INVESTIGATION OF EFFECT OF WELLBORE POSITION UNCERTAINTY ON UNCONVENTIONAL RESOURCE DEVELOPMENT

A Thesis

by

SIMAN PARK

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Chair of Committee,	Samuel F. Noynaert
Co-Chair of Committee,	Jerome J. Schubert
Committee Member,	Zenon Medina-Cetina
Head of Department,	Jeff Spath

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ABSTRACT

The Eagle Ford Shale is one of the largest unconventional oil plays where a large number of horizontal wells with hydraulic fractures have been developed in recent years. Due to its very low permeability, operators complete a fair number of the horizontal wells, with their “ideal” well spacings, from the same surface location to produce estimated unconventional reserves. The problem is; operators typically develop horizontal well positions by assuming parallel, fixed spacing to maximize production and call it “optimized” spacing.

This generalized well spacing is approximated as a single number and treated as having no positional uncertainty of wellbores. However, each wellbore has a wide range of positional uncertainty due to survey errors caused by Measurement While Drilling (MWD) and this positional uncertainty, in turn, leads parallel spacing to a meaningless optimization. Furthermore, these positional errors produce an uncertain magnitude in levels of hydraulic fracture communication between horizontal wells and have an impact on well performance. Such uncertainty depends obviously upon well spacing as well as wellbore positions, but inaccurately positioned wellbores do not convey the fracture communication level clearly.

Within the context of publicly available data, this study evaluates possible cases of wellbore position uncertainty based on MWD error sources for five selected well pads in Burleson County. It provides an estimate to how far the wellbores can be deviated from their parallel positions. By using simulation models and comparing well performances between the parallel positions and practical positions estimated, this study investigates actual wellbore positions. It, then, analyzes the effects of positional changes coupled with fracture communication level on long-term well performance, in terms of Estimated Ultimate Recovery (EUR), to show the wide range of uncertainty in reserve estimates.

These large positional errors of wellbores produce considerable differences in the cumulative oil production, because the extent of drainage radiuses overlapped by fractures of two wells in staggered configurations changes due to wellbore positional changes. These results show that 10-year total EURs of two wells in parallel positions are overestimated by up to 10.7% due to 1.2% - 5.8% probability of causing positional errors compared to their actual positions. The other well pad whose actual well performances are lower than the expected performances of the two wells in a parallel position produces a gross under-estimate of EUR by 9.8% due to positional errors with 9.1% probability of occurring. In addition, a single well that has longer fractures than the other well in the same pad has more impact on EUR due to a strong effect of fracture communication.

These wide ranges of uncertainty in reserve estimates clearly show operators should consider positional errors of wellbores with a probabilistic aspect to avoid over- or under-estimates of reserves that in turn, lead to unexpected economic returns. Using standard MWD tool sets for improved survey, such as multi In-Field Referencing (IFR) and Multi-Station Analysis (MSA) can reduce much of the wellbore position errors. Minimizing wellbore position uncertainty is an important process in the unconventional developments to establish the validity of reserve estimates when horizontal well spacings are optimized.

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Contributors

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NOMENCLATURE

bbls	Barrels
EUR	Estimated Ultimate Recovery
FTP	First Take Point
ft	Feet
HRGM	High Resolution Geomagnetic Model
IFR	In-Field Referencing
ISCWA	Industry Steering Committee on Wellbore Survey Accuracy
LTP	Last Take Point
MD	Measured Depth
MSA	Multi Station Analysis
MWD	Measurement While Drilling
TxRRC	Railroad Commission of Texas
TVD	Total Vertical Depth

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1. INTRODUCTION

The Eagle Ford shale is one of the largest unconventional oil and gas developments in the world where a considerable number of active rigs have been running currently. The Eagle Ford shale play, widely discovered around South Texas trending from the Mexican border into East Texas, has the capability of producing more oil than other traditional shale plays in the states due to its geological characteristics according to the Railroad Commission of Texas (2018). The oil production in the Eagle Ford was targeted early, however what operators call “true” Eagle Ford production actually began in early 2008, increased to 1.2 million barrels per day in 2015, and continues 0.8 million barrels per day in August 2018 (Texas RRC 2018). The developments were focused around South Texas counties such as Karnes County, the largest production area in the Eagle Ford. In recent years of the Eagle Ford production boom, several operators have moved toward southwest along the Austin Chalk trend through Burleson and Brazos Counties due to intense competition for leases and productions around South Texas counties.

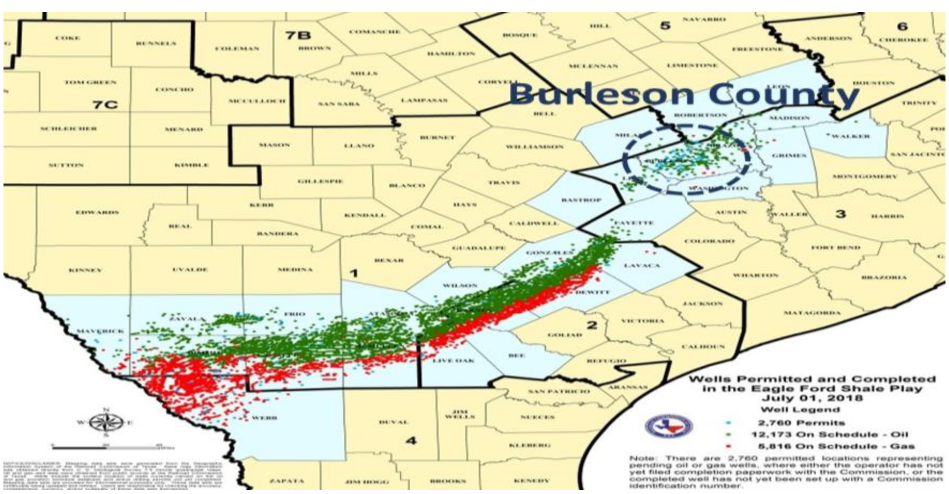

Figure 1: Eagle Ford Shale Play production represented in 2018.

Due to very low permeability of the unconventional play, horizontal wells are mostly developed with hydraulic fractures and well spacing becomes a crucial development decision. Several horizontal wells are typically drilled from the same surface location in a pad and completed similarly to maximize production in the unconventional play targeted. The production as well as well performance depend significantly on how horizontal well spacing is designed; it should be able to stimulate and drain the unconventional play enough in a timely manner while it produces as low of a level of overlapped drainage radius as possible. So, parallel spacings between horizontal wells are generally utilized to have the ideal amount of drainage radius stimulated.

A large number of publications have presented and helped operators optimize horizontal well spacing to enhance the Eagle Ford production. They have analyzed horizontal well performances in terms of EUR with a primary focus of down-spacing for a given drainage radius and provided valuable guidance on the well spacing optimization. Lalehrokh and Bouma showed the optimization of horizontal wells in parallel positions in terms of EUR and Net Present Value (NPV) (2014). The results clearly show down-spacing optimizations depend significantly on the EUR terms that operators estimate for their capitalizations. Two or more horizontal wells with shorter spacings in between were required to have a better well performance for 10-year EURs compared to 30-year EURs. Bharali et al., also shows the effects of horizontal well spacing on EUR; decreases in spacing between wells resulted in reducing EUR of each well by 26% to the maximum but increasing the total recovery in particular areas (2014).

Moreover, Pettegrew et al., described an integrated work with multiple field data to quantify the effects of well spacing and proppant loads on EUR using production and pressure analysis (2016). However, this study only showed the well spacing effects on EURs by two cases of parallel well spacing: 4 wells and 8 wells per section. Additionally, Suarez and Pichon stated the importance of both lateral spacing and fracture completions for well spacing optimization in pad development in the Vaca Muerta Shale (2016). Their simulation approach showed that hydraulically fractured horizontal well spacings need to consider neighboring fractures due to fracture overlaps. The simulation results presented that increasing spacing between horizontal wells for a given area led individual wells to have a higher productivity, but had a negative impact on the total production of the pad.

As the studies concluded, well spacing had a significant effect on well performance and predicting EUR. However, this conclusion was drawn only by down-spacing horizontal wells that were in parallel positions for a given area. The conclusion might be significantly different if each wellbore is not in a parallel position fixed ideally. Furthermore, this uncertain position of a wellbore could result in having a completely different fracture configuration from what operators plan with parallel wellbores, which covers a different drainage radius, and in affecting well performance in the end. In other words, once wellbore position errors that commonly occur in fields and cause the parallel wellbores to deviate from their planned positions are accounted for, production forecast based on EUR will be completely inaccurate.

The positional error of a wellbore in the map view of Eagle Ford, for example, could be as much as 439 feet in any direction from the current position stated (Maus and DeVerse 2015a). Such positional change could result in considerably different reserve estimates from what companies forecast with parallel positions of wellbores fixed. This wide range of uncertainty in reserve estimates, in turn, leads the companies to estimating inaccurate capital expenditure. Thus, wellbore position errors should be considered to not only establish the validity of the reserve estimates and well performance but increase well performance to have better economic consequences.

2. PROBLEM STATEMENT

A large number of methods from reservoir simulations to production history-matching analyses have been used to estimate the Eagle Ford reserves since the boom of horizontal well developments with hydraulic fractures. From individual wells to pad or lease-sized developments, operators evaluate and complete a fair number of wells with a certain spacing to produce the unconventional reserves they target. Most horizontal wells are developed by assuming a parallel and fixed spacing between the wells based on the operators' estimations and called "optimized" spacing. However, this general spacing is approximated as a single number and considered as if there is no positional uncertainty of wellbores during operation.

In fields, most of the horizontal wells are steered and drilled using a Measurement-While-Drilling (MWD) tool. This tool, using an accelerometer and a magnetometer attached in Bottom Hole Assembly (BHA), determines the inclination and magnetic azimuth of the drill bit. This causes sensor errors and the magnitude of the errors escalates due to inaccuracies of their reference models as well as magnetic interference (Maus and DeVerse 2015a). In addition, magnetic field uncertainty and such tool misalignments lead to another negative impact on planned wellbore position alignment. Such errors propagate in magnitude along the measured depth of the wellbore and in the end, lead the optimized spacing to a meaningless optimization.

Furthermore, wellbore position errors cause an uncertain magnitude in levels of hydraulic fracture communication. This uncertainty depends obviously upon spacing between horizontal wells; however, the "optimized" well spacing does not clearly convey the fracture communication level that has a significant effect on well performance. Operators utilize their own techniques of hydraulic fracturing to create the ideal amount of drainage radius with particular fracture configurations; well spacing should enable the drainage radius to encounter enough, but not to be overlapped by fractures. However, inaccurately surveyed wellbore positions result in positional deviations by hundreds of feet from enough close positions optimized (Maus and Deverse 2016). Such large extent of positional uncertainty, in terms of well spacing, causes a low level of fracture communication and results in draining the reservoir incompletely. While a high level of fracture communication occurs when wellbores are placed too close to each other.

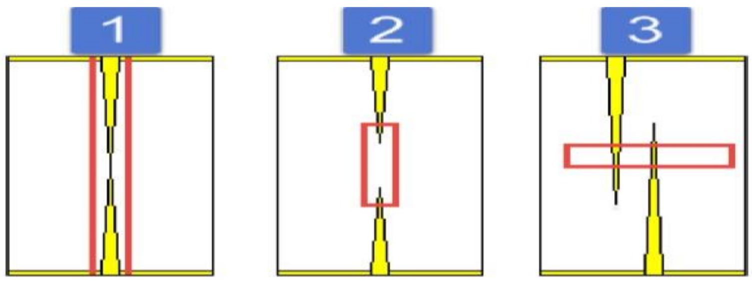

Figure 2: Plan view of hydraulic fracture configurations that can cause interference (Awada et al., 2015).

Therefore, in the interest of well performance, the ideal level of fracture communication that stimulates the drainage radius adequately could result in good performances and lead EUR to the level that operators estimate. On the other hand, a high level of fracture communication like large overlaps (Case 1 and 3 in Figure 2) or a low level of communication in the further-positioned fracture system (Case 2 in Figure 2) could, in turn, lead to over- or under-estimates of EUR.

For those reasons, Maus and Deverse conducted a study on quantifying the impact of wellbore placement errors on reservoir recovery and economy (2016). It showed the remarkable effects of improved wellbore placements by characterizing ellipses of the positional uncertainty based on Instrument Performance Model (IPM) and tool codes arranged by Grindrod et al., (2015). Deverse and Maus also researched the optimization of lateral well spacing based on reduced wellbore position uncertainty by applications of IFR and MSA (2016). The results showed the importance of the improved wellbore placement for the validity of simulation modeling which typically takes into account completion variables and reservoir quality. These publications clearly show how important accurate wellbore positioning is with regard to well spacing and performance; yet, they left positional effects of wellbore coupled with fracture communication level on EUR to be studied further.

This study can propose a solution within the context of publicly available data. Possible scenarios of positional uncertainty of wellbore can be evaluated based on survey error sources. The evaluated positional uncertainty gives a sign to how far the wellbores can be deviated from their ideally parallel positions due to the survey errors. By comparing well performance between the parallel position and practical positions evaluated by the positional errors through simulation models, the actual and simulated performance results can show the effects of inaccurate wellbore positions. The wide range of uncertainty in the reserve estimates in terms of EUR can be then delivered where the wellbore position error is accounted for.

3. METHODLOGY

3.1 Public Data Gathering and Well Selection

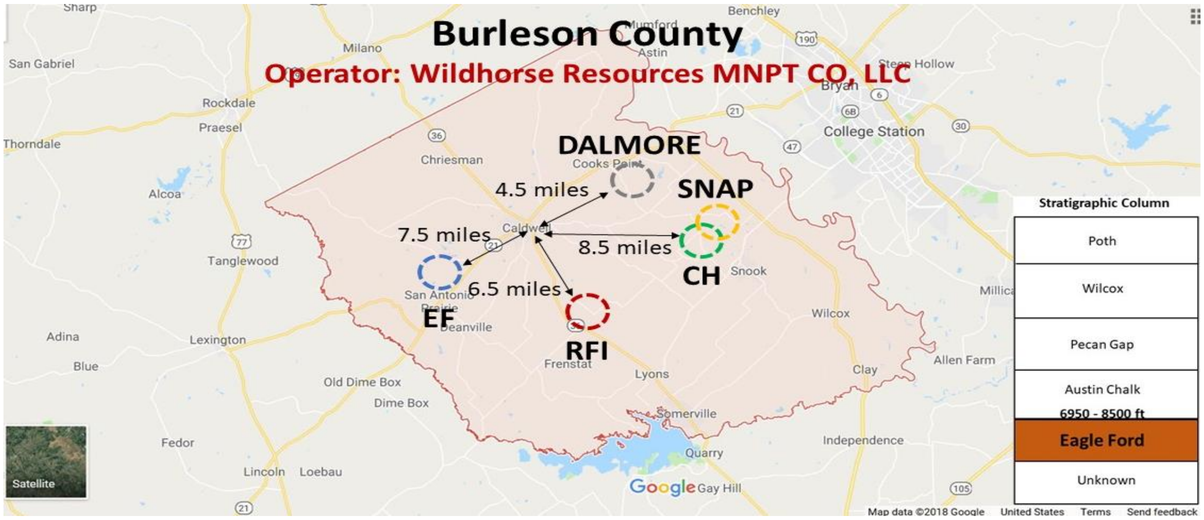

Figure 3: Google map view of selected well pad locations and stratigraphic column for Burleson County.

Public data gathering is an important procedure to identify horizontal well developments and investigate well performances considering effects of wellbore positions. DrillingInfo was used to identify details of wellbores, productions, and hydraulic fracture treatment jobs and FracFocus provided detail information about hydraulic fracturing fluids. Additionally, specific well paths and positions were obtained from MWD survey reports that were submitted to the Railroad Commission of Texas (TxRRC).

Burleson County was chosen among the Eagle Ford production counties because horizontal well developments are less compact than South Texas counties. The conclusion of this study can be drawn more accurately since possible near-wellbore effects such as stress changes, depletions, and interference by adjacent wells are minimal and can be assumed negligible. Thus, five specific well locations with two hydraulically fractured horizontal wells in each pad were selected based on available completion, wellbore surveys, and production data as shown in Figure 3. They are also listed by pad names in Table 1 following the availability of the essential data. A single well pad for the base case of each location, which was set for a reservoir condition for the two-well pad, was chosen based on the distance between the two pads and the same completion jobs. All single well pads were located within 1.4 miles away from two-well pads so, each two-well pad was assumed to have the same reservoir condition as the base case. In addition, there were no adjacent horizontal wells targeting the Eagle Ford play within 1500ft of each location.

Table 1: Summarized information on selected well locations.

Name	Single Well (Base Case)	Completion Date	Two Wells		Completion Date	Distance between
RFI	FLENCHER E	9/1/2015	RFI A	RFI B	12/1/2015	0.80 miles
CH	TURNER 1H	2/1/2018	CROOK (C)	HINES (H)	5/1/2017	0.90 miles
SNAP	TURNER 1H	2/1/2018	SNAP C	SNAP D	8/1/2017	1.00 miles
DALMORE	ASCARI B	12/1/2017	DALMORE 1H	DALMORE 2H	11/1/2017	0.95 miles
EF	KRETZER EF	12/1/2017	DOSS EF (D)	SINDER EF (S)	12/1/2017	1.40 miles

3.2 Ellipse of Wellbore Position Uncertainty

The Industry Steering Committee on Wellbore Survey Accuracy (ISCWSA) and its subcommittees put efforts on producing standards for the industry to survey accuracy as well as estimates of survey-tool performance (2018). They provide both industry and academic fields with standard directions of how positional errors of a well can be defined and calculated and with tool codes for improving survey accuracy on wellbore positions.

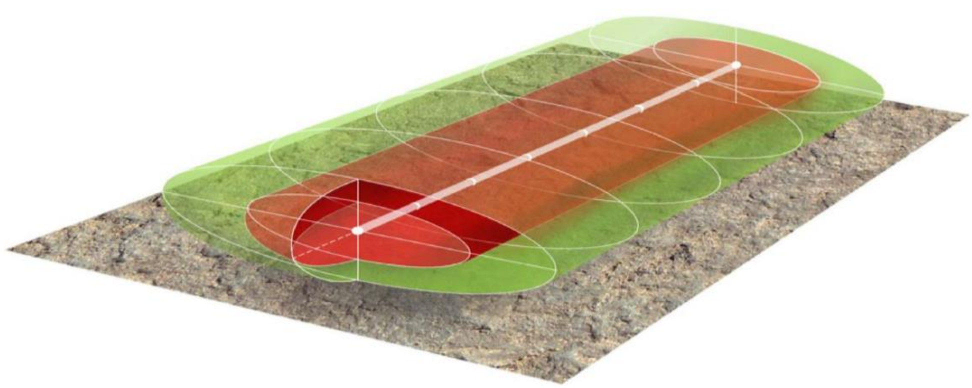

Figure 4: Three dimensional ellipses of wellbore position uncertainty for different error models (Maus and Deverse 2015b).

As Figure 4 shows, ellipses of positional uncertainty can be characterized by wellbore trajectories computed from numerous sources of positional error in directional surveys (Maus and Deverse 2015b). The size of ellipses is quantified by the Instrument Performance Model (IPM) introduced by ISCWA or tool codes arranged by Grindrod et al., (2015). Since all selected wells for this study were surveyed by MWD, the latest error model of the ISCWSA in addition to Williamson's models (1999) were used to create the ellipses of wellbore position uncertainty for each of the two wells.

Error sources caused by MWD should be identified first to evaluate the size of the ellipses. Due to limited information on MWD data reported publicly, the error model for basic MWD was used. Accelerometer and magnetometer sensor errors were only applied with sag and local magnetic dip angle corrections. They were then calculated as scale factors of errors following the ISCWSA error model and these scale factors were applied to every station in a survey leg where the errors occurred during the survey measurements.

Based on identified error sources, survey measurement points, which are measured using azimuth, inclination, and measured depth of a wellbore at every survey station in a survey leg, were evaluated by the partial derivatives to determine the sizes of positional error ellipses. The basic error model was only used for North (+/-) and East (+/-) to create two-dimensional ellipses. That was because considering the lateral errors delivers a more accurate picture of lateral well spacing effects for this study purpose. Details of the partial derivatives using balanced tangential methods between two survey stations are provided in the ISCWSA manual and the example of calculated ellipses of two wells are presented in the result section.

3.3 ECLIPSE Simulation Model

ECLIPSE simulator was used and rectangular-shaped homogeneous reservoirs in predetermined sizes were modeled for all the selected well pads. Reservoir properties and PVT data for targeted Eagle Ford formations were obtained from publications about the Eagle Ford developments in similar geographic areas and reservoir conditions. Reservoir properties of a Burleson County well provided by Agboada and Ahmadi (2013) was referred. Additionally, publications about well performance analysis and history-matched modeling of the Eagle Ford play were referred and averaged out for reservoir properties of this study (Chaudhary et al., 2011; Li et al., 2018; Orangi et al., 2011; and Simpson et al., 2016). Specific values of the reservoir properties applied into each location are listed in Table 2 in the result section.

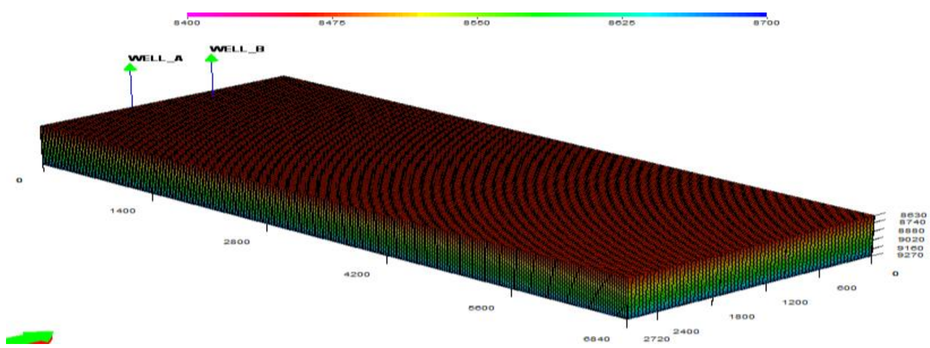

Figure 5: Example of ECLIPSE simulation model.

The dimension of a rectangular-shaped reservoir for a two-well pad was estimated by the drainage area and the wellbore horizontal lengths. The drainage area was approximated by general surveyed spacings between the two selected wells and their adjacent wells. Detail trajectories of both horizontal and vertical well paths as well as the depth of the Eagle Ford formation top and bottom were used to estimate the reservoir dimension. Subsequently, the reservoir dimension for the base case was created by the ratio of horizontal sections of the two wells to those of the base case well. Once the single-well dimension was determined, well completion parameters were used to create specific dimension cells for both the base case and the two-well reservoir model as Figure 5 shows.

3.4 Fracture Design and Simulation Model for Two-Well Pad

In addition to hydraulic fracturing treatment fluids and materials, understanding fracture geometry is key to creating an accurate simulation model for this study. However, the information about actual fractures created and fracture stage counts is confidential to operators and is not updated publicly. Therefore, to create the simulation model for horizontal wells, fracture geometry and stages needed to be estimated with several assumptions.

First of all, based on fracture stage counts and the horizontal sections of wellbores, fractures were assumed to have bi-wing planar transverse geometry at constant intervals. Each fracture was assumed to have the same constant height and width, resulting in a rectangular fracture. The fracture size was then estimated using propped fracture width calculation with publicly listed proppant and base water volumes. It was assumed that proppants were fully packed in each of the rectangular fractures, so the proppant concentration was treated as proppant pack concentration. Generally, the Eagle Ford formation creates a very narrow fracture width and a certain height according to the Eagle Ford publications (Fisher and Warpinski 2011, etc.) and advice given for this study. Thus, fracture heights between 150ft and 180ft, and 0.025ft width were assumed based on the thickness of the targeted formations.

Types and properties of proppant materials can be used to have an idea of fracture conductivity in the created fracture. Experimental measurements of fracture conductivity in relation to rock mechanical properties of the Eagle Ford shale showed that fracture conductivity has a strong relationship with rock properties of geological faces (Enriquez-Tenorio et al., 2016). So, considering proppant material types and sizes, fracture conductivity was estimated based on the proppant concentration calculated and the assumption that closure stress in the Eagle Ford formation of Burleson County is not relatively strong. Total fracture half-length were then calculated and divided by fracture stage counts to have a specific fracture half-length in a single fracture. All mathematical calculation methods for fracture geometry are provided in the book referred (Economides et al, 1994).

Finally, a base case well with specific oil properties such as oil gravity was simulated to determine the reservoir condition. Several reservoir properties that are geologically uncertain such as permeability and porosity were slightly changed to set up a valid reservoir condition by comparing simulated well performance to actual performance of the single well. Once the reservoir condition was determined, the pad with two wells in a parallel position was created in a dimensionally predetermined reservoir and simulated to investigate the effects of wellbore positions on well performances.

3.5 Estimated Ultimate Recovery and Probability of Wellbore Position Changes

10-year EURs were estimated for all the two-well pads to investiagte the effects of wellbore position changes on long-term performance since their actual productions only span between one year and three years. Probabilty distribution for the positional changes was also estimated to show the effects of wellbore position uncertainty on EURs. As Figure 6 shows, point-to-point calculation for wellbore collision in Codling’s publication (2018) was used to calculate the probability distribution with a foot-by-foot integration; the probability was estimated for points of wellbore toes between one parallel well and its largest error position. Two-sigma was used for the normal distribution, and it produced approximately 95% confidence in one dimension.

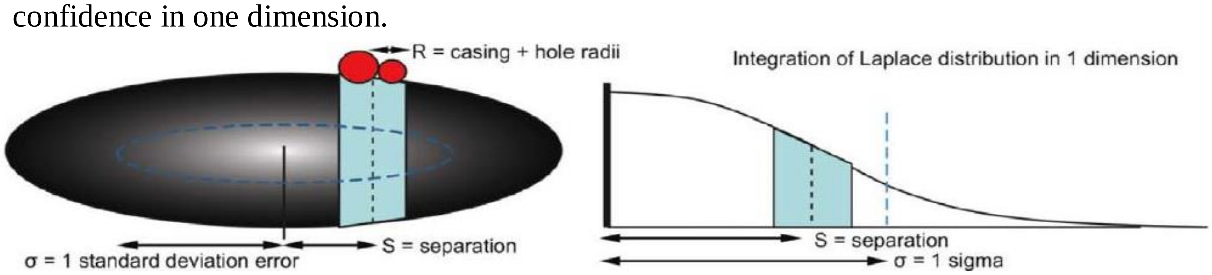

Figure 6: Probability integration for point-to-point calculations (Codling 2018).

4. RESULTS

Table 2: Reservoir properties for all selected well pads.

Well Pad	RFI		CH		SNAP		DALMORE		EF	
Well Name	A	B	C	H	C	D	1H	2H	D	S
Targeted Formation Top (ft)	8630		8490		8390		7270		6960	
Horizontal Permeability, Kh (md)	0.0018		0.0049		0.0049		0.0059		0.039	
Kv/Kh	0.001		0.001		0.001		0.001		0.002	
Porosity (Fraction)	0.011		0.011		0.011		0.011		0.011	
Initial Reservoir Pressure (psi)	8475		8450		8450		7950		7875	
Cumulative Gas Oil Ratio (scf/stb)	980		1020		997		330		111	
Oil Gravity (API)	42.3		42.3		42		44		32.6	
Water Specific Gravity	1.025									
Gas Gravity	0.832									
Bubble Point Pressure (psi)	3814									

Reservoir properties applied for all well pads are summarized in Table 2. Particular reservoir properties, such as permeability and porosity, were slightly changed within a range of the averaged Eagle Ford reservoir properties referred to in the methodology section. The following section specifically describes how the simulation model for a two-well pad was built with actual well pad data and investigated to show results of well performances in relation to wellbore position changes. The procedure described for SNAP pad was used for the other selected well pads. SNAP, CH, and EF well pads were investigated first due to the similarity of their well performances.

4.1 CH & SNAP & EF Well Pad

Table 3: Details of wellbores and hydraulic fracture treatment for SNAP well pad model.

Well Name	FTP MD (ft)	LTP MD (ft)	Total Length (ft)	FTP TVD (ft)	LTP TVD (ft)	Δ TVD (ft)	Spacing Surveyed (ft)	Fracture Stages Assumed
1H (Base Case)	8877	15060	6183	8603.00	8874.00	271.00	-	22
C	9089	14591	5502	8709.84	8927.51	217.67	1624	20
D	9166	14588	5422	8717.49	8938.49	221.00		20
Well Name	**Fracture Stage Interval (ft)**	**Proppant Volume (lbs)**	**Base Water Volume (gal)**	**Proppant Concentration in Fracture (ppg)**	**Fracture Half Length per Stage (ft)**	**Fracture Height / Width (ft)**	**Fracture Conductivity (md ft)**	**Proppant Material / Treatment Type**
1H (Base Case)	294	22152925	18364458	1.21	676.30	150 / 0.025	350	Sand / Slickwater (HC)
C	289	20489928	13842444	1.48	616.82			
D	285	19853336	13253730	1.50	590.59			

Two wells in a pad were modeled for simulation following the wellbore details in Table 3 above. Horizontal sections of two wells and fracture stage counts indicated that fractures of the two wells were aligned in a staggered configuration. The changes in Total Vertical Depth (TVD) as well as the obtained formation thickness also specified vertical positions of the wells.

Moreover, surveyed well spacing was used for a parallel position, and 2-D ellipses of positional uncertainty of two wells were evaluated along the measured depth based on MWD survey points as Figure 7 shows. The error sizes of Well C and D are 755ft and 741ft respectively.

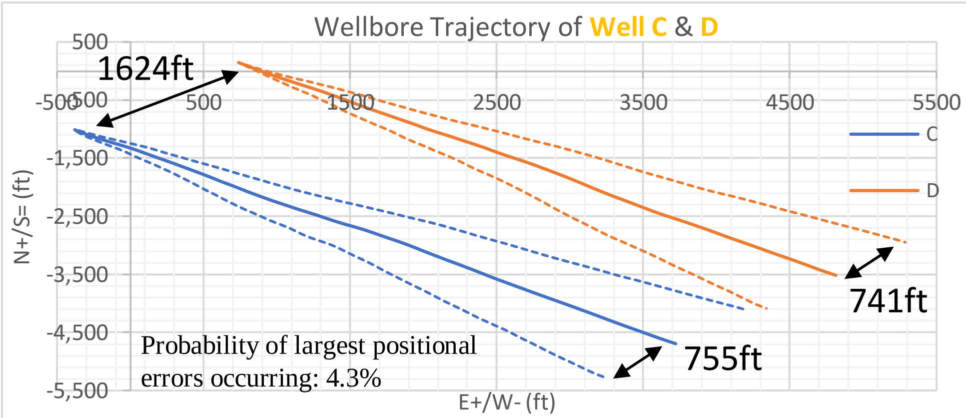

Figure 7: Horizontal well trajectory and two-dimensional ellipses of positional uncertainty of Well C and D evaluated by MWD.

Subsequently, hydraulic fractures were created. Except for RFI well pad, common sands were used as proppant materials. The difference between common sands and 100 mesh white sands was represented as the difference in fracture conductivity: 350 md-ft and 375 md-ft respectively. Particular reservoir properties mentioned previously were determined by comparing the curve of simulation results to that of the actual performance in the base case. Matching the production curve trends and initial production rate with actual ones were also considered to make the reservoir condition more realistic. Figure 8 shows the results of the simulation curves for the base case.

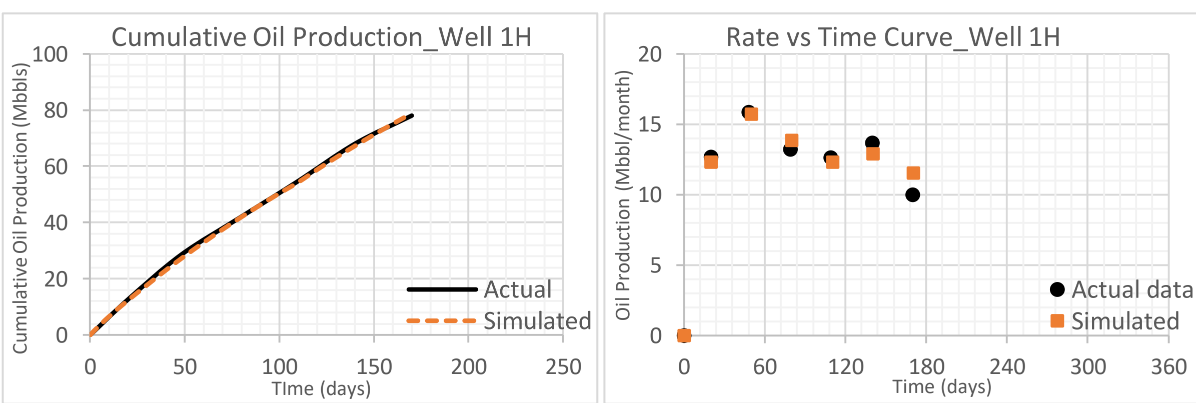

Figure 8: Actual and simulated cumulative oil production and monthly rate of base case Turner Well 1H.

With the reservoir condition results, the simulation model for a two-well pad was created as wellbore positions and fracture geometry for two wells in a parallel position are represented in Figure 9. To simulate the two-well case as similar to the actual case as possible, BHPs of two wells were adjusted to a certain extent for particular points of time in production curves like application of artificial lift. Choke size and maximum fracturing treatment pressure, which provide such a good correlation with BHP, were also considered for BHP adjustment.

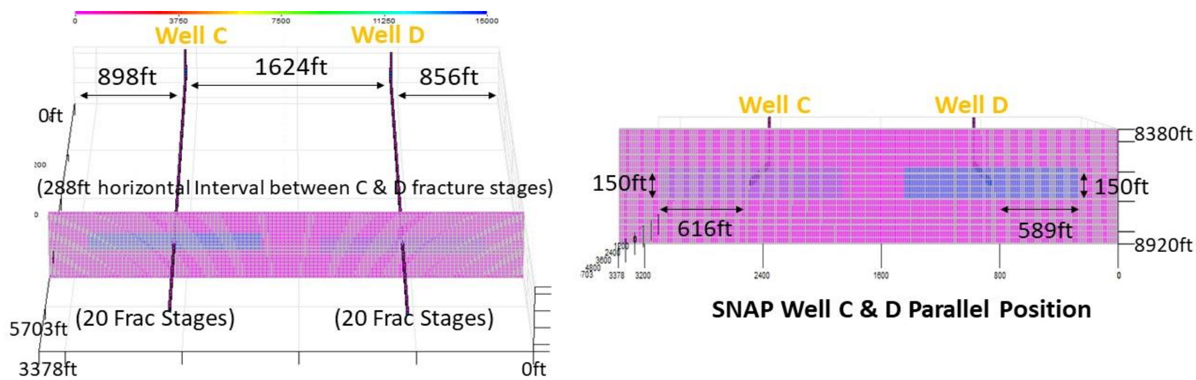

Figure 9: Simulation model of Well C and D in parallel position.

The parallel position case with Well C and D was simulated and their cumulative oil productions were represented as the black dot curves in Figure 11. The actual performances were lower than the expected performances of the two wells in a parallel position. It clearly means that the assumed position was incorrect and there must be a higher level of communication between the fractures of Well C and D. Thus, within an extent of the positional uncertainty ellipses, positional changes of the two wells were made with maximum changes of distance, and simulated to catch a sign of how much the changes could affect well performance.

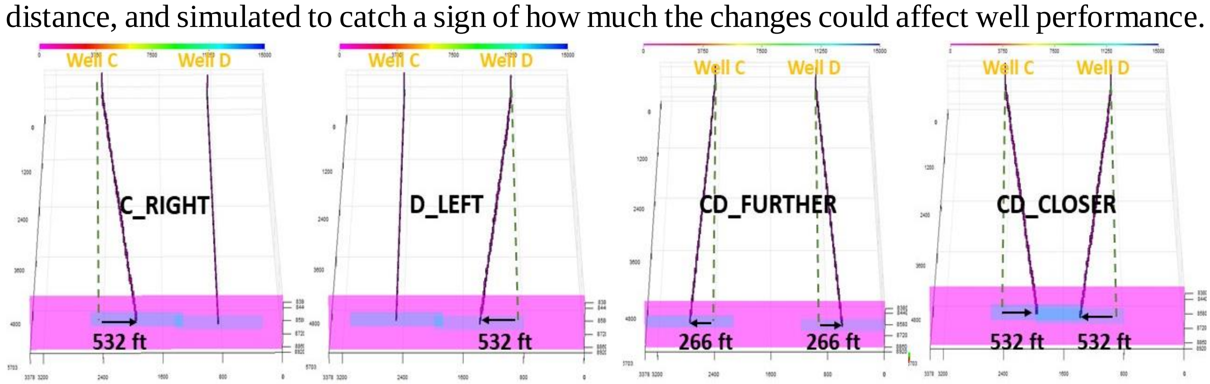

Figure 10: Positional change cases of Well C and D.

As Figure 10 shows, four cases with a single well moved to the left and right, and another four cases with both wells moved simultaneously, were simulated to investigate how specific position changes could affect well performances and which well has more impact. Based on these simulation results, positioning two wells with specific changes of distance was then performed to find the well performance that matches the actual well performance.

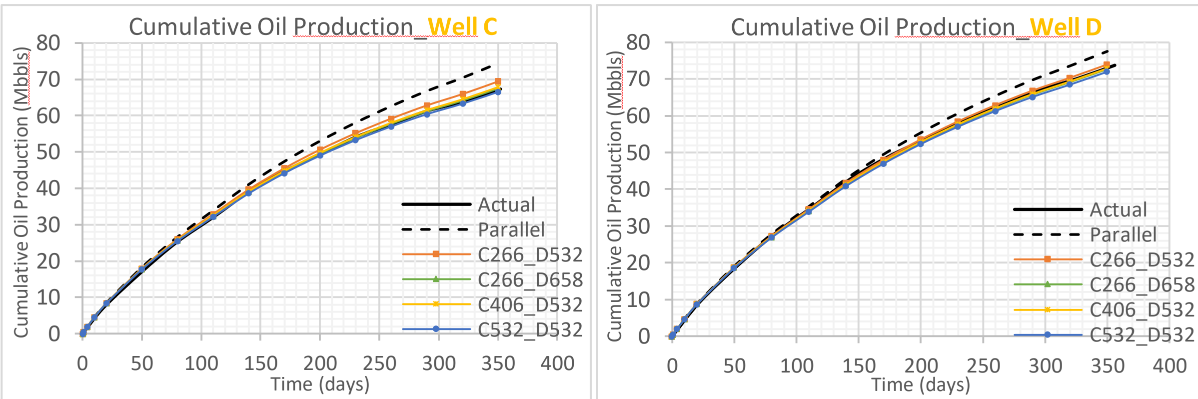

Figure 11: Results of cumulative oil production for positional changes of Well C and D.

As a result of a large number of simulation trials with further positional changes, the detailed cases for the SNAP pad shown in Figure 11 suggested that Well C and D should be positioned 406ft and 532ft, respectively, closer to each other from their parallel position in order for them to have a higher level of fracture communication. In other words, these changed positions resulted in a decrease of the over-performances that were initially expected from their assumed position. The resulted cumulative oil production curves and monthly rate curves in Figure 12 show the identical trends of both Well C and D performances.

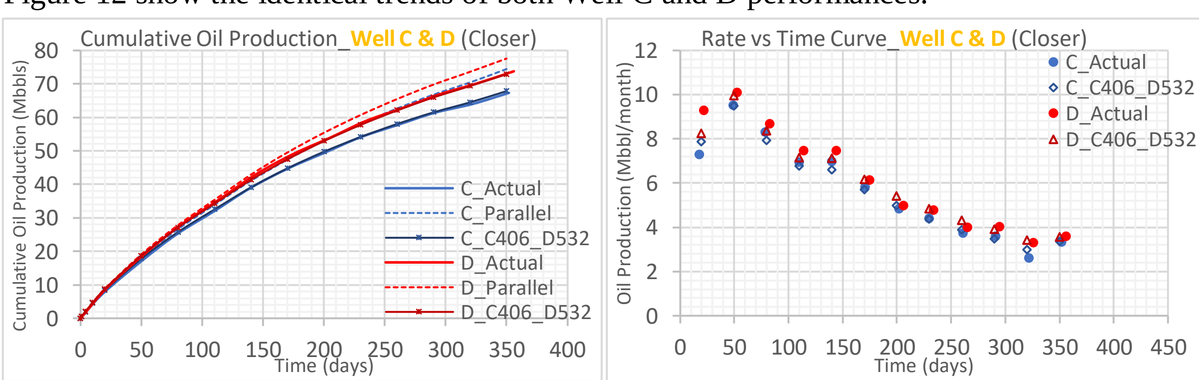

Figure 11: Comparison for actual and simulated cumulative oil production and monthly rate for positional change of Well C and D.

For the CH well pad, same reservoir properties as the SNAP well pad were applied and only BHPs of the Well C and H were adjusted slightly, since Turner Well 1H was shared as the base case with the SNAP well pad due to its geological location as shown in Figure 3. Few changes were made for the reservoir dimension due to different wellbore details and targeted formation depth. Largest sizes of wellbore position errors were evaluated as 1034ft and 1019ft for Well C and H respectively, and these largest errors have 4.2% probability of occurring approximately. As a result of simulations, positioning the Well C and H closer to each other with distances of 500ft and 120ft, respectively, away from their parallel positions showed the most identical results with their actual well performances as Figure 13 represents.

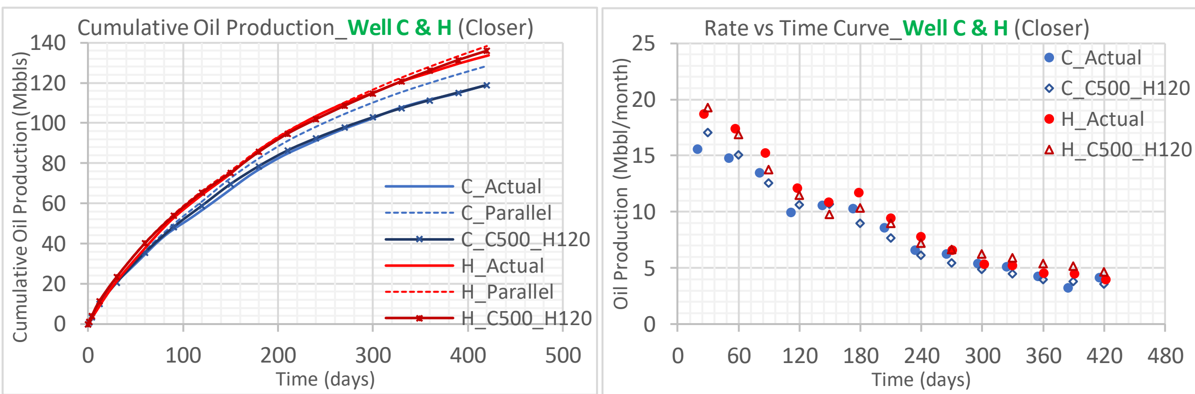

Figure 12: Comparison for actual and simulated cumulative oil production and monthly rate for positional change of Well C and H.

In spite of the fact that EF well pad could be considered as a geological outlier due to a higher permeability, this pad produced similar results with SNAP and CH well pads following the same procedure. The size of wellbore position errors was only evaluated for EF Well D due to a limited MWD data: 1035ft. As a result of simulations, the Well D and Well S positioned closer to each other with distance of 570ft and 420ft respectively away from their parallel positions produced the most identical results to the actual well performances.

4.2 RFI Well Pad

Unlike the other well pads, the RFI well pad had information on hydraulic fracture stage counts, and 100 mesh white sands were used as proppant materials, which assumed 375 md-ft for fracture conductivity. Moreover, oil had been produced relatively longer than the other pads so the production curves for the RFI well pad led to developing a more solid foundation for comparison between the actual well performances and simulated performances and for predicting EURs. Another difference was that the actual performances of RFI Well A and B were higher than the expected performances of the two wells in a parallel position. This result suggested that the two wells should be positioned further from each other and have a lower level of fracture communication to improve the under-performances. The largest errors of wellbore position had 4.4% probability of occurring and caused about 930ft deviation. As a result, Well A and B were positioned further from each other to have the most identical well performances to the actual well performances: 240ft and 150ft respectively as Figure 15 shows.

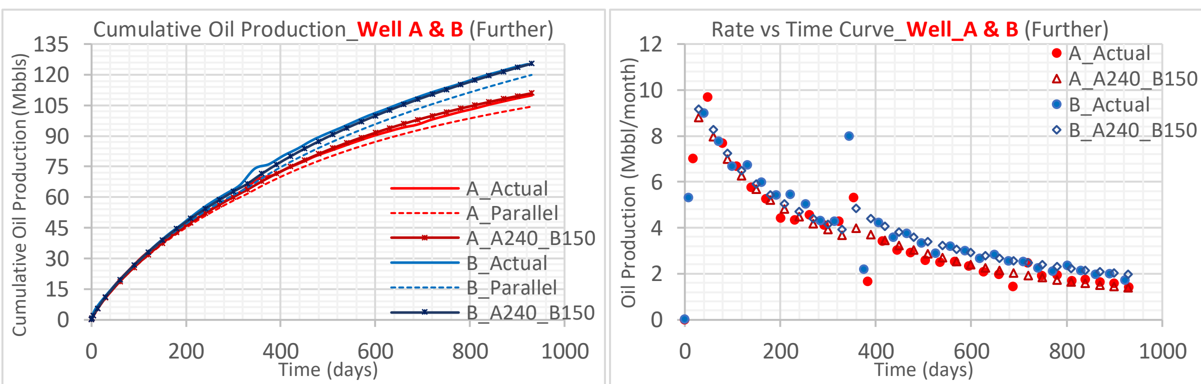

Figure 13: Comparison for actual and simulated cumulative oil production and monthly rate for positional change of Well A and B.

4.3 DALMORE Well Pad

The characteristics of the DALMORE well pad was a tight spacing, 378ft, and 50ft vertical position difference between Well 1H and 2H. The evaluated positional errors of wellbores caused 1050ft deviation approximately. Even though early production period of the two wells and the application of artificial lift caused fluctuations in the production curves, acceptable results of simulated well performances were delivered similarly to CH, SNAP and EF well pads. Well 1H and 2H were suggested to be positioned closer to each other with distances of 154ft and 126ft respectively. Furthermore, one distinctive result was produced by two cases: one with two wells positioned closer to each other and the other with the wellbore toes crossing over each other. Despite the differences in distance changes of the two wells, both cases resulted in almost same well performances. This result means the actual productions of Well 1H and 2H were already such lowest performance levels due to the tight well spacing which caused a very high level of fracture communication between their overlapped fractures.

Due to large position errors of wellbores, considerable differences in cumulative oil productions between parallel positions and actual positions occurred as all the simulation results showed. Table 4 lists essential completion parameters that were used for simulation models and the results of wellbore position changes. 3-D images in Figure 15 in the conclusion section visually show the results and the changes in the extent of fracture communications created between two wells.

Table 4: Summary of simulation parameters and results for all selected well pads.

Well Pad	RFI		CH		SNAP		DALMORE		EF	
Well Name	A	B	C	H	C	D	1H	2H	D	S
Fracture Conductivity (md-ft)	375		350		350		350		350	
Fracture Height / Width (ft)	180 / 0.025		150 / 0.025		150 / 0.025		175 / 0.025		150 / 0.025	
Fracture Stage Counts	17	17	27	27	20	20	28	28	24	22
Fracture Half Length (ft)	684	646	606	525	616	589	418	407	630	678
Total Perforated Interval (ft)	6637	6624	7104	7138	5502	5422	7608	7520	7549	7503
Bottomhole Pressure, Early / Late (psi)	4600 / 4400	4300 / 3800	4000 / 3600	3100 / 2500	4700 / 4550	4550 / 4250	4550/4200/3200	4400/4000/3500	2600/2400/2200	2900/2600/2100
2-D Ellipse Sizes of Wellbore Positon Uncertainty Evaluated (ft)	948	930	1019	1034	755	751	1067	1054	1035	-
Parallel Position Performance Compared to Actual Well Performance	Under		Over		Over		Over		Over	
Positional Changes from Parallel Position (ft)	**Further**		**Closer**		**Closer**		**Closer**		**Closer**	
	240	150	500	120	406	532	154	126	570	420
Parallel (Original) Spacing at Heel (ft)	720		1464		1624		378		1540	
Resulted Spacing at Toe (ft)	1110		844		686		98		550	
Difference in EUR estimates (%)	**5.5**	**4.3**	**6.6**	**1.7**	**6.2**	**4.5**	**-**	**-**	**2.2**	**3.1**

5. CONCLUSIONS

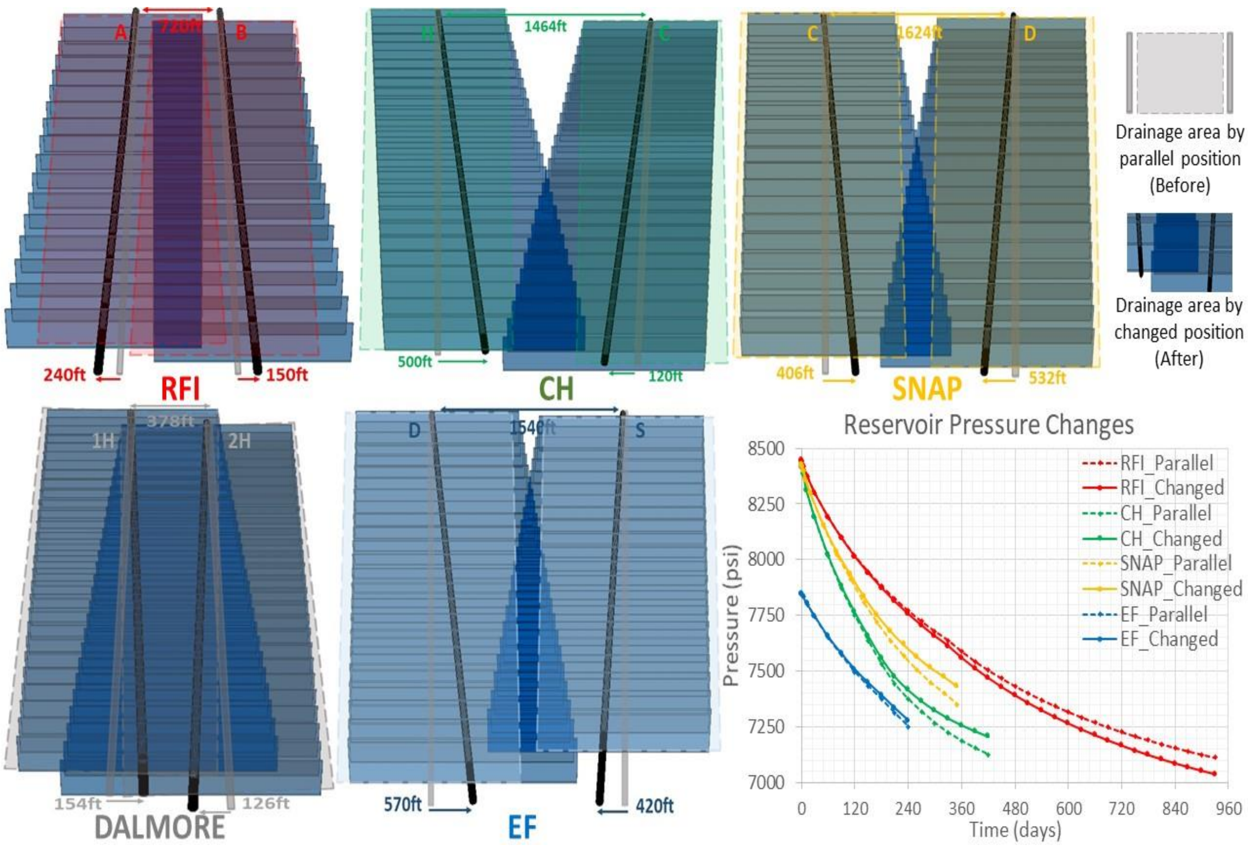

Figure 14: Visualized simulation results of wellbore position changes and drainage radiuses of overlapped fractures and their reservoir pressure changes.

Probability of resulted wellbore position changes with regard to parallel positions and 10-year EURs of CH, SNAP and EF well pads are shown in Figure 14 and 15. CH, SNAP and EF wells in parallel positions produced over-estimates of total EURs because their assumed positions with wide spacings did not initially create "shared" drainage radiuses covered by overlapped fractures of two wells in staggered configuration. As Figure 14 shows, once evaluated wellbore position errors resulted in having the two wells positioned closer to each other, the level of overlapped fracture communication created in between decreased over-performances. The overlapped communication in ECLIPSE simulation did not actually mean fracture interactions in a physical manner, but showed the reduced drainage radiuses between two wells (two wells "shared" smaller drainage radiuses than before) as pressure changes in Figure 14 represent.

SNAP well pad had a relatively low combined probability of causing positional errors: 1.2%. However, large position errors caused a relatively high percent of over-estimates of EUR; the total EUR of SNAP well pad was overestimated by 10.7% due to more than 400 ft of positional errors in two wellbores. The low probability of positional uncertainty might be ignored in fields, but the over-estimate of 13220 bbls in total, which is a relatively large amount in this low performance well pad, can be avoided if the positional errors are corrected. In addition, despite the fact that the Well C resulted in having a relatively smaller position error than the Well D, the EUR of Well C was overestimated by a higher percent (6.2%) than that of Well D (4.5%) because the Well C had longer fractures that have more impact on long-term well performance.

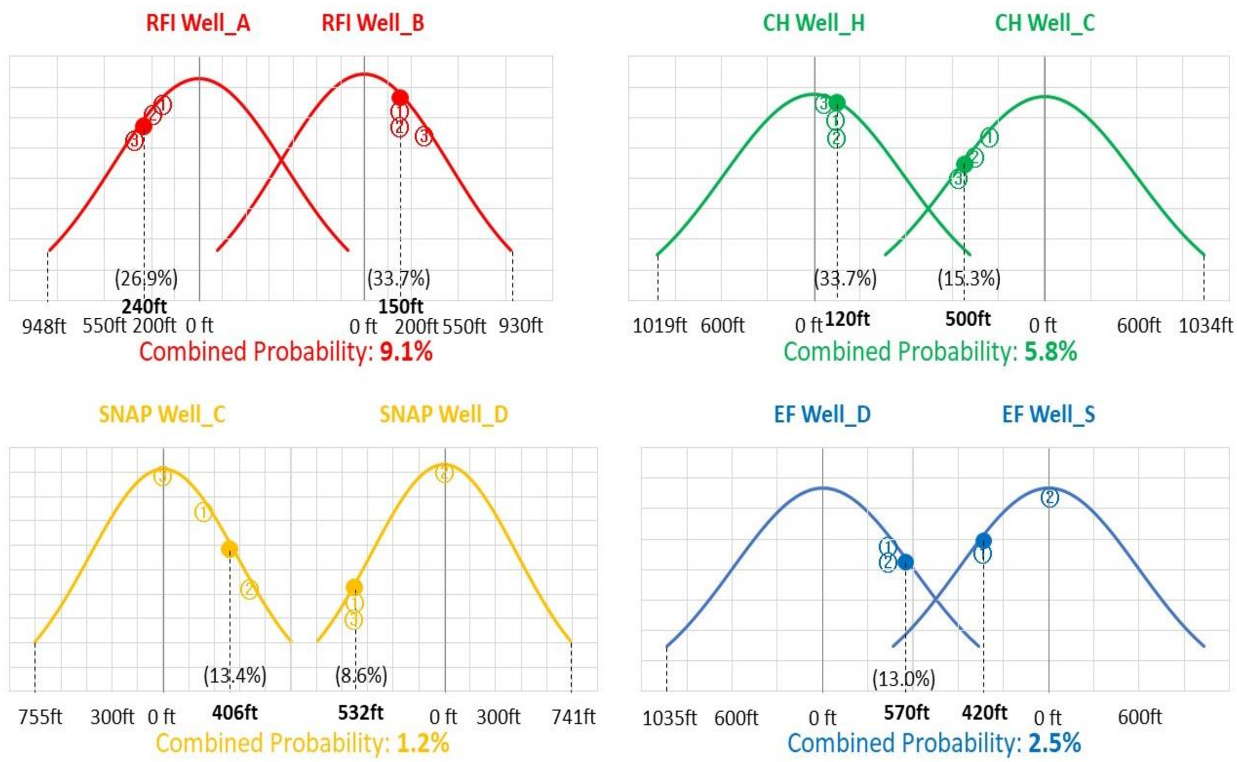

Figure 15: Probability of occurrence for results of wellbore position changes.

Table 5: EURs and probability of occurrence for different wellbore positions.

Well Pad	RFI EUR		Combined	CH EUR		Combined	SNAP EUR		Combined	EF EUR		Probability
Well Name	A	B	Probability (%)	C	H	Probability (%)	C	D	Probability (%)	D	S	for D only (%)
Case 1	5.3	4.0	11.2	5.5	1.6	8.0	4.5	3.3	1.8	1.1	1.6	16.9
Case 2	5.4	4.0	10.1	6.5	1.7	6.0	2.0	1.6	4.3	0.6	0.7	16.9
Case 3	8.1	5.9	4.7	6.9	1.5	5.7	1.9	1.5	4.2	-	-	-

CH well pad had 5.8% combined probability of causing 500ft and 120ft of positional errors. Due to these large position uncertainties, 10-year EURs of Well C and H were overestimated by 6.6% and 1.7% respectively (14760 bbls of oil in total) compared to the assumed positions; this fourfold EUR difference was most likely because the positional error of Well C was approximately 4 times larger than that of Well H. EF well pad also led to the same conclusion; if large position errors of EF Well D and S, 570ft and 420ft respectively, are not considered, over-estimate of their total EUR which is 5.3% (11380 bbls) cannot be avoided.

On the other hand, RFI well pad had 9.1% combined probability of causing positional errors and resulted in 9.8% under-estimate of total EUR. This under-estimate can be improved by having the two wells positioned further from each other, which reduces the level of fracture communication between overlapped fractures of Well RFI A and B in staggered configuration. Once wellbore positions are corrected reducing about 30% of positional uncertainty, 14300 bbls cannot be missed. Moreover, having both wells positioned much further, 320ft each, could increase the EURs of RFI Well A and B by 2.6% and 1.6% respectively (6340 bbls in total) based on the simulation result as Case 3 in Table 5 shows.

The simulation results and calculated probability distributions also show several cases of different wellbore position changes that lead to different EUR estimates as the results in Figure 15 and Table 5 show. The combined probability of causing wellbore position errors does not have a direct correlation with percent estimates of EUR. That is because the positional change of a single well considerably affects EUR estimate of the other well due to fracture communication between the wells. However, the results clearly show that large position errors with a low combined probability of occurrence have a strong impact on EUR estimates. The CH and SNAP cases resulted in overestimating more than 12170 bbls and 4380 bbls respectively and the RFI cases produced under-estimate of 12660 bbls at the lowest.

Improved directional survey can help reduce the extent of wellbore position uncertainty; Grindrod et al., suggest standard survey tool model sets for improved survey quality (2016); MWD+IFR+MSA or MWD+HRGM and supplementary dipmeter or log survey data are selected as the standard sets for MWD survey to reduce much of positional errors. Maus and Deverse showed the application through IFR and MSA corrections (2015a). Their results for southeastward wells in the Eagle Ford play showed that MWD+IFR+MSA survey reduced positional uncertainty of wellbores by 59%. If their results were roughly applied into southwestward wells of SNAP and EF, over-estimates of their total EURs could be reduced to 4.3% and 2.1% respectively.

These wide ranges of uncertainty in reserve estimates clearly show that positional errors of wellbores should be accounted for with a probabilistic aspect to not only avoid over- or under-estimates of reserves but enhance long-term well performance. Even though capital expenditure on using improved survey tool sets should be considered to compensate oil reserves produced, reducing wellbore position uncertainty is an important process in the unconventional developments to improve the validity of reserve estimates when horizontal well spacings are optimized.

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