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Source and Fate of Hydraulic Fracturing Water in the Barnett Shale: A Historical Perspective

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ABSTRACT

Considerable controversy continues about water availability for and potential impacts of hydraulic fracturing (HF) of hydrocarbon assets on water resources. Our objective was to quantify HF water volume in terms of source, reuse, and disposal, using the Barnett Shale in Texas as a case study. Data were obtained from commercial and state databases, river authorities, groundwater conservation districts, and operators. Cumulative water use from ~18,000 (mostly horizontal) wells since 1981 through 2012 totaled ~170 thousand AF (kAF–210 Mm^3); 26 kAF (32 Mm^3) in 2011, representing 32% of Texas HF water use and ~0.2% of 2011 state water consumption. Increase in water use per well by 60% (from 3 to 5 Mgal/well; 0.011–0.019 Mm^3) since the mid-2000s reflects the near-doubling of horizontal-well lengths (2000–3800 ft), offset by a reduction in water-use intensity by 40% (2000–1200 gal/ft; 2.5–1.5 m^3/m). Water sources include fresh surface water and groundwater in approximately equal amounts. Produced water amount is inversely related to gas production, exceeds HF water volume, and is mostly disposed

in injection wells. Understanding the historical evolution of water use in the longest-producing shale play is invaluable for assessing its water footprint for energy production.

INTRODUCTION

Hydraulic fracturing (HF) has become a hotly debated topic, particularly in regard to the volume of water used and the potential for aquifer contamination.[1-2] Although HF and horizontal drilling has been practiced for decades, the combination of the two resulted in the exponential increase in gas production from <1% of U.S. gas production in the early 2000s to 40% in 2012[3] (9.6 Tcf; 9.6×10^{12} standard cubic feet; 272 Gm^3). With expansion of HF into more water-scarce regions in the western U.S. and potential expansion into semiarid regions globally, understanding the volume of water required for HF is particularly important. Even in more humid settings, water availability can be an issue during droughts. Previous studies estimated HF water use for Texas [2011: 81.5 thousand AF (kAF), 100.2 million m^3 (Mm^3), including shales and tight formations, SI section] and in Colorado (2011: 15 kAF/yr, 18.5 Mm^3/yr).[4-5] An estimated 13.2 kAF (16.3 Mm^3) was used for HF in Oklahoma in 2011.[6] Although these water-use estimates represent a small fraction of water used in each state (~0.1% in Colorado, ~0.5% in Texas, and <0.5% in Oklahoma), the volumes may be significant locally, depending on competition with other sectors. Additional water-use estimates are available for the Marcellus Shale, totaling 32 kAF (39 Mm^3) consumed between June 2008 and end of 2012 in the Susquehanna River Basin, mostly in 2011–2012 (15–20 kAF/yr; 18–25 Mm^3/yr)[7] and 23.5 kAF (29 Mm^3) within the 2008-2012 period in the Upper Ohio River Basin, mostly in 2011–2012 (8.4 kAF/yr; 10.4 Mm^3/yr).[8] Water demand in the Bakken area is estimated to be ~22 kAF/yr (~27 Mm^3/yr).[9-10]

Understanding the source of the water used for HF is important to assess the impact on water resources. To date, much of the water used has been fresh water from surface-water or groundwater sources. Plays in more humid regions generally rely on surface water, whereas limited surface-water availability in more semiarid regions may result in more groundwater use. The Marcellus Shale play uses predominantly surface water controlled by different river basins, e.g., the Susquehanna and Delaware basins.[11] In contrast, the Eagle Ford play lies mostly in a semiarid region and relies heavily on groundwater from the Carrizo-Wilcox aquifer because of limited surface water availability.[4]

The amount of HF water that flows back to the surface, commingled with water from the formation (produced water), termed flowback-produced (FP) water (see SI), is important because it controls the absolute volume that can be reused or recycled or the volume that must be disposed.[12-13] *Reuse* is generally understood as requiring little treatment, whereas *recycling* suggests more involved treatment.[12] Shale formations (Marcellus[14] and Eagle Ford[15]), traditionally have been described as having small volumes of FP water.

Disposal approaches vary by play. Piping and trucking to centralized facilities for treatment and reuse is dominant in the Marcellus Shale with some on-site operations,[14, 16-17] but injection wells (see SI) are preferred in the Barnett,[4] Eagle Ford,[15] and Bakken[10, 18] areas, despite improving technological capabilities in using high-salinity waters (50,000 mg/L and higher total dissolved solid (TDS)).[19]

The Barnett Shale play provides an ideal case for assessment of issues related to production of unconventional resources such as shale gas or shale oil. The Barnett Shale area (~26,000 mi^2, 68,000 km^2) occupies ~45 counties in Central and North Texas, extending from suburban to rural settings (Figure S2). This study focuses on a ~10,000 mi^2 (~26,000 km^2) area in ~15 counties in the eastern area of the shale footprint with hydrocarbon production potential.[20-23] It includes the core area (Figure 1) and most of the development activity. It was the first shale play in the world to be fully developed with HF[23-24] and be subjected to intense HF. After a start in the 1981 and through the 1990's with vertical wells, the combined use of horizontal drilling and HF that originated in the play in the early 2000s has allowed to economically recover gas from shales. Operational details related to HF as applied to the Barnett Shale have been described.[19-23] The Barnett Shale produced an average of 1.9 Tcf/yr in the 2008–2012 5-year period (2.1 Tcf in 2011), to be compared to a total U.S. gas production of 28.5 Tcf in 2011, including 8.5 Tcf from shale gas wells.[3] Cumulative production since 1993 totals 14.9 Tcf as of April 2013.[25] Total production, including past and projected production, has been estimated at 45.1 Tcf.[26]

Gas production began in the mid-1990s using vertical wells and transitioned in 2003–2005 to mostly horizontal wells. Following a period of strong growth in the mid-2000s (>2000 wells/yr), drilling declined in the late 2000s because of reduced demand following an economic slump towards the end of the decade and decreasing natural gas prices. Although drilling activity has abated at the edges of the play core, it is still vigorous in the core itself[26-27] and has increased in the so-called combo play (combined oil and gas production) in the northern portion of the play, in Cooke and Montague counties where HF-enhanced oil production has increased sharply since mid-2010.

The objective of this study was to assess the amount of water used for HF and the sources of that water, followed by an analysis of FP water and of its fate, including evaluation of disposal through injection and recycling (Figure S1). This study builds on previous work[4] that quantified

HF water use in all Texas shale plays up to mid-2011 by increasing spatial resolution, increasing temporal resolution from annual to quarterly, extending analysis from water use to disposal and reuse, and assessing reliability of results by interviewing operators.

MATERIALS AND METHODS

Water Use for Hydraulic Fracturing

Data on water use were obtained from the commercial IHS database[28], which, in turn, is based on water use that is self-reported by operators to the Railroad Commission (RRC), the state regulatory agency for oil and gas activities in Texas. Building on Nicot and Scanlon[4], the analysis time period extends through December 2012. The analysis focuses on 2000 and following years as pre-2000 water use is <1 kAF (<1 Mm^3). Data reporting from Barnett Shale operators is high, with >90% of wells reporting water volume, proppant amount, and lateral length of wells providing multiple checks on the reported water-use data. Water-use intensity (water volume used per unit length of lateral), proppant loading (proppant mass per unit water volume), and mean and median values were used to detect reporting errors.[4, 29] Similar information is available from the website FracFocus (http://fracfocus.org), but, as of August 2013, not in a format that can be readily queried and, more importantly, FracFocus only includes data from 2010, precluding retrospective analysis.

Source of Water for Hydraulic Fracturing

The source of water for HF is more difficult to access than amount of water used, because no regulation requires reporting of water sources. Therefore we relied on a mix of hard data and soft data such as interviews to provide estimates. The industry generally uses water sources that are most readily available and economic for a given time and location. Sources can be classified into unequivocal (1) surface water and (2) groundwater, with several other minor categories of either ultimate origin and in decreasing importance: (1) municipal water from either urban reservoirs or water hydrants; (2) recycling/reuse of HF water, of treated industrial or municipal wastewater; and (3) small, distributed sources such as farm ponds. The information can be obtained from either the users (industry) or the water suppliers. We interviewed several major operators in the play about their practices relative to water sourcing in 2012[30] and again in 2013.

Water suppliers include self-suppliers, local landowners, municipalities, larger water districts, and river authorities with various levels of reporting and data accessibility. The first two groups (self-suppliers and landowners) rely mostly on groundwater, whereas the last two groups use surface water mostly. Information on groundwater use is generally obtained from groundwater conservation districts (GCDs, see SI). The study area contains five multicounty GCDs (Figure S2) out of ~100 in the state, all but one created within 2007–2009 (Table S1); therefore, only very recent data are potentially available. Whereas groundwater is owned by the landowner and withdrawals are controlled by the rule of capture with some restrictions posed by GCDs, surface-water use follows a prior appropriation doctrine ("first in time, first in right") and is owned and strictly regulated by the state, which grants permits and regulates the resource. As such, volumes of surface water withdrawn are well-known but their ultimate use is not, because several uses are bundled into larger categories, e.g., in the case of HF, "mining." River authorities are state entities that manage their respective river basins and operate reservoirs and treatment plants. They also hold some water rights. Four river authorities (Figure S2) could potentially provide water to the oil and gas industry. We contacted GCDs, river authorities, water districts, and several municipalities (Fort Worth, Arlington) in the course of this study.

Hydraulic Fracturing Water Quality

Overall, public-domain information on ionic composition of HF water is qualitative at best. Water quality is not reported to the RRC. Some companies report TDS, but not the ionic makeup of HF fluids, to FracFocus. Operator interviews provided additional information. Water quality can be inferred from some sources, e.g., surface water and wastewater treated to state standards being fresh.

Flowback-Produced Water Characteristics

RRC regulations require that operators report oil, gas, and water production on a monthly basis. Although operators perform routine chemical analyses on an as-needed basis, TDS and ionic makeup of FP water are not recorded systematically and very few datasets are available in the public domain. Production water volumes were compiled from the IHS database[28]. About 10% of the wells do not have production water data, most likely because of lack of reporting and consistent with the fraction of wells with no reported HF water use. We examined a total of 12,228 horizontal wells.

Injection of FP Water for Disposal

Information about injection volumes is accessible both through the IHS database[28] and the RRC website. The RRC has the apparent benefit of singling out disposal from HF operations, whereas IHS provides information about individual wells but not the source of the injected water. The RRC regulates U.S. EPA Class II wells and has for many years been tracking water injected for disposal and water used for waterflooding and reservoir pressure maintenance. Injection can be done by commercial entities, which manage wells disposing of oil and gas waste and salt water into non-producing intervals, or by oil and gas companies, which operate the vast majority of Class II wells.

In Texas, most FP water is disposed of into injection wells—information that has recently (end of 2011) become specifically available from the RRC.[31] In the past, reporting of Class II injection from HF operations was combined with conventional (not HF) salt-water disposal. The Texas Class II injection well count is ~50,000; ~20% of these are disposal wells—i.e., injecting into non-producing formations. A query of the IHS database for Class II wells in the 15-county area yielded ~2000 wells. Fluid injection into 1383 wells was reported during the period from 2001 through 2012. Unlike production, which must be reported on a monthly basis, injection volumes are reported to the RRC only annually; therefore, injection volumes in this study are accurate only if reported before and during summer 2012.

RESULTS AND DISCUSSION

Overall, hydrocarbon production is fragmented among ~250+ operators but dominated by a few companies. According to the IHS database, a total of 17,685 horizontal and vertical wells reported in the play at the beginning of 2013 were operated by 250+ companies (see SI).

WATER USE

Historical Water Use and Consumption

Barnett Shale water use in 2011 totaled ~25.8 kAF, amounting to ~32% of the total HF water use in Texas in 2011, including HF in tight formations[30], and down from a high of 28.8 kAF in 2008 (Figure S3). Until the end of 2002, wells were mostly vertical and restricted predominantly to Denton and Wise counties (with a cumulative total of ~3.8 and ~3.6 kAF), out of a cumulative total of 8.3 kAF. The estimated total amount of water used in the play to the end of 2012 is ~170 kAF, including ~152 kAF for horizontal wells (Figure S4a, b) and an additional ~18 kAF for vertical wells. Tarrant and Johnson counties are the largest water users (Figure 1). Water use increased outward from the core area until 2008, contracted back to the core area in 2009, and then shifted toward the combo play to the north and the liquid-rich area to the northwest (Figures S5 and S6).

Water use is currently almost exclusively related to HF of horizontal wells, which peaked in 2008 with fracturing of ~2750 horizontal wells. The peak year for HF of vertical wells occurred in 2002 with a total of ~750 wells. Horizontal wells account for the bulk of the water use and the length of the laterals has been slowly increasing in the past few years (median ~3,800 ft in 2011), with a concomitant increase in water use per well (Figure 2a, Figure S4c; Figure S7). Water use is often reported on a per-well basis, and, in the case of the Barnett Shale, water use per well has increased from ~3 Mgal/well in mid 2000s to ~5 Mgal/well in 2011 (1 Mgal = 3.8 thousand m^3). However, increasing trends in water use per well are misleading because they reflect an almost doubling of the lengths of laterals during that time. A more useful indicator is normalized water use per length of lateral or water-use intensity, which has remained steady at ~1,100–1,200 gal/ft (1.4–1.5 m^3/m) since 2007 (Figure 2b). Note that, in the years 2003–2006, water-use intensity was generally much higher but was steadily decreasing, finally stabilizing when operators perfected the HF technology in horizontal wells; a total of ~2300 horizontal wells were completed to the end of 2006 vs. an estimated 10,500 wells from that point to the end of 2012. In contrast to water-use intensity, proppant loading has been increasing over time, from 0.2 lb/gal in 2002 to ~0.8 lb/gal in 2009 (25 to 100 kg/m^3), plateauing until the beginning of 2012, and slightly decreasing since then (Figure S4d).

Water consumption is different from water use. In this work, *water use* is defined as the amount of water required to perform HF stimulations, whatever the source of the water. *Water* *consumption* is defined as the amount of fresh water abstracted from surface-water or groundwater. Most water used in the Barnett Shale is estimated to be consumed; operator interviews reveal that ~23.7 kAF (~92% of total water use) was consumed in 2011. Additional HF water (~5%) is derived from reuse/recycling of used-water streams. The remainder (~3%) consists of brackish water originating from mostly brackish water sections of aquifers.

The Barnett Shale water use represents a small fraction (0.14%) of total statewide water use (18.1 million AF in 2011) as reported by the Texas Water Development Board (TWDB). Water use in Texas is reported in terms of withdrawal for all categories and consumption for thermoelectric generation. Total water use has averaged 15.4 million AF/yr for 2005 through 2011, with interannual variations related mostly to irrigation needs. Statewide water consumption has been estimated at 10.2 million AF in 2010[32] and 11.4 million AF on average for the period 2005–2011 (13.4 million AF in 2011 translating into 0.18% for Barnett Shale water consumption). When analyzed at the county level, HF water use can represent a much higher fraction, especially in rural, sparsely populated counties (Figure 3). However, water may originate from outside the county, particularly in large population centers (see below). Water for auxiliary uses, e.g., for drilling, is relatively small and strongly operator-dependent. For example, some operators use oil-based muds requiring very little water, while others use water-based muds potentially requiring up to 0.5 Mgal/well but more often <0.25 Mgal/well[29, 33].

Water-use intensity is higher in Denton County and in the eastern half of Wise County, where the Barnett Shale is deepest and also where many older horizontal wells are located (Figure S8). High water-use intensity in Montague County most likely reflects early production from the oil window. The cumulative length of laterals in a given area or county (Figure S9) can be used to estimate the average well density (Figure S10). Density of well laterals is fairly high in Johnson County and the southern half of Tarrant County. The county with the highest relative cumulative length of laterals (Johnson County) yields an average spacing between assumed parallel laterals of ~1,700 ft (Table S2). This value is much greater than the operational distance between laterals of ~1,000 ft or even 500 ft,[33-34] suggesting that Johnson County, despite its past HF activity, is still likely to see further significant drilling and HF activity, as illustrated by the coverage gaps (Figure S8). The decrease in well completion activity in Johnson County (Figure 1) is more related to gas prices than to true depletion of the resource.

Source and Quality of Water for Hydraulic Fracturing

Data on the source of HF water are sparse. The industry is fragmented and, within the same company, practices may differ from one lease to the next and through time. Water contracts are signed and expire in a very dynamic business environment, suggesting that collected information can only be considered semi-quantitative. Available data suggest that the play as a whole relies roughly equally on both groundwater and surface water. At least three temporal phases are discernible, with the middle phase relying more on surface water but all relying strongly on fresh water. During the initial phase, up to 2006, groundwater was estimated at 50%+ of total water consumption [35]. Interviews suggest that, during the second phase, 2007–2010, operators used more surface water, estimated at 70–80% of water consumed during that period,[30] but with considerable variations among operators and locations. A plausible explanation for such a pattern resides in the typical approach followed by operators. Water-supply wells initially tap local groundwater unless the stimulated well is close to surface water. Then, after the initial period during which operators drill to hold leases (often 3 years) and explore for sweet spots (areas of high gas production), exploration and production become more predictable, and semi-permanent water lines are installed from surface water reservoirs that can provide large amounts of water at relatively low cost. The third phase (from 2011) shows a renewed reliance on groundwater related to development of the combo play in Montague and Cooke counties. Montague County groundwater use increased from ~1 kAF in 2009 to 5.4 kAF in 2011.

Groundwater is derived mostly from the Trinity aquifer,[36] the only major aquifer underlying 76% of the 15-county area. A large fraction of Trinity aquifer withdrawals are for municipal use.[36-37] The aquifer is one of the most depleted aquifers in the state.[38-39] The underlying Paleozoic aquifer system[15] supplies some water in Montague County. GCDs provided volumes for some or all HF-related groundwater withdrawals for years 2011-2012 (Figure S11 and Table S3). They account for more than half (~15 kAF/yr) of the annual total HF water use.

Most of the 15-county area of interest is located in the Brazos (51%) and Trinity (46%) river basins. The combined reservoir conservation-pool storage capacity in the 15-county area is 2700 kAF. The Trinity River Authority does not supply water to oil and gas operators. The Brazos River Authority, with the largest watershed, has contracts with operators to provide HF water but data on water deliveries are only available for the broader mining category, which includes HF water use. The Brazos River Authority delivered an increasing water volume from 2001 (2.6 kAF) to 2008 (5.7 kAF), but has supplied 2.1 kAF/yr (in 2012) or less since then in the mining category, following the general trend of HF water use. On the basis of this pattern, it is logical to assume that most of the mining-category water use is for HF.

HF water can also originate far from the Barnett Shale footprint. As is often the case in large urban centers, water is imported from distant reservoirs to provide water to municipal and industrial customers.[40] Such is the case in Tarrant County (which includes the City of Fort

Worth), with the primary water supplier being the Tarrant Regional Water District (TRWD)[41] providing water to many municipalities in the county and operating large reservoirs southeast of Dallas (Figure S12). A significant fraction of the Tarrant County HF water use is provided directly by TRWD and was as high as 3.5 kAF in 2009, decreasing to 1.0 kAF in 2012. The remaining surface-water sources include smaller water providers and unknown surface-water right holders. Municipalities (Arlington, Fort Worth, Dallas) also provide water directly to operators, either through direct withdrawals from urban reservoirs before water is treated, or as treated water through hydrants (>4 kAF in 2011). In both cases, the ultimate water source is from the municipal supply. Tarrant County has the highest water use in the play, both annual and cumulative (Figure 1); however, HF water use is nevertheless a very small fraction of total water use (Figure 3).

Interviews with operators hinted that some use water from brackish aquifers[30], estimated to be ~3% of HF water use and highest in the combo play in Montague County and on the western edges of the play. The Trinity aquifer[42] and the north-central Texas Paleozoic aquifers[15] contain slightly brackish horizons interspersed with fresher horizons. However, the largest source of salinity comes from blending fresh water with FP water. Some operators also use outflow from wastewater treatment plants. Texas Commission on Environmental Quality (TCEQ) has records, but no volumes, showing that some treated waste water from large cities (Dallas, Fort Worth, Waco) and smaller towns (Bowie, Cisco, Keene, Weatherford) is used.

Overall, less recycling/reuse and brackish water use is currently occurring in the Barnett than in other Texas plays further west or south.[29-30] A large operator in 2005–2011 processed 2.24 kAF of FP water to generate 1.6 kAF of pure water to be used for stimulating new wells. Knowing that this particular operator manages ~21 % of the wells and has had a more active recycling program than most operators, we extrapolated that the entire field used ~7.7 kAF of recycled water (1.6 kAF / 21%); i.e., 5.5% of the total of 139 kAF of water used in that period. Interviews with operators are consistent with this estimate, suggesting that ~5% of HF water is from reuse/recycling for the past few years. Periodic droughts, characteristic of Texas climate, do not seem to control HF water use in the Barnett play, which is more sensitive to the price of gas and economic activity (Figure S13).

FP—FLOWBACK/PRODUCED WATER

FP water flow decreases rapidly with time after wells are allowed to produce. Records from the IHS database show that percentiles (5^{th} to 90^{th}) of monthly water production steadily decline through time (Figure S14). Percentiles also show large variability, with a median for maximum monthly production <5000 bbl/month (0.64 AF/month; 1 bbl = 0.159 m^3) but a 90^{th} percentile >20,000 bbl/month (2.58 AF/month) and a 5^{th} percentile of ~0 bbl/month. However, cumulative production can still result in large volumes: median ~75,000 bbl (9.67 AF) after 4 years with a 90^{th} percentile >300,000 bbl (38.7 AF) but a 5^{th} percentile of 7000 bbl (0.90 AF) (Figure S15). A more interesting metric is the ratio of FP water to the amount used for HF, which we call the HF water balance ratio (WB ratio) (Figure 4). After one year, the median WB ratio is ~60% but the mean is >100% because of a few wells with exceptional water production. After several years, the median exceeds 100% of HF water. The variability of the ratio is large (Figure 4), ranging from 20% (5^{th} percentile) to 350% (90^{th} percentile) after 4 years. In interviews, operators tended to underestimate the amount of FP water as reported by IHS, likely focusing on the initial period during which some treatment and recycling can still take place. At later times, monthly volumes are small, but cumulatively they amount to a non-negligible fraction of the overall FP water.

The spatial distribution of the county-level medians of the WB ratios is not random but structured, with a minimum in the core area increasing outward (Figures S16 and S17), suggesting that the higher the amount of HF water retained in the shale, the higher the gas production. It is, however, premature to draw a direct causal relationship. Efforts are underway to relate this observation to various gas-production parameters, including the so-called maturing or soaking time, during which a well remains shut-in after HF, and geological parameters, e.g., porosity, pore-size distribution, and rock competence. A water-encroachment operational explanation, in which the underlying karstic Ellenburger Formation is systematically breached during HF, is unlikely; the Viola-Simpson Formation pinch-out[20-21] does not seem to control the WB ratio. A time-dependence of the WB ratio, suggesting possible operational improvements through time, is not clear: percentiles in Tarrant and Denton counties trend in opposite directions over time (Figure S18). The WB ratio does not appear to be related to operator skill level: comparing WB ratios from different large operators where leases are commingled shows no significant difference. Note that producing less water in the core area means that less water is available for reuse/recycling. Quality and chemical composition of the FP water are only known through anecdotal evidence.[43-44]

INJECTION WELLS

Injection-well count (all vertical) has increased in the Barnett Shale play during the past decade. Until 2002, HF was confined to Denton and Tarrant counties and all injection activities outside of these counties were related to conventional hydrocarbon production (Figure S19, year 2000). Injection activity in Cooke and Montague counties, the NW half of Wise County, Jack and Palo Pinto counties, and the western half of Parker County is clearly related to conventional oil production. All wells active in 2000 in this area with no change or decrease in injection volumes are assumed to be unrelated to FP water and other HF spent-fluid disposal. The Ellenburger Formation that underlies the Barnett Shale is the injection horizon of choice,[45] although FP water was also reinjected into shallower formations above the Barnett Shale in the early years.

Within the 15-county area, 8.8 kAF/yr of water was injected in 2000, representing the base line in the NW corner of the area. In 2011, the injection rate had increased five-fold in ~10 years to 45.7 kAF/yr; i.e., ~36.9 kAF/yr attributed to HF activities through ~150 currently active commercial injection wells.[46] A significant fraction of disposal occurs in Johnson County, which has the highest injection-well count (Figure S20) and receives more than twice the volume of water to be disposed than the county listed second (Parker County) (Figures 5, S21 and S22). A cumulative total of 170 kAF has been disposed of through injection wells from 2000 through 2011, whereas a total of 152 kAF was used in HF operations (Figure S23), although the latter number can be reduced by 5%, to 144 kAF, to account for recycled/reused water.[30] This result is consistent with the observation that many Barnett wells produce back >100% of the volume injected, (Figure 4) and with the understanding that many wells have been fractured only recently and will produce significant amounts of water unless shut-in. Natural evaporation from storage pits could also reduce the volume of fluids to be injected.[13]

Injection of FP water in the Barnett Shale area represents <4% of the wastewater volume injected in Texas each year. Statewide injection volume for a 12-month period (Oct. 2011 to Sept. 2012) was 924 kAF, similar to the previously reported value of 951 kAF for 2007.[47] Note that a small fraction of the injection wells are thought to have produced seismic events strong enough to be felt at the surface,[48-49] but the HF operation itself has not been documented as generating felt seismic events. As mentioned earlier, the RRC has recently started to report water disposal in a specific HF category. However, the statewide volume of 6.0 kAF for the same 12-month period used above shows that the current RRC data clearly underestimate the volume of HF fluids disposed in injection wells, most likely as a result of underreporting in the HF category and reporting to the salt-water general category instead.

IMPLICATIONS AND THE FUTURE

Drilling activity in the Barnett Shale play has been decreasing since a peak in 2008 and this despite periodic surges related to increased demand for natural gas following renewed economic activity or interest in condensates and oil. However, use of water for HF has remained relatively steady since 2009 because the mean lateral length has almost doubled. The price of gas, which steadily increased between 2002 and 2008 to ~\$8/McfHH (thousand cubic feet Henry Hub; 1 Mcf = 28.3 m^3) and higher (Figure S13d) and then quickly dropped to \$2–\$4/McfHH, translated into a focus in the core area which is likely to continue. The current average well spacing and projection of drilling activity[26] suggest sustained drilling for several decades. Broadly, groundwater and surface water each account for half of the new HF water with periodic swings favoring one or the other. HF water needs in the core area will be met by local groundwater resources, in particular, the confined section of the Trinity aquifer, but also, very likely, by imported water. As the Dallas/Fort-Worth area grows, it secures large contracts for water that originates from outside the metroplex. It then makes sense to project that operators in the core area will keep acquiring water from local surface water districts and will be able to meet HF water needs, especially when combined with recycling/reuse and use of brackish water. Currently, most of the FP water is disposed through deep well injection. Given that injected water volumes are larger, on average, than HF volumes, growth in recycling/reuse is possible.

A metric that has been proposed to assess competing water uses is known as the water intensity or the amount of water (gal or m^3) used to produce a unit volume of gas (Mcf or m^3) or unit of energy (MBtu or GJ). Because all water use is upfront during well completion,[4] the ultimate water intensity depends on total gas production and the estimated ultimate recovery. With most wells still producing, this number is not yet accessible, although more and more data are in the public domain (Figure S24). The current water intensity can be computed from cumulative HF water use and gas production (Figure S25); at the end of 2012, it reached 4.37 gal/Mcf (15.7 L/GJ), which is clearly an upper bound. Extrapolating trends from older wells yields more accurate values (Figure S26) and suggests that, after 6 years of production, the water intensity is in the range of 2.5–3 gal/Mcf (9.0–10.8 L/GJ), consistent with findings by Clark et al.[50] . This value would then evolve downward over time, to the range of 1–2 gal/Mcf (3.6–7.2 L/GJ).

SUPPORTING INFORMATION

Some definitions and Figures S1 to S26 and Tables S1 to S3 are included in the Supporting Information (SI). This material is available free of charge via the Internet at http://pubs.acs.org.

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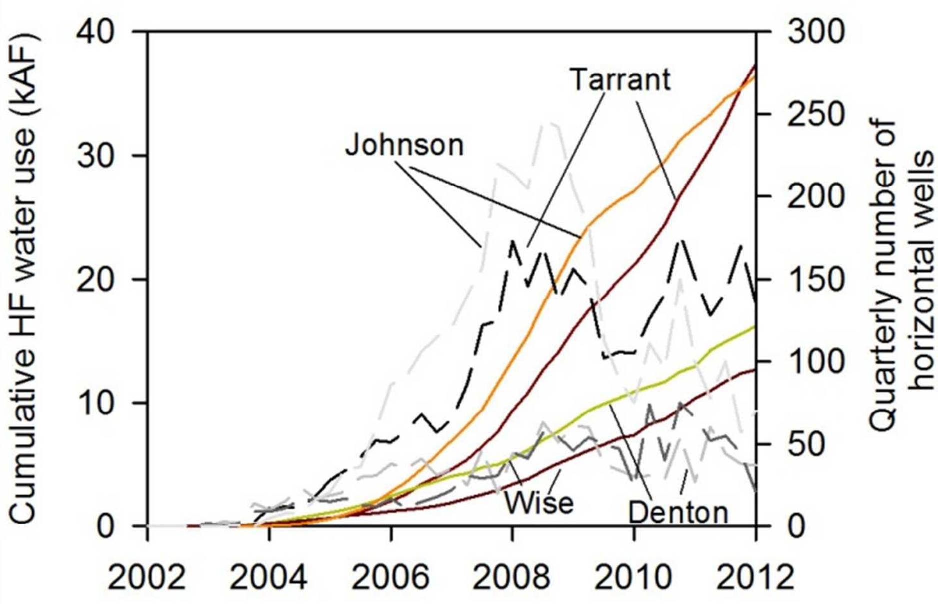
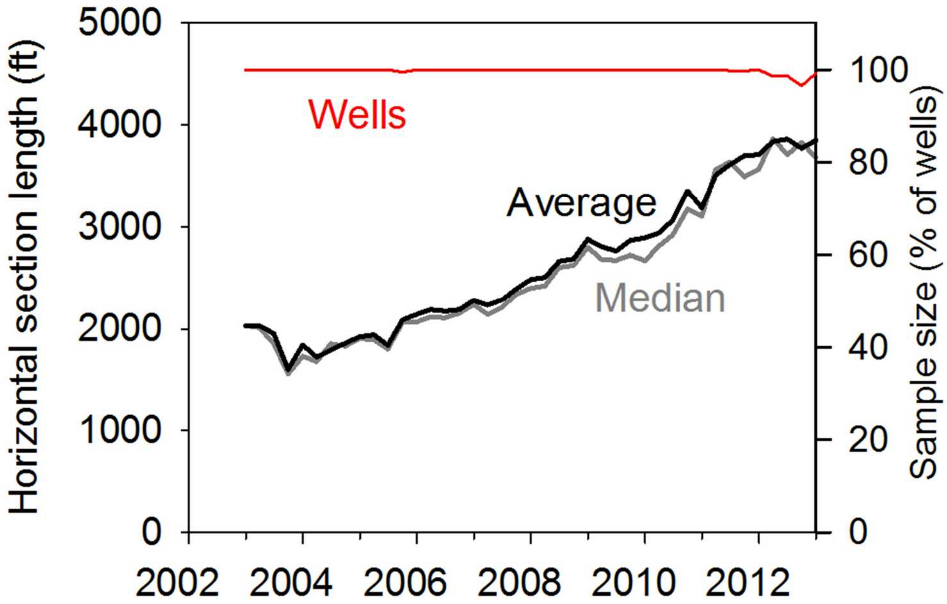
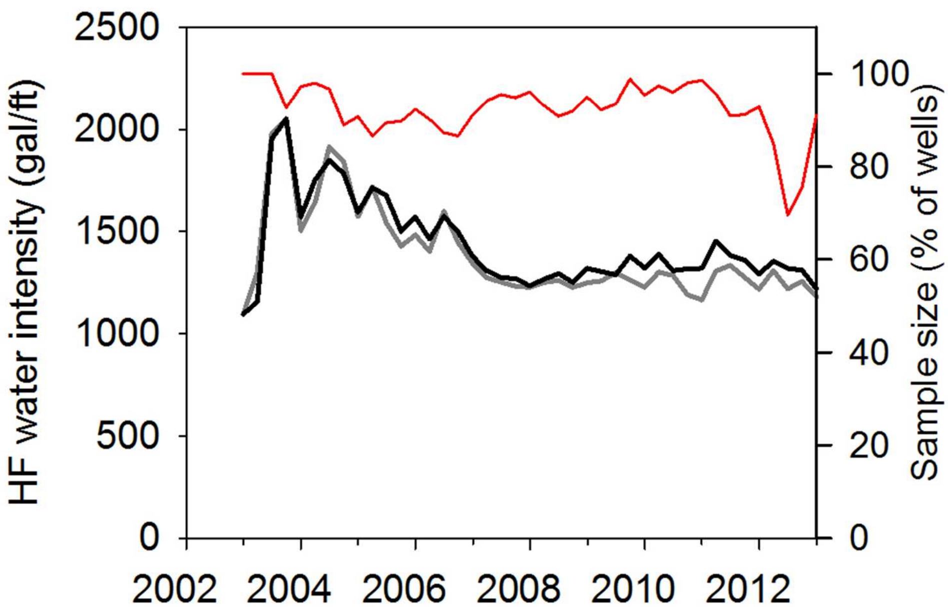


Figure 1. Cumulative water use for horizontal wells and their quaterly well count in the four counties of the core area (Denton, Johnson, Tarrant, and Wise, see SI).



(a)



(b)

Figure 2. Data on Barnett Shale horizontal wells, including various historical parameters and coefficients for reported and estimated water use as a function of time: (a) average/median lateral length and fraction of wells for which it is reported; (b) average/median water-use intensity and fraction of wells for which both HF water use and lateral length are reported; Tick marks on the x-axis represent the beginning of the year. Other parameters are reported on Figure S4 (number of wells completed per quarter and cumulative count; cumulative water use; average/median water use per well; and average/median proppant loading).

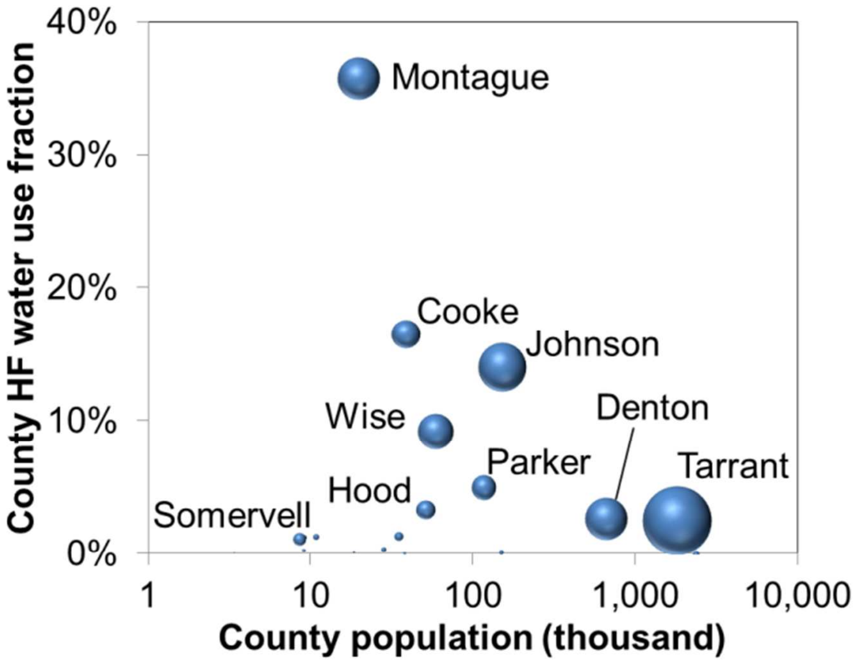


Figure 3. 2010 County population vs. 2011 fraction of water use in the county for HF purposes. Bubble size is related to absolute HF water use (for example, 8.8 kAF in Tarrant County, 1.5 kAF in Cooke County, and 0.3 kAF in Somervell County).

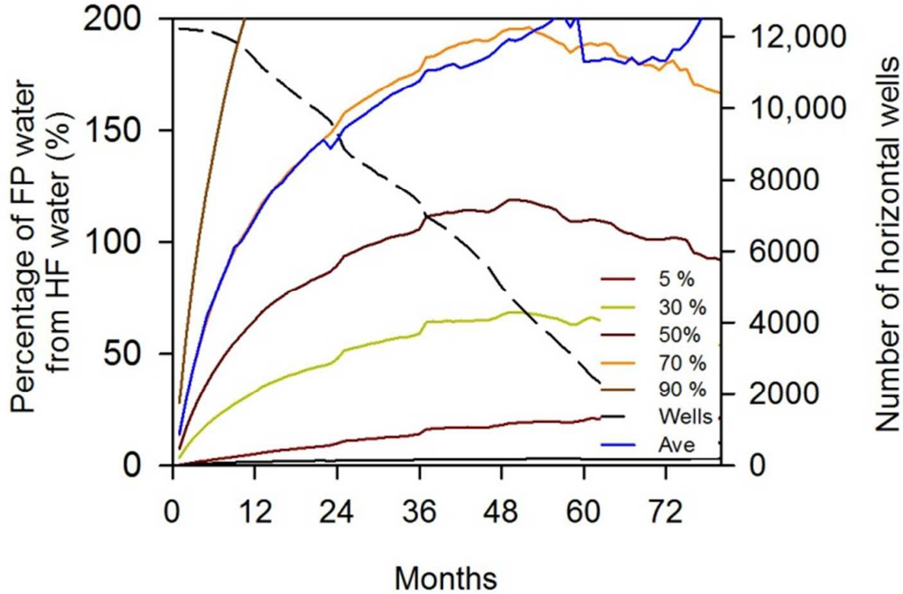


Figure 4. WB ratio; that is, ratio of FP water to HF water through time (5th, 30th, 50th, 70th, 90th percentiles and average) and number of wells having data (dotted line). The base for the calculation includes only horizontal wells. The monthly records of each well were sequentially ordered from the first month where water was produced to the last month of record, specifically ignoring initial months with zero water production. For all wells for a given month, percentiles were then calculated. Logically, the number of wells with many months of production is much lower than the number of wells with a few months of production, because many wells were completed recently.

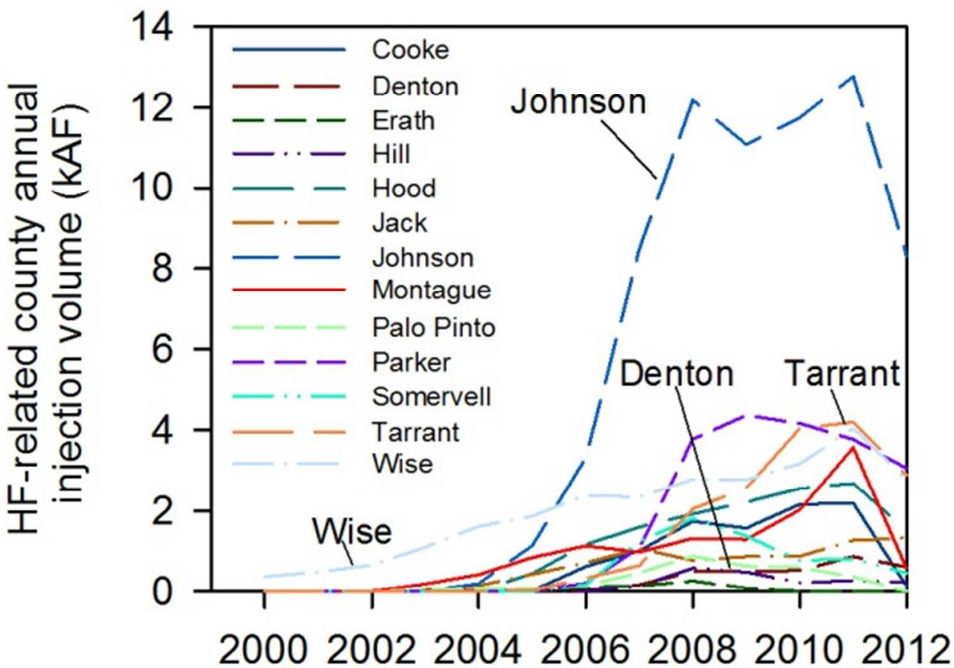
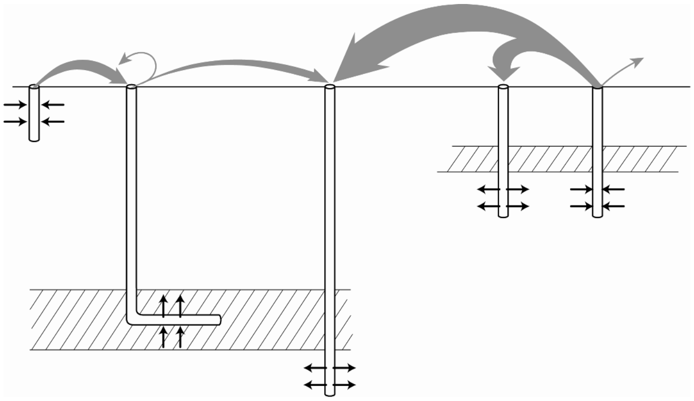


Figure 5. HF-related corrected yearly injection volumes per county in kAF (that is, pre-HF baseline subtracted, assuming that injection from conventional hydrocarbon production stays unchanged). Figure S21 displays uncorrected data, whereas Figure S22 focuses on all counties but Johnson County. No injection well in Dallas and Bosque Counties.

TOC ART



Environmental Science & Technology:

Source and Fate of Hydraulic Fracturing Water in the Barnett Shale: A Historical Perspective

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Supporting Information:

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26 figures

3 tables

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Tables

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Acronyms:

AF	acre-foot
FP	flowback/produced water
GCD	groundwater conservation district (http://www.twdb.texas.gov/mapping/doc/maps/gcd_only_8x11.pdf)
HF	hydraulic fracturing
HH	Henry hub (in Louisiana where many pipelines meet)
IHS	name of the database provider
kAF	thousand AF
RA	river authorities
RRC	railroad commission (http://www.rrc.state.tx.us/)
SI	supporting information
TCEQ	Texas commission on Environmental quality (http://www.tceq.state.tx.us/)
TDS	total dissolved solids
TRWD	Tarrant regional water district
TWDB	Texas water development board (http://www.twdb.state.tx.us/)
UIC	underground injection control (http://water.epa.gov/type/groundwater/uic/)

Units:
There exist numerous volume units even in the SI system, and, in addition, each engineering field uses its customary units barrel (bbl) and thousand cubic feet (Mcf) in the oil and gas industry, million gallons (Mgal) and acre-feet (AF) in the water industry, with the added complexity that “m” or “M” often represents thousand and “MM” represents million in the oil and gas industry, whereas “M” represent million or mega in the water industry. We used customary English in the main text, with metric and derivative unit equivalents that are also summarized below.

Mgal = mega gallon = million gallons; 1 Mgal = 3785 m^3

Mm^3 = mega m^3 = million m^3

kAF = thousand acre-feet; 1 kAF = 1.23 Mm^3 = 326 Mgal

bbl = barrel;

1 bbl = 42 gal = 0.159 m^3; 1 m^3 = 6.29 bbl; 1 kAF = 7.76 MMbbl; 1 MMbbl = 0.129 kAF

Mcf = thousand cubic feet; 1 Mcf = 1×10^3 cf = 28.3 m^3

MMcf = million cubic feet; 1 MMcf = 1×10^6 cf = 0.0283 Mm^3

Bcf = billion cubic feet; 1 Bcf = 1×10^9 cf = 28.3 Mm^3

Tcf = Tera cubic feet; 1 Tcf = 1×10^{12} cf = 28.3 Gm^3

Tm^3 = Tera cubic meter; 1 Tm^3 = 1000 Gm^3 = 1×10^{12} m^3

gal/ft = gallon per feet; 1 gal = 3.7854 L; 1 ft = 0.3048 m; 1000 gal/ft = 1.24 m^3/m

lb/gal = pound per gallon; 1 lb = 0.4536 kg; 1 gal = 3.7854 L; 1 lb/gal = 120 kg/m^3

GJ = gigajoule = billion Joule

MBtu = thousand British thermal unit; 1000 MBtu = 1.055 GJ

Terminology:

Shales and tight formations

Although not always shales from a petrographic standpoint, the term *shale* in the HF context has come to mean any source-rock formation able to produce gas (for example, Barnett and Marcellus shales) or oil (for example, Eagle Ford Shale). *Tight formation* refers to those secondary hydrocarbon accumulations akin to conventional reservoirs but whose permeability is so low that they cannot be economically produced without HF (for example, tight oil in the Bakken Three-Forks dolomite and in many Permian Basin plays and tight gas in the Cotton Valley of East Texas).

Completion, stimulation, and hydraulic fracturing

Completion consists of the suite of operations to bring a wellbore to production (including stimulation) after it has been drilled.

Stimulation describes a treatment method to enhance production of a well (including hydraulic fracturing)

Hydraulic fracturing (sometimes spelled fracing or fracking) is a stimulation method performed in low-permeability formations consisting of creation of a connected fracture network by increasing formation pressure (typically with high-rate water injection).

Flowback/produced water

In an effort to simplify terminology, we gave flowback water and produced water the collective name *FP water*. *Flowback* is generally defined as fluids with a geochemical identity similar to that of the HF fluid, whereas *produced water* is generally understood as coming from the brine or saline fluid residing in the formation. Flowback is also sometimes operationally defined as production water during the first two or three weeks or until gas or oil is actually produced. In most cases, the transition period between the two end members is long and complex.

WB ratio

The HF water balance ratio (WB ratio) is the ratio of the cumulative combined amount of flowback and produced water (FP water) to the amount of water used in the HF process. It is variable through time but stabilizes at a near constant value as the amount of produced water decreases.

Proppant

Fine-grained material added to the HF fluid, whose role is to keep fractures open after the pressure induced during HF subsides. It is generally made of fit-for-purpose sand grains or more rarely ceramics.

Injection wells

Although, from an operational standpoint, water is "injected" into the formation during the hydraulic fracturing step, from a UIC regulatory standpoint, these wells are production wells being developed and stimulated, not injection wells. Throughout this article, we reserved the term injection well to UIC Class II injection wells, typically disposing of flowback / produced water as well as other undesirable fluids such as spent drilling fluids.

Core area

The Barnett Shale underlies all or parts of 45 counties of North and Central Texas, many outside of the oil and gas windows. Extent of the Barnett Shale Play (that is, that section of the Barnett Shale with potential hydrocarbon production) includes the 15-county study area (Bosque, Cooke, Dallas, Denton, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Somervell, Tarrant, and Wise Counties). The core area is generally defined as Wise, Denton, Tarrant, and Johnson Counties and represents the most productive counties. Historical production started in the core area and these counties still provide the bulk of the Barnett Shale play gas production.

Combo play

Precursor kerogen is submitted to increasing pressure and temperature when it is buried along with the shale containing it. Soon conditions are favorable to oil generation (oil window). Additional burial, under higher pressure and temperature will crack molecules of oil components into lighter molecules ultimately leading to a hydrocarbon mixture dominated by methane (gas window). However, there is no sharp transition between the oil and gas windows. When methane and small amount of other hydrocarbon up to C4 (butane isomers) only are present, the gas is termed dry gas. When significant amount of C2-C4 gases are present or when heavier but still light hydrocarbons (≥C5) condensate at the surface once produced, the gas is termed wet gas. Liquids extracted from wet gas are called natural gas liquids (generally C2+). Liquid/condensate production is reported separately or with oil production. Some Barnett Shale counties to the West of the core area have some liquid production (Erath, Palo Pinto, Jack, Wise, Northern Denton Counties). Others (Montague, Cooke, and Clay Counties) have significant condensate production combined with gas, hence the name combo play. See Montgomery et al, (2005) for map and more detailed description.

Waterflooding, waterflood, or water flood
A waterflood is a process in which water is injected into a reservoir to produce additional oil. The water is in general saline water that has been produced earlier with the oil and is reinjected. In some instances, small volumes of fresh or brackish waters are used.

Water use vs. water consumption
Water consumption is different from water use and always smaller than or equal to water use. In this work, water use is defined as the amount of water needed to perform HF stimulations, whatever the source of the water. Water consumption is defined as the amount of fresh water abstracted from surface water or groundwater. For example, the entire volume of water needed to perform HF stimulation on a well (say 4 million gallons) is the water use. It represents the amount of water needed and used for the HF operation. However only a fraction of the water used may come from surface water or/and groundwater, the complement may come from recycling. Only the fraction withdrawn from aquifers or surface reservoir is consumed (that is, is lost to the aquifer or/and reservoir systems). In this paper, water consumption represents the volume of fresh water that is not available to other users.

Water-use intensity
Water-use intensity is defined as the water volume used per unit length of the lateral section of horizontal wells. Units are [water volume] / [unit length].

Water intensity (per unit of gas/energy); water efficiency
Water intensity per unit of standard unit of gas or per unit of contained energy is also called water efficiency. It differs from water-use intensity by the parameter used to normalize the water volume (gas volume or energy vs. lateral length). Units are [water volume] / [volume of gas produced] or [water volume] / [energy content of produced gas]

Lateral
In this context, another name for the horizontal section(s) of a well

Lateral Spacing
Laterals are often oriented as a function of the local stress field. Laterals stemming from neighboring wells end up more or less parallel, parallel enough to define a spacing distance. The spacing varies but could be as low as 300 ft. The traditional way of define spacing (for example, 1 well per 40 acres) also applies. Many leases are based on 1 mile × 1 mile section (640 acres) and laterals are close to being 1 mile long. It follows that a 40-acre well density translates into a spacing of 16 laterals per mile or 330 ft.
The operational distance between laterals is defined as the actual value between laterals not just a computed average.

Barnett Shale Company Count

Overall, hydrocarbon production is fragmented among many operators but dominated by a few companies. Leases from large operators are generally distributed within and limited to a county-size area and relatively close to each other, simplifying company logistics. According to the IHS database, a total of 17,685 horizontal and vertical wells reported in the play at the beginning of 2013 were operated by 250+ companies. The bottom 200 companies operate only a few wells each (<20 wells) and account for 5.5% of the total number of wells. The top four companies (Devon Energy, Chesapeake Energy, EOG Resources, and XTO Energy) account for 55% of all wells, and the top 10 companies account for 73% of all wells. Out of the ~13,450 horizontal wells of the dataset, the same top four and the 10 top companies account for 65.5% and 83.3% of the wells, respectively, but only a total of 172 companies operate horizontal wells. The bottom 5.5% are represented by ~120 companies (<24 wells each). Many smaller companies did not make the technological transition from vertical to horizontal wells.

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Groundwater Conservation Districts (GCDs)

GCDs are county-wide (one or a few counties) local entities that regulate groundwater use with variable level of authority. Exact role and power of each GCD varies, as does the effort put into gathering groundwater-use data. Some GCDs require a permit to withdraw water, whereas others require only registration; some limit the amount of water being withdrawn, others do not; some require reporting, others do not; many enforce well spacing. Table S1 documents specifics of the 5 GCDs overlapping the productive Barnett Shale: Upper Trinity, Northern Texas, North Trinity, Prairielands, and Middle Trinity GCD.

Table S1. Selected information of Barnett Shale GCDs

GCD	County (fraction of county in Barnett Shale)	Permit required?	Registration required?	Reporting required?	Well Spacing	Withdrawal limits?	Export limits?
North Texas**	Denton (~50%) Cook (~10%) Collin* (0%) Created in 2009	None for now (Rule 3.2)	Yes (Rules 3.3-5) except if drilled before 4/2011 and (1) <25 gpm or (2) domestic or ag-related (but not irrigation wells) (Rule 2.1)	Yes, monthly except if <25 gpm or domestic or ag-related (but not irrigation wells) (Rule 3.10)	State law applicable***	None for now (Rules 5.1-3)	None (Rule 6.1)
Northern Trinity	Tarrant (100%) Created in 2007	None for now (Rule 3.2)	Yes (Rules 3.3-5) except if drilled before 10/2010 and (1) <40 gpm or (2) domestic or ag-related (Rule 2.1)	Yes, monthly except if <40 gpm or domestic or ag-related (Rule 3.10)	State law applicable***	None for now (Rules 5.1-3	Not stated in rules
Prairie-lands**	Johnson (100%) Somervell (100%) Hill (~50%) Ellis* (0%) Created in 2009	None for now (Rule 3.2)	Yes (Rules 3.3-5) except if drilled before 4/2011 and (1) <25 gpm or (2) domestic or ag-related (Rule 2.1)	Yes, monthly except if <25 gpm or domestic or ag-related (Rule 3.10)	State law applicable***	None for now (Rules 5.1-3)	None (Rule 6.1)
Upper Trinity	Montague (~90%) Wise (100%) Parker (100%) Hood (100%) Created in 2007	None for now (Rule 3.2)	Yes (Rules 3.3-5) except if drilled before 1/2009 and (1) <25 gpm or (2) domestic or ag-related (Rule 2.1)	Yes, monthly except if <25 gpm or domestic or ag-related (Rule 3.10)	>2400 ft if >80 gpm (Rule 4.3) and state law***	None for now (Rules 5.1-3)	None (Rule 6.1)
Middle Trinity**	Erath (100%) Bosque (100%) Comanche* (100%) Coryell* (100%)	Yes if well drilled after county integration into GCD (p.8 and Rule 3.2); **except** if domestic or	Yes, all wells must be registered	Yes, monthly (Rule 5.3)	>1000 ft if well casing diameter >10” (Rule	Yes, at most 3 AF/yr/ac of land owned (6 AF is some cases) –	None (Rule 12.1)

	Created in 2002; Bosque and Coryell added in 2009	livestock and <17.36 gpm (Rule 5.4) or if **for oil and gas[&&] (Rule 5.4(a)(3) and state rule[††])**; Older wells grandfathered; GCD may decide not to grant any additional permit (Rule 8.2)	(Rule 5.1)		7.4) and state law***	can be reduced depending on DFC[++] (Rule 3.2) but state rules[††] apply for oil and gas	

*: county not included in the 15-county area

**: Use the same template for temporary rules

***: 16 Texas Administrative Code § 76.1000 (Tex. Dept. of Licensing and Regulations, Technical Requirements – Locations and Standards of Completion for Wells—mostly concerned with distances from property lines http://info.sos.state.tx.us/pls/pub/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=4&ch=76&rl=Y

››: Section 36.113(a) of the Texas Water Code states that GCDs shall require a permit for the drilling of wells; some GCDs still operate under temporary rules (for example, 4 of the 5 listed); exemptions include water-supply wells for oil and gas exploration if located in the same oil and gas lease [Section 36.117(b)(2)] http://www.statutes.legis.state.tx.us/?link=WA and http://www.rrc.state.tx.us/barnettshale/wateruse.php

&&: no permit required only if the water-supply well is within the oil or gas lease

††: Section 36.117(b)(2) or (b)(3) of the Texas Water Code states that groundwater withdrawal for oil and gas exploration is exempt from GCD rules http://www.statutes.legis.state.tx.us/?link=WA

++: DFC=Desired future conditions

North Texas GCD: http://northtexasgcd.org/
Northern Trinity GCD: http://ntgcd.com/
Prairielands GCD: http://prairielandsgcd.org/
Upper Trinity GCD: http://www.uppertrinitygcd.com/
Middle Trinity GCD: http://middletrinitygcd.org/

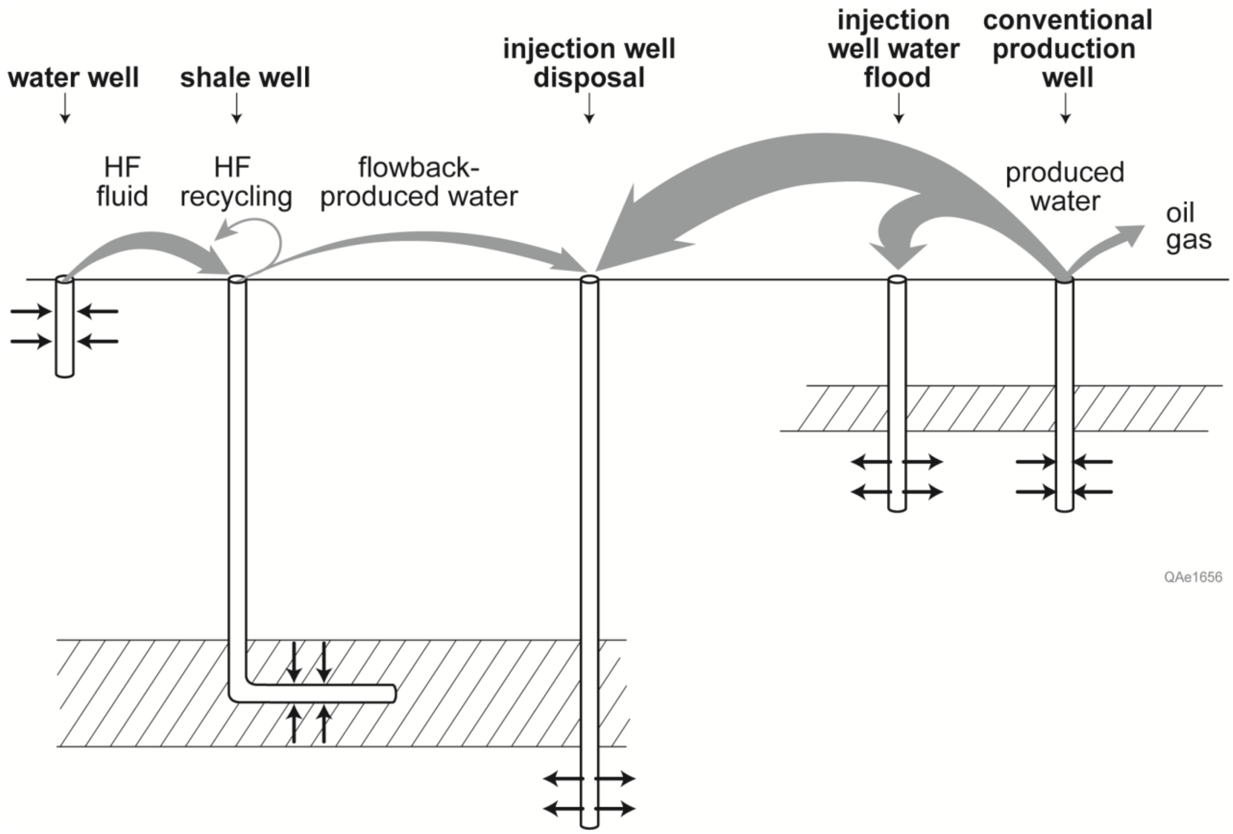


Figure S1. Schematics of water life cycle and subsurface components in the HF life cycle of water. Arrow size illustrates approximate relative volumes.

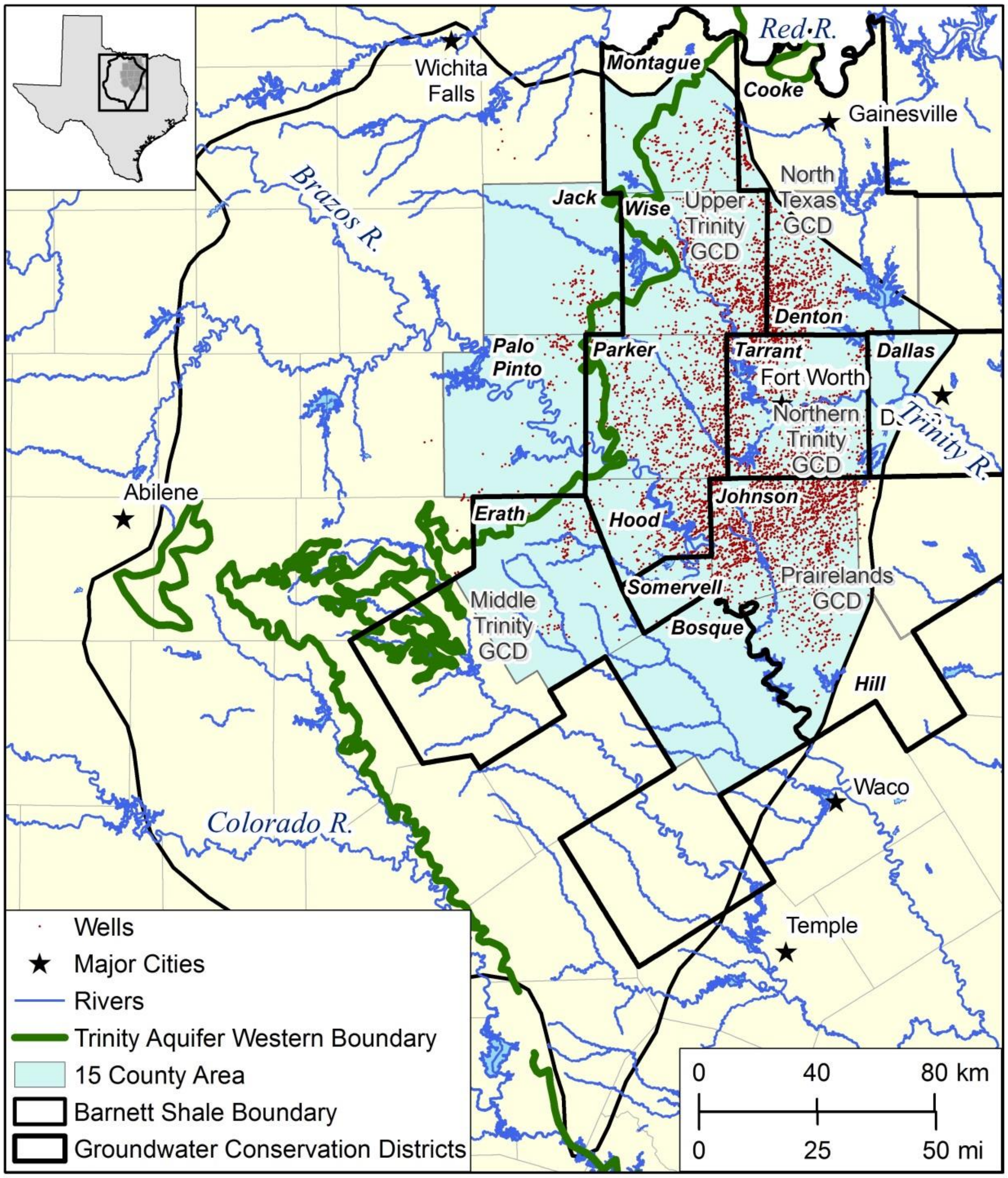


Figure S2. Extent of the Barnett Shale Play in Texas and of the 15-county study area (Bosque, Cooke, Dallas, Denton, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Somervell, Tarrant, and Wise Counties). The Barnett Shale underlies all or parts of 45 counties. The core area is generally defined as Wise, Denton, Tarrant, and Johnson Counties and represents the most productive counties. Groundwater for HF comes mostly from the Trinity Aquifer system, whose unconfined and confined sections are combined on the map. Counties, cities, and major rivers in the region are also shown. Five GCDs are shown (Upper Trinity, Northern Texas, North Trinity, Prairielands, and Middle Trinity); note that Palo Pinto and Jack Counties are not currently included in a GCD. All but the Middle Trinity GCD started collecting data only after 2010. The drainage basins of four rivers form the geographic area of four River Authorities (Red River, Trinity, Brazos, and Lower Colorado).

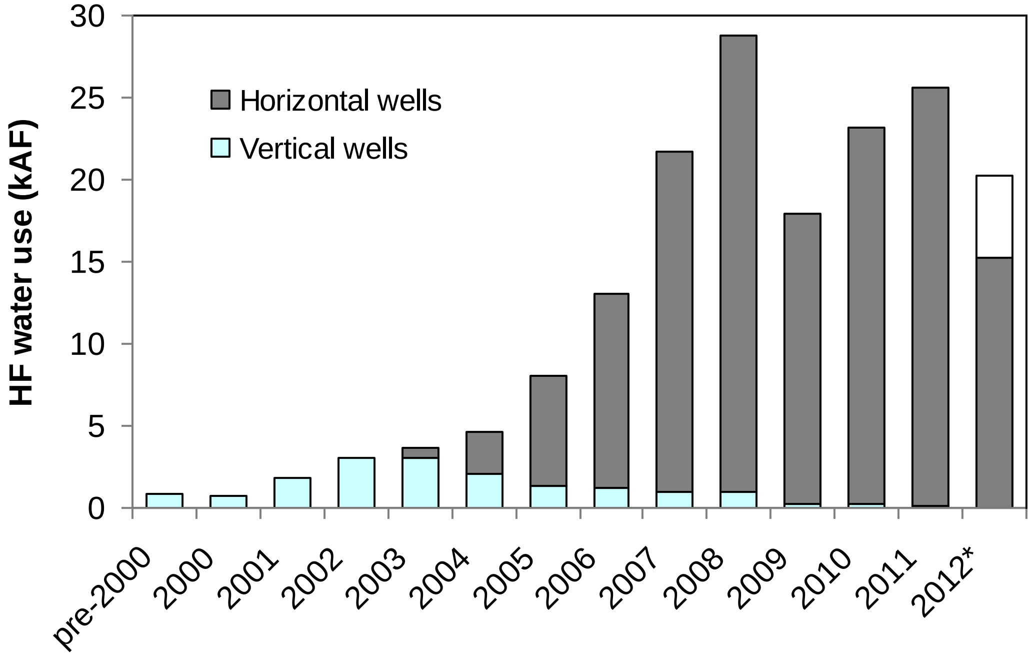


Figure S3. Annual HF water use; 2012 data not complete; 5 kAF, estimated additional 2012 water use not yet recorded in the database, is added to the plot.

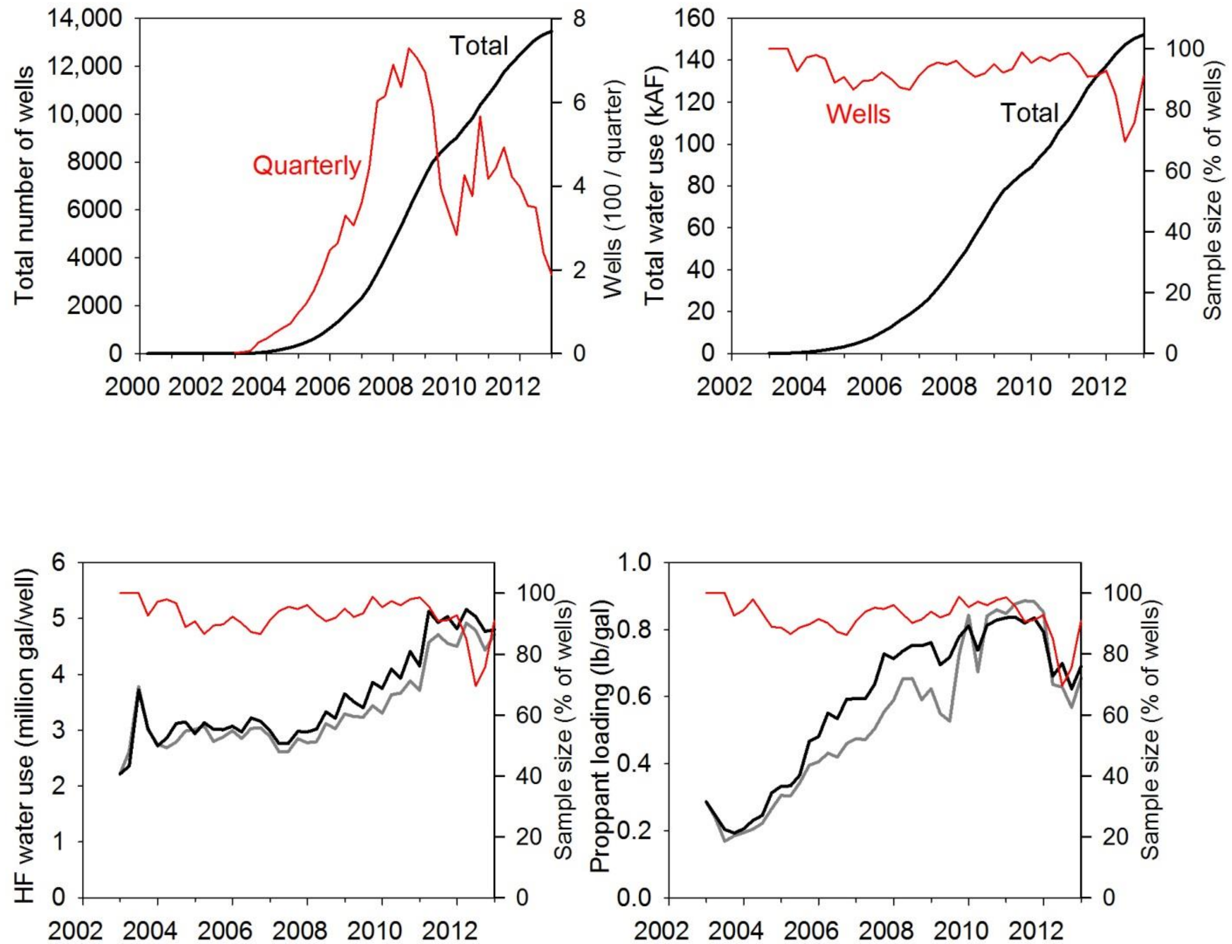
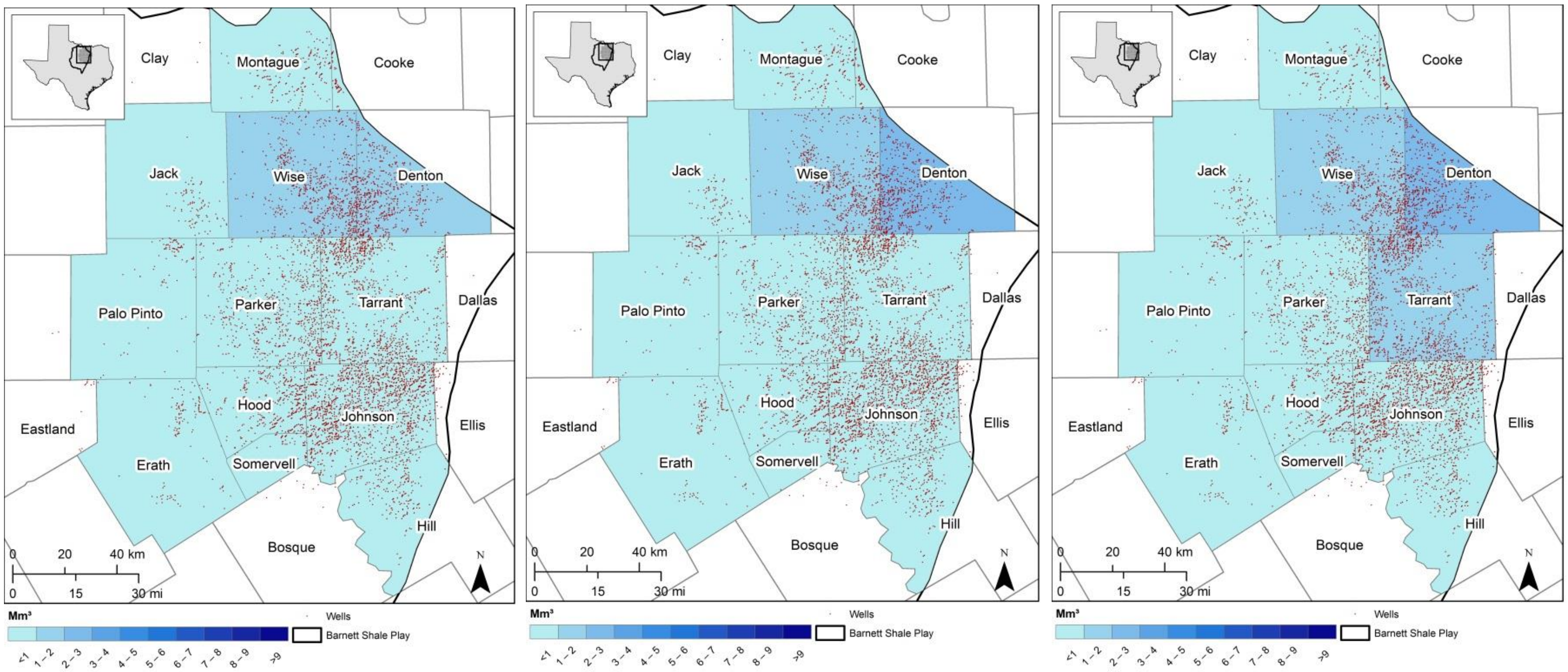
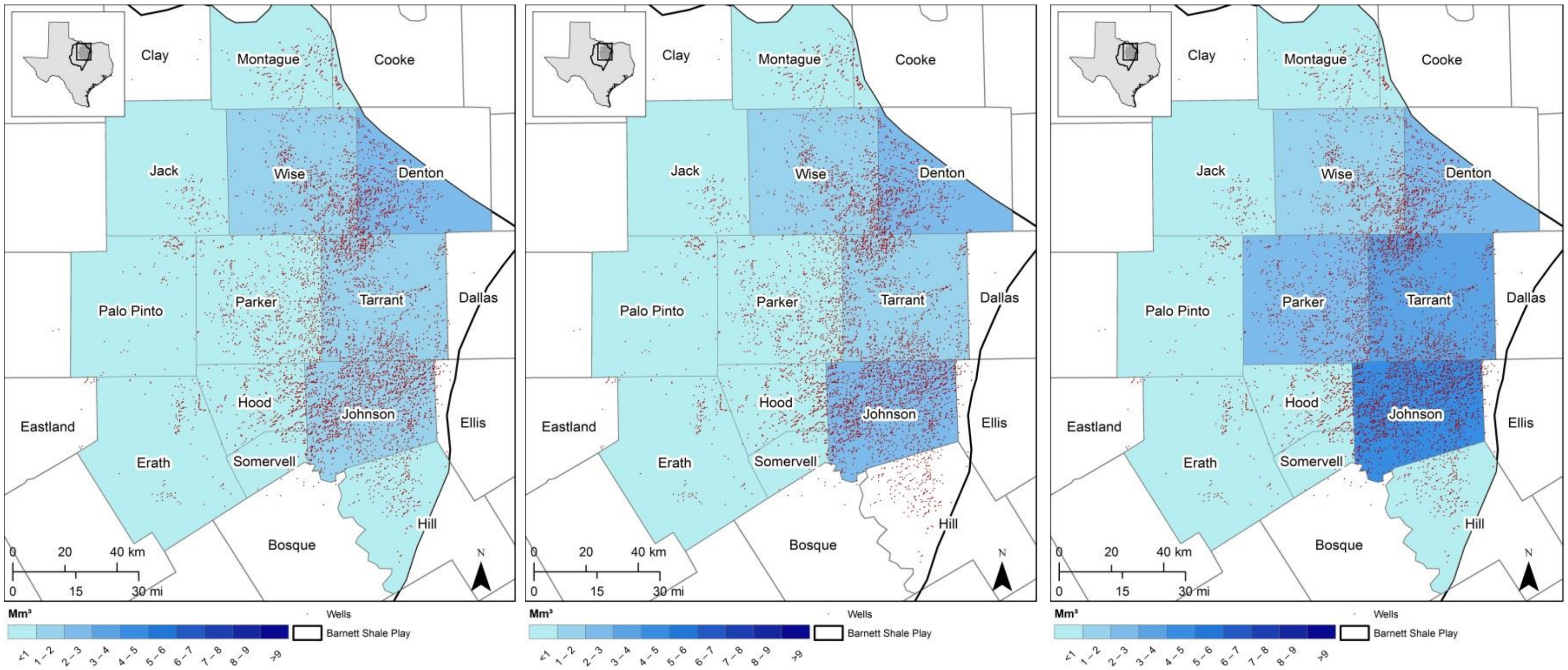


Figure S4. Data on Barnett Shale horizontal wells, including various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells completed per quarter and cumulative count; (b) cumulative water use and fraction of wells for which HF water use is reported; (c) average/median water use per well and fraction of wells for which HF water use is reported; (d) average/median proppant loading and fraction of wells for which both HF water use and proppant use are reported. Tick marks on the x-axis represent the beginning of the year. Average/median lateral length and average/median water-use intensity are reported on Figure 2. Y-axis keys for red curves are on the RHS whereas y-axis keys for black (average) and grey (median) curves are on the LHS.



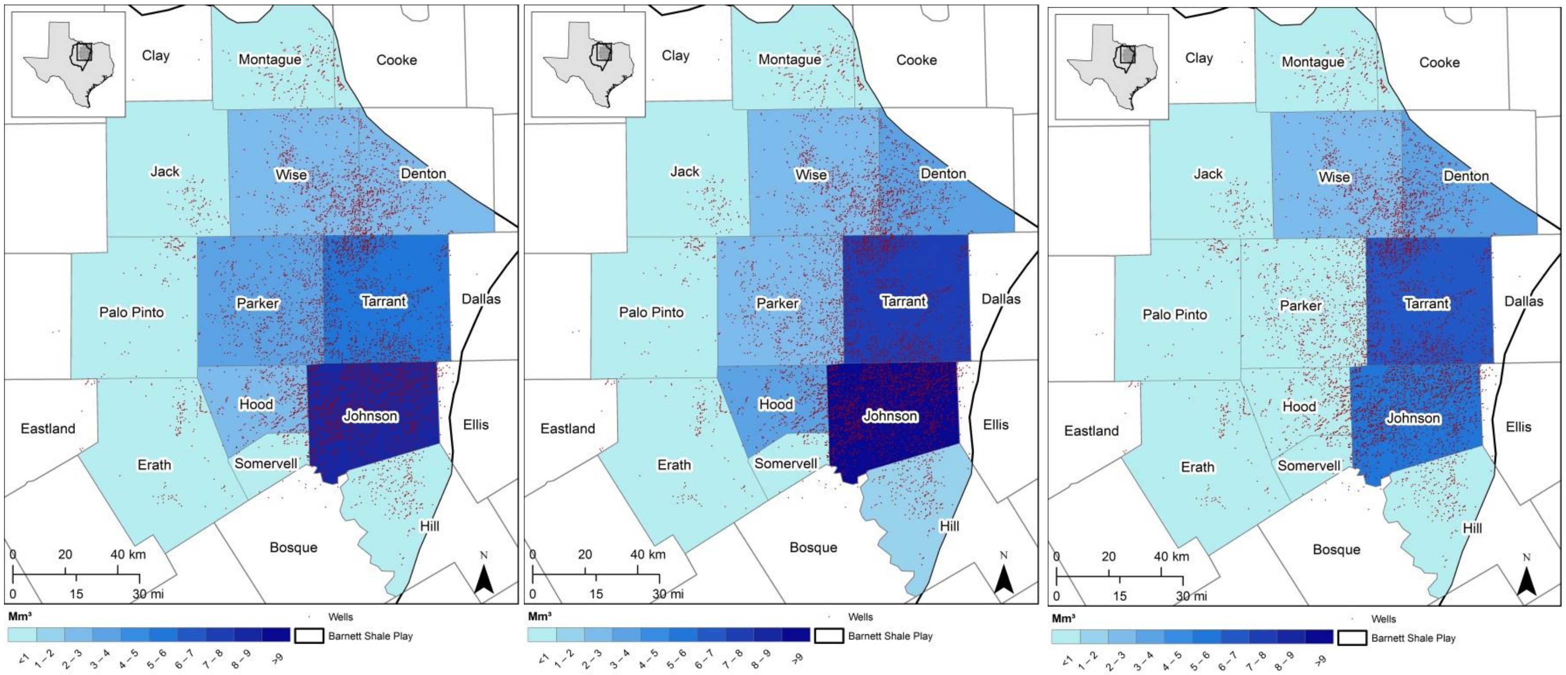
2001 2002 2003

Figure S5. Annual county-level HF water use (in million m^3) in selected Barnett Shale counties. Water use grows and expands from the core area (2001–2008), then contracts in 2009–2010 back to the core area, to expand again to the combo play area towards the north of the play (2011–2012).



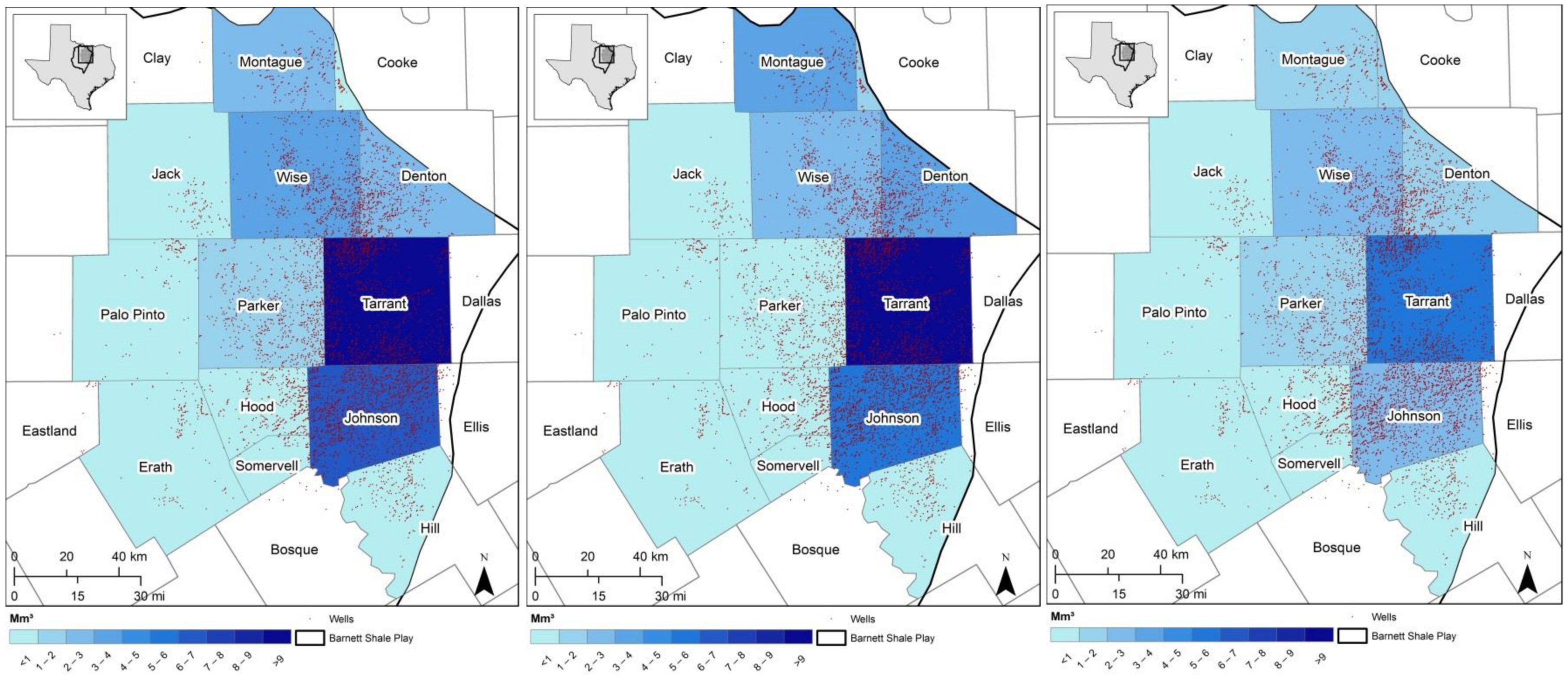
2004 2005 2006

Figure S5. Annual county-level HF water use (in million m3) in selected Barnett Shale counties. Water use grows and expands from the core area (2001–2008), then contracts in 2009–2010 back to the core area, to expand again to the combo play area towards the north of the play (2011–2012). (continued)



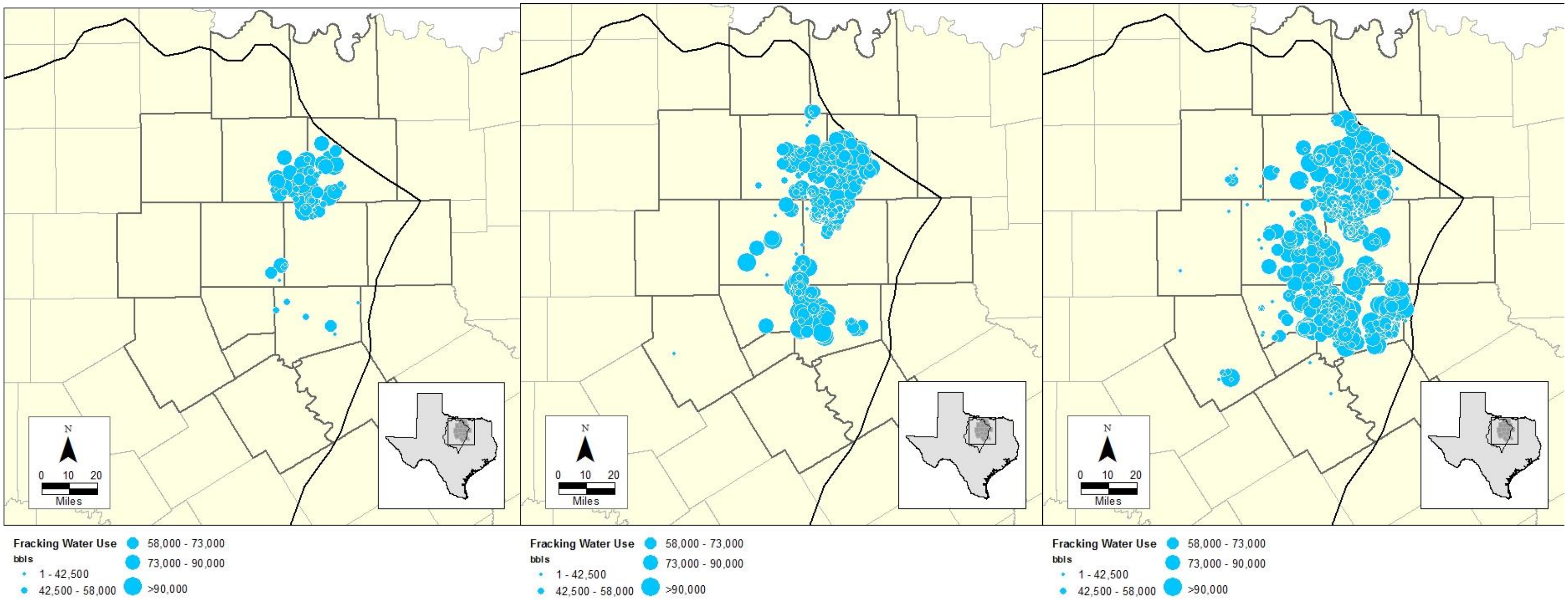
2007 2008 2009

Figure S5. Annual county-level HF water use (in million m3) in selected Barnett Shale counties. Water use grows and expands from the core area (2001–2008), then contracts in 2009–2010 back to the core area, to expand again to the combo play area towards the north of the play (2011–2012). (continued)



2010 2011 2012 (incomplete)

Figure S5. Annual county-level HF water use (in million m3) in selected Barnett Shale counties. Water use grows and expands from the core area (2001–2008), then contracts in 2009–2010 back to the core area, to expand again to the combo play area towards the north of the play (2011–2012). (continued)
Note: Data for year 2012 is incomplete.



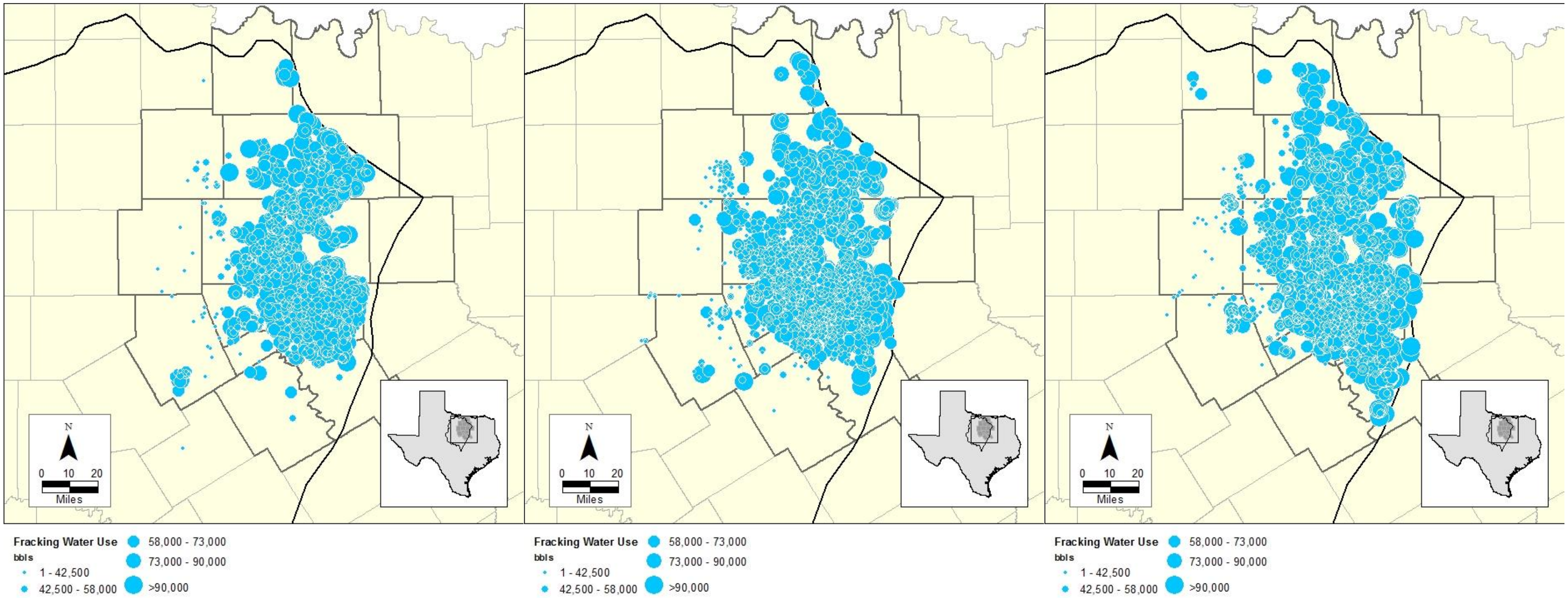
2003
(71 wells)

2004
(279 wells)

2005
(711 wells)

Note: All wells are plotted, including wells for which we estimated water use.

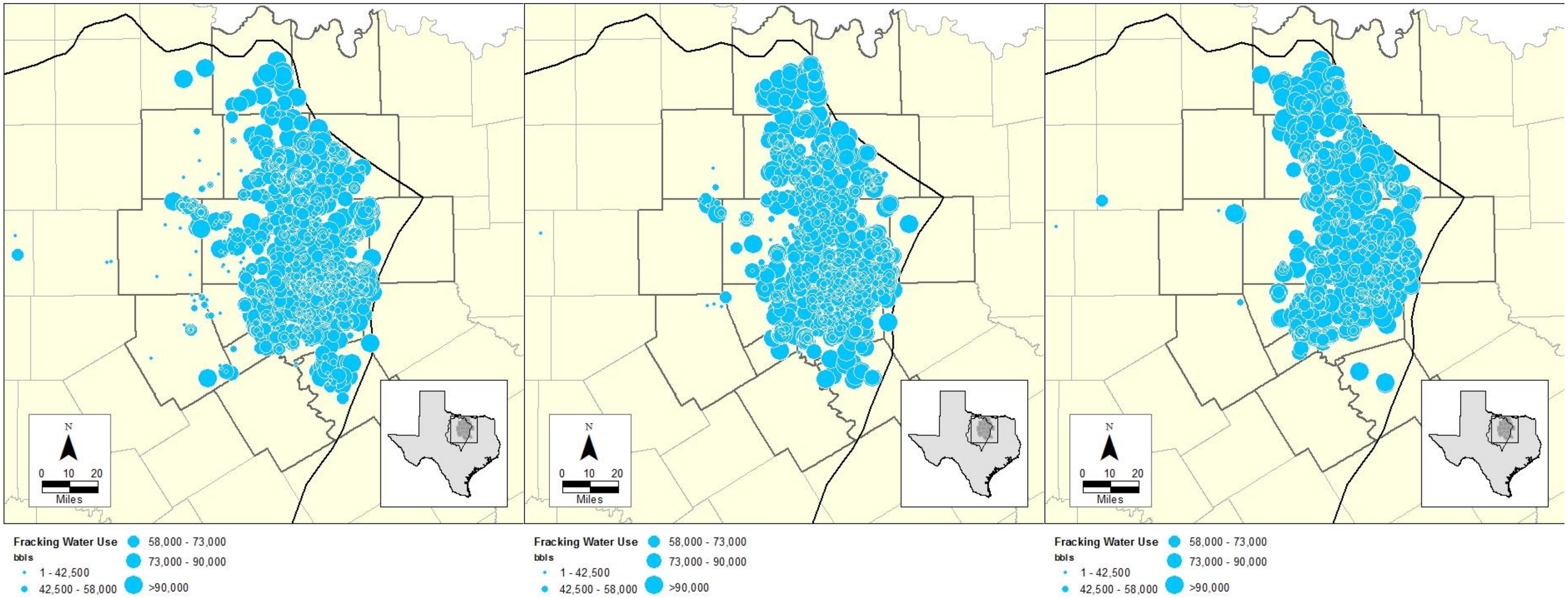
Figure S6. Annual bubble plot of HF water use for horizontal wells.



2006 (1257 wells)	2007 (2349 wells)	2008 (2739 wells)

Note: All wells are plotted, including wells for which we estimated water use.

Figure S6. Annual bubble plot of HF water use for horizontal wells (continued).



2009 (1602 wells)

2010 (1785 wells)

2011 (1545 wells)

Note: All wells are plotted, including wells for which we estimated water use.

Figure S6. Annual bubble plot of HF water use for horizontal wells (continued).

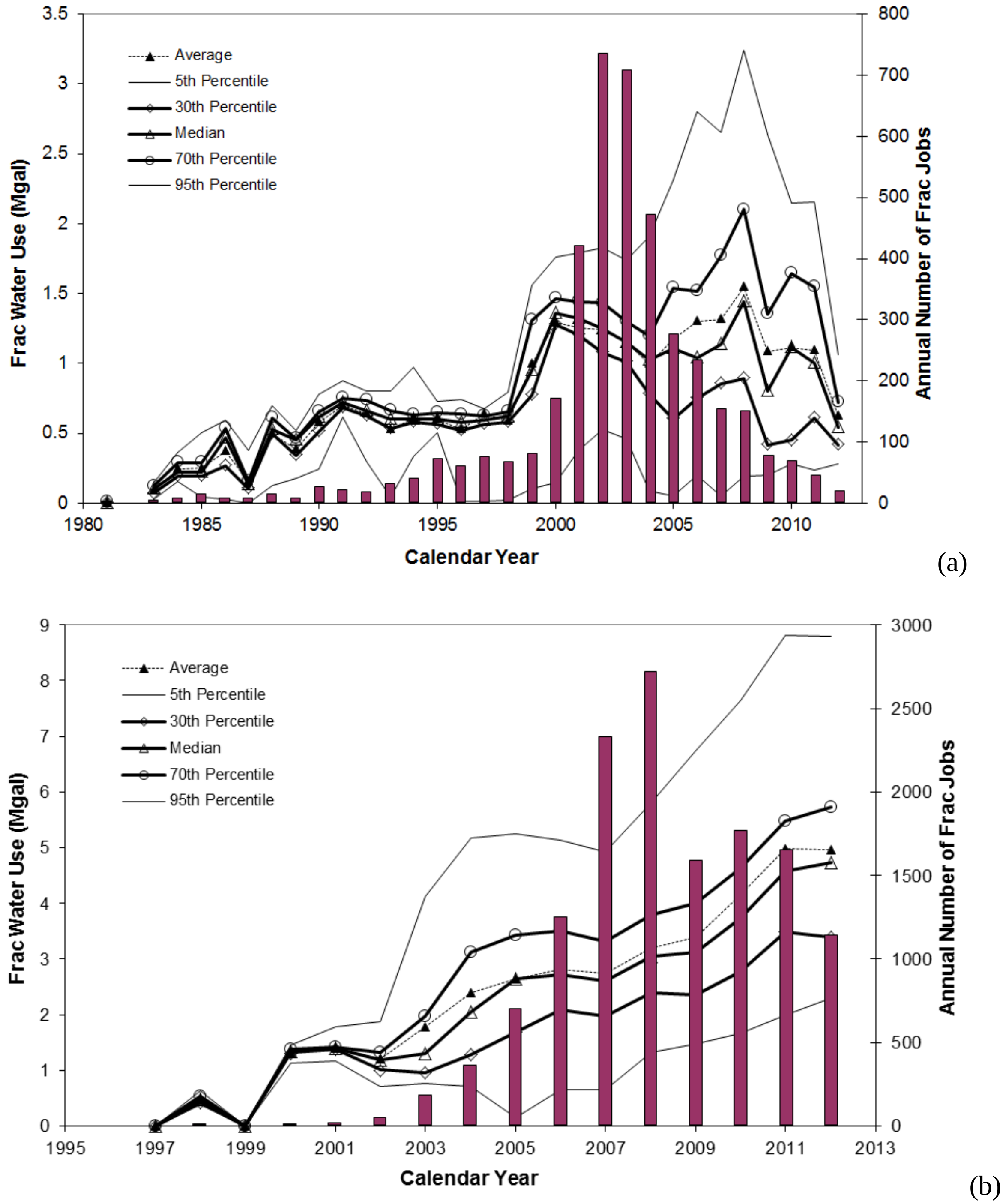


Figure S7. Annual number of wells submitted to HF (bars) superimposed over annual average, median, and other percentiles of individual-well HF water use (curves) for (a) vertical wells and (b) horizontal wells.

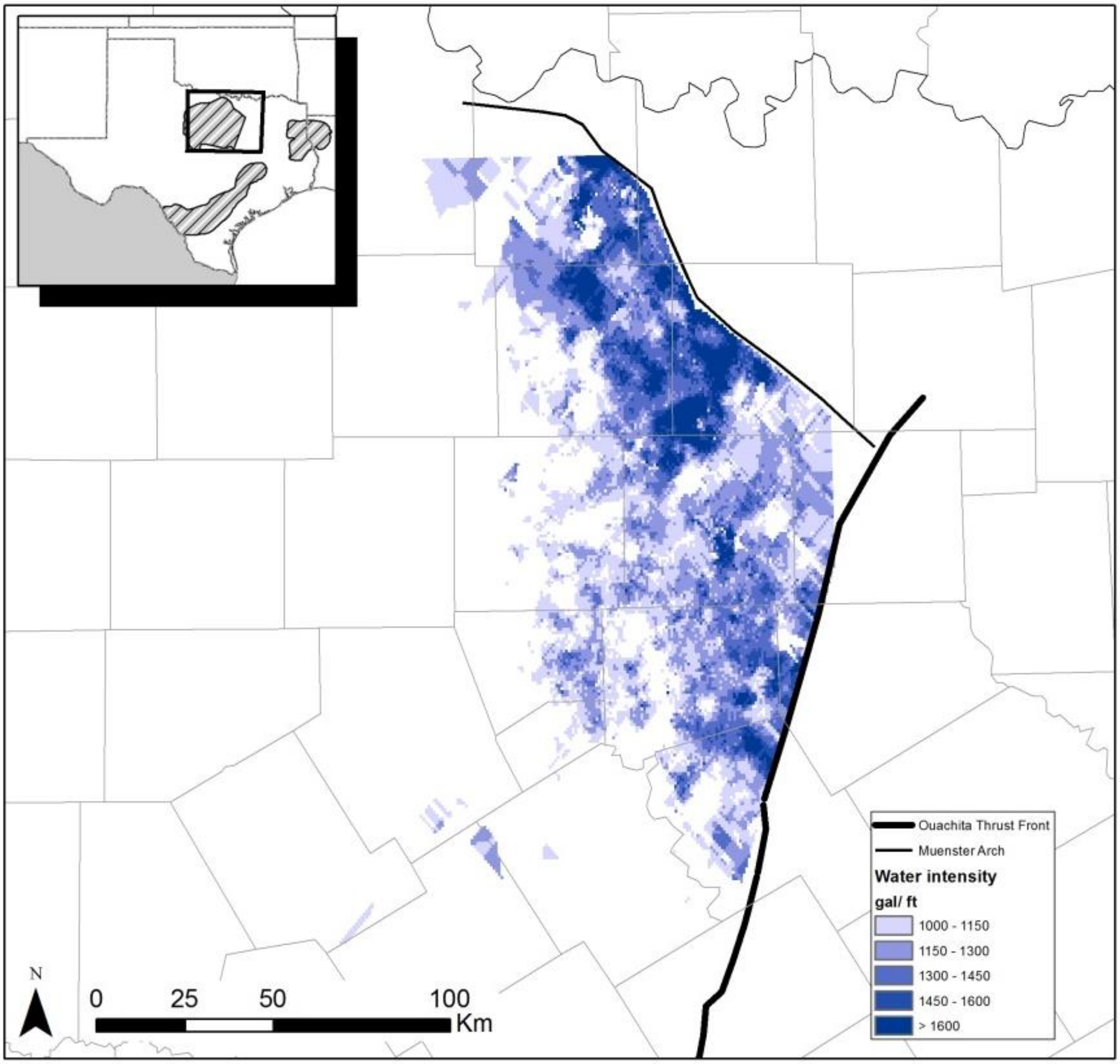
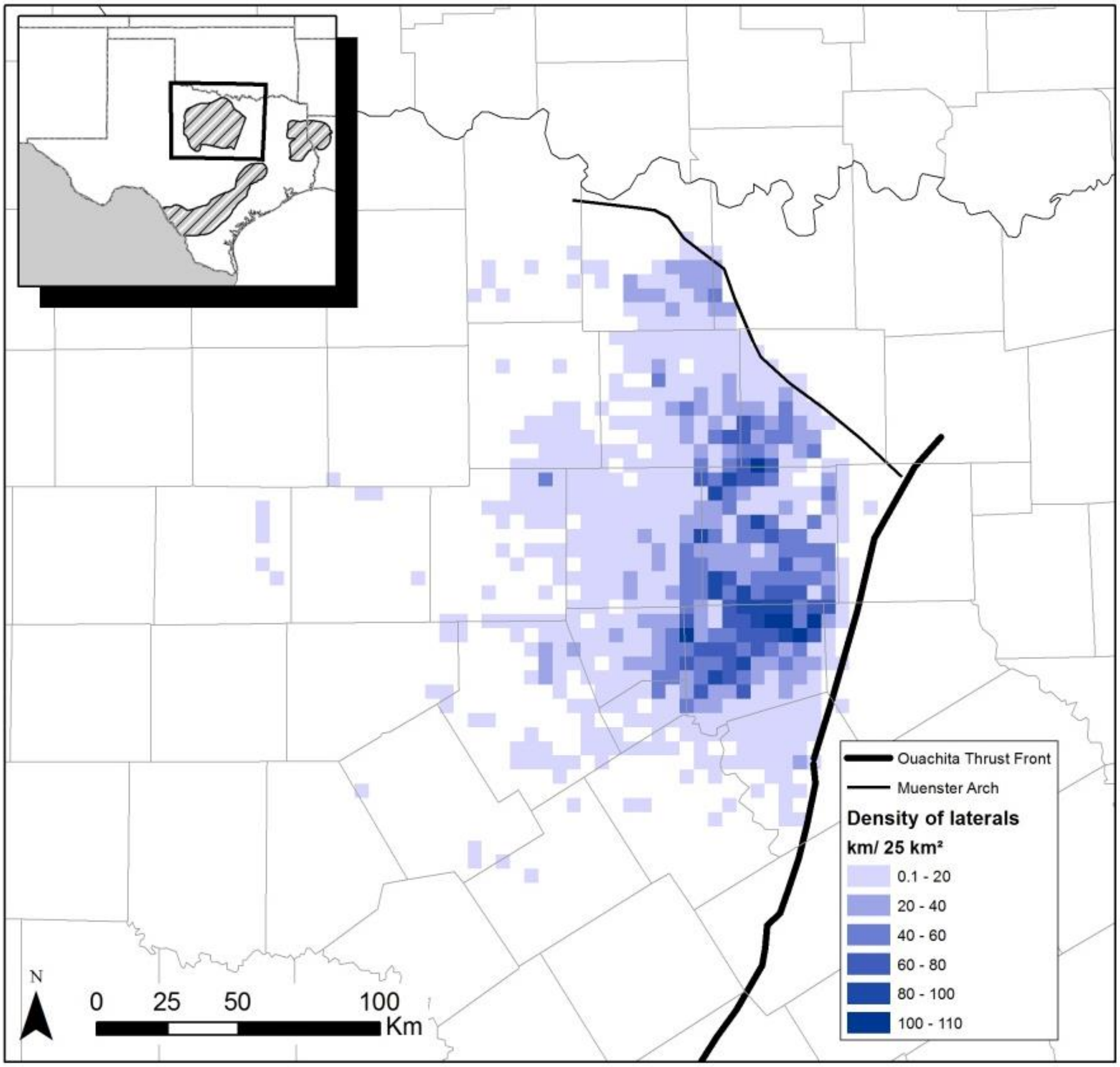


Figure S8. Barnett Shale spatial distribution of water-use intensity.



Note: 25 km^2 = 154 × 40 acres; that is, 154 wells/25 km^2 = 1 well/40 acres.
Figure S9. Barnett Shale spatial distribution of density of lateral (cumulative length per area).

The map shows a smoothed measure of the lateral density using a 5×5 km^2 grid. It was obtained by doing the cumulative sum of all laterals in a 25 km^2 area and assigning the results to the center cell and then moving 5 km in one direction and repeating the calculation.

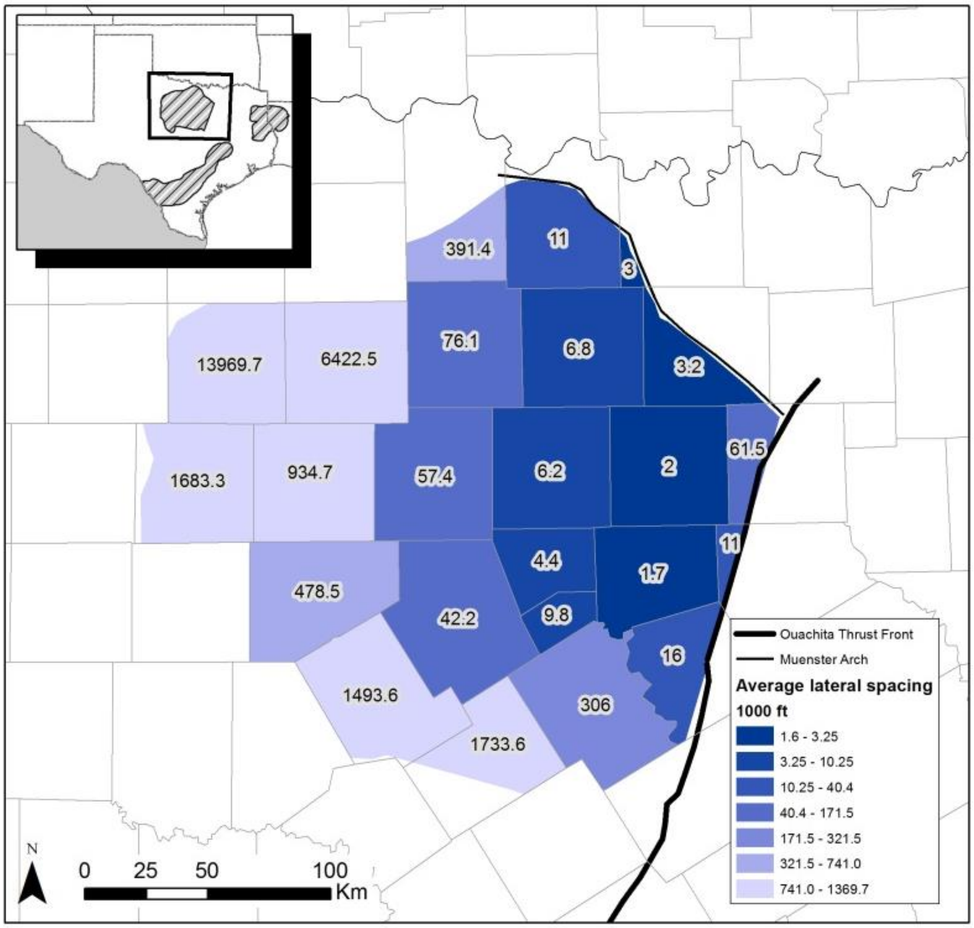


Figure S10. Barnett Shale county-level average lateral spacing.

The average spacing is high in the core area, e.g., a sustained ~2000 ft in areas as large as a county.

Table S2. Barnett Shale county-level average lateral spacing for top producing counties, calculated in those sections of the county with an actual shale footprint.

County name	Sum lateral length / county area (km/km^2)	Average lateral spacing (1000 ft)
Johnson	1.94	1.69
Tarrant	1.66	1.98
Hood	0.75	4.35
Parker	0.53	6.20
Wise	0.48	6.77
Denton	0.47	6.99
Somervell	0.34	9.76
Others		>10×10^3 ft

Note: Average spacing = 1/(lateral length density);
Counties are sorted by decreasing lateral length density

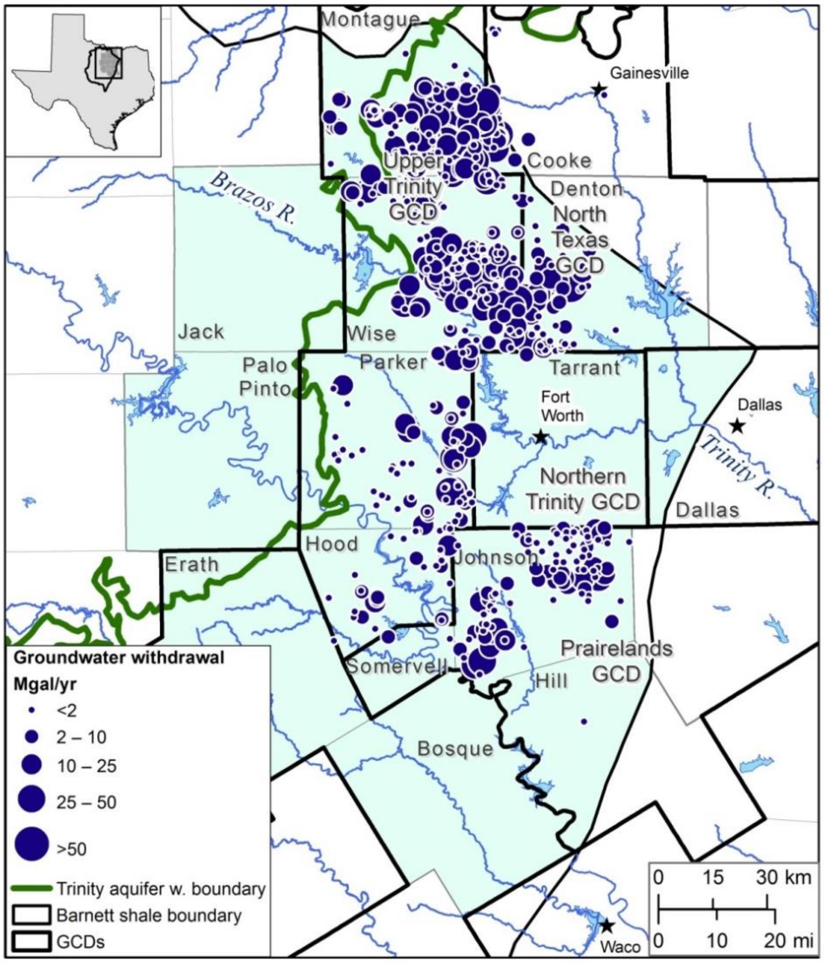


Figure S11. Estimated yearly groundwater withdrawal for the 2011–2012 period (data from GCDs). All wells are represented for a 12-month period, but the period varies: calendar year 2011 (Upper Trinity and North Texas), calendar year 2012 (Prairielands), and from 6/2011 to 6/2012 (North Texas). Withdrawals on the map represent a total of ~14 kAF. Northern Trinity GCD provided water use data but with no specific well location.

Table S3. Groundwater withdrawals for oil and gas use. Data from GCDs. Drilling and possibly oil and gas uses other than HF are included. See Figure S19 for areas of conventional oil and gas production.

County	GCD	Total (Mgal/yr)	Total (kAF)	Total (Mm^3)	Period
Montague	Upper Trinity	1765	5.42	6.66	2011
Wise	Upper Trinity	1103	3.38	4.16	2011
Parker	Upper Trinity	430	1.32	1.62	2011
Hood	Upper Trinity	100	0.31	0.38	2011
Somervell	Prairielands	2.	0.01	0.01	2012
Hill	Prairielands	0	0.00	0.00	2012
Johnson	Prairielands	504	1.55	1.90	2012
Denton	North Texas	471	1.44	1.78	2011 and 6/2011 to 6/2012
Cooke	North Texas	222	0.68	0.84	2012 and 6/2011 to 6/2012
Tarrant	Northern Trinity	>155	>0.48	>0.59	3/2011 to 3/2012
Total			**14.59**	**17.94**	

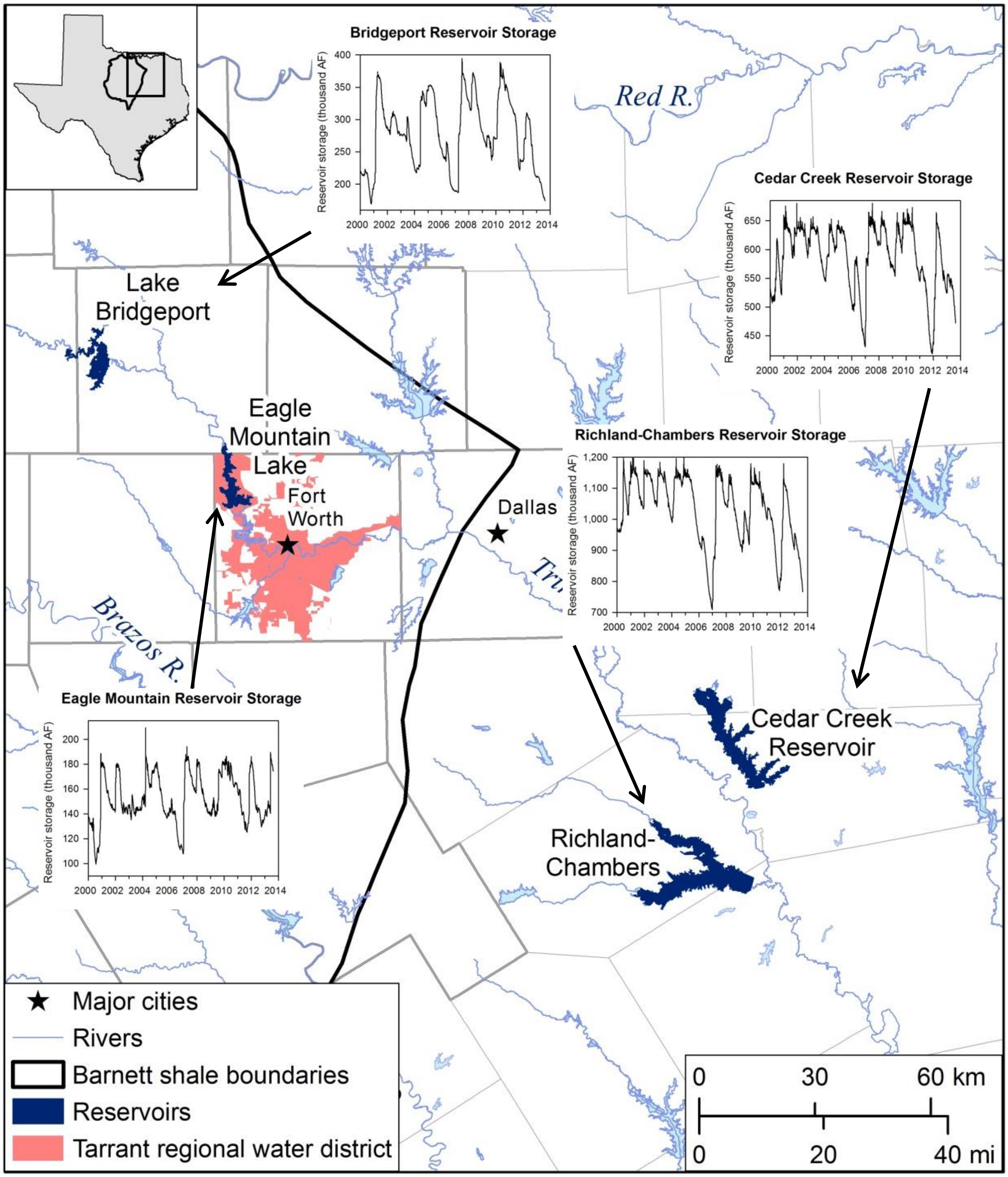
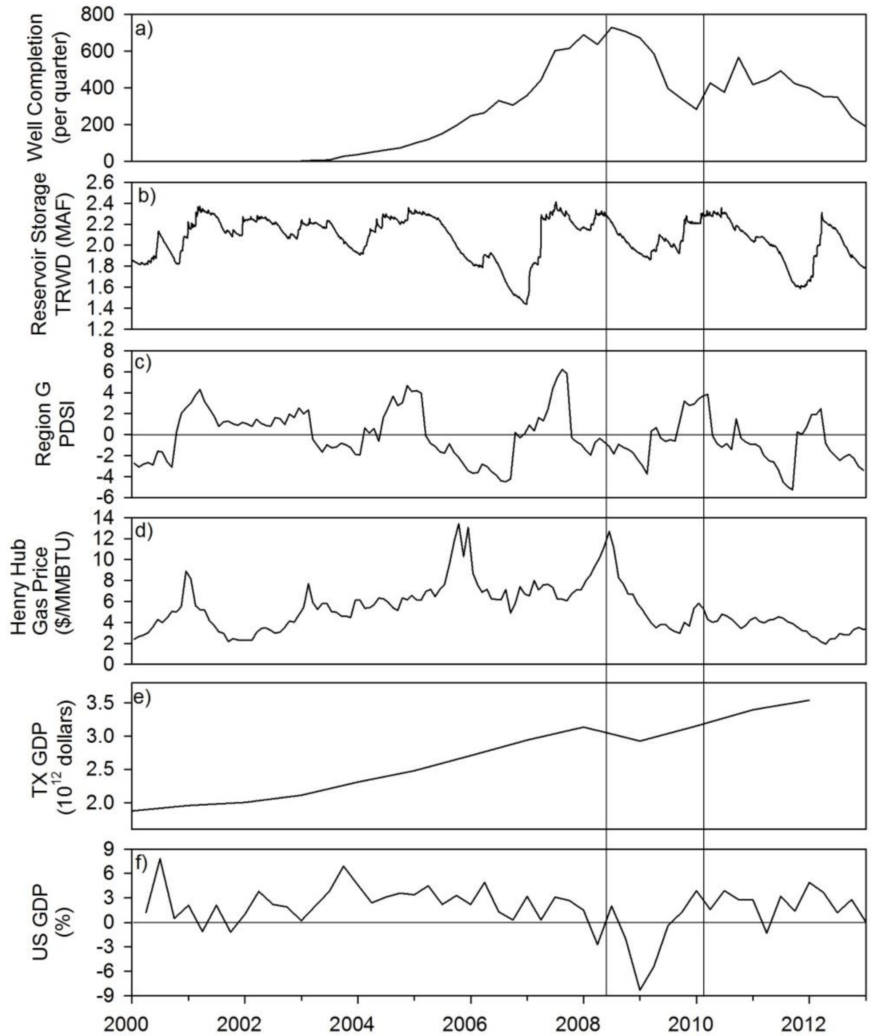


Figure S12. Tarrant Regional Water District area (http://www.trwd.com) and location of TRWD reservoirs: Cedar Creek and Richland-Chambers reservoirs in Henderson and Kaufman and Navarro and Freestone counties.



Data sources:
(a) Number of horizontal wells (IHS Enerdeq database) completed in the quarter;
(b) Daily TRWD reservoir storage (million AF): sum of all four TRWD reservoir storage (TWDB data);
(c) Monthly PDSI (Palmer Drought Severity Index): values <-2 indicate moderate drought and <-3 indicate severe drought. Climate Region G includes: http://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp# ;
(d) Monthly price of gas at the Henry Hub http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm ;
(e) TX GDP: annual state of Texas Gross Domestic Product:http://www.bea.gov/regional/index.htm ;
(f) Quarterly change in U.S. GDP: http://www.bea.gov/iTable/iTable.cfm?ReqID=9&step=1#reqid=9&step=3&isuri=1&903=3

Figure S13. Time correlation of horizontal well count and drought and economic-activity parameters. Drought is assessed by stored water volume (b) and by the drought index (c), whereas economic parameters consist of price of gas (d), Texas GDP (e), and U.S. GDP (f).

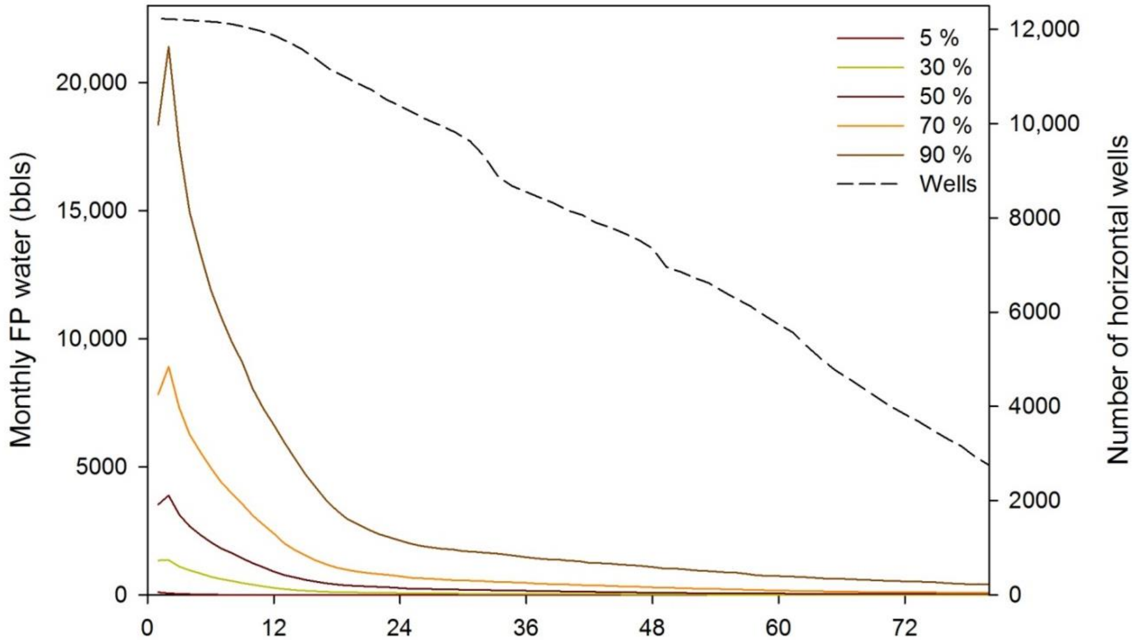


Figure S14. Monthly water-production percentiles (5th, 30th, 50th, 70th, and 90th) and number of wells (dotted line). Note that curve smoothness has been observed not to exist at the well level. 10,000 bbl = 1.29 AF

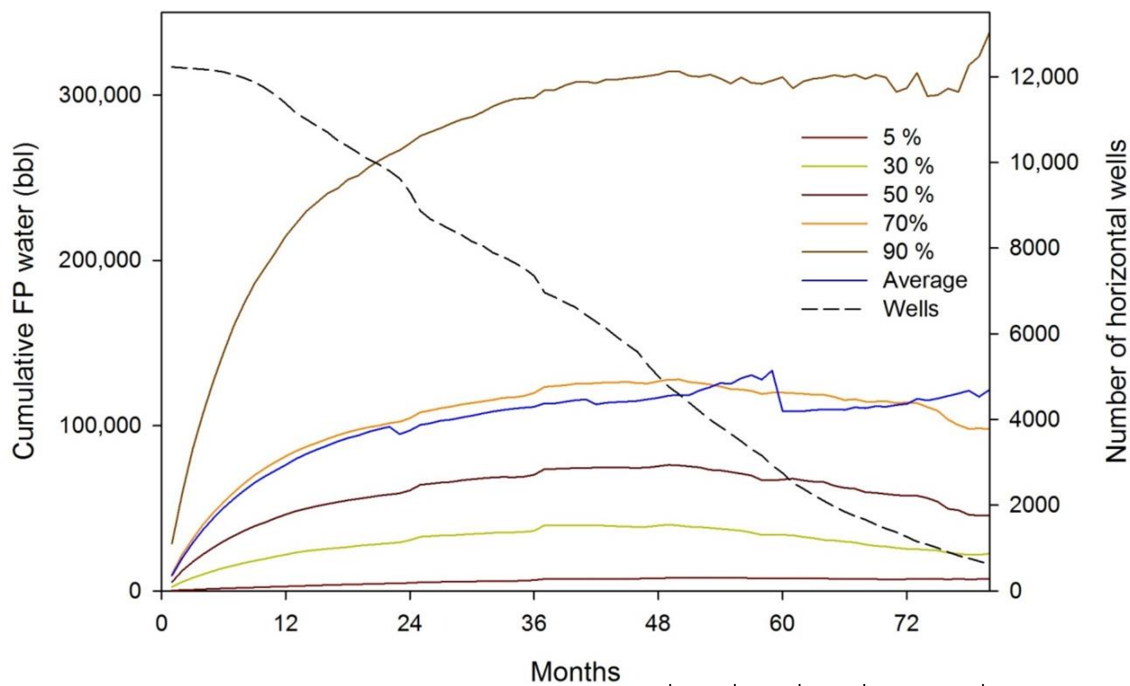


Figure S15. Cumulative water-production percentiles (5th, 30th, 50th, 70th, and 90th) and number of wells (dotted line) computed on a monthly basis. Note that the percentiles are computed on smaller and smaller set of wells. The shapes of the curves suggest that early (>60 months) produced slightly less water than did younger wells, but when they were bad (in terms of water production), they were worse than younger bad wells (90th percentile). 100,000 bbl = 12.89 AF.

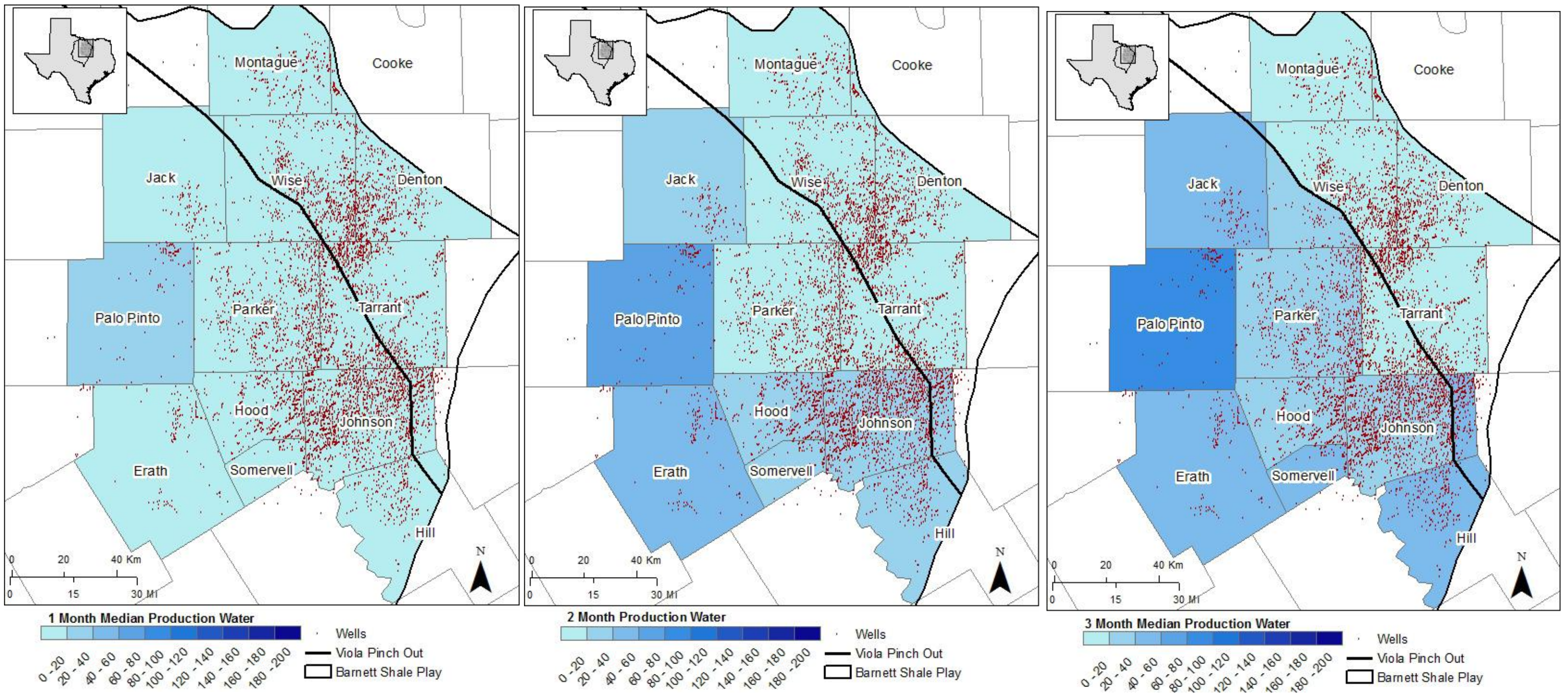


Figure S16. County-level spatial distribution of the WB ratio (ratio of FP water volume to HF volume), month 1, 2, 3, 6, 12, and 24.

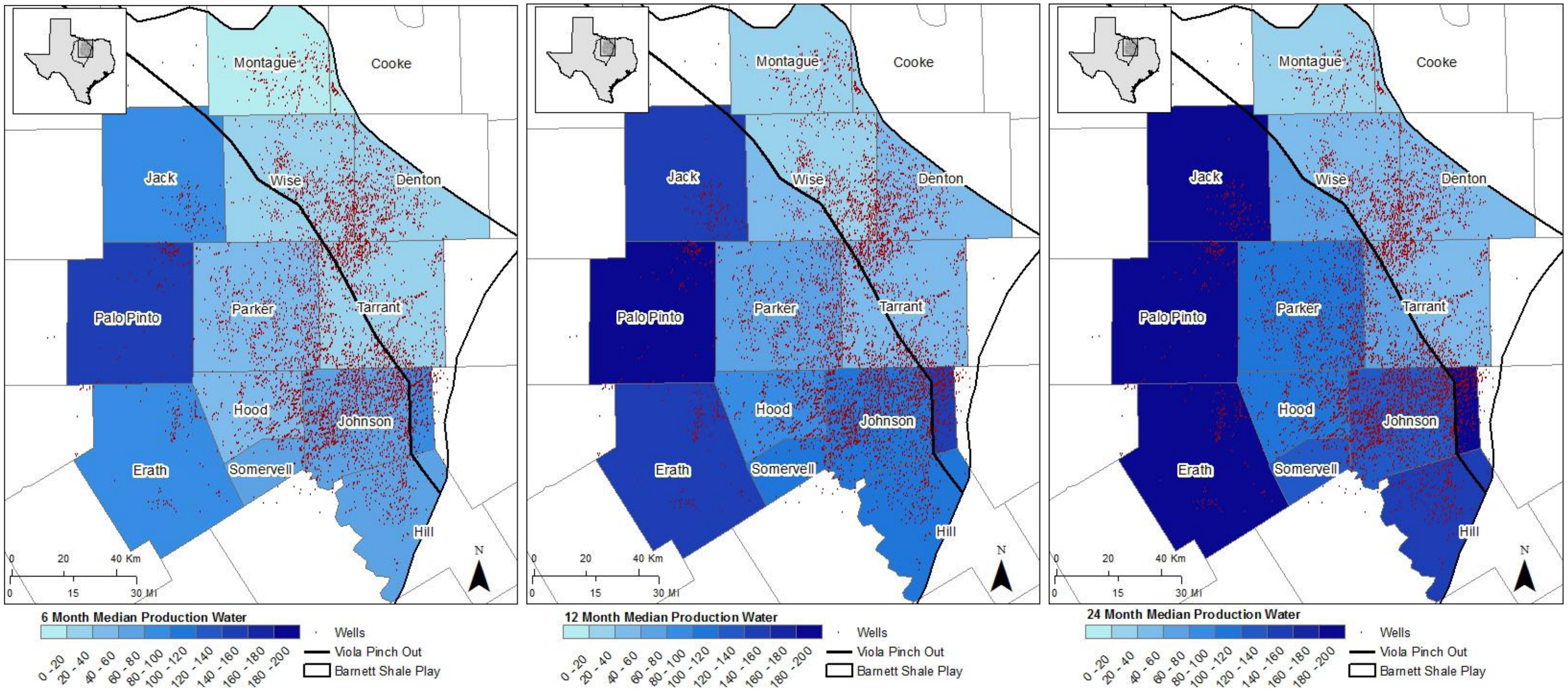


Figure S16. County-level spatial distribution of the WB ratio (ratio of FP water volume to HF volume), month 1, 2, 3, 6, 12, and **24.** (continued).

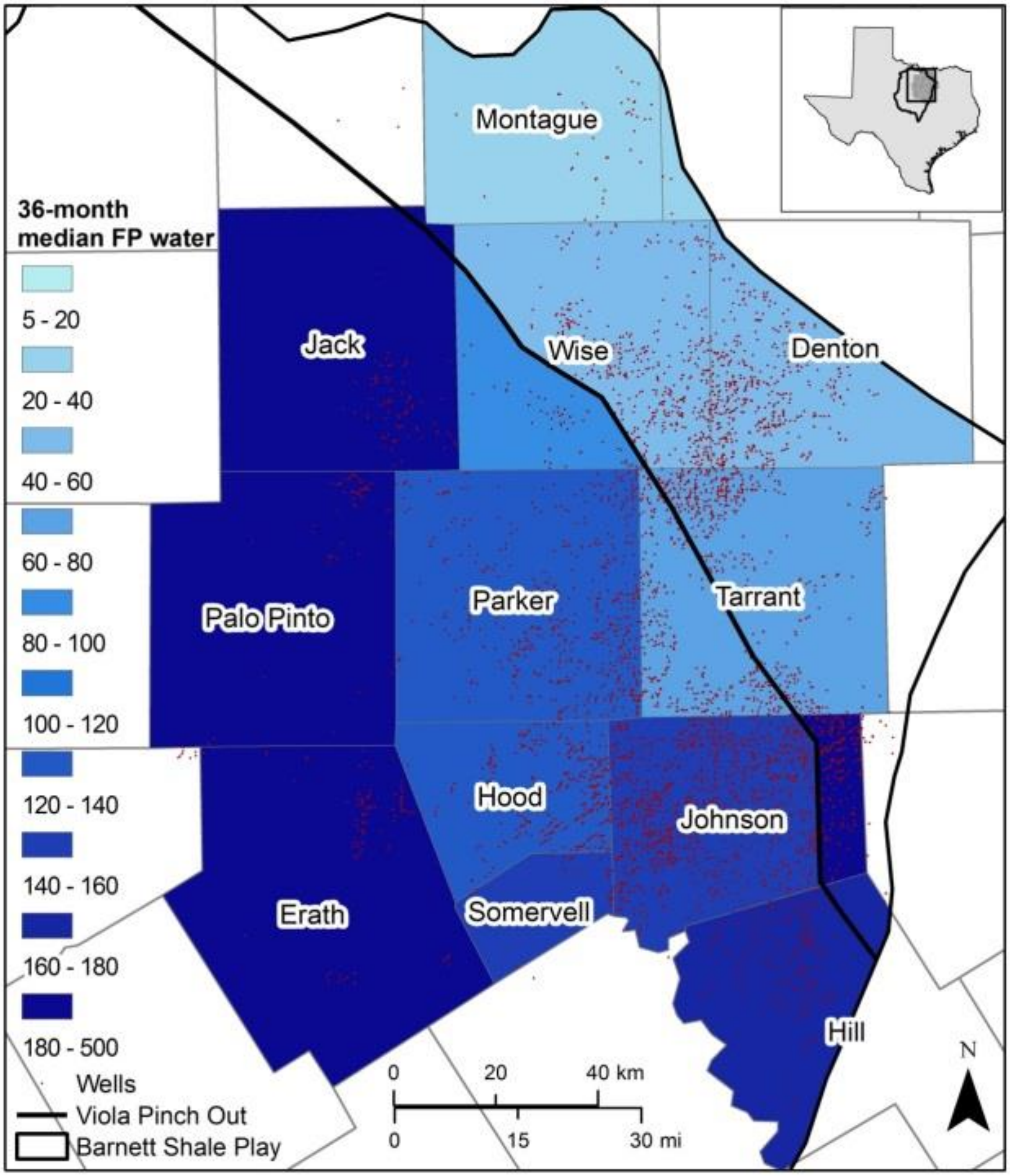


Figure S17. County-level spatial distribution of the WB ratio—the ratio of FP water volume over that of HF volume, measured 3 years after HF operations (month 36). The representative value for each county is calculated by drawing plots similar to Figure 4 but at the county level and extracting the median for a given month (here month 36). The WB ratio is inversely proportional to the gas production: lower in the core area where gas production is high and higher outside of the core area where gas production is lower. Montague County is an unexplained outlier but likely related to the presence of oil.

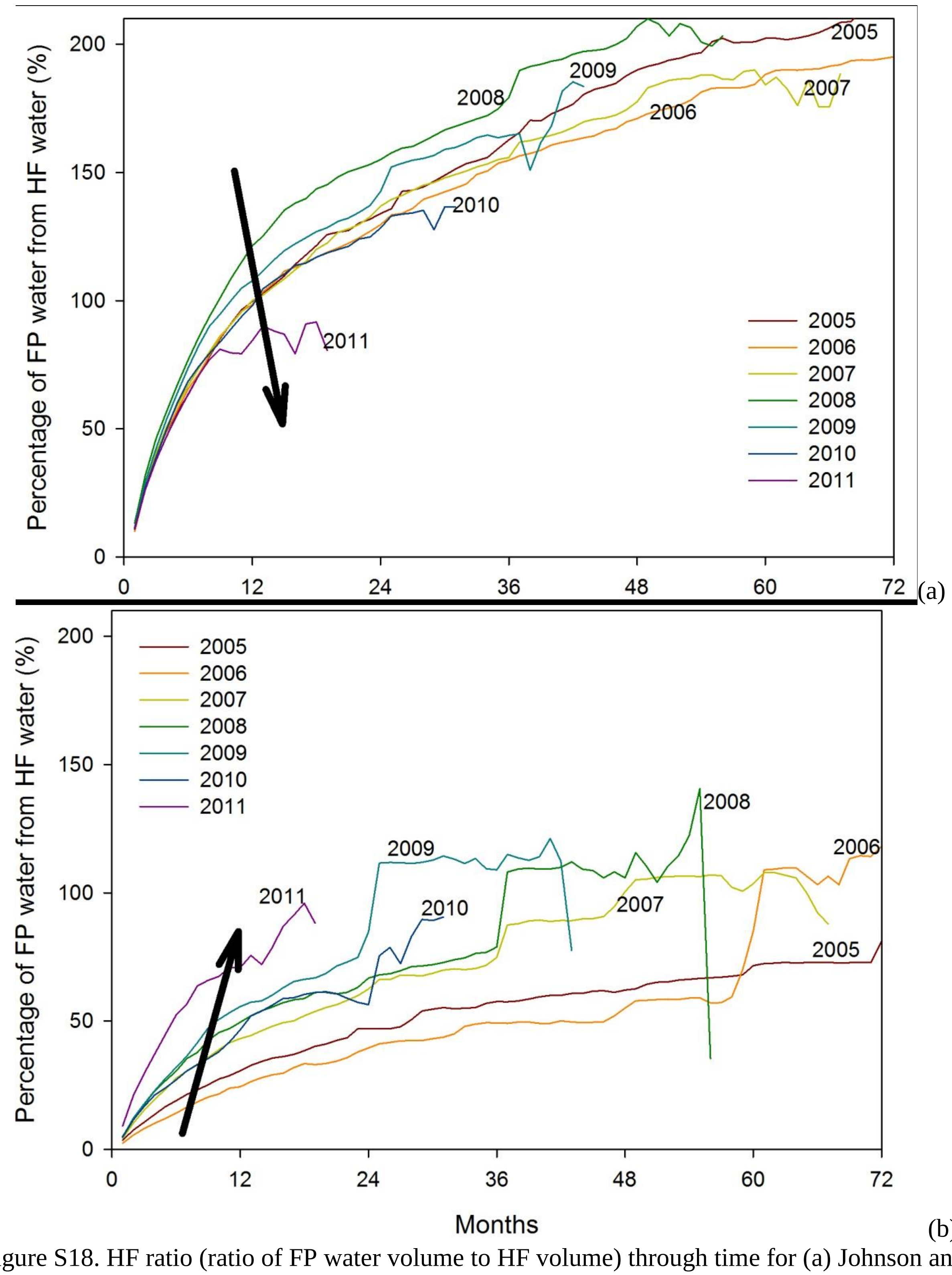
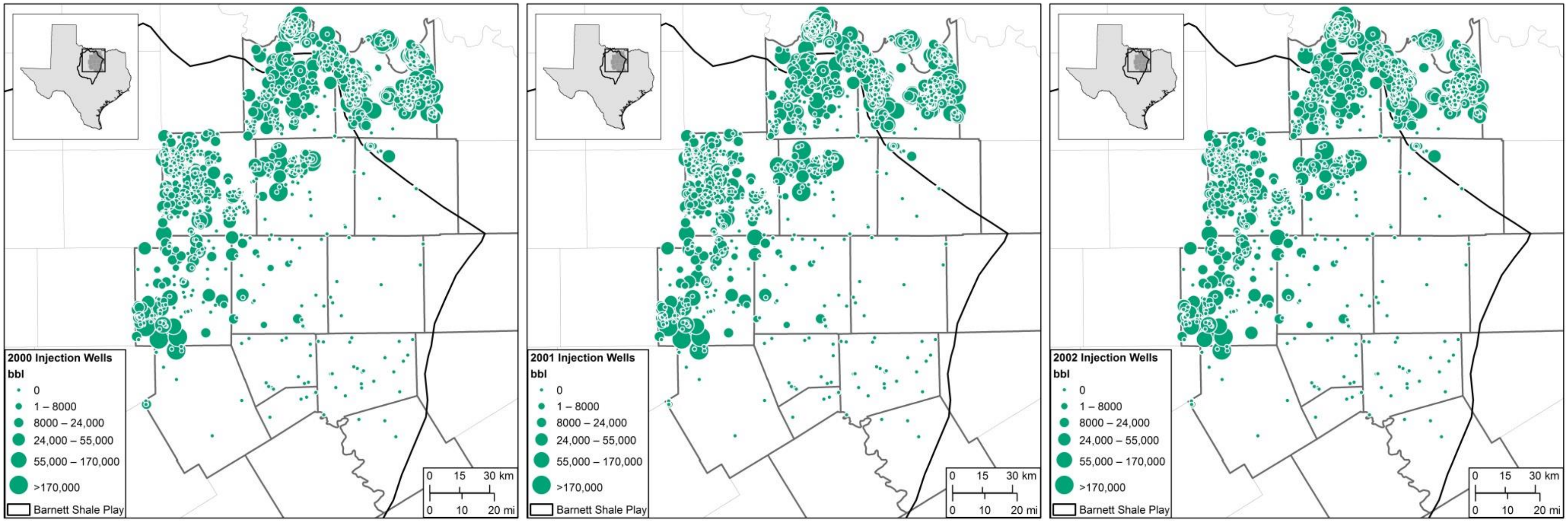
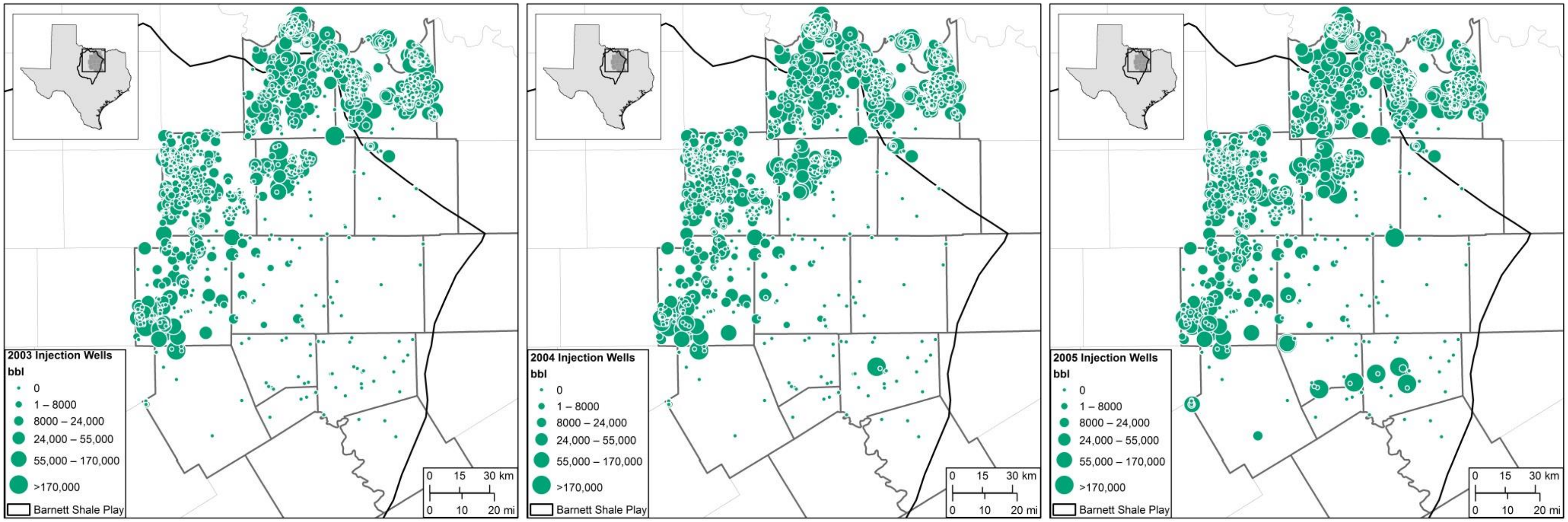


Figure S18. HF ratio (ratio of FP water volume to HF volume) through time for (a) Johnson and (b) Tarrant Counties.



2000 (931 wells) | 2001 (929 wells) | 2002 (941 wells)

Figure S19. Active injection wells and injected volume for individual years (2000–2011).

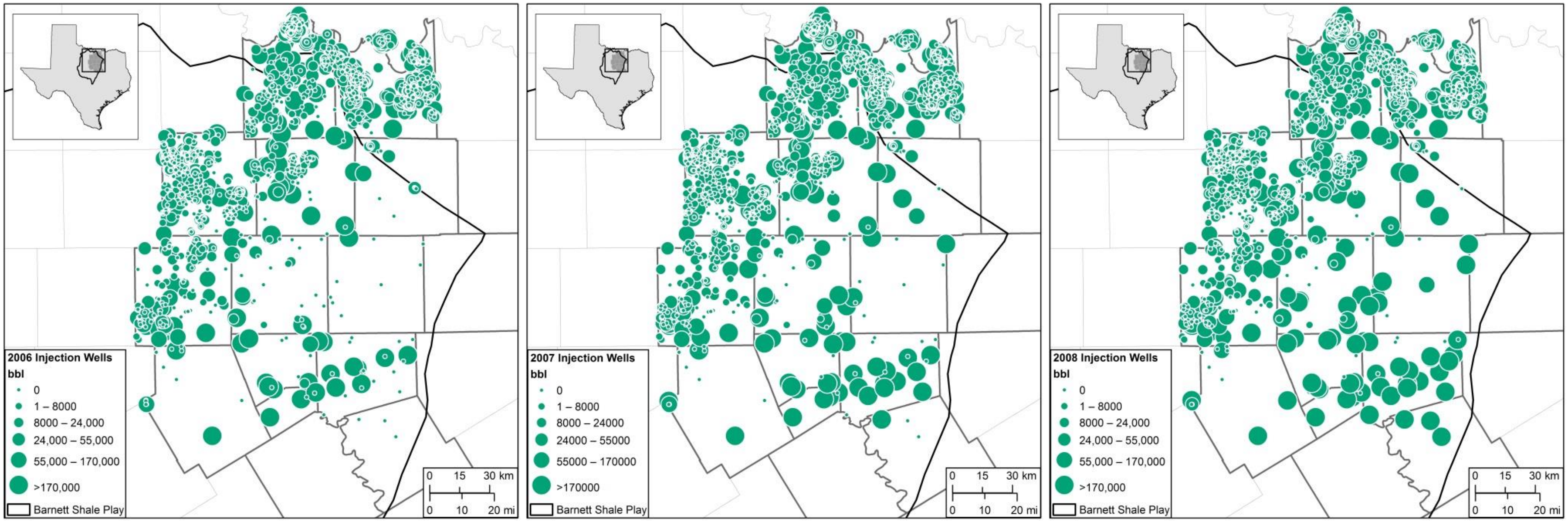


2003
(978 wells)

2004
(1002 wells)

2005
(1056 wells)

Figure S19. Active injection wells and injected volume for individual years (2000–2011) (continued).

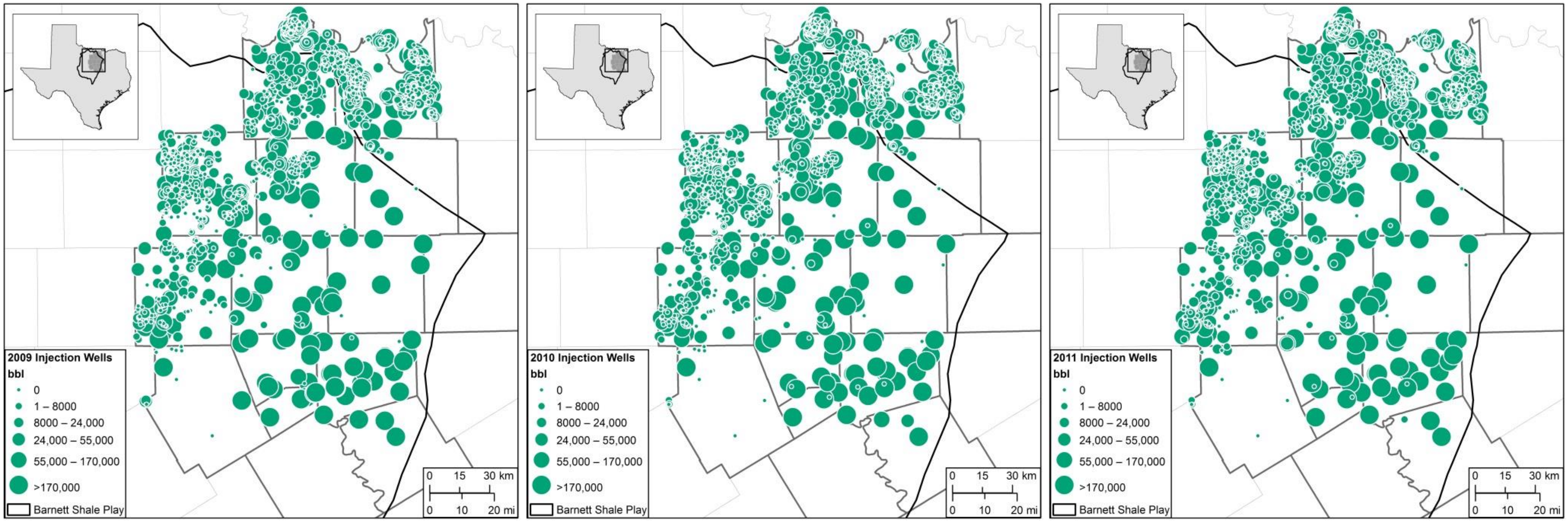


2006
(1078 wells)

2007
(1115 wells)

2008
(1146 wells)

Figure S19. Active injection wells and injected volume for individual years (2000–2011) (continued).



2009
(1163 wells)

2010
(1172 wells)

2011
(1197 wells)

Figure S19. Active injection wells and injected volume for individual years (2000–2011) (continued).

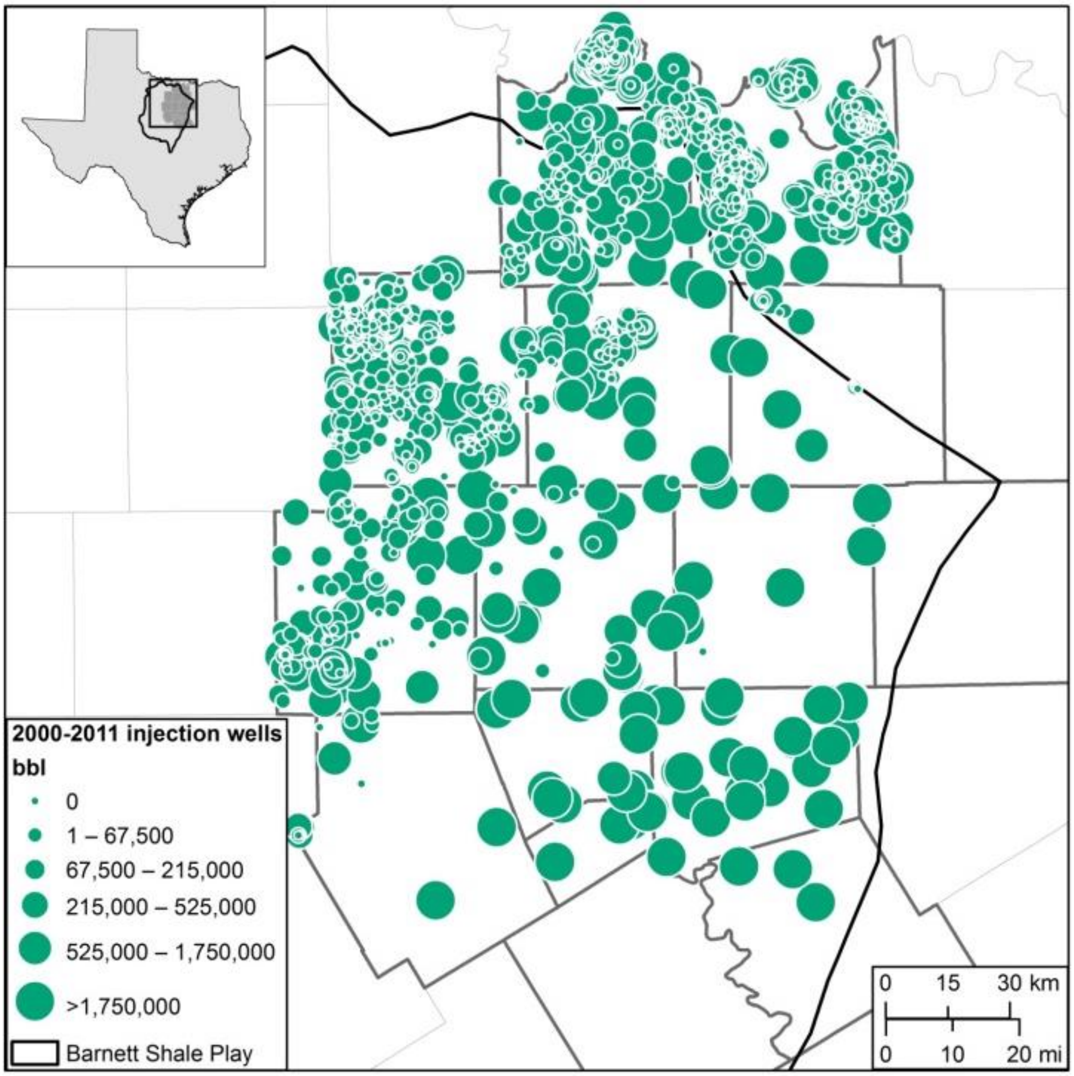
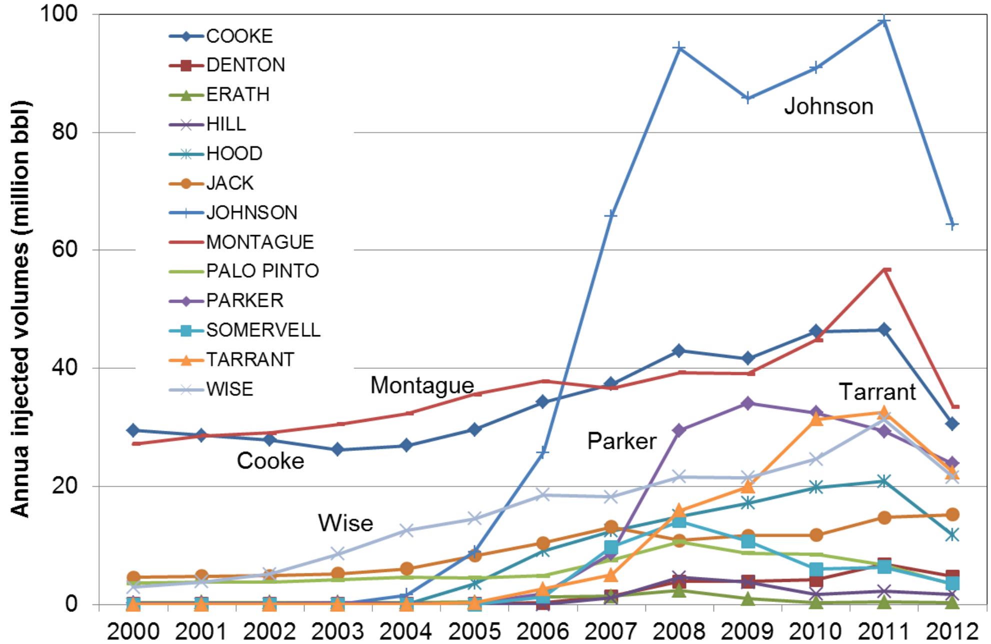
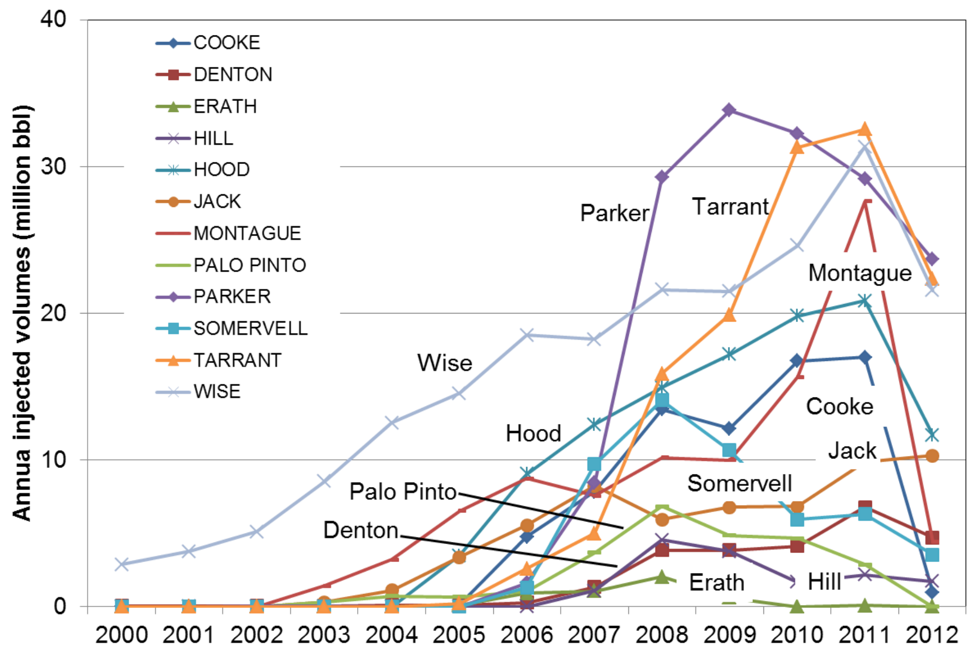


Figure S20. Map of active injection wells and cumulative injected volume from 2000 through 2011.



Note: no injection in Dallas and Bosque Counties.

Figure S21. Yearly injection volumes per county including from conventional oil and gas production; corrected version is Figure 5.



Note: no injection in Dallas and Bosque Counties.

Figure S22. Yearly injection volumes per county (injection from conventional oil and gas production not included); same as Figure 5 but without Johnson County.

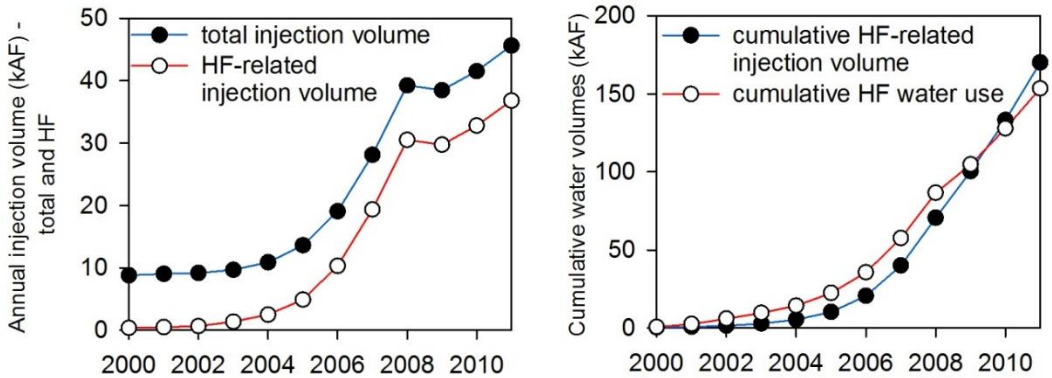


Figure S23. HF and FP water volumes. Plot (a) shows, on a yearly basis, that disposal of FP water and other HF-related fluids (open circles) account for a large fraction of the Class II injection volume (filled circles) in the 15-county area (details for major counties in Figure 5). Plot (b) compares cumulative volumes of HF water use—water to stimulate wells (open circles)—to FP volumes disposed of in injection wells (filled circles).

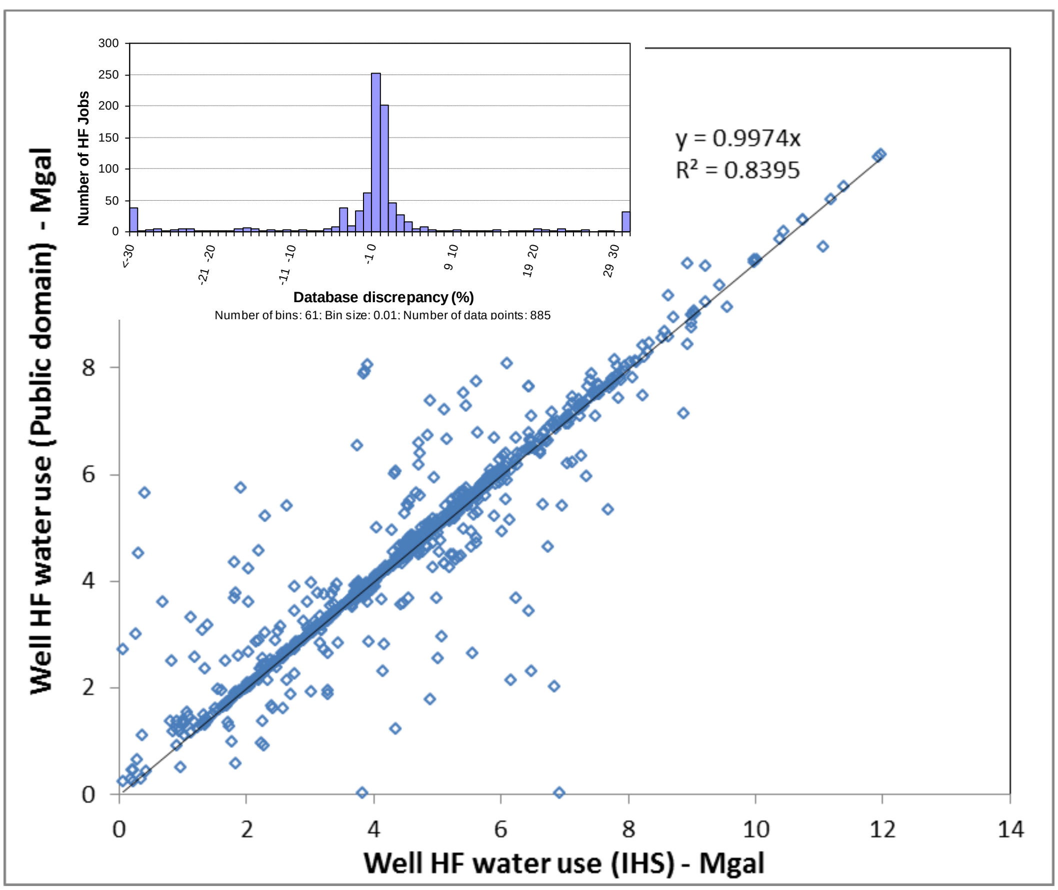


Figure S24. Well-level comparison of HF water use on the basis of IHS database and public domain data.
(http://frack.skytruth.org/fracking-chemical-database/frack-chemical-data-download)

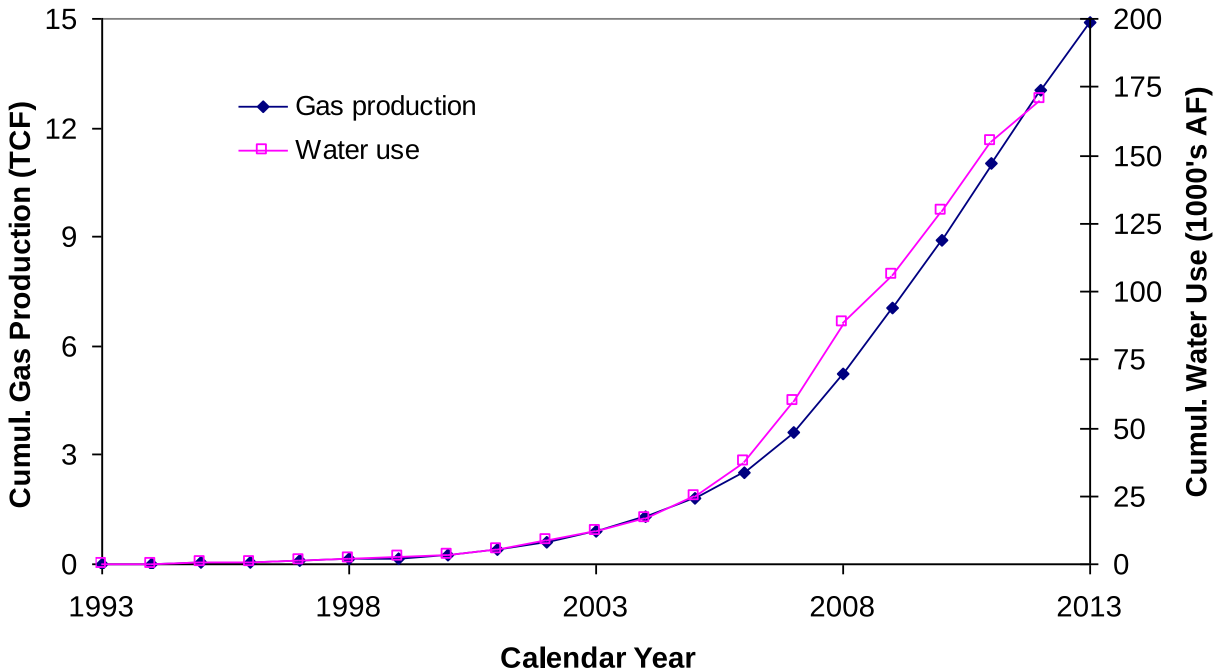
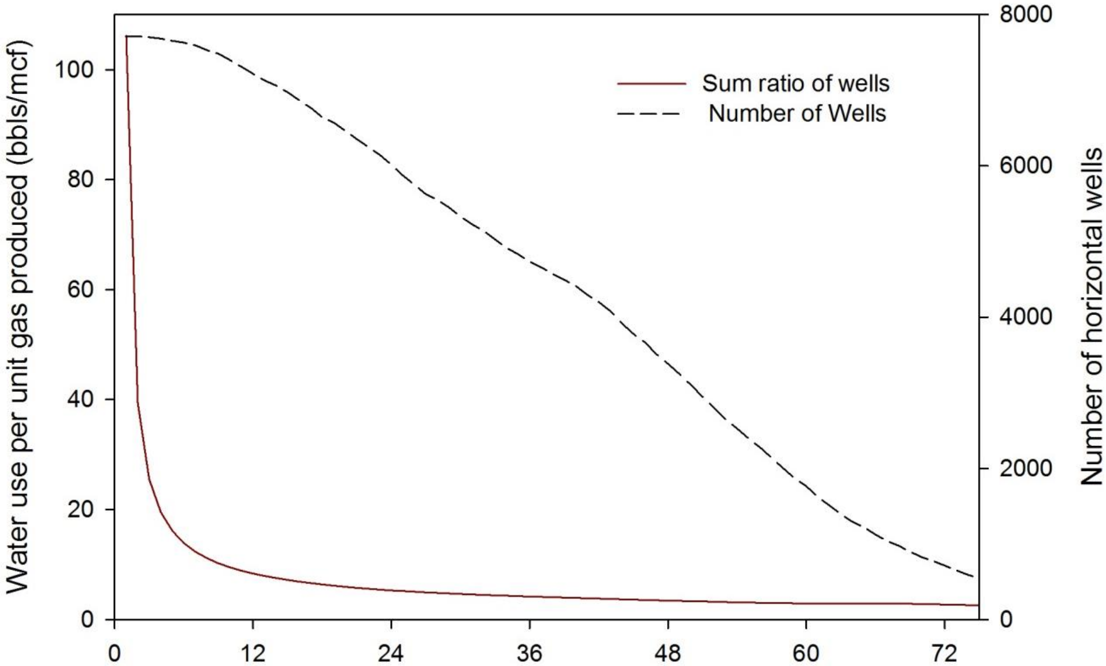


Figure S25. Cumulative gas production and water use track each other. 2012 water use not corrected to the end of 2012 (see Figure S3).

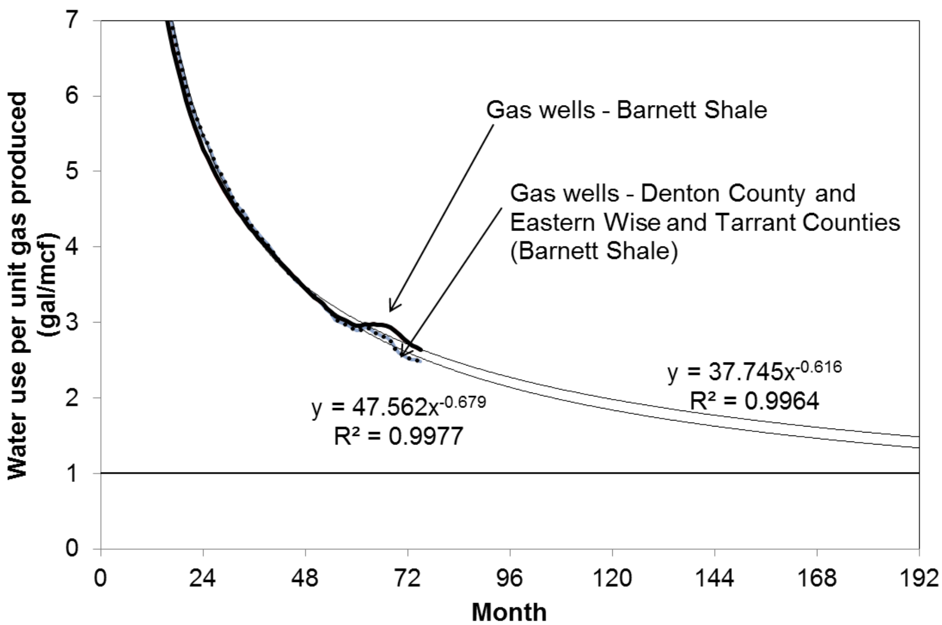
Water intensity was computed by taking the ratio of the estimated water use to the end of 2012 (170 kAF to which we added 5 kAF to account for delayed reported of water use) to the gas production to end of 2012 (13.05 Tcf). Note that the water intensity is slightly overestimated because of the oil wells of the combo play are also included.

175,000 AF × 325,851 gal/AF / 13.05×10^9 Mcf = 4.37 gal/Mcf



(a)

Note: Includes only gas wells for which water use is available.



(b)

Note: Include only gas wells for which water use is available.

Figure S26. Water efficiency (water use per unit gas produced); x-axis represents number of months after completion (all years included). (a) Historical data; (b) projection to 16 years after completion. Extrapolation is consistent with the decrease in production (decline curve) with the inverse of the square root of time (Browning et al., 2013).