# Jetting of Structural Casing in Deepwater Environments: Job Design and Operational Practices

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## Summary

Structural casing jetting operations have become commonplace in deepwater environments. Having originated in the Gulf of Mexico (GOM), structural casing is now jetted in most deepwater basins in the world. Very little literature has been published regarding jetting practices. The lack of published literature, combined with the complex mechanics and hydraulics of the process and the lack of detailed-soil data at most locations, results in an operation that is heavily dependent on the experience and expertise of the rigsite team. This paper reviews current deepwater structural casing jetting job design and operational practices. Also included are several case histories of jetting failures presented to share learnings with the industry and to stimulate the sharing of learnings and practices.


## Introduction

Structural casing (also known by some operators as conductor casing, surface casing, or surface conductor) is defined as the first string of casing installed in the well construction process. By definition, it provides structure and support for all the casing strings, the subsea Christmas tree, and blowout preventer (BOP) stack. Structural casing must be able to resist bending moment loads imposed on it by the mobile offshore drilling unit (MODU) and by future production workover operations. In certain areas with shallower water, the casing may also need to resist loads imposed by trawler net entanglement. The casing must be installed reasonably straight/vertical, usually with less than 1° angle, to avoid drillstring wear on wellhead and BOP components.

Jetting of structural casing has become the preferred method of installation in most deepwater environments where seafloor sediments allow the technique to be used. Operators have found the technique to be faster than the historical method of drilling a rathole and cementing the casing in place. Some deepwater basins, however, have harder seafloor sediments, boulders, or rubble zones that prevent jetting from being an effective technique.

The history of jetting can be traced to the first floating rigs used in the U.S. GOM in the 1960s. Minton (1967) describes the installation process used to install structural casing from the first floating rigs developed in the early 1960s. One hundred feet of 29½-in.×1.0-in. wall thickness casing was set using a combined drive-jet process. The casing was connected to the drive-jet bottomhole assembly (BHA) by means of a J-slot tool with a 3-ft stroke to allow driving action with the BHA. The BHA consisted of 5½-in. drillpipe with two 22-in. leaded drill collars, weighing a combined 60,000 lbm, to impart impact and add additional penetrative weight into the sediments. **Fig. 1** illustrates this assembly. Jetting occurred through a jet sub (no bit or motor) and returns were taken outside of the structural casing. **Fig. 2** depicts the process and shows both fluid and jetted solids were forced to the mudline along the outside of the casing. Minton alludes that, even from the early days of floating drilling, settling of structural pipe has been a concern.

In the 1970s, development of tools such as the positive-displacement mud motor and the wellhead-housing running tool allowed the jetting technique to evolve (Reimert 1975). Ports in the wellhead-housing running tool allowed returns to be taken inside the casing rather than outside the casing resulting in less soil disturbance. Positive displacement mud motors allowed the rotation of bits in the jetting string and more efficient break-up and fluidization of the sediments.

The jetting technique has spread to other geologic basins/geographical areas around the world. Salies et al. (1999) state that jetting of 30-in. structural casing began in the Campos basin of Brazil in 1993. The use of jetting to set structural pipe in the deepwater of West Africa countries such as Angola, Nigeria, and Congo emerged in the middle-to-late 1990s. Operators in deepwater basins off Trinidad, Canada, Australia, and southeast Asia have all adopted structural-casing jetting as the preferred method of installation.

**Fig. 3** illustrates the current basic jetting process. A jetting BHA consisting of a bit, mud motor, and other components, is run inside the structural casing and attached to the wellhead-running tool. The combined assembly is run to the mudline. As the structural casing penetrates the soft mudline sediments by virtue of its own weight, circulation is used to provide a combination of hydraulic washing and bit rotation by means of the mud motor. The process gained the name "jetting" through the hydraulic washing of sediments from the path of the casing. Because the drilled/washed footprint is smaller than the outside diameter of the casing, the casing is pressed into the undersized hole by the weight being slacked off onto the formation. Cuttings and sediments that have been hydraulically loosened travel up the jetting BHA by means of the casing annulus. The sediments exit the annulus by ports in the wellhead and the wellhead running tool to the open ocean. Cementing of the jetted-structural casing is not required because no annular space exists between the formation and the casing. The jetted casing is held in place by the shear friction between the soil and the casing.

Little published information is available concerning structural-casing jetting job design and execution. Beck et al. (1991) discussed jetting job design on the basis of site-specific soil borings. The use of "donuts," or large-clump weights, were advocated to add additional weight-on-bit (WOB) while jetting, and to ensure the final jetted depth of the casing would support the added weights imposed by the 20-in. casing string. The use of the donuts has ceased in the subsequent years, and site-specific soil borings have often been omitted as being a "luxury." Regional data and offset records are now used to determine the length of casing to jet. Jeanjean (2002) updated the work of Beck et al. (1991) and explained his company's current design practices. Operational practices were covered in less detail than the casing design and placement strategy. Eaton et al. (2005) discussed operational practices used for jetting structural casing in a recent deepwater GOM development.

A successful jetting operation can result in time and cost savings, whereas an unsuccessful jetting can result in broaching back to the seafloor, stuck casing, casing subsidence, or complete loss of the wellbore. This paper details design and operational practices used by the operator to jet structural-casing strings. Case histories of jetting failures are presented to share lessons learned with the industry.

## Jetting Job Design: Casing Considerations

The primary question a drilling engineer must answer is: How many joints of structural casing should be jetted to achieve sufficient load capacity? Too few joints and the casing will sink under



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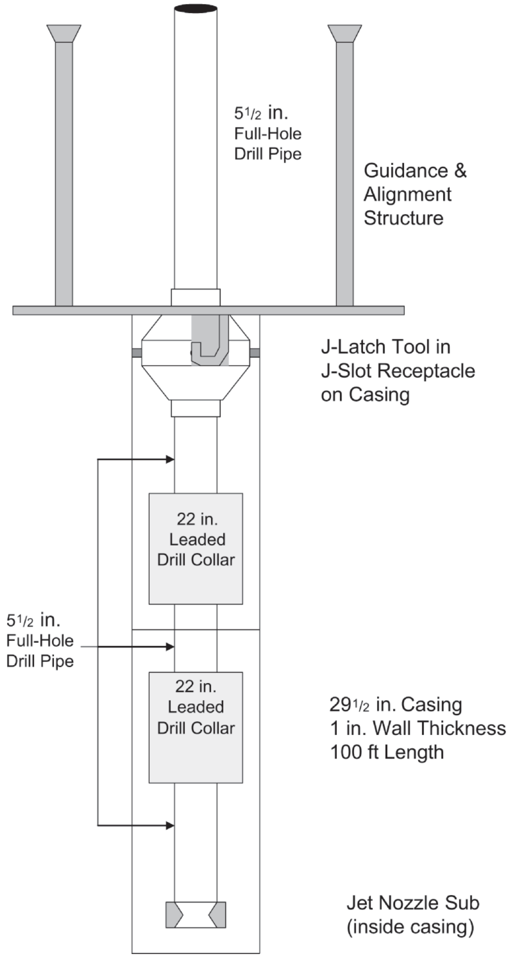


**Fig. 1—Original jetting assembly configuration.**

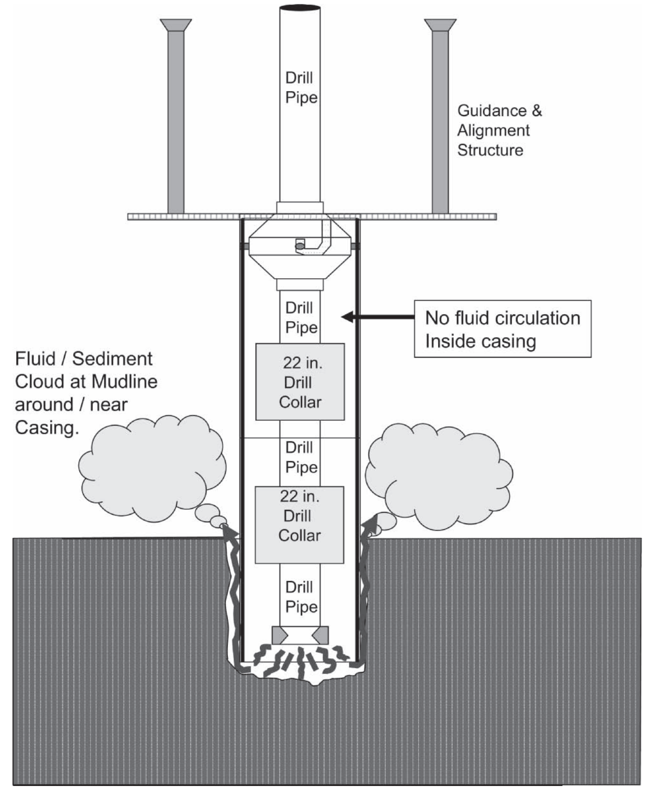


**Fig. 2—Original jetting process.**

load. Too many joints and the drill team runs the risk of not being able to jet to planned total depth (TD).

Jetting of structural casing is aptly compared to the installation of a pile. API-*RP-2A-WSD* (2000) provides guidance on pile design, and jetted casing is often designed using the principles of pile design. The capacity of a pile is dependent upon both the end-bearing capacity and the shear friction along the length of the pile. Shear friction is often referred to as skin friction. Because structural casing is a hollow tube and the tube wall is often unsupported from below because of washout, the end-bearing capacity of structural casing is assumed to be negligible or zero. Hence, all load capacity is developed from skin friction.

The maximum skin friction that can develop is equal to the shear strength of the adjacent soils. In reality, skin friction rarely approaches this strength because of the disturbance of the soils while jetting, the lack of adhesion of the soils to the structural casing, and the coefficient of friction of clean steel vs. the soil shear strength.

The critical parameters used to determine the skin friction of a jetted pipe, all difficult to determine, include:

- Undisturbed soil shear strength.
- Disturbed soil shear strength.
- Change in disturbed soil shear strength with time.

Undisturbed soil shear strength can be determined from soil borings. Unlike drop core samples that only sample the top 10 to 15 ft below the seafloor and have limited value for this application, soil borings are usually taken down several hundred feet. Normally, a dedicated-geotechnical vessel is required for this purpose. While this data is usually collected for platform/structure foundations for a major field development, site-specific soil borings are rarely available for exploration and appraisal wells because of the additional costs and time constraints. An alternative to this approach is to apply regional soil-strength data for a specific basin or soil-boring data from a nearby development. Additional risk of job failure, however, is incurred when non site-specific data is used. Engineers encouraged to apply a safety factor when employing non site-specific undisturbed soil-strength data. Examples of un-

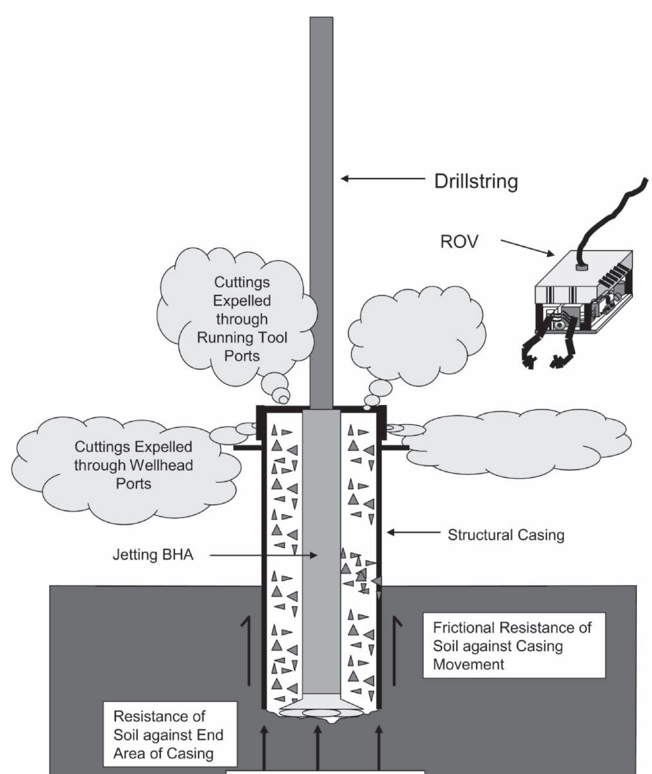


**Fig. 3—Current jetting process.**

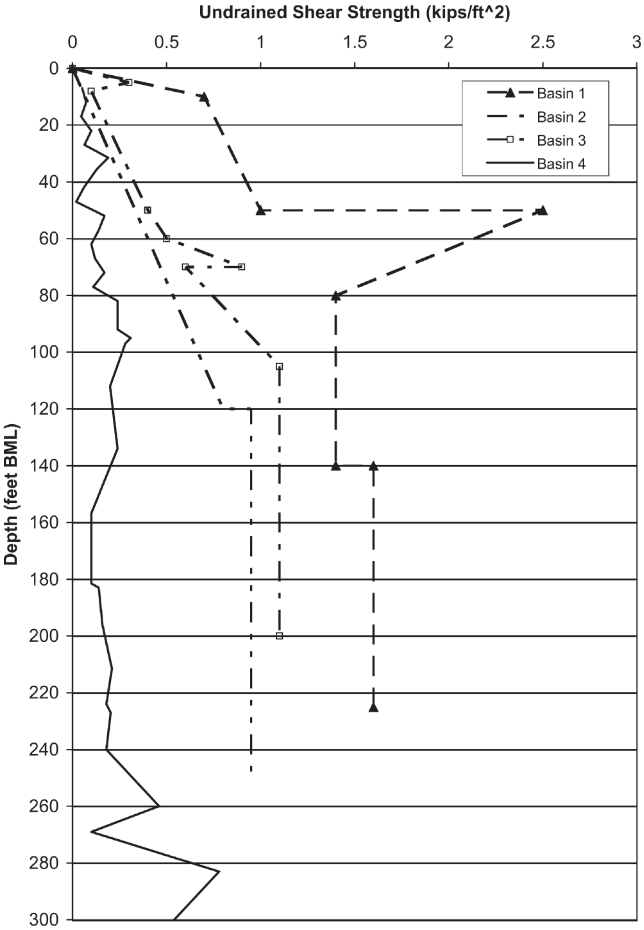


**Fig. 4—Undrained soil shear strength profiles from various basins of the world.**

disturbed soil-strength curves from several of the world's basins where jetting is employed is shown in **Fig. 4.**

The determination of disturbed-soil shear strength is largely empirical. Jetting unconsolidates and weakens the strength of the soil immediately adjacent to the jetted pipe. Beck et al. proposed a method to measure the residual soil-shear strength from soil borings using a miniature vane test. Obviously, this technique requires an actual site soil-boring to be effective. Rather, most companies have estimated the disturbed soil-shear strength as a fraction of the undisturbed strength. Beck et al. offered observations of 25 to 33% of the undisturbed strength. In some uncommon cases, disturbed soil-shear strength factors as low as 10% of the undisturbed value have been used, recognizing that 10% is a conservative approach.

The capacity of a jetted conductor can be calculated using the following equation:

$$Q = Qf = \sum_{x=ML}^{TD} (fx * Asx) = \sum_{x=ML}^{TD} (fos * cx * ax * Asx). \quad \ldots\ldots (1)$$

The determination of the development of skin friction with time is also empirical as it is a function of both soil properties and induced-soil disturbance. In Eq. 1, the development of skin friction with time can be likened to an increase in the value of $\alpha$ with time. Jeanjean presents practices used by his company where they assume an increase of capacity by 20% per log cycle of time, and where they assume an increase of capacity by 100 kips per log cycle of time. He further develops and presents an equation to calculate the increase in skin friction with time on the basis of a database of wells. The most conservative practice is to assume the increase in skin friction with time is negligible. **Fig. 5** shows a sample calculation to determine the number of joints of jetted casing required for an example well. In this example, no increase in disturbed-soil shear strength with time is assumed.

In addition to the number of joints of casing to be run, the tubular connector must also be chosen. Structural casing size and wall thickness are normally chosen not only as a function of the casing program for the well, but for the bending moment capacity

| Soil Strength Gradient from local soil boring or regional data | | |
|---|---|---|
| Soil strength gradient from 0 to 15 ft BML = | 7 | psf / ft penetration |
| Soil strength gradient below 15 ft BML = | 8 | psf / ft penetration |

| DESIGN WEIGHT TO SUPPORT | | | | |
|---|---|---|---|---|
| Casing (inches) | Wt/Ft (lb/ft) | Length (ft) | Air Wt (lbs) | Buoyed Wt (lbs) |
| 36" (est) | 553 | 285 | 157,605 | 136,912 |
| 20" | 133 | 2000 | 266,000 | 231,075 |
| LP Wellhead | NA | NA | 28,800 | 25,019 |
| HP Wellhead | NA | NA | 8,700 | 7,558 |
| MudMat | NA | NA | 12,000 | 10,424 |
| BOP Stack | NA | NA | 257,000 | 223,256 |
| LMRP | NA | NA | 228,000 | 198,064 |
| | | | Total Weight | **832,308** |

| Undisturbed Soil Stength Profile | |
|---|---|
| Depth BML (Feet) | Undist. Soil Strength (Lbs/Ft^2) |
| 0 | 30 |
| 40 | 335 |
| 100 | 815 |
| 160 | 1295 |
| 220 | 1775 |
| 280 | 2255 |
| 340 | 2735 |
| 400 | 3215 |

| CALCULATION OF UNDISTURBED & DISTURBED SOIL STRENGTH | | | | | | | | Cumulative Soil Strength With Reduction for Disturbance After Jetting | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Joint | Top of Joint, ft BML (Feet) | Base of Joint , ft BML (Feet) | Joint Surface Area (Ft^2) | Avg. Undrained Soil Strength (Lbs/Ft^2) | Soil Strength with API-2A SF=2.0 (Lbs/Ft^2) | Undisturbed Soil Capacity of Interval (Lbs) | Cumulative Soil Capacity (Lbs) | 10% Original Strength (Lbs) | 15% Original Strength (Lbs) | 20% Original Strength (Lbs) | 25% Original Strength (Lbs) | 30% Original Strength (Lbs) | 40% Original Strength (Lbs) |
| WH + ext. | 0 | 40 | 376.99 | 182.5 | 91.25 | 34,400 | 34,400 | 3,440 | 5,160 | 6,880 | 8,600 | 10,320 | 13,760 |
| 2 | 40 | 100 | 565.49 | 575 | 287.5 | 162,577 | 196,978 | 19,698 | 29,547 | 39,396 | 49,244 | 59,093 | 78,791 |
| 3 | 100 | 160 | 565.49 | 1055 | 527.5 | 298,294 | 495,272 | 49,527 | 74,291 | 99,054 | 123,818 | 148,582 | 198,109 |
| 4 | 160 | 220 | 565.49 | 1535 | 767.5 | 434,011 | 929,283 | 92,928 | 139,392 | 185,857 | 232,321 | 278,785 | 371,713 |
| 5 | 220 | 280 | 565.49 | 2015 | 1007.5 | 569,728 | 1,499,011 | 149,901 | 224,852 | 299,802 | 374,753 | 449,703 | 599,604 |
| 6 | 280 | 340 | 565.49 | 2495 | 1247.5 | 705,445 | 2,204,456 | 220,446 | 330,668 | 440,891 | 551,114 | 661,337 | **881,782** |
| 7 | 340 | 400 | 565.49 | 2975 | 1487.5 | 841,161 | 3,045,617 | 304,562 | 456,843 | 609,123 | 761,404 | **913,685** | 1,218,247 |
| 8 | 400 | 460 | 565.49 | 3215 | 1607.5 | 909,020 | 3,954,637 | 395,464 | 593,196 | 790,927 | **988,659** | 1,186,391 | 1,581,855 |

more than 8 joints would be required

**Fig. 5—Example calculations to determine length of jetted casing required to support well loads.**

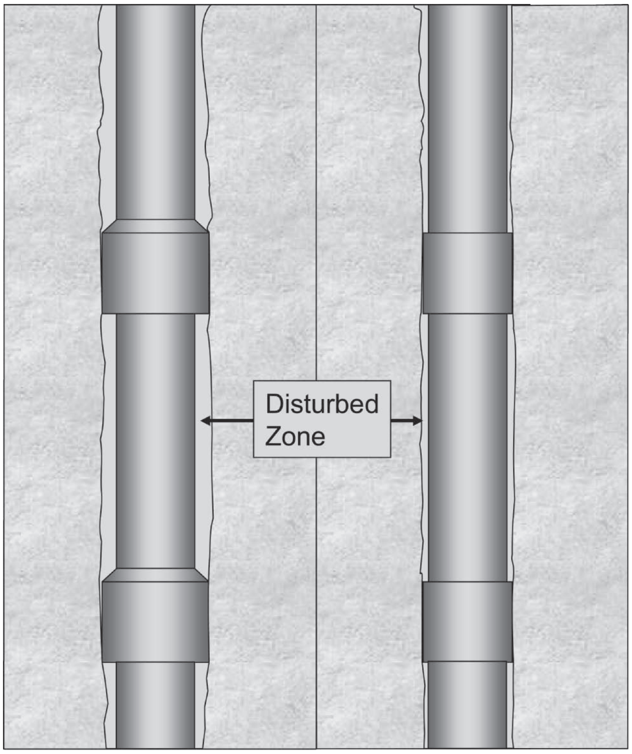


**Fig. 6—Disruption of skin friction caused by larger OD connectors.**

of the casing. The casing must be able to withstand the bending loads imparted by the BOP stack, subsea tree, if present, and loads imparted by the MODU through the drilling riser. The industry shift from 30- to 36-in. structural casing has been driven largely by the need for increased bending moment capacity. Similarly, wall thickness of structural pipe has trended to thicker-walled casing. The thicker-walled casing provides a higher bending-moment capacity and provides greater weight per foot to assist in applying slack-off weight (SOW). The casing connector is normally selected to have a bending-moment capacity to match or exceed that of the casing tube.

Where jetting is concerned, an additional criterion is the connector outside diameter (OD). Larger upsets on the connector tend to disturb the soil more, reduce the residual soil strength, and increase time to rebuild strength/skin friction. Hence, slim-line connectors are preferred for jetting operations. **Fig. 6** illustrates the additional loss of skin friction imparted by the use of larger upset casing connectors.

Another desirable feature in a jetting connection is the inclusion of anti-rotation tabs in the connector design. Many current connectors are made up with a minimum of make-up turns and relatively low torque values. This also infers a minimum of breakout turns to release/decouple the connector. Anti-rotation tabs resist the decoupling of connectors by such forces as reactive torque from high-torque mud motors or from the potential imparted-rotational movement of a drilling vessel.

## Jetting Job Design: BHA and Drillstring Considerations

BHAs used in jetting operations are run inside the structural casing and have the same approximate length as the casing to be jetted. **Fig. 7** shows a typical jetting BHA configuration inside of a structural casing string. The BHA consists of a bit, a mud motor to turn the bit without turning the casing, stabilizers, and drill collars. A measurement while drilling (MWD) tool may be run depending on the well plan. MWD can be used to confirm the conductor is relatively straight by using the near-bit inclinometer and the inclination feature of the MWD. Obviously, azimuth readings will be in error because of magnetic interference. The BHA is run below the low-pressure wellhead running tool. The low-pressure wellhead

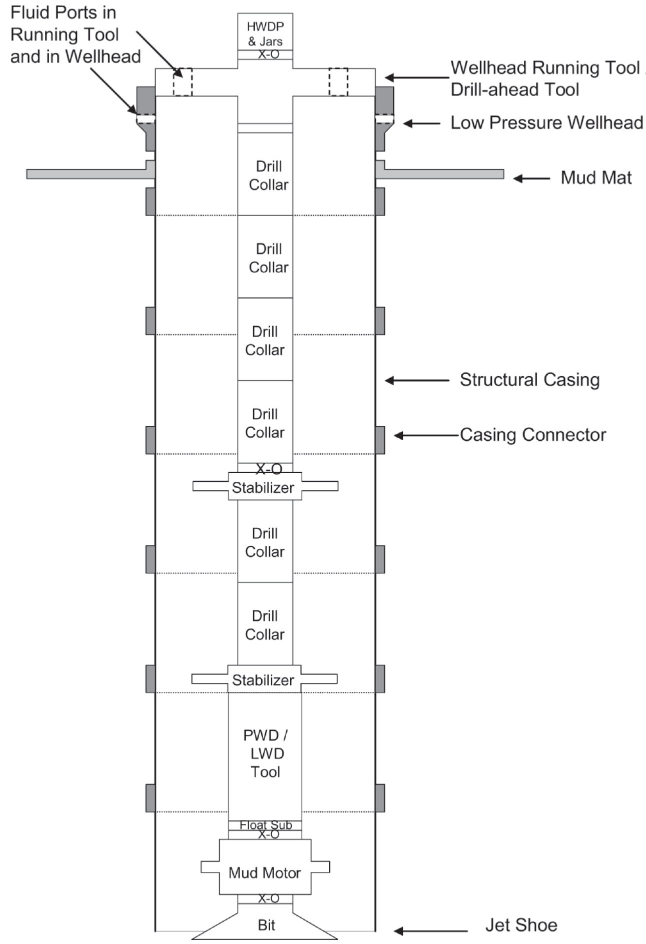


**Fig. 7—Typical jetting BHA and structural casing configuration.**

running tool may be a conventional cam-actuated tool used solely to run and release the casing, or it may be a "drill-ahead" tool, which allows the BHA to be released from the running tool and to drill the next hole section below the structural casing. **Fig. 8** shows a drill-ahead tool for a 36-in.-wellhead. The wellhead-running tool is re-engaged and retrieved while pulling out of the hole. The drill-ahead tool saves a trip by not having to pull out of the hole to lay down the wellhead-running tool.

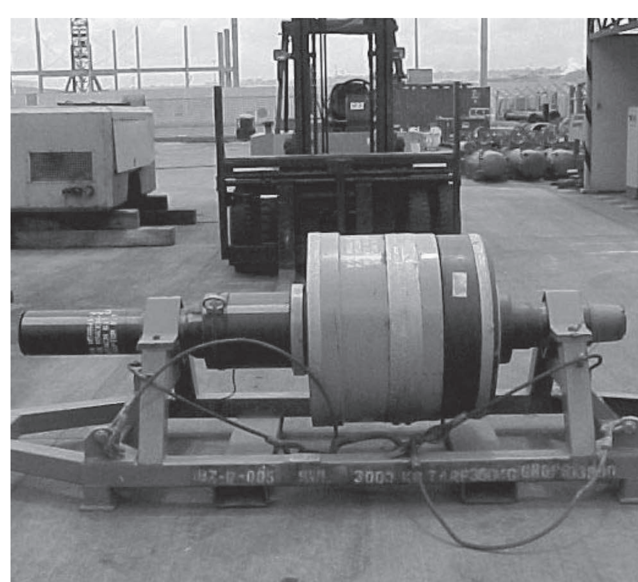

**Fig. 8—Drill-ahead tool for 36-in. wellhead.**

Two important issues in BHA design for a jetting operation are the size of the bit/BHA and the location of the bit in relationship to the end of the jetting string (known as the jet shoe). The bit size is usually selected on the basis of the casing plan for the well and the desire to drill ahead in the subsequent hole. The drill-ahead option may be forgone in some cases in favor of jetting with a larger size bit/BHA and a higher chance of jetting success.

In the jetting operation, the soils in the path of the structural casing are removed by a combination of bit rotation and jet washing from the bit nozzles. A larger size of the bit, in relationship to the inside diameter (ID) of the casing, will result in less soil having to be removed by hydraulic washing. In general, a larger size bit in relationship to the casing ID will result in a higher-jetting success rate. **Fig. 9** illustrates this principle. Shown are four common jetting configurations: 36-in.-casing combined with a 26-in.-bit, and again with a 17½-in.-bit, and 30-in. combined with a 26-in.-bit, and again with a 17½-in.-bit. The percentages of area soil removal by bit vs. hydraulic action are as follows:

Casing/BHA combination:

| | Bitface (% Total Area) *Drilled Area* | Non-Bitface (% Total Area) *Hydraulically Washed Area* |
|---|---|---|
| 30-in. casing×26-in. bit | 92.5% | 7.5% |
| 30-in. casing×17½-in. bit | 41.9% | 58.1% |
| 36-in. casing×26-in. bit | 62.0% | 38.0% |
| 36-in. casing×17½-in. bit | 28.1% | 71.9% |

The position of the bit in relationship to the end of the jetting string or jet shoe is termed the bit space-out or bit stick-out. Bit space-out is achieved by measuring the BHA configuration length closest to the desired jetting length and then trimming the jet shoe joint to achieve the desired space-out. Beck et al. (1991) advocated locating the bit 12 to 18 in. inside the casing. Jeanjean (2002) continued to advocate a bit space-out of up to 18 in. inside the casing. Eaton et al. (2005) mentions a bit space-out of 6 in. below the shoe.

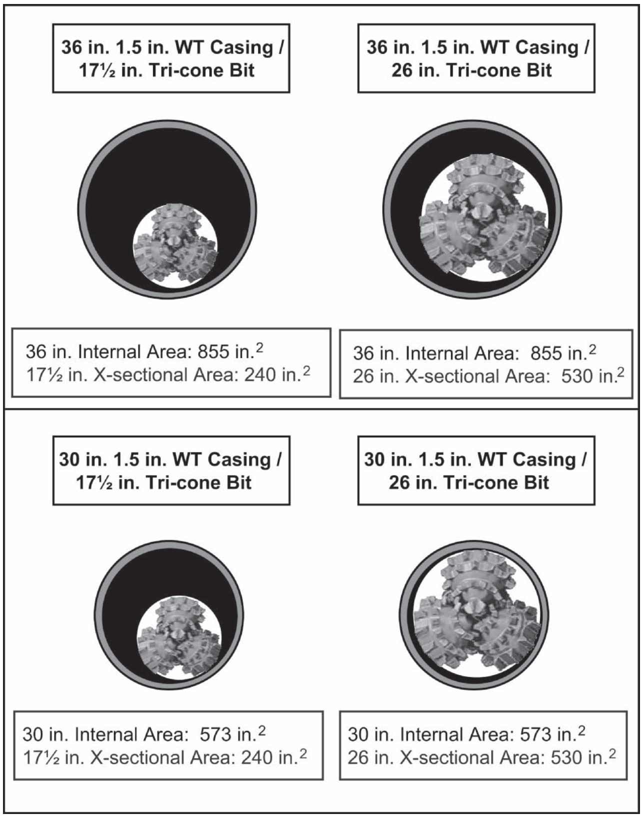


**Fig. 9—Comparison of casing IDs to bit sizes.**

Some operators choose to position the bit just inside the casing to avoid washing out too much formation around the casing, while other operators prefer to position the bit just outside the casing to allow the bit to drill or break up any hard streaks that may be encountered. The experience of this operator has been most successful with the bit located just outside the casing. The design goal has been to locate the bit such that the bit nozzles remain inside the casing while the bit leg and cone are positioned outside the jetting shoe.

Operators have used polycrystalline diamond compact (PDC) bits for jetting structural casing strings with both successes and failures, and justification for PDC bit use is often met with a higher level of scrutiny. PDC bits are problematic for two reasons. First, jetting casing with the PDC cutters near the jet shoe can lead to cutter damage and wear. Second, PDC bits are generally designed with a large and abrupt transition from the bit gauge to the bit shank. An error of only one inch on the bit space-out can result with the bit shank being opposite the shoe. With this configuration, PDC bit blades can conceivably cut formation outside of the structural casing area. This occurrence leads to an even higher percentage of formation inside the structural-casing area having to be removed by hydraulic washing and a greater chance of a cuttings plug forming inside the casing. The combination of a cuttings plug inside the casing and a drilled path outside of the casing can increase the probability of broaching.

BHAs with stabilization close to the bit provide superior performance. The stabilization normally takes the form of a stabilizer sleeve on the mud motor. The function of this stabilizer sleeve during jetting is to assist in keeping the bit path directly beneath the casing and not to the outside of the casing diameter.

The drillstring used for jetting must be selected considering the potential tensile loads. Jetting has been called "controlled sticking" because of the desire that the casing get rapidly stuck when it reaches TD. If the drillstring tensile load is reached before a reciprocation of the casing can be initiated, the casing is stuck by definition. Often in this process, drillstring overpulls to reciprocate casing can vary between 200 and 350 kips over string weight. The drillstring should be checked for its most recent inspection, available overpull, and suitability to the application.

Connections in the BHA from the wellhead-running tool to the bit should be robust. Modern large-mud motors can generate significant reactive torque, which can easily twist off weaker connectors. Connections such as 6-⅝-in. "API Regular" should be selected over smaller connectors such as 4½-in. "IF" whenever possible. In addition, all connections in the BHA should be inspected for cracks before use.

## Jetting Job Design: Operational Parameters

Structural casing and BHA designs are crucial to a successful jetting operation, but the operational parameters used to jet the casing string into place play an equal role. Because the drillstring and casing do not rotate during the jetting operation, operational parameters are limited to slack-off weight (SOW), pump rate, reciprocation of the casing/BHA, and the use of sweeps.

**Slack-off Weight.** SOW is the amount of weight transferred from the rig to the formation at any period of time. While the term weight-on-bit (WOB) is more commonly used, SOW is more accurate because the transferal of weight is not just to the bit/jet shoe, but also to the surface area of the jetted pipe. Most of what is called WOB is actually the development of skin friction between the casing outer surface and the formation. SOW is a key input to the rate of penetration (ROP) of the jetted casing into the formation. Too little SOW can halt forward progress and allow the bit to wash out an interval, while too much SOW can indicate the casing string is sticking. Individual company practices for jetting SOW schedules vary, although the common goal of published practices is to target a final SOW equal to or near the equal buoyed weight of the casing string plus the weight of the jetting BHA. With this amount of weight already transferred to the formation, the jetted casing will not subside when the running tool is released.

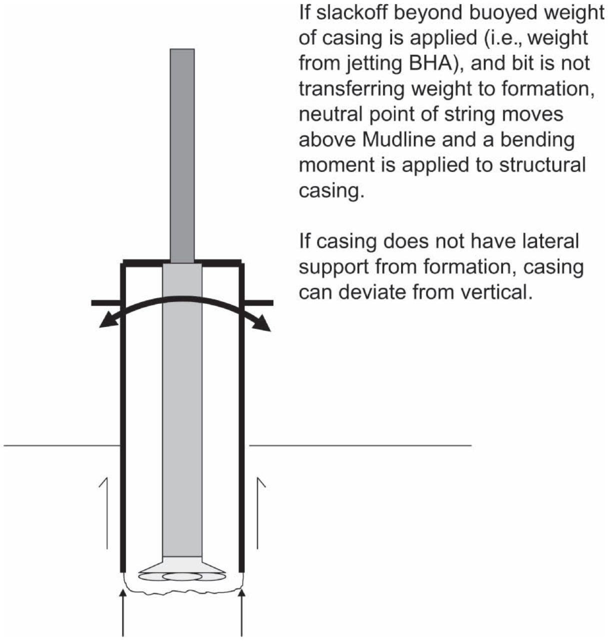


**Fig. 10—Bending moment created by use of BHA weight when weight not transferred to soil.**

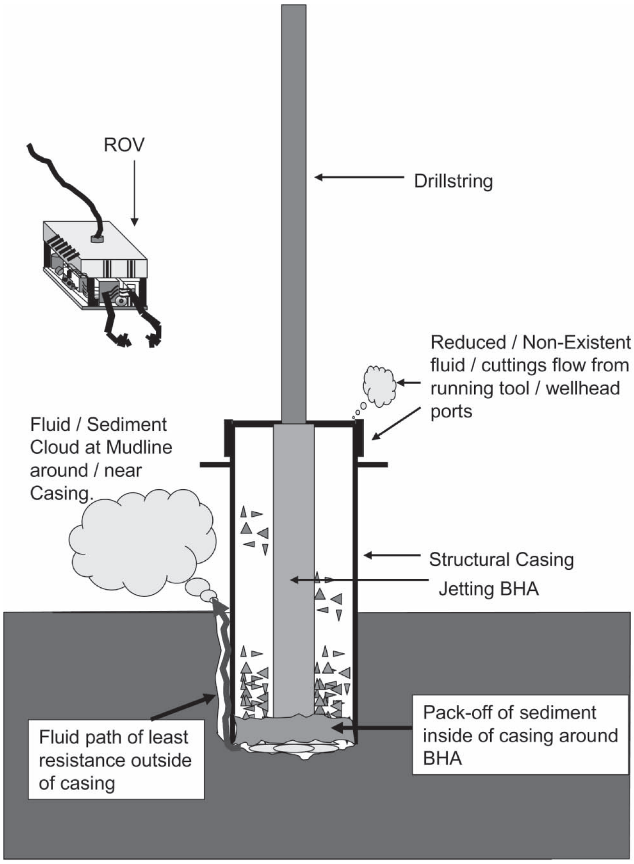


**Fig. 11—Illustration of packoff/broaching event.**

Too much SOW while jetting can result in some degree of string buckling. Any degree of buckling in the string can result in lateral forces and deviated jetting of the casing. A schedule of allowable SOW for jetting can be developed using the Euler Buckling force calculation that has been modified for having one end fixed [casing fixed at an assumed distance below the mudline (BML)]. SOW is restricted to available buoyed weight of the BML casing until buckling ceases to be a concern. Use of the buoyed weight of the BML BHA is not included. This is because of the risk the BHA weight is not being transferred to the formation. If sediments have been washed ahead of the bit, the BHA weight acts as a point weight up at the wellhead-running tool. Applying additional SOW will result in compressional loads above the mudline and the generation of a bending moment. **Fig. 10** illustrates this concept. Once sufficient casing has been jetted to provide lateral stability, use of the weight of the BML jetting BHA is allowed to maximize available SOW. Most operators apply a small safety factor to the maximum allowable SOW to prevent the drillstring from buckling in open water. The Appendix provides further details of the calculations used to construct SOW guidelines that consider casing buckling.

**Pump Rate.** Pump rate plays a key role in the jetting process. Depending upon the casing by BHA configuration, up to two-thirds of the formation removed is hydraulically jetted loose vs. physically drilled. All of the cuttings (drilled or jetted) are removed from the casing by BHA annulus through fluid circulation. Pump rate is critical to removing cuttings from the annulus, keeping the annulus clean, and preventing a packoff, which leads to broaching. An illustration of a packoff/broaching event is shown in **Fig. 11.**

Annular velocities inside structural casing by jetting BHAs are extremely low at the flow rates normally used for jetting, as shown in **Table 1.** For a 36-in.-casing×8-in. drill collar annulus, a flow rate of 1000 gal/min only results in an annular velocity of 24 ft/min. As a comparison with a more familiar hydraulic situation, a 21-in.-drilling riser with 5½-in. drillpipe and a 1,000 gal/min flow rate yields an annular velocity of 69 ft/min.

The extremely large annulus of structural casing yields low annular velocities and slow solids removal from the casing. Neglecting slip velocity, the trip from the jet shoe to the wellhead in a 36-in.×8-in. drill collar×300 ft annulus takes approximately 12 minutes at 1,000 gal/min. At a typical jetting ROP of 120 ft/hr, the annulus will contain over 26 bbl of cuttings at any one time. In 5,000 ft water depth, the resultant additional hydrostatic head from the cuttings is almost 0.1 lbm/gal equivalent mud weight (EMW). **Tables 2 through 4** show sensitivities of these numbers to flow rate, ROP, and annular configuration.

The above discussion shows the need for the highest flow rates possible while jetting. While many operators have switched to larger sizes of structural casing, the flow rates used in jetting

**TABLE 1—ANNULAR VELOCITY IN STRUCTURAL CASING X JETTING BHA ANNULUS AT VARIOUS FLOW RATES**

| Annular Velocities at Various Flowrates for Typical Jetting Annuli (ft/min) | | | | | | |
|---|---|---|---|---|---|---|
| | Flow Rate (gal/min) | | | | | |
| | 200 | 400 | 800 | 1,000 | 1,200 | 1,400 |
| 30 in.-casing x 8 in. DC's | 7 | 15 | 29 | 37 | 44 | 52 |
| 30 in.-casing x 9½ in. DC's | 8 | 15 | 31 | 38 | 46 | 54 |
| 36 in.-casing x 8 in. DC's | 5 | 10 | 19 | 24 | 29 | 33 |
| 36 in.-casing x 9½ in. DC's | 5 | 10 | 20 | 25 | 29 | 34 |

| TABLE 2—TIME SPENT IN STRUCTURAL CASING X JETTING BHA ANNULUS BY CUTTINGS AT VARIOUS FLOW RATES | | | | | | |
|---|---|---|---|---|---|---|
| Time Spent by Cuttings in 300 Feet of Annulus With Zero Slip Velocity (min) | | | | | | |
| | Flow Rate (gal/min) | | | | | |
| | 200 | 400 | 800 | 1,000 | 1,200 | 1,400 |
| 30 in.-casing x 8 in. DC's | 40.7 | 20.3 | 10.2 | 8.1 | 6.8 | 5.8 |
| 30 in.-casing x 9½ in. DC's | 39.1 | 19.5 | 9.8 | 7.8 | 6.5 | 5.6 |
| 36 in.-casing x 8 in. DC's | 62.7 | 31.4 | 15.7 | 12.5 | 10.5 | 9.0 |
| 36 in.-casing x 9½ in. DC's | 61.1 | 30.6 | 15.3 | 12.2 | 10.2 | 8.7 |

smaller structural-casing strings have been maintained effectively reducing the hydraulics.

Operationally, when the structural casing is spudded, the mud pumps are turned off or rolled at a very slow rate to keep the bit nozzles from plugging. Progress is made by virtue of the SOW alone. At a nominal value of SOW (5 to 10 kips), the pump rate is increased. The pump rate continues to increase with depth until a maximum planned flow rate is reached. The depth at which maximum flow rate is targeted is on the basis of broaching history of the area, but is usually before 150 ft BML. As the casing approaches its final depth, pump rate is sometimes decreased for the last 10 to 15 ft to add assurance the sediments near the structural-casing shoe are not washed out, which could result in casing subsidence.

**Sweeps.** Because the drilling fluid used in the jetting process is seawater, the fluid has low cuttings carrying capacity. Sweeps are used to enhance hole cleaning and remove cuttings from the annulus. Viscous sweeps are periodically pumped to sweep the hole of accumulating cuttings. Sweeps are usually composed of seawater with guar gum or prehydrated bentonite. With annular capacities of greater than 1 bbl/ft, large sweeps are required to prevent sweep stringing and dispersement.

Sweeps are important throughout the jetting process. When jetting is commencing, hole cleaning is compromised by the low flow rates used to establish skin friction and prevent broaching. Sweeps provide additional hole cleaning assistance to the limited flow rates. As jetting progresses and flow rate is increased, the sweeps assist in removing larger and more cohesive pieces of formation. As a minimum, sweeps are pumped at connections and mid-stand. On jetting jobs with undersize bits, sweep frequency can be increased as frequently as every 15 to 20 feet.

**Reciprocation.** Reciprocation of the structural-casing string while jetting is a polemic subject with differences of opinion existing even within organizations and drill teams. Reciprocation of casing is the vertical movement of the casing string. As progress is being made during the jetting operation, the formation creeps in behind the casing connectors and begins to fill the void and develop skin friction with the casing. Reciprocation pulls the casing and its connectors back through this disturbed area. The wiping action reduces the developing skin friction and results in less required slack-off weight to make forward progress. Reciprocation does not assist in hole cleaning since cuttings are removed through the casing by BHA annulus. Reciprocation does not lead to broaching since the fluid flow will follow the path of least resistance, which should be inside the casing. Reciprocation will reduce the level of flow resistance of the soils outside the casing that resists broaching. Broaching is caused by a restriction inside the casing such as a packoff around the jetting BHA or a plugging of the exit ports in the wellhead and running tool. It is the restriction inside the casing that makes the alternative path outside of the casing to become the path of least resistance.

Reciprocation should only be used to maintain the WOB schedule. The length of reciprocation can vary from a few meters to as much as the entire stand, depending on the experiences of the personnel involved. Smaller lengths of reciprocation have proved equally effective in many locations. Some drill teams prefer to jet with a locked compensator to allow vessel heave to be transmitted through the drillstring to the structural casing. Hence, the string is jetted with a continuous stroke of the amount of the vessel heave. Caution must be observed such that the instantaneous SOW caused by the heave does not exceed Euler buckling force.

## Post-Jetting Considerations

Once a structural-casing string has been jetted successfully to final depth, the casing annulus must be cleared of cuttings and the running tool/jetting BHA released from the wellhead. A large viscous sweep, 100 to 300 bbl, has proven most effective in removing any cuttings remaining in the annulus. Excessive circulation at TD should be avoided because of the risk of washing out the formation at TD and inciting subsidence.

Once the cuttings have been removed, a period of "soak" time is employed to allow the skin friction to increase and improve the soil to casing adhesion. During the soak period, no circulation is to occur and the hookload should be the same as the final slackoff hookload. The running tool or drill ahead tool (DAT) should not be manipulated in any fashion during the soak period. A soak period of one to two hours is prudent insurance against casing subsidence after running tool release.

| TABLE 3—BBLS OF CUTTINGS IN STRUCTURAL CASING X JETTING BHA ANNULUS AT VARIOUS ROPS AND CIRCULATION RATES | | | | | | | |
|---|---|---|---|---|---|---|---|
| bbls of Cuttings in Annulus While Jetting (36 in. x 8 in. DC Annulus) | | | | | | | |
| | Flow Rate (gal/min) | | | | | | |
| ROP (min/ft) | 200 | 400 | 800 | 1,000 | 1,200 | 1,400 | ROP (ft/hr) |
| 0.33 | 199.1 | 99.5 | 49.8 | 39.8 | 33.2 | 28.4 | 180.0 |
| 0.5 | 132.7 | 66.4 | 33.2 | 26.5 | 22.1 | 19.0 | 120.0 |
| 1 | 66.4 | 33.2 | 16.6 | 13.3 | 11.1 | 9.5 | 60.0 |
| 2 | 33.2 | 16.6 | 8.3 | 6.6 | 5.5 | 4.7 | 30.0 |
| 3 | 22.1 | 11.1 | 5.5 | 4.4 | 3.7 | 3.2 | 20.0 |
| 4 | 16.6 | 8.3 | 4.1 | 3.3 | 2.8 | 2.4 | 15.0 |
| 5 | 13.3 | 6.6 | 3.3 | 2.7 | 2.2 | 1.9 | 12.0 |

**TABLE 4—ECDS IN STRUCTURAL CASING X JETTING BHA ANNULUS AT VARIOUS ROPS AND CIRCULATION RATES (8.57 LB/GAL DENSITY SEAWATER)**

Equivalent Mud Weight (ppg) While Jetting 300 Feet of 36 in. x 8 in. DC Annulus) – 5,000 Feet WD

| | Flow Rate (gal/min) | | | | | | |
|---|---|---|---|---|---|---|---|
| ROP (min/ft) | 200 | 400 | 800 | 1,000 | 1,200 | 1,400 | ROP (ft/hr) |
| 0.33 | 9.08 | 8.84 | 8.70 | 8.68 | 8.66 | 8.65 | 180.0 |
| 0.5 | 8.92 | 8.74 | 8.66 | 8.64 | 8.63 | 8.63 | 120.0 |
| 1 | 8.74 | 8.66 | 8.61 | 8.61 | 8.60 | 8.60 | 60.0 |
| 2 | 8.66 | 8.61 | 8.60 | 8.59 | 8.59 | 8.59 | 30.0 |
| 3 | 8.63 | 8.60 | 8.59 | 8.59 | 8.58 | 8.58 | 20.0 |
| 4 | 8.61 | 8.60 | 8.59 | 8.58 | 8.58 | 8.58 | 15.0 |
| 5 | 8.61 | 8.59 | 8.57 | 8.58 | 8.58 | 8.57 | 12.0 |

## Other Operations Considerations

The remotely operated vehicle (ROV) on the drilling rig is essential to the jetting operation. The ROV allows the jetting team to observe the following key items:

- Bit stick-out/bit space-out.
- Returns emanating from wellhead and wellhead-running tool.
- Broaching at mudline.
- Final jetting depth (wellhead stick-up from the mudline).

Documentation of operational parameters is extremely valuable to assess jetting performance and provide guidance for planning of future wells. Operational parameters and ROP should be documented on a per unit length basis. Reciprocation and sweeps should also be recorded. ROV recordings are essential when attempting to evaluate a non-optimal jetting operation. **Fig. 12** displays jetting data from a deepwater West Africa well in composite graphical form.

## Case Histories

Five case histories are presented below containing lessons learned through incurrence of non-productive time. The intent is to share these experiences and learnings with fellow operators to avoid similar occurrences in the future.

**Case History 1.** 36-in. casing was to be jetted with a 17½-in. PDC bit and BHA. The bit had been run on previous wells with excellent results and used for jetting one other well. A near-bit stabilizer had been planned, but left off the jetting BHA at the advice of the directional-drilling service provider. The casing was run and hung off in the moonpool. The BHA was run and the drill-ahead tool landed in the wellhead. The ROV was launched to check the bit space-out before tripping to the mudline and recorded an acceptable space-out. The drill-ahead tool was then cam-locked into the wellhead and the jetting assembly run to the mudline.

At the mudline, the ROV checked the space-out again but observed an increased bit stick-out from the jet shoe. It appeared most or the entire bit gauge was below shoe. Jetting was commenced, but broaching began almost immediately. Jetting was continued in the hope the broaching might bridge off, but the broaching continued. The operation was ceased and the jetting assembly was pulled. At the mudline, the ROV noted the PDC bit was pushed to one side with a PDC blade protruding beyond the OD of the casing. The inside of the structural casing was plugged off with clay/sediment. **Fig. 13** shows an ROV photograph of the packed-off casing, while **Fig. 14** illustrates the bit pushed past the OD of the casing.

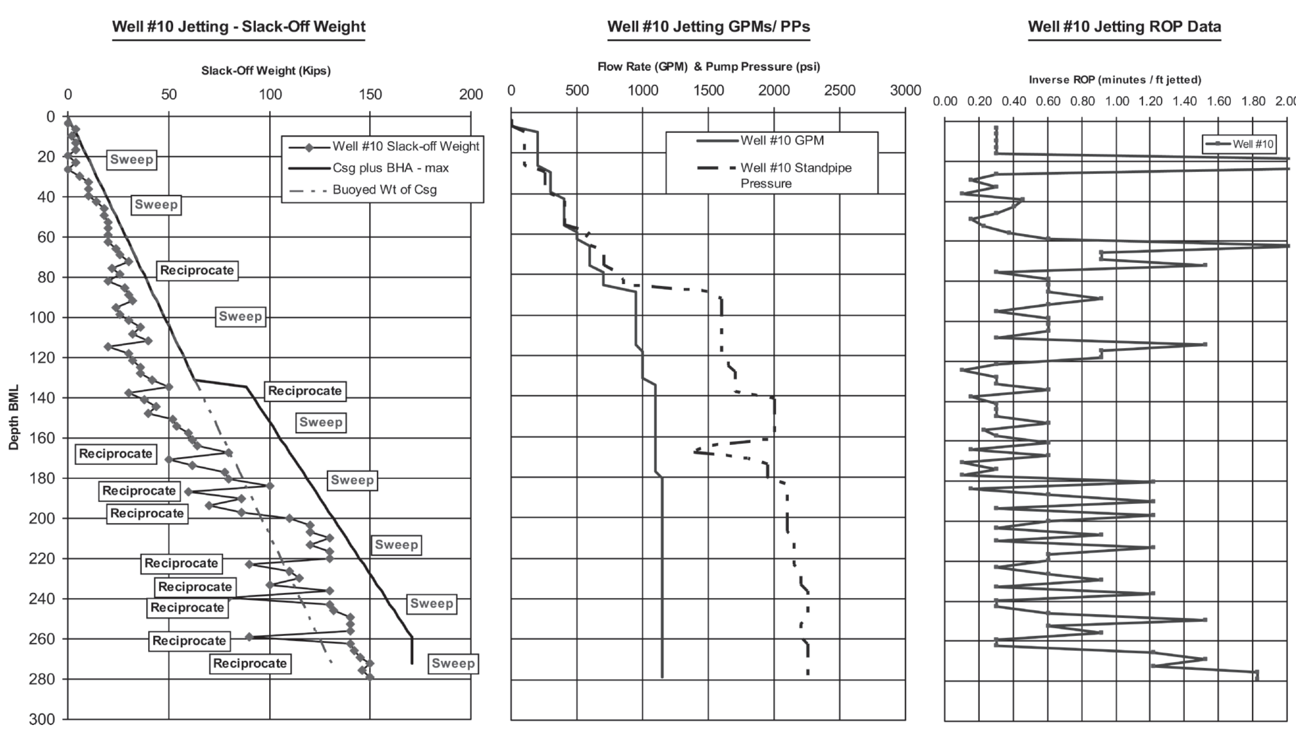


**Fig. 12—Composite graph of critical jetting parameters.**

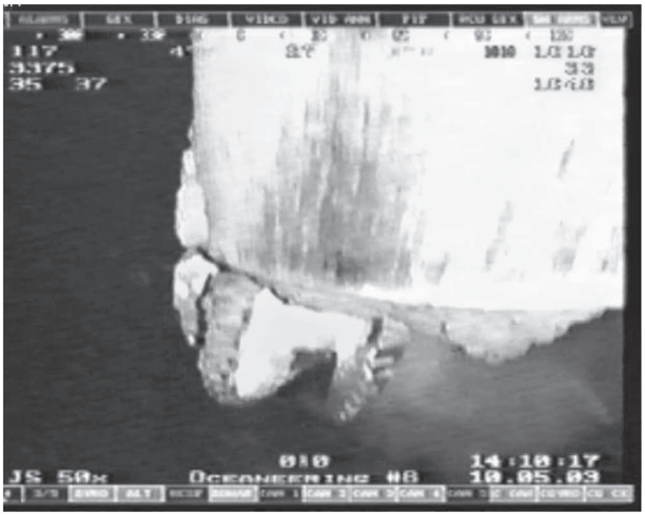

Fig. 13—Packoff/broaching event with PDC bit.

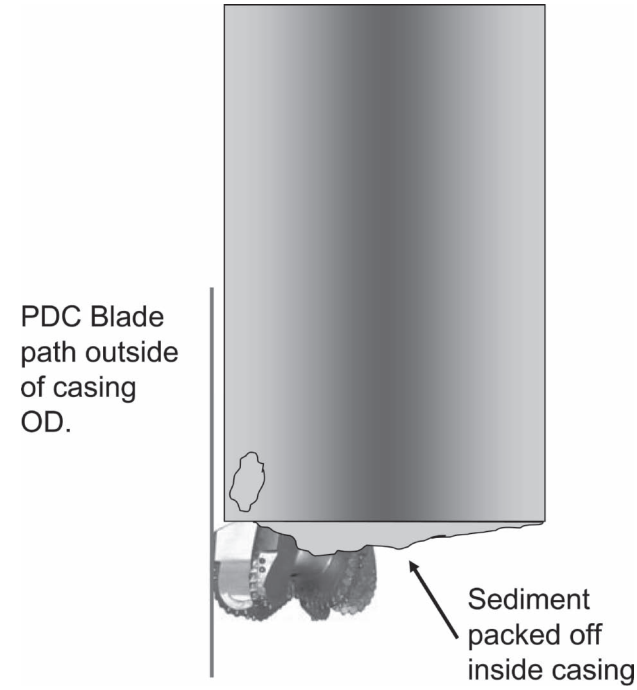


Fig. 14—Illustration of packoff / broaching event, Case History 1.

In this case, the bit stick-out calculation had not considered the stem travel on the drill-ahead tool. When the cam is activated on the drill-ahead tool to lock the tool to the wellhead, the stem travels down by about 2 in. Hence, the bit stick-out appeared to be acceptable when checked at the rig, but when the tool was made up to the wellhead, the bit moved down by 2 in. Because the PDC bit only had 3 to 4 in. of gauge, the downward movement resulted in all of the gauge length sticking out below the jet shoe. The lack of a near-bit stabilizer completed the contributions to the event. With no near bit stabilization, the bit was allowed to be pushed over to one side until the bit shank butted up against the casing. The PDC blade and nozzles were allowed to cut and jet outside the OD of the casing. This created a flow path outside the casing and further reduced flow and cleaning capacity inside the casing.

Lessons learned during this event include:

• Stem travel on the drill-ahead tool, cam-activated running tool must be considered in bit stick-out calculations.

• Bits with a short gauge section and an abrupt transition to the bit shank diameter, such as many PDC designs, have a more critical bit space-out. As a result, these types of bits are prone to be more problematic in this application.

• The use of a near bit stabilizer in the jetting BHA helps keep the bit cutting and jetting action directly below the casing.

**Case History 2.** 36-in. casing was to be jetted with a 17½-in. tri-cone mill-tooth bit. Bit stick-out was 8½ to 9 in. per the well-program guidelines of 8 to 12 in. A connection was made with the jet shoe at 115 ft BML. After the connection was made, the ROV showed one port of the drill-ahead tool (DAT) was plugged off and fluid was no longer exiting the port. The DAT was equipped with six 3-in. ports and the 36-in. wellhead housing (WH) equipped with four 4-in. ports. After the cuttings cloud at the DAT/WH subsided, the ROV dove to the mudline. No broaching was observed at this point. The ROV returned to the DAT/WH and confirmed the cuttings cloud still enveloped the wellhead. The ROV made a second dive to the mudline and at this time, broaching was observed around the 36-in. casing. Jetting had progressed at this point to 160 ft BML. The ROV returned to the wellhead and ceased to observe returns coming from the wellhead circulating ports. The jetted depth, at this point, was 170 ft BML. The casing was jetted an additional 15 to 185 ft BML in hopes circulation from the wellhead ports might be re-established and the broaching would cease. The broaching continued and circulation was not re-established. The decision was made to pull out of the hole, and the trip out of the hole was made with no overpull. Once the casing was clear of the seafloor, the ROV could observe the casing-jetting BHA annulus was packed off with cuttings inside the jet shoe. **Fig. 15** shows two of the ROV images.

The broaching was initiated by the obstruction of the fluid flow path in the casing by jetting BHA annulus, caused by the packoff of sediments in the annulus. No data was available to support a hypothesis that the soils in this area may have been more cohesive or sticky than soils in offsets wells. The packed-off sediments at the jet shoe, combined with pressure while drilling (PWD) data showing no build-up in the equivalent circulating density (ECD) suggesting a cuttings build-up, indicate either initial formation break-up and mobilization or hole cleaning in the lower part of the jetting BHA were major issues.

Lessons learned during the investigation of this incident include:

• The bit stick-out recommendation of 8 to 12 in. below the jet shoe was on the basis of experience with 30-in. casing by 26-in. bit

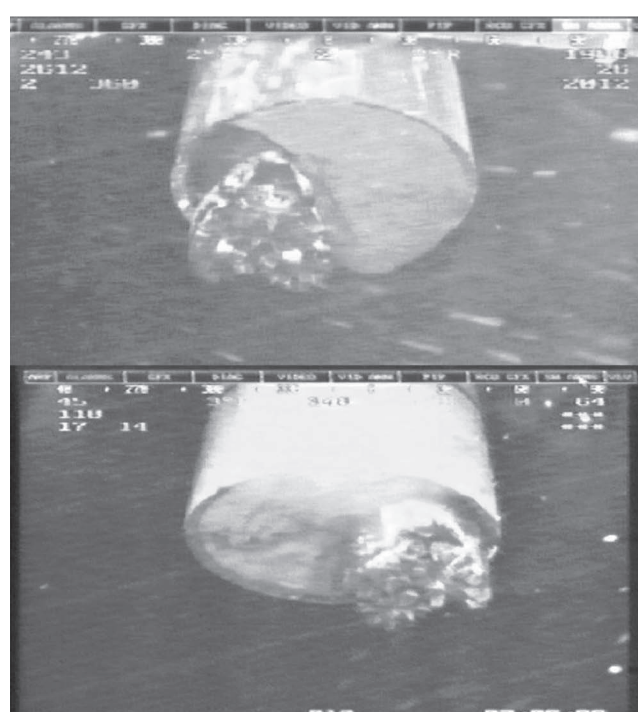

Fig. 15—Packoff at jet shoe, Case History 2.

or 36- by 26-in. bits. A 17½-in. bit with a stick-out of 8 to 12 in. will have its nozzles below the jet shoe. Instead, the new guidelines provide guidance for both size bits. A 17½-in. bit stick-out is now suggested to be in the 4 to 8-in. range.

• ROP should be controlled with 17½-in. bits to limit cuttings in the annulus and to allow more time for the bit and jetting action to break up the formation.

• Flow rates should be increased when jetting a 36-in. casing string as compared to jetting 30-in. casing strings. A minimum of 1,200 gal/min should be used and full circulation rate should be achieved by 150 ft. BML. Still higher flow rates have potential to improve jetting performance.

• Increased sweep frequency and volume are needed in the larger annulus to avoid cuttings buildup. The cost of sweep material is small. Above 150 ft. BML, guidelines have been reinforced to pump 50 bbl sweeps at the middle of stand and before connection. Below 150 ft. BML, guidelines were increased to include pumping 50 bbl sweeps every 15 feet (eight sweeps totaling 400 bbl to TD).

**Case History 3.** 36-in. casing was to be jetted with a 26-in. bit to 290 ft BML. This planned depth was the same depth as the structural casings of the first two wells on the geologic structure. Progress was made to 210 ft BML with normal operational parameters. Below 210 ft BML, ROP began to decrease. The casing was reciprocated with 180 kips overpull to initiate movement. At 250 ft BML, ROP again slowed substantially. Reciprocation initiation took 200 kips overpull. Progress was made to 270 ft BML at a very slow ROP and another reciprocation was made, requiring 230 kips overpull to move the casing upward. This was the limit of overpull available on the drillstring being used. Any increase in skin friction would result in the casing and drillstring being stuck. The drillstring and jetting BHA could be retrieved but the casing would be permanently stuck and the well junked. The casing and jetting assembly were pulled from the well and the casing saved. Examination of the 26-in. bit showed wear around the shirttail, indicating the bit was walking around the ID of the casing that aids formation breakup and removal. The casing was found to be clean, indicating hole cleaning was not a problem.

A second attempt was made at a location 40 ft from the original hole. The targeted jetting depth was reduced from 290 to 270 ft BML on the basis of the results of the first attempt. 26-in. bit stick-out was increased in the hope to increase hole washing to some extent. Jetting during the second attempt proceeded. Despite increased reciprocation, jetting ROP decreased and overpulls required to reciprocate the string increased. At 205 ft BML, the overpull required to work the pipe reached the tensile limit of the drillstring. Again, the casing and jetting BHA were retrieved from the well.

The third attempt used the same casing and jetting BHA configuration. The drillstring was changed out for a heavier string with greater overpull margin. In addition, it was decided to jet with a locked heave compensator to impart vessel motion to the string and have a faster response during string pickup. The adjustment allowed more room to work the pipe at the top of a stand. Jetting with a locked compensator was possible because of the mild weather conditions prevalent at the time.

Jetting progressed at a new location 30 ft from the first two attempts with similar results to the second attempt. However, jetting did not cease once pickup overpulls reached 230 kips. The pipe was reciprocated and jetting continued with progress being made to the final depth.

Lessons learned during this incident include:

• Select a drillstring with sufficient overpull for jetting. The standard design overpull for drillstrings while drilling or running casing is 100 kips. This is not a sufficient design criterion for jetting. Further, the drillstring should be recently inspected to ensure it could deliver expected overpulls.

• Use of a locked compensator was considered one of the keys to success on the third attempt. The pinned compensator allowed a rapid pickup and a longer stroke during the reciprocation.

**Case History 4.** 30-in. casing was successfully jetted with a 17½-in. tri-cone mill-tooth bit to 260 ft BML in two hours. Bit stick-out was reported as 7.6-in. per the well program. Partial returns outside of the casing were continuous during the jetting operation from the mudline down to 165 ft BML. The casing was never reciprocated because of low slack-off weight employed in reading TD. The casing was allowed to soak for two hours to allow skin friction to build. The wellhead-running tool (drill-ahead type) was then torqued to release from the wellhead. The tool would not release. While working and applying torque to the running tool, pumps were run at varying flow rates up to 1,000 gal/min for approximately one hour. While attempting to release the tool, returns were observed around the outside of the casing. When the tool finally released, the casing sank 7 ft. The BHA was tripped to the surface while allowing skin friction to regain strength. However, when the new BHA was run to TD, returns continued outside the casing. The casing could not be retrieved, and the well was ultimately respud 50 ft away.

The principal lessons learned during the investigation of this incident were:

• Minimize/stop pumping while attempting to release running tool.

• The rapid jetting, low WOB, lack of need for reciprocation, and partial returns outside the casing were all signs of very low shear-strength soil. When such conditions are encountered, soak time to rebuild skin friction should be increased beyond standard procedures.

**Case History 5.** 36-in. casing was to be jetted with a 26-in. bit to 270 ft BML. This planned depth was the same depth as the structural casings of the first three wells on the geologic structure. Jetting progressed without incident with connections made at 62 and 157 ft BML. A third connection was made at 250 ft BML. During the connection, the ROV ascertained a further 23 ft remained to be jetted. Following the connection, approximately 20 more feet were jetted with visibility eventually being lost because of the cuttings cloud. The pumps were turned off for 10 minutes to allow the cuttings cloud to dissipate and check the mudmat position for a final check of distance to jet. The ROV determined an additional 6 ft of jetting was required to position the top of the wellhead and the mudmat properly. When picking up on the casing, it was found that the casing was stuck. The casing would not pick up with 230 kips over string weight and would not jet downward with maximum-allowable slack-off and full-jetting pump rate. Because the bending moment loading on the casing was unacceptable and the wellhead sat too high for the subsea development, the running tool was released, the BHA retrieved, and the casing string abandoned in place.

The loss of the structural casing on this well left the drill team with the following lessons learned:

• Do not stop pumping unless there is a connection being made. Static casing allows skin friction to build and increases the risk of sticking casing at an undesired depth.

• Clearly mark structural casing with distances from mud mat for the last 60 feet. Markings should consist of a yellow line around the circumference of the pipe and four large clear distance numbers at 90° intervals.

• Plan drillpipe space-out such that no connection is required in the last 60 ft of jetting. The distance markings should be visible at the mudline and skin friction should not yet be approaching the maximum values observed near final depth.

• Remaining distance to jet should be confirmed during last connection and an ROV video record of the distance be made. This distance should be jetted without stopping. Should the distance to jet fall into question, jetting should continue until the mudmat lands on the mudline. This situation is preferable to sticking the casing high.

## Conclusions

The following concepts and practices have been found key to jetting success:

1. Jetting structural casing to final depth is achieved through a combination of applying increasing SOW to the formation while removing formation from the casing path through a combination of bit action and hydraulic washing.
2. Development and adherence to a jetting SOW plan/plot assures the structural casing remains straight while jetting and should not subside when released from the running tool.
3. Reciprocation is used to break skin friction and transfer applied SOW to the bottom of the jetting string. Reciprocation is an effective tool when used in a judicious manner.
4. Pump rate and sweeps are used to clean the jetting BHA by structural casing annulus. When this annulus is clean, the chance of broaching is minimized, as the annulus remains the path of least hydraulic resistance.
5. Drillstrings used for jetting should be designed for overpulls much higher than typical drillstring design practices. The jetting BHA should be well stabilized and robust. Connections should have been recently inspected.
6. Use of larger OD casing poses new challenges in hole cleaning during jetting. These challenges are exacerbated by well plans using slim-hole bits and DATs, but can be overcome with proper use of reciprocation and sweeps.

## Nomenclature

$As$ = side surface area of structural casing, ft$^2$
$BF$ = buoyancy factor, dimensionless
$BW_{Cx}$ = buoyed weight of casing at depth x, lbm
$BW_{C+JAx}$ = buoyed weight of casing plus jetting BHA at depth $x$, lbm
$c$ = undrained shear strength of the soil at the point in question, lbm/ft$^2$
$D$ = intermediate depth of interest, ft
$D_{FP}$ = depth below mudline to fixed point (casing may move/rotate only above this depth), ft
$D_{\mathrm{MASOW}}$ = depth at which MASOW occurs, ft
$D_{\mathrm{MASOW}=F_B}$ = depth at which MASOW = buckling force limit, ft
$E$ = modulus of elasticity for steel = 29×10$^6$ psi
$f$ = unit skin friction capacity, lbm/ft$^2$
$F_B$ = buckling force limit at intermediate depth(s), D, lbf
$F_{B@FP}$ = buckling force limit at fixed point, lbf
fos = factor of safety for undrained shear strength data
$I$ = casing moment of interia, in.$^4$
ID = inside diameter of casing, in.
$L_C$ = total length of casing, ft
$L_{\mathrm{STICKUP}}$ = length of casing above mudline when jetted to final TD, ft
MASOW = maximum allowable SOW, lbm
MW = density of drilling fluid, lbm/gal
OD = outside diameter of casing, in.
$Q$ = ultimate bearing capacity, lbm
$Qf$ = skin friction resistance, lbm
$SF_B$ = buckling safety factor, dimensionless
$SF_S$ = buckling safety factor, dimensionless
$TD$ = jetting total depth, ft.
$W_C$ = weight of casing, lbm/ft
$W_{JA}$ = weight of jetting assembly, lbm/ft
$x$ = unit of length along the axis of the structural casing, ft
$\alpha$ = dimensionless factor to account for disturbance of the soil by jetting (always<1.0).
$\pi$ = constant pi = 3.14159
$\rho_s$ = density of steel, lbm/gal

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## Appendix—Calculations for Development of the Planned SOW Profile

A typical planned SOW guideline is shown below in **Fig. A-1.** The X-axis is SOW and the Y-axis is depth.

Below mudline (in reverse order).

1. Buoyancy factor,

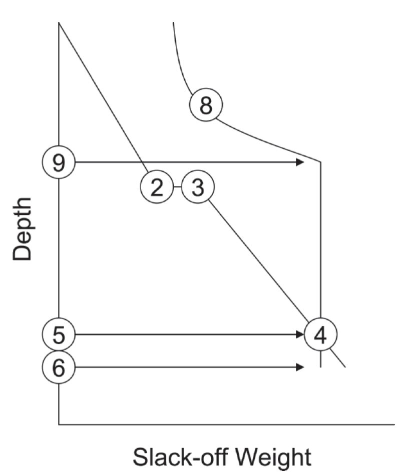
$$BF = 1 - \frac{MW}{\rho_s} = 1 = \frac{MW}{65.45} \quad \text{(A-1)}$$

2. BML buoyed weight of casing at 130 ft BML,

$$BW_{\mathrm{C130}} = BF \times W_C(\mathrm{lb/ft}) \times 130 \quad \text{(A-2)}$$

3. BML buoyed weight of casing+jetting assembly at 130 ft. BML,

$$BW_{\mathrm{C+JA130}} = BF \times (W_C + W_{JA})(\mathrm{lbm/ft}) \times 130 \quad \text{(A-3)}$$



4. Maximum allowable SOW,

$$\text{MASOW} = SF_S \times BW_{C+JA} = SF_S \times BF \times (W_C + W_{JA})(\text{ppf}) \times L_C \quad \text{(A-4)}$$

5. Depth at which MASOW = BML buoyed weight of casing +jetting assembly,

$$D_{\text{MASD}} = SF_S \times L_C \quad \text{(A-5)}$$

6. Jetting TD,

$$TD = L_C - L_{\text{STICKUP}} \quad \text{(A-6)}$$

Calculations required for defining maximum available setdown weight:

7. Casing moment of inertia,

$$I = \frac{\pi}{64} \times (\text{OD}^4 - \text{ID}^4), \text{ in.}^4 \quad \text{(A-7)}$$

8. Buckling force limit at fixed point,

$$F_{B@\text{FP}} = SF_B \times \frac{\pi^2 EI}{(4 \times (12 \times L_C)^2)} \quad \text{(A-8)}$$

Depth at which MASOW = buckling force limit,

$$D_{\text{MASOW}=F_B} = L_C + D_{FP} - \left( SF_B \times \frac{\pi^2 \text{EI}}{(4 \times 12^2 \times \text{MASOW})} \right)^{0.5} \quad \text{(A-9)}$$

9. Buckling force limit at intermediate depth(s), D,

$$F_B = SF_B \times \frac{\pi^2 EI}{(4 \times (12 \times L_C = D + D_{FP})^2)} \quad \text{(A-10)}$$

## Notes:

• From the mudline to the point of full lateral stability (generally found at 100 to 150 ft BML−value of 130 ft BML used in the appendix equation): Setdown weight equal to the lesser of the buoyed weight of the structural casing below the mudline or the maximum setdown weight on the basis of the buckling force. Normally, this is sufficient to provide an adequate penetration rate and will minimize the risk of casing deviation.

• From the point of full lateral stability to structural casing TD: Setdown weight equal to the lesser of the buoyed weight of the combined structural casing and jetting assembly below the mudline or the maximum setdown weight based on the buckling force. The maximum allowable setdown weight is equal to 90% of the buoyed weight of the combined structural casing and jetting assembly. Final orientation of the casing will have been established by this depth and will not change regardless of the amount of setdown weight applied.

## SI Metric Conversion Factors

| | | | | |
|---|---|---|---|---|
| bbl × | 1.589 873 | E–01 | = | $m^3$ |
| cp × | 1.0* | E–03 | = | Pa·s |
| ft × | 3.048* | E–01 | = | m |
| gal × | 3.785 412 | E–01 | = | $m^3$ |
| in. × | 2.540* | E–02 | = | m |
| lbm × | 4.535 924 | E–01 | = | kg |
| psi × | 6.894 757 | E+00 | = | kPa |

*Conversion factors are exact.

**Jay Akers** has been a drilling and subsurface engineer for ExxonMobil Development Company for 23 years. Akers has experience in drilling, completion, and workover operations in the United States, Norway, Nigeria, Angola, and Brazil. He holds a BS in chemical engineering from Texas A&M University and a MS in petroleum engineering from The University of Texas at Austin. He is also a member of SPE.