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(71) Applicant (*for all designated States except US*): **TH HILL ASSOCIATES, INC.** [US/US]; 7676 Hillmont, Suite 360, Houston, TX 77040 (US).

(72) Inventors; and
(75) Inventors/Applicants (*for US only*): **HILL, Tom, H.** [US/US]; 5507 Pillar Park, Houston, TX 77041 (US). **ELLIS, Sean, E.** [US/US]; 15926 Aberdeen Trails Drive, Houston, TX 77095 (US). **REYNOLDS, Nicholas, M.** [JM/US]; 16607 Gentle Stone Drive, Houston, TX 77095 (US). **ZHENG, Nanjiu** [US/US]; 5434 Summer Lakes, Sugar Land, TX 77479 (US).

(74) Agent: **KRESS, Hugh, R.**; Browning Bushman P.C., 5718 Westheimer, Suite 1800, Houston, TX 77057 (US).

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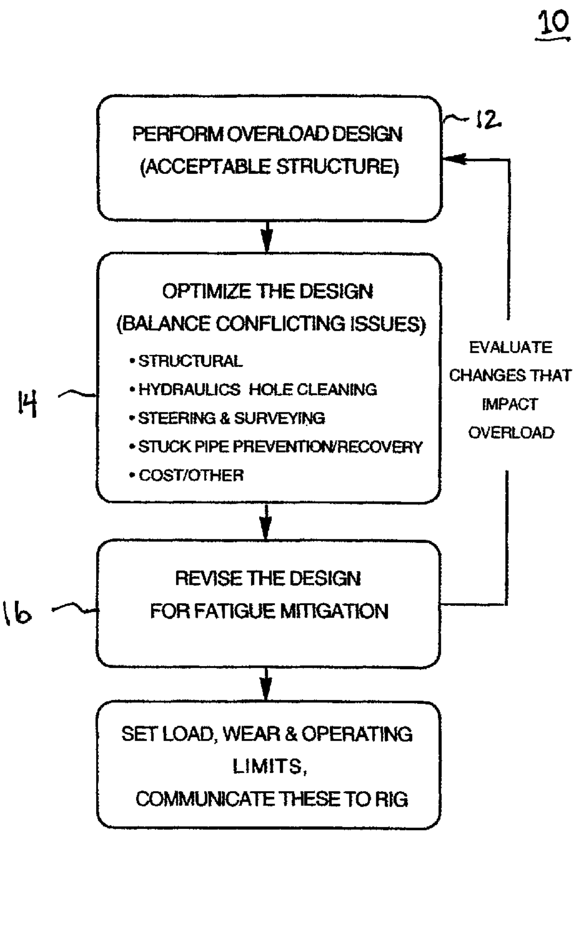

(57) Abstract: A drill string design methodology which utilizes a "comparative approach" in the selection of drill string components. The comparative approach in accordance with the present invention can lead to dramatic reductions in fatigue-related problems. In accordance with one aspect of the invention, a method is provided for establishing objective criteria for evaluating individual components of well construction equipment to determine the preferred component or collection of components to be used from the selection of components available. A plurality of quantifiable design parameters relevant to the issues of fatigue damage and failure of drill string components are defined, and an assessment of each of these parameters is made for two or more candidate components being considered for inclusion in the drill string. A comparison is then made between the candidate components' ratings, and a decision to include or exclude a candidate component is made based upon the results of such comparison.

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DRILL STRING DESIGN METHODOLOGY FOR MITIGATING FATIGUE FAILURE

RELATED APPLICATION

This application claims the priority of prior provisional U.S. patent application Serial No. 60/464,794, filed on April 23, 2003, which application is hereby incorporated by reference in its entirety.

FIELD OF THE INVENTION

The present invention relates generally to the field of hydrocarbon production (i.e., the drilling of oil and gas wells), and more particularly relates to the design and operation of drill strings used in such production.

BACKGROUND OF THE INVENTION

Drill pipe is the principal tool, other than a drilling rig, that is required for the drilling of an oil or gas well. Its primary purpose is to connect the above-surface drilling rig to the drill bit. A drilling rig will typically have an inventory of 10,000 to 25,000 feet of drill pipe depending on the size and service requirements of the rig. Joints of drill pipe are connected to each other with a welded-on tool joint to form what is commonly referred to as the drill string or drill stem.

When a drilling rig is operating, motors mounted on the rig rotate the drill pipe and drill bit. In addition to connecting the drilling rig to the drill bit, drill pipe provides a mechanism to steer the drill bit and serves as a conduit for drilling fluids and cuttings. Drill pipe is a capital good that can be used for the drilling of multiple wells. Once a well is completed, the drill pipe may be used again in drilling another well until the drill pipe becomes damaged or wears out. It is estimated that the average life of a string of drill pipe is three to five years, depending on usage, and that an average rig will consume between 125 to 175 joints (3,875 to 5,425 feet) per year under normal conditions.

Drill collars are used in the drilling process to place weight on the drill bit for better control and penetration. Drill collars are typically located directly above the drill bit and are typically manufactured from a solid steel bar to provide necessary weight.

So-called “heavy weight drill pipe” or “HWDP” is a thick-walled, preferably seamless tubular product that is less rigid than a drill collar, but more rigid than standard drill pipe. Those of ordinary skill in the art will appreciate that heavy weight drill pipe can be provided in a drill string to provide a gradual transition zone between the heavier drill collar and the lighter drill pipe. It is generally recognized by those of ordinary skill in the art that when heavy weight drill pipe is not used, the drill pipe near the top of the drill collars may be unduly susceptible to fatigue damage and possible failure. Further details regarding the use and characteristics of heavy weight drill pipe are set forth in U.S. Patent No. 6,012,744 to Wilson et al., entitled “Heavy Weight Drill Pipe,” which reference is hereby incorporated by reference herein in its entirety.

Among the known considerations in the construction of a drill string is to ensure that it is constructed in a manner which results in it remaining intact, functional, and free from leaks during operation. Pump rates, pressure losses, annular velocities, and flow regimes must accommodate all drilling requirements, while staying within pressure and flow rate limitations imposed by the hole, the rig pumps, and surface equipment. The components in the drill string must enable steering the bit in the desired trajectory, and must accomplish the monitoring and measurements required for the hole interval being drilled. Finally, the drill string should be configured to accomplish operating needs with the lowest possibility of becoming stuck, and to possess the best chance of recovery, should it become stuck.

Those of ordinary skill in the art will appreciate that a drill string design that meets all needs for structural soundness must also take the likely failure mechanisms into account. There are three failure mechanisms that are generally regarded as accounting for a majority all structural failures: overload, fatigue, and sulfide stress cracking ("SSC").

Overload refers to situations in which a component in the drill string is subjected to loads that exceed its rated capacity.

Fatigue refers to progressive, localized permanent structural damage that occurs when a component undergoes repeated stress cycles, even if such stresses are well below the component's yield strength. The cyclic stress excursions most often occur when a component is rotated while it is bent or buckled, and by vibration. As the loads on the component cycle up and down, fatigue damage accumulates at high stress points in the component, and fatigue cracks form at these points. Such cracks may grow under continued cyclic loading until failure occurs.

Finally, sulfide stress cracking is a process in which steel, under tensile stress, cracks in aqueous fluids in the presence of hydrogen sulfide (H_2S). Several sources of hydrogen sulfide have been identified, though the source of principle concern is formation fluids.

Compared to overload and SSC, fatigue damage and failure is far more difficult to manage by design. The mechanisms of fatigue are very complex. Fatigue is driven by point stress, or the stress in and around each geometric discontinuity, or stress concentrator, on the string components. The effects of stress concentrators can be very pronounced, and are difficult to evaluate with accuracy. Furthermore, drilling mud corrosiveness significantly affects fatigue behavior. Finally, since fatigue damage is cumulative, component history is extremely relevant for fatigue life prediction, but methods for tracking component history in meaningful terms are at best gross approximations. (As used herein, the term "fatigue life" will be understood to have its commonly understood meaning in the industry, namely, the amount of time that a particular component can be reasonably expected to operate under specified conditions before suffering fatigue failure. Because it is a prediction of future events based only on the available data, which may be incomplete or imprecise, there is an inherent element of uncertainty in any quantification of "fatigue life" for any given component. Nevertheless, assuming sufficient, reasonably accurate data is available, a quantification of "fatigue life" for a particular component can provide a reasonably meaningful indication of probable performance of that component.)

Fatigue mechanisms are so complex and the important variables (such as point stress, environment, and history) are so little understood, relatively speaking, that predictive models, on an absolute basis, have heretofore been found to be of little value. That is, given the uncertainty of inputs combined with the complexity of the mechanisms, the accuracy of predictive formulas is typically not good enough to form the basis for design decisions. As a result, there is a tendency in the industry not to emphasize fatigue failure mechanisms in the design and composition of drill strings.

Currently, the selection of the components used in the construction of a well has been dictated by standard practices. Thus, a bottomhole assembly or a particular drill string or heavy weight drill pipe string has been specified for a drilling application simply because it met an industry practice or standard. The question of whether the particular drilling component is the best available component for a particular application is not necessarily addressed in the selection process. A difficulty in specifying the best of the available components to be used in the drilling application is that there have been no objective criteria for evaluating the capabilities of the individual components, particularly as it relates to such components' fatigue resistance.

SUMMARY OF THE INVENTION

Notwithstanding the limitations of predictive modeling in designing drill strings that are optimally resistant to fatigue damage and failure, it is nevertheless deemed desirable to achieve drill string designs that are as fatigue resistant as possible. Accordingly, the present invention is directed to a drill string design approach which utilizes a "comparative approach" in the selection of drill string components. It is believed that the comparative approach in accordance with the present invention can lead to dramatic reductions in fatigue-related problems.

In accordance with one aspect of the invention, a method is provided for establishing objective criteria for evaluating individual components of well construction equipment to determine the preferred component or collection of components to be used from the selection of components available. As used herein, the terms "well construction " and "well construction equipment" are intended to include the procedures and equipment used in the drilling and completion of a well.

The method of the present invention provides new design constraints that may be used, for example, by a drilling engineer to make a selection of drilling equipment for a drill stem to be used in drilling a particular well. As a specific example, an objective of the new design constraint is to provide a means for a drilling engineer to compare the fatigue performance of a heavy weight drill string used in drilling a wellbore having a specified wellbore diameter to a standard or to an alternative heavy weight drill string.

A practical application of the new procedure is that a drilling engineer who has a string of heavy weight drill pipe available as a part of the drilling contractor's equipment can determine whether it is more efficient to use the available heavy weight drill pipe or to incur the additional cost of renting a special heavy weight drill pipe string that has a longer fatigue life in the anticipated application. In some cases, it may be more economical to rent a drill string rather than use the drill string supplied by the drilling contractor because the fatigue life of the contractor's heavy weight drill pipe is significantly less in the anticipated application than that available with a different size heavy weight drill pipe string that must be rented from a third party.

Since a drill string designer almost always performs his or her function by selecting from various alternatives, the comparative approach in accordance with the presently disclosed embodiment of the invention involves (1) selecting the design alternative and operating approach that provides the lowest stress excursion; (2) selecting the design alternative offering the lowest stress concentration; and (3) selecting the design alternative offering the best comparative fatigue life; and (4) monitoring and reducing corrosion rates in mud systems.

In accordance with one aspect of the invention, a number of design and operating parameters are quantified as “fatigue indices,” and a predetermined set of design constraints are imposed upon these indexes.

In one embodiment, a plurality of quantifiable design parameters relevant to the issues of fatigue damage and failure of drill string components are defined, and an assessment of each of these parameters is made for two or more candidate components being considered for inclusion in the drill string. A comparison is then made between the candidate components' ratings, and a decision to include or exclude a candidate component is made based upon the results of such comparison.

Among the design parameters defined in accordance with the presently preferred embodiment of the invention are: “Curvature Index,” “Stability Index,” and “Bending Tolerance Rating.”

Drill pipe is rotated through dog legs in a process that causes the pipe to be rotated around a bend. A primary objective of the Curvature Index is to permit comparison of the relative fatigue life of drill pipe under different dog legs and tension loadings during rotation.

In one embodiment, the Curvature Index ("CI") gives a measure of the relative reduction in fatigue life caused by variations in hole curvature, pipe diameter weight, and grade, and axial tension in the pipe. Using the Curvature Index allows the designer to quantitatively compare expected fatigue lives at various points in a given string, or between alternative design choices in a given hole section. Another advantage of using Curvature Index in drill string design is that it can form the basis for setting inspection frequency and acceptance criteria.

In a practical application of the use of the Curvature Index, a drilling engineer may have a choice of wellbore trajectories that may be used for reaching a subsurface objective. For example, the trajectory may involve a wellbore that results in a 3° per 100 ft. dog leg with 450,000 lbs tension in the drill string or the wellbore may result in a 15° per 100 ft. dog leg with 100,000 lbs tension in the drill string to reach the same objective. Drilling the well with a 3° per 100 ft. dog leg may be less costly than drilling the well with a 15° per 100 ft. dog leg. However, the reduced fatiguedamage done to the drill pipe during the drilling of the 15° per 100 ft. dog leg well may offset the savings associated with drilling the 3° per 100 ft. dog leg well

The Stability Index ("SI") is a measure of the relative fatigue life of bottomhole assemblies (BHAs) that are subjected to being simultaneously buckled and rotated. The Stability Index is useful for comparing one design alternative with another to select the alternative most favorable from a fatigue standpoint. More specifically it is used to compare various drill collar and HWDP sizes run in various hole sizes. Having selected a BHA design, the designer can also use the Stability Index to estimate the fatigue resistance of the BHA for the purpose of setting inspection intervals.

Further in accordance with the present invention, the Bending Tolerance Rating ("BTR") is a rating system useful for rating stress effects of a collared component or downhole tool based on the maximum stress levels recorded in the drill string, including stress concentrators.

The Bending Tolerance Rating is used to assist in the selection of bottomhole assembly components that may have an unusual or special configuration with structural capabilities and limitations that are not commonly known to the design engineer. In one embodiment of the invention, establishing the Bending Tolerance Rating involves determining the most sensitive point on the special purpose bottom hole tool by any suitable means such as finite element analysis prediction of the tool working in a curve that has a 10° per 100 ft. build. This Bending Tolerance Rating is useful, for example, when evaluating drill stem components made by companies such as Sperry Sun, Baker, and Dyna-Dril. These companies make special purpose bottomhole assembly tools used for "Measurement While Drilling" and "Logging While Drilling" and other specialty subsurface functions. These bottomhole assembly tools have special geometries and structural limitations that are not defined in the readily available technical literature. For purposes of design analysis, the manufacturers of these specialty tools will determine a Bending Tolerance Rating that may be, for example, a function of the weakest structural point in their special tool. This Bending Tolerance Rating will be published by the manufacturer and may be used by the drilling engineer to confirm that the components can be appropriately used in the proposed drill string assembly selected for drilling a particular wellbore.

BRIEF DESCRIPTION OF THE DRAWINGS

The foregoing and other features and advantages of the present invention will be best understood with reference to a detailed description of a preferred embodiment of the invention, which follows, when read in conjunction with the accompanying drawings, wherein:

Figure 1 is a flow diagram illustrating a drill string design process in accordance with one embodiment of the invention;

Figure 2 is a diagram illustrating the fatigue design review step in the process of Figure 1;

Figure 3 is a graph showing a number of plots of tension versus Curvature Index in accordance with one embodiment of the invention; and

Figure 4 is a graph showing a number of plots of hole size versus Stability Index in accordance with one embodiment of the invention.

DETAILED DESCRIPTION OF A SPECIFIC EMBODIMENT OF THE INVENTION

The disclosure that follows, in the interest of clarity, does not describe all features of actual implementations of the invention. It will be appreciated that in the development of any such actual implementations, as in any such project, numerous engineering decisions must be made to achieve the developers' specific goals and subgoals, which may vary from one implementation to another. Moreover, attention will necessarily be paid to proper engineering and practices for the environment in question. It will be appreciated that such an effort might be complex and time-consuming, but would nevertheless be a routine undertaking for those of ordinary skill in the relevant fields.

Referring to Figure 1, there is shown a flow diagram of a drill string design process 10 carried out in accordance with one embodiment of the invention. The first step in the process, represented by block 12 in Figure 1, is to perform an overload structural design. Preferably, overload design is approached from the classical design standpoint. That is, the loads are predicted, then components capable of carrying the loads are used. Since the predictive formulas for load calculation are generally reliable, the design itself, if properly executed, will be reliable.

Since the plan for any hole section will have many issues and needs other than structure, the next step in the drill string design process 10 is to optimize the design, as represented by block 14 in Figure 1. In step 14, the designer must gain maximum leverage over other, non-structural needs, while maintaining a structural design that meets at least minimum safety factors and design constraints.

Following steps 12 and 14, in accordance with the presently disclosed embodiment of the invention, the next step is to review the design to mitigate fatigue attack. This is represented by block 16 in Figure 1. This step is believed to set the methodology of the present invention apart from prior art methodologies, which do not generally take the fatigue characteristics of drill string components into account during the drill string design process. As noted above, it is believed that this is the case principally due to what is widely viewed as the general unreliability of data which correlate in an absolute sense with the fatigue characteristics of drill string components.

In accordance with one aspect of the invention, on the other hand, the process 16 of reviewing the design for fatigue issues is a "comparative" or relative process. The comparative nature of the approach is a significant feature of the present invention inasmuch as it tends to overcome the problems associated with the unreliability of fatigue mechanism data as an absolute indicator of the fatigue characteristics of drill string components.

Turning to Figure 2, which illustrates the fatigue design review step 16 from Figure 1, the fatigue design review approach in accordance with the presently disclosed embodiment involves comparing alternative designs and selecting the design alternative(s) and operating approaches that (1) provide the lowest stress excursion (block 22 in Figure 2); (2) provide the lowest stress concentration (block 26 in Figure 2); (3) offer the best comparative fatigue life; and (4) reduce corrosion rates (block 24 in Figure 2).

To facilitate the process of fatigue design review, the present invention involves defining one or more "fatigue indices" each representing a quantification of one or more parameters known to correlate to some extent with the fatigue characteristics of the drill string and its constituent components. As used herein, the term "drill string component" shall be interpreted broadly to mean any one or more sections or subsection(s) of an overall drill string, including those section(s) in the upper drill string and those in the bottomhole assembly. Further, as used herein, the term "fatigue characteristics" shall be understood to mean those characteristics of a drill string component which either promote or resist fatigue failure. Preferably, each fatigue index is defined such that a fatigue index value as computed for a particular drill string component under particular operating conditions will provide at least a relative measure by which the likelihood of fatigue for two or more alternative candidate drill string components can be compared. By selecting drill string components based on such relative comparisons between alternative candidate components, the drill string designer is advantageously guided toward defining a drill string which mitigates problems associated with fatigue damage and failure.

One such fatigue index is referred to herein as Curvature Index, defined as a measure of the relative reduction in fatigue life caused by rotating a drill pipe tube in a curved hole section, taking into account the degree of hole curvature (build/drop rate), pipe size, adjusted pipe weight, grade, and axial tension in the pipe.

As noted above, in a practical application of the use of the Curvature Index, a drilling engineer may have a choice of wellbore trajectories that may be used for reaching a subsurface objective. For example, the trajectory may involve a wellbore that results in a 3° per 100 ft. dog leg with 450,000 lbs tension in the drill string or the wellbore may result in a 15° per 100 ft. dog leg with 100,000 lbs tension in the drill string to reach the same objective. Drilling the well with a 3° per 100 ft. dog leg may be less costly than drilling the well with a 15° per 100 ft. dog leg. However, the reduced fatigue damage done to the drill pipe during the drilling of the 15° per 100 ft. dog leg well may offset the savings associated with drilling the 3° per 100 ft. dog leg wellEssentially, the Curvature Index is a non-absolute (i.e., relative) quantification of the potential for fatigue resulting from subjecting a drill string component to curvature and tension in a borehole, which is typically expressed in terms of degrees of curvature per length of borehole, e.g., 10° per 100 feet. To calculate the Curvature Index for a drill string component, the first step is to compute the tension on the drill string under analysis. Those of ordinary skill in the art will appreciate that tension is computed based on various factors, including the weight of the drill string and BHA components, mud volume and/or mud weight, and so on.

Having determined the tension, which is typically expressed in units of pounds, the next step in computing the Curvature Index is to calculate the stress on the drill string. Those of ordinary skill will be familiar with the many factors taken into account in computing stress on a drill string, among them being the amount of curvature, also referred to as dog-leg severity or DLS to which the drill string is subjected.

In one embodiment, the stress is computed using the following methodology: Consider a drill pipe tube rotating in a dogleg while it's in tension. The stress in the outer fiber of the drill pipe tube caused by bending (σ_b) as it rotates in a dogleg is calculated based in part on the work of Arthur Lubinski. Equations (3) and (4) were obtained from Lubinski's work; however, the forms of these equations were derived to suit this application. Equation (3) is used to test whether or not contact is occurring between the drill pipe tube and the hole wall for a given hole curvature and axial tensile load. Equation (4) is used to calculate M_o for cases in which wall contact does not occur between the drill pipe tube and the hole wall. In the case of wall contact, equation (4) will not apply. Therefore, it was necessary to derive equation (5) to handle the wall contact case. This derivation was assisted by the work of Jiang Wu, who solved a

similar problem for pipe under compressive loads.

(1) $$\sigma_b = \frac{D}{2I} M_o$$

Calculate c:

(2) $$c = \frac{1}{R_C}$$

Calculate c_C:

(3) $$c_c = \frac{D_{TJ} - D}{L^2} \frac{(KL)\sinh(KL)}{2 - 2\cosh(KL) + (KL)\sinh(KL)} + \frac{w_b L^2 \sin(\theta)}{EI\,(KL)^2}$$

If c is less than c_C, then the pipe does not contact the hole wall and M_o is given by equation (4). If c is greater than or equal to c_C, then the pipe does contact the hole wall and M_o is given by equation (5).

(4) $$M_o = \frac{KL}{\tanh(KL)}[EIc - \frac{w_b L^2 \sin(\theta)}{(KL)^2}] + \frac{w_b L^2 \sin(\theta)}{(KL)^2}$$

(5)

$$M_o = \frac{w_b L^2 \sin(\theta)}{(KL)^2} + \frac{(KL/2)}{\tanh(KL/2)}[EIc - \frac{w_b L^2 \sin(\theta)}{(KL)^2}] + \frac{2 \cdot (KL/2)^2 \tanh(KL/2)}{(KL/2) - \tanh(KL/2)} \frac{EI \cdot r_c}{L^2}$$

(6) $$K = \sqrt{\frac{T}{EI}}$$

(7) $$r_c = \frac{D_{TJ} - D}{2}$$

Next, the axial stress (σ_a) in the drill pipe tube is calculated.

(8) $$\sigma_a = \frac{T}{A}$$

(9) $$A = 0.7854\,(D^2 - d^2)$$

Nomenclature for stress calculations:

A = Drill pipe tube cross sectional area, (in^2)

D = Drill pipe tube outer diameter, (in)

D_{TJ} = Drill pipe tool joint outer diameter, (in)

d = Drill pipe tube inner diameter, (in)

E = Young's modulus, (psi)

I = Moment of inertia of drill pipe tube, (in^4)

L = Half the drill pipe tube length, (in)

M_o = Bending moment on the drill pipe tube at the tool joint, (in-lbs)

θ = Average inclination angle across the drill pipe tube, (radians)

T = Axial tensile load, (lbs)

R_c = Radius of curvature of hole wall, (in)

c = Curvature of hole wall, (in^{-1})

c_c = Critical curvature of hole wall, (in^{-1}) (hole wall curvature required for the middle of the drill pipe tube to just contact the hole wall for a given axial tensile load)

w_b = Buoyed weight per unit length, (lb/in)

σ_a = Axial stress, (psi)

σ_b = Bending stress, (psi)

The foregoing methodology for computation of stress in the drill string is derived from the work of Arthur Lubinski, "Maximum Permissible Dog-Legs in Rotary Boreholes," SPE 1960, revised 1961, which work is hereby incorporated by reference herein. Methodologies for stress calculation are also discussed in T H Hill Associates, Inc., *DS-1, Drill Stem Design and Operation,* Third edition, Jan. 2003; Hill, T.H., Ellis, S., Lee, K., Reynolds, N., Zheng, N., "An Innovative Design Approach to Reduce Drillstring Fatigue," IADC/SPE 87188, 2004; and Jiang Wu, "Drill Pipe Bending and Fatigue in Rotary Drilling of Horizontal Wells," SPE 37353, 1996, each of which being hereby incorporated by reference in their entireties. It is believed that those of ordinary skill in the art will be familiar with still other methodologies for computation of stress in drill strings, and the selection and use of a particular methodology is not believed to be a critical consideration in the practice of the present invention.

After computing the stress, which is typically expressed in units of pounds per square inch, the next step in computing the Curvature index is to compute a "fatigue life" value. In accordance with one embodiment of the invention, the fatigue life value is determined by assuming that a stress fracture of an arbitrary, predetermined size is present in the drill string. Those of ordinary skill in the art will appreciate that the various tools and methods for identifying and locating stress fractures in drill string components are inherently limited, such that stress fractures below a certain size are essentially undetectable using conventional techniques. Accordingly, in one embodiment of the invention, the fatigue life value is computed based on the assumption that a stress fracture just small enough to be undetectable using conventional techniques is present in the drill string.

Based on this assumption, the fatigue life value is computed using any of various well-known methodologies. In the presently preferred embodiment, the well-known Forman Crack Growth Model is applied. This model is described in further detail in Campbell, J.E., Gerberich, W.W., and Underwood, J.H., *Application of Fracture Mechanics for Selection of Metallic Structural Materials,* ASM, 1982, p. 35.

Summarizing, the Forman Crack Growth Model allows for the computation of crack growth rate da/dN (expressed for example, in units of inches per stress cycle), as follows:

$$\frac{da}{dN}=\frac{C\Delta K^{n}}{(1-R)K_{IC}-\Delta K}$$

$$\Delta K = K_{\max} - K_{\min}$$

$$K_{\max} = \sigma_{axial}\sqrt{\pi a}F_{axial} + \sigma_{bending}\sqrt{\pi a}F_{bending}$$

$$K_{\min} = \sigma_{axial}\sqrt{\pi a}F_{axial} - \sigma_{bending}\sqrt{\pi a}F_{bending}$$

a = crack depth, (in)

C = Forman Crack Growth Model empirical coefficient

da/dN = crack growth rate, (in/cycle)

F_{axial} = stress intensity geometry and crack shape correction factor for axial loads

$F_{bending}$ = stress intensity geometry and crack shape correction factor for bending loads

K_{IC} = critical stress intensity factor, (ksi$\sqrt{in}$)

K_{max} = maximum stress intensity factor, (ksi$\sqrt{in}$)

K_{min} = minimum stress intensity factor, (ksi$\sqrt{in}$)

n = Forman Crack Growth Model empirical coefficient

R = ratio of maximum stress to minimum stress

σ_{axial} = axial stress

$\sigma_{bending}$ = bending stress

Those of ordinary skill in the art will appreciate that the “fatigue life” value is essentially merely a rough estimation of expected time to fatigue failure in the drill string component for which this value is derived.

In the presently preferred embodiment of the invention, the fatigue life value is subjected to a predetermined constant multiplier value to derive the Curvature Index.

In view of the foregoing, those of ordinary skill in the art will appreciate that deriving the Curvature Index in accordance with the presently disclosed embodiment involves essentially processing certain known parameters about the drill string and its environment, based on certain benchmark assumptions, such as DLS, fracture sizes, and so on. As a consequence, the Curvature Index admits to presentation to drill string designers in relatively simple formats, making comparison of the Curvature Index for alternative drill string components and/or for alternative wellbore conditions efficient.

Figure 3 is one example of how the Curvature Index data may be presented to a drill string designer. In the graph of Figure 3, units of tension extend along the horizontal axis, while the Curvature Index values extend along the vertical axis. In the example graph of Figure 3, each numbered plot (1, 2, 3, ... 30) corresponds to a different dog-leg severity (DLS), and the graph of Figure 3 provides Curvature Index data for a particular drill string component (5-inch drill pipe, S135 Premium Class, 6-5/16-in tool joint, etc...). To utilize the graph of Figure 3, a drill string designer would need only identify the tension on the drill string and the DLS, and then locate the intersection of that tension value with the corresponding DLS plot.

Of course, separate graphs like the exemplary one of Figure 3 would preferably be provided for different combinations of pipe sizes, pipe types, tool joint sizes, and so on. With reference to such data, a drill string designer can make a comparative assessment between alternative drill string components for a given drilling operation to determine, as between any two or more design alternatives, which alternative appears optimal from the standpoint of fatigue minimization. It is important to note that the Curvature Index data is intended to provide only comparative information about fatigue resistance as between two or more possible drill string design alternatives, as opposed to absolute data about the fatigue resistance of a particular design.

Another fatigue index utilized in accordance with the practice of the present invention is the Stability Index, which like the Curvature Index is a comparative or relative measure of fatigue life of bottomhole assemblies (BHAs), that are simultaneously subjected to buckling and rotation. Like the Curvature Index, the Stability Index is useful for comparing one design from another to select the alternative most favorable from a fatigue standpoint. Once the designer has selected a bottomhole design, the Stability Index can be used to estimate the fatigue resistance of the BHA for such purposes as setting inspection intervals and the like.

Computation of the Stability Index in accordance with the presently disclosed embodiment of the invention involves steps somewhat similar to those involved in computation of the Curvature Index. First, conventional finite element analysis (FEA) techniques are used to compute the stress in the BHA. Use of FEA techniques for this purpose is very common in the art, and it is not believed that a detailed description of this process is necessary for the purposes of the present disclosure.

Having computed the BHA stress value, a relative "fatigue life" value can be computed using the Forman Crack Growth Model described above with reference to the Curvature Index. From the fatigue life value, the Stability Index value can be derived.

Stability Index data for various alternative BHA configurations can be presented to and used by a drill string designer in the form shown in the example of Figure 4. In the graph of Figure 4, hole size values extend along the horizontal axis, and the various plots correspond to different sizes of drill collars. For a given hole size and drill collar size, the Stability Index can be read off of the vertical axis.

As with the Curvature Index, the Stability Index is intended to provide comparative or relative data between alternative BHA configurations, such that a drill string designer can efficiently compare, from the standpoint of fatigue failure, the relative merits of alternative drill string/BHA designs.

Another comparison factor used in the drill string design methodology of the present invention is a "Bending Tolerance Rating". The Bending Tolerance Rating is used to assist in the selection of bottomhole assembly components that may have an unusual or special configuration with structural capabilities and limitations that are not commonly known to the design engineer. In a preferred form of the Invention, establishing the Bending Tolerance Rating involves determining the most sensitive point on a special purpose bottom hole assembly tool by any suitable means such as finite element analysis prediction of the tool working in a curve that has a 10^{o} per 100 ft. build. This Bending Tolerance Rating is useful, for example, when evaluating drill stem components made by companies such as Sperry Sun, Baker, and Dyna-Dril. These companies make special purpose bottomhole assembly tools used for "Measurement While Drilling" and "Logging While Drilling" and other specialty subsurface functions. These bottomhole assembly tools have special geometries and structural limitations that are not defined in the readily available technical literature.

For purposes of design analysis, the manufacturers of these specialty bottom hole assembly tools will determine a Bending Tolerance Rating that may be, for example, a function of the weakest structural point in their special tool. This Bending Tolerance Rating can be published by the manufacturer and may be used by the drilling engineer to confirm that the components can be appropriately used in the proposed drill string assembly selected for drilling a particular wellbore.

The following Table 1 illustrates one example of a Bending Tolerance Rating schema in accordance with one embodiment of the invention.

TABLE 1

BTR	Maximum Stress in Body (σ_{max})
1	$\sigma_{max} \leq 0.25$*MYS
2	0.25*MYS $< \sigma_{max} \leq 0.4$*MYS
3	$\sigma_{max} > 0.4$*MYS

In the example of Table 1, Bending Tolerance Ratings are defined for various maximum stress ranges as a function of the material yield strength (MYS). As a benchmark, finite element analysis can be employed to determine the maximum stress σ_{max} in the body of a tool (including stress concentrators) for bending in a predetermined dog-leg, for example, 10° per 100 feet. The BTR for the tool is then read out of Table 1 based on this maximum stress. In the example of Table 1, a tool would be assigned a BTR of 1 if FEA shows that the maximum stress in the curvature is less than or equal to 25% of the tool's material yield strength. On the other hand, a tool would be assigned a BTR of 2 if FEA shows that the maximum stress in the curvature is between 25% and 40% of the tool's MYS, and a BTR of 3 if the stress is greater than 40% of the tool's MYS. Such a rating system provides a convenient way for drill string designers to specify to suppliers minimum acceptable bending tolerances for drill string components.

The exemplary embodiment of Table 1 above reflects a three-tiered rating system. Those of ordinary skill in the art having the benefit of this disclosure will appreciate of course, that rating systems with fewer or more rating levels may be defined in alternative embodiments.

From the foregoing description, those of ordinary skill in the art will appreciate how the methodology of the present invention may be put into practice in the design of a drill string. First, of course, the drill string designer must establish one or more operational objectives in the construction of a wellbore segment, and determining limiting parameters of the wellbore segment to be constructed. These may include, for example, bore size, DLS, pipe type(s) and size(s), and so on.

Next, the designer determines a selected first working parameter of a plurality of first components of a first type of equipment available to construct the wellbore segment. In the disclosed embodiment, the first working parameter may be curvature or stability.

The present invention provides a comparison factor for each of two or more of the first components, based on the selected working parameter of the first components. This enables to the designer to compare the respective comparison factors of the first components, and to select a first component from said plurality of first components, using the comparison of comparison factors, to best meet said operational objectives in the construction of the wellbore segment.

Because at least two different indices may be established for characterizing a drillstring component, the methodology of the present invention can further involve determining a second working parameter for two or more second components selected from a plurality of available second components of a second type of equipment available to construct the wellbore segment.

The invention provides a comparison factor for each of said two or more second components using the second working parameter, enabling the designer to compare the comparison factors of said second components, and selecting first and second components, to best meet the operational objectives, based on comparing the comparison factors.

From the foregoing, it will be apparent to those of ordinary skill in the art that a method for constructing a drill string has been disclosed which adopts a comparative selection process for minimizing the likelihood of fatigue damage and failure in the resulting drill string. Although specific embodiments of the invention have been disclosed, it is to be understood that this has been done solely for the purposes of describing various aspects of the invention, and is not intended to be limiting with respect to the scope of the invention as defined by the claims that follow. It is contemplated that various substitutions, alterations, and/or modifications, including but not limited to those design alternatives specifically mentioned herein, may be made to the disclosed embodiments without departing from the spirit and scope of the invention as defined in the claims.

WHAT IS CLAIMED IS:

1. A method for selecting well construction equipment, comprising:

a. establishing one or more operational objectives in the construction of a wellbore segment,

b. determining limiting parameters of the wellbore segment to be constructed,

c. determining a selected first working parameter of a plurality of first components of a first type of equipment available to construct the wellbore segment,

d. determining a comparison factor for each of two or more of the first components, using the selected working parameter of the first components, as used in the construction of the wellbore segment,

e. comparing the determined comparison factors of the first components, and

f. selecting a first component from said plurality of first components, using the comparison of comparison factors, to best meet said operational objectives in the construction of the wellbore segment.

2. A method as defined in claim 1, further comprising:

a. determining a second working parameter for two or more second components selected from a plurality of available second components of a second type of equipment available to construct the wellbore segment,

b. determining a comparison factor for each of said two or more second components using the second working parameter,

c. comparing comparison factors of said second components, and

d. selecting first and second components, to best meet the operational objectives, based on comparing said comparison factors.

3. A method as defined in claim 2, further comprising:

a. comparing working parameters of assemblies of said first and second components using the comparison factor established for said first and second components, and

b. selecting an assembly of said first and second components for constructing the wellbore segment using a comparison of comparison factors for assemblies of said first and second components.

4. A method as defined in claim 3, further comprising:

a. comparing comparison factors of three or more assemblies, each assembly having components of two or more types of equipment, using comparison factors established for each type of equipment in said assembly, and

b. selecting an assembly of said three or more types of equipment for constructing the wellbore segment using comparison factors established for said three or more assemblies.

5. A method as defined in claim 1 wherein the operational objective is to minimize the possibility of fatigue failure of a drill stem in the construction of a wellbore segment.

6. A method as defined in claim 1 wherein the operational objective is to minimize fatigue-caused damage in a drill stem being moved in a curved wellbore section.

7. A method as defined in claim 6 wherein the limiting parameter of the wellbore section is wellbore curvature.

8. A method as defined in claim 7 wherein said first components comprises a drillpipe and said limiting parameters include axial tension load, stress amplitude

(bending stress) and total stress in the pipe.

9. A method as defined in claim 8 wherein said comparison factor for said first components is determined by calculating the fatigue life of the drill pipe and converting the fatigue life into a Curvature Index.

10. A method as defined in claim 12 wherein said comparison factors are reported in graphs of tension load, wellbore curvature, and Curvature Index for various pipe sizes, weights, grades, and classes.

11. A method as defined in claim 10 wherein said comparison of comparison factors is performed by using said graphs to compare fatigue damage potential of different combinations of drill pipe types and sizes, wellbore curvature, and tension load.

12. A method as defined in claim 1 wherein the objective is to minimize the fatigue induced failure of a bottomhole assembly.

13. A method as defined in claim 12 wherein the first components are components of a bottomhole assembly.

14. A method as defined in claim 13 wherein said comparison factor is obtained by determining a Stability Index based on the maximum predicted stress exerted on the bottomhole assembly

15. A method as defined in claim 14 wherein the Stability Index is a numerical index ranging between an infinite life to the shortest life for selected bottomhole assembly components.

16. A method as defined in claim 1 wherein said limiting wellbore condition is a curvature of the wellbore and said first components are downhole tools.

17. A method as defined in claim 16 wherein said comparison factor comprises a bending tolerance rating determined for various maximum stress ranges of the

bottomhole tools as a function of material yield strength.

18. A method as defined in claim 17 wherein the bending tolerance rating for said bottomhole tools is reported in a bending tolerance rating table.

19. A method as defined in claim 18 wherein said bending tolerance rating table is evaluated to perform said comparison of comparison factors.

20. A method of designing a drill string comprising a plurality of drill string components, comprising:

(a) defining at least one fatigue index quantifying parameters known to correlate with the fatigue characteristics of a drill string component;

(b) identifying at least two alternative candidate drill string components;

(c) computing said fatigue index values for said at least two alternative candidate drill string components;

(d) comparing said computed fatigue index values;

(d) selecting one of said at least two alternative candidate drill string components for inclusion in said drill string based on said comparison of computed fatigue index values.

21. A method in accordance with claim 20, wherein said at least one fatigue index comprises a Curvature Index which correlates to a prediction of a drill string component's fatigue life when operated in a curved borehole.

22. A method in accordance with claim 20, wherein said at least one fatigue index comprises a Stability Index which correlates to a prediction of a drill string component's fatigue life when simultaneously subjected to buckling and rotation.

23. A method in accordance with claim 20, further comprising:

(e) calculating the maximum stress exerted on a drill string component under at least one predetermined set of conditions; and

(f) assigning a Bending Tolerance Rating to said drill string component based on the ratio between said calculated maximum stress and said drill string component's material yield strength.

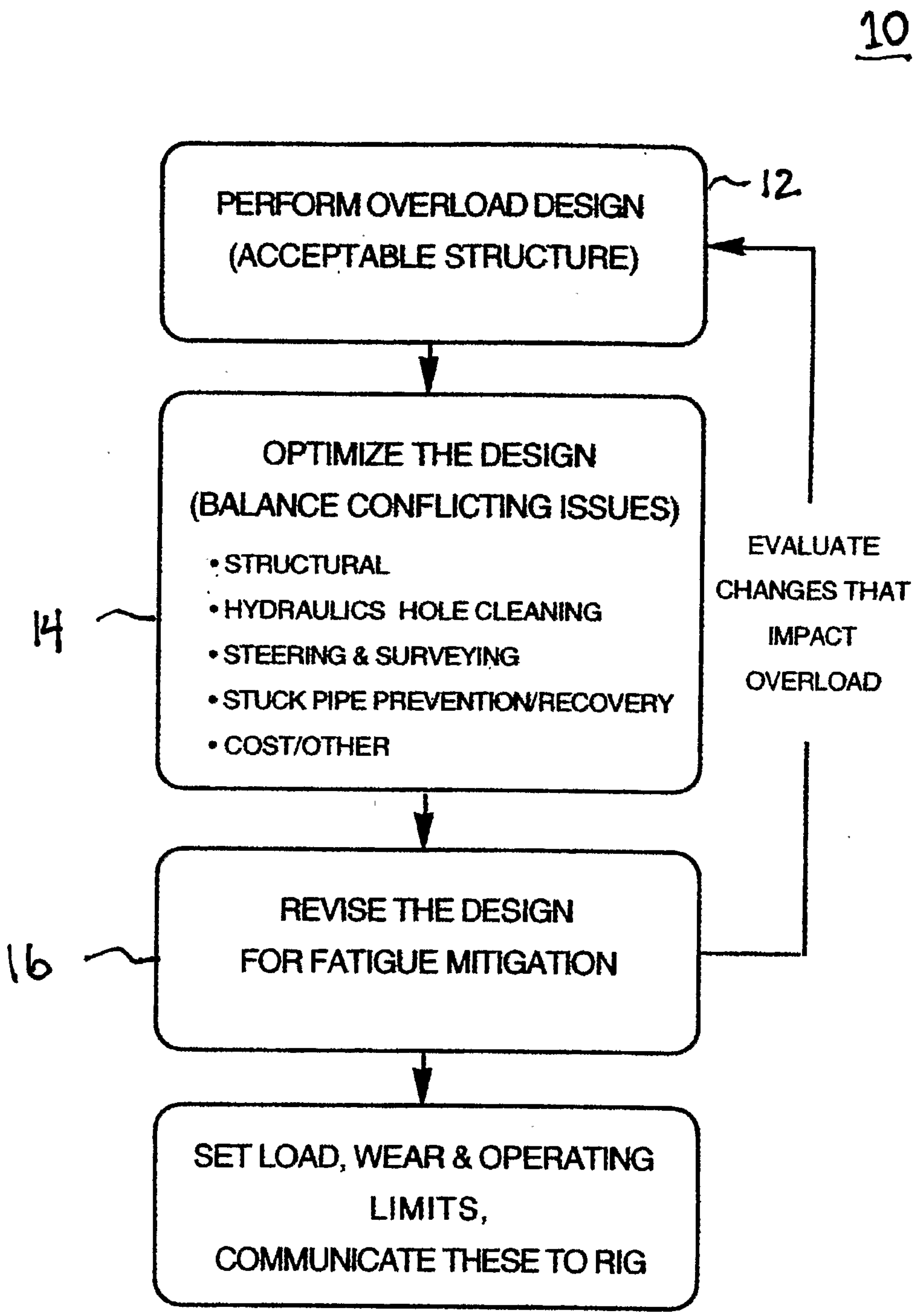
10
PERFORM OVERLOAD DESIGN
(ACCEPTABLE STRUCTURE)
12
OPTIMIZE THE DESIGN
(BALANCE CONFLICTING ISSUES)
• STRUCTURAL
• HYDRAULICS HOLE CLEANING
• STEERING & SURVEYING
• STUCK PIPE PREVENTION/RECOVERY
• COST/OTHER
14
EVALUATE CHANGES THAT IMPACT OVERLOAD
REVISE THE DESIGN
FOR FATIGUE MITIGATION
16
SET LOAD, WEAR & OPERATING
LIMITS,
COMMUNICATE THESE TO RIG

Figure 1

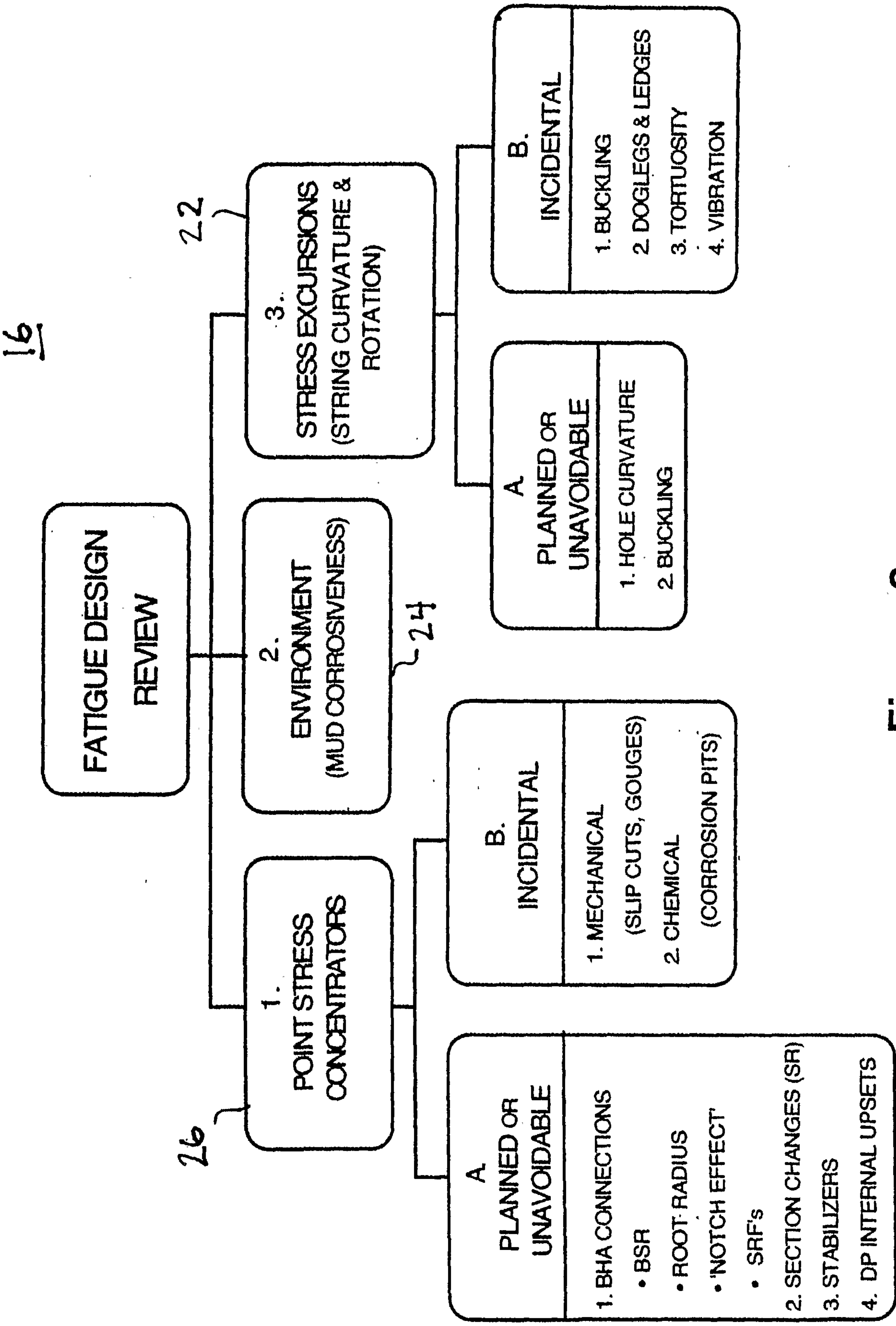
16
FATIGUE DESIGN REVIEW
1. POINT STRESS CONCENTRATORS
26
2. ENVIRONMENT (MUD CORROSIVENESS)
24
3. STRESS EXCURSIONS (STRING CURVATURE & ROTATION)
22
A. PLANNED OR UNAVOIDABLE
1. BHA CONNECTIONS
• BSR
• ROOT RADIUS
• 'NOTCH EFFECT'
• SRF's
2. SECTION CHANGES (SR)
3. STABILIZERS
4. DP INTERNAL UPSETS
B. INCIDENTAL
1. MECHANICAL (SLIP CUTS, GOUGES)
2. CHEMICAL (CORROSION PITS)
A. PLANNED OR UNAVOIDABLE
1. HOLE CURVATURE
2. BUCKLING
B. INCIDENTAL
1. BUCKLING
2. DOGLEGS & LEDGES
3. TORTUOSITY
4. VIBRATION

Figure 2

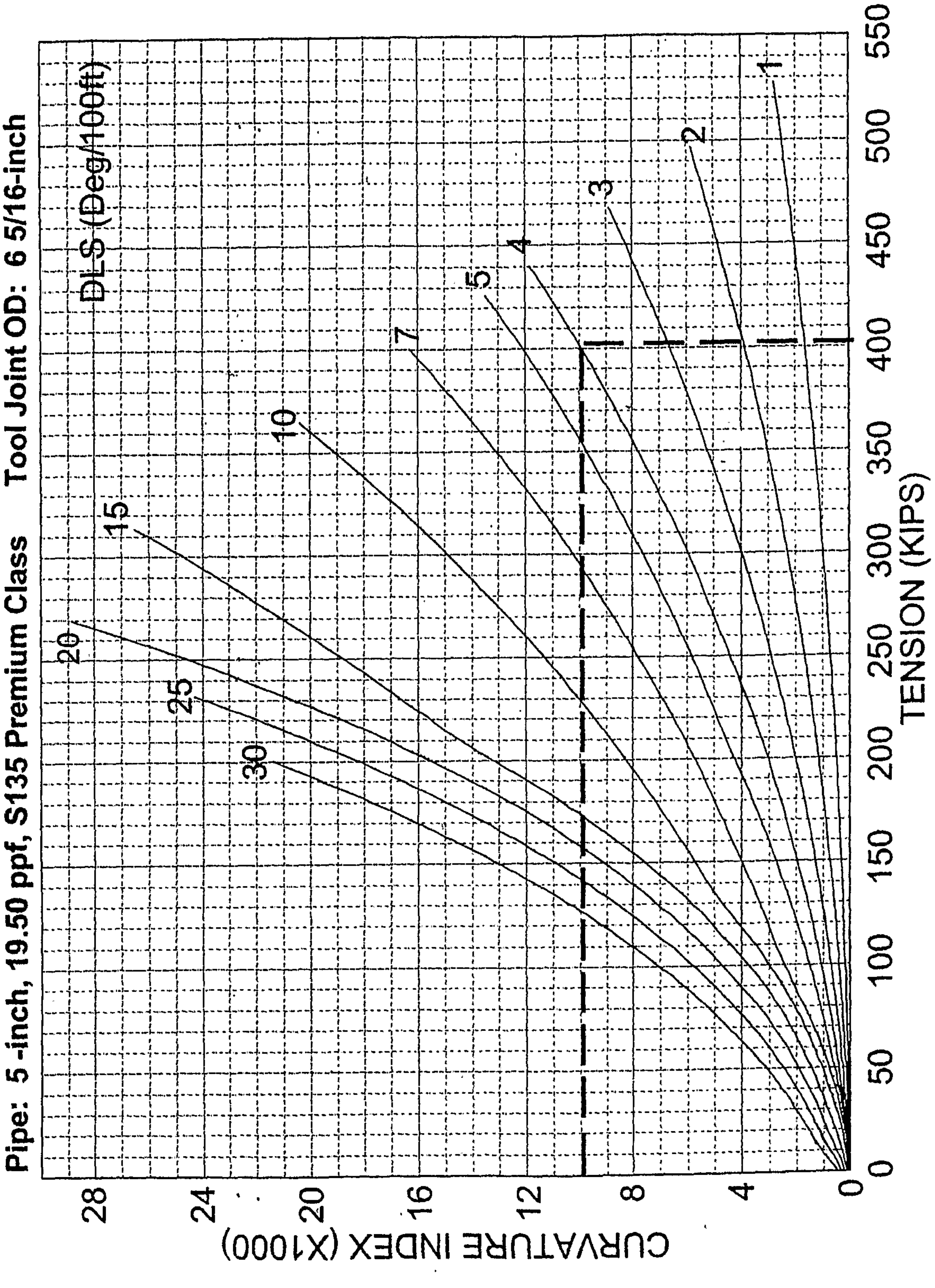
Pipe: 5 -inch, 19.50 ppf, S135 Premium Class Tool Joint OD: 6 5/16-inch
DLS (Deg/100ft)
1
2
3
4
5
7
10
15
20
25
30
CURVATURE INDEX (X1000)
0
4
8
12
16
20
24
28
TENSION (KIPS)
0
50
100
150
200
250
300
350
400
450
500
550

Figure 3

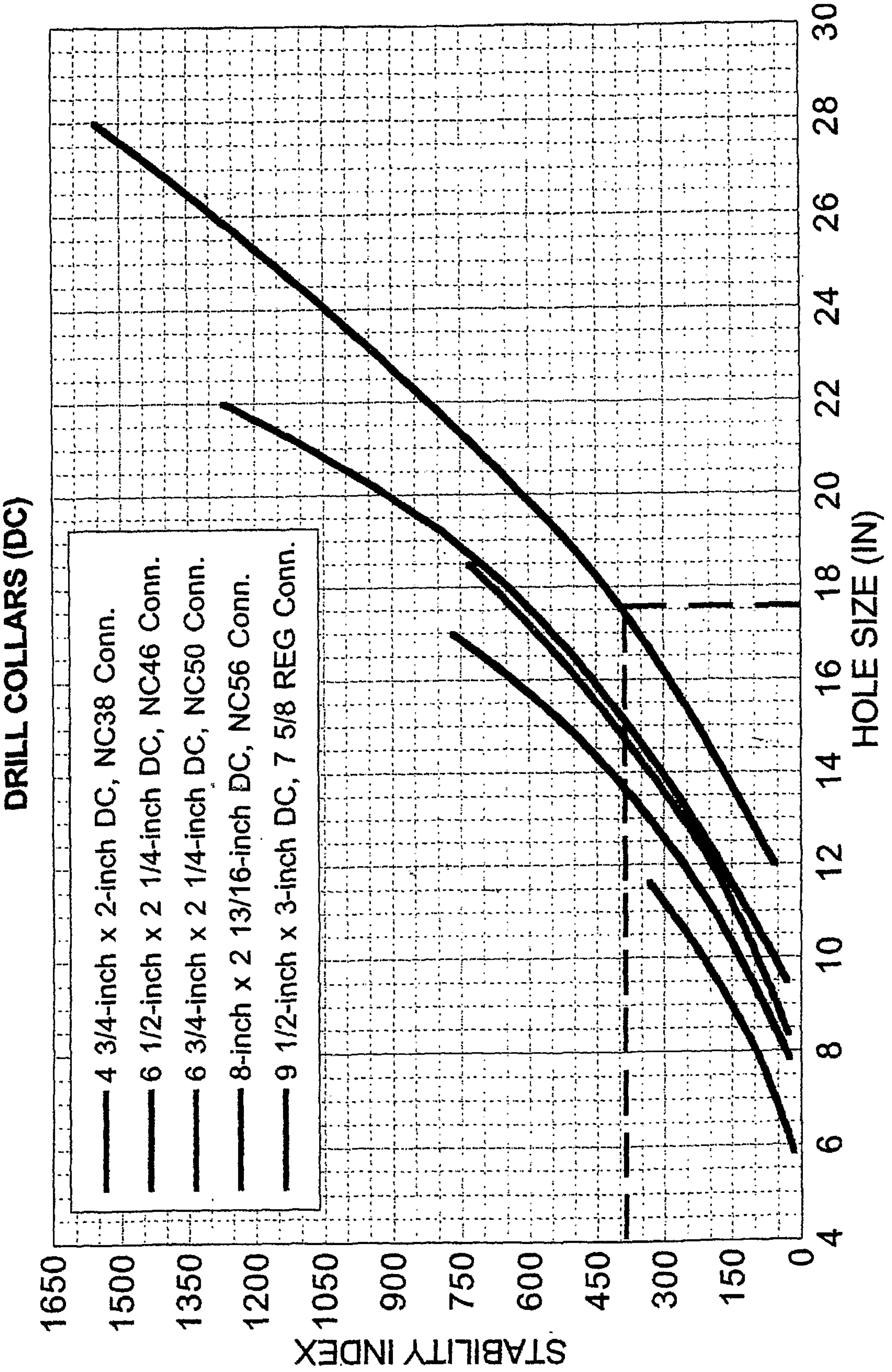
DRILL COLLARS (DC)
4 3/4-inch x 2-inch DC, NC38 Conn.
6 1/2-inch x 2 1/4-inch DC, NC46 Conn.
6 3/4-inch x 2 1/4-inch DC, NC50 Conn.
8-inch x 2 13/16-inch DC, NC56 Conn.
9 1/2-inch x 3-inch DC, 7 5/8 REG Conn.
STABILITY INDEX
1650
1500
1350
1200
1050
900
750
600
450
300
150
0
HOLE SIZE (IN)
4
6
8
10
12
14
16
18
20
22
24
26
28
30

Figure 4