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PATH OPTIMIZATION ADVISOR AND ANALYTICAL TOOLS FOR DIRECTIONAL DRILLING

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PATH OPTIMIZATION ADVISOR AND ANALYTICAL TOOLS FOR DIRECTIONAL DRILLING

by

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Thesis

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

Master of Science in Engineering

The University of Texas at Austin

August 2017

Dedication

To my parents and boyfriend, for their endless love and support.

Acknowledgements

I would like to express my deepest gratitude to my supervisor, Dr. Eric van Oort, for his guidance, support, and encouragement throughout my research and experimentation. I would also like to thank Dr. Pradeepkumar Ashok for his guidance and support throughout my graduate education. Without their knowledge, support, encouragement, and dedicated assistance, this project could not have been possible. Their insight in vision and expertise has helped me solved multiple difficulties.

I would also like to thank Matt Isbell, Jason Murray, Lee Bartholomew, Mariano Gurfinkel and Shawn Behounek from Hess Corporation for supporting this study and providing technical advises. Their support of this project makes it possible to complete my degree and maximize my learning potential. Special thanks to Hess Corporation for providing data and supports.

I also want to thank Dr. Kamy Sepehrnoori, Tesse Smitherman, Frankie Hart, Amy Douglas Stewart, Glen Baum, and Gary Miscoe for their administrative support.

Finally, I would like to thank everyone in RAPID Group for your advice, assistance, patience, and friendship.

Abstract

PATH OPTIMIZATION ADVISOR AND ANALYTICAL TOOLS FOR DIRECTIONAL DRILLING

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In directional drilling, well positioning and drilling instructions are planned based on human experiences and may require excessive computation and drilling times. Directional drilling process nowadays lacks optimization and automation to improve performance and efficiency. A path optimization advisor is developed with novel cost analysis, to support real-time directional drilling decisions.

Spline in tension is used to simulated drilling path in the path optimization algorithms; more accurate and convenient for optimization purposes than commonly used survey calculation methods. The best valued path is solved using multi-loop optimization process, by determining the path with the lowest accumulated cost. Costs specified for each section are formulated and transformed into equal units. Actual drilling instruction is fitted to the optimal path with consideration of motor tendency and capabilities.

The advisor developed using Matlab is validated that such a system can be used in real time directional drilling environments, to provide suggestions. Test cases using simulated drilling situation and historical data are tested for resulting instruction validation. Produced instruction and path results proved to be realistic and optimized based on

specified cost functions. Comparing the optimized path with actual drilling instruction and survey drilled in historical cases, plan suggested by the path optimization advisor provides a better valued correction path.

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Chapter 1: Introduction

Directional drilling is the practice of drilling deviated wellbore along a previously planned path to a target location. Drilling and landing wells to designed position is essential for future completion and production of the well. Current practice of directional drilling depends heavily on human expertise and lacks a robust repeatable scientific approach. Directional drilling contributes to significant non-productive time of more than 5 % (Villatoro, 2009) and can be improved to reduce value wasted.

To address this problem, a path optimization advisor is developed along with an automated directional drilling advisor framework, to suggest the best valued path for directional drilling accuracy and efficiency. The path optimization advisor aims to improve the directional drilling efficiency by suggesting an optimal path and slide and rotate instructions based on appropriate costs analysis. The advisor helps reduce the directional driller's instruction variabilities, and improves the accuracy and computation time of directional drilling instructions.

Seven chapters are included in this thesis. Chapter two lists related literature reviews on commonly used survey calculation methods and errors, path optimization criteria and objectives, and existing path correction algorithms. Chapter three shows a suggested modular frame for automated directional drilling, and briefly discussed the various modules. Chapter four explains the methodologies used in the path optimization advisor, as well as cost function formulation and analysis, and actual drilling instruction formulation. Chapter five displays simulation and actual field data test validations and results. Chapter seven discussed conclusions and future work.

Chapter 2: Literature Review

In this Chapter, we review literatures regarding simulation of a drilling path, directional drilling criteria and cost, geosteering target analysis, and path suggestions. The first set of literature studied is extrapolating and simulating drilling path. Optimization criteria and recent development in automated directional drilling is also looked into.

2.1 Simulating Drilling Path

Conventional survey calculation methods are often used to simulate or extrapolate drilling path. When calculating survey,

The most widely used survey calculation method in the field is minimum curvature method. Many studies have been done on the method, both regarding accuracy and extrapolation. Sawaryn published a compendium of directional survey calculation based on minimum curvature method in 2003 and followed it with another paper in 2005, that detailed extrapolation of survey point and simulation of drilling path (Sawaryn et al., 2005). The papers contain a compendium of algorithms based on minimum curvature method, using vector calculus method to improve mathematical efficiency. This literature shows equations for calculating a point to target trajectory plan using minimum curvature methods, and displayed the benefit and efficiency of using vector methods in three-dimensional directional calculations. Inspiration for simulating drilling path is drawn from Sawaryn's paper where, all drilling trajectory is a combination of circular arc and straight-line projections. However, the combination of circular arc and straight-line path, is not cost efficient nor easily optimized in optimization process. Minimum curvature method used also may not be sufficient to represent actual drilling activities of rotating and sliding.

Another method for calculating survey positions is constant tool face methods, or constant curvature method. Constant tool face method is first used for planning a three-dimensional well path at a macroscale planning (Guo et al., 1992). The method assumes a constant bottom hole assembly tendency and tool face when sliding, which is suitable to an ideal path of slide drilling (Schuh, 1992). Combining with the assumptions of straight-line path for rotate drilling, a drilling path of slide and rotate sequences can be simulated. Therefore, constant tool face method is better at simulating true drilling actions than other path calculation methods, and is used to simulate drilling path.

Many errors in well positioning has also been studied for estimating the directional drilling path. Due to the usage of different survey calculation method, errors in true vertical depth, easting and northing is inevitable but may be controlled to a small tolerance level. The concerns of ignoring the effect of earth curvature in directional drilling using the "flat earth" model is stated and solved in Williamson's paper (Williamson, 2000). Such effect is often neglected due to small influence on well positioning. However, with extended reach drilling of long lateral sections, correcting earth's curvature may be needed.

The Stockhausen effect demonstrates a small sudden in true vertical depth whenever there is a transition between slide and rotate drilling (Stockhausen, 2012). Such effect was validated by directional drilling tests conducted in concrete blocks. The test shows comparison of accurate laser measurements and conventional survey measurement and displayed the vast potential for error in positioning calculation. Figure 2-1 shows the possible true vertical depth error of five feet in true vertical depth over approximately seven hundred feet of measured depth, due to the Stockhausen effect.

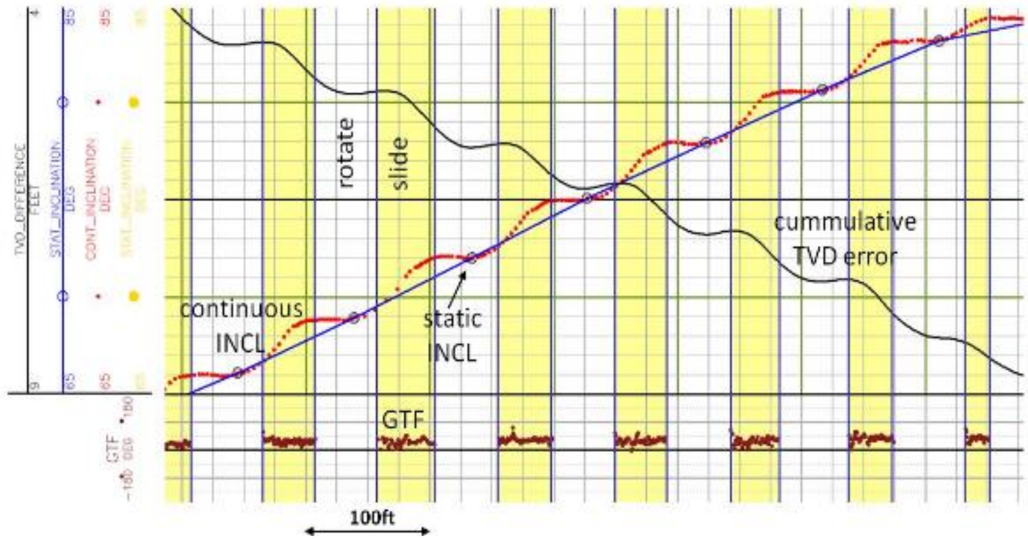


Figure 2-1: Steerable System Slide/Rotate Sequences in the Build to Horizontal Showing TVD Error (Stockhausen, 2012)

Some solutions the industry used to improve well positioning is to use continuous survey (Lesso, 2001) or wired drilling pipe (Lawrence, 2009). Continuous survey while drilling, provides significantly more information regarding well positioning, as well as inclination and azimuth. Such information is more accurate in determining the real drilling path based on the frequency of measurement. Wired pipe, while allowing increased speed for data transferring, also enabled further analysis to manage, process, and visualize data, and stepping toward closed loop automated operations (Wolfe, 2009). Both methods can allow more accurate well positioning while drilling. However, the expense for allowing continuous survey and wired drilled pipe is significant, therefore not often used in conventional onshore drillings.

Splines have been used in recent years to solve specific well positioning problems. Splines allows for the combination of curves and straight-line sections continuously, promoting more efficiency in calculation and optimization. Sampaio published a set of literature deriving spline path calculation, which is used in building the path optimization software for this thesis, and discussed in more detail in later chapters (Sampaio, 2007). Many types of splines had been used in existing directional drilling control system or path determining software due to its continuously path, more suitable for optimization and provide more accurate path results (Yi et al., 2015).

Spline curves are also used to improve torque and drag prediction as shown in a recently published literature by (Abughaban et al. 2017). The literature also listed semi-analytical methods of estimating drilling path using splines, and simulated cases for testing torque and drag. The advanced spline curve explained in (Abughaban et al. 2017) performed better than minimum curvature method in accurate torque and drag predictions. This literature also demonstrated the benefit of using splines for easier simulating path closer to real drilling path than conventional survey calculation methods.

2.2 Correction Path Criteria

Yi published a paper using spline curves to minimize well path energy (Yi et al., 2015). In his paper, different methods of simulating drilling path are compared to use in an optimization path model. In his work, Yi has also set up test cases for his algorithm for finding an optimized path, using the minimum well profile energy criteria. Minimum curvature method, tangential method, and natural curve method are coupled with catenary, spline, and clothoid curves, with detailed derivation to simulate drilling path. The future work of Yi's project is to include three-dimensional analysis and azimuth changes, which would be essential for directional drilling path planning.

In the following year, Zheng Chun Liu and Robello Samuel published a wellbore trajectory control literature, using the minimum well-profile energy criterion for drilling automation (Liu, 2016). The literature proposed a question of correcting path, and how exactly correcting path can be automated without directional driller. This is the goal of our path optimization software as well; to be able to automate and provide better directional drilling instructions. The literature shows a sample problem schematics, which is replicated in Figure 2-2.

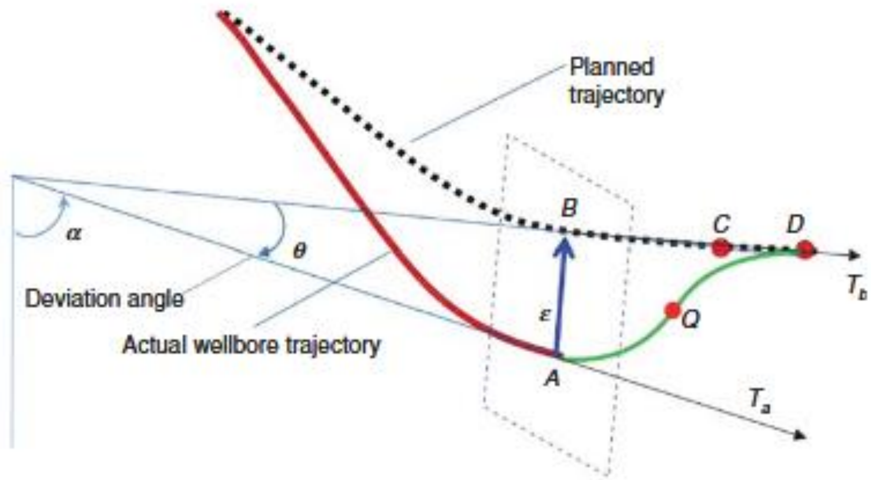


Figure 2-2: Schematic of Deviation Vector AB, Trend Angle θ, and Correction Trajectory A-Q-D (Liu, 2016)

The trajectory control algorithms published by Liu uses proportional-integral-derivative control and fuzzy control (Stoner, 1997) for calculating outputs. To calculate wellbore trajectory estimation, Liu utilized standard minimum curvature model (Zaremba 1973) and the simple balanced tangential model (Michell et al., 2011). Maximum dog-leg severity is also used as one of the constraint. Liualso utilized simulated case problems for correction path, for testing his developed modules.

The criterion for Yi and Liu's model is the minimum well profile energy model developed by Samuel and Liu (Samuel and Liu, 2009). Well profile energy is an index measuring the quality of a wellbore, capturing wellbore torsions and wellbore spiraling, relating to torque, and drag of the drilling path. This index is used as a control method for many path optimization algorithms developed by Samuel.

Another index for measuring wellbore quality is the tortuosity index developed by Zhou, et al., at UT Austin. This index measures how tortuous a well path is using geometrical methods. (Zhou, 2016). The tortuosity index can be calculated in 3-D, which makes it suitable for calculating drilling path in three-dimensional space. A further case studies of tortuosity index and production, rod pump failures and drilling performance is conducted with an operator, proving a clear relationship between tortuosity index and well performance. Therefore, tortuosity index is used as one of the cost functions in the path optimization software. The equation to calculate the tortuosity index developed by Zhou et al., is shown below in equation 2.1.

$$3D\ Tortuosity\ Index\ =\ \frac{n-1}{n*L_c}\sum_{i=1}^{n}\frac{L_{csi}}{L_{xsi}}-1\quad (Zhou, 2016) \tag{2.1}$$

Many key performance indicators are often looked at for directional drilling in the industry, with significant effort to optimize drilling performances. Steps are taken toward advancing current technologies such as advanced rotary steerable system delivering higher build rate capabilities (Eltayeb, 2011), and auto drillers using drilling feed controls to control surface parameters and improve drilling efficiencies (Boyadjieff, 2003).

Most drilling optimization effort was done on optimizing rate of penetration with many published literatures, utilizing artificial neural network (Gidh, 2012), real-time pressure while drilling data analysis (LaPierre, 2006), as well as model simulations (Wiktorski, 2017). Rate of penetration, at the industry practice standpoint, seems to be the most important parameter measuring drilling quality. Surface-downhole weight transfer (Thomson et all, 2017), tortuosity (Zhou, 2016, Bang, 2017), and equipment failure (Rechmann, 2010) has increasing attentions in recent literatures.

Overall, the currently existing path optimization algorithms and software tend to optimize based on drilling parameters, such as ROP, weight on bit, torque and drag. However, drilling quality, as one step out of the entire process for extracting oil, could also influence later steps. The effect of drilling path on completion and production should also be taken into account during path optimization; other performance indicators should also be optimized.

2.3 Recent Development Regarding Optimizing Directional Drilling

Rotary steerable system (RSS) has the capabilities of semi-automated drilling, wherein instructions can be stored or downlinked to the RSS system, allowing the system downhole to control inclination, azimuth, turn rate, build rate etc. (Schaaf, 2000). A closed-loop control can be used for RSS connecting to measurement recorded while drilling to enable faster decisions (Johnstone, 2001). A hybrid approach to close-loop trajectory control is proposed by Matheus, separating trajectory control into an inner loop and an outer loop (Matheus, 2014). This approach sets the outer loop to be running at ninety feet intervals for determining set points, and inner loop to control and maintain inclination and azimuth. The dynamic mathematical model for the trajectory control takes in parameters including rate of penetration, dogleg severity, tool face, steering ratio, dropping rate, and walking rate, azimuth, and inclination. The model also emphasizes the need for parameters determined using historical data that may cause tendencies to inclination, azimuth, and tool face (Matheus, 2010). It is also noted that drilling with rotary steerable system may reduce wellbore tortuosity, due to the small-scale changes it is constantly performing (Weijermans, 2001). Overall, the purpose of rotary steerable system is to be able to reach target, reduce tortuosity, improve rate of penetration, and reduce drilling time. However, due to the expensive cost of rotary steerable service, it is not often used for onshore drilling especially in a low oil price environment.

Auto drillers also utilize close-loop control to optimize rate of penetration, weight on bit, and directional drilling activities (Pink, 2013, 2017). When using real-time system such as wired tubulars, real-time parameter optimization can be done. A process automation system is used for auto-driller to manipulate joysticks, press buttons, and interact with drill ahead activities, which previously manipulated by drillers (Pink 2017). It carries out an automatic process for configuring and performing instructions. An integrated system for NOV's drilling automation system is showing below. The auto-driller combined with wired pipes can be a great step toward optimization and automation. However, the service is also very costly and is not often used in conventional drilling activities on shore.

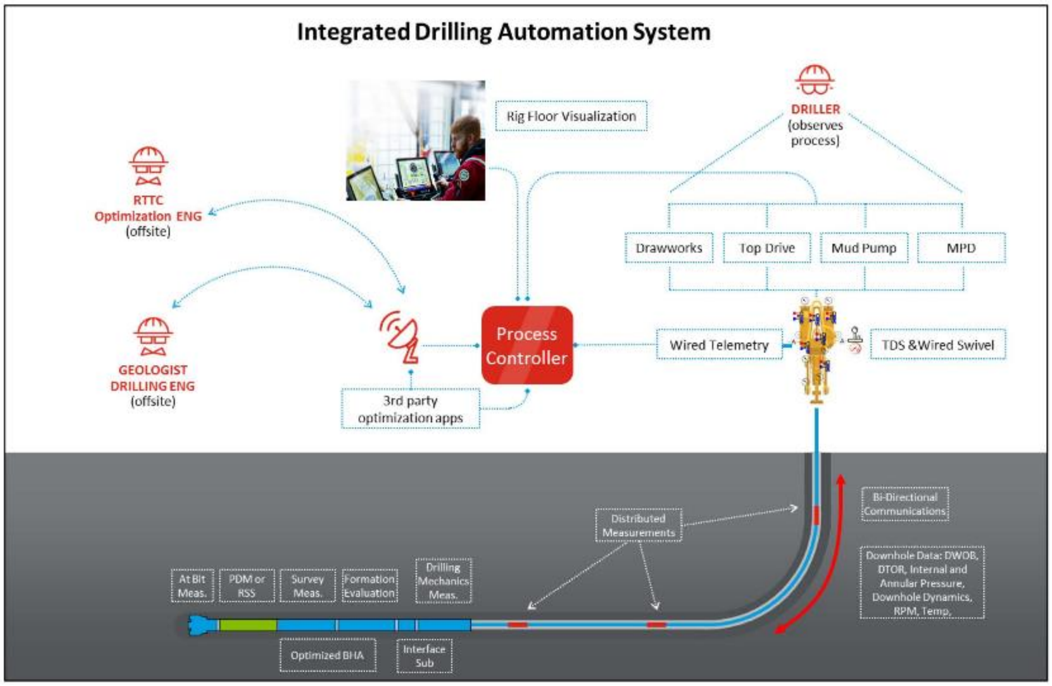


Figure 2-3: NOV's Integrated Drilling Automation System (Pink, 2017)

To optimize a drilling trajectory, many optimization control and methods are used in published literatures. In Panchal works, he has specified an attitude control of directional drilling to develop a path-following algorithm, incorporating optimized geometric Hermite curves as correction path to target, with minimized drills string strain energy (Panchal, 2011). The paper describes the application of optimized geometric Hermite curves for path planning, to generate inclination and azimuth change signals for correction path. In Panchal's later works, he combined trajectory estimation with optimizing for strain energy and torsion, using interior point optimization methods (Panchal, 2013). The path optimization is used for rotary steerable system optimal path determination.

Trajectory design using genetic algorithm is proposed by Ilyasov, as part of a well trajectory design software package (Ilyasov et al., 2014). Genetic algorithm is a heuristic optimization method that mimic the process of natural selection. The strategy is to populate individuals or solutions possible to the problem parameters, and allow crossover and mutations for producing children, and finally determine selection of fitted solutions. The algorithm is an iterative process that repeats a cycle of operations until one of the termination conditions is met: fixed number of generation reached or a solution is found that satisfies the criteria with a level of accuracy. This optimization algorithms is used in the trajectory design software module for RN-KIN, and is used to determine suitable overall trajectory design (Ilyasov et al., 2014). A similar algorithm could also be used for smaller scale path optimization. However, this algorithm is based on set tolerance for criteria, which finds a solution that satisfies constraints but not necessaries the optimized solution.

The path planning problem, solved with an optimal switching control approach, was published by Gong (Gong, et al, 2015). In Gong's paper, a three-dimensional horizontal well path planning problem is formulated as an optimal switching control problem, with the path composed of straight line path and curve path, with local smooth approximation. The paper used time-scaling transformation and constraint transcription in conjunction with local smooth approximation to allow the problem to be solved by gradient descent optimization methods. Curvature of the path and accuracy of landing point constrain the problem. The objective of Gong's path optimization algorithms is to find the least length trajectory.

Path optimization or trajectory design is only part of the overall automated directional drilling process. On a smaller scale of directional drilling path, geosteering, bottom hole assembly used, and formation will need to be taking into account. Below figure illustrate a hierarchy process of path control developed by Ignova (Ignova et al, 2010).

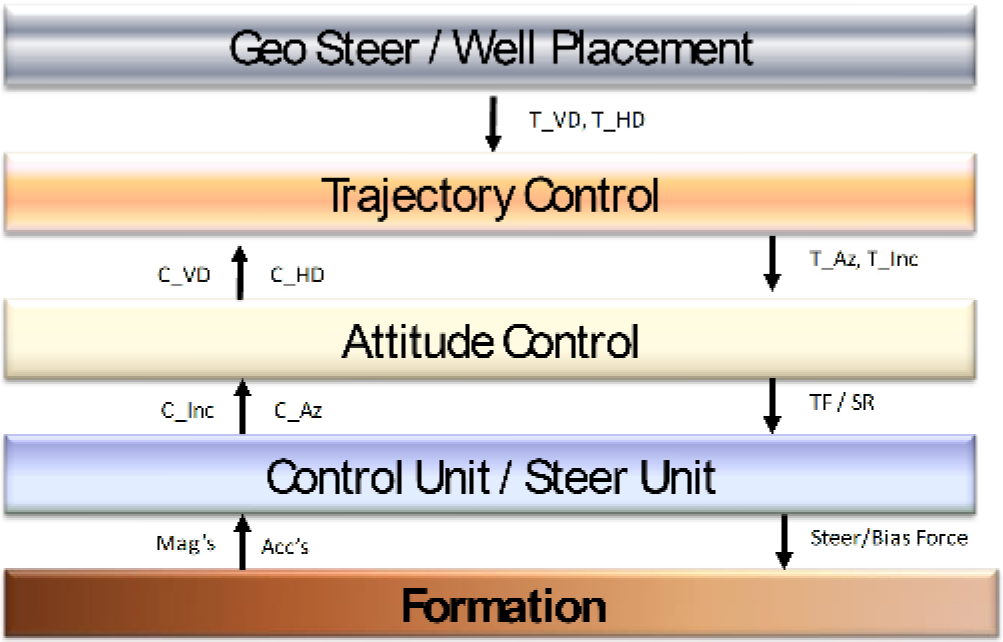


Figure 2-4: Generic Automation for Well Placement (Ignova et all, 2010)

Bottom hole assembly tendency prediction may be coupled with continuous surface and downhole data. Lesso proposed a real-time model to predict build and drop rate of the borehole using hook load, surface and downhole weight-on-bit, torque, rpm, rate of penetration, tool face and inclination and azimuth (Lesso et al. 2001). Once data is fed to the numerical model and the wellbore geometry, formation stiffness, hole enlargement and bit anisotropy index can be predicted. Physical modeling of bottom-hole-assembly and bit is also popular among determining torque and drag, along with time based drilling dynamics modelling (Shi et al, 2016). Reactive torque among setting tool face is also a challenge in optimizing path instructions, which could cause aggressive consequences in drilling (Ledgerwood, 2016). Algorithms predicting reactive torque could be useful for path optimization instructions.

The purpose for directional drilling path optimization is to eventually lead to automated directional drilling. Currently, the oil and gas industry is moving toward optimization but not yet automation. The development of real-time-operation-center (RTOC) is a bridge step toward automation while improving safety, accuracy, and efficiency in drilling activities (Ursem et al, 2003). The environment of a RTOC with different areas of expertise can be very beneficial for directing drilling activities, as well as utilizing a directional drilling software for inputs and output surveillance.

2.4 SUMMARY

Conventional survey calculation methods have been used to estimate drilling path between two surveys. Minimum curvature method is the most widely used method for survey calculation, but does not mimic the actual drilling practices of rotary and slide drilling. Constant tool face method assumes constant tool face for slide drilling. With the assumption of straight line drilling for rotary drilling, constant tool face calculation method can be used to derive drilling instructions. Splines, have recently gained popularity in drilling path optimization, due to their flexibilities and continuous curves (Abughaban et al., 2017). Criteria often used for path optimization is rate of penetration. Other criteria such as minimum well profile energy (Liu, et al. 2015) and shortest path (Gong et al., 2015) are also used. Many approaches toward optimizing direction drilling has been developed, such as advancing in equipment with RSS (Schaaf et al., 2000) and improving drilling efficiency with auto driller (Pink et al., 2017).

More research is still needed for automating directional drilling process. As mentioned, drilling optimization focused primarily on speed of completing the task or minimizing the energy for drilling, but none studied the impact or cost of drilling path related to production and completion. This thesis discusses a novel cost analysis for trajectory planning optimization algorithms and aims to find the optimized path taking into consideration production, drilling time, and well trajectory missed.

Chapter 3: Modular Frame of Automated Directional Drilling Advisor

Directional drilling involves the collaboration of personnel from many disciplines and expertise. Drilling engineers design the initial well plan with the help of a reservoir team who identify optimal well positions. Drilling crews in the field carry out the plan and perform actual drilling activities with communications with the real time center. Geosteerers determine the position of the current well and provide clear target to directional drillers. Directional drillers then determine how the path may be drilled to follow the plan, or reach target, with communication with all parties involved. Many aspects need to be considered to be able to optimize and automate the directional drilling process.

A modular automated directional drilling advisor is suggested as shown in below figure. Five modules are included in the system: geosteering, target determination, bit projection, bottom-hole-assembly tendency, and trajectory path optimization. The module focused in this thesis report is trajectory path optimization.

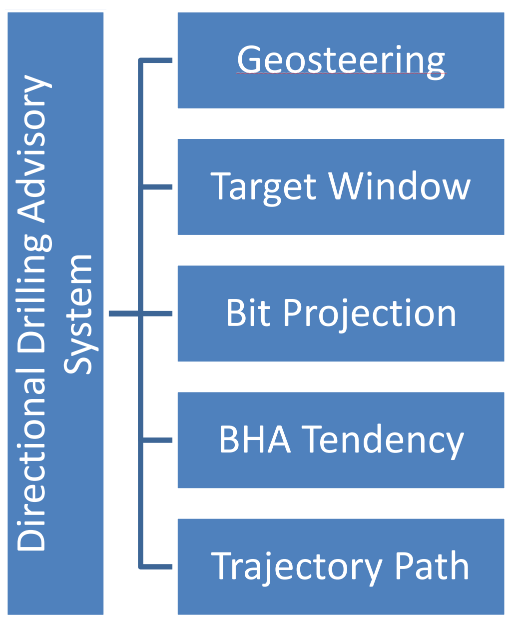


Figure 3-1: Modular Framework of Automated Directional Drilling Advisor

3.1 Geosteering Module

The geosteering module should have the abilities to automatically correlate current gamma ray logs to type log curves. Several geosteering software currently allow for semi-automatic correlation but they require human input and adjustments. The primary reason for the lack of automated geosteering instruction comes from the lack of trust in software compared to human judgement. In current geosteering work flows, the geosteering target instruction requires the geosteerer and operational geologist's analysis of well gamma ray logs and well positioning and subsequent communication of the same with the directional driller and drilling engineers.

Well positioning can affect the success of a well drilled significantly; a well drilled fast but out of target may have severe consequences in terms of potentially low production. The geology team is therefore reluctant to use a fully automated geosteering advisor, and try to avoid possible error that may stem from automated algorithms. One other reason hindering the usage of fully automated algorithms is the poor quality of data streaming in from the field. For all software, the result can only be good as the quality of data fed into it. Although in large amounts, data quality from drilling is not yet organized and clean. Human involvement in data correction and outliers filtering is needed before data processing. Organizing, cleaning and structuring the drilling data is a first step toward automating drilling activities.

3.2 Target Window Module

The optimal target point from a geologist stand point may not be optimal for the drilling; communication with directional driller and drilling engineer is essential for the target instruction to be realistic and efficient for both side. The same communication should happen within the directional drilling advisor, where the geosteering module before reaching a solution, should run through path capabilities test to allow appropriate drilling instructions. Constraints to be considered are: can the target be reached with given tool capabilities and vertical section change limits, does the geosteering target given contain hard formation that had problems in previous drilling activities, etc. These problems should be covered in the setting target window modules of the advisor.

3.3 Bit Projection Module

Bit projection techniques estimate the true position of the bit down hole. Current downhole data measurements come from measuring subs that could be ten to eight feet behind drilling bit. The data transmitted to surface may be correct from these measuring subs, but the data itself is late compare to the front of the bit, causing errors in analysis and calculations. Therefore, estimating the current position of the bit is essential to arrive at accurate directional drilling instructions. A simple equation for estimating bit position is usually used, shown below.

$$Inc_{ptb} = \left(\frac{\cos TF * MDL * Slide_{Svy\ to\ Bit}}{100}\right) + Inc_{survey} \tag{3.1}$$

In above equation, Inc_{ptb} is the calculated inclination projected to bit and Inc_{survey} is the inclination at survey. Inc_{ptb} is often assumed to be the same as current survey if only rotate drilling was conducted. TF is the tool face of slide sections and $Slide_{Svy\ to\ Bit}$ is the slide footage from current survey to the bit. MDL is the motor dogleg severity calculated to estimate motor yield tendency. The equation for calculating motor dogleg severity is shown below. DLS is the dogleg severity calculated from last survey and $CL_{Previous\ Joint}$ is the length of previous joint.

$$MDL = \frac{DLS * CL_{Previous\ Joint}}{Slide_{Svy\ to\ Svy}} \tag{3.2}$$

The bit projection module should also consider the effect of formation tendency on bottom-hole-assembly, the tendency of bottom-hole-assembly itself, and the actual slide direction and motor yield for a more accurate estimation. Other than projection estimation, the closer the measuring tools are placed toward the bit the easier projecting bit position will be. Having close-to-the-bit gamma measurement is also very useful in determining the correct formation, thereby increase the accuracy of geosteering modules. Note that vibration may affect the measurements of close-bit-recorder and should be filtered out.

3.4 Bottom-Hole Assembly Tendency Module

Bottom-hole-assembly (BHA) tendency can be estimated from building physical models or from historical data set. If data is available, analyzing historical tendencies on similar bottom-hole-assembly set up and formations may be useful. A machine learning model is suggested for such analysis to estimate BHA tendencies while drilling. From past drilling data, calculating and visualizing build rate and turn rate versus planned build rate and turn rate may be helpful in determining tendencies. In the vertical section, consistent unexpected build rate in a particular formation can be clearly visualized and used for well planning and directional drilling instructions. If drilling in one particular formation for the lateral sections, identifying formation's effect on dropping and walking tendency will be essential to stay within target window without unnecessary drilling corrections.

3.5 Trajectory Optimization Module

The trajectory optimization module combines the output from all previous modules for the optimal drilling instruction outputs. Geosteering target is fed in from the geosteering modules and target window modules, with vertical section change t and landing target constraints. Bit projection estimation is fed in before optimizing for a path to target. BHA tendency is also used in the trajectory optimization module as motor yield, to correct ideal drilling trajectory to fit current drilling situations. The focus of this thesis is the trajectory path module and will be dicussed in more detail in the following chapters.

Chapter 4: Methodologies for Path Optimization Advisor

The path optimization advisor focuses on determining the best drilling path forward from the current position. en From an operator stand point, performance such as production, equipment failures, drilling efficiencies and safety are the key performance indicators. The path optimization advisor aims to be a tool that can be used to improve performance of directional drilling. Current directional drilling process does involve considerations of how the drilled path might influence production or cause equipment failures, yet these are important criteria to be considered. Many operators utilize a real-time operation center located far away from actual drilling field for directional drilling and geosteering support. These offices allow twenty four hour surveillance and monitoring of the drilling process, giving instructions within short response time. The existence of real-time center saves hours of wellbore positioning and analysis done in conventional drilling activities. However, more time can be saved and more accurate instructions can be given to the crew based on calculated algorithms. One of the purpose of the path optimization advisor is to be able to calculate instruction much faster than human judgement and provide reliable and accurate instructions to avoid the possibility of wrong path drilled. With the different cost analysis implemented, the path optimization advisor could be a useful supporting tool for the real-time operation center on directional drilling.

Unlike well planning, path optimization advisor solves a smaller scale problem specific to the automated generation of sliding and rotating instructions for hundred feets of drilling. The path optimization advisor utilizes a spline in tension to simulate drilling path. Spline in tension has a natural spline shape with curve end segments and near straight line segments in between, simulating sliding drilling at the beginning and the end of the drilling path and rotating drilling in sections between. Variables controlling the relative length of straight line segments and the angle of curve segments are used as optimization variables. During the optimization process, the simulated drilling paths are evaluated based on the cost function to determine the best path. Cost function includes drilling path distance, estimated drilling time and possible influences on production. Cost functions are developed based on historical data and area specific production analysis. The optimization process is separated into two loops. The outer loop determines the vertical distance of the simulated path and the simulated final target point. The inner loop selects the path based on cost function optimization. The optimization advisor outputs the selected lowest cost path, corresponding to the best valued drilling path. In this optimization advisor, 3 sections of drilling are investigated, including lateral section drilling (inclination >85 degrees), tangent section drilling (10 degrees < inclination <45 degrees)and vertical section drilling (inclination < 5 degrees). These sections require different cost functions, input variables and spline target point set up.

4.1 USAGE OF SPLINE IN TENSION FOR SIMULATING DRILLING PATH

Circular arc is often used to simulate drilling path in path planning practices. However, using arc for simulating the path is not realistic to represent slide and rotate drilling activities, especially for smaller scale drilling path. Under ideal conditions, slide drilling results in a circular arc drilling path and rotate drilling results in a straight-line path. An example of slide and rotating drilling simulated path is shown in Figure 1, where orange colored segments represent the sliding path and blue colored segment represent the rotating path. Figure 4-1 is shown in 3D coordinates with the xyz axis corresponding to Northing (NS), Easting (EW), and True Vertical Depth (TVD), all with the unit of feet.

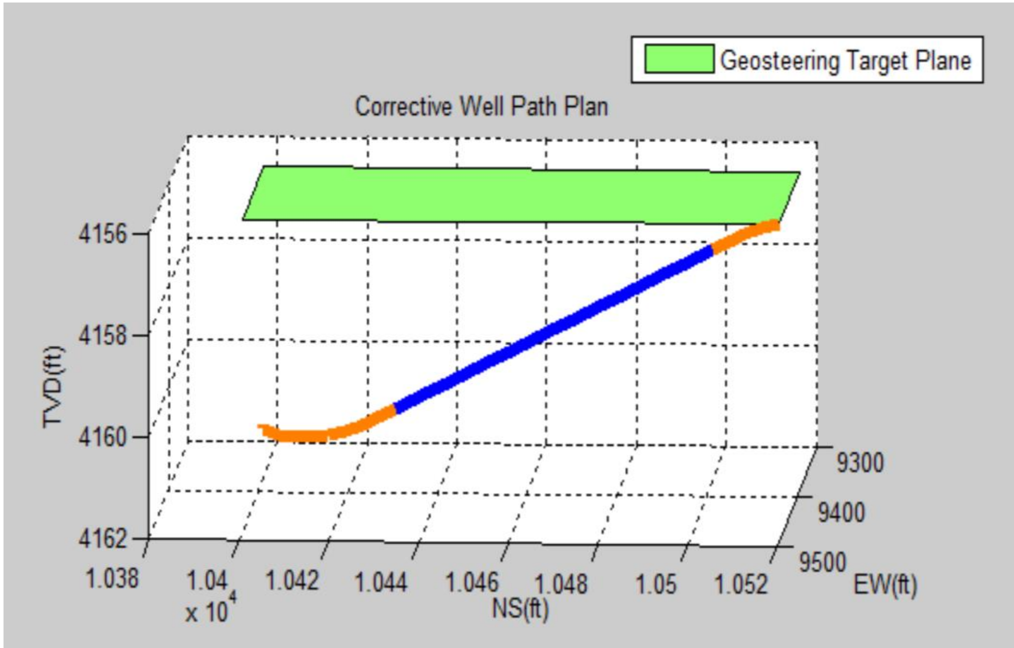


Figure 4-1: Simulated Drilling Path in 3D

Using circular arc as a predicted drilling path will cause the estimated path to be unrealistic. In directional drilling, the purpose of sliding is to reach a pre-determined target, which could be in inclination, azimuth and true vertical depth, or northing and easting. Directional drillers, using their preferred directional drilling planning calculation or software, will plan sliding and rotating instructions on a slide sheet. Often, slide drilling is used only when drilling target window has changed. For the convenience and efficiency of drilling, sliding is performed only once or twice per drilling target window change. When predicting the drilling path using circular arc, the sliding section is separated along the entire curve, causing the landing point to be different from the planned landing point. Same problem exists when the sequence of sliding section and rotating sections are switched, which will cause the estimated landing point to be wrong. These errors are problematic because of the resulting incorrect true vertical depth estimation, which might cause the path to land out of pay zone and out of the target window. Once true vertical depth errors accumulate, severe problems of several hundred feets of inaccurate true vertical depth estimation may result (Stockhausen, 2012).

To better simulate the ideal drilling path of sliding and rotating, tension spline is chosen for the optimization process. Spline functions are continuous mathematical functions and thus are convenient to perform cost analysis. Splines are relatively simple yet satisfy the constraints related to simulating drilling path. Also splines with always end on the input target point.

Spline interpolation, physically corresponds to forcing a thin elastic beam or plate to pass through some constraints (Renka, 1987). Spline in tension has a tension term to force sections of the splines to be close to a straight line. Although not entirely a straight line, if the tension is chosen correctly, the tension spline is sufficient to simulate sliding sections and rotating sections. In this optimization process, spline in tension expressions and derivation used are from Sampaio's works (Sampaio, 2007).

A general expression of spline in tension functions and the derivatives are shown in the equations below, where u is an independent variable, λ is the tension parameters, and coefficients C represent required boundary conditions. The axis y is later substituted to another dimensional axis.

$$y(u) = C_0 + C_1 u + C_2 \sinh \lambda u + C_3 \cosh \lambda u \tag{4.1}$$

$$\dot{y}(u) = C_1 + C_2 \lambda \cosh \lambda u + C_3 \lambda \sinh \lambda u \tag{4.2}$$

$$\ddot{y}(u) = C_2 \lambda^2 + C_3 \lambda^2 \cosh \lambda u \tag{4.3}$$

Three-dimensional tension spline is needed for estimating drilling path in the coordinate systems. Relating to drilling path, coordinates of the starting point is known as well as the slope which corresponds to inclination and azimuth. Target slope and z axis is also known corresponding to target inclination, azimuth, and true vertical depth. In lateral section drilling, but initial and target inclination, azimuth, and true vertical depth is known. In vertical section drilling, target azimuth may be set free.

For lateral section drilling, the inclination and the azimuth tension of the initial and the final ends of the trajectory are assumed to be known. Parameters involved with simulating drilling path with spline in tensions are true vertical depth (TVD), measured depth (M), Northing (N), Easting (E), inclination (θ), and azimuth (ϕ). Parameters known to start with are

Initial Point (0)	V_0	N_0	E_0	θ_0	ϕ_0	M_0
Target Point (1)	V_1	N_1	E_1	θ_1	ϕ_1	

There are up to five degree freedoms when assuming set inclination and set azimuth functions, including L_0, L_1 (the slopes at the start and end points) and the three tension terms (one each corresponding to northing, easing and vertical) . When using the same tension for all coordinate functions, freedom of the spline functions is reduced to 3. When setting initial segment slope and end segment slope to be the same ($L_0 = L_1$), freedom is reduced to 2.

Boundary conditions are calculated using below equations.

$$\dot{V}(1) = L_1 \cos\theta_1 \tag{4.4}$$

$$\dot{N}(1) = L_1 \sin\theta_1 \cos\phi_1 \tag{4.5}$$

$$\dot{E}(1) = L_1 \sin\theta_1 \sin\phi_1 \tag{4.6}$$

With regards to 3D coordinates calculation, C_0 , C_1, C_2 and C_3 are calculated for all 3 dimensions V, N, E. Using the below shorthand notation

$$C = \cosh\lambda \tag{4.7}$$

$$S = \sinh\lambda \tag{4.8}$$

$$f = \lambda S - 2C + 2 \tag{4.9}$$

Coefficients for true vertical depth (V), which is the z-axis, are listed below (Sampaio, 2007).

$$C_0 = \frac{1}{f}\left[(\lambda S + 1 - C)V_0 + (1 - C)V_1 - \left(\frac{S}{\lambda} - C\right)\dot{V}_0 + \left(\frac{S}{\lambda} - 1\right)\dot{V}_1\right] \tag{4.10}$$

$$C_1 = \frac{1}{f}\left[(-\lambda S V_0 + \lambda S V_1) + (1-C)\dot{V}_0 + (1-C)\dot{V}_1\right] \tag{4.11}$$

$$C_2 = \frac{1}{f}\left[(S V_0 - S V_1) + \left(S + \frac{1-C}{\lambda}\right)\dot{V}_0 + \frac{(1-C)}{\lambda}\dot{V}_1\right] \tag{4.12}$$

$$C_3 = \frac{1}{f}\left[(1-C)V_0 + (1-C)V_1 - \left(\frac{S}{\lambda} - C\right)\dot{V}_0 + \left(\frac{S}{\lambda} - 1\right)\dot{V}_1\right] \tag{4.13}$$

Coefficients for Northing (N), which is the x-axis, are listed below.

$$C_0 = \frac{1}{f}\left[(\lambda S + 1 - C)N_0 + (1-C)N_1 - \left(\frac{S}{\lambda} - C\right)\dot{N}_0 + \left(\frac{S}{\lambda} - 1\right)\dot{N}_1\right] \tag{4.14}$$

$$C_1 = \frac{1}{f}\left[(-\lambda S N_0 + \lambda S N_1) + (1-C)\dot{N}_0 + (1-C)\dot{N}_1\right] \tag{4.15}$$

$$C_2 = \frac{1}{f}\left[(S N_0 - S N_1) + \left(S + \frac{1-C}{\lambda}\right)\dot{N}_0 + \frac{(1-C)}{\lambda}\dot{N}_1\right] \tag{4.16}$$

$$C_3 = \frac{1}{f}\left[(1-C)N_0 + (1-C)N_1 - \left(\frac{S}{\lambda} - C\right)\dot{N}_0 + \left(\frac{S}{\lambda} - 1\right)\dot{N}_1\right] \tag{4.17}$$

Coefficients for Easting (E), which is the y-axis, are listed below.

$$C_0 = \frac{1}{f}\left[(\lambda S + 1 - C)E_0 + (1-C)E_1 - \left(\frac{S}{\lambda} - C\right)\dot{E}_0 + \left(\frac{S}{\lambda} - 1\right)\dot{E}_1\right] \tag{4.18}$$

$$C_1 = \frac{1}{f}\left[(-\lambda S E_0 + \lambda S E_1) + (1-C)\dot{E}_0 + (1-C)\dot{E}_1\right] \tag{4.19}$$

$$C_2 = \frac{1}{f}\left[(S E_0 - S E_1) + \left(S + \frac{1-C}{\lambda}\right)\dot{E}_0 + \frac{(1-C)}{\lambda}\dot{E}_1\right] \tag{4.20}$$

$$C_3 = \frac{1}{f}\left[(1-C)E_0 + (1-C)E_1 - \left(\frac{S}{\lambda} - C\right)\dot{E}_0 + \left(\frac{S}{\lambda} - 1\right)\dot{E}_1\right] \tag{4.21}$$

Using above equations, 3 coordinates of V, N, E can be calculated based on input parameters. Note that the initial point is denoted with the subscript 0, corresponding to u = 0. Final point or target point is denoted with subscript 1corresponding to u = 1.

In true vertical drilling, the end azimuth is not necessary to be set due to the inclination range. In this path optimization problem, true vertical drilling is defined to have an inclination less than 5 degrees and often has a target to go back to an inclination of 0 degrees. At such low inclination, the target azimuth (top view direction) can be set free as vertical drilling does not involve horizontal directional movement. Therefore, a set inclination and free azimuth spline function equations are used. The known parameters are shown below.

Initial Point (0)	V_0	N_0	E_0	θ_0	ϕ_0	M_0
Target Point (1)	V_1	N_1	E_1	θ_1		

The set inclination and free azimuth spline functions use the same spline in tension functions, coefficient functions and vertical boundary function shown in the previous page. To find the ending azimuth, the curvature of the horizontal projection at the target point is set to zero. Then a Newton-Raphson scheme is used to find the ending azimuth. The following equations are used (Stroker 1969, Sampaio, 2006, Sampaio, 2007).

$$\dot{N}\,(1)\,\ddot{E}\,(1) - \ddot{N}\,(1)\dot{E}\,(1) = 0 \tag{4.22}$$

Northing derivative calculations are shown below. Note that coefficients C_1, C_2 , C_3 corresponds to northing coefficients only, which are different from easting, or vertical coefficients C_1, C_2, and C_3.

$$\dot{N}\,(1) = \,C_1 + C_2\lambda\,\cosh\lambda + \,C_3\lambda\,\sinh\lambda \tag{4.23}$$

$$\ddot{N}\,(1) = \,C_2\lambda^2\,\sinh\lambda + C_3\lambda^2\cosh\lambda \tag{4.24}$$

Easting derivative calculations are showing below.

$$\dot{E}\ (1) = C_1 + C_2\lambda\ \cosh\lambda + C_3\lambda\ \sinh\lambda \tag{4.25}$$

$$\ddot{E}\ (1) = C_2\lambda^2\ \sinh\lambda + C_3\lambda^2 \cosh\lambda \tag{4.26}$$

An estimation of final azimuth can be calculated using initial northing and easting, and final northing and easting.

$$\phi_0 = \arctan(\frac{E_1 - E_0}{N_1 - N_0}) \tag{4.27}$$

Drilling distance, dogleg severity and other parameters are often needed for the optimization process as well. Trajectory parametrization is used in below calculations. P in below equations corresponds to position with P (0) corresponding to the initial position and P (1) corresponding to the final or target position. The distance of simulated spline path is s, utilizing Euclidean distance. The total distance of the drilling path is when s is at s (1).

$$P(u) = [V(u), N(u), E(u)] \tag{4.28}$$

$$s(u) = \int_0^u \sqrt{V(\dot{\xi})^2 + \dot{N}(\xi)^2 + E(\dot{\xi})^2 d\xi} \tag{4.29}$$

Dogleg severity is calculated using curvature along the spline curve. The magnitude of curvature is denoted as κ and the curvature vector is denoted as K (Sampaio, 2007).

$$\dot{P} = (\dot{V}, \dot{N}, \dot{E}) \tag{4.30}$$

$$\ddot{P} = (\ddot{V}, \ddot{N}, \ddot{E}) \tag{4.31}$$

$$K = \left(\frac{1}{\dot{P}\cdot\dot{P}}\right)\ddot{P} - \left[\frac{\dot{P}\cdot\ddot{P}}{(\dot{P}\cdot\dot{P})^2}\right]\dot{P} \tag{4.32}$$

$$\kappa = \|K\| \tag{4.33}$$

$$Dogleg\ Severity\ \left(\frac{deg}{100ft}\right) = \frac{(100*180)}{\pi} \tag{4.34}$$

4.2 Optimization Problems Variables

The purpose of the optimization problem is to find the best valued path in different drilling sections. Depending on the type of sections (vertical, tangent, lateral), the problem statements and constraint value will be different. In this optimization, the only constraint considering is dogleg severity along the path. Optimization variables, for calculating efficiency, will stay the same for all three sections.

Corresponding to spline in tension functions in the previous section, there are two degrees of freedoms relating to 3D spline in tension functions, which are λ and L_0. Therefore, the variables of the optimization problem are λ and L_0. Again, λ controls the tension of the spline which corresponds to the relative length of the straight segments of the splines. The higher the λ value, the bigger the relative length of the straight segment sections. λ can be adjusted based on different path range needed. For longer distance, increase λ to maintain the same length of straight line segments. λ used in the optimization problems range between one and twenty. L_0 variable controls the end section curve slopes. The higher the L_0 value, the larger the slope of the end segments. Figure 4-2 shows an example of the effect of different L_0 value on the tension spline, with other variable and parameters kept the same.

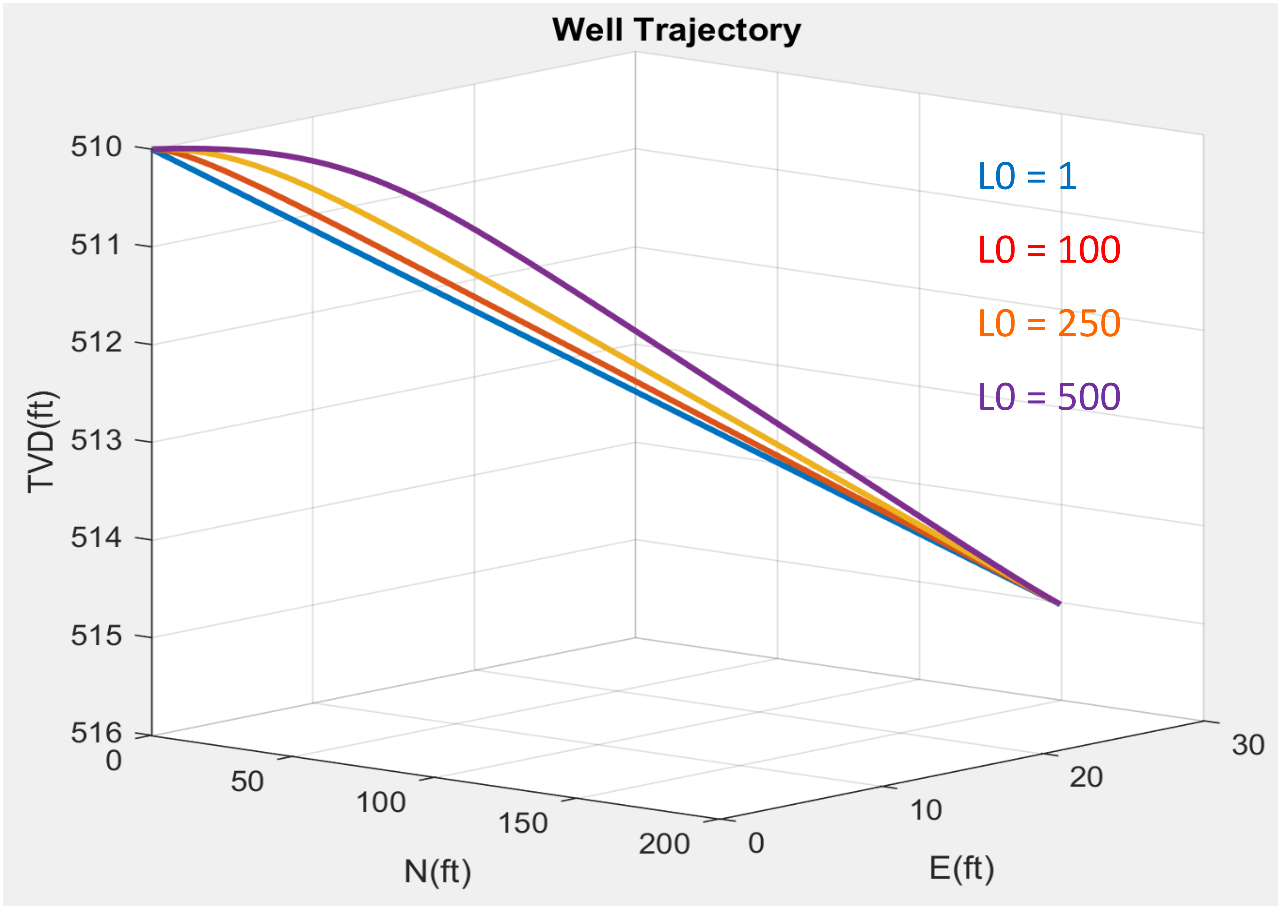


Figure 4-2: Tension Splines with Different L0 Values

In this optimization problem, tension spline function used has been simplified to a two degree of freedom problem, which leads to some simplification in the simulation of the three-dimensional drilling path. The problem first simplified the tension terms for three coordinates in the three-dimensional path: true vertical depth, northing and easting. With this assumption, the problem assumes true vertical depth, northing and easting will all stay the same slope in the straight-line section. This assumption is valid due to the fact that during rotary drilling, the goal is to drill a straight line, while maintaining the slope for all three axes. The second assumption in the problem is to allow the slope of the end curves to be the same. This assumption reduces the variables needed from three variables to two variables, saving computation time. However, a weakness of having only one term for controlling the slope of the curve is it does not allow slope change in one direction. Within the curve segments of the tension spline, slopes in all true vertical depth, northing and easting coordinates will change, affecting both inclination and azimuth change. This effect is later corrected by fitting suitable drilling instructions to the tension splines, but may cause some errors nevertheless.

4.3 Optimization Cost Function Analysis

Three drilling sections are included in the optimization program, each with different target cost functions. In the lateral section, the primary concern is to stay within pay zone and to attain highest production possible. In tangent section, low tortuosity and low dogleg severity are of interest in addition to following the planned well path. In the vertical section, low tortuosity and low dogleg severity is the main concern and the goal is better well quality and reduced equipment failures. All costs are translated into potential cost in dollars, for the convenience of calculating total cost and direct comparison.

In lateral section, three costs are included in the lateral section cost functions: production, drilling time and tortuosity index. The cost function is designed to be developed by user, based on user's production area and history data. The cost function used in the optimization problem comes from analysis of drilling in the Bakken area in North America.

4.3.1 Tortuosity Index Cost

Tortuosity index, is a measure of drilling quality regarding to the borehole. Many analyses of tortuosity had been done in the past such as hole clearance calculation (Lowdon et.al, 2015), geometrical calculation (Zhou et al., 2016) and path torsion (Samuel et al., 2009). In this optimization problem, the tortuosity index calculation from Zhou is used with equation shown below. The three-dimensional tortuosity index can capture both inclination changes and azimuth changes. L_c represent the total path distance, n is the number of path intervals, L_{csi} is the distance of the path in interval i, L_{xsi} is the shortest distance possible between the interval end point and initial point of interval i.

$$3D\ Tortuosity\ Index\ =\ \frac{n-1}{n*L_c}\sum_{i=1}^{n}\frac{L_{csi}}{L_{xsi}}-1 \tag{4.35}$$

Tortuosity index may have several effects on well performance, including drilling time, equipment failures and production. In the lateral section, tortuosity index may be used to estimate possible effect of increasing or decreasing production. A correlation study between production and tortuosity index was done for a specific area. The study showed that higher tortuosity index values, corresponded to lower initial production of the well. This analysis utilized 5000 wells' production and drilling data. A typical range of tortuosity index seen from this analysis is from 2 to 250. Note that if different survey intervals are used, the above tortuosity index calculation will produce inaccurate results and will influence the total cost function. The normalization constant will need to be adjusted for different survey intervals. The cost function for production with the inclusion of tortuosity index is shown below.

$$TIc = \left(TI_{inial} - TI_{final}\right) * (-0.0017) * Predicted\ Total\ Production\ * Profit\ from\ Production \tag{4.36}$$

TIc refers to the cost of tortuosity index. TI_{inial} and TI_{final} are the initial tortuosity of the path and the final tortuosity of the path. The initial tortuosity is the tortuosity index of all drilling path prior to instruction in the lateral section. Without loss of generality, if drilling path prior to instruction is less than two thousand feet, the tortuosity index parameter Lc is assumed to be two thousand feet. The slope -0.0017 refers to the impact of change of tortuosity on final production ratio. Typically, an increase of 50 unit of tortuosity may cost an additional 5% or more on a one-hundred-and-eighty-day initial production cycle. In this cost function, the slope indicates that for every unit of tortuosity increase, the initial production will be reduced by 0.17% of estimated production. Predicted total production is an estimate of the total production possible from current well. This value is often taken from production estimation by reservoir evaluation, prior to the drilling of the well. In this optimization, an estimated production is either taken from historical production data of nearby wells or an estimation based on area average production. For the accuracy of the cost function, is it recommended to use best estimation allowed from specific well analysis prior to drilling. Profit from production has a unit of dollars per barrel, or per volume unit. The profit could be based on current oil price or estimated oil price for when production starts. Due to the cost of transportation, facilities, field maintenance, and other costs, the actual profit from each barrel of oil will be much lesser than the estimate from oil price. Again, cost function should be altered based on the field reservoir, prior production, drilling equipment's and drilling plans used. This analysis is not often done by drilling engineers and may need support from reservoir engineers and geologists.

4.3.2 PAY ZONE LOST COST

A related cost function on production is with regards to pay zone or trajectory missed. Every lateral section has a planned well path for a specific pay zone, also known as the production sweet zone. For unconventional wells, landing in the pay zone may have great impact on future completion and production activities. However, the actual impact of missing pay zone in a specific reservoir was not analyzed in this research and only an estimation for production lost is used. Nevertheless, real-time geosteering allows geosteering geologist to determine where the pay zone is during drilling. Pay zone is often determined and set by true vertical depth and azimuth, influenced for formation along the drilling path. Naturally, the pay zone area will be changing along the way in width, height, inclination, and azimuth. A complete 3D analysis of how the pay zone changes is not computationally feasible for real-time operations. Therefore, gamma ray correlation is often used for determining the pay zone. Gamma ray correlation relates the continuous gamma ray received while drilling to a type log of nearby well. A type log is a gamma log computed in vertical depth of similar formations. By matching the gamma ray to type log, geosteering geologists could estimate the formation currently being drilling. An example of possible gamma ray matching logs is showing below. Figure 4-3 is an example of gamma ray and type log correlation. Offset type well log is showing in dark blue lines and gamma ray logs is showing in blue, pink and yellow. Gamma ray log is shifted up, down, shortened or elongated to match the type log shape, in order to determine relative position to pay zone. Figure 4-4 shows possible automatic curve matching algorithms, utilizing time warping method.

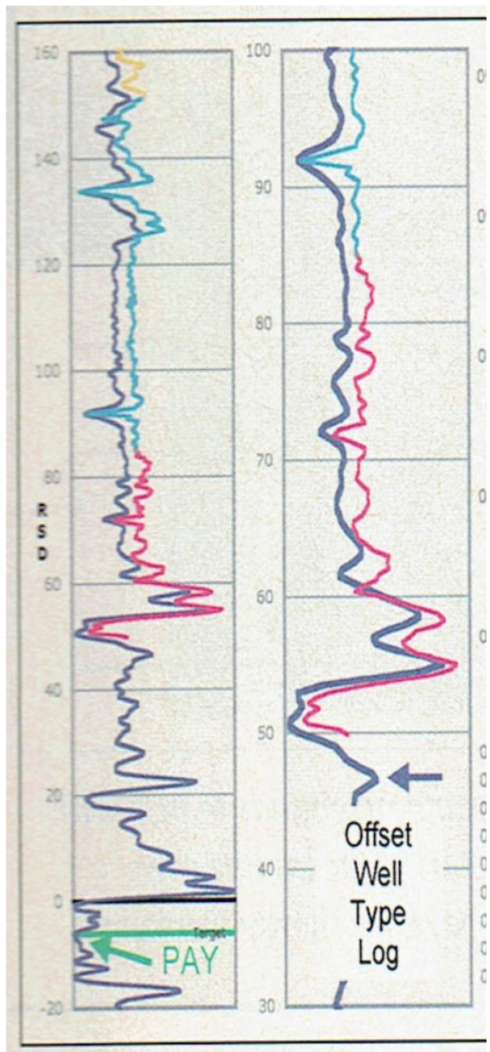


Figure 4-3: Offset Well Type Log for Geosteering (Stoner, 2000)

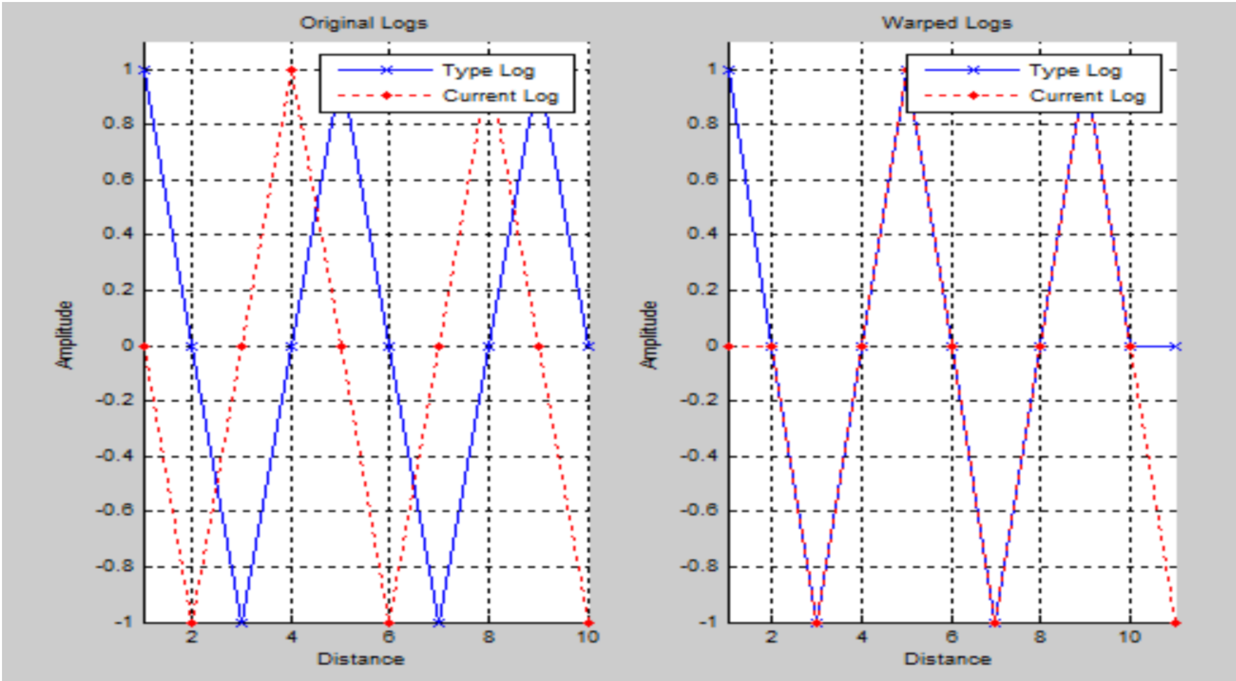


Figure 4-4: Gamma Ray Correlation Between Type Log and Current Log

After geosteerers have determined the well position of current drilling path in comparison to the pay zone, geosteerers will give a target point to directional drillers, and directional drillers may give instruction for a slide or a corrective path to the drilling crew. Planned well path often has boundaries for pay zone, known as the pay zone window. In this optimization, we assume the pay zone window to be plus or minus 5 feet in true vertical depth. Whenever the pay zone is determined by the geosteers, a true vertical depth and an inclination is set to locate the pay zone line, as well as the pay zone window. When a path is drilled or simulated, the path is compared to this drilling window on possibly missing pay zone areas. Depending on the possible pay zone area missed, the production will be influenced likewise. An example of positions of drilling path relatively to the pay zone is showing below.

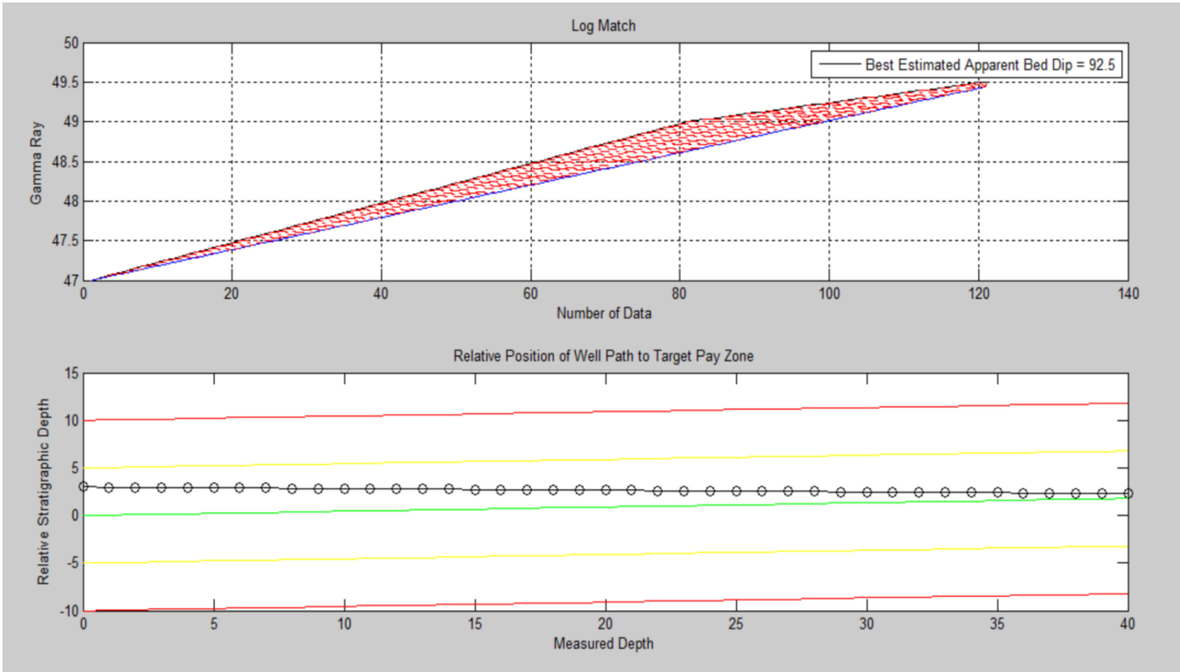


Figure 4-5: Relative Position of Well Path to Target Pay Zone

In figure 4-5, (bottom plot) the pay zone line is the green line, pay zone window is represented with two yellow line, the red line represents out of formation and the estimated drilling path is shown as a dotted black line. The top plot shows automatic matching of gamma ray logs to type logs using red dashed lines. The bottom plot shows the relative position of current well path, based on the automatic gamma ray matching. Assumptions are given based on the position of drilling path relative to the pay zone line: the further away from the pay zone line, the lesser the expected production in the interval. The intervals in this case can be equal to the independent variable of tension splines, u. Utilizing known pay zone positions, the production cost function based on pay zone missed is shown below.

$$\mathrm{PLc(u)} = \frac{Pred.\,Total\ Production * Profit\ from\ Production}{Planned\ Lateral} * Pay\ Zone\ Missed(u) * Production\ Influence\ Index \tag{4.37}$$

In this cost function, $\mathrm{PLc(u)}$ is the cost of production missed due to missing pay zone, predicted total production is the same as the tortuosity cost function as well as profit from production. Planned lateral section distance is used to calculate possible production per vertical section. Pay zone missed is the vertical section of how much the path has drilled while out of pay zone or in a particular production zone. Production influence index is the assumption of what percent of production will be reduced in missing pay zone. Again, a detail analysis for production based on pay zone coverage has not been done for the specific field used in the optimization problems. Assumptions are used for scenario considered in this thesis. The assumptions used in the path optimization advisor is that if the path is out of pay zone, production for the interval could reduce by 30%. Profit from production is estimated to be around fifty dollars per barrel. Where predicted total production and planned lateral vertical sections are not known, default value of 100,000 barrels and 1500 feet was used.

4.3.3 DRILLING EFFICIENCY COST

Drilling efficiency cost function involves the calculation of drilling time and the corresponding drilling cost. Depending on the contract with the drilling contractor, drilling cost per day and or per well will be different. Drilling expense may include contractor and crew budget, unexpected equipment failures, tool and equipment maintenance, natural disturbance of drilling plan, etc. In this optimization, a simpler cost function is implemented for drilling efficiency cost analysis, a shown below.

$$DTc = Average\ Drilling\ Cost\ per\ Hour * Drilling\ Time \tag{4.38}$$

In this cost function, DTc stands for drilling time cost, average drilling cost per hour has a unit of dollars per hour and drilling time has a unit of hour. The average drilling cost per hour includes contractor cost and rig cost; planned equipment and tool switch, maintenance and inspections are not considered. Drilling time is a function of rate of penetrations and the equation is shown below.

$$Drilling\ Time = Average\ Slide\ Drilling\ Rate\ of\ Penetration * Slide\ Drilling\ Distance + Average\ Rotating\ Drilling\ Rate\ of\ Penetration * Rotate\ Drilling\ Distance \quad (4.39)$$

In the drilling time equation, average slide and rotate drilling rate of penetration is calculated based on 3 consecutive survey data prior to the simulated drilling path. The reason to use prior drilling data is to estimate a more accurate drilling time based on the bit dullness, formation encountered and related surface equipment used. The average rate of penetration can be calculated by averaging the rate of penetration of previous stands. Slide drilling distance and rotate drilling distance is obtained from simulated spline path or from actual slide sheet information. When simulating using tension splines, 2 slides section are simulated at the end points with a near straight line segment in between. In the optimization algorithm, a test of changing curvature and dogleg severity is built in to distinguish curve sections and near straight line sections. When the change in curvature is less than 0.01, the intervals are considered reaching the near straight-line segment and will be considered as rotary drilling.

Based on data analysis done on drilling efficiency in the drilling area, some assumption on drilling efficiency has been made as a default for the optimization software. The average drilling cost per hour is estimated to be around six thousand two hundred and fifty dollars per hour. Average rotating rate of penetration is set to a default of two hundred feet per hour, and average sliding rate of penetration is set to be at a default of fifty feet per hour. With advanced technologies and tools, the parameters could be much higher than the default parameters.

For the vertical section cost functions, different criteria have been looked at based on its severity. The three costs taken into account in the vertical section are drilling time, tortuosity index, and deviation from true vertical or planned well path. Similar cost function for drilling efficiency from the lateral section also holds for the vertical section. Deviation from planned well path hold similar cost function as pay zone missed cost function in the lateral section, except for influence on pay zone, an assumed weight is given for off trajectory. In the vertical section, correcting the deviation from planned path is mainly for drilling efficiency of less drilled footage to reach a true vertical depth, or to maintain a drilling cylinder when drilling vertically. Just like the pay zone window, a set drilling cylinder may be used as a constraint for vertical section drilling, often time ten to fifteen feet in radius. In the vertical section, the tortuosity index has been mostly correlated to equipment life span and failures. A case study on tortuosity index and rod pump wear failures was done in a specific area and showed correlation. The study indicated that the higher the tortuosity index, the shorter the life span of rod pump equipment downhole in the vertical section. This could possibly be due to the high tortuosity in the vertical section, especially near the segments where rod pumps are placed. Rod pump repairs can be very costly, especially due to the need of transferring a rig for tripping, transportation of exchanging parts, and reduction in production. Therefore, reducing possible equipment failures is the top concern for vertical section cost functions.

For the tangent section cost functions, only two costs are considered: drilling efficiency and tortuosity index. Tangent section refers to a planned slanted tangent section in the vertical section, to separate different wells on a pad at an easier drilling stage. These tangent sections can be tricky due to build in tortuosity and friction in drilling plans. Conventionally, it is harder to hold tool face at a desired direction further down in true vertical depth. The benefit of having a tangent section earlier is to help with curve section drilling and landing of the lateral section well at the correct position. With a deviation in vertical section earlier on, tool face and azimuth directions are better manipulated and maintained. With the benefit of tension splines, the estimated drilling path will always be landing at target point. The cost concerns are drilling time, which correspond to drilling expenses, and tortuosity index. The concern in the tangent section again is equipment and tool failures. Tortuosity index could be a measurement used to benchmark an index for reducing unexpected failures during drilling. Similar parameters such as dog leg severities could also be substituted for benchmarking equipment failures.

Overall when calculating the final cost function, all three cost functions are combined. Since all costs share the same unit of dollars, it is fair to simply add all cost together as a final cost. Based on the user, weights can be multiplied to each of the cost based on the importance of the cost functions. This is detailed in the next section.

4.4 OPTIMIZATION PROBLEMS OF STATEMENT AND METHODS

The optimization problem has several input target information, historical drilling information and simulated drilling splines boundaries. The optimization problem is looking for the overall best valued path out of all simulated tension spline path. With the support of input data, the variables for the optimization problems are L_1 (the same value as L_0) and λ. λ is the tension parameter that corresponds to the relative length of the straight segments of the splines. With increasing λ, the relative length of near-straight line segment will also increase. L_1 is the end section curve slope; The higher the L_0 value, the larger the slope of the end segments.

$$Determine\ Varibles: \qquad L_0\ , \lambda$$

One of the constraints is dog-leg severity. The need for a dogleg constraint is to address a few concerns. First, the directional drilling tools used, motor and sub-bent for example, can only drill up to a certain curvature constraint. Second, the curvature, or the dogleg severity should be maintained under a certain benchmark to ensure no additional tool and equipment failure occurs when drilling and tripping/ This is also required to reduce pipe friction and the occurrence of stuck pipe incidents. Thus, the following constraints hold at all time, where κ_{max} is the maximum curvature allowed calculated from DLS_{max}.

$$Constraints: \qquad \kappa < \kappa_{max}, \; DLS < DLS_{max}$$

For the cost function explained in the previous section, three parameters are most often used in the cost function calculations: drilling path distance, drilling time and tortuosity index. The following equations shows the calculations for these three parameters with spline in tension functions.

- Path Distance

$$\int \left\| P(\dot{u}) \right\| du \tag{4.40}$$

- Path Drilling time

$$\sum_{i=1}^{n} \left\| P(\dot{ui}) \right\| du \; * v(ui) \tag{4.41}$$

- Tortuosity Index

$$\frac{n-1}{L_c * n} \left(\sum_{i=0}^{n} \frac{\int_i^{i+1} \| P(\dot{u}) \| du}{\| P(i+1) - P(i) \|} - 1 \right) \tag{4.42}$$

Utilizing the three parameters, cost functions can be calculated for each simulated tension spline path. The objective of the optimization is to have the minimum overall costs for the drilling path. The number of cost functions in a section is the value for c.

$$Objective: \qquad \min_{L0,\lambda} \sum_{1}^{c} Cost\ Functions\ (c) \tag{4.43}$$

For example, for the lateral section, the objective function is the minimum of all three cost functions. At this point, the problem statement of the optimization problem is complete.

$$Objective: \quad \min_{L0,\lambda} \mathrm{PLc(u)} + DTc + TIc \tag{4.44}$$

Input to the optimization problem includes target information, drilling data, original planned information, and motor yield estimation from user's experiences. A total of fourteen inputs are needed to solve the problem at this point. With increasing constraints or cost functions, more input might be needed. In the actual graphical user interface, all needed user input has been grouped into an input panel. The following figure is an overview of all inputs necessary to do the optimization.

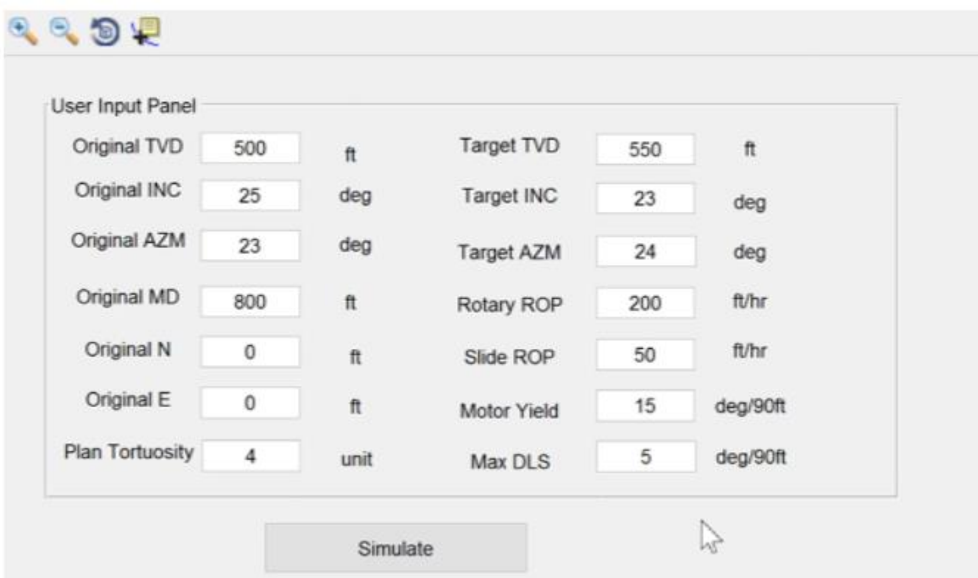


Figure 4-6: Input Data Panel

The target inputs needed are the target true vertical depth (TVD) in feet, target inclination (INC) in degrees, and target azimuth (AZM) in degrees. These target data correspond to the geosteering target sheet target specification. More commonly, azimuth is not considering as an important target to be reach as an absolute value; a more general target tolerance is used for target azimuth. When only target inclination is specified, target azimuth is set to be the same as original azimuth.

drilling inputs needed for the problem are original true vertical depth, original inclination, original azimuth, original measured depth (MD) in feet, original northing (N), original easting, and planned tortuosity for previous surveys. Original true vertical depth, inclination and azimuth are input information for simulating splines in tension. The accuracy of these three inputs are essential for correct drilling path simulation. Original measured depth, northing and easting are used for locating the well position. These inputs will not affect the simulated tension splines, cost functions or drilling instructions. The planned well tortuosity index refers to the tortuosity index of the entire section prior to original position. This planned tortuosity index is used in cost function calculation, where the difference of original (planned tortuosity) and post tortuosity after simulated path are evaluated.

Motor yield, rotate rate of penetration (ROP), slide rate of penetration, and maximum dogleg severity are inputs based on user's experiences or calculation. Motor yield refers to the slide degrees per hundred feet and is calculated from previous drilling surveys. An equation for calculated motor yield is shown below. MY refers to motor yield in degrees per hundred feet(the same unit as dogleg severity (DLS)). $CL_{previous\ joint}$ is the length of the previous joint of pipe drilled in units of feet. $Slide_{survey\ to\ survey}$ is the distance of slide occurred between the last two survey measurements.

$$MY = \frac{DLS*CL_{previous\ joint}}{Slide_{survey\ to\ survey}} \tag{4.45}$$

Motor yield is often used as an estimation for bottom hole assembly (BHA) tendency in different formations. Utilizing motor yield in simulated drilling path will allow us to better simulate slide section and the actual drilling instruction. Motor yield may be smaller than directional drilling tool capabilities in harder formations, or larger if there is bit bouncing between formations or dropping tendency due to gravity effect.

Average rate of penetration for rotate and slide drilling may be calculated by averaging the ROPs of past few sections. Average rate of penetration information is needed to taking into account bit dullness, formation effects on drilling efficiencies and surface to downhole weight transfer. The assumption is that the rate of penetration in a similar geological environment witll be similar when drilled by the same drilling crew, bit, and equipment.

Maximum dogleg severity is an input constraint chosen by the user. Several considerations may be considered when choosing a proper dog leg severity constraints: drilling tool capabilities, avoiding equipment failures and stuck pipe conditions. With conventional motor, a common dog leg severity constraint may be around fifteen degrees per hundred feet. However, if drilled by a rotary steerable system, the capabilities of such tools are much higher than conventional motors. If a high dog leg path is drilled, the chance of stuck equipment and pipes are much higher. Many downhole tools and subs are less capable of bending through the drilling path. With an acute turn angle in the path, subs are more like to produce inaccurate measurements or fail completely. The time and money spent on tripping to replace failed equipment is significantly higher than the normal drilling costs. The same situation could happen to drill pipes.

The optimization problem involves two loops of optimization. The outer loop of optimization utilizes straight line search for searching the proper tension parameters and vertical section changes. The tension parameters λ control the rotate drilling section in the simulated path. Based on target information, a range of tension parameters are used as input to the inner loop for simulated path calculation. A common range for tension parameters is between five and twenty; such boundaries are found through experiences of simulating smaller scale of drilling path, with a total drilling distance of less than four hundred feet. The proper vertical section changes come from restrictions on correction path total distance. Directional drilling or corrective paths often has a goal or a constraint on when the target should be reached in changing vertical sections. Such goals are set by drilling engineers and real-time operation center operators working together. In the optimization problem, a limit of less than five hundred feet in changing vertical section is used as a boundary. As a starting point, based on the input target information, the starting vertical section change is by default set to thirty feet. Again, the resulting tension parameter, and vertical section change is inputted into the inner loop of the optimization.

The inner loop of the optimization has several steps including setting the proper L_0 (slope term), simulating tension splines using all input information, calculating the various cost functions and thereby the total cost, and finally determining the best simulated path. The flow chart below explains the steps.

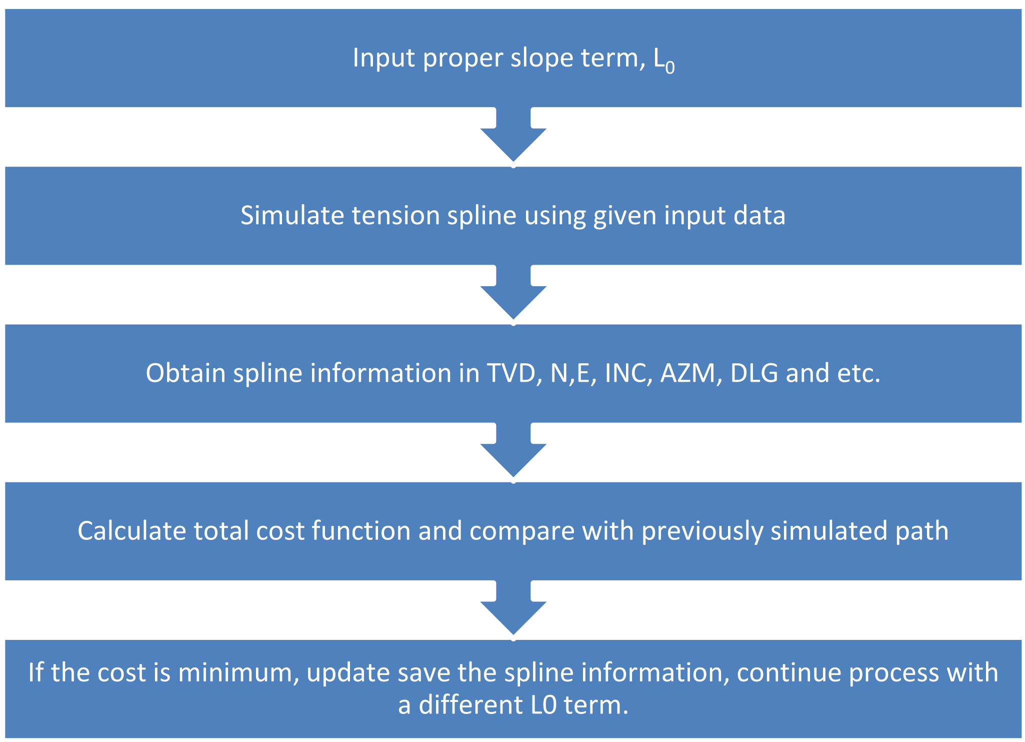


Figure 4-7: Flow Chart of Inner Loop Optimization

The optimization variable L_0 is first set to a default value of ten. In the optimization process, gradient descent or iterative methods determine the output variables. When utilizing gradient descent optimization methods, the difference in total cost functions are obtained The optimization process records the change in slope term and its effect on changing cost term, to manipulate determining variables. The tolerance for this method is set to be at 1% of maximum cost, or a default maximum cost of ten thousand dollars. An example update gradient descent function is shown below, where the output variable is L_0, differential of the neighboring total cost function is dCF and α is the slope for updates.

$$L_0{}^{n+1} = L_0{}^{n} - \alpha \, dCF \tag{4.46}$$

Although less accurate, the iterative method is more time efficient where slope term boundaries can be previously set, and converted into an arrays. Using the iterative methods, the slope term is increasing at a constant value of ten per iteration until reaching set maximum values. The iterative method is less accurate in that a global minimum may be hidden. However, by setting the constant changing value of variables between iterations to be larger, computation times are greatly reduced to less than ten percent of the gradient descent method. A boundary of maximum slope term is set at default to be at five hundred.

When simulating tension splines, target information and original information will remain the same throughout the optimization process except for the changing of the tension variables, the slope variables, and the target northing and easting corresponding to change in vertical sections. The path is simulated on an independent variable, u, which has a range of [0,1]. When the path is simulated, the resulting arrays of position vectors are calculated, which includes: measured depth, path distance, inclination, azimuth, northing, easting, true vertical depth, dogleg severity, curvature, estimated velocity, and tortuosity. Note that all resulting arrays are the same size of the independent variable u. The position arrays of the best simulated splines are later used to determine the actual drilling instructions outputted.

Within each iteration, cost functions are also calculated and the overall best path is chosen where the sum of all costs is minimized. The individual cost functions and as well as the sum are studied here. The following plot shows an example of how a best path has been chosen assuming a single cost function, namely – pay zone missed.

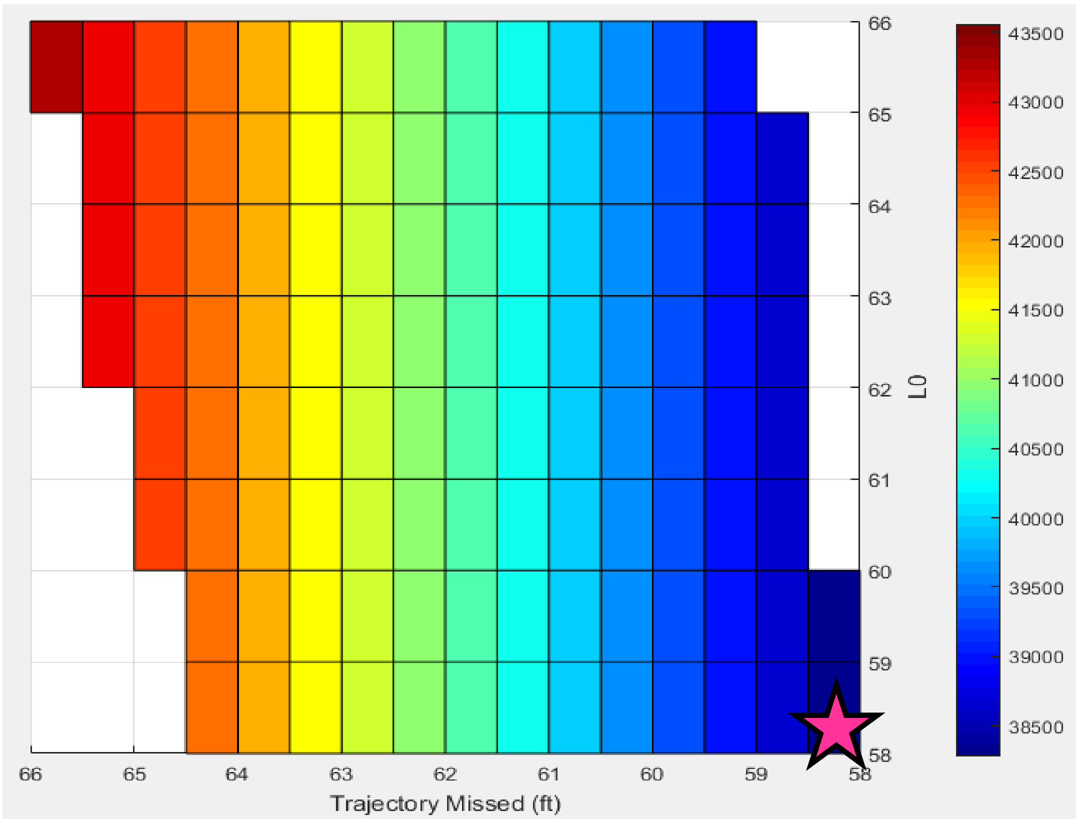


Figure 4-8: Cost Analysis on Lateral Section Pay Zone Missed

The above figure shows one of the cost function, pay zone missed, in a lateral section problem. Note that the cost analysis has the determining variables L_0 in y-axis, and the vertical section change in x-axis. The tension term λ, is assumed to be constant in this analysis. The cost function diagram shows the cost of the pay zone missed for this problem in color codes, with the lowest cost being dark blue and the highest dark red. The minimum point is when vertical section change is 58 feet and L_0 is at 58 unit. The result is logical because the shorter the vertical section missed, the less the pay zone is missed, and therefore higher the production. If only pay zone missed criteria is chosen, the best valued path will be the tension spline generated at the pink star in Figure 4-8.

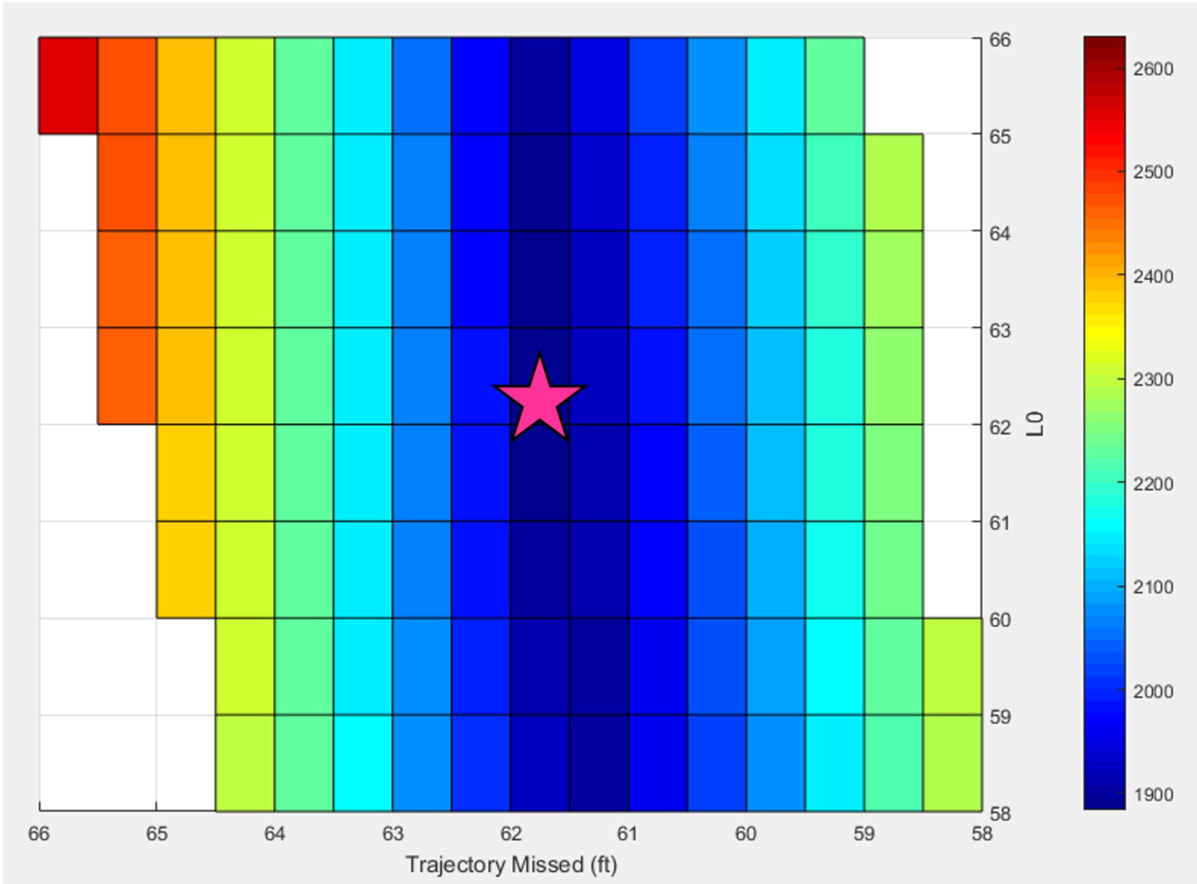


Figure 4-9: Cost Analysis on Lateral Section Drilling Time

A similar analysis on drilling time cost function is shown in Figure 4-9 for the same lateral section problem. The best path if only considering drilling time is at the pink star, far from where the best path determined for shortest pay zone missed was. These two cost analysis figures represent a dilemma currently existing in drilling practices. Drilling engineers and the drilling crew often evaluate how the well is drilled based on how fast the well is drilled. Others only calculate the drilling instructions based on the shortest distance he or she needs to take to reach the desired target. The shortest pay zone missed criteria represent the shortest distance to target path. Comparing both paths, we can see that the two criteria result in different recommended paths. This simulation shows that the fastest drilled path may be different from the shortest distance path, based on the well's rate of penetrations.

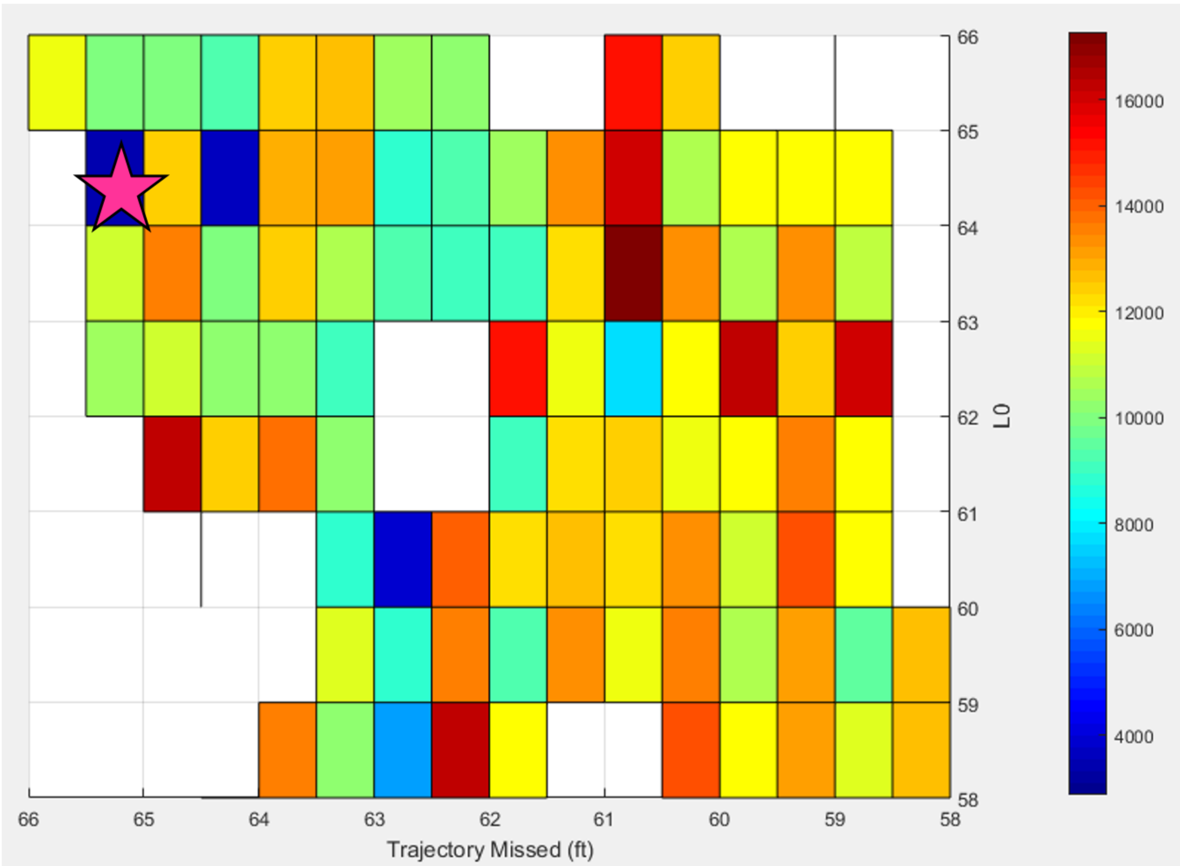


Figure 4-10: Cost Analysis on Lateral Section Tortuosity

The tortuosity cost analysis plot is quite different from the previous plots. It shows a general trend of high cost with smaller trajectory missed value, and smaller cost with higher trajectory missed value. Smaller trajectory missed path often have longer slide drilling sections, which result in higher dogleg severity, and higher severity of turns in the path. This could be the reason for high tortuosity in shorter trajectory missed paths. Overall tortuosity cost analysis plot has an opposite trend with pay zone missed analysis plot.

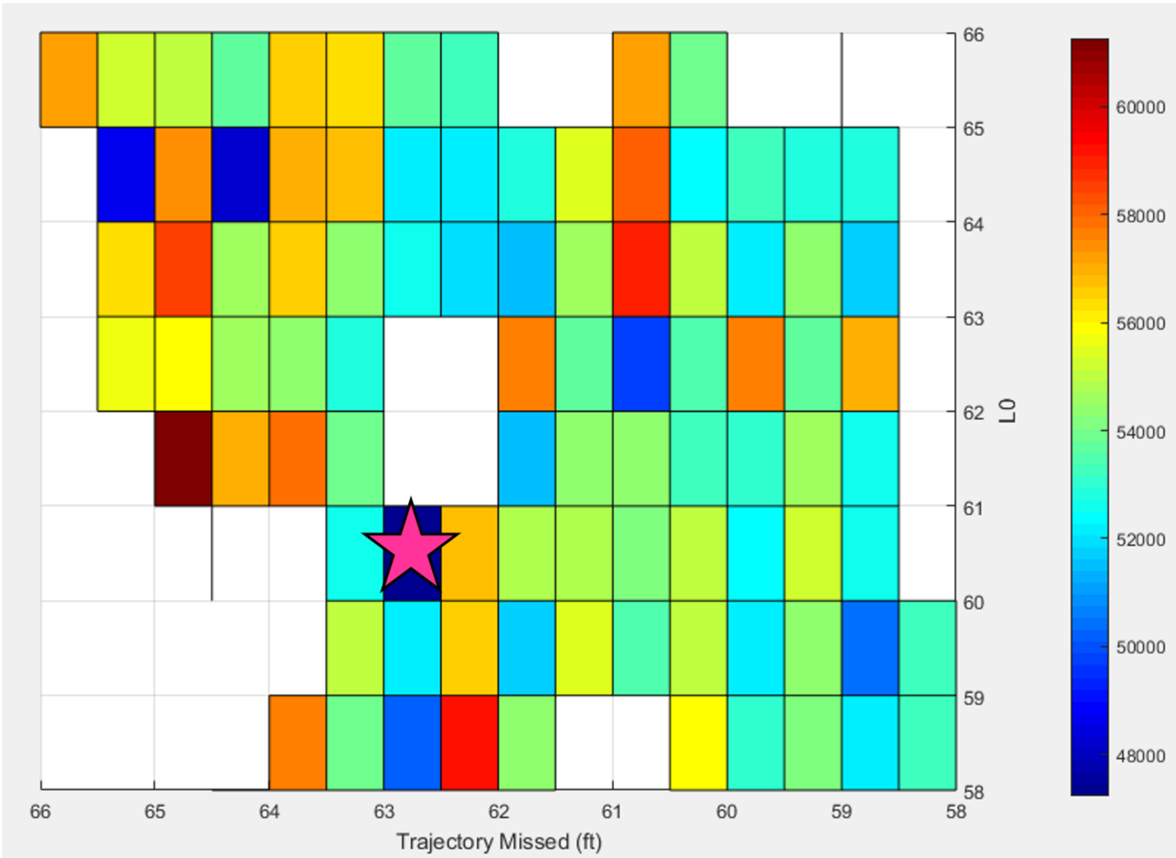


Figure 4-11: Cost Analysis on Lateral Section

A best valued path is chosen when all cost analyses are combined in the lateral section problems. From the color-coded cost grid, we can see production missed from pay zone missed has the highest effect on overall cost, with the maximum cost of \$ 43,000 (Figure 4-8). The tortuosity cost is second in influencing the overall cost with a maximum cost of \$16,000 (Figure 4-10). Drilling time cost has a maximum cost of \$2,600 (Figure 4-9). In figure 4-11, the best path corresponds to trajectory missed at 63 feet and L_0 at 60, with a minimum cost of \$48,000 combined.

4.5 From spline to drilling Instructions

After the best valued drilling path has been chosen from simulated tension splines, actual drilling instruction is fitted to the best spline. As mentioned before, rotate drilling is determined when the spline has a change of curvature less than 0.01 unit in between intervals. This assumption is used in the optimization problem, but can be changed based on problem input and scales. Typically, smaller scale problem such as change in inclination less than 1 degrees, assumption to determine the beginning of rotate drilling with be much smaller. In problems where path distance is larger, bigger curvature change assumptions can be used.

Restricted by the nature of spline in tension, simulated drilling path will always have a curve section in the beginning and the end, and near-straight line segment in-between. This restricts the drilling instructions to be always slide sections at the beginning and the end, with a rotate section in the middle. Tension spline, although closely simulate rotate drilling and slide drilling path, may result in unrealistic drilling instructions. For example, the tension splines will have specific drilling instruction to hundredth of a decimal, which is not suitable as instructions to give to the drilling crew. With smaller change of inclination for target, tension spline may result in slide drilling path of less than 2 ft. Considering the cost of changing from rotate drilling to slide drilling, such small slide drilling distance may not be cost efficient to follow.

When changing from rotate drilling to slide drilling, time is wasted. The drilling crew must first stop rotate drilling and then slightly pull up drill pipes so as to adjust tool face. Adjusting tool face usually requires the crew to rotate drilling pipes several times in both direction. Tool face downhole is estimated by marking the upside of the bent sub in the bottom hole assembly, and continuing to mark a straight line through every joint of pipe drilled downhole. This method becomes less accurate in determining tool face especially when drilling has been performed for a long distance. To ensure that no drill pipes are twisted due to friction, the drill pipes are first rotated before any tool face adjusting may occur. Recent development in automatic tool face adjustment in auto driller, may help significantly in ensure tool face accuracy.

Assumption involved with determining the rotate drilling sections and the slide drilling sections includes: all path recommended have been rounded to the near feet, tool face instructions given is rounded to the near degree, or near five degrees depending on the user, slide drilling instruction of less than two feet is not included. Due to the assumption of minimum slide drilling path, the instructions of simulated path now may be involving only one slide drilling section and one rotate drilling sections. Additional constraint for drilling instruction, such as maximum slide distance, maximum total slide distance, or maximum slide and rotate ratio per hundred feet may also be included. With these additional restrictions, simulated slide sections may be separated into several slide and rotate sequences. Although this restriction will reduce dogleg severity, having such sequence will cause the drilling path to be deviated from the best tension path determined. When this situation occurs, the cost analysis and estimated target information from the optimization process could be inaccurate. Therefore, when large changes in inclination and azimuth are desired, it is recommended to break down the target information into two consecutive problems.

When calculating the specific drilling instructions, constant tool face angle method is used to calculate the path. In most survey and well path planning software, minimum curvature method is used. The minimum curvature method finds a circular arc to fit between two survey points which corresponds to the lowest curvature (Sawaryn, 2005). Although more commonly used, minimum curvature does not represent a physical understanding of the actual sequences of rotate and slide drilling. Ideally, the path will be a rotation of straight line and circular arc. Constant tool face method is in this case more suitable for finding the actual drilling instructions. The formulas for constant tool face method is shown below(Mitchell and Miska, 2011).

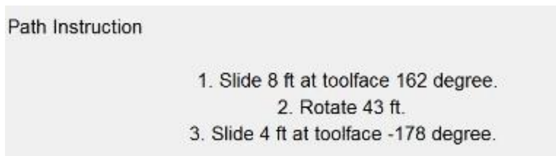
$$TF = \arccos\left(\frac{\cos(\varphi_1) * \cos(\beta) - \cos(\varphi_2)}{\sin(\beta) * \sin(\varphi_1)}\right) \tag{4.47}$$

φ_1 = initial inclination

φ_2 = final inclination

β = arccos(sin(φ_1)*sin (φ_2)*cos (φ_2) + cos (φ_1)*cos (φ_2)

In above equation, TF refers to tool face angle and β is the dogleg, or total angle change between the two survey points. When the inclination of two points within the slide section is known, tool face can be calculated using above calculation. Along with slide path distance, slide drilling path instruction can now be determined. Rotating section follows the first slide path instruction. The assumption for rotate drilling is that the inclination and azimuth of the drilling path will remain constant throughout the rotary drilling section. By setting inclination and azimuth to be the same at the final point of first slide section and the initial point of second slide section, distance of rotating sections can be determined. An example of how drilling instructions are showed on the optimization software is shown below.


Path Instruction

1. Slide 8 ft at toolface 162 degree.
2. Rotate 43 ft.
3. Slide 4 ft at toolface -178 degree.

Figure 4-12: Output Panel on Matlab Graphical User Interfase for Drilling Instruction

Note that due to the drilling instruction being determined based on constraints and assumptions, the actual path from following the drilling instruction will be slightly different from simulated tension spline. The goal of fitting drilling instruction is to allow the drilling instructions to be as close to the spline as possible. An example comparison of actual drilling instructions and simulated spline in shown in figure 4-14. The drilling instruction is shown in pink solid line, and the lowest cost spline is shown in dotted black line.

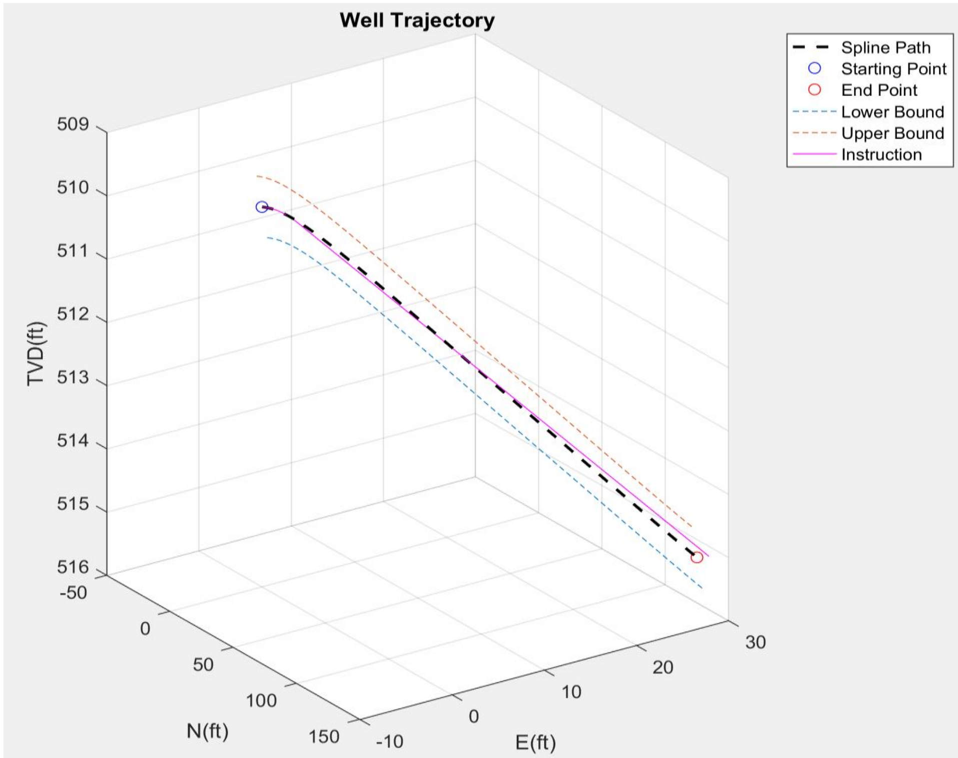


Figure 4-13: Comparison of Drilling Instruction and Tension Spline Determined

Once drilling instructions has been calculated, the estimation of the drilling path with be updated based on the drilling instructions instead of the best valued spline path. Drilling time estimation, end target coordinates, tortuosity at the end of the path and well trajectory missed will all be updated at the end of the optimization process. A graphical explanation of the drilling instruction suggested with also be shown. Along with the drilling instruction, a lower bound and upper bound is set for the drilling path. This allow the drilling engineers to estimate a target drilling window while drilling along the path. The current assumption for drilling boundary is +/- 5 feet in northing, easting, and true vertical depth directions. An example of the final graphical interface suggestion board in shown in the below figure. At this point, the optimization process of the directional drilling path advisor is complete.

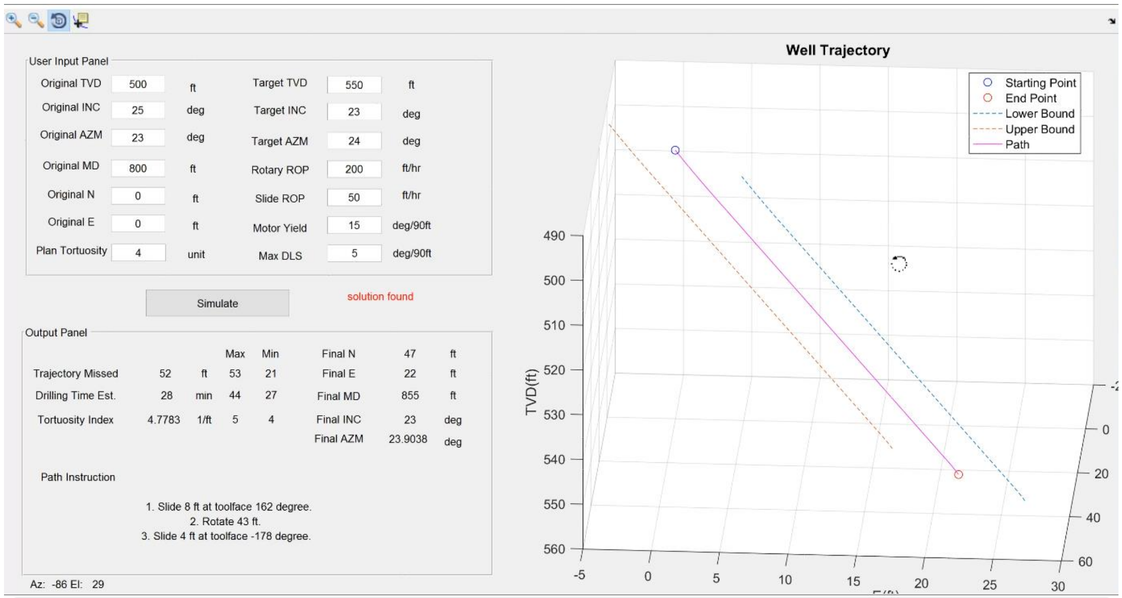


Figure 4-14: Matlab Graphical Interface with Given Results and Illustrations

Chapter 5: Simulation Results and Comparison to Actual Instruction

Utilizing path optimization software developed, example path correction problems are simulated and software tested. The optimization software allows path correction advising in three sections: vertical, tangent, and lateral section. Three sections use different cost criteria for optimization suggested drilling instruction. Lateral section is most tested with possible problem that may be encountered during drilling. Simulated test cases are like problems directional driller faces; the problem often indicated the previously planned well path and target that need to be achieved. The previously planned well path can be from well plan before drilling activity started or from target window determined by geosteerer. The target window and planned well path usually include true vertical depth and inclination needed for target. Restrictions given to the directional driller are maximum vertical section change for correcting path, maximum dogleg severity or slide footage, etc. When calculating instructions, directional driller will also take into account bottom hole assembly tendency, drilling crew efficiency, satisfying restrictions and be cost efficient. A path correction problem in lateral section is often to maintain or get back into the target pay window. A path correction problem in vertical and tangent section is to follow original planned path and ensure accurate landing. Simulated test cases in lateral section is shown in following sections.

5.1 Simulated Path Correction Problems and Results

To test the software to realistic path correction problems and all input possibilities, problems are simulated to mimic real life drilling corrections as similar as possible. The original models for simulated problem comes from slide sheet and geosteering target sheet used by directional driller and geosteerer, which the reason and target for slides are recorded. Software such as Petrolink can be used by operators to track target changes along the drilling path.

Using simulated problem, the path optimization software is run and tested for results and error. Sample testing problem in the lateral section is shown below. Note this problem set up is the same problem set up for the cost color bar analysis in Chapter 4.

Table 5-1: Test Case 1 Problem Set Up

	Initial Condition	Final Target
TVD (ft.)	510	511
Inclination (deg.)	90	89
Azimuth (deg.)	11	11

Motor Yield (BHA Tendency)	15 deg / 90ft
Rotate Average Rate of Penetration	200 ft / hr
Slide Average Rate of Penetration	50 ft / hr
Predicted Total Production	100,000 barrels
Planned Lateral Section Length	1500 ft
Predicted Profit from Oil per Barrel	$50 per barrel
Average Drilling Cost per Hour	$ 6250

The above simulated problem is inputted into the path optimization software. Note the problem stated is the same problem used to simulate color coded cost analysis specified in precious chapter. The result for the optimized path is showing in below figure.

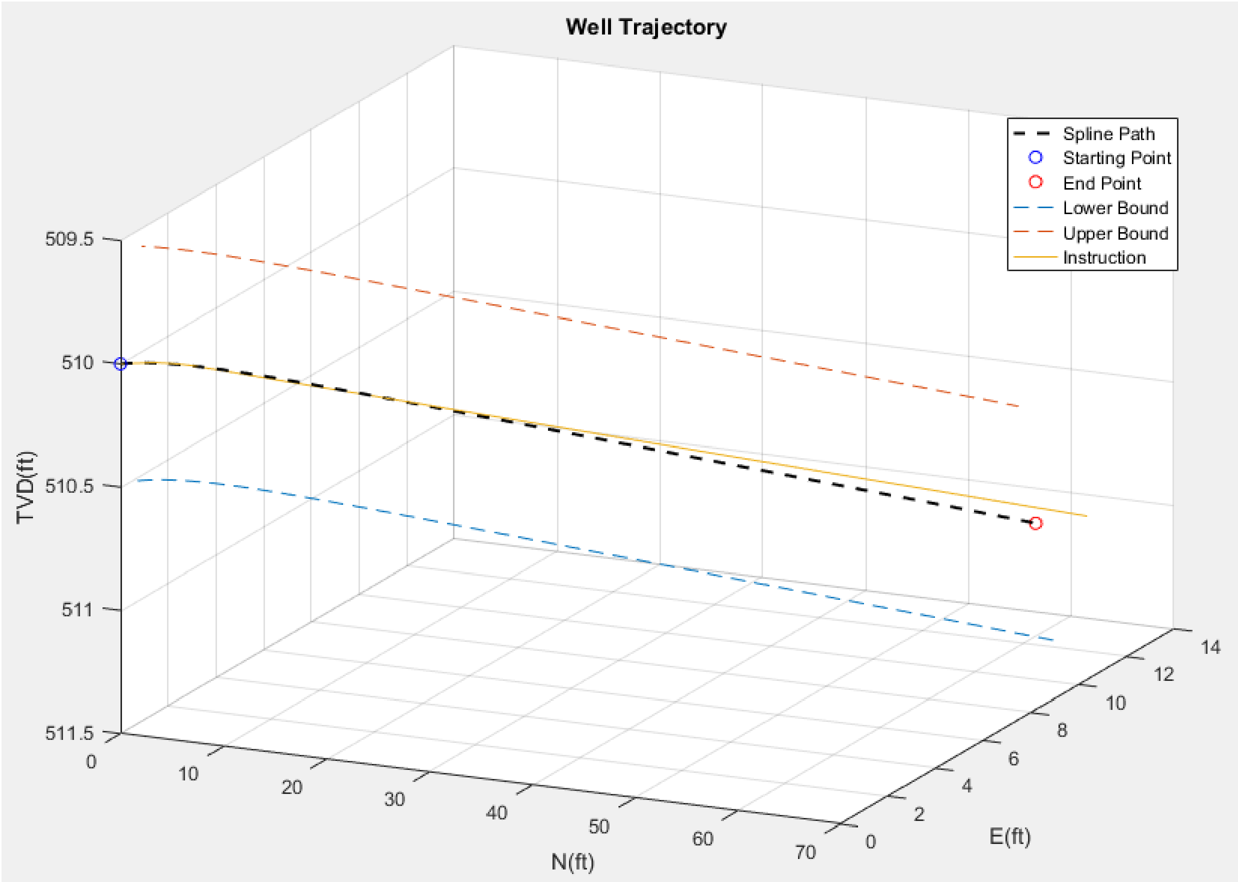


Figure 5-1: Resulting Path from Optimized Path Analysis Test Case 1

Showing in above figure, the optimized spline path is showing in black dashed line. The upper and below boundaries are showing in red and blue dashed lines. The actual instruction given based on the best valued spline is showing in yellow line. The resulting figure is showing in three-dimension, allowing user to rotate plot to view a more comprehensive well plan. If allowed, the optimized bath lines should be combined with previous drilled path surveys. The actual instructions and path results is showing in below table.

Table 5-2: Test Case 1 Problem Result

Drilling Instruction:	
	Slide 6 feet at Tool face 180
	Rotate 62 feet
Path Drilling Time:	25.58 min
Path Distance:	68 feet
Path Trajectory Missed:	63.5 feet
Tortuosity Index:	3.36 $\frac{1}{feet}$

Note the above results is due to different restrictions and constraint used in optimization process. The usage of boundary assumptions in selecting vertical section ranges, L0 range and optimization step size could all alter the resulting path by small changes. Overall, the result should be similar due to the small enough steps taken in the optimization process. Again, the overall cost analysis figure is shown in figure 4-10.

A different test case exanimated, with larger degree of target changes. Note most lateral section inclination range between 85 to 95 degrees. A change of inclination within one degree is common; an inclination change above two degrees is considered high in severity.

Table 5-3: Test Case 2 Problem Set Up

	Initial Condition	Final Target
TVD (ft)	510	515
Inclination (deg)	90	88
Azimuth (deg)	11	11

Motor Yield (BHA Tendency)	15 deg / 90ft
Rotate Average Rate of Penetration	200 ft / hr
Slide Average Rate of Penetration	50 ft / hr
Predicted Total Production	100,000 barrels
Planned Lateral Section Length	1500 ft
Predicted Profit from Oil per Barrel	$50 per barrel
Average Drilling Cost per Hour	$ 6250

Input the second test case problem setup into the path optimized algorithms, the resulting figure and parameters are showing in below figure and table.

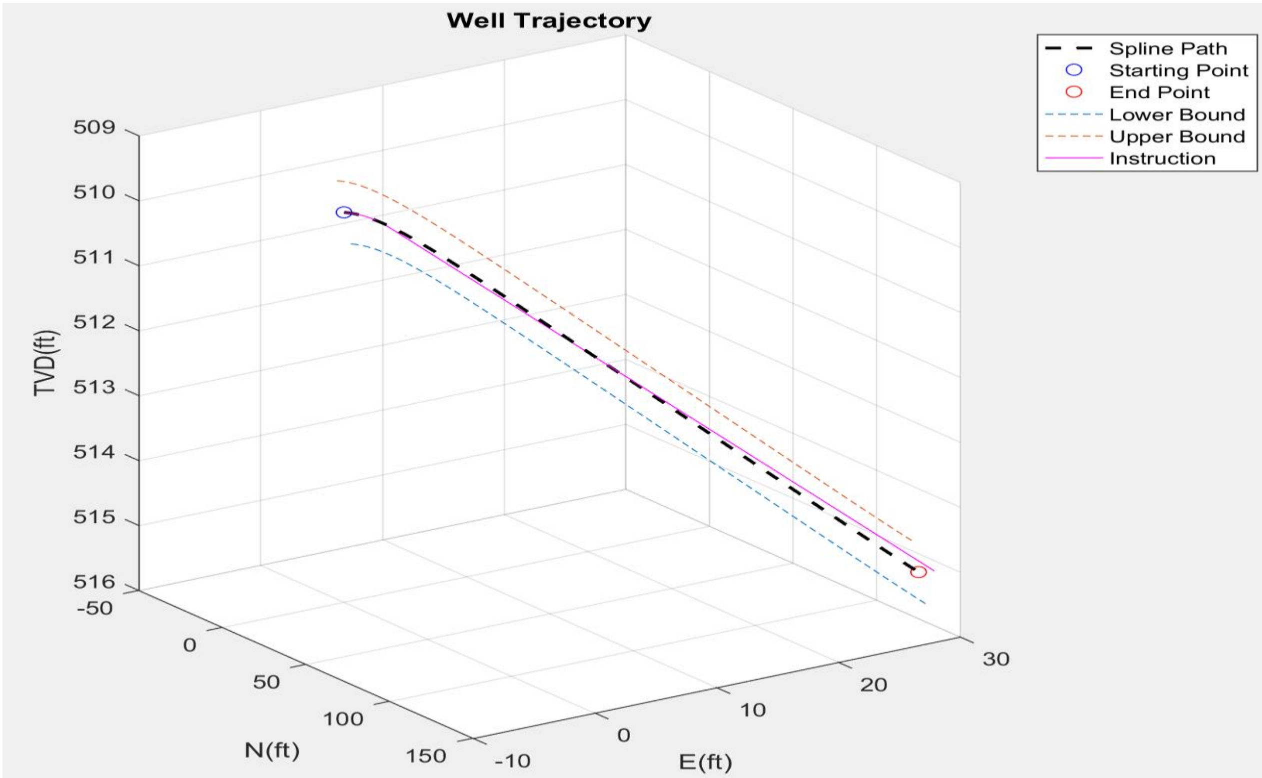


Figure 5-2: Resulting Path from Optimized Path Analysis Test Case 2

Table 5-4: Test Case 2 Problem Result

Drilling Instruction:	
	Slide 12 ft at Tool face 180
	Rotate 137 feet
Path Drilling Time:	56 min
Path Distance:	149 feet
Path Trajectory Missed:	145 feet
Tortuosity Index:	3.85 $\frac{1}{feet}$

Note the drilling distance and drilling time is significantly elongated, mostly to satisfy the change in true vertical depth target. When well path inclination is around ninety degrees, which is near horizontal, change in true vertical depth is extremely costly. The cost analysis, showing in the below figure, display much higher cost than test case problem 1.

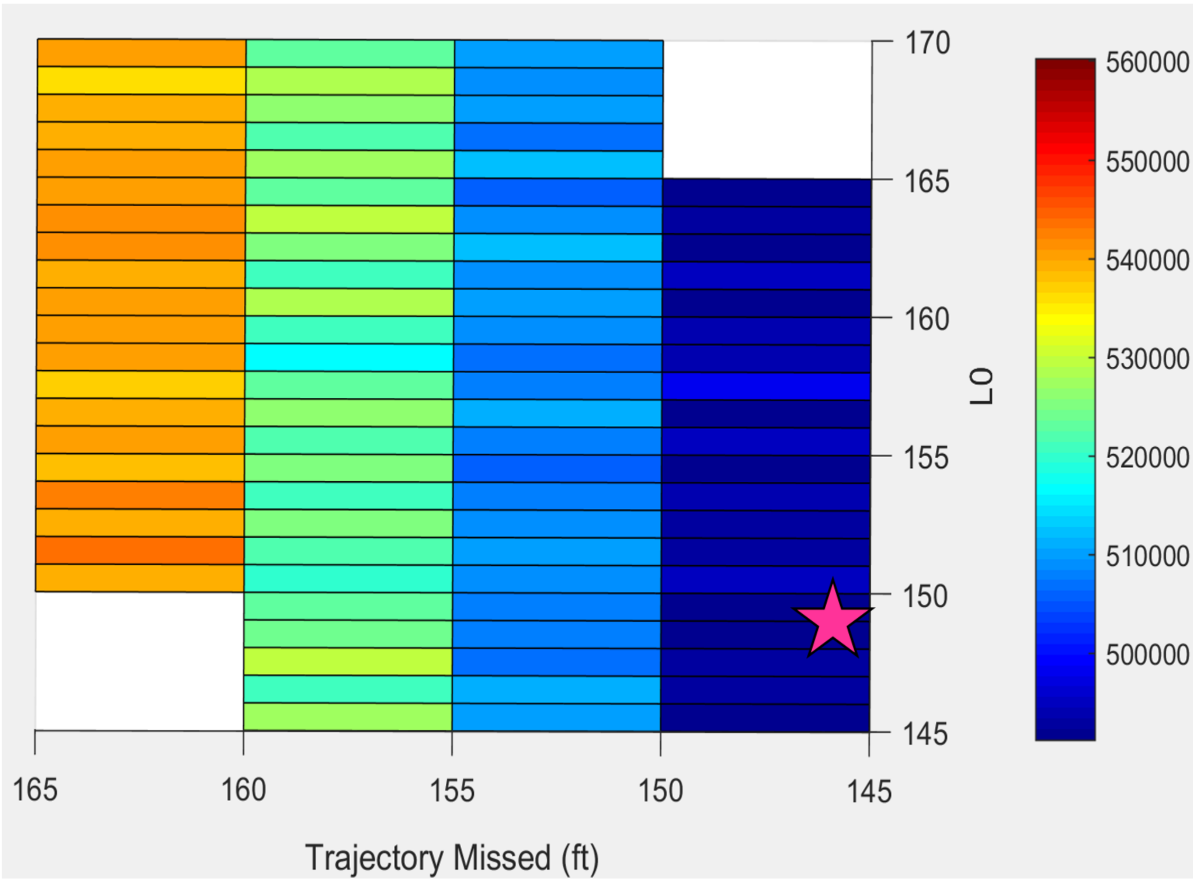


Figure 5-3: Cost Analysis Test Case 2

To show the value of overall cost optimization, two test cases are compared. The first table shows the cost analysis of the overall optimized path. The second table shows the cost analysis of the minimized drilling time path, which is often optimized instead in drilling activities.

Table 5-5: Test Case 2 Overall Optimized Path Cost Analysis

		Cost ($)
Pay Zone Missed	145 ft.	478500
Drilling Time	56 min	5833
Tortuosity Index	3.85	7267
Total Cost	$ 491,600	

Table 5-6: Test Case 2 Minimized Drilling Time Path Cost Analysis

		Cost ($)
Pay Zone Missed	155 ft.	511500
Drilling Time	46.2 min	4857
Tortuosity Index	4	8562
Total Cost	$ 524,919	

As shown in the above tables, the total cost for minimized drilling time cost is $33,319 more than the overall minimized cost path, provide a possible saving of $33,319. This shows the benefit of specified cost functions for each section, allowing the most important criteria to be taken into account when calculating best path. The comparison tables show, the optimized path, when compared with the popular minimized drilling time path, can still show significant value in overall costs. Comparison of optimized path to real drilling instructions are showing in below sections.

5.2 Optimized Path and Real Drilling Instruction Comparison

The optimized path instruction is compared with the real drilling instruction given in a slide sheet and the actual survey measured after the path has been drilled. The goal is to compare three paths results and key performance indicators. The estimated drilling path from slide sheet is estimated by using constant tool face method, equation showing below.

$$Build\ Rate = Motor\ Yield * \cos Tool\ Face \tag{5.1}$$

$$Turn\ Rate = Motor\ Yield * \frac{\sin Tool\ Face}{\sin Inclination(n-1)}^{2} \tag{5.2}$$

$$TVD\ (n) = TVD(n-1) + \cos Inc(n-1) * Slide\ Distance \tag{5.3}$$

$$N(n) = N(n-1) + \sin Inclination\ (n-1) * Slide\ Distance * \cos Azimuth\ (n-1) \tag{5.4}$$

$$E(n) = E(n-1) + \sin Inclination(n-1) * Slide\ Distance * \sin Azimuth(n-1) \tag{5.5}$$

Several assumptions are used when estimating the drilling path from slide sheet instructions. When slide instruction is given, constant tool face method and motor yield are used to estimated slide sections. Since for ideal rotating section, azimuth and inclination will remain constant, so northing and easting is changing on a constant intervals. Motor yield estimated by directional driller, in this case is used as bottom hole assembly capabilities and tendency. It is possible that directional drillers may use bottom hole assembly tendencies based on experience when making instructions. However, such estimation is not documented in slide sheet or any other documents, therefore not taken into account at this point.

The slide sheet instruction used to estimate path to target is based on comments describing activities after target change specified. Currently, only the geosteering target change on target window is analyzed. Slide sections to correct well positioning without specific target is not analyzed due to unclear target documented. Although geosteering target changes are far less than actual slide section performed, but the slide instructions given are very similar. Since the purpose of comparing optimized path instruction to actual situation, geosteering target changes has more accurate target information, therefore is used for such comparison. The path comparison plot is shown in below figure.

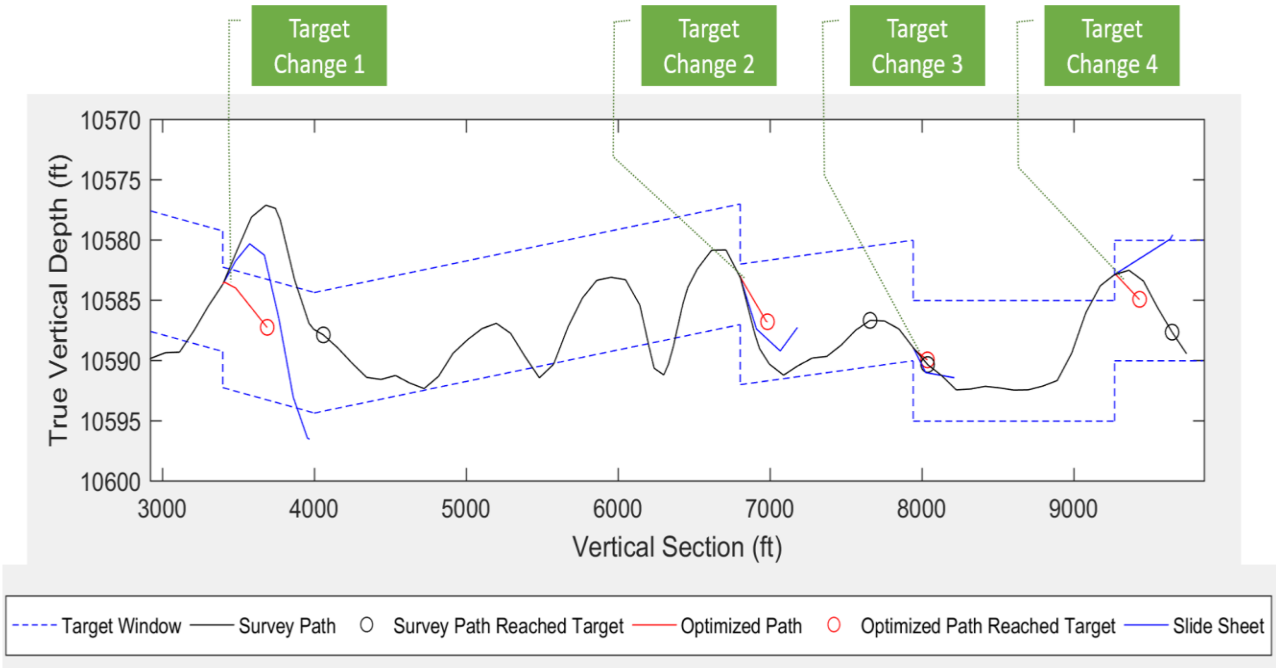


Figure 5-4: Optimized and Actual Path Comparison Case 1

In above figure, optimized path instruction from the path optimization software is showing in red line. The actual survey path is showing in black line and the estimated drilling path from slide sheet instruction is showing in blue line. The comparison plot shows true vertical depth in y-axis and vertical section in x-axis. Thus, the plot shows inclination and pay zone changes more in detail. The blue dashed line illustrates pay zone window specified. Geeosteering target changes occurs when pay zone window is shifted. Note for case 1, optimized path instructions, showing in red, reaches target first compare to slide sheet instructions or actual survey.   Specific comparison for each of the target changes are showing in below comparison figures.

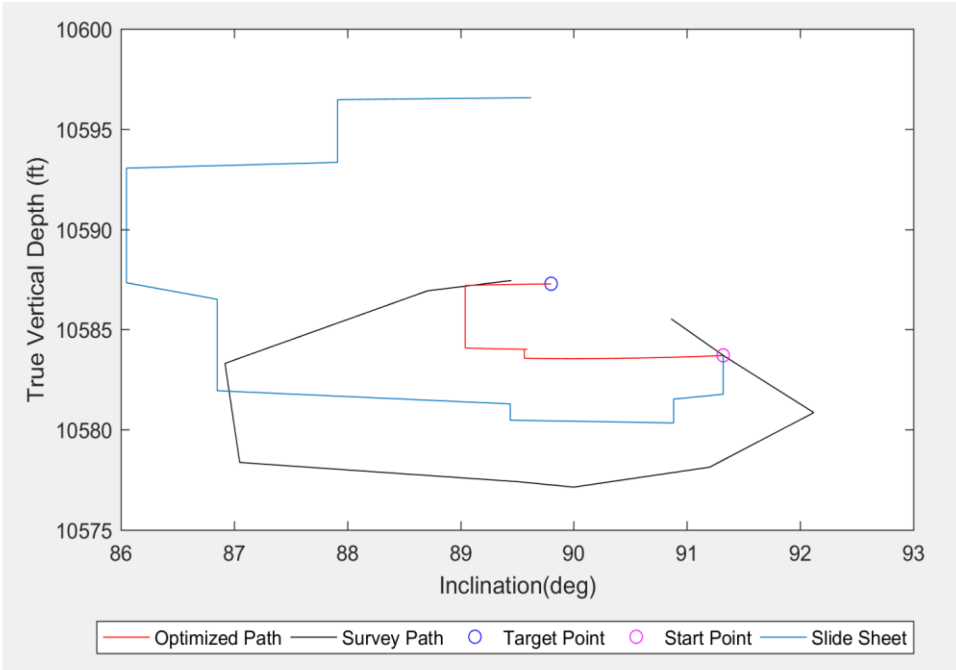


Figure 5-5: Optimized and Actual Path Comparison Case 1 Target 1

For target change 1, true vertical depth versus inclination comparison is computed. In above figure, the starting point is marked by pink circle and the target point is marked by blue circle. The colored lines describe the drilling activities performed by optimized path, slide sheet estimated path and actual survey. Note for optimized path and estimated slide sheet path, horizontal changes in path represent slide sections and vertical segments represent rotating sections with not change in inclination. The actual survey path, however has sloped path. This is due to the actual survey is calculated by minimum curvature method and is not specified to actual rotating and sliding instructions. The result of all paths is compared in below tables.

Table 5-7: Case 1 Target Change 1 Result Comparison

	Survey Path	Optimized Path
Vertical Section Change (ft)	662.14	292.5235
Maximum INC Change (deg/100ft)	7.68	2.4
Tortuosity Index at the Target	4.5599	4.58

	Slide Sheet	Optimized Path
Expected Drilling Time (min)	231.5716	138.41

Showing in above tables, the optimized path suggested much less vertical section changes, smaller maximum inclination change per stand, similar tortuosity index changes compare to survey path. Since the test case is placed in lateral section, saving vertical section changes can avoid reduction in production. Smaller maximum inclination changes may help avoid possible equipment failure and excess friction when drilling. Compared with the estimated slide sheet path, the optimized path shows smaller expected drilling time, improve drilling efficiency. The estimated drilling time is calculated by average slide and rotate section's rate of penetrations in the surveys prior to target change. Similar comparison is done for all other target changes in case 1, figures shown below.

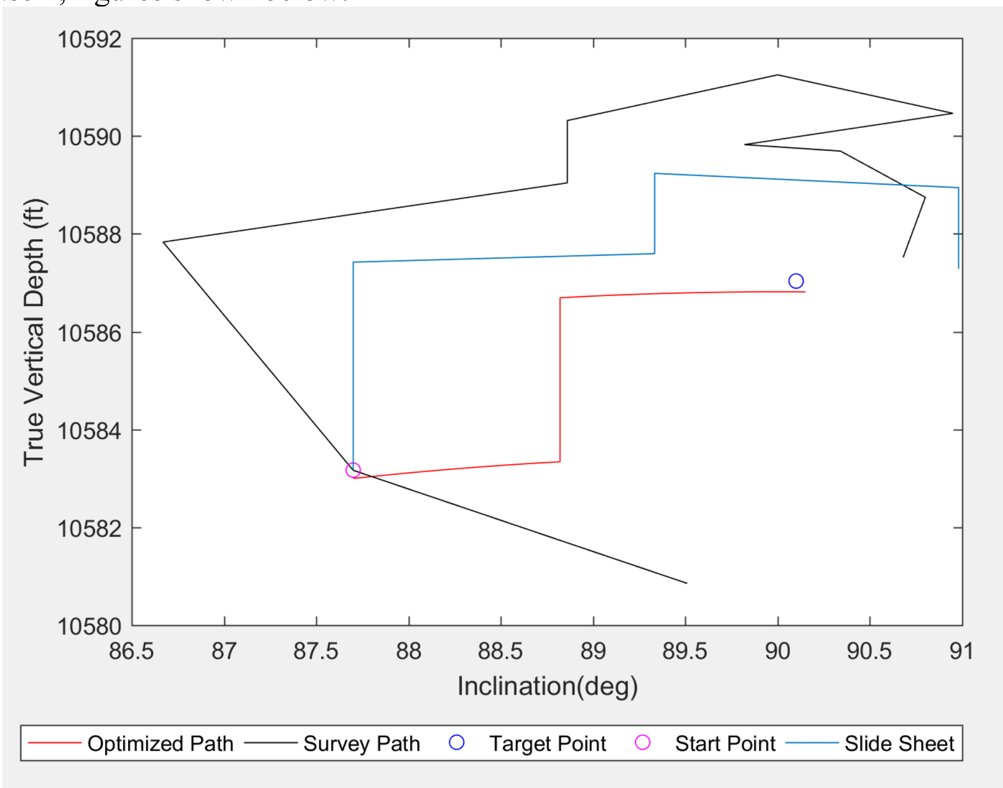


Figure 5-6: Optimized and Actual Path Comparison Case 1 Target 2

Table 5-8: Case 1 Target Change 2 Result Comparison

	Survey Path	Optimized Path
Vertical Section Change (ft)	853.65622	178.5117
Maximum INC Change (deg/100ft)	7.06	1.51
Tortuosity Index at the Target	4.6543	3.94

	Slide Sheet	Optimized Path
Expected Drilling Time (min)	153.11	90.77

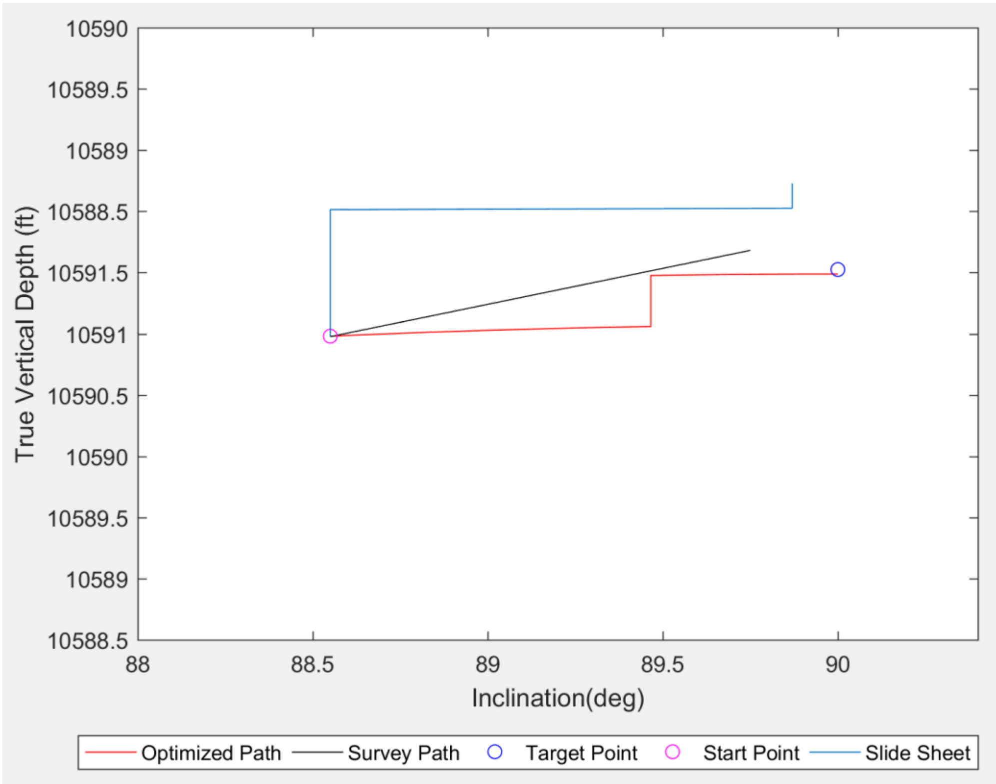


Figure 5-7: Optimized and Actual Path Comparison Case 1 Target 3

Table 5-9: Case 1 Target Change 3 Result Comparison

	Survey Path	Optimized Path
Vertical Section Change (ft)	94.9894	94.0545
Maximum INC Change (deg/100ft)	1.26	1.51
Tortuosity Index at the Target	4.5025	4.92

	Slide Sheet	Optimized Path
Expected Drilling Time (min)	41.77	50.67

Note in target change 3, the slide sheet estimated path has a smaller drilling time estimated than the optimized path. This is because the slide sheet instruction has a shorter slide section than the optimized path instructions. The slide sheet path also landed slightly off the target point. How accurate does the path need to be and what is a good tolerance for landing target point are concerns that need to be determined.

Another consideration is both slide sheet estimated path and optimized path are instructions and estimation, but actual survey measurement tends to be different. Geological formation influence, bottom hole assembly tendency influence, surface parameters, such as weight on bit, influences, should also be included for a more accurate drilling path estimation. Maintaining the proper tool face is also a challenge during drilling; the vibration and friction may cause the tool face to oscillate. Reactive torque after setting tool face could also cause tool face to be inaccurate to start with.

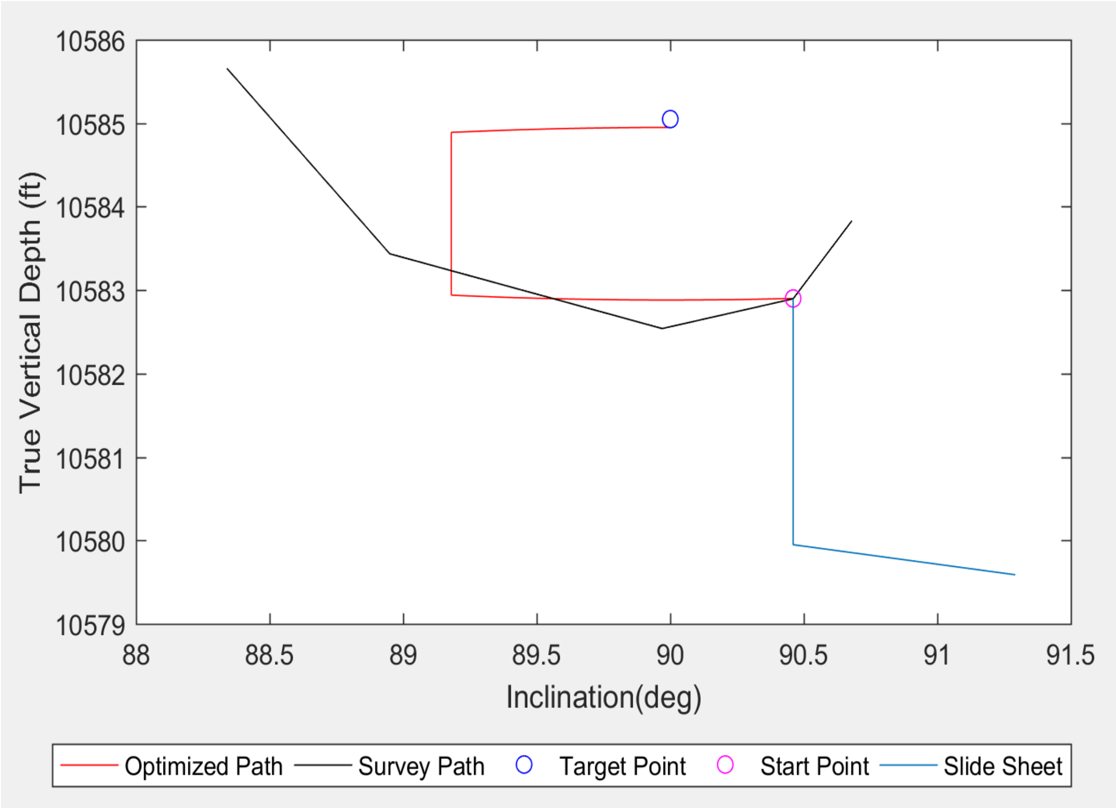


Figure 5-8: Optimized and Actual Path Comparison Case 1 Target 4

Table 5-10: Case 1 Target Change 4 Result Comparison

	Survey Path	Optimized Path
Vertical Section Change (ft)	378.92	164.84
Maximum INC Change (deg/100ft)	1.07	1.47
Tortuosity Index at the Target	4.20	4.20

	Slide Sheet	Optimized Path
Expected Drilling Time (min)	123.02	81.48

In target change 4, it is noted that slide sheet estimated path is opposite to optimized path and the actual survey. A closer look at the slide sheet estimated path, the slide sheet instruction includes rotating sections first, then a buildup slide section to increase inclination. Such instruction may be because of the directional driller has seen formation or other influence on drilling path, causing inclination to drop during drilling. Again, this brings up the concern of the importance of knowing formation influence and equipment influence on drilling path. This is also a direction where the path optimization software needs to be included. Note the effects of tendencies can be severe, displayed by target change 4, where the landing point of survey and slide sheet estimated path is far away from target point.

Following the analysis of optimized path and actual instructions, the next step would be to use the path optimization software in actual drilling situations, as a supporting tool. The concerns regarding reactive torque, formation and other influences should be analyzed. More comparison plots of optimized path, slide sheet estimated path, and actual survey path are showing in Appendix.

Chapter 6: Supporting Analytical Tools

Several supporting tools are included in the path optimization advisor, including slide sheet path estimation and wellbore tortuosity calculation. Since path optimization advisor is one of the modules out of overall automated directional drilling advisor frame, many input is taken from supporting calculations and user experiences, before the other modules can be completed. The slide sheet path estimation tool allows users to input slide sheet from excel spreadsheet, into the Matlab graphical user interphase, and automatically generate estimated slide sheet path. The wellbore tortuosity tool allows users to input directional survey excel spreadsheet into the software interphase and calculated sectional wellbore tortuosity prior to correction path. Note all input files is required to follow a specific format, to allow accurate data conversion and calculation.

6.1 Slide Sheet Estimated Path Tool

Slide sheet estimated path tool allow user inputs of slide sheet instructions, and estimate path from slide sheet instructions. Current tool only allows for sectional evaluation of slide sheet calculation. The tool requires input of slide footage, called tool face, motor yield and initial position of the slides. A sample of slide sheet with all required information is shown in figure 6-1. TF represent tool face angle, which may be specified in magnetic or gravity tool face. Magnetic tool face is generally used for vertical section where inclination is less than six degrees, and when gravity tool face might be less accurate. By recording actual tool face compared with tool face called in instructions, the effect of reactive torque and vibrations on tool face control may be estimated. Motor yield is the capabilities of directional motor and tools, which generally estimated based on experience or calculated. MD is the measured depths along the path. I represents initial and f represents final position.

Surveys			Instruction		Actual Slide			
MD	INC	AZI	Ft.	TF	ActualTF	Motor Yield	Mdi	MDf
2268	2.07	337.67						
			4	340M	4M	15.8	2323	2327

Figure 6-1: Sample of Slide Sheet Information

During path estimation, a rotate section is usually first performed due to the delay of instruction communication and planning. This delay causes the resulting drilling path to be different from slide instruction called, and is often not considered when making correction plans. For rotating sections, inclination and azimuth is assumed to be the same as last survey's measurements. Northing and Easting therefore can be calculated using simple geometry. Note if survey measurements are inaccurate, estimation for rotating sections can be highly delineated from the actual path.

For slide section path optimization, constant tool face method is used to estimated drilling path with the usage of motor yields as estimated tool tendency. The build rate and turn rate are first calculated than the actual coordinates is calculated. The following equations are used to simulate slide path.

$$Build\ Rate = \ Motor\ Yield * \cos Tool\ Face \tag{6.1}$$

$$Turn\ Rate = \ Motor\ Yield * \frac{\sin Tool\ Face}{\sin Inclination(n-1)}^{2} \tag{6.2}$$

$$Inclination(n) = inclination\ (n-1) + Build\ Rate * \ (\ Slide\ Distance) \tag{6.3}$$

$$Azimuth\ (n) = Azimuth\ (n-1) + Turn\ Rate * (Slide\ Distance) \tag{6.4}$$

$$Vertical\ Section\ (n) = Vertical\ Section\ (n-1) + sqrt(\left(N(n) - N(n-1)\right)^2 + \left(E(n) - E(n-1)\right)^2) \tag{6.5}$$

6.2 Wellbore Tortuosity Calculation

Wellbore tortuosity tool is used to calculated tortuosity exists in planned section. The tool takes in well planned data and estimated tortuosity based on given coordinates. Note that to be able to have a fair comparison, it is recommended to separate well planning data into 90 feet coordinates, or set data frequency equals to survey frequency, before input into wellbore tortuosity calculation for each section. Currently curve section is not included in wellbore tortuosity calculation tool, and will be included in the future. A sample coordinate path can have the same format as survey data sheet for easier program set up. A sample survey data format is attached in below figure.

M.D	INC.	AZM	TVD	N/S	E/W	VSEC
2000	0.3	206.1	1858.36	2.88	0.53	-2.88548
2090	0.13	331.25	1983.859	2.70977	0.31697	-2.71299
2018	0.29	315.12	2079.859	2.9774	0.09316	-2.97823
2054	1.18	339.97	2142.853	3.69985	-0.24153	-3.69707
2063	1.68	341.65	2173.843	4.43106	-0.49393	-4.42555
2072	1.96	337.75	2204.828	5.35303	-0.83772	-5.3438

Figure 6-2: Sample of Well Plan Coordinates

The calculated planned wellbore tortuosity value is an input for the path optimization advisor, for calculating cost based on tortuosity changes. This supporting tool can be added into the path optimization advisor algorithm, to allow automatic calculations. The supporting tool can also be used to compare planned tortuosity versus actual tortuosity, for drilling perform and quality visualization.

Chapter 7: Conclusions and Future Works

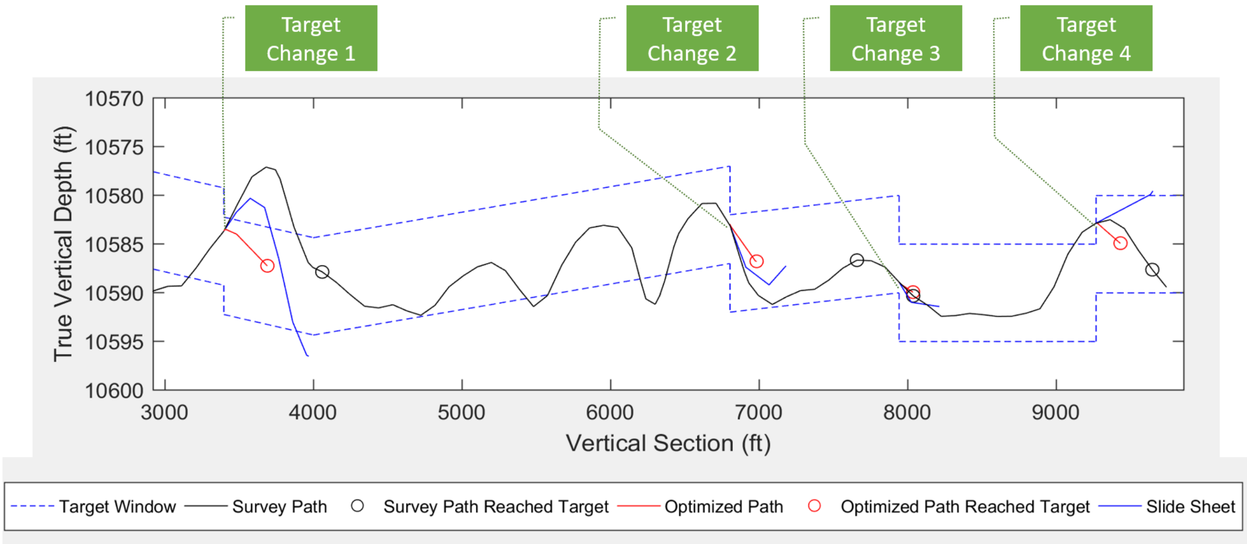
This thesis introduces a path optimization advisor with novel cost analysis. The objective of developing the path optimization algorithms is to improve drilling efficiency, wellbore positioning precision and directional drilling instruction accuracy. The path optimization module is part of the automated directional drilling advisor framework, which aims to optimize and automate the directional drilling process. The algorithm utilizes tension in spline to simulate drilling path, multi-loop optimization for optimizing cost, and produces realistic directional drilling instruction with consideration of motor tendency. Simulated and actual historical case studies are used to test and improve path optimization advisor, and validate the software for real time testing at operating situation. The objective of developing the path optimization software is to advise an optimal path with best value of cost to directional drilling team, and the software has been proven to be beneficial through historical data validation.

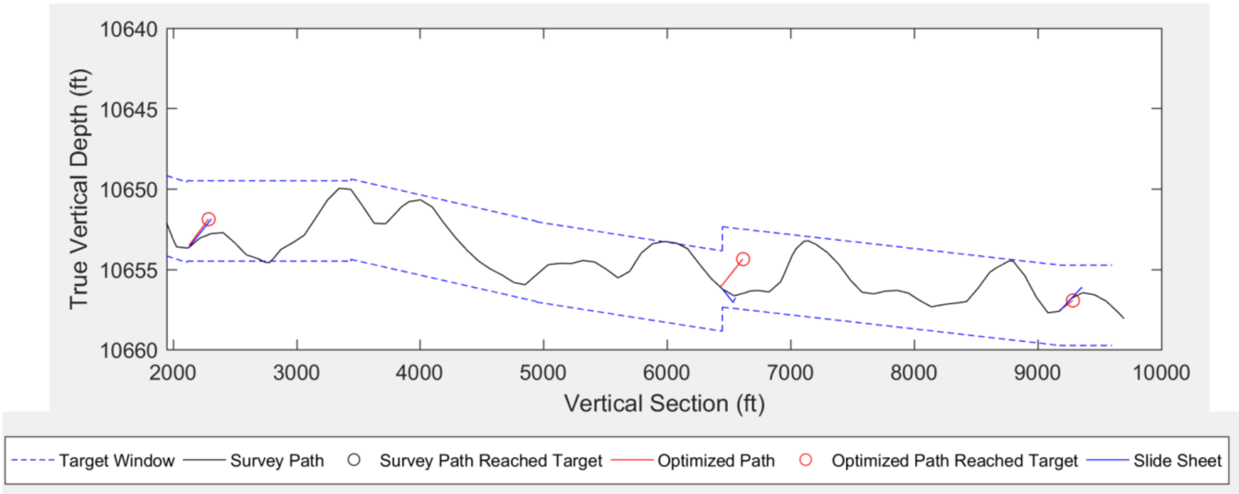
Many modules and improvements can be added in the future to improve the capabilities of the path optimization advisor. Regarding the path optimization module, abilities to include real time reactive torque estimation, and real-time bottom-hole-assembly tendency would be useful. The actual drilling path and survey never follows the planned ideal path. Currently, motor yield is inputted by user, based on their experiences, and is used to estimate tool tendency and ability. This input parameter is recorded in at the beginning of every correction path plan, and is subject to user's knowledge and estimation. Being able to update this value continuously during real-time would be helpful to correct ideal drilling path. When adjusting tool face for slide drilling, reactive torque may cause tool face to change abruptly and influence the actual drilling path. Current method of estimating reactive torque is to use the reactive torque observed in previous correction path. This method does not consider the influences by formation and other drilling parameters, and may introduce errors.

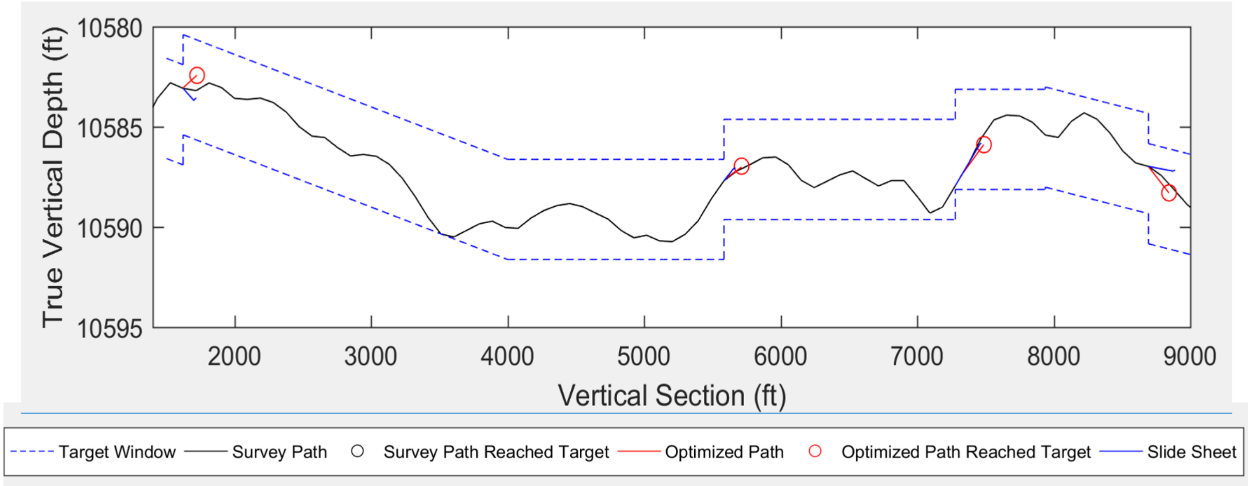
Path optimization is only one of the modules in the directional drilling frame work; other modules needs to be developed to form a complete directional drilling advisor. Geosteering require geologist's expertise in formation evaluation, based on different field of operation. Bottom-hole-assembly tendency, target window set up, and bit projection modules can be completed.

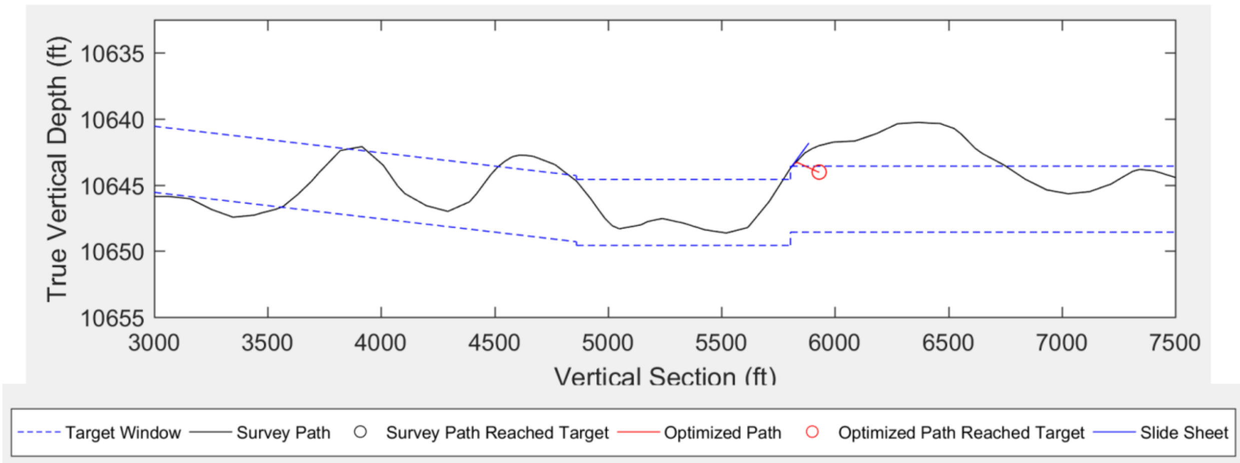
Appendix

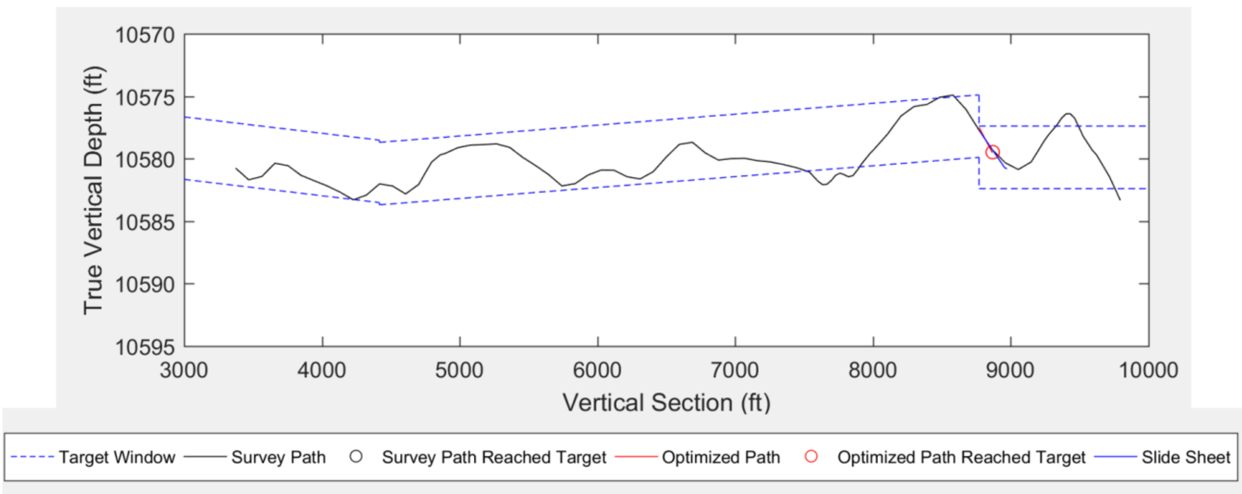
Figure A- 1: Optimized and Actual Path Comparison Cases

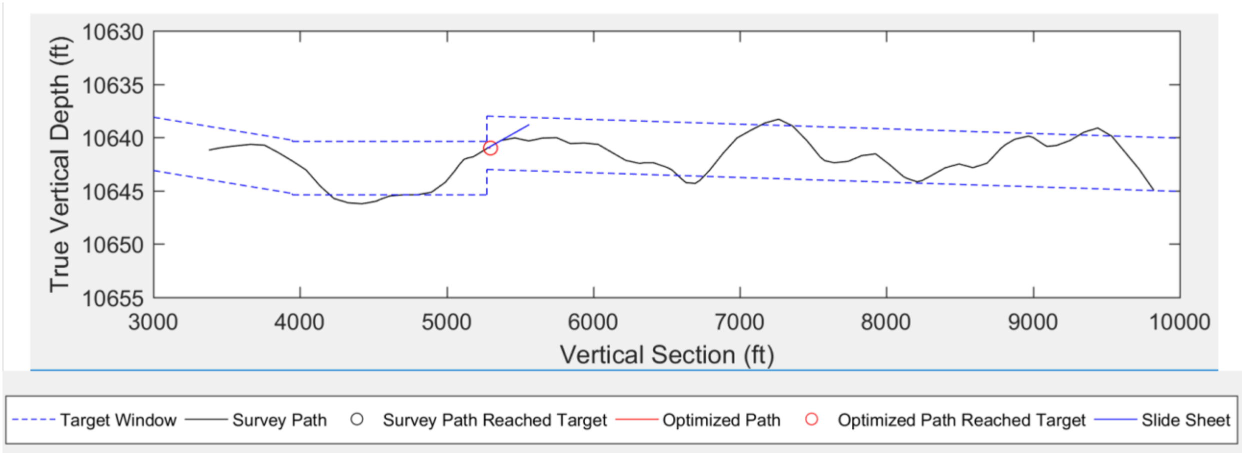





True Vertical Depth (ft)
10580
10585
10590
10595
2000
3000
4000
5000
6000
7000
8000
9000
Vertical Section (ft)
Target Window
Survey Path
Survey Path Reached Target
Optimized Path
Optimized Path Reached Target
Slide Sheet


True Vertical Depth (ft)
10635
10640
10645
10650
10655
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
Vertical Section (ft)
Target Window
Survey Path
Survey Path Reached Target
Optimized Path
Optimized Path Reached Target
Slide Sheet


True Vertical Depth (ft)
10570
10575
10580
10585
10590
10595
3000
4000
5000
6000
7000
8000
9000
10000
Vertical Section (ft)
Target Window
Survey Path
Survey Path Reached Target
Optimized Path
Optimized Path Reached Target
Slide Sheet



True Vertical Depth (ft)
10630
10635
10640
10645
10650
10655
3000
4000
5000
6000
7000
8000
9000
10000
Vertical Section (ft)
Target Window
Survey Path
Survey Path Reached Target
Optimized Path
Optimized Path Reached Target
Slide Sheet

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