

Mud Tank Arrangements

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Abstract

In the recovery from this major ‘downturn’ in the petroleum industry, most companies are seeking ways to save money and operate more efficiently. New technology is appearing in drilling operations but one lucrative method for saving money is paying attention to proven, well-established techniques. Many drilling fluid surface systems are not properly arranged. Contractors purchase “top of the line” equipment but then the system is frequently modified and plumbed so only about 50% of the drilling fluid coming from the hole is processed. The retained drill solids can greatly impact the visible and the invisible Non Productive Time.

This paper discusses how to analyze and evaluate the fraction of drilling fluid processed on any rig and how to make simple modifications to guarantee that all of the drilling fluid is processed properly. Some field examples are shown – with names eliminated to protect the guilty. In addition to looking at improperly plumbed system processing, this paper will also take into consideration cuttings drying applications and the proper processing of recovered drilling fluid from drilled cuttings.

This is a ‘DO IT YOURSELF’ project. The guidelines for calculating the fraction of drilling fluid processed are simple and should be followed as soon as the rig arrives at a location. The investment is small; the rewards can be great.

Introduction

As profit margins decrease, operators continue to seek ways to decrease costs. This can be done in two ways: increase safety to prevent costly accidents and improve efficiency. One way to do both is frequently overlooked on drilling rigs and that is to examine the surface drilling fluid processing procedures. For at least the last fifty years, many contractors are told that the centrifugal pumps in the surface systems should be able to pump fluid from any tank to any other tank. This is a bonanza for valve companies but is almost always guaranteed to decrease drilled solids removal efficiency and create problems with handling kicks.

When an influx of formation fluid is detected in the well bore, the blowout preventers are closed. The drill pipe and casing pressures are measured. The drill pipe pressure indicates how much underbalanced the pressure is at the bottom of the hole BUT only if the fluid in the drill pipe has a homogeneous density. The surface system must be able to blend and maintain a sufficient quantity of homogeneous fluid to ensure uniform

density throughout the drill pipe. The drilling fluid has many functions to fulfill in addition to the homogeneity of the mud weight.

This presentation will concentrate on the removal the detrimental drilled solids from the drilling fluid. Evaluation of a surface system requires calculation of the fraction of drilled solids reporting to the surface that are presented to the solids removal equipment.

Tank Arrangements

The drilling fluid has many functions to perform when drilling a well. The surface mud tank arrangement on all drilling rigs must be arranged properly to assist in the performance of some of the functions required for a quality drilling fluid. A surface mud tank system must consist of three separately identifiable sections:

1. Removal Section: Gas and the evil drilled solids should be removed to prevent visible and invisible Non-Productive time [NPT].
2. Addition Section: Drilling fluid components are added in this section downstream from the removal section to adjust the drilling fluid properties.
3. Suction Section: The fluid in this section must be well-blended to continuously keep the fluid in the drill pipe homogeneous in anticipation of a kick.

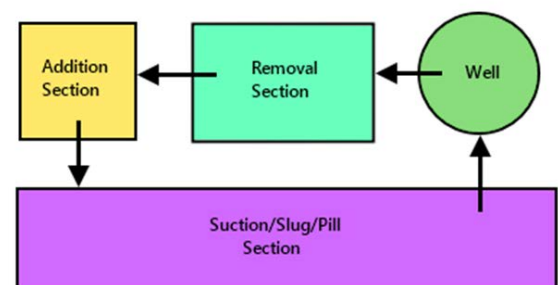


Figure 1: Surface Drilling Fluid Processing Plant

A typical mud tank arrangement for a weighted drilling fluid using fine screening shale shakers might be arranged as shown

in Figure 2.

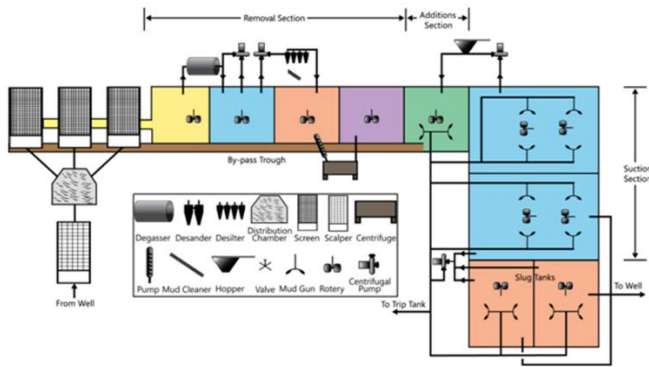


Figure 2: Weighted Drilling Fluid Processing Plant With Fine Screening Shakers

The removal section typically uses agitators to blend the drilling fluid, while often times addition and suction sections use mud guns as well as agitators to blend the drilling fluid.

The suction section volume depends upon the extreme length and inside diameter of the drill string dependent upon the well program. The other two sections are typically smaller in volume. This discussion will concentrate on the plumbing and arrangement of equipment in the removal section. During the life of the authors, correct plumbing systems are rarely observed. Unfortunately, most removal sections seldom process 100% of the drilled solids reaching the surface.

Removal of drilled solids starts at the bottom of the borehole. Cuttings should be transported out of the hole without tumbling and grinding into smaller pieces. Larger cuttings are more easily removed from the active drilling fluid than very small cuttings.

Plumbing arrangements are frequently incorrect and frequently can be corrected with relatively minor changes. Sometimes the correction required is extensive and costly. In one field case, a platform was drilling on the sixth well of twelve planned. The drilling fluid system was incorrectly plumbed on several levels. After finishing the sixth well, 10% of the cost of the 6th well was spent revising the plumbing. The seventh well saved more than this amount compared to the cost to drill any of the preceding six wells because of the elimination of visible and invisible NPT.

Calculating Drilling Fluid Process Efficiency

One of the major problems in drilled solids removal is the inability to process all the drilling fluid. The fluid processing efficiency can be calculated by dividing the volume of drilling fluid treated by the volume of drilling fluid entering the suction compartment. This equation applies only to compartments where the drilling fluid is well blended and homogeneous. If the drilling fluid is not well mixed, the processing efficiency will be significantly lower than the calculated value. Both systems will be discussed.

The fraction of drilled solids processed can be calculated by dividing the processed flow rate by the flow rate of fluid entering the suction tank. This can be more easily observed by considering the tank arrangement in Figure 3. Each dot represents 100gpm. From the shale shaker, four hundred gallons per minute enters Tank #1. The centrifugal pump is moving four hundred gallons per minute through the hydrocyclones and this flows into Tank #2. The 'dirty' dots change to 'clean' dots in Figure 3. No fluid will flow through the equalizing line between Tank #1 and Tank #2.

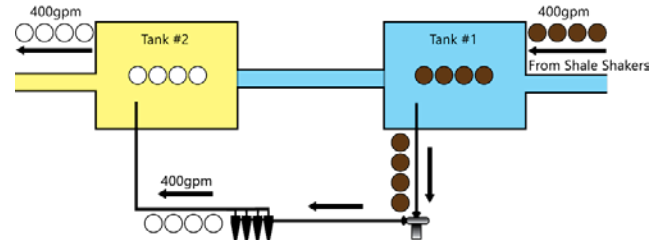


Figure 3: Adequate Arrangement

The fraction of drilling fluid processed, or cleaned, is the volume cleaned by the hydrocyclone divided by the volume entering the suction tank of the hydrocyclone. In this case, the answer is obvious by observing the 'dirty dots'.

$$\eta_{processing} = \frac{Q_{hydrocyclones}}{Q_{in}} \times 100 \quad (1)$$

$$\eta_{processing} = \frac{400gpm}{400gpm} \times 100 = 100\%$$

In this example, all the drilling fluid is cleaned. No fluid enters tank #2 unless it passes through the hydrocyclone. This assumes that no cones on the hydrocyclone bank are plugged from solids which could have by-passed the shale shaker. Note, generally, when 4" hydrocyclones process 50gpm input, the overflow is only 49gpm which 1gpm being discarded (2% of the processing rate). For purposes of estimating the process efficiency of the system, this small discard can be ignored. In Figure 3, the smaller hydrocyclone overflow would actually decrease the removal process efficiency to less than 100%.

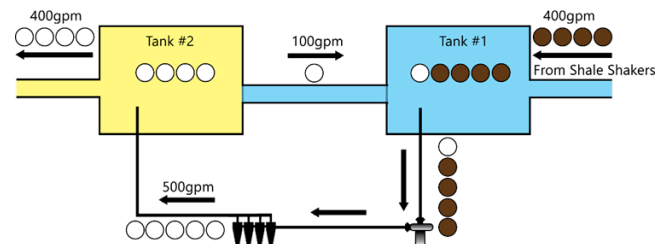


Figure 4: Better Tank Arrangement with Back Flow from Tank #2 to Tank #1.

Processing Considerations

- 1) The Flow Rates in the Well May Not Always Be

Constant:

To provide a degree of flexibility, the hydrocyclones should process more fluid than is arriving in their respective suction tank. In the diagram above, four hundred gallons per minute are arriving at the surface. If the bank of hydrocyclones process five hundred gallons, there will be a back flow between tank #2 and tank #1. This insures that all of the fluid in tank #2 has been processed through the hydrocyclones - or 100% processing efficiency.

The fraction of drilling fluid processed, or cleaned, is the volume cleaned by the hydrocyclone divided by the volume entering the suction tank of the hydrocyclone. In this case, the answer is obvious by observing the 'dirty dots' in Figure 4.

$$\eta_{processing} = \frac{400gpm + 100gpm}{500gpm} \times 100 = 100\%$$

2) Insufficient Processing:

The calculation can be better explained using the next tank arrangement, (Figure 5). In this case, the flow entering Tank #1 from the well is 400gpm; however the hydrocyclones are processing only 300gpm. There will be 100gpm flowing from Tank #1 to Tank #2. Counting the "dirty dots" in Tank #2, reveals that three hundred gallons per minute are clean but one hundred gallons per minute have not been cleaned.

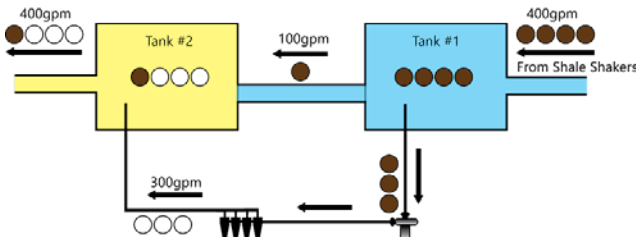


Figure 5: Insufficient Processing Capability

Cleaning process efficiency is the ratio of the fluid volume being cleaned divided by the volume entering the suction tank of the equipment. From the shale shaker, 400gpm is entering tank #1 and only 300gpm is being processed.

$$\eta_{processing} = \frac{300gpm}{400gpm} \times 100 = 75\%$$

In Figure 5, tank #2 contains three clean dots and one dirty dot – or three out of every four gallons is being cleaned. This is a 75% cleaning efficiency.

Usually, however, keeping an exact balance is difficult. More fluid should be processed by the equipment than is flowing from the well. The general rule of thumb for in-line solids control equipment in the removal section is to process 125% of the active circulating volume. In tank #2, three cleaned dots and one dirty dot indicate that only 75% of the fluid is being processed through the hydrocyclones. The equation

predicts the fraction of drilling fluid processed.

Occasionally, someone on the rig will route the overflow from the hydrocyclones back into the same tank with the concept that the hydrocyclones will process the drilling fluid twice and provide a cleaner drilling fluid, (Figure6). Consider the case where 400gpm is coming from the well and the bank of hydrocyclones is cleaning 500gpm and discharging into the tank downstream (like the first arrangement). In this case the hydrocyclones are processing 500gpm but 900gpm (500gpm+400gpm) is entering tank #1. The process efficiency would be:

$$\eta_{processing} = \frac{500gpm}{900gpm} \times 100 = 56\%$$

Instead of the hydrocyclones "looking at the mud twice", it only processes about one-half of the fluid entering tank #1.

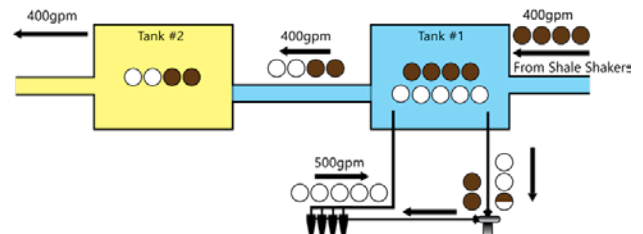


Figure 6: Incorrectly Returning the Overflow From Desilters Back To The Suction Compartment

If the flow from the well was reduced to 350gpm and processing 400gpm should obviously provide a good processing plant; but not if the clean fluid from the hydrocyclones is put back into the suction tank. In this case, only 56% of the drilling fluid is processed, (Figure 6).

Frequently, the hydrocyclone discharge is located upstream from the suction, (Figure 7). In one case, the discharge was a hose that could easily be moved from one tank to another. In the plumbing arrangement in Figure 7, 600gpm is entering tank #1 from the well and the hydrocyclones are cleaning 600gpm. The total flow entering the suction tank #2 of the hydrocyclones is 1200gpm. The processing flow rate is 600gpm. The process efficiency is 50%.

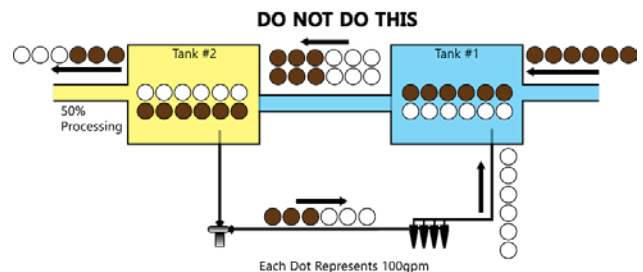


Figure 7: Discharge Upstream from the Hydrocyclone

Another incorrect plumbing situation has been observed on several rigs. The desilter and desander suctions are in the same tank and the discharge from both hydrocyclones is into the same tank, (Figure 8).

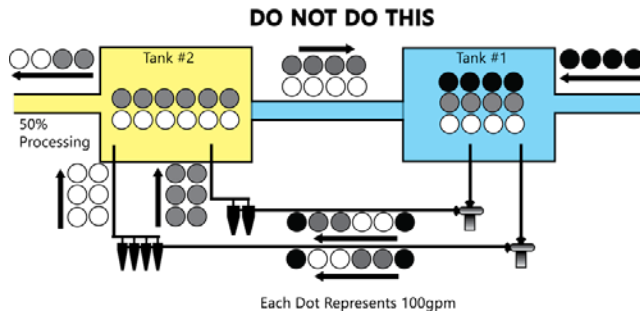


Figure 8: Parallel Processing of Desander and Desilter

In Figure 8, the fluid entering tank #1 from the well is 400gpm. The desilter is processing 600gpm and the desander is processing 600gpm. This probably meets the contract agreement when the solids removal equipment is processing much more than the flow rate downhole. However, the flow rate returning to tank #1 from tank #2 is 800gpm. The desilter processing efficiency is calculated by the equation:

$$\eta_{processing} = \frac{Q_{desilters}}{Q_{in}} \times 100 \quad (2)$$

$$\eta_{processing} = \frac{600gpm}{400gpm + 800gpm} \times 100 = 50\%$$

The desander processing efficiency is also 50%. The hydrocyclones should process fluid sequentially from one tank to the next tank as illustrated in Figure 9. If a fine mesh screen is being used on the main shale shaker, the desander could be eliminated from the processing plant.

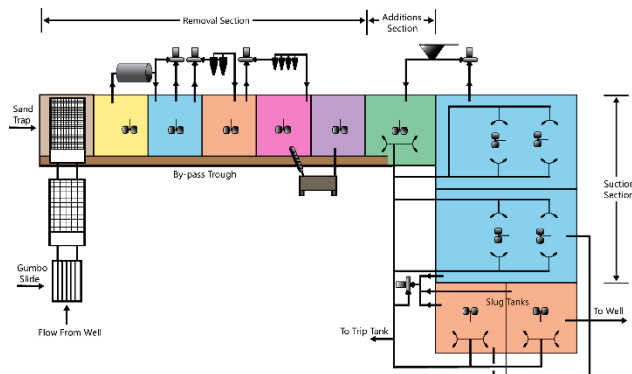


Figure 9: Unweighted Drilling Fluid with Desanders and Desilters

One field example of the plumbing shown in Figure 8 is shown in the picture in Figure 10. Notice that the desander bank (just behind the top of an agitator) is connected to the same line which is feeding the bank of desilters. What is wrong with this system? A sketch of the flow paths reveals a significant problem. The desilter feed and the desander feed lines are from the same pipe. These are in parallel and neither can process 100% of the fluid just like the drawing in Figure 8.

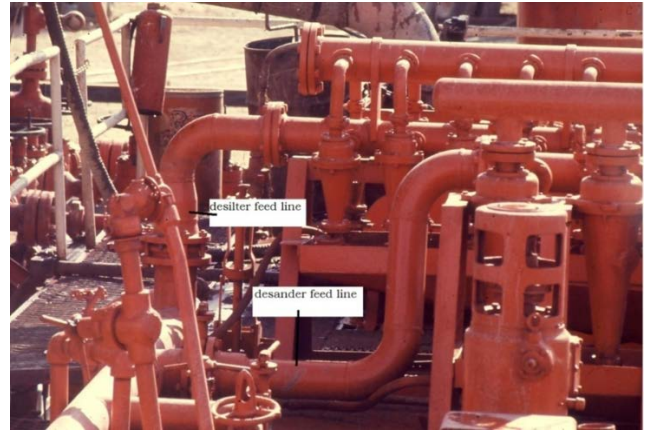


Figure 10: Field Example of the Desilter and Desander in Parallel with Feed From The Same Pump

The total number of cones cannot be counted in the picture Figure 10. Assuming that only 400gpm of fluid was coming from the well, the desanders are processing 600gpm and the desilters are processing 500gpm (perhaps by contract), the system looks good. However, using the equation for the fraction cleaned, the desilter is only processing about 45% of the fluid from the well.

Another bad field example came from a location that wanted to decrease their problems with centrifugal pumps. The Company Man connected all the equipment up to one pump. This pump was connected into the suction tank, (Figure 11). But only one centrifugal pump needed to be used. Several spare pumps meant that pumps could be sent in for repair without shutting the system down. As an interesting exercise, note that removing the desanders from the system will increase the total fraction of fluid processed by the desilters.

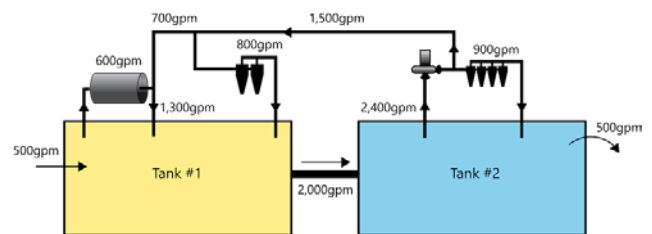


Figure 11: Mud Tank Arrangement Using Only One Pump

Entering the suction tank#1: 500gpm from the well, 700gpm from the degasser jet pump, and 800gpm from the desanders or 2000gpm. [The 600gpm through the degasser leaves and re-enters the same tank.] The desanders are processing 800gpm.

The process efficiency for the desanders is:

$$\eta_{processing} = \frac{800gpm}{2000gpm} \times 100 = 40\%$$

The process efficiency for the desilters is:

$$\eta_{processing} = \frac{900gpm}{2900gpm} \times 100 = 31\%$$

Clearly the drilled solids are going to build in this drilling fluid. The contract might read that the hydrocyclones must process at least 100gpm more than the fluid being pumped downhole. Clearly, in this case, that is insufficient to guarantee good clean drilling fluid.

Suction Section

Consider a 12 ¼" hole being drilled with a 5 ½", 24.7 lb/ft drill string and 600ft of bottom hole assembly (BHA) at a depth of 10,600ft with a 12.0ppg drilling fluid being circulated at 650gpm. In this case, the operator is attempting to decrease the drilling fluid cost and wanted the minimum volume on the surface. The suction compartment had a 200bbl volume. How will this affect the kill procedures when handling a kick?

Conventional Well Control:

When a kick is detected, the blowout preventers are closed. The pressure in the drill pipe at the surface is measured and used to determine the underbalanced pressure at the bottom of the hole. For example, if a kick was detected in the well described above and the drill pipe pressure was 827psi, the amount of mud weight increase needed would be calculated from the following equation:

$$MW_{increase} = \frac{P_{kick}}{(0.052) \times (D)} \quad (2)$$

$$MW_{increase} = \frac{827psi}{(0.052) \times (10600ft)} = 1.5ppg$$

This assumes the drill string is filled with a homogeneous fluid. The pressure at the bottom of the drill string before the kick was:

$$P = 0.052 \times MW \times D \quad (3)$$

$$P = 0.052 \times 12ppg \times 10600ft = 6614psi$$

The pressure at the bottom of the drill string after the kick was 827psi higher or 7441psi. The kill weight drilling fluid would need to be 13.5ppg.

Potential Problem with Small Suction Section

With the 650gpm flow rate, the residence time of the fluid in the suction tank would be:

$$t = \frac{V_{tank}}{Q_{circulating}} \quad (3)$$

$$t = \frac{200bbl \times 42 \frac{gal}{bbl}}{650gpm} = 13min$$

During this interval of time, the derrick man is responsible for maintaining constant drilling fluid properties. For this example, barite is dumped into the tank for only 5 minutes and the resulting mud weight is 13.0ppg. In 5 minutes, the volume pumped into the drill string would be 3250gal or 77.4bbl (volume = (650gpm) × (5min)). The capacity of the 5 ½" drill pipe is 21.19bbl/1000ft or 3653ft. The pressure at the bottom of the drill pipe would be created by a 6947ft column of 12.0ppg drilling fluid plus a 3653ft column of 13.0ppg drilling fluid. The resulting downhole pressure would be:

$$P = 0.052 \times 12.0ppg \times 6947ft + 0.052 \times 13.0ppg \times 3653ft = 6804psi$$

The actual resulting downhole pressure would be 190psi (6804psi – 6614psi) higher than the original pressure with the 12.0ppg drilling fluid. The shut-in pressure in this case would be 637psi (7441psi – 6804psi) instead of the 827psi if the fluid in the drill pipe was homogeneous at 12.0ppg.

Using the shut-in pressure to calculate the kill weight drilling fluid, the 637psi requires an increase in mud weight of:

$$MW_{increase} = \frac{637psi}{(0.052) \times (10600ft)} = 1.0ppg$$

Resulting required mud weight would be 13.0ppg (increase from 12.5 from previous increase). After pumping the kick out with the incorrect mud weight, the well control procedures would have to be repeated. The suction section needs to be larger to allow slugs of over or under weight drilling fluid to be blended in order to provide a continuous supply of homogeneous fluid.

Summary

Complex plumbing in the drilling fluid processing system and multiple valves seems pervasive throughout the industry and has for many years. The picture of the plumbing in Figure 12 was taken many years ago.



Figure 12: Old Picture of Typical Incorrect Plumbing on a Jack-up Rig

The picture of the incorrect plumbing in Figure 13 was taken just recently on a new drilling rig.



Figure 13: Picture of Incorrect Plumbing on a New Rig

Some of these complex pumping systems require hours of study of the piping diagram (which may be incorrect) to decide which valves should be opened and which ones closed to properly process the drilling fluid. Even if there is a possible correct setting for all valves, the likelihood of a roughneck getting it correct is very small.

Guidelines to Follow:

1. The drilling fluid processing arrangement in the Removal Section should have one pump, one switch, and process the fluid into the next tank downstream.
2. Pumps in the Removal Section should not have multiple manifolding so that they can pump from any tank to any other tank. (If this is desirable, install other pumps.)
3. The equipment should process more flow than is entering the suction tank of the removal equipment.
4. The Removal Section should overflow into the Addition section. This will keep a sufficient head on the processing pumps to prevent cavitation and also make the pit level indicators more sensitive to kicks or lost circulation problems.
5. No mud guns should be used in the Removal Section, unless additional equipment is installed to account for the increase in flow into the suction tanks of the equipment or each pump can stir its own suction tank.

Nomenclature

$\eta_{processing}$ = processing efficiency (%)

Q_{in} = flow into compartment (gpm)

$Q_{desilters}$ = flow rate through desilters (gpm)

$Q_{hydrocyclones}$ = flow rate through hydrocyclones (gpm)

$Q_{circulating}$ = rig circulating rate (gpm)

$MW_{increase}$ = mud weight increase needed (ppg)

MW = Mud Weight (ppg)

ΔMW = mud weight increase required (ppg)

D = depth (ft)

P_{kick} = kick pressure (psi)

P = bottom hole pressure (psi)

t = residence time (min)

V_{tank} = volume of tank (gal)