A SYSTEM FOR MEASURING WELLHEAD BENDING MOMENTS DURING COMPLETION OPERATIONS

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Abstract

A problem which is faced during completion operations is that if vessel offsets and tensions are not carefully controlled, excessive bending loads can be applied to the wellhead and associated connectors. Naturally, damage to such a critical component must be avoided, but without a system to monitor and record the bending moments, it is hard for both operators and contractors to assess whether damage has been caused during operations.

This paper describes a novel monitoring system to address this issue, and a system is described for accurately measuring bending moments in the wellhead, which has been validated using a finite element based approach.

The system described uses two inclinometers to record the differential angle between the base of the riser and the middle of the lower stress joint. This information is then transmitted to the vessel via an acoustic modem and the curvature across the lower stress joint can be processed on the vessel using a simple computer program. The computer is able to accurately calculate the bending moment at the wellhead and this can then be displayed on the vessel and compared against preset threshold levels set by the operator. If bending loads become excessive, alarms can be sounded alerting the crew that they need to reposition the vessel or disconnect the riser. The computer will also record the bending moments and produce a summary report of the maximum loads at the end of the operation.

Introduction

During completion or work-over operations, extreme or accidental conditions such as large vessel offsets, or excessive levels of tension applied to the riser, have been known to occur. Such incidents can result in large bending loads at the wellhead, and depending on the magnitude and repetition of these loads, the wellhead and associated components may be subjected to damage.

Being able to monitor wellhead bending moments using a dedicated system would be a valuable tool to the offshore industry as the system could alert the operations team to high levels of bending in the system, and corrective measures can be taken before the bending loads become excessive. Such a system could also provide a log of the bending loads during the operation, which would give the operator confidence that damage has not been caused to their wellhead, and, in the same way, contractors would be able to control their activities and afterwards prove that their work has not compromised the design loads of the system.

Such a system is described in this paper using two inclinometers to monitor the bending in the lower riser by measuring the difference between the inclination of the base of the stress joint and the lower riser. Using a finite element based approach, this paper shows that the bending at the wellhead can be inferred to suitable accuracy using these measurements and shown in real time on the vessel. This read out can then be compared to the maximum allowable bending capacity of the wellhead and surrounding components. With this information, vessel offset and riser tension may be controlled in order to keep bending moments at the wellhead within acceptable levels. Additionally, the presence of VIV in the riser can also be reported and the riser tension adjusted accordingly.

Issues Related to Wellhead Bending

Overloading of a wellhead can be caused by excessive bending moments as a consequence of large vessel offsets and extreme currents during completion and work over activities. Alternatively, damage can also be a result of fatigue caused by oscillating bending moments of smaller magnitude. The most common event related to fatigue damage in subsea equipment is the phenomenon of vortex induced vibration (VIV) caused by current loadings.

A remarkable example of damage in a subsea wellhead took place in the West of Shetland region, in early 80's [1]. The wellhead failure, shown in Figure 1, occurred less than a month after the wellhead had been installed. The well had to be abandoned resulting in considerable non-productive costs. After inspection, it was discovered that an oscillating bending moment due to VIV had caused the incident. Studies showed that the bending moments had a period of 2 to 12 seconds and had deflected the base of the riser by 2 degrees.

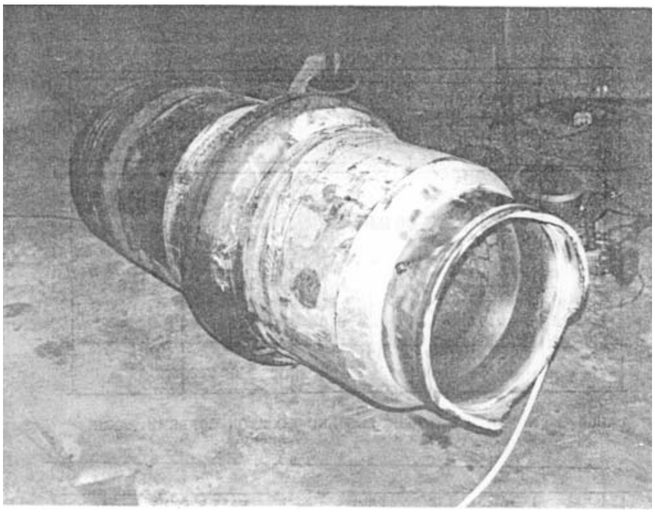

Figure 1 – Failure at Wellhead Extension Joint Weld – An Area of Stress Concentration

This example shows how failure of such a vital component can occur. This type of accident can occur suddenly, without giving any prior warning, and may incur substantial operational and financial losses. The environment may also be damaged if the wellhead integrity is compromised. One means to ensure that the wellhead is not being damaged during completion or workover operations is by monitoring of the system on a real time basis.

Outline of Monitoring System

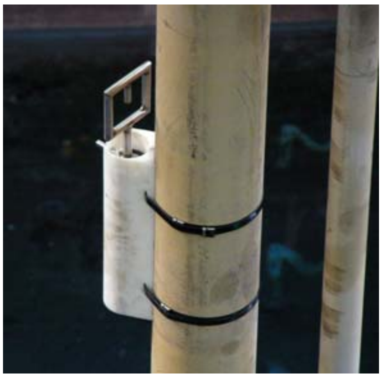

Figure 2 – Loggers mounted on a Completion Riser

The proposed monitoring system is composed of two inclinometer sensors, located at the base of the stress joint and 10m above the top of the stress joint, on the lower riser, as illustrated in Figure 4. The two loggers are to be strapped to the riser and stress joint on the vessel before deployment, as illustrated in Figure 2. The inclinometers are connected by a cable and an acoustic modem transmits the differential angle to an acoustic receiver on the vessel.

As the vessel offsets, the lower riser above the stress joint is pulled over and a curvature is applied to the lower riser and wellhead structure. The majority of the curvature is dissipated in the lower stress joint, which is designed specifically for this function, resulting in a build up of bending moment towards its base. As with all beam structures, the larger the bending moment applied across the joint, the larger the curvature across the component. The bottom riser assembly is exceptionally stiff and is considered to bend negligibly under the loads applied to it. This concept is illustrated in Figure 3. The bottom riser assembly includes the blow-out preventer (BOP) and the XMAS tree.

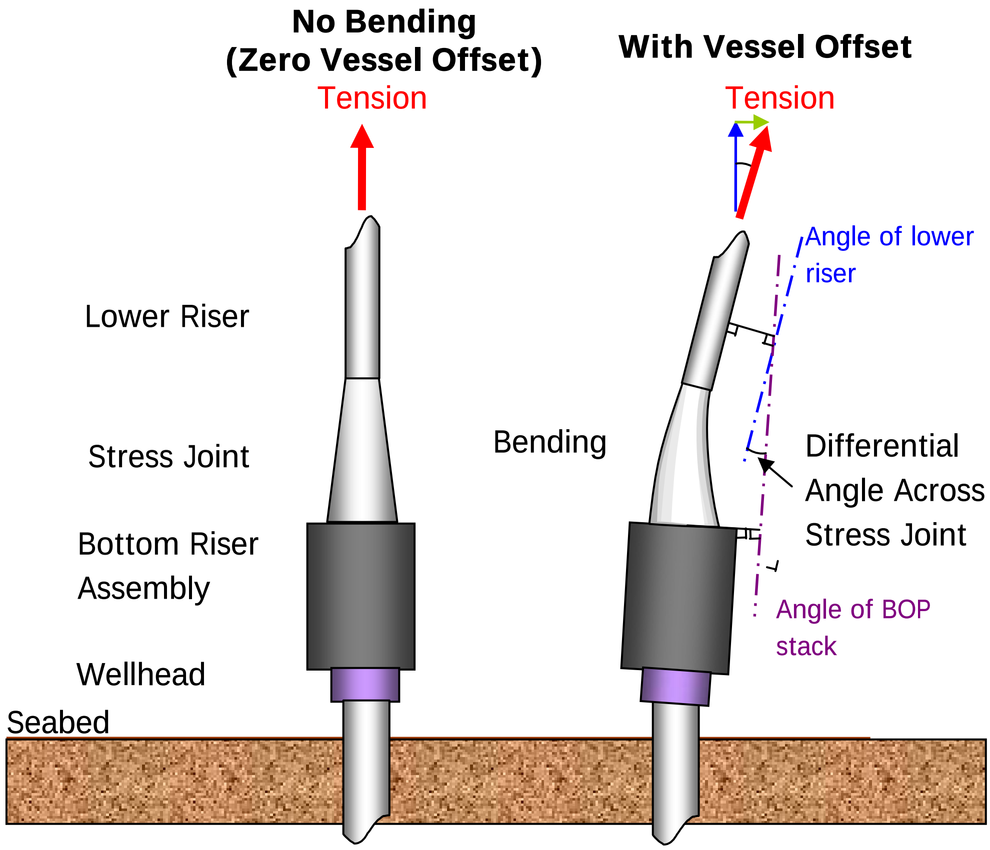

Figure 3 – Lower Riser and Wellhead

The acoustic receivers are fixed to the arms of a supporting frame attached to the top of the riser, at a minimum depth of 20m below the water line, as shown in Figure 4. The frame holds two acoustic receivers on arms of 1.5m fixed at 90degrees to each other. Using two receivers ensures a direct line of communication between the loggers and receivers if the riser is experiencing bending.

Riser tension must also be monitored using a strain gauge connected to the riser tension joint if it does not have its own top tension monitoring system.

The differential inclination at the lower stress joint, as well as the top tension is supplied to a laptop stored on the vessel. The differential angle is combined with properties of the riser and wellhead stackup, such as the bottom riser assembly height and weight, wellhead stickup and riser tension. The system combines all these parameters to calculate the bending moment at the wellhead which is reported on the screen. The software displays the bending moment in real time and an alarm can be sounded at a predefined threshold. A log of the bending moments during the operation can be recorded.

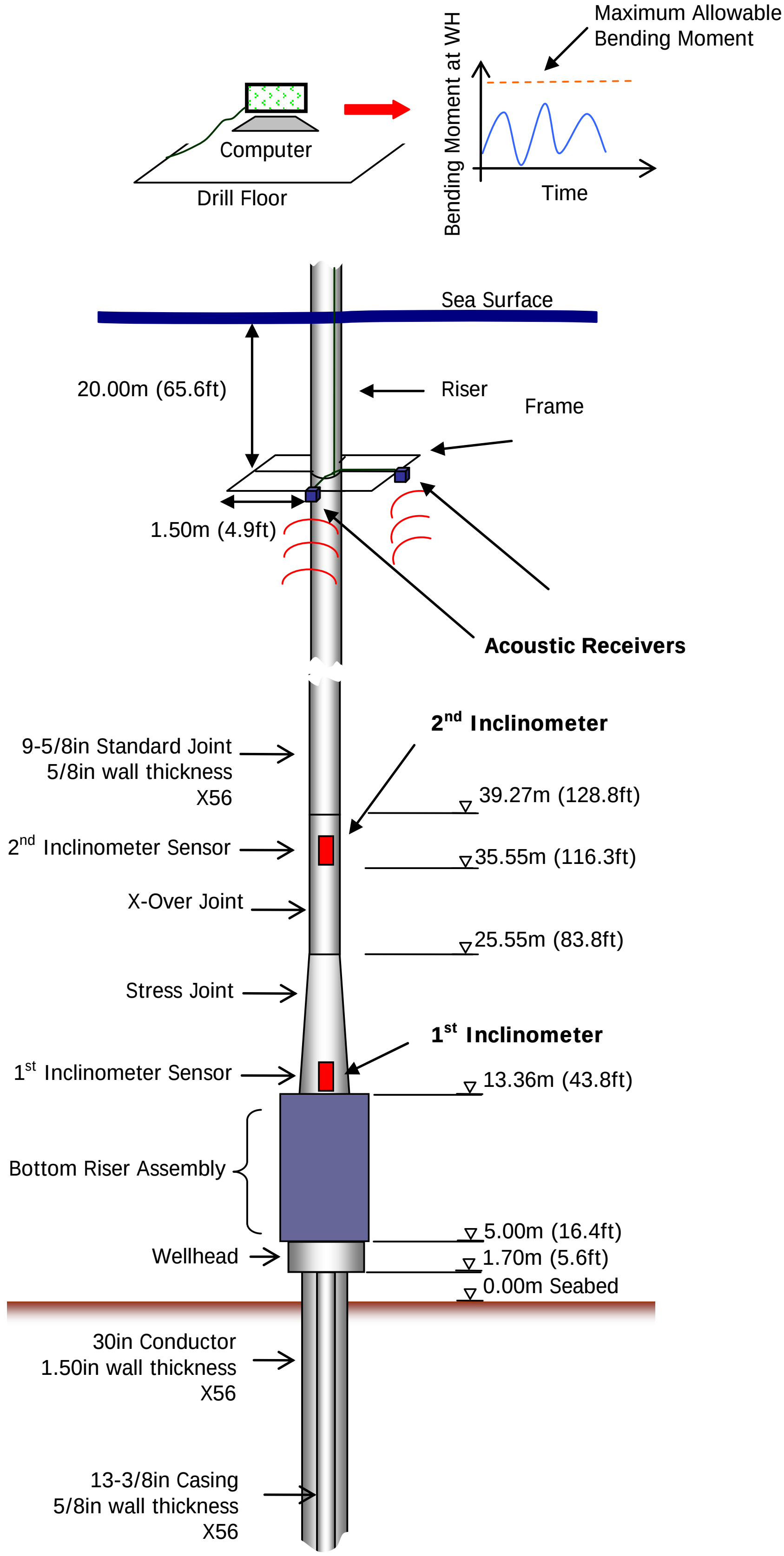

Figure 4 – Lower Riser Stack-up

Theory

The bending moments at the base of the stress joint can be calculated from the curvature across the lower riser and the stress joint. Since the bottom riser assembly components between the base of the stress joint and the wellhead can be considered stiff and bend negligibly under loading, the bending moments measured at the wellhead can be linearly extrapolated from the bending moment at the base of the stress joint.

There is a direct relationship between the differential inclinations of either end of a stress joint and the bending moment across it. The relationship between the angle to the vertical of the top of the segment (Δφ) and its extension (Δs) gives the curvature of the section, as shown in Figure 5 and described in equation 1. An approximation for the curvature in relation to the deflection of the segment (Δv) is presented in equation 2, although this formula is only valid for small curvatures [1].

If the curvature of the segment is caused only by bending (M_b), neglecting the influence of shear forces, this bending moment is related to the segment's deflection by the equation 3, [1], where ***E*** is the Young modulus of the material and ***I*** is the moment of inertia of the cross-sectional area.

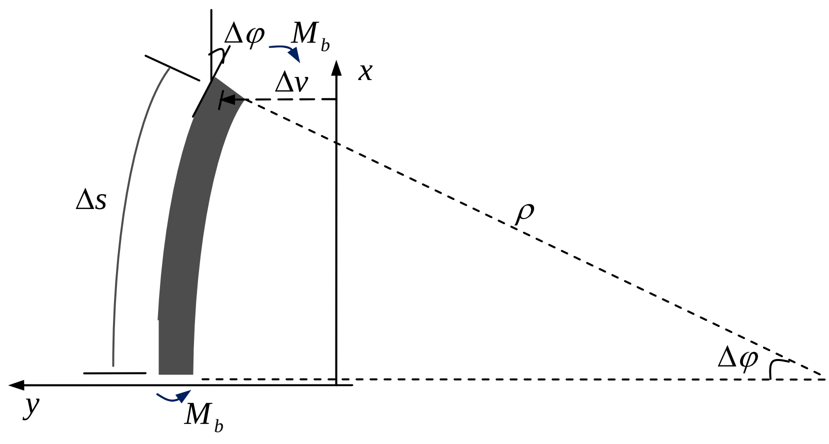

Figure 5 – Deformation of an element of a beam subjected to bending moments M_b

$$\frac{1}{\rho} = \frac{d\phi}{ds} \approx \frac{d\phi}{dx} \quad (1) \qquad \frac{d\phi}{dx} \approx \frac{d^2 v}{dx^2} \quad (2) \qquad \frac{d^2 v}{dx^2} = \frac{M_b}{E \cdot I} \quad (3)$$

It should be noted that the mathematical formulation described above is only valid for pure bending, however, the forces in the stress joint of a completion riser are far more complex and involve tensions and shear forces as a result of external loads such as currents, waves, soil conditions and vessel offsets. A complete mathematical expression that accounts for all these variables is beyond the scope of this paper. Such a formula would need to consider non-linearities due to lateral forces on the system as a result of vessel offsets and current loads, as well as the influence of shear forces, which will occur in a bending system under tension. Finally, it would also have to consider second order terms which must be accounted for in large displacement cases.

Consequently, a finite element based approach is used to study the complex relationship between lower riser deflections and bending moments. For this purpose the non-linear time domain finite element software Flexcom [3] is used.

System Modelling

The bending moment response at the top of the wellhead is analysed using a truncated finite element model of a completion riser, as shown in the lower part of Figure 4. In this model only the lower riser, wellhead and bottom riser assembly are considered. A tension force is applied at the top of the section of riser at a range of angles corresponding to a range of vessel offsets.

The finite element model is built to prove the relationship between the stress joint curvature and the bending moment at the wellhead. The results presented in this paper relate specifically to this model but the same theory can be applied to similar riser systems. The chosen system is composed of a 30inch conductor and a 13-5/8in casing, wellhead, bottom riser assembly stack and a set of joints that make up the lower riser, as shown in Figure 4. The components properties are described in Table 1 and Table 2.

	Outer Diameter (in)	Wall Thickness (in)	Mass per length (lb/ft)	Length (m)
Casing 13-5/8"	13.375	0.625	68	41.7(1)
Conductor 30"	30.000	1.500	457	41.7(1)
Stress Joint	13.000	1.750	258	12.2
Cross-Over Joint	10.750	1.000	147	13.7
Standard Joint	9.625	0.625	107	205.8(1)

1/ Lengths considered for this truncated model. The actual lengths can be different but do not affect the results presented in this paper.

Table 1 – Conductor and Lower Riser Pipes Properties

	Weight in Air (lb)	Weight in Water (lb)	Length (m)
Wellhead	36,217	31,474	3.3
Bottom Riser Assembly	100,375	87,226	8.4

Table 2 – Wellhead and Bottom Riser Assembly Properties

The soil resistance is modelled using non-linear springs, based on the ultimate soil strength and ignoring cyclic effects. The p-y data is converted to spring stiffnesses based on the conductor diameter, assumed as 30inch (jetted well).

The riser system considered in the analysis assumes the riser filled with sea water (1025kg/m^3). For the base case, the soil type adopted is a soft clay soil. The base tension measured at the base of the stress joint is 30Te.

The locations of the inclinometer sensors are shown as small red squares in Figure 4. The difference in vertical inclination at the locations of the two inclinometers and the corresponding bending moment at the wellhead is reported by the finite element analysis for a range of bending loads. The use of two loggers instead of only one allows the calculation of the net rotation of the lower riser, accounting for the effect of the bottom riser stack inclination when the riser is pulled by lateral forces, as shown in Figure 3.

Analysis of the differential angle across the stress joint and bending at the wellhead, during a range of conditions, shows that there is a clear linear relationship between the two parameters, as shown in Figure 6. However, the modelled system does not account for inaccuracies in the monitoring devices or unknown parameters in an offshore environment, such as the soil stiffness or current conditions. To prove the system will work to an acceptable level of accuracy, these uncertainties must also be assessed.

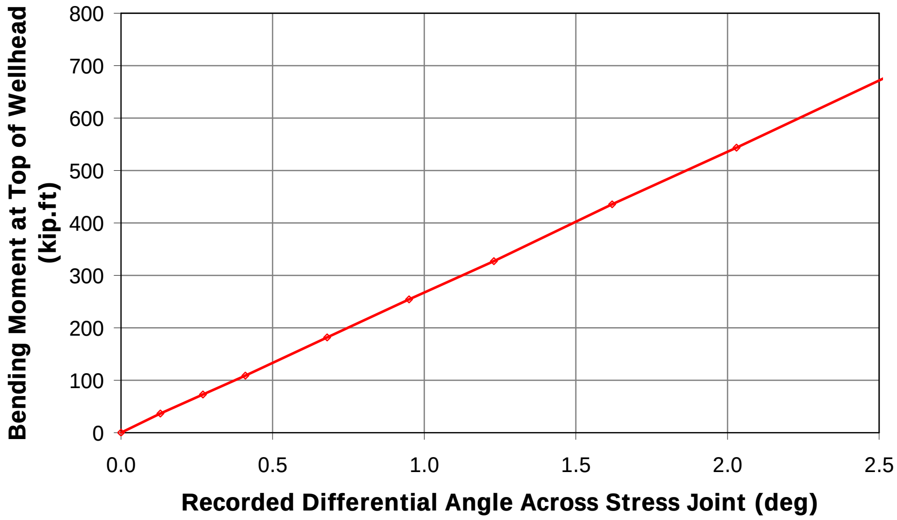

Figure 6 – Relationship between Stress Joint Curvature and Bending Moments at Top of Wellhead

System Accuracy

The system described in this paper uses the measurement of the curvature of the lower stress joint to infer the bending moment, at the top of the wellhead. The consequences of using this indirect approach to calculating bending at a location which may be some distance from the sensors themselves are that some uncertainties exist in unknown parameters and calibration errors. To evaluate these uncertainties, the relationship between the bending moments and the differential angle across the stress joint is reassessed with some key properties changed from the initial values adopted in the base case described in the previous section. The riser system properties are varied to quantify the following potential errors and uncertainties:

- Uncertainty in the base tension at the base of the stress joint;
- Sensor installation and calibration errors due to a non-perfect alignment of the sensor to the pipe. Inclinometer accuracy effects are also analysed;
- Uncertainty in the soil stiffness;
- The occurrence of seabed scour around the conductor.

The error in percentage is calculated for each case using the following equation 4:

$$Error(\%) = \frac{BM_{REAL} - BM_{CALCULATED}}{BM_{REAL}} \quad (4)$$

Where:

BM_{real} is the actual bending moment at the wellhead; and

$BM_{calculated}$ is the bending moment calculated considering a set of properties with some uncertainties

Influence of Top Tension Variation

In order to accurately calculate the bending and shear loads in the wellhead, the system must know the tension in the lower stress joint. However, the exact base tension is often unknown and the influence of calculating the bending moment at the wellhead using an incorrect base tension is assessed. A base tension of 30Te is adopted in the base case reported in the previous section, and the relationship between differential inclinations across the lower stress joint is also assessed for two other lower values of 10Te and 20Te, at the base of the stress joint.

Figure 7 shows that the relationship between differential angle and bending moments at the wellhead remains linear for each of the base tensions. However, an error of as much as 18.5% is found if the base tension is assumed to be 10Te but is actually 30Te. Assuming the same 20Te underestimation of tension, the error remains consistent as the lower stress joint is deflected, as shown in Figure 8.

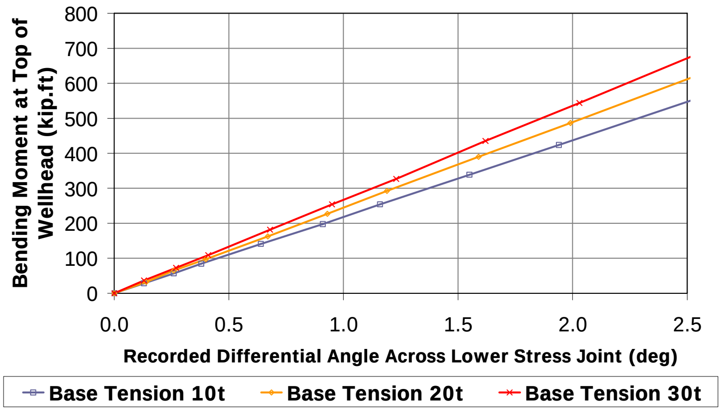

Figure 7 – Relationship between Stress Joint Curvature and Bending Moments at Top of Wellhead for Different values of Base Tension

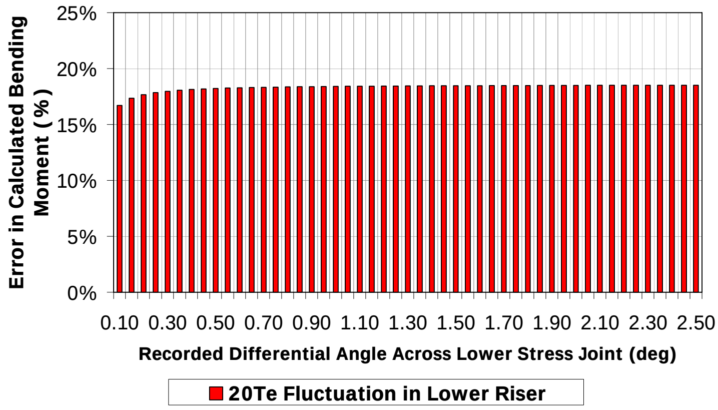

Figure 8 – Error involved in Predicting Bending Moments from Differential Angles if Base Tension has a 20Te of Fluctuation

Such a large error in the system is unacceptable, and therefore must be addressed if the system is to be of practical use. The error can be eliminated by constant monitoring of the riser top tension which can be achieved by using a set of strain gauges installed on the riser tension joint. The riser base tension is then calculated by subtracting the riser and internal fluid weights in water from the top tension recorded by the strain gauges system. Consequently, if the base tension is monitored at the same time as the differential angle across the stress joint, this error no longer exists and does not affect the accuracy of the system.

Influence of Installation and Sensor Accuracy

No matter how carefully the monitoring system is attached to the riser, there will always be a slight mis-alignment between the sensors and the pipe they are attached to, due to manufacturing and installation tolerances. To assess the influence of these uncertainties, it assumed that the inclinometers may have a ±1.00deg installation error and an accuracy error of ±0.02deg. To assess the influence of these errors, the worst case scenario of the lower inclinometer being installed 1.00deg counter-clockwise from the riser vertical axis, and the upper inclinometer 1.00deg clockwise. Assuming the accuracy of the inclinometers is ±0.02degrees, the lower sensor may record an inclination 0.02deg larger than it should be in the counter-clockwise direction and the upper sensor has the same error, but in the clockwise direction. Combining these errors, when the stress joint is in a vertical position, with no bending, the lower logger is measuring a 1.02deg counter-clockwise and the upper logger is rotated 1.02deg clockwise. Hence, the sum of installation and calibration errors is 2.04deg, as illustrated in Figure 9.

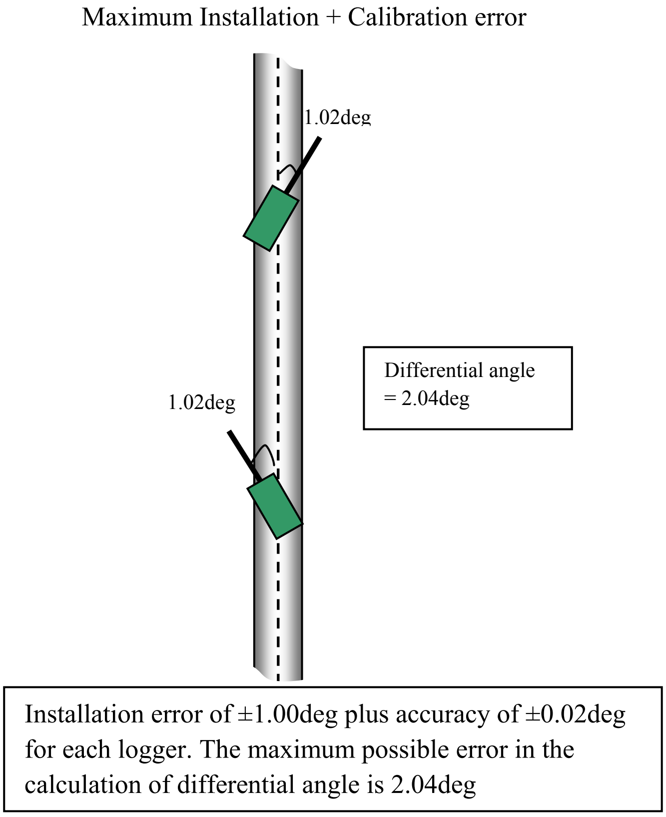

Figure 9 – Maximum Installation plus Calibration Errors

The prediction of bending moments through differential angles is severely affected if a total installation and accuracy error of 2.04deg is considered, as observed in Figure 10 and Figure 11. At small levels of bending in the stress joint, this error is more significant and become less critical as the stress joint starts to bend. The error decreases from 95%, for a differential angle of 0.10deg, to more than 45% error for a differential angle of 2.50deg across the stress joint.

Now, only the ±0.02deg error due to the accuracy of the sensors is considered. It is assumed the worst case where the 0.02deg error of each logger is summed and become a total error of 0.04deg when the riser is in vertical with a null bending moment at the wellhead. For this case, the error decreases from 29.3% at a differential angle of 0.10deg, to 1.6% if the differential angle is 2.50deg.

If only accuracy uncertainties are deemed and assuming a range of critical bending moments from 200kip-ft to 500kip-ft where damage to the wellhead is more likely to occur, the error remains between 5.4% and 1.6%. For example, for a differential angle of 1.80deg, the bending moment at the wellhead can be between 483.5kip-ft and 494.3kip-ft.

The installation error can be excluded by calibrating the system before use. The accuracy uncertainty, although, still remain. During deployment, prior to the stress joint passing through the moon-pool, the readings from the inclinometers are recorded while the system is hanging and no bending loads are applied.

The differential angle between the two sensors is recorded for a number of wave cycles, and then the readings averaged to give the nominal undeformed zero angle between the two sensors. This angle will then be subtracted from subsequent readings used to calculate bending moments.

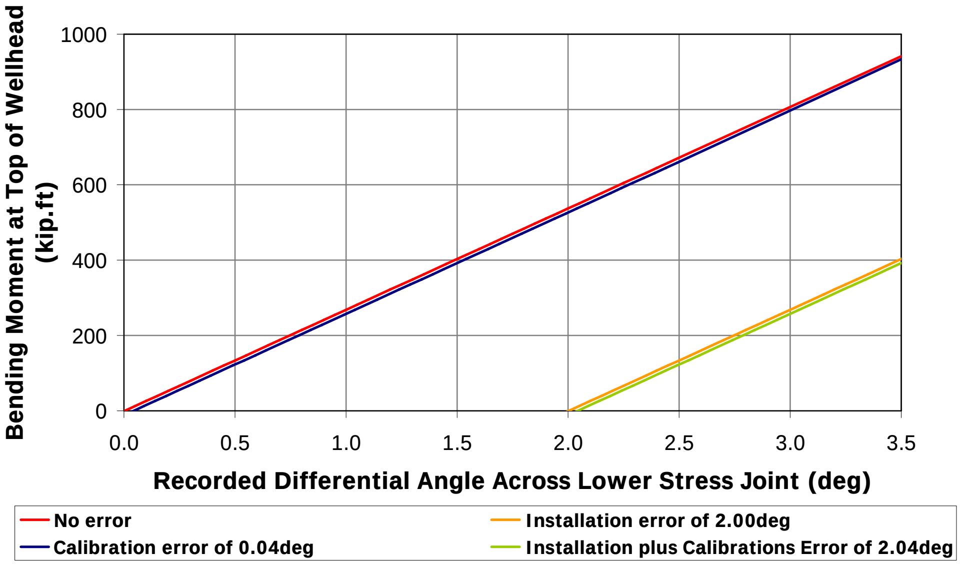

Figure 10 – Relationship between Stress Joint Curvature and Bending Moments at Top of Wellhead for an Accumulated Installation plus Calibration Error of 2.04 degrees.

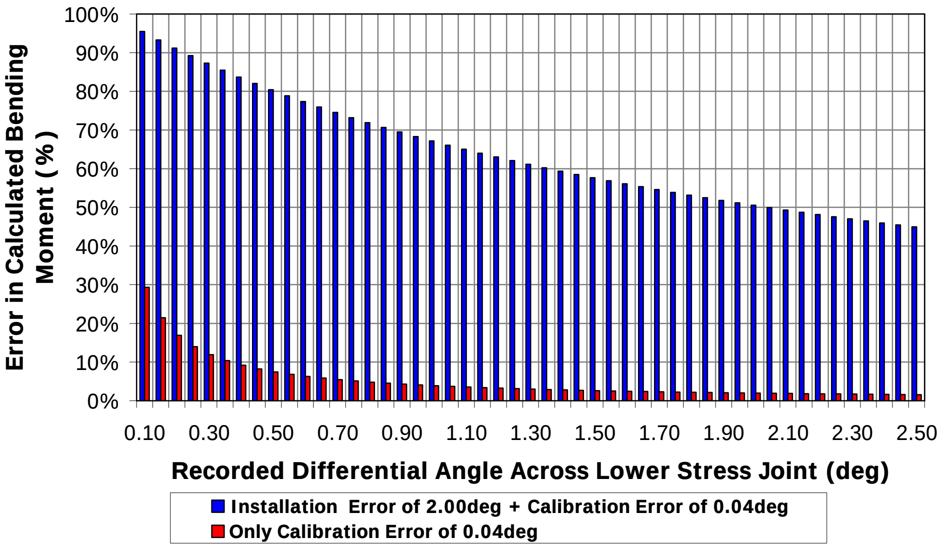

Figure 11 – Error involved in Predicting Bending Moments from Differential Angles if the Sensors are Installed with a 2.00 degree Error from Vertical and the Accuracy is of 0.04deg.

Influence of Soil Stiffness

To account for uncertainty in the soil stiffness, which is likely to be unknown, bending moments at the top of the wellhead are assessed with two types of soil: a soft, lower bound clay, used as the base case, and a stiffer upper bound clay. The lateral soil resistance profile with depth of the both clay types adopted is shown in Figure 12.

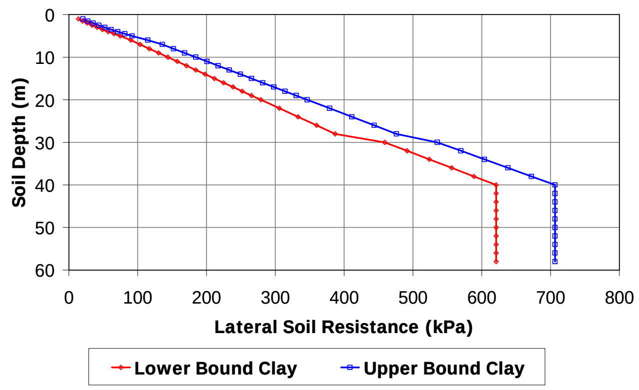

Figure 12 – Lateral Soil Resistance of the two selected types of Clay

The relationship between the bending moment at the wellhead and the differential angle across the stress joint for these two soil types is presented in Figure 13. The figure shows that the differential angle across the stress joint remains the same for each soil type and that the soil stiffness has only a very small influence on the calculated bending moment. Figure 14 shows that the error due to uncertainty of the soil stiffness is higher for small differential angles across the stress joint, being 2.5% at 0.10deg differential angle, which corresponds to a bending moment at the top of wellhead of 26.0kip-ft, if the soil is the lower bound clay, and 26.7kip-ft, if the soil type is the upper bound clay. Hence, the absolute difference in bending moments is small at this level. For differential angles larger than 1.00deg the average error is lower, with a value of -0.3%.

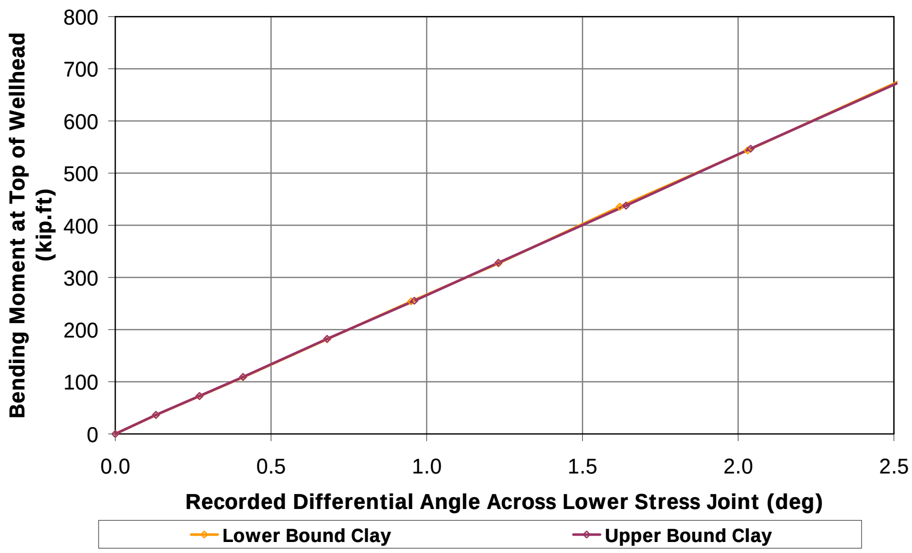

Figure 13 – Relationship between Stress Joint Curvature and Bending Moments at Top of Wellhead for Upper and Lower Bound Clays

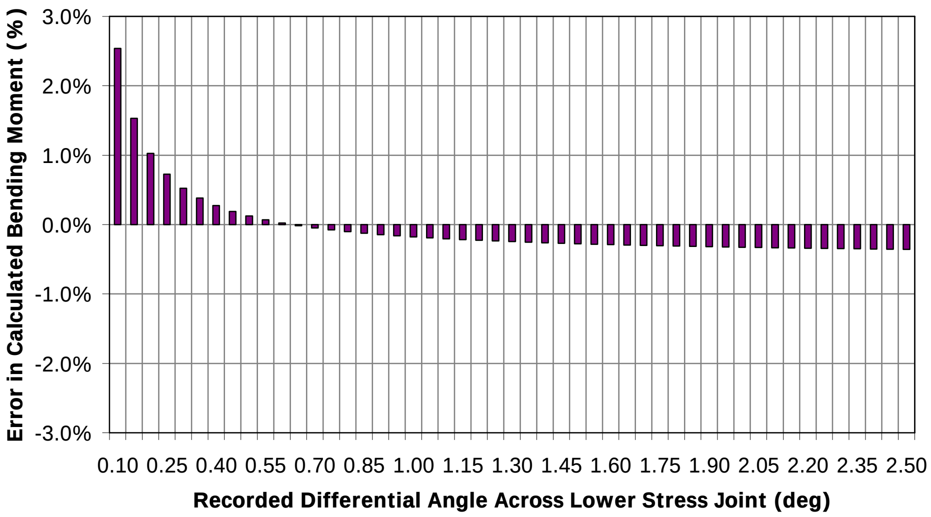

Figure 14 – Error in Calculated Bending Moments from Differential Angles if the Precise Soil Stiffness is not Known.

Influence of Scour in the Soil

Analysis is also conducted considering the possibility of the presence of scour between soil and conductor. This is simulated by removing the soil springs for the required depth of scour below the seabed, meaning that no lateral resistance to conductor bending due to soil interaction is considered through this region.

The relationship between the bending moment at the top of the wellhead and the differential angle across the stress joint is assessed for cases of 3m and 6m scour. The riser base tension is 30Te and the soil considered is the lower bound clay. The difference in relationship of differential angle across the stress joint and bending moment at the wellhead is shown in Figure 15. The analysis shows that the influence of the lack of soil resistance in the few meters below seabed is negligible.

The error in the calculated bending moments from the case where the soil has no scour, against the bending moments assessed from analysis considering 3m and 6m of scour, is shown in Figure 16. The figure shows that the error is higher for small differential angles, but always remains below 1.7%. If 3m of scour is present, the error approaches 0.3% for differential angles higher than 0.70deg. When the no scour case is compared against a 6m scour case, the error approaches 1.0% for differential angles greater than 0.40deg.

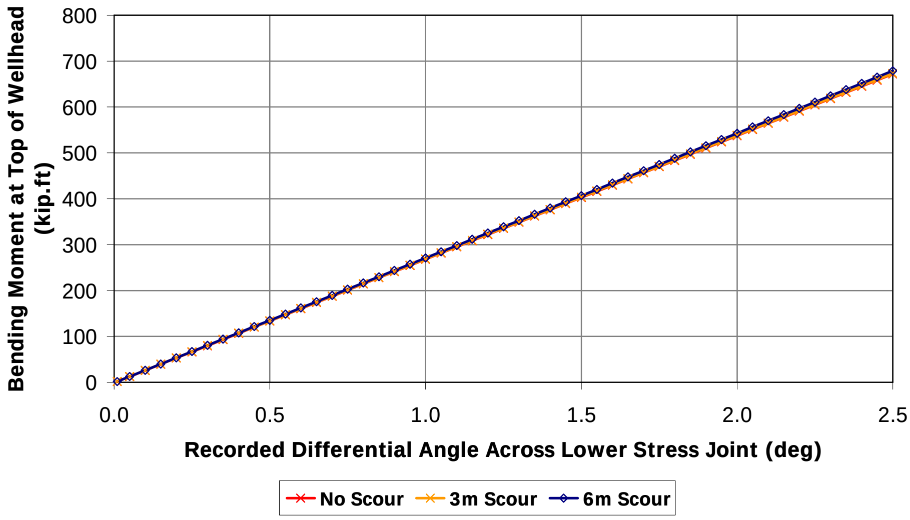

Figure 15 – Relationship between Stress Joint Curvature and Bending Moments at Top of Wellhead for Different Levels of Scour

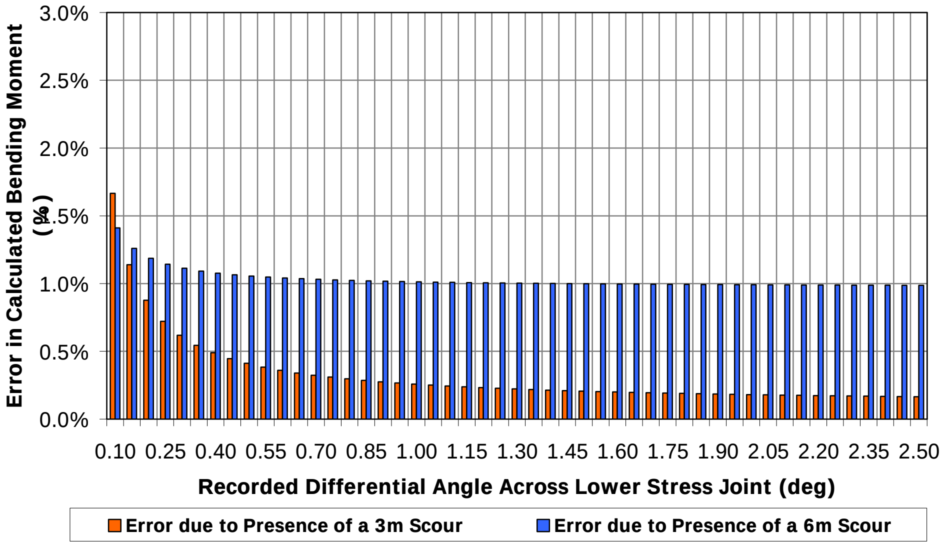

Figure 16 – Error involved in Predicting Bending Moments from Differential Angles if Scouring has Occurred.

Overall System Accuracy

Of the unknown parameters in the system this paper shows that whilst uncertainty about the riser base tension and sensors installation error can significantly influence the accuracy of the system, these errors can be minimized by adopting specific procedures before and during riser deployment. The riser top tension can be measured accurately at the top of the riser. However, the overall riser and internal fluid weights have to be known in order to correctly calculate the riser base effective tension. In case the tensioning system does not have a proper means to measure top tension, a strain-gauge system should be installed on the upper riser and linked to the bending calculation software.

Considering the influence of the other two possible sources of error, a scenario is built to evaluate the maximum error which may occur in the worst case scenario. For this purpose a case where the soil is a lower bound clay without any scour is compared against a scenario of an upper bound clay soil with a 6m scour. The ±0.02deg error due to system accuracy is also considered.

Comparing the results below with those from the previous sections, where the scour and soil stiffness uncertainties are analysed separately without deeming the system accuracy, it is observed that even a small ±0.02deg uncertainty in inclination measurements is relevant for the overall system response. The results define lower and upper boundaries of the possible bending moments at the wellhead predicted from differential angles taken across the lower stress joint, as shown in Figure 17.

The error involved in this lack of certainty about scour presence, soil type and system accuracy is presented in Figure 18. From the plot it is noted that the error decreases from 28.4%, for a differential angle of 0.10deg, to 4.3%, for a differential angle above 1.25deg. The absolute difference from the actual bending moment to the bending moment measured by the system remains between 10kip-ft to 20kip-ft. To give an example, if the differential angle measured by the inclinometers is 1.00deg, the range of possible bending moments acting at the top of the wellhead is from 267.7kip-ft to 2818kip-ft, an absolute difference of 14.1kip-ft.

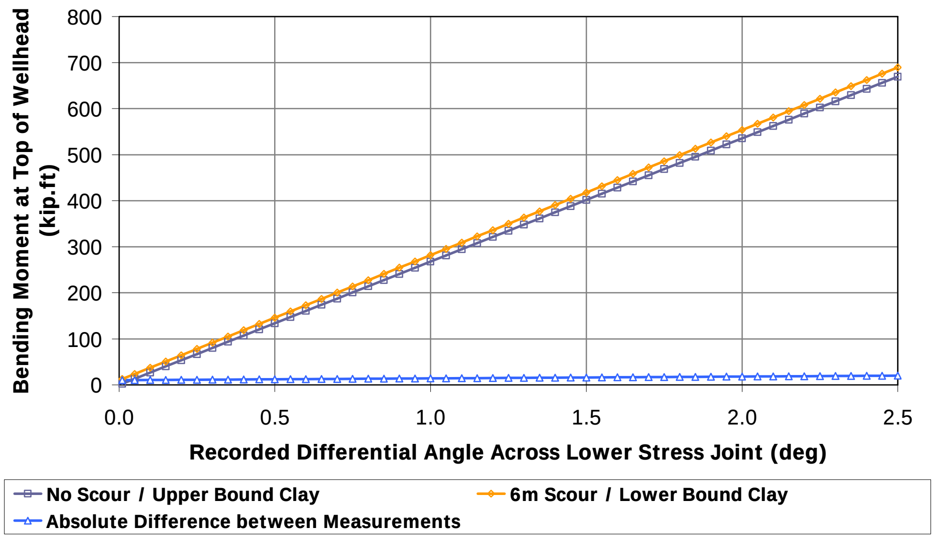

Figure 17 – Relationship between Stress Joint Curvature and Bending Moments at Top of Wellhead if Precise Soil Stiffness is not Known and Presence of Scour is Undetermined. Also considering System Accuracy of ±0.02deg.

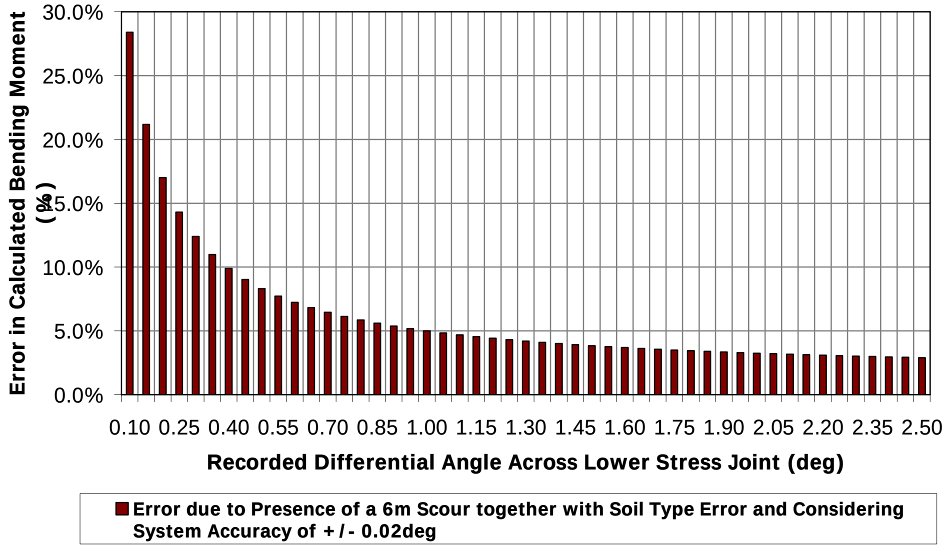

Figure 18 – Error involved in Predicting Bending Moments from Differential Angles if Precise Soil Stiffness is not Known and Presence of Scour is Undetermined. Also considering System Accuracy of ±0.02deg.

Conclusions

This study shows that with a finite element model of the lower riser and wellhead, the bending moments at the top of the wellhead can be calculated to acceptable accuracy if the differential inclination across the lower stress joint is known. The relationship between the difference in the rotations at these two sections and the bending moment at the wellhead is always linear.

In the riser considered for study the maximum error in predicting the correct value of bending moment at the top of the wellhead is 28.4%, for a differential angle of 0.10deg, decreasing to 2.9%, for a differential angle above 2.50deg, as shown in Figure 18. The absolute difference between actual and measured bending moments ranges from 10kip-ft to 20kip-ft for differential angles of 0.10deg and 2.50deg, respectively.

These results consider uncertainty in the soil stiffness and presence of scour, as well as the accuracy of each inclinometer. However, to achieve this level of accuracy the riser base effective tension must be known and errors due to uncertainty about sensors installation angle removed through a simple calibration procedure during installation. Hence, the system described using inclinometers to measure wellhead bending moments can monitor bending loads to suitable accuracy and can be used as a valuable tool during completion operations.

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