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FORECASTING ULTIMATE RECOVERY USING PROBABLISTIC MODEL FOR FLOW-REGIME CHANGES

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FORECASTING ULTIMATE RECOVERY USING PROBABLISTIC MODEL FOR FLOW-REGIME CHANGES

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BY

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To my wife Paula who has always supported me and stood by myside in all of my academic endeavors.

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Abstract

Determination of the yet to be produced oil and gas prescribes the assets of a company. This is important internally in regard to budgeting and externally in regard to the valuation of the company. The yet to be produced oil and gas are known as *reserves* and their determination from historical trends, known as decline curves, are the subject of this thesis. The culmination of this work is to determine stochastic reserves for wells producing in infinite acting linear-flow based on statistical sampling of mature wells whose production life has extended into mature flow-regimes.

Chapter 1

Introduction and Literature Review

This chapter will briefly describe the intent of this research and its objective. A brief overview of the recent estimated ultimate recovery methodologies will be discussed based on current literature available in the public domain. An ephemeral synopsis will be given to the work flow of each chapter and describe the organization of the thesis.

1.1 Overview

The core of this research is to develop a probabilistic model that will empower the user, along with stochastic methodologies, to determine the estimated ultimate recoveries for wells that are still in the linear-flow regime. Society of Petroleum Engineers (2016), states that probabilistic methodologies acts as a check against the more traditional reliance upon deterministic methods quantifying at a high level the expected confidence associated with proved reserve volumes. This method is intended to be used by upstream companies, mid-stream companies, investment firms or entity looking to gain insight into an oil field based on the potential estimated ultimate recoveries of a field of interest coupled with current and future commodity prices for oil. Moreover, the Petroleum Resource Management System (PRMS) criteria will be used to establish proved, probable and possible reserves for public reporting and economic analysis. The research specifications for this study was for wells that have been producing for approximately three to seven years. All wells where required to be horizontally drilled and where drilled in either McKenzie or Williams Counties in North Dakota (Figure 1 and Figure 2), which are currently the most prolifically drilled counties in North Dakota at the time of this study.

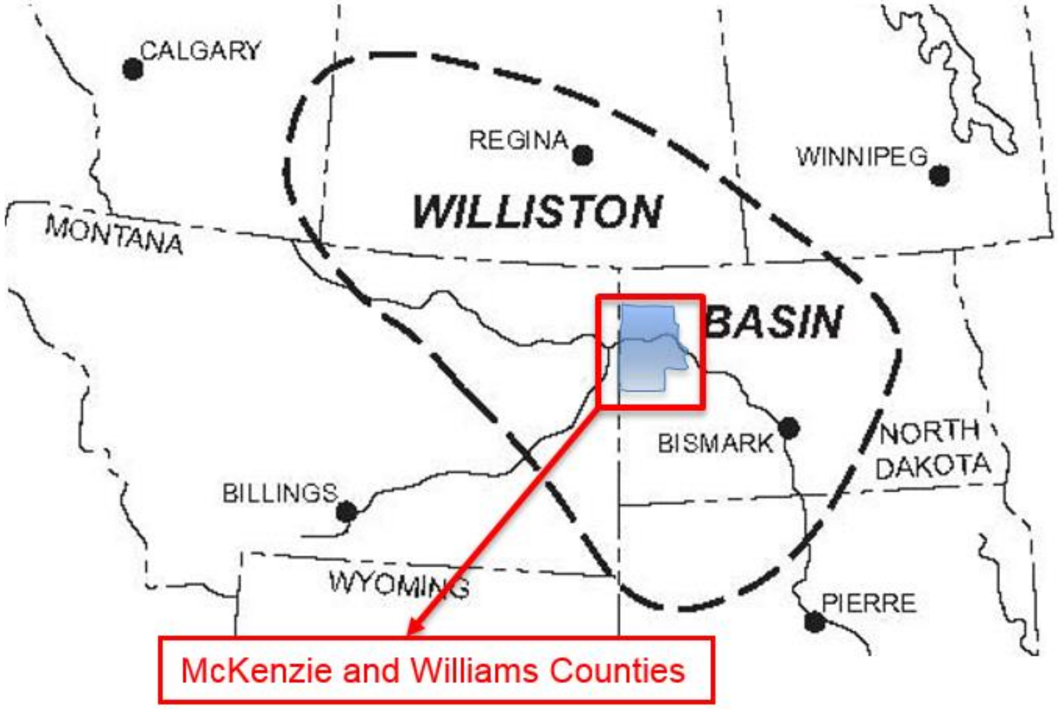

Figure 1. Bakken Shale, McKenzie and Williams Counties, North Dakota. (Great Northern Energy, 2016)

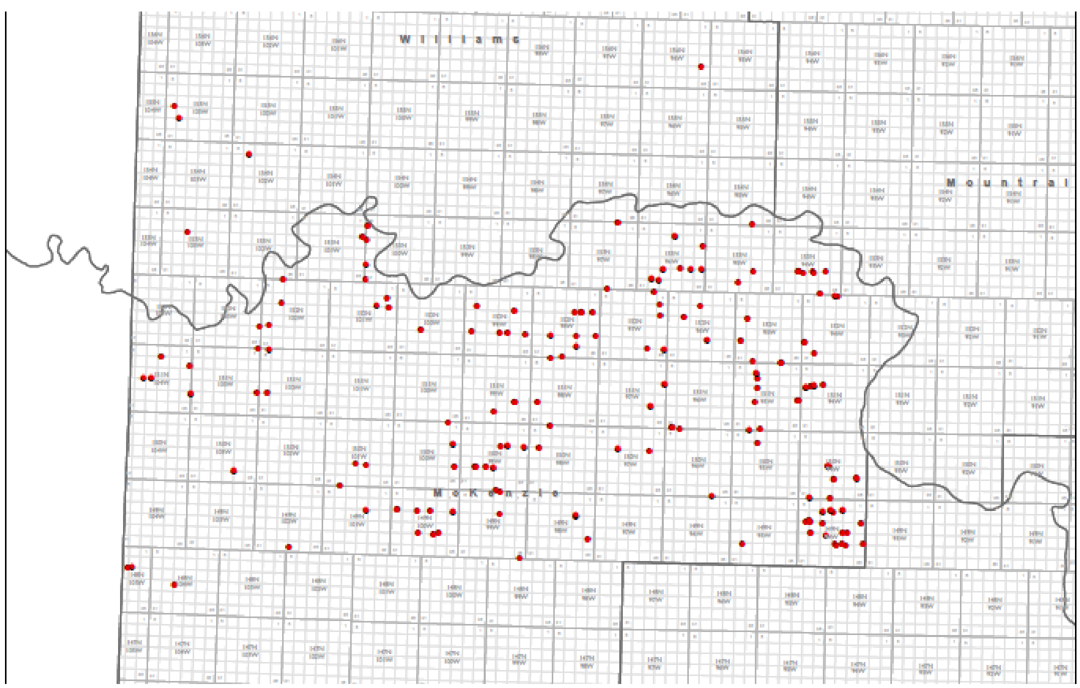

Figure 2. Graphical depiction of the Bakken wells evaluated for this study.

The average estimated ultimate recovery range of the wells in this research was found to be between 290,000 STBs to 470,000 STBs based on assumed operating costs and oil commodity prices that will be presented in detail in chapter five of this study.

1.2 Purpose of Research

The purpose of this research is to establish a new method of analyzing reserves for evaluating estimated ultimate recoveries of oil. At the time of this writing, approximately 75 United States oil and gas companies, (and counting) have filed for chapter 7 or chapter 11 bankruptcy protection since the fall of the oil and gas commodity prices in 2014, Haynesboone (2016). There are many aspects that lead to a company filing for bankruptcy; however, this is a trend that is all too common and cyclical, which make understanding reserves so important. When times are good and oil commodity prices are high, companies can get over-extended in their business portfolios and take on to much risk. High-risk, high-reward mentalities, comes at a cost and that cost could be jobs, forfeiture of a company and value degradation to shareholders, Olsen and Lee (2010). The purpose of this research is to develop a methodology that will allow for the probabilistic determination of the estimated ultimate recoveries of a field such that one can assign a degree of probability on the feasibility of being able to produce oil assets based on operating expenses and future and current oil commodity prices. The probabilistic analysis will be coupled with the Petroleum Resource Management System (PRMS) criteria to establish proved, probable and possible reserves when reporting reserve criteria to public, state or federal agencies.

1.3 Literature Review

Most of the available literature in circulation, at the time of this study, does not look at probabilistic estimated ultimate recoveries from a field production perspective. Most papers look at enhancing the estimated ultimate recoveries based on adding new technologies to improve the estimated ultimate recovery through knowledge of reservoir characterization, well construction and enhancing stimulation and completion practices. The methods found in the literature are mostly deterministic for evaluating ways to enhance the estimated ultimate recovery and have very little in regards to probabilistic analysis. Authors like Shaoyong and Dominic (2013), introduce a modified Stretch Exponential Production Decline Method, which is primarily used to evaluate estimated ultimate recoveries with wells with short production history. Cunningham et.al. (2012), uses multiple linear-regression models that compare and contrast multiple well design properties to the production of multiple wells of interest in the Marcellus Shale to better design the estimated ultimate recovery of future wells. Kabir and Lake (2011), provided analytical solutions considering concentric compressibility elements to be utilized in the continuity equation to ascertain production data from conceptual geobodies. One of the only papers found in the literature was authored by Freeborn and Russell (2015), which proposes a method that involves determining the aggregated distribution of estimated ultimate recoveries for a specified number of wells utilizing a statistical approach with Monte Carlo trials. However, almost all methods presented, with the exception of Freeborn and Russell, depend on reservoir properties or some form of insight into the mechanics of the well. However, most companies - like midstream companies and investment firms - are not able to acquire specific detailed information in regards to the reservoir characterization or the producer's completion and production practices; both are central in determining potential reserves based on deterministic methods. Therefore companies must rely on available public data to use for their due-diligence analysis for specific oil assets.

1.4 Organization of Thesis

The primary chapters in regards to this research are in chapter two, three, four and five of this writing. Chapter two deals with the development of the model for a well in boundary-dominated flow going through the meticulous setup of the model and details the cumulative production versus square-root-of-produced-time profile that will be used as a diagnostic tool to determine various well parameters that will be used in the stochastic analysis.

Chapter three will detail two wells in linear-post-linear and linear-flow. These wells have not reached the time to the end of linear-flow and the use of a probabilistic tool utilizing *Bayesian Theory* will be employed to determine the estimated time to the end of linear-flow based on a probability confidence criteria. Once the procedure has been laid out in full, utilizing the well examples, the stochastic values for all wells of interest will be presented, which will be part of the Monte Carlo numerical simulation setup.

Chapter four will describe the stochastic analysis approach for determining stochastic parameters that will be used in the probabilistic predictions of the estimated ultimate recovery of oil.

Chapter five will show both deterministically found estimated ultimate recoveries of a well along with a Monte Carlo simulation based on the stochastic methods and well parameters found in chapters two, three and four. The Monte Carlo simulation will show the convergence, of an example well, along with the estimated ultimate recovery of the reservoir based on the well parameters found in chapters two and three.

Chapter six will discuss some conclusions and reiterate some important findings outlined in the study.

Chapter 2

Well Evaluation Boundary-Dominated Flow-regime

This chapter looks at the development of the cumulative production versus the square-root-of-produced-time profile with emphasis on a well that has reached boundary-dominated flow. Here the procedural layout will be given such that the user can apply this methodology to wells of interest in a production field. At the conclusion of this analysis four values will be ascertained from the analysis and will be values that will be used for the Monte Carlo simulation to evaluate the estimated ultimate recoveries of oil based on stochastic methods.

2.1 Public Data Gathering

The user of cumulative production versus the square-root-of-produced-time profile will need to identify a public database domain. This research utilized production data gathered from the North Dakota Oil and Gas Division (NDIC) to gather historical production data of horizontal wells that have been producing for three to seven years in the McKenzie and Williams counties of North Dakota (NDIC 2014). It is important to identify credible sites when extracting data that will be used to develop the cumulative production versus the square-root-of-produced-time profile analysis proposed in this research. There are many credible sites to choose from such as state oil and gas databases, NDIC for this research, IHS United States Production and Drillinginfo to name a few; however, it is strictly up to the readers discretion on the choice of production data collection. Once a site has been selected for data gathering it is important to do some background research on the credibility of the data being published. It is a good practice to ascertain how the data being used on the database sites was obtained and documented and what the requirements are to publish data in that domain. This information will be useful if one has to go back and do some due-diligence work to validate the results of one's research when using the model. The requirements for NDIC for petroleum production reporting fall under the reporting standards of the American Petroleum Institute NDIC (2016).

2.2 Caution when gathering production data

It should be noted of the importance of understanding the data that will be used in this analysis. Data is the foundation and cornerstone to this research. If the data has been collected with unreliable methods or measurement instrumentation errors then the analysis, proposed in this research will yield inaccurate results that can have an effect on the decision-making processes with financial impacts. This research used a public database domain that publishes monthly production data only. Furthermore, since this research used a public data base that only publishes monthly production data, it should be understood that there may be some ambiguities when surmising information ascertained using this analysis that would only be seen in daily production data. Therefore, if it is possible to acquire daily production data then this data should be used in lieu of monthly production data. Monthly production data can hide some aspects of the physical phenomena, which can be better defined when using daily production data. Therefore, it is recommended, but not necessary, to use daily production data if possible to ensure optimal results.

2.3 Development of the Production Profile for a well that has reached boundary-dominated flow.

This research looked at over 500 wells from McKenzie and Williams Counties in North Dakota. Only 185 wells were evaluated using the production profile of the cumulative production verses the square-root-of-produced-time to conditions that where established at the beginning of this research. This research was done independent of any knowledge of a producing company's completion or drilling practices.

For this example the Clarks Creek 10-0805H well will be analyzed in detail. The Clarks Creek 10-0805H well is a horizontal well located in McKenzie County, North Dakota. This well has been in production for approximately three years at the time of this study. To begin, well production data was gathered from the North Dakota Industrial Commission website (NDIC). The production data is given in Table 1.

Table 1: North Dakota Industrial Commission (NDIC) production data for the Clarks Creek 10-0805H

Month of Production	Days produced in the month	Oil (bbls)	Gas (Mcf)	Water (bbls)
Jun-12	25	24337	26565	15139
Jul-12	31	24598	14001	6617
Aug-12	30	20209	20781	5307
Sep-12	30	23800	15947	5555
Oct-12	26	12041	15564	2936
Nov-12	21	5518	6247	1385
Dec-12	31	21174	27431	4252
Jan-13	19	10360	14191	2176
Feb-13	24	3507	3385	1112
Mar-13	31	7471	8501	1869
Apr-13	30	16270	23737	3106
May-13	31	15690	27492	3319
Jun-13	30	14412	32473	3328
Jul-13	31	11674	28519	3076
Aug-13	21	4897	4975	1628
Sep-13	30	10779	16956	2728
Oct-13	31	10127	24093	2634
Nov-13	27	7912	13170	2382
Dec-13	31	8119	18595	2325
Jan-14	31	6681	13896	2368
Feb-14	19	4704	13478	1614
Mar-14	31	7070	29515	2528
Apr-14	30	5981	23737	1975
May-14	31	5443	21836	1829
Jun-14	30	4767	10754	2176
Jul-14	31	4889	11748	1780
Aug-14	31	4749	12143	1652
Sep-14	26	4120	10501	1442
Oct-14	31	4774	13713	1662
Nov-14	14	2232	3529	1159
Dec-14	31	5518	12700	2071
Jan-15	31	4293	14397	1836
Feb-15	28	3153	10938	1135
Mar-15	31	4068	12387	1346
Apr-15	30	3510	11257	1301
May-15	31	3600	12226	1254
Jun-15	30	2666	8895	953
Jul-15	31	2908	8006	1065

From Table 1 the cumulative production versus square-root-of-produced-time profile can be generated in accordance as follows, Figure 3.

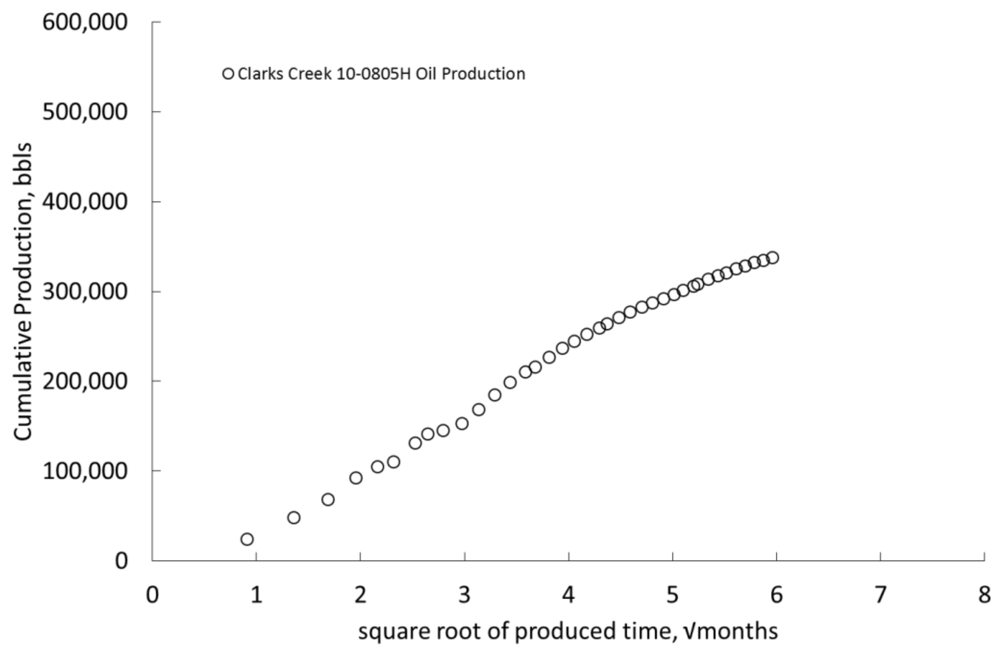

Figure 3. Cumulative production versus square-root-of-produced-time profile of the Clarks Creek 10-0805H.

Figure 3 exhibit the flowing behavior of the well's production, and utilizing this plot the time at which the transition from the infinite-acting flow-regime to the pseudo-steady state boundary-dominated flow-regime can be determined. Henceforth, the infinite-acting linear-flow-regime will be referred to as "linear-flow", and the pseudo-steady state boundary-dominated flow-regime will be referred to as "boundary-dominated flow". For this research if a well exhibits an Arps' exponent of two, from Rodrigues and Callard (2012), this will imply that the well would have an infinite reservoir such that the well would produce forever and never deplete. For example, from Poston and Poe (2008), wells that exhibit Arps' exponent's greater than one could be caused by highly variable permeability where layered and naturally fractured reservoirs may exhibit this type of

Arps' exponent; moreover, also from Poston and Poe, high Arps' exponent values can be the formation of long-lived crossflow patterns caused by the oil or gas feeding from very-low permeability's to high permeability zones. An infinite-acting reservoir is an impossibility over the life of a well due to the fact that all reservoirs are finite and determining when the time to the end of linear-flow occurs is the only way to truly determine the precise approximation of the estimated ultimate recoveries from a well.

2.4 Analysis of the Data and further development of the Model

The next step is to analyze both the linear-flow regime and the boundary-dominated flow regime regions of Figure 3 and prepare a model fit of the cumulative production versus square-root-of-produced-time profile.

To determine the model fit of the cumulative production versus square-root-of-produced-time profile, the linear-flow-regime will be analyzed such that a model fit curve can be applied to the linear portion of the cumulative production versus square-root-of-produced-time profile. This linear portion of the cumulative production versus square-root-of-produced-time profile is known as the infinite acting linear-flow regime. The model fit of the data can be shown for cumulative production versus square-root-of-produced-time (Figure 4) and is represented by the model fit, equation (2-1).

$$N_p = N_{p_i} + m_{csrt} * \sqrt{t_{p_m}} \qquad (2\text{-}1)$$

where N_p is the cumulative oil production, N_{p_i} is the cumulative oil production intercept, m_{csrt} is the slope of the cumulative production versus square-root-of-produced-time profile, $\sqrt{t_{p_m}}$ is the square-root-of-produced-time in months. It should be noted by taking the derivative of the equation (2-1) it can be shown that the economic limit is equal to the cumulative production of oil rate, equation (2-2).

$$\frac{dN_P}{dt} = q_{ecl} = \frac{m_2}{2\sqrt{t_{life}}} \text{……………..…………………….…………...………...…….(2-2)}$$

where q_{ecl} is the economic limit, m_2 is the slope of the linear-post-linear cumulative production versus square-root-of-produced-time profile $\sqrt{t_{life}}$ is the current age of the well of interest.

Furthermore, the next step in the analysis is to develop a model fit of the cumulative production versus the square-root-of-produced-time profile. From Rodrigues and Callard, (2012) the equations needed to develop a model match of the actual production data of the cumulative production versus square-root-of-produced-time profile will utilize the Arps' hyperbolic equation's for model match analysis. As presented in Childers and Callard (2015), a key component of developing the stochastic approach is to determine the simultaneous match of the cumulative production at the end of linear-flow regime and the Arps' hyperbolic exponent during boundary-dominated flow by minimizing the error between the Arps's hyperbolic analysis and the actual oil production data. It is imperative to determine the simultaneous matching of both flow-regimes in order to properly determine the correct time to the end of linear-flow. Figure 4, shows the model match of the oil production for both the linear-flow regime and the actual production data. Figure 4 also displays the future oil production projection based on the model match of the oil production data.

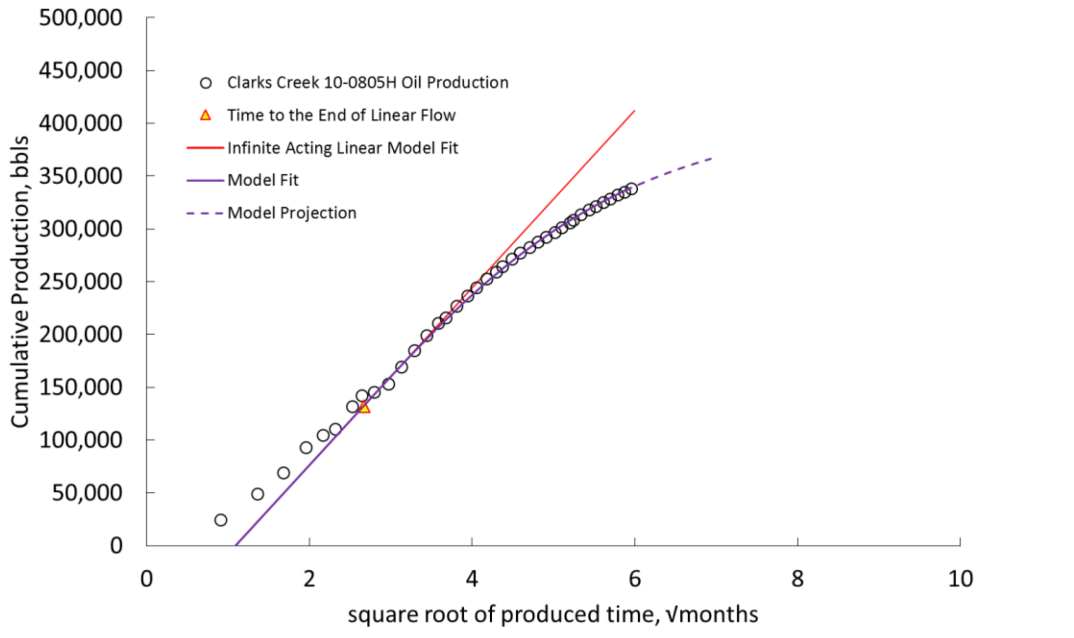

Figure 4. The model fit to determine the time to the end of linear-flow for the cumulative production versus the square-root-of-produced-time in months, future model projection of the Clarks Creek 10-0805H.

From Figure 4 one observations needs to be discussed when analyzing the cumulative production versus the square-root-of-produced-time profile for the model fit of the linear-flow-regime. First, the intercept of the cumulative production versus the square-root-of-produced-time profile can never be positive. From Rodrigues and Callard (2012), the intercept will be non-positive with exception of cases where infinite conductivity fractures occur and the intercept in this case would be zero.

Two variables can be determined from the model fit of the infinite-acting flow regime of the cumulative production versus square-root-of-produced-time profile and these values can be used to determine time to the end-of-linear-flow of a well of interest. The slop and intercept of the cumulative production versus the square-root-of-produced-time can be found from Figure 4, and are m_{csrt} and N_{p_i} respectively. The values of the slope and intercept as well as the time to the end of linear-flow for the Clarks Creek 10-0805H can be found in Appendix B of this study. Moreover, the estimated ultimate recovery for this well can be found deterministically; however, b_{BD} and $t_{p_{elf}}$ will be used stochastically to develop the Monte Carlo simulation for wells that must use probabilistic methods to ascertain estimated ultimate recoveries of oil.

Chapter 3

Well Evaluation for Linear-Post-Linear flow and Linear-flow regimes

This chapter looks at the development of the cumulative production versus the square-root-of-produced-time profile with emphasis on a well that is in linear-post-linear-flow regime as well as a well that is in the linear-flow regime. Here the procedural layout will be given such that the user can apply this methodology to wells of interest in a production field. At the conclusion of this analysis, similar to that found in chapter two, two values will be ascertained from the analysis and will be values that will be used for Monte Carlo simulation to evaluate the estimated ultimate recoveries based on probabilistic methods.

3.1 Development of the Production Profile for a well that is in Linear-post-Linear flow

For this example the Bohmbach 3-35H well will be analyzed using the methodology defined in chapter two. Since this well is analyzed the same way as the Clarks Creek 10-0805H, a few of the steps carried out in the Clarks Creek 10-0805H will be omitted from this example. Appropriate tables and profiles will be shown but the detail as to how those profiles where created are the same as in the Clarks Creek 10-0805H example. The Bohmbach 3-35H well is a horizontal well located in McKenzie county North Dakota. This well has been in production for approximately three years at the time of this study. The difference that is demonstrated by the Clarks Creek 10-0805H that is dissimilar from the Bohmbach 3-35H is that this well is producing in the linear-post-linear-flow regime. As one works through the development of the cumulative production versus the square-root-of-produced-time profile steps, it will become clear that the time at which the end of linear-flow cannot be determined utilizing an error minimization approach, similar to Clarks Creek 10-0805H, through the simultaneous match of the cumulative production and the Arps' hyperbolic exponent to determine the time to the end of linear-flow. Thus to determine the time to the end of linear-flow will require a model fit estimate between two linear-flow-regime fits, and the intersection of these model fits will be defined as the intersection time. The linear-post-linear-flow-regime is realized when a well, acting in the infinite acting linear-flow regime, encounters a boundary, which would give the appearance that the well is acting in boundary-dominated flow. However, the well feels one boundary but not all boundaries have been felt by the well at the onset of the first boundary. As the well continues to produce over time the well moves into a second infinite acting flow-regime, this phenomena is named linear-post-linear-flow and a detail analysis will be shown to reinforce the statements above. First the production data of the Bohmbach 3-35H is given in Table 2.

Table 2: North Dakota Industrial Commission (NDIC) production data for the Bohmbach 3-35H

Month of Production	Days produced in the month	Oil (bbls)	Gas (Mcf)	Water (bbls)
Jun-12	0	0	0	0
Jul-12	7	2223	1194	473
Aug-12	14	6830	7510	1656
Sep-12	30	18097	21265	3666
Oct-12	31	13582	19688	2740
Nov-12	30	10279	14240	1749
Dec-12	28	8157	11702	1367
Jan-13	27	8685	11209	1292
Feb-13	11	2082	3333	328
Mar-13	27	9128	11255	1845
Apr-13	30	7040	10674	1185
May-13	31	6367	8813	1035
Jun-13	30	5635	7573	903
Jul-13	31	5534	6879	735
Aug-13	31	5338	7088	793
Sep-13	28	4558	5145	597
Oct-13	31	5090	6333	810
Nov-13	30	4592	6008	677
Dec-13	31	4573	5835	680
Jan-14	31	4348	5487	585
Feb-14	28	3971	4847	558
Mar-14	31	4118	5266	630
Apr-14	29	3548	4828	483
May-14	31	4119	3383	563
Jun-14	30	3743	4918	687
Jul-14	31	3352	5409	415
Aug-14	27	2941	3531	508
Sep-14	30	3841	4225	650
Oct-14	31	3665	5799	632
Nov-14	29	2739	3921	843
Dec-14	29	3440	3973	982
Jan-15	31	3440	4052	517
Feb-15	28	3034	3889	455
Mar-15	31	3053	4176	387
Apr-15	30	3233	4569	501
May-15	31	3062	4688	482
Jun-15	30	2742	4318	430

From Table 2, the plot of the cumulative production versus the square-root-of-produced-time profile can be generated, Figure 5. The next step will be to determine a model fit of the production data using the Arps' hyperbolic equation defined in Rodrigues and Callard (2012). Applying the Arps' hyperbolic model fit analysis to Figure 4 and trying to use a error minimization analysis as demonstrated in the analysis of the Clarks Creek 10-0805H, it will become very apparent that a solution that can satisfy the error minimization cannot be found. In fact, since the Bohmbach 3-35H is a well that is in the linear-post-linear-flow regime, the Arps' hyperbolic equations cannot be used.

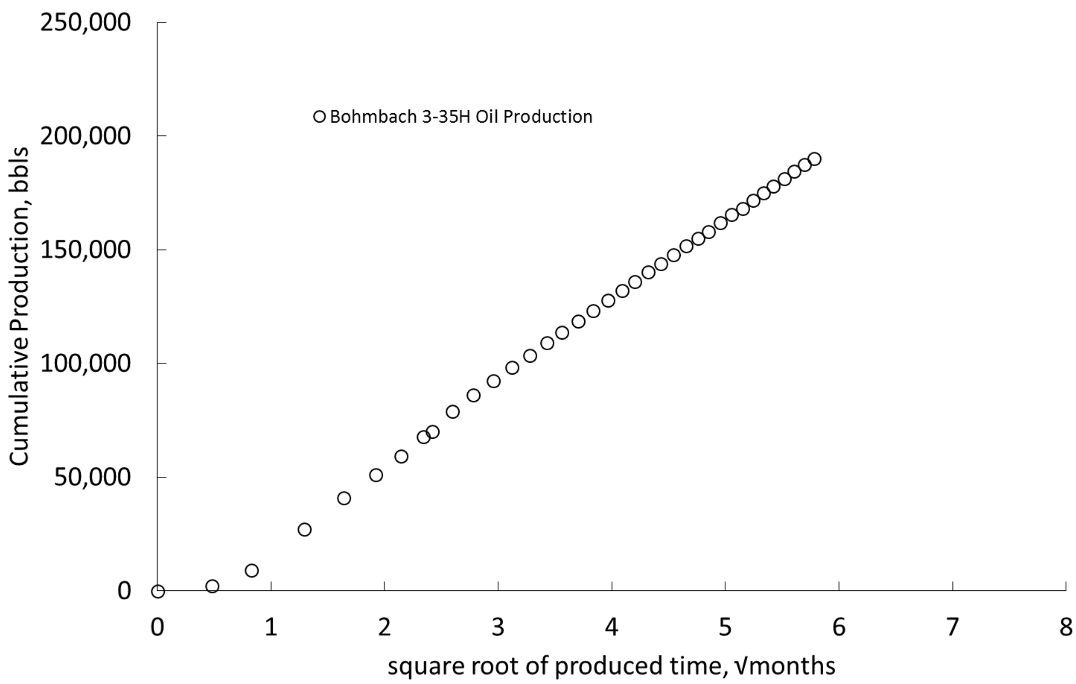

Figure 5. Cumulative production versus square-root-of-produced-time profile of the Bohmbach 3-35H.

Therefore, a new technique will need to be added to determine the intersection time between the linear flow and linear-post-linear flow regimes. To determine the intersection time for a well in linear-post-linear-flow-regime one will have to determine the slope of the first regression line of the infinite acting flow-regime, which in turn will help in the establishment of the slope of the second linear regression line of the second infinite acting flow-regime. A well that is in linear-post-linear-flow can be described as well that is in *semi-infinite-acting-flow regime*. The intersection time can be observed by determining the intersection of the infinite acting flow-regime and the linear-post-linear-flow regime Figure 6. The model fit of the linear-post-linear-flow regime can be modeled by using equation (2-1). It should be noted that a trial-and-error method would be employed such that one can find the approximate intersection of the infinite acting linear-flow regime and the linear-post-linear-flow regime. It's important to note that the ratio of the slope of the infinite acting flow-regime and the slope of the linear-post-linear-flow-regime will always be less than one. Figure 6, shows the approximate location of the intersection time for a well operating in the linear-post-linear-flow regime.

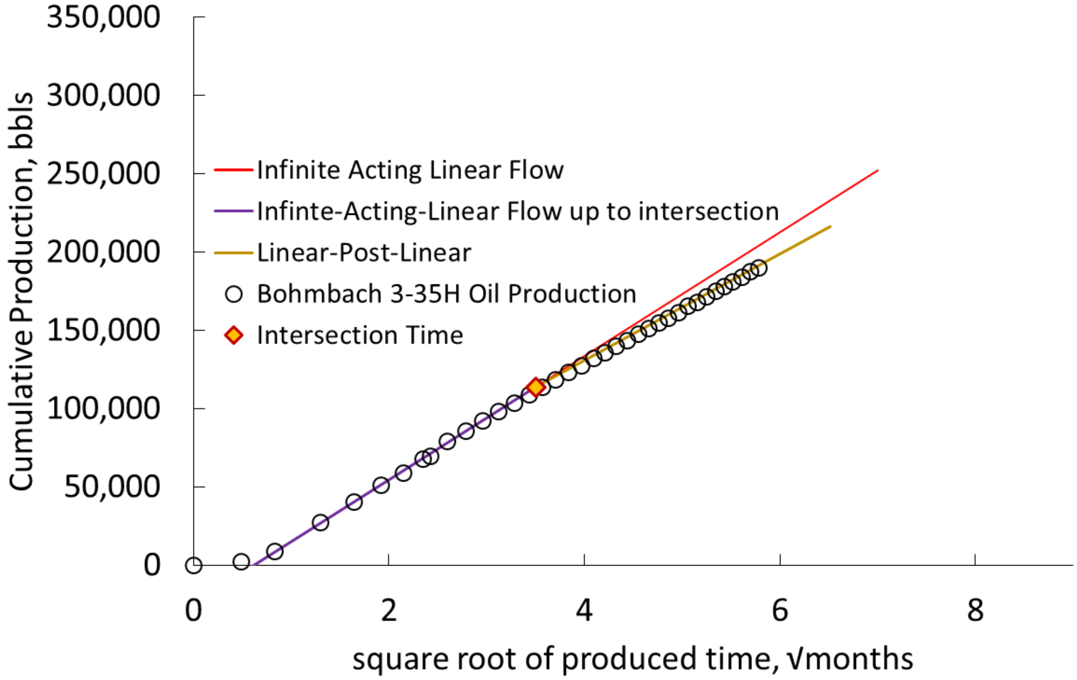

Figure 6. Cumulative production versus the square-root-of-produced-time in months for the intersection of the Infinite Acting Linear-flow-regime and the Linear-Post-Linear-flow-regime of the Bohmbach 3-35H.

From this analysis two additional parameters were found, which are the ratio of the slopes of the cumulative production versus the square-root-of-produced-time and the linear-post-linear best-fit regression analysis, m_2/m_{csrt}, and the intersection time for linear-post-linear-flow-regime, t_x. As in the Clarks Creek 10-0805H the values of the slope and intercept as well as the intersection time and the ratio of the slopes for the Bohmbach 3-35H can be found in Appendix B of this study. Moreover, the estimated ultimate recovery for this well can be found deterministically; however, m_2/m_{csrt} and t_x will be used stochastically to develop the Monte Carlo simulation for wells that must use probabilistic methods to ascertain estimated ultimate recoveries of oil.

3.2 Development of the Production Profile for a well that is in Linear-flow

For this example the Fettig 24-22H well will be analyzed using the methodology defined in chapter two. As stated in previous sections this well is analyzed the same way as the Clarks Creek 10-0805H and the Bohmbach 3-35H. Appropriate tables and profiles will be shown but the detail as to how those profiles where created are the same as in the Clarks Creek 10-0805H example. The Fettig 24-22H well is a horizontal well located in McKenzie county North Dakota. This well has been in production for approximately six years at the time of this study. The difference that is demonstrated by the Fettig 24-22H that is dissimilar from both the Clarks Creek 10-0805H and Bohmbach 3-35H is that this well is producing in the linear-flow regime and a boundary or boundaries have yet to be reached. As one works through the development of the cumulative production versus the square-root-of-produced-time profile steps, it will become clear that the time at which the end of linear-flow cannot be determined utilizing an error minimization approach nor the linear-post-linear approach described in section 3.1. Thus to determine the time to the end of linear-flow will require stochastic approach utilizing Bayesian theory. Bayesian theory will be discussed in detail in chapter four along with other stochastic values that will be needed in the development of the Monte Carlo simulations of the estimated ultimate recovery of oil. The production data for the Fettig 24-22H is presented in Table 3.

Table 3: North Dakota Industrial Commission (NDIC) production data for the Fettig 24-22H

Month of Production	Days produced in the month	Oil (bbls)	Gas (Mcf)	Water (bbls)
Nov-10	3	234	971	0
Dec-10	31	6876	1616	540
Jan-11	31	3946	1009	220
Feb-11	26	3177	745	681
Mar-11	31	3026	1083	735
Apr-11	30	2381	998	527
May-11	31	2066	1043	591
Jun-11	29	1743	960	495
Jul-11	31	1745	1056	633
Aug-11	31	1627	1005	503
Sep-11	30	1431	1005	478
Oct-11	28	1333	925	460
Nov-11	30	1358	1025	411
Dec-11	30	1199	980	250
Jan-12	31	1304	1025	348
Feb-12	23	988	705	468
Mar-12	28	1237	845	297
Apr-12	30	1107	830	293
May-12	31	1055	935	232
Jun-12	30	1030	800	287
Jul-12	31	1064	645	247
Aug-12	31	963	620	267
Sep-12	30	957	600	239
Oct-12	31	930	620	261
Nov-12	30	819	628	182
Dec-12	31	906	1175	183
Jan-13	30	1003	1305	280
Feb-13	28	763	918	247
Mar-13	30	821	1040	191
Apr-13	25	651	800	252
May-13	31	861	926	129
Jun-13	30	759	939	190
Jul-13	31	739	931	213
Aug-13	30	724	901	210
Sep-13	30	710	878	217
Oct-13	25	573	706	198
Nov-13	0	0	0	0
Dec-13	7	454	937	57
Jan-14	28	1042	1684	125
Feb-14	28	701	1173	193
Mar-14	31	738	903	213
Apr-14	30	759	821	182
May-14	25	628	653	212
Jun-14	24	517	570	243
Jul-14	26	678	785	180
Aug-14	22	497	546	210
Sep-14	28	726	563	192
Oct-14	30	592	672	220
Nov-14	28	594	633	203
Dec-14	31	597	677	210
Jan-15	26	544	628	187
Feb-15	27	448	586	135
Mar-15	19	409	541	25
Apr-15	29	671	585	220
May-15	31	634	578	152
Jun-15	30	587	562	173

Using the data found for the Fettig 24-22H the following cumulative production versus the square-root-of-produced-time profile can be created along with the model fit of the infinite acting linear-flow regime, Figure 7.

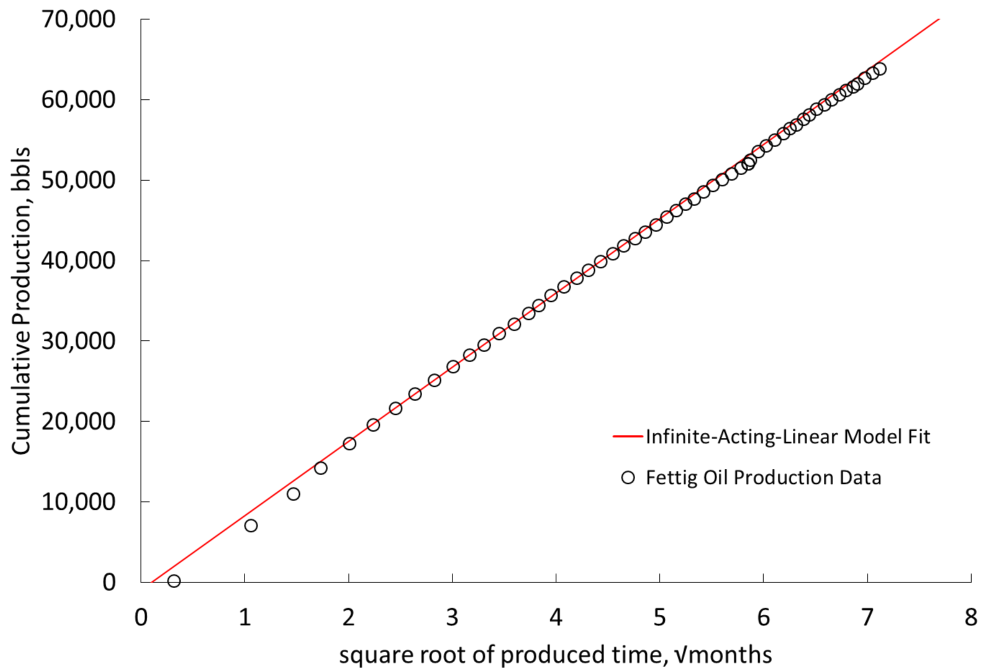

Figure 7. Showing the model fit the linear-flow portion of the cumulative production versus square-root-of-produced-time profile Fettig 24-22H.

One thing to notice in Figure 7 as the cumulative production increases over time is that the data never truly deviates from the linear flow model fit; therefore, as one works through the analysis for boundary-dominated flow in chapter 2, it becomes clear that the Fettig 24-22H is not in boundary-dominated flow but in fact in linear-flow. The next step in the analysis is to determine if the well is in linear-post-linear-flow or if the well is actually still in the linear-flow regime and has not felt a reservoir boundary. One could attempt to apply the second linear model fit to the cumulative production data above; however, since the production slightly deviates but never truly moves off the model fit curve, one can concluded that the Fettig 24-22H well is still in the linear-flow regime. Therefore, since the Fettig 24-22H is performing in the linear-flow regime, the time to the end of linear-flow, nor the intersection time, can be determined for this well utilizing the methods described thus far; in addition, the cumulative production at the end of linear flow cannot be determined. To determine the time to the end of linear-flow for a well in the linear-flow-regime will require a stochastic approach to determine the time to the end of linear-flow based on a probabilistic confidence criteria. To do this will require the use of Bayesian theory, which will be derived in detail in chapter four. As in the two well examples thus far, values of the slope and intercept can be found in Appendix B of this study for the Fettig 24-22H. However, m_2/m_{csrt} = 1 since this will is in the linear-flow regime. Monte Carlo simulations will be required to ascertain estimated ultimate recoveries of oil for a well in the linear flow-regime.

3.3 Determination of the flow-regime of a well

To determine the correct flow-regime of the well of interest will require taking the derivative of the cumulative production versus the square-root-of-produced-time data. Furthermore, three techniques for analyzing a well to determine if the well is in boundary-dominated flow, linear-post-linear-flow and linear-flow have been shown thus far. As one works through a multitude of wells there may be times that it is difficult to ascertain the correct flow-regime. Since the cumulative production versus the square-root-of-produced-time profile is a linear increasing linear profile in the infinite acting phase and an increasing at a decreasing rate in the boundary-dominated phase, the derivative of this plot can be used to determine what flow-regime the well is currently in. The derivative profile is a very useful tool that can help in diagnosing the flow-regime of a well. If a well is performing in the linear-flow regime the derivative of the cumulative production versus the square-root-of-produced-time data would yield a constant value on the derivative curve, straight line. The derivative of the linear-flow regime would yield a constant rate of change. Likewise a well that has reached boundary-dominated flow would yield a constant rate of change on the derivate profile followed by a decrease in the rate of change at a constant decreasing rate on the derivative curve indicating that all boundaries of the reservoir have been reached. For a well performing in the linear-post-linear-flow regime the rate of change on the derivative curve will be constant up to a point that a boundary appears to have been reached only to resume a constant rate of change but at a lower rate of change value. The derivative of the cumulative production versus the square-root-of-produced time are given in figures 8, 9 and 10 respectively. Utilizing the derivative and model fit of the derivative data, one can ascertain the flow regime the well is in. Note that once a boundary has been reached, in the case of boundary-dominated and linear-post-linear flow, the derivative will be constant up to the time to the end of linear flow or intersection time and then change to either linear decreasing rate (boundary-dominated) or a lower constant derivative (linear-post-linear).

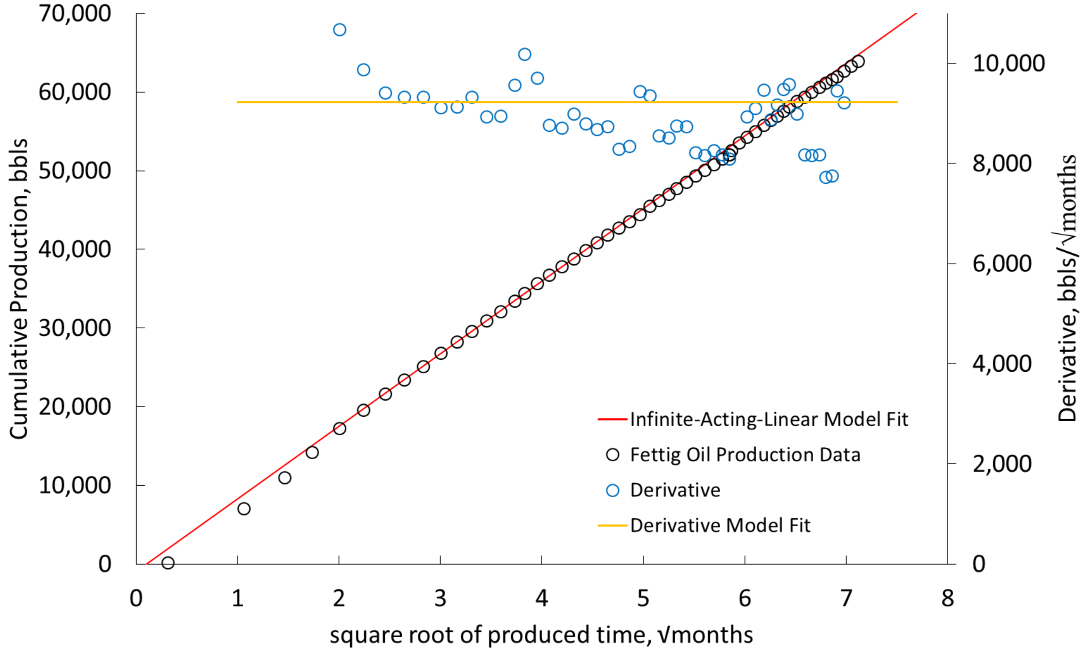

Figure 8. The model fit of the derivative of the cumulative production versus the square-root-of-produced-time in months of the Fettig 24-22H.

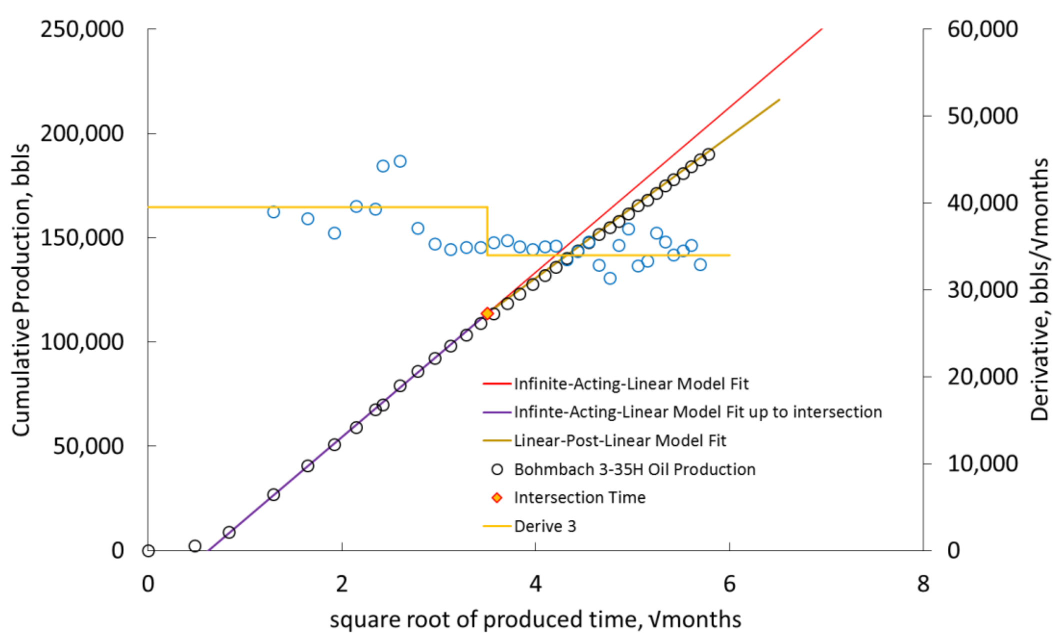

Figure 9. The model fit of the derivative of the cumulative production versus the square-root-of-produced-time in months of the Bombach 3-35H.

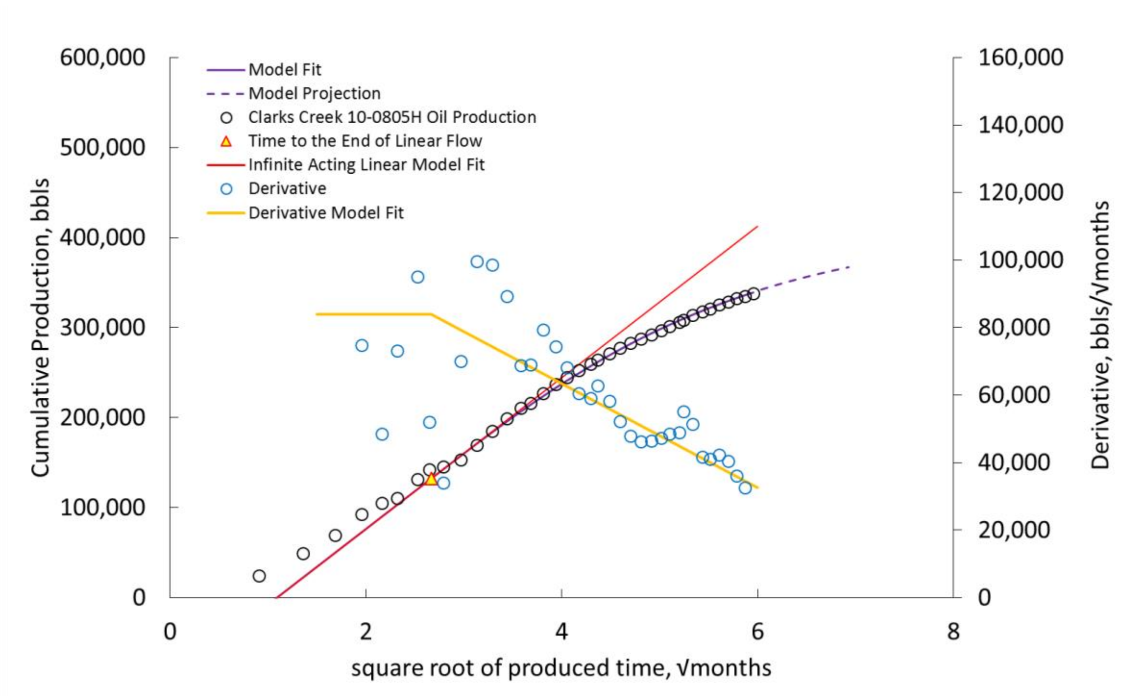

Figure 10. The model fit of the derivative of the cumulative production versus the square-root-of-produced-time in months of the Clarks Creek 10-805H

Chapter 4

Determination of Stochastic Values for Estimated Ultimate Recovery Forecasting

The next phase in the model development is to determine stochastic values looking at four parameters that will be found through analyzing wells in a similar fashion as in chapters two and three. This information will be used in the development of the Monte Carlo simulation for estimated ultimate recoveries of oil. Depending on the flowing behavior of the well, boundary-dominated, linear-post-linear and linear-flow regime will prescribe the evaluation of the well.

4.1 Stochastic Methodology

The stochastic methodology will look at four parameters that are uniquely inherent to the wells analyzed over a particular field. Stochastic analysis will be used for the Arps boundary-dominated exponent, the time to the end of linear-flow for wells in boundary-dominated flow-regime, the intersection time for wells in linear-post-linear-flow regime and the ratio of the slopes of the linear-post-linear-flow profiles. It should be noted that the results presented in this chapter are production field specific! Therefore, the procedure laid out in this chapter to analyze stochastically the four parameters of interest will be the same procedure one would use when applying this methodology to a field of interest; however, the result will be different.

4.2 Stochastic Methodology for the Arps' Boundary-dominated Exponent

This study found, out of the 185 wells analyzed based on the previous specified evaluation criteria, 17 wells that exhibited a boundary-dominated flow-regime. To develop stochastic analysis for the Arps' boundary-dominated exponent the following steps are needed to evaluate the data set.

1. Collect the Arps' boundary exponents for all wells in boundary-dominated flow.
2. Sort Arps' boundary exponents from least to greatest value.
3. Count the number of Arps' boundary-dominated exponent data point occurrences.
4. Each occurrence will be divided by the total Arps' boundary-dominated exponent count plus one (this represents the probability of the Arps' exponent that will occur.)
5. Find the inverse-standard-normal-cumulative distribution of each probability.
6. Plot the log-normal distribution of the Arps' boundary-dominated exponent versus the standard deviation Figure 11.

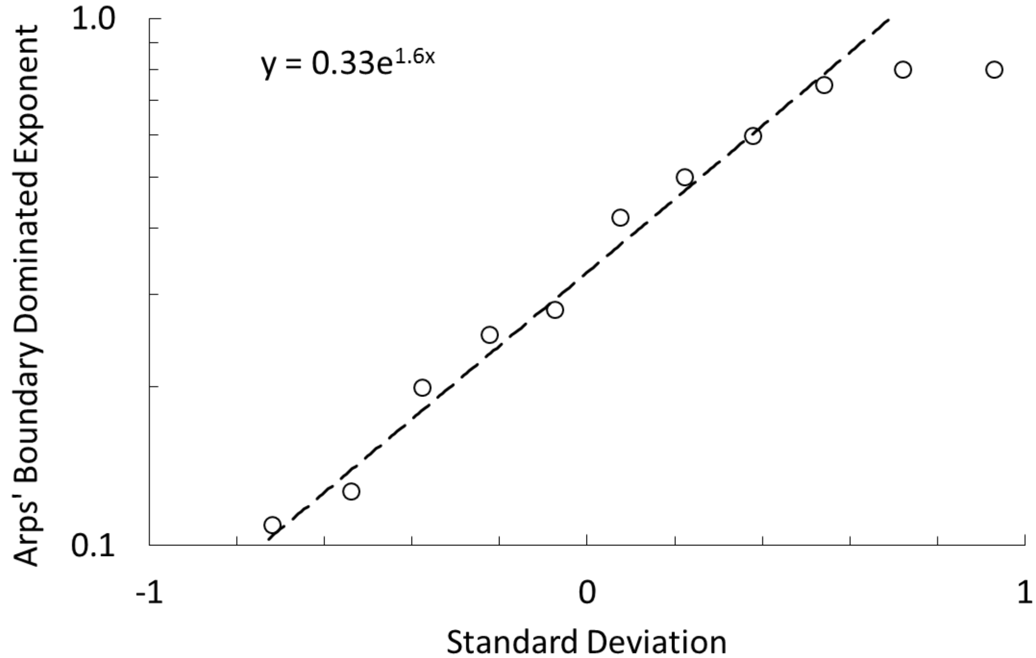

Figure 11. Log-Normal Distribution Arps' Boundary-Dominated exponent

The slope of the log-normal distribution (the standard deviation) was found to be 1.60 and the mean of the log-normal distribution is 0.33.

4.3 Stochastic methodology Ratio of the Slopes of the Linear-post-Linear-flow-regimes

This study found, out of the 185 wells analyzed based on the previous specified research criteria, 134 wells exhibited a linear-post-linear-flow-regime. To develop stochastic analysis for the ratio of the slopes of the linear-post-linear-flow-regime the following steps are needed to evaluate the data set.

1. Collect the ratio of the slopes for all wells in linear-post-liner flow-regime. Note that the ratios must be less than one.
2. Sort ratio of the slopes from the least-to-greatest value.

3. Count the number of ratio of the slopes data point occurrences.
4. Each occurrence will be divided by the total ratio of the slope count plus one (the probability of the ratio of the slopes that will occur.)
5. Find the inverse-standard-normal-cumulative distribution of each probability.
6. Plot the log-normal distribution of the ratio of the slope of the linear-post-linear-flow-regime versus the standard deviation Figure 12.

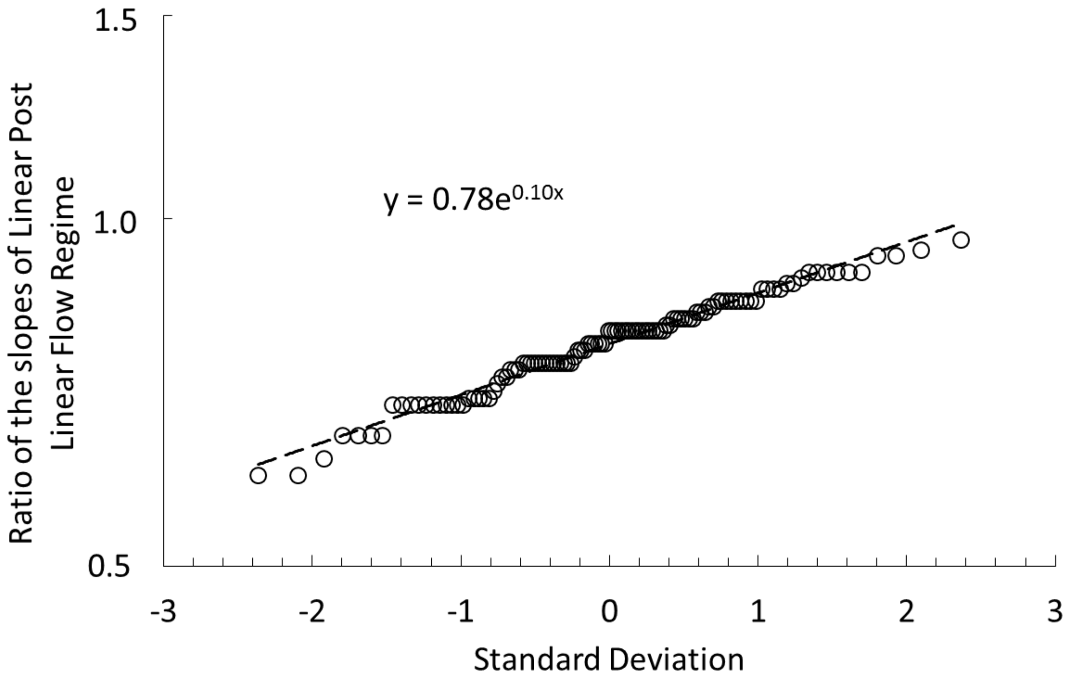

Figure 12. Log-Normal Distribution ratio of slopes of the Linear-Post-Linear-flow regime.

The slope of the log-normal distribution (the standard deviation) was found to be 0.1 and the mean of the log-normal distribution is 0.78.

4.4 Stochastic methodology for the Time to the End of Linear-flow for Boundary-Dominated Reservoirs

As stated previously for boundary-dominated wells, 17 wells exhibited boundary-dominated flow-regime. The time to the end of linear-flow for each well was observed from boundary-dominated analysis. Moreover, stochastic analysis for the time to the end of linear-flow using observed end of linear-flow time for boundary-dominated wells is as follows.

1. Collect the time to the end of linear-flow data set.
2. Sort the time to the end of linear-flow from the lowest to highest value.
3. Count the number of data point times to the end of linear-flow occurrences.
4. Each occurrence will be divided by the total time of end of linear-flow count plus one (the probability of the end of linear-flow time that will occur.)
5. Find the inverse-standard-normal-cumulative distribution of each probability.
6. Plot the log-normal distribution of the time to the end of linear-flow versus the standard deviation Figure 13.

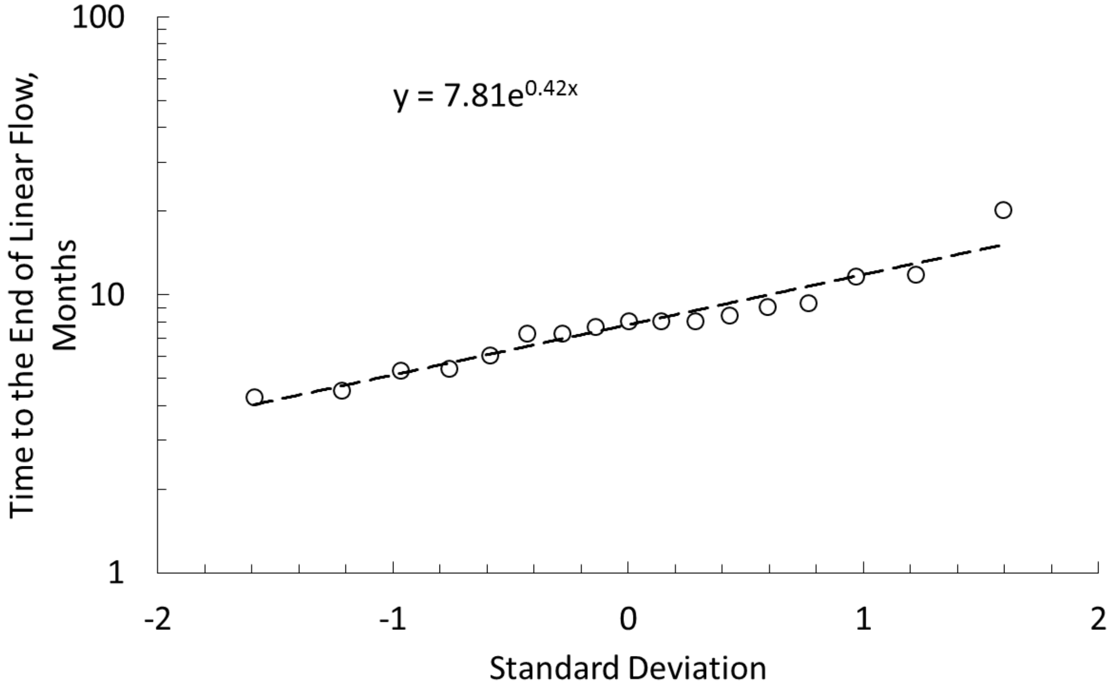

Figure 13. Log-Normal Distribution for the Time to the End of Linear-flow, Boundary-Dominated.

The slope of the log-normal distribution (the standard deviation) was found to be 0.42 and the mean of the log-normal distribution is 7.81.

4.5 Stochastic Methodology for the Intersection Time for wells in Linear-Post-Linear and Linear-flow regimes

The remaining wells in this study exhibited linear-post-linear (134 wells) and linear (34 well) flow-regimes. To predict the time to the end of linear-flow for wells that are still in the linear-flow-regime a new technique will be needed to predict the time at which the end of linear-flow can be ascertained based on a confidence probability. To do this Life Table Actuary Analysis and Bayesian Theory will be adapted to determine the end of linear-flow time of a well not yet reaching the end of linear-flow. The time to the end of linear-flow found for the linear-post-linear-flow regimes will be used in the development of the probabilistic analysis. Henceforth, this analysis will be called actuary time to the end of linear-flow.

First, it should be noted that the development of this time to the end of linear-flow Bayesian tool will be unique to the field production being evaluated. Therefore, the user of this probabilistic model will have to determine the actuary time to the end of linear-flow based on the field of interest.

To develop the actuary time to the end of linear-flow tool the following steps are needed:

1. Collect the intersection time data set for the linear-post-linear-flowing wells.
2. Sort the intersection time from the lowest to highest value.
3. Count the number of data point intersection time occurrences.
4. Each occurrence will be divided by the total intersection time count plus one (probability of the linear-post-linear intersection time that will occur.)
5. Find the inverse-standard-normal-cumulative distribution of each probability.

6. Plot the log-normal distribution of the intersection time versus the standard deviation Figure 14.

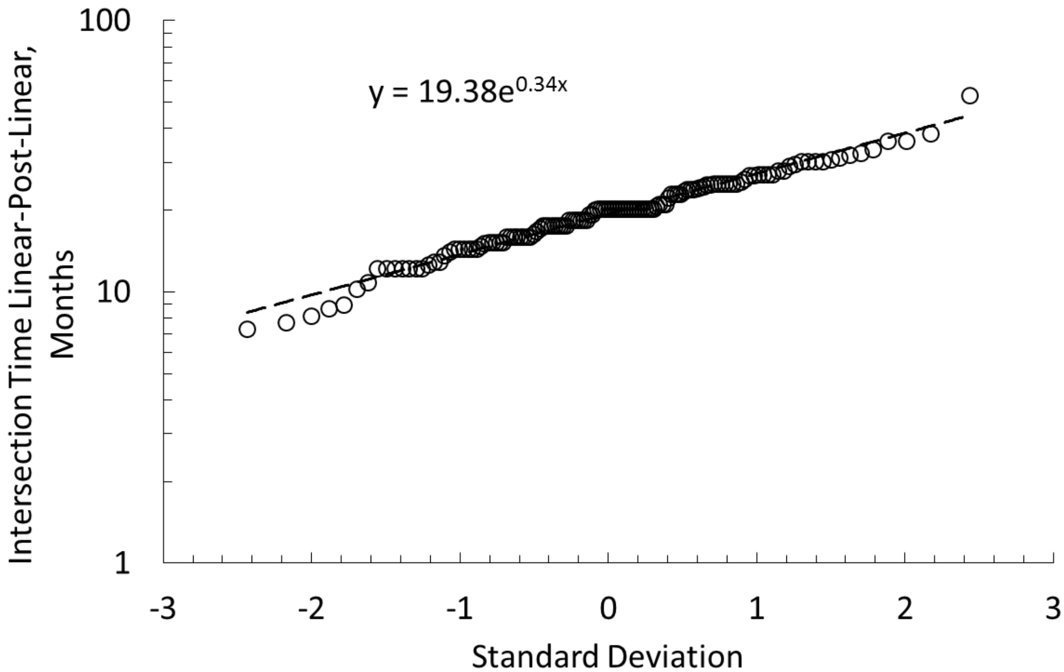

Figure 14. Log-Normal Distribution for the Intersection Time, Linear-Post-Linear.

The slope of the log-normal distribution of Figure 14, which is the standard deviation, was found to be 0.34 and the mean of the log-normal distribution is 19.38.

Applying Bayes Theorem to determine the time to the end of linear flow for wells that are still in the linear flow regime relates probabilities such that the probability of A given B is equal to the probability of A, multiplied by the probability of B given A, divided by the probability of B, equation (4-1). To illustrate, one is interested in knowing the potential time to the end of linear-flow for a well that has yet to reach the end of linear-flow regime will be related to the current production life of the well of interest. Information about the wells age can be used to more accurately assess the probability of what time to the end of linear-flow one can expect

$$P(A \mid B) = \frac{P(B \mid B)P(A)}{P(B)} \qquad (4\text{-}1)$$

The parameters of Bayes Theorem for estimating the time to the end of linear flow is as follows:

$P(A \mid B)$, probability of expected age given current age given as a random variable [0, 1].

$P(B \mid A)$, probability of current given age an expected age greater than current age = 1.

$P(A)$ Probability of achieving an expected age greater than current age. Resulting probability yields expected age.

$P(B)$ Probability of current age from log mean distribution.

Therefore, Bayes theorem can be reduced to equation (4-2)

$$P(A) = P(A \mid B)P(B) \qquad (4\text{-}2)$$

Apply equation (4-2) to find the standard deviation as a function of current well life and using that probability to determine $P(B)$ and use a desired confidence probability interval for $P(A \mid B)$. Note that low confidence intervals will return a higher time to the end of linear-flow and higher confidence probability intervals will yield lower time to the end of linear-flow values. Once $P(B)$ has been determined and $P(A \mid B)$ has been selected equation (4-2) will be used to find $P(A)$. $P(A)$ is the probability that a well will be at a specified time of end of linear-flow based on current production life and its probable outcome. Moreover, once $P(A)$ has been found then the inverse-standard-normal-cumulative distribution of $P(A)$ will be ascertained, this value will yield a corresponding standard deviation to the found probability.

Utilizing the procedures above one can generate a probabilistic profile of the expected end of linear-flow time based on Bayes Theorem.

Furthermore, to help aid in the visualization of utilizing Bayesian Theory to determine the time to the end of linear flow, one can develop the log-normal cumulative probability chart Figure 15. Therefore if one knows the age of a well of interest, then the end of linear flow can be determined. Using the data discussed previously for the time to the end of linear flow and intersection time, a log-normal cumulative probability distribution can be applied. Therefore, there is a six step process that will be used to determine the time to the end of linear flow for a well of interest. The process is as follows:

1. Select the age of the well
2. Determine P(age) based on current age of the well. This will be equal to $P(B)$.
3. Apply Bayes Theorem by selecting a random number [0, 1], this will be equal to $P(A|B)$, determine the probability of achieving an expected age greater than current age. Note that the probability of achieving an expected age greater than current age will be less than the probability of current age based on the age of the well. This will be equal to $P(A)$
4. Once the probability of achieving an expected age has been found, one will move horizontally to the cumulative probability curve.
5. From the cumulative probability curve one will move vertically to the time to the end of linear flow data set.
6. From the time to the end of linear flow data set move horizontally to the time to the end of linear flow axis. This will be the time to the end of linear flow based

on the product of a randomly selected probability and the probability at current age.

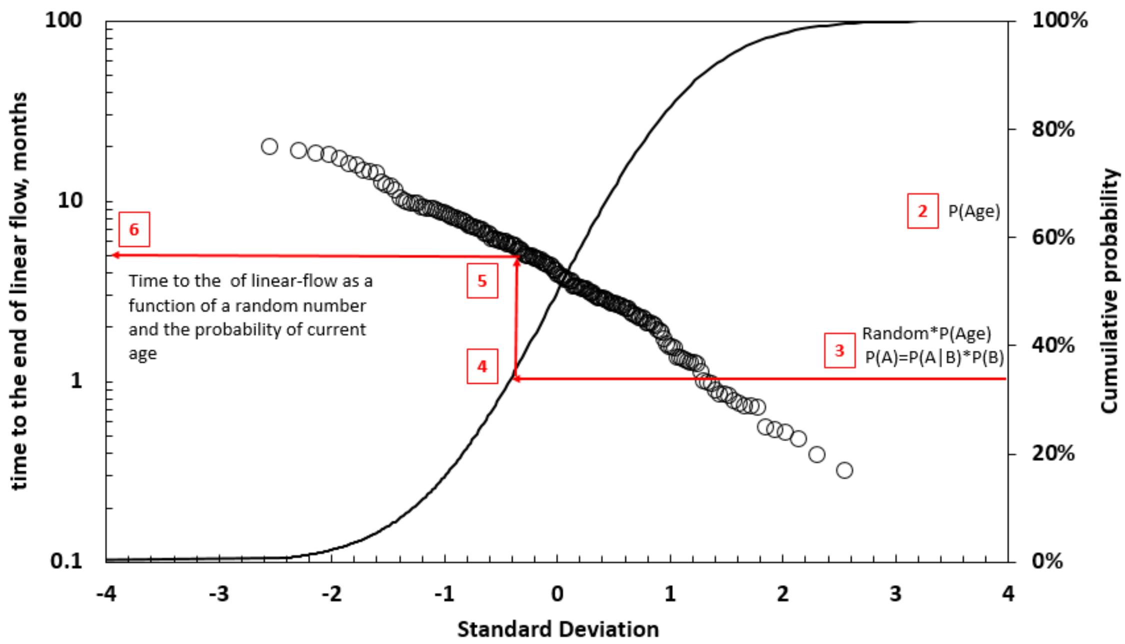

Figure 15. Log-Normal Distribution Cumulative Probability Chart to determine the Time to the End of Linear-flow.

The tabulated stochastic values for this research is given in Table 4.

Table 4: Tabulated values for the Stochastic Analysis

Flow Regime	Values	Slope	Mean
Infinite Acting Boundary Dominated	Actuary time to the end of linear flow (Log Normal)	0.42	7.81
	Arps' Boundary Dominated Exponent (Log Normal)	1.60	0.33
Linear-Post-Linear	Intersection time (Log Normal)	0.34	19.38
	Ratio of slopes of the Linear-Post-Linear Wells (Log Normal)	0.10	0.78

The parameters in Table 4 will be used in the Monte Carlo simulation for estimated ultimate recoveries of oil.

Chapter 5

Monte Carlo Simulations for Estimated Ultimate Recovery Probabilistic Analysis

Applying Petroleum Resource Management System (PRMS) criteria to the well values and the stochastically-found results in chapter four, one can use Monte Carlo simulations for random probabilistic variables for the stochastically-found results to determine the estimated ultimate recovery of a well or wells in a production field. Utilizing this information, one can develop a probabilistic estimated ultimate recovery forecast for economic evaluation purposes.

5.1 Initial setup of the Monte Carlo simulation

Once steps for finding the stochastic values for all wells analyzed from chapter four, Table 4, is completed, the process of setting up a Monte Carlo simulation to evaluate wells that are in boundary-dominated, linear-post-linear and linear-flow regimes to determine the estimated ultimate recovery of oil for a field of interest can begin.

Before one can begin the Monte Carlo setup, the economic limit of the field of interest must first be determined. The economic limit is the limiting amount of barrels one would produce economically. The economic limit is a function of the monthly operating costs, net revenue interest per working interest, severance, and oil commodity prices and will have to be applied accordingly to the evaluation of interest.

The next phase in setting up the Monte Carlo simulation is to acquire the slope and intercept of the cumulative production versus the square-root-of-produced-time profiles of the wells of interest. The three examples, laid out in chapters two and three, will be used and their parameters are found in Appendix B of this study. The slope and intercept for the cumulative production versus the square-root-of-produced-time will be specific to the well being studied. The stochastic values found, utilizing the methodology in chapter four, will be used commonly across all wells analyzed. The stochastic values for wells in boundary-dominated flow and linear-post-linear-flow can be found in Table 4.

5.2 Determination of the Estimated Ultimate Recovery of oil wells in Boundary-Dominated flow and Linear-Post-Linear-flow

To determine the estimated ultimate recoveries of wells in boundary-dominated, linear-post-linear and linear-flow will require the use of the hyperbolic equations defined in Table A.1 of the appendix of Rodrigues and Callard (2012). The equations will be relied on for the setup of the simulation using Monte Carlo numerical analysis.

To determine the estimated ultimate recovery for boundary-dominated flow and linear-post-linear flow regime can be found deterministically utilizing the parameters found in Appendix B for chapters two and three respectively. The deterministic results for the Clarks Creek 10-0805H and the Bohmbach 3-35H are given in Table 6 of section 5.5.

The cumulative production versus the square-root-of-produced-time profiles showing the deterministic estimated ultimate recoveries are given in Figure's 16 and 17 respectively. It should be noted for the Clarks Creek 10-0805H it would have a total well life of approximately 39 years before the estimated ultimate recovery is achieved for the well parameters found through model matching and assumed operating expense defined in the economic limit. Likewise, for the Bohmbach 3-35H it will take approximately 37 years to achieve the estimated ultimate recovery of this well based on the well parameters and economic limit for this well.

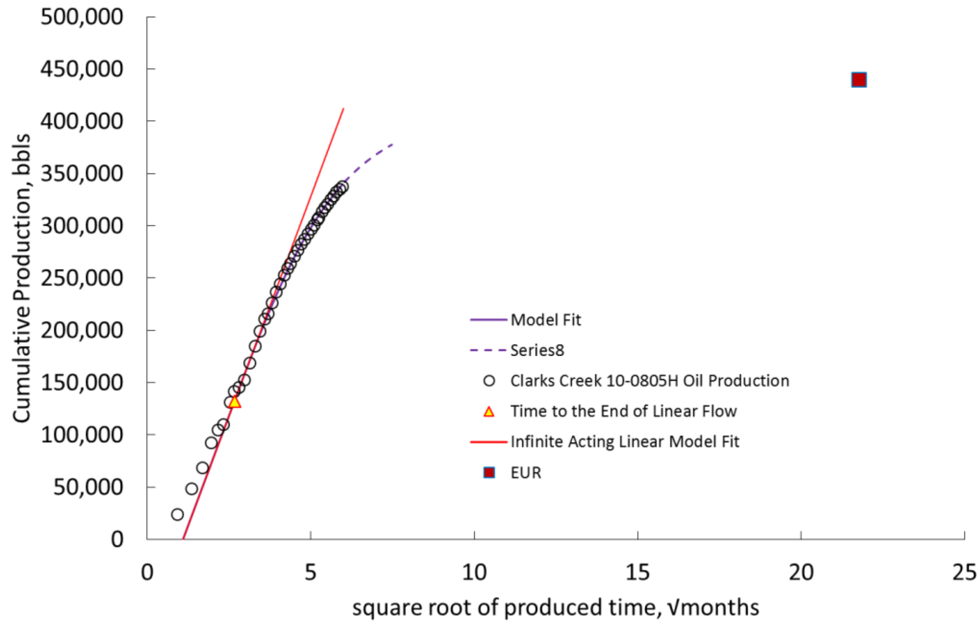

Figure 16. The cumulative production versus the square-root-of-produced-time in months of the Clarks Creek 10-805H with Estimated Ultimate Recovery.

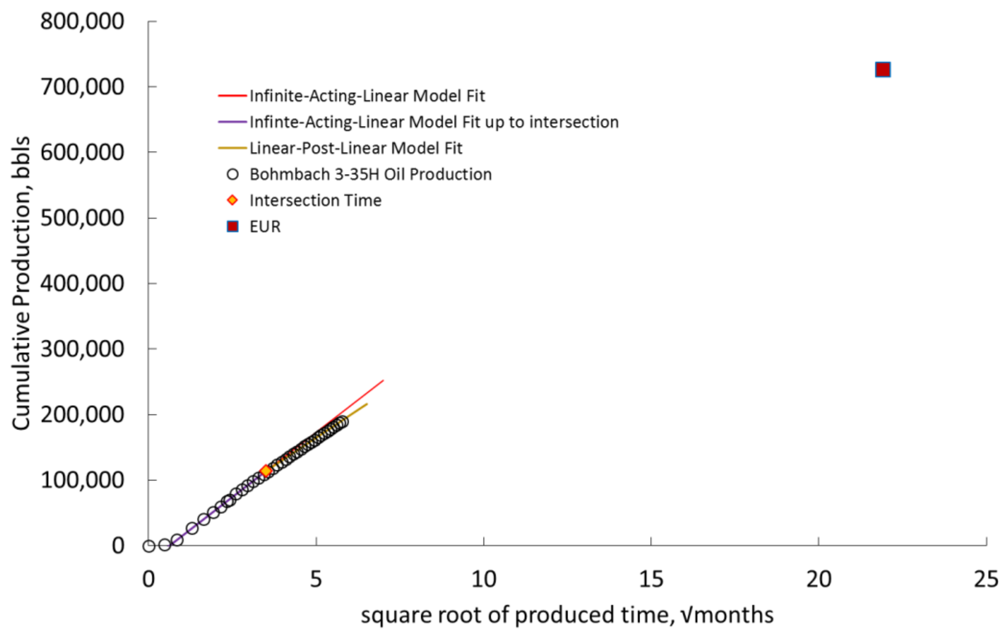

Figure 17. The cumulative production versus the square-root-of-produced-time in months of the Bohmbach 3-35H with Estimated Ultimate Recovery.

5.3 Application of the Monte Carlo Simulation

The Monte Carlo model will be setup such that the analysis will rely on a repeated random sampling of the proportion of wells that are in boundary-dominated flow to the wells in linear-post-linear and linear-flow. This analysis will rely on what will be called *realizations* based on the number of iterations required to reach convergence. The setup of the Monte Carlo simulation is as follows:

1. Determine slope of the cumulative versus the square-root-of-produced-time profile.
2. Determine the intercept of the cumulative versus the square-root-of-produced-time profile.
3. Determine the current cumulative production at the current life of the well.
4. Determine the economic limit of the field of interest.
5. Determine the percentage of the wells in boundary-dominated flow-regime relative to the wells in linear-post-linear and linear-flow-regimes.
6. Using the hyperbolic equations defined in Table A.1 of the appendix of Rodrigues and Callard (2012). Determine the estimated ultimate recoveries of a well in either boundary-dominated or linear-post-linear and linear-flow regimes.
7. The Monte Carlo setup will be such that the estimated ultimate recovery of oil will converge on a series of realizations. Convergence will be acquired by the minimal change of the standard deviation relative to the mean.

5.4 Results of the Monte Carlo Simulation

The results of the linear-flow of the Monte Carlo analysis of the Fettig 24-22H is as follows. Note that the percent BD given in Table 5 is the ratio of the boundary dominated wells to the number of linear-post-linear wells plus the boundary dominated wells. This percentage is used in the decision process of the Monte Carlo simulation utilizing random sampling. Note that this study only found 17 wells that are in boundary dominated flow, 134 wells in linear-post-linear flow and 34 wells in linear flow; therefore, utilizing Bayesian theory, the probabilistic method laid out thus far, will be needed for wells in linear flow.

Table 5: Monte Carlo Input values for the Fettig 24-22H

Well Parameters			**Stochastic Results**		slope (STD)	mean=exp(intercept)
m_{csrt}	9,231	bbls/√months	IABD	acturay telf (log normal)	0.379	7.810
Np_i	-940			bBD (log normal)	1.520	0.224
Np_{max}	63,922		LPL	acturay tx (log normal)	0.337	19.380
				mratio (log normal)	0.099	0.779
			Operational Parameters			
Linear Flow	34			MOC	$15,000	per month
Linear-post-linear Flow	134			Price of Oil and associated gas	$50	per bbl
bondary dominated Flow	17	151		NRI/WI	0.7	
				severence	6%	
percent BD	11%			Economic Limit	456	STB per month

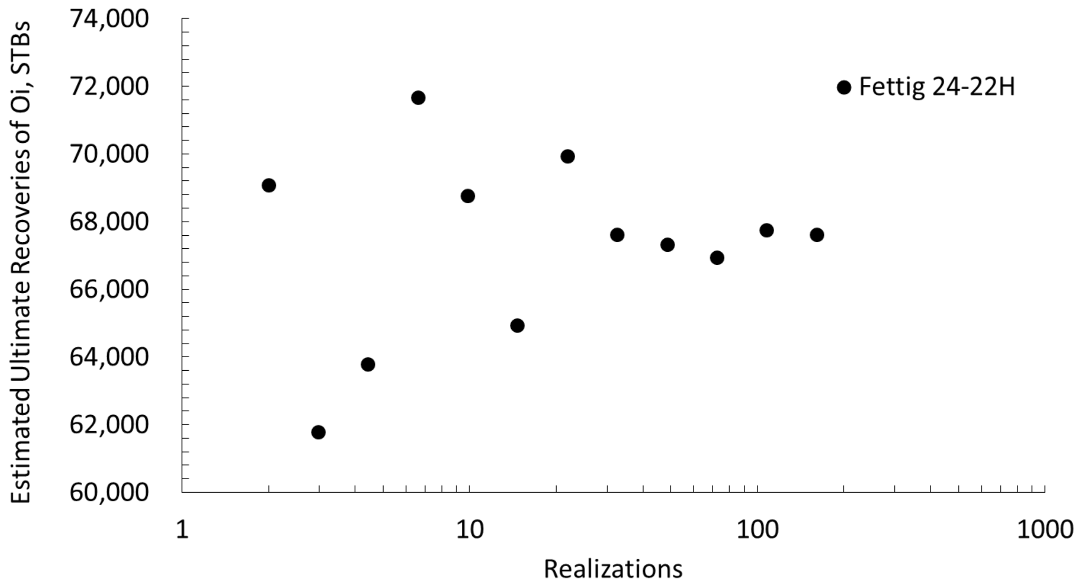

Figure 18. Monte Carlo simulation for and Estimated Ultimate Recovery of Oil, Fettig 24-22H.

Notice how as the realization increase the estimate ultimate recovery values converge on a solution. For the Fettig 24-22H, it took approximately 33 realizations to achieve convergence, Figure 18. The mean value of the estimated ultimate recovery of this well based on the parameters in Table 5 is 68,357 bbls. Figure 19, shows the Fettig 24-22H cumulative production versus the square root of produced time profile with the estimated ultimate recovery for this well utilizing the Monte Carlo estimated ultimate recovery method. It should be noted that based on the intial assumptions for the Monte Carlo analysis, it appears that the Fettig 24-22H will reach its estimated ultimate recovery in approximately 56 months from initial well life.

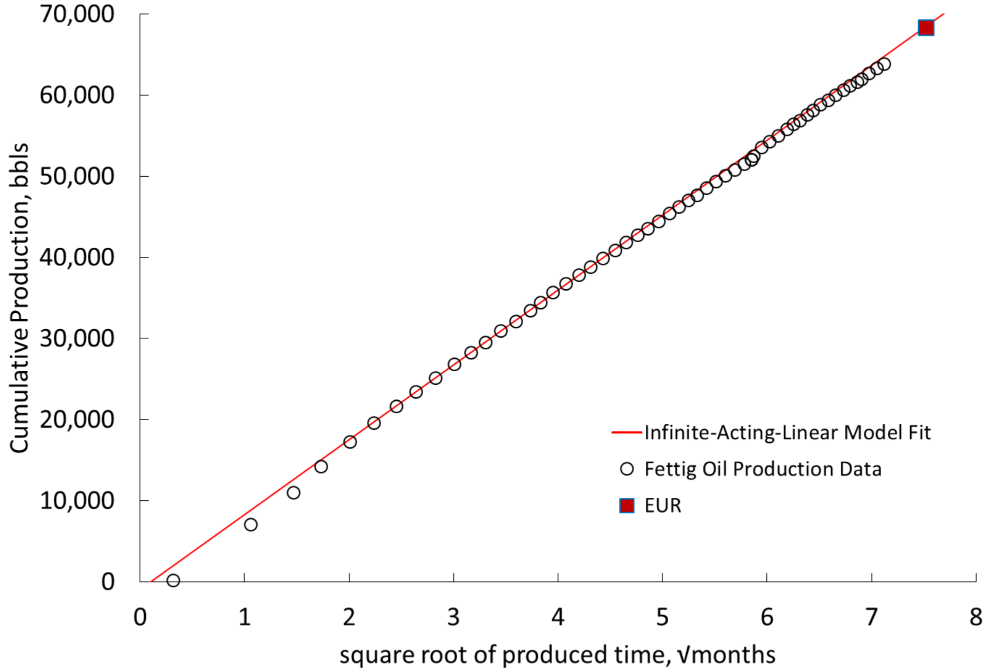

Figure 19. The cumulative production versus the square-root-of-produced-time in months of the Fettig 24-22H with Estimated Ultimate Recovery.

5.5 Applying the Petroleum Resource Management System criteria.

Petroleum Resource Management System Guidelines (PRMS) for proved, probable and possible reserves is used to quantify oil reserves for public reporting. From KelKar (2013), according to the Petroleum Resource Management System (PRMS) criteria, proved reserves represent the most important category of reserves and represent the 10th percentile reserves and should have a 90% probability that these reserves can be produced. KelKar also states, probable reserves represent the difference between the 50th and 10th percentile values or the difference between the 90% and the 50% probabilistic value; furthermore, possible reserves represent the difference between the 90th and 50th percentile or the difference between the 50% and 10% probabilistic value. Therefore, to determine the proved, probable and possible reserves for the Fettig 24-22H well given previously, the mean of the estimated ultimate recovery and the standard deviation was found and is given in Table 6. Note that the standard deviation is used to break down the mean into proved, probable and possible reserves. The process in determining Petroleum Resource Management System criteria (PRMS) is as follows:

1. Determine the standard normal cumulative distribution of the proved, probable and possible, which is 90%, 50% and 10% probability respectively.
2. Find the log-normal distribution of the estimated ultimate recovery based on proved, probable and possible criteria. EUR_{MC} is the estimated ultimate recovery found using the Monte Carlo simulation, z is the standard normal cumulative distribution values and STD_{MC} is the standard deviation of the Monte Carlo values based on the realizations found.
3. To determine proved, probable and possible reserves for public reporting one would multiply the 90% probability to the 90% Monte Carlo estimated ultimate recovery reserves for proved reserves. Furthermore, probable reserves is found by multiplying 50% to the difference in of the 90% and 50% Monte Carlo estimated ultimate recovery reserves. Possible reserves are found by multiplying 10% to the difference between 50% and 10% Monte Carlo estimated ultimate recovery reserves.

The results of the petroleum resource management criteria for the Fettig 24-22H well is as follows.

Table 6: Deterministic and Monte Carlo Results for Proved, Probable and Possible Reserves

Deterministically determined Estimated Ultimate Recoveries		
Clarks Creek 10-0805H (BD)	EUR (bbls)	439,784
Bohmbach 3-35H (LPL)	EUR (bbls)	726,921

Stochastically determined Estimated Ultimate Recoveries			
Fettig 24-22H (L)		Mean EUR	Standard Deviation
		67,679	9.71%
	Standard Normal Cum Distribution	EUR_{Prob}	Reportable Reserves (bbls)
Proved P1 90%	1.28	59,757	53,782
Probable P2 50%	0.00	67,679	3,961
Possible P3 10%	-1.28	76,651	897
		Reportable Reserves =	**58,640**

From the analysis it can be seen that the reserves that would be used for public reporting are the summation of the proved, probable and possible reserve criteria, called Reportable Reserves, found in Table 6 for the Fettig 24-22H. For the Clarks Creek and the Bohmbach wells, the deterministic reserves, which represent the most conservative value, is based on the observed parameters determined through the utilization of the cumulative production versus the square-root-of-produced-time profile outlined in chapter two and three respectively.

Furthermore, if one is evaluating stochastically found reserves and one moves from the proved reservoir criteria and considers projects that would require a higher degree of risk then probable and possible reserve parameters may be used. Furthermore, another way to look at the numbers is to understand that the range of possible barrels that can be recovered, based on a producers operating costs and oil commodity prices, one will never be able to realize the total amount of oil production potential of a well. Therefore, it is important to understand what the numbers say and make economic decisions based on what the data is stating. For example, Fettig 24-22H, the 90% PRMS reserve barrels should be used in lieu of the ultimate potential of the well, in this case the ultimate potential found for this well is 76,651 bbls based on the assumed operating costs and oil commodity prices; however, the best possible outcome of this well cannot exceed the PRMS reserves value, which is the summation of the PRMS proved, probable and possible reserves. Therefore the 90% PRMS reserve value should be used for the economic decision process, which states that there is a 90% probability of producing this amount of barrels and any reservoir volumes greater than this only exasperates the risk potential.

5.6 What the Results Say

The results of the estimated ultimate recovery analysis can be applied to all 185 wells studied such that the estimated ultimate recoveries for oil can be found using the stochastic model for a field of interest. The Petroleum Resource Management System (PRMS) criteria coupled with the estimated ultimate recovery probabilistic reserve procedure proposed in this research exhibit a powerful tool that can help upstream companies, mid-stream companies and investment firms evaluate oil assets. It is possible that estimated ultimate recoveries can be found individually for wells using this technique; however, it needs to be understood that for one to be able to truly determine the correct estimated ultimate recovery of a single well will require knowledge of the production history from the beginning of well-life until abandonment. Since the wells studied in this analysis have only been producing for approximately three to seven years it could take years to determine the true estimated ultimate recovery of a well. Another important factor will be the historical commodity price of oil that will be needed to determine the estimated ultimate recovery of oil for the well in question. Therefore the results allow for an estimation of the ultimate recoveries for a field and should be applied on field-by-field basis.

5.7 Sensitivities of the Estimated Ultimate Recovery values for future Oil Commodity Prices

A powerful component to this technique is looking at sensitivity studies on future oil commodity prices. For example, if a mid-stream provider is looking to provide a transportation service for an upstream company to move oil from the well-head to third-party offloads or processing, a significant capital expense will be burdened by the mid-stream provider. It is paramount that the mid-stream provider carry-out their due-diligence to ensure that the project has an economic viability. The reserve procedure laid out in this research can give the mid-stream provider insight as to the expected ultimate recovery of the reserves by looking at the future commodity prices. This procedure will empower the mid-stream provider to weigh the economic risk burden to the company as well as develop a spending-capital timeline to maximize revenue and hit the acquired target-rate-of-return.

Chapter 6

Conclusion

6.1 Conclusion

The model for flow-regime changes for this study was a success. Deterministic reserves can be determined on boundary-dominated and linear-post-linear wells and two key distributions are desired from an area of interest studied for each late life flow regime. Stochastic reserves can be determined on infinite acting wells using these key distributions and this methodology is not limited to reservoir or fluid and can be used in other fields developed with horizontal wells with multistage fracture stimulation Furthermore, the model was able to allow for the approximation of the estimated ultimate recovery for a field of interest and allow for the quantification of reserves corresponding to the Petroleum Resource Management System (PRMS) criteria for reserve reporting purposes. This method can empower upstream companies, mid-stream companies and investment firms the ability to gain some insight into the potential ability to recover reserves from a field of interest. This model can be used in the economic decision-making process to compare and contrast, along with running sensitivity studies on future commodity prices of oil to ascertain the validity of an oil project or investment.

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Appendix A: Nomenclature

b	Arps' exponent, dimensionless
EUR	Estimated Ultimate Recovery, bbls
G	Gas Production, Mcf
$IABD$	Infinite Acting Boundary-dominated
m_2	Slope of linear-post-linear regression line, STBs /√months
m_{csrt}	Slope of the cumulative production square-root-of-produced-time linear-flow-regime STBs /√months
m_2/m_{csrt}	Ratio of slopes for linear-post-linear, dimensionless
MOC	Monthly Operating Cost, $/bbl
$NDIC$	North Dakota Industrial Commission
NRI	Net Revenue interest, %
N	Oil Production, bbls
N_P	Cumulative Oil Production, bbls
N_{P_i}	Cumulative Oil Production intercept, bbls
$P1$	Proved reserves, bbls
$P2$	Probable reserves, bbls
$P3$	Possible reserves, bbls
STD	Standard Deviation, dimensionless
t_{elf}	Time to the End of Linear-flow for boundary-dominated wells, months
t_p	Well age, months
t_{p_m}	Cumulative production months, month
t_x	Intersection time for linear-post-linear wells, months
WI	Working interest, %
W	Water Production, bbls

Subscripts

$csrt$ Cumulative production square-root-of-produced-time

BD Boundary-dominated

i Intercept

LF Linear-flow

$Life$ Well current age

LPL Linear-post-linear

MC Monte Carlo

n Itteration

p Cumulative

$Prob$ Probability

Appendix B: Bakken Production Data

FILE #	API #	WELL NAME	WELL #'s	OPERATOR NAME	Field	CO	bBD	m_{crst}	m_2/m_{crst}	Np_i	Np_{max}	Np_{elf} or intersection	t_{pelf} (months)	t_{px} (months)
18013	3305303011	MATHISTAD	2-35H	BURLINGTON RESOURCES OIL AND GAS	CROFF	MCKENZIE	2.00	24,732	0.82	-200	158,378	86,363		12.25
18764	3310501802	RICKY	1-18H	CONTINENTAL RESOURCES	SQUIRES	WILLIAMS	2.00	23,265	0.00	-16,577	117,152	81,136		17.64
18782	3310501805	LEE	1-20H	CONTINENTAL RESOURCES	SQUIRES	WILLIAMS	2.00	22,804	0.80	-15,521	123,000	82,535		18.49
18732	3305303119	STORTROEN	1-13T	CONTINENTAL RESOURCES	DIMMICK LAKE	MCKENZIE	2.00	18,295	0.75	-4,241	108,478	71,683		17.22
18946	3305303151	KENNEDY	2X-31H	CONTINENTAL RESOURCES	DIMMICK LAKE	MCKENZIE	2.00	24,697	0.69	-6,027	127,967	105,112		20.25
18542	3305303091	MILES	2-6H	CONTINENTAL RESOURCES	DIMMICK LAKE	MCKENZIE	2.00	31,915	0.69	-28,763	134,419	92,516		14.44
17461	3305302920	BICENTENNIAL FEDERAL	10-34H	CONTINENTAL RESOURCES	BICENTENNIAL	MCKENZIE	2.00	4,189	0.90	-4,077	25,157	16,866		25.00
18138	3305303028	SIMMENTAL	1-21H	CONTINENTAL RESOURCES	ELM TREE	MCKENZIE	2.00	41,562	0.70	-29,387	255,113	157,640		20.25
18909	3305303143	ROLLEFSTAD	2-3H	CONTINENTAL RESOURCES	ANTELOPE	MCKENZIE	2.00	39,480	0.85	-36,685	234,706	140,974		20.25
18911	3305303144	BOHMBACH	2-35H	CONTINENTAL RESOURCES	ELM TREE	MCKENZIE	2.00	29,818	0.87	-17,484	191,730	101,787		16.00
19126	3305303179	LANSING	1-25H	CONTINENTAL RESOURCES	BANKS	MCKENZIE	2.00	71,660	0.65	-121,137	325,928	229,996		24.01
19161	3305303185	ORF	1-17H	CONTINENTAL RESOURCES	RANCH CREEK	MCKENZIE	2.00	13,049	0.80	-4,470	82,666	58,815		23.52
19380	3305303232	NORWAY	1-5H	CONTINENTAL RESOURCES	FANCY BUTTES	MCKENZIE	2.00	30,979	0.84	-20,474	180,424	103,442		16.00
19503	3305303254	SIMMENTAL	2-21H	CONTINENTAL RESOURCES	ELM TREE	MCKENZIE	2.00	35,904	0.75	-25,171	206,559	125,626		17.64
19548	3305303264	GUDMUNSON	1-26H	CONTINENTAL RESOURCES	ELIDAH	MCKENZIE	2.00	23,890	0.80	-6,719	134,864	84,064		14.44
19549	3305303265	LAZORENKO	1-2H	CONTINENTAL RESOURCES	LITTLE KNIFE	MCKENZIE	2.00	9,186	0.85	-4,120	51,708	43,648		27.04
19797	3305303322	PITTSBURGH	1-19H	CONTINENTAL RESOURCES	BANKS	MCKENZIE	2.00	43,880	0.75	-20,386	250,801	177,075		20.25
20354	3305303457	VARDON	1-14H	CONTINENTAL RESOURCES	SIVERSTON	MCKENZIE	2.00	34,185	0.82	-19,936	196,689	123,641		17.64
20803	3305303594	PALMER	1-25H	CONTINENTAL RESOURCES	HAYSTACK BUTTE	MCKENZIE	2.00	30,028	0.74	-21,091	149,329	84,006		12.25
21128	3305303669	CHARLOTTE	2-22H	CONTINENTAL RESOURCES	BANKS	MCKENZIE	2.00	24,835	0.90	-9,938	147,025	111,754		24.01
21148	3305303671	PASADENA	1-11H	CONTINENTAL RESOURCES	BANKS	MCKENZIE	2.00	32,894	0.78	-11,985	164,398	103,146		12.25
21490	3305303768	BOHMBACH	3-35H	CONTINENTAL RESOURCES	ELM TREE	MCKENZIE	2.00	39,531	0.86	-24,588	190,179	113,772		12.25
21692	3305303825	TODD	1-6H	CONTINENTAL RESOURCES	LAST CHANCE	MCKENZIE	0.28	32,840	0.84	-32,853	157,643	72,842	9.36	
22598	3305304043	RANDOLPH	1-2H	CONTINENTAL RESOURCES	WESTBERG	MCKENZIE	2.00	64,682	0.81	-66,561	292,231	192,168		16.00
23352	3305304243	MISSOULA	3-21H	CONTINENTAL RESOURCES	CAMP	MCKENZIE	2.00	29,937	0.85	-14,295	133,498	90,486		12.25
23664	3305304356	CHARLOTTE	3-22H	CONTINENTAL RESOURCES	BANKS	MCKENZIE	2.00	28,846	0.77	-23,256	122,933	93,571		16.40
18509	3310501769	HARDSCRABBLE	1-16H	EOG RESOURCES	LAKE TRENTON	WILLIAMS	2.00	17,172	0.70	-6,209	101,837	88,235		30.25
18464	3305303082	MANDAREE	1-10H	EOG RESOURCES	SQUAW CREEK	MCKENZIE	2.00	25,991	0.75	-5,127	163,352	93,640		14.44
18594	3305303098	MANDAREE	7-17H	EOG RESOURCES	SQUAW CREEK	MCKENZIE	2.00	21,827	0.88	-7,989	146,277	101,144		24.87
18697	3305303114	MANDAREE	4-15H	EOG RESOURCES	SQUAW CREEK	MCKENZIE	2.00	31,639	0.74	-2,070	215,112	154,545		24.50
18774	3305303124	MANDAREE	5-16H	EOG RESOURCES	SQUAW CREEK	MCKENZIE	2.00	21,441	0.76	-6,552	140,074	104,939		26.95
18908	3305303142	MANDAREE	6-20H	EOG RESOURCES	SQUAW CREEK	MCKENZIE	0.50	23,408	0.75	-1,083	152,014	79,000	11.70	
18927	3305303148	MANDAREE	2-09H	EOG RESOURCES	SQUAW CREEK	MCKENZIE	2.00	21,869	0.83	-2,999	147,163	80,104		14.44
19004	3305303164	MANDAREE	12-07H	EOG RESOURCES	SQUAW CREEK	MCKENZIE	2.00	24,035	0.78	-5,889	156,383	90,253		16.00
19247	3305303195	RIVERVIEW	01-32H	EOG RESOURCES	ANTELOPE	MCKENZIE	2.00	31,425	0.75	-5,636	198,604	151,488		25.00
19341	3305303221	BEAR DEN	05-31H	EOG RESOURCES	SPOTTED HORN	MCKENZIE	2.00	24,011	0.78	-3,628	142,306	99,618		18.49
20332	3305303447	WEST CLARK	100-2413H	EOG RESOURCES	CLARKS CREEK	MCKENZIE	0.25	47,613	0.69	-16,369	192,947	83,623	4.29	
20334	3305303449	WEST CLARK	1-2413H	EOG RESOURCES	CLARKS CREEK	MCKENZIE	2.00	52,065	0.47	-24,119	183,409	126,870		8.20
20550	3305303514	CLARKS CREEK	10-0805H	EOG RESOURCES	ANTELOPE	MCKENZIE	0.20	83,988	0.70	-91,669	338,021	132,217	7.11	
20577	3305303523	BEAR DEN	19-2116H	EOG RESOURCES	SPOTTED HORN	MCKENZIE	2.00	35,079	0.60	-17,058	139,367	80,461		7.73
20578	3305303524	BEAR DEN	18-21H	EOG RESOURCES	SPOTTED HORN	MCKENZIE	2.00	43,745	0.68	-9,272	209,655	148,211		12.92
20601	3305303534	MANDAREE	16-04H	EOG RESOURCES	SQUAW CREEK	MCKENZIE	2.00	20,025	0.82	-2,033	108,060	78,066		16.00
20602	3305303535	CLARKS CREEK	15-0805H	EOG RESOURCES	ANTELOPE	MCKENZIE	0.11	81,899	0.80	-52,580	379,478	185,972	8.07	
20887	3305303613	CLARKS CREEK	13-1806H	EOG RESOURCES	CLARKS CREEK	MCKENZIE	2.00	54,750	0.70	-65,866	222,672	180,511		20.25
20888	3305303614	CLARKS CREEK	14-1819H	EOG RESOURCES	CLARKS CREEK	MCKENZIE	2.00	49,355	0.69	-43,206	215,641	159,150		16.81
20890	3305303615	CLARKS CREEK	11-0706H	EOG RESOURCES	CLARKS CREEK	MCKENZIE	2.00	58,089	0.69	-31,963	274,113	212,011		17.64
20892	3305303617	CLARKS CREEK	16-0706H	EOG RESOURCES	CLARKS CREEK	MCKENZIE	2.00	53,395	0.85	-33,761	240,131	174,479		14.81
21688	3305303823	BEAR DEN	103-21H	EOG RESOURCES	SPOTTED HORN	MCKENZIE	0.04	35,839	0.85	-12,322	151,746	76,856	6.07	
21689	3305303824	BEAR DEN	104-2116H	EOG RESOURCES	SPOTTED HORN	MCKENZIE	2.00	42,987	0.60	-15,396	188,572	152,255		15.21
22199	3305303931	RIVERVIEW	100-3031H	EOG RESOURCES	CLARKS CREEK	MCKENZIE	0.01	95,236	0.85	-87,437	390,955	196,576	8.05	
22200	3305303932	RIVERVIEW	4-3031H	EOG RESOURCES	CLARKS CREEK	MCKENZIE	0.13	104,655	0.90	-124,099	368,049	131,430	4.56	
22505	3305304014	CLARKS CREEK	100-0805H	EOG RESOURCES	ANTELOPE	MCKENZIE	2.00	85,052	0.65	-114,335	305,342	208,862		12.63
22962	3305304141	WEST CLARK	5-2425H	EOG RESOURCES	CLARKS CREEK	MCKENZIE	0.01	76,960	0.85	-70,853	273,549	122,044	5.43	
16433	3305302769	LARS ROTHIE	32-29H	HESS	BLUE BUTTES	MCKENZIE	2.00	19,238	1.00	-10,255	151,111			

FILE #	API #	WELL NAME	WELL #'s	OPERATOR NAME	Field	CO	bBD	m_{crst}	m_2/m_{crst}	Np_i	Np_{max}	Np_{elf} or intersection	t_{pelf} (months)	t_{px} (months)
16829	3305302826	OLSON	9-11H	HESS	BLUE BUTTES	MCKENZIE	2.00	23,826	0.80	-24,000	167,292			53.29
17609	3305302934	AN-NORBY-	152-94-0409H-1	HESS	ANTELOPE	MCKENZIE	2.00	38,781	0.85	-23,608	281,293	197,441		32.12
18104	3305303019	BB-STATE A-	151-95-1615H-1	HESS	BLUE BUTTES	MCKENZIE	2.00	47,448	1.00	-427	374,555			
18105	3305303020	BB-FEDERAL A-	151-95-0910H-1	HESS	BLUE BUTTES	MCKENZIE	2.00	40,388	0.93	-5,932	307,191	236,396		36.00
30575	3305306680	BB-FEDERAL-	151-95-0817H-1	HESS	BLUE BUTTES	MCKENZIE	2.00	42,463	1.00	-5,958	310,339			
29163	3305306198	BB-CHAPIN A-	151-95-0403H-1	HESS	BLUE BUTTES	MCKENZIE	2.00	31,504	0.62	-933	162,505	84,129		7.29
18820	3305303135	HA-ROLFSRUD-	152-96-1720H-1	HESS	WESTBERG	MCKENZIE	2.00	39,858	1.00	-3,669	268,695			
19219	3305303191	BROSTUEN	6-1H	HESS	GLASS BLUFF	MCKENZIE	2.00	22,183	0.78	-1,959	146,810	108,956		24.99
19270	3305303199	GUDMUNSEN	27-1H	HESS	ELLSWORTH	MCKENZIE	2.00	26,166	0.69	-601	168,718	124,998		23.04
19538	3305303260	AN-GUDBRANSON-	153-94-2215H-1	HESS	ELM TREE	MCKENZIE	2.00	47,374	1.00	-8,311	263,443			
19723	3305303305	AN-BOHMBACH-	153-94-2734H-1	HESS	ANTELOPE	MCKENZIE	2.00	61,513	0.78	-54,877	304,633	252,688		24.20
19885	3305303346	TATTU	19-1H	HESS	ELK	MCKENZIE	2.00	30,445	1.00	-14,016	187,479			
19887	3305303347	AN-DINWOODIE-	153-94-2833H-1	HESS	ANTELOPE	MCKENZIE	2.00	32,375	0.77	-9,772	188,261	135,914		20.25
20136	3305303402	IVERSON TRUST	1-1H	HESS	GLASS BLUFF	MCKENZIE	2.00	26,051	0.90	-4,209	166,817	113,019	20.22	
20224	3305303418	KLOSE	24-1H	HESS	GLASS BLUFF	MCKENZIE	2.00	26,023	0.85	-9,196	166,307	133,931		30.25
20312	3305303432	MORAN	15-1H	HESS	ANTELOPE CREEK	MCKENZIE	2.00	20,008	1.00	-3,031	120,131			
20470	3305303495	MCGREGOR	26-1H	HESS	ELLSWORTH	MCKENZIE	2.00	26,139	1.00	-4,285	155,858			
20793	3305303593	BW-WILSON	149-99-3625H-1	HESS	JUNIPER	MCKENZIE	2.00	18,929	0.80	-81	107,204	69,955		13.69
21122	3305303667	HA-CHAPIN-	152-95-3229H-2	HESS	HAWKEYE	MCKENZIE	2.00	26,220	0.75	-27,111	115,295	98,747		23.04
21167	3305303676	BW-EDWIN STEN-	149-100-2833H-1	HESS	ELLSWORTH	MCKENZIE	2.00	26,664	0.74	-311	152,995	133,009		25.00
21269	3302501431	BW-R PETERSON	149-99-1102H-1	HESS	MANDAREE	DUNN	2.00	29,719	0.89	-28	177,120	133,706		20.25
21429	3305303746	BB-EIDE	151-95-3328H-2	HESS	BLUE BUTTES	MCKENZIE	2.00	47,546	0.75	-7,993	243,587	191,700		17.61
21477	3305303765	JOHNSON	1-3H	HESS	CHERRY CREEK	MCKENZIE	2.00	34,792	0.85	-711	193,356	131,500		14.44
21526	3305303778	BW-ERLER	149-99-1522H-1	HESS	CHERRY CREEK	MCKENZIE	2.00	30,046	0.78	-252	151,737	88,382		8.70
21645	3305303810	SC-	1WX8-1H	HESS	BANKS	MCKENZIE	2.00	34,002	0.75	-320	183,194	145,889		18.49
21737	3305303838	BW-KKMP-	149-100- 0706H-1	HESS	ELLSWORTH	MCKENZIE	2.00	21,897	0.80	-171	119,877	98,365		20.25
21738	3305303839	BW-ABM	149-100-1819H-1	HESS	ELLSWORTH	MCKENZIE	2.00	17,937	0.90	-733	99,252	74,604		17.64
22146	3305303916	BW-STOVELAND	149-100-1003H-1	HESS	ELLSWORTH	MCKENZIE	2.00	23,094	1.00	-159	126,098			
22159	3305303922	BW-HEDSTROM	149-100-1201H-1	HESS	ELLSWORTH	MCKENZIE	2.00	22,625	1.00	-346	121,664			
22517	3305304019	BW-SHARON-	150-100-2536H-1	HESS	TIMBER CREEK	MCKENZIE	2.00	30,116	0.75	-643	147,213	104,762		12.25
22801	3305304094	HA-LINK-	152-95- 3526H-2	HESS	HAWKEYE	MCKENZIE	2.00	38,809	0.80	-6,769	198,701	179,512		23.04
22982	3305304147	HA-NELSON A-	152-95-3427H-2	HESS	HAWKEYE	MCKENZIE	2.00	39,778	0.75	-7,152	202,513	171,848		20.25
23009	3305304157	HA-GRIMESTAD-	152-95-3031H-2	HESS	HAWKEYE	MCKENZIE	2.00	30,726	0.90	-6,649	159,000	131,618		20.25
23010	3305304158	HA-GRIMESTAD-	152-95-3031H-3	HESS	HAWKEYE	MCKENZIE	2.00	27,022	0.96	-2,161	142,712	92,416		12.25
23071	3305304176	HA-MOGEN	152-95-0805H-3	HESS	HAWKEYE	MCKENZIE	2.00	71,038	0.78	-19,825	334,645	257,225		15.13
23168	3305304198	BB-SIVERTSON	151-95-2019H-2	HESS	BLUE BUTTES	MCKENZIE	2.00	39,627	0.75	-405	202,654	154,142		15.21
17196	3310501674	BL-DILLAND-	156-96-2536H-1	HESS BAKKEN INVESTMENTS	BEAVER LODGE	WILLIAMS	2.00	51,897	0.70	-30,287	276,605	203,251		20.25
18741	3305303120	DAHL	1-5H	NEWFIELD PRODUCTION COMPANY	SIVERSTON	MCKENZIE	2.00	19,749	0.74	-7,442	109,545	68,592		14.82
18626	3305303101	GLADYS	2-9H	NEWFIELD PRODUCTION COMPANY	WESTBERG	MCKENZIE	0.60	35,908	0.69	-2,018	206,589	95,000	7.30	
17811	3305302973	GARVEY FEDERAL	1-29H	NEWFIELD PRODUCTION COMPANY	SAND CREEK	MCKENZIE	2.00	27,911	0.80	-23	192,103	89,293		10.24
17918	3305302996	CLEAR CREEK FEDERAL	1-26H	NEWFIELD PRODUCTION COMPANY	WESTBERG	MCKENZIE	2.00	17,748	0.74	-83	116,191	69,135		15.21
17925	3305302999	WAHUS	1-12H	NEWFIELD PRODUCTION COMPANY	WESTBERG	MCKENZIE	2.00	19,092	1.00	-1,625	129,209	74,743		
18012	3305303010	SAND CREEK FEDERAL	1-23H	NEWFIELD PRODUCTION COMPANY	KEENE	MCKENZIE	2.00	55,209	0.85	-10,756	368,795	276,331		27.00
18205	3305303037	MANTA RAY	1-12H	NEWFIELD PRODUCTION COMPANY	SANDROCKS	MCKENZIE	2.00	11,612	0.85	-3,211	84,864	58,333		28.09
18267	3305303046	CLEAR CREEK STATE	1-36H	NEWFIELD PRODUCTION COMPANY	WESTBERG	MCKENZIE	0.90	10,452	0.74	-27	66,030	29,000	7.71	
18284	3305303049	PITTSBURGH	1-3H	NEWFIELD PRODUCTION COMPANY	SAND CREEK	MCKENZIE	2.00	22,524	0.75	-10	158,650	108,107		23.04
18323	3305303054	SAND CREEK FEDERAL	1-21H	NEWFIELD PRODUCTION COMPANY	SAND CREEK	MCKENZIE	2.00	24,456	0.82	-2,251	168,933	102,909		18.49
19096	3305303173	HELSINGBORG	1-22H	NEWFIELD PRODUCTION COMPANY	SAND CREEK	MCKENZIE	2.00	28,220	0.77	-637	176,541	109,422		15.21
19110	3305303176	MALM	149-98-14-23-1H	NEWFIELD PRODUCTION COMPANY	PEMBROKE	MCKENZIE	2.00	39,551	0.75	-3,983	246,458	173,996		20.25
19497	3305303253	WILSON	150-99-29-32-1H	NEWFIELD PRODUCTION COMPANY	SOUTH TOBACCO GARDEN	MCKENZIE	2.00	28,196	0.75	-20,914	163,842	134,165		29.70
19795	3305303321	JOHNSON	150-99-34-27-1H	NEWFIELD PRODUCTION COMPANY	SOUTH TOBACCO GARDEN	MCKENZIE	2.00	32,997	0.85	-453	213,954	148,033		20.25
19808	3305303324	MALM	149-98-11-2-1H	NEWFIELD PRODUCTION COMPANY	PEMBROKE	MCKENZIE	2.00	39,881	1.00	-12,946	238,496	166,520		
20017	3305303377	HOFFMANN	150-98-18-19-1H	NEWFIELD PRODUCTION COMPANY	SIVERSTON	MCKENZIE	2.00	36,273	0.73	-1,101	217,638	165,755		21.16
20084	3305303389	GARVEY FEDERAL	153-96-29-2H	NEWFIELD PRODUCTION COMPANY	SAND CREEK	MCKENZIE	2.00	22,581	1.00	-262	135,334	94,579		
20155	3305303408	BARRACUDA	150-100-2-11-1H	NEWFIELD PRODUCTION COMPANY	SANDROCKS	MCKENZIE	2.00	36,180	0.72	-10,062	206,509	170,837		25.00
20170	3305303409	MOBERG FED	149-95-29-32-2H	NEWFIELD PRODUCTION COMPANY	BEAR DEN	MCKENZIE	2.00	71,465	0.82	-61,566	348,084	281,467		22.30
20335	3305303450	HOLM	150-99-13-24-1H	NEWFIELD PRODUCTION COMPANY	SIVERSTON	MCKENZIE	2.00	43,443	1.00	-21,573	250,442	226,053		
20347	3305303456	OBENOUR	150-99-21-16-1H	NEWFIELD PRODUCTION COMPANY	SOUTH TOBACCO GARDEN	MCKENZIE	2.00	35,295	0.69	-242	206,712	183,294		27.04
20595	3305303531	WAHUS FEDERAL	152-97-13-24-1H	NEWFIELD PRODUCTION COMPANY	WESTBERG	MCKENZIE	2.00	34,187	0.87	-403	210,394	129,508		14.44

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20737	3305303579	OLGA	150-99-15-22-1H	NEWFIELD PRODUCTION COMPANY	SOUTH TOBACCO GARDEN	MCKENZIE	2.00	31,875	0.75	-17,990	173,693	157,325		30.25
21192	3305303687	BERNICE	150-99-20-17-1H	NEWFIELD PRODUCTION COMPANY	SOUTH TOBACCO GARDEN	MCKENZIE	2.00	31,685	0.73	-3,116	187,758	174,319		31.36
21941	3305303878	INGA	150-99-11-2-2H	NEWFIELD PRODUCTION COMPANY	TOBACCO GARDEN	MCKENZIE	2.00	26,196	0.69	-4,241	136,284	100,544		15.97
23207	3305304205	ORVIS STATE	150-99-21-16-2H	NEWFIELD PRODUCTION COMPANY	SOUTH TOBACCO GARDEN	MCKENZIE	2.00	31,003	0.69	-6,200	164,957	148,814		24.96
16245	3305302726	COLAVITO	1-27H	OASIS	FOREMAN BUTTE	MCKENZIE	0.80	7,454	0.60	-675	53,416	25,000	11.86	
17986	3305303008	AAGVIK	1-35H	OASIS	BANKS	MCKENZIE	2.00	21,563	0.80	-5,944	150,760	108,341		28.09
17882	3305302984	LUNDEEN	4-26H	OASIS	WILDCAT	MCKENZIE	2.00	25,525	0.94	-7,850	175,975	107,015		20.25
18756	3305303121	PEDERSON	10-3H	OASIS	BANKS	MCKENZIE	2.00	37,461	0.90	-27,607	235,627	189,665		33.64
18916	3305303145	MISSOURI FED	5302 44-35H	OASIS	INDIAN HILL	MCKENZIE	2.00	34,269	0.80	-6,663	230,118	205,802		38.44
18980	3305303158	BERQUIST	33-28H	OASIS	BANKS	MCKENZIE	2.00	48,673	0.82	-2,502	302,949	216,526		20.25
19001	3305303163	STEPANEK	8-5H	OASIS	INDIAN HILL	MCKENZIE	2.00	36,662	0.69	-49,983	190,670	140,657		27.04
19061	3305303169	PAYETTE	10-15H	OASIS	DORE	MCKENZIE	2.00	30,191	0.80	-27,078	172,957	145,008		32.49
19350	3305303223	CEYNAR	29-32H	OASIS	BANKS	MCKENZIE	2.00	36,640	0.81	-11,263	231,327	190,256		30.25
19741	3305303311	A. JOHNSON	12-1H	OASIS	BANKS	MCKENZIE	2.00	33,306	0.82	-1,477	207,471	141,741		18.49
20026	3305303380	NORDENG	24-13H	OASIS	BANKS	MCKENZIE	1.00	29,126	0.78	-604	174,549	84,000	8.44	
20197	3305303413	WADE FED	5300 21-30H	OASIS	BAKER	MCKENZIE	2.00	32,319	0.85	-640	193,081	144,794		20.25
20275	3305303426	KLINE FEDERAL	5300 11-18H	OASIS	BAKER	MCKENZIE	0.75	38,398	0.50	-22,799	196,502	95,000	9.06	
20314	3305303433	LEWIS FEDERAL	5300 31-31H	OASIS	BAKER	MCKENZIE	2.00	32,944	0.69	-498	195,866	164,224		25.00
20397	3305303469	WOLD	34-27H	OASIS	SAND CREEK	MCKENZIE	2.00	18,669	0.75	-333	105,224	61,274		10.89
20459	3305303487	LAWLAR	23-14H	OASIS	NORTH TOBACCO GARDEN	MCKENZIE	2.00	29,906	0.88	-5,798	180,508	128,781		20.25
20460	3305303488	LAWLAR	26-35H	OASIS	NORTH TOBACCO GARDEN	MCKENZIE	2.00	37,641	0.85	-6,058	225,735	163,329		20.22
20554	3305303515	NELSON	11-2H	OASIS	BANKS	MCKENZIE	2.00	34,827	0.80	-935	183,697	103,545		9.00
20555	3305303516	NELSON	14-23H	OASIS	BANKS	MCKENZIE	2.00	32,975	1.00	-847	188,799	170,624		
20689	3305303559	PATSY	5-8HTF	OASIS	SIVERSTON	MCKENZIE	2.00	25,421	0.69	-1,620	119,635	93,710		14.06
20863	3305303608	FOLEY FEDERAL	5301 43-12H	OASIS	BAKER	MCKENZIE	2.00	35,879	1.00	-18,041	200,553	179,294		
20961	3305303634	STEPAN	21-28H	OASIS	DORE	MCKENZIE	2.00	24,912	0.80	-21,392	125,800	103,168		24.26
21029	3305303646	ANDERSMADSON	5201 41-13H	OASIS	CAMP	MCKENZIE	2.00	31,643	0.80	-14,899	174,819	149,648		27.04
21118	3305303666	CLIFFSIDE	12-11H	OASIS	ASSINIBOINE	MCKENZIE	2.00	18,259	1.00	-8,542	99,695	83,664		
21640	3305303809	CATCH FED	5201 11-12H	OASIS	CAMP	MCKENZIE	2.00	37,633	0.84	-1,831	222,431	159,990		18.49
21842	3305303860	KNELS	20-29H	OASIS	DORE	MCKENZIE	2.00	21,003	0.69	-17,015	103,181	88,000		25.00
22202	3305303933	JOHNSRUD	19-18H	OASIS	SIVERSTON	MCKENZIE	2.00	31,626	0.85	-26	181,333	145,452		21.16
22343	3305303960	CLIFFSIDE	25-26H	OASIS	ASSINIBOINE	MCKENZIE	2.00	23,111	0.69	-21,282	95,917	82,718		20.25
22892	3305304122	DWYER	27-34H	OASIS	RAWSON	MCKENZIE	2.00	23,190	1.00	-11,070	113,545	93,287		
23376	3305304244	AMELIA FED	5201 41-11B	OASIS	CAMP	MCKENZIE	2.00	37,769	1.00	-22,750	178,141	143,433		
17703	3305302953	WOLLAN	27A-2-2H	PETRO HUNT	CLEAR CREEK	MCKENZIE	2.00	24,070	1.00	-4,400		164,091		
18356	3305303060	USA	153-96-24D-13-1H	PETRO HUNT	KEENE	MCKENZIE	2.00	40,656	0.70	-34,422	205,352	150,562		20.70
18534	3310501772	MORTENSON	5-32 1-H	STATOIL OIL AND GAS	PAINTED WOODS	WILLIAMS	2.00	23,959	0.71	-9,008	140,206	123,962		30.80
21421	3305303744	FRITZ	150-101-32-29-1H	Triangle	PRONGHORN	MCKENZIE	2.00	37,179	0.69	-28,006	160,823	120,708		16.00
21452	3305303754	DWYER	150-101-21-16-1H	Triangle	PRONGHORN	MCKENZIE	2.00	22,808	0.65	-7,172	116,431	104,587		24.01
22097	3305303909	LARSON	149-100-9-4-3H	Triangle	ELLSWORTH	MCKENZIE	2.00	21,285	1.00	-1,674	117,204	106,877		
18128	3305303025	CROSS	2-13H	WPX Energy	MANDAREE	MCKENZIE	2.00	31,180	1.00	-13,415	233,553	133,132		
18948	3305303152	KYW	27-34H	WPX Energy	SPOTTED HORN	MCKENZIE	2.00	50,327	0.80	-50,690	273,107	180,812		21.16
19973	3305303367	WOLF	27-34H	WPX Energy	SQUAW CREEK	MCKENZIE	2.00	31,431	0.85	-13,894	189,628	127,547		20.05
20033	3305303381	RUBIA	16-24H	WPX Energy	MANDAREE	MCKENZIE	2.00	34,422	0.76	-17,304	192,655	137,596		20.25
20238	3305303421	SPOTTED HORN	26-35H	WPX Energy	SQUAW CREEK	MCKENZIE	2.00	22,504	0.90	-2,754	136,615	91,764		17.64

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20320	3305303437	MANDAREE WARRIOR	14-11H	WPX Energy	SQUAW CREEK	MCKENZIE	2.00	46,409	1.00	-34,458	241,903	192,946		
20359	3305303459	BEAR DEN	24-13H2	WPX Energy	SPOTTED HORN	MCKENZIE	2.00	49,429	1.00	-32,187	282,919	170,470		
20556	3305303517	GERALD HALE	33-28H	WPX Energy	SPOTTED HORN	MCKENZIE	2.00	39,578	0.88	-15,332	231,788	184,538		25.50
20603	3305303536	PLENTY SWEET GRASS	18-19HC	WPX Energy	SQUAW CREEK	MCKENZIE	2.00	27,268	0.87	-8,074	159,248	98,273		15.21
20711	3305303565	LUCY LONE FIGHT	16-22H	WPX Energy	SQUAW CREEK	MCKENZIE	2.00	14,086	1.00	-540	90,772	68,482		
20995	3305303641	BLUE BUTTES	3-21H	WPX Energy	SQUAW CREEK	MCKENZIE	0.80	28,316	0.68	-12,848	142,731	54,000	5.37	
21445	3305303753	BENSON	16-3H	WPX Energy	SQUAW CREEK	MCKENZIE	2.00	34,288	0.80	-1,624	201,298	149,244		19.36
22629	3305304055	SWEET GRASS WOMAN	22-15HB	WPX Energy	SPOTTED HORN	MCKENZIE	2.00	52,384	0.87	-34,513	268,317	185,502		17.64
22897	3305304123	KATE SOLDIER	23-14HZ	WPX Energy	SPOTTED HORN	MCKENZIE	2.00	46,127	0.93	-1,904	253,265	196,442		18.49
17113	3305302861	CHARLSON	14X-35H	XTO Energy	CHARLSON	MCKENZIE	2.00	98,211	0.83	-165,691	609,259	335,186		26.01
18152	3305303030	ALKALI CREEK	41X-15	XTO Energy	MONDAK	MCKENZIE	2.00	8,564	0.75	-1,858	58,770	36,681		20.25
18527	3305303089	MONDAK FEDERAL	14X-11	XTO Energy	MONDAK	MCKENZIE	2.00	26,379	0.85	-26,872	166,324	118,211		29.21
18645	3305303104	ROEDESKE FED	12X-21	XTO Energy	MONDAK	MCKENZIE	2.00	8,608	0.80	-7,849	52,313	43,797		36.00
18678	3305303109	CHARLSON FED	34X-12B	XTO Energy	CHARLSON	MCKENZIE	2.00	25,471	1.00	-10,231	142,089	98,109		
18703	3305303116	GILBERTSON	11-26H	XTO Energy	CHARLSON	MCKENZIE	2.00	31,266	1.00	-8,960	221,563	144,245		
18766	3305303122	FETTIG	24-22H	XTO Energy	SQUAW CREEK	MCKENZIE	2.00	9,224	1.00	-940	63,922			
20394	3305303468	HAUGEN	13X-34	XTO Energy	BOXCAR BUTTE	MCKENZIE	2.00	12,662	0.78	-12,809	58,029	14,574		12.96
20719	3305303572	BERGEM	44-28NWH	XTO Energy	TOBACCO GARDEN	MCKENZIE	2.00	16,749	1.00	-12,672	89,898	71,072		
20740	3305303582	SWENSON	41-33SEH	XTO Energy	CHARLSON	MCKENZIE	2.00	47,457	0.65	-48,378	216,821	141,448		16.00
21200	3305303688	ERICKSON	41-25SWH	XTO Energy	GLASS BLUFF	MCKENZIE	2.00	18,946	0.83	-19,643	86,803	46,669		12.25
21316	3305303718	IVERSON	34-19NWH	XTO Energy	GLASS BLUFF	MCKENZIE	2.00	29,872	0.78	-33,097	133,802	98,341		19.36
32175	3305307355	TOBACCO GAR	31-29NEH	XTO Energy	TOBACCO GARDEN	MCKENZIE	2.00	33,394	1.00	-25,703	149,446	131,251		
21683	3305303822	LUND	44-8SH	XTO Energy	SIVERSTON	MCKENZIE	2.00	17,398	1.00	-4,933	92,282	80,319		
32284	3305307406	TOBACCO GAR	41-18SH	XTO Energy	TOBACCO GARDEN	MCKENZIE	2.00	34,879	1.00	-16,482	168,122	139,774		
22682	3305304115	MADSON	11-33SWH	XTO Energy	ALKALI CREEK	MOUNTRAIL	0.42	34,094	0.88	-8,273	161,443	84,004	7.27	
22869	3305304116	FLATLAND	11X-2A	XTO Energy	SAND CREEK	MCKENZIE	2.00	32,757	0.65	-36,919	119,636	100,659		17.64
22870	3305304117	FLATLAND	11X-2B	XTO Energy	SAND CREEK	MCKENZIE	2.00	31,386	1.00	-14,096	141,107	105,171		