WELLBORE SURVEYING AND POSITIONING

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Contents

Introduction

Companies, service providers, and contractors in the wellbore construction industry use directional survey measurements during wellbore positioning. Wellbore construction applications include oil and gas, geothermal, carbon sequestration, coalbed methane, horizontal directional drilling trenchless boring, mineral ventilation and extraction, scientific coring, and all other subsurface borehole construction applications. Good wellbore positioning connects safety and environmental concerns with wellbore collision risk management and the efficient use of resources.

As targeting objectives become more complicated and well paths are drilled near subsurface hazards, such as offset wellbores, proper surveying practices are required to qualify accurate placement of the well to allow for systematic risk management and efficient development of the resources.

Wellbore positioning is a complex and technical subject and when properly implemented, involves detailed planning, skillful execution, and careful record keeping.

Multiple disciplines shall be engaged to achieve consistently good results.

In the past, complex well paths were only found in offshore developments, onshore pad drilling, and single horizontal wells and the issues consisted of shallow proximity concerns. As well complexity and density continue to increase, an increased focus on managing well positions for proximity concerns, reserves recovery, regulatory restrictions, and contingency planning is required.

Just as the environment into which wellbores are positioned is changing, so too are the tools and techniques that are being used. This document will evolve with time to acknowledge alternative approaches, developing technologies, and improvements to the current practice. This document can be complemented at all times with additional methods, processes, and equipment that do not contradict the contents.

The industry has access to numerous tools and calculation techniques to determine wellbore position.

Each operator and service provider shall determine which tools and techniques are needed to meet the goals of a given project.

This document should be used in association with good engineering judgment to provide a framework for determining proper wellbore position based on established practices. Following this document is commendable but it does not imply compliance with an individual regulator’s requirements, which is left to the document’s user to resolve.

1 Scope

The purpose of this document is to provide a framework and minimum guidance for the planning, acquisition, quality assurance (QA), storage, and use of wellbore position data for the well lifecycle. This guidance includes the assessment of well objectives as they pertain to collision assessment and reserves targeting.

This document covers the effective representation of the trajectory (e.g., position measurement), trajectory calculation, rendering and presentation, uncertainty calculation, and use with respect to other wells.

This document is not designed to provide a method for determining the most accurate position, only a position that is properly represented by a mathematical error model that considers both the tool type and the environment in which it was run.

This document includes the following recommendations and guidance:

- methods for assessing well position objectives;
- recommended planning processes to achieve well positioning objectives;
- recommendations for database integrity and minimum software functional requirements [1];
- methods for managing and calculating wellbore proximity in relation to health, safety, and environment (HSE) and economic risk;
- QA processes used before, during, and after surveying operations;
- guidelines for assigning position uncertainty models (PUMs) in accordance with data quality and field acceptance criteria (FAC);
- conventional industry methods for trajectory interpolation and mathematical processing as it pertains to wellbore surveying; and
- guidelines for maps, visual renderings, and other deliverables.

The following are examples of what this document does not include:

- Advanced geomatics, earth sciences (i.e., magnetics and gravity estimations), non-mainstream surveying techniques, emerging survey correction mathematical theory, positional uncertainty model derivation or developments, and directional drilling principles may be mentioned as they pertain to wellbore surveying but are not defined or addressed in detail.

This document shall be reviewed periodically to update with current wellbore surveying proven engineering practices.

2 Normative References

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) applies.

ISCWSA, *Recommendations for management of Inclination-Only Survey Data, Revision D*

SPE 184730-MS and SPE 184730-PA, *Well-Collision-Avoidance Management and Principles*, by S.J. Sawaryn, et al.

SPE 187073-MS and SPE 187073-PA, *Well-Collision-Avoidance Separation Rule*, by S.J. Sawaryn, et al.

3 Terms, Definitions and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply:

3.1.1
accelerometer
A sensor that measures acceleration along a specified axis.

3.1.2
allowable deviation from the plan
The maximum amount of divergence that is deemed acceptable between the actual wellbore trajectory and the planned wellbore trajectory.

3.1.3
along-hole depth

Distance from the well reference point (WRP) to any point of interest measured along the axis of the wellbore. Along-hole-depth (AHD) is the distance along a borehole that has been corrected and calibrated.

3.1.4
anti-collision
Anti-collision or safe separation refers to the measures taken to avoid collisions between existing or planned wells when drilling new ones.

3.1.5
approver
The person who decides to release the plot for its intended use.

3.1.6
attitude
The orientation of an instrument, defined by its inclination, azimuth, and tool face angles.

3.1.7
axial
Orientated in a direction parallel to the long axis of the tool.

3.1.8
azimuth
Angle measured clockwise (looking down from above) from the local north reference to the horizontal projection of the wellpath or instrument direction. Raw gyroscopic measurements always refer to true azimuth. For the purpose of measurement while drilling (MWD), QA, and quality control (QC), the reference is magnetic north.

3.1.9
BTotalDip
Absolute distance between measured and reference magnetic flux density vectors; a scalar that depends on the measured and reference BTotal and magnetic dip angle values

3.1.10
benchmark check shot
A survey point taken at the same depth as one or more previous survey points to confirm measurement repeatability.

3.1.11
bent housing motor
BHM
A type of downhole drilling motor used in directional drilling. It is designed to provide a curved or angled path to the drill bit, allowing for horizontal or directional drilling to access reservoirs and other targets that cannot be reached with a straight drill string.

3.1.12
block height
Distance from the block reference point to a defined reference point (typical rotary table/kelly bushing/drill floor [ZDP]).

3.1.13
bottomhole assembly
BHA
Downhole equipment attached to the drillpipe located at the lower portion of the drillstring, including drilling, reaming, positioning, measurement, stabilization, and other pipe elements. The bottomhole assembly (BHA) may include MWD/LWD tools, heavyweight pipe sections, drill collars, stabilizers, jars, reamers, several specialized subs, and the bit. The specific tools depend on the drilling operation's requirements, including the geological conditions, drilling direction, and equipment used.

3.1.14
BTotal
Scalar magnitude of local magnetic flux density.

3.1.15
business application services
Provides application support for qualifying software systems. Also known as information technology (IT) services.

3.1.16
Bx, By, Bz
Magnetometer measurements along *x*-, *y*-, and *z*-axes.

3.1.17
calibrated depth
AHD measured from the zero-depth point (ZDP) or the well reference point (WRP) to a point of interest defined by a calibrated measurement methodology with defined calibration conditions and is the basic input to "corrected depth" with an uncertainty term defining the calibration uncertainty to one (1)-sigma.

3.1.18
calibration
Determination of coefficient values populating a mathematical model that characterizes the performance of the instrument. The coefficients are typically bias, scale factor, and alignment for each sensor, with associated thermal coefficients. Calibration is performed by a series of measurements to characterize sensor or tool performance.

3.1.19
composite directional survey
CDSA directional survey record (DSR) relates to a combined survey report that includes surveys taken from one or more instruments belonging to the same or different service provider at different phases of the well lifecycle.

3.1.20
confidence level
A statistical measure that represents the level of certainty or probability that the estimated wellbore position and orientation is within a certain range of accuracy.

3.1.21
connection logic
Connection state defined using the hook load and in-slips sensors while the drillstring is stationary.

3.1.22
continuous mode
Survey mode in which the movement of the tool is measured and survey angles are a result of the integration of the measured rate.

3.1.23
corrected data
Raw data that has been adjusted through surface software.

3.1.24
corrected depth
Calibrated depth including environmental corrections (e.g., temperature, pressure, hydrostatic buoyancy, differential pressure–induced sticking, compression, pipe buckling) and measurement corrections (e.g., tension and hence elastic stretch, temperature and hence thermal elongation) with the corrections applied listed and quantified with an uncertainty term defining the correction uncertainty to one (1)-sigma.

3.1.25
covariance matrix
Covariance matrix, often referred to as covariance, is mathematical tool used to describe the uncertainties or errors associated with the measured data, including the inclination and azimuth angles of the wellbore trajectory.

3.1.26
data users
Any person (or entity) that uses well depth data.

3.1.27
dead end
Distance from the lowest effective measure point to the end of the instrument, tool string, or bit along which no measurements are taken or available. (Also see “sensor offset”.)

3.1.28
declination
Angle positive clockwise (looking down from above) in the horizontal plane measured from the true north reference to the magnetic north reference.

3.1.29
definitive survey
A final directional survey used to concatenate and compute the well trajectory.

3.1.30
degaussing
Reduction of remanent magnetization in a ferromagnetic object.

3.1.31
depth
A dimension taken through an object or body of material (in the context of this report), usually downward from an upper surface of something regarded as one of several layers. Increasing depth, i.e., increasing subsurface distance, is defined as a positive value referenced to the start of the measurement that is typically at surface (see “zero depth point” [ZDP]). Units are usually meters (metric) or feet (imperial).

3.1.32
depth shift
Movement of depth data up or down by a fixed amount (typically) used to match values of between measurement methods.

3.1.33
dip angle
The angle formed by Earth's magnetic field lines with respect to the horizontal plane. This angle changes across the Earth's surface. Positive inclination numbers indicate that the Earth's magnetic field is pointing downward, into Earth, at the place of measurement, whereas negative values indicate that it is pointing upward.

3.1.34
Directional and Inclination Module
A D&I Module is a type of downhole tool otherwise referred to as an orientation module used in wellbore surveying. This tool is designed to measure the direction and inclination of the wellbore as it is being drilled. The direction and inclination are essential parameters that help drillers navigate the wellbore and maintain the desired trajectory.

3.1.35
directional survey record
Information, regardless of media or format, that documents a business transaction, decision, or event required to be retained according to the record retention schedule (RRS).

3.1.36
drawworks
DW
A mechanical apparatus used in drilling rigs that provides the power to hoist and lower the drill string into and out of the borehole.

3.1.37
drawworks encoder
An electronic device used in drilling rigs to measure and transmit the rotational speed and position of the DW drum.

3.1.38
drift
Change over time in the gyro output or processed azimuth because of imperfections and un-modeled effects.

3.1.39
drill floor

The primary workspace for personnel on a drilling site. It is situated directly below the derrick and serves as the starting point for the drill string's descent into the subsurface.

3.1.40
drillpipe length
Well depth obtained measuring the length of drillpipe in the well. See "Driller's Depth".

3.1.41
driller's depth
The well depth measured and reported by the driller representing the distance from the ZDP to any point of interest.

3.1.42
drillstring interference
DSI
The change in the measured magnetic vector due to magnetization of components of the drillstring.

3.1.43
electronic (magnetic) multi-shot
A type of downhole tool used in wellbore surveying to measure the wellbore's direction and inclination. Sometimes referred to as a measure while tripping (MWT) magnetic survey instrument.

3.1.44
ellipse of uncertainty: ellipsoid of uncertainty or error ellipse
A three-dimensional representation of the potential location of the wellbore's true position based on survey measurements and errors. It represents the maximum and minimum potential errors in the wellbore's position as a three-dimensional ellipsoid around the wellbore trajectory.

3.1.45
environmental corrections
Adjustments to calibrated measurements made related to the effect of noncalibration conditions imposed on the measurement model by the environment under which the measurement is made.

3.1.46
error term
A component of an error model describing uncertainty caused by a particular source, consisting of a name, a magnitude at 1σ, a propagation mode, and a weighting function.

3.1.47
estimated drillstring interference

Estimated drill string interference calculates the expected magnetic interference caused by a drill string based on its length, diameter, and material. This can be used to adjust survey data.

3.1.48
Euclidean norm
Square root of the sum of the square or Root Sum Squared (RSS) also referred to as L2 norm.

3.1.49
executive action
Physical operation of field equipment performed by the control or safety system due to excursion from expected well conditions or manual activation.

3.1.50
field acceptance criteria

Serve as a basis for quality control and quality assurance of survey data during the drilling process. Survey data that do not meet the established acceptance criteria are deemed unacceptable and may require additional surveying or corrective measures to be taken.

3.1.51
free gyro
A gyroscope that senses changes in attitude from an initial orientation.

3.1.52
g-dependent bias
Change on the output of the sensor as a function of gravity.

3.1.53
gas water contact
The boundary or interface between the gas and water layers in an underground reservoir.

3.1.54
Gref
Local reference value of gravity field intensity, obtained independently of the MWD tool.

3.1.55
gross error
A significant unmodeled survey error or an error term that exceeds its 3σ error model value.

3.1.56
ground level elevation
The vertical distance between the surface of the ground at the location of the well and a reference point, typically the mean sea level.

3.1.57
GTotal
Scalar magnitude of local acceleration due to gravity. Represents the local acceleration due to gravity measured in units of meters per second squared (m/s^2).

3.1.58
Gx, Gy, Gz
Accelerometer measurements along x-, y-, and z-axes

3.1.59
gyrocompass(ing)
A stationary measurement of the earth's rotation to determine azimuth, sometimes called north seeking or north finding.

3.1.60
heave compensation
See "wave motion compensation".

3.1.61
hold-up depth
(Wireline) furthest well depth achieved during a well logging operation.

3.1.62
in-field referencing

Local measurement of the earth's magnetic field, which may be by a fixed instrument located near the wellsite or by inversion of aeromagnetic or seaborne magnetic data.

3.1.63
in-field referencing 1
Measurement of the static earth's field taken at a single moment in time.

3.1.64
in-field referencing 2
Continuous measurement of changes in the earth's field while drilling is taking place. This may be from a single observatory near the wellsite or from a "virtual observatory" obtained by interpolation between two or more actual observatories.

3.1.65
Inclination
Angle between the gravity vector and the local wellpath or instrument direction.

3.1.66
indicated depth
Any well depth measured from the ZDP to a point of interest that is neither calibrated nor corrected and assumes only consistency of measurement method. This includes any well depth measurement that is synchronized to another measurement. No uncertainty term is provided.

3.1.67
initial permanent deformation
Non-elastic deformation of wireline cable (multi- and single-conductor) due to settling of the armor and core elements, typically occurring during initial cable use. The amount of deformation depends on the number of runs and the tension, temperature, and pressure that the cable is subject to. These effects are usually, but not always, minimized after several runs in the well over the length of wireline used.

3.1.68
inrun
Relates a survey data, stationary and continuous, collected as the tool moves to deeper depths (traverses down the wellbore).

3.1.69
instrument
A rigid chassis onto which sensors and electronic boards are mounted, forming a complete assembly that senses the attitude and environment and either reports raw data or calculates driller's angles such as inclination, azimuth, and tool face.

3.1.70
instrument performance model
A unique positional uncertainty model assigned to an actual downhole tool or instrument used in the surveying operation; the instrument performance model is a type of position uncertainty model based on an actual survey instrument and its configuration.

3.1.71
log-down/log-up stretch
Method of determining incremental (or "delta") stretch of a wireline cable by comparing log-down derived well depth with the subsequent log-up depths of a geological marker. The difference is assumed to be the effective stretch, typically applied at or near the bottom of the well.

3.1.72
loss of well control
A risk event relating to the material loss of containment through key operations such as testing and well operations, well construction, and flowback.

3.1.73
M/LWD depth
The adaptation of driller's bit depth to M/LWD applications, considering BHA configuration, the associated sensor offsets, and the movement relative to driller's depth determination.

3.1.74
magnetic dip angle
Angle between the local earth's magnetic field vector and the horizontal plane; positive at locations to the north of the magnetic equator.

3.1.75
magnetic equator
A line circumscribing the earth, joining points where the local magnetic field is horizontal.

3.1.76
magnetic mark
Local magnetization of a wireline providing a fixed-length measure point, used to provide calibrated wireline length at a given tension and temperature.

3.1.77
magnetometer
A sensor that measures magnetic flux density. A scalar magnetometer measures Btotal (q.v.), while a vector magnetometer measures one or two components along specified directions or axes.

3.1.78
management of change
A procedure employed to ensure that modifications to procedures, apparatus, or personnel are adequately assessed, appraised, and executed in consideration of safety and risk management; this is done to prevent wellbore collisions and warrant the security and effectiveness of drilling operations.

3.1.79
mass unbalance
A particular type of g-dependent error that describes the effect of the gravity vector over the input axis of the sensor.

3.1.80
match point check shot
A benchmark check shot taken to overlap the last point in a previous survey.

3.1.81
measure point
Geometric position on the instrument where the instrument signal response is defined as being derived.

3.1.82
measured depth
MD
Measured distance along the wellbore from a surface reference point to the instrument provided without correction.

3.1.83
measurement error
Measured quantity value minus a reference quantity value.

3.1.84
measurement corrections
Adjustments to the calibrated measurements related to deviation of the instrument response caused by noncalibration conditions.

3.1.85
measurement uncertainty
Expression of the error associated with any measurement. This is a non-negative parameter expressed as standard deviation characterizing the dispersion of the values attributed to a measured quantity referenced to an assumed true value. One standard deviation is referred to as one (1)-sigma.

3.1.86
measurement while drilling
A technology used in the wellbore construction industry to collect real-time data about the drilling process while the drilling operation is ongoing, usually obtained from instrumentation contained within the BHA.

3.1.87
minimum allowable separation distance
The minimum distance between two wells or wellbores that needs to be maintained to prevent them from intersecting or colliding.

3.1.88
minimum curvature method
Commonly used method for constructing a wellpath from a survey by joining adjacent survey stations with circular arcs that match the measured inclination and azimuth at each station.

3.1.89
misalignment (offset center)
A tool face-dependent angle between the instrument's longitudinal axis and the local wellbore direction.

3.1.90
misalignment (sensor)
A lack of parallelism between a sensor's corrected sensitive axis and its nominal axis.

3.1.91
monumented
Marked by the positioning of a monument, often in the form of a small stone or concrete structure.

3.1.92
multi-station analysis
A multi-station correction which is the analysis of magnetic field data collected at multiple measurement stations within a wellbore BHA run.

3.1.93
multi-station (analysis) correction
The process of correcting for measurement errors that can occur when collecting data at multiple measurement stations along the length of the wellbore.

3.1.94
N, E, V
Position coordinates in a (North, East, Vertical) coordinate system

3.1.95
north arrow on plan view
A diagram illustrating the relationship between true, grid, and magnetic north, with the selected reference pointing to top of plot.

3.1.96
oil water contact
The boundary or interface between the oil and water layers in an underground reservoir. The oil water contact (OWC) represents the lowest point at which oil and water coexist in the reservoir, and it is a critical parameter for estimating the size, shape, and productivity of the oil-bearing zone.

3.1.97
orientation module
An instrument that measures inclination and azimuth.

3.1.98
outrun
Relates survey data, stationary and continuous, collected as the tool moves to shallower depths (pulled out of the wellbore).

3.1.99
overlapping check shot
Multiple survey measurements taken at a common well depth point during different surveys. The shots are taken at different times, and depth matching may be imperfect.

3.1.100
pipe tally
Record of sequence and length of individual BHA and drillpipe elements run in-hole.

3.1.101
plot project/well name (document ID)
Wells may have many names (e.g., common, legal, asset), but it is recommended that any actual trajectory be associated with a unique identifier (e.g., a plan revision or unique well identification).

3.1.102
plots
The graphical representation of the well separation from the offset wells should be used in both the planning and execution phases.

3.1.103 position uncertainty model
A mathematical model that, using the available data and measurement parameters, estimates the potential errors and uncertainties associated with the position of an object or point in space. A positional uncertainty model is utilized in the context of wellbore surveying to estimate the uncertainty in the wellbore trajectory's position and orientation, using data collected from a variety of downhole instruments and sensors. Although

they are frequently labelled as error models, tool codes, or instrument performance models, certain utility position uncertainty models, such as a blind projection, are not an actual surveying instrument.

3.1.104
quality assurance
Prevention of defects, prior to the survey.

3.1.105
quality assurance / quality control
A general term for quality related practices that combines both quality assurance and quality control with respect wellbore surveying and wellbore placement planning and execution.

3.1.106
quality control
Identification and correction of defects, during or after the survey.

3.1.107
rate gyro
A gyroscope that senses rate of rotation about a specified axis, or two axes in the case of a dual-axis gyroscope.

3.1.108
raw data
Sensor outputs that have been scaled and compensated (calibration has been applied).

3.1.109
raw depth
Output of the depth measurement (for driller's depth, the sum of the pipe tally; for wireline, typically the measure head encoder output) without calibration or optical encoder drift correction from a ZDP to any point of interest.

3.1.110
reference field
Measurements of the local gravity and magnetic fields that are independent from the survey tool.

3.1.111
reference point
The position on the rig or well structure, or any other datum, deemed to be stable and defined as the point from which well depth measurements are made.

3.1.112
reference depth
A point along-hole defined by the data user against which other well depth measurements may be tied-into.

3.1.113
reference laboratories
Well depth measurements and other associated measurements may be traceable to any nationally recognized measurement laboratory (e.g., National Institute of Standards and Technology [US], National Physical Laboratory [UK]; National Measurement Institute [Aus], Physikalish-Technische Bundesanstalt [De], Laboratoire National de Metrologie et d'Essais [Fr], GOST [CIS], National Research Council [Ca], National Metrology Institute of Japan [Jpn], Measurement Standards Laboratory [NZ], etc.).

3.1.114
relative depth
The along-hole displacement from a defined point of interest in a wellbore to a reference point.

3.1.115
revision (document/well ID and revision)
A revision naming convention example is "Plan DDDDDXYZ" where:

- "Plan" is a prefix to the intended final well name;
- DDDD is the document/Well ID or well name;
- X indicates a change to the well trajectory;
- Y indicates a change to wellbore information (e.g., casing depths), but the trajectory is the same; and
- Z indicates changes that are not related to X or Y, such as added notation(s).

3.1.116
rotation check shot set
A set of downhole survey points measured consecutively at a common well depth with varying tool face angles.

3.1.117
roll test
A set of survey points taken at the surface with common inclinations and azimuths but varying tool face angles. Most commonly a horizontal roll test in which the ends of the tool are rigidly supported to fix inclination and azimuth.

3.1.118
rotary kelly bushing
A square or hexagonal bushing that is located at the top of the kelly or top drive shaft in a drilling rig. In the context of wellbore surveying, rotary kelly bushing (RKB) used as a reference point for measuring the inclination and azimuth angles of the wellbore trajectory.

3.1.119
rotary steerable tool
A drilling technology used in the wellbore construction industry for more precise and efficient drilling of horizontal and directional wells. Unlike traditional directional drilling with bent housing drilling motors, the RST allows the drill bit to rotate independently of the drill string, enabling precise control of the drilling direction. It includes rotating bearings, stabilizers, sensors, and software that monitor and adjust the drilling process in real-time, reducing the time and cost required to complete the well.

3.1.120
safety-critical software
Performs an executive action, and has no means to validate output before an action occurs. Action occurs without the direct intervention of a person (e.g., automated systems such as process control, pipe handling, and dynamic positioning systems). Is one of the active barriers in the relevant process risk case.

3.1.121
safety-related data
Data used or generated by the safety-related software that informs a decision.

3.1.122
safety-related software

- Has a potential consequence that exceeds a predefined fiscal, reputational, health, safety, or environmental limit.
- Does not perform an executive action.
- Produces an output used by a human that can be verified before an action occurs.
- Provides an output that would not be corroborated by more than one additional system or process.
- Performs engineering calculations to design or guide the operation of safety-critical components or systems but requires the intervention of a designated human to interpret the output with sufficient time to intervene.
- Can be shown to degrade barriers or barrier elements in the loss of well control defined risk events.
- Has influence over one or more barrier elements in the loss of well control risk events.

3.1.123
sag
A tool face-independent angle between the instrument's longitudinal axis and the local wellbore direction caused by deflection of the BHA under gravity and borehole curvature. The term is commonly used to refer to only the vertical or inclination component of sag.

3.1.124
sag correction
Flex in the drillpipe and the BHA cause the BHA centerline to deviate from the wellbore centerline. This creates errors in down hole measured deviation and azimuth. As a result, the inclination observed may need to be corrected for the misalignment between the MWD sensor and the wellbore centerline.

3.1.125
sensor
A discrete electrical component used to detect and measure a physical quantity, e.g., magnetometer or accelerometer.

3.1.126
sensor offset
Distance from the bottom of a wireline instrument tool string or the bit of a drill string to an effective measure point (see also "dead end").

3.1.127
short survey
A survey point where only partial data are telemetered to the surface while drilling. This data typically consist of inclination, azimuth, and one or more QC values such as BTotal, GTotal, magnetic dip angle, or BTotalDip.

3.1.128
sigma
A measure of the variability or spread of measurements taken at different points along the wellbore. Specifically, it is a statistical measure that indicates how much the measured values deviate from the average or mean value. Often referred to as a standard deviation or a σ value.

3.1.129
slip load limit
Weight used to determine in-slips or out-of-slips for connection logic.

3.1.130
slip-and-cut
Replacement of the drilling line as a precaution against drilling line failure due to fatigue.

3.1.131
spread
The difference between maximum and minimum of a set of measurements.

3.1.132
station
A measurement taken at a specific time and well depth.

3.1.133
stretch and compress shift
Use of interpolation between two or more points to match along-hole data points, (typically) used to correlate core gamma ray or core porosity and permeability with other along-hole data sets.

3.1.134
stick and pull
Irregular tension events characterized by a buildup and then release of surface tension that may or may not be accompanied by a similar behavior of cable-head or top of BHA tension. Applicable to both drill pipe as well as wireline. The measured movement of the wireline or drillpipe at surface does not necessarily relate to movement of the subsurface instrument string movement due primarily to variances in the elastic stretch of the wireline or drill pipe. Sometimes referred to as stick slip.

3.1.135
sum of square residuals
Root sum squares refers to the sum of square residuals or square root of the sum of squares (Euclidean norm). RSS, also known as the L2 norm, of a vector is defined as the square root of the sum of the squares of its components. Mathematically, for a vector x in n-dimensional space, the Euclidean norm is defined as: ||x|| = sqrt(x_1^2 + x_2^2 + ... + x_n^2) where x_i is the i-th component of the vector x.

3.1.136
survey
A set of survey station data acquired consecutively using a single instrument and BHA.

3.1.137
technical specialist (example)
An expert user of software who can provide insight into how the software is used.

3.1.138
technical validation
A process in which the output of the calibrated data sets is compared to expected results to confirm validity of the application algorithms (i.e., sanction testing).

3.1.139
time shift
Applying a shift due to a time-stamping reference to any of the measurement products recorded or being recorded in the acquisition computer or downhole tool. MWD tools record data versus time. The surface

computer records time versus depth. Due to power supply, temperature change, or clock malfunctions, the MWD sensor clock may drift from the surface computer clock.

3.1.140
tool face
Roll angle measured clockwise from high side to a reference mark, plane, or axis, normally the *y* axis. Can also refer to the concave side of a deflection device such as a bent sub, bent housing motor, or whipstock.

3.1.141
total depth
Well depth distance from the ZDP to the rock-face end of the wellbore.

3.1.142
total magnetic field
The sum of all magnetic fields present at a given location in a wellbore survey.

3.1.143
transition (planning to execution)
The process of knowledge transference from the planning group to the execution group.

3.1.144
transverse
Oriented in a direction perpendicular to the long axis of the tool.

3.1.145
true along hole depth
Well depth determined by the length along the center of the drilled hole from the ZDP (e.g., rotary table, kelly bushing, top flange wellhead) to a point of interest in the well expressed as a figure together with an uncertainty term that is defined by the sigma tolerance applicable to the measurement.

3.1.146
true vertical depth
Vertical displacement from the ZDP, or another recognized datum, to the point of interest in the well based on the calculation of vertical position including an associated uncertainty.

3.1.147
units of measure
The scale or scale bar on each plot.

3.1.148
varying curvature analysis
An algorithm used in wellbore surveying to evaluate the quality of survey data.

3.1.149
verification
Quantification of the conformance of the measurement to the calibration process. This is shown by the conformance of the measurement to a defined standard as well as stability of the measurements provided.

3.1.150
vertical depth
Vertical displacement from the ZDP, or another recognized datum, to the point of interest in the well based on the calculation of vertical position not including an associated uncertainty.

3.1.151
vertical section reference direction
For a section plot, the vertical section reference direction corresponds to a direction of the plane of proposal. Often a plane that goes from the well origin to the bottomhole location, and the plot is perpendicular to the reference direction.

3.1.152
wave motion compensator
Also called heave compensation. Apparatus used to adjust for rig movement (typically on offshore floating structures) so that the block height and riser position are compensated for tide and wave-induced movement so as to maintain constant weight on the bit or distance to the seafloor.

3.1.153
weighting function
A set of mathematical formulas describing the sensitivity of derived values to a particular error term value. Strictly, the partial derivative of the derived value with respect to the error term.

3.1.154
well depth
A distance along the centerline of the well bore to TD or any point of interest referenced to the “zero depth point” (ZDP) whereby increasing well depth, i.e., increasing subsurface distance, is defined as a positive value referenced to the start of the measurement that is typically at surface. Units are usually meters (metric) or feet (imperial). Well depth may or may not be corrected and may or may not have an associated uncertainty.

3.1.155
well path
A continuous line in three-dimensional orthogonal space with a mathematical description, starting from a defined point and ending after intersecting the well’s target location(s). It may be described by way of numerical or graphical output.

3.1.156
well plat
Well positioning including horizontal and vertical accuracy statements of WRP and well total depth (TD) in terms of AHD defined using calibrated, corrected, and associated uncertainty.

3.1.157
well reference point
The surface location of the well. This surface location is regarded as being fixed and is defined in terms of the permanent datum.

3.1.158
whipstock
A wellbore departure tool used in wellbore construction to create a side-track or branch off an existing wellbore. It is a wedge-shaped device that is anchored in the existing wellbore at a specific depth and angle, using a set of packers and slips.

3.1.159
wireline depth
Also referred to as “Logger’s Depth”. The well depth measured from the ZDP to a point of interest, measured by the wireline logging service provider and provided as either “Indicated,” “Raw,” “Calibrated,” “Corrected,” or “TAH” depth.

3.1.160
wireline stretch
Elastic elongation of wireline caused by the along-hole tension regime along the length of the cable being measured.

3.1.161
xyz
Orthogonal sensor coordinate system, in which *z* is axial and the *y*-axis is used for tool face reference.

3.1.162
zero depth point
Unique single identified point maintained during all phases of operations and evaluation from which well depth is measured and at which well depth equals zero.

3.1.163
zero velocity updates
A technique used in earth-rate borehole gyro surveying to improve the accuracy and stability of the survey measurements. In this context, ZVU refer to the process of using information from the gyroscopes in the survey tool to detect and correct for any small movements or drifts in the tool's position while it is stationary, such as in a borehole.

3.2 Abbreviations

AC	anti-collision
ADP	allowable deviation from plan
AHD	along-hole depth
AZIM	azimuth
BDIP	btotal dip
BGGM	british geological survey global geomagnetic model
BHA	bottom hole assembly
BHM	bent housing motor
BTotal	total magnetic field
CGRF	canadian geomagnetic reference field
D&I	directional and inclination
DF	drill floor
DFE	drill floor elevation
DSR	directional survey record
DW	drawworks
EDI	estimated drillstring interference
EMS	electronic (magnetic) multi-shot
FAC	field acceptance criteria
GLE	ground level elevation
GWC	gas water contact
HDGM	national oceanic and atmospheric administration high definition geomagnetic model
HDGM-RT	hdgm with realtime updates
HUD	hold-up depth
IFR	in-field referencing

IGRF	international geomagnetic reference field
INC	inclination
IOGP	international association of oil & gas producers
IPD	initial permanent deformation
IPM	instrument performance model
ISCWSA	industry steering committee for wellbore survey accuracy
MASD	minimum allowable separation distance
MD	measured depth
MOC	management of change
MSA	multi-station analysis
MSC	multi-station (analysis) correction
MSL	mean sea level
MVHD	magvar high definition (geomagnetic) model
MVSD	magvar standard definition (geomagnetic) model
MWD	measurement while drilling
N, E, V	north east vertical
OWC	oil water contact
OWSG	operator's wellbore survey group
PUM	position uncertainty model
QA	quality assurance
QA/QC	quality assurance / quality control
QC	quality control
RKB	rotary kelly bushing
RSS	root sum squared or sum of squared residuals
RST	rotary steerable tool
SD	standard deviation
SF	separation factor
SPE	society of petroleum engineers
SS	safe separation
TAH	true along hole
TD	total depth
TVD	true vertical depth
VCA	varying curvature analysis
WCA	wave motion compensator
WD	well depth
WMM	world magnetic model
WPTS	wellbore positioning technical section
WRP	well reference point
ZDP	zero depth point
ZVU	zero velocity updates

4 Wellbore Positioning—Technical Requirements

4.1 Directional Survey Measurements to Wellbore Position Calculations

4.1.1 Directional survey measurements

4.1.1.1 The components of a directional survey measurement shall be:

a) well depth,

b) inclination, and

c) azimuth.

The directional survey measurements shall qualify for use by originating from valid sensor(s) and having an associated QC specification.

The directional survey measurements should have an associated positional-uncertainty performance model and specified range of validity. Multiple sensors and combinations of different types of sensor(s) may be used to produce well depth, inclination, azimuth, and downhole position measurements.

4.1.1.2 Well depth should originate from:

a) a length measurement device such as a ruler, tape measure, measuring wheel or transit-time measurement, including interferometry applied to the downhole string elements or wireline being used to convey the sensors to location, and/or

b) a travelling block height measurement device in combination with the length measurement device described above.

4.1.1.3 Measured inclination should come from devices measuring absolute or relative earth's gravity field or deflection of instrument from known orientation, such as:

a) angular deviation from a plumb line,

b) accelerometer(s), and

c) measurement of downhole string bending relative to pre-existing inclination measurement.

4.1.1.4 Measured azimuth should come from:

a) magnetic compass,

b) gimballed gyroscope set to reference orientation,

c) gyroscope(s) in combination with valid inclination measurement(s),

d) magnetometers in combination with valid inclination measurement(s), or

e) measurement of downhole string bending relative to pre-existing azimuth measurement.

4.1.1.5 Measured wellbore position should come from:

a) inertial navigation system, either stable platform, or

b) strapdown, in combination with a depth measuring system described above.

4.1.1.6 A directional survey measurement shall be produced by one of the following methods:

a) The inclination and azimuth measurements derived from the instrument sensor(s) shall be paired with the instrument's well depth at the time of making the measurements.

b) This may be done directly or indirectly, for example using an intermediate step of matching recorded time from each sensor.

c) Well depth, inclination, and azimuth are backcalculated from the wellbore position measurement so minimum curvature wellbore position calculation results in a trajectory that meets the accuracy specification of the associated positional uncertainty model for the original wellbore position measurement, allowing for all other error sources.

d) The inclination measurement derived from the instrument sensor shall be paired with the instrument's well depth at the time of measurement.

e) This inclination-only measurement shall then be treated as a directional survey measurement in accordance with the Industry Steering Committee on Wellbore Survey Accuracy (ISCWSA) Recommendations for Management of Inclination-Only Survey Data, Revision D.

4.1.2 Reference azimuth

The measurement azimuth may be rotated from its measurement North to a single reference North, such as Grid-North or True-North, by applying the appropriate declination, convergence, and/or fixed offset. The reference north should be stated by the well's operator. Since both declination and convergence are location-dependent, their values may vary along the well path; although common practice is to apply the value(s) calculated for the well's origin.

Any applied convergence shall be calculated for the operator-nominated coordinate reference system (CRS).

Any applied declination should be within the timespan of the collective set of measurements so that the declination error meets the specification given by the applied positional uncertainty model.

4.1.3 Reference information

In addition to the reference north specified above, the directional survey measurements shall be associated with:

a) Well reference point (WRP),

b) Vertical offset from global vertical datum, and

c) Horizontal offset from global horizontal datum.

The WRP is defined as the deepest recoverable point in the well and is often the wellhead. This should be named appropriately for clarity of use.

The wellbore's vertical reference point should be named appropriately for clarity of use and should be described as an offset value relative to a named global vertical datum, such as mean sea level (MSL). It is possible for well depth and vertical depth to have different origins; however, their default should be originating from the same vertical reference point. It is possible for WRP to be offset from the wellbore's vertical coordinate origin, such as when rotary kelly bushing (RKB) is above the wellhead.

When the wellbore's depth reference point and WRP are not coincidental, the offset between the two points shall be recorded.

The wellbore's horizontal coordinate reference point should be named appropriately for clarity of use and should be described as Cartesian coordinates aligned to reference north and east and with global coordinates consistent with the nominated CRS. It is possible for WRP to be offset from the wellbore's horizontal coordinate origin, for example when the platform center is used as the horizontal coordinate origin for all slots on a platform

4.1.4 Directional survey measurement corrections

The technical justification for directional measurement corrections in directional drilling is to ensure accurate wellbore placement and trajectory. Any errors in measuring the wellbore's direction can result in significant deviations from the intended target, which can have severe economic and operational consequences. Directional measurement corrections, such as magnetic declination, gravitational pull, and toolface angle corrections, are necessary to account for the various factors that can influence the accuracy of the measurements. These corrections allow the drilling team to accurately determine the wellbore's true position and direction, which is critical for achieving precise wellbore placement and trajectory control.

There are several quality control measures for directional survey corrections and associated positional uncertainty models in directional drilling. These include:

a) Calibration: Survey tools are regularly calibrated to ensure their accuracy and precision.

b) Data verification: Survey data is verified through multiple independent measurements to ensure consistency and accuracy.

c) Quality control checks: Statistical analyses and quality control checks are performed on survey data to identify any errors or anomalies.

d) Correction models: Sophisticated mathematical models are used to correct for various factors that can affect directional survey measurements, such as magnetic interference or gravitational effects.

e) Error modeling: Statistical models are used to estimate the positional uncertainty associated with directional survey measurements, taking into account various sources of error.

f) Data interpretation: Survey data is interpreted by experienced personnel with a thorough understanding of the underlying physics and statistical models, ensuring that any errors or uncertainties are appropriately accounted for.

By implementing these quality control measures, the accuracy and precision of directional survey measurements can be ensured, and the associated positional uncertainty can be accurately estimated, providing critical information for wellbore placement and trajectory control.

4.1.5 Wellbore position calculations

The calculated wellbore position should originate from the WRP specified relative to the wellbore's vertical and horizontal reference points as part of the reference information above. If the reference wellbore is a sidetrack, or bypass, of another wellbore, the reference wellbore's position should be calculated as if it was a continuation of the wellbore(s) tied directly or indirectly to the WRP. Normally, the inclination at the WRP should be zero; however, the following special situations are permitted in which the WRP is tilted and has an inclination and azimuth at origin.

a) The position of an interval of actual wellbore shall be from either:

   1) dead reckoning using minimum curvature to calculate position of and between directional survey measurement(s), or

   2) wellbore position measurement as described above using minimum curvature calculation to interpolate between measured positions.

b) The position of an interval of planned wellbore shall be from either:

   1) dead reckoning using minimum curvature to calculate position of and between well depth, inclination, and azimuth values, or

   2) dead reckoning using the radius of curvature to calculate the position of and between directional survey measurement(s).

   3) The radius of curvature shall only be used, in preference to minimum curvature, to describe curves where azimuth is changing while inclination is constant as well depth extends.

The calculated wellbore position should comprise the entire length of the wellbore and may be derived from any combination of these methods, with only one method used for any interval, with the stipulation that the actual wellbore position shall not be tied to the planned wellbore position.

4.2 Directional Survey Record (DSR)

4.2.1 General

DSRs are intended to establish a new set of recommended practices to ensure DSRs are properly managed, documented, and retained at the end of the surveying process and through the well life cycle for permanent archiving purposes after well drilling operations have ended. This includes all documents, such as individual trajectory surveys, reference information, and composite directional surveys (CDSs).

4.2.2 Survey Information Archive

4.2.2.1 Survey Station Data

The fundamental survey station data includes wellbore measured depth (MD), inclination (INC), and azimuth (AZIM). Units and azimuth reference of these values shall be explicitly stated in the header data.

The data without MD/INC/AZIM measured values has to be converted to MD/INC/AZIM values. Grid azimuth surveys additionally have to reference the CRS [European Petroleum Survey Group (EPSG code)] (see section 4.5).

4.2.2.2 Calculated Station Data

Calculated survey station data refers to basic and advanced calculated data columns (See Table 1).

Depending on the type of survey report, additional nonbasic data columns can be added as required (units and calculation method of these values shall be explicitly stated).

Table 1—Calculated Data

Basic Calculated Data Columns	Advanced Calculated Data Columns (Additional)
TVD, Vertical depth from the ZDP	Build Rate, + (Build) / - (Drop)
+N/-S , Latitude or Local North/South Distance	Turn Rate, + (Right) / - (Left, Walk Rate)
+E/-W , Departure or Local East/West Distance	TVD_{ss}, True Vertical Depth from MSL or LAT
Vertical Section, Based on a Vertical Section Azimuth	Course Length, Distance Between Survey Stations
DLS, Dogleg Severity	Tortuosity, [ΔDLS/Δft] DLS change per Unit Length
Survey Tool Type (i.e., Gyro, Magnetic)	Closure Distance, Total Displacement
Survey PUM (Tool Code or Error Model)	Closure Azimuth, Origin to Closure Distance Point
Comments (As Required)	Cumulative Tortuosity and Cumulative Dogleg Severity
	Survey Quality Checks (B_{total}, Dip Angle, G_{total}, etc.)
	All other calculated data sets

4.2.3 Sensor Data

Values from orientation sensors (e.g., accelerometer and magnetometer six-axis values, gyroscopic sensor values) are an important part of the DSR and shall be included in the final record of the survey provided to the Operator.

The units and axis orthogonality convention shall be clearly defined and be reported in units of the measured field section.

4.2.4 Tie-on Points

CDSs have to be tied to the WRP, with the option to also include the zero depth point (ZDP).

Tie-on points for surveys within the same wellbore shall be the last accepted survey station and not a projection.

In the event of a sidetrack, the tie-on point may be the last station above the kickoff depth. An interpolated survey point at the kickoff depth based on the parent wellbore should be entered as the second survey station of the sidetrack borehole and labelled as the kickoff depth in comments. Wells with a whipstock or a casing point can define the kickoff depth as the top of the window or casing point.

Interpolated survey stations used in the CDS shall be clearly identified as either inclination, azimuth, or combined inclination and azimuth interpolations, (see 4.2.7).

4.2.5 Projections to Total Depth (TD)

A bottomhole projection to TD drilled shall be clearly identified in the survey report.

4.2.6 Survey Tool-type and Tool-code

Survey data shall be associated with a survey tool type and PUM (tool code).

In addition, unmeasured entries (e.g., interpolation of formation tops or casing points) shall be clearly identified in the survey station data set.

4.2.7 Composite Directional Survey (CDS)

A CDS is used to create the best-known position of the well and shall be clearly identified as such. This is commonly called a definitive CDS.

During the life cycle of a well, new or improved borehole trajectory data may become available. Maintaining consistency in the CRS, datum elevation references and azimuth reference are important when combining new surveys and future survey enhancements.

All adjustments shall be clearly documented.

4.3 Reporting and Data Management

4.3.1 Survey Header and Composite Data

The following data shall be included in the header of all survey reports:

a) Unique Well Identifier (UWI) (US Number [API], [PPDM]);

b) Well Common and Legal Name;

c) CRS (using a specific EPSG Code);

d) Survey Report Generation Date;

e) Azimuth North Reference;

f) Wellhead coordinates;

g) Survey calculation method;

h) ZDP;

i) Elevation reference description [DFE, RKB, ground level (GL), mudline (ML), etc.];

j) Grid convergence, declination (geomagnetic reference model, elevation and calculation date), Gref, and total correction; and

k) PUM code(s) assigned and associated depth range(s).

NOTE Repeated in database section.

4.3.2 Basic Survey Tool and Run Information

Minimum data shall be required encompassing tool type and deployment method.

The types of data that can be used for post-operation QA/QC vary extensively. When determining which survey tool and run information is required, there should be careful consideration to define types of evaluations, corrections, and analysis of survey data performed. Operators should standardize joint operating and reporting procedures within internal documentation (e.g., JSORP documents).

4.4 Records

4.4.1 Post-job Summary Records

A summary of the drilling and surveying operations for any well shall be distributed to the operating company.

Recommended data and information in 4.3.1 should be included in this summary

4.4.2 Digital Records

DSRs provided in a digital format should follow a recognized format (such as the P7/17 [39] digital record format developed by IOGP for general use in the wellbore construction industry). This format should provide a composite final definitive survey and should include raw sensor measurement data. Other examples include:

a) LAS;

b) DLIS;

c) ASCII;

d) CSV-Data Table; and

e) PDF.

An electronic document management system with edit management in place is recommended when archiving well records as opposed to using unstructured shared-drive data folders. Application-specific formats (e.g., Excel) should not be considered as a final digital survey record.

4.4.3 Operator Records Retention

The primary well operator shall retain ownership of the borehole trajectory DSR documents for all wells unless the ownership is divested to another operator.

When wellbore assets are divested, all DSR documents shall be transferred to the new operator.

A records retention schedule is essential for directional wellbore survey records because it specifies how long these records are required to be kept in accordance with legal, regulatory, and operational requirements. Directional wellbore survey records, which document the wellbore's position and trajectory, are crucial for the safe and effective operation of the drilling rig, as well as for regulatory compliance and auditing directional wellbore survey records, which document the position and trajectory of the wellbore, are critical for the safe and efficient operation of the drilling rig, as well as for regulatory compliance and audit purposes.

A records retention schedule (RRS) ensures that directional wellbore survey records are retained for the appropriate amount of time and that they are disposed of in a secure and appropriate manner once they are no longer required. This helps minimize the risk of data breaches or unauthorized access to confidential information, as well as the risk of non-compliance with legal and regulatory requirements. In addition, a records retention schedule can also help improve the efficiency of data management processes by providing clear guidelines for the organization, storage, and retrieval of directional wellbore survey records. Formal establishment of an RRS can help reduce the time and resources required to manage these records, while also ensuring that they are readily available when needed. Overall, a well-designed and properly implemented records retention schedule is an essential component of effective data management for directional wellbore survey records.

4.4.4 Service Provider Records Retention

The surveying company/service provider shall retain DSR documents until the retention period expires (e.g., due to contractual or regulatory obligations).

The original operator or current well operator should be notified before records are permanently destroyed to provide the current well operator with an opportunity to take ownership of the survey records. A service provider should follow an operator's RRS to comply with their requirements for the management and retention of wellbore survey records. This schedule may be based on legal or regulatory requirements, as well as the operator's internal policies. By adhering to the operator's schedule, the service provider can meet their expectations, provide timely information, and improve communication and collaboration.

4.5 Surface Location

4.5.1 General

Well surface coordinates are used throughout the wellbore construction industry to map the positions of wells to help identify, predict, and evaluate the performance of assets. The surface location is critically important for wellbore positioning because it defines the starting point of the wellbore, both horizontally and vertically. Knowledge of the surface location and its accuracy is required to position the wellbore with respect to the reservoir, offset wells, and lease boundaries. Well surface locations and their accuracies are normally captured in a database to meet the individual operator's standards and guidelines for well planning and collision avoidance analysis.

Incidents such as non-optimal well placement, trespass, and collision can occur due to errors in the well's identification or its coordinates, metadata, or assigned accuracy. Examples include:

- drilling at the wrong location;
- using a planned or permitted location during collision avoidance analysis instead of the actual drilling location;
- using an incorrect CRS, map units, or ground elevation; and
- overestimation of location accuracy of nearby wells.

Such incidents may be due to undetected gross errors since these are not modelled or accounted for during the collision avoidance analysis. Instead, gross errors need to be avoided by using unambiguous data modelling, consistent terminology, and standard procedures and checks by competent personnel.

4.5.2 Well Identification System

4.5.2.1 General

A well identification system should provide unambiguous, unique, permanent, and comprehensive identification consistently from a specific ownership authority (regulator) that allows for the unique identification of each connected wellbore and each completion or change in completion of each wellbore (per PPDM WI Global Framework, see http://www.ppdm.org).

Unique and permanent well identifiers should be used as common keys across applications and databases, not the well name.

4.5.2.2 Risks

A proper well identification system is critical for field operations and software applications to ensure that each wellbore is assigned an identifier. This system may prevent misidentification in the field or missing wellbores in the offset database for collision avoidance analysis.

4.5.3 Coordinate Reference System (CRS)

4.5.3.1 General

A CRS definition provides the structured metadata that contains geodetic referencing information to interpret coordinates unambiguously (see IOGP 373-1).

A drilling site shall be assigned a horizontal and vertical coordinate reference system (CRS) consistent with the well planning CRS used by the geophysical team responsible for subsurface mapping and modeling.

If these CRSs are not the same, then this difference should be clearly identified, and the potential risk addressed prior to well (path) planning and drilling operations.

The EPSG CRS code shall be used to define the horizontal and vertical CRS unambiguously and implicitly for reported coordinates.

Additionally, the EPSG CRS name should be provided for clarity. Although included in the implicit definition, the coordinates' unit of measure should be made explicitly clear to end users. Surveying and Positioning Guidance provided in IOGP Report 373-05 [37] should be followed.

4.5.3.2 Risks

Coordinates are ambiguously defined or uninterpretable if the CRS is not fully specified. The ambiguity could be on the order of several hundreds of meters or more, which may lead to missed targets or increased HSE risk.

Inconsistent modeling and lack of standardization of geodetic information (including CRS names) could lead to potentially ambiguous locations, integrity issues between software applications, and confusion between people. This is mitigated by aligning with the IOGP EPSG Geodetic Parameter Dataset [35], the de facto global standard for geodetic information.

The CRS for the surface location and target location may be different, and this difference may go unrecognized. Geodetic metadata may not accompany the coordinates. Mitigation measures raise awareness of geodesy and its importance to wellbore positioning, access to company experts, and the use of standards.

4.5.4 Coordinate Transformation (CT)

4.5.4.1 General

A coordinate transformation enacts a change of datum, using parameters that were empirically derived by modeling measurements. The most common coordinate transformation is between geographic CRSs, such as between WGS 84 and NAD27.

Transformation of coordinates should be avoided during operational workflows. If required, however, it should be executed by competent personnel (e.g., professional survey contractors or geomatics staff).

If reported coordinates were transformed from an original CRS, then an audit trail shall be provided describing the transformations that were applied, particularly for the land survey plat and offshore final fix report.

In databases and report headers, such an audit trail may be accomplished by specifying a field for the CT used. It can also be accomplished by using a shorthand notation using the EPSG CRS name, CT code and CRS code, for example, "NAD27 / BLM 16N (ft US) [1241_32066]", showing in square brackets the coordinate transformation EPSG code 1241 for NAD27 to NAD83 (1), followed by an underscore and the code for the projected CRS.

4.5.4.2 Risks

Coordinates may have been transformed to a new CRS after having been observed in a specific CRS. For example, coordinates can be observed with GPS using WGS 84 and then transformed to a local reference such as NAD27. In general, there are several possible transformations between the source and target CRS, resulting in coordinates that can differ by tens of meters. Hence, it is important to ensure that the same transformation is consistently applied in the same field, and it is necessary to document the transformation that was applied. An additional complication is that over time a newer transformation may become available or mandatory in an area. This is mitigated by having an audit trail of transformations that were used so they can be reversed to take advantage of newer transformations.

4.5.5 Coordinates

4.5.5.1 General

Revised surface location coordinates should be distributed to all appropriate personnel and data archives.

Geographic coordinates should be reported in addition to projected coordinates to provide a minimum redundancy that may be helpful if geodetic metadata were to be lost, as well as to enable a gross error check for positioning. Provisions in ISO 6709:2008[2] (incl. 2009 corrigendum) should be followed.

Coordinates should be quoted to a resolution commensurate with their accuracy. Proposed surface location coordinates should be rounded to the nearest meter or foot unless higher precision is needed for positioning.

Database entry and input for wellbore positioning calculations should use projected coordinates (i.e., easting and northing rather than geographic latitude and longitude).

4.5.5.2 Risks

Gross errors can occur when planned coordinates change or when coordinates are entered or transferred. Such errors could include:

- null coordinates,
- lost geodetic metadata,
- swapped latitude and longitude,
- swapped easting and northing, and/or
- incorrect signs.

This could lead to incorrect hazard assessments or positioning of a rig at the wrong location. Providing geographic and projected coordinates with all required geodetic metadata in a consistent manner mitigates these risks.

Inconsistent representation of coordinates could lead to user confusion or interoperability issues for software, which is mitigated by adhering to standards.

Note that there may be specific requirements that shall be followed for reporting coordinates to the Regulator.

4.5.6 Coordinate Status Indicators

A coordinate type indicator should be used to record the type of surface location as:

a) Proposed,

b) Permitted,

c) Staked (For elevation, status up to and including “staked” assumes ground level before pad construction, unless explicitly noted otherwise),

d) As-drilled, or

e) Definitive (“As-drilled” and “definitive” indicate that a survey or verification of the actual horizontal location and ground level elevation (GLE) was performed after the pad was built and conductor set.

"Definitive" is the highest level and indicates final computations and QC were performed for the recorded coordinates.).

A QC level indicator should be used to define the reliability level of the performed QC when coordinates are entered in a database (see Table 2) as:

a) Unchecked,

b) Unverifiable,

c) Intermediate,

d) High, or

e) Approved.

4.5.6.1 Risks

Wells are not always drilled from their originally planned, permitted, or staked location for many different reasons. It is prudent to verify the well surface location after spud to ensure that the well surface coordinates, constructed pad elevation, and wellhead elevation are accurately documented.

If the status of the coordinates is not recorded on the location plat and in the database, then the most conservative case should be assumed. A risk is that, in practice, a more optimistic scenario is incorrectly assumed, leading to an underestimation of the collision risk or potential suboptimal planning.

Transcription errors may be made when coordinates are captured in a database. The potential impact of such errors is mitigated by QC after data entry and by using the QC level indicator as part of the workflow (e.g., a process in which a second person sets the flag to approved after initial entry).

Mitigation measures include using coordinate status indicators and management systems that allow updates as more accurate coordinates become available during the well's life cycle.

Table 2—QC Level Indicators That Describe Reliability Level of Coordinates Stored in a Database

QC Level		Description	Scenario
0	UNCHECKED	Coordinates have not (yet) been checked or verified. This is a general method to ensure that preliminary coordinates are flagged as subject to change.	This method primarily deals with planned locations of future wells or where well locations have been estimated in a general sense.
1	UNVERIFIABLE	There is no redundant data or supporting information that could be used to verify the coordinates. The CRS is to be estimated or accepted as provided. Crude errors, such as coordinates left unfilled or set to zero or hundreds of kilometers plotted incorrectly, are identified and corrected or rejected from loading accordingly.	Used to describe a set of well locations that only have a single set of coordinates or where multiple divergent coordinate sets exist. This type of coordinate could apply to bulk loading, where only a crude check is executed. For example, all of the wells plot in the region they are believed to be in (e.g., county, state, country) and plot in the right environment such as onshore or offshore.
2	INTERMEDIATE	The well surface location coordinates are verified to the level of field/asset. In addition, spot checks from satellite imagery or maps have been conducted. The CRS was resolved with a fair degree of confidence.	Typically used for bulk loaded third-party well data when available resources do not permit full quality control for each individual well. Quality control in this case focuses on clusters of wells, typically per field or asset.

3	HIGH	Each well undergoes individual QC using multiple sources of coordinate data, e.g., permit and satellite imagery. The CRS was resolved without ambiguity.	This scenario may be used for purchased well data. The coordinates can be resolved with good confidence.
4	APPROVED	Coordinates and CRS have been verified on the basis of as-built survey data or by unambiguous identification on a geo-referenced satellite image or map. This work has been conducted by a professional land surveyor or geomatics specialist.	This status reflects the maximum level of confidence that can be achieved. This is the norm for newly drilled wells under control of the operator loading the data. Purchased well data may be labeled with this status provided their coordinates and CRS are verifiable without uncertainty.

4.5.7 Reference Points

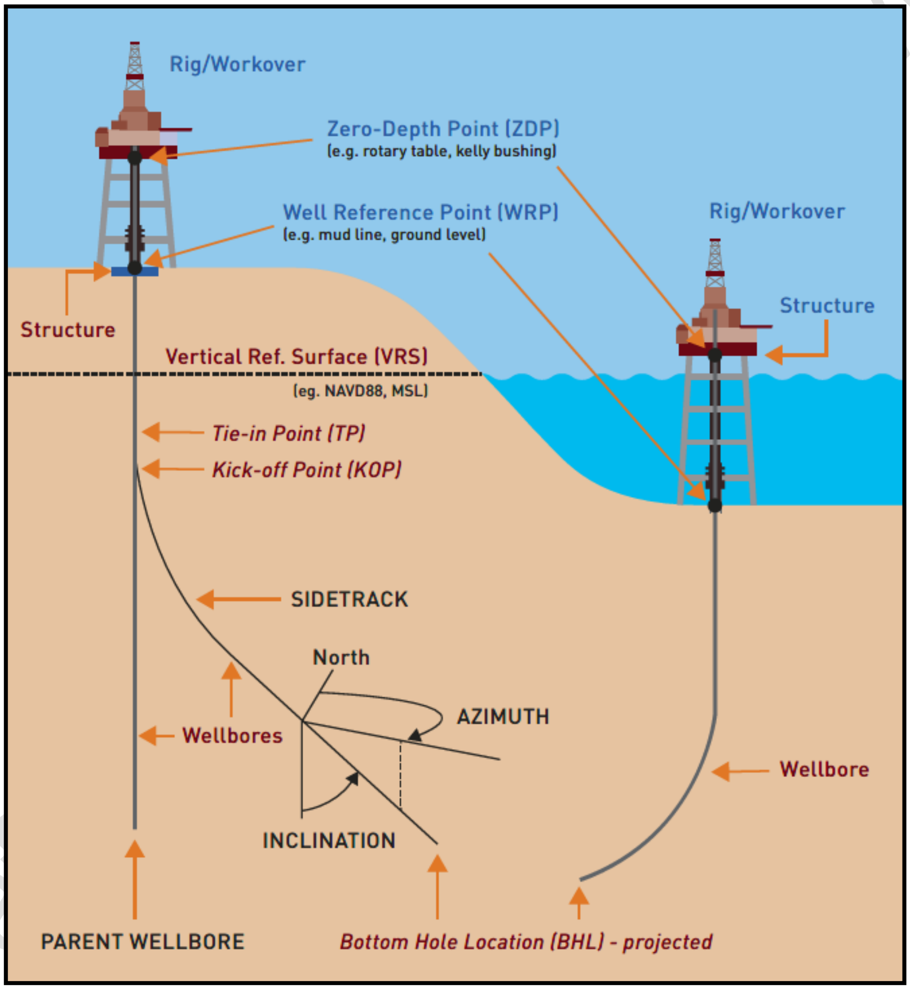


Figure 1—Definition of Various Reference Points [39]

4.5.7.1 General

The WRP type should be consistent in each field. Examples include using the top of the casing head housing or the top of the lowest flange.

The horizontal coordinates of the WRP should be recorded with their uncertainty. If the WRP is on the seabed while the coordinates are measured at the surface, then the additional uncertainty between the surface and seabed should be included. Horizontal uncertainty should not accumulate until the measured AHD is deeper than the WRP.

The vertical coordinate of the WRP (water depth/GLE) should be recorded with its uncertainty. The GLE of the constructed pad should be recorded. An indication should be provided if the reported GLE is subject to change due to construction. Additional vertical uncertainty of the GLE should be included if elevation was measured before pad construction without indication of the final elevation after pad construction. A time stamp should be recorded to account for possible future subsidence. Potential impact of subsidence should be considered throughout the lifecycle of the well.

The vertical coordinate of the ZDP should be recorded with its uncertainty. Onshore, a two-step definition may be used to define the ZDP above or below ground level (e.g., height of DF above GLE). Top of cellar may be used for GLE. Depth measurement errors should begin to propagate at the ZDP. The ZDP can coincide with the WRP.

The elevation/depth of the ZDP should be clearly reported for each operation.

4.5.7.2 Risks

Incorrect or ambiguous definition of the elevation in survey and logging reports poses operational risks. In subsurface applications, the ZDP is generally used as reference for logs to create static models, which if wrong results in economic risk. See also IOGP Geomatics Guidance Note 24 [38] Vertical CRS in the wellbore construction industry [38].

4.5.8 Local and Global Uncertainty

4.5.8.1 General

The global (site) and local (well) surface position uncertainty values should be obtained from the land or marine surveyor or the provider of the coordinates. When this is not possible, e.g., for legacy data, a visual audit using validated imagery should be performed to assess the uncertainty.

WARNING— A conservative error estimate should be used if the survey method and relevant location radius of uncertainty is unknown. For global uncertainty, at least 75 ft (25 m) should be used when wells are on different facility locations and the uncertainty is not known. A value of 3 ft can be used for the local uncertainty for wells on the same site or platform after confirming that the calculated distance (using the coordinates) agrees with the expected distance between the wells.

A conservative default “site” uncertainty value may be warranted, such as when third-party well locations are loaded without further QC, particularly for legacy wells in countries or areas where multiple land grids or coordinate systems have been in use over the years, or when there are known map projection issues between sites that may not have been resolved correctly.

If the locations are referenced as local offsets from a site location (commonly called “slot offset values”), then the slot uncertainty may be adjusted to match the method in which the slots were measured and confirmed from the “site” origin. An example is an offshore platform with a set of slots referenced from a corner of the platform. In some cases, well slot offsets may be referenced to accurate detailed engineering drawings with a high degree of confidence with stated accuracy parameters. In this case, those accuracy specifications may be used for slot uncertainty. However, the actual coordinate used as the “site” center should establish the appropriate uncertainty value from uncertainty reference tables for that coordinate the same as for a standard well coordinate.

4.5.8.2 Risks

The 3D positional uncertainty at a point down the wellbore is composed of the uncertainty at the WRP and the propagated error due to adjustment of the wellbore survey observations. This combined uncertainty is used for collision avoidance and target sizing calculations. Positional uncertainty is of particular importance for offset wells of a vintage that is not well known, since underestimation of the uncertainty may lead to increased risk, whereas overestimation may lead to planning complications.

Table 3—Suggested Minimum Uncertainty for Legacy Coordinates Based on Vintage and Data Source

Era	Data Source	95 % Confidence	Comment
1920s–2000	Unverified regulatory or vendor database	> 450 ft (150 m)	Varied methods used to locate and report wellbore positions. Depending on geographic area, CRS may be unknown (in which case uncertainty will be worse).
2000–present	Unverified well archive records or coordinates calculated from lease offsets	> 300 ft (100 m)	Lease offsets subject to boundary and abstract accuracy. Various survey and geodetic changes over time reflecting variable error.
2000–present	Trusted well archive records (regulatory and vendor databases)	> 225 ft (75 m)	Different position types are often intermixed. Highly dependent on area.
2000 – present	Non–commercial grade Earth Imagery (coordinates properly transformed)	75 ft (25 m)	Image accuracy is unreported, mosaic from multiple sources and/or dates.
2000–present	High-resolution (<1 m) commercial grade imagery	15 ft (5 m)	Licensed or proprietary imagery from known source and georeferencing accuracy.
present	Future planned well locations	6 ft (2 m)	Assumes future wells will be properly surveyed using modern, high-confidence methods and drilled at the planned location.
All	“As-drilled” professional land surveyor certified plat coordinates	3 ft (1 m)	Post-spud verified location (onshore). Depends on survey technology (offshore).

CAUTION— If no external sources are available to confirm the uncertainty, then Table 3 can be used to estimate wellsite location uncertainty based on the vintage and source of the data.

Positional uncertainty of legacy coordinates depends on a variety of circumstances, including geographic area, calibration, misidentification, missing geodetic information or coordinate transformations, uncertainty of boundaries used during calculations, change of location after permitting, errors during data entry, etc. In some cases, local regulatory or operational methods used in the past or currently may be a reason to change the values reflected in Table 3. The uncertainty in Table 3 are neither best-case nor worst-case confidence values. The user should reach out to departments or individuals who have knowledge of the survey practices, according to 4.5.8.1.

4.5.9 Offset Wells Database Checks

4.5.9.1 General

When the coordinates or accuracy of surface locations in the offset wells database is suspected to be incorrect, then a visual audit using validated imagery should be performed. Original survey reports and aerial or high-resolution satellite imagery can be used to help identify and correct such well position errors.

When gross errors or discrepancies appear from such an audit, well locations and elevations should be surveyed by a professional licensed land surveyor.

It should be considered that the area may contain legacy wellbores that are not captured in the offset wells database.

The CRS setup, particularly horizontal and vertical coordinate units, should be checked to ensure accuracy. For example, for onshore drilling projects in the USA, most location plats are mapped using the US survey foot (ft US), and quite often these are loaded into drilling and geological databases using the international foot unit for the Northing and Easting values, resulting in two feet of location error per million feet used for the map coordinates.

Cross-functional databases should be cross-checked periodically to ensure that CRS setup, well coordinates, units, and elevation references are consistent.

4.5.9.2 Risks

The offset wells database contains all known wellbores that could impact planning of the proposed well. Missing offset wells in the database or incorrect coordinates leads to increased risk of collision. Increasing the uncertainty to account for possible location errors mitigates some of this risk, but may not be conservative enough, or may lead to well planning issues. In cases where a particular offset well with a large uncertainty causes planning issues, then its surface location uncertainty should be reduced as far as possible by reviewing documents and imagery or, ultimately, resurveying the field.

4.5.10 Grid Convergence, Scale Factor, and Elevation Factor

4.5.10.1 General

Reports should clearly indicate if a scale factor correction was applied, and which value(s) for which location(s) were used. The impact of (ignoring the) scale factor correction should be assessed, as well as the impact of changing the scale factor along the wellbore path.

Reports should clearly indicate if the elevation factor correction was applied, and which value(s) at which location(s) were used. Since points along the wellbore have different depths, this correction should be applied dynamically to correct distances between survey stations. The impact of truncating or rounding the elevation factor should be considered.

A map convergence correction computed for the projected CRS at the location of the wellbore shall be applied if azimuth angles are reported relative to grid north.

Reports should clearly indicate if a map convergence correction was applied, and which value(s) at which location(s) were used. If the projected CRS is changed, then the grid convergence should be updated accordingly along with any angles referenced to grid north. The impact of ignoring the change of map convergence along the wellbore should be assessed during wellbore planning. The impact of rounding the grid convergence value should be considered.

4.5.10.2 Risks

SPE 56013 describes the error sources and impact of incorrect application of grid convergence, scale factor, and elevation factor.[3] SPE 96813 [4] details an algorithm that avoids the need for scale factor and elevation factor correction during wellbore calculations, which may mitigate some of this risk.[4]

Gross errors like not applying a grid convergence correction, double correction, or correction with an incorrect sign have occurred, which result in a rotation of the computed wellbore path that can amount to tens of meters at TD (depending on the value of grid convergence and horizontal step-out).

There are scenarios for which it is important to consider the change of scale factor, elevation factor, and grid convergence along the wellbore, particularly in the case of wellbores with extreme extended reach.

Some software applications may correct for scale factor and/or elevation factor using a constant computed at the surface location, while others may not, which may lead to confusion if results are compared between them. Reports may indicate the magnitude of correction factors but may not clearly state whether the correction was applied. This can be mitigated by standardized reporting, in particular by explicitly providing the original value, correction, and corrected value at each survey station.

4.5.11 Magnetic Reference Values

4.5.11.1 General

Azimuth using magnetic north as the observation reference should not be used for permanent record in databases because it is model-dependent and changes with time. There are five primary geomagnetic reference model categories:

a) Low Resolution Geomagnetic Model (LRGM)
b) Standard Resolution Geomagnetic Model (SRGM)
c) High Resolution Geomagnetic Model (HRGM)
d) In-Field Referencing Model (IFR1)
e) In-Field Referencing with Real-time Disturbance Field Correction (IFR2)

Table 4 provides specifics regarding the power spectrum degree and update rate requirements for the ISCWSA generic set of PUMs, which encompasses the following five defined geomagnetic reference categories:

Table 4 — Geomagnetic Reference Model Categories

Category	Examples	Update Frequency	Wavelength 40,000 km down	Geomagnetic Power Spectrum degree	Additional Notes
LRGM	CGRF, IGRF or WMM	Less than Yearly	to 4K km or smaller	1 to at least 10	Main field only
SRGM	Pre-BGGM2019 or MVSD	Annual	to 300 km or smaller	1 to at least 133	Main Field plus large scale Crustal and Magnetospheric field
HRGM	Post-BGGM2019, HDGM, MVHD, HDGM-RT	Annual	to 55 km or smaller	1 to at least 720	Main field plus high resolution global crustal field and large-scale magnetospheric field
IFR1	IFR, IFR1, or Ground shot plus secular variation correction	Annual	to 2 km or smaller	1 to at least 20,000	Main field plus regional aeromagnetic, marine or ground survey
IFR2	IIFR, IFRII or IFR1 plus correction for realtime	Annual plus local realtime measurements at 1 minute or	to 2 km or smaller	1 to at least 20,000	Geomagnetic observatory or realtime magnetic disturbance field

	magnetospheric and ionospheric disturbance fields	shorter sampling rate			monitoring station collecting absolute magnetic vector data within about 100 km distance of drill site (depending on geomagnetic latitude). Not applicable to “realtime” models using geomagnetic indices.

Reports should clearly indicate if a magnetic declination correction was applied, and which value(s) at which location(s) were used, as well as the geomagnetic model and computation date.

Care should be taken that the magnetic declination is applied with the correct sign. A sketch showing the relative directions of the north references is indispensable for gross error checks.

WARNING—It is critical to know the observation reference used for the horizontal angles (often called azimuths) and the relation between the three north directions (true north, grid north, and magnetic north) to allow for gross error checks.

4.5.11.2 Risks

SPE 17212 describes azimuth reference systems and their associated risk.[5]

It is generally permissible to satisfy the well objective using a constant magnetic declination angle computed at the well origin. However, there may be instances where the variation of magnetic declination along the wellbore need to be considered. Specifically, this change may become a factor for wells with a long step-out that are located in regions where high-resolution models indicate significant magnetic variation. In particular, this change may become a consideration for wells with long step-out located in areas with significant magnetic variation in high-resolution models.

Different conventions are in use regarding the sign of the magnetic declination. Often it is defined in software as the clockwise positive angle from true-north to magnetic-north, but this is not guaranteed.

Applying the wrong magnetic declination or applying the correction in the wrong direction results in a rotation of the computed wellbore. The impact can be many tens of meters (depending on the value of the magnetic declination angle and the horizontal step-out). This can be mitigated by using consistent terminology and standardized reporting, in particular by explicitly providing the original value, correction, and corrected value at each survey station.

4.5.12 Land Survey

4.5.12.1 General

The land survey contractor is initially notified by the operator about preliminary location information related to the planned drilling site. A reconnaissance field visit may be required. Once the final surface location is agreed upon, the operator notifies the surface surveyor to schedule staking.

Staking and boundary monumentation requirements ensure that procedures and methods are specified so that the critical drilling and right-of-way site information is gathered, documented, disseminated, and stored for the entire life cycle of the asset development.

The survey contractor may be tasked with collecting additional (unmapped) area infrastructure data, e.g., verifying locations of existing nearby wells, elevations, railroads, crossings, hazards, pipelines, roads, fences, waterways, structures, and buildings, as well as sensitive areas, such as private cemeteries.

The survey contractor should provide staking in accordance with the following requirements.

a) A permanent site monument should be established adjacent to the site boundary to ensure well location integrity during the entire life cycle of the well, including abandonment.

b) The site (or location) perimeter should be monumented with permanent markers. Each perimeter marker's specific reference data (including coordinates, GLE, and local coordinates relative to the permanent site monument) should be recorded on the location plat.

c) Temporary markers should be established at each proposed well location. The well marker should be referenced to the permanent site monument and to two of the site location perimeter markers or other witness monuments to enable reconstruction of the staked location after construction of the well pad and cellar. Each well-specific reference data point (including coordinates, GLE, and local coordinates relative to the permanent site monument) should be recorded on the location plat.

The definitive horizontal and vertical coordinates of the well(s) should be confirmed by resurvey or otherwise be verified in the field (for example by using witness monuments) after construction at the wellsite (i.e., when the cellar is built, or conductor set). In particular, the status of the GLE should be clearly reported in case it changes with pad construction.

The wellsite should have permanent signage that cannot be removed with lettering that cannot be erased.

An as-built survey should be performed after development of the site is completed.

4.5.12.2 Risks

Lax procedures or confusion about the latest revision or geodetic metadata can lead to construction of a well pad in an unintended location, to staking at a different location than planned, and to drilling from an unintended location. This laxity or confusion increases collision risk and economic risk due to non-optimal wellbore placement and trespass. These risks are mitigated by using staking procedures with clearly defined roles and responsibilities, adhering to mapping standards and revision management systems.

4.5.12.3 Location Plat

Location plats should be developed by a professional land or offshore survey contractor.

A coordinate status indicator should be used to differentiate proposed coordinates from definitive coordinates. Symbology, informational notes, and text on the plat may be used to achieve this.

The location plat should report coordinates in the same CRS as used for the directional database. If the database is using a different CRS (typically a legacy CRS), while surveying operations or regulatory bodies use a modern CRS (typically based on WGS 84), then coordinates should be reported in both CRSs (for example, NAD27 and NAD83 coordinates).

The location plat should show all existing wells and planned wells and should include their Unique Wellbore Identifiers.

Uncertainty of the WRP should be reported on the location plat. A 95 % confidence interval in the horizontal (radial) direction and the vertical direction should be used (corresponding to 2.45 sigma in northing and easting, and to 1.96 sigma in the vertical, assuming a normal error distribution).

See also the ASPRS Positional Accuracy Standards for Digital Geospatial Data [40] and the Geospatial

Positioning Accuracy Standards Part 3 [41].

The location plat should be delivered as a hardcopy and in a digital format that can be easily entered into a GIS system, i.e., in a standardized data model. A naming convention should be used for delivered files, which could include: the well or wellbore identification number, wellsite or area, the plat status (e.g., LO for permitted and AD for as-drilled verified surface coordinates and wellbore path), and version or revision number. An example of such a filename could be “4212734514_AD_PILONCILLO A-9H X_R0.pdf”.

4.6 Survey Program

4.6.1 The survey program shall be considered part of the well design and included in the drilling program.

4.6.2 The survey program shall define the required wellbore positioning requirements, as they are required during various stages of operations and well construction activities acting as a set of instructions to the operations.

4.6.3 The survey program shall be detailed enough to ensure the requirements are clearly understood so that when executed the positional uncertainty assumptions for the well design remain valid.

4.6.4 A fit-for-purpose survey program shall:

a) prescribe sufficient data to determine the well position with the accuracy estimation prescribed to meet the defined well’s positioning objectives, and

b) provide sufficient survey interval to accurately characterize the wellbore as it is mathematically interpolated between stations within the bounds of the prescribed survey tool PUM.

NOTE Not having sufficient survey density when performing certain drilling operations can introduce gross errors into the trajectory that are not reflected in most positional uncertainty model calculations; operations that are prone to deviations from minimum curvature are BHAs that yield high doglegs, such as BHM drilling, high dogleg rotary steerable tool (RST), directional work in heterogeneous stress formations.

4.6.5 The survey tools specified to assess well objectives shall be reflective of the survey tool that is being used at the time the well objective is encountered (e.g., collision risk midway in the well).

4.6.6 For resurveyed intervals, the improvement in positional accuracy shall not be applied until the tool has been used.

4.6.7 This methodology is known as survey-by-parts.

4.6.8 If the survey program is not executed as specified in the survey program, the planning process assumptions regarding the well's positional objectives (e.g., anti-collision [AC], target dimensions, and relief well requirements) shall be incorrect.

4.6.9 A management of change (MOC) should be required to assess the impact of the survey program change going.

NOTE Failing to use a survey program with a survey by parts methodology could result in overly optimistic uncertainty calculations. A smaller-than-appropriate uncertainty estimation resulting from an abundance of optimism would increase the risk of failing to meet well objectives, as the actual uncertainty was not accurately represented.

4.6.10 A survey program reflecting the sequence of survey operations and shall be tabulated to include:

a) survey tool type,

b) survey interval,

c) start/end depth,

d) positional uncertainty model assignment, and

e) north reference.

4.6.11 Additional information that should be included when applicable are:

a) surface uncertainty,

b) open/cased hole deployment environment,

c) hole and casing sizes,

d) hole and casing depths,

e) planned survey corrections,

f) QC requirements,

g) TF orientation source (gyro tool face, magnetic tool face, and gravity tool face),

h) details about whether the directional survey information is available while drilling (surveying by parts) the depth interval as they occur during the well execution, and

i) comments that include information relevant to operations (e.g., the use of continual inclination and azimuth, slide/rotate surveying sequence, BHM bend settings, TD major axis uncertainty calculations at one sigma).

4.6.12 Example of a survey program is found in a tabulated form—see Table 5 and Table 6 for simple and complex versions—often associated with a graphical example referred to as a tree diagram in Annex A.

Table 5— Example Survey Program (simple)

Part	Seq.	Survey Tool (survey tool code)	Service Provider	Hole Size (in.)	Casing Size (in.)	Well Depth Interval From	Survey Frequency To		Comments / contingencies
1	1	None	N/A	32	26	0	113	N/A	
2	1	MWD (MWD+SAG)	N/A	32	26	0	3515	1/stand	

Table 6— Example Survey Program (complex)

Part	Seq.	Survey Tool (survey tool code)	Service Provider	Hole Size (in.)	Casing Size (in.)	Well Depth Interval From	Survey Frequency To		Comments / contingencies
1	1	None	N/A	32	26	0	113	N/A	
2	1	MWD (MWD-INC_ONLY)	N/A	32	26	0	113	1/stand	
	2	MWD (MWD+SAG)	N/A	24	$18\ ^{5}/_{8}$	113	1660	1/stand	

Part	Seq.	Survey Tool (survey tool code)	Service Provider	Hole Size (in.)	Casing Size (in.)	Well Depth Interval From	Survey Frequency To		Comments / contingencies
3	1	Gyro Casing Multishot (Gyro_CNSG+CASING)	N/A	24	18 $^{5}/_{8}$	0	1660	10m or less	
	2	MWD (MWD+IFR)	N/A	17	13 $^{3}/_{8}$	1660	2040	1/stand	
	3	MWD (MWD + IFR)	N/A	12 ¼	9 $^{7}/_{8}$	2040	3067	1/stand	
	4	MWD (MWD + IFR)	N/A	8 ½	7	3067	3515	1/stand	

4.7 Positional Uncertainty Models

4.7.1 General

The purpose of the provisions herein is to provide a framework and minimum guidance for the correct application of position uncertainty calculations to wellbore positional data throughout the well lifecycle. These position uncertainty estimates are required for the assessment of well objectives, particularly with respect to proximity evaluation and reserves targeting.

These provisions cover the methodology used to estimate uncertainty in wellbore position. Wellbore position uncertainty should be determined by a mathematical PUM that correctly represents the type of survey tool and the conditions under which it was run in hole. Processes should be in place to ensure that the position uncertainty estimates are valid for the survey measurements obtained and to ensure that different users of survey information can replicate position uncertainty results.

The users of survey information generally include drilling engineers, geologists, survey engineers, regulatory officials, and management.

4.7.2 Overview of Uncertainty Modelling

A PUM is a mathematical description of the expected errors in a wellbore survey. A PUM will consist of several terms, each describing a different source of error in the surveys. These error terms will include a magnitude (generally quoted at one standard deviation), equations describing how the error affects the survey measurements, and details of how that error should be summed along the wellpath (i.e., the propagation mode).

The purpose of a PUM is to quantify the anticipated sources of error in a wellbore survey to define, at a user-specified confidence level, the area around the survey within which the well is likely to be found.

The use of incorrect uncertainty values has the potential to lead to very severe HSE incidents, for example when wells collide or when dry wells are drilled. The ISCWSA has defined a mathematical framework defining how these error calculations should be applied.

Results from position uncertainty calculations are generally expressed in the form of error ellipsoids or in terms of N, E and V positional uncertainties. In software, these results may be expressed as the dimensions of the resulting ellipse when this ellipsoid is projected onto either the horizontal plane or the plane perpendicular to the wellbore.

For example, an MWD PUM will contain terms defining the likely contribution from each sensor, terms related to magnetic drillstring interference (DSI), and the accuracy to which the Earth's reference field is known at the drillsite. For example, magnetic sensor errors expressed in nano-Tesla are used with the underlying mathematics to determine the impact on the position error for a given downhole survey. Gyro models are built in a similar manner but have very different governing equations due to differences in the physics of how the gyro and magnetic sensors work.

A good overview of position uncertainty modelling can be found in *Introduction to Wellbore Positioning*.[6]

4.7.3 Application of Position Uncertainty Models

All surveys shall have an associated PUM for use in AC and target sizing calculations.

The selected PUM shall accurately represent the survey tool and the environmental conditions during its operation in the well.

Environmental conditions may include considerations like the length of nonmagnetic spacing between an MWD tool and the bit; the way a tool was centralized in open hole, casing, or drillpipe; the way a gyro was conveyed (e.g., a drop gyro or gyro run on wireline); or other conditions that may affect that particular tool.

The PUM shall be selected for valid technical reasons, not for convenience or because a given PUM gives the smallest ellipse sizes.

Information should be recorded in the survey database sufficient to identify the tool, service provider, corrections applied, and so forth, such that PUM can be correctly identified when looking at historic data.

The PUM shall include all significant error sources to accurately represent the expected uncertainty associated with using the surveying tool.

Use of PUMs with significant error sources missing will lead to an unreasonably optimistic estimate of ellipse dimensions.

PUMs that are used to model survey corrections shall only be applied to survey data if the corresponding corrections have been applied, and their usage shall be documented.

For example, an MWD+IFR PUM shall only be applied if IFR reference data is available for that field and has been used to determine MWD reference values.

Users should be aware of the underlying assumptions of any PUM used to correctly evaluate whether it is appropriate for use in their scenario. For example, different variants of PUM may be used for the same tool depending on how it is conveyed in hole, or whether it is run in open-hole or in casing.

The primary source of PUMs should be the tool provider, who has the best understanding of their tool performance. Alternatively, the ISCWSA and Operators Wellbore Survey Group (OWSG) provide a number of generic PUMs that have been assessed as being representative of real tools. These may be used as an alternative. There is no stipulation that the ISCWSA or OWSG PUMs have to be used.

The PUMs to be used on a project shall be checked and agreed upon between operator and contractor.

With no standardized naming convention, it shall not be assumed that PUMs match just because they have the same name.

For example, different revisions or variants of a MWD model might simply be titled "MWD."

PUMs should follow the ISCWSA general mathematical framework. This does not define the appropriate error sources or magnitudes for modelling a given survey tool but does define mathematics for accumulating uncertainties and determining position uncertainty from the tool=specific terms.

PUMs included in the definitive survey record have to reflect the instruments used and modifications made in the surveys that make up the definitive record (e.g., when surveyed data is processed post-drilling).

4.7.4 Survey Frequency

Generic PUMs and minimum curvature formulae implicitly assume that a well can be adequately modelled as a circular arc between survey points. The depth interval between survey stations should be such that this assumption is valid. For the PUM to be correct, the surveys should be sufficient to ensure that all points of inflection where the path of the wellbore varies from a smooth curve are correctly captured.

A 100-ft survey interval is often specified as a general rule. However, survey frequency should be increased in high dogleg sections of the wellbore or when large slide/rotate ratios are used.

For example, only surveying every stand of a repeated slide-rotate pattern will mean that the wellpath is represented as a smooth arc. Whereas there will be high dogleg sections followed by straighter sections as the drilling changes from slide to rotate. This misrepresentation of the wellpath can lead to significant position errors over a long build. The true shape of the well can only be measured by taking surveys at shorter depth intervals.

Historic data with long survey spacing may require the use of specific PUMs with additional error allowances.

4.7.5 Confidence Level

PUMs define the expected position of the well to a certain confidence limit. The confidence limit can be altered by varying the number of standard deviations to which results are reported.

The input values used in the PUM itself are normally specified at one standard deviation. Ellipse sizes determined from the PUM should be scaled up to an appropriate confidence limit before the results are used in AC or targeting calculations.

The user will determine what confidence limit is appropriate for their application.

This shall be stated in the appropriate AC or well-planning policies.

Confidence levels below two standard deviations are not recommended for AC analysis.

4.7.6 QA/QC

PUMs cannot quantify gross errors or blunders.

Therefore QA/QC tests shall be applied to survey data to ensure that the PUM is valid.

The QA/QC thresholds shall be related to the PUM applied so that passing QA/QC thresholds are a direct indication that the survey data match the assumptions of the PUM.

Some sources of error cannot be directly identified by QA/QC that relies solely on downhole data. Verification by running an independent survey tool that relies on different physics is the best means of providing overall QA/QC and may be used in high value wells. In this case, the survey ellipses from the two tool runs would be expected to overlap or at least touch if both PUMs have been correctly applied. Any other circumstances should be investigated.

For example, there is no way of determining declination error purely by analysing downhole MWD data. However, running a gyro in the same hole section allows a comparison between the two tools, and the two runs can validate each other.

4.7.7 Planning

The well planner has to use a suitable PUM for performing planning calculations. The selected PUM has to satisfy the compatibility requirements of the intended downhole tool and have the ability to accommodate the anticipated corrections specified in the survey program.

Planning calculations will be done with a PUM suitable for the tool expected to be run in hole and the survey plan's anticipated modifications. Even when gyros are planned to be run after a hole is drilled, AC calculations should be based on the MWD tool that will be used to acquire surveys.

Some survey correction methods [such as multi-station corrections (MSCs)] may only satisfy a given PUM if specific criteria are met (for example, a minimum number of surveys or attitude variation to allow the corrections to be determined). PUMs for these corrections should only be used at the planning stage if operational procedures are in place to ensure that all the necessary conditions will be met while drilling.

Where there is a known point of constraint below the slot, (e.g., a seabed template), the position uncertainty should accumulate from that point and not from the DF. A surface uncertainty value should be assigned to the constraint location.

Similarly, when side-tracking, PUM calculations between parent and child wellbore should start from the side-track point.

4.7.8 Tie-ons

When surveys are tied together, the methodology defined in the ISCWSA framework for combining surveys should be followed.

Due to statistical mathematics, the growth of survey uncertainties will tend to be reduced across tie-ons.

Therefore, care shall be taken that these tie-ons are real and do reflect actual change in survey leg to avoid over optimistic uncertainty results.

For subsea templates and side-tracks, refer to 4.5.7.1 for recommendations on where the accumulation of uncertainty should commence.

4.7.9 Reporting of Uncertainty Values

When uncertainty values are reported, sufficient information should be provided to ensure that it is clear what quantity is being specified.

For example, uncertainty calculations lead to error ellipsoids that surround the survey point. Often, when semi-major or semi-minor axis sizes are stated, it is not clear how the two-dimensional ellipse has been projected from the three-dimensional ellipsoids.

Reports shall detail the number of standard deviations that have been used to determine the uncertainty values.

The PUMs used to determine uncertainty values shall be stated in reports.

4.7.10 Surface Uncertainty

Surface uncertainty values shall be entered to appropriately describe the accuracy of the means used to determine surface locations.

Directional software will generally have an option to enter a surface uncertainty value at a stated confidence level.

Appropriate values shall be determined depending on the method used to survey the slot location.

Surface uncertainty may be separated into values for the absolute positioning of the site and the relative positioning of slots, in which case relative positioning of wells from different slots on the same site should ignore the site uncertainty, but positioning between wells on different sites will use both values.

Directional software shall ensure that surface uncertainty values are included with the RSS PUM results.

4.7.11 Projection to Bit

The definitive survey record shall cover the entire length of the borehole.

This may require a projection from the last survey station to the location of the bit. Straight line and trend projection models may be applied. Generally, for normal sensor layback distances, the PUM used for the last survey leg should also be used for the projection to bit. This avoids any erroneous reduction in error growth that could be caused by tie-ins between differing PUMs. A more cautious PUM might be chosen for a projection to the bit beyond the final survey station for extended projections beyond 152.4 m (500 ft).

4.7.12 Utility Models

Aside from normal PUMs, which were designed to quantify the uncertainty in surveys from specific known tools, a number of utility models are often used in the industry to model other circumstances.

Use of these models should be defined in company procedures. Zero PUMs should be applied where there is a known point of constraint in the well below the slot, e.g., seabed template. Blind drilling PUMs may be used where no surveys were taken.

If no data is available to identify the tool run in hole, an Unknown Tool PUM may be used. Unknown PUMs define the accuracy of the worst available survey tool that determined both inclination and azimuth.

Inclination-only measurements do not constitute a true survey of the wellbore, and where possible a well should be properly surveyed. However, a great deal of historic inclination-only data exists in the industry, and accordingly inclination-only PUMs are available. For inclination-only wells, directional software should either consider the wellbore to be vertical and use the inclination measurements to define the error surface. If this option is not available, users may enter the most conservative azimuth for AC calculations.

In the case of blind drilling (non-surveyed drilled interval), PUMs can only make a very rough estimate at the uncertainty in the position of the well since a true survey of the wellbore position does not exist. Therefore, utility models may make certain assumptions about the borehole. These assumptions should be stated, and users should satisfy themselves that the assumptions are appropriate to a specific well.

In general, these utility models should be defined to be conservative to identify possible collision risks. If a collision risk exists to wells that have these PUMs applied, the offset well should be re-surveyed whenever possible.

4.7.13 Management of Position Uncertainty Models

4.7.13.1 Procedures and Controls

The PUMs available in any software application shall be controlled so that only authorised users are allowed to add or modify the available PUMs.

Company planning guidelines should be available so that users can easily and correctly choose the most appropriate PUM.

These guidelines may take the form of company rules on which models to use, a flow chart aiding users to determine the correct model, and/or a written description detailing the assumptions inherent in that model.

Users should be able to clearly identify models and their revision. The use of short names (e.g., MWD+IFR1+AX+SAG) may be ambiguous without further supporting information, which may be part of the survey management system.

The PUMs available in directional software should be periodically audited to ensure that only the correct, controlled models are used.

4.7.13.2 Revisions

PUMs shall contain version numbers and revision information in comments or headers.

Other pertinent information may be included in headers. This should be sufficient to uniquely identify a particular PUM.

When a PUM is updated, a detailed listing of the changes made and the effect on the software shall be provided from the tool model developer.

Guidance should be provided as to whether the new version supersedes old instances. For example, audit notes should document whether the new version provides corrected values, revised in the light of new information, or if the new PUM is an alternative, or if it models a different survey situation.

PUM references in the database should be updated accordingly.

4.7.13.3 Transferring Databases

When transferring survey data between different software databases, PUMs should be mapped from one database to the other. As possible, exact PUM matches should be maintained unless gross errors are noted. If direct PUM equivalents are not available, PUM results should be assessed to ensure a valid mapping. Matching of PUM file names or short descriptions is not sufficient to ensure a valid mapping.

4.7.14 Verification of Position Uncertainty Modelling

4.7.14.1 Verification of Software Implementation

Software implementations of the ISCWSA mathematical framework shall be validated against published test data.

This should be done using all three ISCWSA test profiles.

When validating results, care shall be taken to match the assumptions used in the published data, since results can be presented to different azimuth references.

Software pass criteria should be within 1 % of the quoted covariance matrix values or, if within 20 units, whenever the covariance magnitude is less than 200 units.

4.7.14.2 Validation of Specific Tool Models

The PUM should be validated by data which is representative of downhole performance. This may include stand data, repeatability of calibrations, data derived from in-hole measurements or comparison with independent survey tools run in the same wellbore.

While data from a precision test stand data is useful in determining the size of sensor errors, it cannot be used to determine operational or environmental errors in the borehole, such as misalignment to the borehole or the effect of DSI.

Comparison with other tools run in the same wellbore is the best method for validating that all terms have been correctly accounted for.

PUM providers should provide details of the validation. If a PUM varies from commonly accepted industry values for environmental error terms, a justification with operational data should be provided.

Since PUM results are used to quantify the absolute accuracy of downhole positions, it is important that tool models are created to allow this accuracy to be determined, not simply to provide estimates of the repeatability (or spread) of survey results.

4.8 Quality Assurance (QA) / Quality Control (QC)

4.8.1 General

The purpose of this section of the Recommended Practice is to provide a framework and minimum guidance for standard magnetic survey practices that deliver accuracy consistent with associated PUMs and provide QA/QC data reporting standards.

This section of the Recommended Practice specifies QA/QC standards that are not limited to ISCWSA or OWSG PUMs. Methodologies are developed instead of specifying mathematical details. Minimum calibration standards are specified. This section includes correction mechanisms that can be applied and are consistent with published uncertainty mechanisms. Proper QA/QC requires report formatting that captures pertinent information.

4.8.1.1 Impact of Survey Accuracy

The accuracy of a survey system is described by an PUM or instrument performance model (IPM), a concept introduced by Thorogood[7] and described in detail by Williamson[8]. Their application to quality tests was described by Ekseth et al..[9, 10, 11]

A wellbore trajectory together with the error model can be used to determine the N, E, and V uncertainties or an ellipse or ellipsoid of uncertainty (EOUs), which describes the uncertainty calculated for each survey. Ellipsoid dimensions correspond to the results calculated from the model with a specified number of standard deviations or sigma (σ).

A survey defect can result in a positional error outside expectations defined by the PUM. The survey defect can cause positional error(s) larger than the model's defined error calculation.

4.8.1.2 QA/QC Tests

QA and QC procedures apply tests to the survey data. The test pass/fail criteria are related to the error model, to identify data that is not consistent with the model.

4.8.1.3 Measurement Types

Today's directional survey measurement instruments make independent measurements of measured depth (MD) and wellbore attitude. Wellbore attitude is generally measured with either a combination of magnetometer and accelerometer or gyroscope and accelerometer. Accelerometers alone may be used to measure inclination, a component of wellbore attitude. As a result, directional survey measurement instrument's QA/QC is dealt with as four topics:

- Inclination-Only,
- Accelerometer Measurements of Wellbore Inclination,
- Magnetometer and Accelerometer Attitude Measurements, and

— Gyroscope and Accelerometer Attitude Measurements

— Well depth.

4.8.2 Practices for Inclination-only QA/QC

4.8.2.1 General

Surveys shall not use inclination-only tools at hole inclinations above 3°.
The ISCWSA have proposed PUMs for inclination-only tools, which severely penalize their use at higher inclinations. There is normally no real-time QC applied to measurements from these tools.

4.8.3 Magnetometer and Accelerometer Attitude Measurements

4.8.3.1 General

All magnetic surveys are required to be accompanied by an appropriate error model that takes into account depth accuracy, tool alignment, magnetic interference, the local geomagnetic field, and sensor performance.
NOTE: The error model is used to estimate survey accuracy, for navigation to targets, and for collision avoidance; the ISCWSA and Operators Wellbore Survey Group (OWSG) MWD and EMS PUMs contain the following terms:

— Sensor performance	— Biases and scale factors
— Tool alignment	— Sag and instrument misalignments
— Magnetic interference	— AX
— Local geomagnetic and gravity fields	— Reference field intensity, magnetic dip angle
— Depth accuracy	— Depth reference, scale factor, and stretch

Combination magnetometer and accelerometer instruments can be categorized into four distinct types, each of which have different QA/QC requirements. These requirements are summarized in Annex C Table C.1.

4.8.3.2 MWD QA/QC Tests

4.8.3.2.1 General

QA and QC procedures apply tests to the survey data. The test pass/fail criteria are related to the error model to identify data that is not consistent with the model.

Magnetic surveys shall have passed all tests imposed at the time of calibration or verification, at the service base, on the surface at rigsite, and downhole.

Each magnetic survey shall be associated with the same error model for QC tests and for anticollision computations.

Survey reports shall specify the error model attached to the survey data.

QA/QC test parameters typically fall into one of four categories: (1) field component tests, (2) attitude tests, (3) spread tests, and (4) position tests.

4.8.3.2.2 Field Component Tests

These tests compare a measured component of the magnetic or gravity field against a reference value obtained independently from the instrument or survey tool. Test parameters may include:

$$\Delta G_{Total} = \sqrt{Gx^{2} + Gy^{2} + Gz^{2}} - G_{ref}$$

$$\Delta B_{Total} = \sqrt{Bx^{2} + By^{2} + Bz^{2}} - B_{ref})$$

$$\Delta Dip = \sin^{-1}\left(\frac{Gx \cdot Bx + Gy \cdot By + Gz \cdot Bz}{\sqrt{Gx^{2}+Gy^{2}+Gz^{2}} \cdot \sqrt{Bx^{2}+By^{2}+Bz^{2}}}\right) - D_{ref}$$

When the measurements are taken in a laboratory setting with the tool mounted in a precision stand at known reference attitudes, additional along-axis test parameters may include:

$$\Delta Gx = -G_{ref} \cdot \sin(Inc_{ref}) \cdot \sin(TF_{ref}) - Gx$$

$$\Delta Gy = -G_{ref} \cdot \sin(Inc_{ref}) \cdot \cos(TF_{ref}) - Gy$$

$$\Delta Gz = G_{ref} \cdot \cos(Inc_{ref}) - Gz$$

$$\Delta Bx = B_{ref} \cdot \cos(D_{ref}) \cdot \cos(Inc_{ref}) \cdot \cos(Azi_{ref}) \cdot \sin(TF_{ref}) + B_{ref} \cdot \cos(D_{ref}) \cdot \sin(Azi_{ref}) \cdot \cos(TF_{ref}) - B_{ref} \cdot \sin(D_{ref}) \cdot \sin(Inc_{ref}) \cdot \sin(TF_{ref}) - Bx$$

$$\Delta By = B_{ref} \cdot \cos(D_{ref}) \cdot \cos(Inc_{ref}) \cdot \cos(Azi_{ref}) \cdot \cos(TF_{ref}) - B_{ref} \cdot \cos(D_{ref}) \cdot \sin(Azi_{ref}) \cdot \sin(TF_{ref}) - B_{ref} \cdot \sin(D_{ref}) \cdot \sin(Inc_{ref}) \cdot \cos(TF_{ref}) - By$$

$$\Delta Bz = B_{ref} \cdot \cos(D_{ref}) \cdot \sin(Inc_{ref}) \cdot \cos(Azi_{ref}) + B_{ref} \cdot \sin(D_{ref}) \cdot \cos(Inc_{ref}) - Bz$$

4.8.3.2.3 Attitude Tests

These tests compare the measured attitude of the instrument or survey tool against a precision stand reference attitude or an independent attitude measurement at the same station depth in the wellbore. Laboratory test parameters comparing against a precision stand attitude reference may include:

$$\Delta Inc = cos^{-1}\left(\frac{Gz}{\sqrt{Gx^{2}+Gy^{2}+Gz^{2}}}\right) - Inc_{ref}$$

$$\Delta Azi = tan^{-1}\left[\frac{\sqrt{Gx^{2}+Gy^{2}+Gz^{2}} \cdot (Gx \cdot By - Gy \cdot Bx)}{Bz \cdot (Gx^{2}+Gy^{2}) - Gz \cdot (Gx \cdot By + Gy \cdot By)}\right] - Azi_{ref}$$

$$\Delta TF = tan^{-1}\left(\frac{-Gx}{-Gy}\right) - TF_{ref}$$

Field test parameters comparing the measured attitude against another measurement may include:

$$\Delta Inc = cos^{-1}\left(\frac{Gz_{1}}{\sqrt{{Gx_{1}}^{2}+{Gy_{1}}^{2}+{Gz_{1}}^{2}}}\right) - Inc_{2}$$

$$\Delta Azi = tan^{-1}\left[\frac{\sqrt{{Gx_{1}}^{2}+{Gy_{1}}^{2}+{Gz_{1}}^{2}} \cdot (Gx_{1} \cdot By_{1} - Gy_{1} \cdot Bx_{1})}{Bz_{1} \cdot ({Gx_{1}}^{2}+{Gy_{1}}^{2}) - Gz_{1} \cdot (Gx_{1} \cdot By_{1} + Gy_{1} \cdot Bx_{1})}\right] - Azi_{2}$$

The test parameters *Δazi* and *ΔTF* should be normalized to the range ±180° by adding or subtracting 360° if necessary. The attitudes Inc_2 and Azi_2 will have associated PUMs that contribute to test limits in the same way as those for the current tool. Error model terms that are similar (e.g., parallel, such as axial terms) and correlated across the two measurements do not contribute to the calculation of the parameter test value.

4.8.3.2.4 Spread Tests

This test determines the variation among several measurements of a quantity that should be stable. Spread test parameters may include:

$$Spread(G_{Total}) = max\left[\sqrt{Gx^2 + Gy^2 + Gz^2}\right] - min\left[\sqrt{Gx^2 + Gy^2 + Gz^2}\right]$$

$$Spread(B_{Total}) = max\left[\sqrt{Bx^2 + By^2 + Bz^2}\right] - min\left[\sqrt{Bx^2 + By^2 + Bz^2}\right]$$

$$Spread(Dip) = max\left[sin^{-1}\left(\frac{Gx \cdot Bx + Gy \cdot By + Gz \cdot Bz}{\sqrt{Gx^2+Gy^2+Gz^2} \cdot \sqrt{Bx^2+By^2+Bz^2}}\right)\right] - min\left[sin^{-1}\left(\frac{Gx \cdot Bx + Gy \cdot By + Gz \cdot Bz}{\sqrt{Gx^2+Gy^2+Gz^2} \cdot \sqrt{Bx^2+By^2+Bz^2}}\right)\right]$$

If the measurements are taken in a fixed attitude, such as during a roll test, additional spread test parameters may include the attitude:

$$Spread(Inc) = max\left[cos^{-1}\left(\frac{Gz}{\sqrt{Gx^2+Gy^2+Gz^2}}\right)\right] - min\left[cos^{-1}\left(\frac{Gz}{\sqrt{Gx^2+Gy^2+Gz^2}}\right)\right]$$

$$Spread(Azi) = max\left[tan^{-1}\left\{\frac{\sqrt{Gx^2+Gy^2+Gz^2} \cdot (Gx \cdot By - Gy \cdot Bx)}{Bz \cdot (Gx^2+Gy^2) - Gz \cdot (Gx \cdot Bx + Gy \cdot By)}\right\}\right] - min\left[tan^{-1}\left\{\frac{\sqrt{Gx^2+Gy^2+Gz^2} \cdot (Gx \cdot By - Gy \cdot Bx)}{Bz \cdot (Gx^2+Gy^2) - Gz \cdot (Gx \cdot By + Gy \cdot By)}\right\}\right]$$

The test parameter *Δazi* should be normalized to the range ±180° by adding or subtracting 360° if necessary.

4.8.3.2.5 Position Tests

This test compares the wellbore position coordinates computed from independent surveys at a common MD point. Test parameters may include:

$$\Delta N = N_1 - N_2$$

$$\Delta E = E_1 - E_2$$

$$\Delta V = V_1 - V_2$$

4.8.3.2.6 Test Limit Determination

Since a defective survey is one that fails to meet the accuracy requirement corresponding to its error model, the QA and QC test criteria shall be linked to the error model.

The general formula for computing appropriate test limits is:

$$Limit = N \cdot \sqrt{\sum_{i=1}^{i=k} (W_i \cdot V_i)^2}$$

where

- *N* is the allowable number of standard deviations (significance level);
- *I* is a code designating one of the error terms;
- *k* is the number of error terms relevant to the test;
- W_i is the i^th error term's weighting function for the parameter under test. A weighting function is the sensitivity of the test parameter to small variations in the error term, calculated mathematically as the partial derivative. Weighting functions for inclination and azimuth are described by Williamson (2000), and those for G_{Total}, B_{Total}, and magnetic dip angle are described by Ekseth et al. (2006)[9]; and
- V_i is the value of the i^th error term at one sigma.

Although the weighting functions and therefore the test limits computed in this way are dependent on location and attitude, fixed test limit criteria are acceptable if it can be demonstrated that they are no wider than limits linked to the position uncertainty model.

4.8.3.3 MWD Survey Instrument Calibration

4.8.3.3.1 General

Calibration determines coefficient values, which populate a mathematical model of instrument performance. These are normally biases, scale factors, and misalignments for each sensor, with thermal coefficients for each.

Calibrations shall be followed by acceptance tests as described in Section 6.

Acceptance tests determine whether the calibration is good.

If one or more of the acceptance tests results in failure, the calibration shall be repeated.

4.8.3.3.2 Local Magnetic Field Monitoring

Calibrations shall be performed in a stable earth's field environment.

The local field shall be continuously monitored using a static sensor during calibrations to ensure accuracy. If there is a significant variation detected, the calibration process shall be immediately halted.

While it is impossible to eliminate all variation, efforts should be made to minimize variation of the local magnetic field. Magnetometers should stay within a gradient-free volume during the tests. A reference magnetometer should be used to set magnetometer scale factors if calibration is performed by rotating the instrument in the earth's field.

4.8.3.3.3 Temperature Range for Calibration

Temperature calibration stations shall be sufficient to characterize the instrument's operation over the expected operating temperature range.

Extrapolation of temperature corrections outside the measured range may introduce unmodeled errors.

4.8.3.3.4 Gravity Field and Accelerometer Reporting Units

Gravity field intensity and accelerometer calibration factors shall be reported in units of acceleration.

A "G" or "milli-G" may be an acceptable unit of acceleration, but only if it is associated with a corresponding value in engineering units such as m/s^2 or standard Gs. A standard G is a value of 9.80665 m/s^2. For example, calibration reports referencing local Gs in the Houston, Texas, area should include a note stating that the reported "G" value is equivalent to 9.7929 m/s^2 or 0.9986 standard Gs.

4.8.3.3.5 Calibration Results Reporting

Calibration results shall be recorded and retained for audit purposes.

The computed calibration coefficients and the corresponding acceptance test results shall be retained.

4.8.3.3.6 Acceptance Testing and Verification

Instrument verification determines whether the existing calibration coefficients are modeling the sensor performance adequately. Enough measurements are taken to exercise each sensor through its range.

Acceptance tests are verifications performed on instruments as received from the manufacturer or immediately following calibrations.

Acceptance tests and verifications are normally performed in the same magnetically clean environment as calibrations.

4.8.3.3.7 Testing Verification Impact on Calibrations

Instrument verifications shall be used to verify but not to change calibration parameters.

A verification failure shall be considered cause for recalibration and/or repair.

4.8.3.3.8 Operating Range for Testing

The verification of instruments shall involve measurements that test all sensors across a minimum of 50% of their anticipated operational range.

Acceptance tests should exercise all sensors in both directions. Verifications may exercise the axial accelerometer in only one direction, corresponding to the instrument pointing downward. Verifications can thereby be accomplished with horizontal and low inclination roll tests.

4.8.3.3.9 Acceptance Testing Requirements

Verifications shall apply tests as described in Section 3.

Every measurement shall be tested, including all sensors in all attitudes and at all temperatures under test.

Failure of one or more tests shall cause the verification to be assessed as a failure.

4.8.3.3.10 Acceptance Testing Limits

Test limit values shall not exceed limits derived from the tool's error model at a 2σ significance level, as described in Section 4.

Verification test limits shall be tighter than equivalent downhole station QC test limits to account for deterioration of the instrument during shipment, conveyance downhole, and the downhole environmental conditions.

The susceptibility of a tool to these factors will vary among different designs, and therefore the optimum limit value (expressed as the number of standard deviations) will also vary.

A limit value should be chosen so as to achieve a satisfactory yield (fraction of tools that pass verification), but it shouldn't go over the value derived from the error model at 2σ.

Calibrations are subject to several errors that are not captured in the error model. These error sources may include, but are not limited to:

- spatial variation of the local magnetic field within the range of magnetometer motion,
- time variation of magnetic field during calibration at each temperature,
- calibration stand alignment errors, if the results are sensitive to instrument alignment,
- Helmholtz coil alignment errors (if appropriate), and
- instrument reading resolution or digital roundoff errors.

It is in the interest of service providers to minimize these unmodeled errors during calibration, as they can cause a good instrument to fail acceptance tests, although it is unlikely that they would cause a bad sensor to pass all such tests.

It is also in the interest of service providers to apply realistic test limit values, which for many tools may be substantially tighter than the 2σ minimum requirement. The use of overly optimistic acceptance test limit values will increase the likelihood of failed downhole station QC tests and nonconformant surveys.

4.8.3.3.11 Acceptance Limits Example

To find the pass/fail limit value for the magnetic reference field test parameter ΔB_{Total} for an instrument calibrated in the earth's field, attitude vertical with y-axis towards magnetic north, horizontal field component 25,000 nT, and vertical component 40,000 nT. An example of these requirements are summarized in Annex C Table C.2 where Bx = 25,000 nT, By = 0, Bz = 40,000 nT.

4.8.3.3.12 Acceptance Testing Tool Configuration

Verifications shall be performed using a tool or instrument configuration as close as possible to the downhole configuration.

In particular, the instrument should be tested together with the same electronics and firmware to be used downhole and assembled in a pressure barrel if possible.

4.8.3.3.13 Number of Temperature Coefficients

The verification process shall include conducting tests at a minimum of two temperatures, which should encompass at least half of the anticipated operating range.

A verification shall be able to test temperature coefficients.

An acceptance test shall observe the effect of at least one heat cycle after calibration.

4.8.3.3.14 Acceptance Testing Reporting

Verification results shall be recorded and retained.

Successive verifications performed on the same instrument may be used to identify performance deterioration and to determine appropriate verification intervals. Nonconformant results should be retained to monitor the yield and for statistical purposes.

4.8.3.3.15 Roll Tests

Not all service bases are equipped with the clean magnetic environment necessary for a full verification. Roll tests, consisting of several measurements taken at constant inclination and azimuth but different tool face angles, provide a means for partial verification at a service base. The calculated quantities G_{Total}, B_{Total}, magnetic dip angle, inclination, and azimuth should be constant during each roll.

4.8.3.3.16 Horizontal Roll Test

Survey instruments shall pass horizontal roll tests, which are performed each time an instrument returns from the field to the service base.

A roll test failure shall trigger investigation into its cause.

If it cannot be ascertained that the failure occurred subsequent to the final downhole survey station, the survey shall be deemed nonconformant.

4.8.3.3.17 Roll Test Limit Values

Roll test limit values shall not exceed limits derived from the tool's error model at a 3σ significance level, as described in Section 4.

Maximum post-run roll test limits are similar to equivalent downhole station QC test limits.

4.8.3.3.18 Roll Test Limits Example

To find the pass/fail limit value for the inclination spread test parameter Spread (Inc) for a horizontal roll test, use Annex C Table C.3 for an example of roll test limits.

In the case of a horizontal roll test, the transverse accelerometers do not contribute to inclination errors, while sag and axial accelerometer errors have a constant effect throughout the roll. Therefore, they do not contribute to the spread or variation.

4.8.3.3.19 Roll Test Orientation

Roll tests should be performed in more than one orientation. Roll tests both horizontal and at a low inclination will exercise the axial sensors. Two horizontal roll tests in opposing orientations (e.g., east and west) can detect roll misalignment between accelerometer and magnetometer sensor packages. If significant magnetic gradients are present, the magnetometers should occupy the same location for both opposing tool positions.

4.8.3.3.20 Roll Test Prior to Degaussing

Roll tests conducted on tools returning from field usage shall be performed prior to magnetic inspection or degaussing the tools.

While degaussing of components after the roll test is encouraged, the purpose of the test is to evaluate the performance of the tool in its downhole condition.

4.8.3.3.21 Rigsite Surface Tests

Roll tests can be conducted at the wellsite, but it should be acknowledged that the local magnetic field may not be predictable or constant.

In the rigsite environment, it is possible for a transverse magnetometer to become saturated in some attitudes, resulting in truncation of its sinusoidal output at some tool face positions.

If an axial magnetometer is saturated, this test provides no information for that sensor unless the tool can be moved to a cleaner location.

4.8.3.3.22 Horizontal Rigsite Test

Survey tools should be tested with horizontal rolls when the tool arrives at the rigsite and following a run downhole. The rigsite test may not be quantitative unless a magnetically clean area is available. A clean area and reference azimuth should be used if available.

4.8.3.3.23 Rigsite Accelerometer Test

Roll tests may be augmented by raising each end of the MWD string to check axial accelerometer function. Vertical accelerometer tests may also be performed on the instrument before it is installed in the running gear.

4.8.3.3.24 Benchmark Check Shots

A good survey station that passes all QC tests can be used as a benchmark for comparison with later surveys taken at the same well depth.

4.8.3.3.25 Position of Benchmark Surveys in the Wellbore

Benchmark survey stations should be in regions free of external magnetic interference, such as from casing, and should avoid intervals of borehole curvature or inclinations below 6°.

External magnetic interference may not be constant in space or time.

Check shots are sensitive to depth errors; therefore comparisons of measured attitude require a locally straight hole.

4.8.3.3.26 Comparing Check Shots to Benchmark

Check shots and benchmark shots have to match within a maximum tolerance consistent with the applicable PUMs at the 3σ level.

Limit values smaller than those derived from the error model may be used.

Comparisons between successive tools may include the local attitude (inclination and azimuth), and when compared against other magnetic tools the reference fields (total gravity, total magnetic intensity, and dip angle) are also evaluated for consistency. Comparisons that fail to meet the test limits should trigger investigation, as at least one of the surveys was not meeting the expectations of its error model.

4.8.3.3.27 Check Shot Limits Example

To find the pass/fail limit value for the inclination difference parameter δInc between two MWD tools, attitude horizontal with y-axis up (TF = 0), G_{Total} = 1 standard G, build rate 0.5°/30m (BR = 0.5/30), see Annex C Table C.4 for an example of check shot limits where Gx = 0.0 standard G, Gy = - 1.0 standard G, Gz = 0.0 standard G.

For a check shot comparison against another shot taken with a similar BHA, the sag term is correlated between the two shots, and its contribution should therefore be omitted. For comparison between two shots taken with the same tool and BHA, the ABZ and ASZ terms should be omitted for the same reason, but the MXYa term for misalignment should generally be retained as the two tool faces are uncorrelated.

4.8.3.3.28 Rotation Check Shots

Survey shots at a common well depth with different tool face angles can provide an indication of transverse biases and axial misalignments.

4.8.3.3.29 Maximum Rotation Angle Between Shots

Rotation shots should be taken with no more than 120° of tool face rotation between adjacent stations. In practice this will require a minimum of four shots at the same depth.

4.8.3.3.30 Rotation Shot Test Limits

Rotation shots shall test the measurements against maximum limits consistent with the tool error model at a 3σ level.

Limit values smaller than those derived from the error model may be used.

If data fail these tests, uncorrected surveys shall be deemed out of conformance with the error model.

If the cause of failure can be identified, it may be acceptable to correct the surveys using MSC.

4.8.3.4 Survey Quality Assurance - Gross Error Avoidance

4.8.3.4.1 General

Survey practices shall be designed to avoid gross errors.

4.8.3.4.2 Survey Interval

The positioning of survey stations shall be done at regular intervals to ensure accurate characterization of the wellpath, in accordance with the specified error model.

Standard PUMs are not valid for station separations exceeding approximately 30 m or one stand, and shorter intervals should be used during build and turn sections.

When regular changes in well geometry exist (as in slide/rotate drilling), survey station positions should not be correlated with the slide/rotate sequence. This can be accomplished by varying the slide/rotate pattern on different stands in order to place the survey stations at different positions within the pattern.

4.8.3.4.3 Magnetic Spacing

Magnetic survey assemblies shall space magnetometers sufficiently distant from magnetic BHA components that the estimated effect of AX is within the error model term value.

Adequate spacing should be estimated using EDI software. The magnetization of the BHA should also be physically measured to verify EDI assumptions. If the measured magnetization exceeds the EDI estimates, near-magnetometer BHA components should be degaussed or magnetic spacing increased.

4.8.3.4.4 Survey Tool Movement During Acquisition

Magnetic surveys shall strive to minimize axial and rotary tool movement during survey data acquisition.

Practices to minimize tool movement include the following:

- Stop rotating, allow torque to unwind by working drillpipe in and out of hole.
- Minimize pipe movement during surveys. This may require tensioning pipe by running to bottom and pulling up, or adjustment of the delay time triggering a survey.
- Design BHA and MWD string to have adequate centralization to minimize the space for lateral movement.
- No- or low-flow circulating conditions are required to minimize hydraulic and mechanical noise.

4.8.3.4.5 Survey Correction Management Process

Magnetic survey parameters, calculations, and corrections should be checked by independent personnel trained in survey management. This practice helps to ensure correct application of the coordinate system and datum, declination, convergence, sag correction, vertical datum, software configuration, reference field error terms, and other parameters.

Sufficient records should be kept, enabling corrections to be repeated later.

4.8.3.4.6 Survey Deliverables

The magnetic survey deliverables shall consist of the following information: surface location, datum, reference field values and their source, and north alignment.

For each station, deliverables shall include date and time, well depth, and raw survey data.

There may be multiple reference field values, particularly if IFR is applied. Deliverables should include all such values used in survey QC. Deliverables should include failed surveys, as these have diagnostic value.

4.8.3.4.7 Real-time Detection of Corrupted Data

Real-time data telemetry schemes shall incorporate a means of detecting data corrupted during transmission.

If a telemetry failure is detected, the station should be retransmitted or resurveyed.

4.8.3.4.8 Internal Quality Control (QC)

An MWD tool can measure the range and standard deviation of values on each sensor if the acquisition consists of averaging measurements. These values may be used to indicate whether the tool was stationary. Sensor values that clip one end of the available range can indicate saturation or tool movement during acquisition. Such survey quality indicators may be transmitted to the surface to provide additional QC.

4.8.3.4.9 Internal Quality Control (QC) Survey Failure

Surveys shall not include stations that fail internal QC tests.

Internal QC tests are not required; however, if they exist then failed stations should be excluded from the survey data.

4.8.3.4.10 Survey Station Quality Control (QC) Tests

The real-time measurements of each station should include G_{Total}, B_{Total}, magnetic dip angle, and temperature as QC parameters. Tests of B_{Total} and magnetic dip angle may be combined into a single test of B_{Total}Dip.

To verify whether the actual measurement errors satisfy the requirements of the selected error model, the measured values should be compared with their corresponding reference values. Parameter limits for these tests are commonly known as FAC.

4.8.3.4.11 Ensure All Survey Stations Pass Field Acceptance Criteria (FAC)

All magnetic surveys shall have passed all station QC tests at each station.

Test parameters for G_{Total}, B_{Total}, and magnetic dip angle are like those described in Section 3.2.

While a station QC failure means that the station does not fulfill the specifications of the error model, the reverse does not apply. Passing the station QC test does not guarantee that the measured attitude at a station meets the error model.

For example, G_{Total} will test accelerometers pointing towards vertical, but inclination is dominated by the more horizontal sensor(s). B_{Total} and magnetic dip angle test magnetometers that point primarily towards the magnetic north/vertical plane, while azimuth is dominated by the sensors pointing east-west. If stations within a survey fail FAC in one attitude, the tool may provide inaccurate azimuth values at other stations in different attitudes, even if those stations passed the same FAC tests. Additional tests such as MSA may be helpful in resolving such situations.

4.8.3.4.12 Station QC Test Limits

Station QC test limits shall not exceed values corresponding to the survey error model at a 3σ level.

Test limits can be computed as described by Ekseth et al.[9]. Fixed test limit values are acceptable, provided they do not exceed limit values derived from the error model at 3σ. A failed station QC test means that the station does not fulfill the requirements of the chosen error model. Possible reasons for failure include:

- poor instrument performance;
- reference value errors;
- excessive vibration or interference from the drillstring;
- magnetic interference from the drillstring, the mud system, or an adjacent wellbore;
- telemetry errors (decode errors); or
- high magnetic mineral content of the geological formation.

This list should not be considered exhaustive. Corrective action depends on the suspected reason for the QC failure, and may include:

— retaking the station,

— using more accurate reference values such as IFR1 or IFR2,

— applying an axial magnetic correction if the wellbore orientation permits,

— applying MSC,

— taking one or more rotation shot sets and calculating corrections,

— taking additional nearby survey stations to detect interference from nearby casing,

— replacing the MWD tool,

— using an error model with larger term values, or

— running a different survey tool.

4.8.3.4.13 Pass/Fail Limit Value for Magnetic Reference Example

To find the pass/fail limit value for the magnetic reference field test parameter ΔB_{Total} for an instrument calibrated in the earth's field, attitude horizontal with z-axis towards magnetic west, y-axis up (TF = 0), horizontal field component 25,000 nT and vertical component 40,000 nT where Bx = -25,000 nT, By = -40,000, Bz = 0 nT for the example table of Magnetic Reference Pass/Fail Limits shown in Annex C Table C.5.

4.8.3.4.14 Real-Time Survey Data

Survey tools should transmit real-time data with enough resolution to conduct valid station QC tests.

Data resolution shall be finer than the QC test limits.

If data are not transmitted with sufficient resolution, the station QC tests should be run using memory data following the run.

4.8.3.4.15 Survey Station Temperatures

Survey stations should report temperatures that are consistent with temperatures measured at nearby stations. Temperature jumps are allowed if they are consistent with drilling activities. In such cases, the activities should be reported.

4.8.3.4.16 Combined Quality Control (QC) Test Values

Survey station QC tests for B_{Total} and magnetic dip angle may be combined into a single test with two degrees of freedom, and G_{Total} may also be included in a test with three degrees of freedom. These combined tests give more accurate relationships between probability and the FAC sigma level by taking error covariances into account.

4.8.3.4.17 Appropriate Quality Control (QC) Test Values for Corrected Surveys

Corrected surveys shall pass station QC tests appropriate for those corrections.

If axial corrections or MSC are applied, the station shall be tested against tighter FAC limits than uncorrected data.

In all cases, the test limits shall not exceed limits derived from the error model at a 3σ level.

4.8.3.4.18 Quality Control (QC) Testing of Short Surveys

Surveys that transmit only inclination and azimuth in real time are required to pass station quality control (QC) tests using memory data after the run.

4.8.3.4.19 Use of Short Surveys in HSE Critical Situations

If there is a high likelihood of an event with severe HSE consequences, such as a collision with another well, short surveys without real-time QC tests shall not be used.

Short surveys may be acceptable in the case of potential collisions that do not carry serious HSE risk.

4.8.3.4.20 Multi-station Analysis (MSA)

4.8.3.4.20.1 General

In MSA, existing stations of a tool run are analyzed together as a set. This may be done in real time once enough stations are available, or by post-processing a completed tool run.

MSA may be used to identify systematic errors that persist throughout the tool run, such as sensor biases and scale factor errors, drillstring magnetic interference, magnetic drilling fluid, or misalignments between accelerometer and magnetometer packages.

MSA reliability is greatest when the stations being processed encompass a wide range of tool-face angles and wellbore attitudes. Specific recommendations on the resolvability of parameter combinations are given by Nyrnes,[17] and Hanak et al.[18] provides examples.

4.8.3.4.20.2 Multi-station Analysis (MSA) Maximum Values of Error

An MSA program shall determine maximum-likelihood values of error model terms and deliver these results to the user.

MSA outputs should be used to determine whether the resolvable parameter values are within the error model expectations at a 3σ level, as suggested by Ekseth et al.[9]. MSA normally solves for some or all of the magnetometer biases and scale factor errors. With a suitable data set, MSA may also be able to determine maximum-likelihood values for additional parameters including reference field parameters.

4.8.3.4.20.3 Multi-station *A*nalysis (MSA) *S*olution *S*tability

An MSA program should give an indicator of solution stability, such as a matrix condition number or an estimate of output azimuth uncertainty. The stability indicator can be used as guidance as to whether the MSA program is solving for an appropriate parameter set.

4.8.3.4.21 Survey Stations Repeated with the Same Tool and Bottomhole Assembly (BHA)

A station may be repeated to determine whether a sensor has failed or the magnetic environment (e.g., DSI) has changed between shots. Acceptable inclination and azimuth differences are based on tool face–dependent misalignment and sensor error terms, depth uncertainty applied to local hole curvature, and randomly propagating (time-varying) components of the reference field.

4.8.3.4.22 Repeat Station Agreement

The repeat survey measurement has to be in agreement with other measurements taken at the same station, adhering to the limits specified by the assigned error model, at a 3σ level.

Inclination and azimuth can always be compared if raw data or detailed QC data are transmitted. Similar tests may be performed for total field intensities and magnetic dip angle.

4.8.3.4.23 Multiple Directional Measurement While Drilling (MWD) Sensors

Multiple sensors may be run in one BHA, for example, a standard direction and inclination (D&I) module (sensor arrangement) in tandem with rotary steerable or near-bit sensors. Measurements from the different sensors may be compared at common depth points that avoid doglegs.

4.8.3.4.24 Multiple Sensors at Common Depths

Surveys using multiple sensors shall test the agreement between the sensors at common depth points.

Acceptable differences in attitude or fields shall be related to the PUMs, and data may be considered acceptable if differences do not exceed the error model predictions at a 3σ level.

When the two sensors are in satisfactory agreement, it may be acceptable to combine data from the two sensors and to apply a stricter error model to the combined survey. Details are given by Chia et al. [21] and Ekseth et al.[10].

4.8.3.4.25 Comparison with Independent Tools

4.8.3.4.25.1 General

The strongest QC test requires independent tools with no common error model terms, such as one MWD magnetic and one wireline gyro.

4.8.3.4.25.2 Agreement Between Survey Tools

A magnetic survey should produce measurements of attitude and position that agree with those obtained by a fully independent survey. Agreement is defined as attitude angles or position coordinates within error model predictions at a 3σ level. Comparisons of inclination, azimuth, and position vectors should be made at common depth points that avoid doglegs. Details are given by Ekseth et al.[10]

4.8.3.4.25.3 Memory logs(Trip in and out)

Most MWD tools are equipped with internal memory that can be downloaded at the end of each run. Some battery-powered tools are also capable of recording survey data during trips in or out of the hole.

4.8.3.4.25.4 Comparing Real-time and Memory Surveys

A magnetic survey should use memory data, if present, to verify survey data transmitted in real time. If there is any discrepancy between telemetered data and memory data, the memory data are to be used except in cases of obvious corruption.

4.8.3.4.25.5 Memory Surveys During Trips

A magnetic survey tool that can acquire survey data in memory during trips should do so, and the data should be downloaded after each tool run and stored as memory logs. This procedure enables advanced survey analysis to detect errors, correct the definitive surveys, and reduce positional uncertainty.

Station QC tests should be run on the memory data. Memory data may be used to obtain additional overlapping check shots with little or no cost in rig time.

In-run and out-run trips may be made with the stands broken at different positions to survey additional positions along the wellbore.

4.8.3.4.26 Axial Magnetic (Short Collar) Correction

The axial magnetic correction or short collar correction is a survey correction that substitutes the measured along-hole (axial) magnetometer component with the corresponding value of the geomagnetic reference field. A modified axial correction that is less susceptible to noise or external magnetic interference uses the estimated axial interference averaged over several stations.

4.8.3.4.27 Error Model for Axial Corrected Surveys

The implementation of an axial corrected magnetic survey requires the use of a suitable axial corrected error model, as described by Williamson (2000).

A single station axial magnetic correction assigns all magnetic errors to axial bias.

Steps should be taken to eliminate other causes of magnetic error, such as performing rotation check shots to identify and remove transverse biases and using high-accuracy magnetic reference models. The combination of a roll test with axial magnetic correction was developed by van Dongen and Maekiaho (1987).

4.8.3.4.28 Axial Corrected Survey Quality Control (QC) Test

An axial corrected magnetic survey shall have passed all station QC tests consistent with the error model, such as the B_{Total}Dip test described by Ekseth.[9]

The correlation between residual errors in B_{Total} and magnetic dip arises from the requirement that, upon optimizing the axial component, the magnetic error vector have to be perpendicular to the well path.

4.8.3.5 Application of Axial Corrections Within Inclination and Azimuth Limits

An axial magnetic correction should not be applied without expert oversight in wellbore attitudes above 70° inclination or within 20° of magnetic east or west.

At attitudes that approach horizontal magnetic east or west, the axial correction algorithm becomes extremely sensitive to errors in the reference magnetic field.

The implications on position uncertainty shall be well understood.

4.8.3.6 Multi-Station Correction (MSC)

Parameter values resolved by MSA may be applied to the accelerometer and magnetometer measurements. This practice is MSC. Under some circumstances, it may be possible to apply adjustments to reference field parameters.

4.8.3.7 Multi-Station *C*orrection (MSC) Station Quality Control (QC) Tests

Multi-Station corrected data shall pass all station QC tests consistent with an error model with smaller term values than the uncorrected tool.

Since the application of MSC reduces the residuals in G_{Total}, B_{Total}, and magnetic dip angle against the reference values, specific PUMs for MSC data should be used, and the FAC limits should be based on these MSC models at a 3σ level.

4.8.3.8 Multi-Station Correction (MSC) Independent Verification

MSCs should be verified independently when possible. Verification examples could be mud samples tested or flow on/off comparisons made if magnetic mud is indicated, or the BHA magnetization being measured if significant interference is indicated.

4.8.3.9 Geomagnetic Reference Adjustment and Verification

Adjustments to geomagnetic reference values based on MSCs should be verified by ground, marine, or airborne magnetic measurements.

Some MSC implementations calculate adjustments to the geomagnetic references B_{Total} and magnetic dip angle. If these adjustments are significant, there is a strong likelihood that a geomagnetic declination error also exists. Independent verification will identify such a declination error, which would otherwise be undetectable.

4.8.3.10 Single Failed Sensor Recovery

Triaxial orthogonal sensors provide enough information to determine instrument attitude, plus additional data such as total field intensity and magnetic dip angle, which are traditionally used for QC purposes. If one sensor fails, the reference values for G_{Total}, B_{Total}, and/or magnetic dip angle are sometimes used to reconstruct the missing value.

4.8.3.11 Use of External Field Reference and Dip

Magnetic surveys should not use external reference field intensity or magnetic dip angle to compute attitude, except for axial magnetic correction or MSC.

In certain instances, the single-station axial interference correction may be used for recovery from a failed axial magnetometer, provided that an appropriate error model is applied. For other failed sensors, reconstructed data should not be used for a definitive survey for the following reasons:

a) Appropriate PUMs are not in the public domain.

b) Resulting survey accuracy will not match the survey plan.

c) Accuracy of the reconstruction will be sensitive to AX.

d) Survey QC opportunities are limited.

4.8.3.12 In-field Referencing

In-field referencing of type 1 (IFR1) may be employed to reduce the uncertainty of the geomagnetic reference values by accounting for local crustal magnetic anomalies. IFR1 may consist of local ground shots or reference field values obtained by inversion of aeromagnetic data.

In-field referencing of type 2 (IFR2) may be employed to additionally correct the geomagnetic reference values for time-varying magnetic disturbance fields caused by currents in space and their induced counterparts in the subsurface.

4.8.3.13 IFR1 Uncertainty Estimate

IFR1 values shall be accompanied by uncertainty estimates.

It is essential for reference field values to be accompanied by estimates of uncertainty, as such estimates form part of the survey error model and are used to determine QA/QC test limit values.

4.8.3.14 Use of IFR1 for Entire Wellbore

IFR1 values should account for the spatial variations of the geomagnetic field all along the wellbore, not just at the wellhead.

Accounting for field variations along the wellpath will result in smaller IFR uncertainty and therefore a more accurate magnetic survey. Variations in both horizontal and vertical (TVD) directions should be considered.

4.8.3.15 Local Verification of IFR1 Aeromagnetic Data

IFR1 values obtained from the inversion of aeromagnetic data should be verified by local measurements of B_{Total}, magnetic dip angle, and declination (ground shots). Inversion of scalar data commonly fits the data to a model that is based on assumptions. Local ground shots help to validate such assumptions.

4.8.3.16 IFR2 Meets IFR1 Requirements

IFR2 values shall satisfy all requirements of IFR1.

The crustal field components are obtained from IFR1, and the disturbance field components are obtained from IFR2.

4.8.3.17 IFR2 Uncertainty Estimate

IFR2 values should be accompanied by uncertainty estimates that consider the distance between the monitoring stations and the wellsite.

4.8.3.18 Local Verification of IFR2 Data

IFR2 values may be verified by a local magnetic variometer station.

4.8.3.19 Electronic Multi-Shot (EMS) Surveys—Quality Assessment (QA)/Quality Control (QC) Requirements

Electronic multi-shot (EMS) surveys should pass QA and QC tests similar to those for MWD. If two EMS instruments are run in tandem, as is common practice, the data should also pass multiple sensor tests as described in Section 4.8.5.17.

4.8.4 Practices for Gyroscope and Accelerometer Attitude Measurements QA/QC

4.8.4.1 General

Gyro survey tools operate in many ways depending on the technology and mode at which they are run; in general, they measure rotation rate and acceleration due to gravity. There are tools with single-axis gyros, dual-axis gyros, and triple-axis gyros currently available in the market; all these tools have a different number of accelerometers and different configurations that result in different operating modes and inclination ranges.

Measurements can be taken while the tool is stationary at several discrete survey stations, each associated with a depth measurement; this is normally known as gyrocompassing. Another mode of operation is known as continuous mode, in which the survey tool measures the changes in orientation as it traverses the wellbore.

Similarly, to what is described in the MWD QA/QC section, the accuracy of a gyro survey tool is described by an PUM or error model. For the case of the gyro, the PUM contains the error terms describing the sensor errors, including biases, scale factors, g-dependent bias, and misalignments.

Survey data together with the PUM can be used to determine an EoU that describes the uncertainty assigned to the survey. A survey defect is a survey resulting in an absolute position error outside expectations defined by an EoU based on the PUM. Ellipsoid dimensions correspond to a specified number of standard deviations or sigma (σ). A survey defect may be caused by error(s) larger than the PUM value at 3σ, or by the presence of errors outside the PUM (gross errors).

Weighting functions were originally described in SPE 90408 for inclination and azimuth.[22] Additional weighting functions for G_{Total} and Horizontal Earth Rate were described in SPE 103734.[9] Weighting functions for Total Earth rate and Latitude are described in SPE 168052.[23]

QA and QC are processes and procedures designed to minimize the possibility that a survey fails to meet the accuracy specifications defined by its PUM. QA measures are applied prior to taking the survey to minimize the possibility of an out-of-specification occurrence. QC measures are applied during or after each station is acquired to validate the data and correct it if necessary. In most cases, a corrected survey will result in an PUM that differs from one appropriate for uncorrected data.

Since a defective survey is one that fails to meet the accuracy requirement corresponding to its PUM, the QA and QC test criteria should be linked to the PUM. Test limits can be derived from the PUM in the following manner:

— Determine which error terms are relevant (they affect the comparison being made) and which are not common to both quantities being compared.

— For each relevant error term, estimate its effect on the quantity of interest at 1σ by multiplying the term value by the appropriate weighting function.

— Assemble the contributions of the different error terms by finding their Euclidean norm (RSS).

— Scale up the test limit to the appropriate number of standard deviations. This should not exceed 3σ for field data or 2σ for laboratory data.

4.8.4.2 Gyroscopic Quality Assurance / Quality Control

Combination gyroscope and accelerometer instruments can be categorized into eight distinct types, each of which have different QA/QC requirements. These requirements are summarized in Annex C Table C.6.

4.8.4.2.1 Gyro Calibration Acceptance

Calibration QC has to be stated in the report and aligned with the error model at a 2σ level.

It should specify the temperature range and the tool modes.

4.8.4.2.2 Gyro Reference Values

The following reference values required to implement the calibration process shall be known accurately with an uncertainty value two orders of magnitude smaller than the gyro and accelerometer sensors to be calibrated:

a) latitude,

b) magnitude of the local gravity vector, Gref.

The inclusion of the latitude value in the calibration information is essential to ensure its availability for field data processing and post-processing analysis, as per the requirements.

4.8.4.2.3 Gyro Calibration Stand Alignment

The calibration stand is required to be both level and aligned to true north with a predefined accuracy. This accuracy should be at least two orders of magnitude higher than the expected accuracy of the gyro and accelerometer sensors that will be calibrated.

The precision of the angular positions of the calibration stand shall also be of two orders of magnitude better than the sensors to be calibrated.

The calibration stand shall be mounted on solid ground to prevent changes in the orientation.

In addition, the level and orientation of the stand shall be periodically verified and documented.

4.8.4.2.4 Temperature

The sensor and the electronics shall be calibrated over the temperature range in which the tool will be required to operate.

The temperature values chosen for the calibration and interpolation methods shall be sufficient to describe the tool behavior.

High-order polynomials can cause problems when extrapolation is required.

4.8.4.2.5 Acceptance and Report

The uncertainty of the calibration terms shall agree with the PUM and the operating mode that will apply to the tool being calibrated.

Since the calibration data are collected in ideal conditions, the final acceptance derived from the PUM applied to the instrument shall not exceed the sensor accuracy at a 2σ level.

The temperature range of the calibration, the uncertainty of the sensors, and the tolerance shall be clearly listed on the calibration report.

4.8.4.2.6 Verification at the Service Base

At an interval relevant to the instrument type, the survey instrument shall be tested at the service base for the operation modes expected to be used in the field.

The tolerances on the test shall be set according to the error model.

- Prior to mobilizing survey tools to the survey site, the surveying tools shall have their performance assessed for suitability at the service base.

- This instrument verification process should be designed to ensure that measurements provided by the surveying tool are within the tolerances required for the PUM.

- This evaluation of performance for tools intended for stationary gyrocompass surveying may involve taking a series of measurements to maximize the observability of error sources (such as rotation shots at horizontal east/west, vertical, and upside down); final acceptance test limits shall be connected to the PUM.

- This process may include direct validation of the survey tool's measurements relative to an PUM using a precision stand across the range of orientations and temperatures across which the instrument is expected to operate.

- For tools to be used with continuous surveying, this assessment should include a validation of bias stability for sensors used in measuring attitude changes while surveying. This validation may include comparing the results of a series of zero-velocity updates performed at orientations chosen to optimize error source observability. This comparison may include performing a series of tests where a tool is moved through a range of inclinations and azimuth in a precision stand to verify tool performance relative to an PUM.

4.8.4.2.7 Surface Test at Wellsite

The survey instrument shall be tested at the wellsite on the operation modes expected to be used in the field.

The tolerances on the test shall be set according to the error model.

- Upon arrival at the wellsite, surveying tools should have their performance verified prior to performing a surveying run. This verification process should be designed to ensure that no damage has been sustained by the tool during transport to the wellsite and that measurements provided by the surveying tool are still expected to fall within the tolerances required for the PUM. This verification typically involves performing a subset of the verification process performed at the service base.

- For performance evaluation, this verification may incorporate rotation shots at horizontal East/West to optimize error source observability. Final acceptance test limitations will be linked to the PUM.

— Wellsite acceptance tests should not rely upon precise instrument orientation, as the apparatus required for such test is generally not available at the wellsite.

— This verification may include the estimation of calibration parameters that are expected to change over time. These estimates should be compared to the values calculated at the service base to ensure that they are within acceptable tolerances. On floating vessels or where high levels of vibration (noise) is present, these checks may not be possible.

4.8.4.2.8 Overlapping Checkshots at Start/End of Each Tool Run

The survey shall undergo quality checking by comparing it to the previous survey at a distance of 100 meters or three depths (stationary surveys).

When there is a valid survey on a section of the well, it is possible to compare that data with the new survey data and establish the validity of the new data.

4.8.4.2.9 Wireline Runs

For wireline runs with real-time data, it is possible to compare the prior survey with the present survey and define tolerances based on both PUMs (see C.1.9). The survey needs to be thoroughly reviewed for quality in accordance with the processes provided in this document; nevertheless, a discrepancy outside the error model at the start of the run can save using the wireline tool to a greater well depth.

4.8.4.2.10 Gyro-Measurement While Drilling (MWD)

For the case of gyro-MWD, particularly when it is used at depths at which the MWD tool is affected by magnetic interference, it is very important to determine the functionality of the gyro tool by comparing it with a set of valid surveys from the previous tool. This is important since the gyro could be affected by shock and vibration during the drilling process and, even though the gyro data can be internally quality checked, the data cannot be compared to any other valid survey.

When the MWD tool is free from magnetic interference, three gyro-MWD surveys and MWD surveys should be compared to determine whether the accuracy of the gyro MWD survey of the previously drilled section is in accordance with the error model.

For the case of memory tools like drop or battery tools run in slickline, it is possible to compare the data with other surveys; however, this is not a real-time process. See 4.8.5.10 for more information.

4.8.4.2.11 Rotation Check Shots

A set of rotation shots shall be performed at least once per section.

Shots at a common well depth with different tool-face angles can provide an indication of transverse biases and axial misalignments errors. They will result in azimuth, inclination, and/or Horizontal Earth Rate spreads at a single depth. Rotation shots should be taken with no more than 120° of tool-face rotation between adjacent stations. In practice, this will require a minimum of four shots at each depth point. If parameters are determined to be outside the limits corresponding to the tool error model at a 3σ level, depending on the tool operating mode and the type of operation, it might be required to pull out of the hole. If misalignment correction routine or MSC are available, it is possible to correct the data.

In any case, the running gear and the sensor shall be checked after the run for defects.

4.8.4.2.12 Gyro Survey Practices

Each survey tool shall have a standard operating procedure that ensures conformance with the requirements of the tool error model.

The survey tool shall be run in accordance with this operating procedure.

- Joint Standard Operation and Reporting Procedures (JSORPs) shall be followed to avoid gross errors.
- QC of data is associated with certain tests and actions described in SOPs; if these are not followed, it is likely full and proper QC cannot be performed, and it may not be valid.
- The survey stations for the gyrocompass should be taken at sufficiently close intervals to accurately characterize the wellbore profile.
- The standard error model does not consider any uncertainty on the modeling of the well profile, and common practice is to take a survey measurement approximately every 30 meters or one stand with shorter depth intervals during build and turn sections.
- Proper running gear shall be used according to the SOP and well conditions to ensure that the orientation of the survey tool is aligned with the orientation of the wellbore.
- Movement of the tool during gyrocompass should be minimized, as it affects the accuracy of the survey.
- Temperature shall be stable and within the calibration range of the survey tool.
- For the case of free gyros or survey systems that include a sighting tool, special care should be taken, since QC depends entirely on the operator and adherence to the procedure. Repeated runs and more than one reference point are good practices that help reduce gross errors.

4.8.5 Gyroscopic Internal Quality Control (QC)

4.8.5.1 General

Internal functioning of the tool and noise levels shall be verified at each gyrocompass station.

During the process of taking a gyrocompass, certain measurements can be collected that provide internal validation of the survey.

4.8.5.2 Accelerometer Bias Difference Test

For sensors that are mounted on a precision rotating platform, it is possible to directly measure accelerometer bias of X and Y sensors by taking readings precisely 180 degrees of phase apart from each other. For a four-position gyrocompass, this provides two separate determinations of the accelerometer bias. The difference between these two bias estimations can be used to estimate the magnitude of the residual accelerometer bias. This difference should fall within an acceptable range determined by the PUM.

4.8.5.3 Gyro Bias Difference Test

For sensors that are mounted on a precision rotating platform, it is possible to directly measure gyro bias of X and Y sensors by taking readings precisely 180 degrees of phase apart from each other. For a four-position gyrocompass, this provides two separate determinations of the gyro bias. The difference between these two bias estimations can be used to estimate the magnitude of the residual gyro bias. This difference should fall within an acceptable range determined by the PUM.

4.8.5.4 Gyro Noise Test

For gyro sensors in particular, sensor output stability can be used as an indicator of measurement quality. Statistics on the acquired data, such as the standard deviation of sensor output over a specified duration (e.g., 10 seconds), can be used as a method of evaluating the stability of the gyro output. The acceptable limit of measured gyro noise should be set to ensure conformance with the PUM.

Additionally, it is good practice to monitor the readings of the temperature sensors, currents, voltages, and so on that might indicate issues with the survey tool.

4.8.5.5 Reference Field Tests

The use of survey data readings is required at each station to calculate pertinent reference values for comparison with nominal values. Tolerances have to be established based on the error model.

During the process of performing a stationary gyrocompass, the readings from surveying instrument may also be used to estimate the value of certain reference fields. Error sources that impact the accuracy of the computed tool orientation can also have an impact on the calculation of these fields. The magnitude of these values relative to the known theoretical values should be used to confirm proper operation of the surveying instrument. These reference field tests should be performed at each individual survey point and may be evaluated together across a survey leg to confirm tool performance. Values falling outside the acceptable deviation from reference can indicate a situation where survey measurements may not be well modelled by the PUM being used.

4.8.5.6 Gravity Field

The Earth's gravity field is the vector sensed by accelerometers to determine tool inclination. For sensors using a three-axis orthogonal accelerometer package, the magnitude of this vector can be directly estimated at all tool orientations. A theoretical value for this magnitude at the surveying location can be computed using several methods. The acceptable amount of deviation for a survey point from the theoretical value can be calculated from the expected accelerometer errors in the surveying instrument. The process for computing these limits from a typical error model is outlined in SPE 103734.[9] Given that there is a significant amount of symmetry in how individual accelerometers behave across orientations, a single acceptance value for maximum allowable deviation from reference may be used so long as it is sufficiently small to ensure conformance with the PUM.

4.8.5.7 Horizontal Earth Rate

The horizontal component of the earth's rotation is the vector sensed by rate gyroscopes used in calculating azimuth for a gyrocompass survey. All gyrocompassing systems should be capable of measuring this vector magnitude when determining survey azimuth. The theoretical horizontal earth rate can be computed precisely from the survey location's latitude and total earth rate. The acceptable amount of deviation for a survey point from the theoretical value can be calculated from expected errors in both the gyro and accelerometer sensors in the surveying instrument. The process for computing these limits for a two-axis gyro system is outlined in SPE 103734.[9] The observable effects of gyro defects on horizontal earth rate can be dependent on instrument orientation, and the acceptable limits may be adjusted with tool orientation so long as conformance with the PUM is still ensured.

4.8.5.8 Total Earth Rate

For instruments that use all gyro measurements on three axes of the tool, it is possible to measure a value for total earth rate. The total earth rate is defined solely by the length of the sidereal day and thus is independent of surveying location (15.04 degrees per hour). The acceptable amount of deviation for a survey point from the theoretical value can be calculated from expected errors in the gyro sensors in the surveying instrument. The observable effects of gyro defects on total earth rate can have a dependence on instrument orientation, and the acceptable limits may be adjusted with tool orientation so long as conformance with the PUM is still ensured.

4.8.5.9 Latitude

For instruments that use all gyro measurements on three axes of the tool, it is possible to directly measure a value for tool latitude. This latitude measurement can be compared with the known latitude of the surveying location as a further quality check on the survey. The acceptable amount of deviation for a survey point from the theoretical value can be calculated from expected errors in the gyro sensors in the surveying instrument. The observable effects of gyro defects on latitude can have a dependence on instrument orientation, and the acceptable limits may be adjusted with tool orientation so long as conformance with the PUM is still ensured.

4.8.5.10 Independent Redundant Surveys

Comparison of survey data with the results of an independent survey is the most powerful QC test method. Recommendations on when to run an independent survey for QC purposes is outside the scope of the Gyroscopic Data QA/QC (C.4.2).

When independent data is available, a Chi-square test shall be performed.

"Chi-square test" refers to two surveys that provide uncorrelated information about a given attitude value or QC parameter. A typical example is azimuth determined using MWD data (based on Earth Magnetic Field) and azimuth determined using gyro data (based on Earth Rotation). Other possible tests are inclination for two tools with different BHAs or running gear, gyro MWD and continuous gyro azimuth, two gyro runs from different service companies, and so on. Examples of non independent redundant surveys are azimuth of two MWD tools with the same BHA and inclination from two gyro runs with the same running gear.

For independent redundant surveys, the following tests can be conducted:

4.8.5.11 Chi-square Test – Inclination, Azimuth, and Horizontal Coordinates

A Chi-square test can be used to detect systematic inclination, azimuth, or coordinate differences between two overlapping surveys of a section of well. It is stressed that the validity of such tests relies totally on the independence of the two measurements used. Such tests are only capable of indicating that something is wrong with the inclination, azimuth, or coordinate estimates in at least one of the two surveys being compared. It cannot be used to detect the specific error source that may be affecting the outcome of the test. However, a data check, consisting of combined comparisons of inclinations, azimuths, and coordinates relative to an independent verification survey, is the most powerful QC test method available.

4.8.5.12 Single Shot Test

For real-time operation, when complete survey listings are not available, it is possible to compare single shots (properly interpolated to the same depth) for errors. This is simply a special case of the Chi-square test with one degree of freedom. It can apply to azimuth and inclination, and the same considerations with respect to independence apply.

4.8.5.13 Relative Instrument Performance (RIP) Test

The RIP test is a quantitative comparison of two independent surveys run in the same section of the well. The quality of the comparison is expressed as the mean and standard deviation or their angular differences normalized against their expected combined survey errors. The steps of the RIP test are described below:

NOTE This test is not a replacement for the Chi-square test.

a) Designate one survey (normally the most accurate) as the reference survey and the other as the comparison survey.

b) At each comparison survey station depth in the overlap interval:

   1) interpolate the reference survey inclination,

   2) compute the *observed inclination difference* by subtracting the reference survey inclination from the comparison survey inclination,

3) compute the one standard deviation inclination uncertainty from the definitive and comparison surveys using appropriate PUMs,

4) compute the *expected inclination error* (one standard deviation) from the RSS of the inclination uncertainties, and

5) divide the *observed inclination difference* by the *expected error* (one standard deviation) to give a *normalized inclination difference* (measured in standard deviations).

c) Find the mean and standard deviation of all the normalized inclination differences in the overlap interval and interpret the results.

d) Repeat the process for *observed azimuth differences* and *expected azimuth error*.

e) Care shall be taken with azimuth interpolation differences, as azimuths will roll over from 0–360 degrees.

f) This is often a problem with low-angle surveys.

The following should be considered when interpreting the results.

— A large mean normalized error is indicative of a systematic bias in one or both surveys (reference problems, depth shift, sag errors, etc.).

— A large standard deviation is indicative of large random errors or occasional bad survey stations.

4.8.5.14 Inrun-Outrun Comparison

Inrun and outrun survey logs at common depths shall be compared and checked to verify survey agreement to the expectation of the specified error model.

The Inrun-Outrun comparison method is effective for identifying gross errors in azimuth, inclination, depth, and coordinates. However, it is important to acknowledge that this test has certain limitations.

First, the test cannot be easily linked to an error model or to an error model parameter. It is possible to combine individual error terms appropriately according to their correlation and establish azimuth or inclination uncertainty. However, it is not possible from azimuth and inclination errors to establish the magnitude of individual terms.

The test cannot detect systematic errors that affect inrun and outrun data in same manner; for example, a shift in mass unbalance produces an error with the same value on both inrun and outrun data, and both azimuths matching is not a proper QC. Another example of the limitations of the test is if both data sets have the same tool face when trying to detect misalignment errors comparing inrun and outrun inclination data.

In addition, in the case of a continuous survey, because of the drift on the gyros, it is possible that the inrun and outrun data show a large discrepancy. However, it is possible to correct for linear drift, and, depending on the overall survey, a drift corrected survey can be generated. This survey will fulfill the requirements of the continuous error model even though the initial inrun-outrun comparison showed a discrepancy.

4.8.5.15 Multi-Station Analysis (MSA)

MSA may be conducted whenever readings are available from several survey stations and checks have been made to ensure computed error uncertainties are within error model expectations.

4.8.5.16 Accelerometer Bias and Scale Factor Error Detection

A multi-station accelerometer test shall be conducted when xyz accelerometer measurements are available from a number of survey stations from the same tool.

The test provides estimates of the magnitudes of the individual accelerometer errors (bias and scale factor errors) and/or the average resultant sensor error for each accelerometer, while the single-station gravity test evaluates only the lumped effect of all accelerometer errors. The multi-station test is therefore the more powerful of the two, but has the disadvantage that it can only be used after an extended period of drilling. A least squares estimation process can be used for this analysis. The quality of the multi-station test in terms of the number of individual error terms that can be estimated increases with a larger number of survey stations and with increased variation in inclination and tool face. The test is of little or no value for surveys with only small angular variations, such as tangent section and/or constant tool face surveys. In these cases, the test mathematics will be singular, and strange results can be obtained. In such situations, a reduced multi-station test with fewer error parameters should be used. The result of the MSA can be used to determine whether the estimated accelerometer error uncertainties are within the PUM expectations.

4.8.5.17 Gyro Bias, Mass Unbalance, Scale Factor Error Detection

This test shall be used to estimate the systematic errors in the gyro measurements—principally errors that are known to be less stable over time and can therefore vary following factory calibration of the survey tool.

The multi-station gyro test, like the multi-station accelerometer test, is subject to some geometrical limitations—the test being less effective for tangent section and constant tool face survey sections.

A least squares estimation process can be used for this analysis. A general test quality number, the standard deviation of the individual Earth's rate measurements, can be generated as part of this test procedure. This figure can be compared with a tolerance value derived from the PUM file.

4.8.5.18 Well Depth Corrections

The use of a casing collar locator (CCL) is recommended when conveyance methods of wireline or slickline is employed. This allows for adjusting of the well depth to the drillpipe or casing tally and, therefore, the depth uncertainty on the data is the same as MWD systems–based drillpipe length. Depth uncertainty for slickline and wireline are further discussed in 4.8.

4.8.5.19 Multi-Station Correction (MSC)

Prior to performing corrections to survey data, geometrical limitations and correlations shall be verified.

Multi-Station corrected survey data shall pass all station QC tests consistent with the error model expectations.

The parameter values resolved by MSA may be applied to the gyro and the accelerometer measurements; this process is known as MSC. Since the application of MSC reduces the uncertainty of G_{Total} and HER (or total Earth rate and latitude depending on the system type), specific PUMs and tolerance values for MSC data should be used.

4.8.5.20 Continuous Initialization

The standard operating procedure for the continuous survey tool has to incorporate specific criteria for validating initialization and implementing drift corrections in alignment with the PUM expectations.

The validity of all continuous survey data is dependent on these criteria.

Continuous gyro survey readings by their nature inherit all uncertainty present in the reference measurement used for initialization.

This initialization procedure shall be subject to its own validation process, as no QC of the continuous survey data can confirm the validity of the initialization reference.

Common modes of initialization include performing a north-seeking gyrocompass survey and manually referencing the gyro via a sighting scope. The use of a sighting scope for initialization is not recommended due to the increased potential for gross human errors and the fact that it cannot be checked for quality.

If a manual sight reference is the only possible alternative due to the environment, the survey shall be verified and quality checked with an independent method.

The positional uncertainty model assigned to the survey data shall consider the appropriate amount of uncertainty present in the initialization process used for the survey.

After an inrun/outrun continuous survey, the survey sensor should have its final reading at the initialization point compared to the initialization reference initially used for the tool. Disagreement between these two measurements indicates that unmodeled measurement drift has occurred during the survey process. Another initialization measurement should be taken, either gyrocompass or scope sighting, at the end of the run, and that measurement should be compared with the initial initialization point. The discrepancy of the two points should be according to what is allowed by the error model.

4.8.5.21 Drift Correction

Drift correction shall be performed when a valid reference point is available.

The correction and associated uncertainty has to correspond to the error model.

To improve the accuracy of a continuous gyro survey, zero velocity updates (ZVU) may be performed to measure the rate of azimuth drift in the gyro sensor. Some systems also use the gyro for computing the inclination, which adds an extra measure to check. ZVU involves holding the survey tool stationary for a set amount of time and measuring the change in reported orientation. This drift measurement may need to be updated during the survey at set time intervals or once sufficient tool orientation change has occurred. Readings from consecutive drift updates can be used to verify bias stability in the surveying sensors.

The assessment of all drift updates allows for estimation of the accumulated azimuth error. The quality control tolerance for drift shall be associated with the PUM.

A more comprehensive test called a “continuous azimuth drift test” is described in SPE 105558.[10] This test makes use of the inrun and outrun azimuth differences to estimate the gyro linear drift and the gyro random walk; these two parameters are the main error contributors to continuous run errors, and their uncertainty should be linked to the error model. Since this test uses data collected for the whole of a continuous run, it is recommended as final QC for a continuous run. It is of course possible to run ZVUs and continuous azimuth drift tests in conjunction.

4.8.5.22 Misalignment Correction

Misalignment correction shall be applied to the data when it is part of the standard operations procedure and reflected on the error model.

Under certain circumstances, it is possible to estimate certain types of systematic misalignments that are fixed with respect to tool face.

For the case of drop jobs, in which the survey tool lands into the BHA, the orientation of the survey tool might not represent exactly the orientation of the wellbore. This depends on the size of hole, the BHA configuration, and the tool centralization amongst other things. Rotation shots described in Annex C.4.7 can be used to estimate the misalignment based on the changes in inclination according to the tool-face value.

The estimated misalignment can be systematically removed from all the survey data; the uncertainty on the misalignment estimation shall be linked to the error model.

For the case of continuous surveys in which inrun and outrun data are present, it is possible to estimate misalignment based on inclination differences at the same depth. The process is described in SPE 105558.[10]

The uncertainty on the misalignment value shall be linked to the error model uncertainty value.

4.8.5.23 Sag Correction

Sag correction shall be independently verified.

When available, inclination from an independent source shall be compared for gross error detection.

BHA Sag is the misalignment of tool with respect to the wellbore due to deflection of the drill collar housing the survey tool under gravity and borehole curvature. There is no QC available for checking the results of Sag correction calculation. BHA and wellbore information should be checked by independent personnel trained in survey management. The most reliable way of checking sag is through independent survey verification; two surveys with different surveying instruments and running-gear/BHA. It is sometimes possible to QC sag correction if two different sensors are located in different positions in the BHA, i.e., MWD and gyro-MWD.

4.8.5.24 Post-survey Roll Test and Calibration

A correction or new calibration can be applied to the data post run.

All field QC shall pass for this correction to be valid.

Following a survey run, a surveying tool should be verified to ensure that there have been no changes in instrument performance that impact the validity of the survey.

This verification may include repeating the surface wellsite checks and ensuring that there have been no significant shifts in calibration parameters. Shifts in these parameters can indicate failure of the survey to conform to a particular PUM.

Upon return to the service base, this verification should include repeating the service base verifications to ensure that there have been no significant shifts in calibration parameters. Shifts in these parameters can indicate failure of the survey to conform to a particular PUM.

In some cases, if an otherwise unacceptably large shift has been identified, it may be possible to ascertain from raw data acquired during the survey when this change occurred. In such cases, it may be acceptable to reprocess raw survey data using the new calibration parameters to generate a survey in conformance with the relevant PUM.

4.8.5.25 Survey Degradation

MoC procedures shall be followed when a more conservative error model is assigned to survey data due to failures to comply with error model requirements.

The data shall meet the criteria defined in the standard operating procedures associated with the conservative error model.

When a survey is performed with good results but with some parameter(s) failing the QC, it is possible to downgrade the survey and accordingly assign a more pessimistic error model. For example, a multishot survey might fail the tolerance check in random noise; however, the data can be checked against the tolerance of a single-shot PUM. In this case, the survey is not declared a misrun, but as a survey fulfilling the accuracy requirement of a single shot survey.

4.8.6 Well Depth

This report includes the recommended standard practices intended to result in the delivery of consistency and accuracy in reported well depth information, by minimizing inconsistencies associated with well depth measurement systems, and the provision of consistent data reporting standards. The recommended practices are designed to be minimum industry guidelines for operations.

4.8.6.1 General

This document identifies QA-QC standards for the depth measurement systems and recommended practices that include:

- a framework for expressing well objectives based on depth accuracy,
- fit-for-purpose well depth measurements systems standards,
- calibration standards applicable to well depth measurements,
- correction mechanisms that can be applied,
- proposed methods for defining and applying uncertainty calculations, and
- a reporting format that captures pertinent well depth information.

Well depth measurements shall be directed and managed by the data user and the data provider using defined data-delivery specifications and defined operational responsibilities.

4.8.6.2 Role of Well Depth Data

Well depth data shall include a measurement error requirements statement and an uncertainty requirements statement for depth-data suppliers' response.

Different users of well depth data have different requirements, and these requirements for accuracy are provided using different measurement technologies and methods, as suggested in Table 7.

Table 7— Methods of Measurement and Correction Examples

Depth data use	Relevance	Measurement Method	Correction Method	@ 10,000 ft, ±	
				Trueness	Precision
Geological mapping	Major geological events	Seismic	2-way time, depth conversion	100 ft	20 ft
Well construction	Significant reservoir events	Drillpipe, strapped	Indicated depth	50 ft	6 ft
Mechanical service operations	Minor reservoir events	Wireline single wheel	Indicated depth	30 ft	3 ft
Reservoir geometry	Major bed events		Calibrated depth	15 ft	0.5 ft

OWC/GWC mapping	Minor bed events	Wireline dual-wheel	Straight-line Corrected depth	5 ft	0.15 ft
Detailed OWC/GWC mapping Fracture identification/ placement	Minor bed events	Drillpipe, lasered Wireline magnetic marks	Way-point Corrected depth Wired pipe real-time	2 ft	0.15 ft
Pressure gauge depth synchronization	Detailed fluid levels, compaction events	Wireline magnetic marks high precision	Way-point w/ real-time stretch correction	0.5 ft	0.05 ft

4.8.6.3 Well Depth Measurement References

4.8.6.3.1 General

Conformant well depth measurements shall be referenced to a common reference datum that is identifiable to all sources of well depth measurement during well construction and thereafter.

The reference datum shall be surveyed to provide an elevation measurement to a permanent datum that is identified as being relevant to the field and surrounding area.

4.8.6.3.2 Geodetic Reference Datum

Conformant well depth measurements shall be referenced to a recognized geodetic reference datum that is a regionally recognized elevation metadata standard and is relevant to the measurement objectives.

The vertical reference datum reference shall be identifiable to all sources of well depth measurement during well construction and thereafter.

The vertical reference datum shall be identified and provide elevation reference to the WRP that is identified as being relevant to well.

File Structure:

Record #	Record Label	Content	Source	QA/QC
1	Datum	Vertical Datum	Land Surveyor	Well Planner

This record contains the vertical permanent datum. The most common permanent datum used is MSL. This is internationally and regionally defined. (Examples of MSL definitions are EVRS – European Vertical Reference System, NAVD88 – USA, CGVD2013 – Canada, ODN – UK, NAP – Netherlands, AHD – Australia, MSL – Saudi Arabia, NGVD – Malaysia, etc.)

4.8.6.3.3 Well Reference Point (WRP) Datum

Conformant well depth shall include specification of the WRP used to reference the along-hole well depth data.

The WRP shall be linked to the geodetic reference datum.

The WRP is defined typically as where the bit (theoretically) penetrates the surface, but in some cases this may be a theoretical point (soft surface, elevation affected by compaction, etc.). The WRP is defined when the well is first drilled and is maintained as a point in space thereafter based on the geodetic reference system adopted. The WRP datum will include a one (1)-sigma survey error margin relative to the vertical reference datum.

4.8.6.3.4 Depth Point Datum

Well depth shall be measured from the ZDP datum that is linked to the geodetic reference datum either directly or through the WRP.

The identification of the ZDP is required throughout the entire well construction and post-well construction processes

The ZDP datum measurement will include a measurement error margin to the geodetic reference datum.

This specification shall include the time and date of the definition made and the person responsible.

Record #	Record Label	Content	Source	QA/QC
2	Reference	Well Reference	Land Surveyor	M/LWD

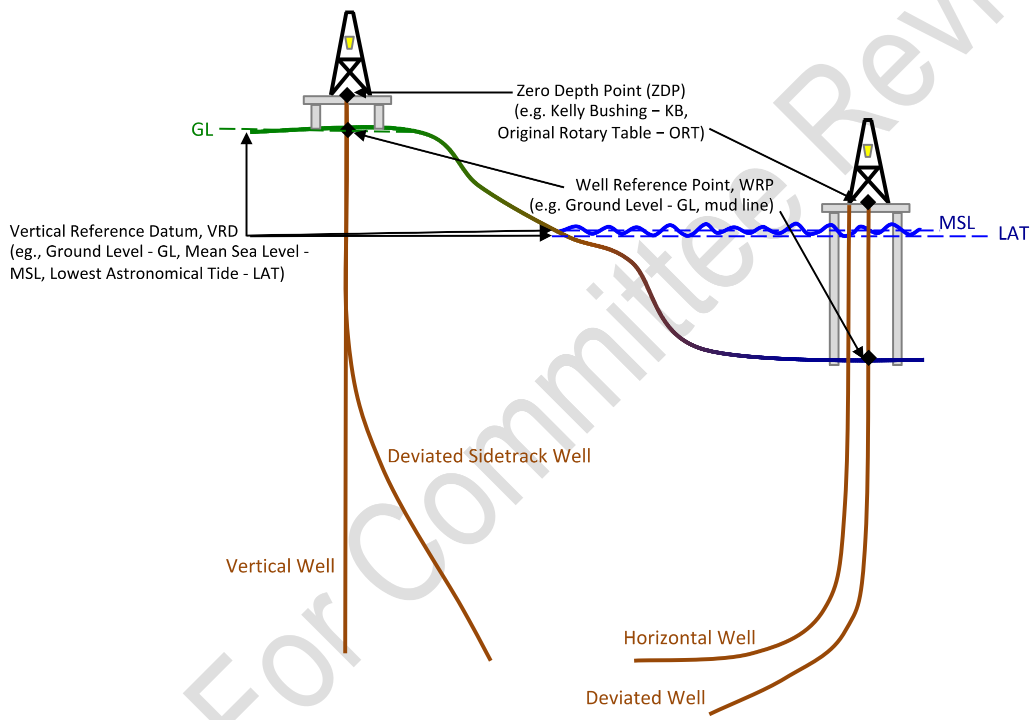


Figure 2—Well Reference and Zero Depth Measurement Points

Examples of reference geodetic reference datum include GL – Ground Level, SF – Sea Floor, LAT – Lowest Astronomical Tide

All well depth measurements shall be uniquely measured from a zero-point identified as the ZDP datum, illustrated in Figure 2.

The Zero Discharge Policy (ZDP) is required to be maintained throughout all stages of well construction, including post-construction workover operations.

The ZDP datum will include a one (1)-sigma survey error margin relative to the Permanent Datum.

4.8.6.3.5 Wave Motion Compensation (WMC)

Conformant well depth measurements subject to heave compensation shall have the amount of heave compensation applied reported.

The WMC movement shall be related to the movement of the ZDP relative to the WRP.

An uncertainty term for the heave compensation movement will be included for true along-hole (TAH) depth determination.

4.8.6.3.6 Well Depth Data Nomenclature

Wells with API conformant well depth will have depth measurements defined as being "Indicated," "Calibrated," "Corrected," or "True Along-hole" (TAH) depth.

4.8.6.4 Current Practices in Well Depth Measurement

4.8.6.4.1 General

Requirements and/or standards for depth measurement accuracy are not commonly provided. The driller's depth is used during well drilling, and M/LWD depths are linked to this depth. Wireline depth may or may not be synchronized to the driller's depth. There are no clear calibration standards or correction routines employed. When depths are synchronized, the amount of shifting, stretching, or compressing of well depth data is rarely recorded. Well depth data uncertainty is not commonly provided.

4.8.6.4.2 Driller's Depth Pipe Measurement

Current practices include the following.

— Driller's depth is the sum of all lengths of pipe measured at the surface.

— The variance in individual driller's pipe length measurements can be significant.

— A drawworks encoder or block position sensor is used to interpolate between drillpipe lengths.

4.8.6.4.3 M/LWD and Mudlogger's Well Depth Measurement

It is general practice that driller's depth is used for M/LWD and mudlogging depth. No corrections are applied, unless specifically directed by the operator.

— Pipe length interpolation is transmitted via Wellsite Information Transfer Specification (WITS) to service providers in a well depth versus time record.

— M/LWD operators assign survey data versus time.

— Downhole tool memory clock-based data shall be adjusted for temperature drift to be synchronized to the surface computer time stamp.

— Mudloggers calculate and add lag time when assigning well depth to samples.

4.8.6.4.4 Sources of Driller's and Mudlogger's Depth Measurement Correction

The following factors represent sources of corrections that can affect the measured length of drillpipe:

— tension and compression,

— temperature for thermal expansion of the drillpipe,

— mud pressure axial pressure effects,

— ballooning effects,

— friction effects,

— buckling,

— drillpipe twist, and/or

— computer-perceived depth changes due to drawworks (DW) cable play misrepresenting movement of the bit.

4.8.6.4.5 Wireline Well Depth Measurement and Correction

The length of wireline cable run into the well determines the well depth of a wireline instrument. This is derived either by measuring at surface discreet calibrated lengths of cable as they pass into the well or by measuring the cable length as it moves through a measure-head equipped with calibrated circumference measure wheel(s).

Either way, the length of cable in the well shall be corrected for a series of environmental and measurement effects, including (but not limited to):

a) tension regime and, hence, stretch regime;

b) temperature;

c) surface pressure—when using pressure control equipment (grease injection or stuffing box type equipment);

d) new cable, where Initial Permanent Deformation (IPD) will occur—special measurement techniques are required to identify and then quantify these effects; and

e) cable torque—this effect can be minimized when using torque-releasing swivels.

4.8.6.5 Recommendations for Well Depth Data Presentation

4.8.6.5.1 General

Well depth data accuracy requirements for the well shall be recognized in terms of the well and operations objectives and data reporting requirements.

These shall be defined by data users, recognizing that different measurement methods deliver different ranges of well depth data accuracy.

a) Well depth data users shall provide their data accuracy requirements to the depth data provider.

b) Well depth data providers shall state on all data files which depth data type is being provided.

c) The drillpipe configuration for each BHA run shall be recorded all the way to surface

d) Both drillpipe and wireline well depth correction methods shall be specified.

e) All correction parameters shall be listed as part of the depth data file.

f) All uncertainty values shall be listed and shown how they were decided upon.

g) When tying one measurement to another, understand the differences in measurements.

h) Calibrated, corrected, and TAH depths shall be used for TVD calculations.

i) Data users should decide which well depth data source is to be used in the reservoir model.

4.8.6.5.2 Well depth measurements shall be presented as one of the following:

a) Indicated Depth,

b) Calibrated Depth,

c) Corrected Depth, or

d) TAH depth.

4.8.6.5.3 Well Depth Quality Measures

Conformant well depth measurements shall be subject to QA and QC.

The QA/QC procedure should encompass the following:

a) establishment of documented processes,

b) comprehensive collection of all factors influencing depth measurements,

c) use of recognized and pertinent calibration methods to calibrate the measurements,

d) implementation of appropriate correction models to account for measurement system and environmental conditions,

e) adoption of uncertainty determination models to determine the associated uncertainty for each measurement,

f) verification of these parameters, and

g) confirmation of adherence to the documented processes.

4.8.6.5.4 Quality Assurance (QA)

The QA systems of the well depth data user and the data provider are equally applicable. The well depth data user is focused on the specifications, definition, and communication of the requirements, and the data provider is focused on the delivery of the data according to the specifications to meet those requirements.

4.8.6.5.5 Quality Control (QC)

4.8.6.5.5.1 General

The well depth data provider QC is important in assuring that the supplied data meets the defined specifications and client requirements.

4.8.6.5.5.2 Activity Audit

API conformant well depth shall provide an audit value associated with depth determination activity.

An audit is required to quantify the integrity of the depth data processes in the organization involved. (Examples of rating and audit processes and criteria are provided in Annex A.)

4.8.6.5.5.3 Well Depth Standard Ownership

The data user shall provide the requirements for the well depth data to be provided.

The well depth data supplier has to satisfy requirements and provide required processes, methods, resources, and personnel to supply data in conformance with recommendations outlined in this document.

4.8.6.5.5.4 Levels of Uncertainty

The operator shall provide a measurement uncertainty specification for well depth data, expressed in terms of the units to be used and commensurate with the data-use expectations for the acquired data.

The well depth data-accuracy requirements are to be stated so that the data provider can equip for the measurements and be assessed accordingly.

4.8.6.5.5.5 Requirements Notification

The operator shall provide well depth data accuracy requirements as part of the technical specifications to the drilling contractor, the M/LWD provider, the wireline contractor, and whoever else is providing well depth data.

These requirements are technical measurement specifications and may be reflected in the contractual conditions. The provision of well depth data is subject to all the normal QA and QC procedures associated with the delivery of a technical specification data product.

4.8.6.5.5.6 Fit-for-purpose Assessment

The well depth data provider is responsible for furnishing the measurement method used, including the measurement principles, calibration procedures, corrections applied, verification procedures, and uncertainty determination—the data provider is not reliant on any particular measurement method.

Additionally, the well depth data provided shall meet the specified level of measurement uncertainty.

This is the fit-for-purpose constraint.

The well depth data shall conform to the stated requirements and provide traceability of the claimed measurement precision, with an audit trail of the data being provided.

The well depth data user requires only a given and specified level of data accuracy and uncertainty and is not a chooser or advocate of any particular method.

4.8.6.5.5.7 Independent Verification

Well depth data verification always includes the “return to surface” zero check, or check at a defined verification point. Other measurement verification opportunities include correlations to other measurements made and should be within the stated measurement uncertainties.

4.8.6.5.5.8 Measurement Discrepancy Management

Both data user and data provider will have procedures in place for handling discrepancies.

4.8.6.6 Well Depth Calibration Standards

4.8.6.6.1 General

Well depth data measurement shall include:

a) a summary of the measurement method used,

b) a description of the calibration standard used, including calibration data for the instrumentation used (including the measurement validity limits),

c) a summary of the corrections applied to the measurement system (if applicable), and

d) the verifications used to validate the measurement.

Additionally, well depth measurement shall incorporate an uncertainty expression of the resulting measurement related to the reference calibration standard.

4.8.6.6.2 Primary Calibration

Conformant well depth and other associated measurements shall be measured using a primary calibration standard related to, or defined by, an internationally recognized standard.

This may be done using the length measurement standard itself, a secondary calibration standard, or a working standard.

4.8.6.6.3 Secondary Calibration

Conformant well depth and other associated measurements, when measured using a secondary calibration standard, shall indicate the relationship to the applicable primary calibration standard and include the uncertainty associated with the secondary calibration standard.

4.8.6.6.4 Working Standards

Conformant well depth and other associated measurements, when measured using a working calibration standard, have to demonstrate the relationship to the applicable primary or secondary Calibration standard and include the associated uncertainty associated with the working calibration standard.

4.8.6.6.5 Uncertainty Determination

Conformant TAH depth data shall include a one (1)-sigma uncertainty term.

Unless otherwise specified, well depth uncertainty should be provided to one (1)-sigma.

4.8.6.7 Well Depth Data Reporting

4.8.6.7.1 General

The database shall store raw depth data for conformant reported depth data. The well depth data used shall be designated as:

a) indicated depth,

b) calibrated depth,

c) corrected depth, or

d) TAH depth.

Raw depth data shall not be edited.

The depth data reporting ought to include the necessary raw data and, depending on the level of detail required, the calibrated, corrected measurements, uncertainties, and verifications to ensure the credibility of the measurements.

Depending on the type of depth data identified, the well depth data reporting shall capture the following items (together with location, date, time, person responsible, equipment and material identifications): see 4.8.4.3.1.3.

4.8.6.7.2 The following data file arrangement suggestions are given in 4.3.1 and Annex B.

a) type of measurement (drillpipe, multiconductor wireline, mono-conductor wireline, slickline, etc.);

b) depth measurement method used (measure wheels only, magnetic marks, pipe length);

c) calibration used and audit trail to standard;

d) calibration date, environmental conditions, and results;

e) corrected depth method used (none, straight line, down log-up log, way-point, modelled tension, etc.);

f) correction parameters used;

g) log of applied corrections;

h) measurement uncertainty parameters used;

i) log of applicable uncertainty;

j) verification points logged and results;

k) return to zero reading and noted difference (for wireline);

l) surface temperature during whole logging trip (for wireline);

m) temperature during magnetic marking of wireline (for wireline if applicable) [31];

n) tension used while magnetically marking the wireline (if applicable);

o) first valid magnetic mark for trip in hole;

p) wireline type and serial number;

q) elastic tension stretch coefficient(s), along with source of value(s) (original equipment manufacturer's specifications, calibration measurement, spooling tension measurement, in-situ hold-up depth [HUD] calculation, magnetic marks measurement, or other);

r) temperature stretch coefficient(s), along with source of value(s);

s) BHA and drillpipe tally, including dimensions and type of metal and strength, along with how (tape measure, laser measurement, or other) and where (pipe rack, vertical, or other) the measurements were performed;

t) strapping device used, serial number;

u) tide height at trip zero;

v) depth adjustment made when engaging heave compensator;

w) active or passive heave compensation used;

x) amount of rig heave throughout trip;

y) line-sag/top-sheave movement check and correction;

z) surface and cable head tension device values, dates, serial number, and calibration audit trail.

4.8.6.7.3 Depth File Record Structure

A well depth file record structure table is a vital component of wellbore surveying and drilling operations, as it provides a detailed record of the depth and location of the borehole at various points during the drilling process. Table 8 provides a general structure table for depth file records.

Table 8—Depth File Record Structure Table

Record #	Record Label	Content	Source	QA/QC
1	Datum	Vertical Datum	Land Surveyor	Well Planner
2	Reference	Well Reference	Land Surveyor	M/LWD
3	Pipe Tally	Pipe Length	Rig	M/LWD
4	BHA	BHA Length	Rig	DD - M/LWD
5	Calibration	Sensor data	Rig	M/LWD
6	Correction	Tally Correction	Rig	M/LWD
7	Re-Calibration	Calibration	Rig	M/LWD

4.8.6.7.4 Well Depth Data Delivery Format

The well depth data delivery includes primarily the vendor-defined well depth, but also additional information such as a reference to, or description of, the method used, the calibration data applicable to the instrumentation, the corrections applied and the associated parameters used, the verification points as were applicable, and the associated uncertainty.

The data provider shall retain on file and have available the raw measured depth data used to derive the delivered AHD measurement.

4.8.6.7.5 Driller's Depth

4.8.6.7.5.1 General

The precise measurement of driller's depth is a critical component of wellbore positioning, which can be categorized as either corrected or uncorrected, utilizing various measurement methodologies. This section outlines general examples and practices aimed at enhancing the precision of what is typically designated as measured depth.

4.8.6.7.5.2 Drillpipe Depth

Driller's Depth is the first depth measurement in a wellbore acquired as the hole is drilled.

Drillpipe depth is measured from the ZDP to the start of running the string in the well (during drilling operations, typically the drill bit). The measured length of each joint of drillpipe and the measured length of the tools that constitute the BHA, the casing, the tubing, or any other additional items, are added to provide a total well depth. The BHA may include MWD/LWD tools, heavy weight pipe sections, drill collars, stabilizers, jars, reamers, several specialized subs, and the bit. All lengths are measured together to obtain the BHA length. Drillpipe depth is provided without measurement or environmental corrections applied.

4.8.6.7.5.3 Bottomhole Assembly (BHA) Tally

A conformant BHA tally shall include the source of the measurement made, the time and date of the measurement made, the person responsible, the measurement conditions (temperature, horizontal [pipe rack] or vertically stacked), and the associated measurement error.

Record #	Record Label	Content	Source	QA/QC
3	BHA	BHA Length	Rig	DD - M/LWD

The record shall contain the date of the measurement, the ambient temperature at the time of measurement, and the method of measurement employed (pipe rack, pipe stand, singles/double/triples, etc.) and identify the person responsible for the measurement, the method of measurement, and the associated measurement accuracy [laser (e.g. +/- 0.005 ft/joint) or tape measure (e.g. +/- 0.02 ft/joint)].

4.8.6.7.5.4 Pipe Tally

A conformant pipe tally shall include the measurement method used, the time and date of the measurement made, the person responsible, the measurement conditions (temperature, horizontal (pipe rack) or vertically stacked) and the associated measurement error.

Record #	Record Label	Content	Source	QA/QC
4	Pipe Tally	Pipe Length	Rig	M/LWD

This record contains the pipe tally as measured by the rig. The record shall contain the date of the measurement, the ambient temperature at the time of measurement, and the method of measurement employed (pipe rack, pipe stand, singles/doubles/triples, etc.) and identify the person responsible for the measurement, the method of measurement, and the associated measurement accuracy [e.g., digitally (e.g., +/- 0.005 ft./joint) or tape measure (e.g., +/- 0.02 ft/joint)].

When pipe lengths are measured and identified against specific pipe element identifications (e.g., serial number), a record of these measurements shall be kept and available. The method of measurement shall be detailed in a written operational procedure.

4.8.6.7.6 Drilling Measurement Methods

4.8.6.7.6.1 General

The drillpipe is measured, or "strapped," by the drilling crew, typically on the pipe rack prior to assembly into the pipe string. Drillpipe may also be measured using laser. Sometimes directional drilling operations transfer some of the pipe measurement responsibility to the directional driller, specifically for measuring the components of the BHA.

Any pipe length calibration shall include the calibration conditions and measurement uncertainty applicable.

4.8.6.7.6.2 Method 1: Manual Pipe Strapping

When the drillpipe arrives on location, joints are unloaded from the trucks or boat and stored in pipe racks. Each piece of pipe is measured with a steel tape measure. The pipe is labeled with a number, and the length is noted on the pipe.

4.8.6.7.6.3 Method 2: Laser Measurement

A digital laser measurement system is often used to measure the individual joints. The digital laser system includes a special stand that positions the instrument at the end of the pipe body, giving an effective shoulder-to-shoulder measurement. The laser measurement systems are typically battery-operated, include a mobile field controller for providing an electronic pipe tally, and can be used at the rigsite, in pipe yards, or in manufacturing facilities.

4.8.6.7.6.4 Method 3: Laser Tape Measuring Device

A laser tape instrument is used to measure the length of the stands as they are made up to the drillstring.

4.8.6.7.6.5 Block Height Calibration

Conformant DW calibration shall provide data on the calibration of the DW, and hence block height, used in depth determination, including the link(s) to the industry calibration standard used, the calibration method, the person responsible, the time and date, the calibration values obtained, and the associated measurement error.

This measurement error is considered to be one (1)-sigma.

Record #	Record Label	Content	Source	QA/QC
5	Calibration	Sensor data	Rig	M/LWD

This record contains the hoisting system calibration. Kelly and top drive rig block height calibration and recalibration frequency recommendations:

a) Kelly Rigs – Geolograph or DW calibration.

b) Top Drive Rigs

   1) Land – DW calibration,

   2) Offshore – DW calibration with or without heave compensator.

c) System shall be recalibrated every time the drill line is slipped and cut.

d) System shall be recalibrated every time the verification measurement difference exceeds a predefined margin. (e.g., 0.5% of stand length to calibrated value).

e) System shall be recalibrated as per the standard operating procedure of the drilling company or its nominated responsible entity.

4.8.6.7.6.6 DW Calibration

A conformant DW Calibration shall provide data on the calibration of the DW used in depth determination, including the link(s) to the industry calibration standard used, the calibration method, the person responsible, the time and date, the calibration values obtained, and the associated measurement error.

Record #	Record Label	Content	Source	QA/QC
6	Calibration	Sensor data	Rig	M/LWD

This record contains the hoisting system calibration. Kelly and top drive rig DW calibration and recalibration frequency recommendations:

a) Kelly Rigs – Geolograph or DW calibration,

b) Top Drive Rigs

   1) Land – DW calibration,

   2) Offshore – DW calibration with or without heave compensator.

c) Block Height Calibration and DW Calibrations are closely related so that they can be combined.

d) System shall be recalibrated every time the drill line is slipped and cut.

e) System shall be recalibrated every time the verification measurement difference exceeds a predefined margin (e.g., 0.5% of stand length to calibrated value).

f) System shall be recalibrated as per the standard operating procedure of the drilling company or its nominated responsible entity.

4.8.6.7.6.7 Driller's Depth Correction

Driller's depth corrections may be used to compensate driller's depth measurements for measurement and environmental divergences from calibration conditions.

All corrections applied shall be reported.

The correction method used, the time and date of the correction, and the person responsible for the correction shall be listed.

The parameters associated with the corrections shall be reported.

The correction value provided shall include an error considered to be one (1)-sigma.

Record #	Record Label	Content	Source	QA/QC
7	Correction	Driller's Depth Correction	Rig	M/LWD

This record contains the applied drillers' depth correction used to return calibrated depth described below:

a) Corrections shall be identified as being measurement or environmental in nature.

b) The correction record shall indicate the rig-state to which the correction is applicable.

c) All corrections require being clearly identified and quantified, with the inclusion of relevant parameters, to determine the applied correction.

d) The correction shall indicate the application method used, i.e., if the correction is a one-off (single-point), straight-line proportional, way-point, or incremental to well depth.

e) The correction data shall indicate the calculated uncertainty per correction made.

f) At the crack of a joint or stand, the pipe tally shall be verified with the system depth (e.g., electronic data recorder or mud logger's computer) and any adjustment made to well depth noted.

4.8.6.7.7 M/LWD Depth

4.8.6.7.7.1 General

There are often two classifications of M/LWD used:

— MWD – Usually refers to directional steering and drilling only tools.

— Logging While Drilling (LWD) – Usually refers to directional plus formation evaluation tools or formation evaluation tools alone.

4.8.6.7.7.2 Measurement While Drilling (MWD)

It has been common practice for MWD operators to rely solely on the driller's depth minus a drillpipe connection "stick up" or connection shoulder at the rotary table/kelly bushing to identify survey well depth. This process is solely dependent on the driller's depth and the accuracy of the driller's pipe tally, with no account for environmental or measurement corrections. In the event of a correction, a simple depth shift is likely used.

4.8.6.7.7.3 Logging While Drilling (LWD)

M/LWD depth is typically based on driller's depth minus the sensor offset. Depth control is fundamental to the success and relevance of the data. The well depth used should be calibrated to the driller's pipe tally and checked (not necessarily adjusted) at each connection, being sure to reconcile tidal variations on floating rigs.

4.8.6.7.7.4 Vertical Depth

Vertical depth is defined as well depth projection to the vertical plane and is calculated based on well depth and directional survey information (specifically, azimuth and inclination).

Vertical depths are described as ViD, VcD, VccD ,or TVtD.

— Vertical Indicated depth (ViD) is vertical depth derived using indicated depth only as the well depth data. The measurement process used is to be stated.

— Vertical Calibrated depth (VcD) is vertical depth derived using only calibrated well depth. The measurement process used, the calibration process, and the associated calibration parameters are to be stated.

— Vertical Corrected depth (VccD) is vertical depth derived using calibrated well depth measurement in conjunction with measurement and environmental corrections. The correction method used and the associated parameters are to be stated.

— True Vertical TAH depth (TVtD) is VccD accompanied with an uncertainty expression for the vertical depth value provided, this in conjunction with the inclination and deviation uncertainties.

4.8.6.7.7.5 Correction Methods

The following recommended practices should be followed:

— The well depth system should be accurately, regularly, and appropriately calibrated/verified.

— Well depth should be diligently monitored and checked regularly.

— Tide should be accounted for on floating installations when deriving M/LWD from driller's depth.

— When discrepancies occur in time-based measurements, the time-depth record shall be appropriately checked and edited as necessary.

— If the recorded time or the time calibration factor is determined to be inaccurate, this may necessitate expansion or compression. This could potentially lead to variations in the perceived depth, which would require adjustments such as displacement, enlargement, or reduction of the derived depth.)

— All edits shall be noted with the associated justifications.

— Doing away with the practice of adjusting counts to catch up; this practice is inappropriate and unacceptable.

— Depth discrepancies can occur between pumps on and pumps off surveys. The axial loads on the drillpipe and tubing are different when the pumps are on because of variances in piston forces, ballooning forces and fluid friction effects. These can cause changes to the effective pipe length and hence the measured versus actual well depth.

— The method of determining and applying the correction is stated.

NOTE When pulling out of hole in simple sliding motion, most of the correction elements that affect drillpipe length are reduced to zero or are nullified, except temperature and pipe tension–induced elastic stretch.

When corrections are applied, it is critical that the source of the corrections, the parameters used to calculate the corrections, and the way in which the corrections are applied, are noted.

4.8.6.7.7.6 Verification

M/LWD well depth values are based on driller's depth and may or may not include corrections.

When using driller's depth, a verification of pipe tally should be made at the end of each hole section. This is usually referred to as "strap out of hole," whereby each joint or stand is measured to confirm pipe/stand/BHA length. Verification should be performed against the original tally to ensure pipe count is true and individual components were not swapped while drilling, potentially identifying sources of systematic error.

When LWD depth uses a combination of driller's depth and corrections, anomalies may arise due to the nature of continuous logging measurements and petrophysical artefacts. Verification of well depth measurement values should be made during each run and while performing repeat logging sections at defined verification points. If discrepancies occur without an acceptable uncertainty range, they should be investigated based on pipe tally and the corrections applied.

4.8.6.7.8 Wireline Depth

4.8.6.7.8.1 General

Wireline depth measurement assumes that, by measuring the wireline length in the wellbore based on tool-zero being defined at the ZDP, the position of the instrumentation and/or tools can be calculated. The HUD is calculated from the well depth reading of the first sensor measure point plus the dead end (first reading sensor offset).

Wireline depth measurement provided shall be defined as follows, dependent on the measurement and correction methods used:

a) indicated depth,

b) calibrated depth,

c) corrected depth,

d) TAH depth.

4.8.6.7.8.2 Line-Length Measurement Methods

Conformant wireline depth shall include a description of the line-length measurement method used.

Also included shall be identification of the measurement equipment used.

The various line-length methods used include:

- single wheel wrap-around,
- single wheel tangential,
- multiple-wheel wrap-around,
- multiple-wheel tangential, and
- calibrated line-length (e.g., magnetic marks, usually measured in conjunction with one- or two-wheel tangential measurement).

The various measurement and correction methods have varying levels of trueness and precision that vary between the companies providing the wireline depth data. Note that the resolution of measure wheel measurements is defined by encoders, measure-wheel diameter, and depth calculation software. The resolution of wireline depth measurement is usually much higher than the pipe lengths being measured.

4.8.6.7.8.3 Calibration

For all except “Indicated depth,” wireline depth shall include the line-length measurement calibration description with measurement results, applicable tolerances, calibration standard used, the uncertainty associated with the calibration, and the time and date of calibration.

The length of the wireline in the wellbore is the quantity being measured. Calibration consists of establishing the relationship between the length of the wireline measured and the industry standard of length.

The calibration procedure shall provide a clear and unequivocal link between the primary standard or a derivative based on the secondary calibration standard.

For field calibrations, the link should be established as part of the calibration procedures on a routine basis, as defined by the procedures defined by the depth data provider.

4.8.6.7.8.4 Wireline Depth Measurement Methods

Wireline depth shall include a description of the depth measurement method used.

There are a number of methods used to define the along-hole line-length depth measurement made, with the most common ones being:

— log-down wireline depth, usually made with wheels-only measurement, and

— log-up wireline depth, usually made with wheels-only measurement or alternatively with magnetic mark–based line length determination.

4.8.6.7.9 Correction Methods

4.8.6.7.9.1 General

For “corrected depth” and “TAH” depth, wireline depth shall include a description of the correction method used and the parameters included in the correction.

Corrections methods are used to overcome measurement and environmental factors.

The reporting process shall provide details on the specific corrections applied and their respective locations, along with the parameters used in the calculation of stated corrections.

4.8.6.7.9.2 Measurement Corrections

Wireline depth measurement corrections may include the following:

— surface slack (line sag) correction,

— wheel-shim correction,

— line diameter correction,

— wheel synchronization (or “fastest-wheel”) correction,

— temperature correction,

— incident angle, and

— IPD correction.

4.8.6.7.9.3 Environmental Corrections

Wireline depth environmental corrections may include the following:

— elastic stretch correction,

— thermal correction,

— buoyancy,

— pressure/compaction, and

— surface pressure.

4.8.6.7.9.4 Correction Methods

The main wireline depth correction methods include the following:

— once-only, including log-down/log-up (also referred to as “delta-stretch”) correction;

- straight-line;
- way-point; or
- increment.

Synchronization of one run to a previous run is not a correction. When synchronized (“tying-in”), the depth type is “indicated depth”.

4.8.6.7.9.5 Verification

Wireline depth shall include a description of the verification(s) of the wireline-length measurement made, the results of the verification, and the acceptable verification tolerances.

The well depth data provider shall provide the following information for any verification point: line-length measurement value, any applied correction and the uncertainty associated with that point, and the acceptable measurement tolerance.

Verification of well depth shall in any case include a return to surface measurement.

The return to surface zero value measured should be within the measurement repeatability and the well depth measured length uncertainty.

4.8.6.7.9.6 Uncertainty

Conformant wireline TAH depth shall include an uncertainty statement of the measurement provided.

Unless otherwise specified by the data user, the uncertainty statement has to account for calibration, measurement correction, and environmental correction uncertainties and be expressed as one (1) sigma.

4.8.6.7.9.7 Other Well Depth Measurements

Wells with well depth measurements conforming to this document will have depth measurements made by nonstandard or service-oriented ancillary measurements defined as being “indicated,” “calibrated,” “corrected,” or “true along-hole” (TAH) depth.

This includes:

- coiled tubing – “indicated depth,”
- slickline – “indicated depth,” and
- tubing-conveyed – “indicated depth,” unless the tubing lengths are calibrated and/or corrected and defined with an uncertainty.

4.8.6.7.9.8 Well Depth Matching and Reconciliation

Conformant well depth shall have options on how to address mismatches between data sets.

When calculated survey information is provided with uncertainty data, three possible well depth cases can exist:

- verified within acceptable limit,
- not verified to within acceptable limits, or
- verified as being outside of acceptable uncertainty limits.

For each of these cases, the data provider and data user shall discuss and develop a course of action appropriate for the well.

4.9 Collision Avoidance

4.9.1 General

4.9.1.1 Collision Avoidance Elements

The eight elements shown in Figure 3 are the component parts required for successful collision avoidance management. Collectively they enforce the minimum allowable separation distance (MASD) requirement.

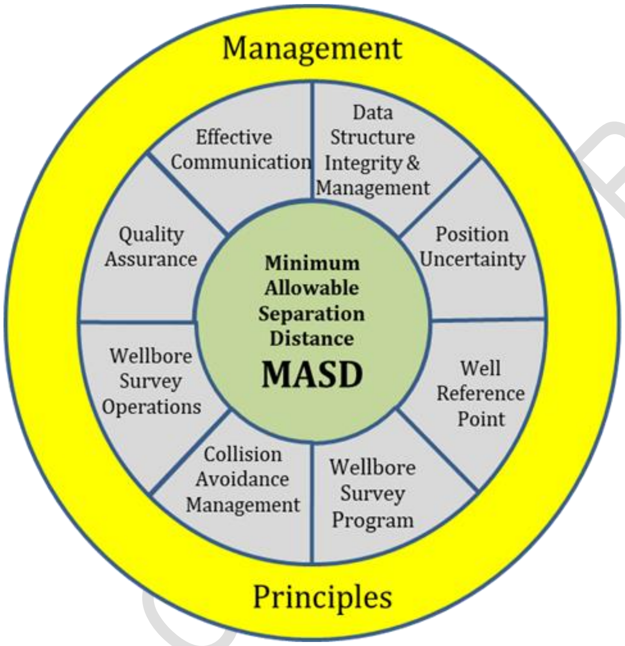


Figure 3— Minimum Allowable Separation Distance (MASD) Collision Avoidance Elements

4.9.1.2 Human factors

For successful collision avoidance management, the following human factors should be recognized and acted on:

a) risk consequences investigated and overestimated when in doubt;

b) training, competence assessment, and audit for people and processes involved in the collision avoidance workflow by both the well's operator and the directional drilling service provider;

c) promotion of a company's STOP WORK authority for use in a potential wellbore collision situation when there are concerns about the safety of an operation;

d) unsafe acts can remain hidden, and design and planning activities can also lead to unsafe conditions.

4.9.2 Data Structure, Integrity, and Management

Processes should be in place to ensure that the directional database, as described in 4.3, is free from errors and remains so as new data are added over the life of the field.

Optimally there should be only one master database, containing all relevant wellbores, including potentially interfering wells from adjacent leases. It should be accompanied by a written plan for its use, maintenance, and disaster recovery for the life of the field. This plan should specify:

a) where the data are stored,

b) who has responsibility for maintaining the content,

c) who has responsibility for the physical management of the database(s),

d) how the data will be secured against potential loss, and

e) how safety-critical software standards [1] are honored.

The plan should specify the global and local CRSs and define how to translate between these two systems. The plan should also define all reporting needed to monitor any well or structure that has been added, edited, or deleted. The master database setup should:

a) manage offset well data integrity,

b) describe all wellpaths that represent potential collisions in a common coordinate system with positions calculated according to the Minimum Curvature Calculation Method (Sawaryn and Thorogood 2005),

c) define a single WRP for each wellpath (see 4.9.2.3),

d) use only operator- and service provider–approved survey PUMs,

e) manage the wellpath plan and actual revisions to ensure that a single planned and a single actual trajectory are clearly identified and defined, and

f) enable sufficiently frequent update of information prior to and during drilling operations.

Offset well selection should go beyond potentially false geographic boundaries assumed to contain wells such as:

a) wells outside some regulatory boundary containing the reference well where a buffer distance to the boundary line may be assumed separate wells, and

b) regulatory boundaries where surface locations or intervals of a reference or offset well may be contained in another regulatory boundary, even where operator or ownership rights are not common to both.

If substantive doubt exists on the potential of a neighboring well to be a collision offset, it should be included in the set of potential offset wells.

4.9.3 Position Uncertainty

All planned and actual surface location and wellpath positions should be assigned valid position uncertainty estimates according to 4.5 and 4.7. The PUMs used to generate such estimates should include all significant error sources and err on the side of conservatism. Similarly, the selection of the most appropriate model from those available should err on the side of conservatism. The directional software should include position uncertainty in a well-to-well clearance scan, applying the calculation methods defined below. Because of the complexity and criticality of the calculations, reliance on manual estimations or calculations should be avoided.

4.9.4 Well Reference Point (WRP)

Well surface location surveys should be referenced to the same datums used for the field setup in the directional database, and a WRP should be established for each well. The WRP is the deepest recoverable point in the well for which coordinates are known without the use of downhole wellbore surveying. The well location should be defined in the appropriate mapping system and converted to local drilling coordinates using the appropriate translation method. Surface locations should be surveyed to an operator-approved accuracy standard and managed to allow updates as better position information becomes available during the well life cycle. The uncertainty associated with the survey method and location should be recorded as part of the well record. Revised surface locations and WRPs should be communicated to all appropriate personnel and data archives. At this time there is no commonly accepted method of addressing changes in location or WRP caused for example by subsidence or regelation in ice flows. Specialist assistance should be sought if either of these situations is encountered.

4.9.5 Wellbore Survey Program

As part of the well planning phase, a surveying program, described in 4.6 and referenced in 5.1, should be defined. This survey program should demonstrably provide sufficient accuracy and reliability to meet the well's directional objectives to a prescribed confidence level. These objectives include:

a) satisfying legislative requirements;

b) avoiding collision with nearby wellbores, structures or hazards;

c) satisfying well control contingency requirements (e.g., facilitate the drilling of relief wells); and

d) achieving the safe intersection of targets (e.g., landing the correct side of a sealing fault).

To ensure that the above objectives are met, survey programs should:

a) be based on the prescribed survey tools with valid PUMs,

b) specify running procedures and QC tests necessary to ensure conformance with positional assumptions, and

c) include sufficient checks, such as survey redundancy, to help identify and eliminate gross error.

4.9.6 Collision Avoidance Management

4.9.6.1 General

Database integrity and adherence to survey programs are prerequisites for successful collision avoidance.

In addition, suitably conservative MASD rules and monitoring procedures shall be established, communicated, and adhered to by all involved.

Collision avoidance procedures shall define how safe separation of wellbores is managed during both the planning and execution of the drilling program.

These management procedures should include categorization of risk and the separation rules applied to each classification. Since wellbore collisions potentially have HSE risk, the procedures should be jointly agreed between the operator and the relevant service provider(s).

Collision avoidance scans, also referred to as AC or proximity scans, should be run against the master database. The planning phase should result in a collision avoidance action program to be followed by both office and rig personnel during the execution phase. Clearance data should be presented to users in usable, meaningful numerical and graphical formats. These presentation formats should help identify appropriate action with ease of correct interpretation.

All personnel involved in wellbore construction activities should be trained in the collision management process and detailed procedures appropriate to their role. The survey program should be executed in accordance with its design. Any changes should be subjected to the appropriate MoC processes.

The directional software application used for wellbore proximity calculations, positional uncertainty models, and workflows using the directional software should be assessed and agreed between operator and service provider beforehand. All software used should be auditable against appropriate safety-critical software standards and software outputs should contain sufficient reference information to enable details of safety-critical calculations and applicable versions, e.g., software engine and build, to be identified.

Collision avoidance management should also include:

a) classification of offset wells in terms of collision consequence;

b) minimum separation criteria per well classification;

c) requirement for collision avoidance scan;

d) design approval prior to drilling;

e) presentation of safe separation tolerances for both planning and execution;

f) verification of position relative to tolerances, including the timeliness of survey updates while drilling;

g) required actions in the event of failure to maintain safe separation;

h) identification of abandoned radioactive sources and other hazards; and

i) retention of the approved scan and associated materials for audit (e.g., workbook format).

4.9.6.2 Management of Change (MOC)

MOC procedures are often cited as the barrier against failure caused by last-minute changes or changes made on the fly, but first the need for MOC has to be recognized, and staff shall know how to manage the change.

When MOC procedures are applied to collision avoidance management involving HSE classified offset wells, the MOC approval process should be independent of drilling operations.

4.9.7 Wellbore Survey Operations

4.9.7.1 General

The survey program defined in the planning phase is designed to meet the well’s directional objectives and should be followed during the drilling phase. Where this proves not to be possible, the exceptions should be managed appropriately to ensure that the directional objectives are achieved. Failure to execute the program means that the objectives may not be met, and if HSE risk offset wells are involved an MOC should be invoked prior to making the changes. It is recommended that wellbore survey operations include at least the following:

a) inclusion of the survey program in the drilling program,

b) adherence to the survey program,

c) conformance with recommended running procedures,

d) application of QC tests designed to validate surveys against positional uncertainty specification,

e) exclusion of failed surveys from the survey log used for calculating wellbore position,

f) the determination and use of the most accurate surveyed position prior to drilling ahead,

g) management of deviations from program to ensure directional objectives are satisfied, and

h) checking for possible unintended sidetracks (e.g., when hole-opening).

4.9.7.2 Surveying Interval

The recommendations in Table 9 for the maximum survey interval are intended only for safe-separation and collision avoidance. They do not address the requirements for routine drilling and meeting other well objectives such as targets. To be valid, all surveys are required to pass the defined QC criteria for the survey tools and positional uncertainty model being used. In general, the survey frequency increases with increasing dogleg severity (DLS) and decreasing separation factor (SF). The intervals may be adjusted for nonstandard tool joints or stands (Double, Triple, Quad, and Range I, II, III) as detailed in API 7G-1 [12]. These intervals may also be extended when there is firmly established and continued divergence of the reference well from all HSE risk classified offset wells.

Table 9—Recommended Maximum Survey Interval (RMSI) for Safe Separation Collision Avoidance

Separation Factor (SF)	Planned Steering Yield or Expected Dogleg Severity (DLS) [°/100 ft MD]		
	DLS ≤ 2°/100 ft DLS ≤ 2°/30m Very Long Radius / Tangent Interval	**2° < DLS ≤ 6°/100 ft 2° < DLS ≤ 6°/30m Long Radius / Steered Interval**	**DLS > 6°/100 ft DLS > 6°/30m Medium Radius / Steered Interval**
SF > 4.0	200 ft (60 m)	100 ft (30 m)	100 ft (30 m)
1.5 < SF ≤ 4.0	140 ft (42 m)		
SF ≤ 1.5			45 ft (14 m) or DP joint length

The information in Table 9 is provided as a general guideline for establishing survey intervals for horizontal, directional, and vertical wells, which should not surpass the minimum regulatory requirements for spacing between surveys. In anticipation of future wellbore additions, it is likewise advised that exploration wells and other self-contained wells conform to these regulations.

Maximum surveying interval (course length) is recommended between the surface (ZDP) and the anticipated intercept, crossing, or closest approach point. After the separation factor surpasses 1.25 and the divergence between the reference well and all offset wells has been firmly established, the survey interval may be lengthened. The minimum separation factor for the proposed well is represented by the separation factors listed in Table 9. These factors shall be implemented throughout the entire wellbore, both before and during the close approach section.

A survey interval of no more than 100 feet is advised for any steered interval of hole. To ensure trajectory trends and BHA directional tendency are recognized, further surveys should be taken at the conclusion of a steered interval. This is because these trends may alter as the well profile, drilling parameters, formation, or BHA wears. Instead of drilling forward and surveying, it is advised to pull back and conduct repeated surveys if a survey reveals unanticipated magnetic interference. In this case, it is advised to use the ladder plot that illustrates the equivalent magnetic field contributed by the nearby wells, which is discussed later in this section.

Long- and medium-radius intervals, such as buildup curve sections, that are consistently steered with a footage ratio (slide-steering or rotary-steering) ≥ 80% steering per stand, do not require surveys every joint. For example, a planned build rate of 10°/100 ft, motor or rotary steerable yield is maintained between 8°/100 ft and 12°/100 ft, resulting in continuous steering for greater than 80% of the stand, 75 ft in a 93-ft stand. In this case directional surveys can be taken every stand. Otherwise, surveys are required at the joint near the end of the steered interval to ensure accurate well placement.

To shorten the survey interval, continuous high-definition MWD or MWT magnetic or earth-rate gyro surveying is suitable. If the wellbore section employing memory surveys is ahead of the close approach interval, stored surveys from downhole tool memory may also be employed to satisfy the RMSI criteria. When used in conjunction with static surveys or in place of actual stationary surveys, memory data should be included prior to the close-approach interval.

The use of synthetic or simulated directional surveys, a technique for adding projected surveys to the survey program while drilling, is an alternative way to adhere to the advised survey interval practice. By looking at steered and non-steered intervals for rotary steerable or steerable motors and using advanced data analytics modeling to construct computer-generated surveys, simulated surveys are included in this scenario.

4.9.8 Survey Quality Assurance (QA)

Procedures such as managed access, periodic audit, and competency assessments are necessary to ensure the integrity of the directional software and database as well as competency of all involved personnel over the life of the field. The QA plan should also define the periodic assessment and audit of drilling and surveying tools and procedures including:

a) software used to prepare directional plans, collision scans, and final survey calculations. Specifically, conformance with safety critical software standards that address all aspects of the software's development, delivery, maintenance, and use throughout its lifecycle,

   1) consistency of algorithms used for the same tasks across different applications with clear definition of any limitations,

   2) availability and consistency of any descendent data set derived from a definitive database. Descendent data is necessary in situations in which a single physical set cannot be established,

b) positional uncertainty models ensuring their claims are justified and that they are appropriate for the survey tools employed,

c) calculation methods employed ensuring they adhere to the prescribed standards,

d) planning and operations personnel training and frequency, and

e) training systems that support the tasks outlined in this document.

4.9.9 Effective Communication

The preceding seven elements fail in the absence of effective communication between those involved in all stages of the planning, execution, and associated administrative processes. Personnel involved in these stages should be clearly defined and engaged in a timely manner. Candidates include, but may not be limited to:

a) sub-surface personnel,

b) drilling/rig, directional, and surveying contractors,

c) drilling, production, and facilities engineering personnel,

d) operations personnel, and

e) environmental, permitting, and regulatory compliance personnel.

Effective communications should take into account at least the following:

a) information complexity,

b) information volume,

c) language, and

d) assimilation learning style and personality diversity.

4.9.10 Well Separation Rule

The separation rule relates to the probability of the reference well crossing into an unacceptable risk region associated with a specified offset well (see Figure 4) and crossing includes a well collision. The possibility of crossing unknowingly is undesirable due to the risk of steering into the offset well while assuming to steer away from it.

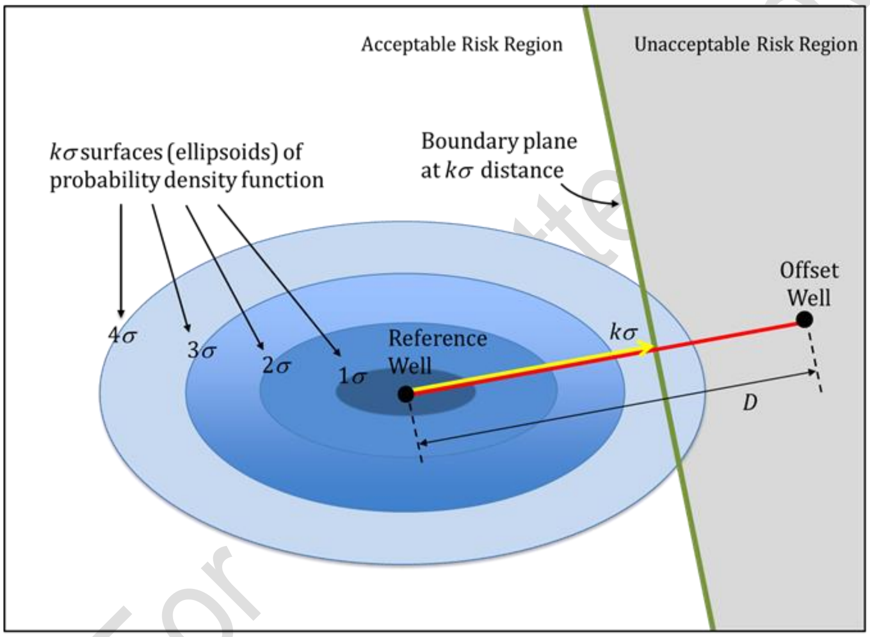


Figure 4—Separation Rule Example Illustration

NOTE In this illustration of the separation rule, the relative uncertainty is assigned to the reference well, and well dimensions have been neglected; the rule defines a boundary denoted by the green line at a distance *kσ* from the reference well, separating space into the unacceptable risk region (shaded) and the acceptable risk. The boundary is a plane in 3D (a straight line in 2D), perpendicular to the line connecting the wells' points of interest.

The separation rule defines a boundary at a distance *kσ* from the reference well, separating space into the unacceptable risk region (shaded) and the acceptable risk region.

The adoption of a particular separation rule, no matter how conservative, does not ensure an acceptably low probability of collision as the factors described in the eight collision avoidance elements shall be addressed.

The separation rule is often expressed as a dimensionless number, a ratio of an adjusted center-to-center distance between wells divided by a function of the relative positional uncertainty between the two. This ratio is referred to as separation factor (*SF*), and customarily the ratio is scaled so that the threshold *SF* = 1 indicates a critical condition. At this point, drilling should cease while the situation is referred to higher authority and scrutiny. The *SF* definition is given by Equation 1, and its parameters are described below.

$$SF = \frac{D - R_r - R_o - S_m}{k\sqrt{\sigma_s^2 + \sigma_{pa}^2}} \tag{1}$$

The term $k\sqrt{\sigma_s^2 + \sigma_{pa}^2}$ is equivalent to the distance from the reference well to the boundary plane shown in Figure 4. Separation factor parameters and descriptions can be found in Table 10.

Table 10—Description of Separation Factor (SF) Equation Parameters

Parameter	Description
D	The distance between a specified point on the centerline of the reference well and the nearest point on the centerline of the offset well. The point on the reference well is specified first. The point on the offset well is identified as the point of closest approach in three-dimensional space or in the plane normal to the reference well when travelling cylinder (TC) diagrams are being used for collision monitoring.
R_r	The openhole radius of the reference borehole.
R_o	The openhole radius of the offset borehole.
S_m	The surface margin term increases the effective radius of the offset well. It accommodates small, unidentified errors and helps overcome one of the geometric limitations of the separation rule, described in the separation rule limitations section of this recommended practice. It also defines the minimum acceptable slot separation during facility design and ensures that the separation rule will prohibit the activity before nominal contact between the reference and offset wells, even if the position uncertainty is zero.
k	The dimensionless scaling factor that determines the probability of well crossing.
σ_{pa}	Quantifies the one standard deviation uncertainty in the projection ahead of the current survey station. Its value is partially correlated with the projection distance, determined as the current survey depth to the bit plus the next survey interval. The magnitude of the actual uncertainty also depends on the planned curvature and the actual BHA performance at the wellbore attitude in the formation being drilled. The project-ahead uncertainty is only an approximation, and although it is predominately oriented normal to the reference well it is mathematically convenient to define σ_{pa} as being the radius of a sphere.
σ_s	Relative uncertainty at one standard deviation between the two points of interest, derived from their respective positional uncertainties σr and σo in the direction of D. Note that $\sigma_s = \sqrt{\sigma_r^2 + \sigma_o^2}$.

4.9.11 Parameter Values

The surface margin value S_m = 0.3 m shall be used.

For HSE risk applications, the value for *k* is 3.5, assuming normally distributed position errors.

The project-ahead uncertainty σ_{pa} = 0.5 m should be used as long as the maximum survey intervals provided in Table 9 are adhered to. If these intervals are not adhered to, the project-ahead uncertainty should be increased as an exponential function of survey interval. While drilling in formations where predicting BHA steering responses is difficult, the project-ahead uncertainty should also be increased.

These parameter values are only valid if the survey data are reliable with no gross errors according to 4.8.

Substituting these parameter values in Equation 1 provides the separation rule applicable to HSE risk wells, Equation 2 (using metric units):

$$SF = \frac{D - R_r - R_o - 0.3}{3.5\sqrt{\sigma_s^2 + 0.25}} \tag{2}$$

4.9.12 Threshold Values

For the separation rule, the threshold *SF* = 1 indicates the critical condition, implying that acceptable well separations require *SF* ≥ 1. Adherence to this critical value is mandatory for HSE risk wells. Further *SF* threshold values may be defined as triggers for other collision avoidance actions.

- The threshold value *SF* = 1.25 should be used in planning as a prompt for a detailed engineering review.
- During execution, the threshold value *SF* = 1.25 should be used to trigger preventive measures and an MOC.
- The value *SF* > 4 should be used during planning to exclude offset wells from further consideration, particularly in circumstances where hundreds of wells are involved.

4.9.13 Crossing Probability

For *k* = 3.5 and normally distributed position errors, the probability of being in the unacceptable risk region of the boundary plane, the crossing probability, at the critical condition, *SF* = 1 is approximately 0.0002 or 1:5000. The probability of a well collision, with actual well-to-well contact is always less than this value, and these two probabilities should not be compared directly with well crossing being the identified unacceptable condition.

4.9.14 Minimum Allowable Separation Distance (MASD)

Well collisions are avoided by maintaining a suitably conservative separation distance from an offset well. This distance is referred to as MASD, and it varies with depth, taking into account the position uncertainties associated with the well trajectories. Offset wells that could represent an HSE risk are subject to the most stringent MASDs. The distance from the plan to the MASD is termed the allowable deviation from the plan (ADP), although in practice the ADP may be further restricted to avoid collision problems deeper in the well.

4.9.15 MASD and ADP

Any given *SF* value represents a specific probability of the reference well crossing the offset well. The distance *D* at which a particular *SF* value occurs is situation specific. For any point on a reference well, the critical value *SF* = 1 defines an MASD from the specified offset well along *D*, Equation 3:

$$D_{MASD} = k\sqrt{\sigma_s^2 + \sigma_{pa}^2} + R_r + R_o + S_m \tag{3}$$

If the distance *D* falls below D_{MASD}, then *SF* < 1. The difference between the planned distance D_{plan} and the D_{MASD} is the allowable deviation from the plan D_{ADP}, Equation 4:

$$D_{ADP} = D_{plan} - D_{MASD} \tag{4}$$

If the actual wellpath deviates from the planned wellpath towards the offset well by more than the *ADP*, then *SF* < 1.

4.9.16 Offset Well Categorization

After performing the MASD calculations and collision analysis, the next step is to assess whether the consequence of a physical collision poses an HSE risk. The most common HSE collision risk is a well control situation resulting from an unintended wellbore collision, but a wider range of HSE collision risks such as abandoned radioactive sources, platform piles, and mines have been identified. To determine whether the well control situation presents an HSE risk, it is necessary to evaluate the reference well and offset well pressures. Calculating the reference well pressure at the point where the breach might occur requires knowledge of the fluid parameters such as mud types (air or mud), weight, and the TVD where the potential intersection occurs. It is also important to assess the consequences of a collision on well control. For example, during drilling, if the reference well pressure is higher than the offset well pressure, it is likely that drilling fluid will flow to the offset well until the pressures are balanced. A sufficiently large volume of drilling fluid should be available to remediate this event.

If drilling is switched to air or other underbalanced methods, then the possibility of an increased risk shall be assessed.

4.9.17 HSE Risk Wells

An offset well is termed an HSE risk well if a collision with it could result in an uncontrolled release of material, such as hydrocarbons or chemical, nuclear, biological, or physical matter, or undermine facilities. The release does not have to be at surface. Subsurface blowouts and seabed discharges may also represent an HSE risk. Some common examples are:

- hydrocarbons at pressures above that in the reference well,
- H_2S (e.g., plugged and abandoned well in a field known to produce H_2S),
- wells under injection (e.g., gas or water),
- radioactive material (e.g., lost-in-hole LWD tool), and
- high-pressure steam (e.g., geothermal well).

Mine workings should be treated as offset wells and working mines treated as HSE risk hazards. For lost-in-hole radioactive sources, the offset well should be classified as being an HSE risk over the well depth interval between the shallowest and deepest possible positions of the sources, allowing for the possibility of the BHA having slipped downhole after being lost and with the addition of at least 100 ft uphole and downhole. Offshore, platform piles should be included in scans to avoid intersecting them or washing away their supporting formations.

4.9.18 Well Pressures

Evaluating the pressure in the offset well may be challenging and should err towards the conservative, high-pressure, value.

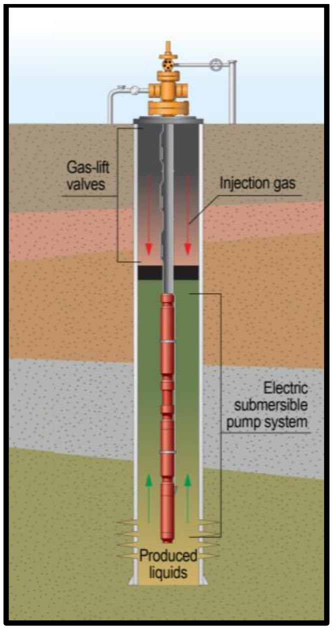
Offset well pressure should consider at least the following:

a) well status such as completion method, production status, any lifting mechanism (injection or artificial lift),

b) reservoir pressure,

c) fluid/gas column pressure, and

d) surface pressure.



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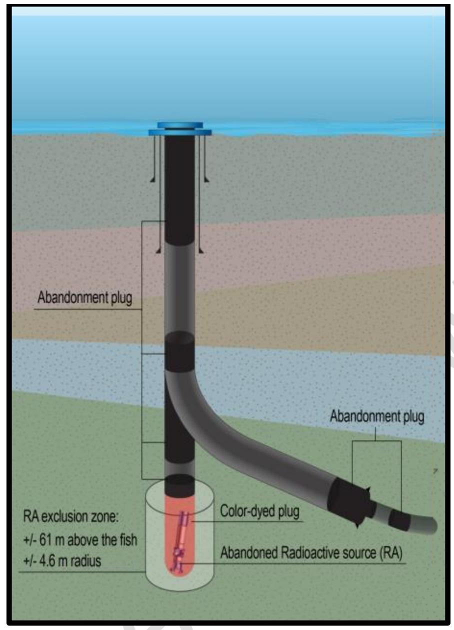

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Figure 5—Illustration for a) offset well environment and b) drilling hazards

4.9.19 Offset Well Categorization Risk Assessment and Temporal Risks

It is recommended that all offset wells are initially categorized as HSE risk offsets and that the assessment be done to assess them as non-HSE. As part of the offset well categorization process, a risk assessment may be needed for assurance that an offset well is non-HSE. In order to assess the impact of a collision on well control, it is critical to evaluate the reference well and a) the offset well environment and pressures, and b) the drilling hazards, during the risk identification process (Figure 5).

The risk assessment should encompass the offset well environment and account for necessary remediation measures in case of a collision, taking into account potential limitations or delays in accessing the offset well.

The risk assessment should also consider the consequences of contact with an offset well, as these may be severe enough to render the offset well inoperable. Additionally, it is necessary to consider the possibility that the HSE risk status may persist for a period of time after a close approach or collision risk has passed. Contact with an offset well may incur HSE risk status even if penetration does not occur, as an offset well's casing may be deformed, resulting in unexpected loss of containment, or it may be further damaged by subsequent drilling and tripping activities prior to setting casing in the reference well. The extent of this type of damage is unpredictable and requires risk assessment in association with offset well categorization.

4.9.20 Non-HSE Risk Wells

Non-HSE risk offset well may include:

a) interruption to the planned operations,

b) lost production,

c) well abandonment challenges, and

d) other challenges such as the loss of wells and slots.

If a non-HSE risk well has an unacceptable collision risk**,** the operator may choose to treat it as if it were an HSE risk offset.

4.9.21 Offset Well Environment

The offset well environment shall be incorporated into any offset well categorization risk assessment and consider the wellbore statuses, completion types, wellbore fluids, and lifting mechanisms shown in Table 11.

Table 4—Categorization of the Offset Wellbore Environment

Offset Well Environment		Description
Wellbore Status	Active	Producer, producing hydrocarbons, steam or chemical
		Injector, injecting fluid to maintain reservoir pressure or gas storage
		Disposal, disposing of solids or fluids by injecting to a formation
	Inactive	Plugged and abandoned, no chemical or radioactive source present
		Cased but not perforated
		Waiting on production, contains pressure or contains no pressure
		Waiting on workover, contains pressure or contains no pressure
		Waiting on abandonment, or temporarily abandoned
		Monitoring/observation wells
Completion Type	Open Hole	Producing from the open hole
	Cased Hole	The well is cased then perforated at the reservoir depth of interest or cased with pre-perforated casing or screens positioned at depth
Wellbore Fluids	Type	Hydrocarbon, oil, gas, or water
	Density	Gas, oil or water or a mix fluid that can dynamically change along the wellbore
	Phase	Single phase or multiphase that could affect the fluid density
Lifting Mechanism	Natural Flow	Flows naturally to surface (consider temporal risks)
	Artificial Lift	Increasing the wellhead pressure or lowering the hydrostatic head in the wellbore

4.9.22 Non-natural Flow

For any offset well categorization risk assessment, non-natural flow, also known as artificial lift, should incorporate the information in Table 12.

Table 5—Influence of Artificial Lift Methods on HSE Risk Assessment

Artificial Lift Method	HSE Risk Assessment
Rod Pump	The consequences of collision with a non-naturally flowing well using a rod or sucker-rod pump may be non-HSE if collision would cause damage to the pump system only.
Progressive Cavity Pump (PCP)	The consequences of collision with a non-naturally flowing well using a PCP may be non-HSE if collision would cause damage to the pump system only.
Hydraulic Pump	The consequences of collision with a non-naturally flowing well using a hydraulic pump may be non-HSE if collision would cause damage to the pump system only.
Gas Lift (GL)	The consequences of collision with a GL well at shallow depth would be an HSE risk. The high-pressure gas injection would be able to displace the mud column of the reference well and therefore result in a well control situation.
Shut In Bled Off (SIBO) GL	In the event of a decision to maintain operations while minimizing HSE risks by shutting down the GL well, it is necessary to safely release the high-pressure injector gas. This release should be done gradually to maintain a manageable low differential pressure and prevent any potential well control issues.
Electric Submersible Pump (ESP)	The consequences of collision with an ESP lifted well at shallower depth could be either HSE or non-HSE. If the collision occurs above the ESP without damaging the electrical cable, the ESP can still operate. This would displace the mud, causing a well control situation. Depending on conditions, it might be possible to reduce the well to a non-HSE risk by shutting down the ESP.
Hybrid Lift System GL and ESP	The consequences of collision with this type of well at a shallower depth will be HSE, similar to a GL type well. At a deeper depth with the ESP, it could be HSE or non-HSE. A detailed assessment needs to be made to determine whether non-HSE conditions can be met by shutting in the gas supply and bleeding off the annulus.
Shut In (SI) GL or ESP	If this GL shut in is not possible, the ESP shall be shut in to maintain non-HSE conditions until drilling ceases.
Hybrid Lift System ESP and Natural Flow	The consequence of collision with this type of well is the same as with natural flow, which could result in HSE risk. To operate under non-HSE conditions, a detailed assessment needs to be made to determine whether it is possible to shut in the ESP only. If it is not possible, non-HSE status can be achieved by setting a downhole plug.

4.9.23 Presentation of Well Separation

Well separation should be available for presentation in at least numeric and graphical forms. Whichever form(s) are used, the presentation should be unambiguous and provided with sufficient reference information to identify parameters and values that have been selected in performing the underlying calculation. The presented information should include at least the following:

a) positional uncertainty model selection,

b) hole sizes,

c) K factor,

d) surface margin, and

e) project ahead uncertainty.

4.9.24 Graphical Representation of Well Separation

The graphical representation of the well separation from the offset wells should be used in both the planning and execution phases. Graphical representations are key devices for depicting the well proximity and tolerances. These plots should be used to support the effective review and approval of the collision avoidance actions in the drilling program. During execution, they should also be used to monitor progress, project ahead, and assess closure between wells. At all stages of both planning and execution, these plots may also be used to aid communications for achieving common situational awareness between all the stakeholders. To satisfy all these requirements, the plots should be simple, consistent, and unambiguous and be the minimum set to achieve the desired goals. Human factors issues, such as color blindness, should also be considered.

Wellbore surveying and collision avoidance plot types can be broadly classified into five categories:

a) Plan view plot displays the wellbore trajectory projected onto a horizontal plane.

b) Profile view plot shows the wellbore trajectory in a vertical profile.

c) Multi-well plot displays the trajectories of multiple wells in the same area.

d) Collision risk plot displays the potential collision risk between two or more wells, based on their respective wellbore trajectories and safety zones.

e) 3D trajectory plot displays the wellbore trajectory in a three-dimensional view.

In addition to these plot types, there are other specialized plot types used in wellbore surveying and collision avoidance, including:

e) Traveling cylinder plot: This plot displays the clearance between the wellbore and a hypothetical cylinder that moves along the well path. The plot can be used to identify potential collision risks and to optimize well spacing and placement.

f) Spider plot: This plot displays the deviation of the wellbore from a reference trajectory, such as a planned well path. The plot can be used to monitor the drilling progress and to identify deviations from the planned trajectory.

g) Varying curvature plot: This plot displays the changes in curvature of the wellbore over a certain interval.

These plot types are all important tools for visualizing and analyzing wellbore trajectory data and for managing collision risks in drilling operations. The specific plot types used may vary depending on the requirements of the drilling operation and the available software and tools.

It is recommended that the north-referenced, normal plane travelling cylinder (TC) diagram be used in conjunction with a ladder plot. The ladder plot should show three-dimensional distances and the expected positional error for each of the offset wells. The ladder plot may also be used to display the depth sections in the plan beyond which the effect of magnetic interference should be negligibly small. In addition, interactive tools, such as a three-dimensional presentation showing either ADP or MASD, may be used to supplement these recommendations.

Note that the distances and tolerances (ADP) shown on the normal plane TCs plot will generally be greater than those reported and shown in the ladder plot for all depths except for points of closest approach of the wells, which are the same.

4.9.25 Travelling Cylinder (TC) Diagram

The north referenced, normal plane TC diagram is recommended for use and remains the simplest method to present complex three-dimensional inter-well tolerances on the allowable position of the borehole trajectory unambiguously. Training is recommended for its use. Due to the potential for near orthogonal crossings to be missed, (Figure 6), the scan should either run down the offset well or use some additional qualifications or refinements to the published algorithm to identify these near crossings.[13] The published algorithm does not detect either a near-orthogonal or end-to-end approach, where the reference well stops short of the offset well. The ladder plot described in the following subsection should also be used for detecting such situations. It is possible to detect a reference well (blue) approaching in a near-orthogonal direction while falling short of the offset well (red) by artificially extending the TD of the reference well (Figure 6).

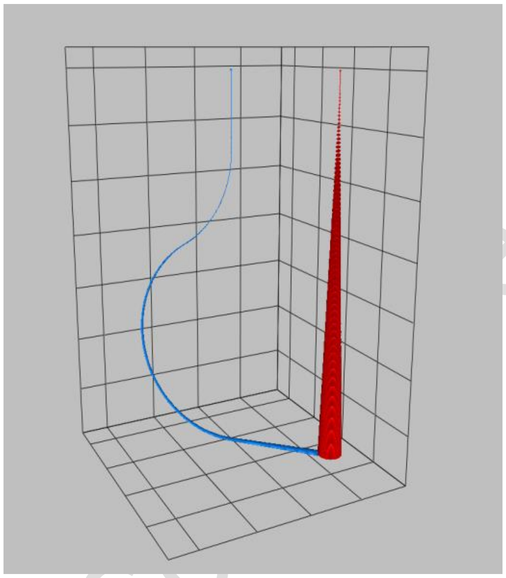


Figure 6—Reference Well and Offset Well Illustration

4.9.26 Ladder Plot

The ladder plot (Figure 7) shows the closest three-dimensional distance from the reference well at the well depth shown on the horizontal axis to each of the offset wells and should be used to identify intervals where collision monitoring is required. For each well, the distance to the well is the line on the upper edge of each ladder, and the lower edge is the allowable separation consistent with the MASD. The example ladder diagram illustrating magnetic interference will be visible in the reference well until an estimated depth of 2,430 feet. Gyro surveys might be appropriate at that depth (Figure 7).

A line showing the approximate zone of expected magnetic interference caused by offset casings may be superimposed on this plot for use producing the survey program to help ensure the directional survey measuring device is appropriate for its environment. Setting the separation distance to greater than 15 ft (Equation 5) is recommended to identify the boundary value for earliest use of magnetic tools. In the vicinity of an offset wellbore's casing shoes, the recommended separation distance should be tripled to 45 ft or more.

$$\left[\sum_{n=1}^{N} \frac{1}{\left|\underline{p}_n - \underline{p}_r\right|^2}\right]^{-\frac{1}{2}} > 50\,ft \tag{5}$$

The ladder plot does not distinguish the direction or orientation in which the MASD occurs. Because of this tool face dependency, during drilling the reference well can go behind a boundary shown on this plot and still be safe.

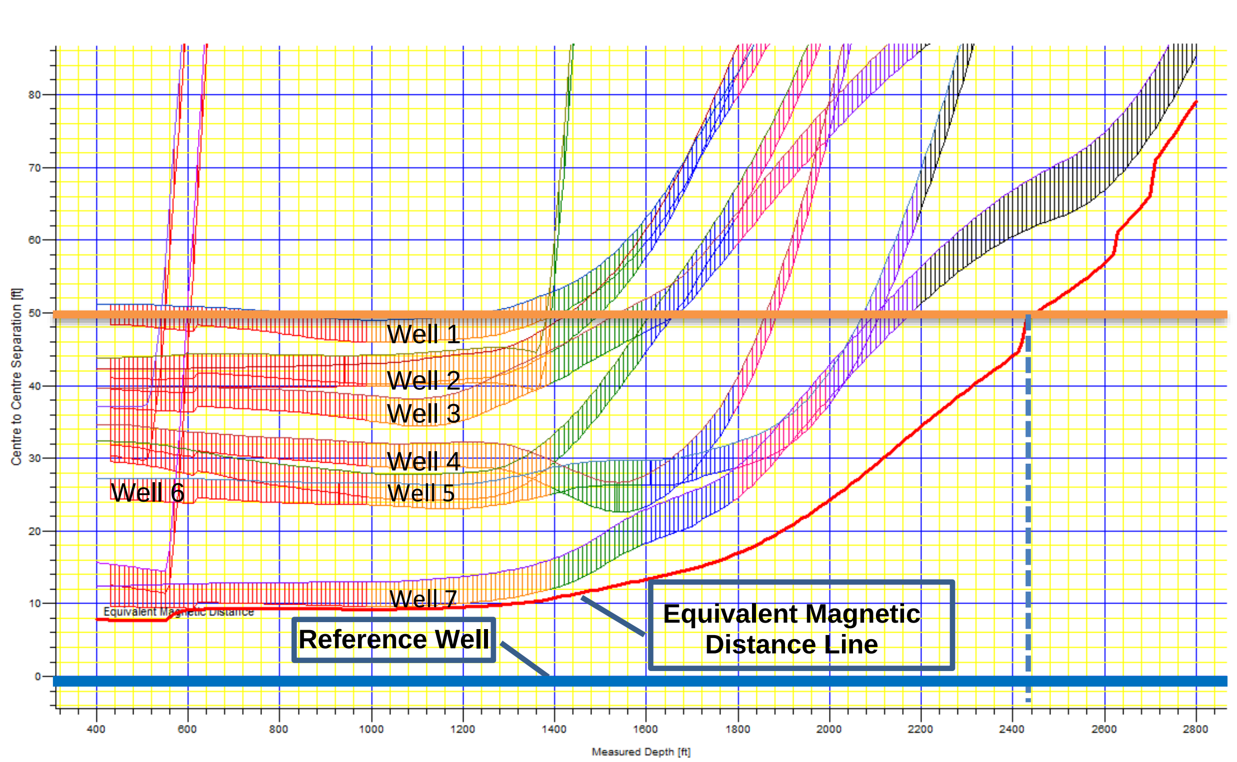


Figure 7—Ladder Plot Illustration

4.9.27 Tolerance Lines

The tolerance lines on a TC plot are envelopes developed from no-go areas drawn around selected depths in offset wells. These lines represent the MASD from the offset well center point at a specified well depth, or range of well depths in the reference well. These tolerance lines make clear the tool face–dependent ADP and should be used by the directional driller when making steering decisions.

At all points in the approved plan there should be space to safely drill and adequate ADP to provide the directional driller some latitude to steer the well. Re-planning of the wellpath is required if there is an unacceptable probability of breaching the tolerance lines when drilling starts. Re-planning is also necessary should the tolerances overlap the central point of the TC plot at any point along the trajectory. To promote clarity, only the minimum number of tolerance lines necessary should be used to communicate the drilling restrictions. This involves identifying the major pinch points in the plan and then adjusting the frequency of any intermediate tolerance lines to match what could reasonably be expected from the BHA performance tendencies.

Throughout, the default meaning of a tolerance line is DO NOT CROSS THIS LINE, and other uses are discouraged. If another use of a tolerance line is deemed necessary, then its purpose should be clearly stated on the plot, differentiating the line's meaning by using a different line style.

4.9.28 Calculation of No-go Areas

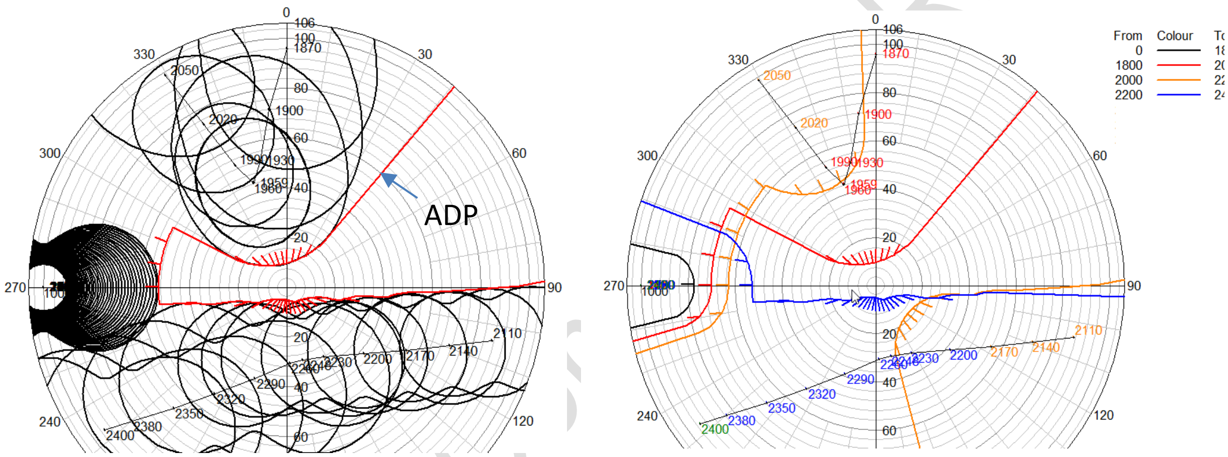
For each offset well at the depth of interest, a vector $\underline{u}$ is generated at radial points in the tool face plane, at an angle β from the 12-o'clock position. The vector $\underline{u}$ can be expressed in terms of the highside and right-side unit vectors.[12] For the north-referenced, normal plane TC plot, set the north reference azimuth ϑ equal to the reference well azimuth ϕ. Otherwise, for highside referenced plots, set $\vartheta = 0$ (Equation 6).

$$\underline{u} = \begin{bmatrix} \cos\theta\cos\phi\cos(\beta-\vartheta) - \sin\phi\sin(\beta-\vartheta) \\ \cos\theta\sin\phi\cos(\beta-\vartheta) + \cos\phi\sin(\beta-\vartheta) \\ -\sin\theta\cos(\beta-\vartheta) \end{bmatrix} \tag{6}$$

If Σ_{NEV} is the covariance matrix for the relative uncertainty between the well centers, the 1σ error in the tool face direction corresponding to $\underline{u}$ is given by Equation 7, (Ledroz et al.[14]).

$$\sigma_s = \sqrt{\underline{u}^T \Sigma_{NEV}\, \underline{u}} \tag{7}$$

Substitution of this value in Equation 3 from 4.9.15 gives the radius of the no-go line or MASD for this direction. The resulting no-go area is contained within a pedal-curve.



a b

Figure 8—Traveling Cylinder Allowable Deviation Plots

The red tolerance line delineates the resultant ADP for the intended well in the depth range of 2000–2400 meters, with respect to the tool face of offset wells 01, 05, and 8 (Figure 8a). The depth ranges from which the resulting ADP was derived are displayed (Figure 8b). At each depth, the nearest of the tolerance lines forms an envelope for ADP and represents the boundary of the no-go area on the TC plot. Figure 8a shows the tolerance line boundaries constructed against three offset wells for depth increments between 2000–2400 m. The figure shows how the plot can quickly become cluttered, making interpretation difficult, so the plot should be simplified by showing a single tolerance line that defines the ADP. Each line should be drawn with a distinctive color or line style, keyed to the applicable depth interval so that it can be distinguished from lines for other depth zones (Figure 8b). Automated calculation of these lines and decluttering may help eliminate human error and are encouraged.

4.9.29 Collision Avoidance Workflows

The collision avoidance elements are applied as part of a systems approach in both the planning and execution workflows, Figure 9 and Figure 10, respectively.

4.9.30 Planning

Referring to Figure 9, the inference of an engineered wellpath in step A is that issues such as target sizing, torque and drag, BHA design, and hydraulics are solved at the same time as the geometric requirements, such as maximum DLS and inclination limits. These requirements are described in 5.1 and are complemented by the collision avoidance planning included here. The flow chart can then be restricted to what is required for collision avoidance analysis.

In step B there are two crucial operations. The first is the selection of all offset wellbores that have the potential to be regarded as collision candidates, while the second is the initial classification of the wellbores into one of two mutually exclusive categories: HSE or non-HSE.

The person responsible for well-planning shall ensure the original set of wellbores from which the offset wells are selected is complete.

For each offset well, the depth ranges of potential intersection should be identified along with the likely consequences of an intersection. If there is any doubt, then the offset well should be classified as HSE risk.

Steps C and D are normally performed simultaneously. These steps are the calculation and analysis stages, identifying those HSE offset wellbores where SF > 1.25 is acceptable and any wellbores where this is not the case.

If SF is less than the threshold value (1.25) for any HSE offset wellbore, then action needs to be taken. The proposed actions to manage ADP are listed in step J. If SF = 1, then ADP is zero.

To have a positive ADP, SF shall be greater than 1.

Multiple actions may be adopted as well as other actions, such as the following:

- re-evaluation of the offset well's classification by choosing to plug and depressurize the offset well below the deepest potential point of intersection,
- use of ranging technology as would be applied to a relief well situation,
- some other conforming action sanctioned by the operator.

If none of the actions described in step J are possible, then the well plan should be abandoned and an alternative plan sought, step L. If all the SF values to the HSE offset wellbores are acceptable, then the tolerance lines showing the ADP are developed in step E based on the SFs. Step F is included to encourage both improvements to the well plan and other actions that may reduce the probability of penetration in the event of a collision. None of the improvements may be permitted to alter any of the conditions or assumptions on which the collision avoidance scan and SF determination were based, step G.

Any changes of this nature shall cause the process to revert to step B.

Once the well plan is ready for execution, the only remaining action is to control and communicate the revision to help ensure that the intended operations are carried out, step H.

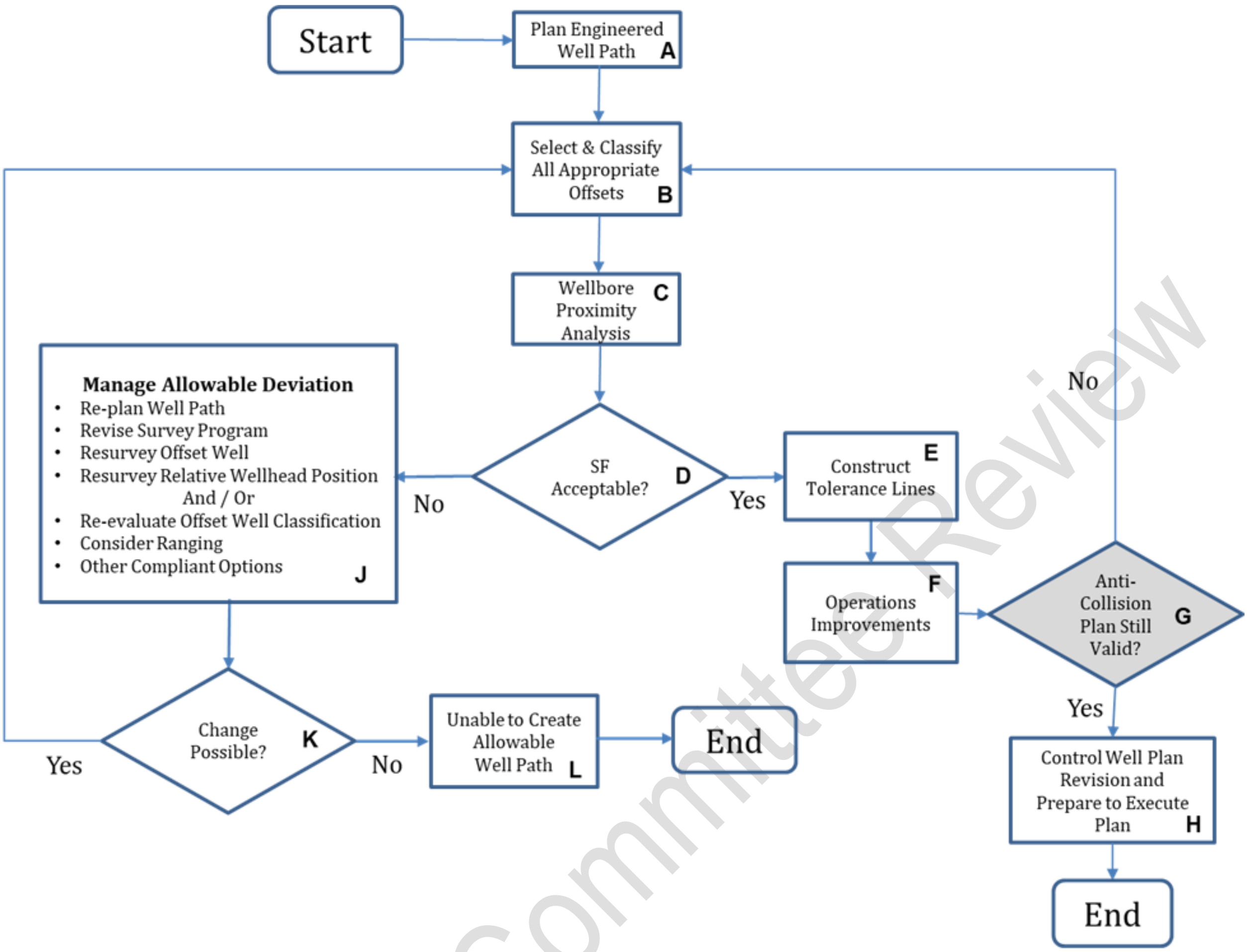


Figure 9—Planning Phase Workflow

4.9.31 Subsurface Safety Valves

If the potential depth of collision is above the subsurface safety valve (SSSV), the valve may be used to shut in an offset well prior to drilling so its status is changed from an HSE risk well to a non-HSE risk well. Some margin of depth error in the possible collision depth should be included.

The well shall then be depressurized, and the wellhead pressure monitored while drilling takes place.

These conditions may be reversed once the reference well has drilled completely clear of the potential collision zone.

These actions shall be clearly stated within the drilling program.

The SSSV should undergo a preliminary test several weeks ahead of drilling, and a plug set in the well if it fails. This may be impractical in some circumstances, such as with subsea wells, and the only remaining option is to replan the reference well.

Control line pressure to the SSSV shall be bled off, as the SSSV may not automatically shut in the event of a collision.

Although the SSSV is a failsafe valve, it is held open by a control line under pressure. The collision may penetrate the well, but it may not damage the control line, which would otherwise automatically close the

SSSV. The SSSV closure then depends on manual activation once the collision is detected, which is neither dependable nor desirable.

4.9.32 Execution

The starting point for the execution workflow (Figure 10) is the successful completion of the planning workflow.

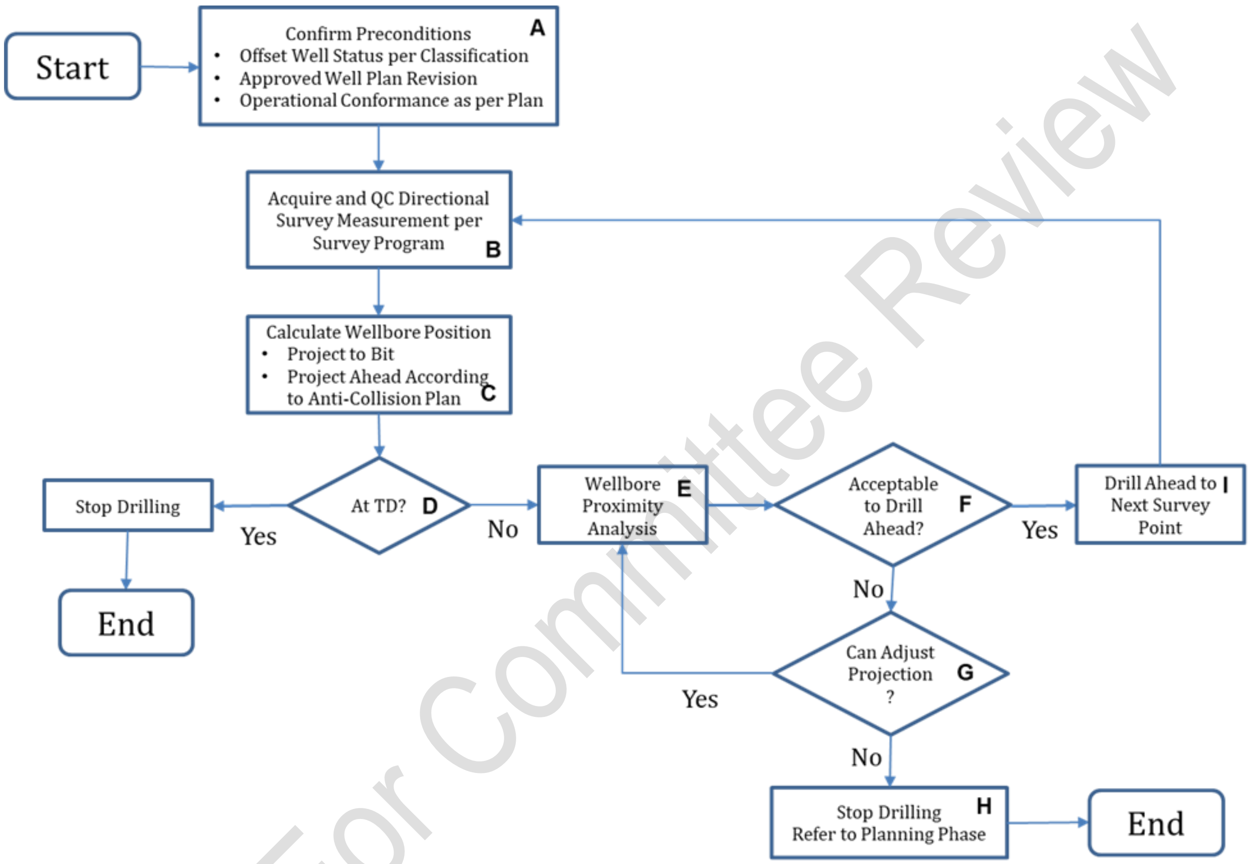


Figure 10—Execution Phase Workflow

Step A requires that all the preconditions are met, confirming that offset wellbores have the status they were assigned in the planning phase, the well plan version is correct and approved, and operations are set to conform to the plan, particularly with respect to the tolerance lines. Operational conformance requires honoring all the conditions set for these and is described more fully in 5.2.

The active collision-monitoring process described here complements 5.3. It starts at step B with the acquisition of a directional survey measurement that passes QC. This measurement is used in step C to calculate the position of the wellbore at the survey sensor and projecting the calculated position, first down to the bit and then farther ahead by a length required by the collision avoidance plan. Drilling stops if TD has been reached, step D.

Step E is the comparison of the measured and projected reference wellpath against the tolerance lines. In step F, operational team determines whether it is safe to drill ahead to the next survey point and that there are no anticipated problems based on the projection ahead.

In step G, if drilling parameters such as WOB or tool face settings need to be modified, the wellbore proximity analysis in step E shall be repeated.

If the well separation factor and risk are acceptable, drilling continues in step I before repeating this cycle from step B.

If the projection ahead indicates that an excursion outside the prescribed tolerance lines cannot be avoided, drilling shall be halted and referred to higher authority and scrutiny, step H.

In these circumstances it is usual to refer to the planning workflow, then either drill to the new well plan or plug back and sidetrack. If either of these options is taken, the MOC process described above should be used.

The flow chart has been constructed assuming that collision monitoring is being performed throughout the process of acquiring directional survey measurements. It is acceptable practice to identify and perform collision monitoring only to the drilling intervals where there is a recognized collision risk. Identifying these intervals should reference the relevant ladder plot. Controls should be put in place to identify situations where the reference well is drilled significantly off-plan such that there may be a latent collision risk. Ideally, the possibility of these gross departures from the plan, such as when drilling in soft formations or when using BHAs with strong walk tendencies, should be identified in the planning process, and limits should be established. If there is any doubt, the default should be to perform collision monitoring.

5 Wellbore Positioning~~—~~Process

5.1 Planning and Engineering

5.1.1 General

This section deals with requirements for both well planning and engineering in preparation for drilling a well. For the purpose of this document a well plan is defined as a continuous line in three-dimensional orthogonal space with a mathematical description, starting from a defined point and ending after intersecting the well's target location(s). It may be described by way of numerical or graphical output. While a well plan is not a requirement for all wells, there should be a well plan if any of the following are true:

a) planned deviation from vertical,

b) target boundaries, or

c) any spatial hazard that has been assessed in the well's vicinity, for example an offset wellbore or a geologic hazard.

5.1.2 Well Planning Process

Well planning may be iterative with changes incorporated to optimize the well's safety, cost, and productivity. The well planning process should include consideration for the purpose and lifecycle of the well so that completion and intervention work may be performed efficiently.

Before designing the well, all reference information needs to be established, and this information needs to be as accurate as possible.

Any changes to the reference information should be recorded in the well plan revision tracking system.

To start the well planning process, there will be reference information, a proposed surface location, and target location(s).

If there are any existing wellbores nearby, their wellbore positions and positional uncertainties shall be included in the well planning process.

This should be done as early in the process as possible.

The offset wellbore information shall be accurately positioned in relation to the well plan's reference information.

Other nearby and valid well plans should be incorporated into this well planning process. If the well plan is a sidetrack of an existing wellbore, the definitive wellbore position of the parent wellbore should be available to accurately define the sidetrack location. The sidetrack well plan's tie-point may be defined as an actual survey point, an well depth interpolation between two directional survey measurements, or a projection ahead of a directional survey measurement to the planned well depth in the expected orientation of the parent wellbore.

The well plan geometry will be dependent on many factors, including:

- target location relative to surface location and size,
- directional drilling tool capability,
- directional survey measurement requirements and tool capabilities,
- offset wellbore collision avoidance,
- well intervention and completion requirements, such as conveyance of wireline tools and pump placement,
- geologic expectations such as formation drilling ability, formation dip, faulting, lost circulation zones, over-pressure zones, and water flows,
- casing design and hole size, and
- coring requirements.

The well planning should also take into account anything that may restrict well placement, such as:

a) subsurface objects in the vicinity of the well plan, such as:
   1) salt mines,
   2) coal mines, and
   3) tie-down piles.
b) lease boundaries;
c) surface land restrictions, such as:
   1) pad layout,
   2) surface structures, and
   3) pipelines;
d) shallow hazards, such as shallow gas; and
e) subsea infrastructure, such as:
   1) pipelines,
   2) manifolds,

3) templates, and
4) flowlines.

As relevant, these restrictions should be incorporated into the well planning process at the earliest opportunity.

The well plan should accurately reflect the intended method of drilling and be compatible with its associated survey program. The well plan is expected to incorporate straight-line tangents separated by constant radius/fixed DLS curves. The default method for connecting points on a well plan is minimum curvature; however, radius of curvature should be used for azimuth turns with a constant inclination (flat turn), as minimum curvature will drop inclination between the start and end of the curve. This effect is only significant at higher inclination and longer intervals.

Well planning will normally be performed using a software application with adequate functionality and approved for use by at least the directional drilling contractor. Further specification of software requirements can be found in the software section.

5.1.3 Approval

Prior to commencing drilling operations on the planned well, the directional drilling contractor and the well's operator should both approve the primary well plan to signify that this plan has been reviewed, is considered achievable, meets the wellbore's positioning objectives, and is the well plan that is intended to be drilled. Well plan approval should involve parties with appropriate levels of authority for all aspects of the plan. The date of approval should also be recorded. Any subsequent revision to the primary plan should also be approved, indicating that it is now the primary well plan, and distributed to the planning and execution teams.

5.1.4 Well Plan Revisions

To help control the well plan selected for engineering calculations and execution, there should be a process that uniquely identifies each version. It is common practice for several well plans to be developed before selection of a single, definitive well plan for execution. Well plan deliverables such as reports, plots, and transfer files should include a reference to this unique well plan version identifier. The unique identification for these individual well plans should be explicit, clear, concise, and able to be catalogued. For more explanation, please review 5.3.

Well plans are revised at the discretion of the plan owner. Changes in versions, or revisions, to the well plan should result from changes to any of the following:

- target location, boundary, or target inclusion / deletion,
- surface, sidetrack, or starting location,
- geometric description of the well plan such as changes to DLS, location of curves or tangents, and deepening or shortening, and
- reference information such as starting point elevation relative to a global vertical reference or azimuth north reference.

Changes in version may also result from changes to any of the following:

- hole sizes and depths,
- survey program, including changes affecting target sizing,
- associated geologic information, such as formation top depths,
- casing program, and

— declination or convergence.

It is recommended that there be a system for tracking the status of well plan revisions to identify a definitive, or primary, well plan and record changes made between each successive well plan revision to help ensure proposed changes have been made. More details can be found in section 4.9.32.

5.1.5 Identification of Well Plan Revision in Engineering Calculations

An explicit and unique well plan revision identifier should be included on associated engineering calculations, especially those that are dependent on the wellbore geometry such as:

a) torque and drag analysis,

b) BHA vibration and directional behavior analysis,

c) BHA design, especially nonmagnetic spacing calculations, and

d) casing design.

5.1.6 Discrepancy Between Planned and Actual Surface Locations

The well plan should reference the well's actual surface location, but there may be exceptions.

In these circumstances, the actual and planned surface locations shall be clearly identified and used for their intended purposes.

All reports containing actual or planned wellbore data require a common datum as a reference and local coordinates to clearly identify which location is being reported.

Alternatively, if a single "well reference" is to be used then the plan shall be retied to the actual wellbore location, revised as required, and reissued.

If a surface location other than the planned one is used, it is necessary to conduct a thorough review of the collision avoidance calculations pertaining to the established well plan. This review aims to ensure accurate identification and effective management of all potential wellbore collision risks.

The approved plan shall incorporate known potential discrepancies between actual and intended surface location and pre-set an acceptable tolerance.

The actual surface location shall be measured, and information shall be disseminated in a timely manner so that subsequent wellbore positioning activities can be conducted safely.

A typical example is a mobile offshore drilling unit (MODU) used to spud a well close to, but distinct from, the planned surface location due to tolerance in positioning the MODU. There will be situations in which a reworked plan retied to the actual location is not desired, and the approved plan with the planned surface location may continue to be used. Typically, the plan will be unchanged when there are detailed AC planning materials that would need rework during a critical drilling phase.

5.1.7 Changes to the Well Plan Revision While Drilling

The wellpath may deviate from the well plan, and such deviations are permissible.

Projections are normally created during the execution phase as ad hoc well plans. Examples of recommended situations for revising the well plan include the following:

a) a projection best represents the intended wellpath position for the remaining interval and requires well modification for an interval with curvature outside the tolerance limit, or cumulative curvature that will negatively impact future drilling ability,

b) collision avoidance actions for the projection indicates unacceptable risk is worse than desired in the approved well plan,

c) the projected wellpath does not achieve one or more of the well plan's objectives, and

d) there are changes to well plan reference information such as a revised RKB elevation.

Further discussion of projections can be found in the execution phase in 4.9.32.

Both sidetracking an existing wellbore and bypass operations shall require a well plan revision.

5.1.8 Collision Avoidance Planning Process

Collision avoidance planning happens simultaneously with the creation of the initial well plan and all following revisions. Workflow diagrams have been created in the Well-Collision-Avoidance Separation Rule peer approved SPE paper for both predrill planning and active drilling plan revisions. These workflow diagrams can facilitate proper planning protocols through the collision avoidance process. However, the diagrams are generic, so the owner of the well is responsible for details needed to calculate the SF, well scan radius, and survey confidence level. Be aware of regulatory requirements and responsibilities for maintaining and supplying offset wellbore data to add to the directional database. Responsibilities for maintenance and validation of the directional planning database should be clearly defined.

The following general process and guidelines are aligned with the diagrams and shall be followed.

a) Create initial well plan: define survey program and apply proper tool PUM(s).

b) Scan along the wellpath to detect problematic wellbores: the scanning radius along the wellpath should be a minimum of 1,000 ft (305 m).

c) Review data for offset wellbores that are found on the scan:

   1) Categorize offset wellbores as either HSE risk or non-HSE risk.

   2) Apply proper tool PUMs for data discovered for offset wellbores.

d) Run an anti-collision (AC) report for the subject well; include all wellbores that were returned in the scan.

e) Analyze the AC report; flag wellbores that fall below the predetermined collision avoidance criteria.

f) Use techniques to reduce risk of collision such as:

   1) resurveying offset wellbores, and

   2) improving surveying program for subject well.

g) Rerun AC report.

h) Repeat process until a satisfactory result is achieved.

i) For each offset wellbore that continues to fall below the predetermined criteria:

   1) a full risk assessment carried out by a competent authorized team may determine potential HSE consequences following from a collision and breach of the offset wellbore, and

   2) and where the assessment determines there are no HSE consequences, it may be permissible to fully document mitigations and limitations that are to be followed to exempt the offset wellbore from the criteria (established AC rules).

5.1.8.1 For active drilling wells, the process follows a similar path in which every plan revision that is created shall pass all AC requirements and be accompanied by an AC report.

5.1.8.2 The steps below shall be used as a guide:

a) Create plan revision to achieve geologic or drilling goal.

b) Run AC report for the plan revision including all wells in the initial well scan.

c) If needed revise the well plan to comply with collision avoidance practices.

d) Rerun AC report and repeat previous step until conforming.

e) Attach AC report with well plan revision.

5.1.8.3 Sidetrack wellbores, in the context of collision avoidance, will be treated as new wells and therefore shall follow the predrill guidelines for the initial sidetrack well plan.

5.1.8.4 When working through iterations of a well plan, it is prudent once a well plan is accepted to calculate collision risk associated with the edges of the drilling window associated with the well plan. These may be included in the AC report as a comprehensive view of the overall risk associated with the well plan.

5.1.9 Reference Information

Reference information associated with a well plan includes:

— surface location: vertical (depth/elevation) and horizontal coordinates relative to both global and local frames of reference,

— geodetic CRS,

— azimuth north reference, and

— global vertical reference.

The surface location horizontal and vertical reference points shall be designated with specific names, such as "Slot #1 (plan)" for the horizontal reference point and "RT" for the vertical reference point at the rotary table.

The surface location shall have a defined CRS, which is represented as both latitude and longitude, as well as grid coordinates that are consistent with the stated CRS.

The surface location should also be expressed in local coordinates relative to the WRP or another nearby, fixed point (e.g., slot coordinates that are referenced to platform center). Well depth and vertical depth should have a fixed, tangible reference point that can be described relative to a geodetic vertical reference for the duration of drilling. Examples of geodetic vertical reference points include:

— MSL,

— LAT, and

— ground level (GL),

Vertical reference format examples are typically defined as “RT at xxft above GL” and “RT at xxm above LAT”.

Azimuth north reference should either be true north or grid north.

If grid north is used, its orientation and convergence values shall be consistent with the location information's CRS.

For well plans the reference information should conform to regionally accepted practices for well location and should be consistent with the well operator's and directional drilling service provider's reference information standards.

The surface location should be defined as early in the planning process as possible to facilitate anticollision analysis, identify any legal/regulatory issues, and allow calculation of the magnetic environment for wellbore surveying purposes.

If a geomagnetic model is used to calculate declination, it should also be clearly identified and valid for the proposed date of drilling.

All associated reference information should be available when the well plan is reviewed.

5.1.10 Lease Boundaries Requirements

The volume in which an operator has authorization to drill is labeled here as a lease for ease of reference and irrespective of the ownership arrangement.

The producing section of the planned wellpath shall remain inside any lease boundary constraints, considering an appropriate level of wellbore position uncertainty.

Where regulation allows a well to be in contact with a lease boundary or include portions that are outside of the operator's authorized drilling volume, the set of offset wellbores should include an adequate subset of wells in the neighboring lease.

5.1.11 Targets and Target Sizing

A well plan's target(s) should include an appropriate allowance for both deviation from the planned wellpath and wellbore position uncertainty, since it may be prohibitively expensive to intersect exactly at a single point. Usually, geologic boundary tolerances are assigned to the target point such that the actual wellbore location can be anywhere within these and still meet the wellpath objectives. These boundary constraints on a target point will be referred to as the geologic target. During the well-planning process, both the surface location positional uncertainty and the wellbore's positional uncertainty at the time of intersecting the target should be used with the geologic boundary to define a more restrictive driller's target boundary, as described in Annex A. The wellbore's positional uncertainty depends on the survey program, described in the survey program tolerance, and should be used to calculate the driller's target's reduction from the geologic target boundary. The calculated wellbore position should intersect this driller's target boundary, outlined in the execution phase, during well execution. If the calculated positional uncertainty exceeds the target's dimension, it is recommended that either the target's geologic boundaries be reassessed or the survey program be revised to sufficiently decrease the well's positional uncertainty, as insufficient guarantee can be made of the wellpath intersecting the target even if the reported position is exactly centered within the geologic target boundaries.

When performing the driller's target calculations, a confidence level should be used commensurate with the operator's risk tolerance for not intersecting the well's intended location. Table 13 outlines the probabilities of intersection associated with different dimensions of target boundary constraint and positional uncertainty confidence level.

Table 6—Probabilities of Intersection

Confidence Level	1 Dimension	2 Dimensions	3 Dimensions
1 sigma	68.2 %	39 %	20 %

2 sigma	95.4 %	86 %	74 %
3 sigma	99.7 %	99 %	97 %

5.1.12 Engineering Calculations Associated with Well Planning

While many engineering calculations have a dependency on the wellbore's trajectory and may influence the overall well design, the engineering calculations identified here are limited to only those that may be considered directly necessary to achieve the wellbore's trajectory. These calculations will both affect and be affected by the geometry of the wellbore.

These calculations should include some assessment of the following:

a) measurability of the wellbore's position, including:

    1) survey program (see 4.6), and

    2) nonmagnetic spacing requirements;

b) ability to drill the wellbore, including:

    1) BHA program,

    2) torque and drag, and

    3) hydraulics; and

c) logging, casing, and completion, including:

    1) casing program,

    2) completion program, and

    3) logging/intervention program.

5.1.13 Nonmagnetic Spacing Requirements

The BHA used for directional survey measurements relying on earth's magnetic field has to have sufficient nonmagnetic material to meet the PUM specification.

The preferred calculation method is provided within the survey math section. Reducing the length of nonmagnetic material in the BHA will degrade the measuring device performance, which is acceptable if the positional uncertainty model accounts for this degradation. Use of the axial magnetic correction algorithm is acceptable when matched with the appropriate positional uncertainty model and applied within the range of orientations where this correction is valid as described in Annex A. The axial magnetic correction should not be used if the sensors are placed within 3 ft (1 m) of ferrous material, as the magnetic field's perturbation is less likely to lie along the borehole axis of the BHA. Sufficient nonmagnetic material is also required to avoid saturating the magnetometer, which would make the measurement invalid.

5.1.14 BHA Program

The BHA program should be matched to the well plan because it needs to be capable of both creating the planned DLS and drilling the wellbore given its range of attitudes. The BHA program is described in more detail in 4.9.32.

5.1.15 Torque and Drag

Since torque and drag values are also affected by the well's trajectory, consideration should be given during well-planning to designing a wellpath that is compatible with the following:

a) rotation of drillstring even at the deepest planned well depth,

b) lifting and lowering the drillstring from and to the deepest planned well depth,

c) sufficient drillstring load capacity for adequate drilling progress, and

d) both drilling and completions requirements.

5.1.16 Hydraulics

For deviated wellbores, hole cleaning may become a concern and, along with having the capacity for sufficient flow rate at each section, TD should be analyzed as part of the well-planning process.

5.1.17 Casing and Completions Programs

Both the casing and completions programs may impose restrictions on the well plan in addition to requirements for placing these programs in the wellbore listed as part of the hydraulics and torque and drag engineering. Other considerations that should be considered as part of the well-planning process include the following:

a) inclination limits for gravity deployment of logging and well intervention tools;

b) wellbore tangent for equipment placement, such as a downhole pump or casing shoe;

c) curvature or inclination restrictions, for example to reduce rod wear or for borehole drainage;

d) off-bottom casing set and inside cement/float collar requirements with respect to survey and survey program.

5.1.18 Multiwell Site Orientation

If a multiwell development has identifiable wellhead locations/slots, then the slot to be used shall be identified as part of the well plan's description. Additional considerations should be included in the well planning process when the well plan originates from a multiwell site, such as:

a) subsea template,

b) cluster of individual wellheads sharing infrastructure,

c) land pad, and

d) offshore platform.

There should also be a recorded slot to target allocation that assigns wellhead locations to well plans. These well plans should be sufficient in detail to ensure drilling from that slot remains viable considering collision avoidance requirements.

The slot to target allocation should take into account at least the following:

a) distance and direction from slot to target,

b) maximum planned DLS required to intersect target(s),

c) drilling sequence,

d) collision avoidance requirements and need for well separation, and

e) survey program and well separation required for accurate magnetic measurements.

This slot to target allocation should be periodically updated to remain current with the drilling requirements.

In determining a multiwell site's location and layout, many factors need to be considered. From a wellbore positioning perspective, these factors should include reducing the total:

a) collision risk,

b) well length, and

c) geometric tortuosity.

In planning the layout of the site, consideration and priority should be given to the requirements of wellbore positioning and directional drilling operations to enable these to proceed safely and efficiently.

5.1.19 Relief Well Requirements

The relief well plan may incorporate both trajectory and well kill recommendations; however, only the wellbore positioning requirements are included here. Any relief well plan should be capable of being executed to achieving its intended purpose. A relief well plan should be prepared at the same time as the drilling plan when either there is a regulatory requirement or the well plan is assessed by the operator as having exceeded some risk tolerance for requiring a relief well plan. A risk assessment at the very least should consider:

a) the well's location and supporting infrastructure,

b) drilling complexity,

c) well productivity and reservoir pressure, and

d) wellbore collision risk.

Identified potential surface location(s) for a relief well plan should take into account surface location restrictions such as:

a) subsurface shallow hazards,

b) water currents and direction,

c) prevailing wind direction,

d) seasonal constraints,

e) predicted plume dispersal,

f) blowout's potential crater's radius growth rate,

g) heat radiation from blowing well, and

h) blowing well's predicted noise profile.

Relief well-plan should be achievable, considering at least the following:

a) directional drilling tools to be used,

b) potential requirement for sidetracking to achieve a close approach,

c) available drilling rig capability, and

d) ranging and intersection interval requirements described according to ISCWSA—Well Intercept Sub-committee eBook[15]

The number of required achievable well plans should be based on the blowing well's anticipated flow rate and pump rate required to kill the blowing well and may be based on the difficulty in drilling to the close approach interval.

The relief well plan's ranging and intersection interval should be designed for:

a) location of close approach and intersection,

b) requirements of ranging method being used for finding and tracking blowing well, and

c) intersection method.

It is recommended that the relief well plan incorporate an interval of close proximity as contingency against not finding the blowing well in its described location.

Examples of execution issues that shall be addressed in the relief well plan include:

a) intersection above the deepest casing shoe on the blowing well,

b) use of ranging to help ensure drilling progress despite potential for unintended collision,

c) maximum inclination for wireline deployed ranging tools, and

d) low incidence angle at close approach.

Beyond the depth anticipated for locating the blowing well, the relief well plan should maintain a distance and incidence angle to the blowing well such that the blowing well is continually within range of the relief well.

5.1.20 Outputs

Outputs from the well planning process should include either or both numeric and graphic trajectory description, wellbore proximity analysis, and data in a transfer format to create multiple copies of the well plan and its associated offset wellbores for the purpose of collision monitoring.

Outputs shall conform to the well plan revision identification described above.

Specification of outputs should be determined by requirements of the associated engineering and operations personnel and should include:

a) surface location tolerance,

b) well plan deviation tolerance with depth variances,

c) DLS restrictions/tolerance and reasoning,

d) survey program contingencies and reasoning, and

e) offset well list containing (can also be found in AC report):

   1) status of each well, and

   2) well depth of close approach for each well.

Outputs should be capable of identifying a planned wellbore's proposed coordinates relative to either or both a local or geodetic reference frame consistent with the reference information listed above. Further specification of outputs can be found in the outputs section.

5.2 Handover from Planning Team to Operations Team

5.2.1 Communication Plan

The planning and operations groups should jointly develop a communication plan during transition. The communication plan should be written and distributed to operation team members who monitor and evaluate well trajectory during execution. At a minimum, the communication plan should contain trajectory criteria and protocol, reporting requirements, and a well plan revision methodology.

5.2.2 Trajectory Criteria and Protocol

The plan objectives have been reviewed during transition, and operation limits have been defined during that review. One item critical to successful well position is trajectory limits that define the trajectory criteria. Specifically, at what deviation from the well plan does trajectory need to be adjusted or replanned. Protocol is the defining of personnel responsibilities once the trajectory criteria or trajectory limit is reached. Both criteria and protocol should be specific to the well being drilled. They should also be written and available for reference by rigsite and office personnel.

Criteria should be established into three limit areas or zones. The first zone is the normal operation limit. The well path is maintaining the planned trajectory within normal limit, and drilling proceeds as planned. The second zone is the caution operation limit where the trajectory has deviated from the plan but may still achieve the objectives. Drilling proceeds, but with additional monitoring, evaluation, or parameter restriction. The third zone is where drilling can no longer proceed and achieve the well objectives without a plan revision. Drilling stops while contingency planning is evaluated.

Protocol should be defined to address when a limit is reached in the three criteria zones. While different systems may be used when an action or decision is required, all protocol should identify the name or job position of who is responsible; who is accountable; who can consult, contribute expertise, or review; and who should be informed of the decision or action. A simplistic example of a zone 1 normal drilling protocol would be a driller or directional driller is responsible for the well trajectory. A rigsite company representative is accountable for the well trajectory. A planning engineer, well planner, drilling advisor, or drilling supervisor may be consulted. Any of several team support supervisors may be informed of the action or decision.

5.2.3 Reporting Plan

Executing a well plan could involve a large team of support personnel or multiple discipline expertise. It is likely that reporting will be required from multiple rigsite personnel to multiple support staff, and these personnel may change during the well duration. All personnel should have access to the current reporting requirements as well as the current revision of plan and data to ensure that the correct data is used for evaluation and decision making. A reporting plan should include in writing the information to be reported, the name of the person receiving and sending the report, a reporting timeline, and methods of communication. The plan should be discussed at transition.

5.2.4 Well Revision Plan

The well trajectory may not be drilled exactly as planned, or the objective may have changed based on new information. There should be a well revision plan documented and discussed during transition. Revision Definition

Define which criteria make a well plan adjustment a new revision and which criteria are simply a projection within the existing and current trajectory revision. A new revision may adjust well objectives and tolerances but could have other criteria based on region or permitting regulations.

5.2.5 Revision Approval

The approval and revision numbering should already be formally defined in the communication plan. Approved revisions should be identified by a unique revision name, which should contain a revision number and may contain a date or time. The technical review personnel and process as well as the acceptance by responsible and accountable personnel should be documented in the communication plan and assigned to personnel by name.

5.2.6 Revision Distribution

Approved revisions should be distributed so that all personnel are working from the same plan and data set. The specifics of distribution method should be defined and documented in the plan transfer system.

5.2.7 Revision Tracking

Approved plan revisions should be tracked in a control system as documented in the plan transfer system. All personnel should include a verification check of current plan usage in their operation methodology using the control tracking system or document.

5.2.8 Revision Special Circumstances

The revised plan may introduce a special circumstance into the operation. This special circumstance would be an event or process that had not been discussed in the plan review. In these situations, a plan transfer meeting should occur between the relevant personnel before executing the revised plan. The meeting should include planning and operational personnel as a minimum and should discuss any well trajectory impact. The meeting deliverable should be a written operational instruction that is tied to the plan revision and tracked. Examples of special circumstances could be defining a new sidetrack tie-in point for a whipstock interval or an actual sidetrack point while steering from a cement plug.

5.2.9 Pre-spud Checks and Gross Errors Examples

The final stage of transition is the verification of plan basic information. Often a checklist is used to ensure previous errors are not repeated. Checklists may vary by region or organization, and the following topics are applicable to most well plans and should be verified during the transition from planning to operations. Specifically, the topics below should be verified during rig mobilization and before picking up a drilling BHA:

- Well specific drilling program or prognosis,
- Directional survey and logging (lwd and mud) program,
- Offset wells and safe-separation analysis,
- Drilling fluids program,
- Blowout response plan and well control procedures,
- Collision avoidance procedures,
- Boundaries and hardlines,
- Wellbore schematic, casing program and completion summary,
- Geological, geophysical and subsurface hazards,
- H2s information and procedures, and
- Waste and discharge information and procedures.

5.2.10 Revision Verification

The well plan to be drilled should be validated to ensure that it is the final and approved plan and that all parties are using the same revision. The proposed BHA plan should similarly be validated to ensure it is the final and approved version. Using a documented control system with a documented distribution methodology should make this verification routine. Drilling an incorrect plan is a documented root cause for many well placement investigations.

5.2.11 Collision Avoidance Requirements

A collision avoidance plan specific to the approved well trajectory is discussed in the transition objective review. What needs to be clear to the rig execution team during the pre spud checks are the rules that define collision avoidance and how the data sets will be transferred to execution users and validated.

5.2.12 Bridging Document

There may be multiple documents or operation standards on location depending on the operating partners, service providers, and regulatory governance involved in the well drilling operations. Each document is likely to have slight differences in the avoidance rules; however, none of these rules may be violated during routine drilling operations without triggering additional review or approvals. These differences should have been previously addressed, and a document should have been generated, approved, and available to the execution team that will provide the collision avoidance rules to be followed during well operations. This document is frequently called a bridging document and should be discussed by the involved parties prior to picking up a BHA. Ambiguity of collision avoidance rules has been identified as a contributing factor to well collision during root cause investigation and has also been a contributor of nonproductive rig time during operations.

5.2.13 Data Set Validation

Well collision avoidance is dependent upon an accurate collection of the wells surrounding the trajectory, which are also known as offset wells. A verified positional survey of the offset wells and an accurate positional estimation of the subject well, the well being drilled, are required to perform well separation estimates. These estimates are the basis for the well collision avoidance plan and are only as good as the data used. While the plan transfer method discussion occurs during transition, a validation that the correct data set is being used by all involved parties should occur during the pre-spud checks. Root cause from well collision investigations have used the wrong databases in collision avoidance computations, specifically, databases containing incorrect positional surveys, incorrect surface references, or missing offset wells.

5.2.14 Reference System Validations

An earth reference system is required to transfer survey measurements into a three-dimensional well position estimate. The reference system used by involved parties should be verified against the definitive final plan prior to drilling. This system includes, at a minimum, the coordinate system, the north reference, the magnetic declination, and the grid convergence angles. Incorrect coordinate systems and references impact trajectory position with respect to target objectives as well as collision proximity estimations.

5.2.15 Surface Location Validation

Surface location impacts target objectives and collision avoidance calculations and should be verified during predrill and rig placement during rig move. The actual surface location should be used during drilling and documented on the final definitive survey listings. Engineering teams use an estimated surface location when planning a new drill project with the knowledge that the actual surface location may differ due to rig placement limitations, location access challenges, or regulatory restrictions. The teams should pass the surface location ADP to operations during or before review of the plan objectives. The ADP is the maximum distance separation from the plan’s surface location that still achieves the well target and collision avoidance objectives. ADP is not normally the surface uncertainty, which is a term used in uncertainty calculations while using the actual surface location.

Validation should include not only the surface location, but confirmation that all involved parties are using the actual WRP and actual vertical distance from the datum rather than the estimates provided in the well plan. An example would be the actual RKB from MSL for the actual location once the rig has finished moving. Surface location and well reference validations should prevent the frequent error of drilling from the wrong wellhead or slot on multi-well locations as well as drilling from incorrect surface locations on single well locations. Vertical reference point validation should prevent outside scope or unplanned gross vertical depth errors.

5.2.16 Survey Program and Error Model Validation

The planning process results in a prescribed survey program for the well plan that specifies the type of survey tool, depth over which the tool will be valid, and the PUM applicable for that tool. Factors that contribute to incidents include violating the survey program by using wrong survey tools, improper PUMs for the available survey tools, and exceeding the programmed survey depths when root cause has been investigated.

Pre-spud verification of the survey tool plan according to the well section, the availability of the tools and crew, and developing a survey methodology that works for the rig's efficiency and the well's hazards should happen during transition prior to drilling. When a survey tool is planned to be run, the PUM for that tool should be validated as appropriate, checked against the survey program, and verified used by all involved parties.

5.2.17 BHA Program and Nonmagnetic Spacing Validation

BHAs impact well position through both trajectory control and wellbore surveying while drilling. BHA dogleg capability as well as the distance from the bit to the survey measurement point contribute to calculating the safe drilling distance between surveys. Insufficient nonmagnetic material in the BHA can render survey quality inadequate for well objectives. Removing magnetic interference with mathematic algorithms may be possible and planned for the well, but operational requirements may impact critical well operations and should be understood by operations prior to running in the hole with a drilling BHA. In summary, the survey program execution can be greatly impacted by unplanned BHA changes at the rigsite.

The initial BHAs should be verified against the well plan at pre-spud, including the nonmagnetic material spacing. The plan for surveying should be reviewed with involved parties once the initial BHAs are completed with measured components to be run. If the plan includes survey tool run inside the BHA, inside diameters and landing devices should be confirmed adequate. Any change in the BHA at the rigsite should be reviewed to ensure well and survey objectives are not compromised prior to running in the hole during well operations.

5.3 Operations and Execution

5.3.1 General

The purpose of the provisions herein is to provide the framework and minimum guidance for the operation/execution phase to ensure the wellbore is delivered safely while managing changes and meeting the fit-for-purpose positional objectives in a timely manner.

These requirements focus on the execution of the well objectives by operations personnel, including the acceptance of the wellbore planning package, understanding of well objectives and the associated risks, communication protocol, data validation, managing projections and changes in real time, and handing over from one service provider to another.

5.3.2 Single Well Versus Batch Drilling

The planning process should have determined whether the well will be drilled as a single well or one of multiple wells on a pad or platform. If there are multiple wells, the plan should specify the skid order, whether they are to be drilled top-to-bottom or batch-style, and the depth to be drilled prior to skidding.

During execution, operations personnel should ensure the well(s) are drilled as planned and that collision risk is re-evaluated each time the rig skids from one well to the next. Collision avoidance plots and reports should be regenerated by planning personnel and distributed to operations each time the rig skids to reflect the actual well path of the previous well or section drilled.

5.3.3 Plan Validation

The well plan and any additional diagrams, plots, reports, contact information, or collision avoidance information should be sent to the rig in a well package. Operations personnel should confirm they have received the well package and loaded it to their directional drilling application. They should confirm that the well package contains the latest approved plan revision, survey program, and any contingency plans and ensure all plan documentation received is up to date and reflects the correct revision number. The rig personnel should maintain their local copy of the directional drilling application, including relevant offset well analysis to be used in collision avoidance. It is a good practice for rigsite personnel to conduct frequent, planned synchronizations between their local directional drilling application and the corresponding office database. The following items should be verified by operations personnel:

a) Software: operations personnel are using the latest version of their directional drilling software.

b) Surface location:

   1) The rig is positioned over the correct slot. Confirm slot selection using staking sign information.

   2) The vertical reference is verified by confirming ground elevation, sea depth, and rotary table height.

   3) Follow operator's procedure to resurvey the slot at ground level.

c) Slot locations and pad/platform orientation: refer to pad layout and orientation documentation for confirmation.

d) Revision: revision received by operations personnel matches the latest approved revision number.

e) Equipment: equipment received on location matches that which is required to achieve the well plan objectives.

5.3.4 Collision Avoidance Management

Operations personnel are responsible for managing any collision risks that have been identified and communicated to them. Preventive and mitigation measures will have been identified during planning and should be adhered to while executing the well plan.

The survey program shall not be changed without reviewing the possible consequences related to collision avoidance unless a contingency plan is in place.

If operations personnel do have to use the contingency plan, they shall confirm all conditions of the contingency plan are met.

AC diagrams, plots, and reports are generated based on the survey program. If the survey program is changed, that documentation is no longer valid. Revised AC documents should be made available for any contingency plan. If neither the primary survey program nor the contingency plan is valid, a risk assessment should be performed using the revised survey program to determine whether it's safe to drill ahead.

a) Visual scan: Upon arriving to the rigsite, a visual scan of the area should be performed to identify any wellheads that are not included on the AC analysis. If a well is found missing from the analysis, the situation should be escalated to planning and engineering personnel.

b) ADP: ADP defines how far the actual trajectory can deviate from the plan before the AC rules are violated. TC plots should be used to visualize ADP tolerance lines and ensure they are not crossed.

c) Risk assessment, HSE, or non-HSE risk:

   1) During planning, each wellbore section should have been classified according to the highest collision risk level based on the definitions established by the operator and using the framework of a Risk Matrix Standard through which to assess the situation. As the well progresses and the database is updated, risk levels can change.

   2) Risk assessments should be performed by competent staff.

d) Preventive and mitigation actions:

1) Preventive and mitigation actions to be taken should have been identified during the planning phase. These steps are implemented during execution to ensure the residual risk is as low as reasonably practical.

2) To reduce the risk, wellbore separation and potential well integrity problems should be monitored while drilling. This may include updating requirements for the processes, procedures, and practices used during the construction and operation of the asset wells.

3) The scope of work for a risk assessment is to report:

i) the separation between the wellbores,

ii) the various barriers available (both in the design of the reference well and those that exist in the offset well[s]) that prohibit unintended fluid movement, and

iii) the likelihood and consequences of a collision.

e) STOP

1) When drilling a well with risk of collision, the onsite supervisor shall not permit the well path to drop below the SF = 1.0 tolerance line, unless a specific MOC is in place.

2) If there is no MOC, and if it is projected that the tolerance line will be crossed (or if the tolerance line has already been crossed), then drilling operations shall be stopped.

3) Operations can resume once a risk assessment has been completed and a dispensation from the standard minimum separation has been approved.

4) MOC can be used in the planning phase to manage close-approach drilling. Risks will have been evaluated prior to execution, and conditions for dropping below the SF = 1.0 tolerance line will have been defined.

5) If the conditions defined under the MoC are not met, then drilling operations shall be stopped.

6) A risk assessment will be performed to determine whether it is safe to drill ahead.

5.3.5 Effective Communication

Communication will be consistently effective if the well program is concise and current, and execution of the program is actively monitored. This monitoring should not only ensure that the elements of the design are followed, but that the assumptions within the design, such as survey tool performance, are continually tested and re-tested for validity. If execution is not properly following the design, a communication protocol should be in place for operations to document issues and request a revised well design with realistic objectives.

One database shall be designated as definitive and maintained as such.

This helps settle issues of data flow and access control.

a) Protocol:

1) Establishing a drilling sequence, having a directional drilling survey plan in place for field development, and submitting groups of wells (from either pads or platforms) at once to obtain approved permits to drill will help in the planning to avoid having to deal with the possibility of physically colliding with another wellbore. In those cases, most of the risks taken are only generated by poor planning, and it will reflect on the operations during execution.

2) All well-positioning software systems, transmission protocols, and communications methods used in the activities outlined in this recommended practice should be evaluated for accuracy to reliably perform in accordance with the level of risk and safety function described in this document. Data should be protected against unauthorized user access and manipulation and malware/virus threats. While this has obvious relevance for safety-related issues, the same verification should also be applied where the consequences of data corruption may result in significant economic loss.

b) Service provider; hand-over from one service provider to the next:

1) The service provider is required to distribute current documentation, including a communication package, to stakeholders and team members directly involved in the progress of wellbore construction.

2) The objective is to define the control processes through which the well surveying program should be distributed among all stakeholders and well team members.

3) The handover process shall be applicable to any documentation produced by or supplied to the service provider.

4) It shall cover the control, registration, transmission, tracking, and review of activities related to wellbore surveying and reporting throughout the well's drilling progress.

5) During operations and execution, the onsite manager (location foreman) is understood to be the focal point for document distribution and tracking.

c) Wellbore objectives:

1) To effectively contribute to the understanding of what will be accomplished, specific objectives that set expectations for capital spending should have been identified and defined during planning.

2) These objectives need to be understood by all field personnel.

3) Targeted zone, required length in reservoir contact, wellbore position relative to existing wells, lease boundaries, direction of minimum and maximum formation strengths, etc. need to be well-understood.

4) There has to be an established system in place to QA/QC survey stations in real time and validate the final well trajectory.

5) Survey stations shall meet their acceptance criteria to validate the survey program.

6) Final well geometry, torque and drag, drill-ahead rule adherence, tortuosity, and dogleg severities will impact the full life cycle of the well. These trajectory related attributes will need to accommodate completion techniques and artificial lift mechanisms and will directly impact well productivity.

d) Collision avoidance risks: Collision risk shall be assessed and classified for all well sections prior to drilling.

e) Database information shall be used to calculate and monitor well paths, uncertainty, and SF as the well progresses.

f) Drill-ahead conditions: Conditions for drilling ahead shall be communicated to field personnel.

g) If any of these conditions are violated, drilling should be discontinued until a risk assessment has been performed and drill-ahead conditions have been revised.

h) Remote drilling, support, and rigsite:

1) Remote drilling operation protocols shall be disseminated to all pertinent personnel. The understanding of escalation procedures is essential.

2) Communication between remote and field personnel should be reliable and redundant.

3) Responsibility and accountability should be assigned and understood by all parties.

5.3.6 Management of Change (MoC)

5.3.6.1 Significant changes to the well design, equipment, or plan shall require:

a) written notification from responsible engineer of the change,

b) communication of the potential impact of the change on the original well design and equipment (pressure, tensile, or burst limits to casing strings, etc.), and

c) written approval from supervising engineer and drilling or completion manager.

MoC should be used during the planning phase to assess and manage the risk involved in collision avoidance. If there is a risk of violating drill-ahead conditions, MoC should evaluate that risk and outline revised drill-ahead conditions to include preventive and mitigative actions. During execution, the revised drill-ahead conditions should be monitored.

If the revised conditions are violated, drilling operations shall be stopped.

To satisfy potential audit requirements, all written notifications and approvals, which may be in the form of an email or attachment, will be kept in a defined repository file structure.

a) Revisions to the well plan: Requests for well plan revisions and corresponding approvals shall be captured and saved appropriately.

b) Escalating collision risks: Escalation of collision risks and any subsequent communication or mitigation recommendations shall be saved.

c) Violation of drill-ahead conditions: If projections ahead of the bit indicate violation of drill-ahead conditions, drilling operations should be stopped. The situation should be escalated to a competent risk assessor.

d) Escalation of the violation and corresponding actions taken shall be saved in the repository.

e) Communication with relevant parties involved:

   1) Consultation of the drilling superintendent and drilling engineer is required for proper implementation of any well design or plan change.

   2) All handover or relief notes from the responsible engineer and lead rig onsite supervisors shall be captured and saved in the destined repository.

f) Service provider, handover from one service provider to the next: Communication protocols outlined in 4.9.9 shall be saved to the repository.

5.3.7 BHA and While-drilling Checks (Scribe Line Offset / Tool Face References)

5.3.7.1 General

While picking up the BHA, the difference between the high-side reference of the BHM and the MWD or gyroscopic tool high-side reference shall be measured.

This measurement shall be performed by transposing the BHM reference up to the MWD or gyroscopic tool reference (or vice-versa),a method known as scribing.

Next, field personnel should make a visual estimate of the tool face offset (in degrees) from the MWD or gyroscopic tool reference to the BHM while looking downhole and measuring in the clockwise direction. Once multiple people have made estimates, two measurements should be taken:

a) the arc length from the MWD or gyroscopic tool reference to the BHM reference, measured clockwise looking down the hole, and

b) the circumference of the BHA component where the first measurement was taken.

These measurements are to be used to calculate the tool face offset angle shown in equation 8.

$$\frac{Arc\ Length}{Circumference} \times 360° = Tool\ Face\ Offset\ (°) \tag{8}$$

If possible, the MWD or gyroscopic tool high-side should be oriented such that the tool face offset is 0°.

The planning phase should have specified the required accuracy of the scribe line transposition and tool face measurement. Field personnel should confirm that their calculated tool face offset is within the specified accuracy.

The tool face offset should be entered in the MWD or gyroscopic tool acquisition system, and field personnel should confirm that it was entered correctly.

5.3.7.2 Nonmagnetic Spacing

The effect of drillstring magnetic interference from the steel components of the actual BHA shall be estimated and compare to the planned BHA configuration.

If the estimated drillstring interference (EDI) of the actual BHA exceeds that of the planned BHA and exceeds the specification of the survey program, then additional nonmagnetic material is required in the BHA. A contingency plan can be considered to allow for a less accurate tool code when the EDI of the actual BHA is greater than planned.

5.3.7.3 Multi-Station Survey Corrections (MSCs)

MSCs can be performed while drilling to mitigate the effect of drillstring magnetic interference on the axial component of the azimuth measurement. The effect of the interference is magnified when drilling at higher inclination in the magnetic east or west directions. Interference observed in the cross-axial direction from a hot spot on the nonmagnetic collar can be mitigated. However, external interference from drilling mud, cuttings, and nearby wellbores would be challenging to correct for because it may not be consistent from one survey to the next.

5.3.7.4 Survey Program

Operations personnel should understand the primary survey program in addition to any contingency plans. The QA/QC team should provide QC and procedure. The QA/QC procedure should confirm whether the survey meets the survey program. If it does not, contingency survey program should take effect. The QC procedure and criteria should be based on the tool code used in the survey program.

The proper tool codes should be applied to surveys in the directional drilling application. The software application defines the size of EOUs and allows for operations personnel to determine overall size and orientation of the uncertainty in relation to offset wells.

The survey program may define overlapping surveys in the survey program to reduce uncertainty in the wellbore trajectory. These overlapping surveys could include running a gyroscopic tool or performing batch MSCs after completing a particular section of the well. Operations personnel should ensure these overlapping surveys are taken as planned.

5.3.7.5 Actual Well Path Versus Proposed Well Path

5.3.7.5.1 As the well is being drilled, the actual well path should be plotted on the directional drilling application and compared to the proposed well path. At each survey station, the following actions should be taken.

a) Confirm survey meets QC criteria based on the tool code associated with the survey program. Apply MSCs if necessary.

b) Assign an appropriate tool code to the survey.

c) Calculate wellbore position, SF, ADP, and BHA yield (steering effectiveness).

d) Calculate BHA yield requirements needed to reach the next target and compare to actual yield to evaluate whether the next target is achievable with the current BHA.

e) Create a straight-line projection to the bit depth and calculate the wellbore position, SF, and ADP. If steering actions have been taken between the survey depth and the bit position, BHA yield should be accounted for when calculating the bit projection.

f) Project ahead of the bit using BHA yield, and calculate wellbore position, SF, and ADP.

g) Review ADP. If the projection ahead of the bit shows actual deviation to be greater than ADP, then STOP. Contingency plans should be evaluated to determine whether the alternative plans are achievable within the required ADP. If not, MoC should take place, and a revised plan should be developed and implemented.

5.3.7.5.2 Once drilling resumes, the following actions should be taken between survey stations.

a) Monitor continuous inclination and continuous azimuth while drilling between survey stations to monitor trajectory and confirm there is no unexpected or undesired deviation.

b) Calculate BHA directional trend or yield.

c) Continuously verify BHA yield is sufficient to achieve targets and avoid collision.

d) Monitor effect of drilling parameters on torque and drag, hole cleaning, shock and vibration, and adherence to BHA specifications.

e) Confirm tool face as measured while making up BHA correlates with results of steering actions.

f) Populate slide sheet with drilling parameters and steering actions.

5.3.8 Target, Drilling Hazards, and Collision Avoidance Objectives

5.3.8.1 General

Various objectives were defined during the planning phase, and considerations should be made during execution to ensure those objectives are met.

5.3.8.2 Allowable Deviation from Plan (ADP)

The allowable deviation of the actual well path from the proposed well path, as defined by ADP, determines the threshold at which drilling operations will stop.

The ADP should have been defined during the planning phase and monitored during execution.

The correct tool codes shall be used during execution to ensure ADP is accurate.

If the actual well path deviates significantly from the proposed well path, then a revised plan should be designed, and ADP should be updated to reflect the new plan.

ADP should be limited primarily by collision avoidance constraints. Additionally, geological targets and hard line/lease line limitations can be considered to define a comprehensive ADP. Based on the ADP, the drilling tunnel can be illustrated to visualize the objective.

5.3.8.3 Reservoir Horizon

The reservoir horizon can be defined by a vertical depth, dip angle, and vertical section distance.

The vertical section definition (origin and direction) used by the geologist and the directional driller shall match.

The definition of the reservoir horizon may require multiple segments to define changes in dip or shifts in vertical depth due to faults.

The thickness of the reservoir should be defined in the planning phase. Uncertainty in the geological target coupled with uncertainty in the wellbore position creates risk in reaching that geological target objective.

If the planned and contingency tool codes are not achieved, then the risk in intersecting the geological target shall be re-evaluated.

Techniques can be used to reduce the risk in intersecting the geological target. Geosteering can be used to determine relative position within the reservoir and recommend steering actions accordingly. Uncertainty in calculated vertical depth position can be reduced using sag correction.

5.3.8.4 Hard Line and Lease Line

Hard lines and lease lines should be defined during the planning phase and communicated to operations personnel. These lines define the allowable drilling and production areas for the subject well, and, if they are crossed, there can be costly legal implications.

Planning personnel should define the distance required to be maintained from the lease line or hard line. This distance should be based on tool code uncertainty. If the required tool code is not achieved, contingency plans should define more conservative requirements for the distance from the lease line or hard line. If the projection ahead of the bit shows that the distance requirement will be violated, drilling should STOP, and risks of crossing the line should be evaluated.

In the scenario that the well is planned to overlap a hard line, the requirement may be defined as a limitation on the allowable deviation from that hard line. Similarly, if projections ahead of the bit show that the requirement will be violated, drilling should STOP, and risks should be evaluated.

5.3.8.5 Relative Positioning

Formation evaluation data can be compared to the geological model to revise geological targets based on the wellbore position relative to formation tops. Formation markers can be identified and compared to offset wells to determine the relative position. This can also be used to define dip angles.

While drilling in the horizontal section of the well, relative position within the reservoir can be tracked by identifying the signature of formation evaluation data. Distance from the top or base of the reservoir can be identified, and steering decisions can be made to optimize position within the reservoir.

Magnetic ranging is another method of relative positioning. This is typically only used in wellbore intersection scenarios, and the requirements should have been defined during the planning phase. During execution, operations personnel should ensure they understand how to execute the plan and ensure they are on track to meet the objective.

5.3.9 Conductor Setting Operations, Jetting, Shallow Kickoff/Scribing-in

When drilling in an area with a high density of wells near the surface hole location, the proposed well path may require that it is kicked off at a shallow depth. The planned kickoff depth should be defined with a specified tolerance, and the risks of violating that tolerance should be communicated to operations personnel. If the well cannot be kicked off within that tolerance window, drilling should STOP so that a revised plan can be designed.

One strategy for kicking off at a shallow depth is known as “scribing-in.” This strategy involves transposing the high-side line of the BHM up the drillstring as it is run into the hole. Once drilling commences and the directional driller is ready to begin deviating the wellbore, he should orient the scribed line in the direction of desired deviation. BHA design and yield should have been planned after taking the possibility of soft formation or hole enlargement into account. The tolerance for azimuth accuracy should be defined during the planning phase as well. The method of scribing in is not a precise steering technique, and the risks of an inaccurate scribe should be understood. If there is risk of violating the tolerance requirement for azimuth accuracy during execution, then contingencies should be available, such as the use of a gyroscopic steering tool instead of the scribing-in technique.

5.3.10 Sidetrack and Bypass

Sidetrack typically refers to drilling a wellbore to a different geological target, away from an original or mother wellbore. It could also refer to unplanned activity or an unintentional sidetrack, especially if running into the hole and reaming with a stiff BHA.

Bypass refers to an intentional sidetrack that is designed to bypass a problematic area to the intended geological target. This could include a fish left in the hole, junk in the hole, or a collapsed wellbore.

The specific requirements for operations personnel in a sidetrack scenario depend on the method of departure.

a) Whipstock:

   1) A whipstock is a steel inclined plane that intentionally deviates the wellbore in a specified direction.

   2) Field personnel shall scribe the whipstock to an MWD or gyroscopic tool, similar to the scribing process when using a BHM.

   3) Activation mechanisms should be understood by field personnel. Unintentional activation can result in setting the whipstock at an undesired well depth.

   4) Once the desired well depth is reached, the whipstock shall be oriented to the desired azimuth direction.

5) Multiple tool face points should be taken to confirm orientation before activation.

6) If using a whipstock to sidetrack out of casing, a mill should be used to create a window through which the subsequent BHA can pass.

7) The window shall be dressed by the mill to prevent BHA components from becoming entangled or damaged during passage.

8) Field personnel should understand the estimated yield for the whipstock so they can perform bit projections and make steering decisions.

9) Field personnel should confirm that they have successfully kicked off the sidetrack by monitoring inclination/azimuth, drilling parameters, and cuttings. If drilling parameters are erratic and cuttings are showing steel and cement, it could indicate that the sidetrack was not successfully kicked off and that the original wellbore is still being tracked.

b) Time drilling:

1) A sidetrack may be performed in open hole using a process called “time drilling”.

2) The directional driller begins by creating a trough in the desired sidetrack direction by working pipe up and down and holding a stable tool face. This creates a ledge at the bottom of the trough from which the sidetrack can be kicked off. Once the trough has been established, the directional driller begins time drilling by limiting the rate of penetration to as little as one or two feet per hour.

3) When planning an openhole sidetrack, details of the troughing and time drilling process should be designed and communicated to the field personnel.

4) Field personnel should confirm that they have successfully sidetracked the well by monitoring drilling parameters and inclination/azimuth. If weight can be applied to the BHA and differential pressure is seen, then those are positive signs that the sidetrack is successful.

c) Cement plug:

1) Another method of sidetracking involves setting a cement plug.

2) The cement shall be planned such that the plug is harder than the formation.

3) That way, the BHA will follow the path of least resistance and drill into the formation rather than the cement.

4) During execution, the BHA should be tripped into the hole carefully when approaching the expected depth of cement. The plug could be shallower or deeper than expected. Contingencies should be planned for both scenarios where the sidetrack could be kicked off shallower or deeper than expected.

5) Field personnel should also confirm that the cement plug was set successfully when tagging up. If the BHA does not take weight, that could indicate a poor cement job.

d) Interpolated tie-in: An interpolated survey station at the point of departure may be *used* to accurately model the wellbore trajectory.

e) External magnetic interference:

1) External magnetic interference refers to interference from a nearby well, casing, a fish in the hole, or some other steel components outside of the drillstring (such as a whipstock).

2) The measured azimuth from an MWD tool is not reliable if the measurement is affected by magnetic interference. Similarly, the magnetic tool face is not reliable if it is affected by magnetic interference.

3) When sidetracking out of casing or using a whipstock, magnetic interference should be considered. A gyroscopic tool should be used for steering if MWD is unreliable due to magnetic interference. Once the MWD sensor has established sufficient separation from sources of interference, it can be used for steering and surveying purposes.

4) If a fish has been left in the original borehole, the proximity of the MWD sensor to that fish should be tracked. If the MWD sensor is too close to the fish, then surveys and magnetic tool faces will be unreliable until the sensor is sufficiently separated from the fish.

f) Drilling hazards risk mapping:

1) Drilling hazards should be mapped with a correlation to formation tops and communicated to field personnel.

2) Hazards should be considered when making steering decisions. Significant steering should be avoided when drilling through a formation with known difficulties in steering efficacy.

3) Improper planning or execution of hazard prevention and mitigation can result in a sidetrack or bypass scenario. Proper planning and mitigation of potential stuck pipe or hole instability situations result in proactive avoidance of an unplanned sidetrack.

g) Collision avoidance*,* preventive and *mitigative* actions:

1) Planned preventive and mitigative actions should be executed to meet objectives related to collision avoidance.

2) When performing a sidetrack or bypass, the SF relative to the original wellbore will violate drill-ahead rules. When planning a sidetrack, the requirements for separation from the original wellbore should be defined. During execution, field personnel should ensure they have established sufficient departure from the original wellbore.

h) Multilateral, fishbone, hand fans, and steam-assisted gravity drainage well profiles: These profiles involve planned sidetracks or close-approach scenarios. The SF drill-ahead rule will be violated when departing the original wellbore. Requirements for separation should be defined on a case-by-case or project-by-project basis. Operations personnel should understand these specific requirements and ensure they are met during execution.

5.3.11 Remote Operations

Remote operation crew models have become prevalent recently. Experience can be spread across multiple rigs at once, and health, safety, and environmental risk exposure is reduced by reducing the number of rigsite personnel. It is critical that operations personnel follow communication protocols when remote operations are in place to ensure information is not omitted during handover.

a) Communication protocol:

1) A protocol for reliable communication between remote operations and rigsite personnel should be established and adhered to.

2) If communication methods break down due to interruptions in satellite connection or cellular service, contingency plans shall be in place to re-established communication to avoid interruptions to operations.

b) Responsibility and accountability: Because remote operations personnel support multiple rigs, the responsibility for deliverables or decision-making can be ambiguous. All responsibilities and accountabilities should be clearly defined in the remote operations crew model. Consequences for not meeting objectives should be established to ensure accountability.

c) Wellbore position ownership while and after drilling: Ownership of the survey depository should be defined. While drilling the well, operations personnel maintain ownership of the survey database. Protocols should be in place to ensure QA/QC processes are followed and the survey database is accurate. After drilling has been completed, operations should hand over the survey depository to planning and engineering personnel for final QA/QC and archival.

d) Handover document:

 1) Standard documentation should be in place for handing over the directional and surveying responsibilities from one person to the next. This documentation should encompass the status of achieving well objectives in addition to any upcoming risks. The latest well package should also be included during handover.

 2) Handover documentation applies when one remote operations person hands over to the next or when there is a change in service providers.

e) Remote support: Remote support is often available to operations. Support personnel are not responsible or accountable for operational duties, but they are available to share their expertise in troubleshooting issues encountered during operations.

f) Archiving: The preserving of wellbore positioning data and records shall occur upon completion of the execution phase. The archive shall consist of the following items:

 1) Working survey: The working survey database managed by field personnel should be handed over to planning and engineering so that it may be finalized and archived.

 2) Definitive survey: The working survey database is marked as definitive after being handed over to planning and engineering for archival.

 3) Plan versus actual: The plan versus actual plot is a visual representation of the location of the actual wellbore trajectory as it relates to the plan.

 4) Daily and end of well reports: These reports should be archived for future review and investigation. These should include slide sheets, run summaries, and failure reports.

g) Capture lessons learned:

 1) Field personnel should discuss with planning and engineering to evaluate which objectives were met and where they had difficulties. These lessons learned can be incorporated into future planning to proactively prevent these issues from occurring.

 2) Lessons learned should include any of the following observations:

  i) difficulties steering and suspected root cause (formation push, bit wear, tool failure),

  ii) other formation issues (taking a kick, losing circulation),

  iii) ADP versus actual deviation from plan,

  iv) comparison of torque and drag and hydraulics models to actual results to calibrate models for future wells,

  v) recurring surface issues that could affect downhole tools, and

vi) shock and vibration issues and suspected root cause (problematic formation, bit wear, BHA design).

5.4 Post-well Data Reintegration

After a well has been completed, the next and most important step is to reintegrate the new data from the now completed well back into the database and archives. Reservoir, geology, drilling, completions, and production all rely on having the most up-to-date information to make informed decisions for current and upcoming projects. It is easier and more consistent to collect, QC, and distribute data directly after operations have been completed. Each company should have a process that lists the various data types, where they are to be stored, and on whom the responsibility falls to ensure it is done properly. Figure 11 shows a flow chart depicting the circular data cycle.

For further clarification on database and archiving, reference sections 4.3 and 4.4 of this recommended practice.

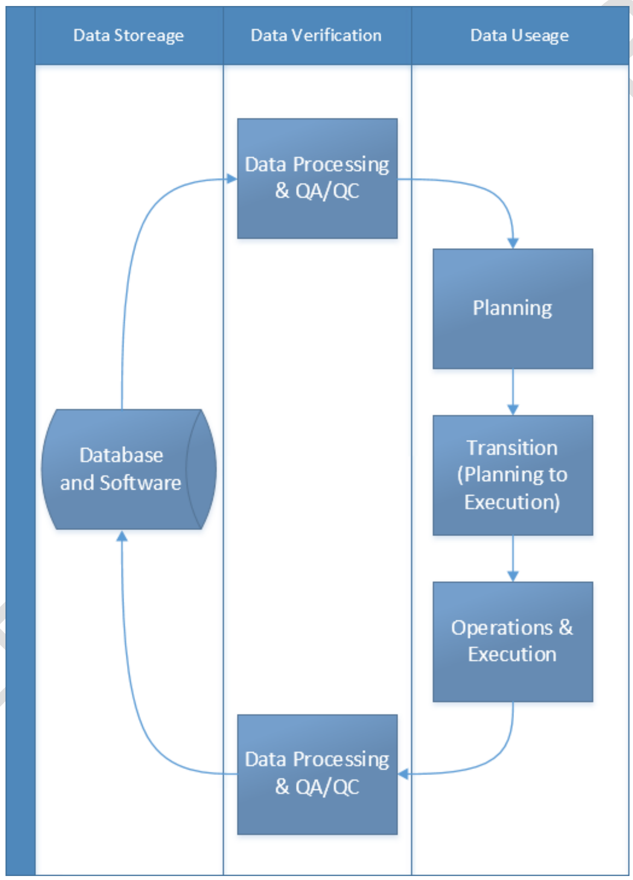


Figure 11—Data Lifecycle

6 Data Transfer—Output, Deliverables, and Transfer Files

6.1 General

Several types of plots are available and useful during the well planning, drilling, and post-drilling activities. This document will not address every possible plot or its use. For this document, there are four recommended plot types used in wellbore construction: plan view, section view, ladder plot, and TC plot. Of these, only the TC plot is designed for, and recommended for, AC and proximity planning and monitoring purposes.

This section recommends purposefully choosing the most appropriate plots for a project, or to clarify what the plot is not used for and to standardize essential plot metadata, all in service to improve user understanding of the information available or needed from these plots for their intended purpose.

The plot purpose, limitations for use and metadata described in this section can be a template or guide when considering use of additional plots for the purpose of improving safety & performance monitoring or decision making while maintain standardization across all plots used.

6.2 Recommended Plots

6.2.1 The four plots are:

a) Plan view

Two-dimensional view of well(s) from above, also called "map view." These plots may include more information than just the planned well; they may also include offset wells wellbore targets, lease lines, or other information appropriate to wellbore construction. One common application of the plan view is managing well lateral distance to lease lines.

b) Section view

Side view of plan, with TVD versus distance along a specific direction (azimuth) on the *x*-axis; often the vertical section azimuth is from slot to TD in the horizontal plane, but other appropriate azimuths may be used. The resulting plot is within what is called the vertical section plane (VSP). This plot can be used to monitor well position high or low to plan.

While most of the information necessary on the plan view is the same for the section view plot and others as listed (see 6.3 Plot Standard Conventions), the section view plot has the added necessity to include the VSP (azimuth direction).

c) Ladder plot

Well depth versus distance to offset wells or tolerance lines (or both), where the plan well depth is along the X-axis, and the distance from the plan to offset wells or tolerance lines, and so forth, is along the Y-axis.

d) TC plot

A polar plot with the center of the plot representing the planned path of the reference well. The projection is normalized so that the high side of the planned path of the reference well displayed on the diagram corresponds to the planned azimuth of the reference well at that depth. This convention eliminates the discontinuities that are apparent in some implementations of the method, where the high side is set to zero on the polar plot and the planned path of the reference well involves a nudge in one direction before being brought back to vertical and then kicked off in another direction. Offset wells, including actual survey position and projections, are shown where they intersect a plane normal to the reference well at a specific well depth. The value annotated on the offset well corresponds to the well depth in the reference well plan at which the offset well intersects the normal plane of the reference well. Scanning is always carried out down the offset wells onto the reference well to ensure detection of near-perpendicular crossings. A recognized defect in the implementation of the Normal Plane TC diagram is when the software incorporates scanning from the reference well. This implementation can miss offset wells in the case of a near-perpendicular crossing. The correct implementation is to scan down offset wells back to the reference well. In this way, a perpendicular intersection is never missed. The practice of scanning from the reference well is a fundamental flaw and was recognized and specifically documented in the peer-reviewed literature. Software containing this feature should not be accepted for safety-critical applications.

Since the reference well direction is always perpendicular to the plane of the display, the diagram shows absolute rates of convergence or divergence of the offset wells to the reference well. This property of the diagram enables the user, when projecting the path of the reference well while drilling, to make an objective assessment of the available options for steering the well and rapid determinations of the consequences of steering decisions.

When drilling towards offset wells that may be perpendicular to the planned reference well, well plans should be projected by a minimum of the expected lateral uncertainty in the position of the offset well to check for possible interference.

6.2.2 Attributes of the normal plane TC diagram include the following:

a) The TC diagram shows pure relative motion between reference and offset wells.

b) One plot can be used for the entire wellbore trajectory with no need to recreate the plot as drilling commences:

   1) Plots can be prepared in advance by specialists using a definitive database.

   2) There is less burden on the rig team to create or recreate the plot or maintain the integrity of a the complete database used in the creation of the TC plots.

c) The normal plane TC diagram is the only AC method that has been the subject of peer-reviewed publication.

6.3 Plot Standard Conventions

Plot selection and presentation can be a subjective process; however, some specific metadata should be common on any plot of record as follows:

a) Common Plot metadata, where all wall plots include:

   1) header:

      i) magnetic parameters (model, dip, magnetic declination, field strength, grid convergences, total correction, date, and the arrows showing grid, true, and magnetic),

      ii) surface location (EPSG code, datums, etc.): well name unique ID and current revision;

   2) survey program:

      i) survey depths for each survey tool to be used,

      ii) required survey intervals,

      iii) whether run in cased hole, open hole or drillpipe (or wireline/slickline),

      iv) any special corrections or contingencies (this needs to be processing versus corrections): PUM (error model) to be used for each survey;

   3) driller's target(s);

   4) vertical section (VS) and plan view (VS needs VS direction);

   5) critical points, well profile by depth; and

   6) signature of originator and approver(s).

b) TC Plots shall be north-referenced and normal plane as specified in SPE 187073-MS, with the following:

1) operator,
2) field,
3) structure/site,
4) well,
5) wellbore/plan and revision,
6) date,
7) calculation method: normal plane,
8) ring interval,
9) azimuth interval,
10) start depth: (recommend tie-on depth), and
11) end depth: (recommend TD).

6.4 Other Considerations

A user's color blindness can render a plot dependent on color less suitable, possibly unusable for use. Consider eliminating or at least reducing a reliance on colors alone, and consider adding different line types to remedy color dependency. When possible, as a contingency for color blindness, drawings should be created that lessen or eliminate confusion based on color dependency alone.

Plot accessibility issues to consider include: size, scale, readability, digital/hard copy, access environment (where will the plots be used, digital devices on rig floor, etc.), and hard copies with multiple markups/deletions while plotting/projective progress.

6.5 Other/Future Plots

Software packages generate many different types of plots and graphical representations that may add design rigor and value. The plots described in this section are the most successfully used historically. However, their success does not mean that they are the only or best plots to use; indeed, the rich assortment of visualization tools, such as rendered three-dimensional graphics available in directional software, may be extremely helpful. Equally, with advances in augmented reality, the prospect for improved visualization such as heads-up displays, may find a place in this list in future revisions.

Annex A

(normative)

Survey Mathematics

A.1 General

atan2 functionality: Where the formulation involves the arc tangent ($\tan^{-1}$) function, proper calculation of the value requires use of the atan2 (numerator, denominator) function to ensure the result is placed in the correct quadrant. Consideration should be given to specify the numerator and denominator in the proper order since not all implementations of atan2(y,x) functionality has the same input order which returns the arc tangent of the two numbers x and y.

Trigonometric accuracy: A mixture of arc tangent, arc cosine, and arc sine functions are included here. These will not provide the same level of accuracy from a given set level of input precision, and the user will both provide results in the appropriate quadrant and reformulate the equations to provide the greatest accuracy given any limited precision of input.

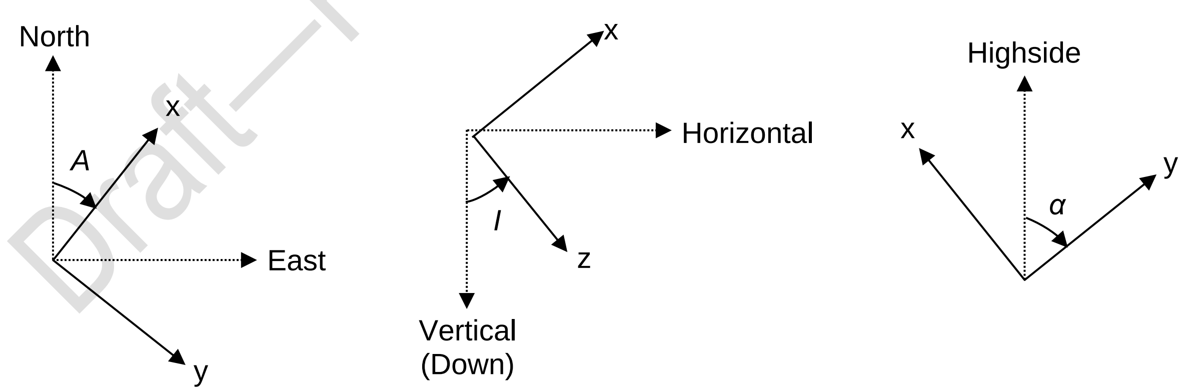
A.2 Coordinate Reference

Local geographic axes: Defined by the directions of true north and the local vertical as a right-hand coordinate system of North-East-Down (NED).

Magnetic reference axes: Defined by the directions of magnetic north and the local vertical.

Survey tool axes: Coincident with the principal body axes of the tool (xyz), where z is parallel to the longitudinal axis of the tool, and x and y are orthogonal to the z-axis and to each other, completing a right-hand coordinate system; y is coincident with the projection of the vertical “up” direction into the plane normal to the tool axis when the tool face angle is zero. This pseudo-up direction is referred to as “high side.”

Illustrations of azimuth (*A*), inclination (*I*), and tool face (*α*) angles are in Figure A.1:



(a) Azimuth **(b) Inclination** **(c) Tool Face**

Figure A.1—Azimuth, Inclination, and Tool Face

The right-hand coordinate system is illustrated in Figure A.2:

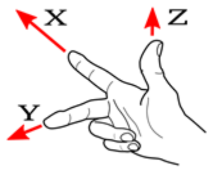
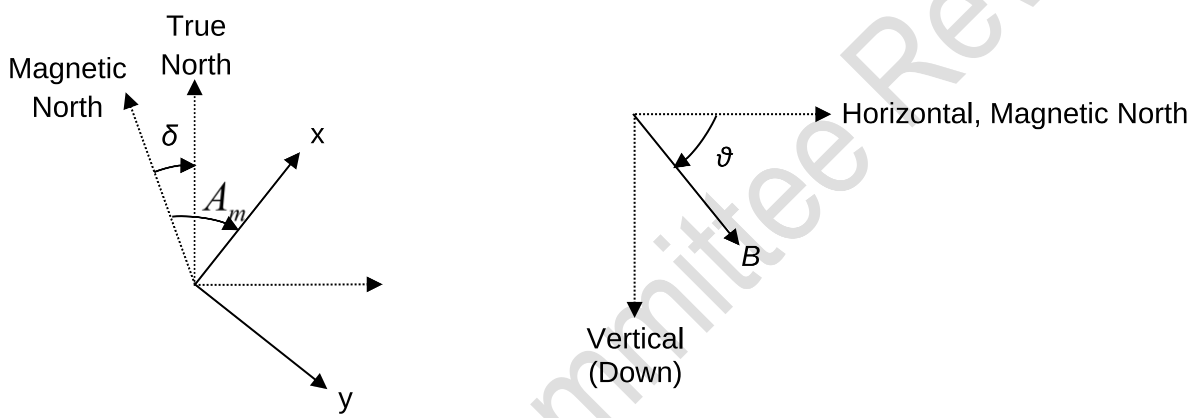


Figure A.2—Right-hand Coordinate System

The magnetic azimuth (A_m), declination (δ), and dip (θ) angles are illustrated in Figure A.3:

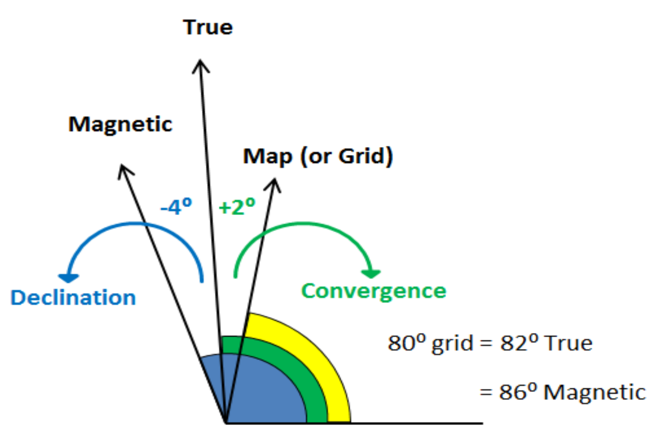


(a) Magnetic Azimuth and Declination **(b) Dip**

Figure A.3—Magnetic Azimuth, Declination, and Dip Angles

A.3 Application of Declination and Convergence

The total azimuth correction is a poorly defined term and is dependent on both the measurement's north reference and the corrected azimuth's north reference. Figure A.4 shows declination and convergence.



NOTE 1 True Azimuth = Magnetic Azimuth + Declination

NOTE 2 Grid Azimuth = True Azimuth – Convergence

NOTE 3 Grid Azimuth = Magnetic Azimuth + Declination – Convergence

Figure A.4—Declination and Convergence

If the measurement's north reference is Magnetic North and the corrected azimuth's north reference is Grid North, then: total azimuth correction = declination – convergence.

Or if the measurement's north reference is True North and the corrected azimuth's north reference is Grid North, then: total azimuth correction = –convergence.

NOTE The inverse of convergence is sometimes referred to as grid correction.

If the measurement's north reference is Magnetic North and the corrected azimuth's north reference is True North, then: total azimuth correction = declination.

If the measurement's north reference is True North and the corrected azimuth's north reference is True North, then: total azimuth correction = 0,

where

declination is the clockwise angle from True North to Magnetic North, and

convergence is the clockwise angle from True North to Grid North.

A.4 Wellbore Position, Course Length, and Dogleg Severity (DLS) Calculation

All calculations of actual wellbore position and most calculations of planned wellbore position should use the Minimum Curvature calculation method described in API D20[16]. Planned wellbore position calculation for an interval of combined inclination hold and azimuth turn should use the Radius of Curvature calculation method also described in API D20[16].

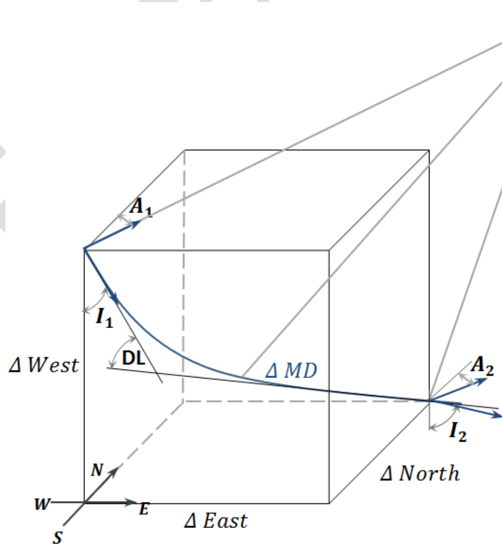


Figure A.5 – Directional Survey Vectors and Dogleg Diagram

A.4.1 Dogleg

$Dogleg\ (DL) = \cos^{-1}[\cos(I_2 - I_1) - \sin(I_1)\sin(I_2)\,(1 - \cos(A_2 - A_1))]$ from Figure A.5.

A.4.2 Course Length

$$Course\ Length = \Delta MD = MD_2 - MD_1$$

A.4.3 Dogleg Severity (DLS)

The imperial formula given below us used to calculate DLS in °/100 ft. This formula is altered when using metric units to provide a DLS over an appropriate interval, usually 30 m and occasionally 10 m.

DLS = 100 × DL (°) / Course Length (ft)

A.4.4 Minimum Curvature

— $Ratio\ Factor\ (RF) = \left(\frac{2}{DL}\right)\tan\left(\frac{DL}{2}\right)$; NOTE: if $DL = 0, RF = 1$

— $\Delta N = \left(\frac{\Delta MD}{2}\right)[\sin(I_1)\cos(A_1) + \sin(I_2)\cos(A_2)] * RF$

— $\Delta E = \left(\frac{\Delta MD}{2}\right)[\sin(I_1)\sin(A_1) + \sin(I_2)\sin(A_2)] * RF$

— $\Delta TVD = \left(\frac{\Delta MD}{2}\right)[\cos(I_1) + \cos(I_2)] * RF$

A.4.5 Radius of Curvature

— $\Delta N = \frac{\Delta MD[\cos(I_1)-\cos(I_2)][\sin(A_2)-\sin(A_1)]}{(I_2-I_1)(A_2-A_1)}$

— $\Delta E = \frac{\Delta MD[\cos(I_1)-\cos(I_2)][\cos(A_2)-\cos(A_1)]}{(I_2-I_1)(A_2-A_1)}$

— $\Delta TVD = \frac{\Delta MD[\sin(I_2)-\sin(I_1)]}{(I_2-I_1)}$

A.5 Vertical Section, Closure, and Resultant Tool Face

A.5.1 Vertical Section

— Section North = Wellbore Position North – Vertical Section North Origin

— Section East = Wellbore Position East – Vertical Section East Origin

— Section Length = sqrt (Section North² + Section East²)

— Section Direction Offset = Arctangent (Section East / Section North) – Vertical Section Azimuth

— Vertical Section = Section Length * Cos (Section Direction Offset)

A.5.2 Closure

— Closure North = Wellbore Position North – Wellbore North Origin

— Closure East = Wellbore Position East – Wellbore East Origin

— Closure Length = sqrt (Closure North² + Closure East²)

— Closure Direction = Arctangent (Closure East / Closure North)

A.5.3 Resultant Tool Face (RTF)

— $RTF = \tan^{-1}\left[\frac{\sin(I_2)\sin(A_2-A_1)}{-\sin(I_1)\cos(I_2)+\cos(I_1)\sin(I_2)\cos(A_2-A_1)}\right]$

RTF is the highside tool face required to get from the initial attitude (Inclination$_1$ and Azimuth$_1$) to the resultant attitude (Inclination$_2$ and Azimuth$_2$). It should be noted that the tool face angle will not necessarily be constant over the maneuver. The above equation provides the tool face angle at the start of the maneuver, corresponding to I_1 and A_1.

A.6 Inclination Derived from Accelerometer Sensor Measurements

The three orthogonal accelerometer and three orthogonal magnetometer sensors making up the total of six sensors are each assumed to form a right-hand system with the z-axis in line with the orientation of the along-hole wellbore. The x-axis and y-axis are therefore both assumed to be cross-axial shown below in Figure A.6.

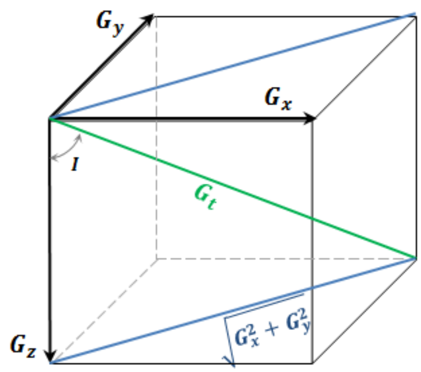


Figure A.6 – Gravity Vector Diagram

A.6.1 Inclination:

$$I = \tan^{-1}\left[\frac{\sqrt{G_x^2 + G_y^2}}{G_z}\right]$$

If G_t is known, inclination may also be calculated using:

— $I = \cos^{-1}\left[\frac{G_z}{G_t}\right]$

or

— $I = \sin^{-1}\left[\frac{\sqrt{G_x^2+G_y^2}}{G_t}\right]$

It is important to note that use of a reference value for G_t in the above equations, as opposed to the measured value, will yield an inclination value of lower quality than the formula using all three sensor measurements, depending on the orientation of the tool. They should only be used in the event the other sensor measurement(s) are not available. Importantly, the ISCWSA PUMs do not model the additional error introduced by mixing reference and observed data values associated with these equations. Use of these PUMs in such situations would be invalid and would likely significantly understate vertical position error.

A.7 Tool Face Derived from Accelerometer, Magnetometer, and Gyro Sensor Measurements

Tool face may be referenced relative to the gravity field (Highside Tool Face), relative to the magnetic field (Magnetic Tool Face), or relative to the spin axis of the Earth (Gyro Tool Face). A closely related value is the scribeline azimuth. Scribeline azimuth is the azimuth of the projection of the tool y-axis onto the horizontal plane. It is used to help define the orientation of the tool inside the wellbore. This contrasts with the more common usage of azimuth, which refers to the direction of the wellbore. This latter azimuth (wellbore azimuth, or just azimuth) refers to the direction of the projection of the tool axis onto the horizontal plane.

— $TF_{hs} = \tan^{-1}\left[\frac{-G_x}{-G_y}\right]$

— $TF_m = \tan^{-1}\left[\frac{B_x}{B_y}\right]$

— $TF_{gyro} = \tan^{-1}\left[\frac{\omega_x}{\omega_y}\right]$

Scribeline Azimuth

$$A_{scribeline} = \tan^{-1}\left[\frac{G_t(B_xG_z - B_zG_x)}{B_y(G_x^2 + G_z^2) - G_y(G_xB_x + G_zB_z)}\right]$$

Scribeline azimuth and magnetic tool face are good approximations of one another at very low inclinations. Both are also roughly equivalent to gyro tool face at low inclinations, provided they have been referenced to True North by the addition of magnetic declination.

Importantly, scribeline azimuth and magnetic tool face as calculated above are referenced to Magnetic North. The correction of declination and convergence shall be applied, as necessary, to re-reference the measurements to either True North or Grid North.

Similarly, the equation for gyro tool face is referenced to True North.

It shall be corrected for convergence to be re-referenced to Grid North.

Note that:

Highside Tool Face ≈ Scribeline Azimuth – Azimuth,

where both scribeline azimuth and azimuth are referenced to the same North.

This equation is an approximation, good at only low inclinations (generally ±5°). The relationship between highside tool face and scribeline azimuth given above may be sufficient to provide highside tool face in the event of cross-axial accelerometer failure at low inclinations. The equation can also be used with magnetic tool face substituted in place of scribeline azimuth.

<u>Tool Face (item of interest)</u>

The tool face of any item in the drillstring can be inferred from the tool face angle of the measurement device by adjusting it for the scribeline angle offset (SLO). This is the angular difference between the measurement device and the item of interest measured in the clockwise direction when viewed from above.

Tool Face (item of interest) = Tool Face (measurement device) + SLO

A.8 Azimuth Derived from Magnetic, Gyro, and Accelerometer Sensor Measurements

A.8.1 Magnetic Azimuth:

$$A_m = \tan^{-1}\left[\frac{G_t\left(B_y G_x - B_x G_y\right)}{B_z\left(G_x^2 + G_y^2\right) - G_z\left(G_x B_x + G_y B_y\right)}\right]$$

A.8.2 Gyro System Azimuth (two-axis):

$$\tan A = \frac{\left(\omega_x \cos\alpha - \omega_y \sin\alpha\right)\cos I}{\omega_x \sin\alpha + \omega_y \cos\alpha - \Omega \sin\phi \sin I}$$

where

ω_x and ω_y are the gyro readings on the x- and y- axes;

Ω is the Earth Rotation rate;

φ is the latitude;

α is gyro tool face; and

I is inclination*.*

The equation becomes singular at 90 degrees inclination.

A.8.3 Gyro System Azimuth (three-axis):

$$\tan A = \left[\frac{\omega_x \cos\alpha - \omega_y \sin\alpha}{\left(\omega_x \sin\alpha + \omega_y \cos\alpha\right)\cos I + \omega_z \sin I}\right]$$

where ω_x, ω_y and ω_z are the gyro readings on the x-, y-, and z-axes.

A.9 Total Magnetic Field, Total Gravity Field, Magnetic Dip Angle, and Bdip Derived from Magnetic and Accelerometer Sensor Measurements

A.9.1 Total Gravity Field (G_t):

$$G_t = \sqrt{G_x^2 + G_y^2 + G_z^2}$$

A.9.2 Total Magnetic Field (B_t):

$$B_t = \sqrt{B_x^2 + B_y^2 + B_z^2}$$

A.9.3 Magnetic Dip Angle (*Dip*):

$$Dip = \tan^{-1}\left[\frac{B_x G_x + B_y G_y + B_z G_z}{\sqrt{\left(G_y B_z - G_z B_y\right)^2 + \left(G_x B_z - G_z B_x\right)^2 + \left(G_y B_x - G_x B_y\right)^2}}\right]$$

or

$$Dip = \sin^{-1}\left[\frac{B_xG_x + B_yG_y + B_zG_z}{BtGt}\right]$$

A.9.4 Bdip:

$$BDip = \sqrt{B_{t,measured}\left(Dip_{measured} - Dip_{reference}\right)^2 + \left(B_{t,measured} - B_{t,reference}\right)^2}$$

where

B_t is the total magnetic field strength and

Dip is the magnetic field dip angle.

The measured values of B_t and *Dip* are calculated from the preceding equations. The corresponding reference values may be obtained from a geomagnetic model, an independent measurement of the magnetic field, or some other source. Note that equation requires the *Dip* angle be represented in radians.

Bdip is interpreted as the norm of the vector difference between the observed and predicted magnetic field vector (excluding declination differences). This definition holds regardless of the reference frame used for the vector representation because vector norms are invariant to frame rotations. Thus, another way of calculating the same value would be to calculate the root-sum-square of the horizontal and vertical magnetic field differences.

A.10 Horizontal Earth Rate, Total Earth Rate, and Latitude from Gyro Sensors

When using a two-axis gyro system, it is possible to calculate the horizontal component of the Earth Rate and use that as a quality check of the gyro readings.

$$\Omega_H = \sqrt{\left(\omega_x \cos\alpha - \omega_y \sin\alpha\right)^2 + \left(\frac{\omega_x \sin\alpha + \omega_y \cos\alpha - \Omega \sin\phi \sin I}{\cos I}\right)^2}$$

When using a three-axis gyro system, it is possible to calculate the total Earth Rate and the latitude and use those quantities as quality checks for the gyro readings.

$$\Omega = \sqrt{\omega_x{}^2 + \omega_y{}^2 + \omega_z{}^2}$$

$$\phi = \arcsin\left[\frac{-\left(\omega_x g_x + \omega_y g_y + \omega_z g_z\right)}{\Omega g}\right]$$

A.11 Direct Sensor Bias Determination

For a cosine sensor such as accelerometer, magnetometer, or gyroscope, it is possible to directly estimate the sensor bias by averaging measurements 180 degrees out of phase with each other taken using a precision fixture. A four-point rotation shot permits two separate bias determinations, which can be compared to provide and check on this determination:

Biased cosine sensor response:

$$S_\theta = F * \cos(\theta) + \beta$$

Direct Bias Estimation:

$$\frac{S_\theta + S_{\theta+\pi}}{2} = \frac{F * \cos(\theta) + \beta + F * \cos(\theta + \pi) + \beta}{2} = \frac{F * \cos(\theta) + \beta - F * \cos(\theta) + \beta}{2} = \beta$$

Four-Position Bias Comparison:

$$\frac{S_\theta + S_{\theta+\pi}}{2} - \frac{S_{\theta+\frac{\pi}{2}} + S_{\theta+\frac{3\pi}{2}}}{2} \approx 0$$

where

S_θ = sensor output at angle θ

F = total field strength

θ = angle between total field vector and sensitive axis of the sensor

β = sensor bias

A.12 Gravity Field Prediction

This prediction of gravity is based on either the GRS67 or GRS80 ellipsoids, both of which are in common use. Gravity may also be estimated using a model based on actual field measurements such as the Global Acceleration Reference Model.

A.12.1 GRS67:

Gravity(m/s²) = 9.78031846 * (1 + 0.005278895 * (sine(φ))^2 + 0.000023462 * (sine(φ))^4)

A.12.2 GRS80:

$$g_0 = 9.7803267714\left(\frac{1 + 0.00193185138639 \sin \varphi^2}{\sqrt{1 - 0.00669437999013\ \sin \varphi^2}}\right)$$

where φ is the latitude of the directional survey measuring device's position expressed in degrees.

For deepwater and/or deep TVD applications, the gravity prediction may be adjusted, as it is a function of both depth relative to the vertical datum and the overburden density. This may be done using the Bouguer correction formulas below which are illustrated in Figure A.7:

$\Delta g_B = 2\pi G\rho\Delta h$

$g_B - G_A = 2\pi G\rho\Delta h$

ρ = Average Density of crustal rocks

Δh = Height difference with the reference level

A.12.3 The Bouguer Correction

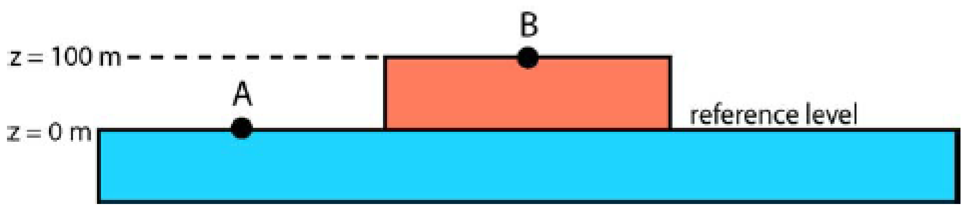


Figure A.7 – Bouguer Correction Illustration

A.13 Magnetic Field Vector Zone of Exclusion, Incidence Angle, and Predicted Bz

These formula have been grouped together because of their common use of the dot product.

A.13.1 Magnetic Field Vector Zone of Exclusion

$$Magnetic\ Field\ Incidence\ Angle = \cos^{-1}[\sin(I)\cos(A_m)\cos(Dip) + \sin(Dip)\cos(I)]$$

The magnetic field vector zone of exclusion takes the form of a minimum angle value requirement for the magnetic field incidence angle. That is the angle the tool axis makes with the Earth magnetic field vector. This magnetic field vector zone of exclusion may be used to help ensure that any cross-axial magnetometers will not simultaneously be measuring a very small field strength, which would compromise the validity of both the magnetic-only tool face and the scribeline azimuth.

A.13.2 Incidence Angle

- Incidence Angle Between Wellbores = Arccosine(u_1(x) * u_2(x) + u_1(y) * u_2(y) + u_1(z) *u_2(z))
- $u_1(x)^2$+$u_1(y)^2$+ $u_1(z)^2$ = 1
- $u_2(x)^2$+$u_2(y)^2$+$u_2(z)^2$ = 1
- x(East) = Sin(Inc) * Sin(Az)
- y(North) = Sin(Inc) * Cos(Az)
- z(TVD) = Cos(Inc)

These formulae are used to calculate the incidence angle between two wellbores defined by the point of interest on the subject well and its corresponding point on the offset well. The calculation uses inclination and azimuth at these points to calculate unit vectors used in the calculation of the incidence angle.

A.13.3 Predicted Bz

Predicted Bz = Bt * [sin(Inc) * cos(Mag Az) * cos(Dip) + Sin(Dip) * Cos(Inc)]

A.14 Ouija Board Calculations (Determining Tool Face and Projecting Ahead)

Determining Tool Face and Distance to Drill from Inclinations, Azimuths, and DLS

- $DL = \cos^{-1}[\sin(I_1)\sin(I_2)\cos(A_2 - A_1) + \cos(I_1)\cos(I_2)]$
- Distance to Drill (ft) = 100 * DL (°) / DLS (°/100ft)
- $TF_{HS} = tan^{-1}\left[\frac{sin(I_1)*sin(I_2)*sin(A_2-A_1)}{cos(I_1)*cos(DL)-cos(I_2)}\right]$, and can also be calculated using
- $TF_{HS} = tan^{-1}\left[\frac{sin(I_2)*sin(A_2-A_1)}{cos(I_1)*sin(I_2)*cos(A_2-A_1)-sin(I_1)*cos(I_2)}\right]$

Determining Tool Face and DLS from Inclinations, Azimuths, and Distance to Drill

- $DL = \cos^{-1}[\sin(I_1)\sin(I_2)\cos(A_2 - A_1) + \cos(I_1)\cos(I_2)]$
- DLS (°/100ft) = 100 * DL (°) / Distance to Drill (ft)

— $TF_{HS} = tan^{-1}\left[\frac{sin(I_1)*sin(I_2)*sin(A_2-A_1)}{cos(I_1)*cos(DL)-cos(I_2)}\right]$

— $TF_{HS} = tan^{-1}\left[\frac{sin(I_2)*sin(A_2-A_1)}{cos(I_1)*sin(I_2)*cos(A_2-A_1)-sin(I_1)*cos(I_2)}\right]$

Determining Inclination and Azimuth from Inclination, Azimuth, Distance Drilled, Tool Face, and DLS

— Dogleg (°) = DLS (°/100ft) * Distance Drilled (ft)/100

— Az_2 (°)=Az_1 (°)+ Δaz (°)

— $I_2 = \cos^{-1}[\cos(I_1)\cos(DL) - \sin(I_1)\sin(DL)\cos(TF_{HS})]$

— $\Delta\text{az} = A_2 - A_1 = \tan^{-1}\left[\frac{\sin(DL)\sin(TF_{HS})}{\cos(I_1)\sin(DL)\cos(TF_{HS})+\sin(I_1)\cos(DL)}\right]$

Projecting Ahead

Calculate MD_2 using the formula below and Inc_2 and Az_2 from Distance Drilled, Tool Face, and DLS formula above:

— MD_2(ft)= MD_1(ft)+ Distance Drilled(ft)

Calculate position of projection ahead by substituting MD_2, Inc_2, and Az_2 into the Minimum Curvature formula above.

A.15 Wellpath Curve Calculations with Azimuth Hold

The equations listed below are based on the use of feet for length measurements and °/100ft for DLS. The equivalent metric equations are easily derived by applying the appropriate scale factor.

A.15.1 DLS and Curve Radius

— DLS = 18000 / (Radius *π)

— Radius = 18000 / (DLS * π)

A.15.2 Build Rate / "2D" Curve–Calculations

— Δdisplacement = (cos(Inc–) – cos(Inc_1)) * 18000 / –Build Rate * π)

— Build Rate = (cos(Inc–) – cos(Inc_1)) * 18000 / (Δdisplacement * π)

— ΔTVD = (sin(Inc_2)-sin(Inc_1)) * 18000 / (Build Rate * π)

— Build Rate = (sin(Inc_2)-sin(Inc_1)) * 18000 / (ΔTVD * π)

— ΔMD = 100 * (Inc_2-Inc_1) / Build Rate

— Build Rate = 100 * (Inc_2-Inc_1) / ΔMD

A.15.3 Turn Rate / Flat Curve Calculations

— ΔMD = 100 * (Az_2-Az_1) / Turn Rate

— Turn Rate = 100 * (Az_2-Az_1) / ΔMD

A.15.4 DLS & Build Rate / Turn Rate

DLS ≈ sqrt(Build Rate²+Effective Turn Rate²) where

Effective Turn Rate = Turn Rate * sin((Inc_1+Inc_2) / 2)

Highside Tool Face ≈ arctangent(Effective Turn Rate/Build Rate)

A.16 Wellpath Tangent/Straight Line Calculations

There are six formulae for calculating the remaining two variables from any two of the four variables associated with a right-angled triangle. The four named variables associated with a right-angled triangle are inclination, displacement, MD, and TVD, arranged as shown in Figure A.8.

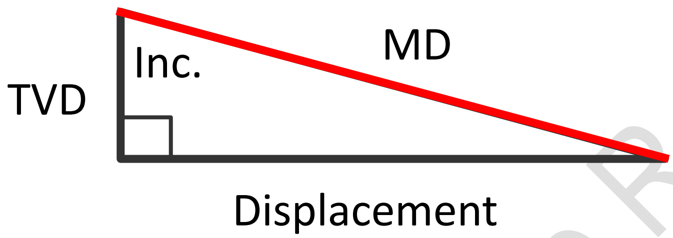


Figure A.8—Variables Associated with a Tangent (red line)

— ΔMD = sqrt(ΔTVD^2+Δdisplacement^2)

— ΔTVD = sqrt(ΔMD^2-Δdisplacement^2)

— Δdisplacement = sqrt(ΔMD^2-ΔTVD^2)

— inclination = arcsine(Δdisplacement/ΔMD)

— Inclination = arccosine(ΔTVD/ΔMD)

— Inclination = arctangent(Δdisplacement/ΔTVD)

These remaining formulae are provided for convenience and are rearrangements of the formulae given above.

— Δdisplacement = ΔMD * Sin (Inclination)

— ΔTVD = ΔMD * Cos (Inclination)

— Δdisplacement = ΔTVD * Tangent (Inclination)

— ΔMD = Δdisplacement / Sin (Inclination)

— ΔMD = ΔTVD / Cos (Inclination)

— ΔTVD = Δdisplacement/Tangent (Inclination)

A.17 Directional Survey Measurement Correction Algorithms

A.17.1 Correction—Axial Magnetic Interference (AX)

Description – Synthesis of axial magnetometer value based on predicted magnetic field strength, predicted magnetic dip angle and the cross-axial magnetometer values

NOTE Also known as short collar correction (SC or SCC).

Application – Only in the situation where magnetic measurements are failing QC due to axial magnetic interference (AX) and where sin(Inc) * sin(mag Az) ≤ 0.85. If sin(Inc) * sin(mag Az) > 0.85, this correction can sometimes be replaced by MSC or be applied by a survey management specialist.

Algorithm – Alternately calculating the predicted axial magnetic field and resulting azimuth until there is no change in either, or directly solving a fourth-order polynomial in $\cos(Az_{mag})$. These equations simplify when the tool is horizontal with the potential for substantial error. The algorithm has the potential to generate two equally valid solutions that are roughly equally spaced from magnetic East and magnetic West and so may result in selection of the incorrect azimuth.

Limitations – This algorithm solves each directional survey measurement independently and does not account for the expected consistency of any BHA-derived AX. A quality check for this correction is given by the range and standard deviation of applied axial interference. Both range and standard deviation should be relatively small. The correction assumes all the interference is oriented axially and will be incorrect if applied to external magnetic interference, such as from offset casing. Additionally, errors in the reference magnetic field strength or dip angle will cause significant unmodeled position error in the resulting survey that may be undetectable by the quality check.

A.17.2 Correction—Cross-Axial Magnetic Interference (XAX)

Description – The cross-axial correction compensates for errors associated with the tool's cross-axial measuring system such as cross-axial magnetic interference (XAX) from the BHA and bias of cross-axial magnetometers and accelerometers. The corrections are computed from a "rotational shot," which has at least four surveys taken at a constant depth and at various tool face angles. Experience has shown that six surveys taken at random tool face angles provide adequate input data for calculation of the cross-axial corrections.

NOTE Also known as rotational shot.

Application – The rotational shot consists of at least four accepted surveys. It is recommended that at least one rotational shot for each BHA run is taken. The rotational shot should be taken in a magnetically undisturbed part of the well (i.e., at least 30 m away from the last casing shoe). If a rotational shot for the cross-axial corrections is not taken at the start of the BHA run, the reduction in error achieved with the cross-axial correction cannot be applied until the correction is performed and applied.

Algorithm – The bias of a cross-axial sensor is derived from at least four measurements, of which each is taken in a different tool face quadrant. After plotting the four sensor measurements as function of tool face, a least-square best-fit sinus curve is fitted through the measurements. The offset of the sine curve (i.e., the difference between the minimum and the maximum value of sine curve) represents the sensor bias.

Limitations – This algorithm does not solve at each directional survey measurement when the inclination of the rotational shot is taken at an inclination less than 5°. A quality check for the rotational shot is given if an acceptable azimuth spread in a rotational shot survey after application of the cross-axial corrections is less than before the corrections were applied. An acceptable inclination spread after application to the cross-axial corrections to accelerometer readings is less than one and a half (1.5) times the inclination spread before the corrections were applied.

A.17.3 Correction—Bottomhole Assembly (BHA) Sag

Description – Correction of the inclination value due to misalignment between the measuring device and the wellbore most commonly attributed to the force of gravity acting on the BHA resulting in bending.

NOTE Also known as sag.

Application – Reduction in vertical positional uncertainty in nonvertical wellbores either for target sizing or for collision avoidance. This correction may be applied to any wellbore attitude measurements whether they are acquired by inclination-only, magnetic-based, or gyro-based measuring devices.

Algorithm – A range of algorithms are used from the simple through to finite element analysis. The simpler algorithms identify the contact points of the BHA, such as stabilizers, and quantify the bending between these contact points based on the drill collar's moment of inertia, force of gravity, and the fulcrum effect at the contact points. More sophisticated algorithms also take into account the forces being applied to the BHA as a result of the local wellbore curvature, and this may result in changes to the azimuth value as well as the inclination value. As directional survey measurements are commonly taken while static and with zero weight on bit, the sag correction does not normally consider these effects.

Limitations – The sag prediction commonly assumes that the wellbore is of a uniform size and shape, so this correction is not considered valid when hole quality is also an issue. It is recommended that this correction only be applied to stabilized BHAs, as unstabilized BHAs may be assumed to lie to low-side and be aligned to the wellbore.

A.17.4 A.17.4 Correction—Multi-Station Analysis (MSA)

Description – Quantification of sensor bias and scale factors, and possibly reference field errors, using multiple directional survey measurements from the same device to verify the quality of these measurements.

NOTE Also known as MSC.

Application – Multi-station analysis (MSA): An additional qualification of directional sensor measurements. It is used to help ensure selection of the appropriate PUM. This is a more rigorous QC than is commonly applied through checks of Gt, Bt, and Dip.

MSC: A form of downhole sensor calibration that may be used to correct sensors readings for systematic effects such as bias and scale factor error. It can also be used to reduce position uncertainty. Since AX may appear as a bias of the axial magnetic sensor, MSC as well as Axial Magnetic Correction may be used to correct for this. The advantage of MSC is that it evaluates the consistency of the correction, is generally more accurate than single-station axial magnetic correction, and is better suited when the BHA has entered the AX correction exclusion zone but prior to that had produced sufficient data to quantify the magnitude of the axial bias. The disadvantage is difficulty applying this correction in real time and the need for multiple data points prior to its application. The technique is also commonly used to correct for the effect of magnetized mud, as this will tend to systematically ameliorate the earth's magnetic field.

Algorithm – Least squares linear regression applied to each sensor's measured values to identify the slope (scale factor) and intercept (bias) associated with the sensor. Advanced algorithms based on maximum likelihood statistical estimation also exist to provide direct insight into the accuracy and quality of the estimates. Such algorithms can additionally estimate errors in the reference field values.

Limitations – Best results are achieved for the calculated scale factor and bias when the sensors change orientation relative to the field being measured (gravitational, rotational, or magnetic). For the cross-axial sensors, this change is commonly a change in tool face, while for the axial sensors this change would be a change in wellbore attitude (inclination and azimuth). The quality of the calculated scale factor and bias generally increases with the number of measurements and the amount of change in the wellbore direction. The minimum number of measurements required to perform MSC vary by provider and approach.

Unfortunately, the accuracy of the sensor scale and bias estimates cannot be assessed directly from the quality of the linear regression fit. The type of algorithm used, the accuracy of the reference field prediction, the wellbore orientation, and the change in the wellbore orientation all affect the accuracy of the analysis. The two primary ways of verifying an accurate result are to use either a minimum set of data requirements that have been verified offline to ensure accurate results or statistical estimation tools to directly calculate the accuracy of the slope and bias estimates. While use of a high-fidelity magnetic prediction such as HRGM, IFR1, or IFR2 should improve the quality of the MS solution it may still result in a solution that does not meet the accuracy requirements

Use of MSC to reduce position uncertainty should be rejected unless the technique used for the purpose is documented to be valid for that purpose. Using a combination of SPE 125677[17] and HRGM, IFR1, or IFR2 has been shown to be unreliable for this purpose[18] and should not be used.

A.17.5 Correction—In-Field Reference (IFR)

Description – Improved magnetic environment variables, declination, total field strength, and dip angle, incorporating magnetic crustal anomalies based on some form of measurement of the local magnetic environment and compensating for secular variation.

NOTE Also known as IFR1, GRS.

Application – With the use of a more accurate declination value there is a reduction in lateral positional uncertainly over a main field low resolution geomagnetic model (LRGM) such as IGRF or WMM or over a standard resolution geomagnetic model (SRGM) such as British Geological Survey (BGS) Global Geomagnetic Model (Pre-BGGM2019). There is no reduction to either vertical or radial uncertainties.

Algorithm – The substitution of a more accurate declination in the azimuth reference formula is at the core of this correction; however, this correction is often enhanced with improved measurement QC and variation of the declination value based on both depth and location.

Limitations – As the IFR correction is based on actual local measurements, this data shall be available before drilling the wellbore.

.The quality of these measurements should be verified, and since the measurements are often scalar they may need to be inverted to produce the vectors (dip and declination), which requires both time and expertise. The scalar data processing may also be depth-continuous so a varying declination may be applied based on TVD.

A.17.6 Correction—Interpolated In-Field Reference (IIFR)

Description – Improved magnetic environment variables, declination, total field strength, and dip angle, incorporating both magnetic crustal anomalies and magnetic field temporal disturbances based on measurement of the local magnetic environment compensated for secular variation and with additional disturbance monitoring.

NOTE Also known as IFR2.

Application – With the use of an even more accurate declination value there is a reduction in lateral positional uncertainty over IFR. There is no reduction to either vertical or radial uncertainties. In addition, as a result of magnetic field disturbance monitoring, accurate azimuths may be obtained even when the magnetic environment is changing, such as results from space weather.

Algorithm – The substitution of a more accurate declination in the azimuth reference formula is at the core of this correction; however, this is also enhanced with improved measurement QC and with varying the declination value based on depth, location, and time. The correction uses time-based magnetic observatory data that is interpolated for the wellbore's location.

Limitations – Because the IFR correction is based on actual local measurements, this data shall be available ahead of drilling the wellbore.

The quality of these measurements should be verified, and since the measurements are often scalar they may need to be inverted to produce the vectors (dip and declination). This correction method requires both time and expertise. The scalar data processing may also be depth-continuous, so a varying declination may be applied based on TVD.

In addition, the magnetic observatories shall be identified and an appropriate data stream obtained so that the real-time declination, field strength, and dip angle are available.

A.17.7 Correction—Measured Depth (MD)

Description – Adjustment of assigned MD to compensate for temperature and stretch effects.

NOTE Also known as MD, Stretch.

Application – Provide a more accurate wellbore position. Generally, this correction is focused on providing a more accurate TVD. There is currently no standard approach for modelling the positional uncertainty improvement. Implicitly this correction is for drillstring-conveyed directional survey measurement tools, as wireline conveyed tools are often stretch-corrected based on existing wireline practices.

Algorithm – The simplest algorithm based on empirical data is based on MD and calculated TVD, while more sophisticated algorithms account for the drillstring and drag. As directional survey measurements are commonly taken while static and with zero weight on bit, the MD correction does not normally have to consider the effects of varying weight on bit. This would not be true of data acquired continuously with the drilling process.

Limitations – The more sophisticated corrections are difficult to employ in real time due to the complexity of the calculation. The wellbore position is commonly only one part of an MD-related data set being acquired while drilling the wellbore, and it may be important for the wellbore position and any formation evaluation or drilling dynamics data sets to be assigned a consistent MD; however, the LWD data will have an MD that is affected by weight on bit. Because of the relationship of MD and vertical depth to horizon and reservoir mapping, this correction should be applied to either none or all wells in a field. As a result of these limitations, this correction should only be used with the agreement of the asset team.

A.17.8 Correction—Dual Sensor, Multi-sensor

Description – The averaging of independent measurements taken at the same well depth by equally accurate instruments to improve overall accuracy. Most commonly this is done for inclination; however, it could, and has been, done for azimuth as well. Most commonly it involves just two independent sensors; however, the principle can be extended to multiple sensors.

NOTE Also known as Dual Inclination (DI).

Application – Provide more accurate attitude measurements reducing positional uncertainty. Because this correction is most commonly applied to inclination, it is more common that the TVD accuracy is improved.

Algorithm – Assuming the measurement is the average of two independent readings, the combined value's accuracy is calculated by applying a factor of $1/\sqrt{2}$ to the appropriate error terms. More generally, the combined value's accuracy is calculated by applying a factor if $1/\sqrt{n}$ where n is the number of independent sensors.

Further quality control (QC) is necessary, as both measurements have to pass an independent QC assessment and also meet a consistency check. The expectation is that their distribution would align with the anticipated pattern for independent measurements of the same attribute.

Limitations – This correction requires the deployment of two independent and equally accurate sensor packages, such as running two MWD tools in the same drillstring, and requires that the measurements be taken at the same depth. A simpler situation is a continuously transmitted inclination from one tool being matched to the inclination periodically transmitted from the other. For dual inclination it is normal to pair this with the sag correction described above, and, similarly to the sag correction, the DI correction is only valid if the misalignment of the measuring device to the borehole remains consistent.

A.17.9 Correction – Integration of Continuous and Static Directional Measurements

Description – Enhancement of the wellpath position calculation with the addition of MWD to better characterize the wellbore's curves.

NOTE Also known as High-definition Survey, Waypoints.

Application – This correction should be used to refine the wellbore position by taking into account localized changes in wellbore curvature using additional attitude measurements.

Algorithm – The assumption is there are multiple data sources provided by a single directional measurement instrument such as static measurements using all available sensors and continuous MWDs ahead using only the axial sensor(s). The continuous measurements taken while rotating or sliding are of lower quality, as they generally use a single sensor and an assumed value for the field's magnitude; however, they may reveal additional character to the wellbore's orientation in the interval between the static measurements. By their inclusion in the data set, these continuous measurements should improve the wellbore position calculation. When only continuous inclination measurements are included, interpolating azimuth is commonly based on measured depth and the bounding static measurements.

Limitations – The process of selecting and rejecting continuous measurements for use in the wellbore position calculation may be subjective and reliant on a survey management specialist. Because selection of the appropriate measurement relies on forward-looking information, this correction is generally not applied in real time, and if azimuth is being interpolated it cannot be done in real time. As the merged data set contains data of varying quality, there is currently no consensus on its associated positional uncertainty modeling, and the default is to assign the static measurement's positional uncertainty model.

A.18 Positional Uncertainty Calculation

A.18.1 General

Formulae for calculating positional uncertainty values derived from error sources associated with both gyroscope and magnetic devices are too complex to be reproduced here and instead should follow the description given by the ISCWSA, also known as the SPE WP TS. These descriptions are primarily provided in SPE 67616[8], SPE 90404[19], and as updated by the ISCWSA's Error Model Maintenance subcommittee. Note that these positional uncertainty models can also be used to model the positional uncertainty associated with inclination-only measuring devices and can also be used to model positional uncertainty in the event that directional survey measurements are missing or are of uncertain quality.

Combination of independent uncertainties: $\sigma_{combined} = \sqrt{\sigma_1^2 + \sigma_2^2 \cdots + \sigma_n^2}$

This formula may be used when combining the wellbore's position uncertainty value with its surface measurement position uncertainty value to arrive at an overall positional uncertainty value. The formula is known as RSS or L2 norm.

A.18.2 Pedal Curve

The pedal curve (see Figure A.9) is the shape enveloping an ellipse where a tangent to the extremity of the positional uncertainty ellipse is drawn orthogonal to the center of the ellipse.

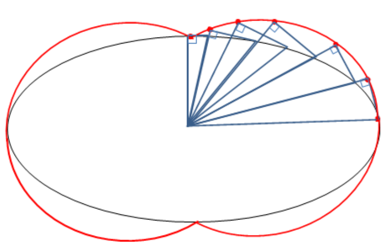


Figure A.9—Pedal Curve

Assuming the relevant positional uncertainty in the plane of interest forms an ellipse that could be described in the following Cartesian form:

$$\frac{x^2}{a^2} + \frac{y^2}{b^2} = 1,$$

then the pedal curve surrounding that ellipse is given by the equation:

$$x^2 * a^2 + y^2 * b^2 = (x^2 + y^2)^2.$$

A.19 Wellbore Proximity, Ellipse Separation, and Separation Factor (SF)

There are multiple methods for performing wellbore proximity and collision avoidance calculations. At the heart of these calculations is the distance formula reproduced below. This formula can be used to calculate the distance between points on two wellbores. Once a point of interest on the subject wellbore is selected, the identification of the point of interest on the offset wellbore is generally done using either the closest approach or TC plane, whichever is appropriate for the application. As numeric, rather than analytic, methods are often used to identify this point of interest on the offset wellbore, these methods remain out of scope for this document; however, it is recommended that a test be performed using the collision avoidance calculation test data set provided by ISCWSA. to help ensure that whatever software application is being used to identify this point conforms with industry norms.

The two common planes used for wellbore proximity calculations are the closest approach and the TC planes. The TC employs a disc-oriented perpendicular to the subject wellbore and whose radius is continually expanded until it finds the offset wellbore. This disc is incremented down the subject well, and the process is repeated. An orientation is attributed to the proximity, and this orientation may be referenced either to the subject wellbore's high-side or to the reference North. Closest approach, also known as minimum distance, reverses the orientation of the disc, with it now being perpendicular to the offset wellbore; however, the identifying point remains on the subject wellbore. The two planes handle end conditions differently; the TC will not return an answer if the offset well does not lie in the subject well's perpendicular plane, while closest approach will tilt the disc at the two ends of the offset wellbore into whatever orientation minimizes the distance to the identified point on the subject wellbore. A full description of the TC can be found in SPE 19989[13].

Distance Formula: Distance = sqrt(Δnorth² + Δeast² + ΔTVD²)

where

Δnorth is the difference in the North coordinate values for subject and offset wellbores,

Δeast is the difference in the East coordinate values for subject and offset wellbores, and

ΔTVD is the difference in the TVD coordinate values for subject and offset wellbores assuming an orthogonal Cartesian system.

This distance is often referred to as the Center-to-Center distance and may be abbreviated to C-C.

Ellipse Separation = C-C – Subject well pedal curve radius – offset well pedal curve radius

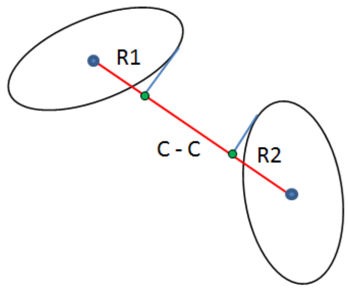


Figure A.10—Ellipse Separation

Variations of this formula are available. A common variation is to also subtract the subject wellbore's hole radius and the offset wellbore's casing radius from the center-to-center distance illustrated in Figure A.10.

SF = C-C / (Subject well pedal curve radius + Offset well pedal curve radius)

This formula is also known as clearance factor. Variations of this formula are available. Two common variations are to either subtract the subject wellbore's hole radius and the offset wellbore's casing radius from the center-to-center distance or add the subject wellbore's hole radius and the offset wellbore's casing radius to the denominator.

A.19.1 Expansion Method

An alternative method for estimating collision risk is given by proportionally expanding the subject and offset well's positional uncertainty ellipsoid until they are touching. The collision risk statistic is the number of standard deviations required to inflate the ellipsoid. This method is fully described in SPE 159840.[20]

A.20 Magnetic Field Prediction

The purpose of magnetic field prediction is to provide a declination value to re-reference magnetically derived wellbore azimuths along with magnetic QC variables: total field strength (B_t) and magnetic dip angle (*Dip*). The earth's magnetic field is composed of three components: main field, crustal field, and disturbance field. It does not follow any simple pattern relating to geodetic location, and because of that a full description of the math is out of scope. However, some of the principles of geomagnetic modeling along with an alternative method of local measurement are described. Local measurement is described in the directional survey measurement correction algorithms under IFR and IIFR. Geomagnetic models such as International Geomagnetic Reference Field (IGRF), BGGM, high-definition geomagnetic model (HDGM), and MagVar High Definition (MVHD) are generally spherical harmonic models based on magnetic observatory data, which may also incorporate satellite data. These models have different degrees of harmonics determining the magnetic field wavelength spectrum that should be captured. For example, a degree 50 spherical harmonic model should adequately model wavelengths of 800 km and larger (minimum wavelength = circumference / spherical harmonic degree ≈ 40,000 km/50). Geomagnetic models are also periodically updated to incorporate the latest observatory data and have a limited period of validity over which the secular variation is considered predictable, and whenever a geomagnetic model is used to predict the declination it is recommended that only the latest available model is used.

A.21 Horizontal Wellbore Position in Geodetic Coordinates

The calculation of a wellpath's geodetic coordinates should be done by first calculating its Cartesian coordinates relative to a local origin using the minimum curvature calculation described in Annex 4.4 and then converting these coordinates to geodetic coordinates after a single common reference point, often the wellhead, has been identified.

The conversion from local to geodetic coordinates shall take account of any difference in North reference and the application of a scale factor commonly associated with geodetic mapping.

For any point on the wellpath, there is a unique relationship between its latitude and longitude and its geodetic coordinates once the CRS has been identified; however, this relationship is outside the scope of this recommended practice.

A.22 Magnetic Quality Control (QC)

Gravity– Field Acceptance– ABS [G_t (reference–) – G_t (measured)] ≤ G_t (tolerance)

Magneti– Field Acceptance– ABS [B_t (reference–) – B_t (measured)] ≤ B_t (tolerance)

Magnetic Dip –Angle Acceptance: –ABS [*Dip* (reference–) – *Dip* (measured)] ≤ *Dip* (tolerance)

Bdip Acceptance: Bdip (tolerance) = sqrt((B_t (reference)**Dip*(tolerance))^2 + B_t (tolerance)^2)

where

Bdip(measured) ≤ Bdip(tolerance)

A.23 Nonmagnetic Isolation

Magnetic Field Strength Due to Monopole:

$$B_{monopole} = \frac{P}{4\pi r^2}$$

where

$B_{monopole}$ = magnetic field strength in Tesla (T),

P = magnetic flux (magnetic pole strength) in Weber (Wb), and

r = radius in meters.

This equation can be rearranged to calculate magnetic flux (magnetic pole strength)

$P = B_{monopole} * 4 * \pi * r^2$

Axial Interference Magnetic Field:

$$B_{interference} = \frac{|P_1|}{4\pi(L-z)^2} + \frac{|P_2|}{4\pi z^2} - \frac{|P_2|}{4\pi(z+L_{bit})^2}$$

where

$B_{axial\ interference}$ = magnetic field strength in Tesla (T),

P_1 = magnetic flux (pole strength) of the upper magnetic pole in Weber (Wb),

P_2 = magnetic flux (pole strength) of the lower magnetic pole in Weber (Wb),

L = length of the nonmagnetic section in meters (m),

z = length from point of interest to the bottom of the nonmagnetic section in meters (m), and

L_{bit} = length from the bottom of the nonmagnetic section to the base of the bit in meters (m).

Predicted Azimuth Error due to Axial Interference:

$$Err_{azi} = \frac{-\sin(I)\sin(A_m)B_{interference}}{\cos(Dip)\,|B_t|} * \left(\frac{180}{\pi}\right)$$

Nonmagnetic Spacing Acceptance:

Baxial interference ≤ AMIL * sigma

where,

AMIL = ISCWSA positional uncertainty model axial interference term value specified at 1 sigma, and

sigma = appropriate confidence level associated with acceptable axial interference, normally 3.

A.24 Target Sizing

Target sizing is the name for the operation used to reduce the height, area, or volume of a wellbore's target to accommodate the wellbore's positional uncertainty. The initial target size is normally referred to as the geologic target, while the eroded target is commonly called the driller's target. Target erosion should use the appropriate confidence level.

The method for target erosion should be one of the following:

a) For one-dimensional TVD targets, subtract vertical positional uncertainty from target top and bottom depths, narrowing the target TVD window.

b) For two-dimensional targets linked to a geologic marker, subtract lateral uncertainty from the target's lateral bounds and radial uncertainty from the target's displacement boundaries.

c) For two-dimensional targets anchored in three-dimensional space, subtract lateral uncertainty from the target's lateral bounds (high-side uncertainty/cosine [wellbore inclination at target]) and from the target's displacement boundaries.

d) For three-dimensional targets, subtract lateral uncertainty from the target's lateral bounds, radial uncertainty from the target's displacement boundaries, and vertical uncertainty from the target's top and bottom boundaries.

Annex B

(informative)

B.1 Wellbore Depth Data Process Audit

The conformant depth shall provide an audit value associated with depth determination activity according to the following tables.

An audit is recommended to quantify the integrity of the depth data processes in the organization involved. Tables B.1 and B.2 highlights areas of strength and elements where there may be potential for improvement.

The table may be expanded to include additional evaluation criteria, but for the purposes of this document, these additional criteria shall not be incorporated into the evaluation.

Companies can be rated as follows:

— A: Documented processes, systematic auditing, continuous improvement of the models.

— B: Documented processes, auditing shows consistency and almost no exception. PUMs may not be optimal.

— C: Has documented processes that are followed most of the time but with poor auditing.

— D: Provides some additional information inconsistently; processes are documented but may not be followed.

— E: Provides “a” depth, with undocumented processes, no systematic auditing and/or no continuous improvement of models.

Tables B.3 to B.6 are examples of how organizations, both using and providing AHD data, may assess their strengths and weaknesses. For a more detailed audit, it is advised to contact competent suppliers of these services.

Table B.1—Audit Assessment Criteria

clear	There is a clear, documented discipline description, and the documentation content is integrated into operations and QA/QC systems. The description has a founded background and is metrologically responsible. The subject is formally assimilated into the company training agenda.
available, but not detailed	There is a documented discipline description, but it is either incomplete or is not absorbed into operations of a QA/QC systems, or there is a rigorous application of the discipline, but the process has significant shortcomings in the process description documentation.
unclear or indefinite	The documentation is summary, incomplete, out of date, or bears little metrological significance.
mentioned, but not apparent	The subject is acknowledged, and there is operational cognizance of the subject, but it is not formally integrated into the organization or used on a regular basis.
not mentioned	No recognition or evidence of the discipline in the organization.

Table B.2—Audit Assessment Elements

Accuracy requirements statement	Expectations in accuracy, described in terms of calibration standards and traceability, measurement results and tolerances.
Uncertainty requirements statement	Expectations in terms of measurement uncertainty, typically expressed in sigma-units.
Discrepancy limits specification	Measurement divergence limits, which trigger acceptance, or otherwise, of delivered data.
Discrepancy decision responsibility and authority statement	Organizational description of the responsibility holder for acceptance or otherwise of data discrepancies.
Data delivery format requirement	Format in which data is delivered to the data user.
Method description	Measurement system used, including basis of the measurement and metrological relevance.
Calibration method	Method of calibration, including calibration traceability, limits and validity statements.
Correction method	The corrections that are applied to the measured data using established and readily available methods and including variable parameters.
Verification method	Acceptable standard and nonstandard verification process methods and limits of acceptability.
Uncertainty determination	Method of determining measurement uncertainty.
Tie-in procedure	Acceptable standard and nonstandard tie-in procedures.
Discrepancy management	Method of identifying and reporting measurement discrepancies. Organizational framework for dealing with discrepancies, including responsibility descriptions and acceptance decision framework.

Table B.3—Operator (well depth data-user)

	100	75	50	25	0	weighting, %
Accuracy requirements statement	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	50
Uncertainty requirements statement	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Discrepancy limits specification	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Discrepancy decision responsibility and authority statement	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Data delivery format requirement	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10

Table B.4—Driller (well depth data-provider)

	100	75	50	25	0	weighting, %
Method description	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Calibration method	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Correction method	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Verification method	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Uncertainty determination	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Tie-in procedure	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Discrepancy management	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10

Table B.5—Wireline Company (well depth data provider)

	100	75	50	25	0	weighting, %
Method description	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Calibration method	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Correction method	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Verification method	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Uncertainty determination	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Tie-in procedure	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Discrepancy management	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10

Table B.6—Example Audit for Drilling Company Providing Well Depth Data (fictitious drilling depth data-provider)

	100	75	50	25	0	weighting, %
Method description	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Calibration method	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Correction method	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	20
Verification method	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Uncertainty determination	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Tie-in procedure	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10
Discrepancy management	clear	available, but not detailed	unclear or indefinite	mentioned, not apparent	not mentioned	10

NOTE 1 There is a standardized method for drilling depth data acquisition, which is documented but outdated and not adapted to the individual rigs; the method is summarily included in training.

NOTE 2 The calibration method is documented but not consistently applied; there is no calibration maintenance scheme, drillpipe is strapped on the pipe racks and checked in when racked in stands; measurement consistency is questionable, pipe length is chalked, and individual stand length data is lost once run in-hole other than the noted pipe tally.

NOTE 3 Corrections to drillpipe length are only rarely applied, usually in cases of high deviation or in stuck-pipe situations; the parameters used are not routinely provided.

NOTE 4 There is no way of verifying the delivered depth information, and no attempt to consider this.

NOTE 5 Uncertainty is considered, but there is no fixed method, and neither is this done consistently.

NOTE 6 Tie-in depth synchronization is well documented and routinely followed.

NOTE 7 The driller makes ad-hoc decisions as to how to manage depth discrepancies; these are documented, but not referred into town prior to implementation.

NOTE 8 Total weighted score is: (75 * 20 %) + (50 * 20 %) + (25 * 20 %) + (0 * 10 %) + (25 * 10 %) + (100 * 10 %) + (50 * 10 %) = 48/100.

B.2 Wellbore Depth Header Requirements

The following examples, Tables B.1 to B.16, are relevant to the depth measurement, and their information should be included in the supplier's record, using those elements relevant to the measurement provided.

Table B.7—Example Header for All Records

Depth Measurement Type	Indicated Calibrated Corrected True Along-hole (TAH)	Required Measurement Error	
		Required Uncertainty at 1-σ	
Type of Measurement	Drillpipe Multi-Conductor E-line Mono-Conductor E-line Slickline Other (specify)	Method Used	Pipe Length Measure Wheel(s)-only Magnetic Marks

Table B.8—Example Header for Measure-Wheel Measured Depth

Depth Measure Wheel #1 Calibration Device Type		Depth Measure Wheel #2 Calibration Device Type (if applicable)	
Serial Number		Serial Number	
Calibration Value		Calibration Value	
Calib. Date Wheel #1		Calib. Date Wheel #2	
Calibration Temperature		Calibration Tension	
Calibration Audit Trail to Standard	Yes/No Reference	Responsible Person	

Table B.9—Example Header for Wave Motion Compensation (WMC)

Tide Height at Trip Zero		Depth Adjustment Made When Engaging Heave Compensator	
Active or Passive Heave Compensation Used	Active Passive	Amount of Rig Heave Throughout Trip	

Table B.10—Example Header for Surface Tension Recording

Surface Tension Device Type		Serial Number	
Calibration Values		Calibration Audit Trail to Standard	Yes/No Reference
Date		Responsible Person	

Table B.11—Example Header for Bottomhole Assembly (BHA) or Cable Head Tension Recording

BHA pipe tension or Cable Head Tension Device Type		Serial Number	
Calibration Values		Calibration Audit Trail to Standard	Yes/No Reference
Date		Responsible Person	

Table B.12—Example Header for Wireline Recorded Depth

Wireline Type		Serial Number	
Low tension surface slack (line-sag) correction		Surface slack (line-sag) correction depth in/out	
Verification Points Logged and Results		Return to Zero Reading and Noted Difference	

Surface Temperature During Entire Logging Trip		First Valid Magnetic Mark for Trip in Hole (if applicable)	

Table B.13—Example Header for Wireline Recorded Depth

Drillpipe #1 Size		Serial Number Tally	Yes/No
Drillpipe #1 Density (#/ft)		Number of Joints	
Drillpipe #1 Total Length		Metal Strength	
Drillpipe #1 ID		Measurement Temp.	
Measurement Made On	Pipe Rack Stands Other (specify)	Measurement Equipment	Tape Laser Other (specify)
Date		Responsible Person	
Drillpipe #2 Size		Serial Number Tally	Yes/No
Drillpipe #2 Density (#/ft)		Number of Joints	
Drillpipe #2 Total Length		Metal Strength	
Drillpipe #2 ID		Measurement Temp.	
Measurement Made On	Pipe Rack Stands Other (specify)	Measurement Equipment	Tape Laser Other (specify)
Date		Responsible Person	
Drillpipe #3 Size		Serial Number Tally	
Drillpipe #3 Density (#/ft)		Number of Joints	
Drillpipe #3 Total Length		Metal Strength	
Drillpipe #3 ID		Measurement Temp.	
Measurement Made On	Pipe Rack Stands Other (specify)	Measurement Equipment	
Date		Responsible Person	

Table B.14—Example Header for Magnetic Mark Calibration Record

Mag. Mark Interval		Mag. Mark Device Serial #	
Mag. Mark Tension		Mag. Mark Temperature	
Mag. Mark Measured 1-σ		Mag. Mark Date	
Calibration Audit Trail to Standard	Yes/No Reference	Responsible Person	
Mag. Mark Verification Device Type		Serial Number	
Calibration Values		Date	
Mag. Mark Tension Device Type		Serial Number	
Calibration Values		Calibration Audit Trail to Standard	Yes/No Reference
Date		Responsible Person	

Table B.15—Example Header for Correction Method Used

Correction Application Model Used	None Single Point Straight Line Way-Point Modelled Tension Incremental Other (specify)	Correction Parameters Included	Temperature Surface Tension BHA (CHT) Tension Pressure Friction Other (specify) Down Log-Up Log
Log of Applied Correction	Yes/No	Responsible Person	

Table B.16—Example Header for Measurement Correction Parameters

Elastic Stretch Coefficient		Source of Coefficient	OEM Specifications Calib. Measurement Spooling Tension In-situ HUD Mag. Mark Derived Calculation (specify) Other
Temp. Coefficient		Source of Coefficient	
Other Corrections Applied		Other Parameters Used	
Date		Responsible Person	

Annex C

(informative)

C.1 Magnetometer and Accelerometer Measurements QA/QC

Table C.1—Magnetometer and Accelerometer Instrument-type QA/QC Requirements

QA/QC Practice		Directional Survey Measurement Magnetic Tool-type			
		a	b	c	d
		Magnetic compass without surface readout	Three-axis magnetometer with surface readout deployed as part of drillstring	Three axis magnetometer with surface readout deployed in open hole	Three-axis magnetometer without surface readout
1	Instrument calibration	*R*	*R*	*R*	*R*
2	Acceptance testing and verification	*R*	*R*	*R*	*R*
3	Roll tests	*N/A*	*R*	*R*	*R*
4	Rigsite surface tests	*N/A*	*R*	*R*	*N/A*
5	Benchmark check shots	*O*	*O*	*O*	*O*
6	Rotation check shots	*N/A*	*O*	*N/A*	*N/A*
7	Survey QA/QC practices	*R*	*R*	*R*	*R*
8	Internal QC	*N/A*	*O*	*O*	*O*
9	Survey station QC tests	*N/A*	*R*	*R*	*R*
10	Comparison to independent survey instrument	*O*	*O*	*O*	*O*
11	MSA	*N/A*	*O*	*O*	*O*
12	Survey station repeat with same tool	*O*	*O*	*O*	*O*
13	Multiple sensors at common depths	*O*	*O*	*O*	*O*
14	Axial magnetic correction	*N/A*	*O*	*O*	*O*
15	MSC	*N/A*	*O*	*O*	*O*
16	Single failed sensor recovery	*N/A*	*O*	*O*	*O*
17	In-field referencing	*O*	*O*	*O*	*O*

Key
R = required; tool's measurements cannot be qualified for use without the practice.
O = optional; tool's measurements may be further qualified for use with this practice.
NA = not applicable for this tool type.

See Section 4.8.3.1 for more information about QA/QC requirements.

Table C.2—Example of Acceptance Limits

Error Term	Value	Weighting	Value × Weight Contribution	Notes
MBX	70 nT	Bx/B_{Total}	70 × 0.5300 = 37 nT	Bx bias term at 1σ
MBY	70 nT	By/B_{Total}	70 × 0 = 0 nT	By bias
MBZ	70 nT	Bz/B_{Total}	70 × 0.8480 = 59 nT	Bz bias
MSX	0.0016	Bx^2/B_{Total}	13250 × 0.0016 = 21 nT	Bx scale error term at 1σ
MSY	0.0016	By^2/B_{Total}	0 × 0.0016 = 0 nT	By scale error
MSZ	0.0016	Bz^2/B_{Total}	33920 × 0.0016 = 54 nT	Bz scale error
MFI	5 nT	-1	5 × (-1) = - 5 nT	Reference field uncertainty

Resultant limit value at 1σ:	= 91 nT	RSS of the above
Maximum test limit at 2σ:	= 182 nT	Scale up to 2σ (*N* = 2)
NOTE For this laboratory test, the MFI reference field error term value describes the reference magnetometer and not the uncertainty in a main field model where Bx = 25,000 nT, By = 0, and Bz = 40,000 nT.		

Refer to Section 4.8.3.3.11 for this acceptance limits example.

Table C.3— Example of Roll Test Limits

Error Term	Value	Weighting	Value × Weight Contribution	Notes
ABX	0.0040 m/s^2	cos(Inc)·sin(TF)/G_{Total}	0.0040 × 0/9.80665 rad = 0.0°	Gx bias term
ABY	0.0040 m/s^2	cos(Inc)·cos(TF)/G_{Total}	0.0040 × 0/9.80665 rad = 0.0°	Gy bias term
ASX	0.0005	Gx·cos(Inc)·sin(TF)/G_{Total}	0.0005 × 0/9.80665 rad = 0.0°	Gx scale error term
ASY	0.0005	Gy·cos(Inc)·cos(TF)/G_{Total}	0.0005 × 0/9.80665 rad = 0.0°	Gy scale error term
MXYa	0.06°	1	0.06 × 1 = 0.06°	Misalignment
Resultant maximum error at 1σ:			= 0.06°	RSS of the above
Double the error to estimate spread limit (opposing tool faces):			= 0.12°	Spread limit at 1σ
Maximum test limit at 3σ:			= 0.36°	Scale to 3σ (*N* = 3)

Refer to Section 4.8.3.3.18 for more information about roll test limits.

Table C.4— Example of Check Shot Limits

Error Term	Value	Weighting	Value × Weight Contribution	Notes
ABX	0.0040 m/s^2	cos(Inc)·sin(TF)/G_{Total}	0.0040 × 0/9.80665 rad = 0.0°	Gx bias term
ABY	0.0040 m/s^2	cos(Inc)·cos(TF)/G_{Total}	0.0040 × 0/9.80665 rad = 0.0°	Gy bias term
ABZ	0.0040 m/s^2	sin(Inc)/G_{Total}	0.0040 × 1/9.80665 rad = 0.2°	Gz bias term
ASX	0.0005	Gx·cos(Inc)·sin(TF)/G_{Total}	0.0005 × 0/9.80665 rad = 0.0°	Gx scale error term
ASY	0.0005	Gy·cos(Inc)·cos(TF)/G_{Total}	0.0005 × 0/9.80665 rad = 0.0°	Gy scale error term
ASZ	0.0005	Gz·sin(Inc)/G_{Total}	0.0005 × 0/9.80665 rad = 0.0°	Gz scale error term
SAG	0.08°	sin(*Inc*)	0.08 × 1.0 = 0.08°	Sag error
MXYa	0.06°	1	0.06 × 1 = 0.06°	Misalignment
DREF	0.35 m	BR	0.35 x 0.5/30 = 0.01°	Depth match error
Resultant maximum error at 1σ:			= 0.10°	RSS of the above
Scale up by √2 to account for the same terms with a separate tool:			= 0.15°	Spread limit at 1σ
Maximum test limit at 3σ:			= 0.44°	Scale to 3σ (*N* = 3)

See Section 4.8.3.3.27 for more information about this example of check shot limits where Gx = 0.0 standard G, Gy = - 1.0 standard G, Gz = 0.0 standard G.

Table C.5— Example Table of Magnetic Reference Pass/Fail Limits

Error Term	Value	Weighting	Value × Weight Contribution	Notes
MBX	70 nT	Bx/B_{Total}	70 × (-0.5300) = - 37 nT	Bx bias term at 1σ
MBY	70 nT	By/B_{Total}	70 × (-0.8480) = - 59 nT	By bias
MBZ	70 nT	Bz/B_{Total}	70 × (-0.8480) = 0 nT	Bz bias
MSX	0.0016	Bx^2/B_{Total}	13250 × 0.0016 = 21 nT	Bx scale error term at 1σ
MSY	0.0016	By^2/B_{Total}	33920 × 0.0016 = 54 nT	By scale error
MSZ	0.0016	Bz^2/B_{Total}	0 × 0.0016 = 0 nT	Bz scale error
AMIC	220 nT	Bz/B_{Total}	220 × 0 = 0 nT	AX
MFI	130 nT	-1	130 × (-1) = - 130 nT	Reference field uncertainty
Resultant limit value at 1σ:			= 159 nT	RSS of the above
Maximum test limit at 3σ:			= 476 nT	Scale up to 3σ (N = 3)

See Section 4.8.3.4.13 for more information about this example table of magnetic reference pass/fail limits where Bx = -25,000 nT, By = -40,000, Bz = 0 nT.

C.2 Gyroscope and Accelerometer Attitude Measurements QA/QC

Table C.6—Gyroscope and Accelerometer Instrument-type QA/QC Requirements

QA/QC Practice		Directional Survey Measurement Gyro Tool-type							
		a	b	c	d	e	f	g	h
		Surface Orientation Referenced without Surface Read-out	Surface Orientation Referenced with Surface Read-out	Gyro-Compass (2-axis gyro) without Surface Read-out	Gyro-Compass (3-axis gyro) without Surface Read-out	Gyro-Compass (2-axis gyro) with Surface Read-out	Gyro-Compass (3-axis gyro) with Surface Read-out	Continuous Running (2-axis gyro)	Continuous Running (3-axis gyro)
1	Calibration Acceptance Check	R	R	R	R	R	R	R	R
2	Calibration Verification	R	R	R	R	R	R	R	R
3	Tool Function Surface Test	R	R	R	R	R	R	R	R
4	Overlapping Check Shots between Survey Runs	O	O	O	O	O	O	O	O
5	Rotation Check Shots	NA	NA	O	O	O	O	NA	NA
6	Standard Operation Procedures for Survey Practices	R	R	R	R	R	R	R	R
7	Internal Gyro QC	O	NA	R	R	R	R	NA	NA
8	Reference Field Tests	NA	NA	R	R	R	R	NA	NA

9	Reference Orientation	NA	R	NA	NA	NA	NA	O	O
10	Comparison to Independent Survey Instrument	NA	O	O	O	O	O	O	O
11	In-run/Out-run Comparison	NA	NA	O	O	O	O	O	O
12	MSA	NA	NA	O	O	O	O	NA	NA
13	Continuous Initialization	NA	NA	NA	NA	NA	NA	R	R
14	Drift Correction	NA	O	NA	NA	NA	NA	O	O
15	Misalignment Correction	NA	NA	O	O	O	O	O	O
16	Post-survey Roll Test/ Calibration	O	O	O	O	O	O	O	O
17	Survey Degradation	NA	NA	O	O	O	O	O	O
18	Survey Measurement Corrections:	NA	NA	O	O	O	O	O	O
a	Depth	—	—	O	O	O	O	O	O
b	Multi-station	—	—	O	O	O	O	NA	NA
c	Sag	—	—	O	O	O	O	NA	NA

Key
R = required; tool's measurements cannot be qualified for use without the practice.
O = optional; tool's measurements may be further qualified for use with this practice.
NA = not applicable for this tool-type.

See Section 4.8.4.2 for more information about this summary table of gyroscope and accelerometer instrument-type QA/QC requirements.

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