculate the volume of liquid moved by the rig pumps.
2. Just before tripping for a new bit, circulate at several pump rates and measure accurately the standpipe pressure at each rate.
3. Calculate and subtract the bit nozzle pressure drops from the measured standpipe pressures (This gives the circulating pressure loss through the system, except for the bit nozzles.)
4. Plot the circulating pressure loss as a function of flow rates on log-log paper.
5. Draw the best straight line through the circulating pressure losses.
6. Measure the slope of the circulating pressure line with a ruler or scale.
7. Calculate the optimum pressure loss and corresponding flow rate through the bit to give either the maximum hydraulic force or the maximum hydraulic power at the bit.
8. Calculate nozzle sizes for the next bit.

Summarizing, the OCHO™ technique collects standpipe pressure data for various flow rates, subtracts the bit nozzle pressure loss to yield the wasted energy line. Then the optimized operating point is computed, which fixes the flow rate and desired bit pressure drop, so that the TNFA of the nozzles can be computed and nozzles selected accordingly.

**Example**

For brevity, we assume the pumps have been calibrated and the driller has taken the data (OCHO™ steps 1-2). The collected data, with strokes per minute (SPM) converted to gallons per minute, are shown below in the first two columns:

**Table 1-Example Data from Well**

GPM (Calc. from SPM and pump efficiency)	Standpipe Pressure (measured)	$\Delta P_{bit}$ (calc)	$P_{circ}$ or the wasted energy line (calc)
200	621	160	461
300	1245	360	885
500	3000	1000	2000

The right two columns represent OCHO™ step 3, where the bit pressure drop is calculated, (column 3), and then subtracted from the standpipe pressure to yield column 4, representing the wasted pressure loss in the system.

To calculate column three, the  $\Delta P_{bit}$ , the equation below was used, which already has the pressure recovery effect, reported earlier, included (for convenience) by changing the nozzle coefficient.

**Equation 2**

$$\Delta P_{bit} = \frac{(MW)(Q)^2}{12042 (1.03)^2 (TNFA)^2}$$

Where:

MW is the mud weight in ppg

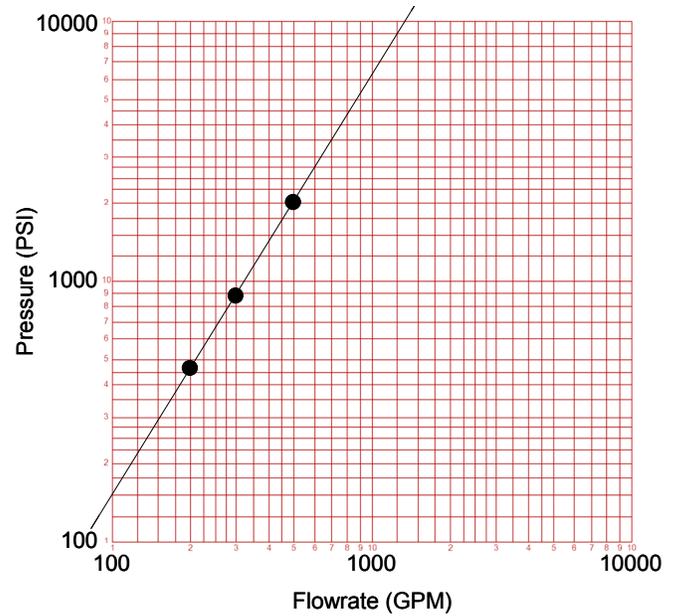
Q is the flow rate, in gpm, and

TNFA is the total flow area of the nozzles, in square inches.

Note that this square inch term is squared in the equation.

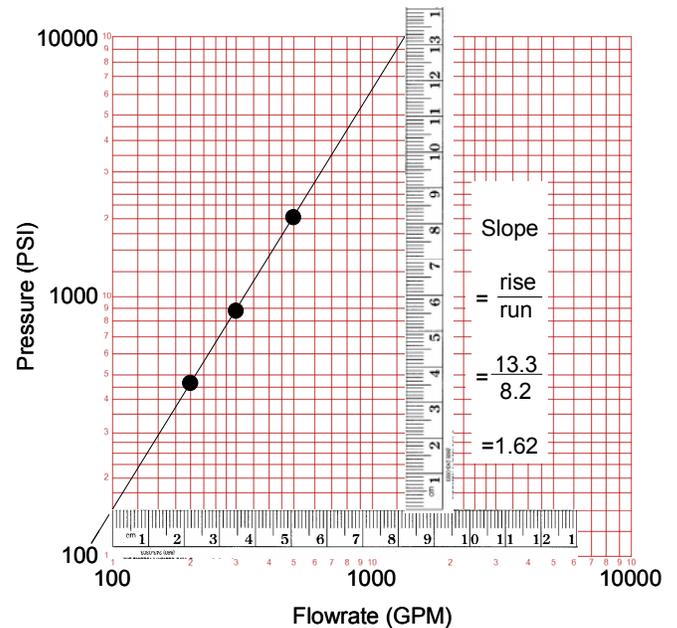
This equation is slightly different from older and perhaps more familiar equations in that the nozzle coefficient of 0.95 has been replaced by a nozzle coefficient of 1.03 for the new nozzle shapes. This is an attempt to quantify the pressure recovery effect observed from field measurements. This coefficient was also independently validated in controlled laboratory tests.<sup>4, 5</sup> Note that in some companies, the 12042 constant and the nozzle coefficient are combined into a single term for convenience.

Further, note that API RP13D committee members did not agree on an exact value of the nozzle discharge coefficient (and pressure recovery), but did recognize the problems facing hydraulics designers. Additional research is needed in this area.



**Figure 3-Wasted Pressure Line Constructed**

OCHO™ steps 4, 5, and 6 are shown graphically in Figure 3, where the wasted energy line is plotted, a best fit straight line is drawn through the points, and in Figure 4, where the slope of the line measured linearly (i.e. with a ruler).



**Figure 4-Slope (or exponent) Measured**

For our case, the slope was measured to be 1.62. This is considerably lower than the “standard” values used by many available computer software programs, which typically range from 1.8 to 1.9 or so. These values are artifacts of research conducted decades ago on mud systems of that day, and likely

do not accurately work for modern drilling fluids in use today.

At this point it must be emphasized that the wasted pressure line constructed in Figure 3 represents the entire circulation system except for the bit. It includes surface piping, drill string components, and return annuli. To flow at any flow rate across the x-axis will extract the corresponding amount of pressure indicated on the y-axis.

### Optimum Conditions-Pressure Limited

For most conditions of interest to most drillers, the rig will have a practical limit on pressure. If pressure drop across the bit is being optimized, both the optimum bit and the optimum wasted pressure can be calculated with the equations below, for jet impact force (JIF) or hydraulic horsepower (HHP). For the interested reader, these are derived in reference 1, and are now included in the recently approved API RP 13D, Recommended Practice on the Rheology and Hydraulics of Oil-Well Drilling Fluids.

Optimum  $\Delta P_{bit}$

Optimum  $\Delta P_{circ}$  (or Waste)

#### Equation 3

$$\text{JIF-1} \quad \Delta P_{bit\ opt} = \frac{u}{u+2} P_{max}$$

#### Equation 4

$$\Delta P_{circ\ opt} = \frac{2}{u+2} P_{max}$$

#### Equation 5

$$\text{JIF-2} \quad \Delta P_{bit\ opt} = \frac{u+1}{u+2} P_{maxHP}$$

#### Equation 6

$$\Delta P_{circ\ opt} = \frac{1}{u+2} P_{maxHP}$$

#### Equation 7

$$\text{HHP} \quad \Delta P_{bit\ opt} = \frac{u}{u+1} P_{max}$$

#### Equation 8

$$\Delta P_{circ\ opt} = \frac{1}{u+1} P_{max}$$

Note that the equations for any particular optimization scheme (JIF-1, JIF-2, or HHP) are complementary. The left column equations give the optimum impact force or hydraulic horsepower across the bit, while the right column gives the corresponding optimum circulation system losses (i.e. the waste line) for the three cases.

Note also that there is a mathematical discontinuity between JIF-1 and JIF-2, that is interpolated at what has been termed the critical flow rate, or the flow rate where maximum standpipe pressure (the JIF-1 criteria) intersects with maximum available pump horsepower (the JIF-2 criteria).

NB: As a practical matter, the JIF-2 criteria are rarely met and are presented for completeness.

For OCHO™ step 7 illustration, we go back to our example, where the slope (or value of the “u” exponent term in the above equations) is 1.62. The math then results in the bit optimization being 44.7% of standpipe pressure (or 1475 psi) for the JIF-1 criteria and 61.8% (or 2039 psi) for the HHP criteria. Conversely, the wasted pressure line at the optimum point would be 55.3% and 38.2% of standpipe pressure,

respectively. Assuming the maximum standpipe pressure to be 3300 psi, these  $P_{circ}$  lines would be plotted horizontally at 1825 and 1261 psi. These values, along with the  $P_{max}$  of 3300, are shown in the plot below.

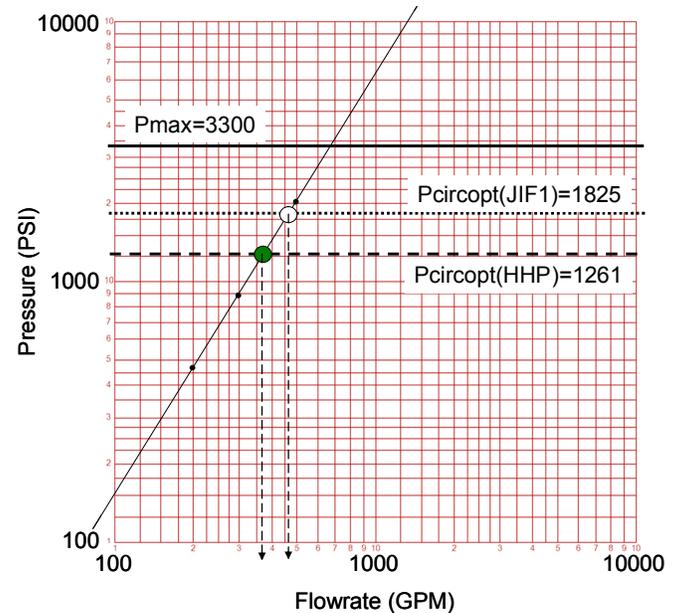


Figure 5-Optimum Circulation Rates & Pressures

For the JIF-1 criteria, the intersection of the theoretical optimum and the real-world waste pressure ( $P_{circ}$ ) line occurs at approximately 465 GPM. For the HHP criteria, the intersection occurs at approximately 370 GPM.

### Sizing the Nozzles

Now that the exponent on the wasted energy line is known, leading us to the theoretically best place to operate, both in terms of pressure and flow rates, it becomes a brief exercise to determine the actual nozzles for the next bit run, as per OCHO™ step eight. The bit pressure drop equation is rearranged to solve for the total nozzle flow area, TNFA, and is solved using the optimum conditions determined above.

The bit nozzle pressure loss equation becomes:

#### Equation 9

$$\text{TNFA} = \sqrt{\frac{(MW)(Q_{\text{optimum}})^2}{(12042)(1.03)^2 (\Delta P_{bit\ \text{optimum}})}}$$

Going back to our example, for the JIF-1 criterion, this a TNFA of 0.3680 square inches results, and is satisfied by a 12/32” and two 13/32” diameter nozzles.

For the HHP criterion, the TNFA is 0.2490 square inches, corresponding to an 11/32” and two 10/32” nozzles.

Close examination of the Figures will make it clear that with the JIF-1 criteria, a higher flow rate and less pressure drop across the bit is achieved when compared to the HHP criteria. As a result, some find the JIF-1 to be most suited to conditions requiring more flow, such as PDC bits, and the HHP best suited to conditions benefiting from higher pressure loss (and hence jet velocity) across the bit nozzles, such as would be the case of roller cone bits.

### Extrapolations

Particularly with today's long-lived bits drilling longer and longer intervals without requiring tripping, one must consider the effects on hydraulics to avoid "running out of pump" towards the end of the bit run. While calculations of drill string and annuli pressure losses are inaccurate in and of themselves, they all agree that extended depth (i.e. extra length of the flow path), has a linear effect on pressure loss. Hence, if a bit is expected to last from 10,000 feet measured depth to 15,000 feet measured depth, circulating losses will be a linear ratio of the two depths higher when the bit is pulled than when it arrives green on bottom.

#### Equation 10

$$\Delta P_{\text{circ out}} = \left( \frac{\text{Depth Out}}{\text{Depth In}} \right) P_{\text{circ in}}$$

Similarly, increased (or decreased) mud weight will increase (or decrease) pressure losses in a similar linear ratio fashion.

#### Equation 11

$$\Delta P_{\text{circ out}} = \left( \frac{\text{MW Out}}{\text{MW In}} \right) P_{\text{circ in}}$$

Naturally, in many cases both effects will be felt, and hence the combined effect of depth and mud weight changes is also easily accounted for by combining the two equations above.

#### Equation 12

$$\Delta P_{\text{circ out}} = \left( \frac{\text{Depth Out}}{\text{Depth In}} \right) \left( \frac{\text{MW Out}}{\text{MW In}} \right) P_{\text{circ in}}$$

This combined effect can be quite large. Consider a well drilling from 10000 to 15000 and simultaneously raising mud weight from 9.8 to 12.4 ppg. The combined effect by the end of the bit run would be *1.9 times* the pressure loss at the time the OCHO™ calibration was run (at the end of the prior bit run).

In order to account for this extrapolation, a column is added to the collected data. Again going back to our first example, and using a combined correction factor of 1.9, the table would become:

This corrected data would then be plotted (electronically or otherwise), and the nozzle selection would be done using the corrected data instead of the initial raw data. This would have the effect of the wasted pressure line moving "up" on the plot, leaving less pressure drop available for the bit at a given flow rate.

A different set of optimization equations is used for the highly unusual case of being limited by the available hydraulic horsepower at the surface (as opposed to being limited by the standpipe pressure). In the horsepower limited case, the technique described above is the same, but the maximum standpipe pressure  $P_{\text{max}}$  becomes a function of flow rate. A complete treatment of this part of the optimization is included in reference 1.

**Table 2-Example Data from Well-Extrapolated**

GPM (Calc. from SPM and pump efficiency)	Standpipe Pressure (measured)	$\Delta P_{\text{bit}}$ (calc)	$P_{\text{circ}}$ or the wasted energy line (calc)	$P_{\text{circ}}$ corrected to the next bit TD
200	621	160	461	876
300	1245	360	885	1682
500	3000	1000	2000	3800

### Epilogue

Some cases arise when bit hydraulic optimization is the low man on the totem pole, so to speak. Other considerations, such as control drilling, mud motors, directional drilling, MWD/LWD, artificially imposed limits on flow rates, and hole cleaning considerations can take precedence over hydraulics optimization.

However, even in these cases, optimized hydraulics is well worth the effort. Regardless of where one is forced to operate in terms of flow rates, the wasted pressure line is still valid and hence the remaining pressure drop between maximum pressure and the wasted pressure line (including the above mentioned tools), is available and should be used as best as possible, rather than simply giving up and using overly large nozzles.

In some cases, the relevant flow vs. standpipe pressure data may be lacking. However, one should still have two data points, namely the end of the bit run operating conditions and the well control related slow pump rate. This should suffice. In some rare cases, one might not have a reliable slow pump rate. Even in that case, using the prior operating point and assuming a slope, based on the best available information, would still yield superior hydraulics than a "seat of the pants" approach.

## Conclusions

A straight-forward method for optimizing hydraulics across the bit nozzles is presented. It has the following advantages over more conventional theoretical computational approaches:

- OCHO™ does not require extensive mud property measurements.
- OCHO™ can be implemented entirely on the rig site.
- OCHO™ can be used with or without additional drill string components such as mud motors and MWD/LWD equipment.
- OCHO™ improves penetration rate and bit life.
- OCHO™ is more energy efficient.
- OCHO™ can accommodate minimum and maximum flow constraints.
- OCHO™ is amenable to computer assistance.
- OCHO™ can easily be extrapolated to different depths and mud weights.
- OCHO™ works!

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## Nomenclature

$BHA$	=	<i>Bottom hole assembly</i>
$\Delta P_{bit}$	=	<i>Pressure drop across the bit</i>
$\Delta P_{bit\ opt}$	=	<i>Optimum pressure drop across the bit</i>
$E_m$	=	<i>Mechanical Efficiency</i>
$E_v$	=	<i>Volumetric Efficiency</i>
$F$	=	<i>force</i>
$Gpm$	=	<i>gallons per minute</i>
$HP$	=	<i>horsepower or hydraulic power</i>
$HHP$	=	<i>Hydraulic Horsepower</i>
$M$	=	<i>mass</i>
$MW$	=	<i>Mud weight</i>
$P_{bit}$	=	<i>Pressure drop across the bit</i>
$P_{circ}$	=	<i>Pressure drop through rig circulating system exclusive of the pressure drop through the bit</i>
$Psi$	=	<i>pounds per square inch</i>
$P_{max}$	=	<i>Maximum surface pressure available on a rig</i>
$Ppg$	=	<i>pounds per gallon</i>
$P_{surf\ opt}$	=	<i>Standpipe pressure at the surface under optimum conditions</i>
$Q$	=	<i>Flow rate</i>
$Q_{crit}$	=	<i>Flow rate where the two operating limits of maximum pressure and maximum available hydraulic power intersect</i>

$Q_{opt}$	=	<i>Optimum flow rate for optimized hydraulics across the bit</i>
$\rho$	=	<i>rho - density</i>
$t$	=	<i>time</i>
$u$	=	<i>exponent of flow rate in the power law equation, and, slope of best fit line on logarithmic paper</i>
$v$	=	<i>velocity</i>

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