Assessment of Industry Water-Use in the Barnett Shale Gas Play (Fort Worth Basin)

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ABSTRACT

The Barnett Shale play, located in North Texas and currently the most prolific onshore natural gas play in the country, has seen a quick growth in the past decade with the development of new "frac" (a.k.a. fracture stimulation) technologies needed to create pathways to produce gas in the very low permeability shales. This technology uses a large amount of fresh water (millions of gallons in a day or two on average) to develop a gas well. There are currently over 10,000 gas wells in the Barnett Shale play with thousands more likely to be drilled in the next couple of decades as the play expands out of its core area. A typical vertical and horizontal well completion consumes approximately 1.2 and 3.0-3.5 million gallons of fresh water, respectively. This has raised some concerns among local communities and other ground water stakeholders, especially in the footprint of the Trinity Aquifer. This paper presents a summary of a Texas Water Development Board (TWDB)–funded study carried out to estimate water use. Total water use during the life of the play is highly uncertain, being dependent above all on the price of gas. Other important factors include geologic risk factors, technological factors (horizontal vs. vertical wells, water recycling), operational factors (number of well completions that can be done in a year, proximity of a fresh water source), and regulatory factors. Projections for the high water use scenario yields a total ground water use of 417,000 acre-ft, an annual average ground water use of 22,000 acre-ft over the 2007-2025 period for the whole Barnett Shale play.

INTRODUCTION

The Barnett Shale play, located in North Texas and currently the most prolific onshore gas play in the country, has seen a quick growth in the past decade with the development of new "frac" (a.k.a. fracture stimulation) technologies needed to create pathways to produce gas in the very low permeability "shales." This technology uses a large amount of water in a short period of time (up to 5 million gallons of water within a day) to develop a gas well. There are currently more than 10,000 wells tapping the Barnett Shale, with thousands more likely to be drilled in the next few years and possibly decades. The so-called core area has seen its initial production in the 1990s and includes part of Denton, Wise, and Tarrant counties (Fig. 1). The production area has been rapidly expanding in the past few years to the southwest, into Parker and Johnson counties, and may eventually include more than 20 of the 44 counties of the Fort Worth Basin covered in all or partly by the Barnett Shale footprint. The core area and its recent extensions are officially known in Texas Commission on Environmental Quality (TCEQ) files as Newark East Field.

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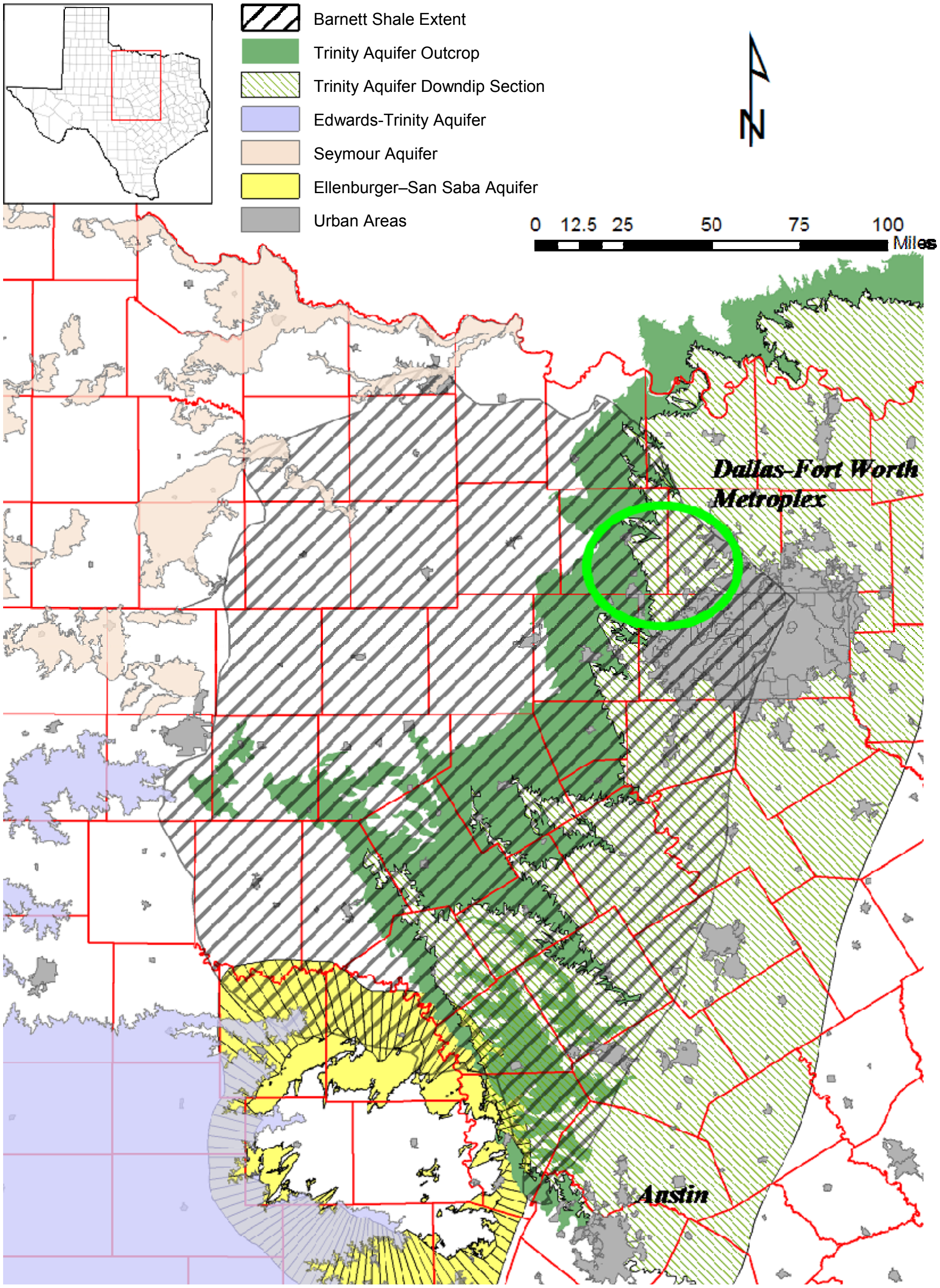

Figure 1. Barnett Shale extent and Texas Water Development Board (TWDB) major aquifers. The Llano Uplift is outlined by the Ellenburger Aquifer. The lower downdip limit of the aquifers is set at salinity of 3000 ppm. The circle west of the Dallas–Fort Worth (DFW) metroplex highlights the so-called core area where the first successful production wells were located.

This work was initially performed to provide input to an updated version (Bené et al., 2007) of the Trinity Ground water Availability (GAM) model. The Texas Water Development Board (TWDB) requested the update following concerns about a possible excessive drain on water resources, especially ground water, derived from a combination of factors: (1) exurban growth and suburban and urban development west of the Dallas-Fort Worth metroplex; (2) recurrent drought conditions in North Texas; and (3) oil and gas industry water use associated with (a) rapid growth of the Barnett Shale play in urban environment; (b) impressive amount of water used in a very short time; (c) important increase in truck traffic (hauling water back and forth); and (d) issues of frac water disposal. The goal of the study was to determine how much water, especially ground water, is being used and how much water would be used in the future. Currently, it is not clear how much water is being pumped out of the Trinity Aquifer because there is no requirement to report the source (ground water or surface water) of the frac water.

Barnett Shale characteristics have been described in many other publications (Montgomery et al. 2005; Pollastro et al., 2007; Pollastro, 2007). Although complex in the details, the Barnett Shale is a generally black, fine-grained rock formation that exists under wide areas in Texas (Fig. 1) behaving more like a conventional source rock for oil. It is up to 800 ft thick in the core area thinning outwards to the west and south. The Barnett Shale dips gently toward the core area from the south where it crops out and west where it thins considerably and its base reaches a maximum depth of ~8500 ft (subsea) in the northeast confines of its extent. Per-well reserves are relatively low, and play success is sensitive to gas price. A large drop in gas price will stop the viability of the play. There seems to be some agreement that the gas price needs to stay above $5/Mcf for the play to stay viable in the long term (Fig. 2). Reserves are also "continuous" (similar to coalbed methane), that is, the resource is distributed across large geographic areas and there may be few dry wells. Natural permeability is in the micro-darcy to nanodarcy range and artificial stimulation is required – usually fracture treatments ("frac jobs"). This leads to small well spacing and possibly large surface impact.

The U.S. Geological Survey (USGS) estimated the mean of the gas resources at ~26 Tcf of gas (USGS, 2004; Pollastro, 2007), whereas Montgomery et al. (2005) put proven reserves (in the core area) at 2.7 Tcf, at the time the paper was written, and ultimate producible resources between 3 and 40 Tcf. The play is currently producing gas at a rate >1 Tcf/year (Fig. 2) and has already produced ~5 Tcf at the end of 2008 (Fig. 2). This compares to an annual gas production in the country of ~25 Tcf/yr in this decade (Energy Information Administration, 2009).

DATA SOURCE AND METHODOLOGY

Most data on UIC Class II wells (that is, related to the oil and gas industry) ultimately come from the RRC (Railroad Commission) W2 and G1 ("completion") forms but vendors have it processed in a searchable and user-friendly fashion. We turned to both Drillinginfo and IHS Energy vendors to obtain Barnett Shale well completion information. We also gained useful insight by talking to operators in meetings and conferences, including those held by the Barnett Shale Water Conservation and Management Committee (see Galusky, 2007).

This paper focuses on estimating future water use in the play by extrapolating historical data but also by including soft data such as general geological knowledge and geologic insight and discussions with operators. There are five steps in estimating future water use:

1. The first step consists in deriving geographic extent (integrating gas window, thickness, well economics) and defining high, low and medium scenario cases;

2. The second step consists in characterizing a "somewhat absolute maximum" water use at the subcounty level by hypothetically assuming that the subcounty is entirely drilled up with either vertical or horizontal wells or both as appropriate (see below) and applying an average water use per vertical well or linear of lateral. The remaining steps then consist in correcting for several factors as suggested below and in distributing the resulting total water use through time.

3. The third step consists in applying correction factors (but with a different numerical value for the high, low and medium cases): prospectivity, well spacing, and karst avoidance factor .

4. The fourth step consists of adding time-dependent constraints such as availability of drilling rigs, activity curve with start and peak years and period length, potential growth of recycling techniques (they are increasing but are still a small fraction of total water use and they may not have a large impact unless legislated), recomple-

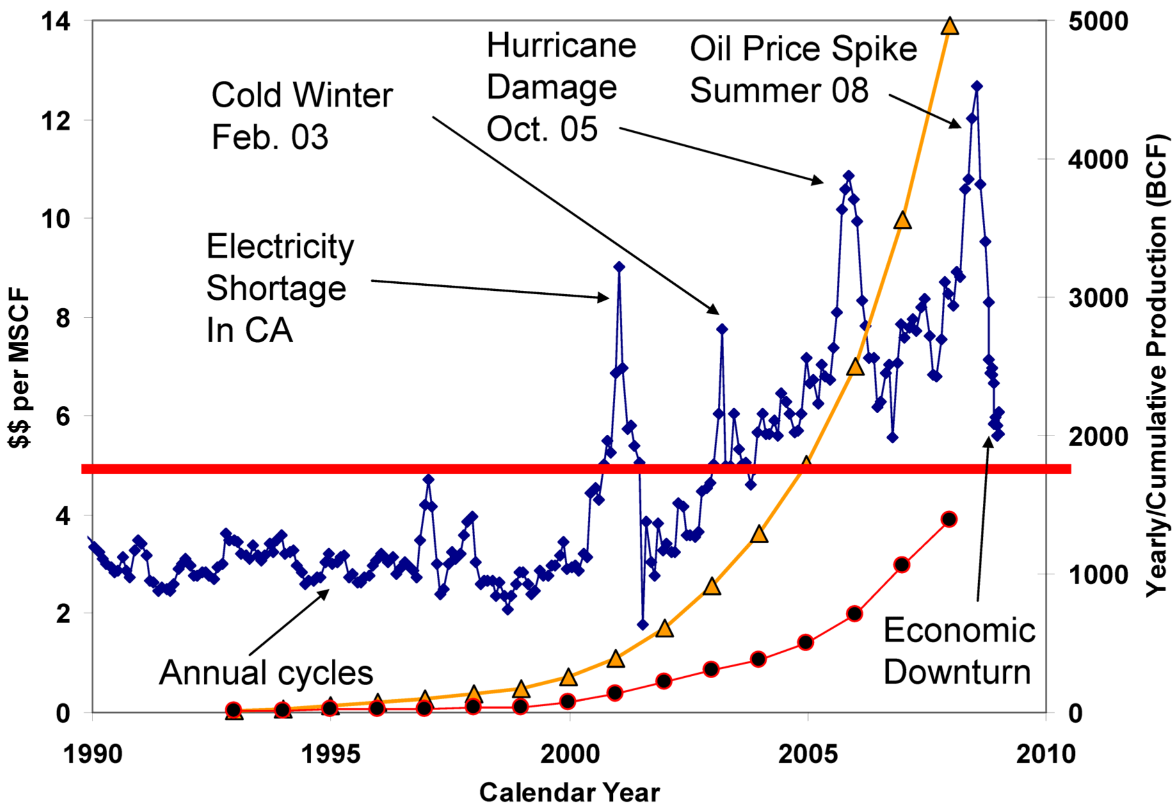

Figure 2. Price of natural gas ($ per thousand cubic ft) and Barnett Shale gas annual (lower smooth line) and cumulative (upper smooth line) production (in billions of cubic ft) since 1990 (Energy Information Administration, 2009). Horizontal line at $5 represents the usually accepted lower limit of rentability of the play. Events explaining natural gas price ups and downs are displayed in the plot.

tion frequency (unlikely for horizontal wells; once after 5 years for vertical wells), slight technological improvement over time.

5. The fifth and last step to obtain projection through time of ground water use (and thus impact on the Trinity Aquifer) is to apply some ground water / surface water split in which we assumed an increased reliance on ground water through time.

CURRENT AND PAST PRODUCTION PRACTICES

Historical Background

Given the extremely low permeability of the Barnett Shale, hydraulic fracturing seemed a logical solution. The concept is to prop natural or induced fractures open by injecting fluids in order to raise the pressure beyond the point at which it can be sustained by the rock, creating artificial fractures. Addition of a proppant to the fluid is needed to keep the induced fracture open once the fluid has been removed and the pressure has subsided. Sand is usually used as a propping agent. Starting in the early1980s to just before 1997, operators tried several design approaches to produce gas economically from the Barnett Shale. Initially, massive hydraulic fracture treatments with high-polymer crosslinked gel fluids and large amounts of proppant at moderate concentration were used (e.g., Ketter et al., 2006; Moore and Ramakrishnan, 2006), as it was generally done in the U.S. at the time. The first breakthrough came in 1997, when Mitchell Energy (subsequently bought out by Devon Energy in early 2002) realized that much less expensive slickwater completions with small amounts of sand proppant would produce as much gas as the extremely expensive gel frac jobs (Bowker, 2007). In essence, a high flow rate of fresh water has replaced the higher viscosity of previous fluids to keep proppant particles moving with the fluid. Very large amounts of fresh water are injected in a short time period (~1 day). Water is injected at a high rate of 60 to 80 bbl/min (2520-3360 gpm) (e.g., Ketter et al., 2006) in a 5.5-in casing, or possibly even higher 140 bbl/min (5880 gpm) (Lohoefer et al., 2006) in a larger casing (7 in). One may wonder why operators would need to use fresh water instead of the abundant saline water produced in the basin. In general, Barnett Shale operators prefer using fresh water for technological and operational reasons. Saltwater significantly increases the potential for scale deposition in the formation, tubing, casing, and surface equipment, as well as the potential for corrosion. In addition, chemicals needed to carry out a good frac job (friction reducer, bactericide, scale inhibitor, etc.) do not perform as well with saltwater.

The extent of the Barnett Shale play has been growing since the initial successful slickwater frac jobs in the so-called core area in parts of Wise, Tarrant, and Denton counties (Fig. 3). The first well intended to test the Barnett Shale was drilled in 1981, and the number of total completions, mostly using vertical wells, stayed below 100 until 1991. The number of annual completions then rose steadily, to reach more than 1,000 for the first time in 2005. A second breakthrough occurred when operators understood the need for horizontal wells and were able to expand out of the core area. Horizontal wells are more expensive to drill and develop but have better performance and larger production on average. The need for horizontal wells derives from the local geology. Operators' interest is to frac as much of a vertical section of the Barnett Shale as possible because production is clearly related the length of the frac'ed material. A frac job in the core area can be highly successful, even if it cracks into the underlying Viola Formation. This formation acts as a barrier between the older Ellenburger and the Barnett but it pinches out southwest of the core area. In addition, thickness of the Barnett Shale decreases away from the core area. A frac job with a too-large rate or volume will frac into the Ellenburger Formation where the Viola buffer is absent. The permeability of the Ellenburger is relatively high and the less-than-successful frac job will put in direct communication the well bore and the Ellenburger water, leading to gas production problems and an unacceptable water cut. The solution put forward by operators is to use horizontal wells and multiple carefully sized frac stages. Another geologic feature of interest has also emerged. Dolomites of the Ellenburger Formation are, at least in some areas underneath the Barnett Shale, paleokarsts—that is, cave-collapse cavities are common. Many of the resulting sags do impact the Barnett Shale, as well as other overlying formations (e.g., Hardage et al., 1996). Barnett Shale horizontal wells drilled through the faults of these collapse features could again encounter weakness zones prone to water flow and directly link the Ellenburger to the borehole. These features are possibly common; observations of the same structures cropping out near El Paso, Texas, suggest that the features are widespread in the Ellenburger, and many early well failures could possibly be explained by them. Vertical wells are less likely to encounter a fault, even when they are drilled in the middle of a collapse structure, and are not as affected as horizontal wells.

Water Use per Well

We compiled information from thousands of frac jobs performed between 2002 and 2006. A sizable percentage of frac jobs performed on vertical wells range from 1-1.5x10^6 gal/well (Fig. 4A). The numbers represent the sum of water use in all stages performed on a given well at a given date. Unlike vertical-well frac technology thought to be mature enough to have (at least temporarily) stabilized in its water use, horizontal well technology, as applied to the Barnett play, might still be evolving, and only those frac jobs performed in 2005 and 2006 were included in the histogram (Fig. 4B). If vertical well water use was clearly unimodal, the distribution of water use for horizontal wells appears much noisier and has a much larger spread with multiple peaks. One of the reasons could be that, contrary to vertical wells, whose length is constrained by the thickness of the formation, horizontal-well laterals can be made as long as technology allows. It follows that a better metric for water use in horizontal wells is water-use "intensity," or water volume per unit length (gal/ft) (Fig. 4C). The transformation filtered out some noise from the raw number distribution and appears now to be unimodal. Although using the mode as a representative value is tempting, it probably underestimates the true average because of the long tail on the high values clearly visible on the histograms. On the other hand, taking a simple average of the results is not a robust solution because of typos in the databases. Instances where water use had extra zeros or units were reported as

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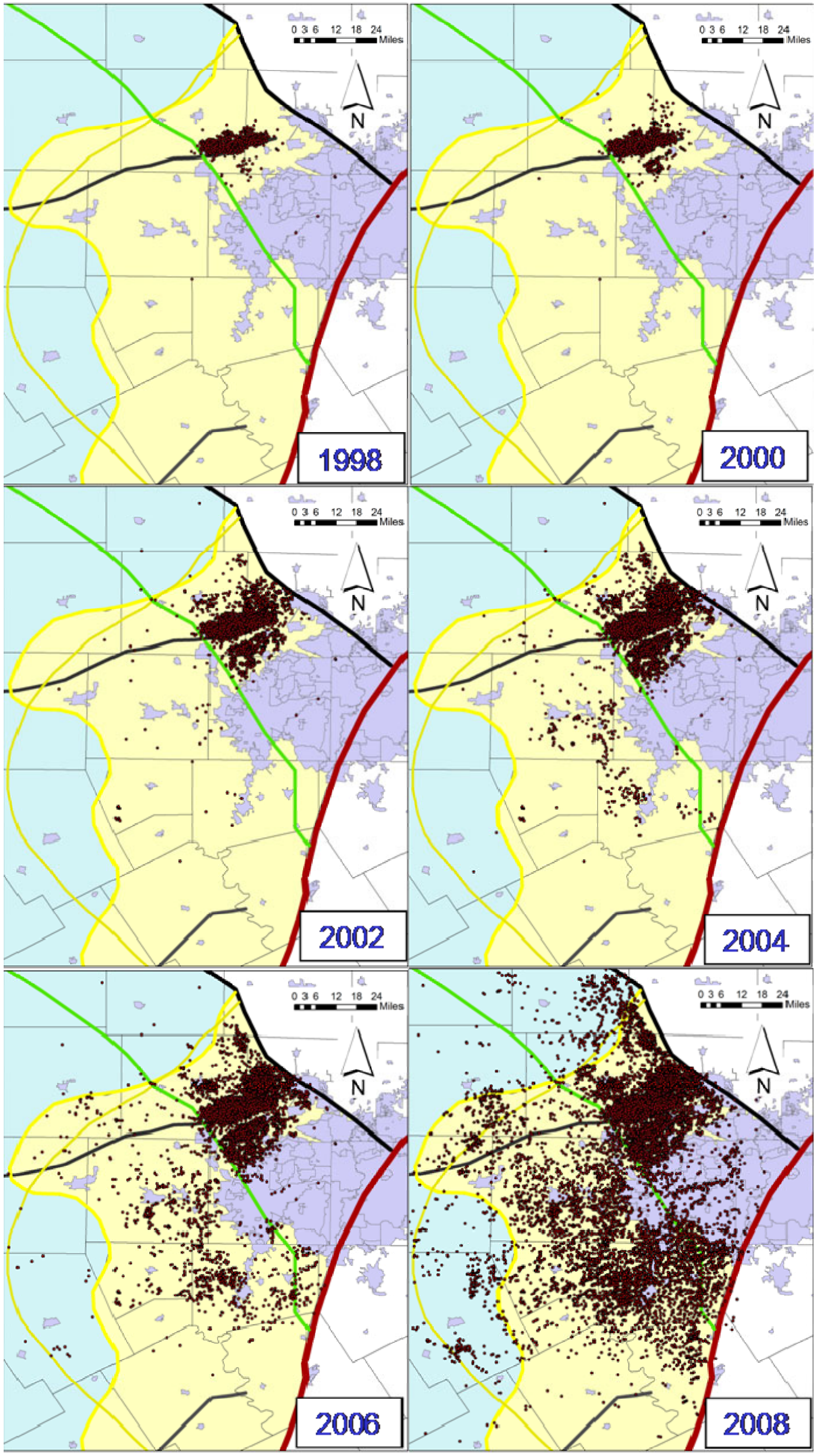

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(FACING PAGE) Figure 3. Maps showing large increase in total number of well completions in the Barnett Shale (black dots) from 1998 to 2008. Operators avoided the DFW metro area (center right on the map) until recently. Also shown are the structural limits of the Barnett Shale on its eastern boundaries: Muenster Arch oriented northwest-southeast and Ouachita Belt oriented north-northeast–south-southwest. Parallel to the Muenster Arch, the Viola line (see text) initially confined completions to the east of the line. Several interpretations of the favorable gas window are also displayed. They include most of the completions to date. The Barnett Shale extends past the limits of the maps towards the west and south. Two minor structural attributes present inside the gas window are also featured.

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barrels instead of gallons have been observed. This practice will tend to overestimate the true average. Undoubtedly, a similar difficulty can happen on the low side when a digit is not entered or when the unit is entered as a gallon instead of a barrel. The solution was to use the average of those frac jobs composing between the 10th and 90th percentiles. The raw average and average of the values between the 10th and 90th percentiles for vertical wells is 1.25 and 1.19×10^6 gal, respectively. A value of 1.2×10^6 gal is retained. The raw average for horizontal wells (2005-2006) is 3.07×10^6 gal/well, whereas the truncated average is 2.65×10^6 gal/well. Water-use intensity raw average is ~10,000 gal/ft, obviously biased by inaccurate entries, either in water use or in lateral-length columns. The averages of values truncated beyond two complementary percentiles vary somewhat because of the additional uncertainty due to the lateral length, although a value of 2400 gal/ft seems conservatively reasonable for the medium scenario. Values of 2000 and 2800 gal/ft are retained for low and high scenarios, respectively. These numbers agree well with data provided by Galusky (2007) directly gathered from interviews with operators.

WATER USE PROJECTIONS

Maximum Hypothetical Water Use

For all parameters, we defined high, medium, and low scenarios at the subcounty polygon level, mostly on the basis of geologic and cultural constraints. A polygon is defined as a county or fraction of a county characterized by one of the categories below. In addition to gas prices, extension of gas production in the Barnett Shale is ultimately controlled by geology. Assuming adequate thickness and total organic carbon content, the single most important parameter is thermal maturity. We used approximate boundaries as defined by Montgomery et al. (2005) and Zhao et al. (2007) (Fig. 5A) as the maximum extent of the Barnett Shale play for the high scenario. The low scenario corresponds to operators moving very little away from the core area. The medium scenario is of intermediate spatial extent (Fig. 5B). Finer polygon definition includes (1) the contrast between urban and rural areas with the assumption that gas production growth in urban areas will be a lot slower than in rural areas and (2) the presence or absence of the Viola Formation. We defined the following categories: (1) No Viola—Rural: this category includes a large fraction of the high scenario area. All wells are assumed horizontal because the absence of the Viola Formation generally precludes successful vertical frac job completions. (2) No Viola—Urban: this category includes only the underdeveloped southwest third of Tarrant County, absence of the Viola Formation, as well as urban environment, requires use of horizontal wells as in the previous category, but development will be slower. (3) Viola—Rural: this category initially represented the core area, that is, numerous vertical wells because of the presence of the Viola Formation and unimpeded by urban environment constraints. This category contains a combination of horizontal and vertical wells, as shown by the current infilling of the core area with horizontal wells. (4) Viola—Urban: this category encompasses the western half of the DFW metroplex. The current lack of development of this area illustrates the difficulties and challenges of urban drilling. The area will be developed with horizontal wells only but at a slower pace than that of the No Viola—Rural category.

A maximum water use is then attributed to each polygon by assuming well density (1 to 0.25 well/40 acres for vertical wells and 2000 to 800 ft between horizontal laterals in the high and low scenario, respectively) and average water use per vertical well or linear of horizontal lateral (2800 and 2000 gal/ft in the high and low sce-

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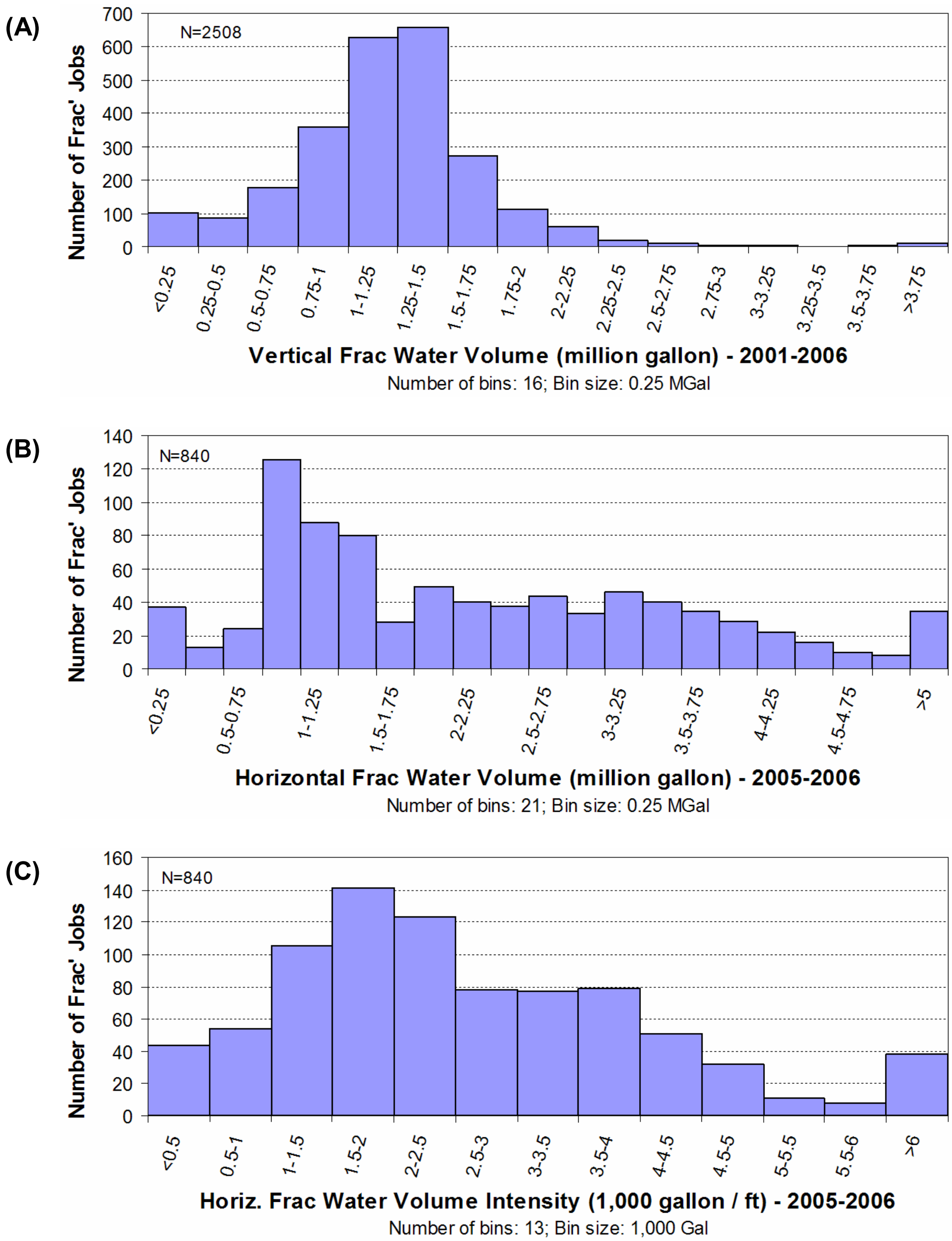

Figure 4. Distribution of historical water use in (A) vertical wells, (B) horizontal wells, and (C) horizontal wells scaled by lateral length. Histograms (A) and (B) were obtained by compiling data from the 5000+ wells examined for this study. Reported values for frac job water use were sorted into 0.25 million gallon interval bins. Histogram (C) underwent an additional step: raw frac job water amount was divided by the length of the horizontal well and then sorted in 500 gal/ft interval bins.

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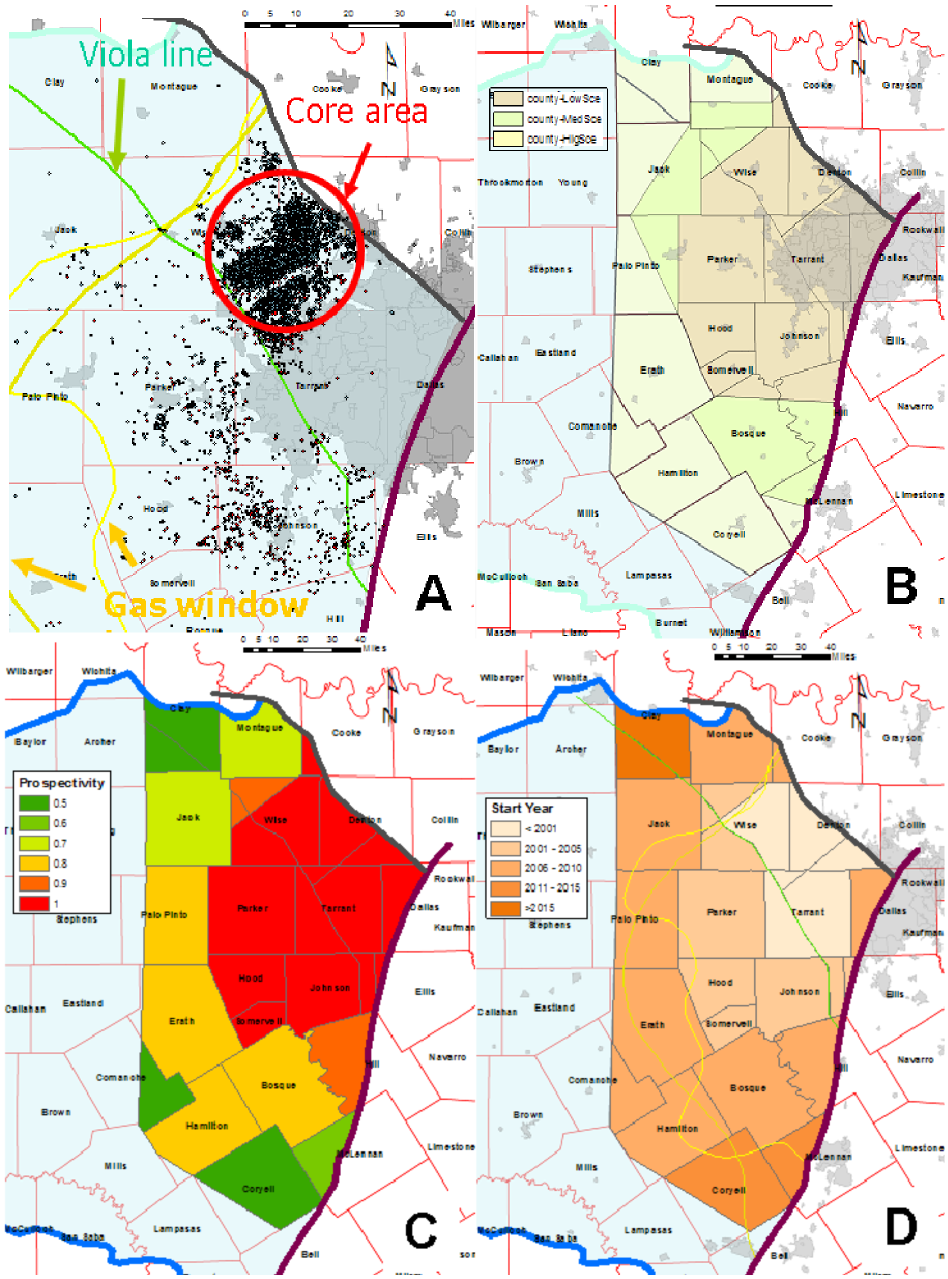

Figure 5. Maps showing spatial distribution of some of the factors controlling water use projections; (A) technological and cultural constraints: a county/subcounty polygon is either northeast or southwest of the Viola line and either urban or rural (that is, a total of 4 categories). Core area is clearly delimited between the Muenster Arch to the northeast (oriented northwest-southeast) and the Viola Formation pinch-out (green line) but remains outside of urban areas; (B) spatial definition of high, medium, and low scenarios; medium and high scenarios include and are larger than the low, and low and medium scenarios, respectively; (C) prospectivity, mostly based on thermal maturity, gas-oil ratio and thickness; likelihood of success decreases as operators move away from the core area; and (D) assumed start year for each county/subcounty polygon, that is, year at which gas production in the polygon is assumed to ramp up beyond initial exploratory production wells.

narios, respectively). Distance between lateral was suggested by several microseismic studies that map induced fracture extent. A correction factor owing to the presence of karstic collapse features in the Ellenburger Formation is then applied. However, because the true impact of the features on operator strategies is unclear, we assume no impact for the high scenario and a 40% avoidance impact (area not covered by drilling) in the low scenario case.

The hypothetical maximum total water use in a county polygon accounts for polygon surface area, footprint fraction, number of vertical wells, lateral footage of horizontal wells, sag feature avoidance factor, and average water use per well type. The value of this parameter varies from 2.75 million acre-ft of water that could eventually be used on the play in the high scenario, to 0.860 and 0.134 million acre-ft in the medium and low scenarios, respectively. There is a factor 20 difference between the high and low scenarios explained by the difference in total surface area and the systematic choice of high water use and low water use for the high and low scenarios, respectively. Those high and low scenarios are unrealistic extremes of water use but a necessary step of the adopted methodology .

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Time-Dependent Constraints

After computing maximum hypothetical water use and applying time-independent constraints, we then add time-dependent constraints: availability of drilling rigs, growth of recycling techniques, and recompletion frequency. The number of wells drilled is obviously limited by operational controls such as the number of drilling rigs and/or trained workers available. After a ramp-up of a few years we estimated that the maximum annual number of completions would be 3000 and 1500 in the high and low scenario cases, respectively. In addition, early indicators from operators seemed to suggest that re-stimulating wells will not be widespread. We assumed limited re-stimulation. On the other hand, some of the largest operators in the play have shown interest in recycling flowback. We assumed increased recycling with time reaching 20% of total water use in 2025. Finally we use an activity curve for each polygon assuming the activity goes through several phases of initial ramp, peak, decrease, and long tail in a period of approximately 30 years and centered around a peak year determined by the prospectivity/risk factor (Fig. 5C). The curve was based on historical data from Denton, Tarrant, and Wise counties. Start year for each subcounty polygon is displayed on Figure 5D.

RESULTS

The current number of total completions in the Barnett Shale is >10,000 but there has not been an update to the water use studies done by Nicot and Potter (2007), attached as an appendix to Bené et al (2007), and by Galusky (2007). The last known water use estimation dates back from 2006 when the number of total completions was ~5600. At that time, documented total water use was ~7200 acre-ft (~2350 x10^6 gal). However, total water-use projections are not sufficient to determine the impact of Barnett Shale production on ground water resources in general or on the Trinity Aquifer in particular because water sources are various. External sources of frac job water, excluding recycling, can be (1) ground water, (2) surface water (river, lake, private pond), or (3) municipal water or treated (municipal) waste water whose primary source is either surface or ground water. If pumping permission or rights can be secured and if yield is adequate, ground water is likely the better alternative. In addition, in the Barnett Shale footprint, amount of surface water decreases toward the south and west (combination of a decrease in precipitation and increase in evaporation); as the play expands southward and westward, the fraction of ground water use will most likely increase through time. Using Galusky's (2007) estimate of ground water / surface water split per county, we assumed that 60% of total water use is from ground water in 2005 increasing to 100% in 2025 in the high scenario to account for overall movement to the west and south of the play, areas with globally less surface water available. Similarly, increase is assumed from 60% to 80% in the medium scenario but fraction of ground water use stays constant at 60% for the low scenario case.

After all corrections have been done, the low scenario utilizes 29,000 acre-ft of ground water to the 2025 horizon, a clear retreat from current annual rate of water use by the industry, that would correspond to a large drop in gas price or the development of sources of cheaper gas elsewhere. The high scenario calls for a total water use between 2007 and 2025 of 417,000 acre-ft of ground water (Fig. 6A). It corresponds to sustained gas prices, allowing operators to expand to all economically viable areas and produce most of the accessible resource, but also includes the assumption that water use is not limited. All scenarios assume that operators continue using water at a per-well rate similar to that of today and that no technological breakthrough will bring it down. The medium scenario, not necessarily the most likely, assumes a ground water use of 183,000 acre-ft (Fig. 6B). In the high scenario, ground water use steadily climbs from ~5000 acre-ft/yr in 2005 to 20,000 acre-ft/yr in 2010 and then slowly increases to a maximum of ~25,000 acre-ft/yr in 2025. The medium scenario follows a similar path, climbing to a maximum of ~13,000 acre-ft/yr in 2010, and then slowly decreases to ~7,500 acre-ft/yr in 2025. Projections for the low scenario are approximately 29,000 acre-ft. Overall, frac ground water use does not make up a large fraction of the total ground water use, only a few percent (Bené et al., 2007), but could locally create nuisance as this fraction can be higher for some counties and much higher locally.

CONCLUSIONS

In this work, we carried out an estimation of water use by the oil and gas industry in North Texas as a result of gas production from the Barnett Shale. We presented historical information showing the sharp increase in well completions, as well as in water use, in the past few years. The exploration boom started in the core area in Wise and Denton counties but has been expanding southward and westward. Using geological public knowledge and cues from operators, we defined three scenarios that vary in their spatial coverage and water-use attributes. There are still major uncertainties related to evolution of the play as seen by the sharp decrease in the price of natural gas in 2008 but other major technical uncertainties remain: Is water use by the average frac job going to decrease significantly because of technological progress? Is water recycling going to make up for a possible larger number of annual completions? How often can or will a given well be frac'ed? The numbers provided are reasonable. The high scenario yields a total ground water use of 417,000 acre-ft, an annual average ground water use of 22,000 acre-ft over the 2007-2015 period, and a cumulative areal ground water use of 0.05 acre-ft/acre. The medium and low scenarios utilize a total 183,000 and 29,000 acre-ft of ground water for an annual average of ~10,000 and 1500 acre-ft, and a cumulative areal ground water use of ~0.04 and 0.009 acre-ft/acre, respectively. As evidenced by the large range in the results, much uncertainty remains, including in the spatial distribution of those regional averages.

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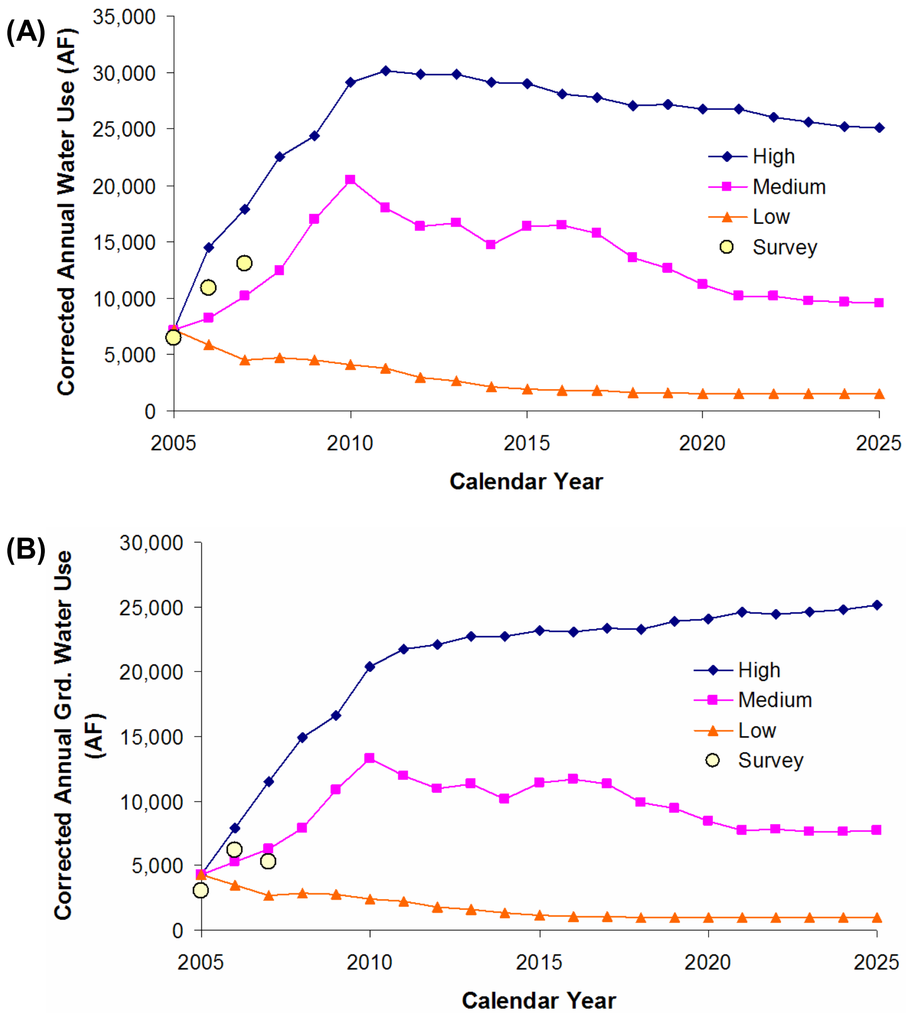

Figure 6. Water use projections for the high, medium, and low scenario in acre-ft (1 acre-ft [AF] = 325,851 gal). (A) Projected frac total water use (including surface water), and (B) projected frac ground water use. Survey points were obtained from Galusky (2007). The survey points are consistent with initial projection scenarios.

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