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Original Paper

How Quickly Do Oil and Gas Wells "Water Out"? Quantifying and Contrasting Water Production Trends

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Water production from petroleum (oil and natural gas) wells is a topic of increasing environmental and economic importance, yet quantification efforts have been limited to date, and patterns between and within petroleum plays are largely unscrutinized. Additionally, classification of reservoirs as "unconventional" (also known as "continuous") carries scientific and regulatory importance, but in some cases the distinction from "conventional" wells is unclear. Using water, oil, and gas production data, we calculated a set of quantitative metrics that elucidate trends in the water-to-petroleum ratio over the life of each producing well. The percent growth of the water-to-petroleum ratio quantifies the degree to which a well "waters out" over time; values calculated for 153,900 wells in 18 oil and gas plays show generally much higher values for conventional wells than for continuous/unconventional wells. Analysis of the percent growth along with the slope and median metrics reveals greater variation between conventional plays and between continuous (unconventional) plays than previously recognized. Further, an example from the Bakken Formation in the Williston Basin, USA, illustrates that, within a single play, the metrics provide insight into spatial variation of water production trends, as influenced by geology and reservoir characteristics. By quantifying the variability of water production trends within individual plays and between plays, including differences between conventional and continuous (unconventional) plays, these results provide a more nuanced view of water production from oil and gas wells than has previously been possible and they illustrate the degree to which water management considerations vary spatially and temporally.

KEY WORDS: Produced water, Oil and gas production, Conventional resources, Shale gas, Unconventional oil and gas.

INTRODUCTION

Produced water represents the largest waste stream in oil and gas operations, and produced water management is a critical environmental and economic consideration (Supplemental Information SI Table S1). Produced water refers to all water that comes out of oil and gas wells along with hydrocarbons, including hydraulic fracturing water that flows back to the surface during the early days or months of petroleum production, and formation water that exists with the petroleum in the geologic formation (petroleum refers to oil, gas, and natural gas liquids). These types of water are intermingled from the earliest days of production (Laughland et al., 2014; Birkle, 2016; Ni et al., 2018; Oetjen et al.,

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2018) and are difficult to distinguish other than with isotopic analyses (Laughland et al., 2014; Rowan et al., 2015; Birkle, 2016; Rosenblum et al., 2017; Travers et al., 2019). Produced water represents an opportunity for reuse that may reduce industrial demands on other sources of water (Murray, 2013; Nicot et al., 2014; Barnes et al., 2015; Scanlon et al., 2020b). Alternatively, produced water can be a waste that presents concerns related to spills during transportation and storage (Vidic et al., 2013; Gleason et al., 2014; Preston and Chesley-Preston, 2015) and/or seismicity triggered by high-volume injection into disposal wells (Ellsworth, 2013; Weingarten et al., 2015; Keranen and Weingarten, 2018). In addition, disposal via injection can complicate ongoing oil and gas drilling by increasing formation pressures in overlying units (Basu et al., 2019; Sanchez et al., 2019; Wilson et al., 2019), with significant impact on the economic viability of resources and operating companies (Jacobs, 2016; Duman, 2019).

With the growing recognition of the importance of produced water management, efforts at modeling and quantifying water production are receiving increasing attention. Paralleling established approaches for calculating estimated ultimate recovery (EUR) of oil or gas (Lyons and Plisga, 2005), authors have developed approaches for quantifying total water production over the life of a well using monthly, or similar, production data (Bai et al., 2013; Yu et al., 2016; Ikonnikova et al., 2017; Kondash et al., 2017; Scanlon et al., 2020a). Estimates of total water production per well are useful for questions tied to the total quantity, but they do not capture patterns of water production variation over the life of a well or during the span of production in a play. (A petroleum play is a group of oil and/or gas wells that share a set of geologic characteristics in a common area.) Accordingly, these total water estimates can provide insight into bulk quantity variability across a play and differences between plays, but they miss temporally varying water production rates and proportions. These temporal variations can be critical to management concerns and to understanding the ramifications of ongoing transitions in hydrocarbon production.

The shift toward production of oil and gas from shale and related geologic formations (often referred to as unconventional or continuous resources) has led to shifting and amplified concerns regarding water (Scanlon et al., 2017). Water requirements for hydraulic fracturing and other purposes (Goodwin et al., 2014; Chen and Carter, 2016; Yu et al., 2016; Ikonnikova et al., 2017; Entrekin et al., 2018; Kondash et al., 2018), and volumes of produced water (Laughland et al., 2014; Kondash et al., 2017; Zemlick et al., 2018) are straining existing hydrologic systems (Scanlon et al. 2017). Other authors have noted that produced water could potentially fill some of the need for hydraulic fracturing water, water concerns may still prove to be a significant limitation for oil and gas development (Jacobs, 2016; Scanlon et al., 2020a). Pandemic-related market shifts in 2020 led to a short-term reduction in hydrocarbon demand and drilling, but water production from existing wells was not impacted, and oil prices have returned to pre-pandemic levels. In the long term, it is anticipated that US demand for oil and gas will decrease in the coming decades, but petroleum development and associated water concerns are likely to remain prevalent due to global demand (US Energy Information Agency, 2023a).

The classification of petroleum resources as "unconventional" is based on their characteristics being distinct from the "conventional" petroleum resources that dominated global oil and gas production prior to approximately the year 2000. Conventional oil and gas accumulations are characterized by discrete reservoirs with relatively high porosity and permeability. Buoyance causes the petroleum (typically migrating from deeper source rock units) to overlie water, and its continued upward migration out of the reservoir is prevented by low-permeability geologic features that seal the fluids in structural and/or stratigraphic traps (Cole, 1969; Schmoker and Klett, 2007) (Fig. 1). The separation of gas, oil, and water within a reservoir is imperfect, dependent on reservoir characteristics and fluid dynamics, but permeability and buoyancy result in a petroleum-dominated zone (with gas above oil if both are present) overlying a water-dominated zone (Fig. 1). The term "unconventional" is used broadly to encompass petroleum accumulations that do not fit the characteristics of conventional reservoirs; examples include shale oil and gas and tight (low permeability) gas sand formations. Many, but not all, of these formations are source rock, that is, geologic units containing high levels of organic carbon where oil and/or gas are generated, a distinction from conventional reservoirs. The term "continuous" has been used as a more descriptive and geologic alternative to "unconventional," referring to the semi-uniform spatial distribution of petroleum across a broad area

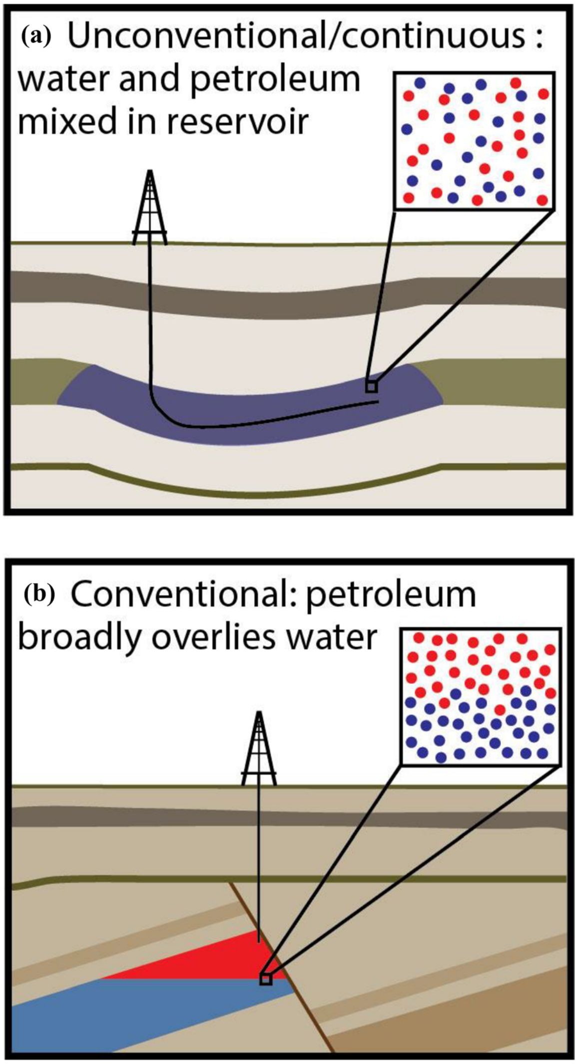

Figure 1. Primary characteristics of idealized (**a**) conventional/continuous and (**b**) conventional (**b**) reservoirs. A key conceptual distinction is that, whereas petroleum (oil, gas, or both) generally overlies water in a conventional reservoir (with limited mixing between the fluids), the fluids are essentially homogeneously mixed in a continuous/unconventional reservoir and reservoir conditions are continuous or nearly continuous over large spatial areas. Red represents oil or gas, and blue represents water.

(Schmoker and Klett, 2007; Sonnenberg et al., 2017), and we use this term throughout this contribution. In continuous reservoirs, petroleum and water are intermingled within the reservoir rock, due to low-permeability and/or anomalous formation pressure that prevents density-driven vertical separation (Fig. 1). Largely driven by development of these resources, US dry natural gas production increased by approximately 70% between 2010 and 2022, and upward trends are projected to continue at least through the year 2050 (US Energy Information Agency, 2023a). Similarly, US oil production more than doubled between 2007 and 2022, largely due to development of shale and related resources (US Energy Information Agency, 2023b).

Concerns relating to various aspects of the development of continuous (unconventional) resources have led to a suite of studies predicated on these resources being fundamentally different from conventional resources (US Department of Energy, 2015; Kondash et al., 2017; Scanlon et al., 2017) and have led to regulations specifically related to "unconventional" resources (Hass and Goulding, 1992; Holditch, 2006; Gehman et al., 2012; 40 CFR § 435, 2016; US Environmental Protection Agency, 2019). Nevertheless, the distinction between the two reservoir types is more conceptual than concrete, and classification of some plays is ambiguous. Petroleum reservoir conditions are never known perfectly, and even the existence of a "water leg" (water located beneath petroleum) may be uncertain. Distinctions based on permeability (Holditch, 2006; Jarvie et al., 2011) may be useful, but reservoir characteristics are heterogeneous and often uncertain. Oil and gas development is sometimes viewed as unconventional when it involves the use of horizontal drilling and hydraulic fracturing (Scanlon et al., 2017), but these techniques are not uniformly employed in continuous petroleum production (Bai et al., 2013; Cumella et al., 2014; Hawkins et al., 2016) (SI Table S2). Further, both technologies existed prior to the recent boom in continuous resource development, and they remain widely used in conventional oil and gas development (SI Table S2). Adding yet more complexity, some petroleum plays, such as the Bakken Formation and the Austin Chalk, exhibit characteristics of both reservoir types (Pearson, 2010, 2012; Hill et al., 2011; Jarvie et al., 2011; Pollastro et al., 2013; Theloy et al., 2019).

Using production data, we calculated a set of three metrics that quantify the rate at which water production changes relative to oil or gas production, capturing the degree to which wells "water out" or trend toward greater water production and decreasing petroleum production. The combined metrics provide a qualitative and quantitative tool for understanding the temporal and spatial patterns of water production from petroleum wells, which is valuable for long-range modeling and planning and toward characterization of reservoirs. The metrics enable quantification of water production differences within and between plays, revealing previously

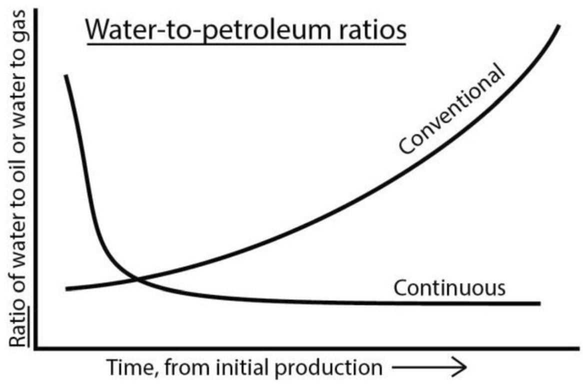

Figure 2. Plot illustrating idealized water production trends for conventional and unconventional/continuous reservoirs. Continuous reservoirs typically show petroleum and water production that decrease together with time, following the initial flowback period. Conventional reservoirs typically show decreasing petroleum production and increasing or relatively increasing water production over time.

unrecognized heterogeneity. Conventional wells are known to show generally increasing water production later in the well life, and continuous wells have more recently been recognized as showing distinct water production trends (Haines, 2015; Scanlon et al., 2016, 2020a) (Fig. 2); our metrics quantify these patterns and reveal previously unidentified heterogeneity.

We first describe our data and computational approaches. We then demonstrate the utility of the new water production metrics with a comparison of nine conventional and nine continuous plays located across the USA, with nearly 153,900 wells from a mix of oil and gas plays. We demonstrate additional utility of the water production metrics for characterizing spatial patterns within individual plays, using the Bakken play as an example, and finally, we explore the implications for long-range water production from conventional versus continuous plays. The purpose of this work was to establish approaches for quantifying water production trends and to illustrate the range of behaviors that exist within and between plays. Informed discussions of produced water need to consider the different water production trends between conventional and continuous (unconventional) resources, between plays within each of these categories, and within individual plays.

OIL, GAS, AND WATER PRODUCTION DATA

Oil and gas production regulations vary between states, and data reporting requirements, data reporting lags, and data availability vary similarly. For all states, oil and gas volumes are reported, as these provide the basis for calculating royalties paid by the operating companies. An additional common use for oil or gas production data is the calculation of EUR, which is widely used for many purposes. In many states, production reporting includes water in addition to oil and gas; these three volumes are typically reported on a monthly basis to the state for each producing well. For other states, such as Texas, Louisiana, and Oklahoma, fluid production reporting is limited to oil and gas, and the volumes may be summed for groups of wells (''leases'') rather than being reported for individual wells.

For states where monthly water production data are reported, we calculated ratios of water to oil (for wells that produce predominantly oil) or water to gas (for gas wells). For each well, we calculated this ratio for each month for which we have the necessary data (Fig. 2), using values from the IHS Markit™ database (IHS Markit™, 2018). We followed the designations of wells as ''oil'' or ''gas'' as provided by IHS Markit (2018); these are reported by each state regulatory agency. To address problems including missing data and erroneous values, we have developed a set of quality analysis and quality control approaches (Varela et al., 2017). If individual production numbers are anomalously low, we reject those data points and, if a well shows an excessive number of missing data points, we remove that entire well from our analysis. This approach is based on the assumption that either of these patterns most often indicates either erroneous reporting or unusual well behavior such as maintenance operations. Because we focused on the volume ratio of water to petroleum, our approach is insensitive to any factors (including data irregularities or borehole length or directionality) that would comparably impact water and petroleum volumes. Because of apparent widespread irregularities with water production data from Pennsylvania, we did not include the Marcellus Formation in our analyses.

For Texas, Louisiana, and Oklahoma, we calculated water-to-petroleum ratios using data from ''production tests'' that oil and gas operators conduct periodically. These tests of oil, gas, and water production (generally, the volume of each fluid in one day) are typically conducted at the onset of production (''initial production tests''), and they may be conducted at regular intervals over the life of the well (''capacity tests''). The interval between production tests depends on state requirements and/

or operator preference, typically six months to one year. Using production test data from the IHS Markit™ database (IHS Markit™, 2018), we calculated water-to-oil ratios or water-to-gas ratios for each test, and then interpolated ratios between the available tests in order to create a month-by-month time series for each well. Based on analysis of data from the limited locations where data are sufficient for the purpose, we determined that production ratios calculated from test data showed very similar trends to ratios calculated from monthly production data (SI Figure S1 and Table S3). Due to the coarse time sampling for test data relative to monthly production data, this approach is suitable primarily for long-term analyses such as those described here.

METRICS FOR QUANTIFYING WATER PRODUCTION TRENDS

Using monthly water-to-petroleum ratio data for a given well (water-to-oil ratio for oil wells, and water-to-gas ratio for gas wells), we calculated three metrics that capture water production trends (Fig. 3). The early months of production for many wells show high water-to-petroleum ratios; this is generally associated with the return of hydraulic fracturing water to the surface ("flowback"), and we observed that the duration was typically between two and six months and occasionally a year or greater. Because flowback water production is at least partly related to engineering choices, we calculated our metrics using data beginning with the twelfth month of production in order to focus on reservoir-related patterns rather than flowback idiosyncrasies (Edwards et al., 2017).

The first of our three water metrics is the median of the water-to-petroleum ratio for months 12 to 24 (Fig. 3); this represents the baseline water production ratio—early in production, but after flowback has subsided. We used the median to capture the central tendency of the relevant production ratios because, unlike the mean, the median is insensitive to outlying values. The units of the median metric are barrels[1] (bbl) of water per barrel of oil for oil wells, and barrels of water per thousand cubic feet[2] (mcf) of gas for gas wells. Two key distinctions of our median metric relative to other quantification approaches are that we avoided complexities associated with flowback water, and the median metric shows the starting point for water production for a well (after flowback), rather than an average for the entire life of the well.

Our second metric is the slope of the water-to-petroleum ratio from month 12 to the end of reported production (Fig. 3), calculated with linear regression. This slope provides a simple measure of the change of the water production ratio over the life of a well; it can be positive or negative. The units for the slope metric are bbl per bbl per month for oil wells, and bbl per mcf per month for gas wells.

Our third, and foremost, metric is the percent growth of the water production ratio, calculated as the slope divided by the median (Fig. 3):

$$\text{Percent Growth} = 100x\frac{\text{Slope}_{\text{month 12 to end}}}{\text{Median}_{\text{months 12 to 24}}}$$

This metric quantifies the change in the water production ratio relative to the starting value. Put another way, the percent growth is the rate of change (slope) normalized by the starting point (the median). The units for the percent growth metric are %/month for both oil and gas wells. The common measurement units allow for direct comparison of oil and gas wells or plays, an important feature. The percent growth metric measures the degree to which a well "waters out" over the span of petroleum production; it is our principal metric, revealing useful reservoir information by itself and also in conjunction with the other two metrics.

In our analyses, we generally considered vertical, horizontal, and directional wells together. This was based on our observation that, although well directionality (along with lateral length) may play a role in total fluid volumes, it does not play a noticeable role in fluid ratios. We noted that several conventional plays include many non-vertical wells and several continuous plays include many non-horizontal wells (SI Table S2).

APPLYING THE WATER PRODUCTION METRICS

Comparing Trends for Conventional and Continuous Oil and Gas Plays

Because the percent growth is our primary metric, we describe it first throughout this section,

[1] 1 bbl = 42 gallons = 0.16 cubic meters

[2] 1 mcf = 28.32 cubic meters

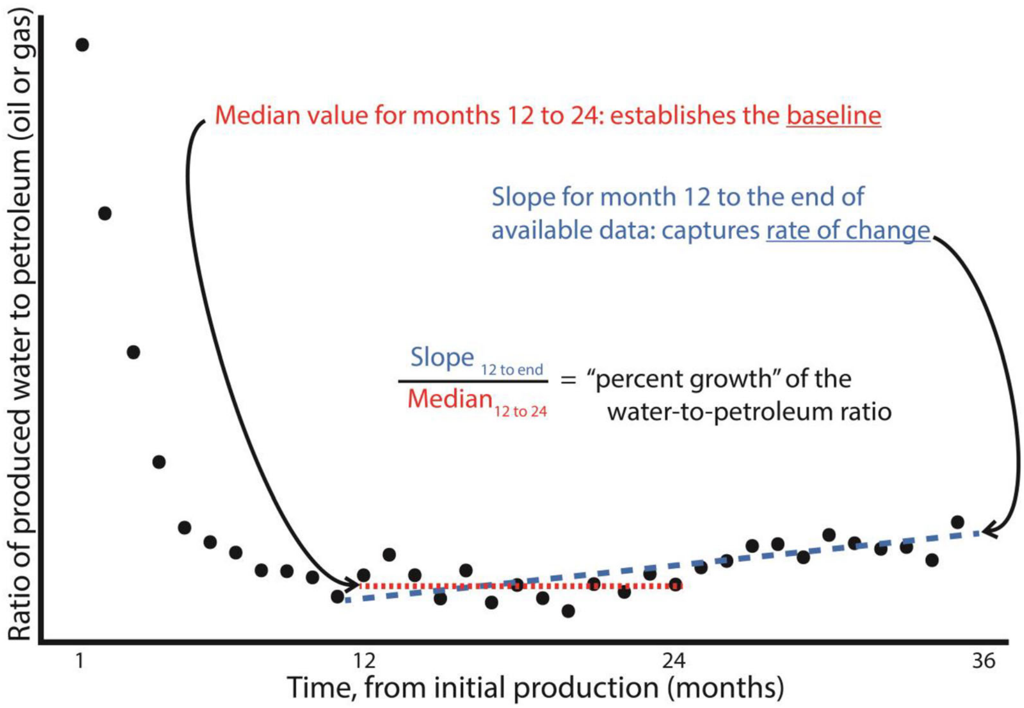

Figure 3. Schematic diagram of the calculations that go into our three metrics, based on hypothetical data for a single petroleum well. The black dots represent the ratio of produced water to petroleum (oil or gas) for each month, beginning with initial production. The metrics capture different aspects of the water-to-oil or water-to-gas production ratio over time. The hypothetical data in this plot are representative of a well with flowback (high water-to-petroleum ratios) in the early months and a slowly increasing water ratio. The metrics are calculated similarly for any well, and the slope can be positive or negative.

followed by the median and slope metrics. Analyzing data from 153,900 wells in 18 oil and gas plays distributed across the USA (Fig. 4), we obtained percent growth results (Fig. 5, SI Table S4). This includes nine plays that are typically considered continuous (unconventional) and nine that are considered conventional. Technically, some of our well groups (e.g., those that correspond with specific oil or gas fields) might be considered parts of larger plays, but we use the word "play" for simplicity and because these fields are representative of the larger plays. Our included continuous plays are all shale, tight sand, and related formations; methane produced from coal beds, bitumen produced from oil sands, and kerogen produced from oil shales are also considered continuous or unconventional resources, but many characteristics of these systems are distinct and thus likely fall outside of the observations presented herein.

For each play, calculated percent growth values for all wells for which we had sufficient data are plotted together in a standard box/whisker format (Fig. 5). We observe considerable variation of percent growth values between plays and within plays, with values ranging from slightly below zero to several tens of percent, and distinct patterns for conventional versus continuous (unconventional) plays. Percent growth values for wells in continuous plays (P50 between − 0.6 and 0.8%/month, where the P50 is the median of the distribution of values for each play) are generally lower than those for the conventional plays (P50 between 1 and 6%/month), indicating that many wells in conventional reservoirs watered out much more rapidly than wells in continuous reservoirs. In addition, the ranges spanned by wells in continuous plays (interquartile range between 0.7 and 4%/month) are generally much narrower than the ranges spanned by wells in conventional plays (interquartile range between 1 and 20%/month), indicating a wider range of behavior in conventional wells.

We gain further insight into differences between plays by looking at the median and slope metrics (Figs. 6 and 7, SI Tables S5 and S6). When

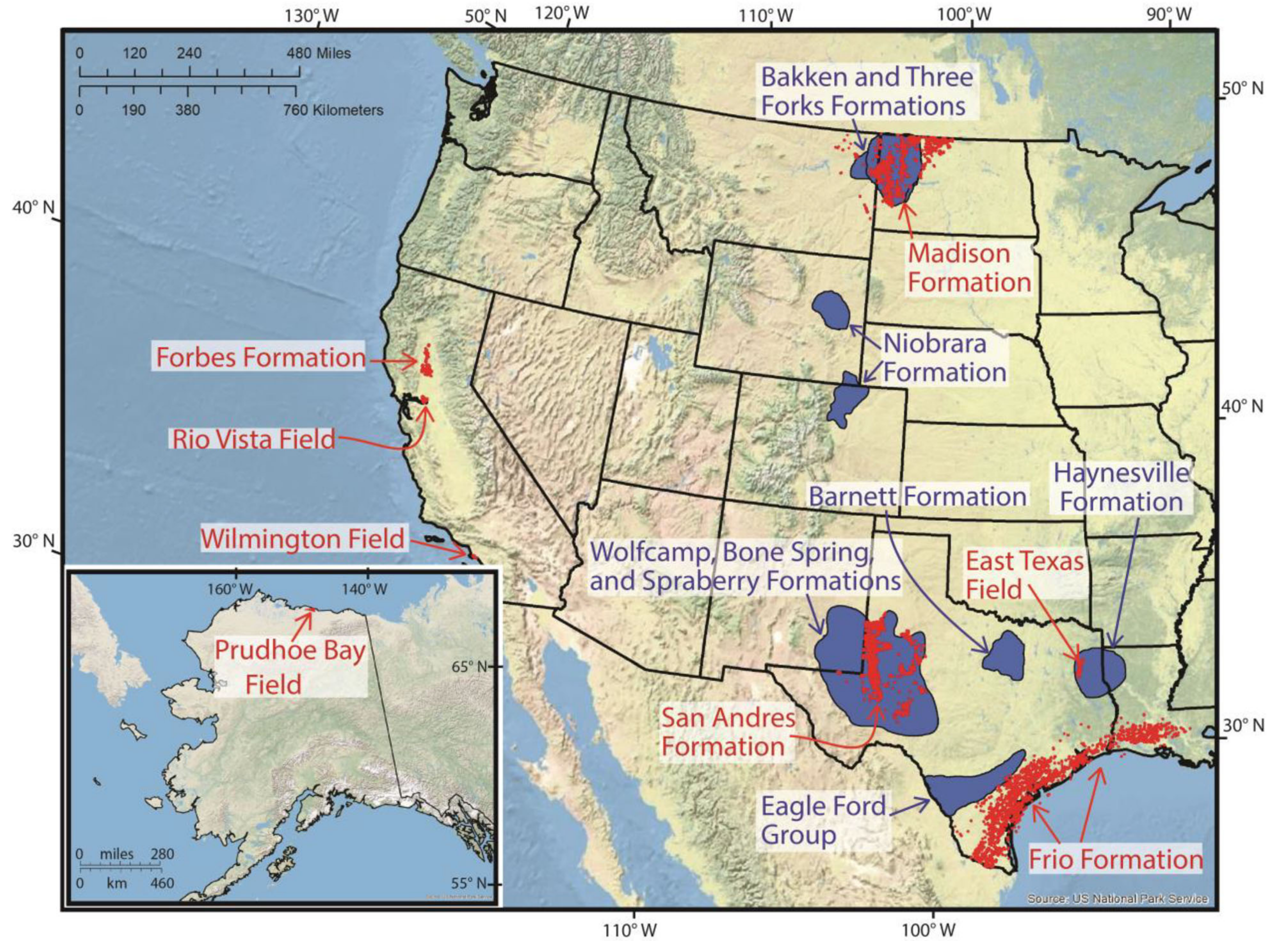

Figure 4. Map of western USA, showing locations of the 18 plays analyzed in this study. Blue polygons indicate the spatial extent of continuous plays, and red dots indicate wells in conventional plays.

considering the slope and median metrics, we generally consider oil and gas plays separately, because the units of measurement were different and because reservoir dynamics differed between oil and gas reservoirs. In Figure 6, we again see generally distinct behavior for conventional and continuous plays—continuous oil plays show consistently low median (P50 between 0.2 and 1.7 bbl/bbl) and slope (P50 between $-$ 0.0009 and 0.005 bbl/bbl/mo) values and narrow ranges (interquartile range for the median between 0.09 and 1.6 bbl/bbl and interquartile range between 0.003 and 0.1 bbl/bbl/mo for slope), while conventional oil plays show generally larger values (P50 medians between 0.1 and 11 bbl/bbl and P50 slopes between 0.006 and 0.17 bbl/bbl/mo) and much wider ranges (interquartile range for the median between 0.1 and 21 bbl/bbl and interquartile range between 0.006 and 0.9 bbl/bbl/mo for slope). This corresponds with continuous plays generally producing relatively limited water and little change with time, and conventional plays often showing greater water production and more increase with time. We also note the general pattern of slopes and medians for each play tended to mirror one another; that is, plays with high and widely spread medians tended to also have high and widely spread slopes. Slope and median patterns for gas plays are much more scattered (Fig. 7), with widely distributed values and limited correlation between slopes and medians for each play. We also do not observe a clear distinction between conventional and continuous gas plays in the slope and median patterns (Fig. 7).

Comparing our values with published work, we observed that our calculated medians are similar to, but generally somewhat lower than, related but

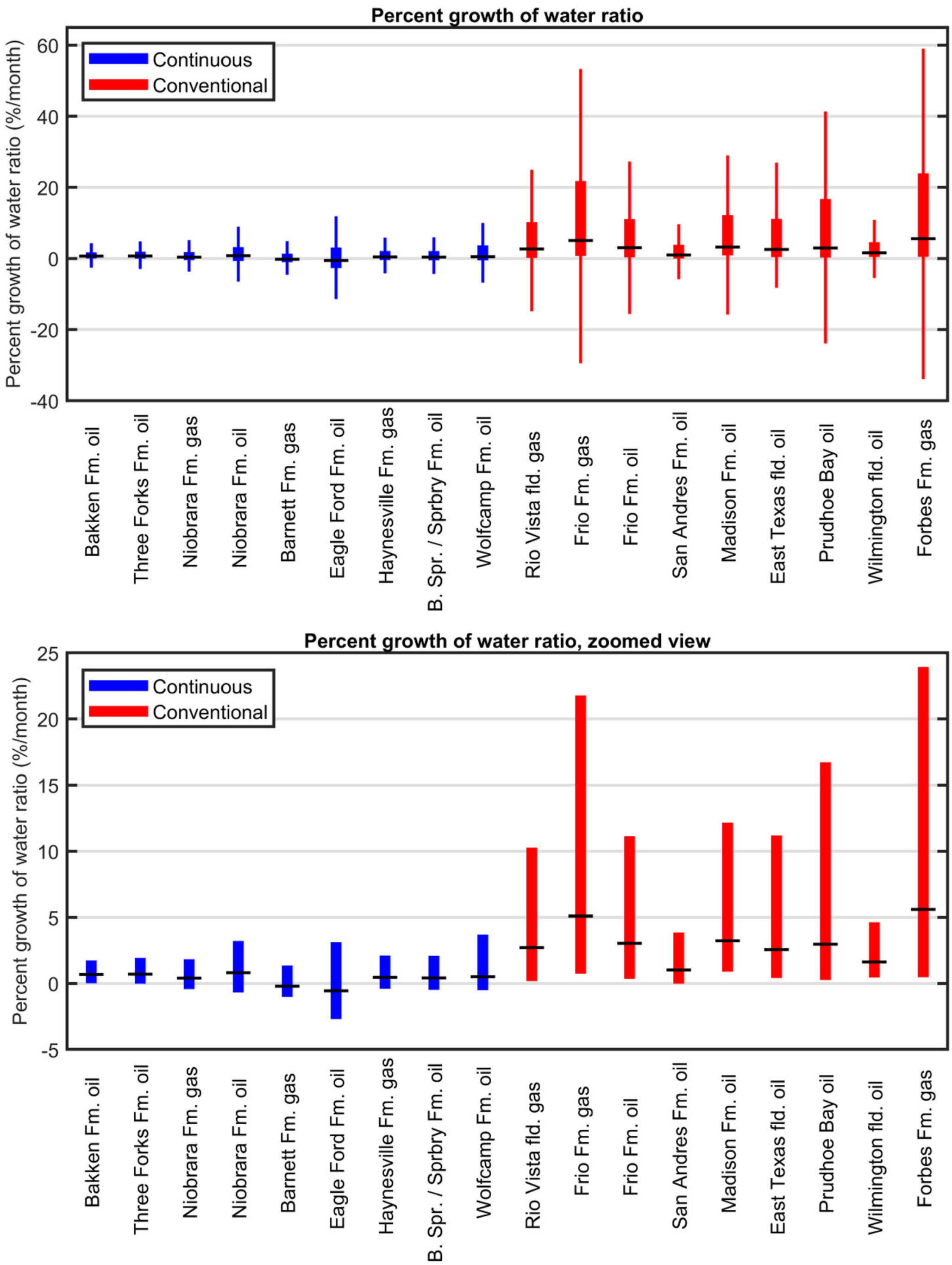

Figure 5. Percent growth analyses for 153,900 wells plotted as standard box and whisker plots. For each well grouping, the box indicates the interquartile range Q1 to Q3 (that is, P25 to P75, spanning the central 50% of the data points), the P50 value is indicated with a horizontal black line, and in (**a**) the whiskers (vertical lines) indicate the range that spans approximately 99.3% of the data points. The lower plot (**b**) includes the same values as the upper plot (**a**), scaled to include just Q1 to Q3. Continuous plays are plotted in blue and conventional plays are plotted in red. Fm = Formation; fld = field; B. Spr = Bone Spring; Sprbry = Spraberry.

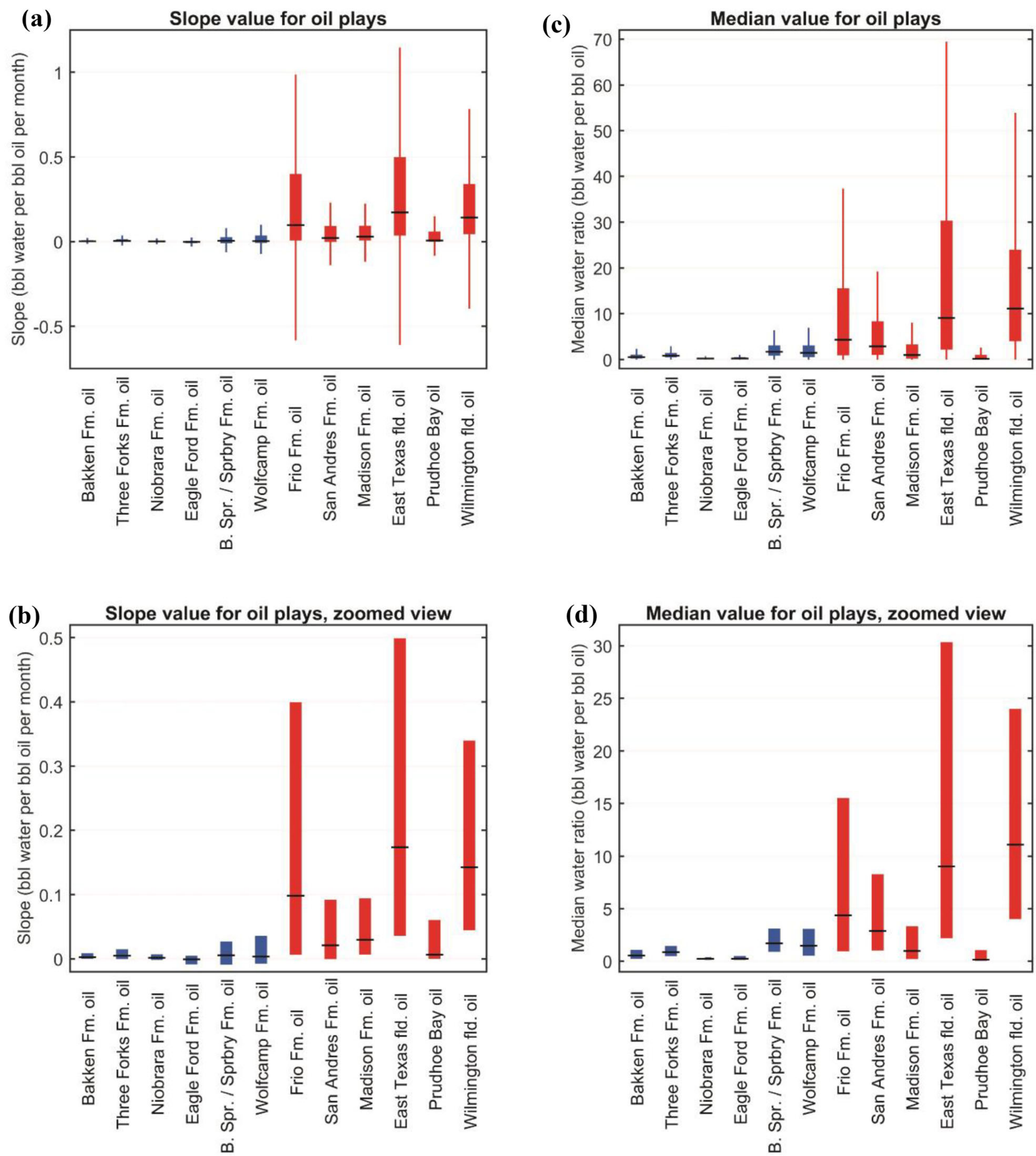

Figure 6. Slope and median analyses for the 12 oil plays plotted as standard box and whisker plots. (Box shows Q1 to Q3, and the P50 value is indicated with a black line.) The lower plots (**b** and **d**) include the same values as the upper plots (**a** and **c**), scaled to include just the Q1 to Q3 interquartile range. Continuous plays are plotted in blue and conventional plays are plotted in red. Units: "bbl" indicates barrels (1 bbl = 42 gallons = 0.16 cubic meters). Q1 and Q3 indicate the quartiles of the distribution for each play. Fm = Formation; fld = field; bbl = barrels; B. Spr = Bone Spring; Sprbry = Spraberry.

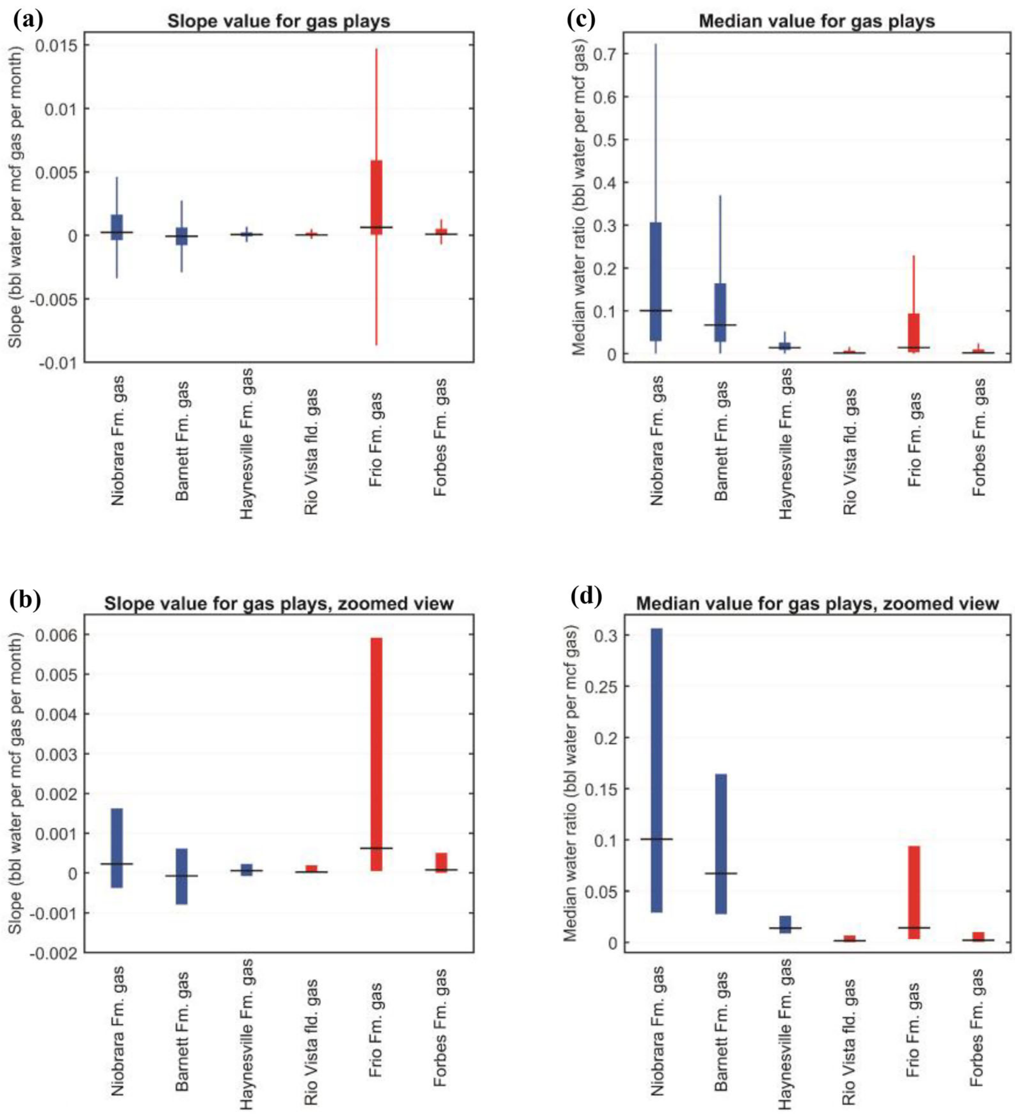

Figure 7. Slope and median analyses for the six gas plays plotted as standard box and whisker plots. (Box shows Q1 to Q3, and the P50 value is indicated with a black line.) The lower plots (b and d) include the same values as the upper plots (a and c), scaled to include just the Q1 to Q3 interquartile range. Continuous plays are plotted in blue and conventional plays are plotted in red. Units: ''bbl'' indicates barrels (1 bbl = 42 gallons or 0.16 cubic meters), and ''mcf'' indicates thousands of cubic feet (1 mcf = 28.32 cubic meters). Q1 and Q3 indicate the quartiles of the distribution for each play. Fm = Formation; fld = field; bbl = barrels; mcf = thousands of cubic feet.

distinct values observed in other studies (Scanlon et al., 2017, 2020a; Theloy et al., 2019); a key difference is our exclusion of flowback when calculating water production ratios. Comparing our calculated oil and gas values, we see little or no relation between hydrocarbon type and percent growth (Fig. 5). Direct comparison of oil and gas slopes and medians is not possible due to different units but conversion of gas to barrels of oil equivalent (boe, estimated as 1 boe = 6 mcf gas) allows some observations (SI Table S7). We note that often, but not universally, gas wells yielded less produced water per energy equivalent than oil wells. Similar patterns have been noted in other studies and attributed to thermal maturity (Scanlon et al., 2020a). For migrated gas (all conventional gas plays and some continuous plays), thermal maturity is likely less of a factor in water production. Another factor impacting oil versus gas comparisons is that water injection is heavily used in some conventional oil reservoirs to maintain reservoir pressure, as described in the next section.

Contrasting Reservoir Characteristics

As described in the previous section and shown in Figure 5, comparison of percent growth for continuous versus conventional plays reveals behavior that broadly meshes with the simple reservoir models depicted in Figures 1 and 2. The model for conventional reservoirs represented in Figure 1 relies on flow of water into the reservoir to replace produced fluids, a concept known as "water drive" (Cole, 1969; Hartmann and Beaumont, 1999). In a water-drive system, as the petroleum-dominated part of the reservoir shrinks, the water-dominated part of the reservoir expands, and production of water from a vertical well increases. Other reservoir drive mechanisms exist and many reservoirs show characteristics of multiple drive mechanisms (Cole, 1969; Hartmann and Beaumont, 1999). Another key factor in reservoir dynamics is the concept of "wettability," which indicates the fluid phase that coats the grains and thus typically exits the reservoir more slowly. Most conventional reservoirs are water-wet, but continuous reservoirs show more complex behavior (Alvarez and Schechter, 2016; Gupta et al., 2018). Also relevant is that long-term petroleum production has been maintained in many conventional oil reservoirs through injection of water ("water flooding") or gas (natural gas or carbon dioxide), two forms of "secondary recovery" (Cole, 1969) aimed at maintaining reservoir pressure and in some cases avoiding surface subsidence. The full breadth and complexity of reservoir engineering fall outside the scope of this paper but we discuss several prominent observations here.

Percent growth values for Prudhoe Bay oil wells are as expected for a conventional play—moderate to high, corresponding with increasing water ratios (Fig. 5). The median and slope metrics (Fig. 6) reveal, however, that the play is unique among our conventional oil plays. Prudhoe Bay wells produce very little water (low medians), such that although the slopes appear relatively low, the resulting percent growth values are high. This corresponds with the fact that Prudhoe Bay reservoirs have negligible water drive, and long-term pressure maintenance has been accomplished through injection of gas and water. (All gas produced in this area must be used locally because there is no pipeline for commercial sale.) This example illustrates the benefit of the percent growth metric (slope normalized by the median) relative to the raw slope, which may convey only part of the story.

Two groups of conventional oil wells, for the San Andres Formation and the Wilmington Field, show relatively low percent growth values (Fig. 5). Both areas have substantial production dating to the 1920 s. The Wilmington Field lacks natural water drive, and it has seen substantial water flooding since the 1950 s to mitigate land subsidence and maintain reservoir pressure; correspondingly, the medians and slopes in Figure 6 show very high, and increasing, water production. Essentially, water production was already elevated at the start of production of these wells and additional "watering out" was minimal. Reservoirs in the San Andres Formation also lack substantial water drive, and secondary recovery has included both water flooding and gas injection (Galloway et al., 1982); correspondingly, the medians and slopes (Fig. 5) are low to moderate. These cases illustrate the necessity of looking at the median and slope metrics in addition to percent growth and to understanding the production histories of individual fields.

The included gas plays follow anticipated patterns for percent growth, and in fact the gas plays are some of the "best behaved" in Figure 5. Looking at the slopes and medians in Figure 7, however, we were left with a more complex picture—there is no clear distinction between conventional and continuous gas plays in either of these two metrics. We attribute this broad range of slopes and medians to the diversity of conditions that exist in gas reservoirs, and we suggest that these gas plays further illustrate the benefit of the percent growth metric relative to the un-normalized slope.

Map View: Spatial Heterogeneity Within the Bakken Play

In this section, we demonstrate how our water production metrics can reveal spatial trends within individual plays, focusing on the Bakken Formation in the Williston Basin in Montana and North Dakota. The Bakken is generally considered a continuous play (Pollastro et al., 2013; Gaswirth and

Marra, 2015; Sonnenberg et al., 2017; Theloy et al., 2019), though some areas appear to show characteristics of conventional reservoirs (Hill et al., 2011; Jarvie et al., 2011; Theloy et al., 2019).

The plots in Figure 5 indicate that wells producing from the Bakken Formation have generally low percent growth values relative to other plays and that they span a relatively narrow range (interquartile range less than 1.8%/month). In map view (Fig. 8a), however, we see that two regions of Bakken production show percent growth values that are higher than in the rest of the play. The area around the Billings anticline has been associated with elevated porosity and natural fracturing (Pollastro et al., 2013; Sonnenberg et al., 2017), and oil production there may include contributions from adjacent formations (Sonnenberg, 2014); these factors likely contribute to the somewhat more ''conventional'' water production patterns. The Parshall area has been identified as having some characteristics more often associated with conventional reservoirs, including oil migrated from thermally more mature areas to the west (Hill et al., 2011; Jarvie et al., 2011) and patterns indicative of trapping mechanisms (Theloy et al., 2019), corresponding with the relatively high percent growth values in the eastern part of the area.

Relative to other oil plays (Fig. 6), the Bakken shows very low initial water production (low median metric) and minimal increase in water production over time (low slope). In Figure 8b, we see a strong spatial pattern in the median metric, corresponding with many of the major geologic features of the play (Pollastro et al., 2013; Gaswirth and Marra, 2015; Theloy et al., 2019). Particularly low water production is observed in the Elm Coulee, Billings anticline, and Parshall areas, and along the Nesson anticline. These areas of low water production corresponded with high formation pressures and high oil EUR (Gaswirth and Marra, 2015), and the Nesson anticline is an area of production of conventional resources from other formations in the basin (Fig. 4). The map in Figure 8b looks qualitatively similar to a standard ''water cut'' map (Roth and Roth, 2014; Theloy et al., 2019), but it shows greater detail and a more direct tie to reservoir properties because we exclud the flowback period. In Figure 8c, we observe more spatial scatter in the slope metric, with the Elm Coulee area showing particularly low values, and a small portion of the easternmost Parshall area showing elevated slopes (again, potentially corresponding with the somewhat more ''conventional'' characteristics in this area).

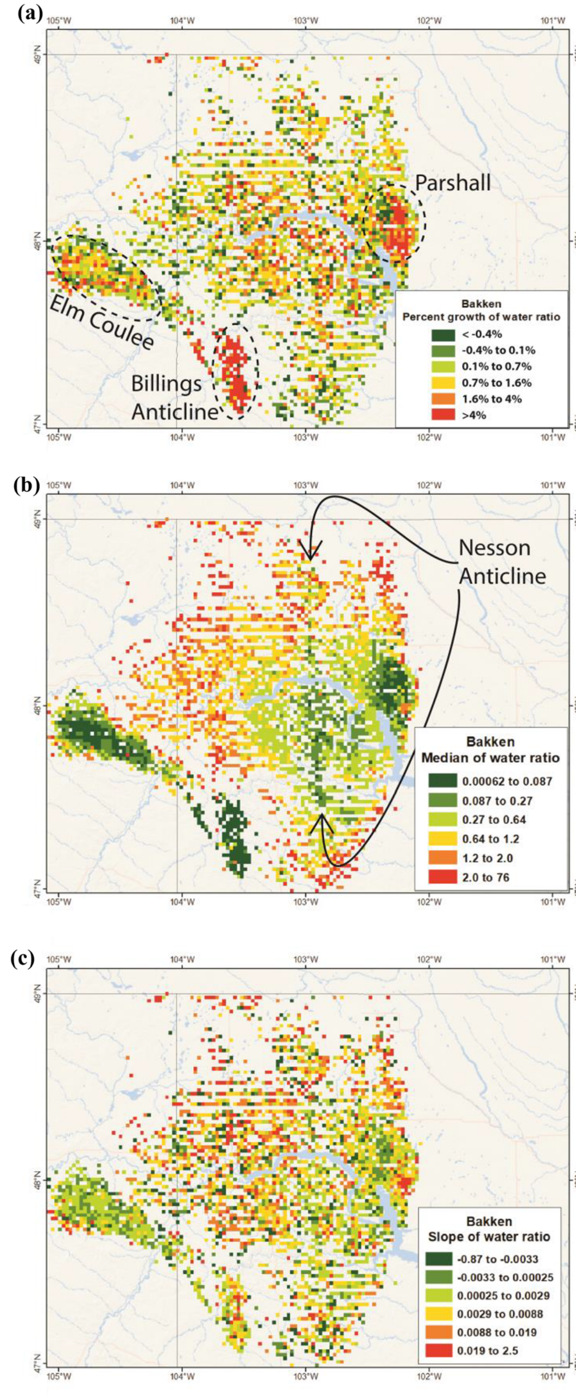

Figure 8. (**a**) Percent growth, (**b**) median, and (**c**) slope metrics plotted in map view, for the Bakken Formation. Well location points are sampled to a 2-mile grid. Plotted values indicate the mean value of all wells within each grid cell, if there are multiple wells. Major geologic features are indicated in (**a**) and (**b**).

Implications for Water Long-Term Water Production

The results presented in the preceding sections illustrate and quantify the breadth of behavior that exists within conventional and continuous plays, and the breadth of behavior within individual plays, as elucidated by our three water production metrics. Up to this point, we have focused on water-to-hydrocarbon ratios, and in this section, we shift to water volumes and implications for water studies and for water management.

In Figure 9, we provide a set of summary plots that illustrate the long-term differences in water production for continuous (unconventional) versus conventional wells, based on the metrics presented earlier. In these plots, we show water production volumes, as per month production and cumulative production versus time, rather than the water-to-petroleum ratios that are the focus of earlier discussion and figures. For the plots in Figure 9, we calculated hypothetical water production by first calculating oil production curves for each play type (Fig. S2), using standard approaches for petroleum decline curves (e.g., Poston et al., 2019), and then we used our median and slope metrics to calculate estimated water production corresponding with the modeled oil production. We provide separate projections for wells in continuous and conventional plays in Figure 9; we represent the dominant trend for each play type with the mean of the p50 values of the plays within each play type (Fig. 6 and Table S5) and we illustrate the range of water production for each play type by including the mean p25 and p75 values (darker shaded area) and the minimum p25 and maximum p75 values (lighter shaded region). This analysis is limited to oil wells because the median and slope metrics for gas plays do not follow clear patterns.

Contrasting Figure 9a with 9b, we observe that continuous oil wells typically produce substantially less water than conventional wells and that water production declines more rapidly for continuous than conventional wells. In addition, the range of monthly water volumes is much wider for conventional than for continuous oil wells. Contrasting Figure 9c with 9d, we again observe much greater water production (by a factor of nearly 10) for conventional wells relative to continuous wells and that despite conventional wells showing much higher values for the slope metric (Fig. 6), differing shapes of oil production decline curves result in only modest increase in cumulative water production with time.

Together, the plots in Figure 9 illustrate the large degree to which water management considerations must differ between continuous and conventional wells; additionally, the plots illustrate the high variability of water production between wells in each well type, and particularly between wells producing from conventional plays. Whether the water is disposed of via injection, or reused for hydraulic fracturing or other purposes, these differences will necessitate varying strategies. With new exploration in the USA focused almost entirely on continuous resources, but large numbers of conventional reservoirs still under production, the resulting basin-scale shifts in water production are in progress and will be more evident in the coming years and decades.

DISCUSSION AND CONCLUSIONS

Our set of metrics provides a quantitative approach for characterizing water production trends for oil and gas wells. The resulting insights into water production are relevant to a range of scientific studies, to water management planning, and to regulation, including shedding light on the distinction between conventional and continuous (unconventional) hydrocarbon resources. All of the included continuous plays show water-to-petroleum ratios that are unchanging or increasing slowly, and wells within each continuous play show characteristics that are generally similar to one another. Many (but not all) of the conventional plays show water-to-petroleum ratios that increase substantially during production, and wells within a given play show heterogenous behavior over space and time.

The distinction between conventional and continuous (unconventional) plays carries environmental and regulatory implications (Verleger, 1980; US Joint Committee on Taxation, 1981; Hass and Goulding, 1992; Holditch, 2006; Gehman et al., 2012; 40 CFR § 435, 2016; US Environmental Protection Agency, 2019). While the 18 plays presented here do broadly conform to expected water production patterns, the three metrics reveal that considerable variability exists within these broad classifications—conventional plays can vary substantially from one another, continuous plays can vary to a lesser degree from one another, and wells within a given play can show spatial patterns that correspond with reservoir characteristics. For plays that show

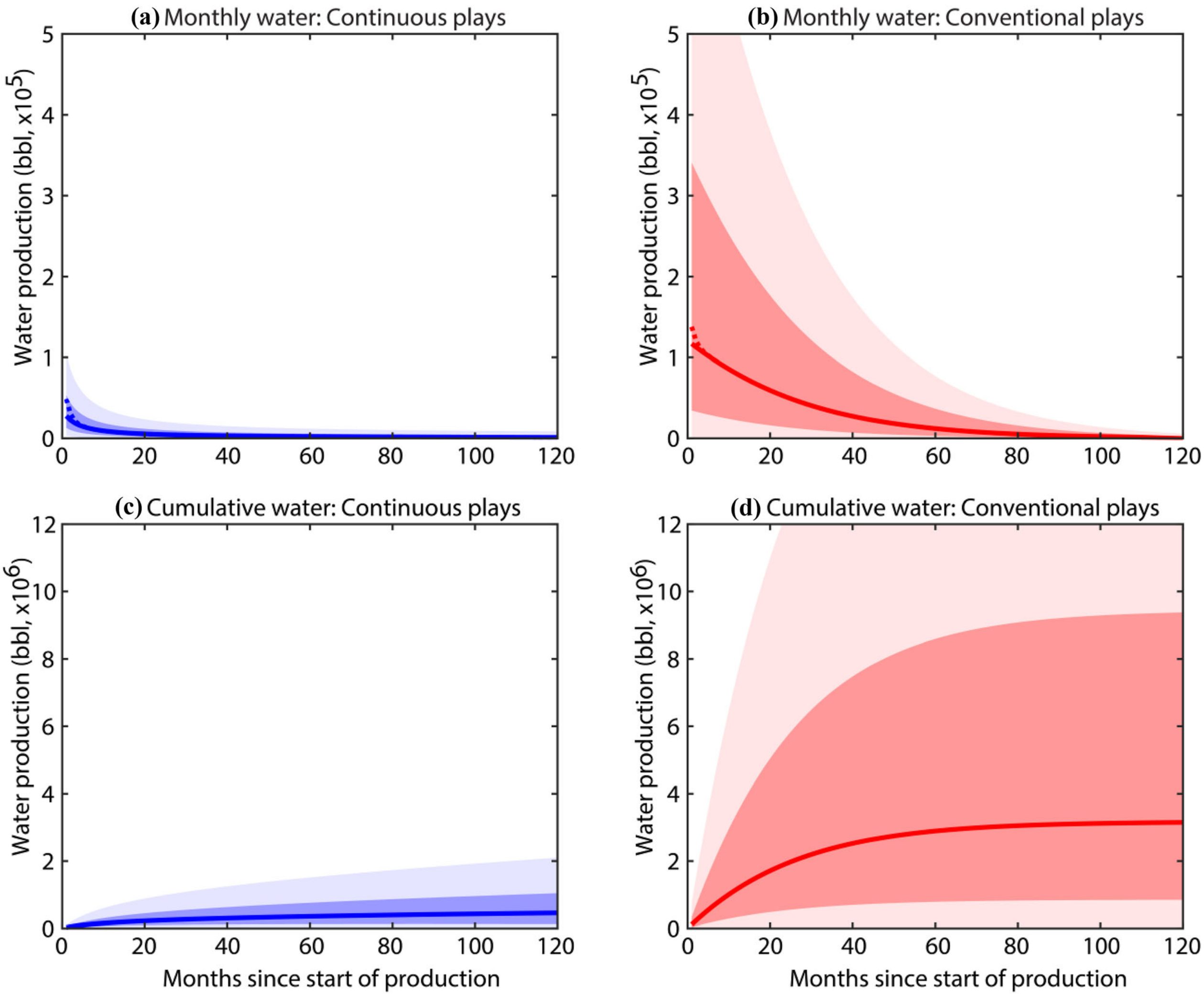

Figure 9. Plots illustrating the ramifications of differing water production behavior for continuous versus conventional oil wells and within each grouping, based on assumed total oil production of 500,000 barrels per well. Plots in (**a**) and (**b**) show generalized monthly water production curves for individual oil wells in a continuous (unconventional) and conventional plays, respectively. In each plot, the solid line represents the mean of the p50 values for all the plays of that play type, the darker shaded region indicates the range from the mean p25 to the mean p75 value, and the lighter shaded region indicates the range from the minimum p25 value to the maximum p75 value. Plots in (**c**) and (**d**) show the resulting cumulative water production for each well, with the same plotting style. The dotted lines in (**a**) and (**b**) represent water production including typical hydraulic fracturing flowback; the impact of flowback on cumulative water production is negligible. Note that the vertical scale is different for (**a**) and (**b**) versus (**c**) and (**d**). Bbl = barrels.

characteristics of both conventional and continuous reservoirs (e.g., Pearson, 2010, 2012), our metrics represent a means for characterizing the degree of ‘‘conventional-ness’’ or for identifying plays or regions within a play that show greater tendency toward watering out. With water production drawing increasing attention (Laughland et al., 2014; Barnes et al., 2015; Veil, 2015; Kondash et al., 2017; Zemlick et al., 2018), the ability to characterize and model water production is increasingly important for research purposes; our results show that studies need to consider the breadth of possible water production variation between plays and within individual plays. The heterogeneities highlighted by our results also have substantial practical ramifications for water handling during hydrocarbon production, and thus for resource economics and development impacts (Jacobs, 2016; Duman, 2019) and possible reuse (Barnes et al., 2015; Scanlon et al., 2020b).

Most wells show water production ratios that increases with time. (Greater than 68% of the wells in our analysis show positive percent growth in Fig. 5 and positive slopes in Figs. 6 and 7.) For conventional plays (82% positive values), this is as expected—as petroleum is produced, the petroleum-dominated portion of the reservoir becomes smaller and the subsurface level of underlying water-dominated zone (Fig. 1b) generally rises (in water-drive reservoirs), leading to "watering out." For continuous plays (59% positive values), increasing water ratios are not predicted by the simple model (Fig. 1) of petroleum and water mixed homogenously within a closed-system reservoir, which would be expected to yield a constant ratio of water to petroleum. Plays, or groups of wells, that show increasing water ratios indicate more complex reservoir behavior such as flow from adjacent formations. For example, an increasing water ratio in a continuous reservoir could be explained by a horizontal well that intersects a fault or fracture (natural or caused by hydraulic fracturing) extending into an adjacent water-bearing zone. High water production in Barnett gas wells has been attributed to flow from the adjacent highly porous Ellenburger Limestone (Scanlon et al., 2020a). In the absence of fractures and faults, gradually increasing water ratios may be explained by different mobilities of the different fluid types, linked to complex wettability in continuous reservoirs (Alvarez and Schechter, 2016; Gupta et al., 2018) and/or differing molecular sizes, as well as drainage from different parts of the formation porosity or possibly by a small degree of fluid separation in the reservoir. As such, our three metrics provide insight into complex characteristics in continuous reservoirs, an important topic in water studies and in petroleum geology.

In developing these water production metrics, we considered and tested several alternative options. In addition to the advantages described throughout this document, our metrics provide robust results even though we included many wells currently in production and possibly wells for which we had incomplete data. Nonetheless, data quality problems that are inherent and unavoidable in these datasets still pose a limitation to these analyses; this is a strong reason to focus analyses on groups of wells rather than individual wells. A related possible concern is that in a high-permeability water-drive conventional reservoir, "watering out" may occur very rapidly (days/weeks), such that reported data do not include the highest final water ratios; this problem cannot be avoided with available monthly or longer-span production data. Given anticipated trends for conventional reservoirs, it may seem preferable to quantify change in the slope of the water production ratio (that is, curvature such as indicated in Figure 2c), but extensive experimentation with well data has demonstrated to us that results are more consistent and reliable using the linear metrics presented here.

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Conflict of Interest The authors have no competing interests to declare that are relevant to the content of this article.

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SUPPLEMENTARY INFORMATION

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