ASSESSMENT OF BAKKEN PETROLEUM SYSTEM PRODUCED GAS COMPOSITIONS

Final Report

(Project Period: October 15, 2019 – June 19, 2020)

Prepared for:

Justin Kringstad

North Dakota Pipeline Authority
State Capitol, 14th Floor
600 East Boulevard Avenue, Department 405
Bismarck, ND 58505-0840

Prepared by:

Bethany A. Kurz
Xue Yu
Alexander V. Chakhmakhchev
Lu Jin
Bao Jia
Bradley G. Stevens
James A. Sorensen
Tao Jiang
Chunxiao Li
Xincheng Wan
Shaojie Zhang
James L. Vrtis

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018
Phone (701) 777-5050; Fax (701) 777-5181
bkurz@undeerc.org

2020-EERC-09-04

September 2020

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EXECUTIVE SUMMARY

This report presents the results of a study conducted by the Energy & Environmental Research Center (EERC) for the North Dakota Pipeline Authority (NDPA) to assess how the chemical composition of natural gas liquids (NGLs) produced from the Bakken and Three Forks (TF) Formations varies spatially across the play and temporally through the life of a typical well. In November of 2019, natural gas production in North Dakota reached an all-time high of over 3.1 billion cubic feet per day and is expected to increase with ongoing development of the Bakken petroleum system (BPS). Better understanding of the NGL content of produced gas from the BPS and how NGL content varies spatially and temporally across the play is essential to forecasting future NGL production in the BPS. This information is fundamental for planning and optimization of gas pipelines and gas-processing facilities, as well as for evaluation of future petrochemical development opportunities in North Dakota.

The work performed through this effort comprised several key components: literature review, collection and analysis of gas composition data, geographic information system (GIS)-based mapping, and modeling and simulation. The key objectives were to:

1) Review and summarize existing literature on predicted or observed changes in natural gas chemistry over time in shale plays and/or tight reservoirs.
2) Collect and compile existing gas composition data from the EERC, the North Dakota Industrial Commission (NDIC), EERC partners, and other public sources.
3) Evaluate spatial trends in NGL content across the BPS, and assess the key geochemical and geologic factors that affect gas composition using data analytics and machine learning.
4) Develop a reservoir model to match historical measured data and to forecast gas composition from a typical Bakken and TF well after 1, 10, 20, and 30 years of production.
5) Perform simulations using the reservoir model to evaluate how produced gas enhanced oil recovery (EOR) efforts in the BPS could impact gas composition over time.

The data used in this effort included industry-supplied gas composition data from 7316 data points across 12 counties in the North Dakota and Montana portion of the BPS. The data set contained measurements of C1–C5 hydrocarbons (HCs), other heavier liquids, and non-HC gases. Geologic and geochemical data for the BPS were derived from the EERC's internal database comprising publicly available data and in-house analyses. Pressure, volume, temperature (PVT) data and associated production data for two wells were provided by EERC partners and used to perform compositional forecasting.

Based on the data used in this effort, the average composition of the gas produced from the BPS (expressed in mole percent [mol%]) is as follows: 58 mol% methane (C1), followed by 20 mol% ethane (C2), 11 mol% propane (C3), 4.9 mol% butane (C4), and 1.6 mol% pentane (C5), while concentrations of other components are very small except for N_2 (2.7 mol%). The average

initial wetness of gas produced from the BPS (defined as [{C2+C3+C4+C5}/{C1+C2+C3+C4+C5}] × 100) was estimated at 39.9%. Distinct spatial patterns in gas compositions were observed across the Bakken region; in the core area, the wetness is typically less than 40%, and some areas outside of the core have wetness values above 45%. A temporal analysis of gas content showed that, in most locations, methane content increases within the first 5 years of production then remains stable out to 7 years of production. Evaluation of changes over longer production periods were limited by data availability. Ethane content was shown to decrease slightly during the first 3 to 5 years of production, after which it levels off or begins increasing slightly in some areas. Propane content, as with butane and pentane, is variable during the first 6 months of production, after which all three components generally decline until about 18 months to 3 years of production. Starting from 18 months to 3 years of production, the propane, butane, and pentane concentrations generally remain stable throughout 7 years of production.

An evaluation of correlations between gas content and the geochemical and geologic characteristics of the BPS show that initial gas composition and gas composition throughout production correlate significantly with the thermal maturity of the Bakken shales and other associated geologic parameters, such as temperature and depth. The more thermally mature areas of the BPS tend to have drier gas, and conversely, the less thermally mature areas have wetter gas.

A series of reservoir simulation activities were performed to investigate the long-term gas composition change based on models of two wells: one located in McKenzie County and one in Williams County. An evaluation of different production scenarios showed that the long-term changes in gas composition are strongly influenced by production rates and reservoir pressure. The simulation results show that methane content generally increases within the first 5 years of production and then decreases with long-term production. Concentrations of ethane and propane remain unchanged or decrease during the first few years of production, then increase gradually over time. The long-term changes in gas composition in the simulation scenarios with normal or accelerated production from the BPS were evaluated and suggest that methane content from individual wells could decrease significantly after approximately 10 years of production, at which point NGL content could increase significantly. A comparison of the simulation data with the long-term gas composition trend data from 32 wells suggests that while the timing of the predicted changes in gas composition is consistent with measured data, the magnitude of the long-term predicted changes may be high.

Without performing more extensive basinwide modeling and forecasting of future BPS development trends, it is difficult to determine what the long-term supplies of NGLs might look like. While it is encouraging that the long-term simulation results suggest trends of significant increases in NGL content within individual wells over time, the magnitude of that NGL contribution and the impact of the gas contribution from new wells coming online were not evaluated as part of this effort.

The reservoir model was also used to simulate changes in gas composition that may occur during CO_2-based or produced gas EOR efforts. The simulation results suggest that during produced gas EOR, the composition of the produced gas follows the composition of the injected gas. During CO_2-based EOR, the concentrations of the various produced gas components gradually decrease over time and follow similar trends.

ASSESSMENT OF BAKKEN PETROLEUM SYSTEM PRODUCED GAS COMPOSITIONS

1.0 INTRODUCTION

Oil and gas production from the Bakken petroleum system (BPS) in North Dakota has increased rapidly since 2007 (Figure 1-1). Natural gas production reached an all-time high of 3.1 billion cubic feet per day in November of 2019, and with increasing gas-to-oil ratios (GORs), gas production is expected to increase with ongoing development of the BPS. Despite the rapidly increasing volumes of natural gas being produced, little is known about compositional changes in produced gas over time and as a function of location and associated geologic/geochemical properties of the BPS.

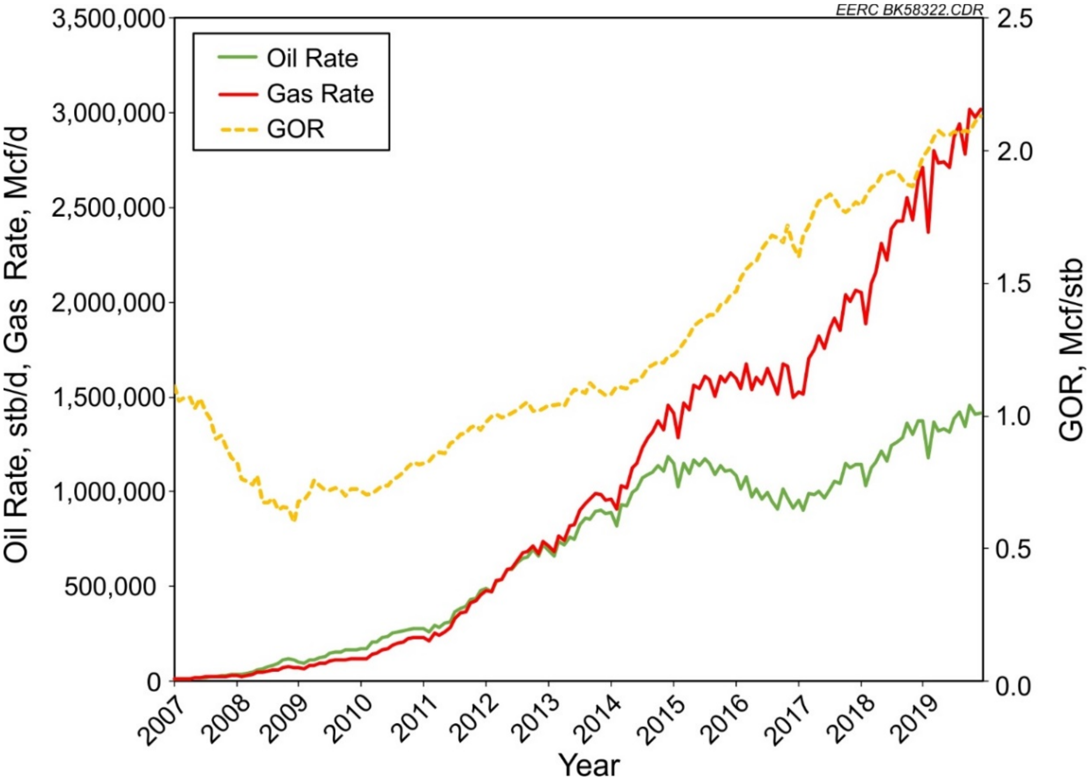

Figure 1-1. BPS oil production since 2007.

Current approaches to modeling of gas composition are hindered by a lack of knowledge on the temporal changes in natural gas liquid (NGL) composition over the producing life of BPS wells. Presently, the North Dakota Pipeline Authority (NDPA) and industry forecast models assume a static NGL composition throughout the forecast period, while even small changes in the NGL makeup over the life of a well could result in significant forecast fluctuations (North Dakota Pipeline Authority, 2019, personal communication). Better understanding of the NGL content of produced gas from the BPS and how NGL content varies spatially and temporally across the play is essential to forecasting future NGL production in the BPS. This knowledge is fundamental for planning and optimization of gas transportation and processing facilities and infrastructure, as well as for evaluation of future petrochemical development opportunities in North Dakota.

To better understand and predict gas compositions in the BPS, the Energy & Environmental Research Center (EERC) performed a study to assess how the chemical composition of gas produced from the Bakken and Three Forks (TF) Formations varies spatially and temporally and to predict long-term changes in gas composition produced from a typical Bakken and TF well. The key objectives of the study were to:

1. Review and summarize existing literature on predicted or observed changes in natural gas chemistry over time in shale plays and/or tight reservoirs.

2. Collect and compile existing gas composition data from the EERC, the North Dakota Industrial Commission (NDIC), EERC partners, and other public sources.

3. Evaluate spatial trends in NGL content across the BPS, and assess the key geochemical and geologic factors that affect gas composition using data analytics and machine learning.

4. Develop a reservoir model to match historical measured data and to forecast gas composition from a typical Bakken and TF well after 1, 10, 20, and 30 years of production.

5. Perform simulations using the reservoir model to evaluate how produced gas enhanced oil recovery (EOR) efforts in the BPS could impact gas composition over time.

The following report summarizes the results of the EERC's effort and provides valuable insight into the factors that affect gas composition across the BPS. The success of the study was due, in large part, to the EERC partners who were willing to provide gas composition data for use in this effort. The EERC is extremely grateful to those partners and hopes that the results of this study will help inform their operations in addition to providing the critical data and information requested by NDPA.

2.0 LITERATURE REVIEW

The chemical composition of oil and gas produced from subsurface reservoirs varies throughout the producing life of a well. In conventional reservoirs, the primary reason for compositional changes can be attributed to shifting phase equilibria caused by reservoir pressure decline (Freeman and others, 2013). The compositional trends in associated gas in various basins and supporting results from laboratory experiments have been discussed in older literature (Chakhmakhchev, 1983). It was reported that during the course of oil production from conventional reservoirs, associated gas composition changes over time, especially during the later stages of the reservoir life. Initially, methane dominates the composition of the produced gas. With the progression of production and associated reservoir pressure drop, concentrations of ethane, propane, and other heavier gases begin to increase and the proportion of methane declines. At the end of the reservoir's primary production life, when the pressure drop is significant, associated gas wetness reaches maximum volumes. Laboratory experiments were conducted to evaluate the change in gas composition over time with stepwise depressurization of bottomhole oil samples. The results confirmed the field observations and demonstrated an increase in wet gas components of the separated gas with declining pressure. In unconventional plays, reservoir pressure can also affect hydrocarbon (HC) composition; however, other physical mechanisms come into play that contribute, or even dominate, HC composition.

The reservoir rocks targeted in the BPS include the Middle Bakken (MB) Member, a nonshale lithofacies of the Bakken Formation, and the TF Formation. Both the MB and TF comprise mudstone, siltstone, and fine-grained sandstone, many of which are rich in carbonate minerals. The oil and associated natural gas found in these rocks are generated in the organic-rich Upper and Lower Bakken shales by a combination of primary thermogenic degradation of organic matter and secondary thermogenic decomposition of petroleum (Sonnenberg and Pramudito, 2009; LeFever and others, 2011; Lillis, 2013). After generation and expulsion, the gas is stored in the MB lithofacies in three different ways (listed in order of significance): 1) by solution, which refers to gas (also referred to as associated gas) that exists in solution in oil and water; 2) by nonadsorbed gas, which refers to free gas (also referred to as nonassociated gas) that occurs within pore spaces or fractures within the reservoir rock; and 3) by adsorption, which refers to adsorbed gas that is physically attached (adsorption) or chemically attached (chemisorption) to the surface of clay minerals (Speight, 2017).

The initial composition of natural gas from tight formations is influenced by several geologic factors and processes: 1) the composition of the organic matter in the formation from which the gas is sourced; 2) the thermal maturity at which the gas is generated from the source rock; 3) the gas generation process, specifically whether gas is generated through primary cracking of kerogen, from secondary cracking of oil to gas, or from secondary cracking of wet gas to dry gas; 4) fractionation during gas migration from source to reservoir; 5) leakage from the reservoir; and 6) bacterial alteration by oxidation of gases (Speight, 2017). The dominant factors controlling initial gas composition in the BPS are likely the type of the organic matter in the source rocks (the Bakken shales) and their thermal maturity.

Schettler and others (1989) showed that the composition of the gas produced from tight reservoirs shifts during the production history of the well. This gas fractionation in the producing well is related to adsorption or absorption phenomena within the reservoir. The produced gas comes from several sources within the reservoir, and the gas from each source has different compositions and is characterized by its own decline curve. Even if the composition of gas from each source is assumed to remain constant, the composition of the natural gas at the wellbore will change with time if the relative flow rate of each source changes with time (Schettler and others, 1989).

Processes that can contribute to changes in gas composition from the well production stream over the course of production include 1) adsorption of the gas components on the reservoir rock, 2) adsorption of the gas components on any nongaseous organic material in the reservoir,

3) dissolution of the gas components in any organic or inorganic liquids (oil, water) in the reservoir, and 4) absorption and diffusion of the gas components within the pore system of the reservoir rock (Speight, 2017). The presence of clay minerals in the reservoir rock intensifies adsorption processes by providing surface (sites) for the process to occur. The diffusion mechanism that occurs through small pores (100–1000 Å), such as those present in tight reservoirs, is referred to as Knudsen diffusion. This type of diffusion allows molecules of methane with less mass to diffuse through pores preferentially when compared to molecules with a larger mass, such as ethane. Differences in methane versus ethane behavior were observed in laboratory experiments conducted by Schettler and others (1989), who showed that ethane sorption was greater than methane in tight rocks because of its higher polarizability. Because the aforementioned mechanisms are common in tight reservoirs like the Bakken, they can explain various fractionation trends observed in different wells, such as preferential sorption of ethane versus methane and propane.

Freeman and others (2013) recognized that multiple distinct physical phenomena influence the behavior of fluids in tight rocks, resulting in measurable compositional changes in the produced gas over time. They linked compositional changes to differential desorption, phase behavior, and preferential diffusion in their numerical model. They compared the results of the modeling against field data, both of which exhibited trends of increasing methane concentrations and a decrease of ethane and propane over time.

Walker and others (2017) analyzed Devonian-age shale production in Alberta, conducted modeling experiments, and concluded that preferential adsorption impacted gas composition, even at early stages of production life. They observed an increase in the C1/C2 ratio over 3 years of production in several wells, which confirmed the conclusions from modeling efforts.

The studies conducted by Freeman and others (2013) and Walker and others (2017) both modeled compositional changes in tight producing formations and validated their modeling results against field observations. In both cases, gas composition shifted toward increasing methane (C1) concentrations during production.

In summary, the literature on gas composition changes in unconventional formations is very limited; thus it is difficult to make conclusive statements on whether or not the trends described above are universal. However, the results of this study, which are likely the most data-rich and comprehensive analysis of gas composition changes in an unconventional oil play conducted to date, support the trends described in the literature and suggest that perhaps similar results could be observed in other unconventional formations.

3.0 DATA MINING OF GAS COMPOSITION DATA

3.1 Materials and Methods

3.1.1 Data Acquisition

A key objective of this effort was to collect and compile as much gas composition data as possible, as well as supporting data, to allow for a thorough analysis of gas composition trends both spatially and temporally. Three data types were collected: 1) measured gas composition by well, 2) geologic and geochemical parameters of the BPS formations, and 3) oil and gas production data. The gas composition data were provided by EERC partners and contained measured methane and NGL concentrations from 7361 BPS wells. To preserve the confidentiality of the data, well names were not provided to the EERC, and the well locations were only given within approximately ±100–200 feet. Out of respect for the willingness of our partners to share the data, the EERC did not attempt to determine well names or more precise locations. Given that the well names or total vertical depths were not provided or determined, it was impossible to differentiate between MB and TF wells. Instead, the data from both reservoirs were combined. Because the MB and TF are part of the same petroleum system, typically separated by less than 50 feet of Lower Bakken Shale (LBS), combining the data from both reservoirs was considered to be appropriate. While this effort was focused on evaluating gas composition data from BPS wells located in North Dakota, a data set was available that included wells from Montana; thus those well locations were also included.

The measured gas components are listed in Table 3-1. They are divided into four groups based on their chemical properties and processing requirements, i.e., 1) dry gas (C1), 2) NGLs (C2–C5), 3) other heavier liquids (C6–C10), and 4) non-HC gases (H_2S, N_2, CO_2, H_2, and H_2O). The two forms of butane (i.e., isobutane and n-butane) are grouped as a single-variable butane, and the two forms of pentane (i.e., isopentane and n-pentane) are also grouped as a single-variable pentane.

Table 3-1. Measured Gas Components in the Bakken

Category	Gas Name	Abbreviation	Chemical Formula
Dry Gas	Methane	C1	CH_4
NGLs	Ethane	C2	C_2H_6
	Propane	C3	C_3H_8
	Butane	C4	C_4H_{10}
	Pentane	C5	C_5H_{12}
Other Heavier Liquids	Hexane	C6	C_6H_{14}
	Heptane	C7	C_7H_{16}
	Octane	C8	C_8H_{18}
	Nonane	C9	C_9H_{20}
	Decane	C10	$C_{10}H_{22}$
Non-HC Gases	Hydrogen sulfide	H_2S	H_2S
	Nitrogen gas	N_2	N_2
	Carbon dioxide	CO_2	CO_2
	Hydrogen gas	H_2	H_2
	Water	H_2O	H_2O

The geologic and geochemical data were collected from the EERC's internal databases, developed over the course of several previous Bakken-focused research projects, which include source rock characteristics such as hydrogen index (HI), T_{max}, and total organic carbon (TOC), as well as reservoir parameters including formation depth and temperature. The HI represents the potential of the source rocks to generate HCs and is expressed as micrograms of HC divided by grams of TOC. The parameters used to calculate HI are determined using an analytical technique referred to as rock-eval pyrolysis (Peters and Cassa, 1994). The geologic data associated with the source characteristics were collected for both Upper Bakken Shale (UBS) and LBS, and the reservoir properties were collected for MB Shale and the TF Formation. A summary of the geologic variables used in the analysis, including units and basic statistical characteristics, such as mean and 25%–75% quantiles, is presented in Table 3-2.

Monthly oil and gas production data were also included in the analysis. Those data were collected from the NDIC database.

Table 3-2. Geologic Variable Information

Variable	Unit	Mean	25%–75% Quantile
UBS HI	mg HC/g TOC	120	156–264
LBS HI	mg HC/g TOC	210	140–252
UBS TOC	weight %	12.5	12.1–12.7
LBS TOC	weight %	12.1	11.2–13.0
UBS T_{max}	°C	451	447–455
LBS T_{max}	°C	440	436–444
MB Temperature	°C	110	107–115
MB Depth	ft	10,430	10,312–10,812
TF Depth	ft	10,503	10,384–10,884

3.1.2 Temporal Trend Analysis

In order to understand how the NGL content changes over time, for each compositional data point, the production time was calculated as:

$$T_P = T_S - T_F \qquad \text{[Eq. 3-1]}$$

Where:

T_p = the production time (in days, month, or year) of the data point.
T_s = the date when gas sample was tested.
T_F = the date when the sampled well started oil production.

To better understand relative trends of methane and NGLs in BPS production streams, two new variables were introduced into the analysis, namely, wetness and dryness. Their definitions are below:

$$Wetness = \frac{C2+C3+C4+C5}{C1+C2+C3+C4+C5} \times 100 \qquad \text{[Eq. 3-2]}$$

$$Dryness = \frac{C1}{C1+C2+C3+C4+C5} \times 100 \qquad \text{[Eq. 3-3]}$$

Where:

Wetness = ratio of NGL gases to the sum of C1 to C5.
Dryness = ratio of dry gas (C1) to the sum of C1 to C5 (NGLs).
C1–C5 = mole percent (mol%) to the total gas content.

Gas composition data were collected from 2004 to 2020 from 7361 Bakken wells, with a higher number of samples after the year 2012. The data were divided into two sets based on completion year. The first data set included wells representing "older completion practices" with the first production date before 2012. The second data set comprised wells with the first production date in or after 2012 and represented "newer completion practices." The wells with newer completion practices represent wells that were completed with larger stimulation practices (i.e., larger volumes of water and proppant), had shorter stage intervals, and had more consistent lateral lengths and stage numbers. While some of the wells drilled in 2010 and 2011 had longer lateral lengths similar to those of current-day completions, there was still a lot of inconsistency in well design and completion types (West and others, 2014). Because the new completion practice data set has more samples and they represent state-of-the-art technology, most of the analysis was focused on this second data set.

The initial gas composition was determined using data collected within the first 90 days of production. It was challenging to reliably evaluate the time-series trends, because within the available data set, the number of single wells with long-duration temporal data were limited. Moreover, the sampling frequencies were rather random and inconsistent from well to well. The mean sampling frequency was 68 samples per well with a standard deviation of 44, with ranges from 1 to 156. Therefore, the temporal gas composition trend was calculated by using aggregated values from multiple wells in nearby locations in order to fill missing data gaps for various production periods.

To select wells located in close proximity for use in aggregating temporal gas composition, circles of different radii were drawn around select well locations across the BPS based on regional differences in initial gas compositions. A total of six wells were selected across the BPS to serve as "center point" wells, around which circles of different radii were drawn (Figure 3-1). Wells within each radius were assumed to have similar properties; hence the gas composition data were aggregated by production time (i.e., production by month or by year). It was unclear how large the circled area should be, such that ample data points would be gathered for temporal analyses. Therefore, different radii were used (i.e., 1, 3, 5, and 10 miles) to evaluate the temporal trends in data sets of varying sizes. The average gas composition of the wells located in the different radii circles were determined and used to assess the temporal trends at each location.

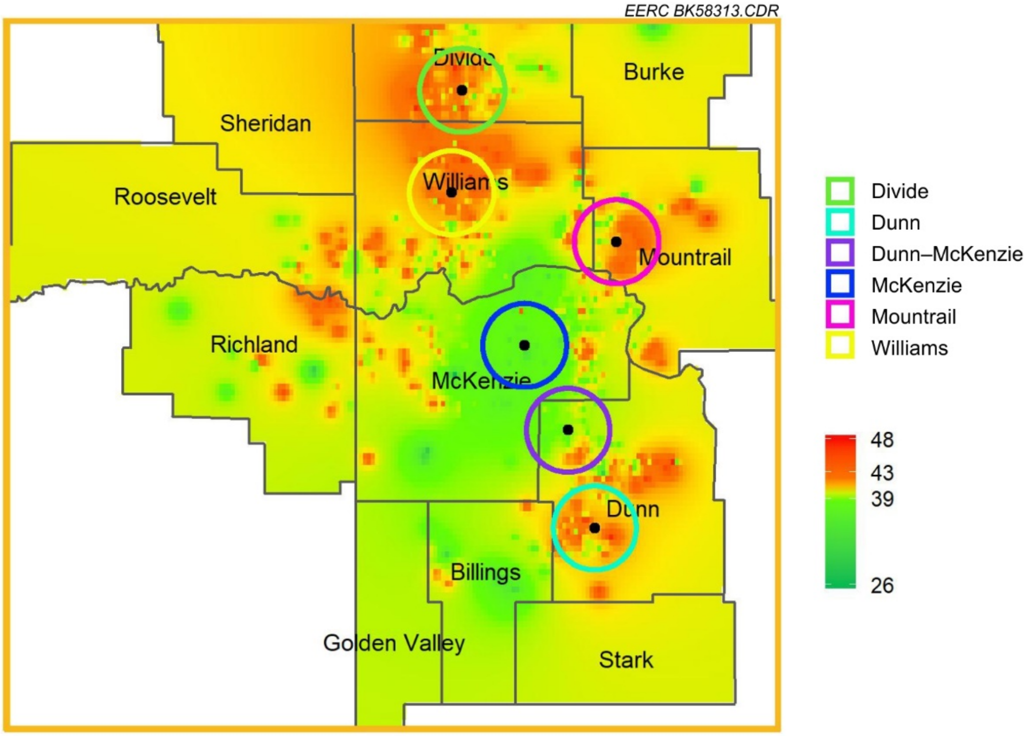

Figure 3-1. Location of the six focus wells selected for temporal analysis superimposed on the initial gas wetness map. The analysis also included data from wells located in a circle radius of up to 10 miles surrounding each well (as indicated by the circles on the map).

3.1.3 Spatial Pattern Analysis

To evaluate the spatial patterns in gas composition, the measured well-level data were interpolated over the entire BPS region using an inverse distance weighted (IDW) approach. The spatial patterns were calculated for each gas component and for gas wetness. Spatial patterns in gas composition at specific well production times (i.e., after 1 year of production) were also determined and mapped. To calculate temporal changes in gas composition, the initial gas composition from a given well was subtracted from the composition after set periods of production.

3.1.4 Correlation Analysis

To explain spatial and temporal distributions of the NGLs in Bakken production, correlation analysis of the compositional data and select geologic/geochemical variables was conducted. The relationship between different variables and the magnitude of the correlations were visually represented using correlation matrix plots.

3.2 Data-Mining Results and Discussion

3.2.1 Overall Gas Composition

The overall gas composition statistics for all samples are presented in Figure 3-2, with values listed in mol%. Methane (C1) is the dominant gas component. The overall mean of the C1 content is 58.3 mol%, with a standard deviation (SD) of 5.6% and 95% confidence interval (CI) values of 58.32%–58.35%. The overall mean wetness is 38.8%, with a SD of 5.5% and 95% CI values of 38.83%–38.86%. The average mean composition of C6 is about 1 mol%, while compositions of C7–C10 are close to zero. There is a relatively high concentration of N_2, with an overall average value of 2.7 mol%. The CO_2 content is very small at 1 mol%.

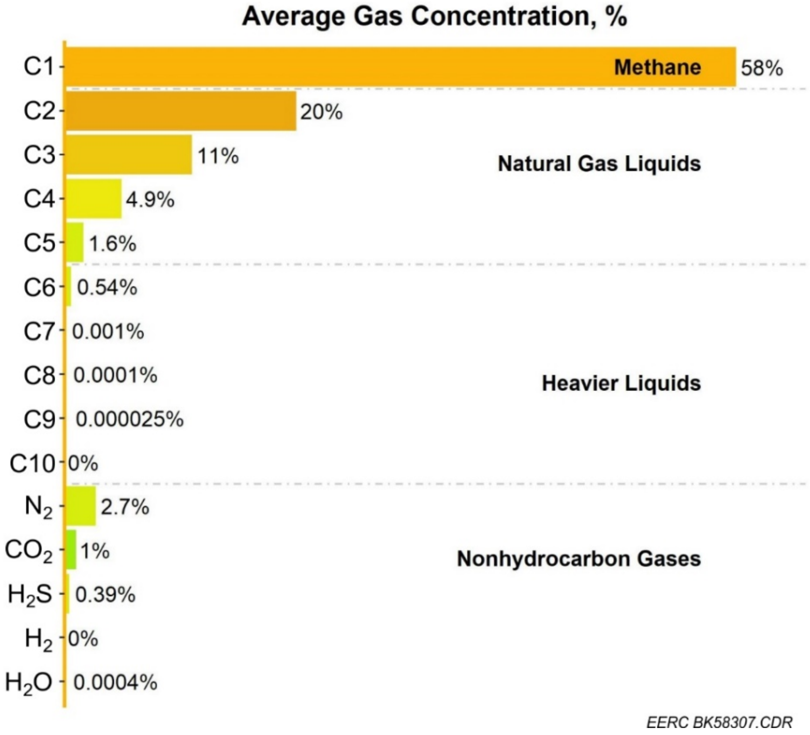

Figure 3-2. Average gas compositions (in mol%) based on all samples.

3.2.2 Initial Gas Composition

To estimate the initial gas composition of BPS wells, only those wells with gas samples collected within the first 90 days of production were included, which resulted in a total of 2936 wells. The initial gas wetness in Bakken wells was estimated to have a mean of 39.9%, SD of 3.7%, and 95% CI was 39.9%–40.0%. The statistics of the initial compositions for different gases are presented in Figure 3-3. The mean initial methane in the BPS is 57.9 mol%, with a SD of 3.5% and 95% CI values of 57.8%–58.0%. The spatial patterns show that in the core Bakken area, wetness is typically less than 40% and some areas outside of the core have wetness above 45%.

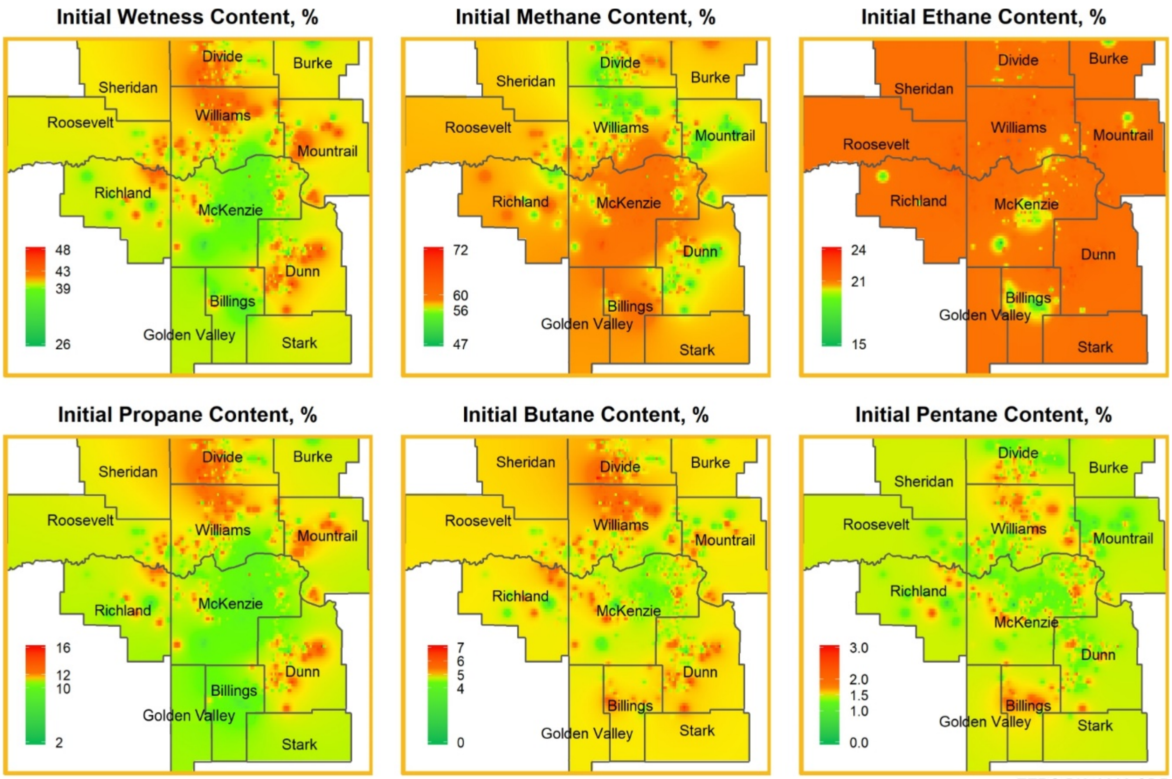

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Figure 3-3. Initial content of gas wetness (%) and various gas components (mol%) in the BPS. The legends have different scales in six plots for better visualization.

As expected, spatial distributions of wetness and methane content followed opposite patterns, where areas with high values of wetness generally correspond to lower content of methane. The spatial patterns of initial wetness and propane content are rather similar. The correlation matrix plot of the initial gas compositions showed that both wetness and dryness (methane) were generally highly correlated with all gases (Figure 3-4). Wetness is most correlated with propane (C3, r = 0.95), which is also reflected by their very similar spatial patterns. Generally, methane (C2) does not correlate with other gas components. Propane (C3), butane (C4), and pentane (C5) were found to correlate with other gases except C2.

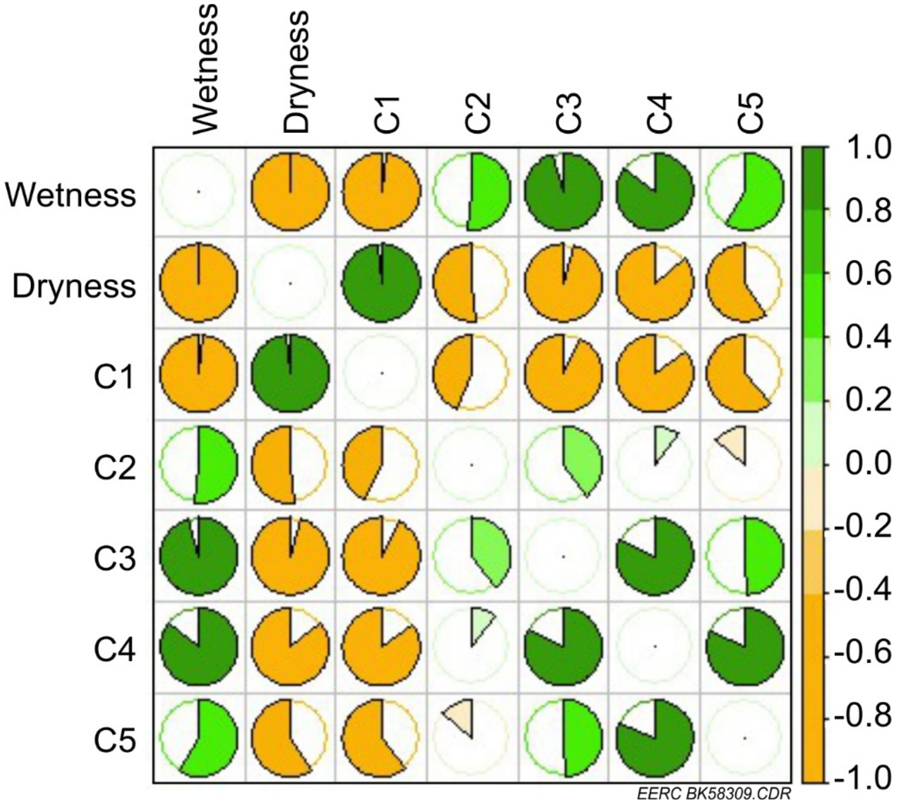

Figure 3-4. Correlation matrix of the initial gas compositions in the BPS. Both the size and the color of the pie represent the degree of correlation between variables. Smaller “wedges” (and lighter colors) indicate weak correlations, and larger wedges (and darker colors) indicate stronger correlations. Orange pie charts represent negative correlations, and green pie charts represent positive correlations.

3.2.3 Spatiotemporal Patterns

The initial spatial patterns in various gas components were presented and discussed above. The spatial patterns in NGL content over the producing life of a well were analyzed by mapping the gas composition during different production periods following initial production (IP). The spatial gas composition patterns based on well production year are shown in Figure 3-5. For example, the spatial patterns in gas composition for any wells with gas samples collected within the first 90 days of production were analyzed together (and designated as “Production Year 0”). The locations of samples collected from 91 to 365 days after IP were designated as “Production Year 1.” Sampling was denser in Divide, Williams, McKenzie, and the northwestern part of Dunn Counties. More wells have samples collected within the first 5 years of production, and less measurements were made after the eighth year of production. This is because the data set only includes wells with IPs occurring in the year 2012 or later; thus fewer wells have been producing for 8 years. The locations of the sampled wells cover a wide area of the Bakken play and include a significant number of samples collected over different production periods, thus allowing for reasonable interpolation of gas compositions across the BPS.

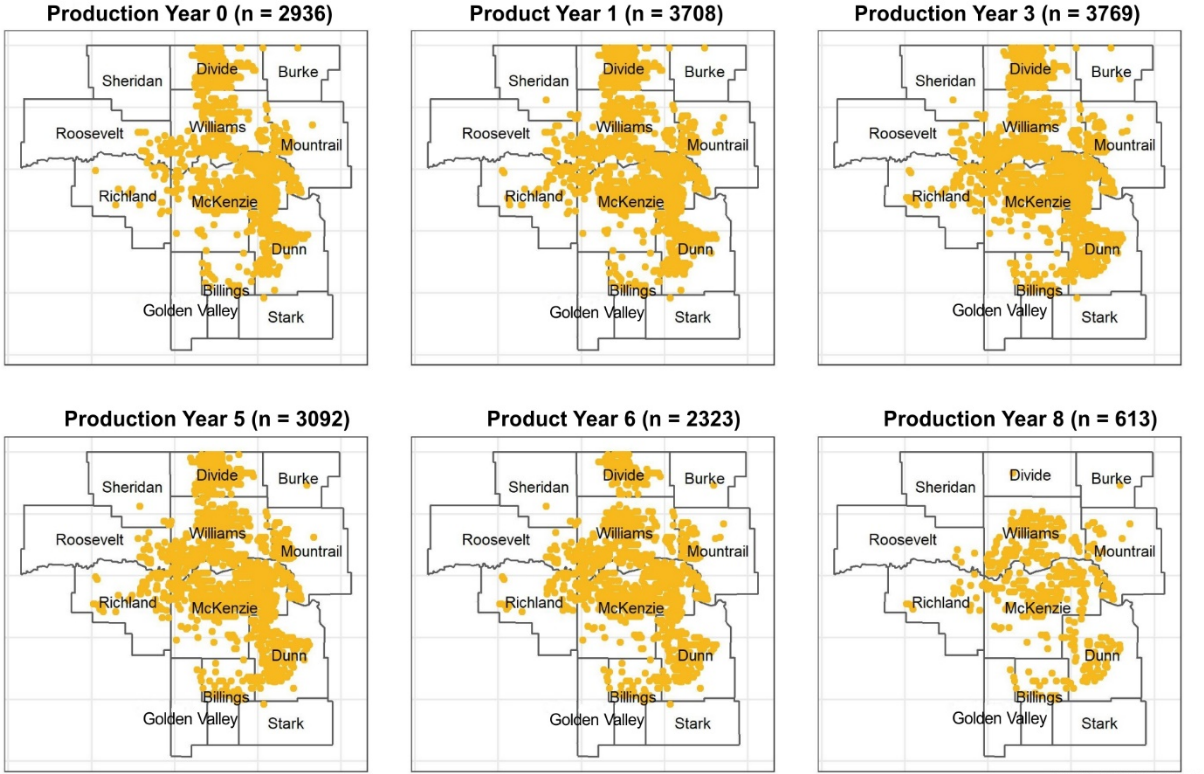

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Figure 3-5. Locations of the wells for which gas composition data exist for a given period of production. The number of wells that had at least one gas composition measurement during the given production period is given by “n.” Note that “Production Year 0” represents the first 90 days of production, whereas “Production Year 1” represents the production period from 91 to 365 days following IP.

The interpolated spatial patterns of wetness values over different production years are shown in Figure 3-6. During IP, there are fewer differences in wetness across the BPS. Over time, the variations in wetness become more pronounced across the play. Generally, wetness decreases over time as represented by the green areas (less than 40% gas wetness composition) which increase in size on the map with increasing production period (Figure 3-7). In some locations, gas wetness initially decreases and then begins to increase after 5 years of production (such as the small area between McKenzie and Richland Counties).

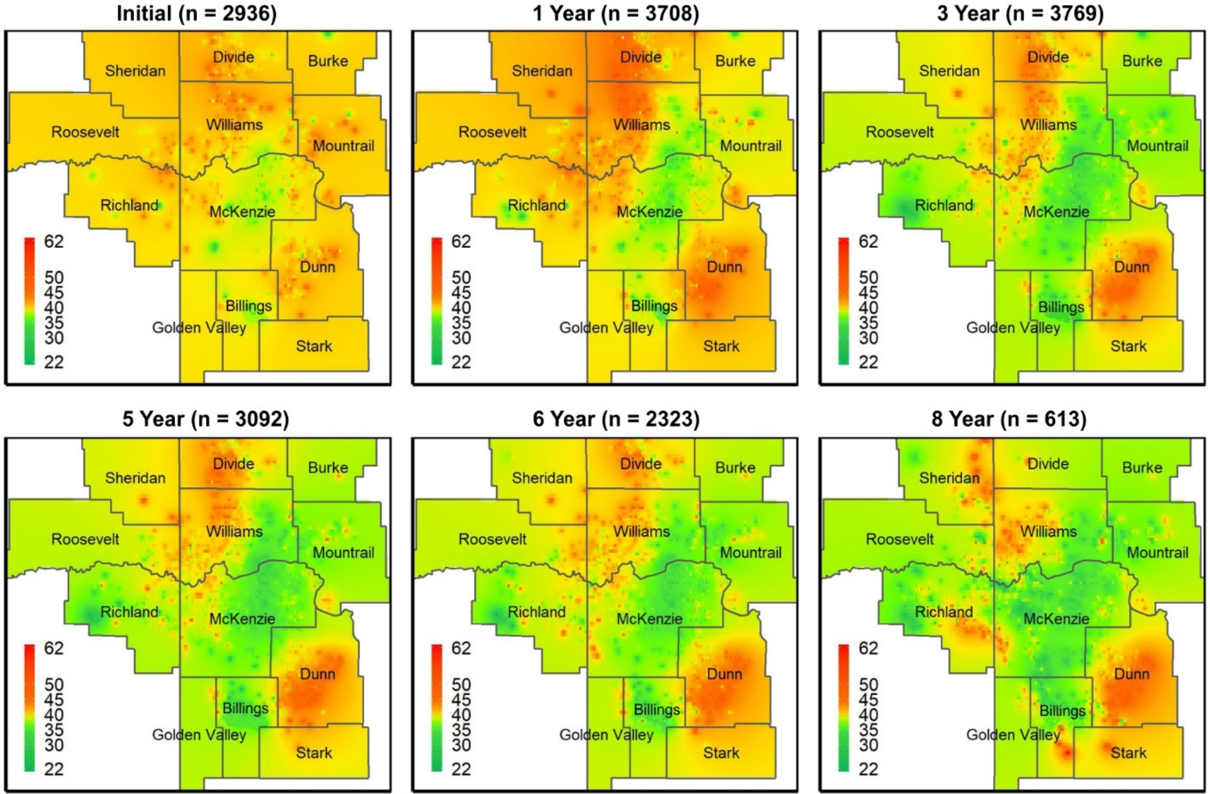
Initial (n = 2936)
1 Year (n = 3708)
3 Year (n = 3769)
5 Year (n = 3092)
6 Year (n = 2323)
8 Year (n = 613)

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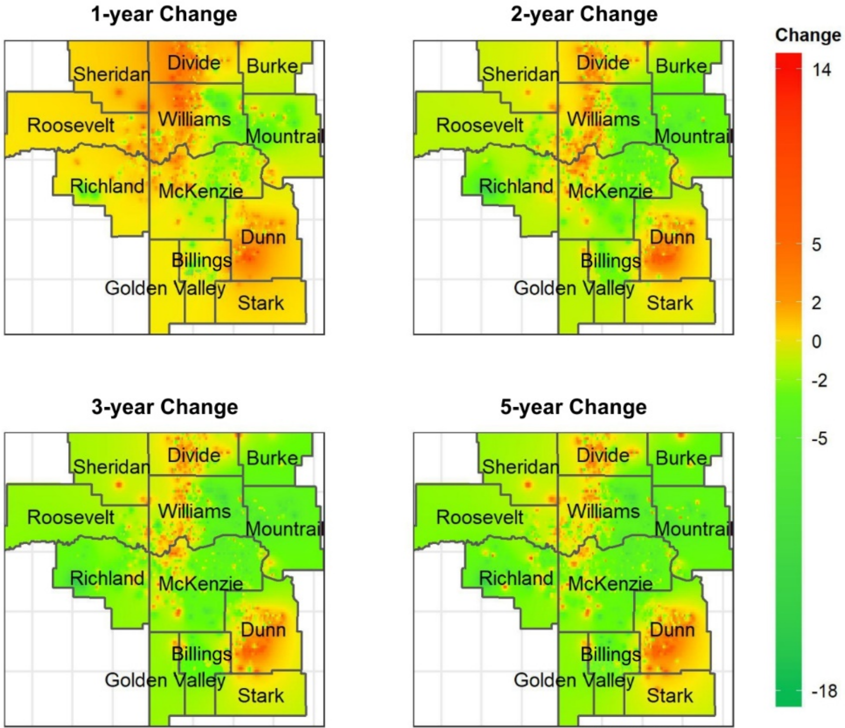
Figure 3-6. Spatiotemporal patterns of associated gas wetness (units in %) starting with IP and following 1, 3, 5, and 8 years of production (only including wells that came online after 2012).


1-year Change

2-year Change

3-year Change

5-year Change

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Figure 3-7. Spatiotemporal changes in gas wetness relative to the initial gas wetness calculated for different production years (1, 2, 3, and 5 years' production) in the BPS.

The spatiotemporal changes in gas wetness were also analyzed by comparing temporal gas wetness changes relative to the initial gas wetness (Figure 3-7). Gas wetness increases in larger areas for the first production year in most counties except McKenzie and Williams Counties. Generally, starting in the second year of production, wetness decreases in most BPS wells throughout production; however, in some wells located in Williams, Divide, and Dunn Counties, wetness increases throughout production. As the length of production increases, the magnitude of change in wetness from IP decreases. In general, the bulk of the changes in gas wetness occur during the first 2 years of production.

Temporal Patterns

Six wells were selected as focal points to conduct an analysis of temporal changes in gas composition. As originally shown in Figure 3-1 and shown again in Figure 3-8 (for reference), the well locations were selected based on their differences in initial gas composition and were labeled according to their location within the core BPS counties (i.e., Divide, Dunn, Dunn–McKenzie, McKenzie, Mountrail, and Williams).

The count and location of the wells within each focus area are shown in Figure 3-8. As would be expected, the number of wells increases in the circles with larger radii, while only a few wells appear in the circles with a 1-mile radius.

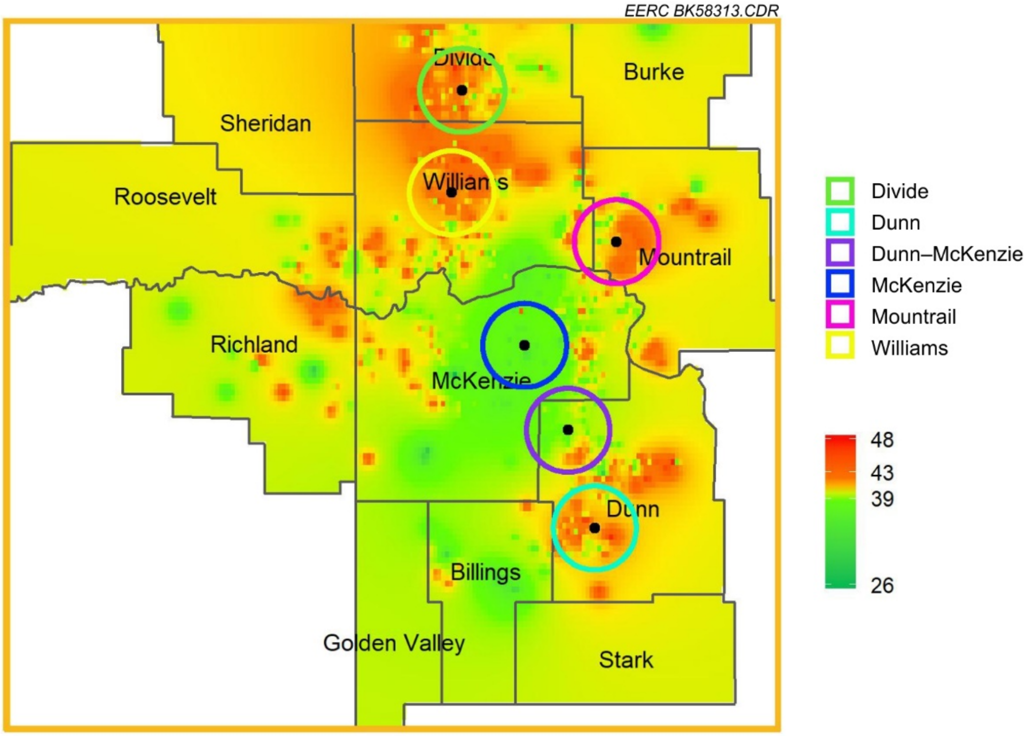

Figure 3-8. Locations of the wells within each focus area selected for the temporal analysis.

The numbers of wells and the duration of production data for the wells located within each of the different focus area radii are presented in Figure 3-9. In all six areas, the circles with the 10-mile radius contained the largest number of wells and represent the most reliable data sets for analysis and interpretation of temporal trends. For the areas with a circle radius of 1 or 3 miles, the number of wells was not large enough to perform a reliable trend analysis.

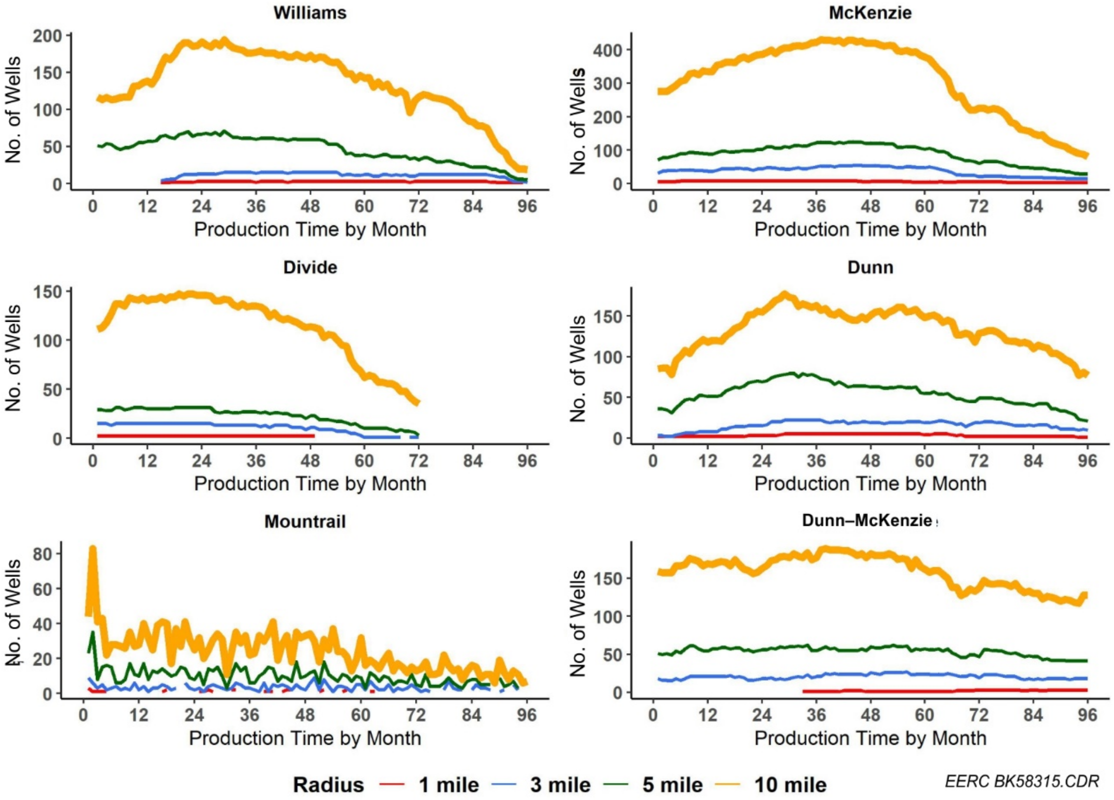

Figure 3-9. Well count and production duration for the wells located in the different radii circles in the six focus areas.

The temporal patterns in gas compositions based on the aggregated data for the six different focus areas are shown in Figure 3-10. Fewer wells appear within the 1- and 3-mile-radius circles; thus the time series is highly variable. The time-series trends are more stable in the circles with larger radii. For this effort, the interpretation of temporal changes in gas composition was based on the wells located within the 10-mile radius of the six focus areas.

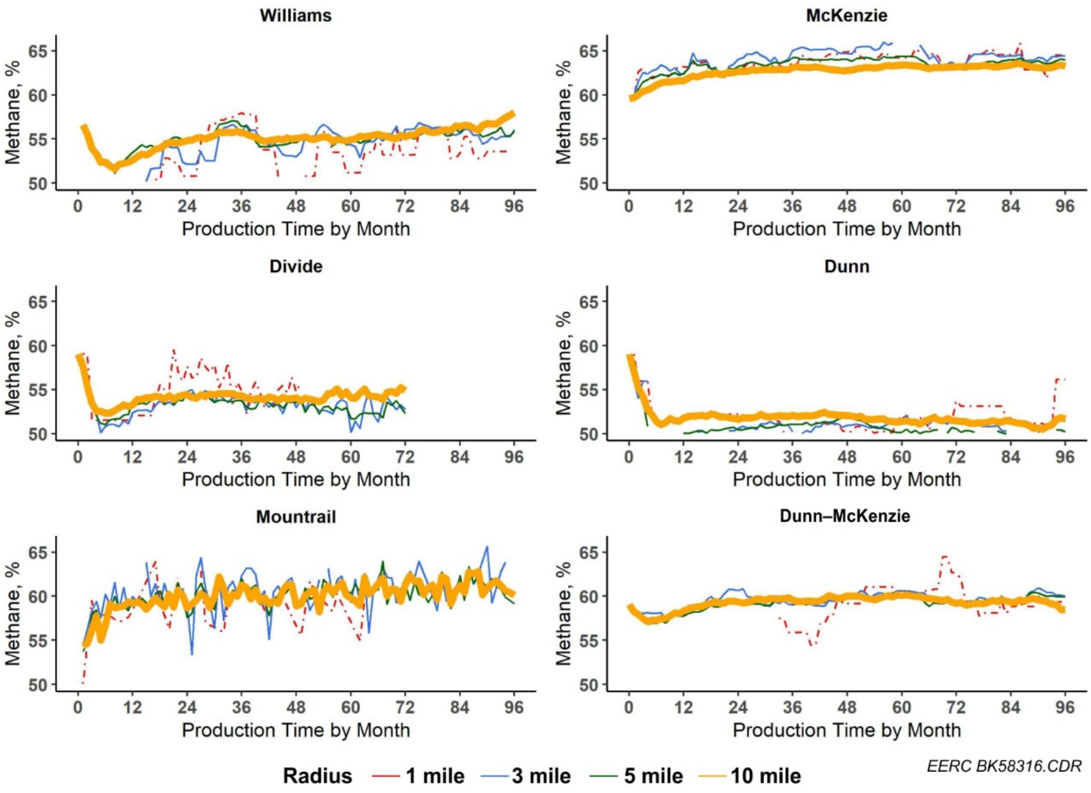

Figure 3-8. Temporal patterns in methane composition (mol%) from the produced gas in the six focus areas.

The temporal patterns in gas composition vary significantly among different gas components and different locations (Figure 3-11). Gas wetness shows temporal patterns similar to propane (C3) and less so with the other NGLs, which indicates that propane strongly drives the variation in gas wetness. This is supported by the high degree of correlation between propane and gas wetness as previously discussed and shown in Figure 3-4.

The initial methane concentrations average approximately 58 mol% for all locations except the focus area in Mountrail County, where methane is relatively low at 54 mol%. The temporal trends in methane content during the first year of production show mixed patterns, with methane concentration decreasing in some locations during the first few months, then increasing with production, whereas, at other locations, methane increases steadily following the IP year. According to internal EERC data collected in conjunction with industry partners, reservoir pressure drops dramatically in the first several years of production and then decreases more slowly or levels off thereafter. Overall, the pattern of pressure drop is similar to that of oil production decline. Methane has a lower solubility in oil than other C2–C5 gases and is more likely to partition into the gaseous phase when pressure drops. Therefore, based solely on thermodynamics, the methane composition should increase during IP. This trend is reflected in the field observations at some locations, such as in the temporal trends at the McKenzie and Mountrail County focus areas. However, in other locations, methane decreases initially for a few months and then increases with ongoing production. The decrease and subsequent increase in methane content

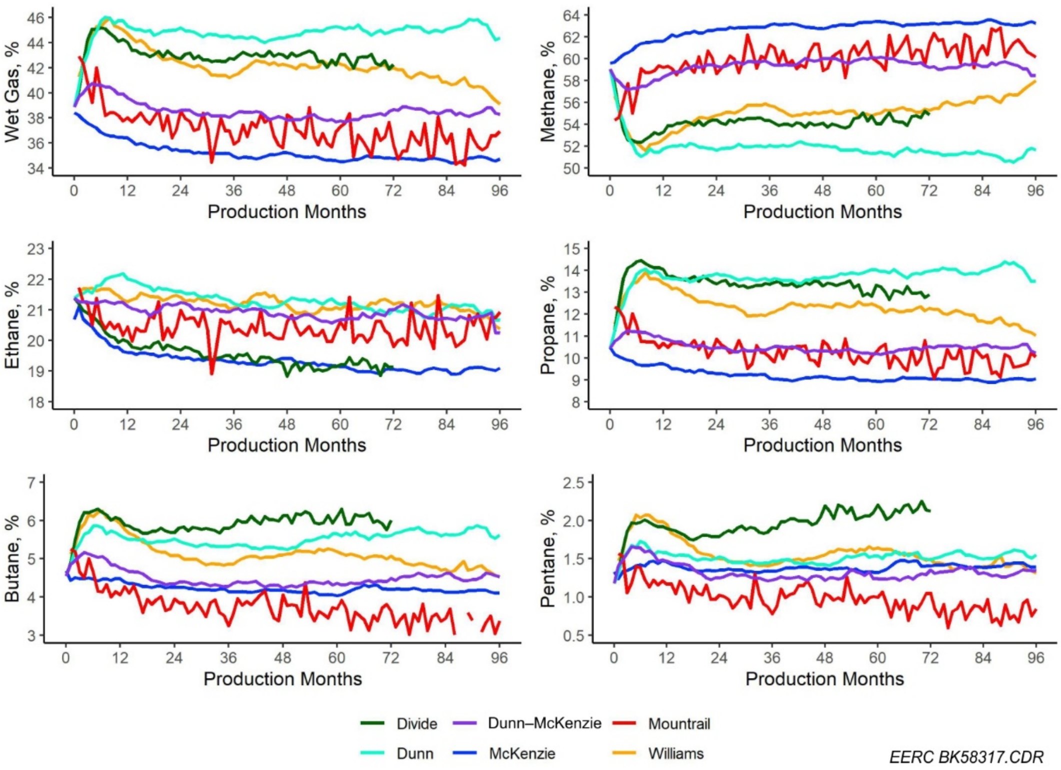

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Figure 3-9. Temporal patterns in gas wetness (%) and associated gas components (mol%) in the six focus areas.

at these locations indicate that the environment is more complex during actual production than in an idealized scenario. The geology and geochemical and petrophysical conditions are more complex for many reasons, including fluid dynamics in small pore spaces, interactions between oil and gas with the reservoir matrix, operational conditions, and perturbation of the formation during production. Several of the other gas components (C3–C5) also exhibit dramatic changes over the first 6 months of production in some of the locations. Again, this is likely an effect of the dramatic changes in reservoir pressure during this period, coupled with the aforementioned complexity that occurs between the reservoir matrix, pores, and fluids within unconventional systems.

Ethane content generally decreases with production at all locations; however, the magnitude of the decrease is small, and ethane concentrations generally decrease only 1 or 2 mol%. After about 3 to 5 years of production, the concentration of ethane levels off and even begins increasing slightly in some areas, such as at the Dunn–McKenzie and Williams County locations.

Propane, as with butane and pentane, shows an initial increase during the first 6 months of production in the Divide, Dunn, Williams, and Dunn–McKenzie County locations (pentane also exhibits an increase in McKenzie County). After about 6 months of production, propane content declines slightly (by ~1 to 2 mol%) until about 36 months of production, after which it remains at consistent levels, except in Divide County, where it continues a slow decline.

The temporal patterns of butane and pentane are similar. For both butane and pentane, the compositions remain fairly steady over the production period at the McKenzie County location. At the Divide, Dunn, and Dunn–McKenzie County locations, butane and pentane increase for the first 6 months, decrease until after about 18 to 24 months of production, and then level off over the remaining production period. The butane and pentane concentrations decrease until 3 years of production then fluctuate for the remaining production period at the Mountrail County location.

Most of the available compositional data discussed earlier covered a production history of 96 months or less. To investigate temporal gas compositional trends for longer production periods, a total of 32 wells with compositional data covering production intervals of up to 168 months were available for analysis. As previously discussed, one of the challenges with evaluating the long-term time-series data from individual wells was the sporadic nature of the data points available for each well. For the long-term production history analysis, there were a total of ten wells from Williams County, six wells from McKenzie County and 16 wells from Mountrail County with a relatively complete long-term gas composition data series. There were not enough wells in the other counties will relatively complete long-term time-series data for inclusion in this assessment.

The aggregated well compositional trends by county (McKenzie, Williams, and Mountrail) are shown in Figure 3-12. The aggregated well data for each county show different trends for each gas component. It should be noted that in most cases the changes in gas content vary by no more than ~5 mol% and in many cases by only 1 to 2 mol%. The aggregated well data from McKenzie and Williams Counties have similar long-term trends in methane concentrations, where methane begins to increase after 36 to 48 months (3 to 4 years) of production and then begins decreasing after about 132 months (11 years) of production. The ethane and gas wetness contents in the McKenzie and Williams County wells also demonstrate similar patterns in long-term production, where concentrations begin to increase slightly after 10 to 12 years of production. The trends in propane composition are different for each county. The gas composition trends from the wells located in Mountrail County show different patterns than the wells located in McKenzie and Williams Counties.

To evaluate the variability in gas composition data between wells located within a given county, or between each of the three counties, the wetness composition time-series data for each of the wells located in McKenzie and Williams Counties are shown in Figure 3-13 and for the wells located in Mountrail County in Figure 3-14. The temporal trends in methane, ethane, and propane composition for each individual well in McKenzie, Williams, and Mountrail Counties are provided in Appendix A. It is important to note that many of the wells had a limited number of samples collected over a long-duration production period; thus the interpolated trend lines should be taken with caution.

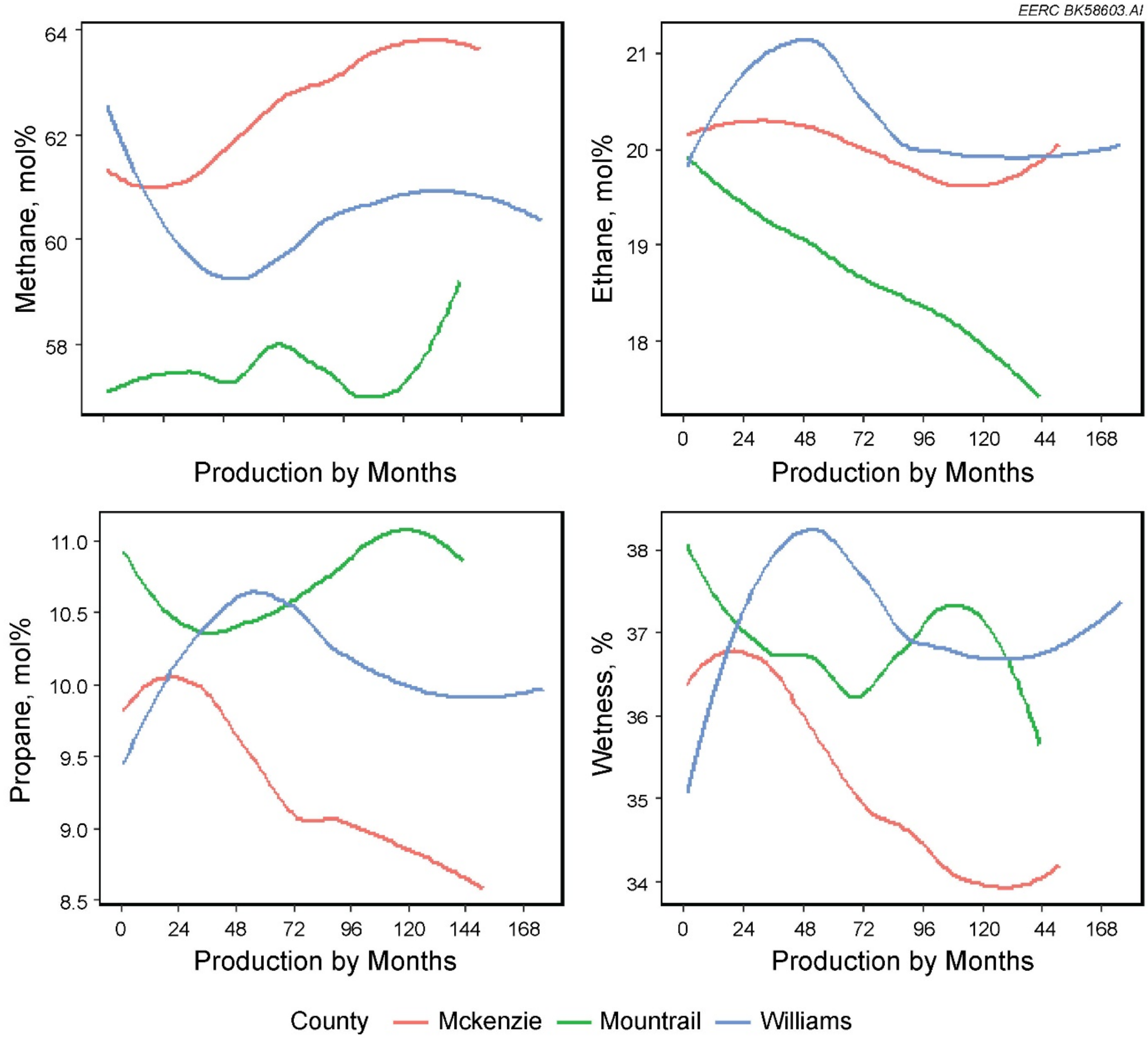

Figure 3-10. Temporal trends in gas composition change in three counties based on a limited number of wells with longer (>12 years) production histories.

Overall, the wells located in McKenzie County show fairly similar temporal trends with respect to gas wetness, where wetness initially declines and then levels off or begins increasing after about 10 years of production. There is slightly more variation in the gas wetness trends between wells located in Williams County versus McKenzie County. There is considerably more variation in the gas wetness trends between wells located in Mountrail County.

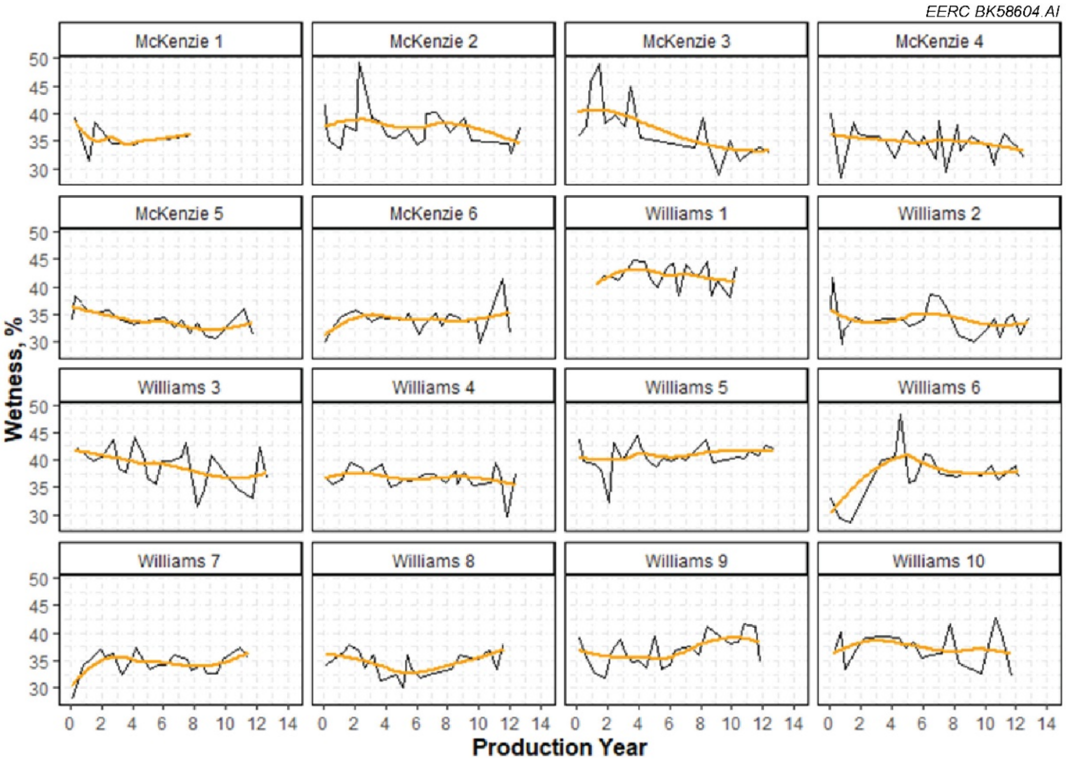

Figure 3-113. Temporal changes in gas wetness based on the time-series data of the wells located in McKenzie and Williams Counties.

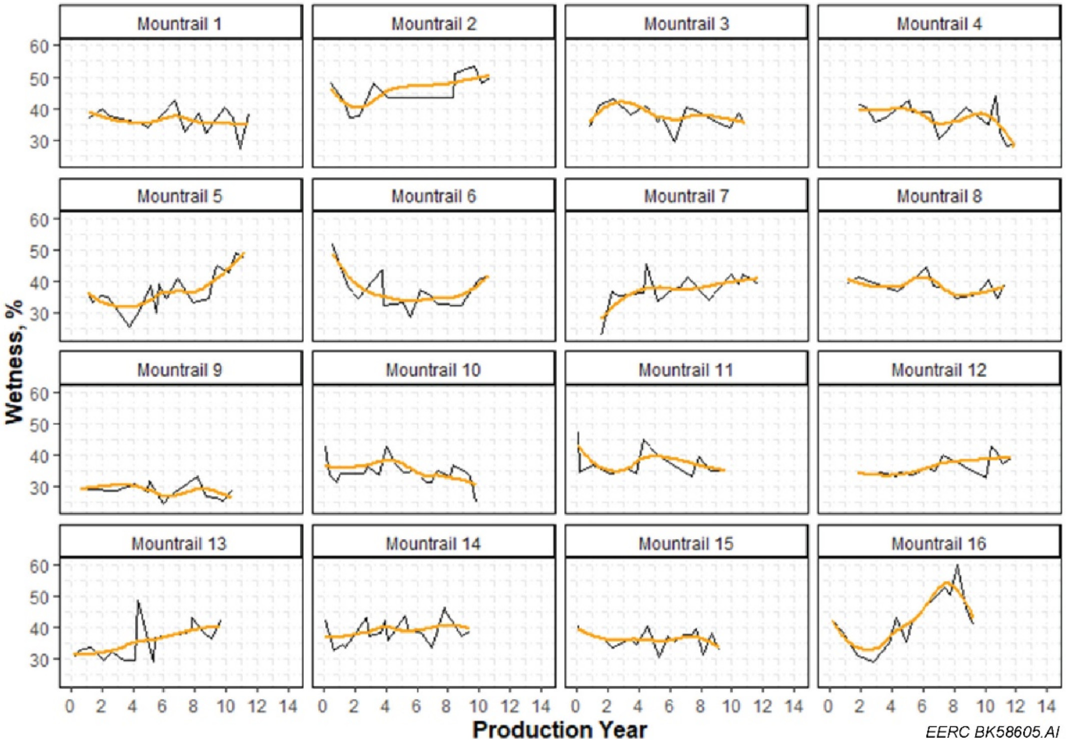

Figure 3-12. Temporal changes in gas wetness based on the time-series data of the wells located in Mountrail County.

In summary, the limited number of wells with long-term production data (12 years or more) show somewhat similar trends in McKenzie and Williams Counties, whereas the Mountrail County wells show different trends. Variations in produced methane and NGL content within a 2–3 mol% range are likely related to several co-occurring processes that can impact gas composition, including dissolution of methane and other gases in oil as well as gas desorption and diffusion. In addition, small variations in rock properties and different well completion strategies can also impact the composition of produced gas.

3.2.4 Factors Influencing Gas Composition

Correlation matrix plots between the geologic and geochemical characteristics of the BPS and the gas composition during various stages of production (i.e., IP, third, fifth, and eighth year of production) are presented in Figure 3-15. The results of the correlation analyses show that the thermal maturity of the BPS affects initial gas composition as well as gas composition over time. Propane and overall gas wetness levels are positively correlated with the HI of the UBS and LBS and negatively correlated with T_{max} from both Bakken shales. This indicates that the lower the thermal maturity of the formation is, the higher the gas wetness, and conversely, it means the

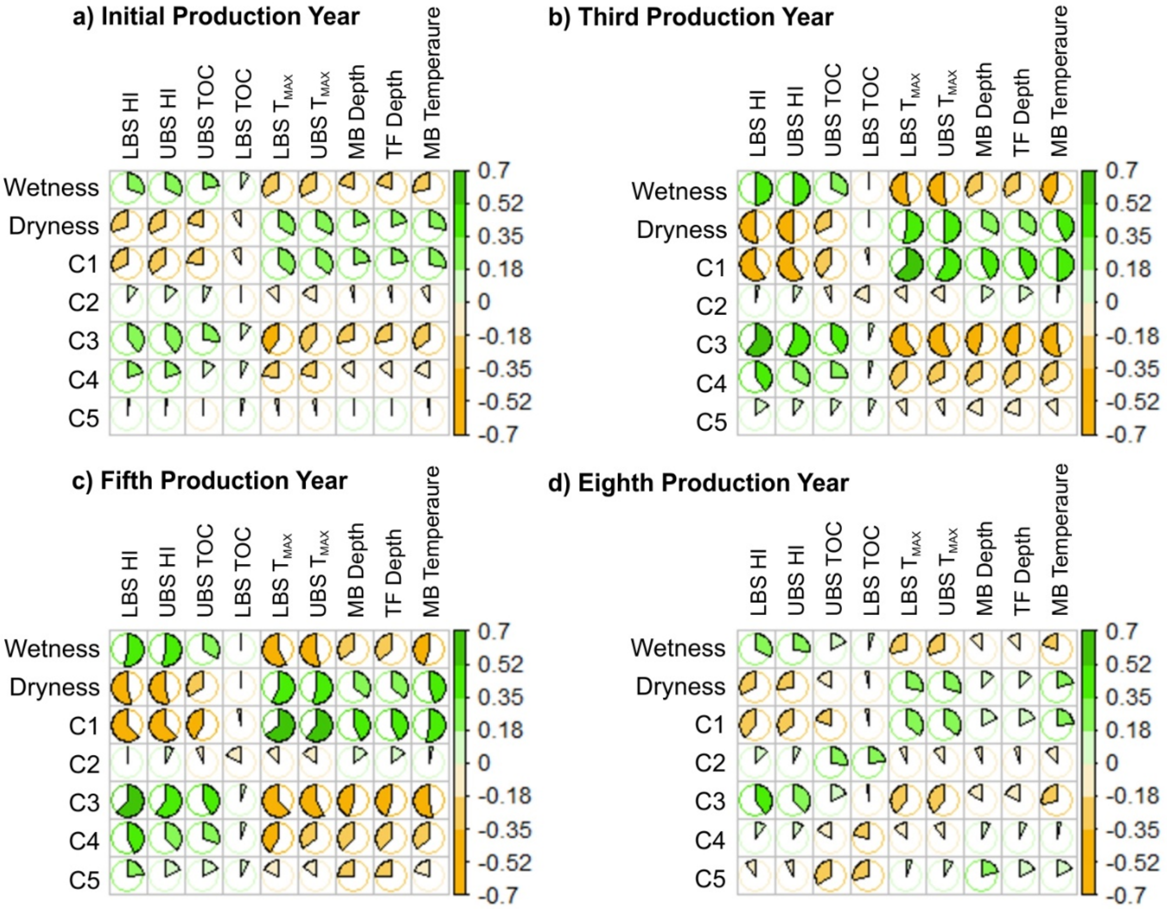

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Figure 3-13. Correlations between geologic and geochemical parameters and gas composition.

higher the thermal maturity, the higher the methane content. This makes sense because during the thermal maturation process, the gas that is formed becomes less enriched in NGLs as wet gas components are converted to methane during secondary cracking (Speight, 2017). As would be expected, the MB and TF depths and temperatures correlate with other geochemical indicators (i.e., HI and T_{max}).

As shown in Figure 3-15, the correlations between gas composition during the IP year and the eighth production year and the geologic/geochemical parameters of the BPS were noticeably weaker than those with the gas compositions after 3 or 5 years of production. While the reason for the weaker relationship between geology and gas composition during the later stages of production is unclear (unless it is due to fewer data points), the lower degree of correlation during the first year of production could suggest that engineering-related factors, such as well stimulation design or production technique, have somewhat more influence on produced gas composition during IP and the later stages of production. The influence of engineering-related factors on gas composition can be explained by the complexity that exists in the reservoir during IP where there are dramatic declines in reservoir pressure and large differences in pressure between stimulated fractures, naturally occurring fractures, and the rock matrix. Given the tight rock matrix and very small pore spaces, the pressure drop within the well-connected fracture networks is not reflected in the rock matrix. Thus in some locations within the reservoir, the reservoir pressure may decline enough to allow for liberation of different gas components, while in other areas, the pressure is still high enough to keep gas in solution. The effect of production technique (and associated pressure decline rate) on long-term gas composition is supported by the modeling and simulation, as discussed in Section 4 of this report.

It is interesting to note that the ethane content shows the lowest degree of correlation with any of the other factors included in the correlation matrix. As previously discussed in the literature review, lab-, modeling- and field-based research efforts conducted by several authors (Schettler and others, 1989; Freeman and others, 2013; Walker and others, 2017) have demonstrated the preferential adsorption of ethane over methane and other gas components in tight reservoirs. Thus the lack of correlation between the ethane content and other geochemical or geologic variables could be due to the preferential retention of ethane in the reservoir. If ethane were adsorbed in the reservoir and not produced proportionately with the other gas components, the produced gas composition would be different from the in situ gas composition. It may be that ethane is also highly correlated with thermal maturity and other geochemical factors, but that the proportion of ethane produced at the surface is not representative of what exists in the reservoir.

There are no significant differences in the correlations between the geologic and geochemical properties of the UBS and LBS and gas composition, except for the different correlation factors between TOC content and gas content between the two shales. Whereas the TOC content of the UBS shows a low to moderate correlation with several gas components, the TOC content of the LBS exhibits a low to insignificant correlation with the other variables.

4.0 SIMULATION AND MODELING OF FUTURE TRENDS

Reservoir simulation integrates the geologic and fluid properties of a reservoir with fundamental physics and mathematics into a numerical reservoir model, which allows for analysis and prediction of fluid flow behavior in porous media over time. Reservoir simulation is one of the main tools used by the oil and gas industry to understand the dynamics of oil, water, and gas in underground formations, especially in unconventional reservoirs because of the complex fluid dynamics in shale plays and other unconventional reservoir matrices.

Because of the complexity of the reservoir model, the multiple assumptions that went into model development, and a lack of long-term field data, it is appropriate to provide clarification of study constraints as follows:

- The simulation models were developed by the EERC based on data collected from NDIC and partner companies/institutes. Because there is a lack of fundamental data on Bakken reservoir characteristics, several assumptions, including fracture properties (lengths, heights, permeability, and geometries, etc.), reservoir relative permeability, and the distribution of pressure in the reservoir, were made in order for the simulation results to match the production data.

- The simulation results presented in this study are based on the data available and EERC engineering experience. The actual gas composition changes in the field strongly depend on the operational methods and constraints of individual operators.

- The EERC does not guarantee the accuracy of the predictive results because of the continuously evolving operational conditions in the field.

A systematic reservoir modeling and simulation procedure was developed and applied in this study to predict the long-term gas composition in the NGLs produced from the BPS. The key steps involved in the modeling and simulation effort included:

1. Identification of a study area based on the distribution of gas production in the main gas-producing counties of the BPS.

2. Collection of available pressure, volume, temperature (PVT) data from the MB and TF Formation wells located in the top gas-producing counties.

3. Selection of one MB and one TF well location based on gas composition trends and available PVT data.

4. Development of equation-of-state (EOS) models (or PVT models) for reservoir simulation.

5. Development of two reservoir simulation models integrated with the EOS model for the MB and TF wells.

6. Calibration of the simulation models using history matching to reproduce the production data from the two wells.

7. Predictive simulation using the calibrated reservoir simulation models to forecast the long-term gas chemistry change from the MB and TF Formations.

4.1 Selection of Typical Wells in the MB and TF Formations

The selection of “typical” MB and TF wells for this effort was based on two key factors: the county in which the well was located and the availability of PVT data for Bakken/TF crude oil. PVT data describe the phase behavior of oil, gas, and water at reservoir and surface conditions and are critical components in reservoir simulation. PVT analyses are expensive, and PVT data collected by the oil and gas industry are not often shared, thus finding locations of “typical” Bakken and TF wells with available PVT data was challenging. In addition, the project team thought it was important to select wells located within the top gas-producing counties, which, as shown in Figure 4-1, are McKenzie and Williams Counties. After an assessment of available PVT data for wells located in those two counties, suitable MB and TF wells were selected for the modeling and simulation activities (Figure 4-2).

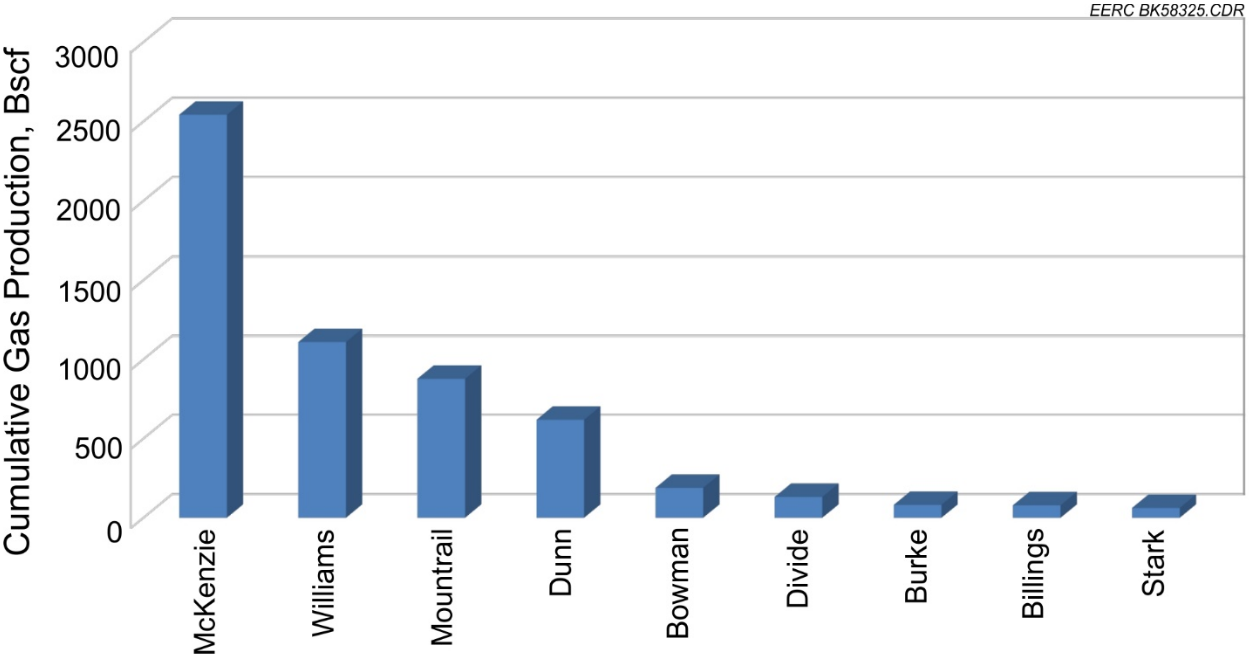

Figure 4-1. Total gas production in individual North Dakota counties after the Bakken boom (September 2006 to March 2020).

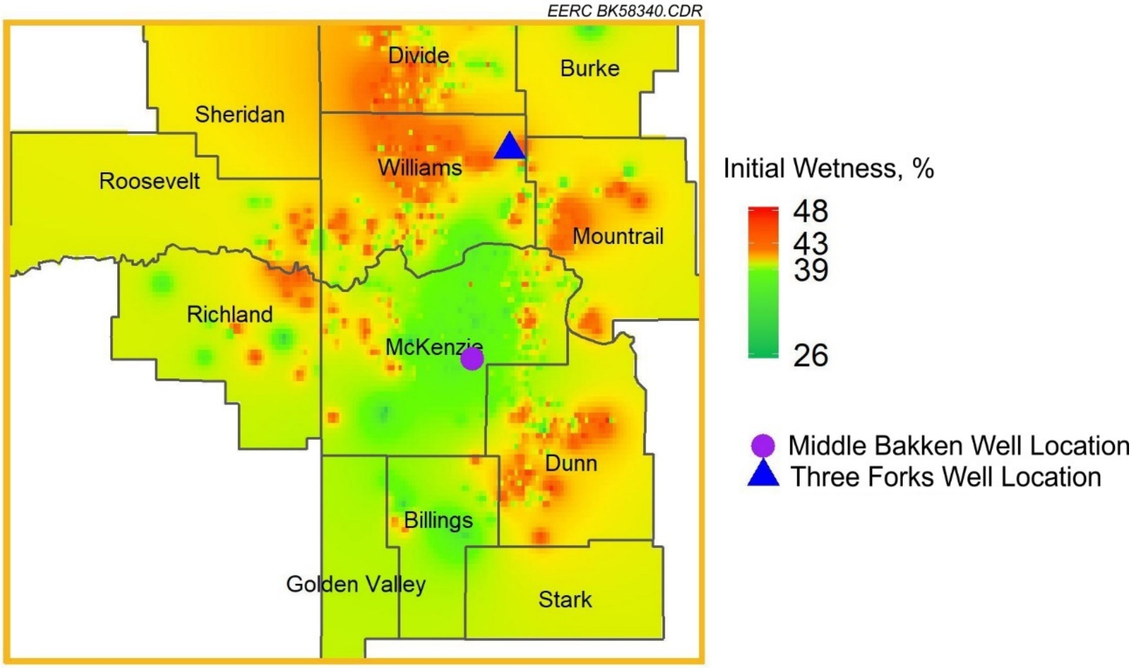

Figure 4-2. Location of the two wells selected from the MB and TF Formations in McKenzie and Williams Counties, respectively.

The general well and reservoir information can be found in Table 4-1. Both wells have over 5 years of production, ensuring well performance is representative for most of the wells in the two counties.

Table 4-1. General Well and Formation Information for the MB and TF Wells

Parameter	MB Well	TF Well
County	McKenzie	Williams
Formation	MB	TF
Depth, ft	11,200	9695
Length, ft	9500	9900
Spud year	2013	2014

4.2 Selection of PVT Data and Development of PVT/EOS Models

An essential part of reservoir simulation includes the development of an EOS which describes the phase behavior of reservoir fluids in both subsurface formations and surface facilities. An EOS is developed based on PVT data measured in the lab, which includes molecular weight/mole fraction, saturation pressure (P_b), density, viscosity, GOR, compressibility factor, and formation volume factor (FVF), etc., which are critical in setting up the proper parameters for reasonable phase behavior calculation at reservoir conditions. Thus PVT data provide fundamental information necessary to understand the change in oil and gas composition during BPS production.

To assist in building the reservoir model, two PVT data sets were acquired for the MB and TF oils in McKenzie and Williams Counties, respectively. Table 4-2 shows the basic PVT data for the two oil samples, and Figure 4-3 illustrates the distribution of HCs in the oils. The data indicate that the two oil samples have similar composition and properties even though the samples are from different formations and counties.

Table 4-2. Basic PVT Data for the Two Oil Samples

Parameter	MB Oil	TF Oil
Experimental Temperature, °F	241	240
Saturation Pressure, psi	2872	2505
Compressibility at P_b, 1/psi	2.6×10^{-5}	2.8×10^{-5}
Oil FVF at P_b, rb/stb	1.83	2.1
Solution GOR at P_b, scf/bbl	1866	1472
Oil Density at P_b, lb-m/ft^3	36.6	36.6
Oil Viscosity at P_b, cP	0.18	0.18

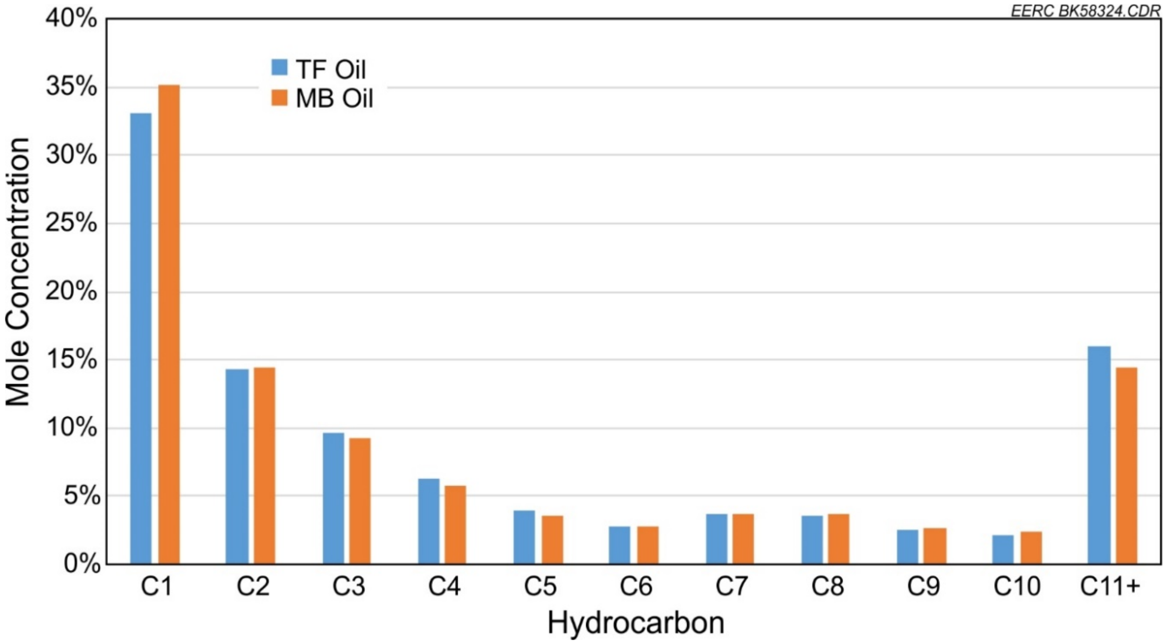

Figure 4-3. Distribution of HCs in the oil samples from the MB and TF Formations.

Based on the PVT date sets, a ten-component EOS was developed for each oil sample. The EOS includes five individual gas components (CO_2, N_2, CH_4, C_2H_6, and C_3H_8) and five lumped HC components (IC4 to NC4, IC5 to C07, C08 to C12, C13 to C19, and C20 to C30+). Figure 4-4 shows that the EOS matches the experimental data satisfactorily after careful tuning. The EOS offers a flexible way to consider different operational strategies for EOR and to predict the trend of each gas component.

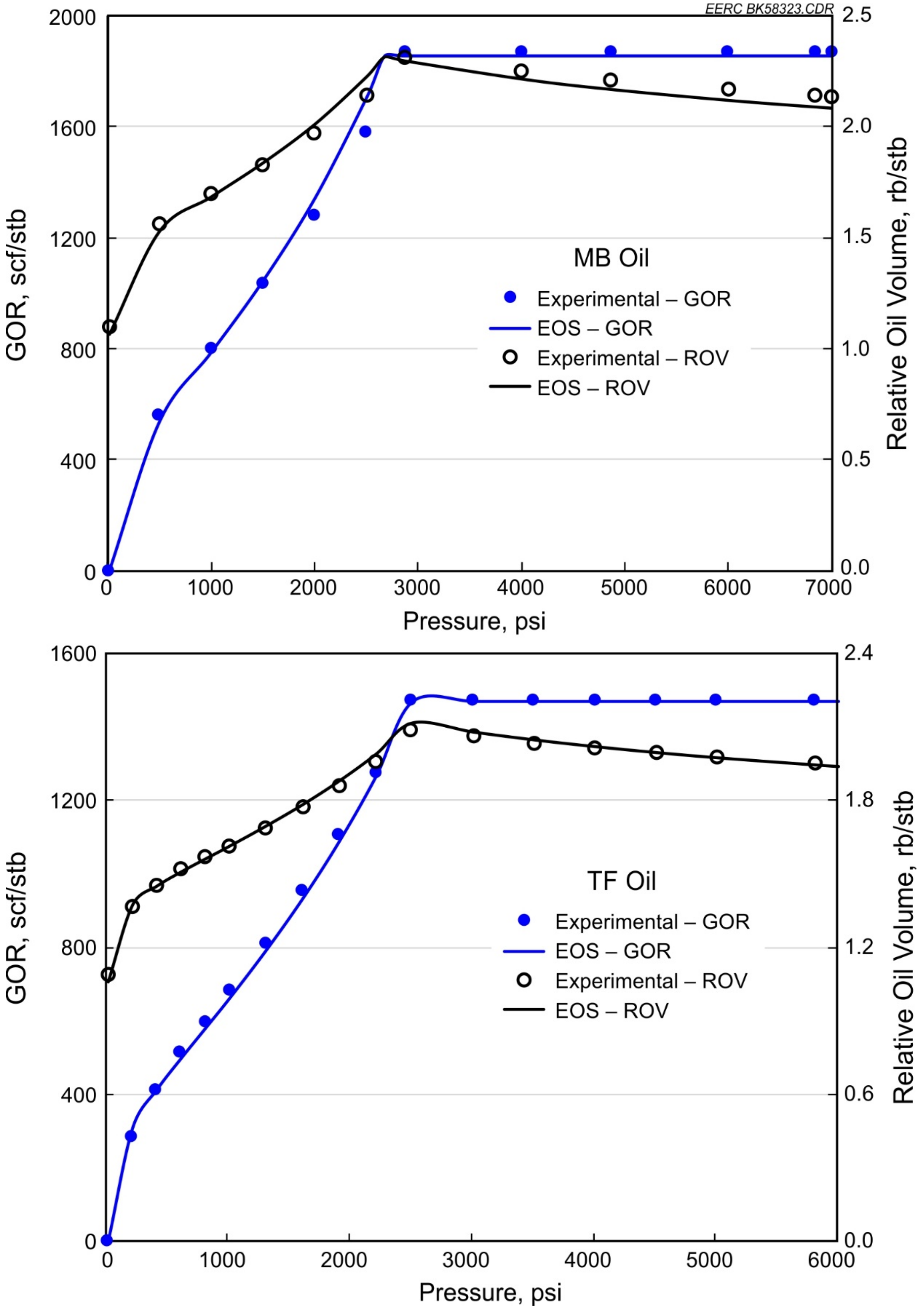

Figure 4-4. EOS tuning results for GOR and FVF for the MB (top) and TF (bottom) oil samples. ROV is relative oil volume.

4.3 Development of Reservoir Simulation Models for the Selected Wells

Two reservoir simulation models with different hydraulic fracture and natural fracture settings were developed for the selected wells in the MB and TF Formations. An advanced fracture simulation approach, embedded discrete fracture model (EDFM), was applied to construct the fracture network along the well. Figure 4-5 demonstrates a schematic of the reservoir simulation model developed for the TF well after the fracture network was integrated into the tight matrix. A compositional simulation method was employed to calculate the macroscale fluid flow behavior and the microcompositional change in the fluids using Computer Modelling Group's General Equation-of-State Module (CMG GEM). This module is specifically designed for compositional, chemical, and unconventional reservoir modeling and simulation.

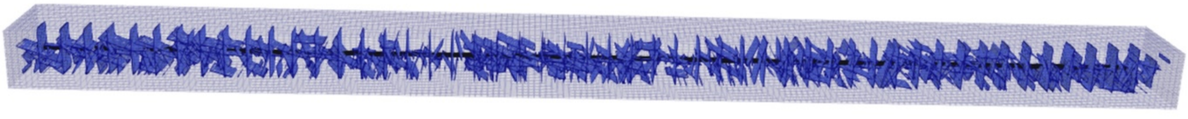

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Figure 4-5. Schematic of the fracture network within the reservoir simulation model developed for the TF well.

4.4 History Match for the MB and TF Wells

Systematic simulation activities were conducted to calibrate the MB and TF simulation models by matching the production history of the wells, including oil, water, and gas production. Key reservoir variables that were tuned to reproduce the field data include porosity, permeability, and relative permeability curves for the matrix and fractures, as well as the diffusion coefficients of the main gas components. The history match results for the MB and TF wells are shown in Figures 4-6 and 4-7, respectively. The large spike in production in the MB well during 2019 was likely a result of a fracture hit as several new wells on the pad were completed at that time. The results indicate that the simulation models satisfactorily mimic the macroscale fluid flow behavior of the studied wells in McKenzie and Williams Counties.

4.1 Prediction of Long-Term Changes in Gas Composition

A series of predictive simulations were conducted to forecast the long-term change in gas composition in the two wells using the history-matched reservoir models. In addition, to evaluate how EOR scenarios using produced gas or CO_2 might impact produced gas composition, two EOR scenarios were evaluated.

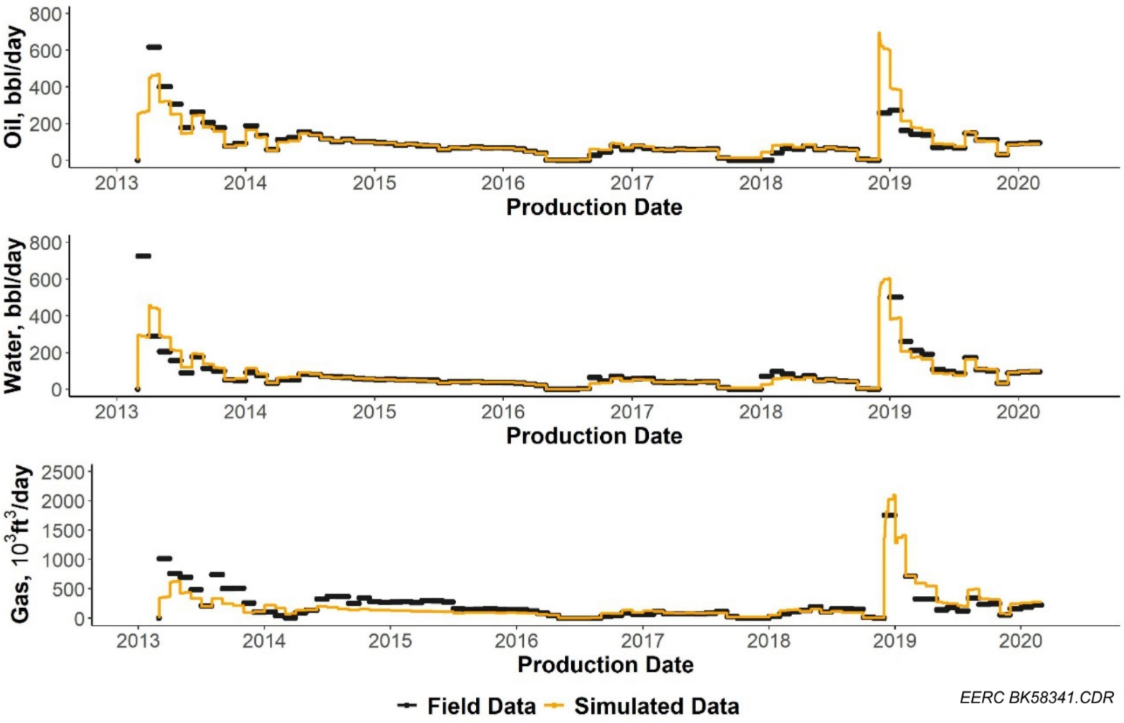

Figure 4-6. History match results for the MB well in McKenzie County.

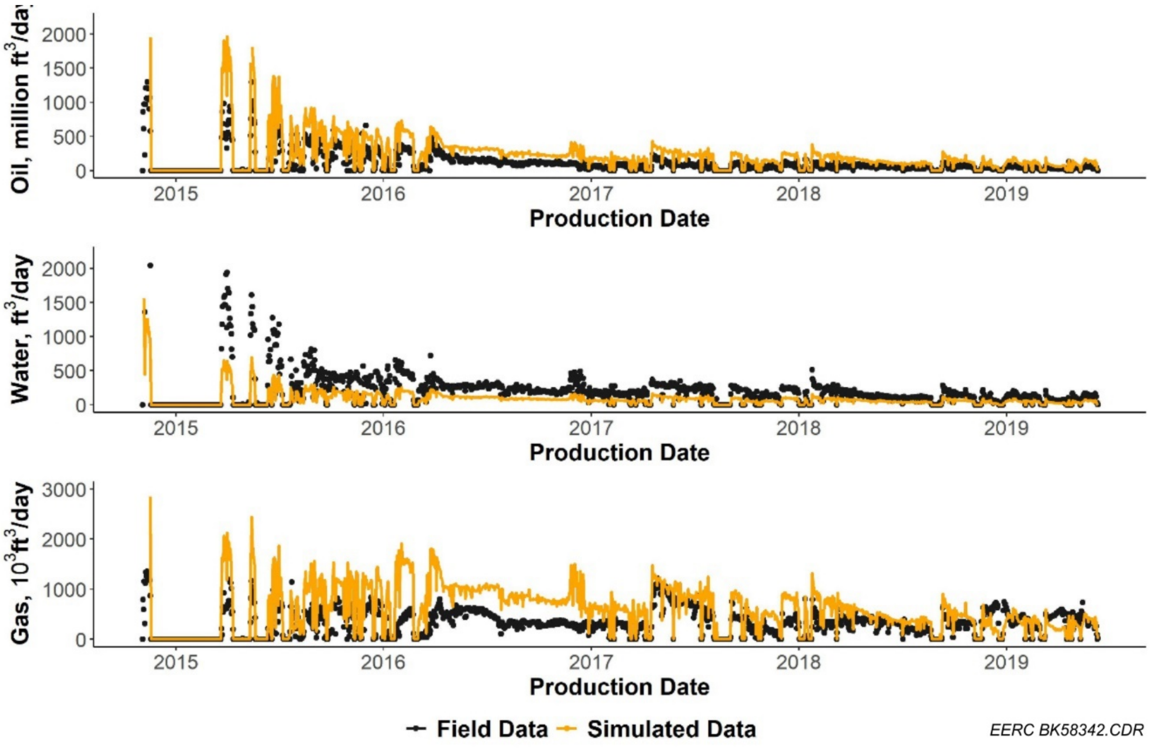

Figure 4-7. History match results for the TF well in Williams County.

4.1.1 Primary Production Scenarios

Three primary production scenarios were considered in this study, as shown in Table 4-3. Long-term (30-year) trends were simulated for all cases. The normal depletion scenario assumed that the well was operated at a constant oil and water production rate for 30 years if the rate could be maintained. The fluid production rate was set to the last known flow rate before prediction. The fast depletion scenario assumed that the well was operated at a flow rate that is 10 times higher than the last known flow rate. The slow depletion scenario assumed that the long-term production rate of the well was low. It is important to note that the production rates refer to the long-term operation of the wells and are not reflective of the initial production rates. For example, the initial oil production rate of the TF well was more than double that of the MB well. In fact, because the initial production rate of the TF was so high and the reservoir pressure was depleted so quickly, by default the production rate after approximately 2 years was low because of the low reservoir pressure.

Table 4-3. Simulation Cases for Predicting Long-Term Gas Composition Change

Well and County	Production Method	Time Frame, year(s)
MB Well in McKenzie County	Normal depletion	1, 10, 20, 30
	Fast depletion	1, 10, 20, 30
TF Well in Williams County	Slow depletion	1, 10, 20, 30
	Fast depletion	1, 10, 20, 30

The predictive results for the normal and fast depletion scenarios in the MB well are illustrated in Figure 4-8. Generally, the produced gas composition is different for the two operational methods between approximately 7 and 16 years of production, after which the gas compositions are close. In both cases, the initial concentration of C1 in the gas stays flat during the first 5 years of production in the MB well, followed by an increase and then a rapid decrease after reaching a peak, as shown in Figure 4-8A.

The reason that there is little variation in the predicted C1 content of the gas during the first 5 years of production is due to operational conditions, where the well was operated at a relatively low production rate (not to exceed 600 bpd) to maintain bottomhole pressure in the well above the bubble point pressure (2872 psi). Because the initial solution GOR does not change when the reservoir pressure is greater than the bubble point pressure, the gas composition did not change significantly in the MB production stream.

The concentrations of C2 and C3 in the gas exhibited the opposite trend to C1, as shown in Figure 4-8B and C, respectively. The results suggest that during more rapid pressure depletion, the C1 content would be lower and the C2 and C3 content would be higher from about Years 7 through 16 of production.

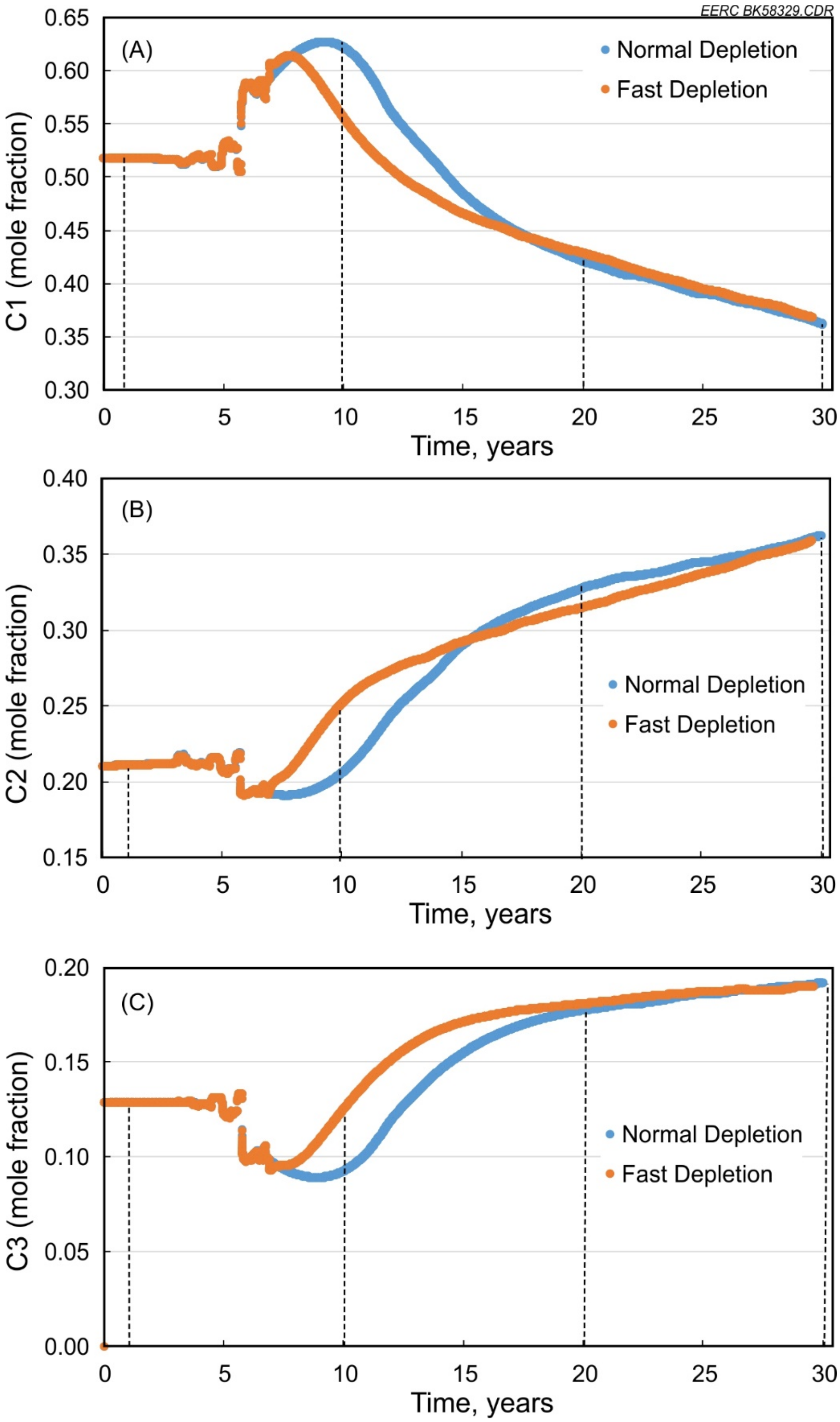

Figure 4-8. Gas composition change in the MB well (McKenzie County) in 30 years with pressure depletion operations: A) C1, B) C2, and C) C3.

Compared to the gas composition changes predicted in the MB well, the TF well has a similar overall trend in gas composition after long-term production; however, the initial gas composition trends are different in that the TF well does not have the initial period of relatively stable C1 concentrations. Instead, C1 increases early in the well production followed by a decline, whereas C2 and C3 initially decrease and then increase, especially after about 3 years of production.

Again, the difference in the predicted gas compositions between the MB and TF wells is due to operational parameters. In the TF well, the reservoir pressure decreased much more rapidly than the MB well because of a much higher initial production rate (1200 bpd), plus the initial reservoir pressure in the TF well (~6000 psi) was significantly lower than in the MB well (~8000 psi). The pressure dropped below the bubble point quickly, resulting in preferential partitioning of methane from the oil and the resulting increase of C1 in the production stream after about 6 months of production. Similar to the simulation results from the MB well, as C1 begins to decline, C2 and C3 start increasing.

Another key difference between the two wells is the late-stage gas composition change for the two primary depletion cases. The fast depletion case has a much lower predicted concentration of methane and much higher concentrations of ethane and propane in the produced gas than the slow depletion case in the TF well after 15 years of production, as shown in Figure 4-9. The fast depletion case more closely matches the normal and fast depletion cases from the MB well.

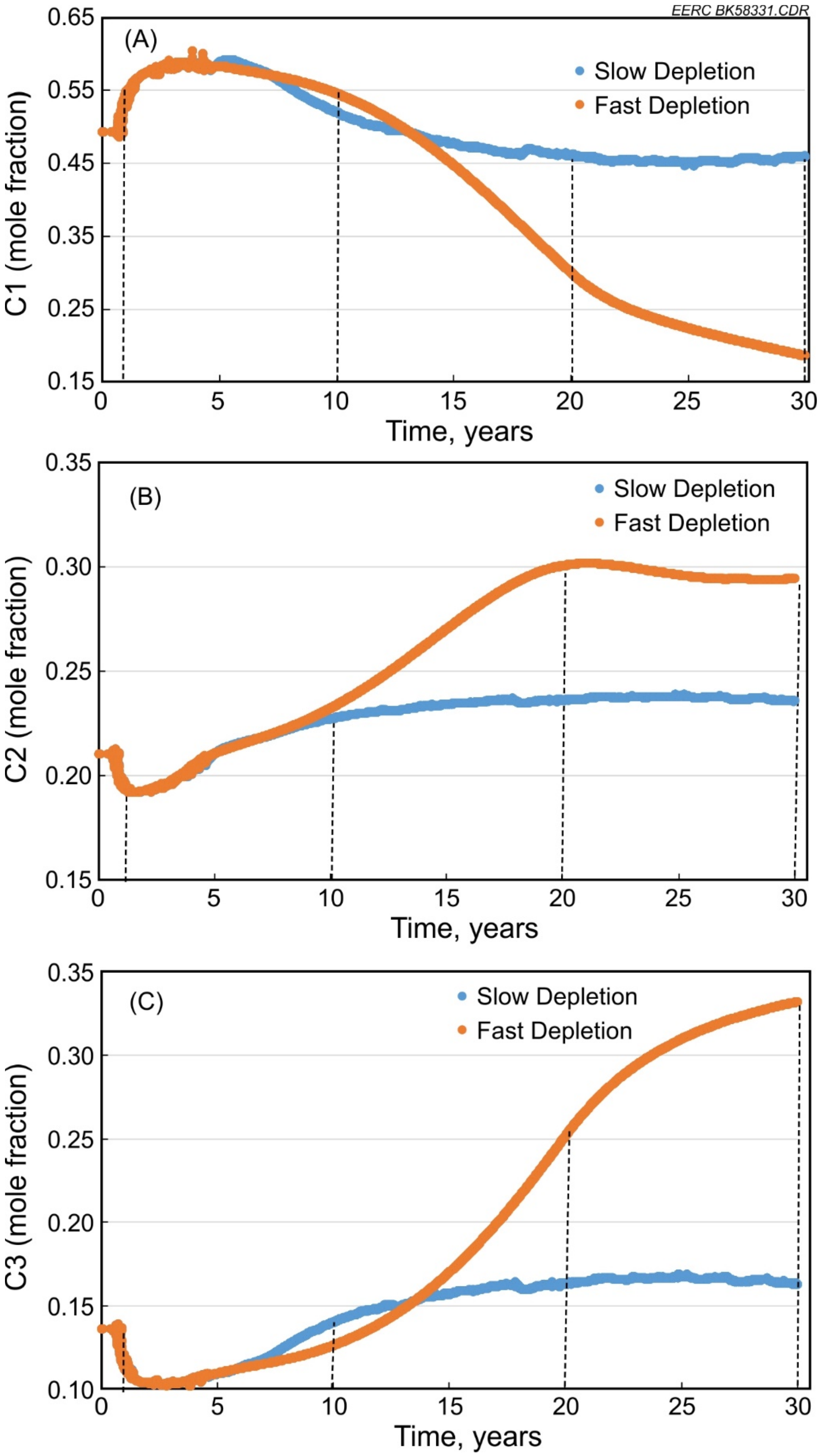

Figure 4-9. Gas composition change in the TF well (Williams County) over 30 years of production with pressure depletion operations: A) C1, B) C2, and C) C3.

The nonlinear change in gas composition for the studied scenarios indicates that different oil and gas flow mechanisms may be involved in the complex fracture–matrix systems of the Bakken reservoirs. Recent studies on unconventional flow mechanisms confirm the importance of microflow behavior, including adsorption, diffusion, and imbibition, etc., on oil and gas flowing in tight/shaly rocks. Guo and others (2017) studied the shale gas adsorption and desorption characteristics and their effects on shale permeability, and the results showed that desorption of methane can increase the shale permeability under high-pressure conditions and make flow easier. Jin and others (2017a, b) identified two distinguishable flow regimes in the fractured, HC-rich Bakken Formation: viscous flow in high-permeability fracture networks and diffusion-dominated flow in the low-permeability matrix with high oil saturation. The integration of microflow mechanisms into a simulation model can improve the accuracy of simulation results. Jia and others (2018a, b) quantified the effects of molecular diffusion in heterogeneous, naturally fractured shale reservoirs using both experimental and simulation approaches. Wang and Liu (2016) and Yang and Liu (2019) studied gas diffusion coefficients in tight coal matrices and found that the coefficient controls the long-term production performance of methane production from the tight coal bed. Although the geologic properties of coal beds and the tight formations in the BPS are very different, both coal and the Bakken matrices have abundant tiny pores (nanometer to micrometer scale) where the majority of the gas resides. Diffusion is the main mechanism to transport gas from the matrix to fractures in both matrixes. The gas diffusion coefficient determines the gas transport effectiveness from matrix to fracture/cleat system, and most importantly, the diffusion mechanism strongly depends on the pressure change in the production process. Therefore, reservoir pressure plays a critical role in the long-term gas composition changes in the tight Bakken reservoirs.

Figures 4-10 and 4-11 show the average reservoir pressure change around the MB and TF wells, respectively. The MB well has a more complicated fracture network in the reservoir model because of the fractures from the neighboring wells on the pad. Therefore, the reservoir pressure depletes to a very low level – below 1000 psi after 12 and 10 years in the normal and fast depletion scenarios, respectively. The reservoir pressure becomes the same after 18 years, and the gas composition change becomes identical, as shown in Figure 4-8. Compared to the MB well, the TF well exhibits a different pressure behavior between the slow and fast depletion scenarios, as shown in Figure 4-11. The reservoir pressure was maintained above 1000 psi in the slow depletion case through the predictive period, while the pressure dropped below 1000 psi after 9 years of production in the fast depletion case. Thus the trends in gas composition change are different between the two scenarios because of this significant pressure difference, especially in the late stage of the predictive period. The detailed gas composition values for each component at key time points can be found in Tables 4-4 through 4-7.

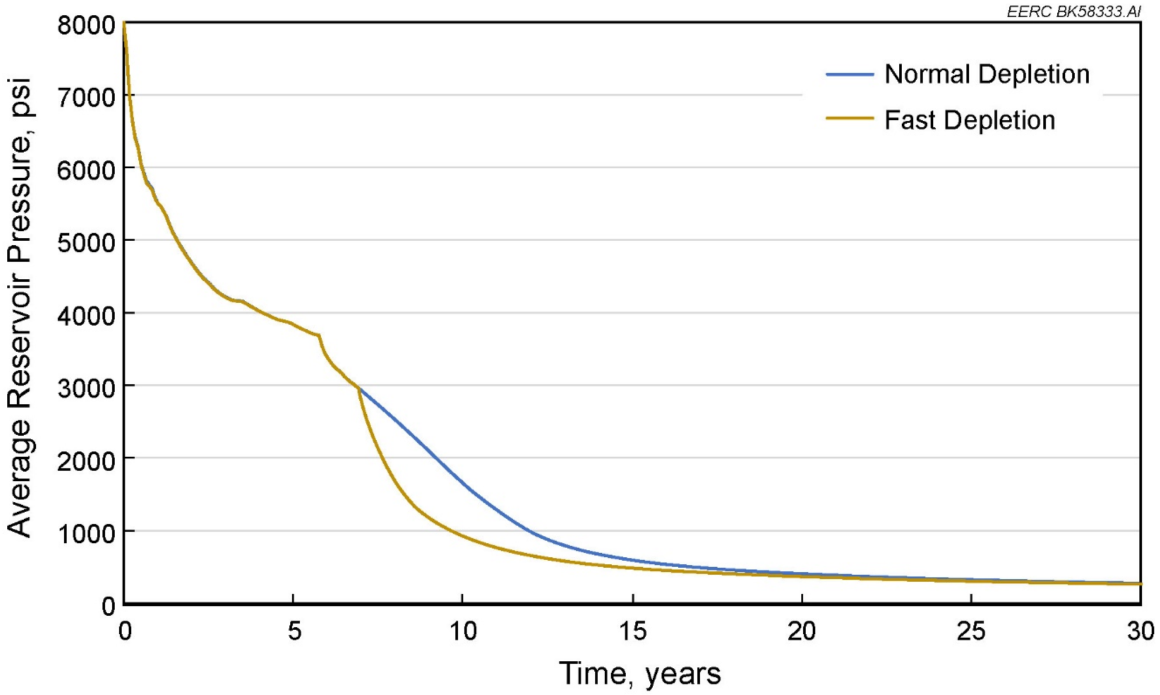

Figure 4-10. Pressure depletion in the MB well for the normal and fast depletion scenarios.

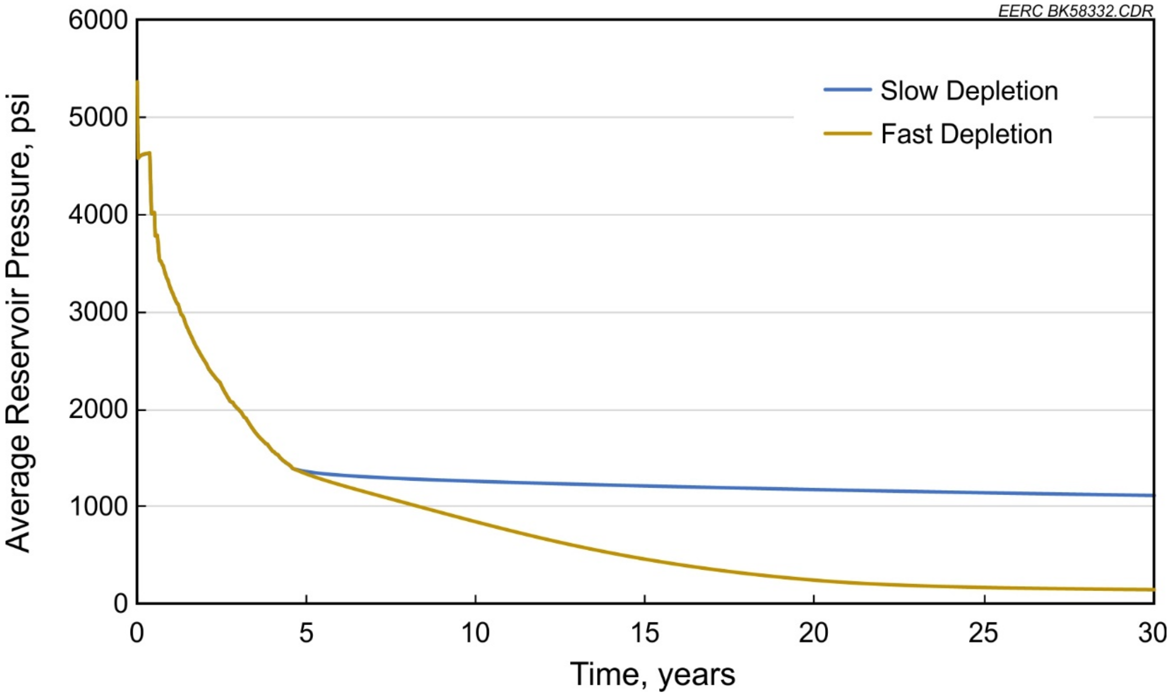

Figure 4-11. Pressure depletion in the TF well for the slow and fast depletion scenarios.

Table 4-4. Predicted Gas Composition from the MB Well Location Following 1, 10, 20, and 30 years of Production for the Normal Pressure Depletion Scenario

	Gas (mole fraction)			
Gas Component	**1 year of Production**	**10 years of Production**	**20 years of Production**	**30 years of Production**
C1	0.52	0.62	0.42	0.37
C2	0.21	0.20	0.33	0.36
C3	0.13	0.09	0.18	0.19
C4	0.07	0.034	0.025	0.03
C5–7	0.045	0.034	0.037	0.037

Table 4-5. Predicted Gas Composition from the MB Well Location Following 1, 10, 20, and 30 years of Production for the Fast Pressure Depletion Scenario

	Gas (mole fraction)			
Gas Component	**1 year of Production**	**10 years of Production**	**20 years of Production**	**30 years of Production**
C1	0.52	0.58	0.43	0.37
C2	0.21	0.25	0.31	0.36
C3	0.13	0.12	0.18	0.19
C4	0.07	0.024	0.026	0.03
C5–7	0.045	0.035	0.036	0.036

Table 4-6. Predicted Gas Composition from the TF Well Location Following 1, 10, 20, and 30 years of Production for the Slow Depletion Scenario

	Gas (mole fraction)			
Gas Component	**1 year of Production**	**10 years of Production**	**20 years of Production**	**30 years of Production**
C1	0.51	0.52	0.46	0.46
C2	0.20	0.23	0.24	0.19
C3	0.14	0.14	0.16	0.19
C4	0.078	0.056	0.075	0.076
C5–7	0.052	0.047	0.050	0.050

Table 4-7. Predicted Gas Composition from the TF Well Location Following 1, 10, 20, and 30 years of Production for the Fast Depletion Scenario

	Gas (mole fraction)			
Gas Component	**1 year of Production**	**10 years of Production**	**20 years of Production**	**30 years of Production**
C1	0.51	0.55	0.30	0.19
C2	0.20	0.23	0.30	0.29
C3	0.14	0.13	0.25	0.33
C4	0.078	0.041	0.078	0.101
C5–7	0.052	0.039	0.056	0.065

The predicted changes in methane, ethane, and propane content at 1, 10, 20, and 30 years of production for the four primary production scenarios (MB – normal and fast, TF – slow and fast) are shown in Figures 4-12 through 4-14. As shown in Figure 4-12, the fast production scenario from the TF well simulation model showed the largest change in methane concentration over the 30-year production period, especially after 20 or 30 years of production. The magnitude of change between the four scenarios was lower with respect to ethane and propane concentration changes over time (Figures 4-13 and 4-14). The predicted trends in propane variation over time (Figure 4-14) were similar to that of methane in that the fast production scenario had the largest deviation in propane content when compared to the other scenarios, especially after 20 and 30 years of production. The predicted propane content from the other scenarios was actually quite close. The changes in ethane content (Figure 4-13) were also quite similar between three of the scenarios. However, in this case, it was the slow prediction scenario from the TF well that exhibited the largest deviation in ethane content after 20 and 30 years of production.

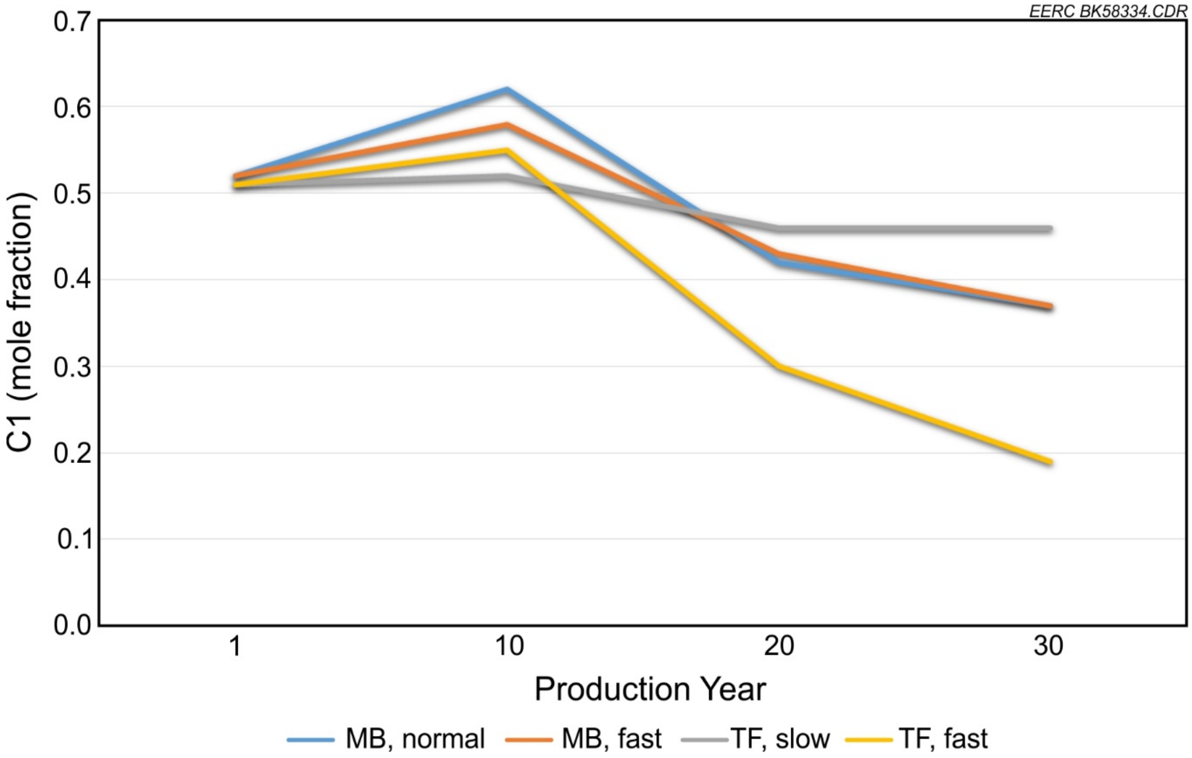

Figure 4-12. Predicted methane concentrations after 1, 10, 20, and 30 years of production for the four primary production scenarios, including normal and fast production in the MB well and slow and fast production in the TF well.

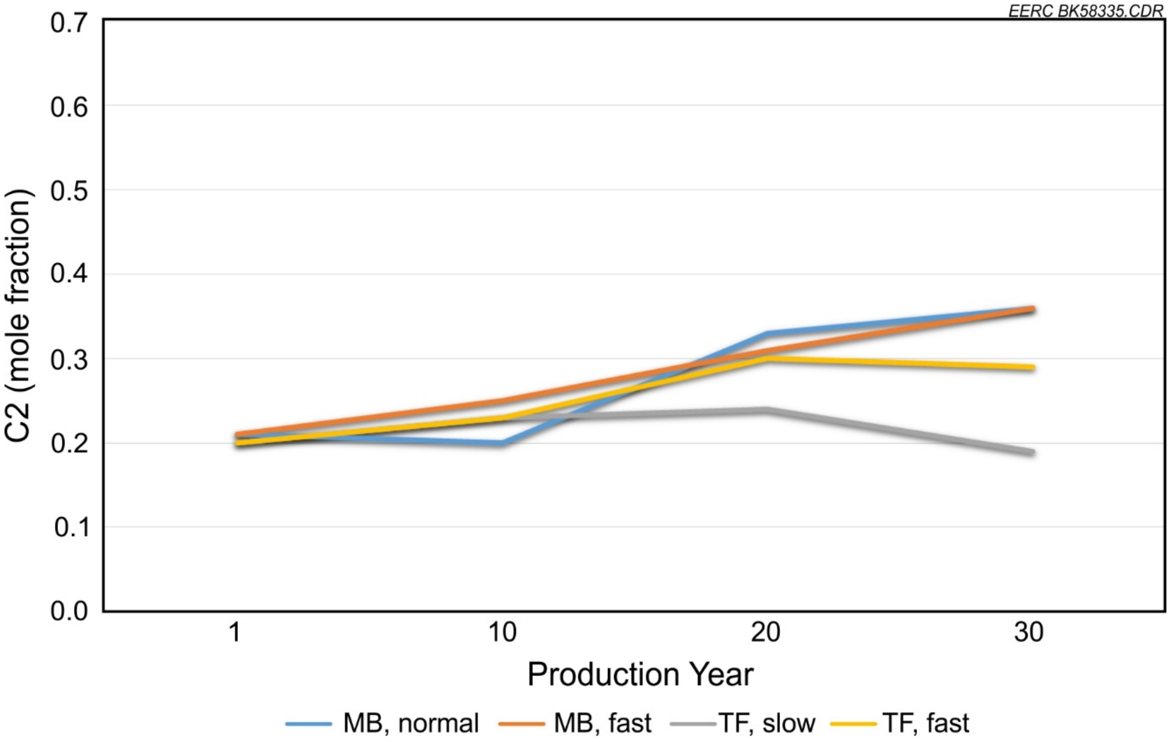

Figure 4-13. Predicted ethane concentrations after 1, 10, 20, and 30 years of production for the four primary production scenarios, including normal and fast production in the MB well and slow and fast production in the TF well.

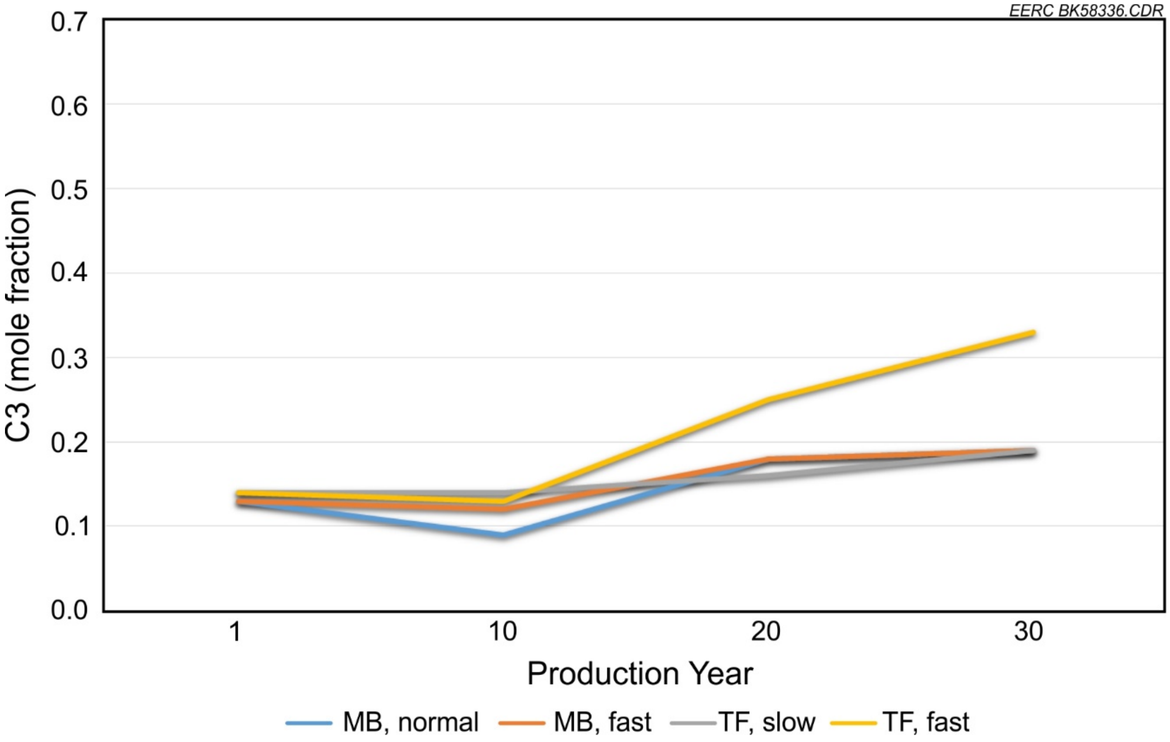

Figure 4-14. Predicted propane concentrations after 1, 10, 20, and 30 years of production for the four primary production scenarios, including normal and fast production in the MB well and slow and fast production in the TF well.

Overall, the results of the simulation scenarios suggest that significant variations in gas composition could occur in BPS wells, especially during the later stages of production. In general, the simulation results support the temporal trend patterns seen in the measured data during the early stages of production (up to ~8 years). Unfortunately, there are a limited number of wells with long-term production data; however, some general observations can still be made. A comparison of the simulation results to the wells with long-term data suggests that the magnitude of change predicted by the simulation model may be larger than those measured in the field. This could be due to differences in the predicted decrease in reservoir pressure versus actual decreases in reservoir pressure (especially within the unfractured reservoir matrix), or perhaps a result of sorption mechanisms that are poorly understood in unconventional reservoirs. While the magnitude of change in each gas component is higher in the predicted cases, the simulation also suggests that the most significant changes occur after 10 years of production. The measured data from McKenzie and Williams Counties show a trend of increasing gas wetness after about 11 years of production; thus it is possible that the magnitude of change could increase over time.

4.1.2 EOR Scenarios

To evaluate how EOR scenarios performed in the BPS might affect gas composition, two scenarios were evaluated, including produced gas EOR and CO_2-based EOR, as shown in Table 4-8. While the MB model was used for the produced gas EOR case and the TF model was

Table 4-8. Simulation Cases for Predicting Long-Term Gas Composition Change with EOR Operations

Well and County	Production Method	Time Frame, years
MB Well in McKenzie County	Produced gas EOR	1, 10, 20, 30
TF Well in Williams County	CO_2 EOR	1, 10, 20, 30

used for the CO_2 EOR case, the PVT data from both wells were similar and both reservoir models are considered representative of the BPS.

The produced gas EOR scenario assumed that a gas mixture of 70% methane, 20% ethane, and 10% propane was injected into the well at 10 million scf/day for huff ‘n’ puff (HnP) operations for 30 years. The HnP schedule was fixed through the EOR time frame and assumed 30 days of injection, 10 days of soaking, and 100 days of production. The maximum injection pressure was limited to 5000 psi. The CO_2 EOR scenario assumed that pure CO_2 was injected into the well at 10 million scf/day for HnP operations for 30 years. The HnP schedule and pressure limit for CO_2 EOR were the same as the produced gas EOR scenario.

For the produced gas EOR case, the concentrations of the three components are relatively stable and mainly follow the composition of the injection gas, especially after 5 years of production (Figure 4-15). The predicted change in mass rate for each gas component throughout the duration of the EOR operation is shown in Figure 4-16. After an initial decline in mass rate for each component during the first ~5 years of production, the gas mass rate levels off and remains consistent throughout the 30 years of EOR operations.

Figure 4-17 shows the predicted gas composition change as a result of CO_2-based EOR operations in the BPS. In the CO_2 EOR case, the concentration of all three gas components decreases consistently and follows the same pattern as CO_2, progressively penetrating the rock matrix and extracting the available HC components. The total mass of each gas component is constant, which means that the more HC gases produced to the surface, the less remaining in the reservoir. As a result, fewer and fewer gas components (C1, C2, and C3) can be produced from the matrix with progressing CO_2 injection. Figure 4-18 illustrates the predicted change in mass rate for each individual gas component in the TF well (Williams County) over 30 years of CO_2 EOR production.

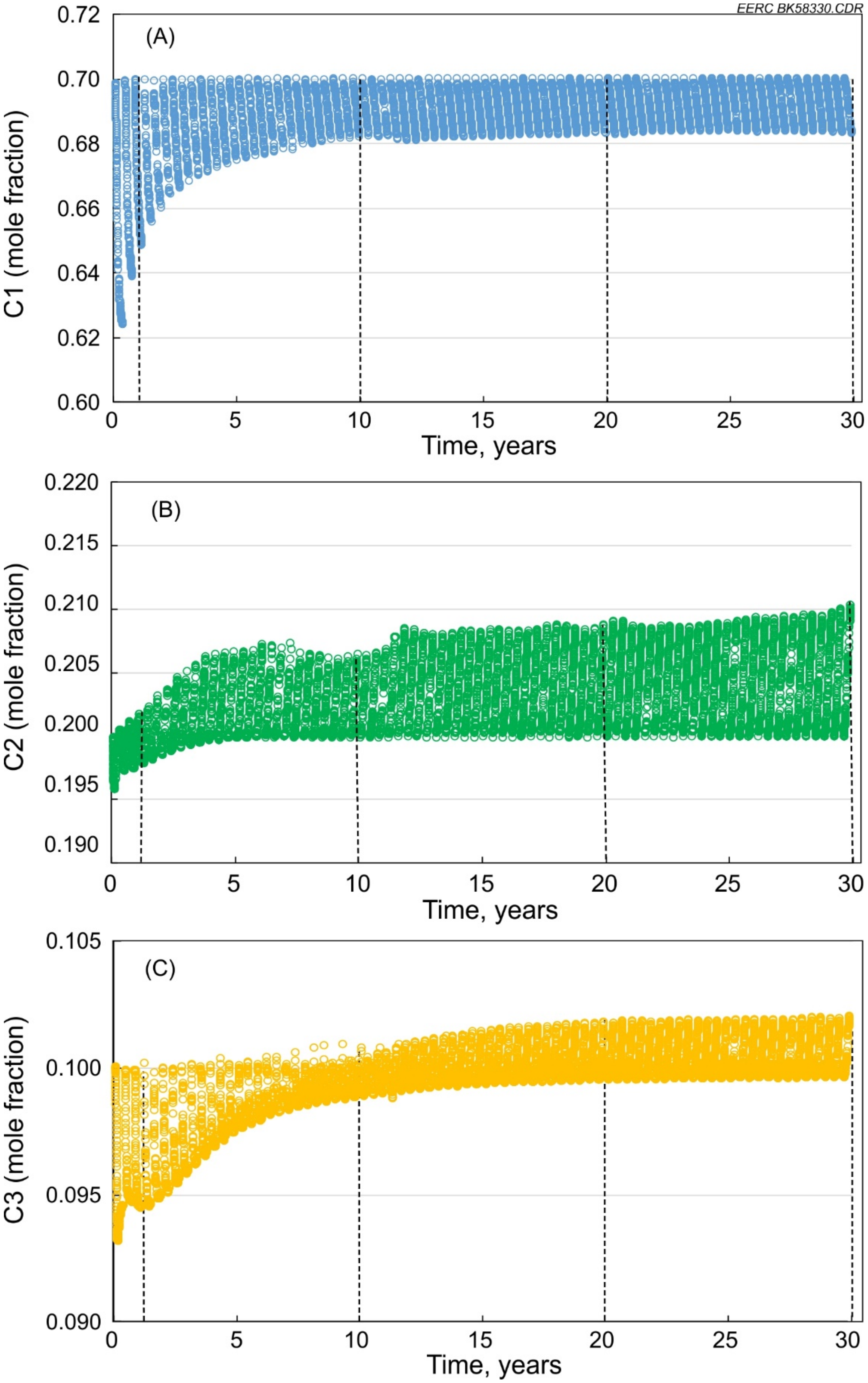

Figure 4-15. Predicted gas composition change in the BPS following 30 years of production with produced gas EOR operations: A) C1, B) C2, and C) C3.

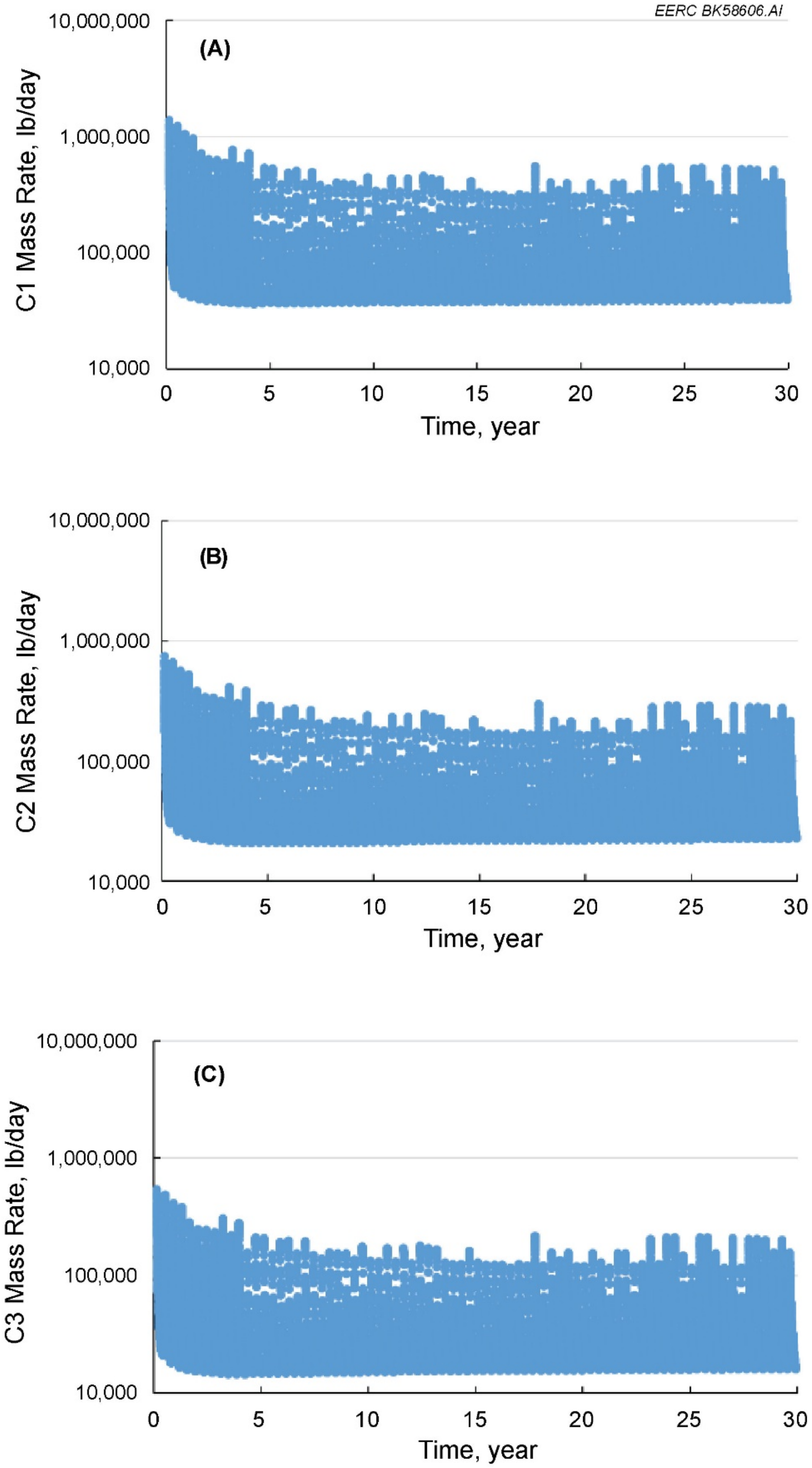

Figure 4-16. Predicted change in mass rate for each gas component in the BPS following 30 years of production with produced gas EOR operations: A) C1, B) C2, and C) C3.

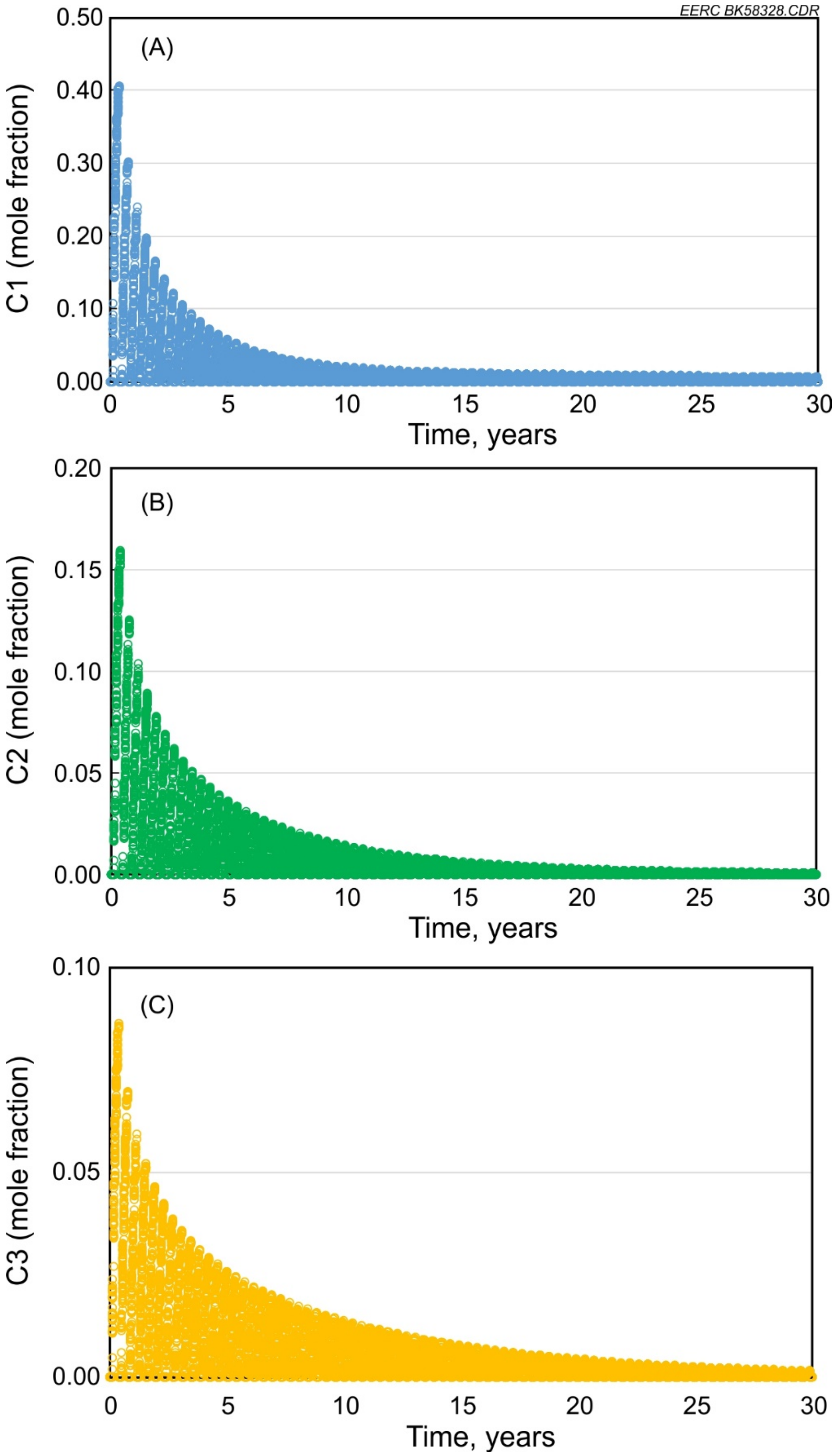

Figure 4-17. Predicted gas composition change in the BPS following 30 years of CO_2 EOR operations: A) C1, B) C2, and C) C3.

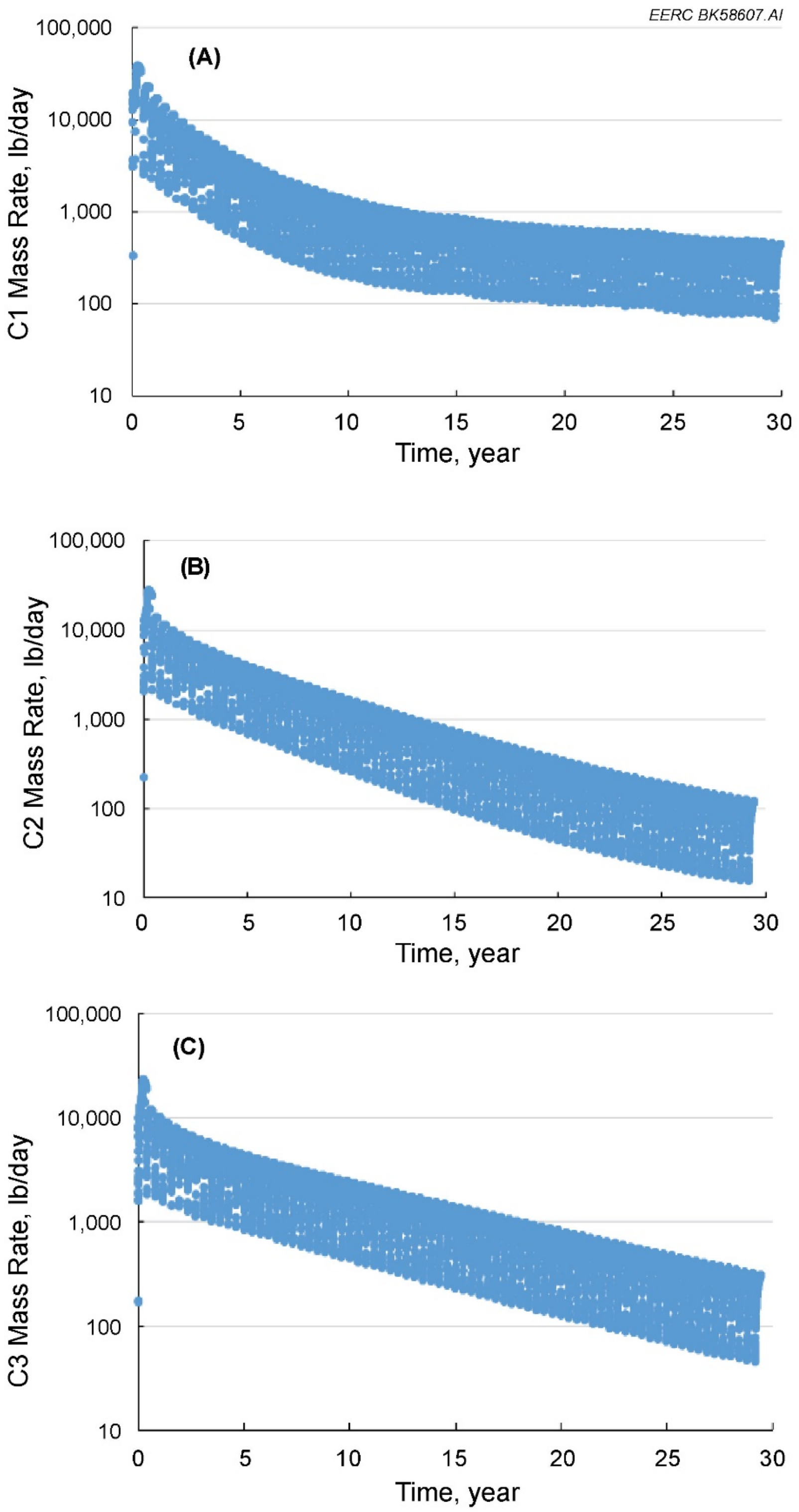

Figure 4-18. Predicted change in mass rate for each gas component in the TF well (Williams County) over 30 years of CO_2 EOR production: A) C1, B) C2, and C) C3.

The results of the EOR simulations suggest that even if produced gas EOR were widely applied in the BPS, only minor differences in produced gas composition would be seen and only within the first 5 or so years of well production. Obviously, different EOR strategies, such as ethane-only EOR, could affect these results; however, most produced gas scenarios applied or anticipated for the BPS rely on a blend of produced gas such as was used in the simulation scenario. As would be expected, CO_2 EOR is anticipated to result in a produced gas composition that is diluted with CO_2.

5.0 CONCLUSIONS

5.1 Key Findings

Data analytics were performed to analyze the gas composition data from 7361 wells in the BPS. The data set contained measurements of methane (C1), NGLs (C2–C5), other heavier liquids, and non-HC gases. The majority of the gas composition measurements were made after 2012 from wells with multistage hydraulic fracturing completions. In terms of the overall average gas concentration, C1 is the dominant component with an average value of 58 mol%, followed by C2 (20 mol%), C3 (11 mol%), C4 (4.9 mol%), and C5 (1.6 mol%), while concentrations for other components are very small except for N_2 (2.7 mol%). The average initial wetness was estimated as 39.9% and dry gas at 60.1%.

Distinct spatial patterns in gas compositions were observed across the Bakken region; in the core area, the wetness is typically less than 40%, and some areas outside the core have wetness above 45%. Propane is the primary component that influences gas wetness, followed by butane, pentane, and ethane. Temporal changes in gas composition were also observed and, in most locations, tend to follow the trend of increasing methane and decreasing gas wetness during the first 5 years of production, primarily because of decreases in NGL content over that time frame. Ethane content was shown to decrease slightly during the first 3 to 5 years of production, after which it levels off and, in some locations, begins increasing. Propane, as with butane and pentane, shows an initial increase during the first 6 months of production in the Divide, Dunn, Williams, and Dunn–McKenzie County locations (pentane also exhibits an increase in McKenzie County). After about 6 months of production, propane content declines slightly (by ~1 to 2 mol%) until about 36 months of production, after which it remains at consistent levels, except in Divide County, where propane continues a slow decline throughout 6 years of production. The temporal patterns of butane and pentane are similar to each other, and concentrations generally decrease from 6 months of production to about 18 to 36 months of production, after which the concentrations remain largely unchanged.

A small number of wells in three counties had sufficient temporal data to allow for evaluation of longer-term production trends (12 years or more). Gas composition trends based on aggregated well data were similar in McKenzie and Williams Counties, whereas the trends in Mountrail County were significantly different. The gas composition trends in the individual wells in Mountrail County also showed the most variation between wells. The aggregated well data from McKenzie and Williams Counties have similar long-term methane concentration and gas wetness trends, where methane then begins decreasing after about 11 years of production and gas wetness begins to increase.

An evaluation of correlations between measured gas content and the geochemical and geologic characteristics of the BPS shows that initial gas composition and gas composition throughout production correlate significantly with the thermal maturity of the Bakken shales and other associated geologic parameters such as temperature and depth. The more thermally mature areas of the BPS tend to have drier gas, and conversely, the less thermally mature areas have wetter gas. This trend can be explained by the thermal maturation process, where the gas composition becomes increasingly enriched over time as NGLs are converted to methane during secondary HC cracking.

It is worth noting that the correlations between gas composition during the first and eighth years of production and the geologic/geochemical parameters of the BPS were noticeably weaker than those with gas compositions after 3 or 5 years of production. The reason for the weaker relationship between geology and gas composition during the later stages of production is unclear and could be due to a smaller number of wells that have 8 years' worth of production history. The lower degree of correlation during the first year of production could suggest that engineering-related factors, such as well stimulation design or production rate, have somewhat more influence on produced gas composition during IP and the later stages of production. The influence of engineering-related factors on gas composition can be explained by the complexity that exists in the reservoir during IP where there are dramatic declines in reservoir pressure and large differences in pressure between stimulated fractures, naturally occurring fractures, and the rock matrix. Given the tight rock matrix and very small pore spaces, the pressure drop within the well-connected fracture networks is not reflected in the rock matrix. Thus in some locations within the reservoir, the reservoir pressure may decline enough to allow for liberation of different gas components, while in other areas, the pressure is still high enough to keep gas in solution. The effect of production technique (and associated pressure decline rate) on long-term gas composition is supported by modeling and simulation, as discussed below.

The modeling and simulation results suggest that long-term changes in gas composition are strongly influenced by the production rate and changes in reservoir pressure. In general, the simulation results support the temporal trend patterns seen in the measured data during the early stages of production (up to ~8 years). The simulation results suggest that, in general, the concentration of methane increases within the first 5 years of production and then decreases with long-term production. Concentrations of ethane and propane remain unchanged or decrease during the first few years of production, then increase gradually over time. Unfortunately, there are a limited number of wells with long-term production data; however, a comparison with a limited number of wells with longer-duration data suggests that the magnitude of change predicted by the simulation model may be larger than those measured in the field. While the magnitude of change in each gas component is higher in the predicted cases, the simulation also suggests that the most significant changes occur after 10 years of production. The measured data from McKenzie and Williams Counties show a trend of increasing gas wetness after about 11 years of production; thus it is possible that the magnitude of change could increase over time.

The simulation results are supported by historical observations from conventional oil reservoirs, which typically produce abundant methane initially, but in the course of production demonstrate compositional changes and an increase in gas wetness. This shift in associated gas composition is related to the significant reservoir pressure drop in conventional reservoirs after 10 or more years of production life. These timelines are in general agreement with the simulation results presented in this study, which suggest that the reservoir pressure is mostly depleted (<1000 psi) after ~10 to 15 years of production.

While the gas composition trends between the two simulation wells are similar, caution should be used when applying these results to evaluate basinwide gas composition as it is unknown at this time how the long-term trends vary from location to location. The encouraging aspect from these results is that while the MB well was located in an area with very low initial gas wetness and the TF well was located in an area with moderate initial gas wetness, the long-term trends in gas composition change were similar. That being said, the temporal aspects of when wells come online will undoubtedly affect aggregate gas compositions on a field scale and across the BPS. For example, if all BPS wells came online at the same time, we might see significant increases in NGLs following long-term production. However, the picture is more complex because total basin production volume is a composite of gas from thousands of wells that started production at different times and likely had different initial gas compositions. Based on the measured data and the simulation results, newer wells will likely exhibit a trend of increasing methane content during the first 5 to 8 years of production and decreasing NGL content during the first ~3 to 5 years. Thus when new wells come online, they could offset any trends of increasing NGL from the long-term production of existing wells. Moreover, all these wells have different production rates and their contribution to total gas production could vary by an order of magnitude or more. While a well may have a higher NGL content after 10 or 20 years of production, it will also be producing less gas and thus less NGLs. One final complicating factor is that the viable producing life of older and newer BPS wells is unknown. It may be infeasible for BPS wells to produce for 30 years, or even 20, but that is unknown at this time.

Without performing more extensive basinwide modeling and forecasting of future BPS development trends, it is difficult to determine what the long-term supplies of NGLs might look like. While it is encouraging that the long-term simulation results suggest trends of significant increases in NGL content within individual wells over time, the magnitude of that NGL contribution and the impact of the gas contribution from new wells coming online were not evaluated as part of this effort.

The reservoir model was also used to simulate changes in gas composition that may occur during CO_2-based or produced gas EOR efforts. The simulation results suggest that during produced gas EOR, the composition of the produced gas follows the composition of the injected gas. During CO_2-based EOR, the concentrations of all three gas components decrease consistently and follow the same pattern because of the large volume of CO_2 injected during the EOR process. As a result, CO_2 becomes the dominant component in the produced gas, and the concentration of other gas components decreases over time.

5.2 Suggested Future Work

The results of this study demonstrate that significant spatial and temporal patterns in gas composition exist across the BPS and that several factors contribute to variations in gas composition. The geochemical properties of the BPS source and reservoir rocks are important factors that contribute to both the initial gas composition as well as temporal changes in composition. Moreover, the modeling analyses suggest that well production rates and associated reservoir pressure changes have a large effect on temporal gas composition changes.

The key area in which additional work is recommended is related to better understanding the basinwide changes in gas composition as a whole that result from changes in gas composition over time in existing wells coupled with the input from new wells coming online and the associated gas composition of those wells. While the dynamics of future development in the BPS are difficult to predict, various scenarios could be evaluated that account for different development patterns with varying numbers of new BPS wells coming online every year. The expanded modeling effort could include additional simulation work on the PVT behavior of the reservoir fluids in additional gas-producing counties and using multiple-well scenarios with different operational modes to allow for more detailed prediction of the long-term gas composition changes across the BPS.

To help support a basinwide modeling effort, the collection of targeted, time-series gas composition data would be useful in helping to eliminate the uncertainty associated with using aggregate well data and to increase the accuracy of the temporal analysis. This information could also be used for validation of the temporal gas composition data determined with the aggregate data. The newly collected data and/or the existing data set provided to the EERC could also be used to determine if the gas composition from the parent well of a drill spacing unit is different than that of the subsequent child wells that come online. Better understanding the temporal changes in gas composition on spacing units and whether or not those patterns change based on the location of the spacing unit would also support a larger, basinwide modeling effort.

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APPENDIX A

LONG-TERM GAS COMPOSITION TRENDS FOR SELECT WELLS

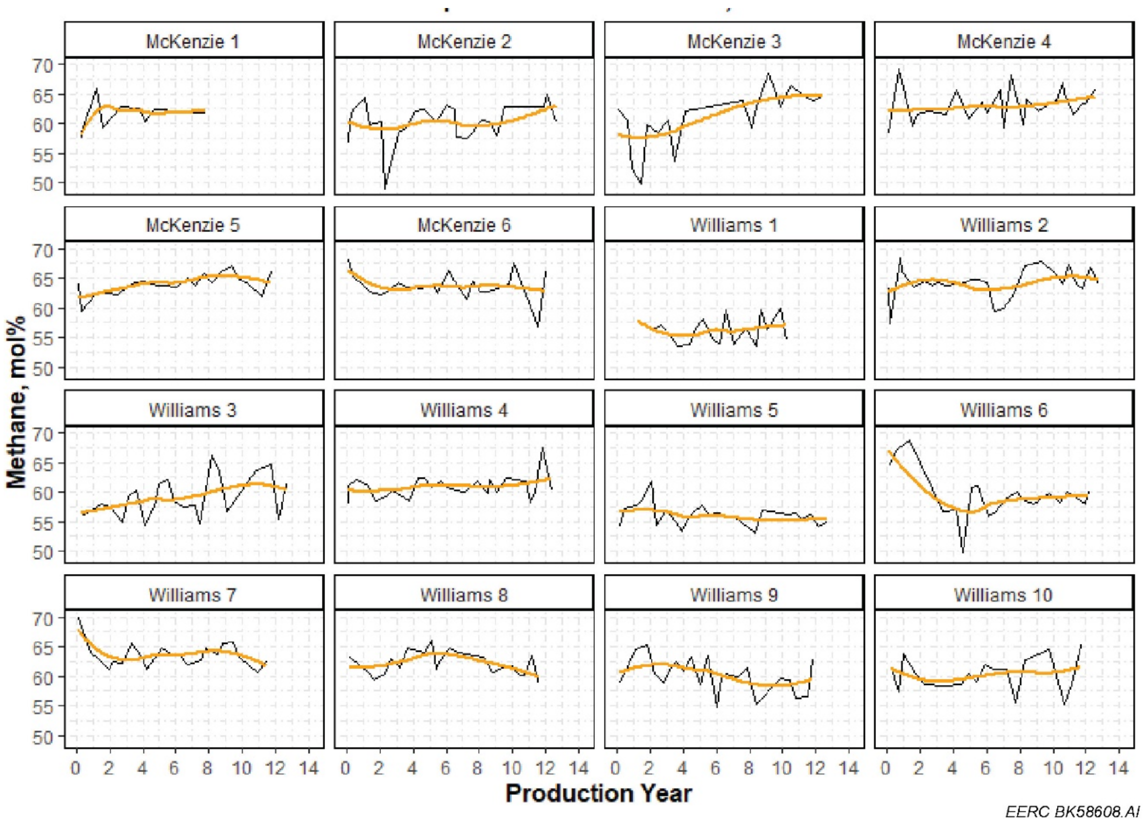

Figure A-1. Temporal changes in methane based on the time-series data of the wells located in McKenzie and Williams Counties. The orange line is the fitted loess smooth line.

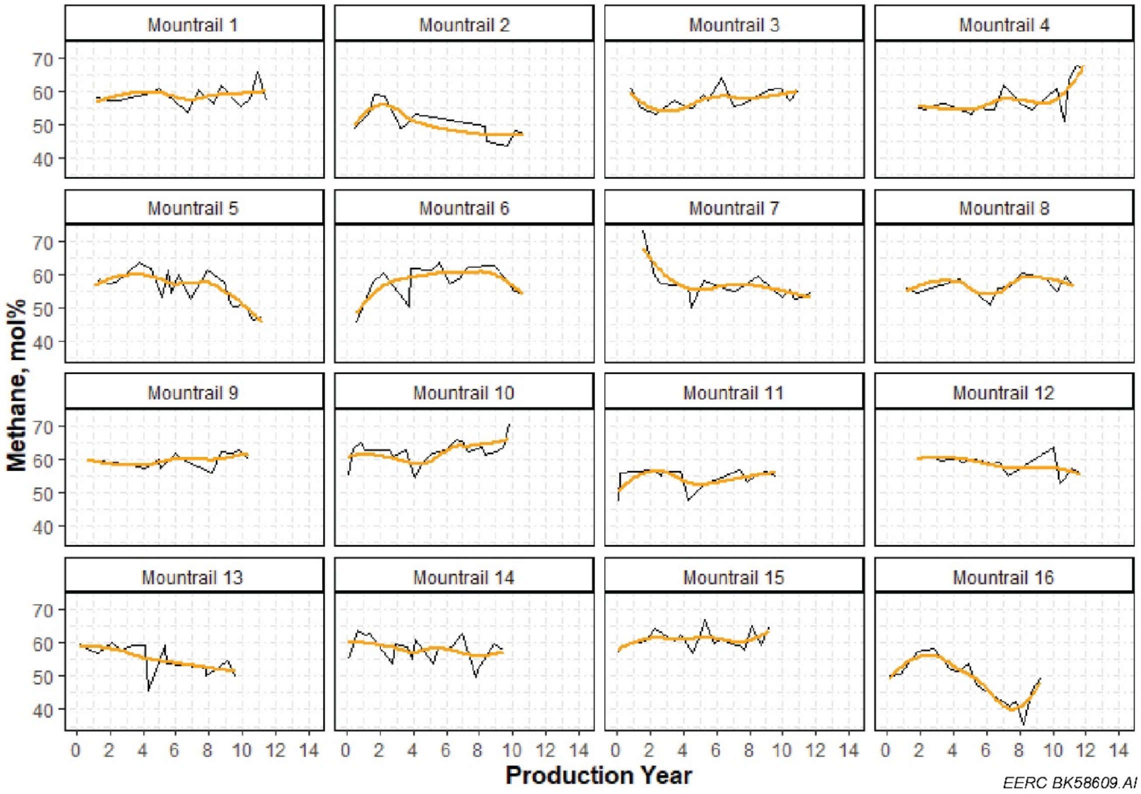

Figure A-2. Temporal changes in methane based on the time-series data of the wells located in Mountrail County. The orange line is the fitted loess smooth line.

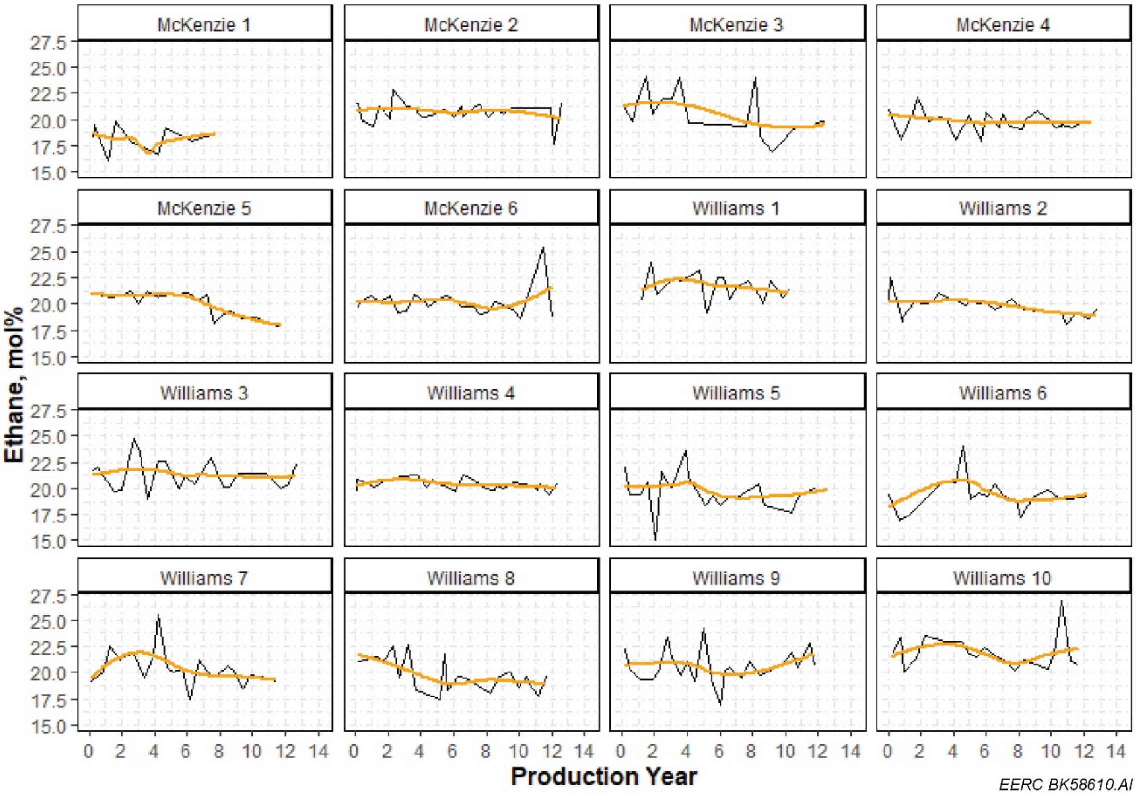

Figure A-3. Temporal changes in ethane based on the time-series data of the wells located in McKenzie and Williams Counties. The orange line is the fitted loess smooth line.

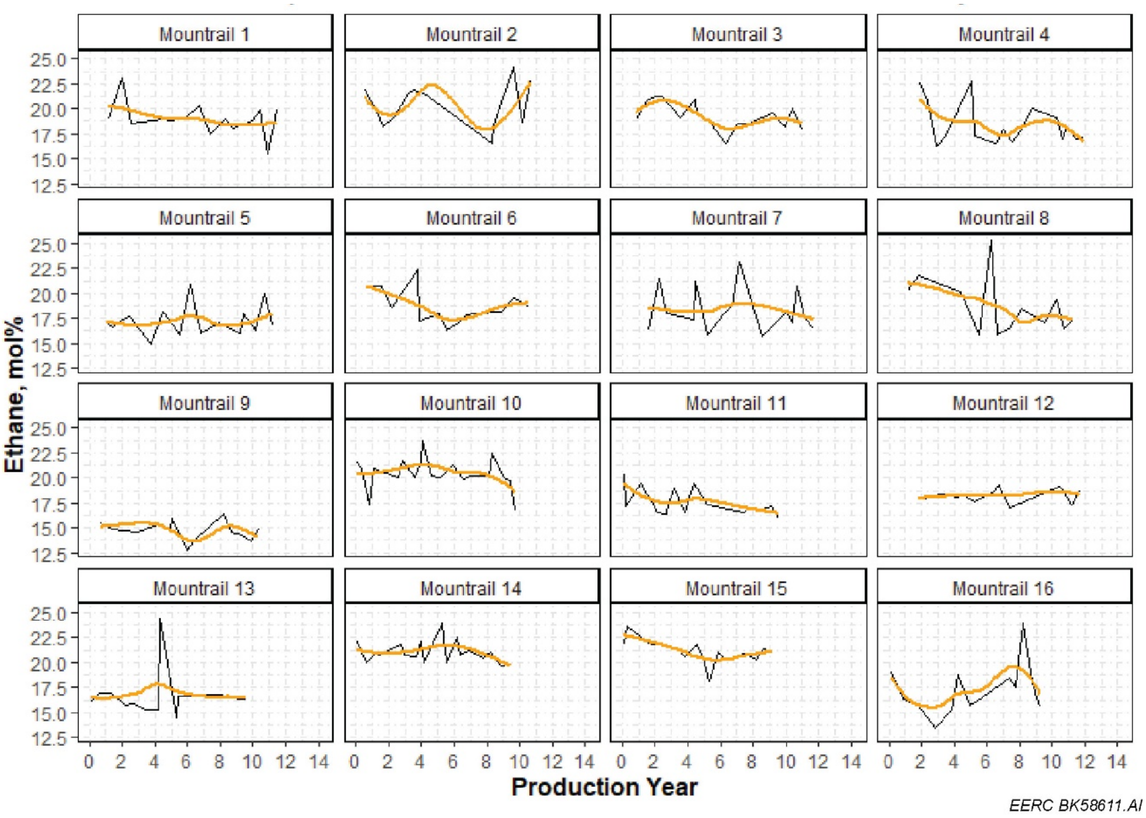

Figure A-4. Temporal changes in ethane based on the time-series data of the wells located in Mountrail County. The orange line is the fitted loess smooth line.

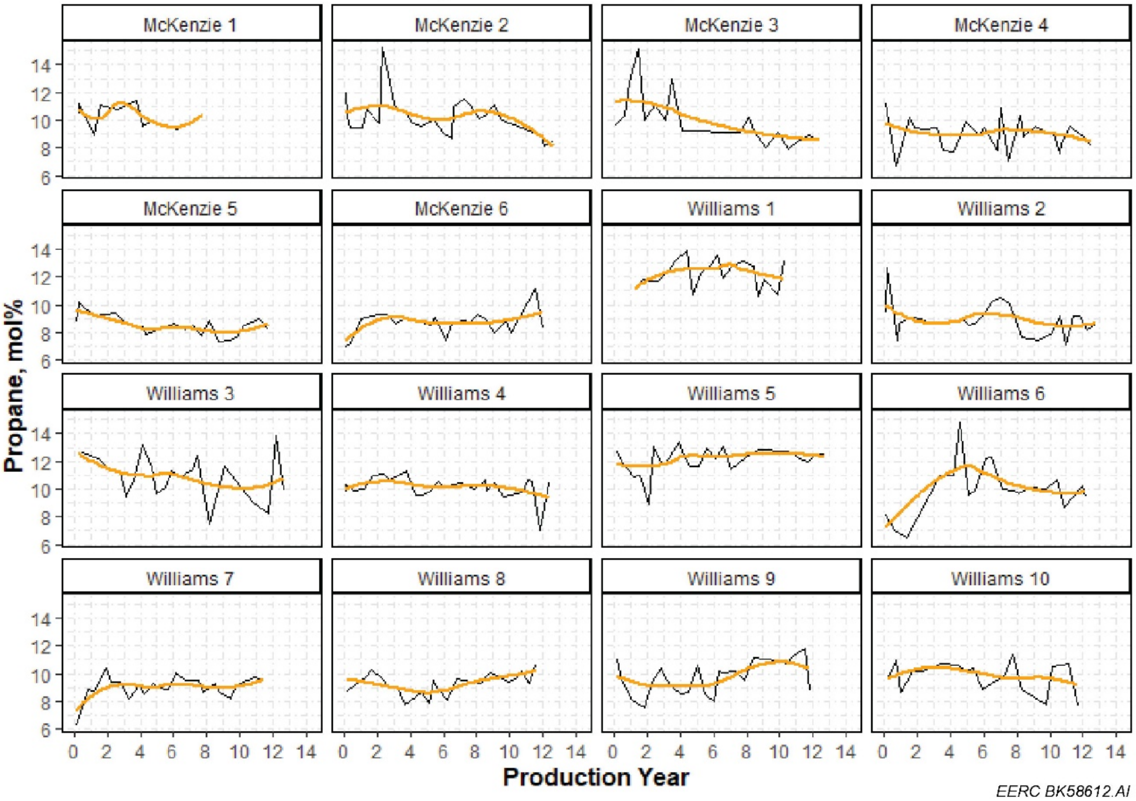

Figure A-5. Temporal changes in propane based on the time-series data of the wells located in McKenzie and Williams Counties. The orange line is the fitted loess smooth line.

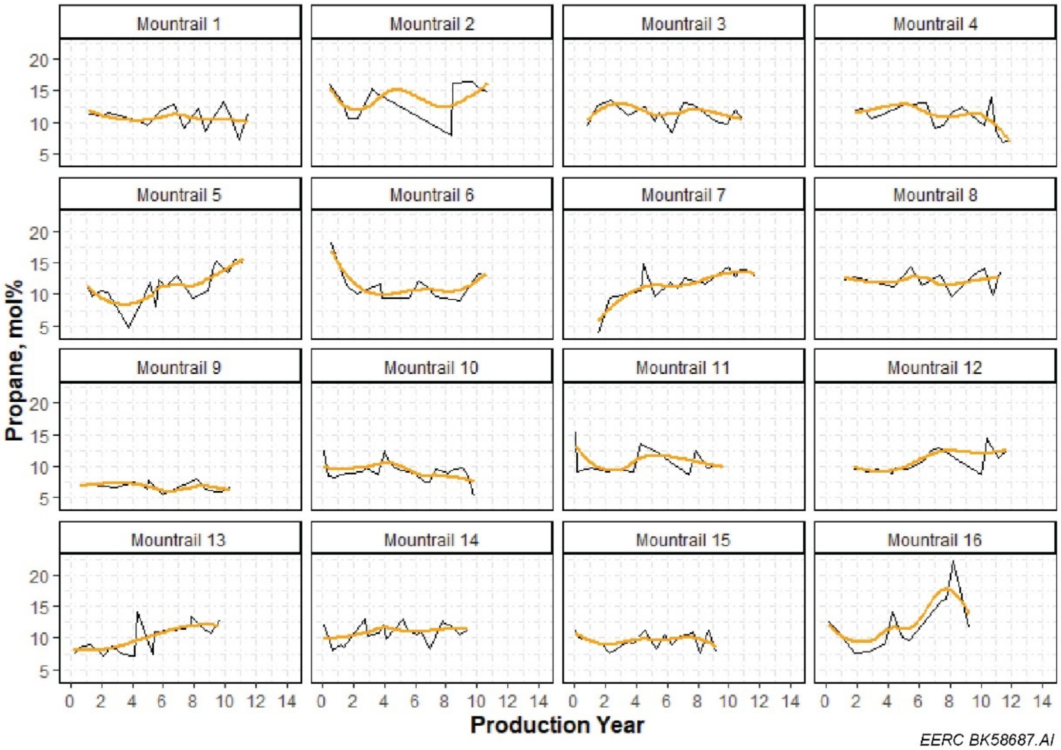

Figure A-6. Temporal changes in propane based on the time-series data of the wells located in Mountrail County. The orange line is the fitted loess smooth line.