Project Ahead Uncertainty: Implications and Interpretation

ISCWSA Collision Avoidance Subcommittee guidance

Revision History			
Revision	Revision Details	Issuer	Date
0.2	Draft	Gary Skinner	March 2022

Contents

Purpose

This document expands the discussion of the project ahead uncertainty term, σ_{pa} (Sigma-PA), from SPE paper SPE-187073, to provide a reference for people seeking justification for its value, or to alter its value, accompanied by procedural changes.

Equation 1: SPE WPTS Rule

$$\frac{Dist - \left(HoleRad_{ref} + HoleRad_{off}\right) - Sm}{k\sqrt{\sigma_s^2 + \sigma_{pa}^2}}$$

When published, the value for σ_{pa} of 0.5m (1 standard deviation) was a consensus estimate with limited empirical evidence assuming a survey interval of less than 30m. As the SPE HSE Stop Drilling Rule uses a scaling factor of 3.5, the scaled σ_{pa} of 1.75m represents a probability of approximately 1 in 5000 that this value will be exceeded in the direction of any given offset.

To date, arguments have been made for reducing σ_{pa} when survey interval length is reduced. The impact of sensor-to-bit distance and borehole curvature when reducing σ_{pa} with reduced course length, has not been fully addressed.

Background

SPE-187073: Well-Collision-Avoidance Separation Rule defines a term for project ahead uncertainty: This was introduced to quantify the uncertainty in the projection ahead of the current survey station and is a fixed distance-uncertainty which is root sum squared with the combined uncertainty of the reference and offset wells at each calculation point.

SPE-187073 provides the following information

> *Quantifies the 1-SD [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 on 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 predominantly oriented normal to the reference well, it is mathematically convenient to define σpa as being the radius of a sphere.*

As σ_{pa} accounts for modelled uncertainty, it dominates when wellbore position uncertainty is small, but where positioning errors can have tangible collision risks. In most situations this is near surface, with nominally vertical wellpaths, and large hole sizes.

Guidance for choosing a value for σ_{pa}

When deciding on a value for σ_{pa}, a holistic approach is required incorporating:

- Corporate risk profile
- Previous experience in similar campaigns
- Directional sensor to bit distance
- Project ahead distance (survey interval)
- Angular control from BHA

Prior to adjusting the WPTS published rule a thorough risk analysis should be performed.

A rule of thumb is to adopt a value of 0.01 meter per meter (1%) total projection to bit and Lookahead distance.

For simplicity, and to avoid proliferation of rules, 2 additional variants are proposed defined by survey course length (Lookahead):

Rule	Proj to bit (m)	Lookahead (m)	σ_{pa} (m)	Angular Control equivalent
WPTS (Standard):	-	≤30	**0.5**	≤2.5°
WPTS (10m survey)	≤20	≤10	**0.3**	≤0.5°
WPTS (continuous survey)*	≤10	≤5	**0.15**	≤0.15°

Empirical Data

Analysis of drift data from vertical for a large data source was presented during ISCWSA 54, and reviewed for this paper, indicating that 0.5m / 30m course length @ 1 standard deviation is an appropriate value for σ_{pa}.

The data and methods employed in this analysis only show the impact of the lookahead distance. The size of the data set is sufficient to let us assume an average projection to bit distance.

Impact of Project Ahead uncertainty on MASD

Minimum Allowable Separation Distance (MASD) is a re-arrangement of the collision avoidance separation rule that provides a centre-to-centre distance measure when the rule's pass/fail limit value is met.

As σ_{pa} is combined with other uncertainty sources in the separation rule, its impact on MASD will typically decrease with increasing measured depth.

Figure 1 shows the impact on MASD of various values of σ_{pa} from two parallel vertical wells based on ISCWSA test Well #1 and both using ISCWSA MWD Rev 5 models. Dashed lines represent horizontal drift over 30m $(30 \times \sin\theta)$ for constant inclination angles: 2.0°, 1.0°, and 0.5°.

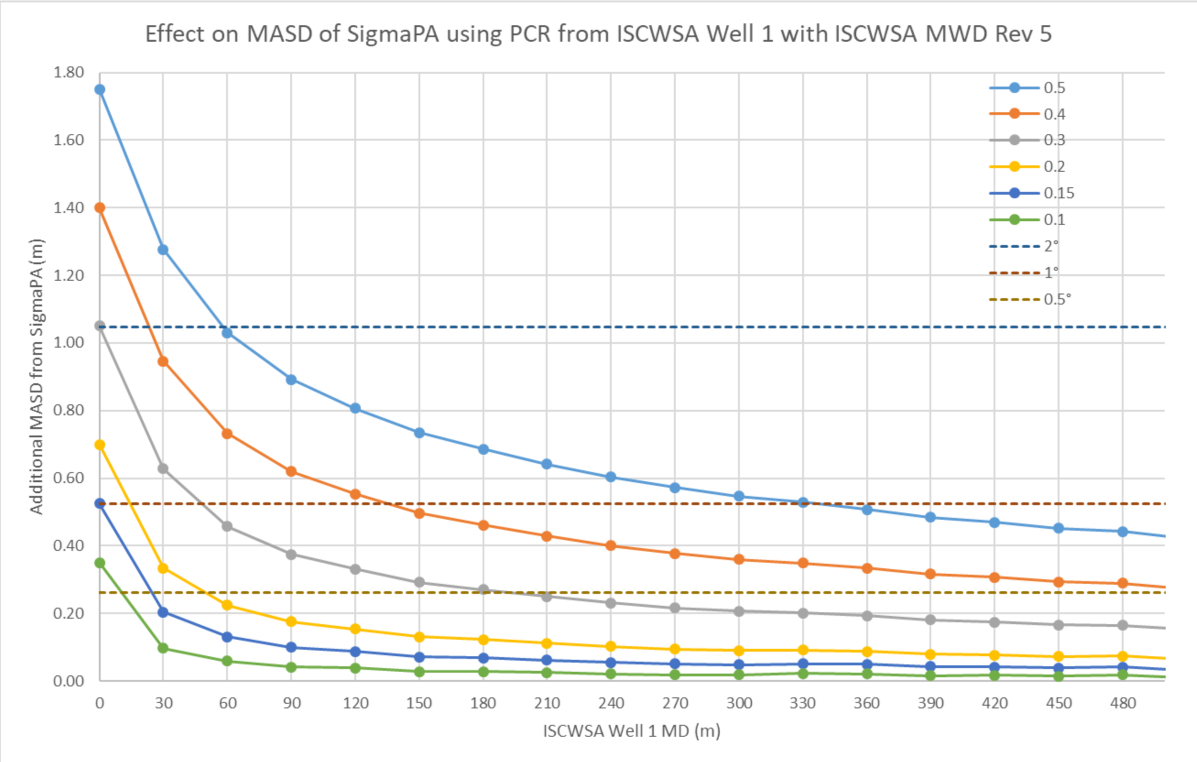


Figure 1: Effect on MASD of Sigma-PA

Table 1 shows the additional MASD values for the initial survey intervals by Sigma-PA. The values represent the positional control required to stay within the additional MASD provided by project ahead uncertainty.

- Light orange = less than 0.5m (20in)
- Orange = less than 0.25m (10in)
- Dark Orange = less than 0.10m (4in)

Table 1: MASD values (m) based on Figure 1

MD	Sigma-PA					
(m/ft)	0.5	0.4	0.3	0.2	0.15	0.1
30/100	1.28	0.95	0.63	0.33	0.20	0.10
60/200	1.03	0.73	0.46	0.22	0.13	0.06
90/300	0.89	0.62	0.38	0.18	0.10	0.04
120/400	0.81	0.55	0.33	0.15	0.09	0.04
150/500	0.73	0.50	0.29	0.13	0.07	0.03

When analysing data to with the intention of adjusting σ_{pa}, it is important to focus on the impact on Available Space vs. the impact to separation factor. Will there be sufficient space to account for the directional driller being off-plan.

The impact on σ_{pa} is dependent on its size relative to the offset and reference wellbore's pedal curve radii. In the example both reference and offset wellpaths use ISCWSA MWD Rev 5 error models with no relative surface uncertainty. Using a less conservative model, such as ISCWSA MWD Rev 4, will result in a smaller pedal curve radii for the wellpaths, and σ_{pa} will have a larger effect for longer. A more conservative model, producing larger pedal curve radii such as an inclination only planning model, will have a smaller effect for shorter. Any surface uncertainty applied to the reference and offset wellpaths uncertainty will increase the pedal curve radii.

Angular Control

Table 2 converts the values in Table 1 to angular change per 30m assuming a straight line using $\sin^{-1}\left(\frac{MASD}{30}\right)$.
This is a measure of the control the directional driller requires to stay within the additional MASD provided by project ahead uncertainty.

- Light orange = less than 1°
- Orange = less than 0.5°
- Dark Orange = less than 0.1°

Table 2: Equivalent displacement angle (°) from excess MASD

MD (m/ft)	Sigma-PA					
	0.5	0.4	0.3	0.2	0.15	0.1
30/100	2.44	1.81	1.20	0.64	0.39	0.18
60/200	1.97	1.40	0.87	0.43	0.25	0.11
90/300	1.71	1.18	0.72	0.34	0.19	0.08
120/400	1.54	1.06	0.63	0.29	0.17	0.07
150/500	1.40	0.95	0.56	0.25	0.14	0.05

Available Space and Separation Factor

In the following example, Available Space, also referred to as Allowable Deviation from Plan (ADP), is used which is [Centre-to-Centre Distance] – [MASD].

MASD was calculated from the same parallel wells used in Figure 1, with example values producing a numerator of 2.0m:

- Centre-to-Centre separation distance = 2.91m
- Offset and Reference hole Radii= 0.91m
- Surface Margin = 0.0m

For simplicity, values of σ_{pa} were limited to 0.5, 0.3 and 0.0. Solid lines are Available Space, plotted on the left hand vertical scale, dashed lines Separation Factor plotted on the right.

At 150m:

- blue line (σ_{pa}=0.5) fails with a separation factor 0.82 and available space -0.43m.
- orange line (σ_{pa}=0.3) 'passes' with a separation factor of 1.00, and available space of 0.01m
- green line (σ_{pa}=0.0) passes with separation factor of 1.18, and available space of 0.31m

No project ahead uncertainty (green line) shows an apparently very good separation ratio. However, the 0.31m of free space equates to a drift angle of 0.59°.

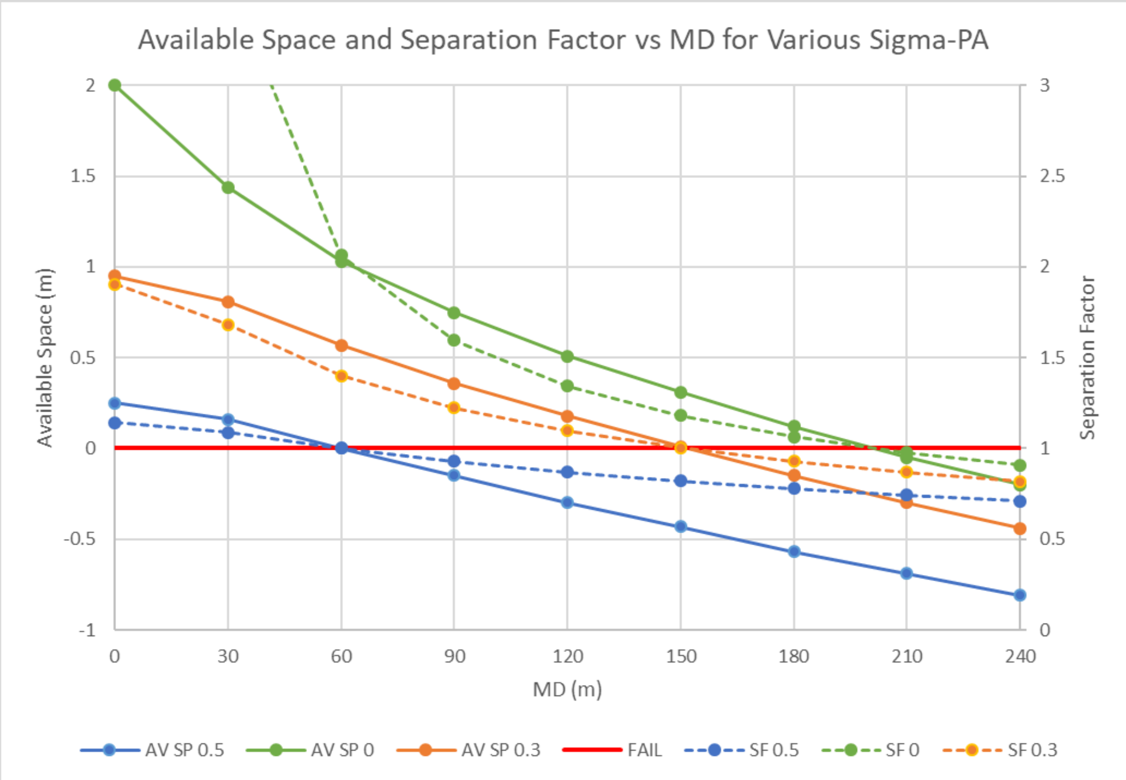


Figure 2: Available Space and Separation Factor vs MD

Factors captured in Project ahead uncertainty

We calculate a wellpath's position by using attitude measurements (inclination and azimuth) at discrete survey stations (measured depth) and joining the survey stations using a minimum curvature arc. Taking a new survey shows where we have been, but we don't know the bit's attitude when the survey is taken or the position of the bit when drilling commences after that survey.

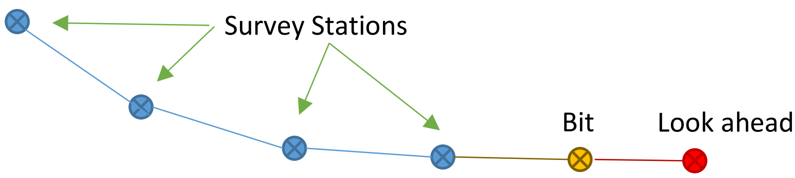


Figure 3: Schematic of Survey, Bit Position and Look Ahead

Error! Reference source not found. shows 4 survey stations (blue), the bit position after the last survey (yellow) and the look ahead (red) which is the bit's projected position after drilling the next interval. This schematic shows that during drilling operations, project ahead distances cover two zones of, as-yet, unsurveyed wellbore that are critical for collision avoidance management:

- Distance from measurement sensor to the end of the open hole interval
  - Projection to bit distance
- Distance from Projection to bit to where the bit will be when the next survey is taken
  - Look-ahead distance
    - Other terms may be used for this distance, this name was chosen to remove possibilities for confusion.
  - Defined as survey course-length / survey frequency in the survey program

Over these two intervals, some effects that are generally considered to be random over the course of a survey log cannot be assumed to act randomly over a projected interval.

Projection to bit distance

Projection to bit distance is determined by the components that make up the bottom hole assembly (BHA), so is fixed for a particular directional sensor in a BHA.

Typical near-surface BHAs consist of a directional motor, stabilizers, and non-magnetic drill collars holding a magnetic MWD tool. In this configuration the distance from the MWD sensor to the bit can be 20m (+/- 5m).

In collision-risk scenarios, a gyroscopic sensor is often used. A while-drilling gyro can be placed below (closer to the bit) or above the MWD; a drop gyro system will be substantially above the MWD with the Gyro-to-bit distance possibly exceeding 40m.

Rotary steerable (RSS) BHAs, typically have far shorter MWD-to-bit distance, and, additionally, often incorporate near-bit inclinometers and/or magnetometers within 1 or 2m of the bit. While the data from these sensors may not achieve the accuracy of survey qualified measurements, they provide trend data that can be used to verify directional control.

Table 3: Bit to Sensor distance ranges for typical BHAs

Scenario	Typical Range	
	(m)	(ft)
RSS Near-bit	1-5	3-15
RSS+MWD	5-10	15-30
Motor+MWD	15-25	50-80
Motor+MWD+Gyro	25-35	80-115
Motor+MWD+Drop Gyro	30-50	100-170

*ft values approximated from metric range

A steerable motor assembly will have a theoretical build-up rate based on the stabilisation and bend angle of the motor. The larger the build-up rate and, importantly, the bigger the difference to the planned build-up rate through collision risk intervals, the more critical projection-to-bit distance becomes as the possibility for undetected deviation from plan increases.

Lookahead distance

The coordinates at the end of the lookahead are the best estimate of where the bit will be after drilling to the next survey point. As a result of the relationship to the survey interval, lookahead distance is determined as part of collision avoidance planning, and encoded in the survey program as the survey course length/survey frequency.

Operationally, survey course length for static MWD surveys, defaults to the number of joints of drillpipe that the rig can pick up and drill with, before circulation is broken and another length of drillpipe added. Today, most rigs pick up 3x joints of drillpipe (or singles), some handle 4x joints, with each joint nominally 10m/30ft. A group of singles is called a stand (3x or 4x).

This leads to the default of 30m/100ft course length used for MWD. For simplicity, taking a survey at each joint, single, of 10m/30ft is used when more frequent surveys are needed.

Steering information

Calculated rotating measurements of inclination and/or azimuth, and toolface orientation can be transmitted from MWD tools at a set time interval. The depth spacing of these values is dependent on rate of penetration, but several values will be received at surface per stand.

Additionally some BHA components contain independent sensors which may provide data closer to the bit than the directional sensor. These data are often transmitted on a temporal basis, usually multiple times per stand.

Steering information is used by the directional driller (DD) to understand the behaviour of the steerable assembly between surveys.

- Example Values
    - Toolface orientation (High-side, magnetic, gyro)
    - Continuous/rotating/calculated inclination and/or azimuth
    - Bending measurement / orientation
- Assumption: Toolface Orientation setting is already used in the projection
- Considerations
    - Sensor Position
    - Measurement accuracy
    - Data update rates
- Use of steering information to reduce σ_{pa}
    - Best case: Less effective than reducing survey interval to similar distances
    - Worst case: No change

The possible variability between different directional drillers, different automation platforms, and different drilling systems needs to be incorporated into σ_{pa}. For example, SPE 199556 quotes a standard deviation of toolface precision of 20%, and a case showing a difference of 4° in estimated bit inclination between human (29°) and automated forward modelled (25°).

Ability to follow planned wellpath

Pre-drilling collision management analysis assumes that the directional driller follows the well plan. As σ_{pa} applies at all points in the reference wellpath, part of it will account for being off plan. This assumption also applies during the projection to bit and Lookahead interval.

Intervals where there are changes in borehole curvature, i.e. change in dogleg severity, represent a higher risk of not precisely following the plan. The steerable technology employed will impact the ability of the directional driller to hold a given borehole curvature.

Appendix A: Additional Factors

A non-exhaustive list of additional, situation specific, factors that could affect the ability to follow a planned trajectory are described below.

- Challenges in drilling planned curvature
    - Unconsolidated formations
    - Interaction with boulders/stringers
    - Eccentric hole gauge from rotary drilling with steerable motor assembly
- Low BHA stabilization
    - BHA not centralised in borehole, leading to additional misalignment
- Sensor Challenges
    - Inaccurate magnetic toolface due to offset wells
    - Inaccurate highside toolface due to verticality
    - Poorly defined azimuth results at low inclinations
- Environmental impacts on surveying
    - Higher surface vibration as less string in hole to damp vibrations
    - Sea effects (currents, tides, etc)
- BHA's ability to self-steer
    - E.g. downhole closed loop steering to maintain verticality

Changes to the misalignment error model terms for ISCWSA Revision 5 should improve the modelling of some of these effects in large hole and will apply over the projection intervals

Appendix B: Modelling Assumptions

This paper assumes that, when applied to while drilling clearance calculations a contiguous survey log is used that incorporates survey stations, projection to bit and look ahead trajectory. The result of this logic would be a perfectly drilled wellpath would return the same position uncertainty as its plan.

Software implementations that applies a different error model to the projection to bit distance and/or the look ahead trajectory should incorporate project ahead uncertainty into their modelling. These models should not implement standard tie-in logic for uncorrelated log-to-log terms to avoid improper position uncertainty reduction.

Appendix C: Modelling σ_{pa} as a function of Projection to bit and look ahead distances

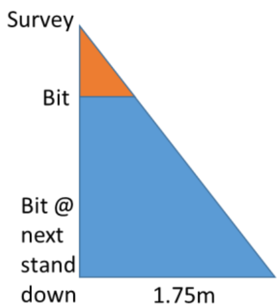
This appendix outlines alternative methods for translating σ_{pa} into tangible values. The examples are based on cases where σ_{pa} is the only source of uncertainty.

As σ_{pa} combines projection to bit and Lookahead distance, and applies at all points in the clearance calculation, two viewpoints may be assumed when looking to model σ_{pa} based on their values:

- Total length of blind interval (bit depth at next survey – survey depth)
  - Projection to bit + look ahead
  - Can be visualised as σ_{pa} growing with length of blind interval
  - Provides a simple relationship of σ_{pa} to total length
  - Can be tied back to 'excess dogleg severity'
- Assume 2 independent blind intervals
  - Projection to bit & look ahead
  - $\sigma_{pa} = \sqrt{\sigma_{p2b}^2 + \sigma_{la}^2}$
    - p2b = projection to bit, la = Lookahead
  - Better accounts for interaction of the directional driller with the drilling process as data are acquired between the surveys
  - Could create excess rules, increasing possibility of confusion

Both viewpoints can correspond to physical realities, and neither is perfect.

Total Length Example



- total length = 50m
  - e.g. 20m projection to bit + 30m Lookahead;
- scaled $\sigma_{pa} = 1.75$
  - $\sigma_{pa} = 0.5;\ 3.5\ \times \sigma_{pa} = 1.75$

Therefore
- the angle made in the triangle = 2°
  - $\left(\tan^{-1}\frac{1.75}{50}\right)$
- The change of angle = 1.20°/30m
  - equivalent to a dogleg severity

By using this change of angle per length value, we can then derive σ_{pa} values for various lengths:

Table 4: Impact on σ_{pa} of total length holding change of angle constant

σ_{pa} (m)	Pr.to.bit (m)	Look ahead (m)	Total Length (m)
0.08	10	10	**20**
0.18	20	10	**30**
0.32	10	30	**40**
0.50	20	30	**50**
0.72	30	30	**60**
0.98	40	30	**70**
1.28	50	30	**80**

The smaller values of σ_{pa} (highlighted in yellow) allow for less than a bit-diameter of project ahead uncertainty: $0.08m \times 3.5 = 0.28m \sim 11in; 0.15m \times 3.5 \sim 20in; 0.18m \times 3.5 \sim 24in$.