Draft Report – February 2011

Current and Projected Water Use in the Texas Mining and Oil and Gas Industry

Prepared for
Texas Water Development Board

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Cover photo: Aggregate facility in Bexar County (courtesy of Google Earth)

Prepared for
Texas Water Development Board

under
Contract No. 0904830939

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Glossary and Abbreviations

AAPG	American Association of Petroleum Geologists
AF	Acre-foot (1 AF = 325,851 gallons)
Bbbl	Billion barrels
Bcf	Billion cubic feet (1 Bcf = 10^3 MMcf = 10^6 Mcf)
bgs	below ground surface
BTU	British Thermal Unit
CBM	Coal-bed methane
CCS	Carbon capture and storage
EIA	Energy Information Agency
EOR	Enhanced oil recovery
EUR	Estimated ultimate recovery
GAM	Groundwater availability model
GC	Gulf Coast
GCD	Groundwater conservation district
GIP	Gas-in-place
GSA	Geological Society of America
IP	Initial production
ISL	In situ leaching
ISR	In situ recovery
LCRA	Lower Colorado River Authority
LPG	Liquefied petroleum gas
MAF	Thousand acre-feet
MGD	Million gallons per day
Mcf	Thousand cubic feet
MMbbl	Millions of barrels
MMBTU	Million BTU
MMcf	Million cubic feet (1 MMcf = 10^3 Mcf)
NGL	Natural gas liquid
NGW	Natural Gas Week Journal
NOGA	National oil and gas assessments (by USGS)
NORM	Naturally occurring radioactive materials
O&GJ	Oil and Gas Journal
OOGP	Original gas in place
OOIP	Original oil in place
OSHA	Occupational Safety and Health Administration

PBSN	Powell Barnett Shale Newsletter
PGC	Potential Gas Committee
PPA	Pounds of proppant added per gallon of fluid
RRC	Railroad Commission of Texas
RWPG	Regional water planning group
SIC	Standard industrial classification
st	Short ton
TACA	Texas Aggregate and Concrete Association
TCEQ	Texas Commission on Environmental Quality
Tcf	One trillion cubic feet (1 Tcf = 10^3 Bcf = 10^6 MMcf = 10^9 Mcf)
TDS	Total dissolved solids
Th. AF	Thousand acre-feet
TMPA	Texas Municipal Power Agency
TMRA	Texas Mining and Reclamation Association
TOC	Total organic content
TWBD	Texas Water Development Board
TXOGA	Texas Oil and Gas Association
UIC	Underground injection control
USGS	U.S. Geological Survey
VR	Vitrinite reflectance
WAG	Water alternating gas
WCAC	Water Conservation Advisory Council
WUG	Water user group (TCEQ jargon)
WUS	Water use survey (TWDB jargon)

Note to the reader:

In the oil industry m or M stands for 1,000 (one thousand, as in Mcf, one thousand cubic feet) but it means million in the water industry (as in MGD, million gallons per day). We try to spell out numbers or use plain units to limit the confusion.

Acknowledgments

The authors would like to thank all individuals and organizations that helped make this work successful. We benefited from discussions with members of the Water Planning team involved in this study (Stuart Norvell, Kevin Kluge, and Dan Hardin) at the Texas Water Development Board (TWDB). We are grateful as well to Lana Dieterich (BEG) for her editing of this report, as well as many BEG researchers and graduate students: Bill Ambrose, Sigrid Clift, Michelle Foss, Scott Hamlin, Ursula Hammes, Tucker Hentz, Hamid Lashgari, Bob Loucks, Seay Nance, Eric Potter, Steve Ruppel, and Silvia Solano. Staff from other state agencies were also extremely helpful: Fernando De Leon, Doug Johnson, and Tim Walter at the Railroad Commission of Texas (RRC).

We are also appreciative of the time and effort by our contacts at the trade associations, Shannon Lucas at TMRA, Don Bell at TACA, and C. J. Tredway at TXOGA, as well as others, for advertising the surveys and pushing their membership to respond to and contribute to this work. We are grateful to all members of these associations for the useful information we collected. We also thank individuals who spent time discussing and explaining these issues to us: Steve Eckert, David Freeman, Bob Hook, Matt Mantell, Michael Nasi, Charlie Smith, Ed Steele, Joel Trouart, Paul Weatherby, and many others. We also thank the review panel who agreed to spend time reviewing the document.

Last, we would like to acknowledge our University sponsors for free access to their databases: IHS Energy and Drillinginfo.

1 Executive Summary

In the middle of 2009, we undertook a study of water use in the so-called mining industry in Texas, both current and projected for the next 50 years. The study concerned the upstream segment of the oil and gas industry (that is, water used to extract the commodity until it leaves the wellhead), the aggregate industry (sand and gravel and crushed rock operations, washing included but no further processing), the coal industry (mostly pit dewatering and aquifer depressurizing), and other substances mined in a fashion very similar to that of aggregates (industrial sand, lime, etc.), as well as through solution mining. In general we followed the definition of mining according to SIC/NAICS codes. It follows that cement facilities, despite their large quarries, are considered to belong to the manufacturing, not mining, category. The objective of the study, that was essentially prompted by the sudden increase in shale-gas production, was to help in the next cycle of water planning by the state agency in charge of such planning, the Texas Water Development Board (TWDB).

The approach to the study is twofold: (1) to collect water-use data and auxiliary information by contacting actual mining facilities and (2) to interview experts and other knowledgeable individuals in their respective fields to fill in the gaps in water-use data and to understand future development/contraction of water use in the different segments of the mining industry. We surveyed the industry either through formal questionnaires sent to the membership of trade associations (TACA for aggregates; TMRA for aggregate, coal, and uranium; TXOGA and others for oil and gas), through surveys sent to water providers/observers such as GCDs, or through survey results from other organizations (MSHA, RRC, TCEQ, TWDB, USGS), and especially private vendors of the oil and gas industry. We contacted and had in-depth interviews with multiple representatives of every major segment of the mining industry to help us understand how the water is used, how much is recycled, what its source is (groundwater, surface water or something else), whether it is fresh or brackish (saline water use is not tallied in this study), how much is rejected outside of the mining facility, etc.

Results from the surveys were useful but not as extensive as hoped for us to assemble a representative sample of the hundreds of mining facilities in the state, with the exception of the coal industry (a significant water user) and the uranium industry (a minor water user). We were also able to gather relatively accurate data from the stimulation stage when a well is being readied for production (the so-called fracing process), but we are more uncertain about water use for drilling wells and waterfloods. Results of current water use for the aggregate industry relied on previous information somewhat calibrated and updated by survey results. Overall, in 2008 (latest year with complete information), we estimate that the state used ~139 thousand acre-feet (AF) in the mining industry (Figure ES1), including 35.8 thousand AF for fracing wells (mostly in the Barnett Shale/Fort Worth area) and ~21.0 thousand AF for other purposes in the oil and gas industry, although more spread out across the state, with a higher demand in the Permian Basin area in West Texas. The coal industry used 26.7 thousand AF along the lignite belt from Central to East Texas. The 43.0 thousand AF used by the aggregate industry is distributed over most of the state, but with a clear concentration around major metropolitan areas. The remainder amounts to 12.2 thousand AF and is dominated by industrial sand production (~80% of total).

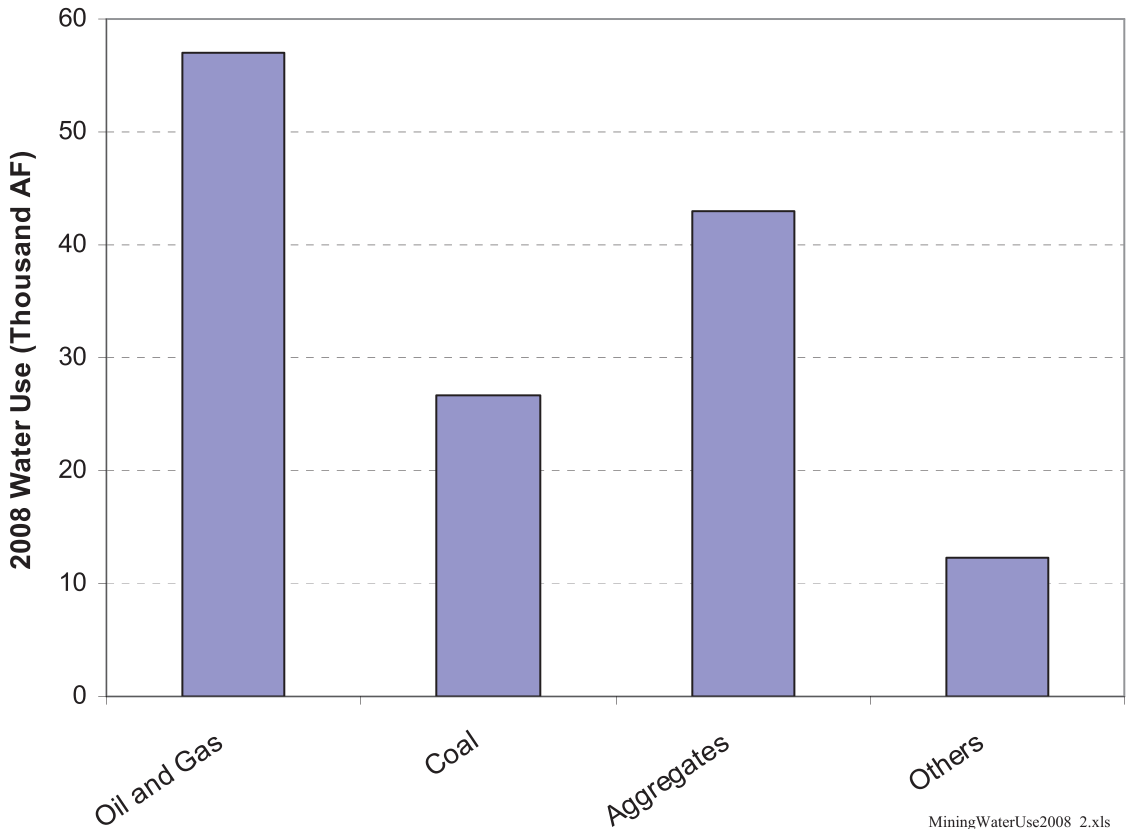

Figure ES1. Summary of estimated water use by mining industry segment (year 2008)

Water is used mostly for drilling wells, stimulating/fracing wells, and secondary and tertiary recovery processes (oil and gas industry); for dewatering and depressurizing pits, with a small amount used for dust control (coal industry); and for dust control and washing (aggregate industry and industrial sand). Reuse/recycling has been accounted for in water-use figures, as well as opportunity usages, such as stormwater collection (aggregates). As such, the numbers represent mostly consumption. Only some of the coal-water use could be construed as nonconsumed withdrawal when groundwater extracted for depressurization purposes is discharged into streams (40–50% of total). The split between surface water and groundwater is difficult to assess, short of having information directly from facilities (such as for coal and some aggregate facilities), especially for exempt use in the oil and gas industry.

Projections for future use were done by extrapolating current trends, mainly for coal (more or less stable) and aggregates (following population growth). Projections for the oil and gas industry were made with the help of various sources by estimating the amount of oil and gas to be produced in the state in the next decades and by distributing it through time. Given the volatility of the price of oil and gas, it is easy to see that the figures provided are only indicative of a possible future. We projected that the state overall water use will peak in the 2020–2030 decade at ~250 thousand AF (Figure ES2), thanks to the oil and gas unconventional resources that will start to decrease in terms of water use around that time. Both coal and aggregates are slated to keep increasing, more strongly for aggregates.

Note (1) that we endeavored to generate results at the county level but, given the uncertainty inherent to future production and to the approach, we estimate that individual counties may be off by a factor of 2 or 3, although a group of counties will have a much lower range of uncertainty; (2) that projections presented in this report are not binding to the facilities cited in the report and are made through integration of many other external factors; and (3) that these figures do not represent official TWDB projections but that they will be used as a tool by TWDB to make official projections for use in the next water-planning cycle.

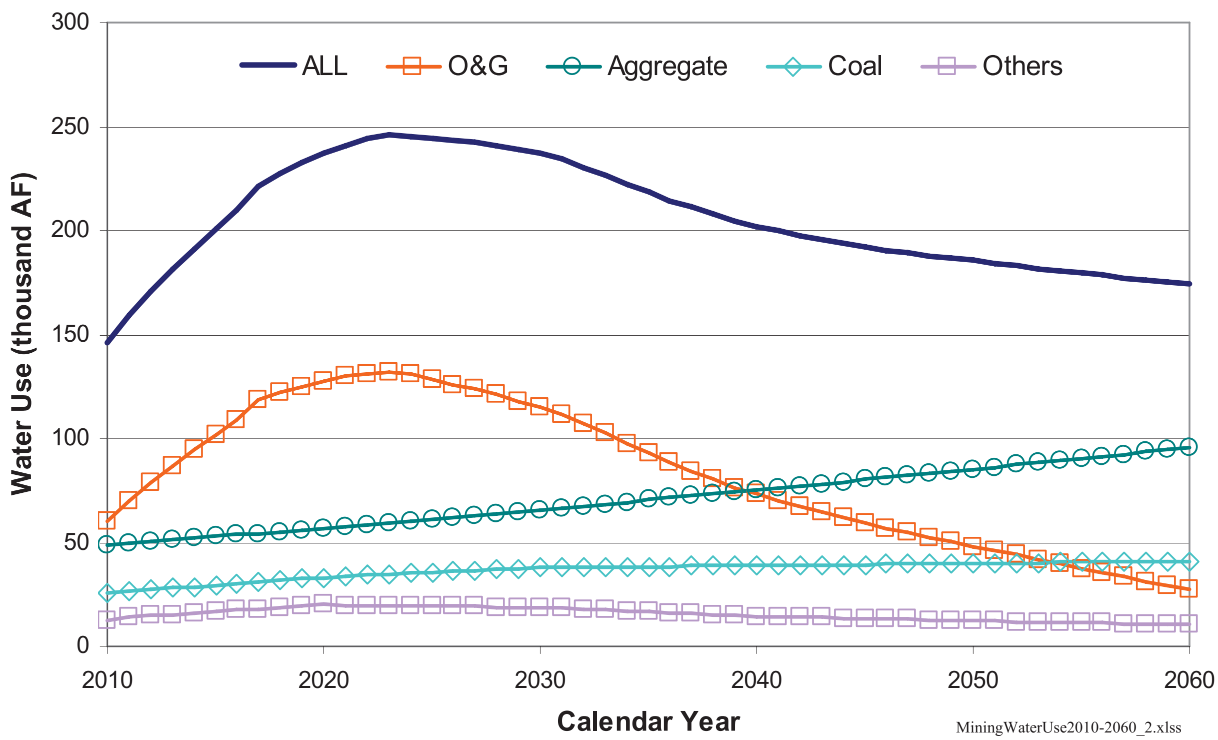

Figure ES2. Summary of projected water use by mining industry segment (2010–2060)

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2 Introduction

The Texas Water Development Board (TWDB) has contracted the Bureau of Economic Geology (BEG) at The University of Texas at Austin to compile information about current water use in the mining industry (to be more thoroughly defined later) and to make water-use projections for the next 50 years to 2060. The project was launched as a response to a Request for Statements of Qualifications on Topic 3 of the 2009 Water Research Study Priority Topics by TWDB Water Resources Planning Division, headed by Dr. Dan Hardin. The present report documents results for the four tasks described in the scope of work of Contract #0904830939: (1) identify major mining operations and analyze water-use patterns, (2) estimate current water use withdrawal and consumption (3) develop long-term water-demand projections at the county level, and (4) report the findings of the study and prepare an electronic database. The project is the result of the collaboration between the Bureau of Economic Geology at The University of Texas at Austin; Steven Walden Consulting, Austin, TX; Texerra, Midland, TX; and LBG-Guyton, Austin, TX. The project also benefited from strong cooperation from major players in the Texas mining industry, particularly the following trade associations: Texas Mining and Reclamation Association (TMRA), Texas Aggregate and Concrete Association (TACA), and Texas Oil and Gas Association (TXOGA).

The report is divided into several sections. In each of them, we successively address oil and gas, coal, aggregates, and other mineral substances. Oil and gas activities are not always necessarily compiled with other mining activities, but they are for the purpose of this report. It is also consistent with the way the federal government catalogs all economic activities (SIC and NAICS codes; more on this later). In the next few paragraphs, we present an overview of the mining industry in Texas and a high-level discussion of its water use. In Section 3, we describe the methodology used to generate figures for current and projected water use. Section 1 describes current water use, whereas Section 5 addresses projected water use. The general approach in the latter section consists of extrapolating historical and current water-use trends and applying some corrections. We think that quantitatively attempting to include new processes or events that might emerge or occur in 50 years is a worthless exercise. The current shale-gas boom, largely unforeseen by industry watchers, is a case in point. It follows that projections are mostly valid in the 5- to 10-year term. We did add a subsection on speculative resources, whose water-use figures were not included in final totals.

2.1 Overview of Mining Activities in Texas and a High-Level Perspective on Water Use in the Industry

2.1.1 Mined Substances

Before water use is discussed in detail, an understanding of the big picture, as well as the mining landscape in terms of operations, might be useful. USGS publishes regular updates to national nonfuel mining activities (http://minerals.usgs.gov/minerals/). The latest USGS (2009) compilation uses data from 2006 (Table 1). Estimated value of nonfuel minerals is $3.0 billion, 62% of which is related to cement activities. Note that cement is included in the USGS compilation, although neither cement plants nor allied quarrying operations are included in this report. This definition of mining is consistent with previous approaches by TWDB. Oil and gas importance dwarfs that of other minerals in terms of value (>$50 billion) but, as documented in this report, not in terms of water use (Table 1).

Recently BEG (Kyle, 2008) released a factsheet presenting the industrial minerals in Texas consistent with information provided by the USGS. Kyle and Clift (2008) also provided geologic background, explaining in general regional terms why the diverse facilities are located where they are and the uses of these mined substances. In addition to the oil and gas produced over most of the state and to the coal produced within a narrow inland section parallel to the coast, the mining industry, in terms of volume, generates value through sand and gravel, mostly exploited along rivers, and crushed stone, mostly present in the footprint of the Edwards Limestone.

Oil and gas resources are generally sorted into conventional and unconventional categories (Figure 1 and Figure 2). The former represents the archetypal reservoir traps in either sandstones or carbonates and is made up of interconnected pores that allow “easy” communication with the well bore. The latter is generally characterized by the use of advanced technologies and consists of different types of formation and/or extreme environmental conditions (pressure and temperature). In terms of amount produced, unconventional resources have already passed the “conventional” reservoirs (Stevens and Kuuskraa, 2009). Relevant characteristics include low permeability and a need to stimulate the reservoir through hydraulic fracturing. In this study, the unconventional category consists of tight formations, usually “tight gas,” and resource plays such as gas shales and liquid-rich shales. We do not describe the technology in this document; see, for example, King (2010) for a summary. Coalbed methane (CBM), producing mostly gas, could also be added to the list of unconventional reservoirs. Resource plays are generally defined as those plays with relatively predictable production rates and costs and with a lower commercial risk, as compared with conventional plays. Gas-shale plays with their extensive, continuous resources and “no dry well” are examples of resource plays. The challenge for operators is to find those sweet spots that will produce gas at a profit.

Note that the exact terminology to describe hydraulic fracturing as practiced by the oil and gas industry has not been settled yet. We opted for “*frac*”, “*fracing*” and “*fraced*” although “*frack*”, “*fracking*” and “*fracked*” would have been acceptable too. We also refer to “*gas shales*” when the focus is on the formations as a generic term including Barnett, Eagle Ford, etc shales. In contrast, the terms “*shale gas*” or “*shale oil*” suggest that the focus is on the commodity itself not the formation. The term “*oil shale*” is sometimes understood as mostly applicable to those formations in Utah and Colorado which require more efforts and energy to recover the oil. To avoid confusion with common usage, we settled on the term “*liquid-rich shale*”.

Coal is generally ranked as anthracite, bituminous, subbituminous, or lignite, listed in decreasing order of energy content. Low-rank, low-energy coals include lignite and subbituminous coals, and they are the only coals present in Texas in significant amounts (Figure 3). High-rank coals, including bituminous and anthracite coals, contain more carbon and lower moisture than lower-rank coals, and thus have higher energy content. Coal has been produced in Texas since the late 1880’s. At that time the most common mining method was underground mining, but currently only surface mining is utilized. Lignite makes up most of the current coal production and will do so in the near future as well. Whereas bituminous resources are still available, the economically recoverable resources have already been mined. The lignite belt stretches diagonally across Texas from Louisiana to Mexico. It is represented by the Wilcox, Jackson, and Claiborne Formations of the upper Gulf Coast, whereas, farther west, Pennsylvanian and Permian pockets represent bituminous resources. BEG has published many reports on Texas coal (for example, Fisher, 1963; Henry and Basciano, 1979; Kaiser et al., 1980).

Aggregates (Figure 4), as sand and gravel and crushed stone are collectively known, are the most important category in terms of volume and dollar amount, after the oil and gas industry. Crushed stone consists mostly of limestone and dolomite, with many facilities located along the IH35 corridor (San Antonio to the Dallas-Fort Worth metroplex) (Figure 5). Because of important capital costs, those operations tend to be larger than the sand and gravel facilities. The latter are concentrated along streams and on the coast (Figure 6). Allied mined substances include industrial sand and dimension stone. There are other substances but they tend to be mined at only a few locations (Table 2 and Table 3). Note that several mining activities do not require fresh water or even water. Brine production may require fresh water for drilling wells, but its use is nominal, which is equally true for gas wells producing from conventional reservoirs. Another less systemic example is crushed stone operations, which uses water only for occasional dust suppression.

2.1.2 Mining Facilities

The first step of the study, before estimating water use, consisted of determining the actual number of mining facilities. Their spatial distribution and count at the county level represent the next level of complexity as they guide the final mining water use at the county level. Oil and gas operations are present in most Texas counties. Number of traditional mining facilities is given by several sources, the most complete being from the U.S. Census Bureau (USCB). USCB reports survey data every 5 years. The 2002 survey was released in 2005, and the 2007 had not been released at the time this report was written. Disregarding oil and gas wells and other oil- and gas-related facilities, the USCB listed a total of 11 lignite mines, 100+ crushed stone and ~200 sand and gravel operations, many of them small, and ~70 facilities of a different type, neither lignite nor aggregate. Not counting wells tapping the subsurface (solution mining), the vast majority of operations are open-pit operations. USCB (2005) reported six underground mining operations in 2002, all but one (rock-salt operation) being very small.

MSHA (Mining Safety and Health Administration) also manages a database of abandoned and active mines across the country because mines must submit health and safety applications and obtain permits. As of July 2010, 1,869 abandoned and 692 active mines (including cement plants and coal mines) were officially registered in the state of Texas (Table 3). However, the overlap with USCB data is not perfect because the MSHA database includes (1) facilities treating the raw material but not necessarily extracting it locally and (2) nonactive facilities that have not been officially abandoned.

The database for the Source Water Assessment and Protection (SWAP) program, a federally mandated program managed by the Texas Commission of Environmental Quality (TCEQ), contains an inventory of potential sources of contamination (POSC) susceptible to contaminating sources in potable water (both groundwater wells and surface-water intakes). Those sources include a whole range of human activities from cemeteries to gun ranges to dry cleaners, including mining facilities ("Natural Resource Production"). TCEQ cites the Railroad Commission of Texas (RRC), the U.S. Geological Survey (USGS), and BEG as sources for the mining subset of the database. Information that can be depicted on an aquifer map is a more detailed and useful inventory than a listing of facilities (Figure 7, Bastrop and Lee Counties).

2.1.3 Water-Use Overview

Overall, mining water use in Texas represents only a small fraction of total water use in the state, and estimates have varied, given the relatively low priority of this category of water use. Previous water-demand surveys and projections estimated ~280 thousand AF as the demand for water use in mining compared with 17 million AF (1.6%) for total water use in 2000 (TWDB, 2007, Table 4.2), ~250 thousand AF and ~17 million AF (TWDB, 2002, Table 5.2), and ~200 thousand AF and ~16.5 million AF (TWDB, 1997, Table 3.2), both also for year 2000 (Table 4). Those figures represent only fresh water, the generally accepted definition of which is any water with a total dissolved solid content (TDS) <1,000 mg/L. Livestock as well as crops tolerate higher TDS, perhaps as high as 6,000 and 10,000 mg/L, respectively. Some sources define fresh water as water <3,000 mg/L. Inability to reconcile the different definitions adds uncertainty to the final figures provided in this report. Under the Safe Drinking Water Act, any <10,000 mg/L non-exempt aquifer is considered a potential underground source of drinking water. Note that there is no consistency (including in the documents cited in this work) in the definitions of fresh, brackish, and saline water which depend mostly of the context.

The overarching goal of this report is to confirm these figures. We provide some explanation on why results presented in this report differ from previous projections by TWDB, but they are due mostly to a change in accounting and to the impact of shale-gas production. The work presented in this report will not formally be included in the 2012 water plan, but will inform it. An issue of great impact to this work is the split between groundwater and surface water. This information is not always easy to identify, but in the course of this project, we tried to collect as much as possible. Approximately 59% of the water used in the state is groundwater (TWDB, 2007, p. 176), although this statistic is biased because a sizable fraction comes from the Ogallala aquifer in the Texas Panhandle and is used for irrigation. In this area of Texas the groundwater-use fraction is somewhat higher, whereas elsewhere it tends to be smaller. Irrigation is an important category used by TWDB to detail water use in the state and is the largest in terms of volume. Other categories in approximately decreasing volumes are municipal, manufacturing, steam-electric, livestock, mining, and domestic/other.

In addition to efforts at the state level, several federal organizations interpret information flowing from the states. USGS publishes every 5 years (with a lag of a few years relative to data collection) information about all types of water use across the nation. The most recent versions are authored by Kenny et al. (2009) for year 2005 and by Hutson et al. (2005) for year 2000 (Table 5). Sources of data feeding the reports are left to the judgment of local state offices and vary with water-use type and state (Kenny, 2004). For the State of Texas, BEG, RRC, TCEQ, and TWDB are typically contacted. USGS also performs its own survey, although it is not always successful in obtaining comprehensive information from all facilities. USGS typically extrapolates from the information obtained and publishes only aggregated data. For the State of Texas, Kenny et al. (2009, Table 2B) reported a mining-water withdrawal of 102 and 614 thousand AF/yr, respectively, for water of fresh (defined in the USGS report as <1,000 mg/L) and saline (>1,000 mg/L) quality. All saline water was reported as groundwater, whereas only 30 thousand AF of the fresh-water category was reported as groundwater (Kenny et al., 2009, Table 3B and Table 4B). Most of the saline water is counted toward secondary recovery of hydrocarbons (disposal not included). Kenny et al. (2009, p. 35) stated that dewatering operations are included in the water withdrawal total only if the water is put to beneficial use (for example, dust control). The work presented in this report follows a different approach (see section on Methodology). USGS figures for the year 2000 (Hutson et al., 2005, Table 4) are somewhat different and more closely align with those of the TWDB, with a total fresh-water use of 246 thousand AF (144 groundwater and 102 surface water). The total amount of saline water (produced water) at 565 thousand AF is not sizably different. Whereas 1995 (Solley et al., 1998) figures are consistent with those of 2000, the difference between 2000 and 2005 figures corresponds to a change in accounting.

2.2 Overview of Recent Projections

The TWDB Office of Planning provides projection figures to the State Water Plan (e.g., TWDB, 2007). Norvell (2009) represents the latest effort before the work presented in this report. An earlier effort by a consultant on behalf of TWDB (2003) includes manufacturing in addition to mining. Both Norvell (2009) and TWDB (2003) attempted to link economic activity at the county level to water use. In essence, the approach consisted of developing a correlation between historical water use and economic output at the county level and extrapolating future water use from a forecast of economic activity. The correlation was made through so-called water-use coefficients (ratio of water use and gross economic output) determined at the county level. Mining-specific constraints were dismissed and hidden as being part of the overall economic activity (TWDB, 2003, p. 2–3). Overall, results of this approach were not very satisfying for the mining category.

Table 1. Fuel and nonfuel raw mineral production in Texas

Mined Substance	Quantity	Approx. Value (1,000s of $)
	MMbbl	**~$57/bbl[f]**
Oil[a]	344.5	~19,000,000
	Tcf	**$5/Mcf[g]**
Gas[b]	7.53	~37,650,000
	1000s short tons	**~$18/Short ton[h]**
Coal/lignite[c]	37,099	~668,000
Uranium[d]	Withheld	Withheld
Nonfuel Minerals[e]	**1000s metric tons**	
Cement (overwhelmingly portland)	11,682	1,120,700
Clays (common clay, bentonite)	2,289	14,900
Gypsum	1,430	11,800
Lime	1,650	130,000
Salt	9,570	132,000
Sand and gravel:	99,500	603,000
Industrial sand	1,530	65,600
Crushed stone:	136,000	824,000
Dimension stone	31[i]	12,600
Subtotal		2,902,000
Other: talc, brucite, clays (Fuller's earth, kaolin), helium, zeolites, sulfur		78,000
Total		2,980,000

Source: [a]: http://www.rrc.state.tx.us/data/production/oilwellcounts.php —2009 data;
[b]: http://www.rrc.state.tx.us/data/production/gaswellcounts.php —2009 data;
[c]: http://www.rrc.state.tx.us/industry/_COALPRODthru2009.XLS —2009 data;
[d]: Information withheld for confidentiality (small number of producers)
[e]: USGS (2009) —2006 data;
[f]: 2009 annual average for Texas; http://www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm
[g]: 2009 annual average for Texas; http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_STX_a.htm
[h]: 2008 annual average for Texas; http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html
[i]: Seems to be a slow year or underreporting

Table 2. Estimate of the number of mining facilities in the State of Texas in 2002 (USCB)

Industry Type	Total Number of Establishments	>20 Employees
Crude petroleum and natural gas extraction	2803	286
Natural gas liquid extraction (includes sulfur extraction)	180	57
Total Oil and Gas Extraction	**2983**	**343**
Bituminous coal and lignite surface mining	11	9
Total Coal Mining	**11**	**9**
Fe ore mining	3	0
Au ore and Ag ore	4	0
Cu, Ni, Pb, and Zn ore mining	1	0
U, Ra, V ore mining	5	1
Other metal ore mining	2	0
Total Metal Ore Mining	**15**	**1**
Dimension stone mining and quarrying	18	5
Crushed and broken limestone mining and quarrying	71	23
Granite mining and quarrying	3	0
Other crushed and broken stone mining and quarrying	15	5
Total Stone Mining and Quarrying	**107**	**33**
Construction sand and gravel mining	198	51
Industrial sand mining	19	5
Kaolin and ball clay mining	1	1
Clay and ceramic and refractory minerals mining	11	4
Total Sand, Gravel, Clay, and Ceramic, and Refractory Minerals Mining and Quarrying	**229**	**61**
Potash, soda, and borate mineral mining	1	1
Other chemical and fertilizer mineral mining	6	1
All other nonmetallic mineral mining	19	2
Total Other Nonmetallic Mineral Mining and Quarrying	**26**	**4**
Total Nonmetallic Mineral Mining and Quarrying	**362**	**98**

Source: USCB (2005)

Table 3. Number and diversity of minerals mining operations in Texas (MSHA)

Primary Commodity	# of Fac.	Primary Commodity	# of Fac.
Alumina	2	Dimension sandstone	11
Barite barium ore	7	Dimension stone NEC	47
Bentonite	3	Dimension traprock	1
Cement	12	Fire Clay	7
Clay, ceramic, refractory mnls.	2	Gypsum	8
Common clays NEC	19	Iron ore	6
Common shale	2	Lime	2
Construction sand and gravel	250	Manganese ore	1
Crushed, broken granite	1	Misc. nonmetallic mnls. NEC	1
Crushed, broken limestone NEC	167	Pigment minerals	1
Crushed, broken marble	3	Potassium compounds	1
Crushed, broken sandstone	6	Salt	2
Crushed, broken stone NEC	52	Sand, common	15
Crushed, broken traprock	3	Sand, industrial NEC	10
Dimension limestone	32	Talc	5
Dimension marble	1	Zeolites	1

NEC:
Source: MSHA (http://www.msha.gov/DRS/DRSextendedSearch.asp), data from June 2008

Table 4. Historical projected mining water use (top) and total water use (bottom) for all water uses in Texas by TWDB (MAF)

Water Plan	1990	2000	2010	2020	2030	2040	2050	2060
1997	149 15,729	205 16,586	187 16,867	182 17,135	191 17,489	194 17,900	188 18,354	
2002	149 15,729	253 16,919	246 17,662	245 18,195	252 18,732	252 19,369	244 20,022	
2007		279 16,977	271 18,312	281 19,011	286 19,567	276 20,105	277 20,759	286 21,617

Source: TWDB (1997, 2002, 2007)

Table 5. Historical mining water use in Texas by USGS (thousand AF)

	Fresh	Saline	Total
1995			
Groundwater	143	458	602
Surface water	93	0	93
Total	236	458	694
2000			
Groundwater	144	565	709
Surface water	102	0	102
Total	246	565	811
2005			
Groundwater	30	614	644
Surface water	72	0	72
Total	102	614	716

Source: Kenny et al. (2009), Hutson et al. (2005), Solley et al. (1998)

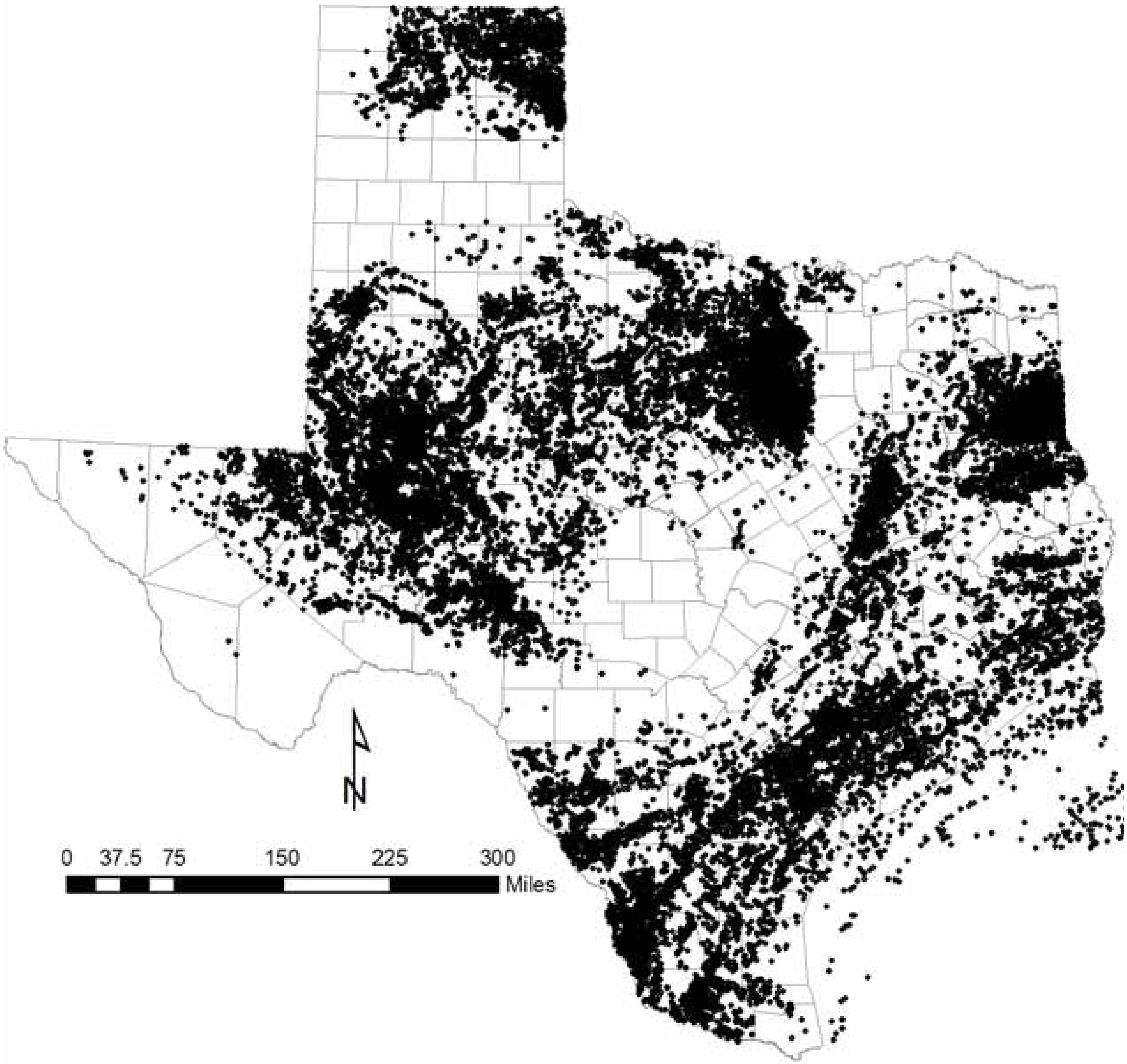
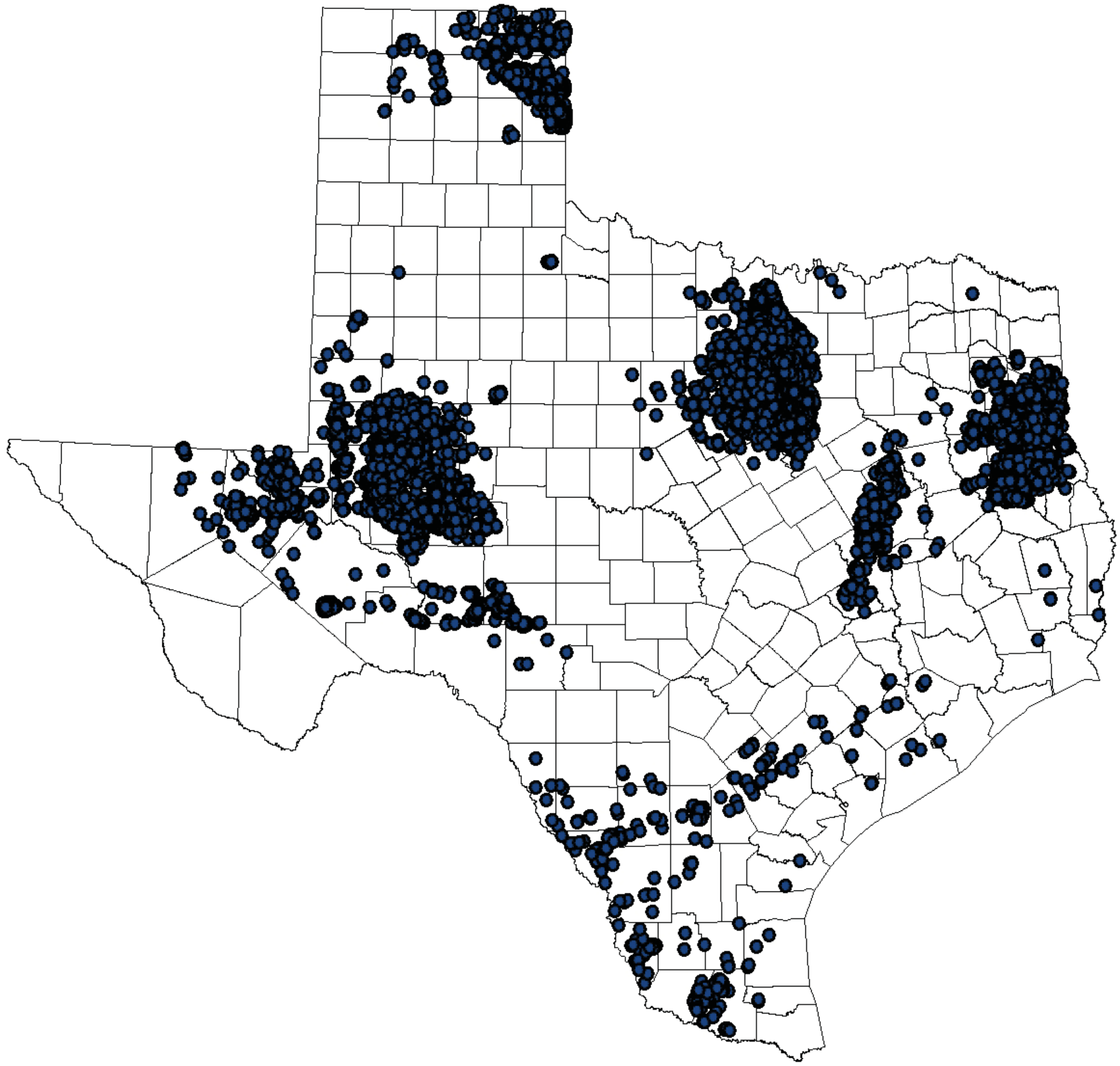


Figure 1. Location map of all wells with a spud date between 2005/01/01 and 2009/31/12 (approximately ~75,000 wells)



Source: IHS database

Figure 2. Map showing locations of all frac jobs in the 2005–2009 time span in the state of Texas. Approximately 23,500 wells are displayed

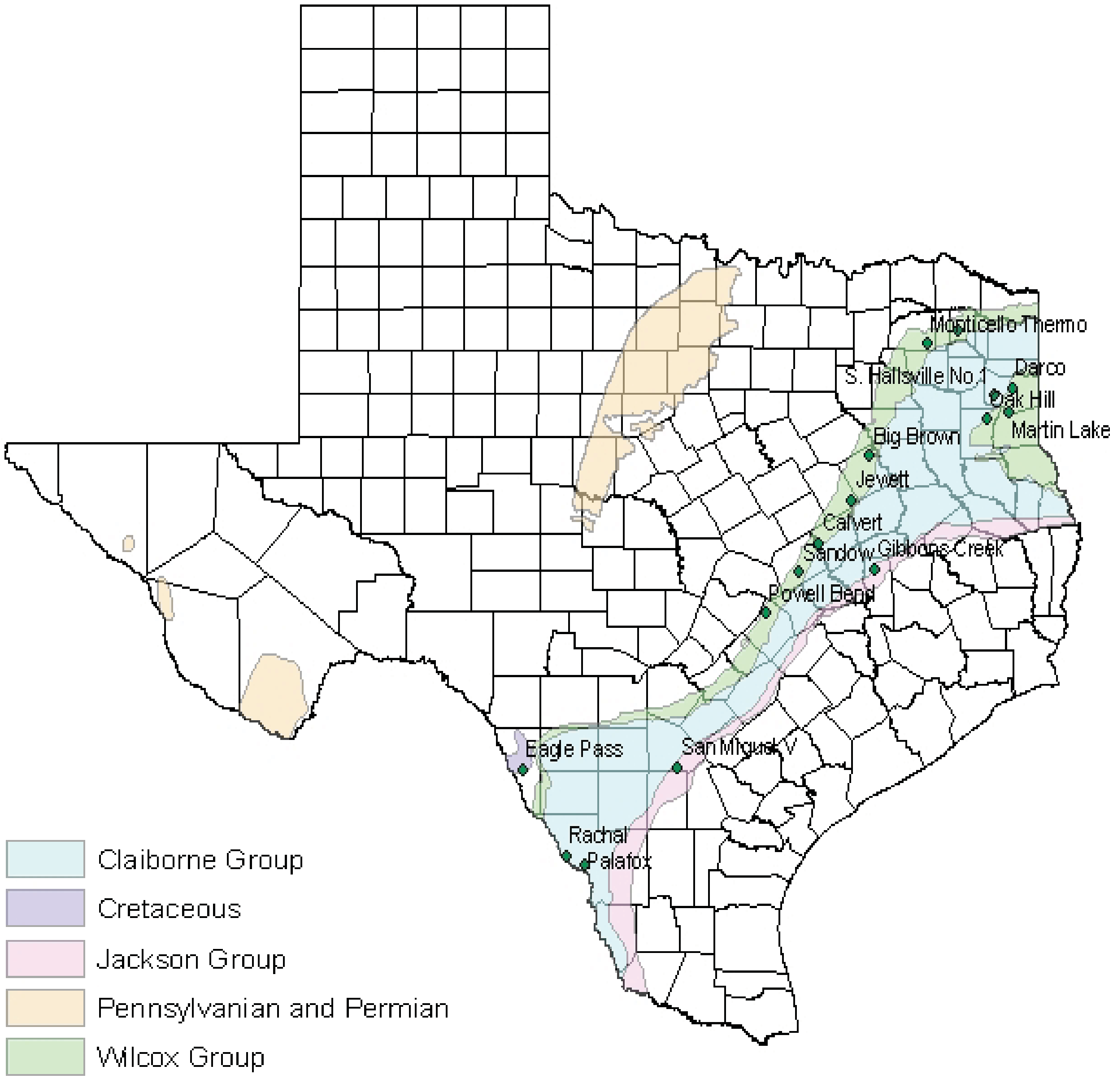
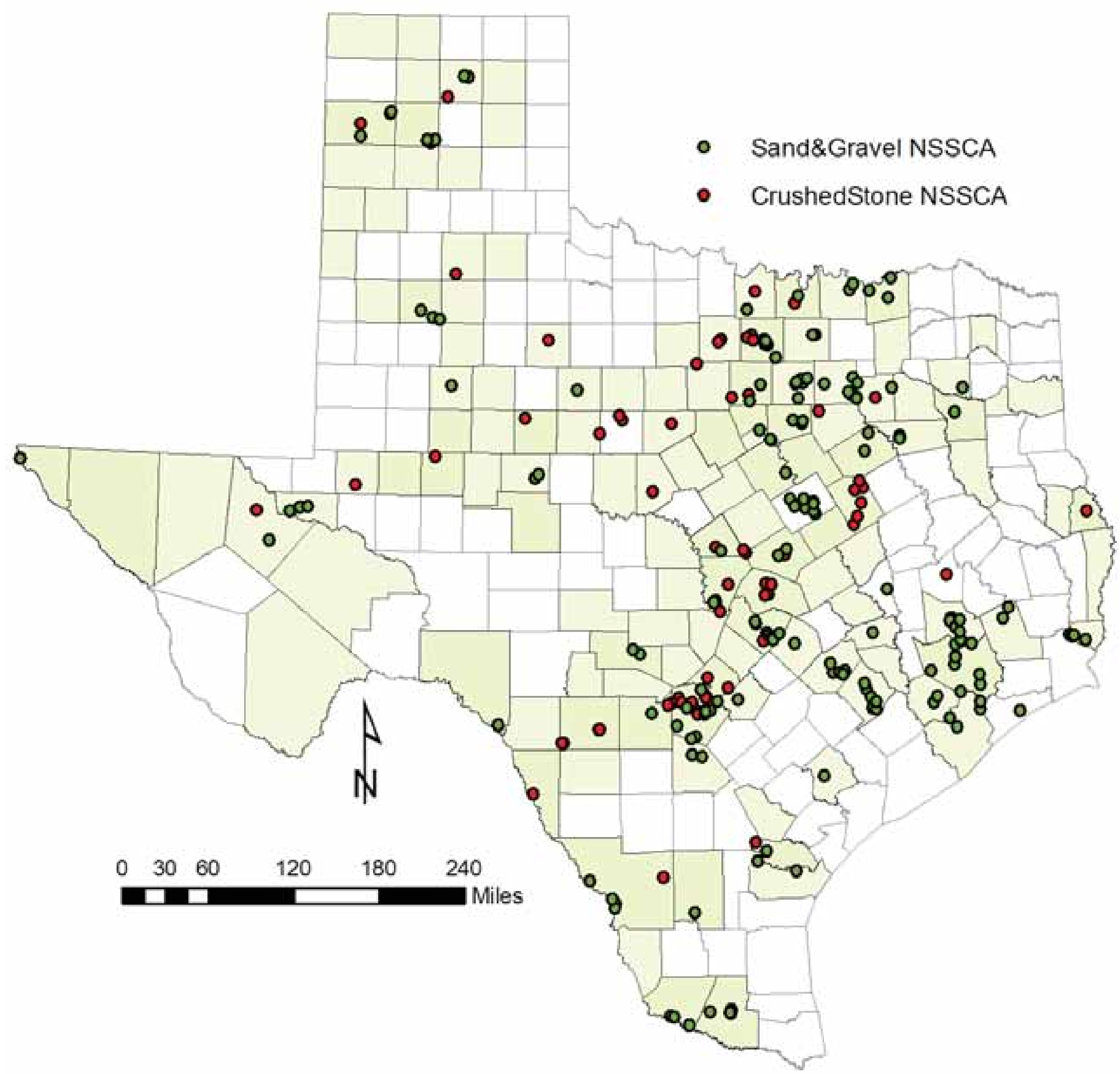
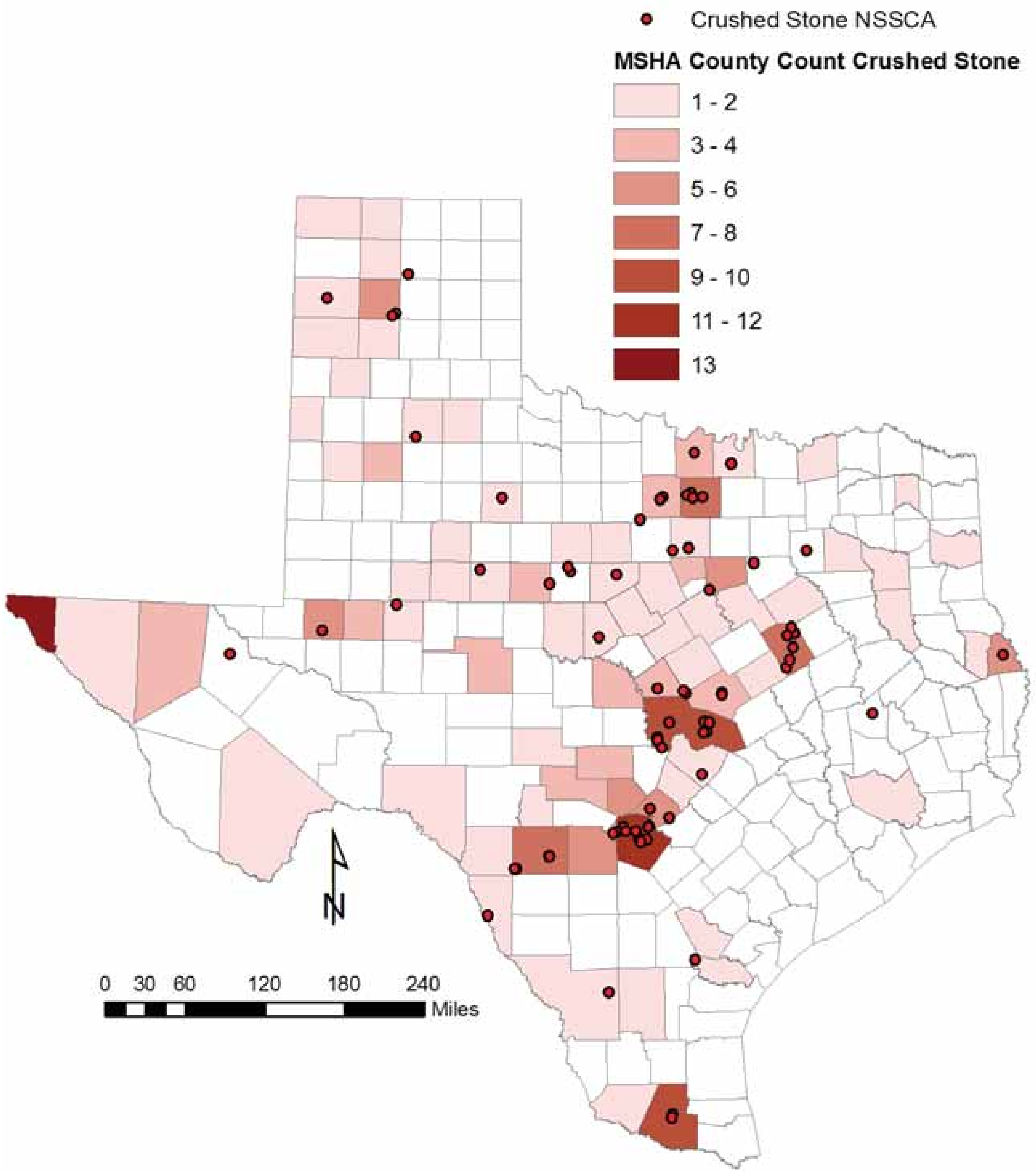


Figure 3. Location map of coal/lignite operations



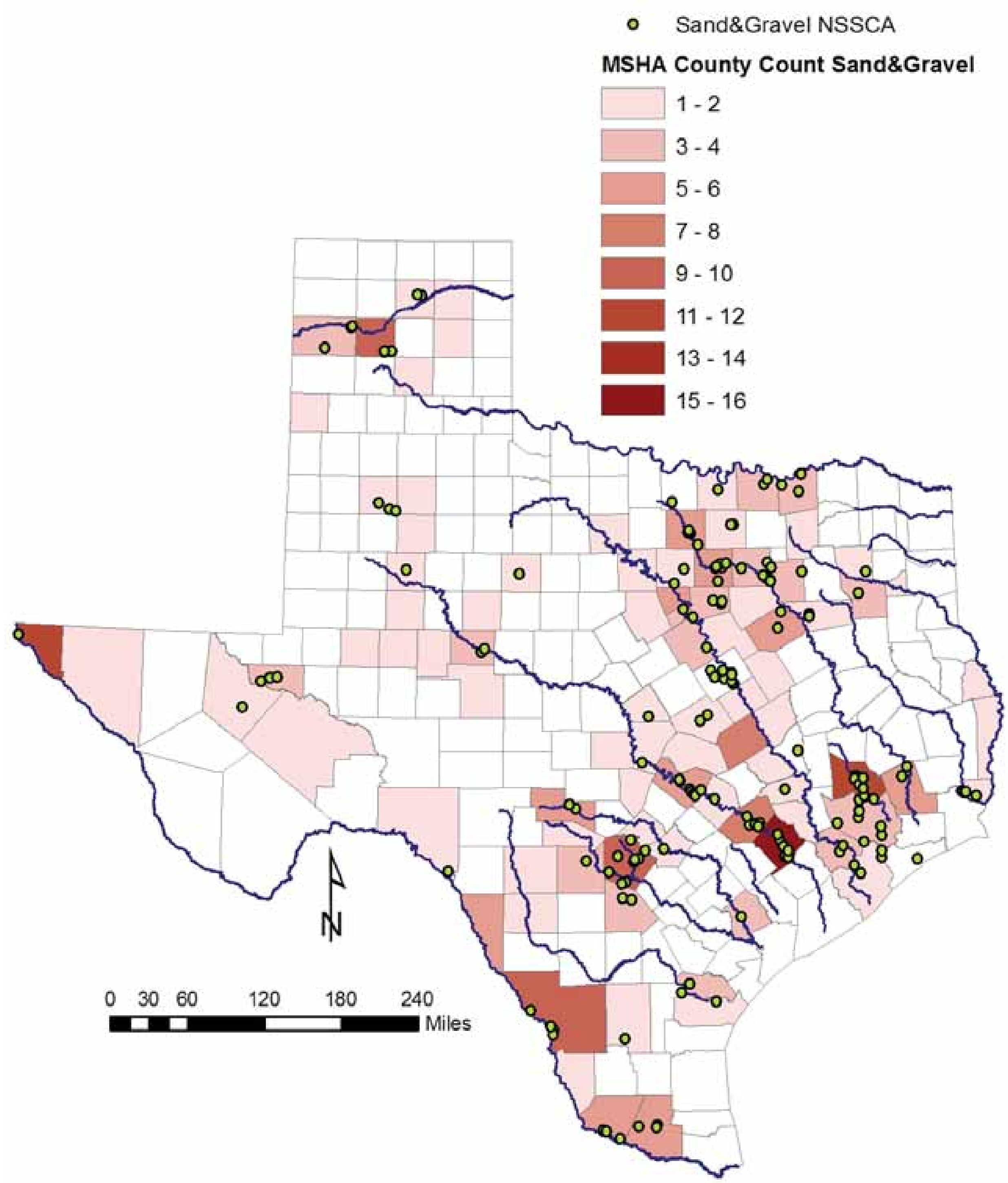
Source: NSSGA/USGS database and MSHA database
Note: deleted from the NSSGA database were all facilities whose names included “yard,” “asphalt,” “concrete,” or “cement,” as well as plants of well-known cement producers; facilities with “chemical” are treated in the other nonfuel minerals section (Section 4.5)

Figure 4. Location map of aggregate operations from NSSGA database (data points) and MSHA database (selected counties)



Source: NSSGA/USGS database and MSHA database

Figure 5. Location map of crushed-stone operations from NSSGA database (data points) and MSHA database (selected counties illustrating number of operations)



Source: NSSGA/USGS database and MSHA database

Figure 6. Location map of sand and gravel operations from NSSGA database (data points) and MSHA database (selected counties illustrating number of operations)

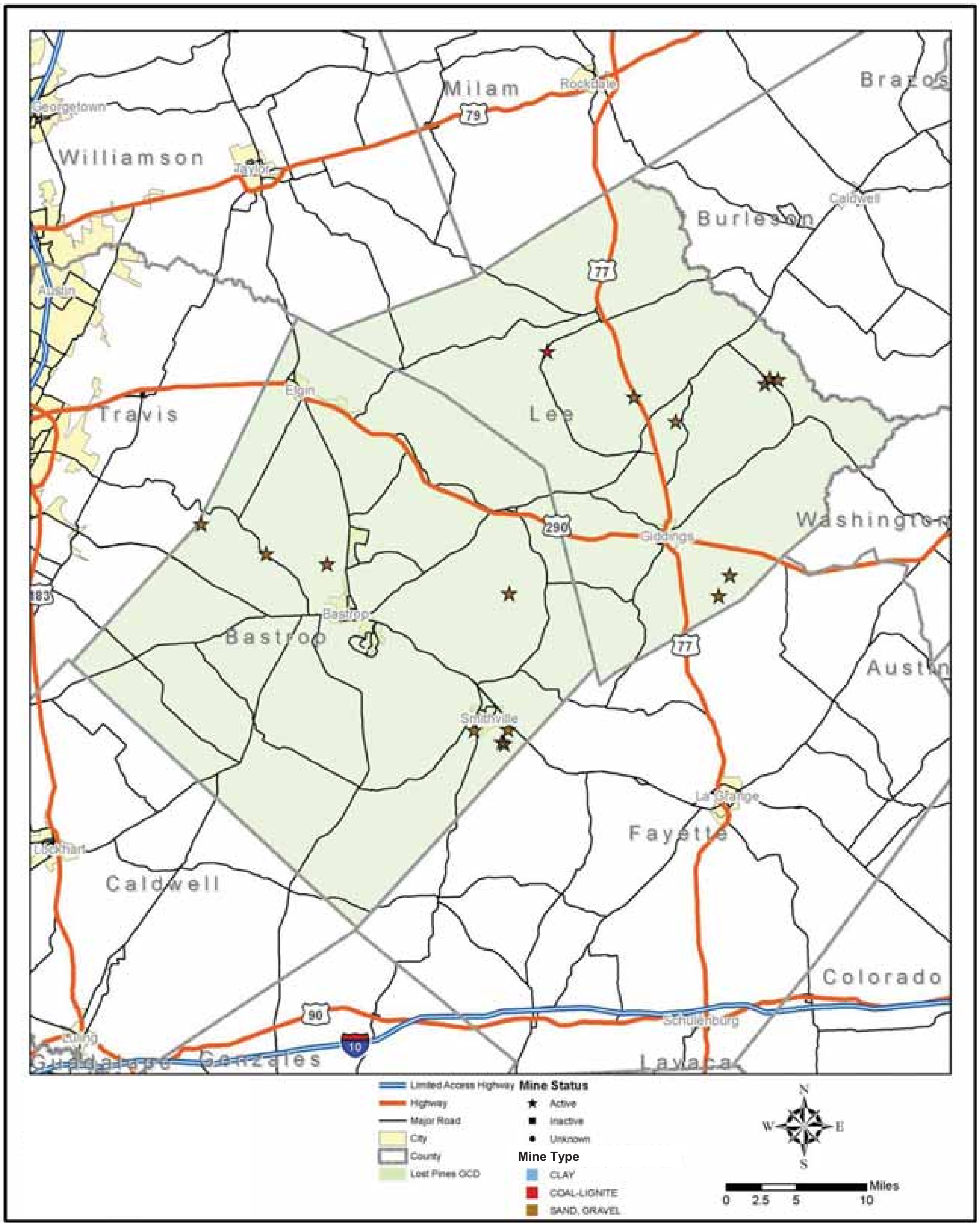


Figure 7. Example or representation provided by the SWAP database

3 Methodology and Sources of Information

With thousands of operations in the state and with no legal requirement to report production and water use (except partly for oil, gas, and coal), some choices had to be made to deliver an acceptable product within the allocated budget. We followed two guiding principles: (1) focus on the biggest users, that is, oil, gas, coal, and aggregates, and (2) if a county has no operations of the previous category, check for any minor mining activity. Several methodologies have been used in the past at the national and state level. Norvell (2009) and TWDB (2003) tried to link economic activity and water use to a black-box approach without including the detailed processes specific to each mining sector. This approach cannot predict groundwater/surface water split.

Another approach calls for the use of water-use coefficients. These coefficients, intensive in nature, are obtained by taking the ratio of two extensive values for a few facilities: (1) water use and (2) commodity production that results in a unit of gallons per weight or volume of the commodity. In a second step, the overall water use for all facilities of that type is computed by applying the water-use coefficient to the overall production for each facility, each county, or across the state. This approach has limitations because 1) the few facilities used to develop the coefficients may not be representative of the overall industry (they are typically chosen because they provided information not because they are representative), and 2) a large state, such as Texas, has considerable climate differences which make it more difficult to apply a single, general coefficient to all facilities. USGS presented in a recent report its approach to estimating mining water use at the national level in 2005 (Lovelace, 2009) and, for the most part, it made use of water-use coefficients. Unfortunately, the specific water-use coefficients are not publicly available. Lovelace (2009, Table 1) gave a broad range in the following general categories that are applicable to the whole nation: metal mining (140 to 1,567 gal/st), coal mining (50 to 59 gal/st), and mining and quarrying of nonmetallic minerals except fuels (30 to 997 gal/st).

This second approach does not work for oil and gas water use because many oil and gas areas use only water to drill and stimulate wells, usages not directly related to hydrocarbon production. A third approach consists of actually obtaining the information directly from the facilities/operators responsible for most of the water use. This approach is particularly effective when databases contain the information, such as in the case of shale gas and oil.

3.1 General Sources of Information

The TWDB Office of Planning obtains material for its projections by regularly collecting data through annual water-use surveys (WUS—http://www.twdb.state.tx.us/wushistorical/) for input into water planning. In Texas, water planning is done through 16 Regional Water Planning Groups (Figure 8; http://www.twdb.state.tx.us/wrpi/rwp/rwp.asp). Data collection by TWDB goes back >50 years to 1955, although the legislature increased the impetus when Senate Bill 1 was passed in 1997, requiring State and local governments to become better informed on how water was utilized in their jurisdiction. Sending back the requested information to TWDB is voluntary, however. TWDB then extrapolates the incomplete information to the whole state. BEG has access to the data collected by TWDB, and the latest water-mining-use information is available is 2007. Unfortunately, the response rate for a given year is low, although through the years many companies have returned surveys.

Overall, during the course of this study, we acquired both soft and hard data. Soft data, such as guesstimates of the future direction of the different mining sectors, were attained mostly through (1) discussion with professionals from the industry and (2) by perusing the web (USGS, EIA, etc.) and other sources of reports and papers (for example, Powell's *Barnett Shale Newsletter*, a weekly newsletter providing information on various gas shales in the U.S.; the *Oil&Gas Journal*; *Energy Intelligence Natural Gas Weekly*; *Texas Drilling Observer*; SPE onepetro database articles, *Fort Worth Oil and Gas Magazine*, and DOE news alerts).

The large amount of knowledge accumulated about production from shales has not fully made its way to the peer-reviewed literature yet, thus requiring us to rely on many noncitable data. As such, this project involved a great deal of interaction with workers in the field, indispensable to locating the latest source of information and to updating it to current knowledge. Fairly complete hard data on water use in the gas industry ("frac jobs") were obtained from IHS Energy, a private vendor compiling all information filed by operators to the RRC (as well as many other governmental entities around the world), and putting it into a format easy to search and retrieve. We also directly used the query tool available from the RRC website. However, not having direct access to the database for custom queries was a handicap. RRC aggregates its data by fields, counties, or districts (Figure 9).

Data on water use for drilling and waterflooding are much harder to obtain because operators do not have to report their water use as such. The latest thorough data collection of water use in the oil and gas industry was the 1995 RRC survey (De Leon, 1996). We updated these 15-year old data by contacting a trade association, TXOGA, and by surveying operators in West Texas, the area with the most waterflooding in the state, which helped constrain current and future water use.

Data on the coal industry were obtained through a survey of Texas coal operators (~100% response rate) and a follow-up with them, consulting with RRC and collecting information from its paper files. Information about the aggregate industry was obtained through surveys we requested from two trade organizations (TMRA and TACA) and discussion with selected operators. For all other operations, we did not gather additional information but relied on published information. Exceptions were a few clay operations, as well as a few uranium operators affiliated with TMRA, from whom we also received survey results. The search was guided by previous work from the TWDB, as well as by published and unpublished documents.

We also sent out, with modest success (see Appendix D), a questionnaire to various water governmental entities for information on mining activities in their jurisdictions. Apart from those mentioned in the body of this report, very few Groundwater Conservation Districts (GCDs) have accurate knowledge on the amount of water used in their areas in the mining category unless the information is readily available (for example, lignite operations) (see Appendix E for details). Figure 10 displays a current map of GCD locations, with active and inactive mine locations superimposed.

3.2 Definition of Mining Water Use for the Purpose in this Report

For consistency with previous estimates and comparison with other studies, we followed the standard classification for economic activities. According to the Standard Industrial Classification (SIC), mining industries are given the following four-digit codes:

Major group 10 (1000 to 1099): metal mining

Major group 12 (1200 to 1299): coal mining
Major group 13 (1300 to 1399): oil and gas extraction
Major group 14 (1400 to 1499): mining and quarrying of nonmetallic minerals, except fuels

These major groups also include *beneficiation*. Operations that take place in beneficiation are primarily mechanical, such as milling–crushing and grinding, washing, dust suppression on service roads, and outdoor machinery. Manufacturing, which includes chemical and more involved processes, is represented by major groups 20 to 59. Major group 32 consists of stone, clay, glass, and concrete products, including cement (3241 is hydraulic cement) and clay products. SIC codes have been superseded by NAICS codes but are still widely in use. The more recent six-digit NAICS code defines "Mining, Quarrying, and Oil and Gas Extraction" as Sector 21. Beneficiation of mined material is included in this category that also includes the following groups: 211xxx oil and gas extraction, 212xx mining (2121xx coal mining; 2122 metal ore mining, 2123 nonmetallic mineral mining, and quarrying), 213xxx: support activities for mining. Similar to the SIC classification, several potential mining products are in an ambiguous position: clay and refractory products, cement (SIC3241 hydraulic cement and 3273xx cement and concrete product manufacturing), and lime manufacturing.

Introduction to the SIC3241 group (hydraulic cement) on the official website states: "*When separate reports are available for mines and quarries operated by manufacturing establishments classified in this major group, the mining and quarrying activities are classified in (…) mining. When separate reports are not available, the mining and quarrying activities (…) are classified herein with the manufacturing operations.*" In this report, we have included small clay pits but have not included cement raw materials, limestone and clay, that are sintered together to make the clinker that will be finely ground to become the main constituent of portland cement. Some cement-producing facilities just grind the clinker and include additives without performing any quarrying activities. More generally, concrete plants of the *ready-mix* or *central mix* type are not included in this study. A rough calculation yields ~125 gal water/st of cement to make concrete or, equivalently, 30 gallons of water per short ton of aggregate. Including concrete manufacturing in the water use of aggregate quarrying operations would inflate mining water use. This distinction seems logical on paper but may be hard to apply in the field, where different water uses may not be tracked separately, or worse, water use for the whole process may be reported as mining. Similarly, asphalt plants and brick manufacturing plants are not included. We also excluded as much as possible water used to convey materials from extraction sites to offsite processing facilities. Thus, water for slurry pipelines and tank farms was not classified as mining water.

The opposite issue occurs with gas plants and other oil and gas facilities located not far from the extraction wells. They are listed with a mining code (SIC 1321) and are excluded from this study. Similarly, some other operations are listed with a mining SIC, for example SIC1459 (clay, ceramic, and refractory minerals), but most of the water is used in manufacturing, not mining activities. The matter can worsen if some of the raw material used in the plant is not locally extracted.

Another important issue is dewatering, especially of coal mines. In agreement with TWDB, we considered aquifer dewatering as consumption because the water is no longer available for other aquifer users. It should be noted, however, that the water could still be put to beneficial use when discharged to local streams and rivers. In other words, some mining operations could be considered as net producers of water, not as users of water, for planning purposes. And yet the position taken in this document is that, as long as there is no directly specifically targeted user, the water must be counted toward consumption.

3.3 Methodology: Historical Water Use

Historical water use was computed using direct data if available (for example, shale gas, coal), with the potential problem of completeness (missing facilities), in which case extrapolations were performed. In other cases, water-use coefficients were used. We used the year 2008 as the reference year because at the beginning of this work, not all 2009 data were yet available and because the year 2009 is likely not representative, owing to the economic slowdown.

3.3.1 Oil and Gas Industry

3.3.1.1 Gas Shales and Other Tight Formations

Gas shales are called resource plays in the sense that most wells will yield some gas over a large regional area, as opposed to conventional oil and gas production that needs to tap actual reservoirs of limited spatial extent (Figure 11). We extracted data from the IHS database relative to all fracing operations from the origins of the technology. We collected names of plays typically fraced by consulting BEG researchers with expertise in this field. Collecting all historical information allows for an understanding of the evolution of the technology—from small-scale fracing to improve permeability around the well bore in relatively permeable oil and gas formations, to medium-scale operations on tight gas to generate fracture permeability required to produce gas, to recent large-scale operations on shales (to recover mostly gas but also more and more oil).

We determined the plays with active frac jobs by downloading from a database provided by a private vendor: IHS Energy. The ultimate source of most of the information was forms submitted to the RRC by operators, but with the added advantage of a powerful querying tool. Before drilling a well, including recompletion, operators must apply to the RRC for a drilling permit (form W-1). Once completed, operators submit a W-1 form (for oil-producing wells) or G-1 form (for gas-producing wells). The two latter forms contain information about well stimulation, including slick-water fracing.

We compiled all wells completed in the 2005–2009 period (5 years) and then selected wells with water use >0.1 Mgal. This threshold is somewhat arbitrary and was used to distinguish true frac jobs from simple well stimulation by fracing and acid jobs. This approach is better than relying on operator classification of acid vs. frac vs. some other IHS category because our experience shows this method to be unreliable. We then compiled all plays with at least one frac job in that period and returned to the IHS database to obtain all wells fraced in these plays (including earlier than 2005). Further processing is detailed later. An additional download of the 2010 data was done in November 2010 to identify recent trends.

Nicot (2009a) and Nicot and Potter (2007) (also in Appendix B of Bené et al., 2007) detailed one of the methodology approaches followed in this current work as applied to the Barnett Shale. Appendix B presents the successful postaudit of the projections made during the 2006–2007 Barnett Shale study. Because of budget constraints, it is not possible to reproduce the finer level of granularity achieved in the previous study, but the general methodology stays identical: (1) gage the eventual level of drilling (and upper bound of ultimate water consumption) at the end of the play history by estimating reserves and prospectivity and (2) distribute water use through time by estimating rig availability for the next few decades and by applying time-varying correcting factors. Many papers emphasize that each play is different and that even wells in close proximity show widely different behavior (Matthews et al., 2007; Chong et al., 2010; King, 2010). However, we assume that, at the county level, most of these differences average out and that it is appropriate to use averages.

The whole process relies on having accurate historical data, which, in this work, are obtained from the IHS database (*header* and *test treatment* options). The first step of the processing is to check the data and fix possible typos (wrong units, additional or missing zeros, etc.). Not paying attention to the typos (generally <10% of the selected portion of the database) could decrease or increase individual well-water use. Typos artificially increasing water use represent the larger risk. The general approach to achieving this goal was to compute proppant loading and water-use intensity for each individual well (not individual stage).

Proppant loading is computed by summing up the amount of proppant mixed and the amount of water used and taking the ratio. Field units are pounds per gallon (ppg or lb/gal). An acceptable value is near 1 (0.5 to 2, e.g., Curry et al., 2010, p. 3; our own statistics). This parameter has to be used with caution because, in past treatments, proppant loadings were at least twice as high but with a smaller water volume. Hamlin et al. (1995, p. 9) mentioned 50,000 to 70,000 gal of gel and 100,000 to 120,000 lb of sand for Canyon Sands in the Val Verde Basin of West Texas. Dutton et al. (1993, p. 45) cited a typical treatment in the Cotton Valley sandstones of 0.4 Mgal and 1.7 million lb of sand. They also indicated (p. 79) that 150,000 gal of x-linked gel and 450,000 lb of proppant were appropriate for the tight sands of the Vicksburg Formation of South Texas.

Water-use intensity is computed by dividing up total amount of water used by length of the productive interval, either vertical length for vertical wells or total lateral length for horizontal wells. Lateral length can be computed from two techniques that generally agree: distance between surface location of the wellhead and bottom-hole location and/or length of total driller depth minus true depth (Figure 12). These are approximations that work well as long as they are applied consistently across a play and as long as most wells are constructed similarly. The so-called directional wells present a challenge, but they are not very numerous in the IHS database and are folded into the horizontal-well category.

Total water use, total proppant amount, water-use intensity, or proppant loading out of the common range create additional scrutiny for that particular frac job. The process is semiautomated because there have been tens of thousands of frac jobs across the state in the past few years. Building a histogram or using the filter feature in Excel are the two ways used to catch these outliers. Many errors can be caught by looking at the consistency of metrics. The decision is then made to fix an obvious typo (for example, barrel unit instead of gallons or tons instead of pounds or an extra zero for water a figure that matches expected water intensity and proppant loading only when it is removed). If no fix is evident, the frac job receives the median water use for that play and year(s). Frac jobs with missing water use are also treated by estimating what they should be from the proppant amount and the median proppant loading for that play and year(s). If neither the water volume nor the proppant amount is given (can be as high as 30% of the data set for a play), the frac job receives the median water use for that play and year(s). The focus is more on the median than on the average, which can be heavily biased (Nicot and Potter, 2007).

Once the selected data set were cleaned up, we used in-house visual basic scripts within Excel to build various histograms and plots for each play: (1) location map and geological information as available, (2) plots of historical number of frac jobs per year in combination with percentiles of water use (for vertical then horizontal wells), (3) comparison of distribution of vertical vs. horizontal wells through time, (4) histogram of water use per vertical well, (5) histogram of water use per horizontal well, (6) histogram of water use intensity for horizontal wells, (7) histogram of proppant amount, and (8) histogram of proppant loading. Historical plots do not include wells with no water-use value, but those wells are added to the 2008 reference year, assuming a median water-use value.

A major assumption is that all makeup water is fresh. Typically, higher TDS water (mostly because of calcium) will increase friction-reducer demand, one of the additives. Hayes (2007) discusses the industry requirements in terms of TDS and ionic makeup. A brackish water (or even saline water, for example, from the underlying Ellenburger Formation in the Barnett Play) could be used if the pressure required to frac the shale is not too high (translating into lower pumping rate and, consequently, less friction reducer). Some higher-TDS water (from reuse of flowback) can be used too, but it is accounted for in the use of a recycling coefficient.

3.3.1.2 Waterflooding and Drilling

RRC neither systematically compiles information on waterflooding and similar recovery processes nor does it collect data about drilling-water use. RRC does post information about injected fluid volumes, but there is no systematic information on the nature of the fluid. Most is likely water, but often there is no indication of the TDS of the water, nor is the groundwater/surface water split well constrained. Fresh-water injection wells need to be permitted as such. Form H-1 asks for the type of injected fluid (saltwater, brackish water, fresh water, CO_2, N_2, air, H_2S, LPG, NORM, natural gas, polymer, and others). For waters other than saltwater, the form requires the applicant to provide information on the source of the injection water "*by formation, or by aquifer and depths, or by name of surface water source*" (fresh-water questionnaire or form H-7) and to demonstrate that no other source water of adequate quality is available nearby. A companion form (form H-1A) requests maximum daily or estimated daily injection rates of each fluid type (including fresh and brackish water when appropriate). Actual water use is reported on form H-10 (http://webapps.rrc.state.tx.us/H10/h10PublicMain.do). A UIC query (http://webapps2.rrc.state.tx.us/EWA/uicQueryAction.do) also provides useful information about individual wells, although no breakdown in type of injected fluids. In addition, the regulatory focus is on the total volume injected and the pressure rather than the type of fluid injected. Experience has shown that H1 forms are only of little use in estimating fresh-water use; rates provided by the applicant largely overestimate actual rates.

Other researchers have also tried to collect waterflood information. Lovelace (2009), in a USGS summary of the approach used to estimate 2005 oil and gas water use across the nation, presented the assumptions made to develop the final figures including into his fresh and saline categories. (1) all water is groundwater; (2) if several water types are indicated in the H10 form, they are assumed to be of equal volume; and (3) because injection volumes are not provided for individual wells, all wells were assumed to contribute equivalent volumes of water. However, the 1995 RRC study (De Leon, 1996) invalidates some of those assumptions; a significant fraction of the water is surface water.

In the end, to gather information about waterflooding, we decided to send quantitative survey forms to ~25 leading oil-producing companies in West Texas, where waterflooding and EOR operations are concentrated (Galusky, 2010). This mailing was followed up with telephone calls and e-mails, and we communicated to them that all of the information and data that they provided would be held in strict confidence by Texerra/P. Galusky, who would submit only an aggregate compilation and summary of key findings in its report to BEG. Additional data and information on drilling activity, oil production, and related parameters were obtained from various publicly (internet) available and private (commercial) data sources.

Drilling-water use is generally not reported, and waterflood reporting combines all water sources from fresh to saline. A logical approach is then to collect information from operators. Drilling-water-use information was collected through informal discussions with practicing field engineers.

3.3.2 Coal/Lignite

Determining the amount of water used within the coal mining industry proves to be a complicated task because no entity currently tracks consumption; however, all coal mine operators must report total pumping rates to the RRC as a requirement for their mine operating permits under Title 16, Part 1, Chapter 12 of the Texas Administrative Code. When a mine operator applies for a new permit, estimates of current conditions and future drawdown must be provided to allow the RRC to determine allowable pumping rates. Once mines are in operation, operators must report their drawdown and pumping rates quarterly for the first 2 year, and then once every year following the 2-year period. The RRC does not restrict the amount of water to be pumped. The agency simply tracks pumping rates and requires documentation of the drawdown impact of mining operations on the surrounding areas (T. Walter, RRC, 2009, personal communication). Dewatering and depressurization totals were collated from each mine from RRC public records with the cooperation of Tim Walter, as well as results from the survey sent to each operator.

To help in the process of collecting data, in-depth literature searches and discussions with industry experts were conducted to help us decide on the best route for determining withdrawal and consumption estimates. We concluded that estimates for specific mining activities, such as hauling or dust suppression, vary for each active mine, depending on climate, location geology, production techniques, and other factors. Therefore, it would be necessary to analyze each mine individually. Fortunately the number of facilities is small, and all of them are large and well documented. We launched a survey in coordination with the Texas Mining and Reclamation Association (TMRA), which was very successful (~100% response rate).

An important question was whether to include pit-dewatering volumes into water consumption/withdrawal. Pit water originates from rain falling into the pit and being captured by its drainage area, as well as seepage from the overburden. The latter can be minimized but never eliminated by pumping groundwater from the formations to be removed before mining. Many mines divert runoff and pit water from precipitation into retention ponds and use it, for example, for dust control. For consistency with the approach followed in the aggregate category, we did not include pit dewatering (strictly defined) in water use.

Aquifer depressurization also lacks the clear-cut classification of some other water uses. Although the amount pumped for depressurization represents a net loss to the aquifer, the water is available for other uses, in particular environmental flow. In addition, in at least one mine, depressurization is put to immediate beneficial use when some wells are turned over to a water supply company (T. Walter, RRC, 2009, personal communication). This amount of water is not counted toward mining so as to avoid double-counting when merging all water uses, although it could bias water-use coefficients (they are not, however, used for coal in this study).

3.3.3 Aggregates

The approach for aggregates is different from that for oil and gas, about which relatively little is known or for coal/lignite, about which a complete data set exists. TWDB already has a working database from past water-use surveys. Various other reference sources and data sets were examined in an effort to determine whether available information could be used to further validate the TWDB water-use estimates and/or to refine our estimates at the county level. Resources examined include

- USGS
- MSHA
- TWDB
- TCEQ
- Interaction with and web search of the largest producers in the state (Martin Marietta Materials, Inc., Vulcan Materials, Inc., and Capitol Aggregates).

Furthermore, we recognized that although most aggregate operations recycle or reuse a large proportion of the water used in their processes, water-use data sometimes reflect the full volumes used and do not account for the recycled volumes. Such an uncertainty may result in inappropriate inflation of the values used for planning purposes. This report also attempts to assess the availability of additional information that may differentiate between water used in aggregate mining and that actually consumed or lost in these processes. A significant effort was made to conduct a survey in coordination with TMRA and TACA to obtain water-use and water-consumption data for a sampling of representative member companies and facilities across the state (survey questionnaires in Appendix D). Despite the cooperation of the two associations and multiple attempts to encourage participation, only seven companies of the many companies contacted responded to the survey request. They provided information for 27 separate facilities with information on location, production, water use, recycling rate, and source water.

These database reviews and survey results were analyzed and compared in order to supplement the information obtained by earlier surveys and planning documents. Results of the survey were highly variable, with some data tending to validate information obtained from earlier work by other agencies and some data suggesting significant differences. The survey highlighted the difficulties in using this approach to gather information on the industrial mineral mining sector. Some of the factors that may have influenced the response include the number, diversity, and relatively small size of many of the mining operations; the concern expressed by many in the mining industry of disclosing competitively sensitive information; the lack of available personnel to compile or calculate data; and the lack of regulatory requirements to collect and report requested information.

Issues we had to overcome or mitigate included (1) information on the types and numbers of industrial mineral mining facilities in Texas obtained from the Mining Safety and Health Administration (MSHA)—681—differed significantly from data from TCEQ—3,125 and (2) water-consumption coefficients, expressed in terms of gallons per ton of product extracted (gal/t) or gallons per dollar of production output (gal/dollar), which have been developed to estimate current and future demands on the basis of population growth or financial forecasts. The coefficients for washed crushed-stone mining derived from the survey were significantly different from those previously determined by either the USGS or the TWDB, whereas the coefficients for construction sand and gravel operations were similar to previous estimates.

Directly useful data in our possession were

(1) Production and water-use information for a few facilities (27) from the BEG survey;

(2) Water-use information from TWDB WUS survey dating back from 1955, although only recent information was used (26 facilities with some overlap with the BEG survey);

(3) List and locations of facilities trying to limit the potential problem of having listed the location of the company headquarters possibly located in a county different from that of the quarry/pit;

(4) Generic industry water-use coefficients from other studies;

(5) Water-use information at the county level for all mining activities from USGS (year 2005); it is thought that the fresh-water-use data include mostly coal and aggregates;

(6) County-level population information from TWDB projections;

(7) Annual state production in 2008 (153 million tons crushed stone and 87.7 million tons sand and gravel) and earlier years (for example, 136 and 99.5 million in 2006, respectively)

As noticed by earlier workers, there is no clear correlation between production and water use, an observation again confirmed by the BEG survey. If that were the case, we could simply infer water use from production. However, neither production nor water-use figures are readily available. Actually, production figures are available that are aggregated only at the state level and do not result from direct data compilation. USGS collects production information and does it through surveys (and information collected from state agencies) but is never able to collect comprehensive data and has to rely on extrapolations. TWDB is focused on water use and does similar regular surveys but with limited success. Some companies consistently and voluntarily report their water use, whereas others are less straightforward. Regional Water Planning Groups (RWPGs) (Figure 8) know the reality of their region but are rarely focused on mining, which is typically a small fraction of total water use, and often relies on TWDB figures. Similar to previous USGS and TWDB reports, we elected not to link the data we present later in this report to individual facilities.

We used a two-pronged approach to assess aggregate water use:

(1) When water-use figures are known for a given county, they are used.

(2) For counties with only partial or no information on water use, we rely on estimated production combined with an estimated water-use coefficient. Water-use coefficients are computed from (1) a BEG survey and (2) generic coefficients from previous work. Estimated production at the county level is computed from local population and number of facilities. A higher number of facilities in a county relative to the population suggest a particularly favorable geology and a higher production per facility.

These detailed steps were used for crushed-stone water use:

(1) Derive statistics from BEG survey results.

(2) Compare with TWDB WUS and USGS county-level mining-water use.

(3) Compare with generic aggregate water use.

(4) Determine counties with crushed-stone facilities. Sort into two types: (a) of primary importance and listed on the NSSGA/USGS database, potentially deserving markets up to 50 miles away and lasting to the end period of this study and beyond or (b) of secondary importance and listed only on the MSHA database with only local subcounty impact and likely ephemeral in nature (a few years).

(5) Distribute crushed-stone production throughout the state using facility list from NSSGA/USGS; county-level production is anchored by the few counties for which production is known and scaled from the state production according to local population (more details on the mechanics of this in the methodology section for future water use—Section 3.4). Counties with facilities listed in the NSSGA/USGS directory are assigned the population of that county and that of surrounding counties; counties with facilities solely in the MSHA database are not included (Figure 13).

(6) Apply average/generic water use for those counties with no information. Given the large range in water-use coefficients, although likely relatively accurate at the state level, estimated county-level figures may diverge from actual figures if their facilities are more water conscious or less efficient than those of the average facility. USGS uses employment data from MSHA to estimate size of facility. We confirmed the size of some facilities, especially those with seemingly high water use, through Google Earth. Combined with other sources of information, Google Earth could be a good tool for estimating more accurate water use, especially through time, using the historical imager option. Excavation changes through time would help put bounds on production, and pond size and other water features would suggest water use.

Water use in the sand and gravel category follows the same approach except that all production is assumed to be consumed locally within the county; that is, population of surrounding counties does not figure into the calculation. Again, note that we did not include cement or concrete facilities (as far as we can tell by the description given in the databases) in this study. They are part of manufacturing, even if they have quarry operations onsite.

3.3.4 Other Mined Substances

Methodology for other mined substances is done on an ad hoc basis but mostly it is done by collecting information from TWDB WUS. We also collected direct information from some uranium and clay facilities with the survey through TMRA (Appendix D). Specific details are given in the current water-use section (Section 4.5). We included industrial sand operations in the “other” category, although they bear many similarities to the aggregate industry, although the much higher water use coefficient sets them apart.

3.3.5 Groundwater–Surface Water Split

Accessing the source of water used is difficult in most cases. Water use is well documented for some mining-industry segments, such as coal mining, but it varies widely for oil and gas and aggregate-mining segments. Historically the trend in the state has been to rely more and more on surface water. The best source of information is direct surveys, but even knowledge of current sources may have little predictive power. For example, in Louisiana, Haynesville shale frac water initially from the Carrizo-Wilcox aquifer (Hanson, 2009) has switched to alluvial aquifers and, mostly, surface water (Red River) after suggestions by the Louisiana Department of Natural

Resources. And treated wastewater from a paper mill in northern Louisiana has recently been added to the mix of water sources used in the play.

We provided information about the groundwater– surface water split as it became available during the data-collection process but did not try to generalize to the whole mining industry.

3.4 Methodology: Future Water Use

What are the substances currently being mined? How much longer will they be mined? Do any of the substances mined in the past have a credible chance of being exploited again, both in terms of substance and location? What are the new substances that could be mined in the future? Some of these questions are not easy to answer, but overall the main driver of water use in the mining sector is mostly (1) population growth and (2) economic development, especially concomitant energy demand nationally. Population growth relates to resources consumed within the state (aggregates, coal), whereas economic development impacts all substances, including those mostly exported out of the state either in their raw form or transformed. A project such as this includes many levels and types of uncertainties. A tentative comprehensive sampling despite the appearance of completeness can overlook several facilities, although not any one large facility. Operators can make honest mistakes when reporting information or include water-use categories that should not be included. Even more uncertain is extrapolating for long periods of time from a short period of time of a few years, such as for shale gas and oil. Long-term energy projections do not have a very good track record (Figure 14, Figure 15). Figure 14 provides an example of the difficulty of making projections. A natural tendency is to extrapolate trends; projection of U.S. gas consumption made in 1970 is a simple extrapolation of the strong trend of the previous year. Projection for 1972 follows the same model with a smaller growth rate. Year 1974 projection continues to extrapolate, although one of the marking events, energy-wise, of the second half of the 20th century occurred in 1973. Figure 15 demonstrates that, even in the midst of a known energy-paradigm change, shale-gas production (and, by extension, water use) was consistently underestimated. Hindsight or postaudits are a great way to improve the reliability of such scenarios. BEG published an analysis of water use in the Barnett Shale using data from 2005 (Nicot and Potter, 2007), and a comparison to actual water use is presented in Appendix B. The overall conclusion is that projections match recent data but only because of the recent economic slowdown.

We debated having deterministic vs. a range of projections (for example, high, medium, low) and concluded that we would focus on a ***single best-guess scenario,*** with the understanding that uncertainty increases with annual horizon. Although working on a 50-year horizon helps in an understanding of heavy trends, we tried to focus on the next 10 years, the timeframe in which this work could have the most impact. Another concern is higher-frequency changes, again mostly applicable to shale gas, such as the current economic slowdown. A long-term decade-level horizon makes it easier to ignore these high-frequency cycles and to focus on long-term trends. The downside of such an approach is that projections may not be correct in the rate of change of water use from one year to the next but they may be more accurate cumulatively.

Post-mortem analyses of long-term projections show that they often deviate from actual figures because of unpredicted events. A case in point is the rapid development of water-intensive gas production from gas shales. Such events are by nature unpredictable and, although we can develop scenarios, their multiplicity quickly becomes unmanageable: what year does it begin, how fast does it develop, is it permanent or transitory, what is the magnitude of impact, etc.?

Including the uncertainty of abrupt changes in water use, projections would render them meaningless, so our approach has been to ***assume that current trends will continue***. In contrast to abrupt changes, long-term shifts in water use, particularly in the energy sector, can be better tackled. As discussed previously, a large fraction of the mining output is related to energy production (oil, gas, coal). King et al. (2008) discussed future directions of the energy sector in Texas as it relates to water use. For example, development of nuclear power would merely transfer water use from the mining category to the power-generation category, as well as move it to different counties and regions, as would a shift from coal to natural gas. This project does try to predict the unpredictable but always assumes a slow rate of change, such as gas slowly overtaking coal as the major electricity-generating fuel in Texas or the rise and decline of gas production. However, most gas is exported out of state and, because of a projected overall increase in energy consumption, is not denting water use by the coal industry.

Next, we discuss the relationship between three of the major water users in the mining industry: oil vs. gas and gas vs. coal. Oil in terms of energy has always been at a premium relative to gas (for example, Kaiser and Yu, 2010), being sold at a higher price for the same energy content. Natural gas, being a gas at surface conditions, requires more advanced technologies for it to be transported to areas of consumption. The year 2010 has seen a rush toward the oil window, thought to be more profitable, in some so-called gas shales but more accurately described as liquid-rich shales, such as the northern confines of the Barnett Shale or the western section of the Eagle Ford. Such a trend of operators focusing on oil rather than gas, if it persists, will impact water use at the county level, if not at the state level. This focus on oil is analogous to a smaller-scale shift in oil and gas operators' thinking. In this project, we assigned a slightly higher weight to these oil window/combo counties, but on the whole we consider this oil focus a short-term deviation. Another example concerns some gas plays very much in the news 2 or 3 years ago, such as the Pearsall Formation in South Texas or formations of the Palo Duro Basin in the Texas Panhandle, that have since disappeared from the radar, while others such as the Haynesville and, even more so, the Eagle Ford, have exploded in terms of activity. In this ever-changing environment, it is challenging to predict where the gas industry will be active 5 years from now. Another single event with possible repercussions, particularly in terms of legislation, is the Macondo well. On April 20, 2010, a grave accident occurred in the deep offshore Gulf of Mexico. Responding to a likely increase in regulatory scrutiny and, therefore, increased cost, many operators, particularly independents, may redirect their efforts onshore, especially to unconventional oil plays (the Eagle Ford, Barnett Shale oil windows).

Coal and natural gas are used mostly for energy production. Both industries are optimistic about their futures. The Texas energy portfolio consists of mostly coal, nuclear, natural gas, and others, including oil and renewables. King et al. (2008), looking at energy use in Texas by 2060, assumed an annual electricity growth rate of 1.8% in business-as-usual scenarios. These workers also investigated a low-energy-usage case. They described four scenarios combining high/low natural gas prices and implementation (or not) of carbon capture and storage (CCS). In both high-natural-gas-price cases, coal use expands and natural gas use stays steady. However, if natural gas price stays low, coal share decreases even if overall energy consumption decreases. If, in addition, CCS is made mandatory through a hypothetical cap-and-trade or carbon-tax legislation (to deal with climate change, the advantage of natural gas relative to coal is that it releases less CO_2 per unit energy than coal), coal share in the energy mix decreases even faster. However, EIA (2010, p. 79) suggested that lignite production may increase in Texas. Coal mined in Texas is always used locally (mouth-of-mine coal-fired power plants), but a significant fraction of the gas goes into the general market and is exported out of state. For example, 45+% of electricity consumed in the state is produced by natural gas, for a total of ~200,000,000 MWh (equivalent to 0.68×10^9 MMBTU, with 1 MMBTU = 0.2931 MWh). In 2009, natural gas production in the state was 7.66×10^9 Mcf (equivalent to 7.66×10^9 MMBTU, with 1 Mcf =1 MMBTU). Major growth in other parts of the world may boost the gas industry for export, and development of LNG terminals in Texas or the glut of the gas commodity may keep the prices too low for its development to have a major impact on water use (averaged over decades). An authoritative recent study on natural gas (MIT, 2010) suggests that use of natural gas will expand and an earlier study by the same organization (MIT, 2007) acknowledges that coal use is likely to increase overall even if its relative share in the energy mix decreases.

To develop our own understanding of those issues, we collected material from Washington-based think tanks, attended specialized conferences (Nicot, 2009a; Nicot and Ritter, 2009; Nicot et al., 2009; Hebel et al., 2010; Nicot and McGlynn, 2010; Ritter et al., 2010) and discussed the matter with experts. Overall, we decided to use a middle-of-the-road scenario, and because of the mixed signals received from different entities about coal consumption, either up or down, we assumed that it stays at its current level with no sharp increase or decrease in absolute figures (but decreasing in the state energy portfolio), in agreement with discussions with coal producers. Texas gas production is controlled by external factors independently of population growth, whereas aggregate production is controlled entirely by population growth.

Judgment on future water use of nonfuel substances is either more straightforward (aggregate) or less consequential in terms of total water use. Information about future water use was determined not only through direct results of forward-looking survey questions and general understanding of the commodity, but also by scouring Regional Water Planning Group (RWPG) reports. Texas is composed of 16 RWPGs, each of which is charged by law to project water needs and water sources for its own area and to submit information for incorporation into the state water plan. Water Plans (TWDB, 2002, 2007; http://www.twdb.state.tx.us/wrpi/data/proj/demandproj.htm for year 2007) present projections but in general are aggregated at the regional planning level.

3.4.1.1 Gas Shales

The general philosophy of the approach is top-down, that is, distributing estimated overall oil and gas production, as well as water use, across counties, rather than a bottom-up approach, in which a time-consuming and hard-to-get detailed compilation of fields, formations, and local input would be aggregated to deliver county-level figures. This section is untitled gas shales but includes the oil window generally located updip of gas shale proper (liquid-rich shales). As far as water use is concerned, well stimulation does not seem to be approached very differently. Quantitative approaches to future water use in shales fall into two broad categories: (1) production-based approach and (2) resource-based approach. The latter was applied to the Barnett Shale by Nicot and Potter (2007) and Nicot (2009a). In this report, we followed both approaches simultaneously, making sure results were consistent.

A ***production-based approach*** follows five steps, which are further described later in this section:

(1) Determine with the help of BEG experts (or gather from the literature) the total amount of gas/oil contained in the shale, as well as the recoverable fraction and the estimated annual production level. This step also involves recognizing the boundaries of the play.

(2) Decide on (or gather from the literature) the average Estimated Ultimate Recovery (EUR) for a single well.

(3) Compute the total number of wells needed.

(4) Apply the average water use per well (computed from historical data, we have a good handle on water use of many individual wells across many gas plays in the state, as detailed in Section 4.1), possibly corrected by factors accounting for technology advances and increased recycling and, perhaps, additional rounds of well stimulation. Well count for the first few years is estimated, given rig availability, which after a few years becomes irrelevant because the service industry will respond to needs by constructing them.

(5) Distribute through time (expected life of the play) and space (county level) as a function of prospectivity and other parameters. This step is the most uncertain and open to interpretation.

A ***resource-based approach*** follows four steps:

(1) Gather historical data in terms of average well-water use and average well spacing.

(2) Estimate ultimate well density across the play; it is a function of factors, such as geological prospectivity (for example, within play core or not, shale thickness) and cultural features (urban/rural). In this step, ultimate boundaries of the play are identified.

(3) Compute total number of wells needed.

(4) Distribute through time and space, constrained by the assumed number of drilling rigs available (see earlier comment).

As an entity whose strength is applied geology, BEG had the opportunity to develop its own assessment of shale-gas reserves in Texas. Gas accumulations can be biogenic, in which microbes biodegrade organic matter to release methane, or, as in all Texas shale-gas plays, thermogenic. Thermogenic gas is produced by the natural cracking of complex organic molecules into oil and gas, owing to an increase in pressure and temperature, as well as sufficient time at required depths. The deeper the conditions (without some limits), the more advanced the cracking of the organic matter, whose ultimate fate is methane. Some shale plays contain only gas (if they stay in the gas window for long enough)—an example is the Haynesville Shale—others contain both oil and gas either at the same location (a well will produce both oil and gas) in a so-called combo play (for example, the northern section of the Barnett) or spatially distinct oil and gas zones with a mixed transition combo zone (for example, the Eagle Ford Formation). There is a relationship between total organic content (TOC) and potential gas content. Vitrinite reflectance (VR) is a measure of the maturity of the evolved organic matter/kerogen: the higher its value the more likely it is to be in the dry-gas window (VR>~1.5–2). For VR values ranging between 1 and 1.5, the shale is likely to be in the wet gas window. Below a value of 1, oil is produced, whereas if VR<0.6, the sediment is immature, and no commercial accumulations are likely to be found. Combining information about formation thickness, TOC, VR, and a few exploratory wells, specialists can infer gas resources. The core area of a play is subjectively defined as the area where the most favorable combination of thickness, TOC, and VR exists. The core areas of the Barnett and of the Texas portion of the Haynesville consists of each of four counties, whereas they have an additional 20+ whole or not counties and ~10 counties considered noncore, respectively. Core counties have not been defined for other shale-gas plays, including the Eagle Ford Formation, yet. Other known important factors are not used in this study; for example, an emerging model (S. Ruppel, BEG, personal communication, 2010) suggests that margins of shale plays are more prospective because of the influx of carbonate and other clasts with the right combination of organic matter and detrital material, making the setting more favorable.

We decided early on to rely as much as possible on published information rather than developing our own estimates. Nevertheless, knowledge of these parameters helps in determining the prospectivity of an area (county in this case), that is, its attractiveness to operators, which is obviously linked to water use as well as the boundaries of the play. Geological maps and previous drilling and production activity help in constraining the final spatial extent of the play. In practice, prospectivity (maturity, core area) is a positive number ≤1. Each county within a play is assigned a prospectivity factor (generally 1, 0.75, 0.5, or 0.3). This assignment was done in a purely ad hoc manner and in a more cursory manner than in Nicot and Potter (2007), as this parameter is softer than, for example, the play footprint and, owing to a lack of information, includes some guess work relative to where the industry is headed.

Many gas-production projections are published at the national level (EIA, USGS, PGC) aggregated from individual plays and sometimes extrapolated to prospective shale plays. Information about recoverable reserves of individual shale plays (in general, ~30% of OGIP or OOIP) are relatively easy to collect, but unfortunately there is a lack of consistency between the different figures we can gather, mostly because the methodology used to arrive at those figures is not explained in most cases. In the Future Water Use section (Section 5.1), we list figures for all Texas shale plays and explain the choice of the value we used. Another difficulty relates to the fine granularity (county level) we attempt to meet. Projections made at the national level perhaps end up being more accurate because of the low granularity of the system (many oil and gas plays), as opposed to a single state even if it is large because only a few shale plays exist. For example, Appendix B shows that careful work does not necessarily generate accurate predictions at the county level, even though they might be at the multicounty or regional/play level. We expect the same observation to be truer in this higher level study. Results at the county level may be off by a factor or 2 or 3, especially when the time component is added.

Later we focus on the production-based approach because the resource-based approach was already described by Nicot (2009a) and Nicot and Potter (2007). Some published EUR values seem to be problematic. Individual-well EUR can be estimated at 0.5 to 3 Bcf, maybe up to 10 Bcf, in highly profitable wells. Most EUR is derived from limited data, not necessarily in terms of number of wells but in terms of time frame (Figure 16). Reported average EUR values most likely reflect good wells drilled in the core area of a play and might be inflated. Water use computed from number of wells based on EUR and total recoverable gas only is therefore highly uncertain because both can vary substantially. For example, the commonly found EUR value for Barnett wells of 3 Bcf, combined with an assumed <60 Tcf of recoverable gas, yields <20,000 wells. Clearly, even taking into account that many of these wells are vertical wells with a lower EUR, more wells will be drilled in the Barnett. The very first well drilled in the core area of the Barnett in 1982 has produced 1.7 Bcf so far (PBSN, Nov.1, 2010).

Therefore, in the Barnett, either recoverable reserves are underestimated or average EUR is overestimated; that is, production drops faster than currently projected. This report puts more weight on the latter explanation, but without negating the possibility of the former. Actually, there are voices (Shook in NGW, 2009) advocating that shale gas will not carry all the promises put forward by operators. For example, SPEE-Anonymous (2010), Berman (2009), and Wright (2008) suggested that decline curves were too optimistic, but they seem to be in the minority. Their approach has been strongly contested by the gas industry in the literature, as well as in the field, as majors (ExxonMobil, Shell, Total, ENI, Statoil, BP) started investing in shale gas. It seems that with a diversified gas-well portfolio and a statistically sufficiently high number of wells, good producers more than make up for more numerous low-performing, uneconomical wells and render the whole operation profitable for most gas operators. In other words, the viability of a play is determined by its top producers, perhaps the top 10th or 20th percentiles. Note that from a water use standpoint, however, uneconomical wells and good producers consume the same amount of water during fracing. Low-rated wells may even be fraced a second time shortly after the initial frac job in an effort to improve gas production.

A typical play containing 100 Tcf of gas in place, 30% of which is recoverable, translates into 15,000 wells at 2 Bcf EUR, on average. Distributing projected production/water use through time is difficult but is the essence of this project. We relied on several sources in addition to informal information, but particularly Mohr and Evans (2010) and Mohr (2010, Chapter 6), who inventoried all relevant gas shales at the time and summarized available information on projected gas production for the Barnett and Haynesville Shales. They also provided a peak year for gas production (best guess of 2015 and 2031, respectively). Similarly we assigned a peak year for each gas-shale play, which is clearly highly uncertain. Most publications assign a peak year for gas production, which typically comes after the peak year for initial well completion. However, translation from gas production to water use requires the knowledge of the EUR and the details of the production decline curve. It has been commonly observed that production decreases from an "initial production" (IP) (Figure 16). Given the relatively steep decline from IP, new wells must be drilled to sustain production. Information received from informal discussion suggests that 3000+ new wells a year are needed to sustain production at current 2010 production rates.

A commonly circulated IP value in the Barnett is 5 MMcf/d. Overpressured plays, such as the Haynesville, have generally a higher IP—reported value can be as high as 8 or even 20 MMcf/d. More generally, individual gas-well performance is characterized by their IP, how fast they decline from the IP (decline curve), and their cumulative potential (EUR). There is some evidence that pushing production to its max IP is detrimental to the EUR, so most operators throttle production to a rate somewhat lower than the possible maximum. Doing so also makes sense economically when gas prices are depressed. A large body of literature deals with decline curves, which have been a topic of considerable interest in the petroleum industry because they help forecast future performance and production. Two broad families of these mostly empirical curves exist: exponential and hyperbolic (see for example, the classic Arps, 1945; Economides et al., 1994; Ilk et al., 2008; Lee and Sidle, 2010; Valko and Lee, 2010). The former curve model is used when the decline is linear on a semilog plot against time. We tentatively used a simplified version of the Arps decline-curve equations for hyperbolic decline, which is typically faster than exponential decline.

$$q = q_i \exp(-Dt) \quad \text{(exponential decline)} \qquad \text{Equation 1a}$$

$$q = q_i (1 + Dbt)^{-1/b} \quad 0 \le b \le 1 \ \text{(hyperbolic decline)} \qquad \text{Equation 1b}$$

Although the parameter b should be ≤ 1 to meet model assumptions, it is often set to values >1 for tight formations (Ilk et al., 2009). This parameter is difficult to assess with the limited information available early in the history of a well. Assuming an average well EUR, a decline curve, and a given life, we can attribute a fraction of the EUR to each year. After some trial and error, we were able to match gas production from Mohr and Evans (2010), assuming an average EUR substantially lower that the most-cited core ones and with input from the resource-based approach. Note that the chosen production model is only one among many, although a middle-of-the-road, defensible one. Exploring all possible production outcomes would entail much larger efforts than available for this study. The fraction produced during the first year is ~45% and ~25% for what we defined as an overpressured *Haynesville type* and a normally pressured *Barnett type*, respectively (Figure 17), over the 30 years of the producing life of a well. The curves displayed in Figure 17 show a drop of 75% and 60% between average production in years 1 and 2 in Haynesville and Barnett types, respectively. Figures are consistent with those presented in Jarvie (2009) that document decrease in the 60–80% range during the first year of production for various shale plays in Texas and elsewhere. Note that the decline curve is just one component in estimating water use, and, although it obviously has a large impact on the production numbers, water use is less sensitive to it, especially when the production-based approach is compared with the resource-based approach.

Spatial coverage density is an important step in the resource-based approach. Figure 19 and Figure 20 display examples of thorough coverage from multiwell pads. Horizontal-well laterals are all oriented in the approximate direction that is perpendicular to minimum local horizontal stress. Nicot (2009a) and Nicot and Potter (2007) used a range of 800– 2000 ft. Generally speaking, 16 40-acre vertical wells ($16 \times 1.7424 \times 10^6$ ft^2 = 1 square mile) translates into seven 4000-ft-long laterals with 1000-ft spacing that could be all drilled from the same pad with a much larger recovery. There seems to be a relationship between lateral length and lateral spacing (Figure 18).

A limiting factor controlling the number of wells drilled every year in a play is the number of drilling rigs available. Figure 22 illustrates a time snapshot in the distribution of drilling rigs in Texas in June 2010. Rigs typically specialize as gas or oil rigs and are binned as a function of the maximum depth they can reach and the type of well they can drill (horizontal vs. vertical), but this level of detail was not included in the study. We estimate that it takes 3 to 6 weeks to drill a vertical section and a lateral in the Barnett and Haynesville, respectively. An average spud-to-release time in the Haynesville was 44 days in early 2010 (LRNL, 2010). Nicot and Potter (2007) estimated an average spud-to-spud time of 1 month in the Barnett, which is currently down to ~3 weeks. Figure 21 demonstrates the high variability in the number of active drilling rigs. Rigs travel from one play to the next and across state lines, depending on demand and on the perceived or actual potential of a play. Figure 21 shows a rig count increasing at a rate of ~100 rigs/yr between Spring 2002 and Fall 2008, then a sharp drop, and a sharper increase rate at ~375 rigs/yr between June 2009 and June 2010. This steep rate is likely due to rigs mothballed near the new drilling sites and being put back in use quickly. As of December 2010, the Barnett Shale play had ~80 rigs, and that number has varied little since early 2009 (multiple issues of PBSN). Most of the previous year, in 2008, the rig count was at ~180 active rigs. The number of frac jobs (that is, water use) is clearly related to the rig count. Nicot and Potter (2007) underestimated the ability of operators to bring in more rigs to the state. Emergence of more efficient rigs will shorten the rotation time between drilling sites and increase the number of boreholes that a single rig can drill in a year. But again, showing the difficulty of making projections, the industry may run out of trained crews to man the rigs.

Details on recycling, refracing, and other approaches are given in Section 5.1.2. We did not try to resolve the surface water– groundwater split for future decades.

3.4.1.2 Tight Formations

Tight gas (for example, the Cotton Valley Formation in East Texas) or other tight formations containing oil (for example, the Wolfberry play in the Permian Basin) are also subject to hydraulic fracturing. The main difference between them and gas shales, from a practical standpoint, is that (1) these tight formations are conventional resources in the sense that they occur in a discontinuous manner and (2) they are not new plays and have been producing gas/oil for years or even decades for the most part. We applied the same approach to compute future water use, as was employed for the gas-shale category. The approach is particularly similar to that used for the Barnett shale, which already has significant production. At the county or field level, we examined the *burn rate* of the reserves as well as the remaining reserves. Coleman (2009) presented a recent historical overview of gas production from tight sandstones.

3.4.1.3 Drilling and Waterflooding of Oil and Gas Reservoirs

Future water use for drilling was estimated at the state level only by assuming water use for shale-gas wells as provided by the literature for several plays (Section 5.2.2) and assuming an average value for the remainder of the wells. The number of wells to be drilled in the future was computed from (1) the oil subcategory for which we used recent work by Galusky (2010) in the Permian Basin; we then applied a multiplier to account for oil production outside of the Permian Basin; and (2) the gas subcategory, for which we used results from the production-based approach for shale and tight-gas plays, and to which we, in turn, applied a multiplier to account for conventional gas production.

Water use for secondary and tertiary oil production is less dependent on the number of rigs because most of the consumption occurs after drilling and during pressure maintenance or enhanced-recovery operations. We assumed that waterflooding activities occur mostly in the Permian Basin, which is also the world center of CO_2 EOR (a WAG process is typically used, in which water is injected behind slugs of CO_2). Estimates in this category are obtained through a combination of historical data, survey results, and knowledge of the industry.

3.4.1.4 Coal

Energy makeup of the state still relies heavily on coal-fired power plants (although some of the coal is imported from out of state), with nuclear energy as a distant second. The complement comes partly from natural gas and oil. As discussed earlier, we assumed a business-as-usual scenario for the coal industry and accepted figures provided by the comprehensive survey of all operators in the state. The main uncertainty resides in the possibility that the industry will start relying on coal imported from western states to feed the coal-fired power plants instead of relying on local lignite resources. Another uncertainty is the possibility of having most depressurization water volumes captured for municipal use or other beneficial use (for example, fracing), in which case mining water use may be different but not the total water use. Such a development is not accounted for in this study.

3.4.1.5 Aggregates

If some mining activities such as oil and gas are independent of the state population because their products are not necessarily consumed in the state, others, such as aggregates and lignite coal, which have high transportation costs, are consumed mostly locally and depend more strongly on the population level in the state, nearby counties, and economic activity. Future aggregate production (and concomitant future water use) is correlated with population growth. Population of the state is predicted to grow by 20 million people, from ~25 million in 2010 to ~45 million in 2060 (both are estimates). We used TWDB population projections, which are slightly different from those of the U.S. Census Bureau, although differences are well below the level of uncertainty brought about by other parameters.

To estimate future aggregate production we relied on extrapolation from historical data and noted that aggregate production is coupled to absolute population level, but also to its derivative through time (population growth). Numerical details of the analysis are given in Section 5.4 (future water use in the aggregate category), but we based extrapolation of production and population on their changes in the past 20 years. In 2008, the amount of crushed stone produced per capita was ~153 Mt/ 24,000,000 people; that is, ~ 6.5 ton/capita/yr. During the same 1-year period, population growth was ~0.5 million people, that is, ~310 ton/capita growth/yr. A similar analysis yields ~4 ton/capita/yr and ~200 ton/capita growth/yr for the sand and gravel category. Extrapolating solely from gross population numbers seems unrealistic. Norvell (2009) used historical data and determined that over a 20-year span (1982–2003), aggregate production was best predicted by a combination of total population and the state gross product (GDP) related to construction. Population and state GDP were both approximately equally weighted in terms of coefficients, but construction state GDP in billions is about twice the population in millions, so its weight is, in essence, higher. The report states "*coefficients indicate that on average as population grows by 1000 people, aggregate output in Texas rises by 4,800 tons (i.e., about 4.8 tons per person), and every $1 million increase in gross product for the construction industry results in an additional 5,760 tons of aggregate extracted.*" The figure of 4.8 t/capita/yr is somewhat lower than the average of our two figures, although plainly consistent with them. Given the time and budget constraints to develop this report, we assume that population growth is somewhat equivalent to the economic output variable of Norvell (2009) and other economic analyses. As a whole, additional people will need houses, highways, and other facilities at a higher rate than people already living, the state supporting the assumption that population growth has a greater impact on aggregate consumption than the population parameter itself:

$$Aggr.Prod. = 2/3 \times Pop. \times Rate1 + 1/3 \times Pop.Growth \times Rate2 \qquad \text{Equation 2}$$

The population-growth component stays at a stable absolute level because growth rate itself stays stable, whereas the population as a whole component keeps increasing in absolute value and as a fraction of the total.

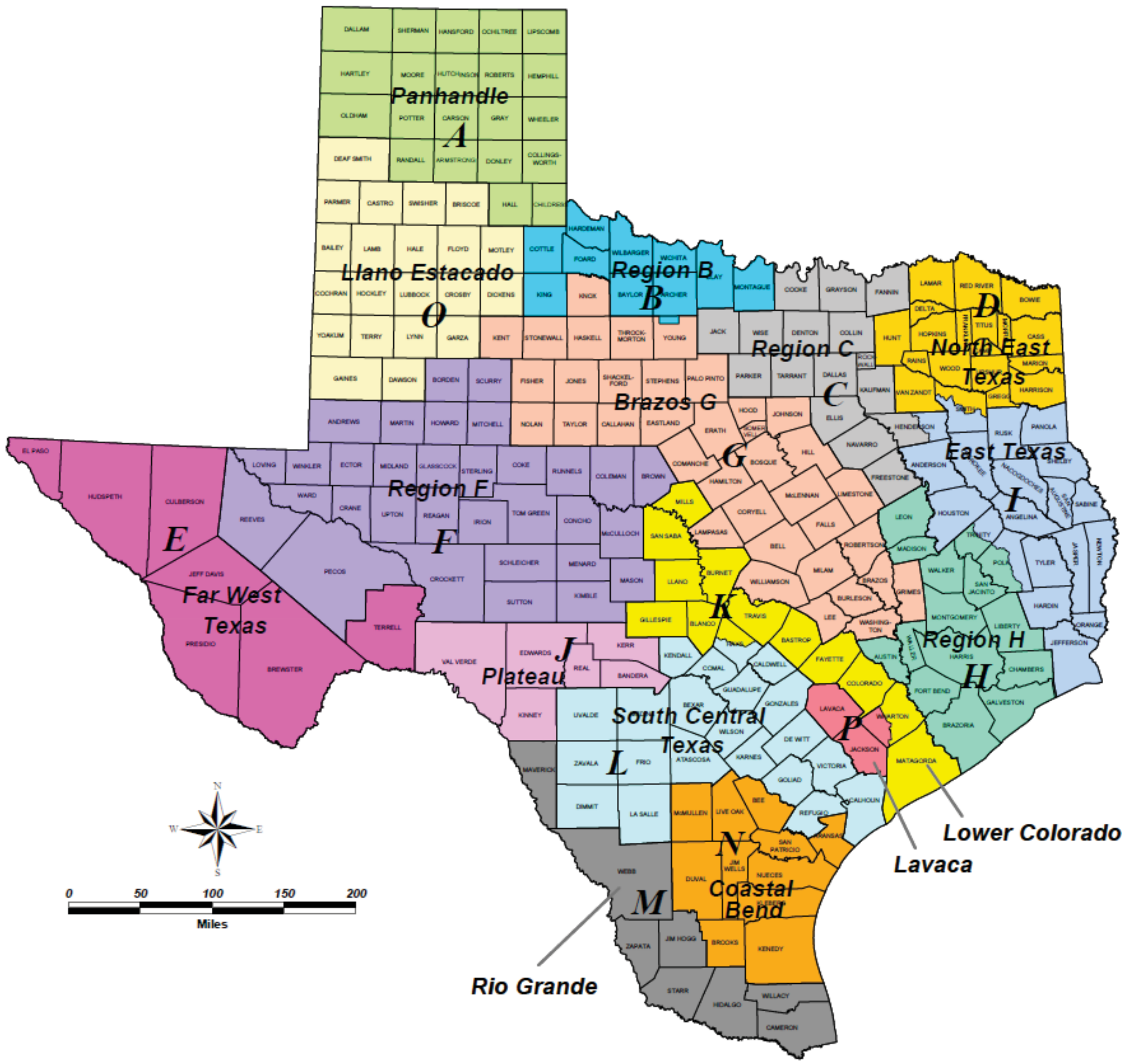
Once aggregate production at the state level has been determined, we could apply water-use coefficients already gathered in the previous phase of the work to obtain aggregate water use at the state level. Difficulties arose when we tried to distribute state-level water use to individual counties. In order to limit distortions due to the impact of artificial administrative boundaries (for instance, large growth in a county next to that of the aggregate facility, as we did for current crushed-stone water use), we used a simplified radius of influence technique (county of interest and neighboring counties) to apportion water use, whereas sand and gravel production is assumed consumed within the county in which it is produced. We also assumed that aggregate production and consumption strictly stay within state lines. Counties on state lines do not take into account growth on the other side of the state line or the possibility of importing aggregate from out of state. Future water used for those few counties for which we have reasonable knowledge of production and water use was extrapolated from current use and county population projection according to Eq. 2, with the caveat presented later for urban counties. The remainder of state-level water use was distributed among the remaining counties. Lack of data on individual facilities compelled us to use this approach involving averages that may not necessarily give accurate results at the county level. This lack of data is made worse by the high variability in reported water use. If need be, when new sources of information update average water use, the figures given in this report can simply be scaled by a more accurate value.

Because we based our projections on population growth, aggregate use will also include aggregate recycling (presumably classified in the manufacturing category) and export/import balance from neighboring states. We assumed that both are small and will stay small. Some aggregate recycling has been estimated at 5% of total consumption in 1998 across the nation (USGS, 2000). More recent figures put the amount at 1.7 million tons (USGS, 2010) in Texas (<1%). In addition, we did not assume more water recycling than is currently done. Nor did we include reclamation and irrigation water use in aggregate water use (at least not explicitly).

We also assumed that the same counties will keep operating the same facilities or their extensions, particularly crushed-stone facilities, because of the difficulty to gain acceptance from the public of new large facilities (Robinson and Brown, 2002, p. 3). The main exception concerns urban counties. These authors stated that "*although development and maintenance of infrastructure in metropolitan areas require a continuing supply of aggregate, aggregate production rates begin to fall in counties when the population density reaches approximately 1000 people per square mile. At population densities of about 2000 people per square mile, production of aggregate in many counties may diminish significantly.*" One of the problems of linking population growth and aggregate output at the county level is that counties with high growth are likely to crowd out mining operations and rely on neighboring counties for their aggregate needs. This scenario is assumed true for Travis County in the crushed-stone category and for Bexar, Dallas, Harris, Tarrant, and Travis Counties in the sand and gravel category.

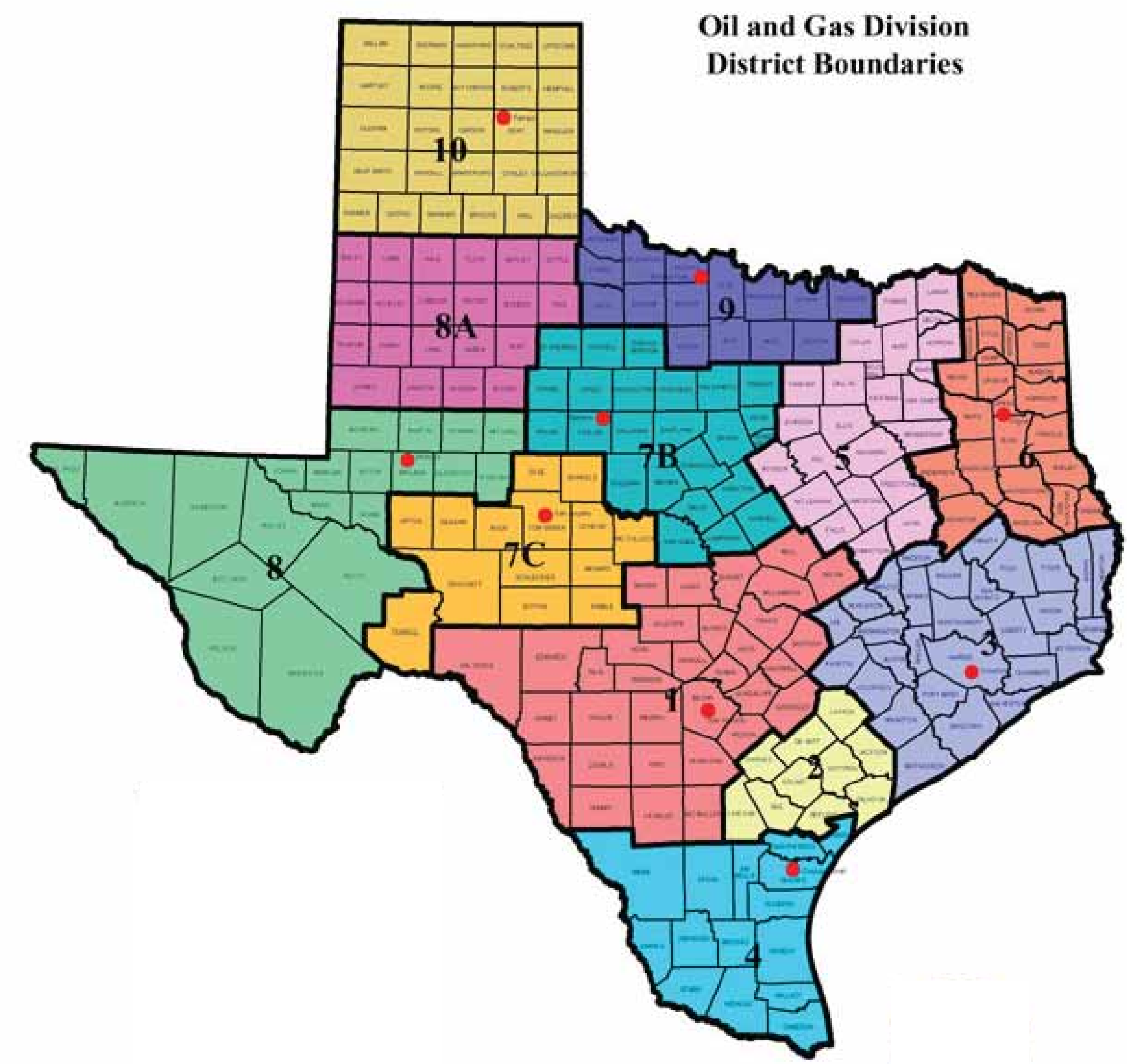
3.4.1.6 Other Mineral Commodities

As was done in the Current Water-Use Methodology Section, future water-use methodology for other mined substances is done on an ad hoc basis. Specific details are given in the Current Water Use section (Section 4.5).



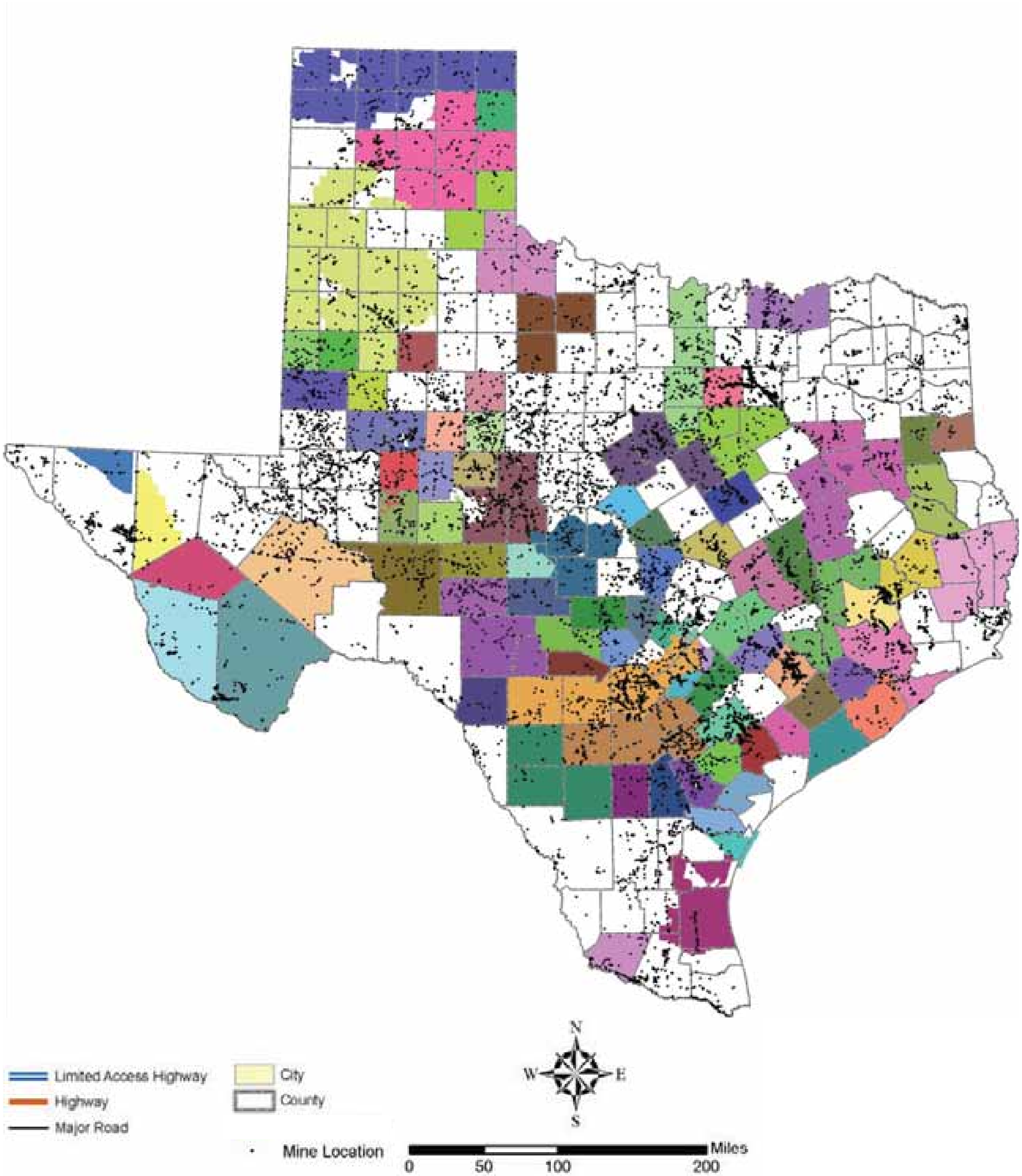
Source: TWDB - http://www.twdb.state.tx.us/mapping/maps/pdf/sb1_groups_8×11.pdf

Figure 8. Map of Regional Water Planning Groups



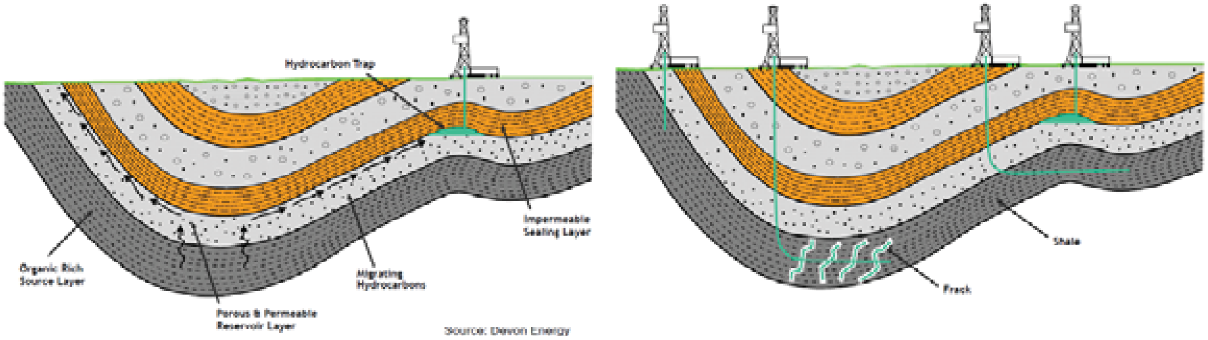
Source: RRC website http://www.rrc.state.tx.us/forms/maps/ogdivisionmap.php

Figure 9. State map of RRC districts



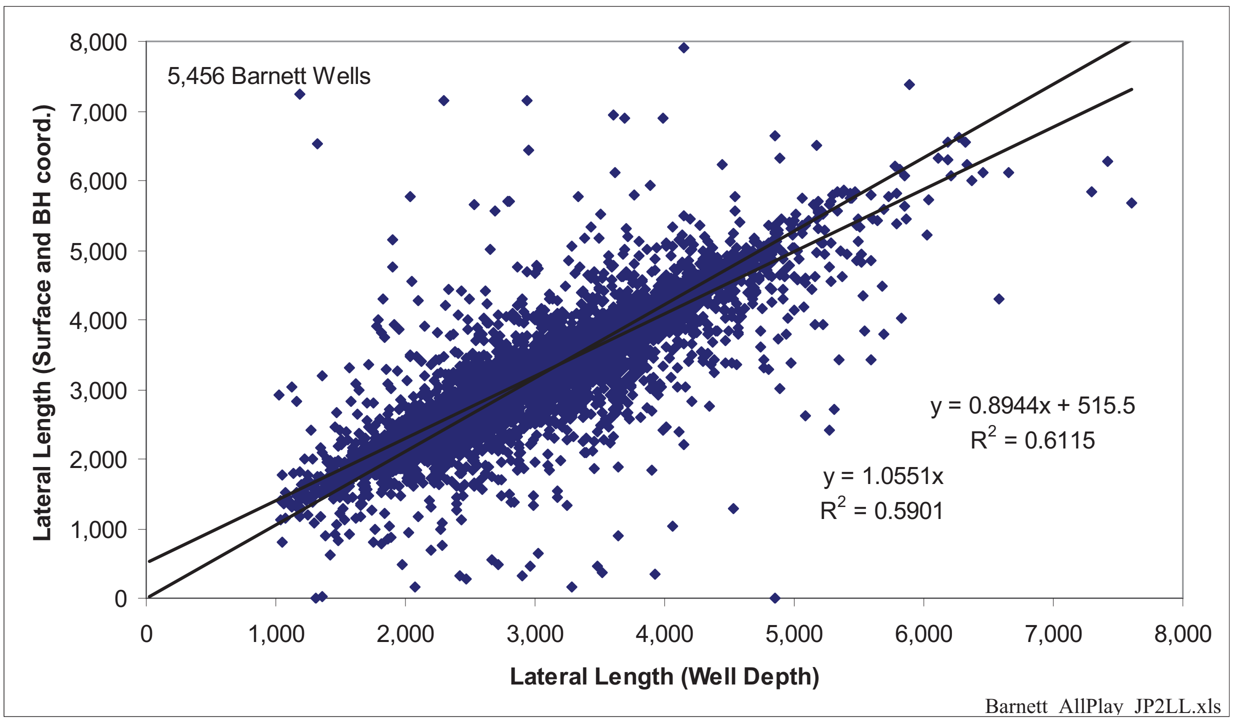
Source: TWDB (GIS coverage of GCDs) and TCEQ SWAP

Figure 10. GCDs and active and inactive mine locations in the TCEQ SWAP database



Source: Devon Energy website

Figure 11. Trap vs. resource play



Note: equation for best fit and fit through the origin are shown. Only those points for which both values are available are shown. Plot also provides estimate of typical and maximum lateral length.

Figure 12. Comparison of the two approaches to compute lateral length

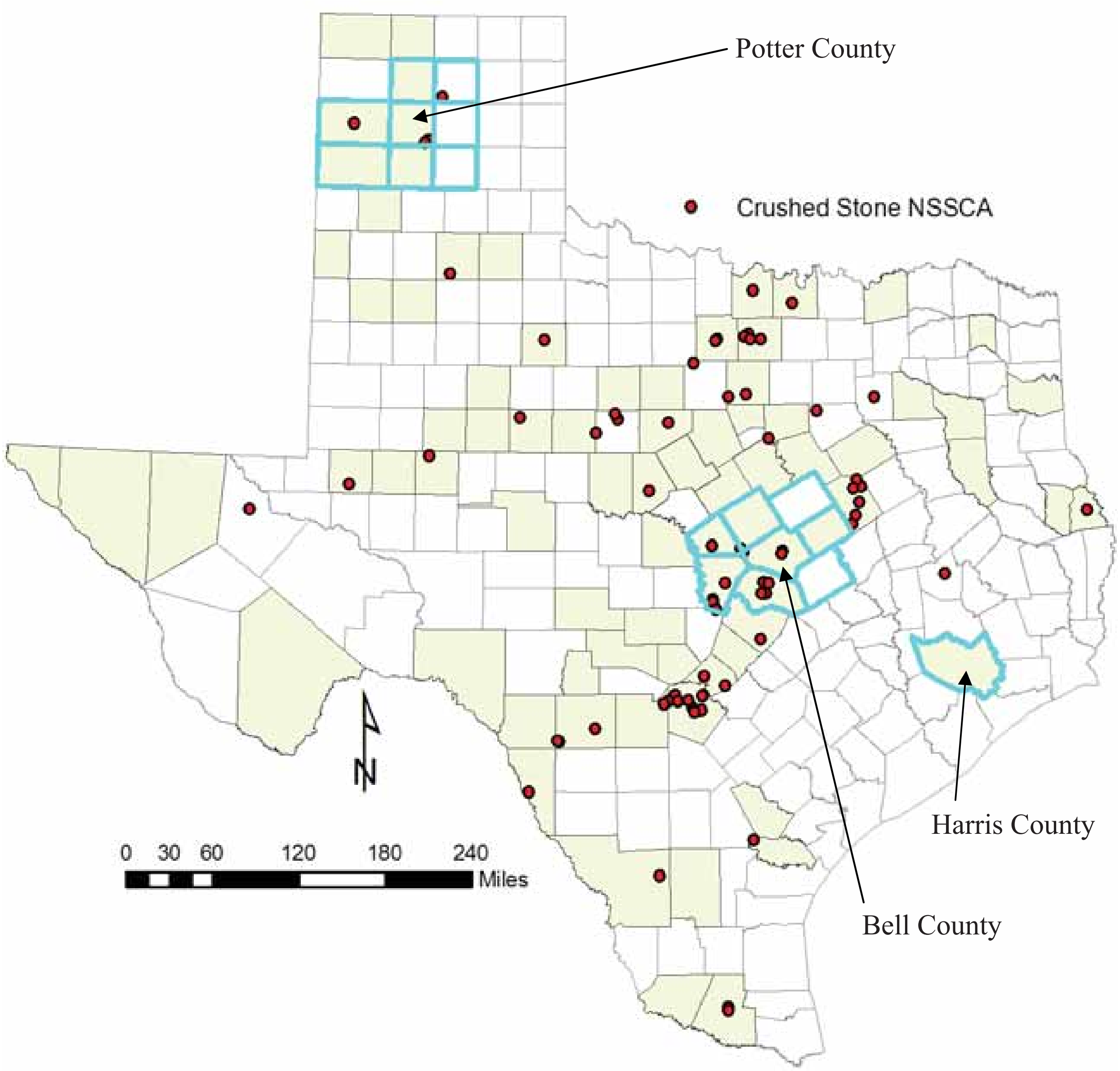
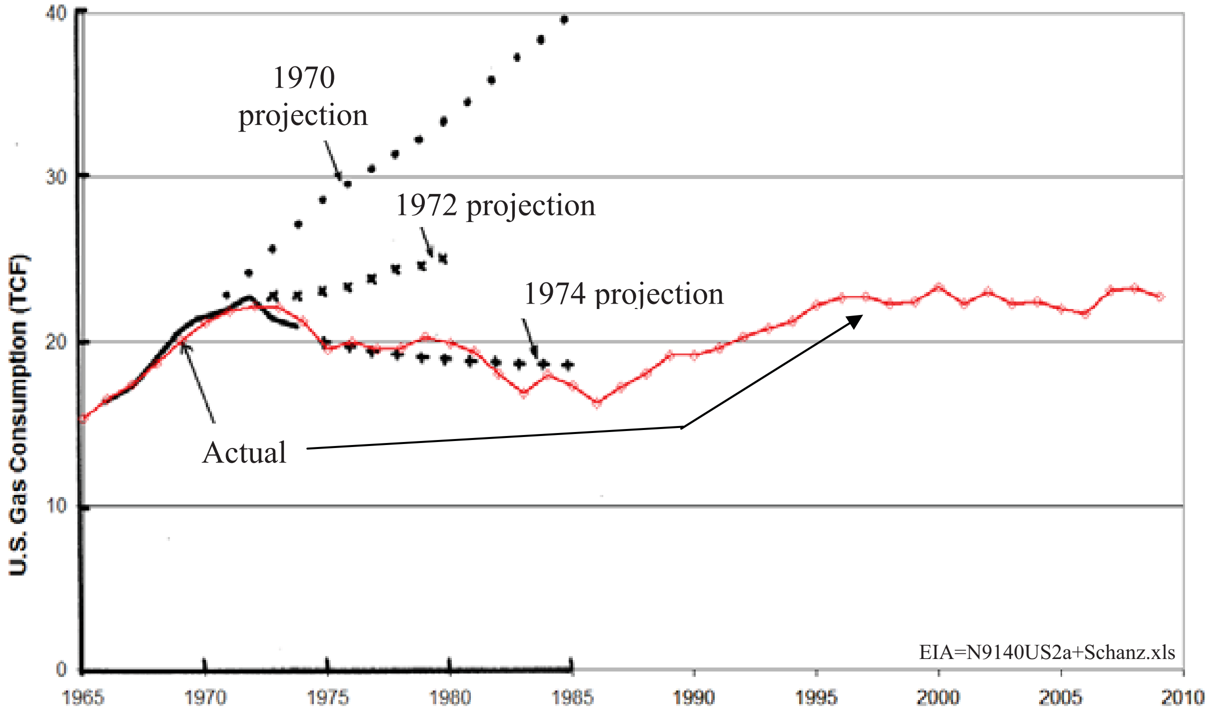
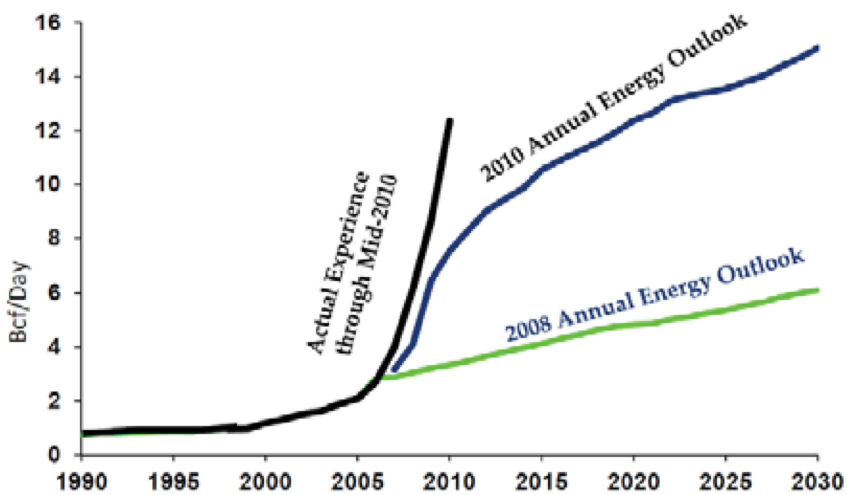


Figure 13. Map illustrating population-count mechanism for crushed-stone facilities.
Also showing Potter County and relevant surrounding counties; Bell County and surrounding counties; Harris County count with no NSSGA facility does not include surrounding counties.



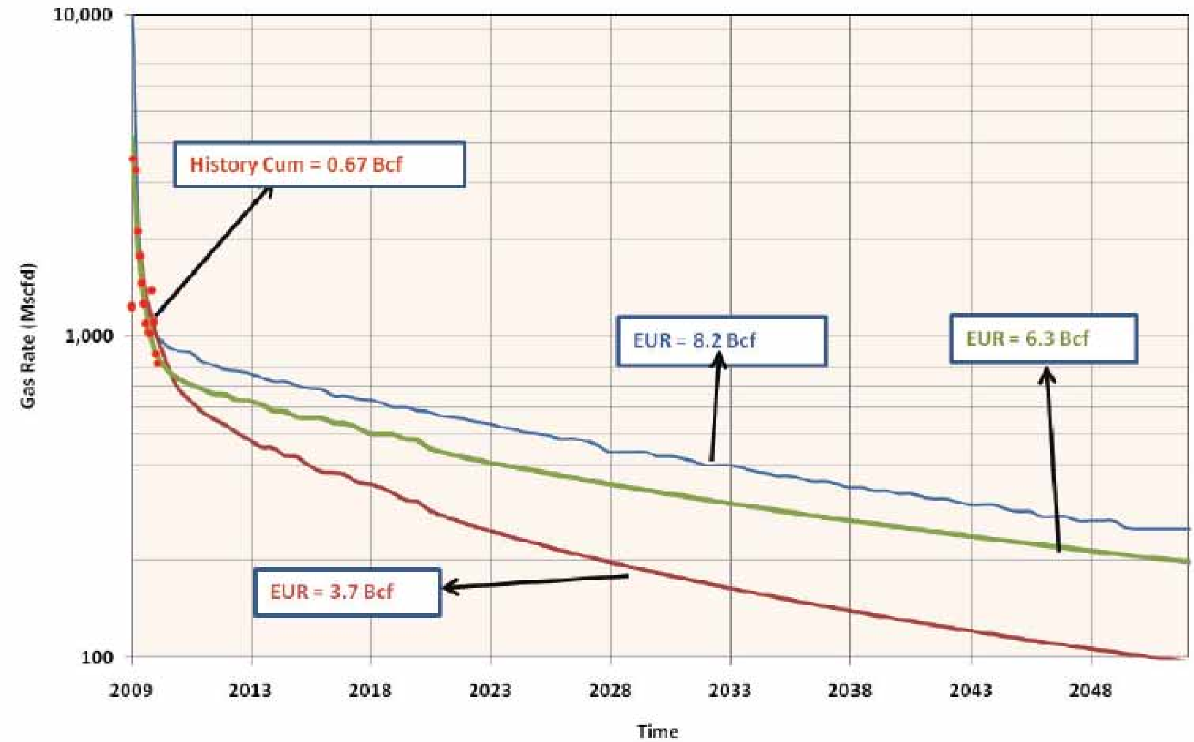
Source: Schanz (1977) and EIA website (gas consumption)
Note: figure superimposes plot from Schanz (1977) showing actual data until 1974 and projections done in 1970, 1972, and 1974 and actual data (red line) until 2009 downloaded from EIA website.

Figure 14. Making long-term projections is an art—part 1



Source: presentation by R. Smead, Navigant
http://www.naseo.org/events/winterfuels/2010/Rick%20Smead%20Presentation.pdf

Figure 15. Making long-term projections is an art— part 2



Source: modified from Vassilellis et al. (2010, Fig. 4)

Figure 16. Multiple EUR projections extrapolated from limited early data for an Eagle Ford well

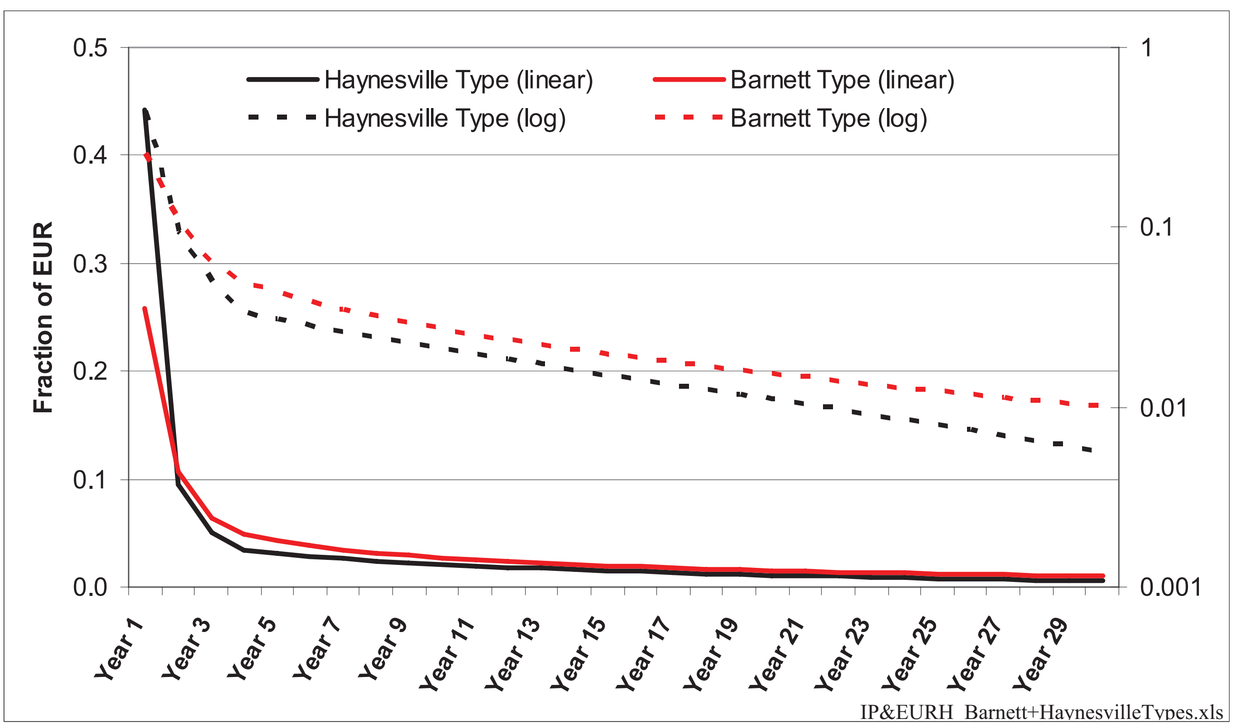
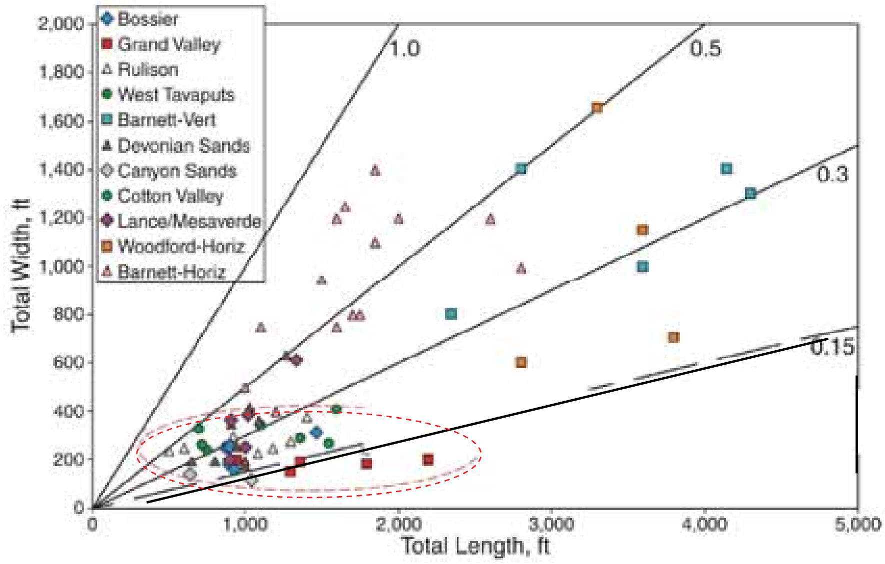
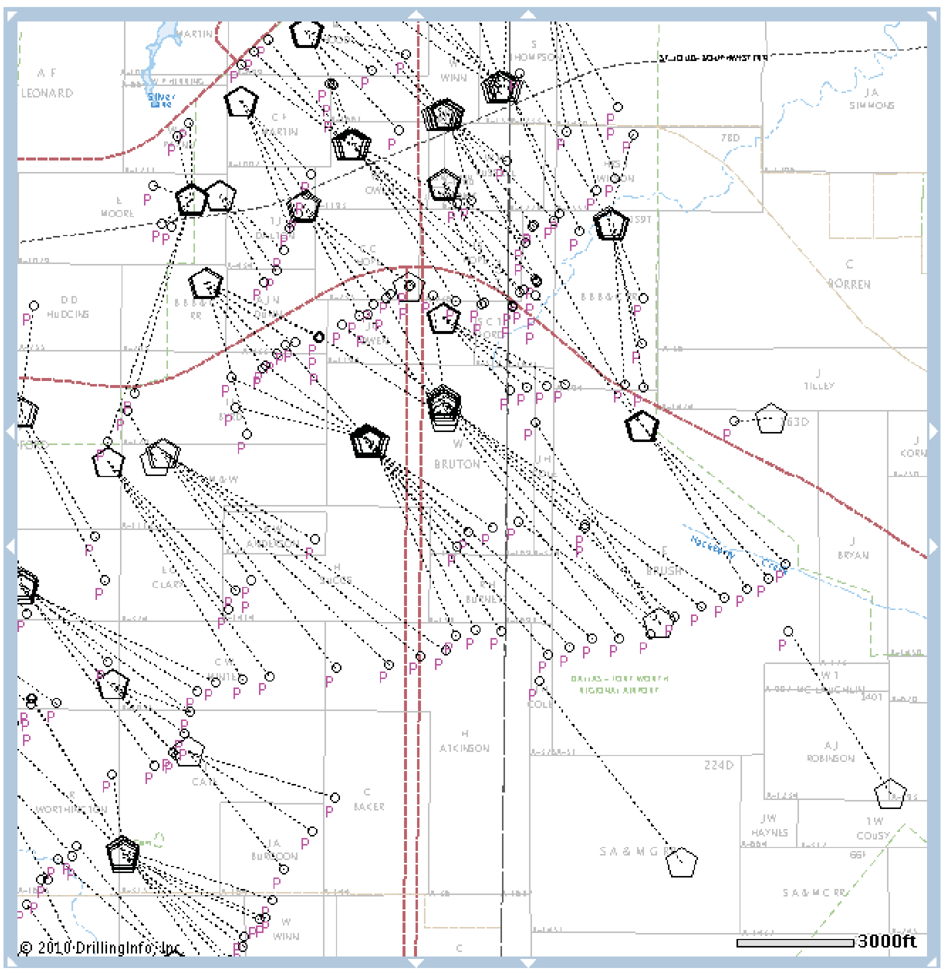


Figure 17. Decline curves assumed in this study (production-based approach)



Source: Chong et al. (2010) modified from Cipolla et al. (2008)

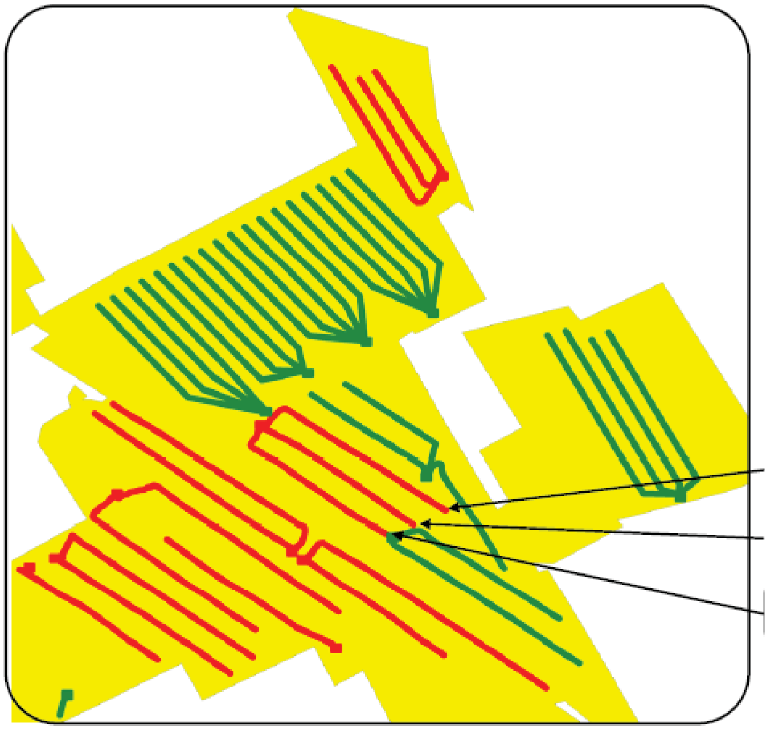
Figure 18. Lateral length vs. estimated impacted width.



Note: map displays an average drainage area of ~80 acres / well (laterals not pads) where laterals are dense.

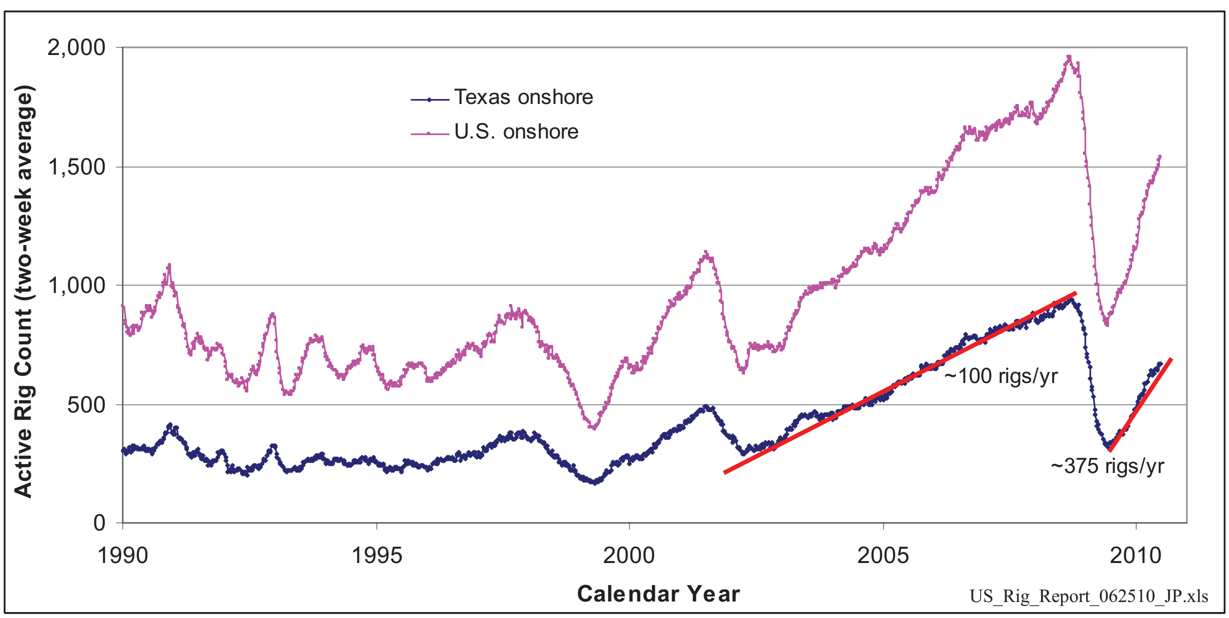
Source Courtesy of DrillingInfo

Figure 19. Example of Barnett Shale density of laterals (Dallas-Tarrant county line)



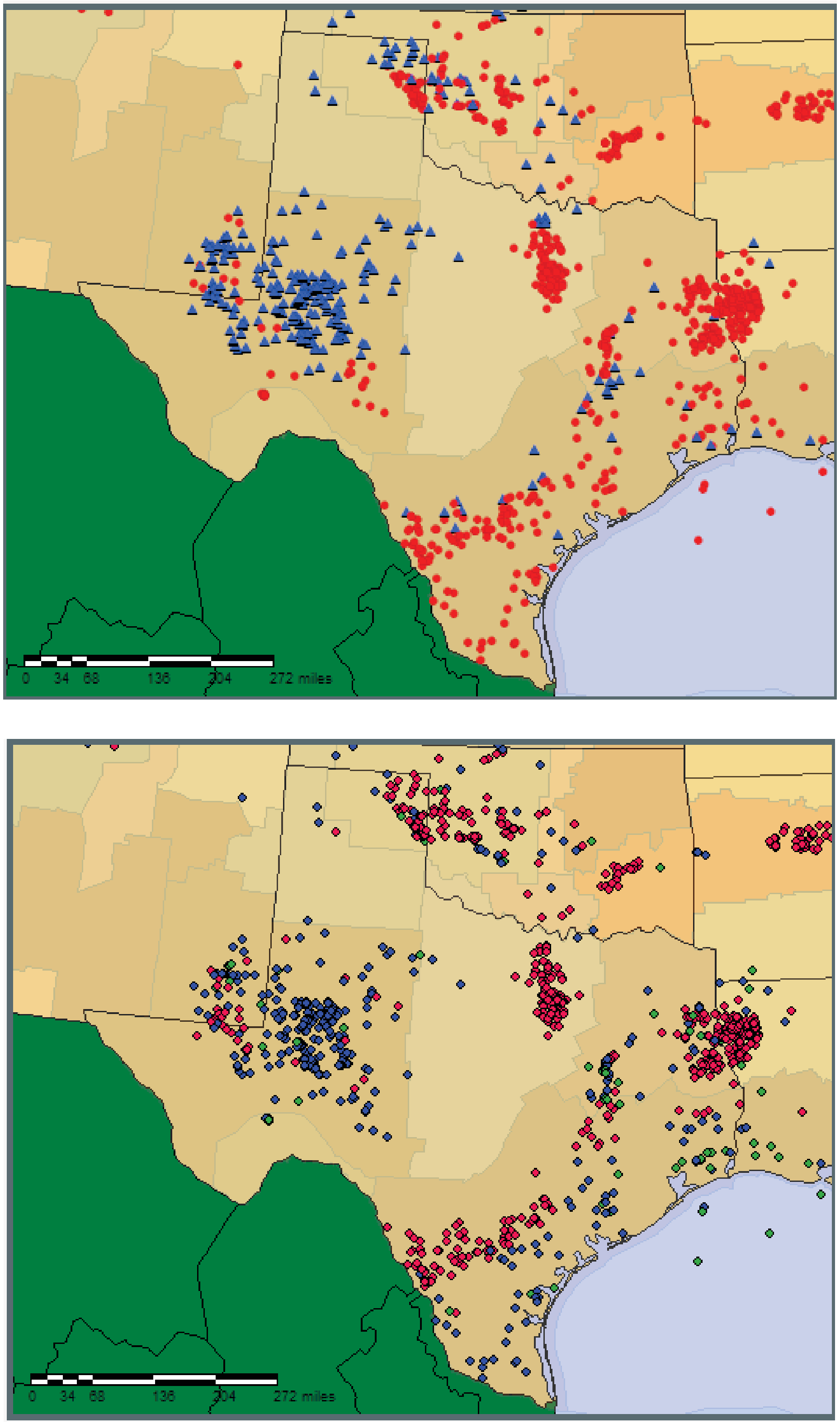
Source: Courtesy EOG Resources— Presentation to analysts, January 2008
Note: 16 completed wells (red trace) and 27 to be completed (planned in 2008)

Figure 20. Example of Barnett Shale density of laterals (Johnson County)



Source: Baker-Hughes website

Figure 21. Active rig count in the U.S. and Texas from 1990 to current



(a)

(b)

Source: Baker-Hughes website

Figure 22. Rig count as of June 25, 2010. (a) Red and blue dots denote gas and oil rigs, respectively; (b) red, blue, and green diamonds denote horizontal, vertical, and directional rigs.

4 Current Water Use

We chose the year 2008 as representative of *current use* for two reasons: (1) this work started in 2009, and not all the 2009 data were yet available, and (2) 2009 is not a representative year because of the economic slowdown; 2008 is the last year with water use more representative of what might occur in the future and is thus more appropriate as a starting point for projections.

4.1 Shales and Tight Sands

The literature on gas shales and related water use is abundant (for example, Arthur et al., 2009; U.S. DOE, 2009) and will not be reprised herein. Several reports also detail current practices in well-pad construction, drilling, completion, and well stimulation for fraced wells. (Veil, 2007; U.S. DOE, 2009; Veil, 2010).

4.1.1 Location and Extent

Section 4.1 provides an overview of the different shale and tight-sand plays in Texas. Present in all corners of the state (Figure 23, Figure 24), they include the Barnett Shale, Haynesville and Bossier Shales, Eagle Ford Shale, Barnett Shale in West Texas, and Woodford Shale, as well as liquid-rich plays such as the Granite Wash in the Anadarko Basin and the Wolfberry in the Permian Basin, the Bossier, Travis Peak and Cotton Valley Tight Sands in East Texas, and multiple formations in South Texas. U.S. DOE published a primer (U.S. DOE, 2009) summarizing the state of knowledge on fracing of gas shales and other tight formations. Good general background can also be found in PGC (2009, p. 179–192). They exist in all major basins of the state (Figure 26).

In terms of approximate numbers, as given by the scoping analysis of the 2005–2009 period, number of frac jobs was >2,500, >4,500, >6,200, >6,600, and >3,700, respectively, from 2005 through 2009, for a total of >23,500 frac jobs (2009 might be incomplete, data downloaded in April 2010). The “>” is used because a nonnegligible fraction of frac jobs is described as such but with no corresponding water-use amount in the IHS database, although it does show proppant use or long laterals, etc. These “zero” water-use wells are assigned water-use amounts as described in the methodology section. In this 5-year period, ~100 formations were fraced (Table 6), but the bulk of the frac jobs are limited to a few formations (Figure 25). In 2005, the Barnett Shale had the larger number of frac jobs (~42%), followed by the Cotton Valley of East Texas (~23%; ~27% if Travis Peak is added), Granite Wash (Anadarko Basin) at ~13%, and Wolfberry in the Permian Basin at 7%. In 2006, the order had not changed: Barnett (~57%), Cotton Valley and some Travis Peak (16%), Granite Wash (~10%), and Wolfberry (~6%). In 2007, the Barnett Shale was still dominant (~62%), but followed by Granite Wash (14%), Cotton Valley and Travis Peak (15%), and then Wolfberry (5%). In 2008, the Barnett Shale still led (~40%), but Wolfberry collected ~15%, followed by Cotton Valley and Travis Peak (~11%) and Granite Wash (~7%). In addition, there is a clear increase in geographic coverage because other plays in the Permian Basin (Grayburg, Canyon, Caballos, Clear Fork), Anadarko Basin (Cleveland), and South Texas (Vicksburg, Olmos) are starting to be fraced. The year 2009 saw an overall decrease in the number of frac jobs, but they are still led by the Barnett Shale (~41%) and Wolfberry (19%). Other previously strong plays, such as Granite Wash (6%) and Cotton Valley (~6%), lose rank as newer fraced plays such as in the Pennsylvanian and Permian of the Permian Basin keep growing in terms of the number of frac jobs. Many plays all around the state go beyond the testing stage as tens of frac jobs are performed on 10+ additional formations. Note that this ranking is done in terms of number of frac jobs, which may or may not be the same as ranking for water use.

To address the last comment and as a final check on the trends in this fast-evolving field, we performed an analysis of all wells completed in 2010 to date (early November 2010). Among a total of 10,268 completed wells, 7650 (~75%) received a treatment making use of water, including ~3850 wells (~37% of total) using >0.1 Mgal of water (Table 7 and Table 8). The minimum amount of water used is over 6 billion gallons or ~18.5 thousand AF, almost ⅔ of it in the Fort Worth Basin Barnett Shale.

4.1.2 Gas (and Oil) Shales

This report does not comprehensively document the different formations described in this section, but rather focuses on water use and mostly provides information needed to access it and make projections. Water use is different in each play and is impacted by local geological factors. There are three very active "shale gas" (oil is also produced) plays as of end of 2010 in Texas: Barnett, Haynesville/Bossier, and Eagle Ford shales. To them can be added the Pearsall Shale, Barnett and Woodford Shales in the Permian Basin, and perhaps the Bend Shale in the Palo Duro Basin in the Texas Panhandle. A map by EIA (Figure 23a) does display them all but with inaccurate footprints.

4.1.2.1 Barnett Shale

The Barnett Shale (Figure 28) is the formation where the current technology was pioneered, and it has been producing gas since the early 1990s. Productive Barnett Shale is found at depths between 6,500 and 8,500 ft in North-Central Texas, with a net thickness ranging from 100 to 600 ft. Pollastro et al. (2007) and Galusky (2009) provided an update to information presented in Nicot and Potter (2007), whereas Martineau (2007) summarized the history of the play. The Mitchell Energy / C. W. Slay #1, a vertical well, went into production in June 1982, has produced over 1.7 Bcf of gas, and is still producing after 28+ years. It is given credit as the first Barnett Shale producer (PBSN, Nov 1, 2010). As slick-water-frac and horizontal-drilling technologies were being perfected, the balance of wells initially favoring vertical wells is now disproportionally in favor of horizontal wells (Figure 27), with >2500 horizontal wells and only 100+ vertical wells completed in 2008. Figure 29 illustrates the transition and its impact on water use. There is a clear jump in the average water use in 1998 for both horizontal and vertical wells to ~1.5 million gallons/well. The amount of water used then stays more or less constant through time for vertical wells but with a much larger variance, whereas it keeps increasing for horizontal wells until it reaches a current average of 3–4 million gal/well. Progress in the technology is also visible on the histograms of the frac water volume, with a clear bimodal distribution (Figure 30a). The most recent vertical fracs (Figure 30c) display a well-behaved normal distribution centered on ~1.3 million gal/well. A histogram of horizontal well-water use, depicted in Figure 31a, also shows a well-behaved distribution, but with a broad mode and a very large range (from <1 million to >8 million gal/well). However, when reported to the total lateral length (Figure 31b), water intensity seems normally distributed, with a mean/mode of ~1000 gal/ft. Proppant amount distribution is biased toward lower values, with a long tail toward high proppant amount (Figure 32a and Figure 33a). The observation remains true in a plot of proppant loading (Figure 32b and Figure 33b).

Core counties consist of Denton, Johnson, Tarrant, and Wise Counties. Production has been relatively stable in the past 2 years at ~5 million Mcf/d (PBSN, Nov 1, 2010) although the so-called “combo” play in Montague and Clay Counties in the oil window has seen a recent increase in activity. Other counties (Stephens, Shackelford) south of the core area and in the oil window also seem to stir some interest. Other counties producing from the Barnett are Archer, Bosque, Comanche, Cooke, Coryell , Dallas, Eastland , Ellis, Erath, Hamilton, Hill, Hood, Jack , Palo Pinto, Parker, and Somervell Counties. In 2008, water use in the Barnett Shale was ~25 thousand AF (Table 9). Table 9 also presents completion water use at the county level, with Johnson County displaying the highest water use at ~8.5 thousand AF, followed by Tarrant County at 5.1 thousand AF, and Denton, Wise, and Parker Counties at 2.8, 2.1., and 1.8 thousand AF, respectively.

4.1.2.2 Haynesville and Bossier Shales

The productive interval of the Haynesville Shale of Jurassic age is >10,000 ft deep. It is an organic-rich, argillaceous, silty, calcareous mudstone that was deposited in a restricted, intrashelf basin in relatively shallow water (for example, Spain and Anderson, 2010). The current core area (Texas section) includes Harrison, Panola, Shelby, and San Augustine Counties, but the play also covers Angelina, Gregg, Marion, Nacogdoches, Rusk, and Sabine Counties (Figure 34). Typical thickness of the Haynesville Shale ranges between 300 and 400 ft in western Louisiana and 200 and 300 ft in Texas, at burial depths between 11,000 and 14,000 ft. Further west, the shale transitions to the so-called Haynesville carbonates, which are known for their excellent production from carbonate shoals and pinnacle reefs in the East Texas Salt Basin (Hammes, 2009; Hammes et al., 2009). The Haynesville Shale is overpressured, increasing the amount of gas per unit rock relative to a normally pressured shale.

The first year with significant fracing water use was 2008 (Figure 35), before which date any frac was mostly exploratory in nature. The few vertical wells stimulated in the early years of 2000 (Figure 36) probably targeted carbonate facies. Currently the bulk of wells are horizontal, with a wide range of water use from <1 million to >10 million gal/well (Figure 37a). Water intensity (Figure 37b) is not as clearly defined as it was in the Barnett Shale because of the much smaller sample size, but it stays in the same 1000 to 1200 gal/ft range (we used 1100 gal/ft). Proppant loading is higher on average than that in the Barnett Shale (Figure 38). As of October 2010, the IHS database contained ~100 wells of which ~50 of which have water-use information. After we corrected for obvious typos by assessing water-use intensity (gal/ft) and proppant loading (lb/gal), the total reported water use to date is ~260 million gal. Assigning reasonable water-use values to wells with missing data (through knowledge of proppant amount and/or lateral length), total water use to date (2008 to ~mid-2010) is ~0.5 billion gal or 1.5 thousand AF, 7% of which (0.1 thousand AF) was used in 2008, 50% (0.75 thousand AF) in 2009, and 43% (0.65 thousand AF) during the first ~8 months of 2010.

Groundwater–surface water split is unclear in Texas. However, Louisiana parishes bordering the Texas state line, where gas production started, are also part of the Haynesville core. Initially frac jobs relied heavily on the local groundwater resources of the Carrizo-Wilcox aquifer (Hanson, 2009) but, thanks to a grass-root effort, the bulk of the water use has shifted to surface water (Gary Hanson, LSU Shreveport, personal communication, 2010).

The Bossier Shale directly overlies the Haynesville Shale and represents distal parts of the overlying Cotton Valley siliciclastic wedge. The upper Bossier Shale, dominated by siliciclastics, is not as overpressured, is less organic rich, and contains less TOC than the Haynesville Shale (Hammes, 2009; Hammes and Carr, 2009). The RRC webpage describing the Haynesville combines Haynesville and Bossier, owing to a terminology issue.

4.1.2.3 Eagle Ford Shale

The Eagle Ford Formation of Late Cretaceous age covers a large section of South Texas all the way to East Texas, where it meets the deltaic deposits of the Woodbine Formation of equivalent age, as depicted in the schematic cross section of Figure 39. It lies below the Austin Chalk and is probably the source of its hydrocarbon accumulation. Located at a depth of 4,000–11,000 ft, the play is slightly overpressured (pressure gradient of 0.43 to 0.65 psi/ft; Vassilellis et al., 2010), making it more attractive because of the higher initial production rates. Most current interest is focused on the South Texas section of the Eagle Ford (Figure 40 and Figure 41). The discovery well was drilled by Petrohawk in 2008 in La Salle County (PBSN, Sept 20, 2010). The formation produces natural gas, condensate, and oil. Earlier wells were vertical, located in Central Texas (Brazos, Burleson Counties), and looking for oil. The Central Texas play is somewhat disconnected from the South Texas play (from the Mexican border to Gonzales and DeWitt Counties) by the San Marcos Arch, a constant higher-elevation structural feature (Figure 39). The Eagle Ford Shale contains oil updip, gas downdip, and gas and condensates in between. The "shale" is carbonate rich, up to 70% calcite (Cusack et al., 2010, p. 171), much higher than that of the Barnett Shale, which makes it more prone to fracing. The play is still too young to determine the location of the core area, if it exists, but most of the fracing has taken place in Dimmit, LaSalle, and Webb Counties.

As of October 2010, the IHS database contained ~270 wells, 174 of which have water-use information (Figure 42), almost all of them horizontal (Figure 43). The average frac water amount is higher than either the Barnett or Haynesville (Figure 44a), ranging from ~1 to >13 million gal/well. A histogram of water intensity shows that this shale is not as well behaved as the two previous shales (Figure 44b). We used an average of 1250 gal/ft. Total proppant amount being correlated to total water use is higher than in the Barnett and Haynesville (Figure 45a), but the proppant loading lies in between (Figure 45b). After correcting for obvious typos by assessing water-use intensity (gal/ft) and proppant loading (lb/gal), we found the total reported water use to date to be ~977 million gal. Assigning reasonable water-use values to wells with missing data (through knowledge of proppant amount and/or lateral length), we found total water use to date (~mid-2008 to ~mid-2010) to be 1.43 billion gal, or 4.4 thousand AF, 3% of which was used in 2008 (0.13 thousand AF), 37% (1.6 thousand AF) in 2009, and 60% (2.6 thousand AF) during the first ~8 months of 2010.

4.1.2.4 Woodford, Pearsall, Bend, and Barnett-PB Shales

The extent of the Woodford Formation of Devonian age is shown in Figure 46. It covers most of the Permian Basin and a small area of what would become the Central Basin Platform. It can be as thick as 600 ft in Loving and Winkler Counties but radially decreases to <100 ft outward to subcrop boundaries. In the Delaware Basin depth can reach 15,000 ft, whereas shale is ~7,000 to 9,000 ft deep in the Midland Basin. The main current target in the Anadarko Basin in Oklahoma is also shown, where the formation is called the Caney Shale. The Woodford Shale is stratigraphically equivalent to several Devonian black shales in North America, including the Antrim Shale in the Michigan Basin and the Bakken Formation in the Williston Basin (Comer, 1991, p. 6). Overall, maturity of the Woodford in the Permian Basin seems low and unpromising.

The Permian Basin Barnett seems more clay rich and not as organic rich as in the Fort Worth Basin. Figure 47 displays occurrences of the Barnett Shale in the Permian Basin. Its well-known occurrence in the Fort Worth Basin is also displayed. Kinley et al. (2008) provided a description of its most promising occurrences in the Delaware Basin. Thickness of Mississippian-age sediments in the Permian Basin is larger and can be >2000 ft in what would become the Delaware Basin and has a maximum of 700 ft in the Midland Basin.

The Pearsall Shale (Loucks, 2002; Hackley et al., 2009a) is overpressured (Wang and Gale, 2009, p.785–786; Vassilellis et al., 2010) with a pressure gradient of 0.80 to 0.89 psi/ft and is located at depths between 7,000 and 12,000 ft. Water use has been small, given the limited number of wells drilled so far.

Figure 48 displays the surge in drilling starting in 2006 and subsiding in 2009 in those 3 West Texas plays (13 in the Woodford, 12 in the Pearsall, and 22 in the Barnett-PB), with a mix of vertical and horizontal wells (Figure 49). Overall frac water use per well remains small (Figure 50) at <2 million gal per well, probably because the plays have not seen much activity in the past 2 years. Woodford, Pearsall, and Barnett-PB shales total 11.3, 44.2, and 37.8 million gal, respectively, that is, 0.035, 0.14, and 0.12 thousand AF, respectively.

The Bend Shale in the Palo Duro Basin does not seem to live up to earlier expectations, although older BEG and other reports (Dutton, 1980; Dutton et al., 1982; Brister et al., 2002; Jarvie, 2009) have credited the basin with some oil and gas generation potential. There is a scarcity of information on this shale that was described early on as a good prospect. The Palo Duro's Bend Shale tests as thermally mature and reaches gross thicknesses between 500 and 1,000 ft at depths from 7,000 to 10,500 feet (Wagman, 2006). No further work is done in this study on the Bend Shale in the Palo Duro Basin.

4.1.2.5 Conclusions on Gas Shales

Completion water-use shale-gas wells was dominated (99.0%) by the Barnett Shale in 2008 at ~25.5 thousand AF used (Figure 51 and Figure 52), whereas, as detailed in the next section, all tight formations across the state amount to ~10.4 thousand AF (Table 10). In 2008, Johnson County in the Barnett Shale footprint achieved the highest water use at 8.5 thousand AF. Note that this water-use amount includes some recycling, but, as will be described in the Future Water Use section, it is likely to be at the very most 10% and more likely just a few percent. Also note that some of the water used directly originates from stormwater collection systems and is thus not considered surface water or groundwater. However, the fraction of this source among the total water used cannot be determined easily because undoubtedly many surface ponds are filled with landowner-supplied groundwater.

Table 6. List of formations currently being fraced heavily or with the potential of being fraced heavily in the future

Name	Basin/Subbasin	IHS Word Search
Gas Shales:		
Barnett	Fort Worth	Barnett, Ellenburger, Forestburg, Marble Falls, Viola
Barnett PB	Permian	Barnett
Haynesville	East Texas	Haynesville
Eagleford	GC Rio Grande	Eagleford
Pearsall	Maverick	Pearsall
Woodford-PB	Permian	Woodford
Woodford-AB	Anadarko	Woodford
Tight Gas		
Anadarko Basin		
Atoka-AB	Anadarko	Atoka, Bend, Morrow, Granite Wash, Pennsylvanian
Cleveland	Anadarko	Cleveland, Marmaton, Cherokee, Kansas, Caldwell
East Texas Basin		
James	East Texas	James
Pettet	East Texas	Pettet, Pettit, Sligo
Travis Peak	East Texas	Travis Peak, Hosston
Cotton Valley	East Texas	Cotton Valley, Austin Chalk, Taylor, Gilmer, Schuler, Buckner
Bossier	East Texas	Bossier
Smackover	East Texas	Smackover
Fort Worth Basin		
Atoka-FWB	Fort Worth	Atoka, Bend, Morrow, Granite Wash, Pennsylvanian
Permian Basin		
San Andres	Midland+CBP	San Andres, Grayburg (Glorieta, Abo, Wichita)
Spraberry	Midland	Spraberry, Dean
Clear Fork	CBP	Clear Fork
Bone Spring	Delaware	Bone Spring
Wolfcamp	Midland	Wolfcamp
Cisco	Permian	Cisco, Canyon, Strawn, Pennsylvanian
Canyon	Permian	Cisco, Canyon, Strawn, Pennsylvanian
Strawn	Permian	Cisco, Canyon, Strawn, Pennsylvanian
Atoka-PB	Permian	Atoka, Bend, Morrow, Granite Wash
Devonian	Permian	Devonian, Thirtyone, Devonian Cherts, “Silurian”
Canyon Sands	Val Verde	Canyon, Canyon Sands
Caballos	Marathon	Caballos, Tesnus
Gulf Coast Basin		
Vicksburg	Gulf Coast	Vicksburg, Frio, Hackberry
Wilcox	Gulf Coast	Wilcox, Indio, Tucker, Lobo, Sabine Town
Olmos	Gulf Coast	Olmos, San Miguel, Navarro, Escondido

Table 7. Well statistics and water use for 2010

Category	Water Use (% of Total)	Number of Wells (% of Total)	Vertical Wells (% of Wells for Category)
Not fraced	0.0%	25.6%	
Stimulated	1.7%	34.6%	
Anadarko Basin	3.0%	2.2%	28.1%
East Texas Basin	7.8%	5.0%	44.8%
Fort Worth Basin	57.3%	13.6%	2.0%
Gulf Coast	12.3%	4.8%	33.4%
Permian Basin	17.9%	14.1%	94.1%

Table 8. Major active formations in 2010 completed well count

Category	Play/Formation	Count
Anadarko Basin	Granite Wash and others	124
	Cleveland	50
	Marmaton	18
	Others	18
	Total	**210**
Permian Basin	Delaware Group	32
	Spraberry/Dean/Wolfcamp	863
	Clear Fork	232
	Canyon Sands	48
	Caballos/Tesnus	19
	Others	168
	Total	**1362**
East Texas Basin	Cotton Valley Group	200
	Travis Peak	47
	Haynesville/Bossier Shales	115
	Cotton Valley Sands	26
	Others	99
	Total	**487**
Gulf Coast Basin	Eagle Ford	193
	Olmos	68
	Vicksburg	39
	Wilcox/Lobo	64
	Frio	20
	Others	80
	Total	**464**
Fort Worth Basin	Barnett Shale	1295
	Others	23
	Total	**1318**
Stimulated only (<0.1 Mgal)	Permian Basin	2460
	East Texas	315
	Gulf Coast	169
	Fort Worth	132
	Others	733
	Total	**3809**
Not Stimulated	Frio	482
	Wilcox	185
	Austin Chalk	140
	Others	1811**
	Total	**2712**

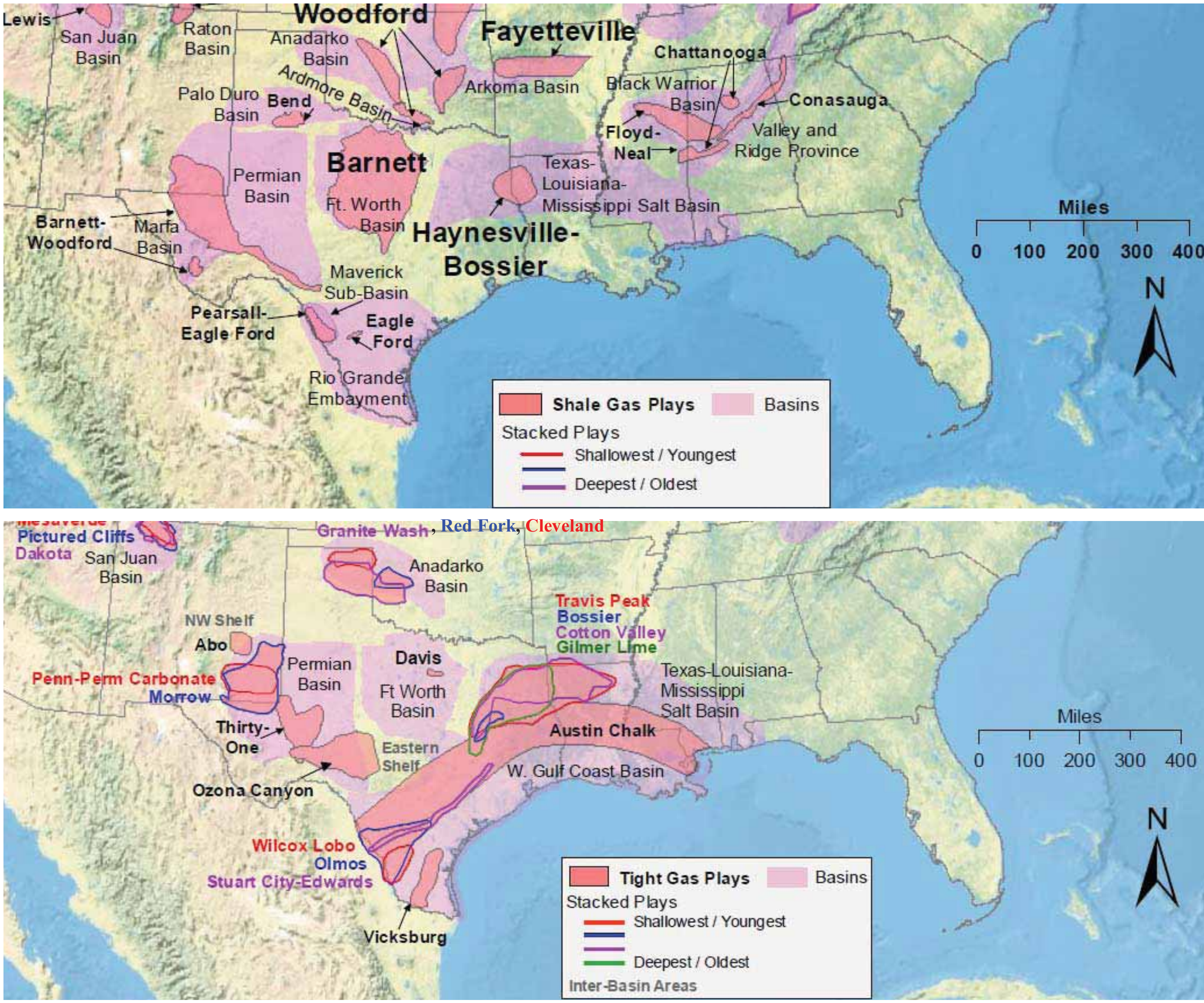
Table 9. County-level shale-gas-completion water use in the Barnett Shale (2008)

County	Water Use (thousand AF)	County	Water Use (thousand AF)
Archer	0.003	Jack	0.085
Brazos	0.008	Johnson	8.459
Burleson	0.034	La Salle	0.010
Clay	0.020	Maverick	0.007
Cooke	0.229	Montague	0.571
Culberson	0.045	Palo Pinto	0.206
Dallas	0.076	Panola	0.036
Denton	2.752	Parker	1.768
Dimmit	0.044	Reeves	0.048
Eastland	0.012	Rusk	0.011
Ellis	0.096	Somervell	0.171
Erath	0.295	Tarrant	5.147
Harrison	0.058	Webb	0.007
Hill	1.137	Wise	2.217
Hood	2.154	**Total**	**25.70**

Table 10. Summary of fracing water use

Play	Water Use (thousand AF)
Barnett Shale	25.45
Haynesville Shale	0.11
Eagle Ford Shale	0.07
Woodford/Barnett PB/Pearsall Shale	0.09
Anadarko Tight Formation	2.22
East Texas Tight Formation	4.26
Permian Basin Tight Formation	3.09
Gulf Coast Tight Formation	0.6
Caballos/Tesnus Tight Formation	0.17
Sum Shale (filtered at >0.001 Mgal)	25.71
Sum Tight Fm. (filtered at >0.001 Mgal)	10.33
Sum All (filtered at >0.001 Mgal)	36.04

MiningWaterUse2008_2.xls

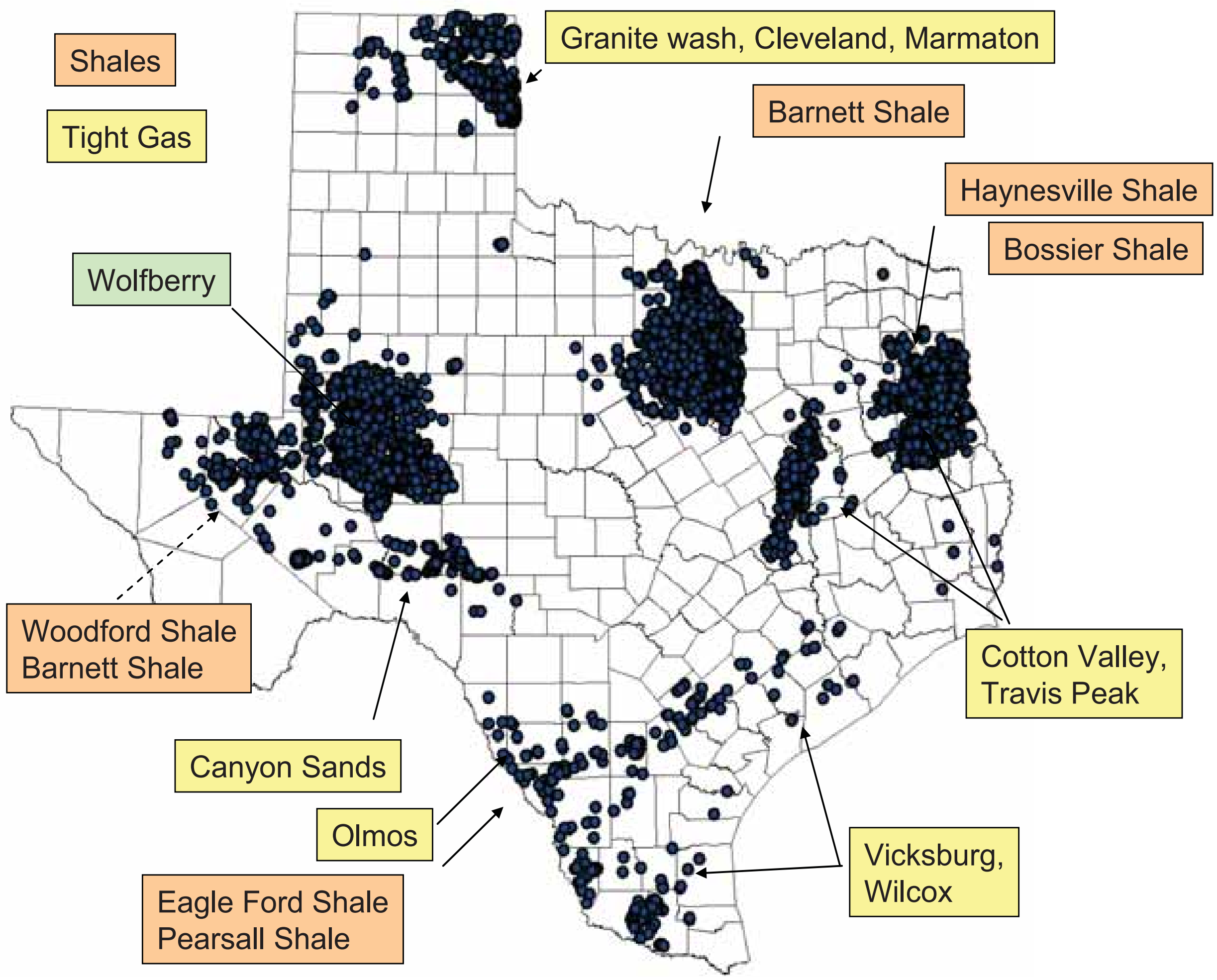


(a)

(b)

Source: EIA website, updated Spring 2010

Figure 23. EIA spatial definition of shale-gas and tight-gas plays



Source: IHS database

Figure 24. Map showing locations of all frac jobs 2005–2009, and main (mostly) gas plays

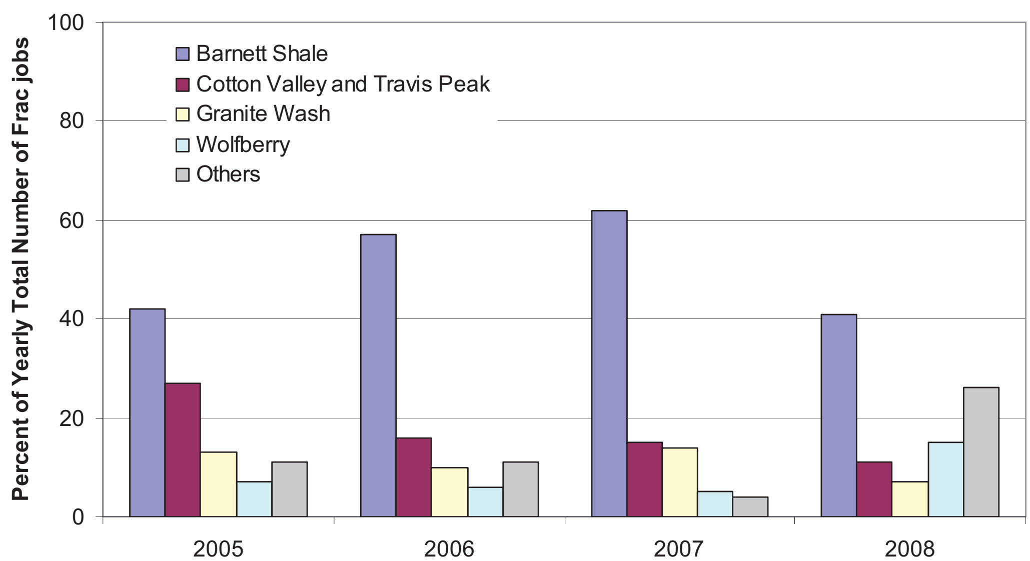
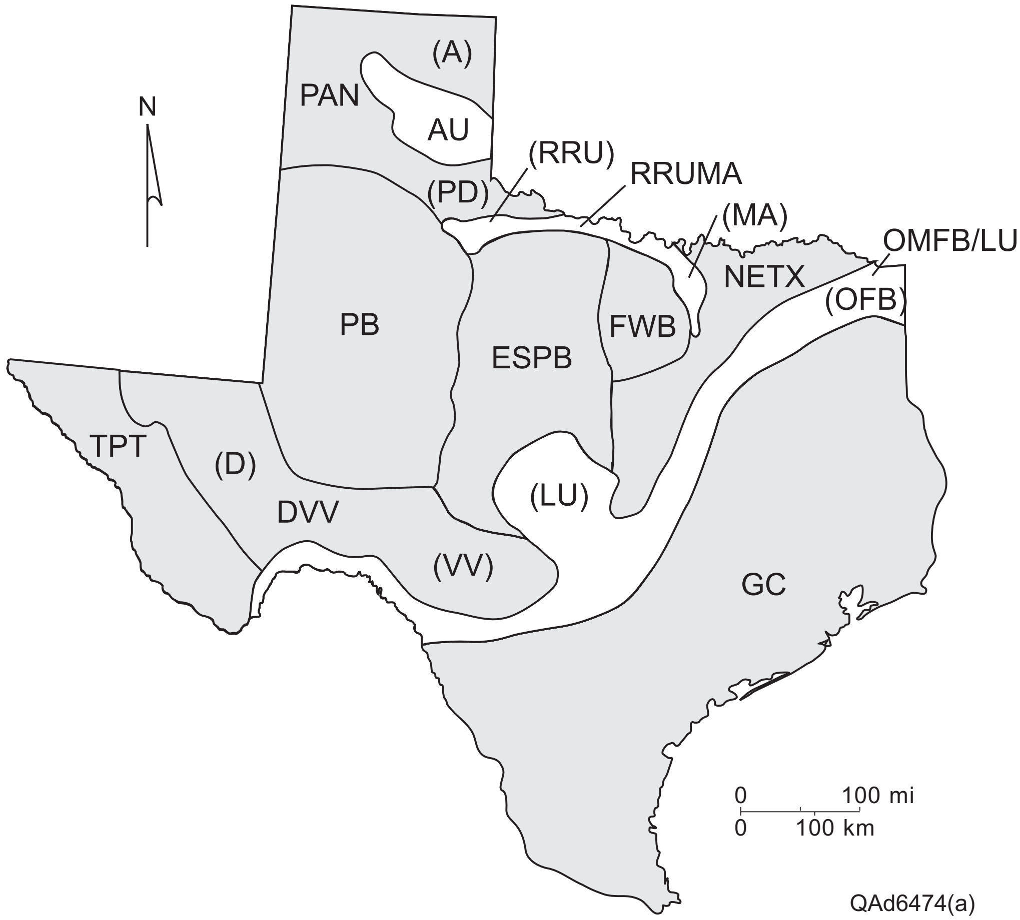


Figure 25. Percentage of frac jobs (not water use) in major plays in 2005-2008



Source: Ambrose et al. (2010)
Note: Regions are: AU Amarillo Uplift, DVV Delaware (D) and Val Verde (VV) Basins, ESPB Eastern Shelf of the Permian Basin, FWB Fort Worth Basin, GC Gulf Coast, LU Llano Uplift, NETX Northeast Texas, OFB Ouachita Foldbelt, OMFB/LU Ouachita and Marathon Foldbelts and Llano Uplift, PAN Texas Panhandle, PB Permian Basin, PD Palo Duro Basin, RRUMA Red River Uplift (RRU)-Muenster Arch (MA), TPT Trans-Pecos Texas

Figure 26. Major geologic regions (basins and uplifts) in Texas

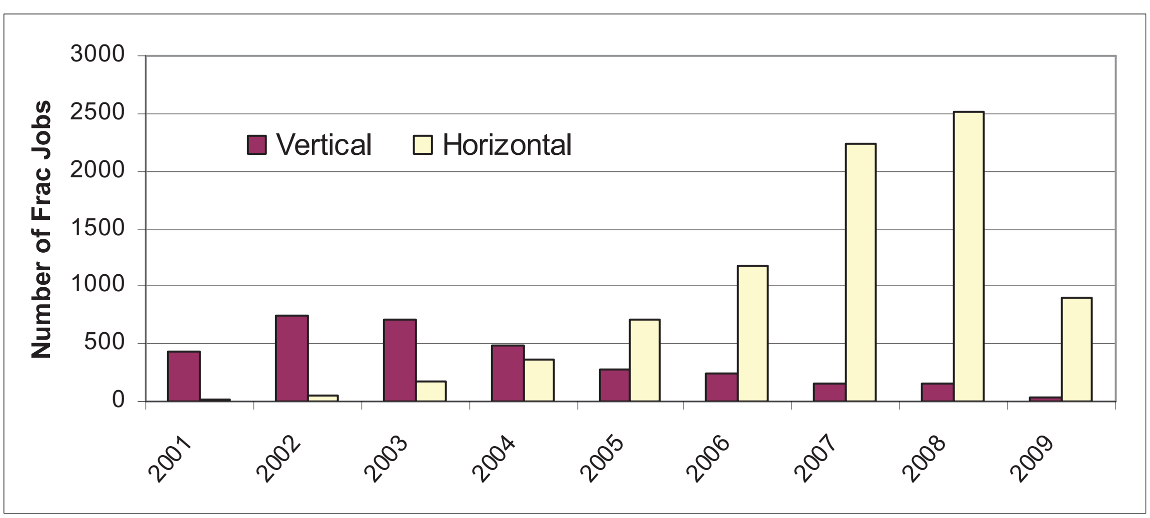
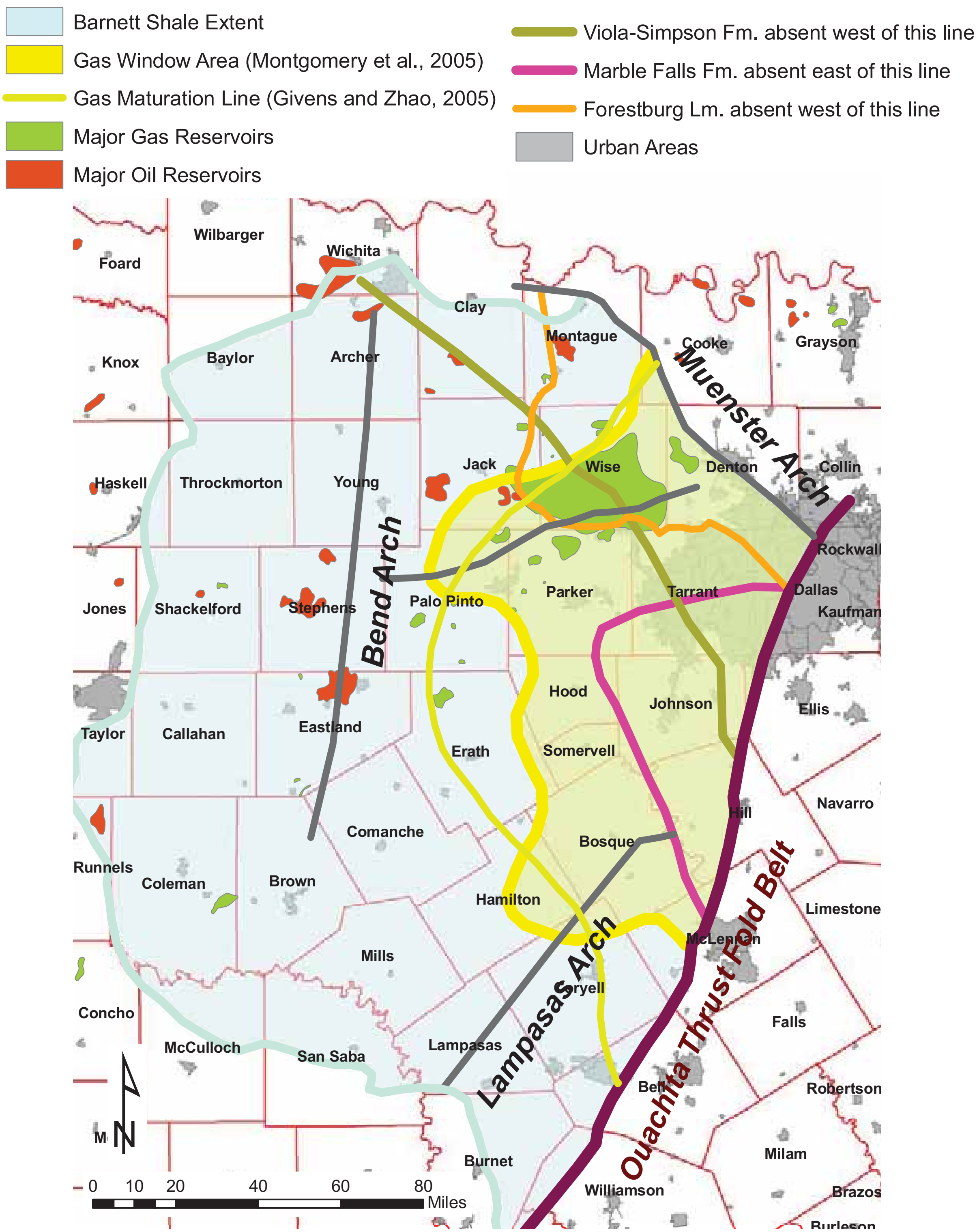
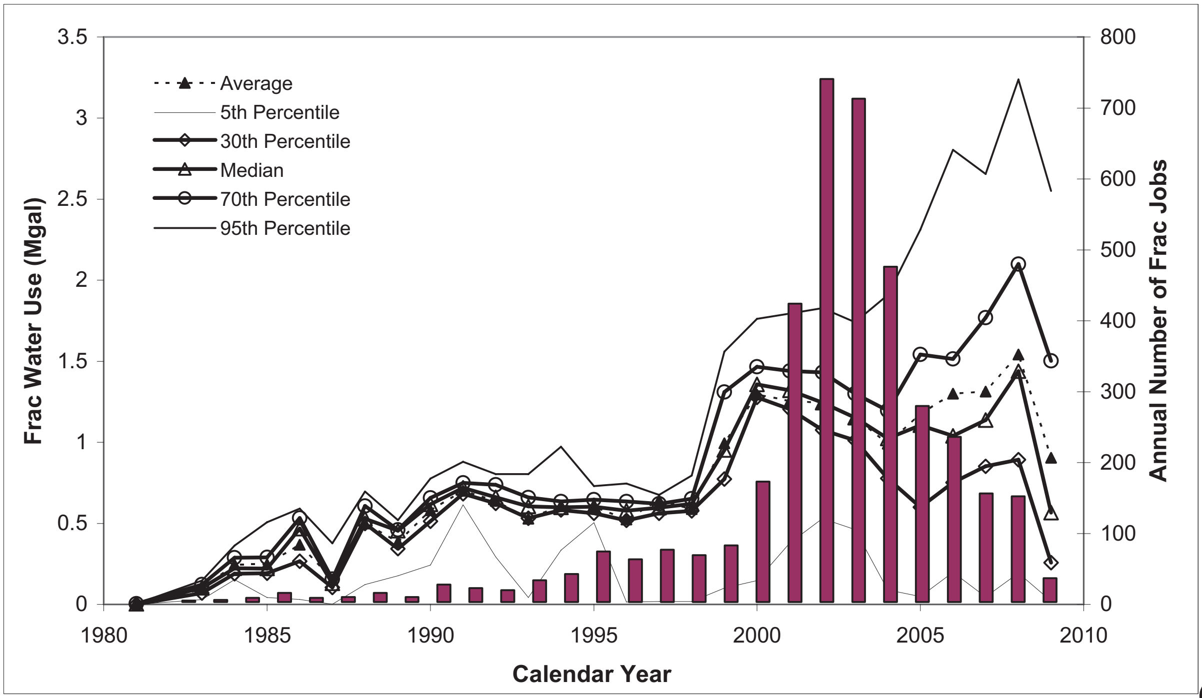


Figure 27. Barnett Shale—vertical vs. horizontal and directional wells through time

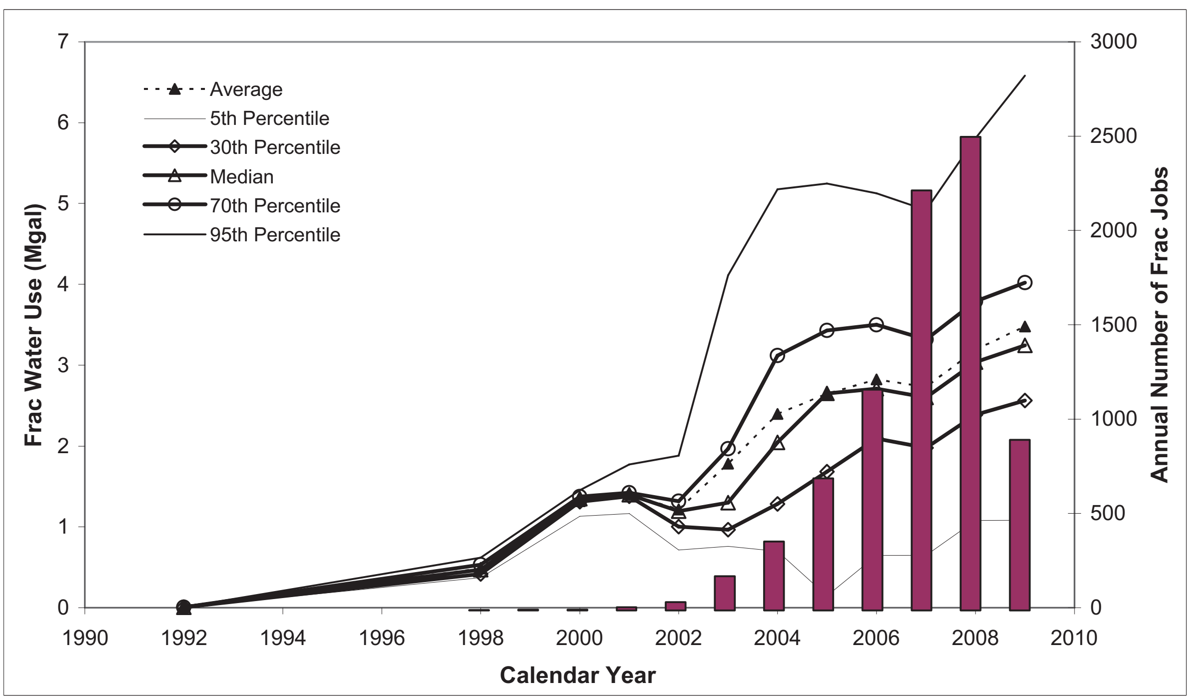


Source: Nicot and Potter (2007)
Note: Forestburg limit modified from Zhao et al. (2007); all others modified from Montgomery et al. (2005); major oil and gas reservoirs from Galloway et al. (1983) and Kosters et al. (1989). The Major Gas and Oil Reservoirs refer to non-Barnett production.

Figure 28. Barnett Shale footprint



(a)



(b)

Figure 29. Barnett Shale – Annual number of frac jobs superimposed to annual average, median, and other percentiles of individual well frac water use for (a) vertical wells, and (b) horizontal wells.

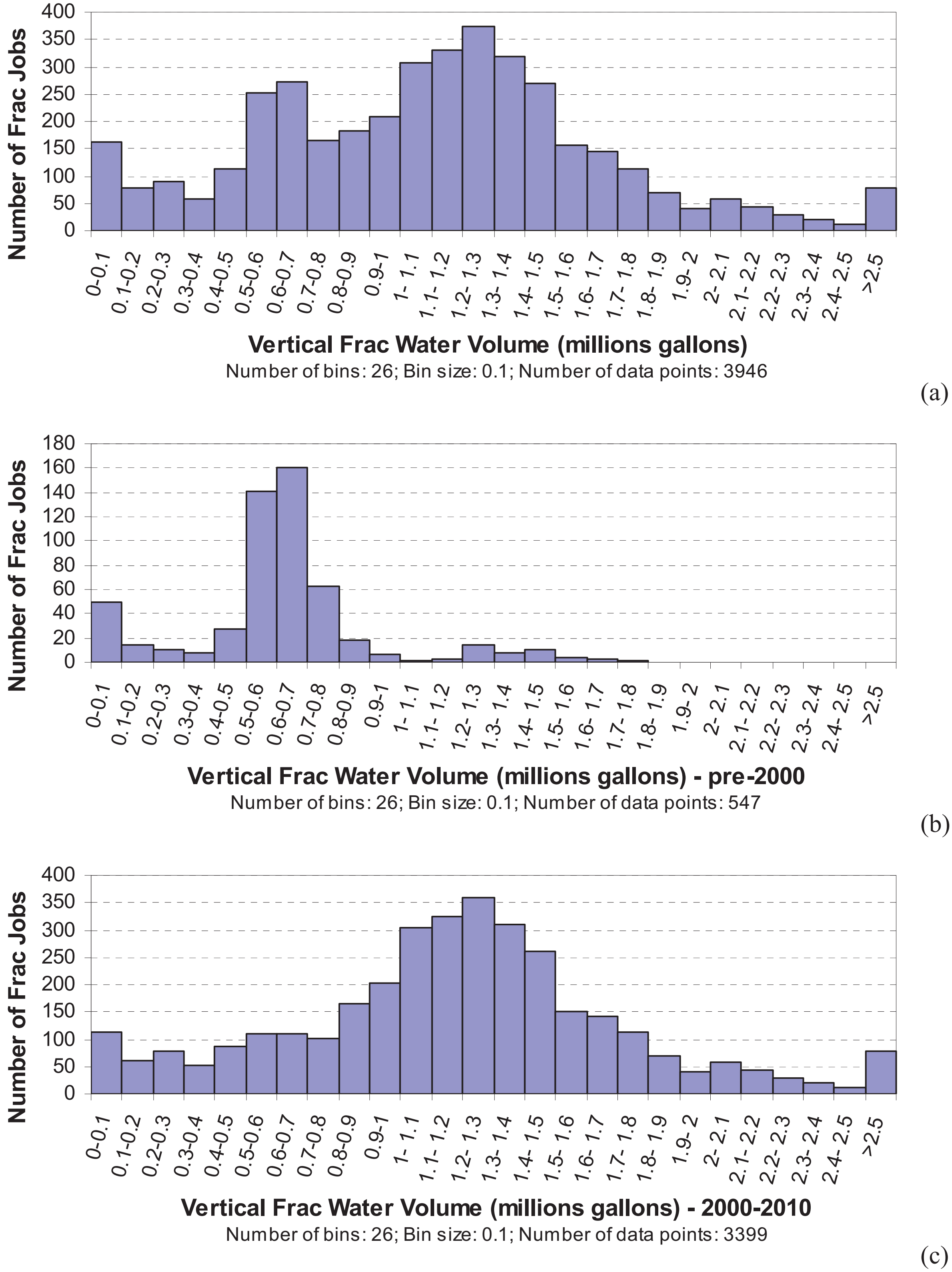
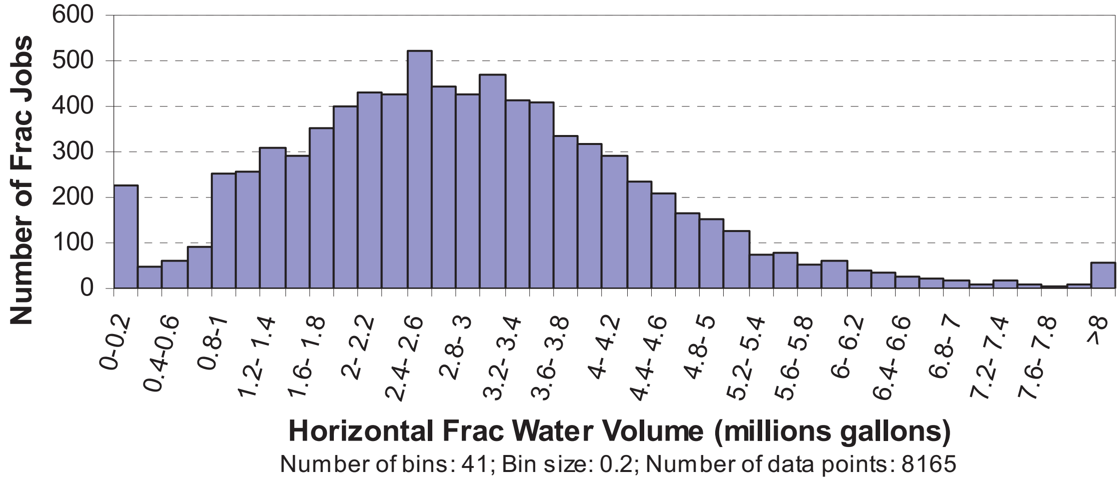
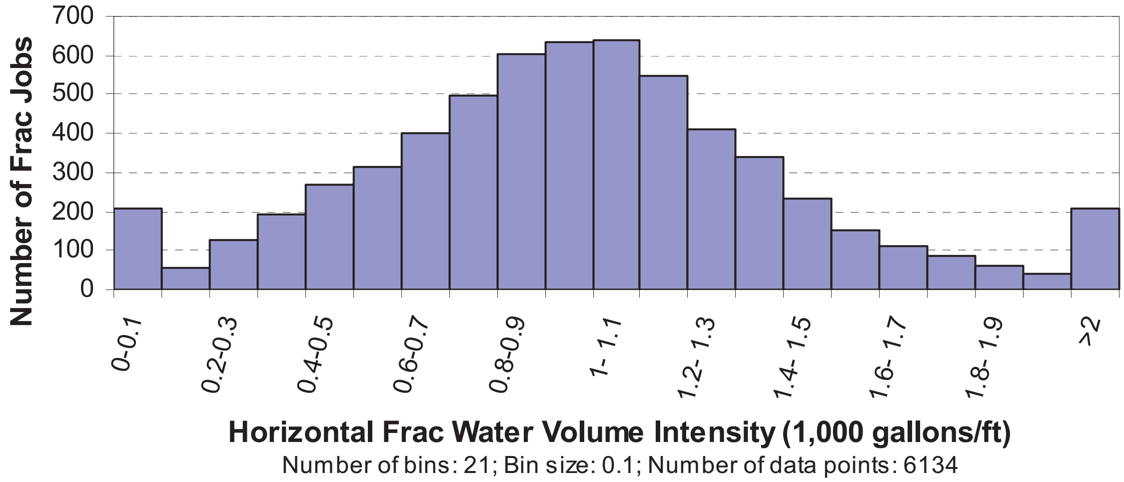


Figure 30. Barnett Shale— Histograms of frac water volume for vertical wells for (a) all wells, (b) pre-2000 wells, and (c) 2000–2010 wells

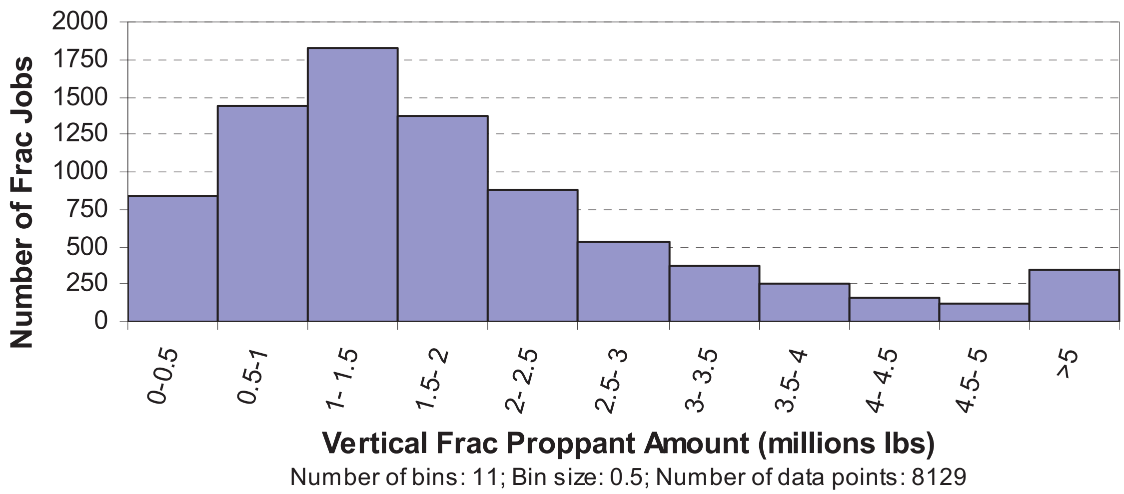


(a)

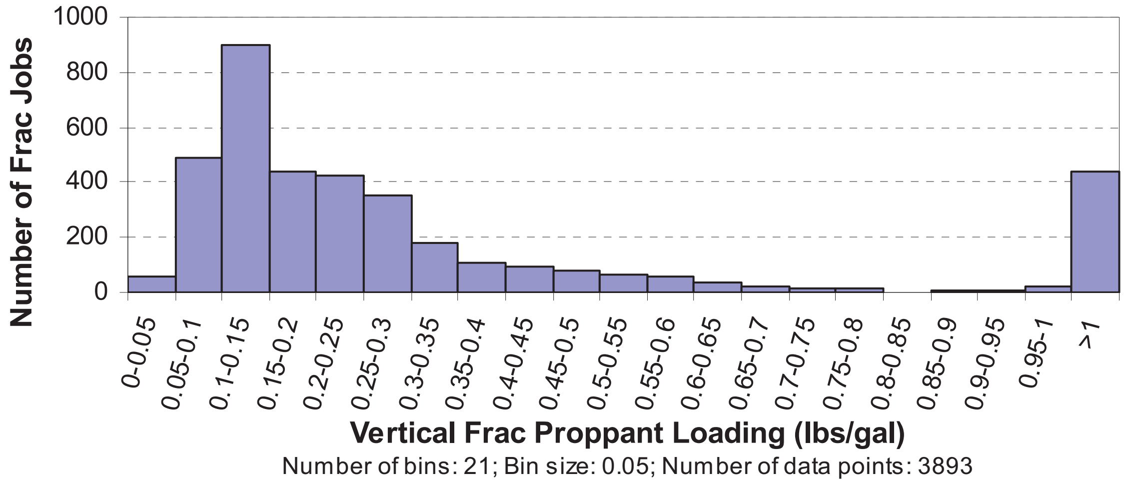


(b)

Figure 31. Barnett Shale—frac water use: (a) total volume, (b) intensity in 1,000 gal/ft

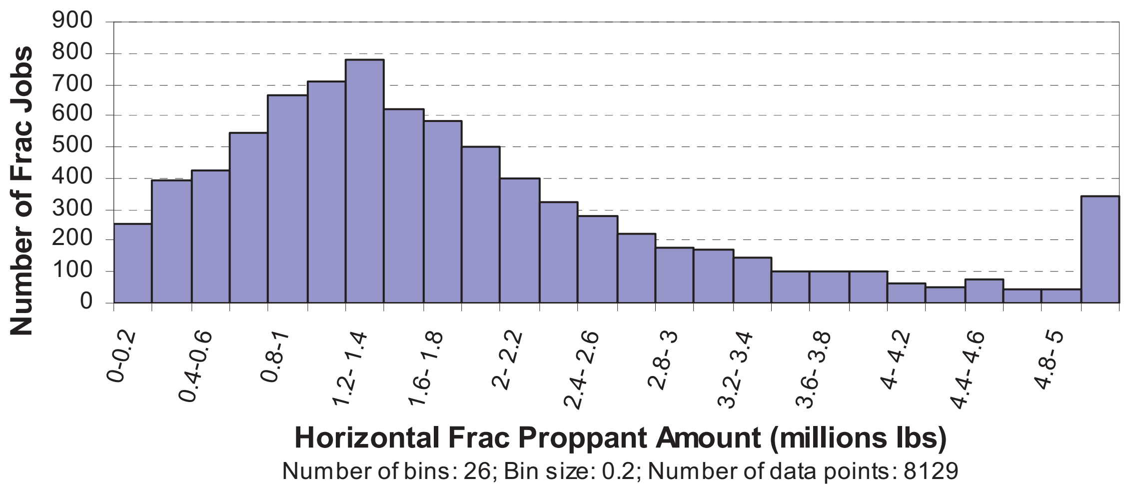


(a)

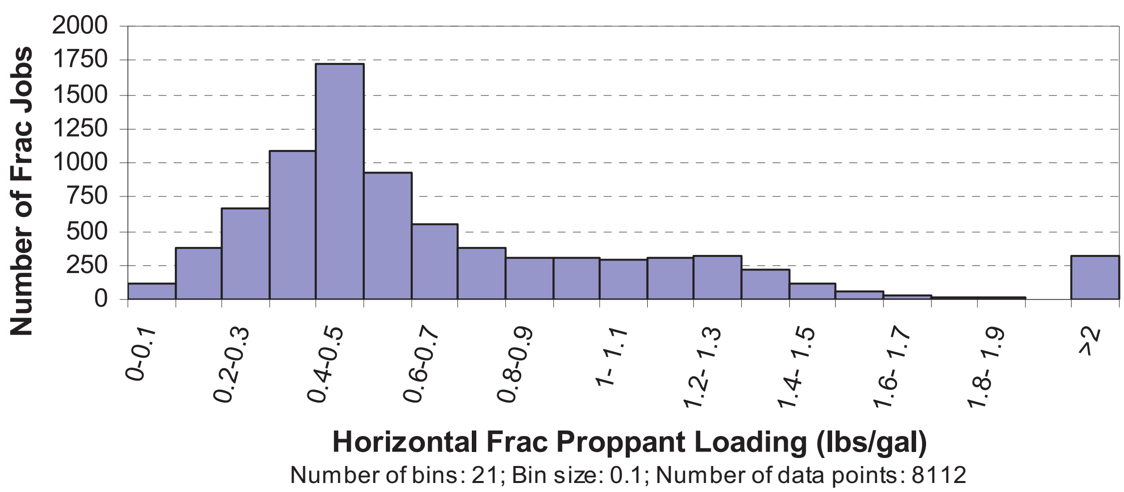


(b)

Figure 32. Barnett Shale—vertical well: (a) total proppant amount and (b) proppant loading

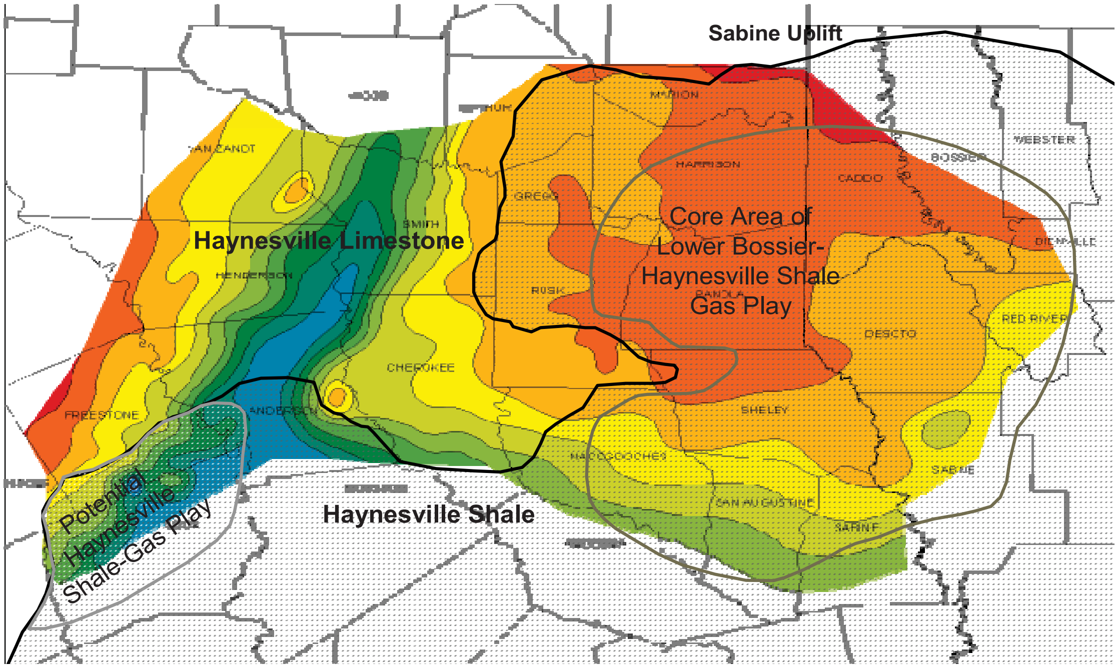


(a)



(b)

Figure 33. Barnett Shale—Horizontal well: (a) total proppant amount and (b) proppant loading



Source: courtesy Dr. Wang, BEG

Figure 34. Haynesville Shale footprint

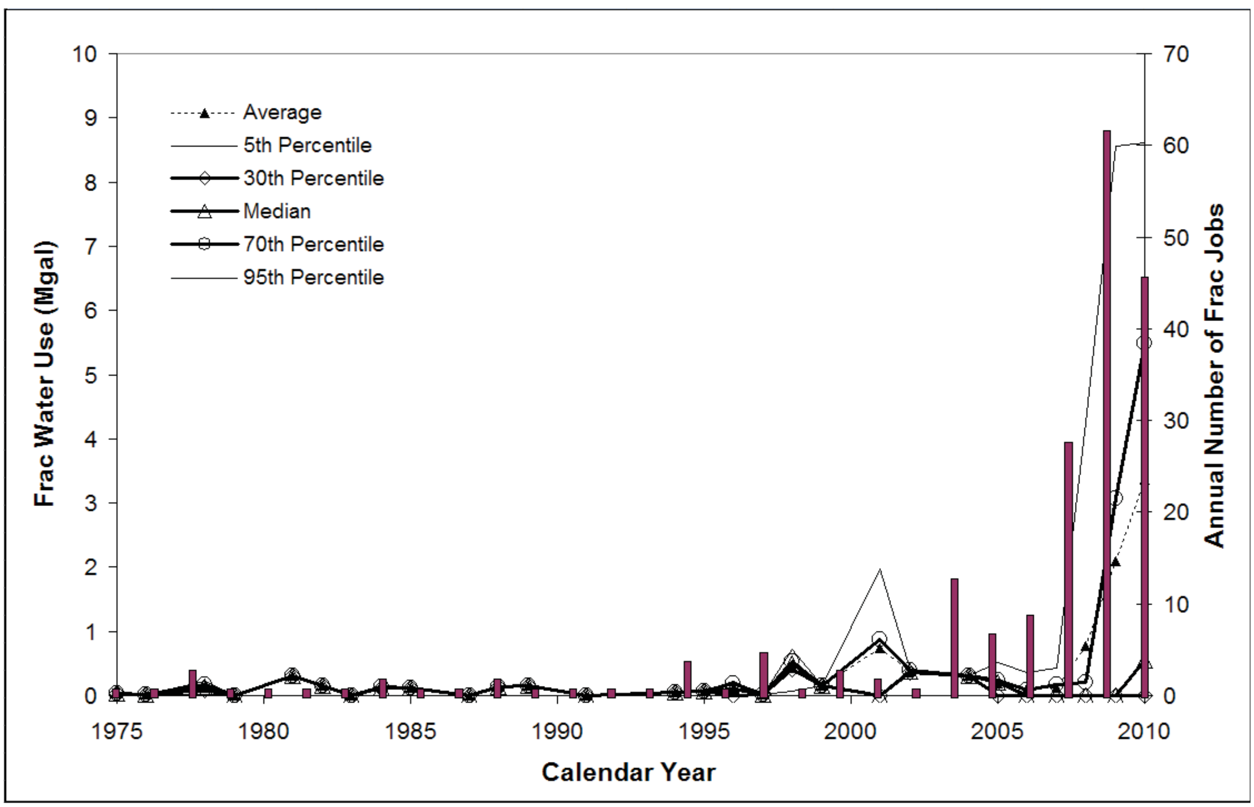


Figure 35. Haynesville Shale—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

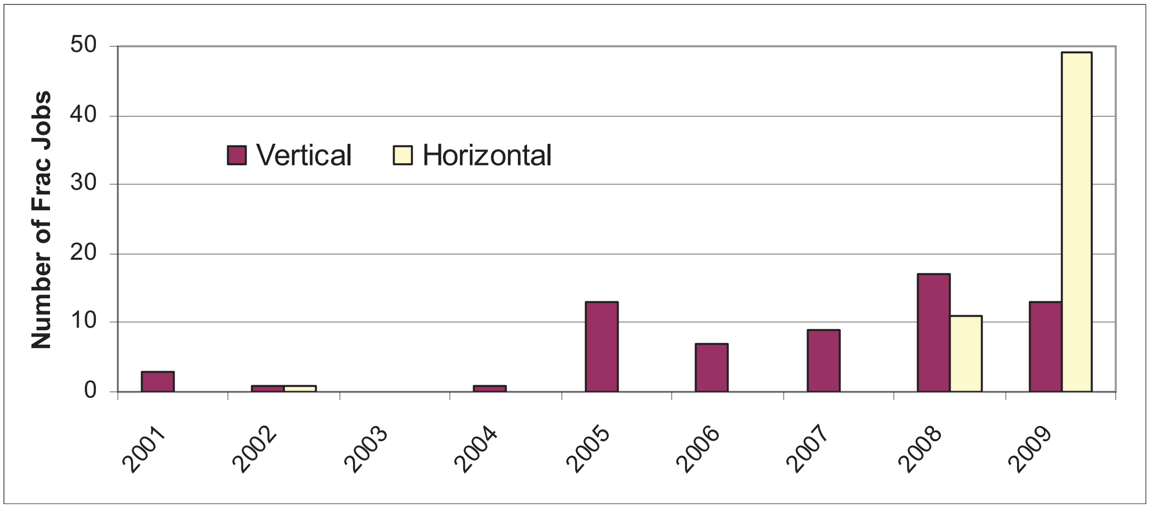


Figure 36. Haynesville Shale—vertical vs. horizontal and directional wells through time

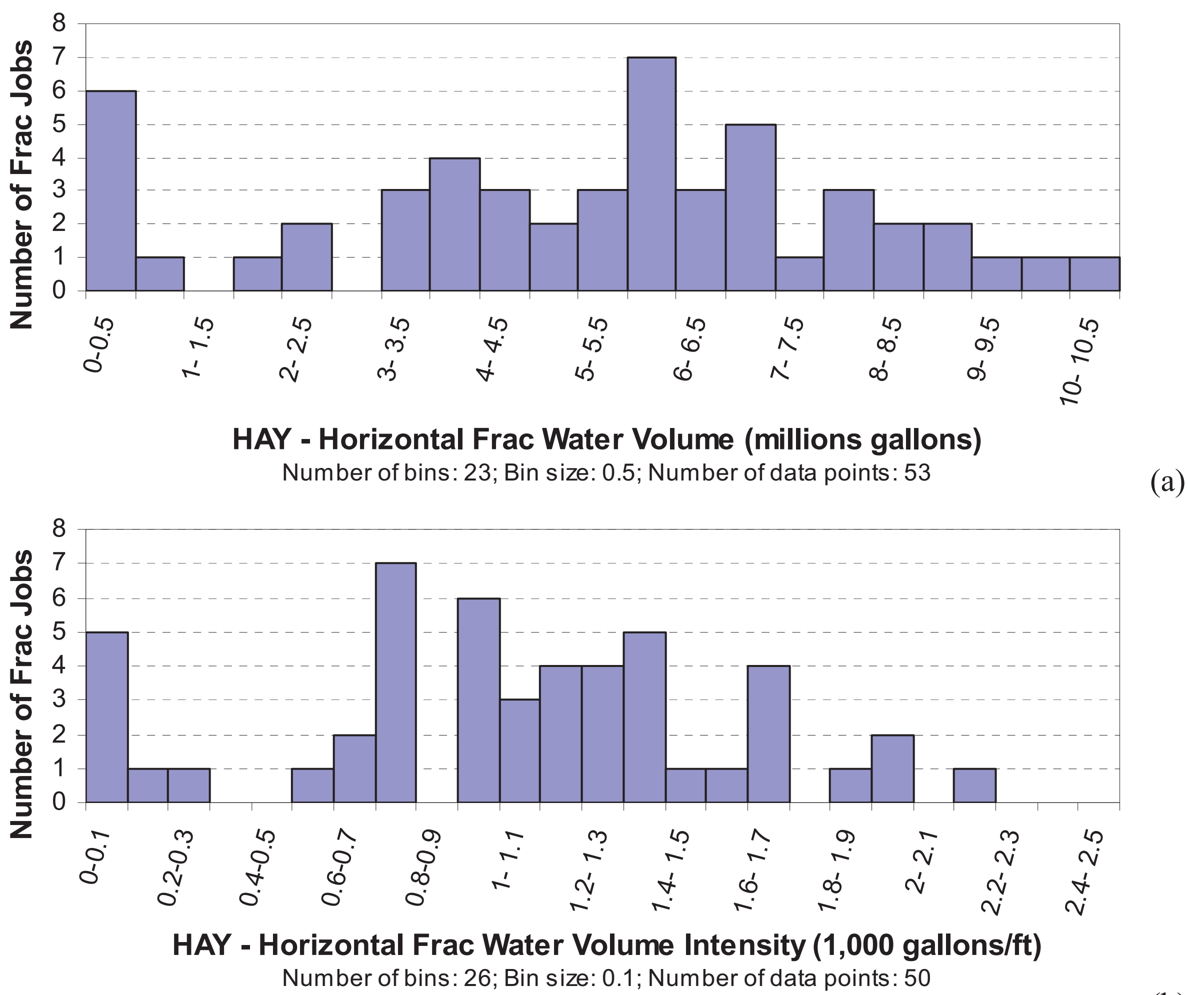
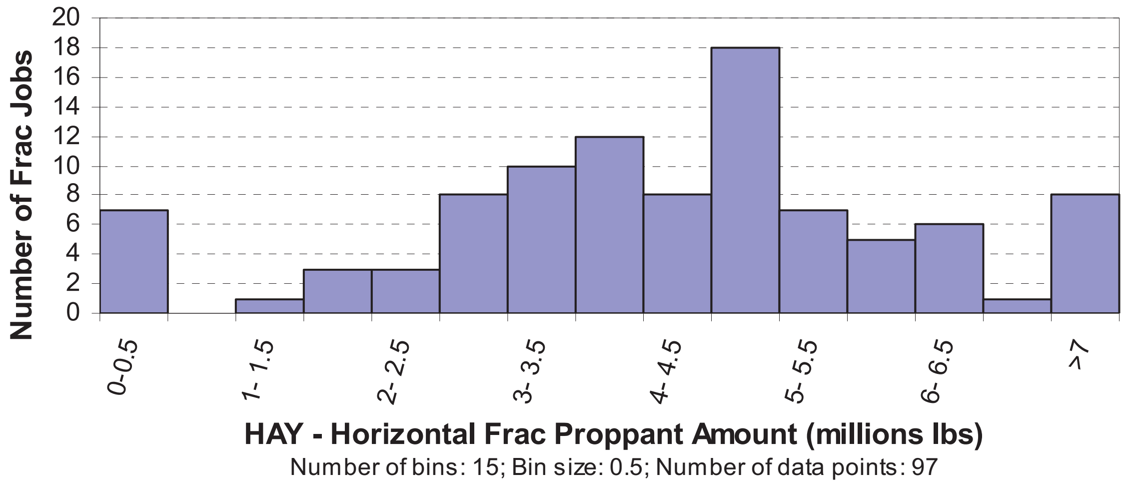
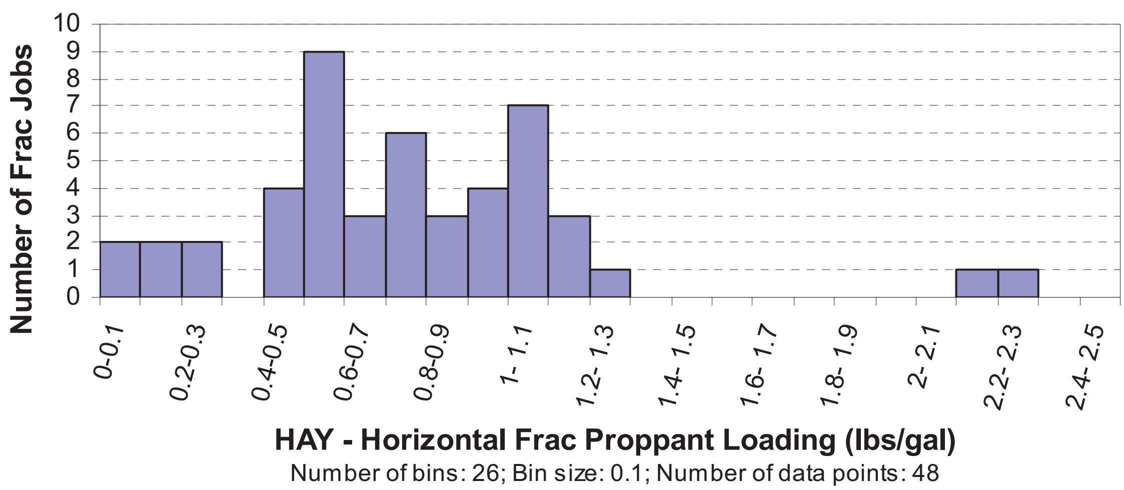


Figure 37. Haynesville—horizontal well frac water use: (a) total volume; (b) intensity in 1,000 gal/ft (2008 and beyond)

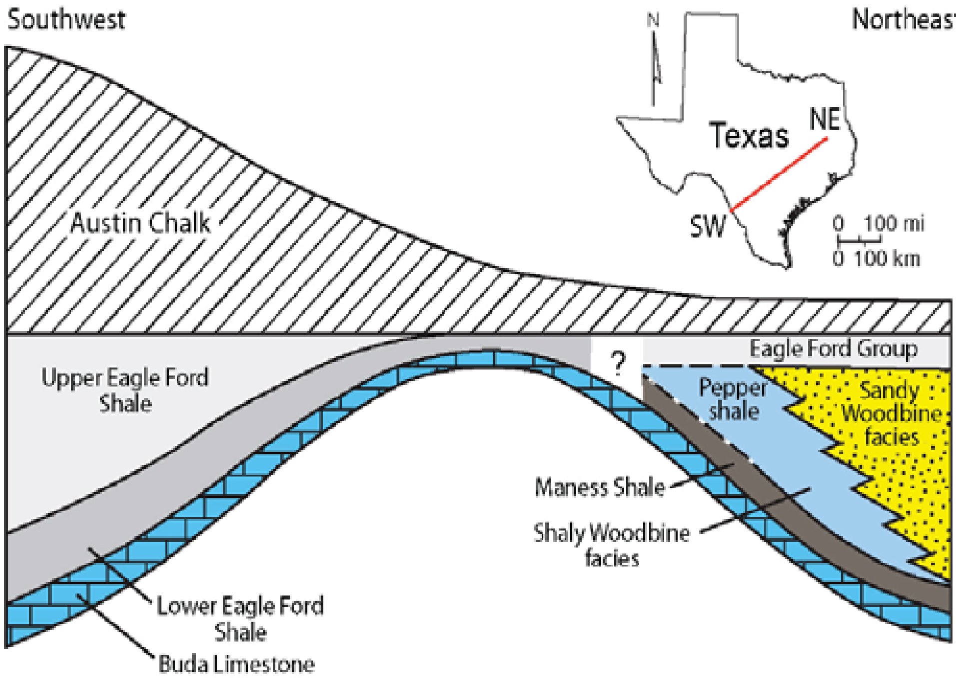


(a)



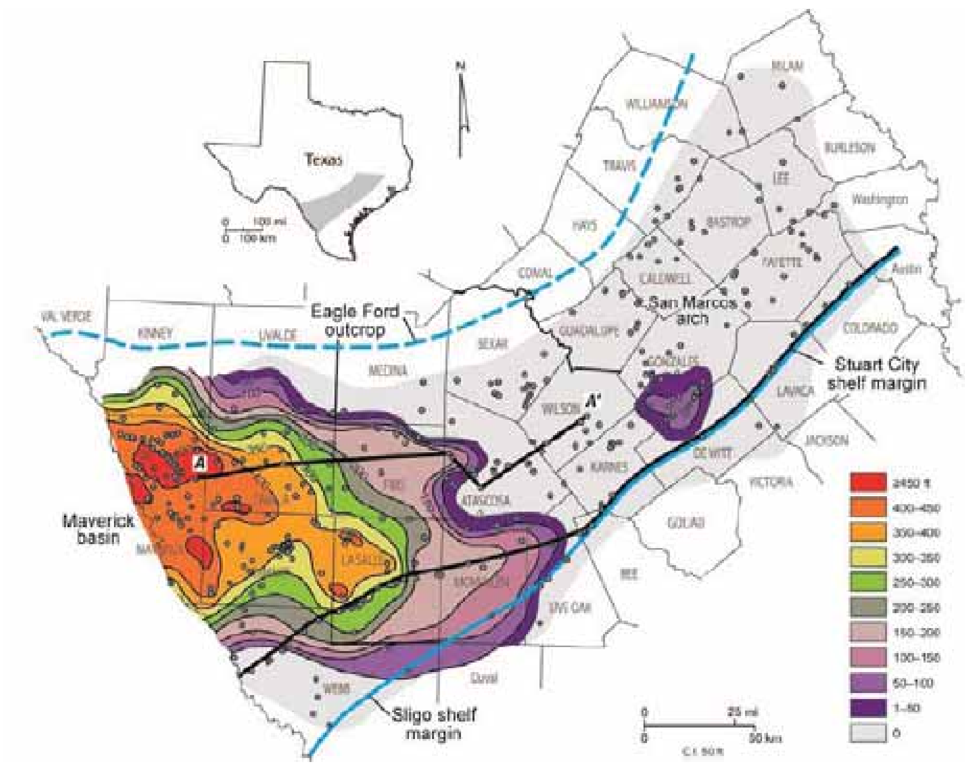
(b)

Figure 38. Haynesville—horizontal well: (a) total proppant amount and (b) proppant loading (2008 and beyond)



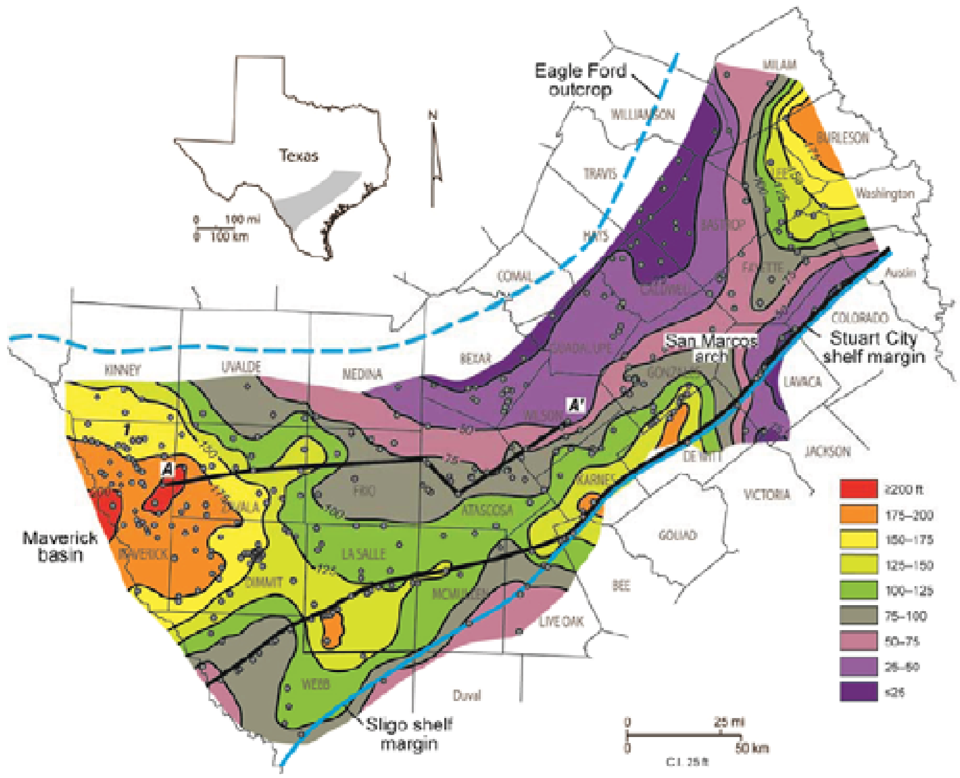
Source: Hentz and Ruppel (2010, Fig. 9)
Note: cross section hangs on top of Eagle Ford; top of Eagle Ford shallower in East Texas Basin than in Maverick Basin to the southwest

Figure 39. SW-NE schematic strike cross section illustrating regional lithostratigraphic relationships across the Eagle Ford play area



Source: Hentz and Ruppel (2010, Fig. 7)

Figure 40. Isopach map of upper Eagle Ford Shale



Source: Hentz and Ruppel (2010, Fig. 6)

Figure 41. Isopach map of lower Eagle Ford Shale

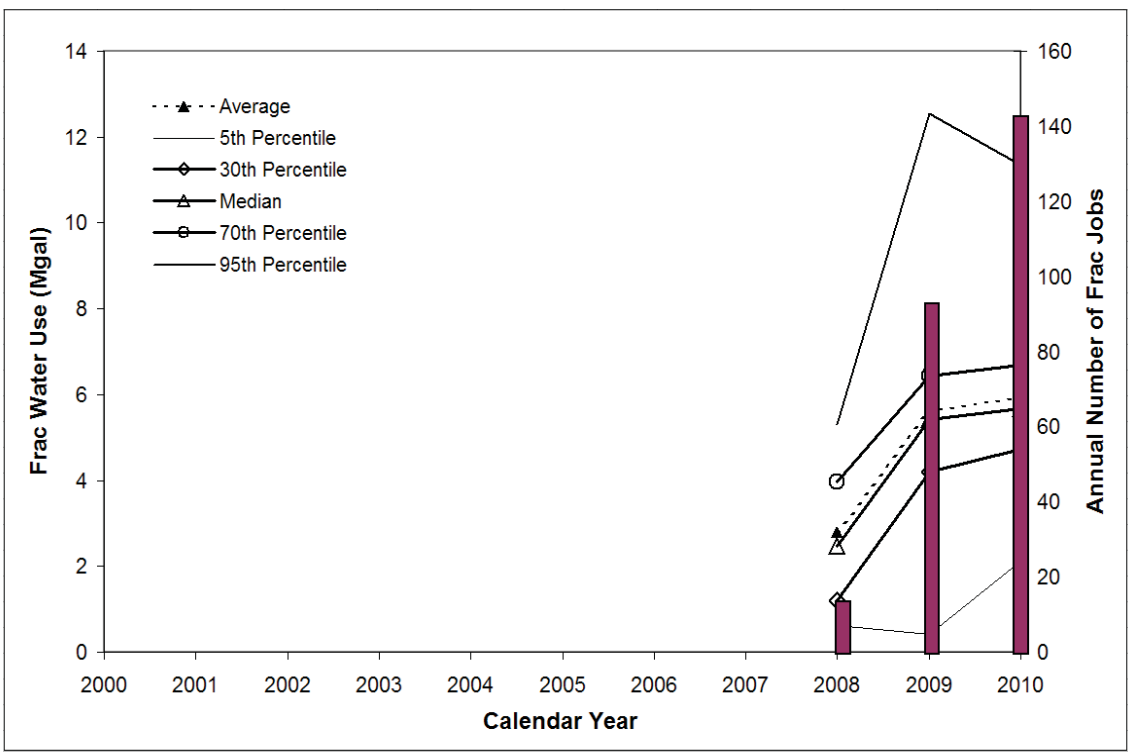


Figure 42. Eagle Ford Shale—Annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

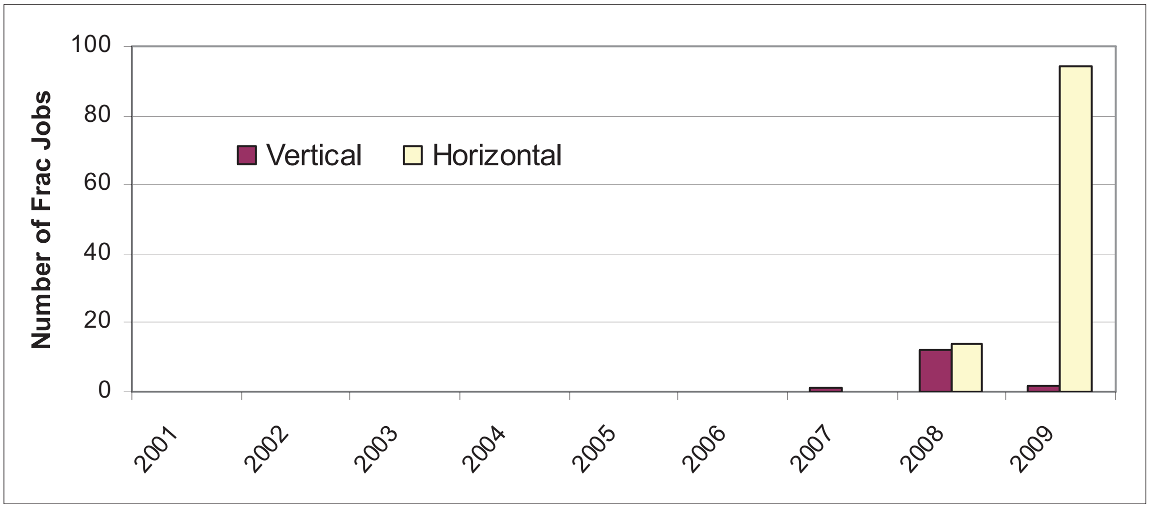
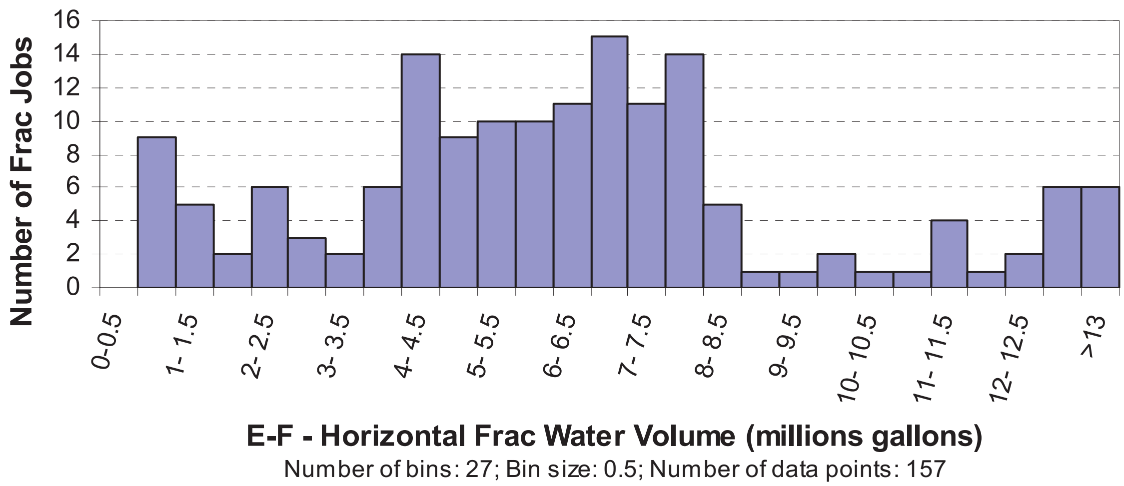
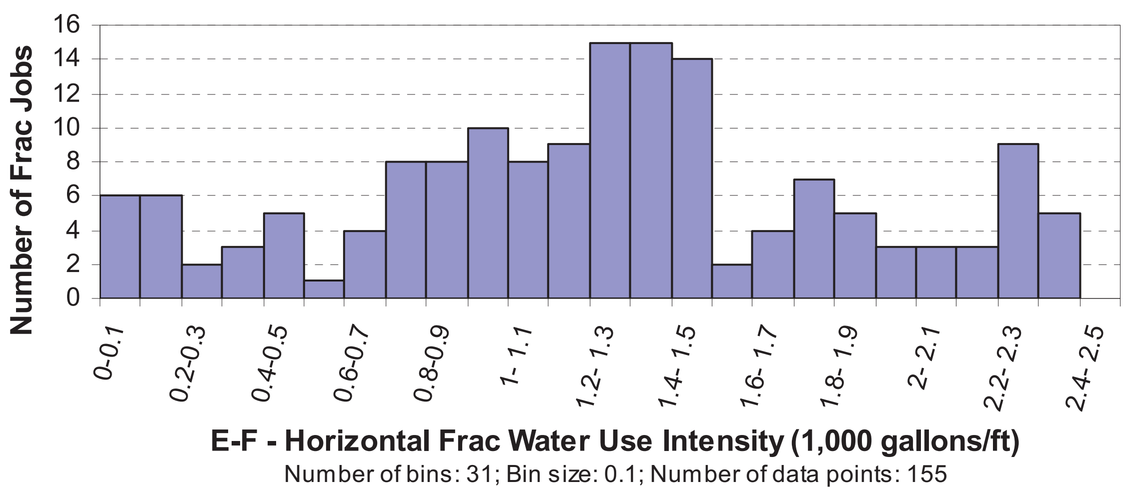


Figure 43. Eagle Ford Shale—vertical vs. horizontal and directional wells through time

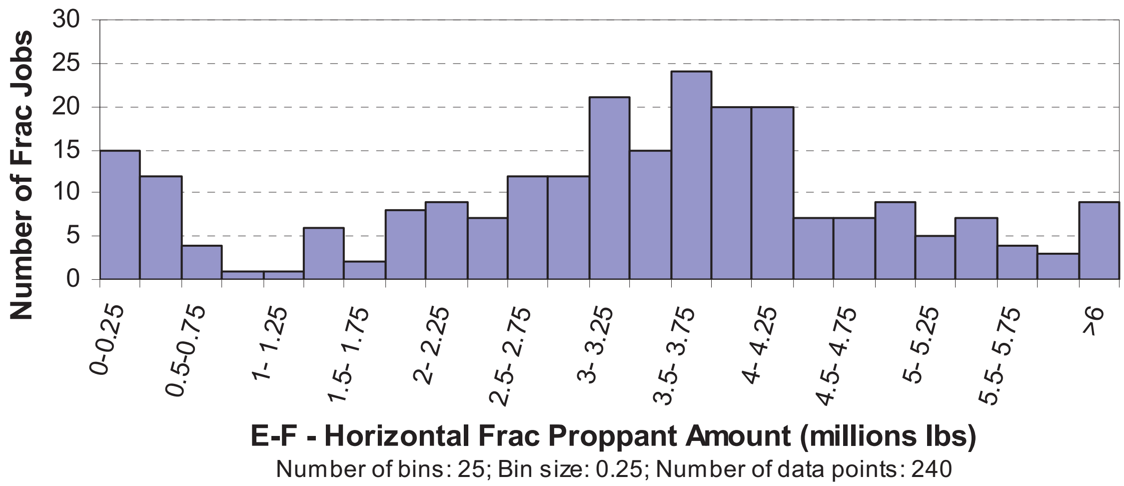


(a)

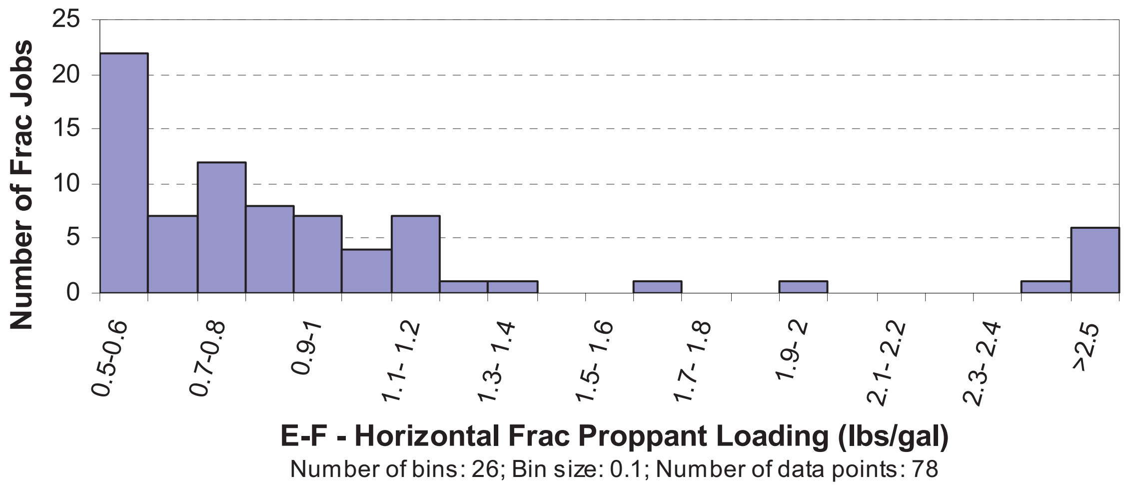


(b)

Figure 44. Eagle Ford—horizontal well frac water use: (a) total volume; (b) intensity in 1,000 gal/ft (2008 and beyond)

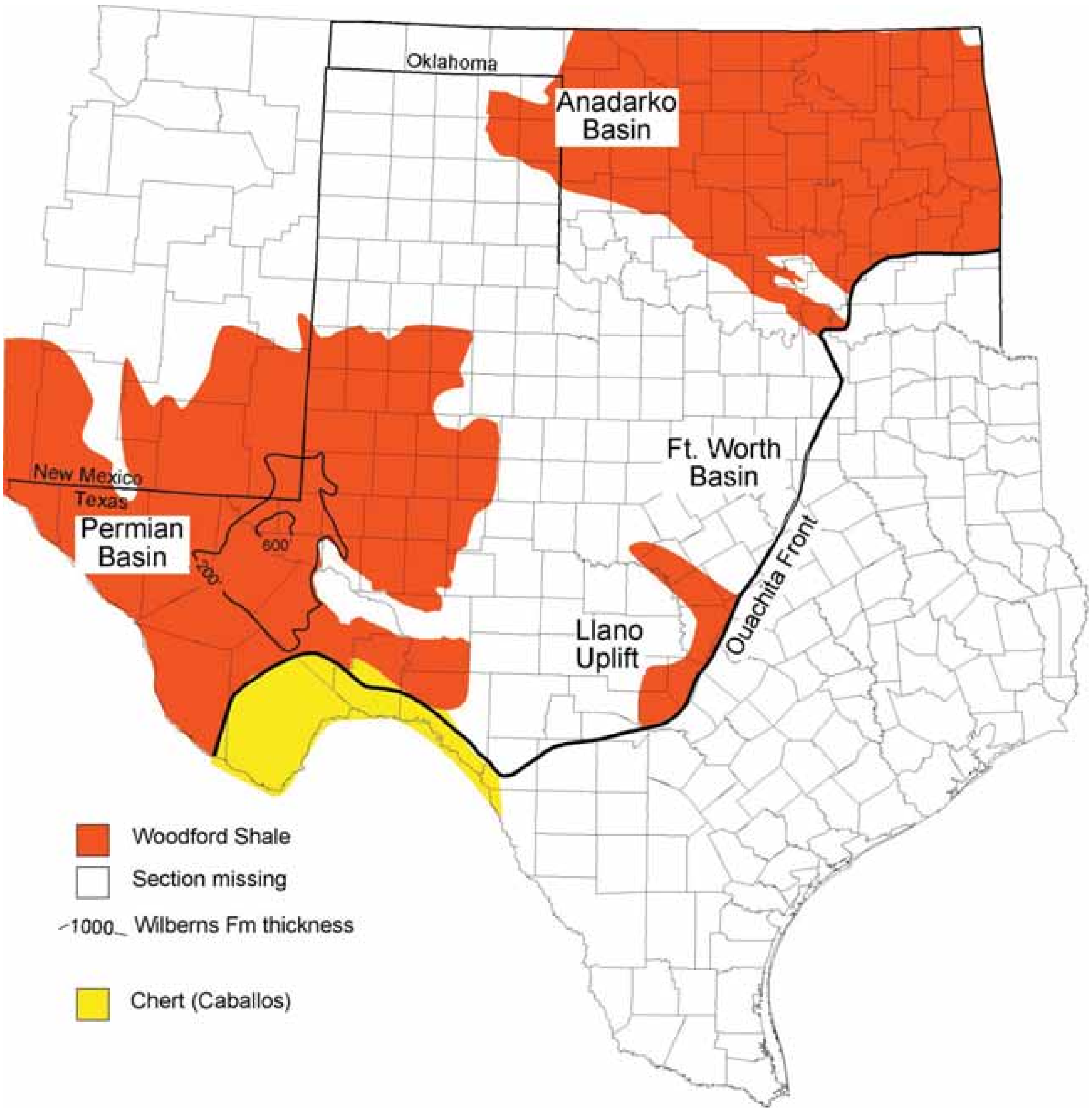


(a)



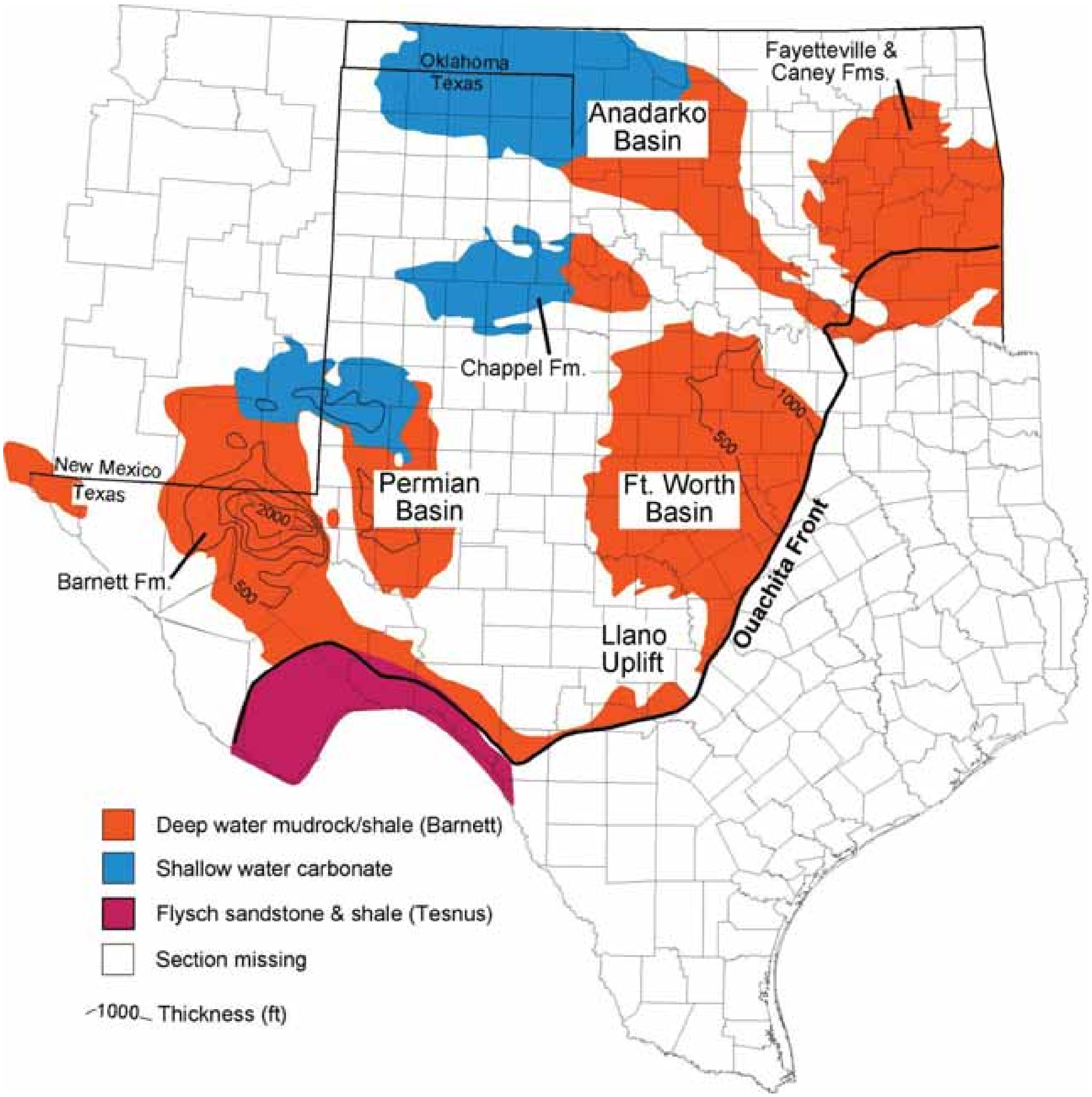
(b)

Figure 45. Eagle Ford—horizontal well: (a) total proppant amount and (b) proppant loading (2008 and beyond)



Source: Craig et al. (1979) modified by Stephen Ruppel and mudrock group (BEG)
Note: plot also displays thickness of the Wilberns Formation of Cambrian age

Figure 46. Woodford (Upper Devonian) occurrences in Texas



Source: Craig et al. (1979) modified by Stephen Ruppel and mudrock group (BEG)

Figure 47. Mississippian (including Barnett) facies distribution

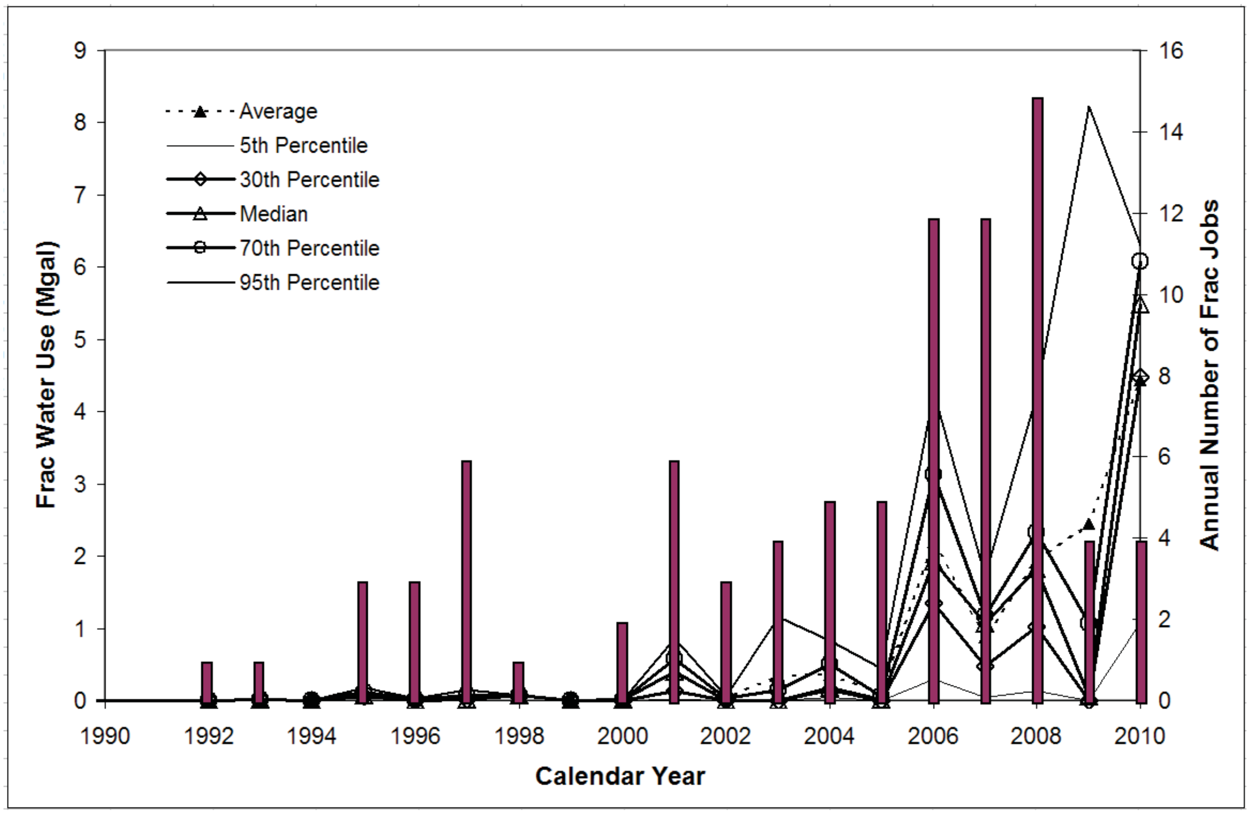


Figure 48. Woodford-Pearsall-Barnett PB—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

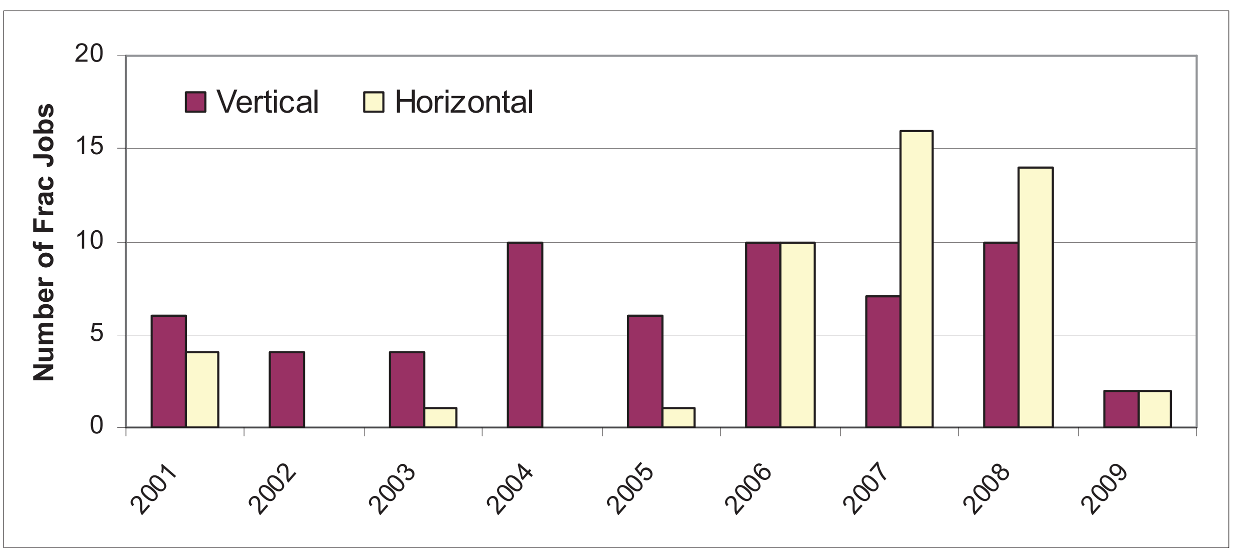


Figure 49. Woodford-Pearsall-Barnett PB—vertical vs. horizontal and directional wells through time

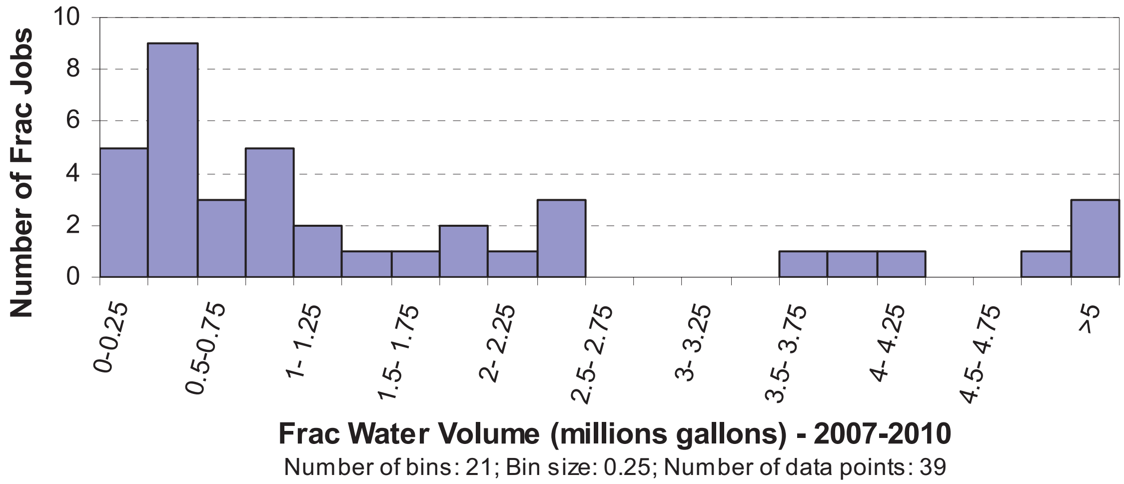


Figure 50. Woodford-Pearsall-Barnett PB horizontal and vertical well frac water use

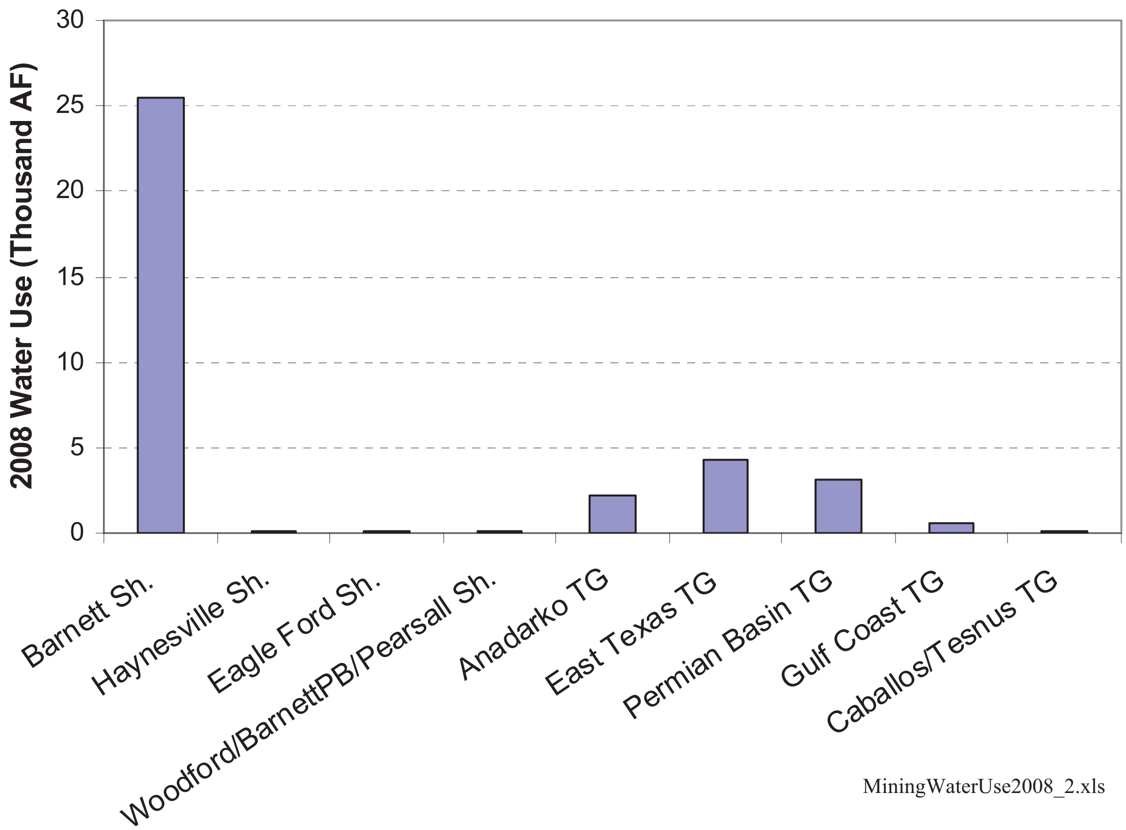


Figure 51. Water use for well completion in gas shales and tight formations (2008)

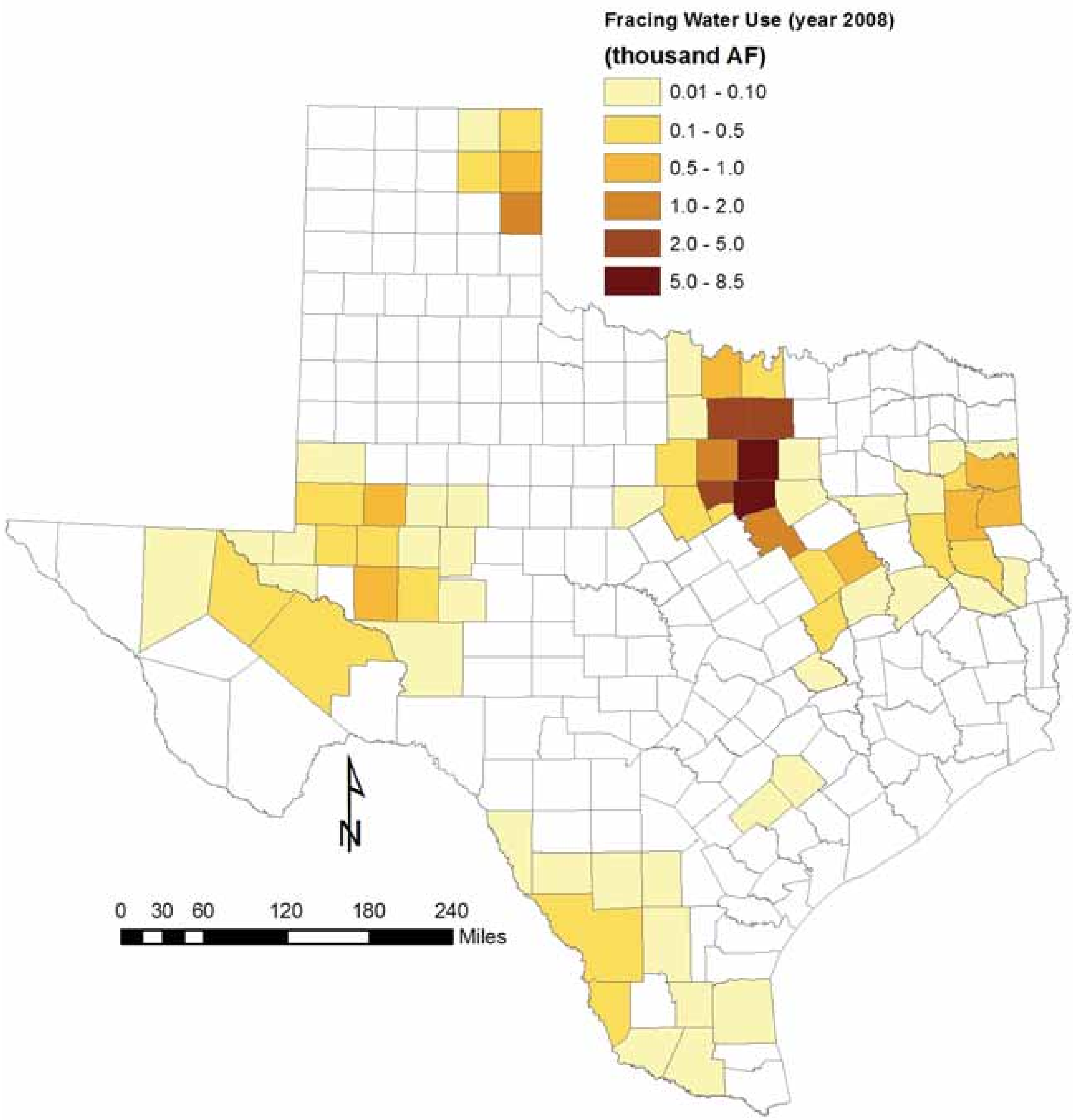


Figure 52. County-level fracing water use (2008)

4.1.3 Tight Reservoirs

Tight-sand plays are more numerous than shale-gas plays and have a longer history, going back to the 1950s and early days of the frac technology. In each basin, many formations have been fraced one time or another, and in this report they are grouped by rock type and geological affinity. BEG published many reports in the 1980s and 1990s in collaboration with GRI (Gas Research Institute, now GTI) related to tight-gas hydrocarbon accumulations. Extended summaries were presented by Finley (1984) and then Dutton et al. (1993), who considered the following Texas tight gas plays: Travis Peak (Hosston) Formation and Cotton Valley Sandstone in East Texas, Cleveland Formation and Cherokee Group in the Anadarko Basin in the Texas Panhandle, Olmos Formation in the Maverick Basin of South Texas, and the so-called Davis sandstone in the Fort Worth Basin (informal unit of the Atoka Group) (Figure 53). They were chosen because they were major gas producers at the time. Dutton et al. (1993) added the Vicksburg Formation and Wilcox Group along the Gulf Coast, the Granite Wash to the Anadarko Basin, the Morrow Formation in the Permian Basin, and the Canyon Sands in the Val Verde Basin. An observation made about many of these tight reservoirs is that low permeability is diagenetic and is caused by pore occlusion rather than depositional due to a clay matrix. In opposition to the gas shales previously discussed, tight sands are conventional in that they form reservoirs and local accumulations (Dutton et al., 1993, p. 5). A map by EIA (Figure 23b) cites them all, but with inaccurate footprints.

4.1.3.1 Anadarko Basin

Sediments of the Anadarko Basin occur mostly in Oklahoma, but its western section is located in the northern Texas Panhandle, including Gray, Hansford, Hemphill, Hutchinson, Lipscomb, Ochiltree, Oldham, Roberts, Sherman, and Wheeler Counties. The Anadarko Basin contains a thick (>18,000 ft) accumulation of siliciclastics and carbonate sediments resulting from the deposition of large volumes of arkosic sediments eroded from the Amarillo Uplift (Ambrose et al., 2010). These sediments are overlain and interfingered by carbonate and sandy deposits of the Marmaton Group and Cleveland Formation (Hentz and Ambrose, 2010). Most of the historical tight gas occurs within the thick undifferentiated interval of the so-called Granite Wash of Pennsylvanian and Permian age. Formations of similar age, such as the Caldwell, Cherokee, Cleveland, and Marmaton, contain tight-gas reservoirs as well as oil.

The basin has seen several cycles of activity since the 1950s, as evidenced by its fracing history (Figure 54b). However, the wells were vertical and the fracing water volumes were small (<0.1 Mgal/well) (Figure 54a). Since 2008, the frac water volume has increased to an average of **0.4 Mgal/well** (Figure 54a) but with a very long tail (Figure 55a). More recently, deviated vertical (directional) and horizontal have been developed in the basin (multimodal histogram of Figure 54b). Average water intensity is ~450 gal/ft (Figure 54c) with a broad mode. Both horizontal and vertical wells have been growing (Figure 56). The formation described as the Granite Wash has been fraced the most often, followed by the Cleveland Formation (Figure 57). In 2008, **2.22 thousand AF** of water was used for fracing purposes.

4.1.3.2 East Texas Basin

The East Texas Basin, sometimes incorporated into the Gulf Coast Basin in high-level regional studies, is a clearly individualized feature in northeast Texas with thick sediments of mostly Cretaceous age. It consists of a deep trough aligned in Anderson and Smith Counties (East Texas Salt Basin) and two flanks with formations of similar age but not necessarily of similar lithology on each side (Table 11). The eastern flank abuts the Sabine Uplift over the Texas-Louisiana state line. The Travis Peak (also called Hosston) Formation (Early Cretaceous) and the Cotton Valley Sandstone (Late Jurassic) have been historical targets and producers in the tight-gas category, most of the activity being confined east of the trough, although many opportunities also exist farther west. The Cotton Valley Sandstone (Figure 58) has a spatial distribution similar to that of the Haynesville Shale. It consists of multiple generally low-permeability sand layers interspersed with shaly material. So that the reservoir could drain efficiently, well spacing has been reduced to 20 acres in many places (Baihly et al., 2007). Cotton Valley is the formation currently being fraced the most, followed by the Travis Peak Formation (Figure 60), although several other formations are also being stimulated, such as the Bossier and the Pettet Formations.

Most of the wells are vertical, although the proportion of horizontal wells is growing (Figure 59). Fracing took off in the 1990s, as it did in other tight formations, with a sharp increase in average water use in recent years (Figure 61)— **0.9 Mgal** and **3 Mgal/well** for vertical and horizontal wells, respectively (Figure 62). In 2008, the East Texas Basin used a total of **4.26 thousand AF** of water for fracing purposes.

4.1.3.3 Fort Worth Basin

The Fort Worth Basin hosts the Barnett Shale and is home to the areally extensive and highly productive Pennsylvanian fan-delta sandstone and conglomerate play (Kosters et al., 1989) (likely sources from the Barnett). Formations include Atoka and Bend Conglomerate (Thompson, 1982). This area has not been traditionally an area with significant tight-gas accumulations. Dutton et al. (1993) mentioned an interval called the Davis Sandstone, but it does not seem to be of significance, given the few wells possibly fraced recently in this interval (Table 8). In addition, any completion would be dwarfed by the Barnett Shale.

4.1.3.4 Permian Basin

The Permian Basin contains a thick accumulation of sediments from Cambrian to Permian age on a Precambrian basement. Despite its long hydrocarbon production history (>30 Bbbl, or about half the state's overall oil production) as compiled according to play by Dutton et al. (2005a,b), the basin still contains important reserves because <30% of the OOIP has been produced (Dutton et al, 2005a, p. 343). Most of the Permian Basin is in the oil window, although significant amounts of gas may exist deeper. Major operators have been content to focus on the abundant oil resources (Figure 63). The classical division of the Permian Basin into the Delaware Basin, Central Basin Platform, and Midland Basin, from west to east (to which the Eastern Shelf can be added), holds only for Permian and Pennsylvanian times (Table 12, Figure 64). At earlier periods, the Permian Basin area was not individualized in basins but presented a more complex but more regionally uniform geometry, with sediments deposited before the expression of the Delaware and Midland Basins. This geological history allows for grouping of the many series described in the IHS database into logical larger groups. However, techniques used by the operators respond more to the nature of the rock than to its age.

The Delaware Basin is in general deeper than the Midland Basin (on the other side of the Central Basin Platform) for a formation of the same age. For example, Bone Spring, Clear Fork, and Spraberry are formations of equivalent age (Figure 65). Similarly the Delaware Mountain Group in the Delaware Basin is equivalent to the San Andres-Grayburg on the Central Basin Platform and in the Midland Basin. Carbonates dominate the platform sediments, but clastics and calcareous mudrocks are more prevalent in the basins.

In Texas, the Delaware Basin includes Culberson, Reeves, and Loving Counties, as well as parts of Jeff Davis, Pecos, Ward, and Winkler Counties. The Central Platform extends from Gaines to Pecos Counties, and the Midland Basin from Terry and Lynn Counties to the north to Crockett County to the south. The Eastern Shelf parallels the Midland Basin to the east, all the way to the Bend Arch and the Fort Worth Basin and Llano Uplift.

The Delaware Basin also contains formations of interest, such as the Bone Spring Formation (also called the Avalon Shale or Leonard Shale in New Mexico) (Figure 66). It is present in Loving, Reeves, and Ward Counties, although maturity drops off quickly. The Bone Spring has seen a surge in interest but is still relatively unexplored. The Delaware Mountain Group, stratigraphically above the Bone Spring Formation, but similar in terms of lithology and broad depositional environments, has many reservoirs from shallow depth (2,500 ft) to much deeper levels (>8,000 ft). Recovery is low, <30% after secondary and possibly tertiary production (Dutton et al., 2005a, p. 312–314). The top of the gas window in the Delaware Basin is estimated to be at ~10,000 ft.

The important development of the so-called Wolfberry play in the Midland Basin corresponds to operators fracing similar rocks of stacked Spraberry, Dean, and then Wolfcamp (Figure 67), and possibly Strawn basinal deposits involving up to 12 stages in vertical wells at a depth of >7,000 ft. Spraberry/Dean reservoirs have historically had a fairly low recovery (10% of OOIP, Dutton et al., 2005a, p. 205). Most of the fracing has focused on the margins of the basin along the Central Platform and the Eastern Shelf. There has been a considerable interest in the Wolfberry play in the past few years, as illustrated by the number of recent wells (Figure 24).

Canyon Sands in the Val Verde Basin, a southeastern extension of the Permian Basin south of the Ozona Arch (Crockett County), were deposited in deep environments (Dutton et al, 1993, p. 122). The Canyon Sands, initially thought equivalent to the Canyon Formation in the Permian Basin, are actually mostly of Permian age (Hamlin et al., 1995, p. 4-5), although the name remains. For convenience, we also added the Devonian Caballos and Mississippian Tesnus Formations south of the Ouachita Front (Figure 46 and Figure 47) to the Permian Basin category.

Overall the Permian Basin has seen 50,000+ frac jobs in the past 50 years (Figure 68), including 18,300+ with water use >0.1 Mgal (Figure 69), and ~2,900 frac jobs with water use >0.5 Mgal, mostly in the past few years. The plots show a clear upward trend in all percentiles since 2000, with average water use approaching **1 Mgal/well** (Figure 70) with a broad distribution (once <0.1Mgal jobs are removed) (Figure 71). This is a relatively modest amount per current standards, but most of the wells are vertical (Figure 72). Many formations are being fraced, but the Spraberry/Dean in the Midland Basin, the Clear Fork in the Central Platform, and the Wolfcamp underlying both form the bulk of the frac jobs (Figure 73 and Figure 74). Devonian formations are also the subject of interest. We treated the Caballos and Tesnus Formations separately because they are located farther south, but their statistics are similar to those of other formations of West Texas, with a sharp increase in recent years (Figure 75) and an average water use at ~0.35 Mgal/well (Figure 75 and Figure 76).

In 2008, the Permian Basin (Texas section) used a total of **3.25 thousand AF** of water for fracing purposes (including 0.17 for the Caballos/Tesnus).

4.1.3.5 Maverick Basin and Gulf Coast

The Texas southern Gulf Coast province is well known for its gas-prone hydrocarbon accumulations and includes the Frio Formation, a prolific conventional gas producer, as well as the Wilcox deltaic (Table 13; Figure 147 in Appendix C). Tight-gas formations such as Vicksburg and Wilcox Lobo tend to occur deeper (Dutton et al., 1993). The Maverick Basin, included in the Gulf Coast area for the purpose of this study, contains the Olmos Formation, another important tight-gas formation. Overall, Gulf Coast tight formations have not seen the increase in average frac water volume as seen in all other basins, despite a sharp increase in the number of frac jobs (Figure 78). The reason may be due to the lack of horizontal wells (Figure 73). Recently active plays include the Vicksburg, the Wilcox, and the Olmos Formations, which have been traditionally fraced (Figure 79). The amount of water used is low (**<0.2 Mgal/well** for the most part) (Figure 80), but the proppant amount is relatively high (Figure 81), leading to a high proppant loading (Figure 82). These plays have most likely not been swept by the new fracing technologies, but we assume that they will in the future (we assume a water use of **0.5 Mgal/well** or projections), as operators revisit older plays through refracing and infill wells.

In 2008, the Gulf Coast Basin used a total of **0.60 thousand AF** of water for fracing purposes.

4.1.3.6 Conclusions on Tight Formations

Water use for tight formation completion is less than half of that for gas shales, at 10.4 thousand AF (Table 10 and Figure 51). Table 14 lists all counties with a total use >0.001 AF in 2008. Average water use across the 84 counties (Figure 52) is~120 AF, and Wheeler County, in the Panhandle, has the highest water use at 1.07 thousand AF.

Table 11. Simplified stratigraphic column of the East Texas Basin showing commonly fraced intervals, as well as potential targets (in bold)

System	Age	Formation / Group		
			Salt Basin	
Cretaceous		**Austin Chalk***		
		Glen Rose/Fredericksburg/ Washita/Eagle Ford		
		Pearsall / Rodessa / James		
		Sligo / **Pettet***		
		Hosston/**Travis Peak***		Hosston/**Travis Peak***
		Cotton Valley*		**Cotton Valley***
Jurassic		**Bossier Sands***		**Bossier Shale***
		Haynesville Limestone		**Haynesville Shale***
		Smackover/Buckner		

Table 12. Simplified stratigraphic column of the Permian Basin showing commonly fraced intervals, as well as potential targets (in bold)

System	Age	Formation / Group		
		Delaware Basin	**Central Platform**	**Midland Basin**
Permian	Ochoan	Salado/Rustler/Dewey Lake and Dockum		
	Guadalupian	**Delaware Mountain Group* (Brushy, Cherry, & Bell Canyon)**	Queen/Seven Rivers/**Yates***/Tansill San Andres Grayburg	
	Leonardian	**Bone Spring***	Clear Fork	**Spraberry*/Dean***
	Wolfcampian	Wolfcamp Basin	Wolfcamp Platform	**Wolfcamp Basin***
Pennsylvanian		Morrow/Atoka/Strawn/Canyon/Cisco		
Mississippian		**Barnett***	N/A	Platform Carbonates **Barnett***
Devonian		**Devonian*/Woodford***		
Silurian		**Siluro-Devonian***		
Ordovician		Simpson Group/Ellenburger		
Cambrian		Wilberns		

Table 13. Simplified stratigraphic column of South Texas Gulf Coast showing commonly fraced intervals, as well as potential targets (in bold)

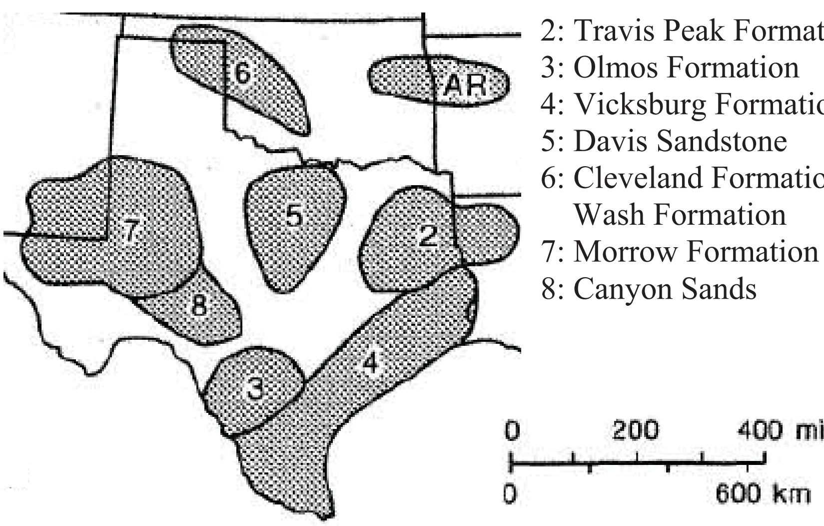
System	Age	Formation / Group
Oligocene		**Vicksburg*/Frio***
Eocene / Paleocene		**Wilcox-Lobo***/Carrizo/Queen City/Sparta/ Yegua/Jackson
Paleocene (Early)		Midway
Cretaceous		**San Miguel*/Olmos*/Escondido***
		Austin Chalk*
		Eagle Ford*
		Glen Rose/Edwards/Stuart City/Georgetown/Del Rio/Buda/
		Pearsall*
		Hosston/Sligo
Jurassic		Cotton Valley

Table 14. County-level tight-formation-completion water use (2008)

County	Water Use (thousand AF)	County	Water Use (thousand AF)	County	Water Use (thousand AF)
Andrews	0.132	Harrison	0.815	Ochiltree	0.071
Angelina	0.090	Hemphill	0.721	Panola	0.908
Bee	0.006	Henderson	0.028	Pecos	0.183
Borden	0.003	Hidalgo	0.074	Reagan	0.308
Brazoria	0.003	Houston	0.013	Real	0.002
Brooks	0.015	Howard	0.047	Reeves	0.057
Calhoun	0.003	Irion	0.062	Roberts	0.216

County	Water Use (thousand AF)	County	Water Use (thousand AF)	County	Water Use (thousand AF)
Cherokee	0.120	Jackson	0.004	Robertson	0.208
Colorado	0.002	Jim Hogg	0.002	Rusk	0.540
Crane	0.003	Kenedy	0.027	San Augustine	0.088
Crockett	0.026	La Salle	0.017	San Patricio	0.002
Culberson	0.012	Lavaca	0.018	Smith	0.052
Dawson	0.007	Leon	0.055	Starr	0.068
DeWitt	0.013	Limestone	0.264	Sterling	0.022
Dimmit	0.004	Lipscomb	0.141	Terrell	0.008
Duval	0.020	Live Oak	0.003	Terry	0.004
Ector	0.183	Loving	0.030	Upshur	0.030
Edwards	0.002	McMullen	0.044	Upton	0.999
Fort Bend	0.003	Marion	0.029	Val Verde	0.001
Freestone	0.501	Martin	0.560	Van Zandt	0.002
Frio	0.004	Matagorda	0.008	Ward	0.067
Gaines	0.018	Maverick	0.015	Webb	0.112
Glasscock	0.096	Midland	0.371	Wharton	0.006
Goliad	0.009	Mitchell	0.027	Wheeler	1.071
Gregg	0.128	Nacogdoches	0.384	Willacy	0.005
Hale	0.002	Navarro	0.004	Winkler	0.014
Hansford	0.003	Newton	0.001	Yoakum	0.005
Hardin	0.001	Nueces	0.008	Zapata	0.107

MiningWaterUse2008_2.xls



2: Travis Peak Formation and Cotton Valley Sandstone
3: Olmos Formation
4: Vicksburg Formation and Wilcox Group
5: Davis Sandstone
6: Cleveland Formation, Cherokee Group, and Granite Wash Formation
7: Morrow Formation
8: Canyon Sands

Source: modified from Dutton et al. (1993, Fig. 1)

Figure 53. Location of basins in Texas containing low-permeability sandstone with historical frac jobs

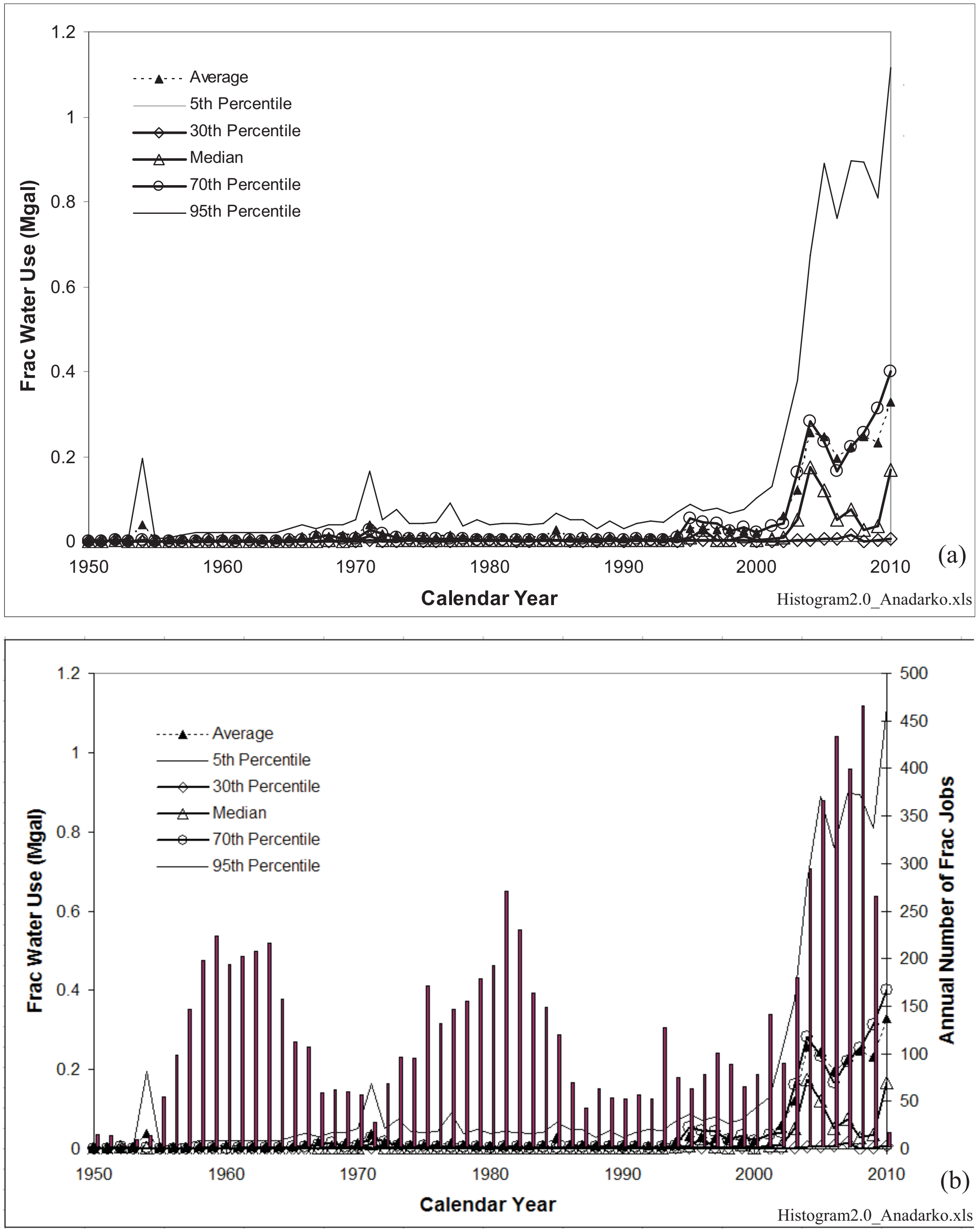
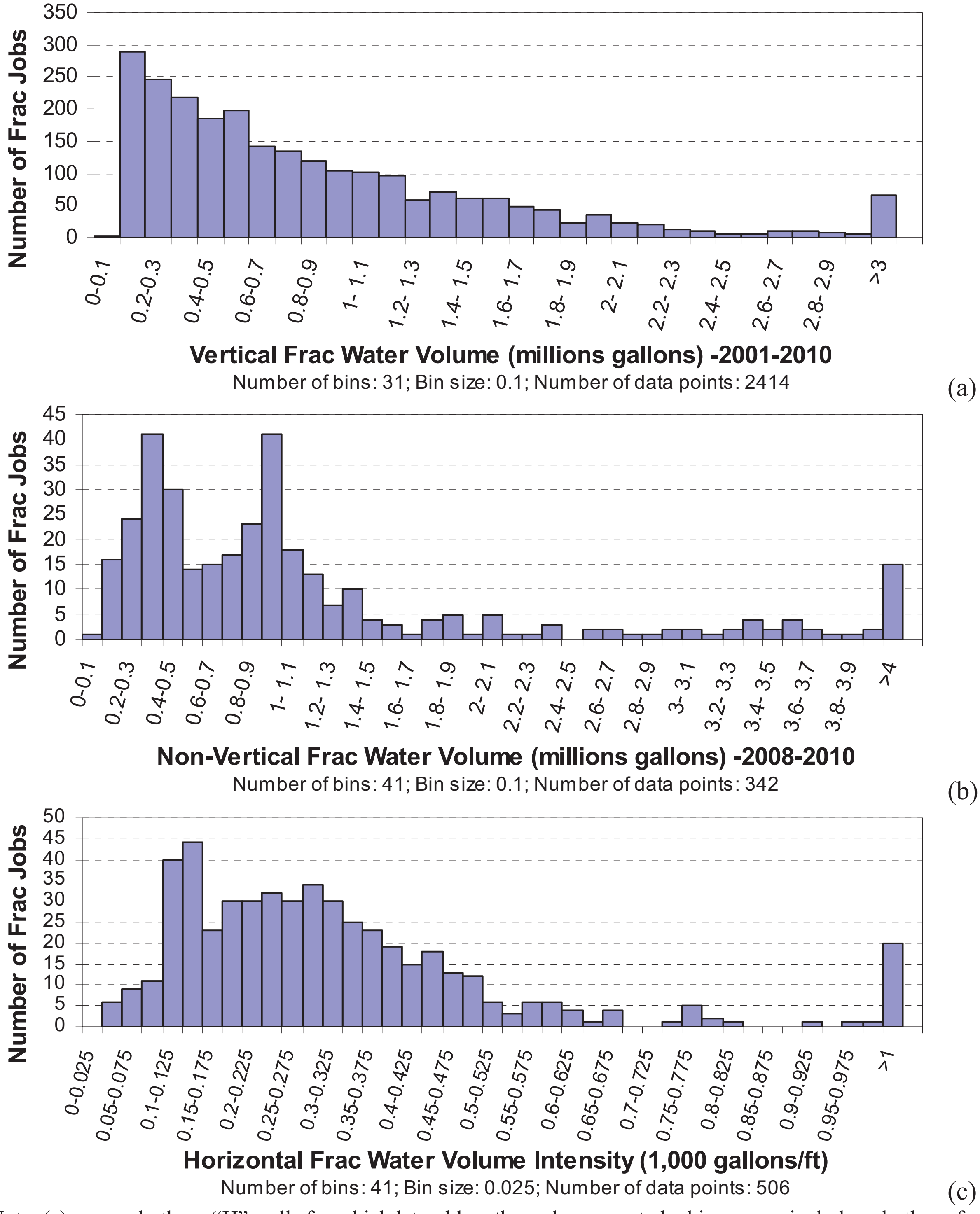


Figure 54. Anadarko Basin—annual number of frac jobs (b) superimposed on annual average, median, and other percentiles of individual well frac water use (a)



Note: (c) uses only those "H" wells for which lateral length can be computed—histograms include only those frac jobs using >0.1 Mgal.

Figure 55. Anadarko Basin—frac water use in vertical wells (a), nonvertical wells (b), and water-use intensity in selected horizontal wells (c)

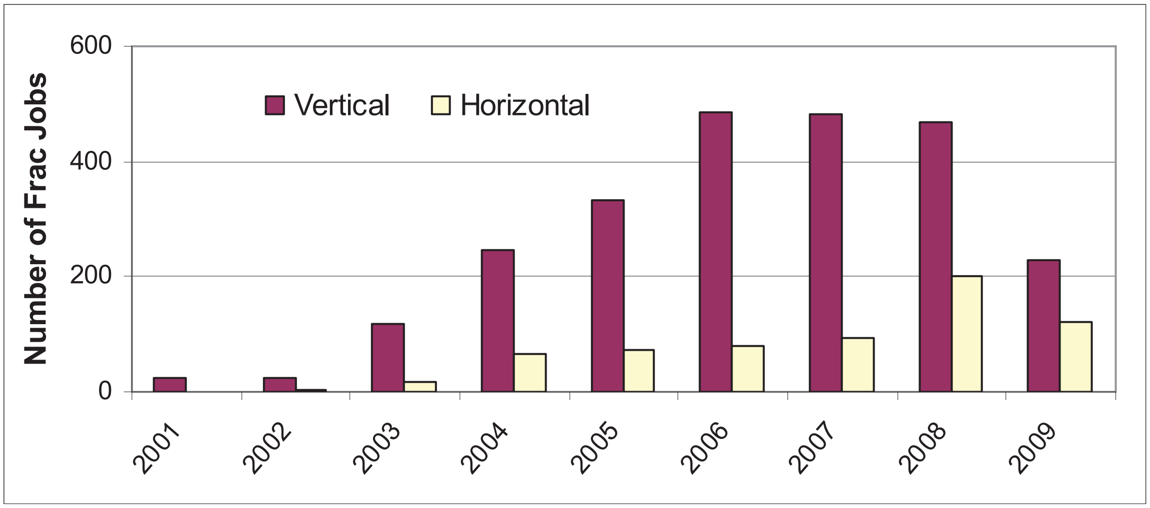


Figure 56. Anadarko Basin—vertical vs. horizontal and directional wells through time

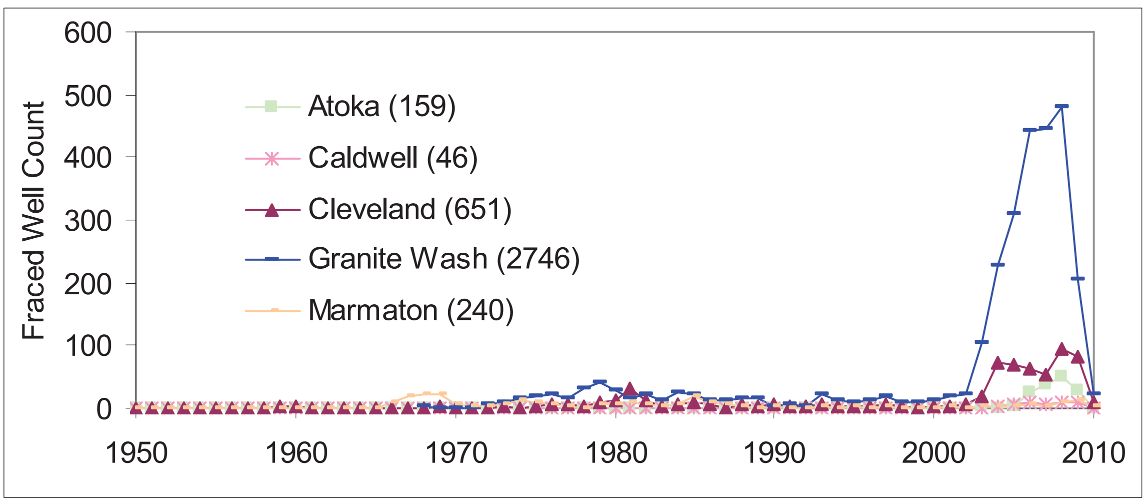
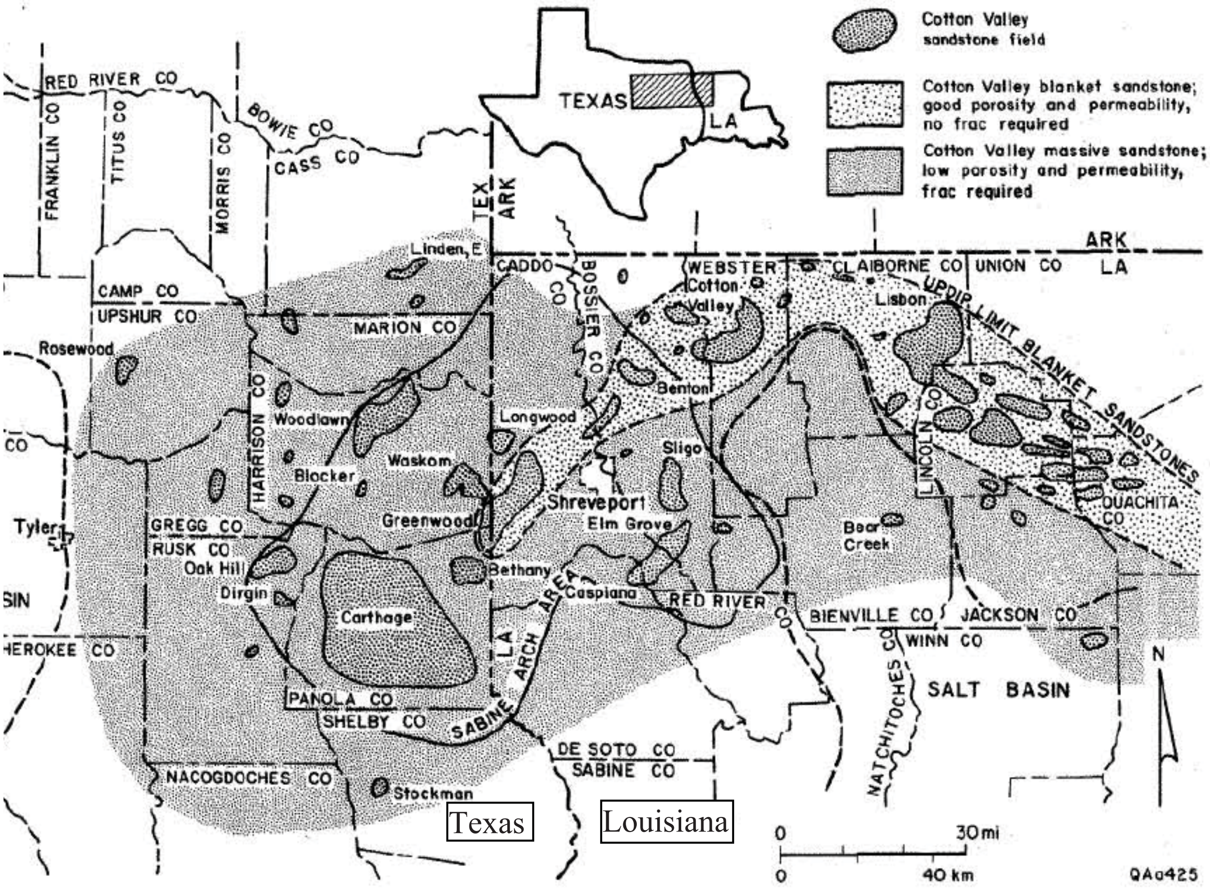


Figure 57. Anadarko Basin—fraced well count per formation



Source: Dutton et al. (1993, Fig. 24)

Figure 58. Distribution of Cotton Valley reservoir trends in East Texas

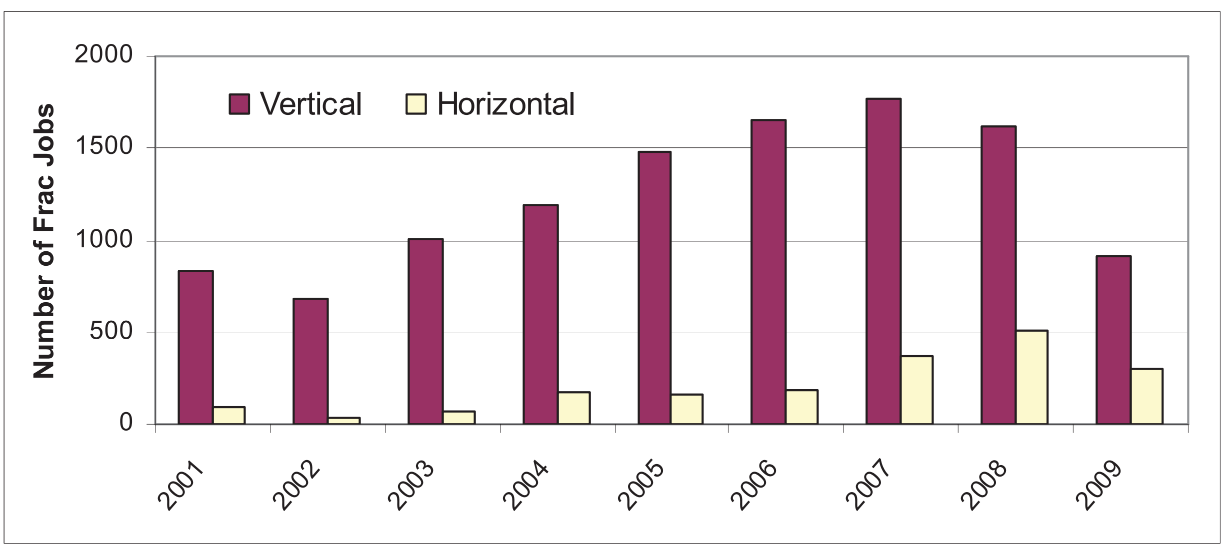
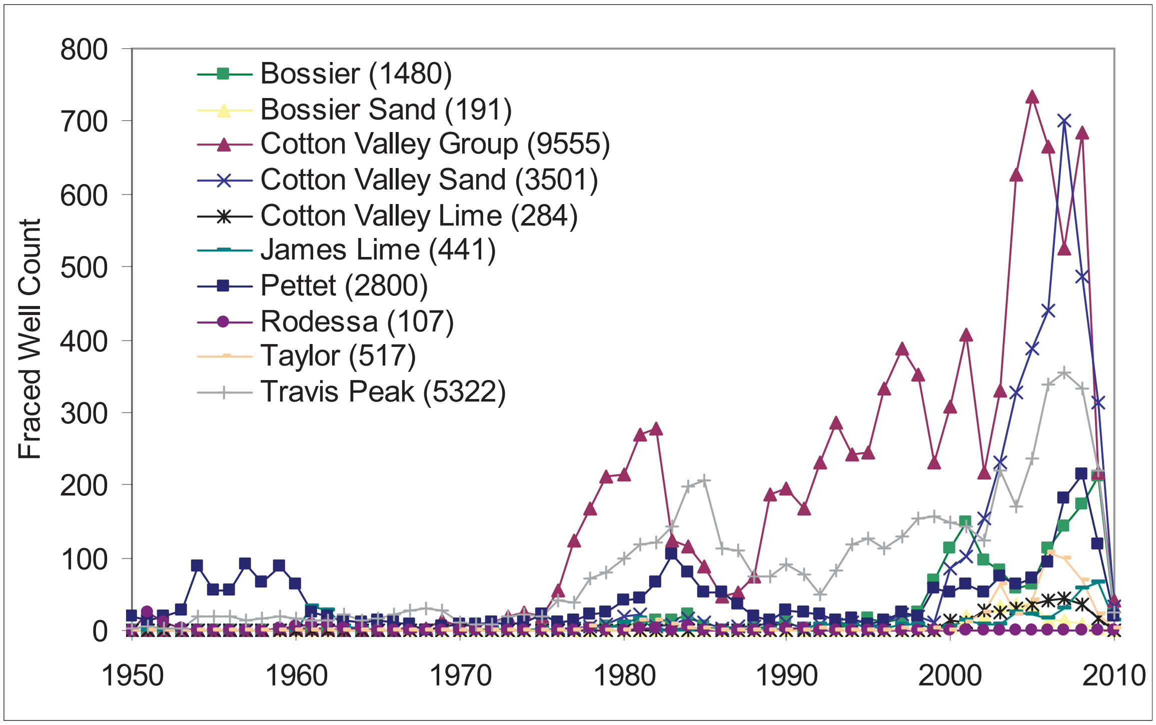
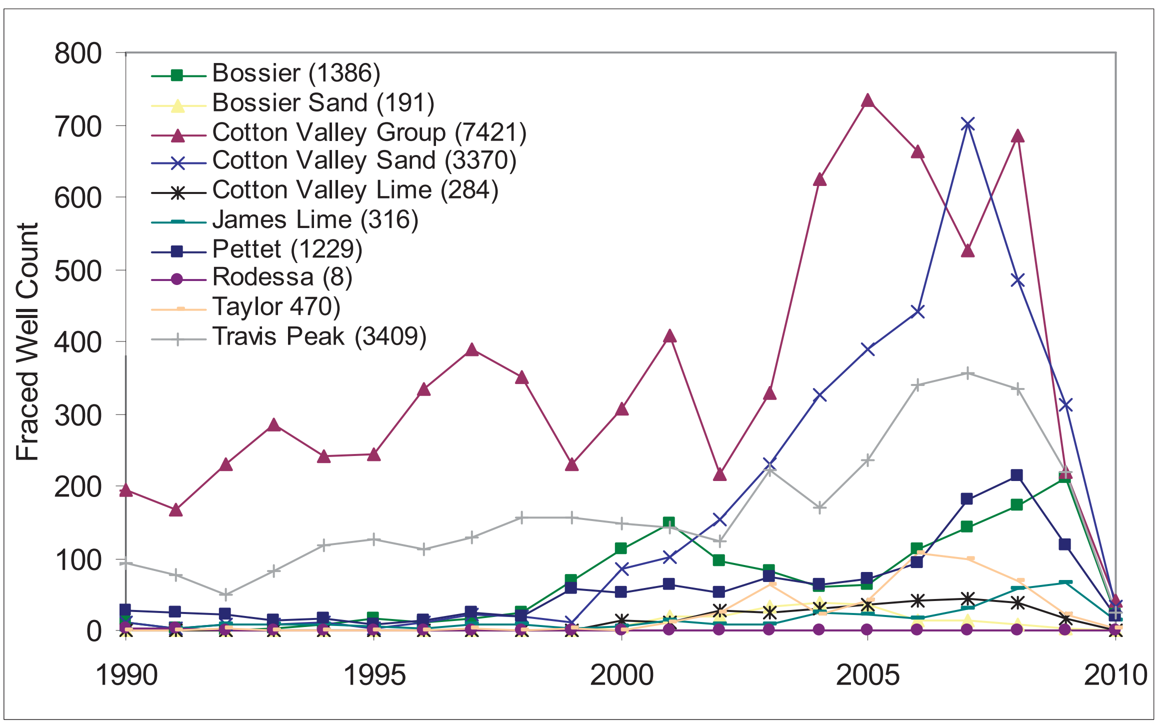


Figure 59. East Texas Basin—vertical vs. horizontal wells through time

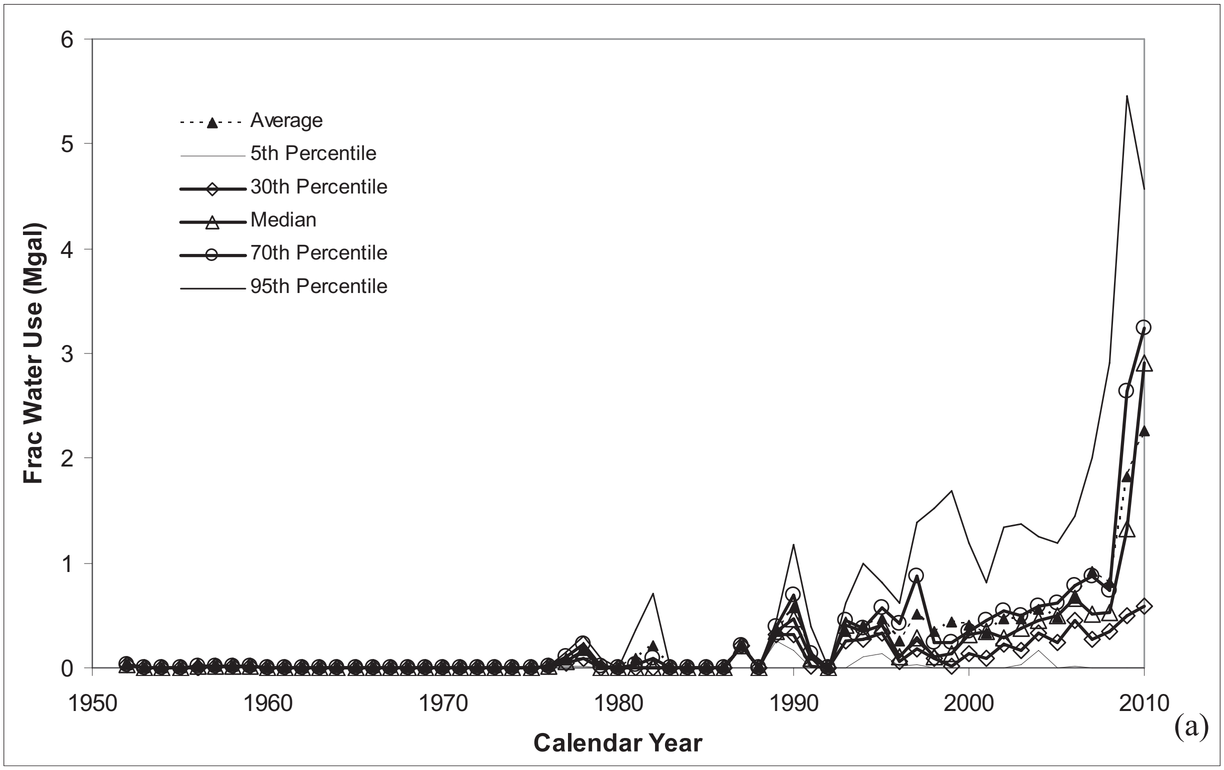


(a)



(b)

Figure 60. East Texas Basin—Fraced well count per formation from 1950 (a) and 1990 (b)



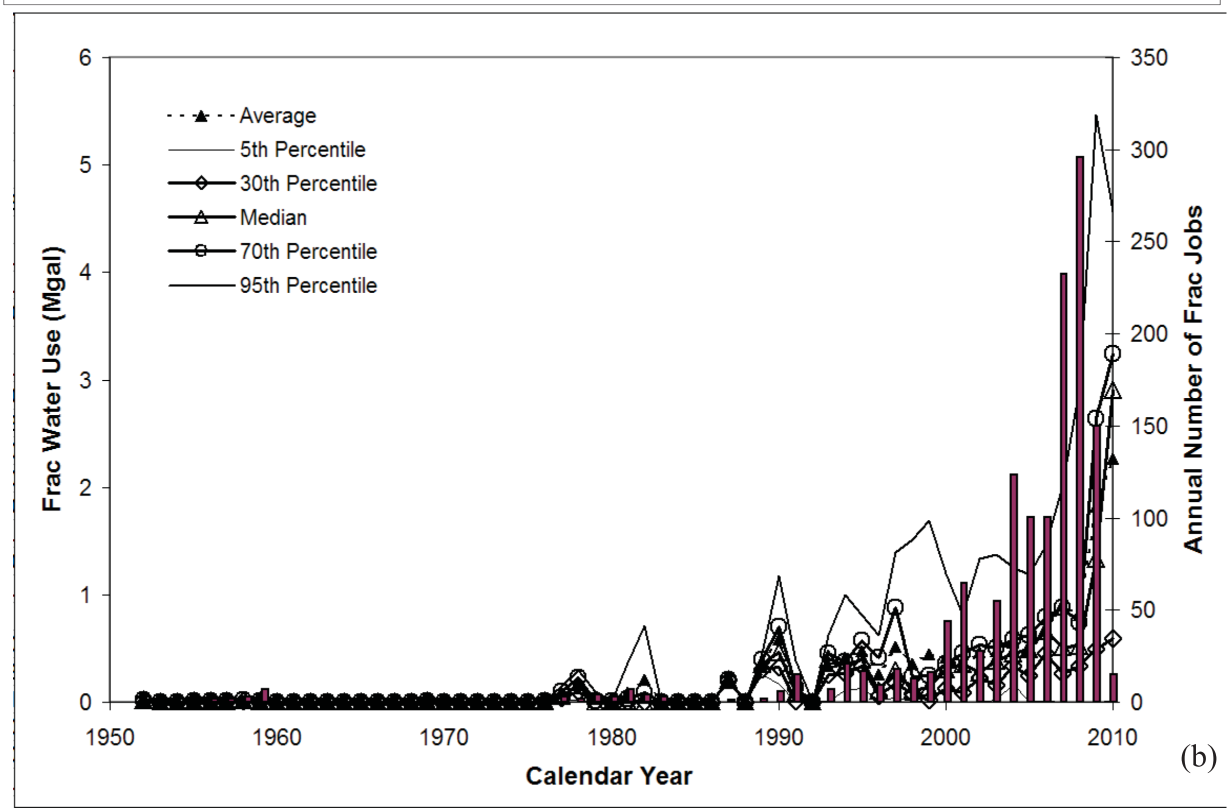
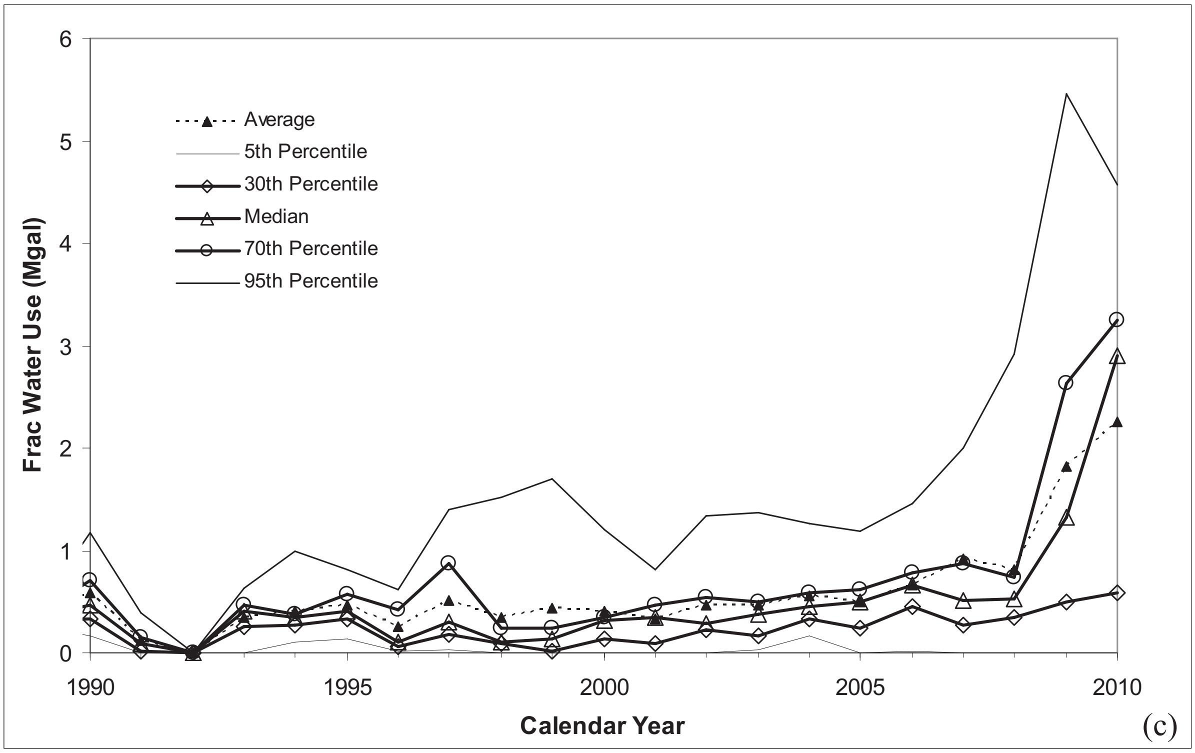


Figure 61. East Texas Basin—annual number of frac jobs (b and d) superimposed on annual average, median, and other percentiles of individual well frac water use (a and c) for 1950–~2008 (a and b) and 1990–~2008 (c and d) periods



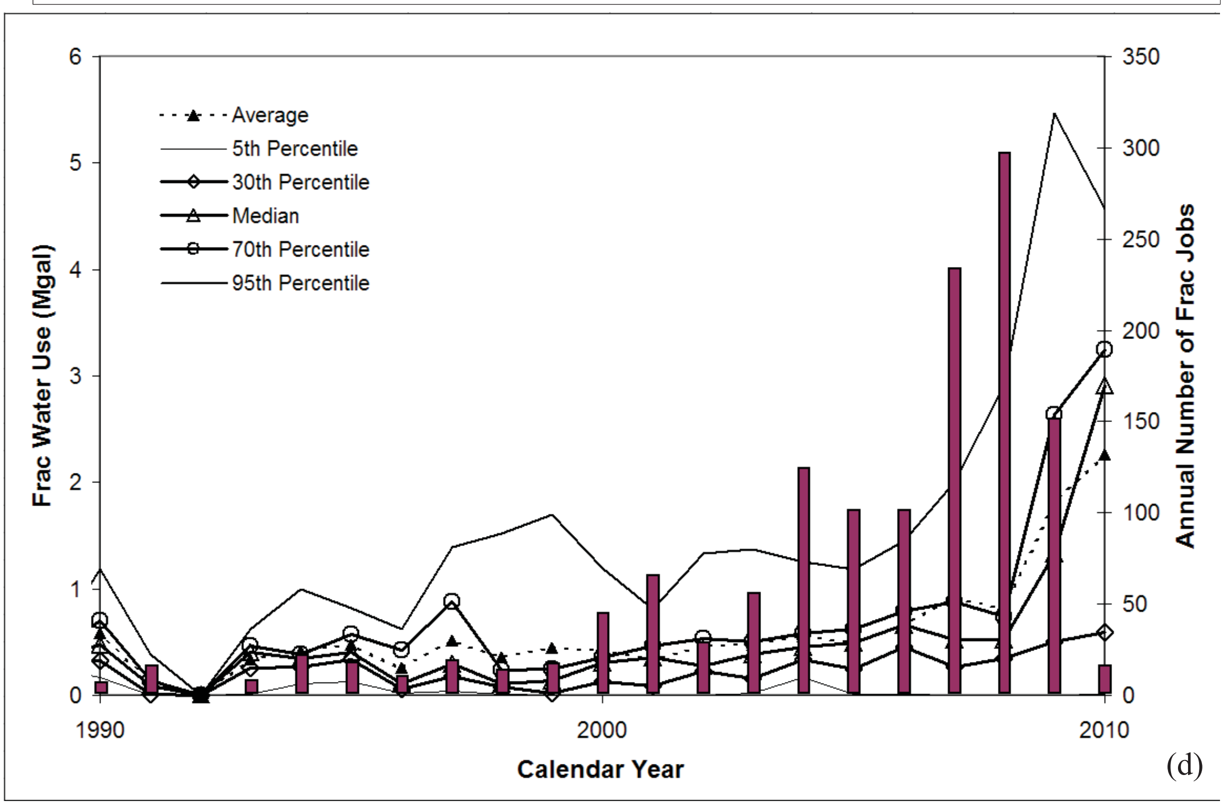
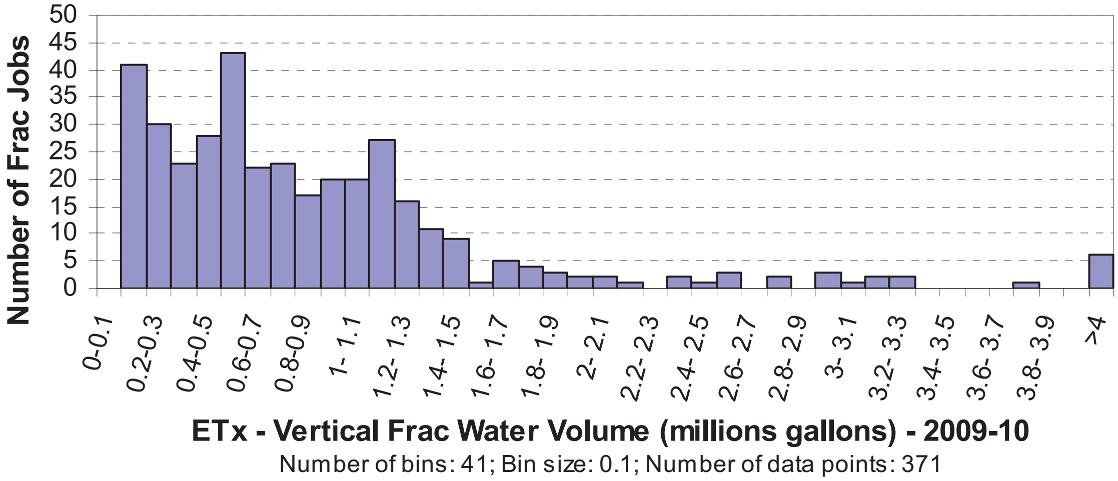
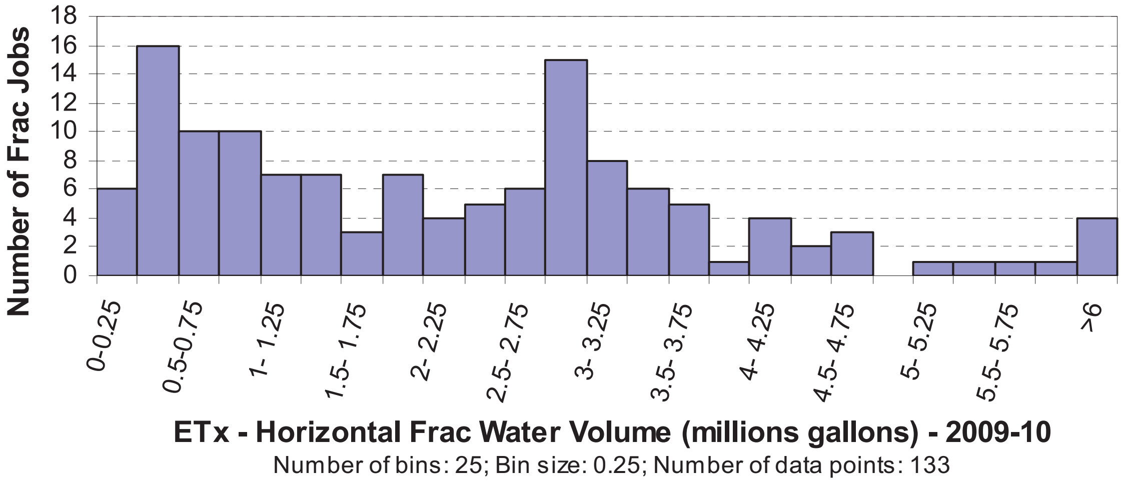


Figure 61. East Texas Basin—annual number of frac jobs (b and d) superimposed on annual average, median, and other percentiles of individual well frac water use (a and c) for 1950–~2008 (a and b) and 1990–~2008 (c and d) periods (continued).



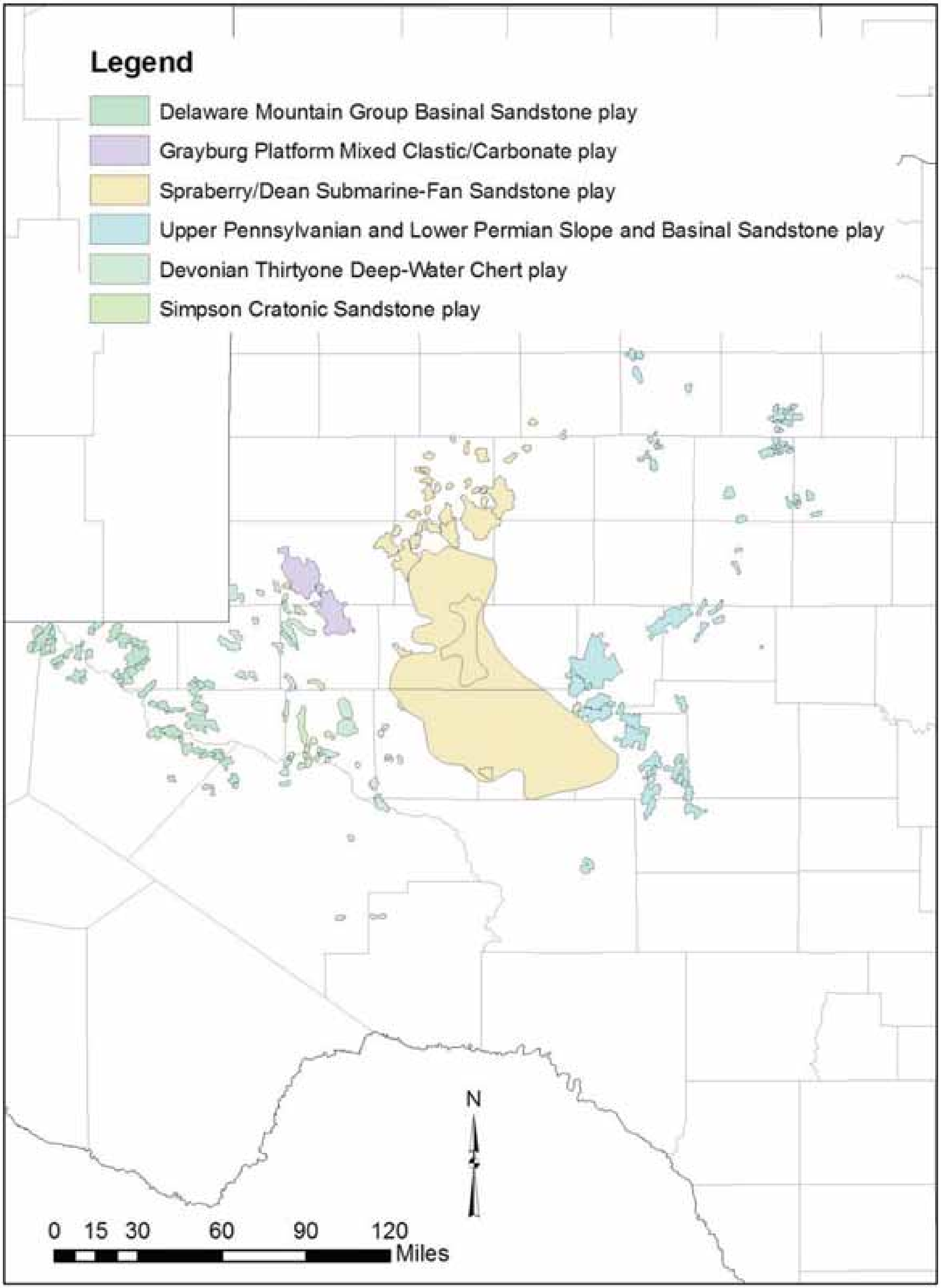
(a)



(b)

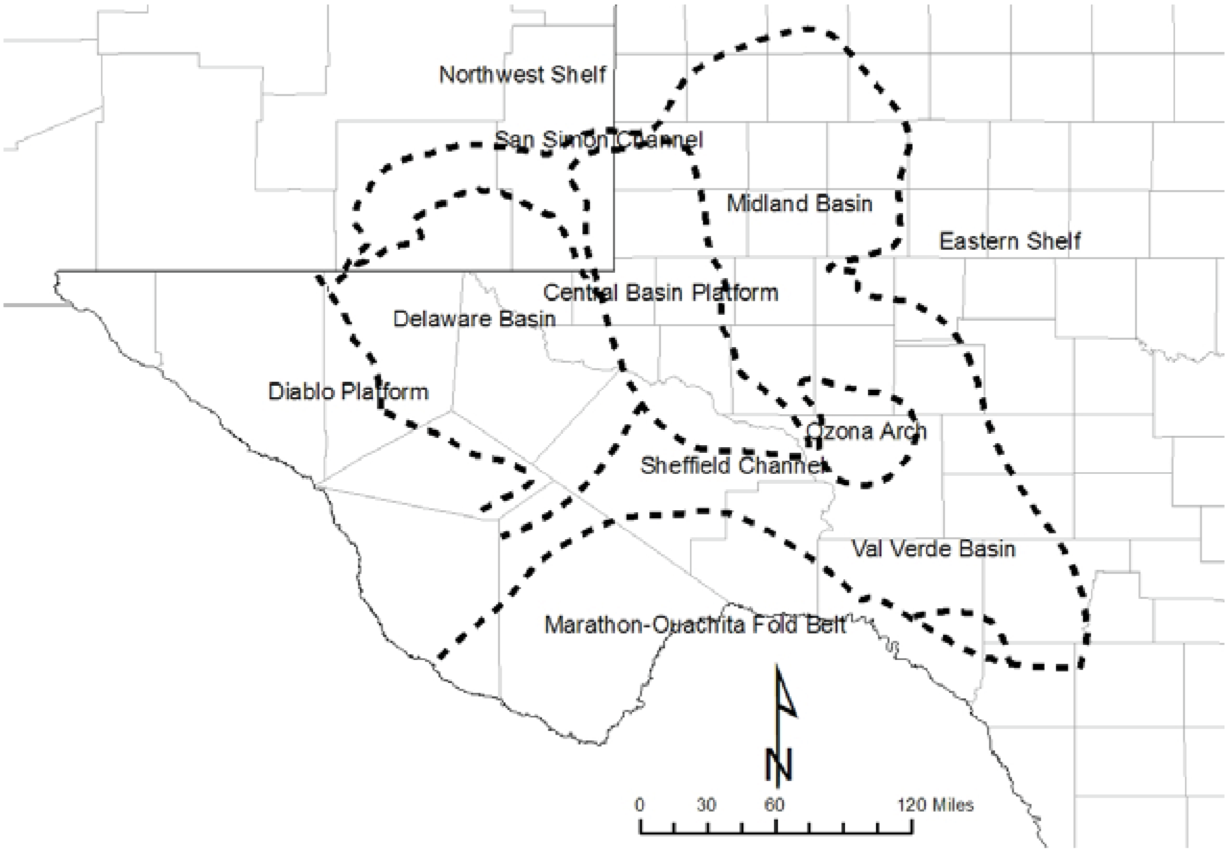
Note: Histograms include only those documented frac jobs using >0.1 Mgal

Figure 62. East Texas Basin—frac water use in vertical wells (a) and horizontal wells (b)



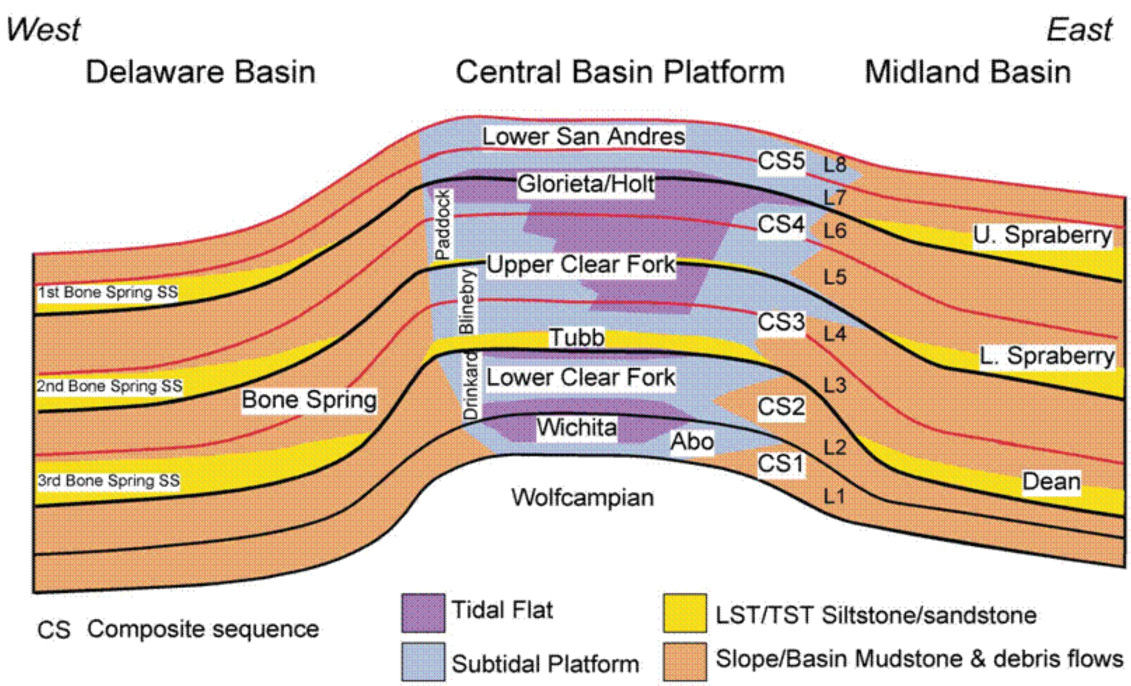
Source: Dutton et al. (2005a—GIS files)

Figure 63. Main clastic plays in the Permian Basin



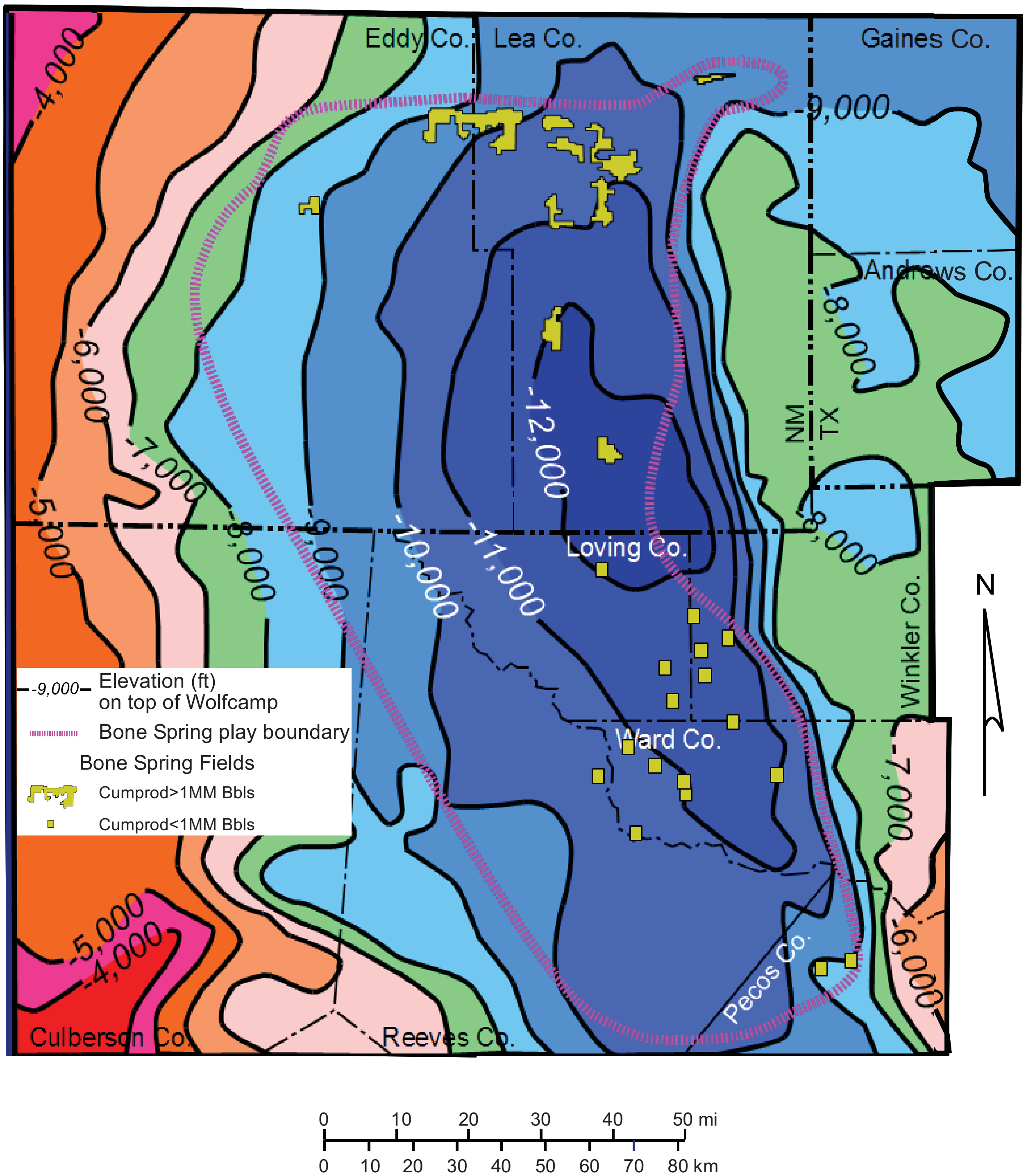
Source: from GIS coverage of companion CD of Dutton et al. (2005a)

Figure 64. Permian Basin geologic features



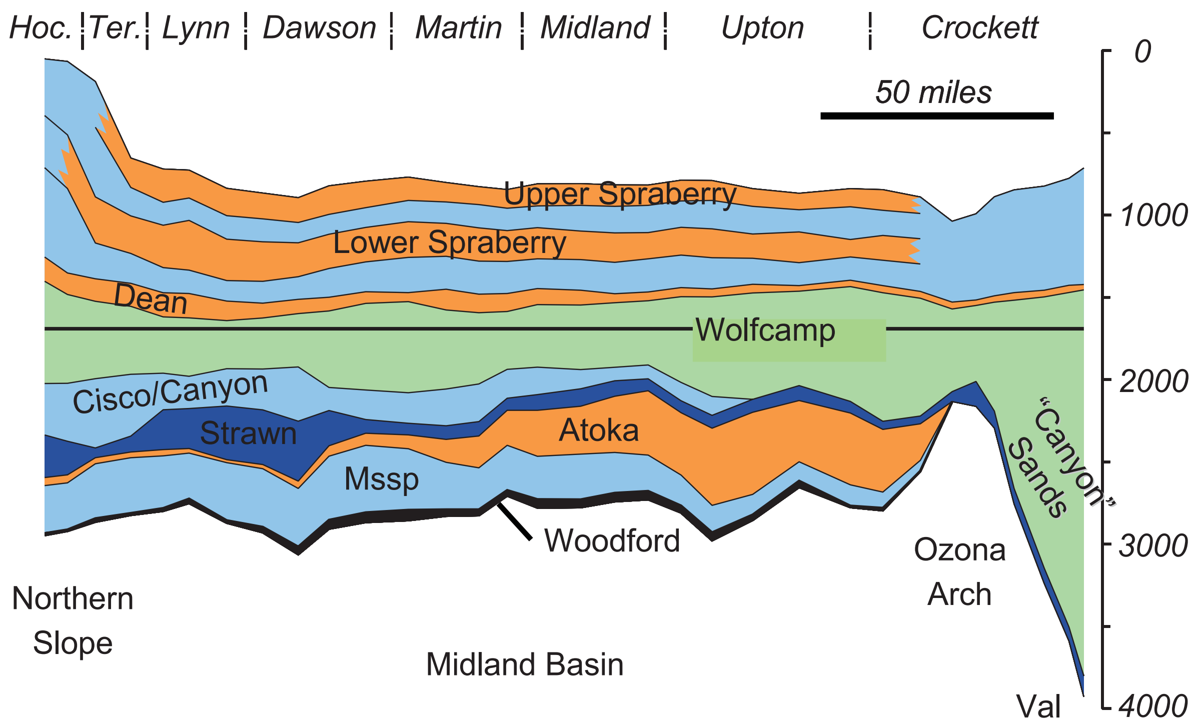
Source: Courtesy of Stephen Ruppel and Mudrock group at BEG

Figure 65. Regional sequence stratigraphy of the Leonardian (Permian)



Source: Seay Nance and the Mudrock Group at BEG

Figure 66. Bone Spring footprint and elevation of top of Wolfcamp



Source: Scott Hamlin and the Mudrock Group at BEG; vertical scale in feet

Figure 67. North-south Midland Basin cross section of Permian (Leonard and Wolfcamp), Pennsylvanian, Mississippian, and Devonian

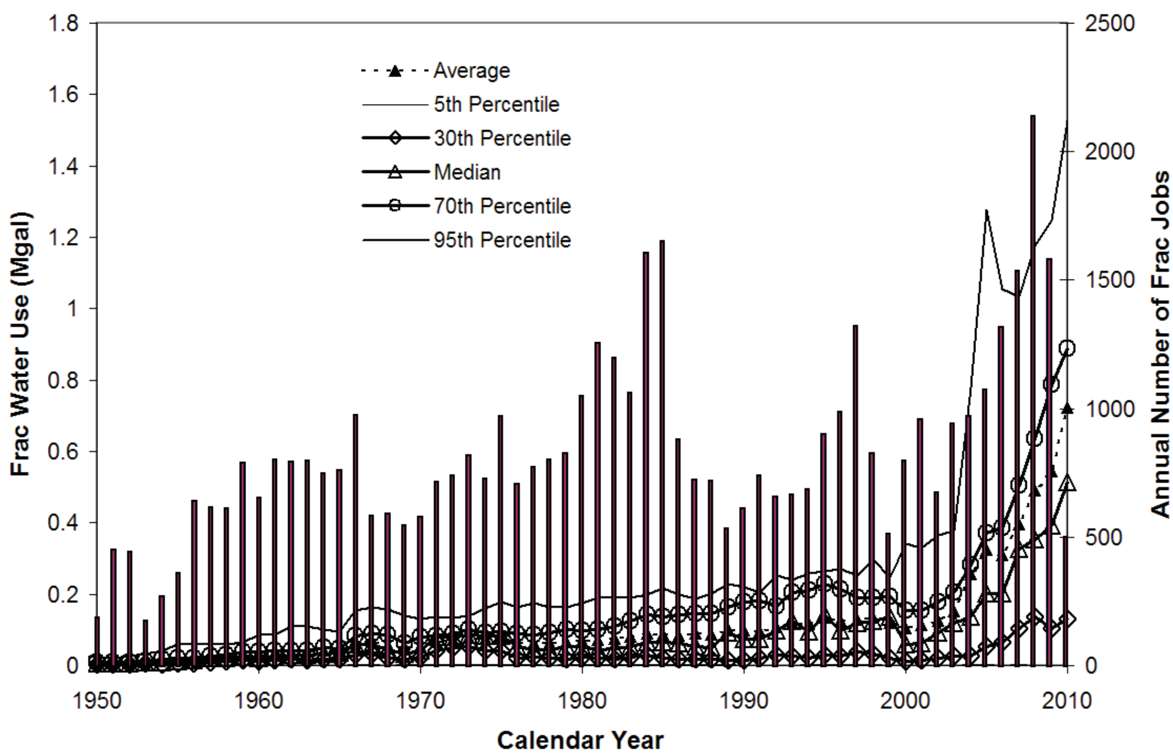


Figure 68. Permian Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use (all 50,000+ wells).

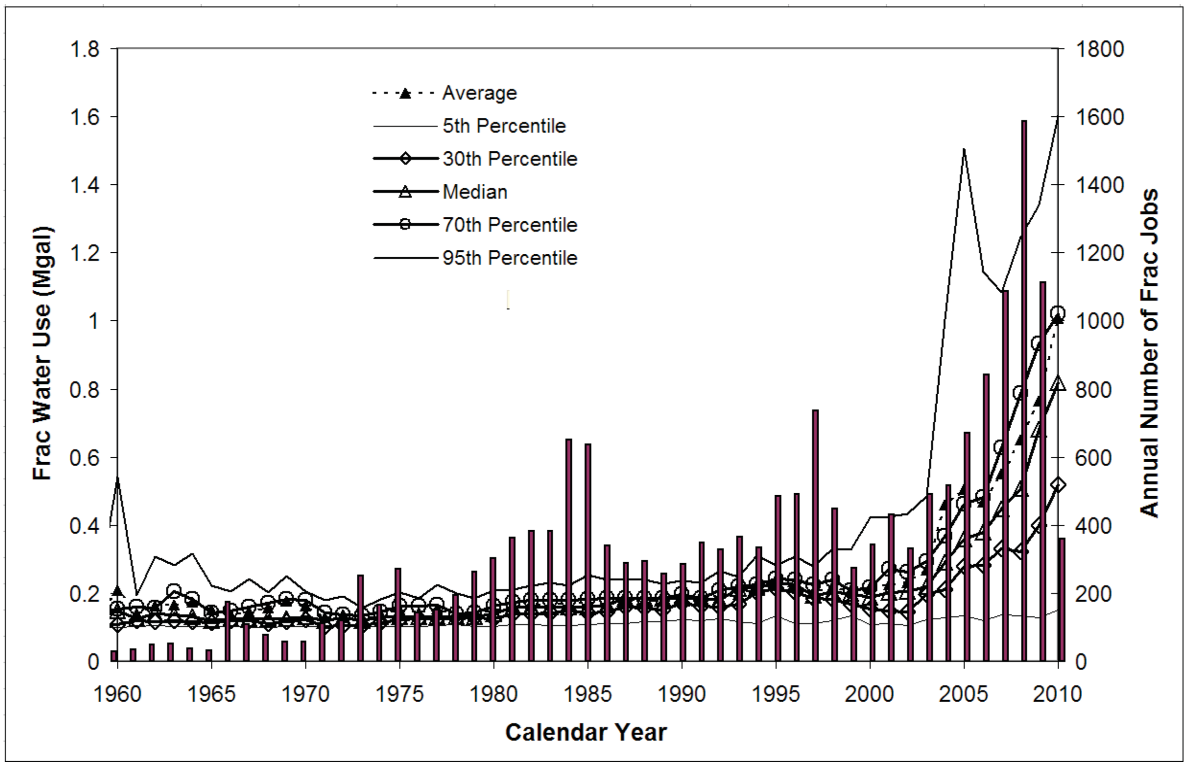


Figure 69. Permian Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use (water use > 0.1 Mgal)

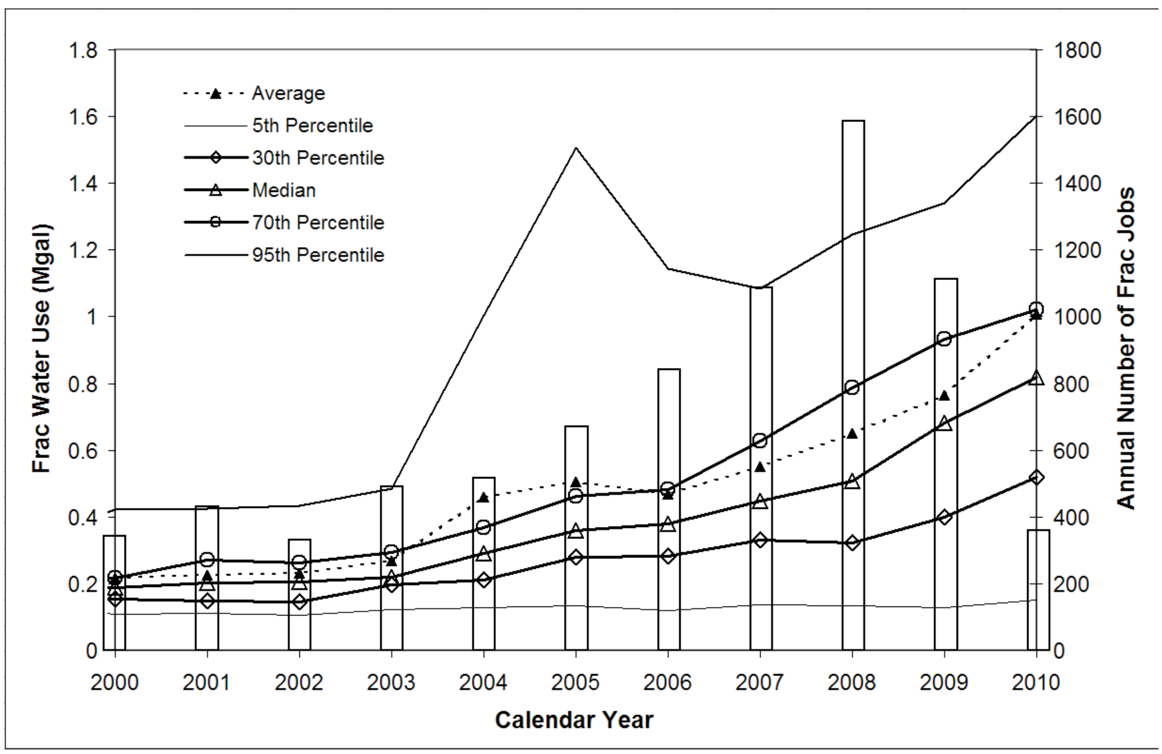


Figure 70. Permian Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use (water use >0.1 Mgal since 2000)

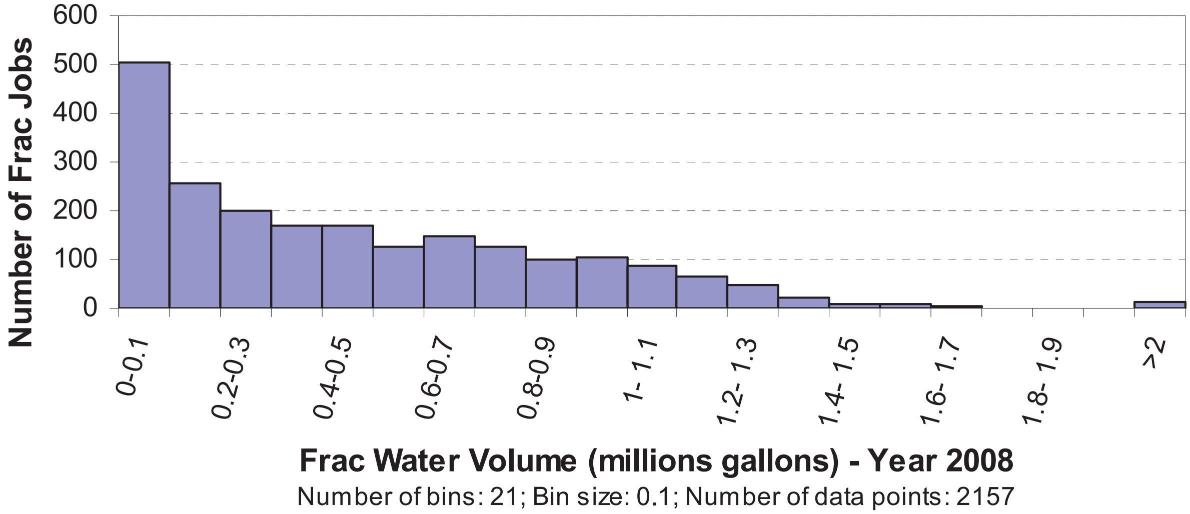


Figure 71. Permian Basin—frac water use in vertical wells

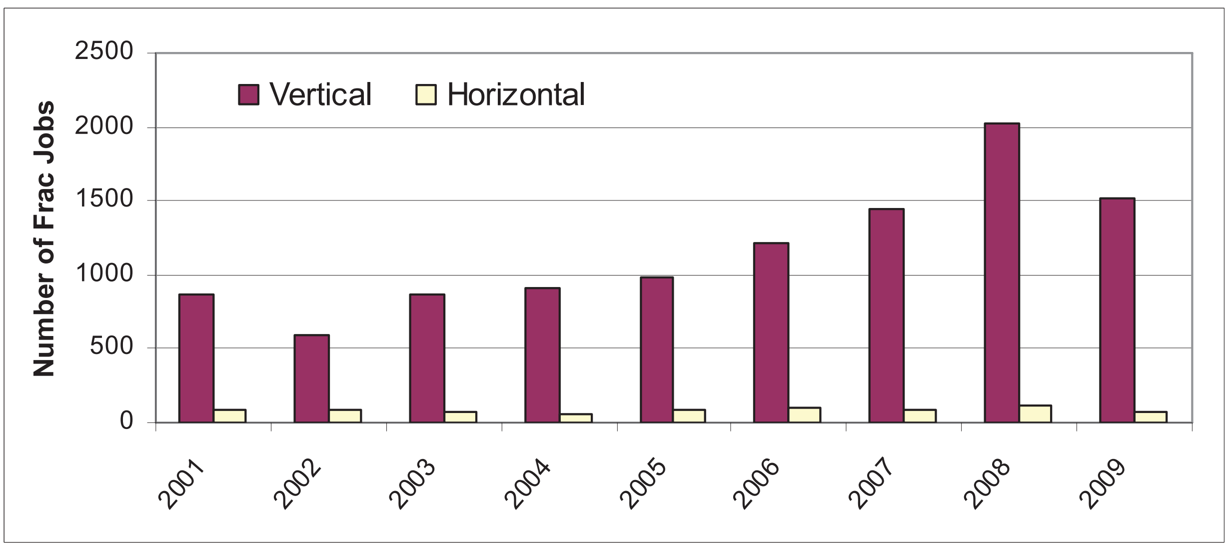
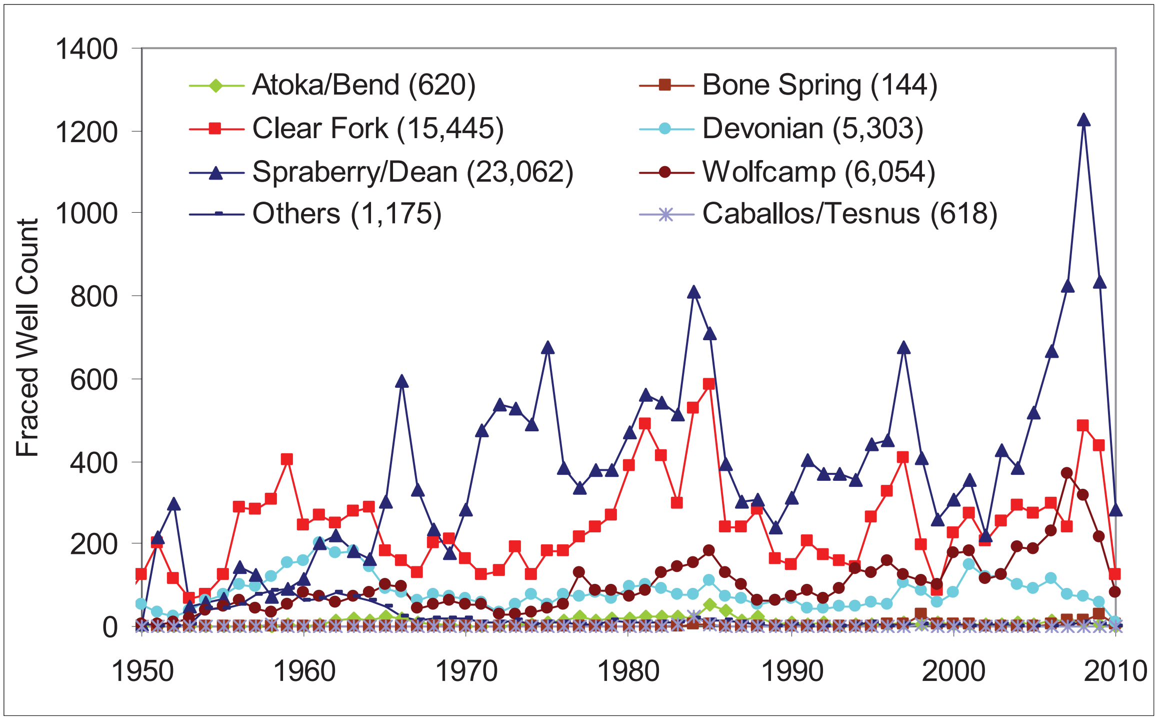
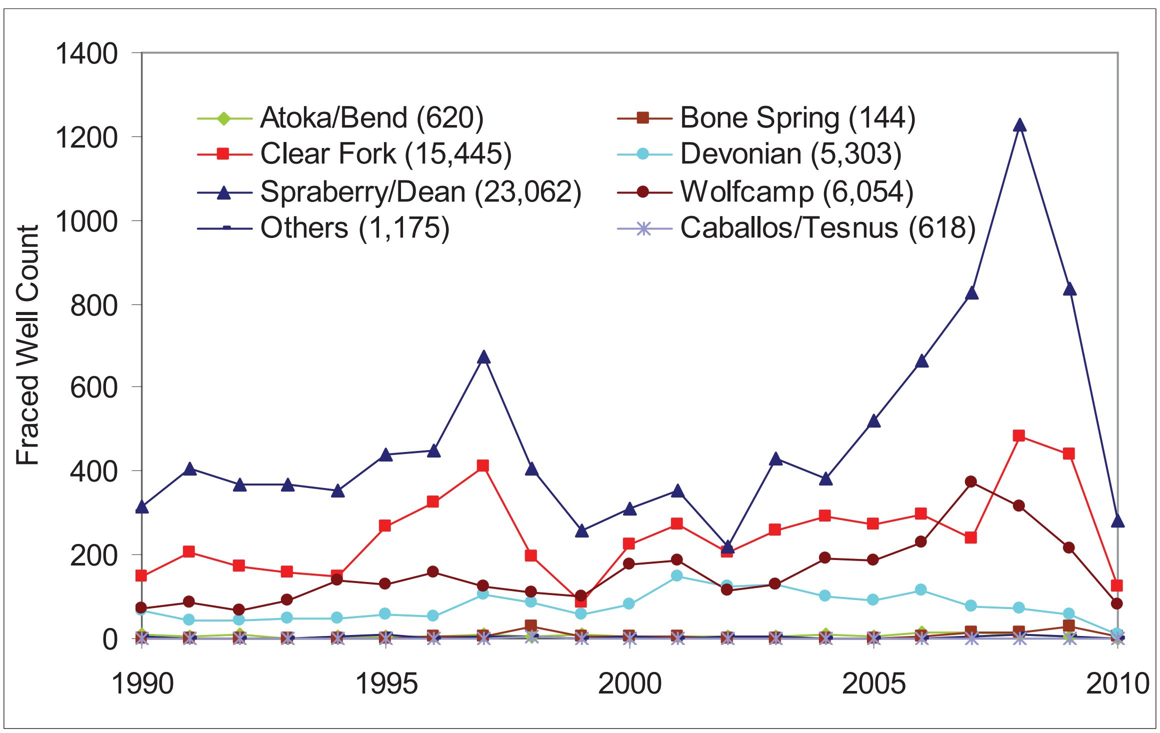


Figure 72. Permian Basin—vertical vs. horizontal wells through time

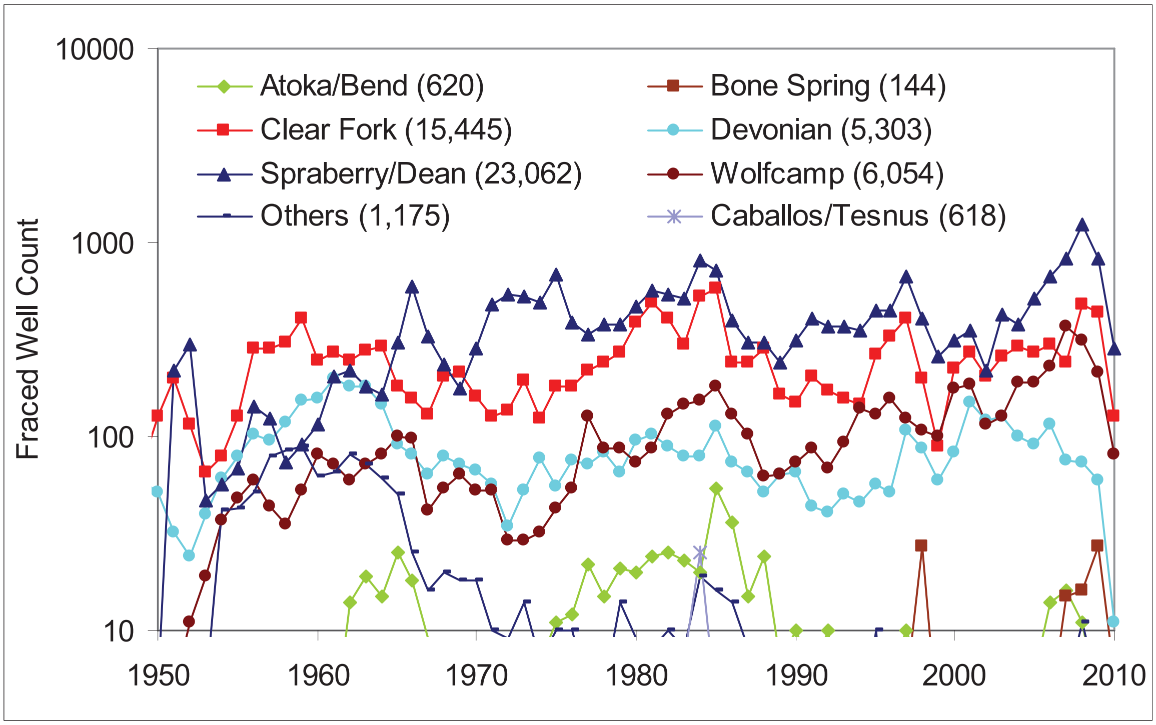


(a)

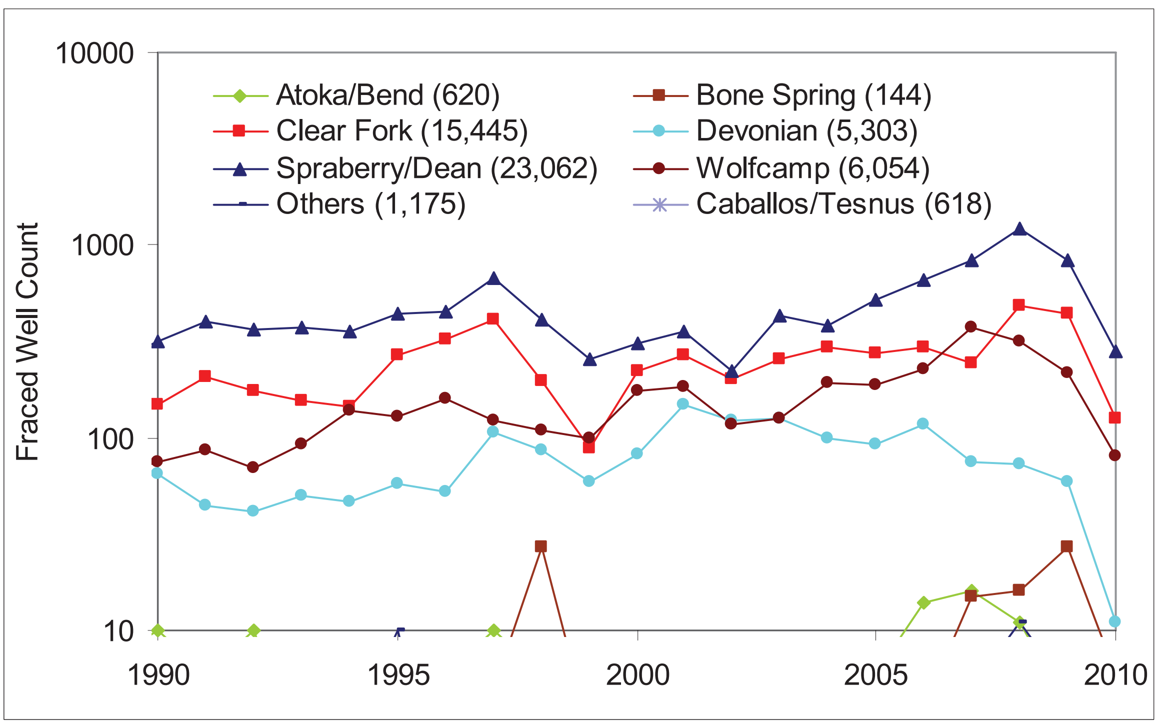


(b)

Figure 73. Permian Basin—fraced well count per formation from 1950 (a) and from 1990 (b) (linear scale—including Caballos/Tesnus)



(a)



(b)

Figure 74. Permian Basin—fraced well count per formation from 1950 (a) and 1990 (b) (log scale—including Caballos/Tesnus)

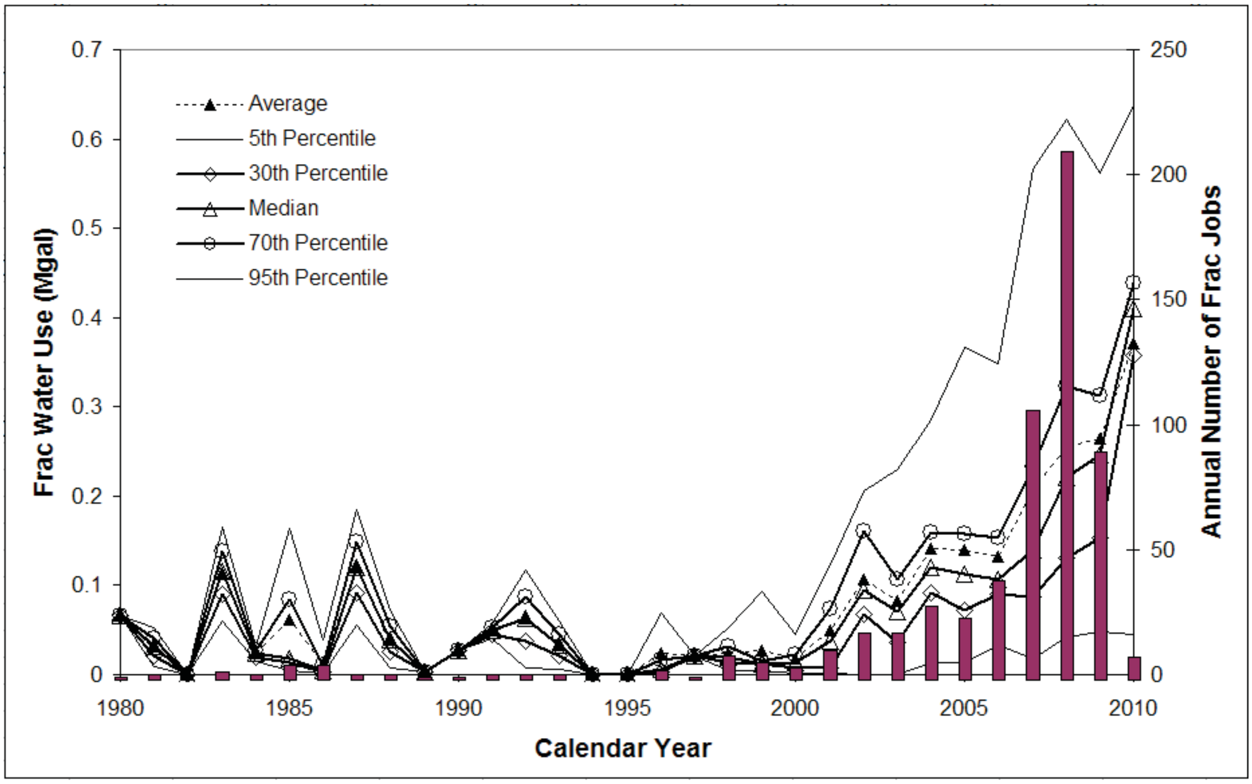


Figure 75. Caballos-Tesnus—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

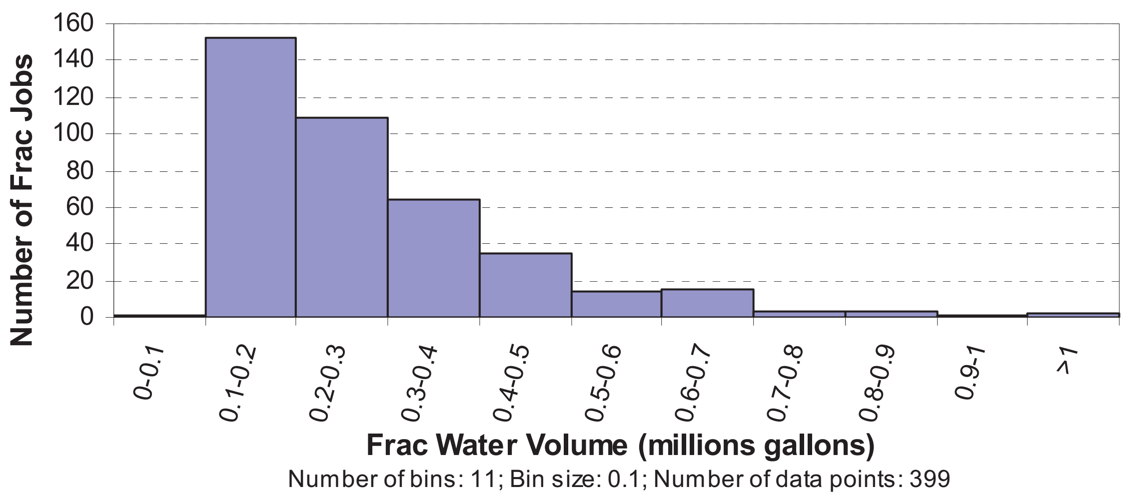


Figure 76. Caballos-Tesnus—frac water volume

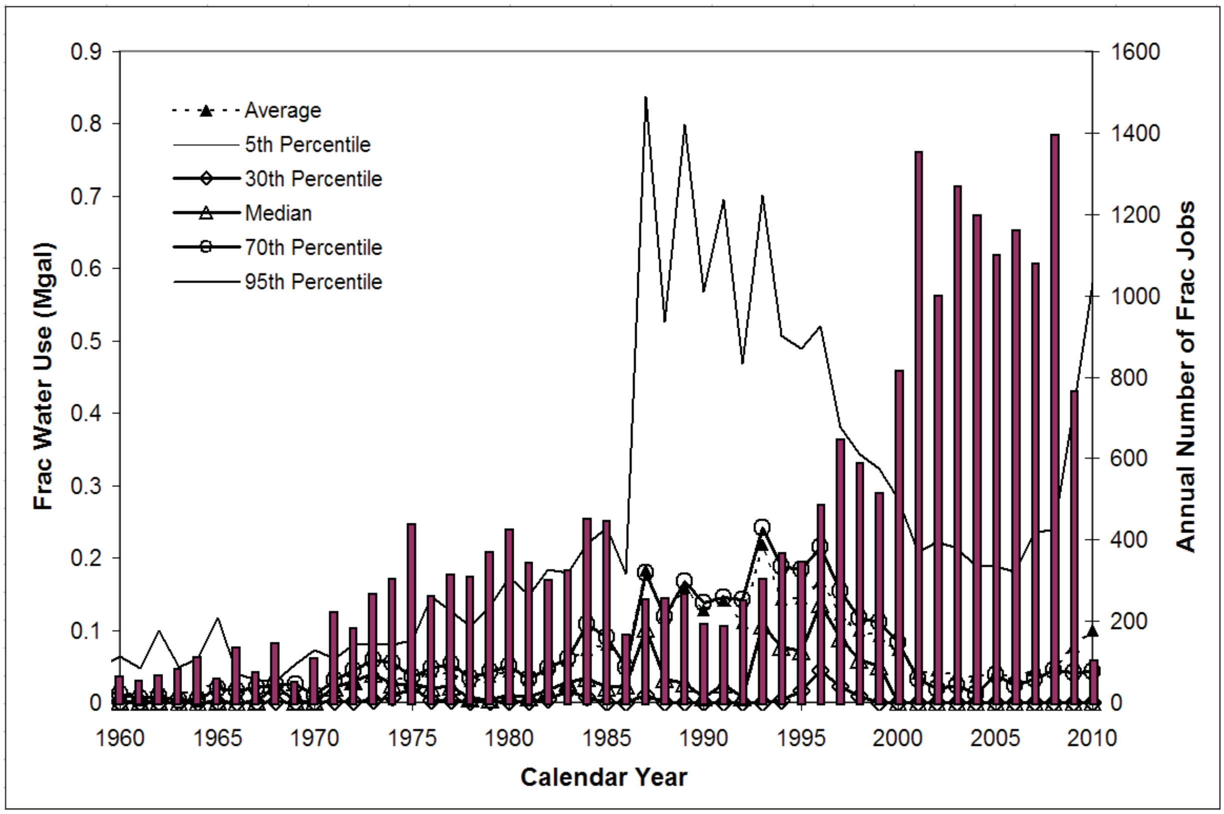


Figure 77. Gulf Coast Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

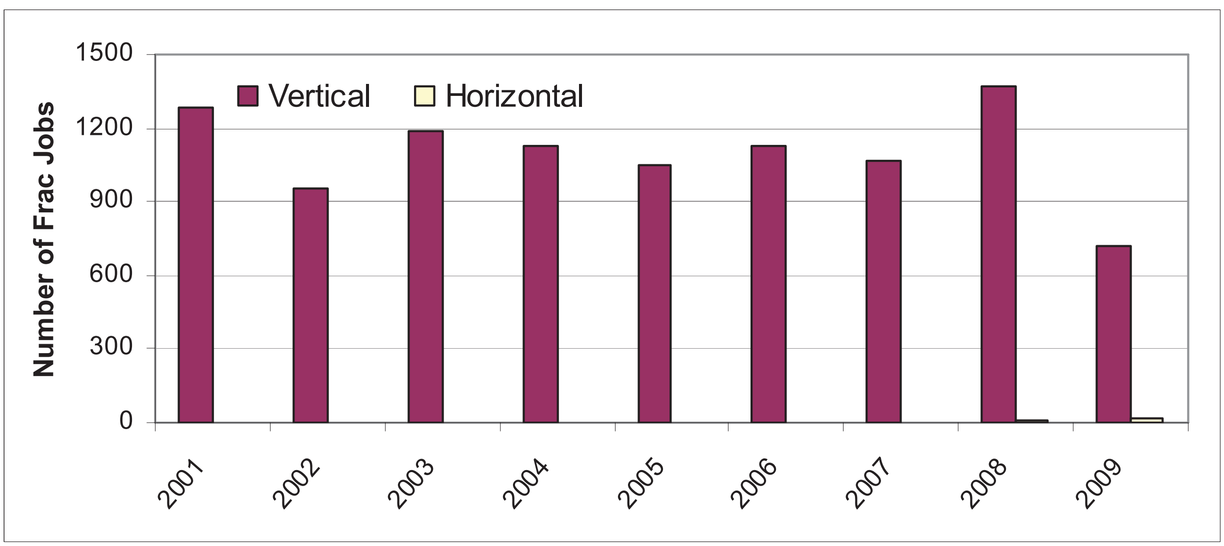
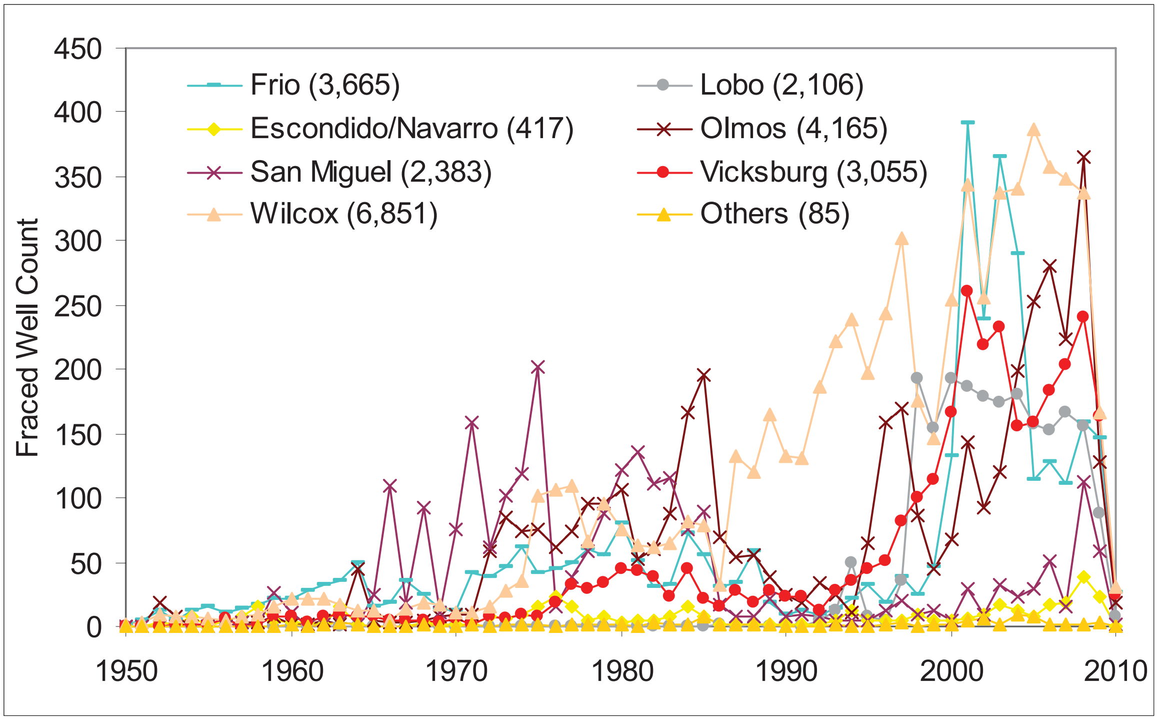
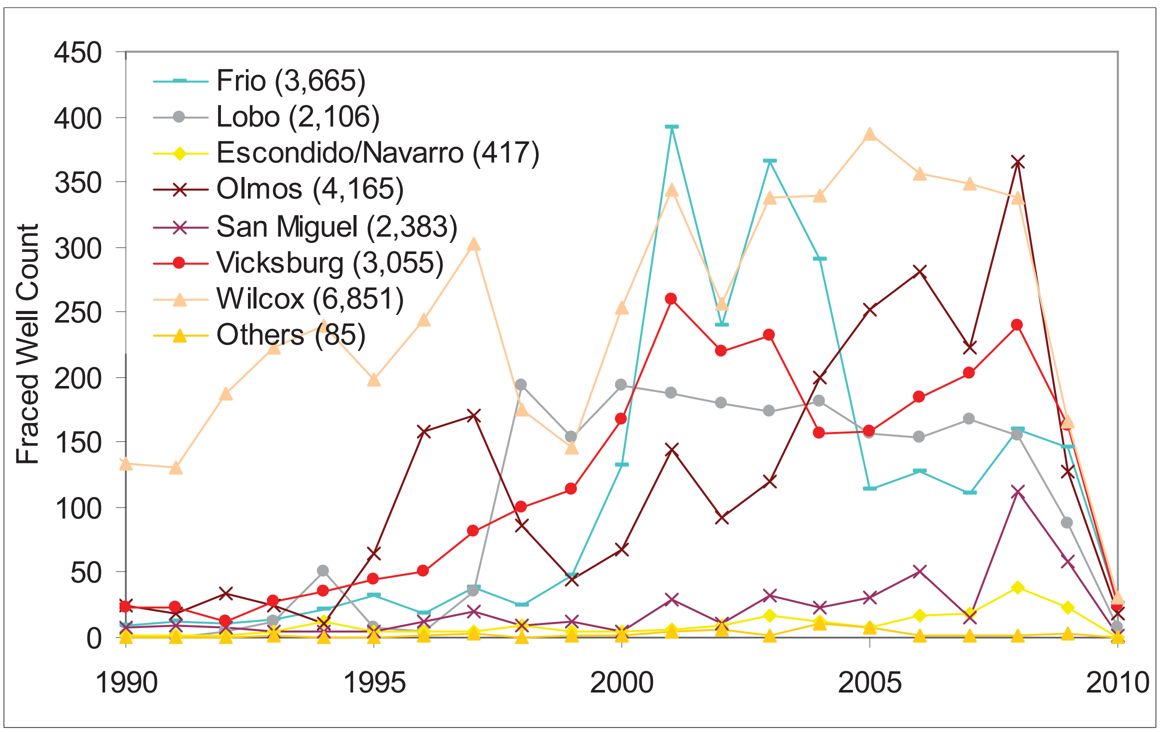


Figure 78. Gulf Coast Basin—vertical vs. horizontal wells through time



(a)



(b)

Figure 79. Gulf Coast Basin—fraced well count per formation from 1950 (a) and 1990 (b)

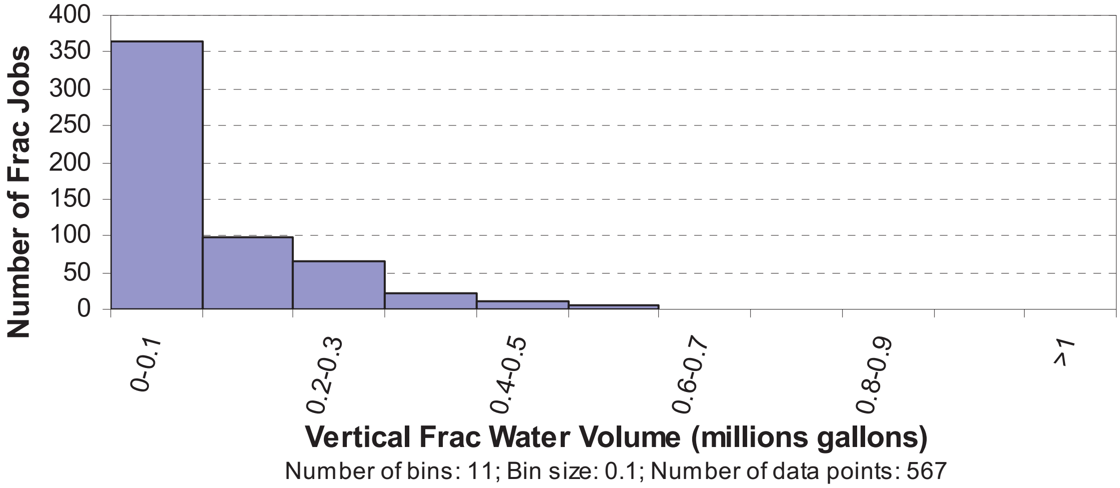


Figure 80. Gulf Coast—frac water volume (2008)

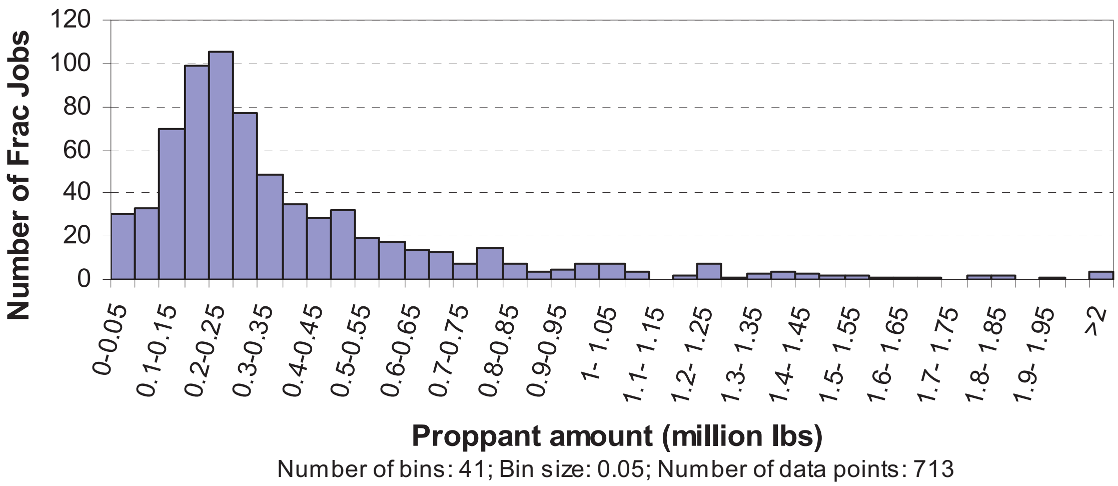


Figure 81. Gulf Coast—proppant volume (2008)

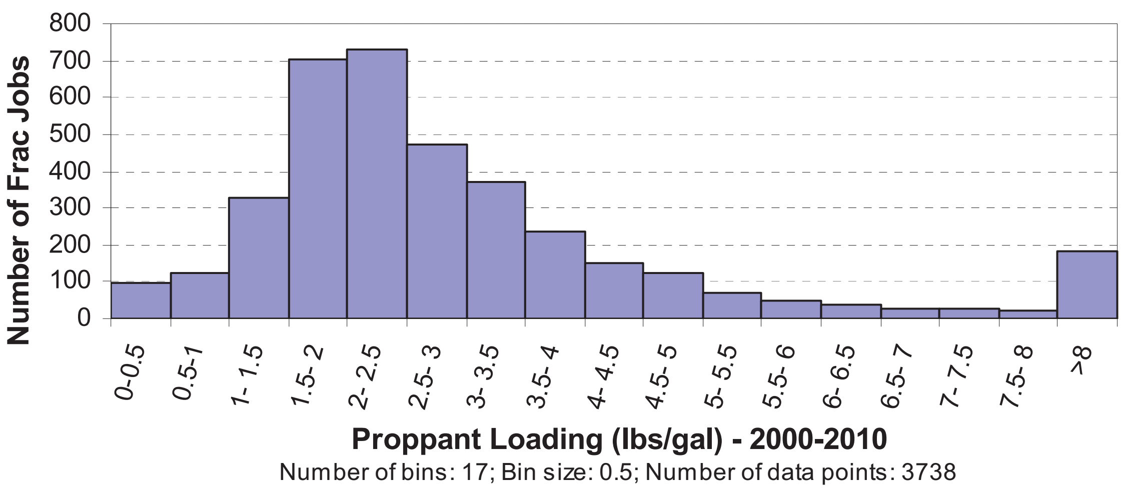


Figure 82. Gulf Coast—proppant loading (all years)

4.2 Oil and Gas Drilling and Waterflooding

Besides stimulation, the oil and gas upstream industry makes use of fresh water during waterflooding operations and the drilling of wells. The amounts used are uncertain because they are not clearly documented in regulatory forms. In Texas, there is no requirement to document exactly the type of fluids injected in UIC Class II wells (such as those wells used for waterflooding); only the overall total volume and the types of fluids (by "checking a box" in the mandatory H10 form) need be documented, without specifying their share. A cursory calculation also shows that the amount of water used to develop drilling muds for the 10 to 20,000 wells drilled each year in the state could significantly contribute to total fresh water use in the mining category. U.S. DOE (2009, p. 64) put forward a figure of 400,000 and 1,000,000 gal to drill a well in the Barnett and Haynesville Shales, respectively. Volumes undoubtedly vary substantially between wells, and those horizontal wells with long laterals represent the high end of the range. Still, these values are significant and could have a large impact on overall mining water use if all the water is fresh and if the rate per well is sustained at the state level.

4.2.1 Waterflooding

4.2.1.1 Information available before this study

A look at historical reports suggests that the amount of fresh water used in the oil and gas industry has been decreasing during the past few decades. Guyton (1965, p. 40) estimated that in Texas (mostly Permian Basin) and southeast New Mexico, the industry used approximately 50 to 70 thousand AF/yr of fresh water in the early 1960s for the extraction process. In the middle of the 20th century, the RRC used to publish biennial reports on secondary and tertiary recovery, including water use. The latest of such reports seems to have been published in 1982 (RRC, 1982). Fresh-water use was reported at ~80 thousand AF in 1980 and 1981 (Table 15). The latest comprehensive survey of fresh-water use in the oil and gas industry dates back to the 1990s (De Leon, 1996), and fresh water use was estimated at ~30 thousand AF. The survey concerned mostly pressure maintenance, waterflooding, and other EOR techniques, but not drilling. We summarize next the content of the letter report. In 1996, the RRC sent a survey request of fresh and brackish water usage in EOR projects in 1995 to oil and gas operators. The survey was initiated in November 1996 using a special makeup water-survey form (Form H-17). A total of 1,543 forms were mailed, with a return rate of ~84%. Whether the results were scaled to account for unresponsive operators is unclear, but they probably were not. The forms documented the injection of 251,716,698 bbl (32.444 thousand AF) of fresh water during calendar year 1995. Definition of fresh water is more lax than for the rest of this document because it includes all water with a TDS <3,000 mg/L. The volume of fresh water actually injected was only 7.6% of the total fresh water volume permitted for injection in 1995 (3.3 Bbbl). The volume of fresh water actually injected represents 3.3% of the total combined volume of all liquids (7.63 Bbbl) injected ca. 1995. The forms also documented the injection of 78,180,043 bbl (10.077 thousand AF) of brackish water during the same period. Brackish water in this RRC survey is defined as having a TDS between 3,000 and 10,000 mg/L. Brackish-water use represents about (24%) of the combined non-saline water. The top five counties (Gaines, Stephens, Hockley, Yoakum, and Andrews) represent 76% of the total fresh-water consumption, and adding five more (Cochran, Lubbock, Dawson, Garza, and Leon) represents 88% of the total (Table 16 and Figure 83). De Leon (1996) did not document the breakdown of brackish-water use by district or county. All of the top 10 counties belong to the Permian Basin except the last one (Leon County). A total of 55 counties were reported by operators to receive fresh-water injection. Many others in the list are also located in West Texas (Figure 83); RRC districts 8A+8 (~Permian Basin) correspond to 69.4% of total fresh-water injection, and adding district 7B (>99% in Stephens County) increases the share to 92.0%. Adding district 7C instead of district 7B results in 69.7% of total fresh-water injection; a combination of districts 7C, 8, and 8A corresponds to a common definition of the Permian Basin using RRC districts. The large amount of water reported to have been used in 1995 in Stephens County is anomalous, both in terms of its location and of its high county-level water-use coefficient (that is, water amount used in the county divided by county production) (Figure 84) and is investigated later because it makes up >20% of the total fresh water used in 1995 in Texas oil fields. Recomputing the water-use coefficients by including production only from those fields being flooded (list provided in De Leon, 1996) still shows a high coefficient but within the tail of the distribution (Figure 85). Most of the fields are in the 2- to 7-bbl range of water/bbl of oil, although Stephens County regular fields display a water-use coefficient three times higher. Something like this could have happened if a large EOR operation had started around that time, but a look at the production of these combined fields does not show an uptick in production in 1995 (at ~3.7 million barrels) or shortly thereafter, but, instead, a slow decrease until 2002, at which time production stabilized at ~2 million bbl/yr. However, publications by Weiss (1992) and Weiss and Baldwin (1985) suggest that major EOR operations were ongoing at the time in Stephens County.

Approximately ¾ of the fresh water used in 1995 is groundwater, most of it from the Ogallala aquifer (~85% or ~60% of total injected fresh water). However, note that 1995 received less than average precipitation (NOAA historical climatological data and records for Midland) and that groundwater use in that year might have been anomalously high. Another important note concerns double-counting: in 1995 >40% of the fresh water was purchased. Anecdotal evidence suggests that water purchase is still current practice. There is no issue if the water was purchased from wholesalers, but if it was purchased from municipalities, then it may already have been counted toward municipal use.

Total water use of fresh and brackish water in the oil and gas industry amounted to 330 million barrels (42.5 thousand AF) in 1995. RCC (http://www.rrc.state.tx.us/barnettshale/wateruse.php) projected that it would have decreased to 316, 276, 254, and 212 million barrels (40.7, 35.6, 32.7, and 27.3 thousand AF) in 1998, 1999, 2000, and 2001, respectively. Note that these figures were extrapolated before shale-gas growth but may include reporting from tight-gas water use, particularly in East Texas. The basis for these figures is not explained in the RRC documents.

4.2.1.2 Extrapolations from the RRC 1995 Survey

Early studies suggest that most waterfloods take place in West Texas (RRC Districts 8, 8A, and 7C; see Figure 9 for location). In addition, most of the oil produced in the state comes from the Permian Basin (Figure 86 and Figure 87). Only oil reservoirs are typically waterflooded. A look at the number of wells permitted to inject fresh water (Table 17) confirms that Districts 8 and 8A are the center of this practice. This section focuses on these districts. Given the current lack of specific reporting of fresh- and saline-water volumes, our approach is to relate known volumes of oil produced in 1995 with known waterflood water volumes. The 1995 RRC survey is the most recent comprehensive survey to be completed on waterflood water use and was used as a basis for estimating current water use. The RRC survey was combined with another survey performed for this study (Galusky, 2010).

One way to compute future water use is to tie oil production and water use, which can be done at the county level and which is the elemental unit of this study (Figure 84), or at the finer field level (Figure 85). The first step is to analyze 1995 production data vs. RRC survey fresh/brackish-water use (De Leon, 1996). Production numbers were extracted from the RRC online query engine for the calendar year 1995. At the coarsest state level, Texas produced 1134 million barrels in 1995, resulting in an average water use of 0.22 bbl/bbl. If one considers only those counties that reported fresh-water use, the average climbs to 0.79 bbl/bbl for oil production of 319 million barrels. Average water use can be low in some counties (<1 bbl/bbl) because many fields may not undergo secondary or tertiary recovery, but in those counties regularly performing waterfloods, a reasonable average is between 1 and 2.5 bbl/bbl. Field scale seems the most appropriate scale for understanding water use, but even then figures depend on the stage of the waterflood and on the fraction of those production wells not yet impacted by the flood. However, given the relatively large number of fields considered (~100), we expect the data to be representative of waterflood water use in 1995. The "Stephen County Regular" oil field has an anomalously high water use, accounting for ~20+% of total 1995 fresh-water use. Overall fresh-water consumption obtained by summing up all field oil production and water use and taking the ratio is 2.28 bbl/bbl, which is equivalent to making the average per field weighted by the field production. Taking the average, giving the same weight to all fields, results in a value of 5.67 bbl of fresh water/bbl of oil. Somewhat arbitrarily dismissing outlier fields with an average >15 or <1 bbl/bbl results in an average of 4.5 bbl of makeup fresh water/bbl of oil.

A piece of information more readily available than fresh-water injection is total injected fluid volume (made available in RRC records as disposal in producing formations, disposal in nonproducing formations, and waterfloods and other secondary and tertiary recovery processes). Thus, in order to make fresh-water-use projections, we need an estimate of the share of fresh water relative to all water being injected for waterflood secondary-recovery processes. Unfortunately, the RRC website does not currently include injection volumes for 1995, the reference year for fresh-water injection, and we were not able to access the information. It does, however, contain injection volume at the district level for 1998 through 2002 (Table 18, Table 19, and Figure 88). The website (http://www.rrc.state.tx.us/data/wells/statewidewells.php) breaks down water as injected into disposal wells (either in the producing formation or not) or for recovery. Here we are only interested in water used for waterflooding and other recovery processes that represents ~58% of total injection in this year range. Although variable across the years, a representative number is 3.5 million barrels, ~75% of which is injected in districts 08 and 8A in the Permian Basin, and ~90% if districts 7B and 09 are also included. In these four districts, making up almost of the water used for secondary and tertiary recovery, most of the water is used for secondary recovery (>75%) and not disposed of (Figure 89). Percentage of fresh water in the total volume of water used in waterflood varies (Table 20). Contrasting reported waterflood volume (all water types) during the 1998–2002 period to reported fresh water used in 1995 suggests that, at least 10 to 15 years ago, at most 4% of waterflood water was fresh (later we will add correction factors). District 7C is anomalously high at ~14%; a likely reason is that there is less produced water available near the waterflooded field and the proximity of Possum Kingdom Lake in Stephens and neighboring counties. District 8A, with more than half of the state volume of waterflood fresh water, shows a percentage close to 10% fresh-water use, and close to 13% if brackish water is added.

Closer to 2008, after a lack of data for a few years (2003–2006), the RRC website provides data from 2007 through an interactive query site compiled from H10 forms (http://webapps.rrc.state.tx.us/H10/h10PublicMain.do). However, unlike the 1998–2002 period, there is no breakdown in water type. A plot of injection volumes collecting 1998–2002 and

2007–2008 data sets (Figure 91) shows no major change in the injection volume pattern. A simple extrapolation, assuming that waterflood/total injection and fresh-water waterflood ratios have not changed in the past 15 years and using total injection figures from 2007 and 2008, results in total waterflood water use of ~28 thousand AF (Table 21), most of it in district 8A. This value must be considered only preliminary because, as described in the next section, adding correction factors more than halves this initial water-use estimate.

4.2.1.3 Current Waterflooding Water Use

In this section, we integrate results from the Permian Basin operator survey (Galusky, 2010). The survey provided information (1) on added operator reliance on brackish water as opposed to fresh water, (2) on switching from disposal into nonproducing formations to useful injection into producing intervals, and (3) increased dependence on secondary and tertiary recovery, as illustrated in Figure 92, with a stable water-injection level combined with decreasing oil production. The 1995 RRC survey (De Leon, 1996) reports a fresh-water–brackish-water split of ~75%– 25%. New confidential, anecdotal information obtained through the informal survey of Permian Basin producers suggests that the 2010 fresh– brackish water split now favored brackish water –20% fresh water and 80% brackish water. In other words, the fraction of fresh water in the usable (fresh+brackish) water category went down from 75% to 20% in 15 years. In addition, although the information was gathered from Permian Basin operators, we assumed it valid across the state (error, if any, is small at the state level because most fresh water for waterflooding purposes is injected into the Permian Basin). We also assumed that, overall, increased reliance on waterfloods and other recovery processes is balanced by the increased useful use of saline water.

Note that in the following developments we discuss projections to 2060, as well as current fresh-water use. Both are calibrated in the same calculation with the help of the 1995 RRC survey. The estimation (more accurate than the preliminary estimate of the previous section) of historical and forecast water use for oil-field-pressure maintenance in EOR (waterfloods and CO_2 floods) production entailed the following steps:

a- Historical (1995–2010) annual oil production from EOR was estimated on the basis of published data and company surveys and anecdotal information (for waterflood oil production) (Figure 93).

b- Applying and generalizing basic reservoir engineering principles, we estimated that at least 1.3 bbl of water is required for EOR pressure maintenance for every barrel of oil produced.

c- The fresh-water fraction of EOR makeup water in 1995 was estimated to be ~75% of the total. The fresh-water fraction of EOR makeup water in 2010 was estimated to be 20% of the total and was taken from the returned company surveys. We assumed that there has been a linear decline in the fraction of fresh water used in EOR between these periods and that this decline will continue until it reaches a value of 5% by 2023, at which point we forecast that it will hold this percentage through 2060.

d- We estimated the fraction of oil production from EOR in 1995 to be approximately 61% of total oil production and assumed that this fraction increased linearly to a value of 66% in 1997, as estimated by RRC. We then held this rate of annual increase through the last year of the forecast period of 2060. Anecdotal evidence (for example, Henkhaus, 2007) suggests that about ⅔of the oil is produced through EOR processes.

e- Total annual oil production was forecasted by extrapolating 1995– 2010 production through 2060 using a simple exponential decline curve.

f- Makeup water use was then estimated by multiplying the total annual oil production times the fraction of oil production from EOR, times the makeup water factor (1.3 bbl water/bbl oil as described earlier), times the respective water fractions (fresh versus saline/brackish). Makeup water use was calculated in this way for both the historical period of record (1995–2010) and forecasted through the year 2060. This calculation was done on the basis of aggregate regional oil production and on a county-level basis, according to their respective historical and forecast total annual oil production values.

A simple scaling was then applied to those counties outside of districts 8, 8A, and 7C according to their fresh-water use in 1995 and total injection volume in the 2002–2005 period. The state-level estimated 2008 water use for **nonprimary recovery processes is ~13 and 25.5 thousand AF for fresh and brackish water**, respectively (Figure 94 and Table 22). As expected, the spatial distribution of waterflood water use is heavily weighted toward the Permian Basin (Figure 96). We are reasonably confident in the total of 38.5 thousand AF, but less in the distribution between fresh and brackish categories.

4.2.2 Drilling

The number of holes drilled per year in the past 50 years has varied from 30,000+ to <10,000, whereas the number of oil and gas wells completed during the same period has varied from 5,000+ to <25,000 (Figure 95). The holes-drilled category includes, in addition to completed wells, dry holes, service wells, and the like. The past decade has seen a steady increase in the number of wells drilled per year in Texas, which was interrupted only by the recent economic slowdown. A significant fraction is related to recent shale-gas production (gas-well curve crossing over the oil-well curve in Figure 95), but the recent interest in unconventional oil is also visible; many other wells were drilled in conventional reservoirs.

Well drilling requires a fluid carrier to remove the cuttings and dissipate heat created at the drill bit. The fluid also keeps formation-water pressure in check. Broadly, three types of fluids are used: (1) air and air mixtures, (2) water-based muds, and (3) oil-based muds. By far the most common method involves water-based muds. Clean water is needed to optimize the mud performance. Air drilling is traditionally used in the thick unsaturated zone with no source of water nearby or low-permeability formations with sufficient strength, but it is becoming more popular (U.S. DOE, 2009, p. 55), as in the Marcellus Shale in Pennsylvania, in which many wells are drilled in the formation with little added water. For similar subsurface conditions, drilling practices differ from region to region, and we did not attempt a comprehensive study of drilling practices. Oil-based mud is typically used at greater depths or when sensitive clays, for example, could be a problem. As a general rule, a water-supply well (typically the most convenient way of obtaining water) is drilled next to the drilling site, although the amount of water used is not always metered. The amount of water required is what is needed to fill up the well bore, as well as the mud pit (must be large enough to allow time for the fine rock cutting to settle), if neither a closed loop is used nor auxiliary equipment. An additional factor is that for many wells, the mud system has to be changed, at least partly, in the course of the drilling. An approximate rule of thumb would be to multiply the borehole volume by some coefficient. Anecdotal evidence suggests that this multiplier could range from 3 to 6 or higher. Additional water is used to wash equipment to prepare the cement slurry for these wells to be completed. A proper cement set up also requires clean water. Overall, the water used is typically fresh or slightly brackish; produced water is typically not used because it is dirty and the operator would need to treat it at a cost before using it.

Several approaches were followed to collect data on drilling-water use: (1) survey of operators in the Permian Basin (Galusky, 2010), (2) borehole-volume approach with information downloaded from the IHS database, and (3) other, less structured evidence gathered from the literature and through informal discussion with site engineers.

The last category includes documentation published by Chesapeake (2009) of 400,000 gal/well in the Barnett Shale, 600,000 gal/well in the Haynesville Shale, and 125,000 gal/well in the Eagle Ford Shale (Marcellus consumes only 100,000 gal/well). A Chesapeake Barnett well is drilled all the way using water-based mud. The Haynesville is typically much deeper than the Barnett, and the horizontal section is drilled using oil-based mud, whereas most of a Chesapeake Marcellus well is drilled using oil-based muds except for the air-drilling USDW section (M. E. Mantell, personal communication, 2010). No data were collected on the drilling approach in the Eagle Ford Shale. Computing average well-bore volume from the IHS database for the Chesapeake Barnett and Haynesville wells (17.3 and 36 thousand gallons, respectively) provides a multiplier on the order of 15. Barnett Shale survey results from Galusky (2007, p. 7 and Table 1) indicate that, in 2006, about 10% of total water use was dedicated to drilling, that is, 150,000 to 300,000 gal/well. The split between groundwater and surface water is likely to be similar to that of completion (about equal) for those fraced wells. However, the split is unknown for nonfraced wells, although likely to favor groundwater because laying pipes from surface-water bodies would be prohibitively expensive to obtain the relatively small amount of water needed for drilling. More anecdotal evidence from the Middle Pecos GCD suggests that water use for well drilling was in the range of 200,000 to 300,000 gal/well in 2009. A significant fraction of major and minor aquifers in Pecos County are brackish, however, so average fresh water is probably about half of this figure. A rule of thumb applicable at least in the Permian Basin suggests 0.3 to 1 bbl/ft, that is, between 75,000 and 250,000 gal/well for a 6,000-ft-deep well. In Texas, many wells are drilled to the 5,000- to 7,000-ft depth range because many reservoirs are located around those depths (Nicot, 2009b). Another rule of thumb heard during this study was 1 barrel of water per cubic foot of hole, which translates into a multiplier of 5.6.

The borehole-volume approach consists of extracting dimension information about all wells drilled in Texas in a given year (Table 23), correcting for those wells with no casing information (20% on average) and applying a multiplier to estimate drilling-water use. The average Texas well has a volume of ~15,000 gallons. Clearly, the deeper the well, the larger the water use. However, the increase is not linear for several reasons: borehole diameter decreases with depth in a stepwise fashion, the use of several mud systems is more likely, surface installation are larger. We initially used a multiplier of five to find average drilling-water use during the past decade of ~3,000 AF, varying from 2.4 to 4.6 thousand AF/yr. However, in light of survey returns (see later section) and increased interest in generally deeper gas shales, a multiplier of 10 seemed more realistic, resulting in an initial preliminary estimate for average drilling-water use of 6 thousand AF/yr in the past decade across the state.

The third approach consisted of accessing the information through an operator survey in the Permian Basin (Galusky, 2010) in districts 8, 8A, and 7C, which consistently represent one-third of the wells drilled in Texas (Table 24). A reasonable value used for the computation was ~130,000 gal/well (0.41 AF/well) of fresh water combined with ~500,000 gal/well (1.59

AF/well) of brackish and saline water. This computation resulted in total water use for the three districts of ~2,300 AF in 2008 (~6,300 wells spudded according to IHS database) and ~2,200 AF in 2010, amounts not predicted to grow unless shale-gas production takes hold in a strong way in West Texas.

Although not negligible at the state level, drilling water use is distributed across all oil- and gas-producing counties in the state. In 2008, about ~20,000 wells had been spudded in Texas (IHS database and RRC website). Barnett Shale Tarrant and Johnson Counties had the most wells spudded, 825 and 890, respectively. Assuming an average 0.4 million gal water use per well (conservative because vertical wells are also included in the count) results in drilling-water use of 1,000 AF in each county. Next are Permian Basin counties (Andrews, Upton, Ector, Pecos, Webb, Martin, and Midland, in decreasing order of number of wells), with 550 to ~250 wells spudded per county in 2008, resulting in 0.23 to 0.1 thousand AF per county. A final figure of 130,000 gal/well for 20,000 wells was eventually retained, leading to a **drilling-fresh-water use of 8.0 thousand AF**. Note that reuse is likely occurring in the drilling field as flowback water from fracing operations can be used for drilling additional wells. There is no data on how widespread the practice is.

Table 15. Historical water use in secondary and tertiary recovery (million barrels)

	Saltwater		Brackish Water		Fresh Water		BW	FW
	(million bbl)							
District	1980	1981	1980	1981	1980	1981	1995	1995
1	13.0	12.4	13.3	17.3	4.5	3.4		1.4
2	31.6	20.6	0.0	0.0	0.0	0.0		0.0
3	71.6	59.9	0.0	0.0	0.1	0.0		0.0
4	84.8	79.6	0.1	0.0	0.0	0.0		0.0
5	14.3	9.3	0.0	0.0	1.1	1.0		4.2
6	57.8	57.5	2.4	2.4	23.8	24.6		8.5
6E	0.5	1.6	5.1	6.2	1.0	1.0		0.8
7B	131.6	133.5	1.7	1.4	46.0	41.5		57.0
7C	53.2	52.1	8.3	6.7	5.8	4.7		1.0
8	603.8	617.2	462.7	440.4	73.5	81.2		19.3
8A	791.3	855.1	42.1	41.0	453.3	413.3		155.3
9	277.8	292.3	3.3	3.3	12.4	12.1		1.1
10	19.6	20.5	0.0	0.0	15.9	14.5		3.1
Total	**2150.9**	**2211.6**	**539.1**	**518.7**	**637.5**	**597.3**	**78.2**	**251.7**

Source: RRC (1982) and De Leon (1996)

Historical Injection 2=fromRRC1982Report.xls

Table 16. Fresh-water use in EOR operations (1995 RRC survey)

County	Fresh-Water Use (bbl)	County	Fresh-Water Use (bbl)	County	Fresh-Water Use (bbl)
Gaines	59,347,090	Frio	1,076,890	Williamson	95,238
Stephens	56,208,617	Irion	963,590	Bastrop	88,625
Hockley	42,684,399	Scurry	896,000	Ward	73,000
Yoakum	19,466,366	Gregg	818,571	Bowie	70,262
Andrews	12,520,625	Marion	640,379	Cass	54,750
Cochran	8,857,214	Franklin	628,405	Stonewall	44,147
Lubbock	8,146,162	Nolan	557,791	Panola	42,323
Dawson	5,517,713	Young	534,265	Hardin	40,783
Garza	4,448,645	Winkler	365,000	Atascosa	22,850
Leon	4,203,810	Howard	220,462	Jack	15,602
Ector	3,574,347	Martin	214,778	Archer	4,305
Anderson	3,145,589	Dickens	196,060	Coleman	3,000
Gray	3,145,143	Clay	194,280	Callahan	1,800
Hale	2,421,237	Rusk	163,173	Tom Green	375
Terry	2,139,628	Eastland	158,393	Wilson	45
Smith	1,933,184	Zavala	143,054		
Wood	1,658,113	Cooke	134,394	**Total (bbl)**	**251,716,698**
Pecos	1,257,715	Camp	120,745	**Total (AF)**	**32,444**
Lynn	1,149,368	Knox	117,233		
Mitchell	1,090,170	Wichita	100,995		

Source: De Leon (1996)

FreshWater+OilProduction_RCC1995.xls

Table 17. Number of permitted fresh-water injection wells as of January 2010

District	Injection into Nonproducing Intervals	Injection into Production Formation	Secondary Recovery	Total
01	5	18	380	403
02	1	1	0	2
03	0	1	3	4
04	3	0	5	8
05	1	0	68	69
06	3	42	244	289
6E	0	8	40	48
7B	1	39	628	668
7C	0	5	87	92
08	1	81	3,961	4,043
8A	5	368	9,075	9,448
09	2	12	112	126
10	2	30	199	231
Total	24	605	14,802	15,431

Source: Fernando De Leon (RRC, January 2010) custom data pull

Table 18. District-level total water injection volume vs. waterflood volumes (1998)

1998—All volumes in bbl						
District	**Disposal in nonprod. zone**	**Disposal in prod. zone**	**Waterflood**	**Other**	**Total**	**Water-flood/ Total**
1	221,676,839	36,224,868	21,626,651	0	279,528,358	7.7%
2	121,625,598	29,673,891	58,255,145	0	209,554,634	27.8%
3	378,303,159	77,043,184	38,606,639	1,653,895	495,606,877	7.8%
4	77,713,906	19,949,912	29,217,354	0	126,881,172	23.0%
5	24,783,981	29,833,615	15,594,964	0	70,212,560	22.2%
6	122,873,017	73,922,979	53,064,690	0	249,860,686	21.2%
6E	0	356,784,106	26,290,016	0	383,074,122	6.9%
7B	25,100,019	28,512,343	321,250,271	0	374,862,633	**85.7%**
7C	45,307,377	73,054,222	79,496,652	0	197,858,251	40.2%
8	139,510,861	208,640,430	1,203,840,221	341,660	1,552,333,172	**77.6%**
8A	68,752,368	115,105,922	1,211,495,952	0	1,395,354,242	**86.8%**
9	24,556,396	36,674,585	198,195,141	15,370	259,441,492	76.4%
10	25,714,081	24,599,525	20,115,688	0	70,429,294	28.6%
Totals:	**1,275,917,602**	**1,110,019,582**	**3,277,049,384**	**2,010,925**	**5,664,997,493**	**57.8%**

Source: RRC website InjectionVolume_2002_RRC_+1998-2001.xls
http://www.rrc.state.tx.us/data/wells/statewidewells.php
Note: includes all water types (fresh to saline, produced and others)

Table 19. District-level total water-injection volume vs. waterflood volumes (2002)

Year 2002—All volumes in bbl						
District	**Disposal in nonprod. zone**	**Disposal in prod. zone**	**Waterflood**	**Other**	**Total**	**Waterflood / Total**
1	209,482,615	29,795,963	12,464,957	0	251,743,535	5.0%
2	112,608,696	20,504,067	56,234,669	0	189,347,432	29.7%
3	323,989,781	71,070,254	23,308,202	292,511	418,660,748	5.6%
4	84,577,088	13,963,848	21,024,812	0	119,565,748	17.6%
5	36,118,853	28,867,538	15,452,586	0	80,438,977	19.2%
6	149,292,665	86,293,340	41,801,873	0	277,387,878	15.1%
6E	158,881	348,180,269	31,694,999	0	380,034,149	8.3%
7B	24,602,044	26,477,559	252,445,261	1,528	303,526,392	**83.2%**
7C	40,711,999	63,911,860	88,144,873	0	192,768,732	45.7%
8	152,802,343	194,498,880	1,163,394,951	159,900	1,510,856,074	**77.0%**
8A	65,416,720	114,281,934	1,258,302,110	0	1,438,000,764	**87.5%**
9	26,395,288	30,699,374	156,616,151	27,386	213,738,199	73.3%
10	16,073,237	19,443,141	16,880,842	0	52,397,220	32.2%
Totals:	**1,242,230,210**	**1,047,988,027**	**3,137,766,286**	**481,325**	**5,428,465,848**	**57.8%**

Source: RRC website InjectionVolume_2002_RRC_+1998-2001.xls
http://www.rrc.state.tx.us/data/wells/statewidewells.php
Note: includes all water types (fresh to saline, produced and others)

Table 20. Estimated district-level fraction of fresh-water in waterflood water volumes

District	Waterflood water use average (all types) 1998–2002 (million bbl)	1995 fresh-water use (million bbl)	Fresh / Total	Fresh + Brack / Total*
01	267.0	1.43	0.53%	0.70%
02				
03	496.5	0.04	0.01%	0.01%
04				
05	81.6	4.20	5.15%	6.75%
06	288.4	8.46	2.93%	3.84%
6E	420.7	0.82	0.19%	0.00%
7B	393.8	56.97	14.47%	18.95%
7C	223.6	0.96	**0.43%**	**0.56%**
08	1,689.3	19.32	**1.14%**	**1.50%**
8A	1,578.3	155.27	**9.84%**	**12.89%**
09	252.1	1.10	0.44%	0.57%
10	69.6	3.15	4.52%	5.92%
Totals	**5,760.8**	**251.72**	**4.37%**	**5.59%**

InjectionVolume_2002_RRC_+1998-2001.xls

*Obtained by multiplying by the same coefficient of 1.31 for all districts to account for brackish-water use

Table 21. Initial guess for extrapolated district-level fresh-water use for waterfloods

District	1998–2002 Average Fraction of Waterflood vs. Total Injection	1995 Fresh-Water Use Fraction vs. Total Waterflood	Average 2007–2008 Total Injection (million bbl)	Extrapolated Fresh-Water Use (thousand AF)
01	6.1%	0.53%	485.0	**0.02**
02	28.5%	0%	[213.7]	
03	6.3%	0.01%	469.0	**0.00**
04	20.3%	0%	[137.0]	
05	19.8%	5.15%	197.0	**0.26**
06	11.7%	2.93%	756.6	**0.15**
7B	84.8%	14.47%	388.0	**6.13**
7C	42.9%	0.43%	287.5	**0.07**
08	77.2%	1.14%	1,652.7	**1.88**
8A	87.5%	9.84%	1,716.3	**19.03**
09	74.0%	0.44%	263.9	**0.11**
10	31.5%	4.52%	105.7	**0.19**
Total	58.2%	4.37%	6321.62	**27.85**

InjectionVolume_2002_RRC_+1998-2001_1.xls

Table 22. County-level estimate of fresh-water use for waterfloods

County	Fresh 2008	Fresh 2010	Brack 2008	Brack 2010	County	Fresh 2008	Fresh 2010	Brack. 2008	Brack. 2010
State Total	**12.95**	**7.87**	**25.52**	**29.91**					
Anderson	0.013	0.008	0.026	0.031	Lipscomb	0.005	0.003	0.009	0.011
Andrews	0.552	0.384	1.243	1.457	Loving	0.038	0.074	0.240	0.282
Archer	0.005	0.003	0.009	0.010	Lubbock	0.359	1.307	4.239	4.968
Atascosa	0.001	0.001	0.002	0.002	Lynn	0.051	0.207	0.670	0.785
Baylor	0.000	0.000	0.001	0.001	Marion	0.001	0.001	0.002	0.002
Borden	0.123	0.000	0.000	0.000	Martin	0.009	0.084	0.273	0.320
Brown	0.008	0.005	0.016	0.018	Maverick	0.001	0.001	0.003	0.003
Callahan	0.029	0.018	0.057	0.067	McCulloch	0.010	0.009	0.029	0.034
Camp	0.004	0.003	0.009	0.010	McMullen	0.001	0.000	0.001	0.001
Carson	0.001	0.000	0.001	0.001	Menard	0.002	0.250	0.809	0.948
Clay	0.002	0.001	0.004	0.004	Midland	0.328	0.035	0.114	0.134
Cochran	0.390	0.005	0.017	0.020	Mitchell	0.048	0.003	0.009	0.011
Coke	0.034	0.109	0.355	0.416	Montague	0.006	0.004	0.012	0.014
Coleman	0.035	0.021	0.068	0.080	Moore	0.001	0.001	0.003	0.003
Comanche	0.001	0.000	0.001	0.001	Motley	0.004	0.027	0.089	0.104
Concho	0.027	0.108	0.351	0.412	Navarro	0.004	0.002	0.007	0.008
Cooke	0.007	0.004	0.014	0.016	Nolan	0.074	0.045	0.146	0.171
Cottle	0.002	0.007	0.022	0.026	Ochiltree	0.006	0.004	0.012	0.015
Crane	0.399	0.027	0.086	0.101	Oldham	0.005	0.003	0.010	0.012

County	Fresh 2008	Fresh 2010	Brack 2008	Brack 2010	County	Fresh 2008	Fresh 2010	Brack. 2008	Brack. 2010
Crockett	0.086	0.007	0.021	0.025	Palo Pinto	0.029	0.018	0.058	0.068
Crosby	0.020	0.228	0.739	0.866	Pecos	0.055	0.066	0.212	0.249
Culberson	0.007	0.033	0.108	0.127	Potter	0.001	0.000	0.001	0.002
Dawson	0.243	0.039	0.125	0.146	Reagan	0.152	0.024	0.077	0.090
Dickens	0.009	0.000	0.000	0.000	Red River	0.001	0.001	0.003	0.003
Dimmit	0.001	0.000	0.001	0.002	Reeves	0.027	0.019	0.061	0.071
Eastland	0.115	0.070	0.228	0.267	Runnels	0.027	0.060	0.194	0.228
Ector	0.158	0.019	0.061	0.072	Rusk	0.019	0.011	0.037	0.044
Fisher	0.150	0.091	0.295	0.345	Schleicher	0.016	0.030	0.096	0.112
Floyd	0.000	0.031	0.101	0.119	Scurry	0.039	0.000	0.000	0.000
Foard	0.001	0.001	0.002	0.002	Shackelford	0.075	0.046	0.148	0.173
Franklin	0.002	0.001	0.004	0.004	Sherman	0.003	0.002	0.006	0.007
Freestone	0.002	0.001	0.004	0.005	Smith	0.007	0.004	0.014	0.016
Gaines	2.616	0.002	0.007	0.008	Stephens	1.786	1.086	3.520	4.126
Garza	0.196	0.011	0.036	0.042	Sterling	0.045	0.007	0.023	0.027
Glasscock	0.156	0.085	0.276	0.324	Stonewall	0.218	0.132	0.430	0.503
Gray	0.024	0.014	0.047	0.055	Sutton	0.001	0.001	0.005	0.005
Grayson	0.002	0.001	0.004	0.004	Taylor	0.025	0.015	0.049	0.057
Hale	0.107	0.271	0.880	1.031	Terrell	0.004	0.106	0.343	0.401
Hansford	0.002	0.001	0.003	0.004	Terry	0.094	0.019	0.061	0.072
Hartley	0.003	0.002	0.005	0.006	Throckmorton	0.069	0.042	0.137	0.160
Haskell	0.031	0.019	0.061	0.072	Titus	0.003	0.002	0.005	0.006
Hockley	1.881	0.001	0.004	0.005	Tom Green	0.032	0.011	0.036	0.042
Hopkins	0.015	0.009	0.029	0.034	Upshur	0.012	0.007	0.024	0.028
Howard	0.010	0.014	0.046	0.053	Upton	0.315	0.000	0.001	0.002
Hutchinson	0.006	0.004	0.013	0.015	Van Zandt	0.019	0.012	0.038	0.044
Irion	0.042	0.169	0.548	0.642	Ward	0.003	0.003	0.010	0.012
Jack	0.001	0.001	0.002	0.002	Wheeler	0.001	0.000	0.001	0.002
Jones	0.041	0.025	0.080	0.094	Wichita	0.020	0.012	0.040	0.047
Kent	0.297	0.006	0.019	0.023	Wilbarger	0.003	0.002	0.005	0.006
King	0.121	1.818	5.893	6.907	Wilson	0.001	0.000	0.001	0.001
Knox	0.001	0.001	0.002	0.003	Winkler	0.016	0.022	0.071	0.083
Lamb	0.013	0.136	0.442	0.518	Wood	0.006	0.004	0.012	0.014
Leon	0.019	0.011	0.037	0.043	Yoakum	0.858	0.219	0.709	0.832
Limestone	0.001	0.001	0.002	0.003	Young	0.003	0.002	0.005	0.006

InjectionVolume_2002_RRC_+1998-2001_1.xls

Table 23. Estimated and calculated oil and gas well drilling water use

	No. of Wells w/ Casing Data	Average Borehole Volume (gal/well)	Total BH Volume (Mgal)	Total BH Volume (Th. AF)	Total No. of Wells	Corrected Total BH Volume (Th. AF)	Multiplier	Water Use (Th. AF /yr)
2009	9,019	16,093	145.1	0.445	11,542	0.570	10	**5.70**
2008	16,311	15,585	254.2	0.780	19,121	0.915	10	**9.15**
2007	14,513	15,168	220.1	0.676	16,930	0.788	10	**7.88**
2006	13,273	14,890	197.6	0.607	15,832	0.723	10	**7.23**
2005	11,535	15,744	181.6	0.557	13,929	0.673	10	**6.73**
2004	9,964	15,851	157.9	0.485	12,488	0.607	10	**6.07**
2003	9,067	15,709	142.4	0.437	11,539	0.556	10	**5.56**
2002	7,013	16,203	113.6	0.349	9,146	0.455	10	**4.55**
2001	8,676	15,628	135.6	0.416	11,504	0.552	10	**5.52**
2000	7,412	14,897	110.4	0.339	10,411	0.476	10	**4.76**

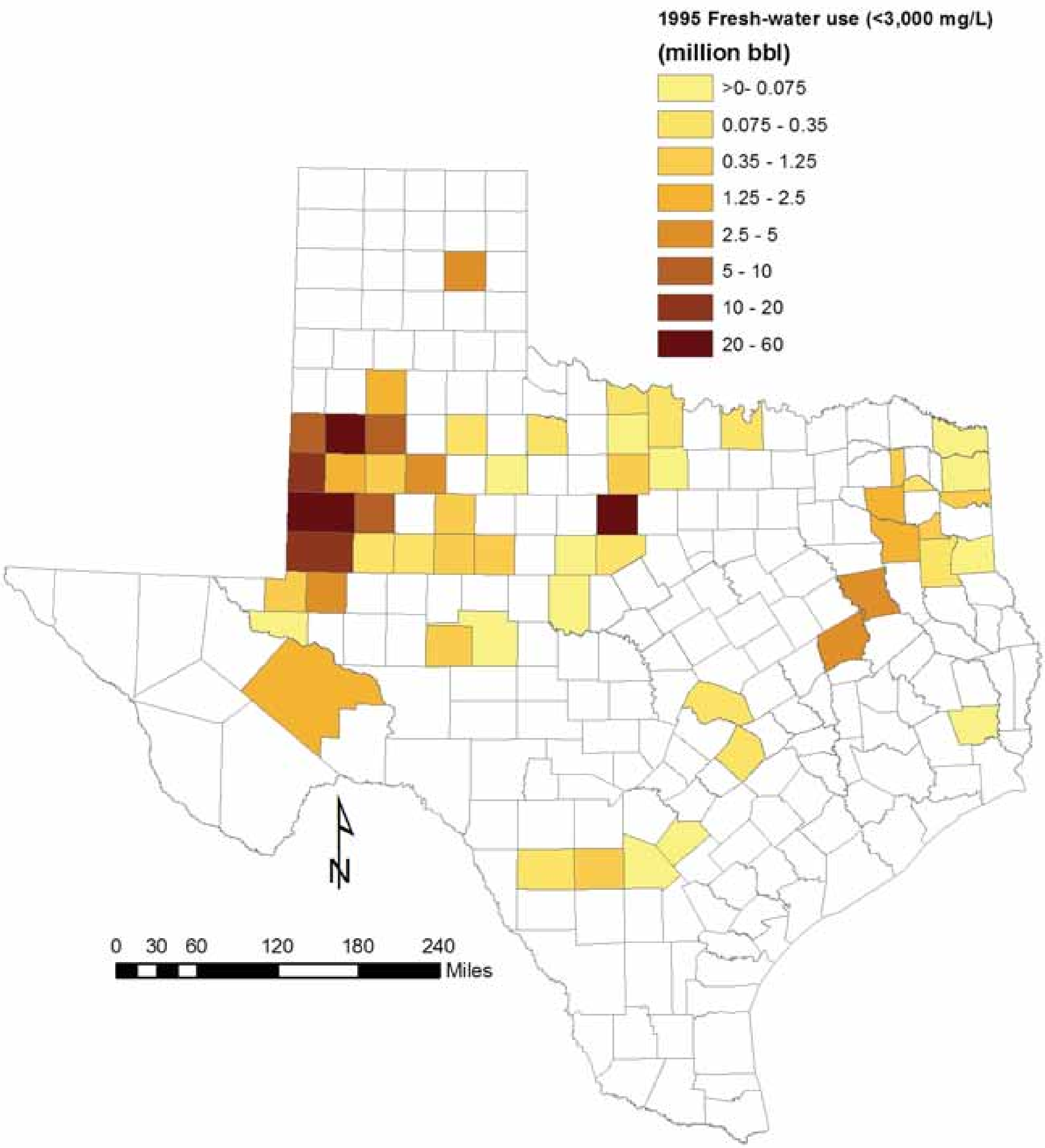
Source: IHS database

Results 2000-2009 1.xls.xls

Table 24. New drill per district

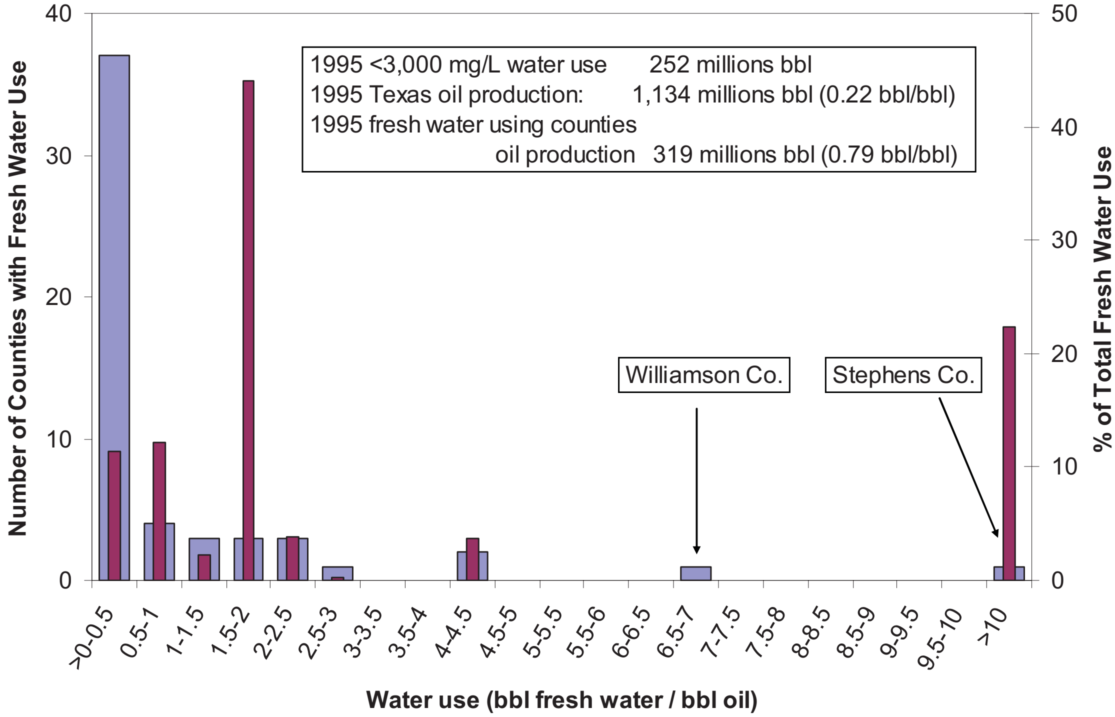
District	01	02	03	04	05	06	7B	7C	08	8A	09	10	Total
2006	369	510	451	1,354	555	1612	409	1,539	1,557	778	1,614	1,003	12,188
2007	354	398	422	982	621	1,968	327	1,565	1,789	698	2,214	952	12,291
2008	428	447	496	1,162	678	1,884	689	2,033	2,368	532	3,492	1,046	15,255

Source: RRC website



Source: 1995 RRC survey

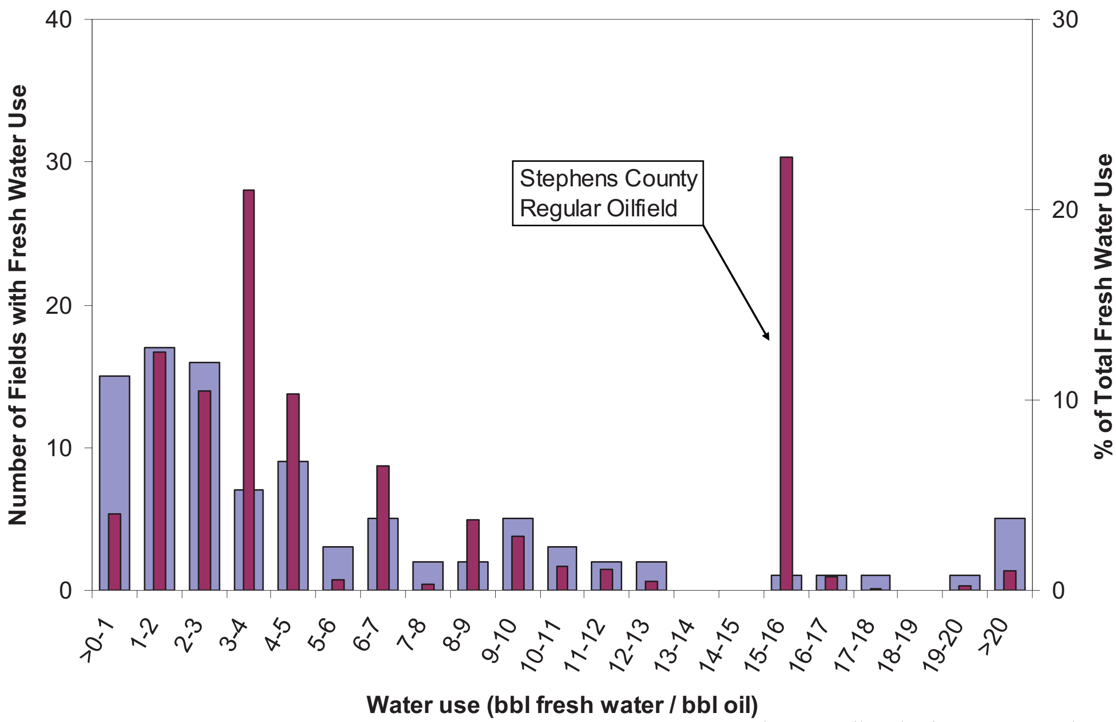
Figure 83. Map of counties using fresh water in EOR operations according to the 1995 RRC data (1 million bbl = 129 AF)



FreshWater+Oil Production RCC1995.xls

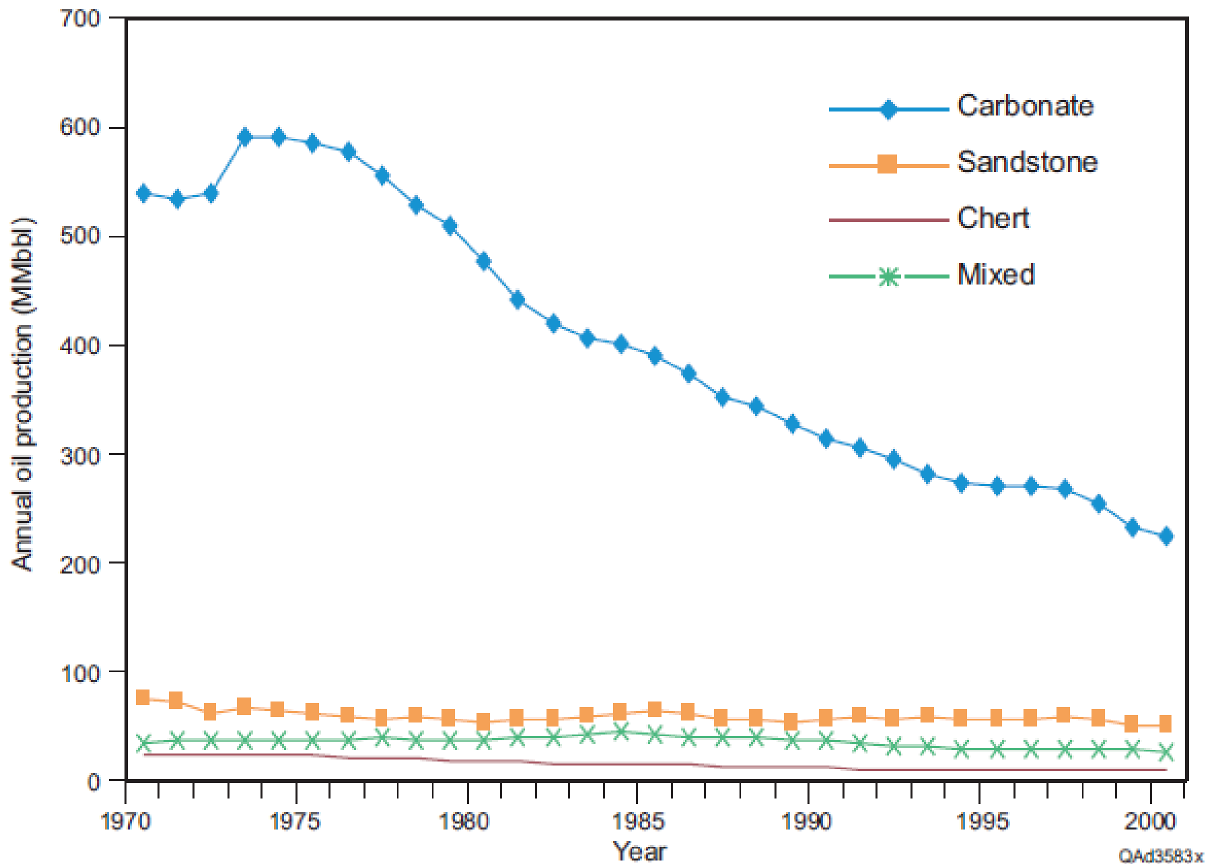
Note: obtained by dividing fresh-water use as reported by RRC by county production regardless of the actual number of fields being waterflooded

Figure 84. Histogram (year 1995) of county-level waterflood water-use coefficient (wide columns) and fraction of total fresh-water use for each bin



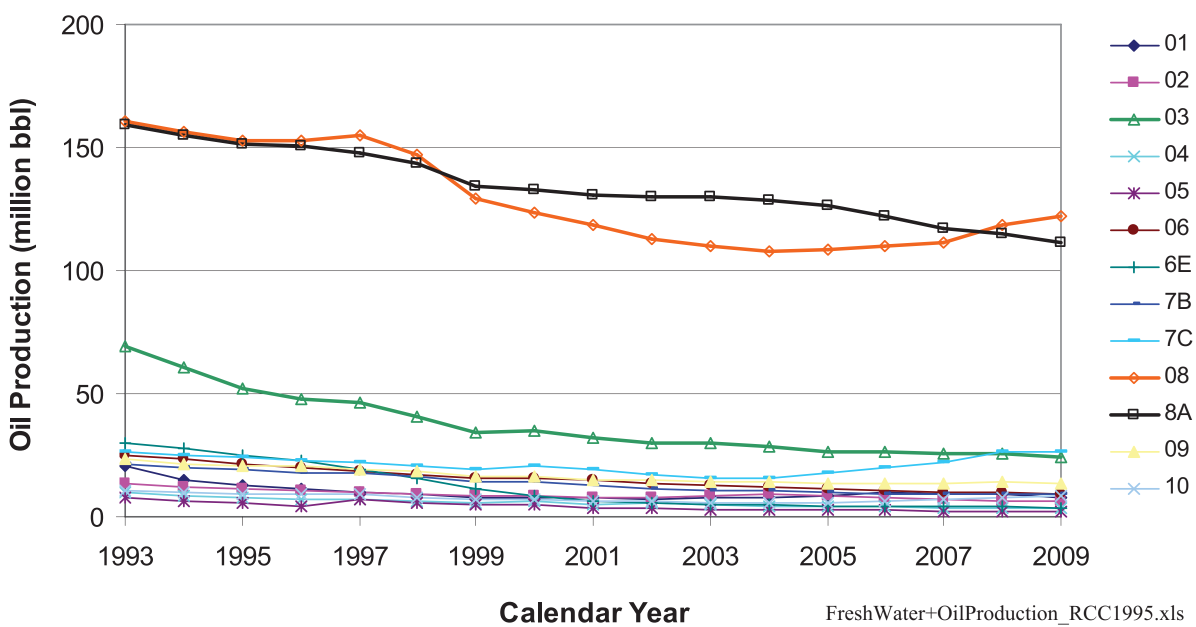
FreshWater+OilProduction RCC1995.xls

Figure 85. Histogram (year 1995) of water-use coefficient in waterflooded oil fields (wide columns) and fraction of total fresh-water use for each bin



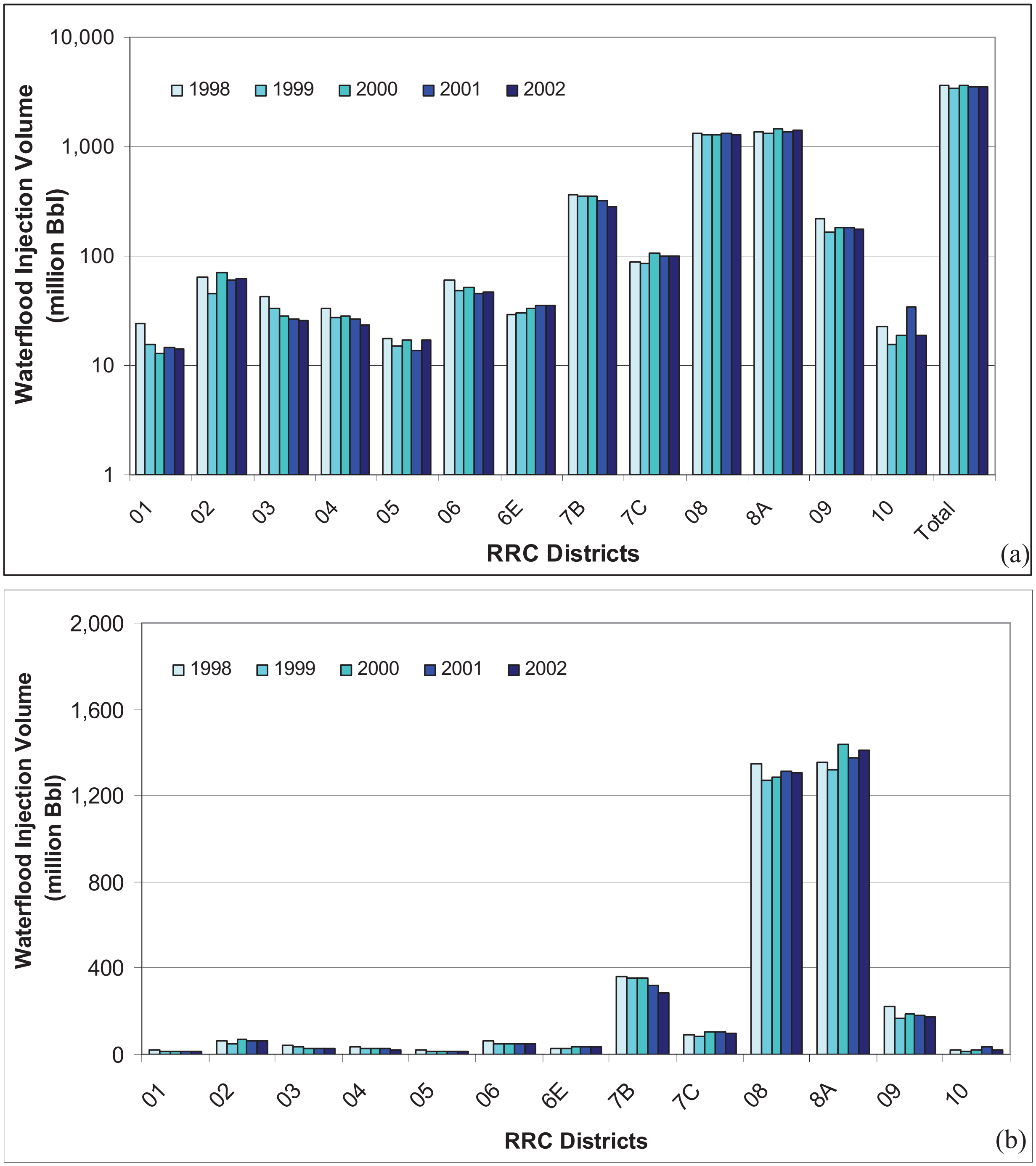
Source : Dutton et al. (2005a, Fig. 130)

Figure 86. Production histories of significant-sized oil reservoirs in the Permian Basin by lithology



Source: RRC online system http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do

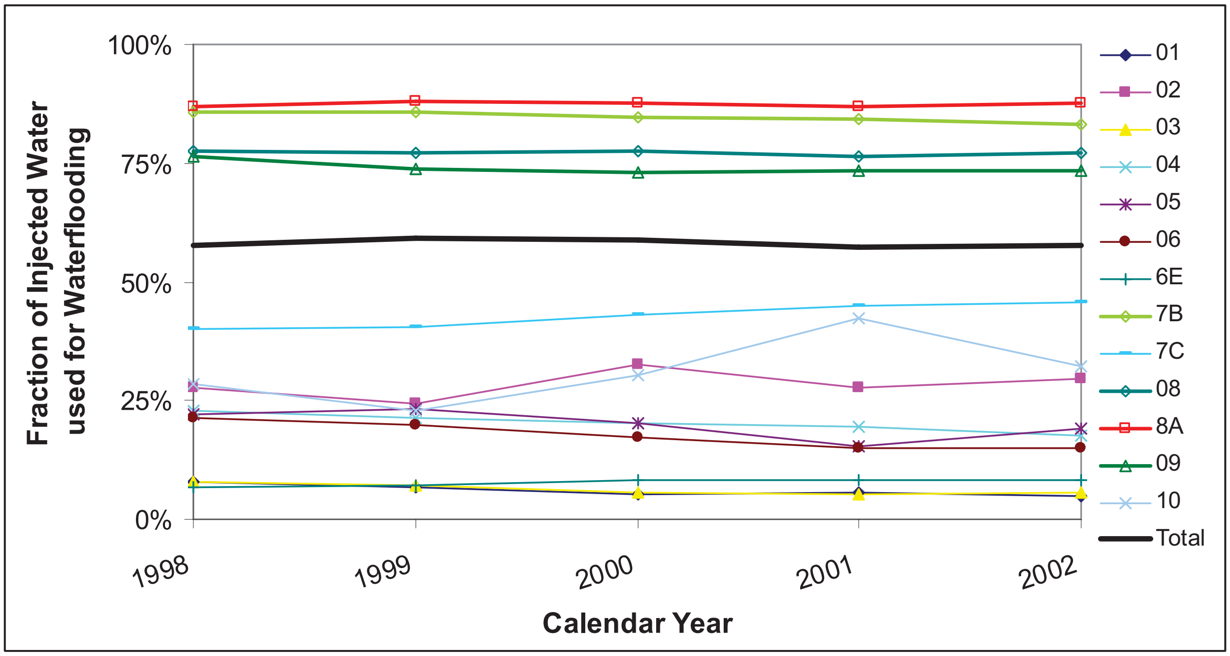
Figure 87. Annual oil production per district (1993–2009)



InjectionVolume_2002_RRC_+1998-2001.xls

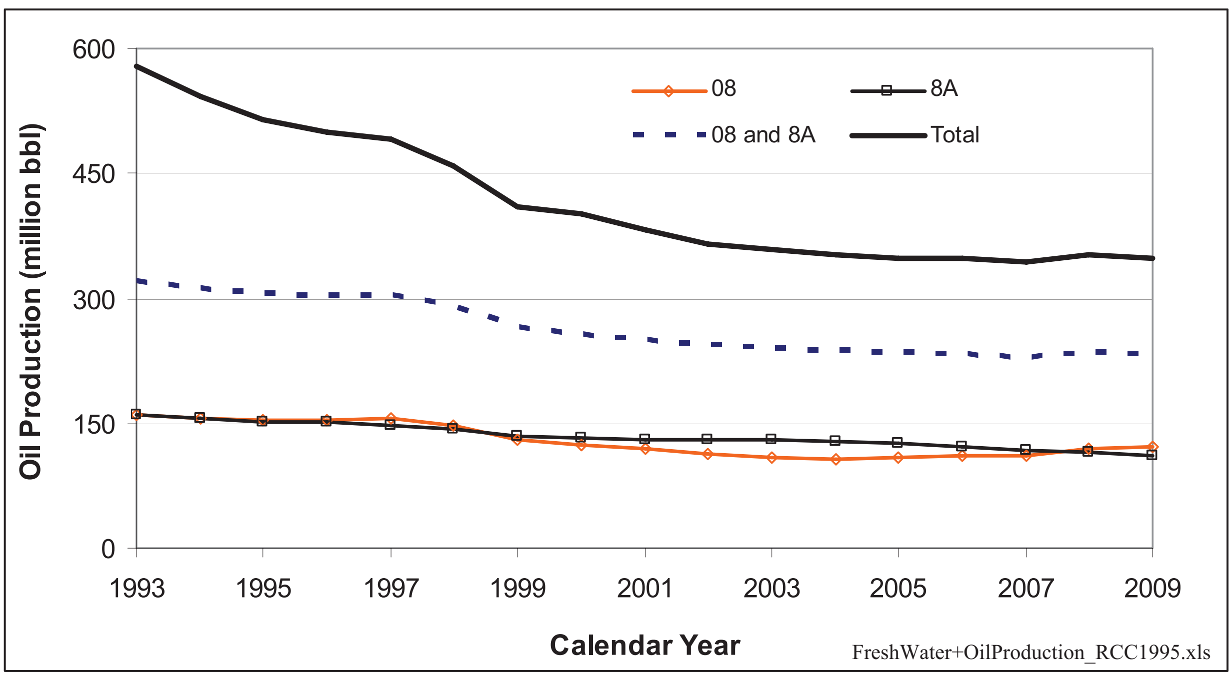
Source: RRC website http://www.rrc.state.tx.us/data/wells/statewidewells.php
Note: figures were corrected by the statewide correction factor for incomplete data (typically 10% more than reported)

Figure 88. RRC district-level annual waterflood-dedicated injection volume in Texas (1998–2002): (a) log scale, (b) linear scale



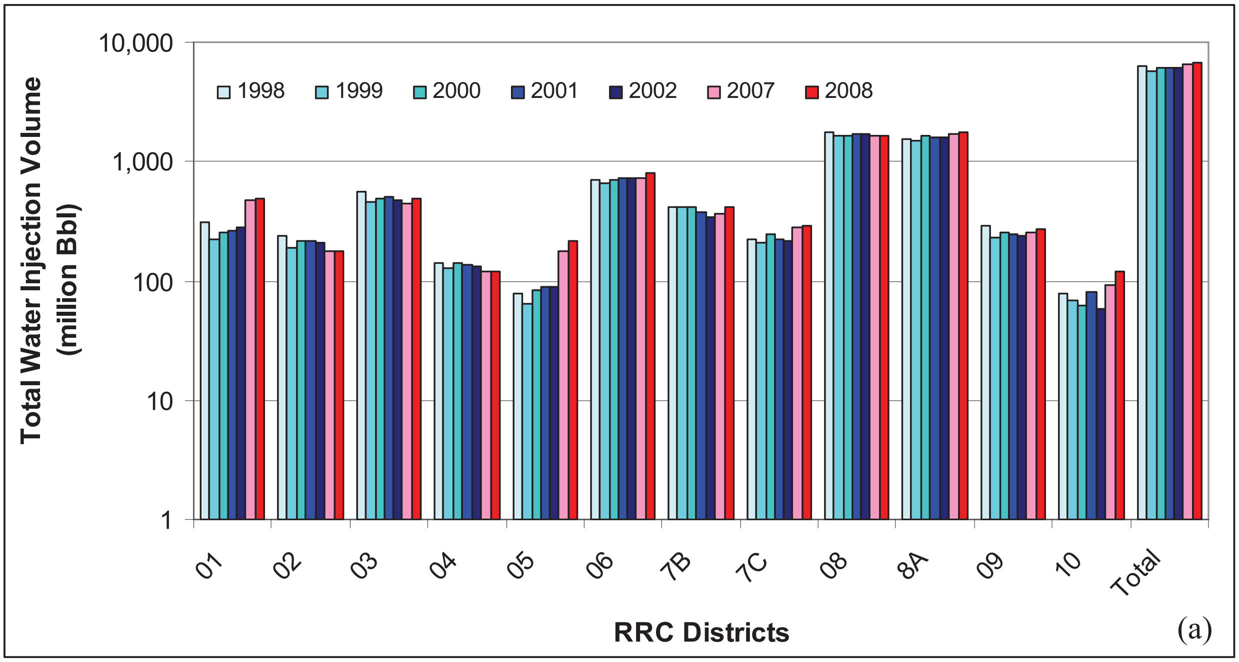
Source: RRC website   InjectionVolume_2002_RRC_+1998-2001.xls
http://www.rrc.state.tx.us/data/wells/statewidewells.php

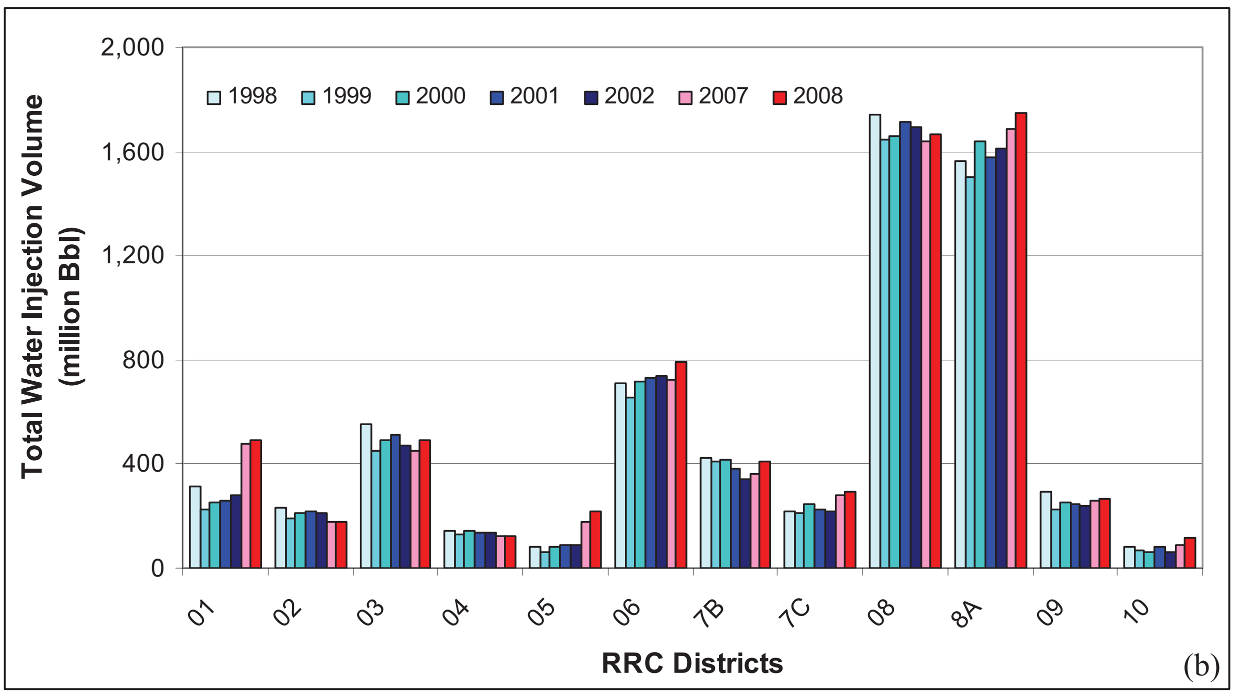
Figure 89. RRC district-level fraction of injected water (of all types) used for waterflooding



Source: RRC online system http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do

Figure 90. Oil production in districts 8 and 8A





InjectionVolume_2002_RRC_+1998-2001.xls

Source: RRC website http://www.rrc.state.tx.us/data/wells/statewidewells.php for years 1998 to 2002 and http://webapps.rrc.state.tx.us/H10/h10PublicMain.do for years 2007 and 2008
Note: districts 6 and 6E are now combined

Figure 91. RRC district annual total water (of all types) injection volume (1998–2002 and 2007–2008): (a) log scale, (b) linear scale

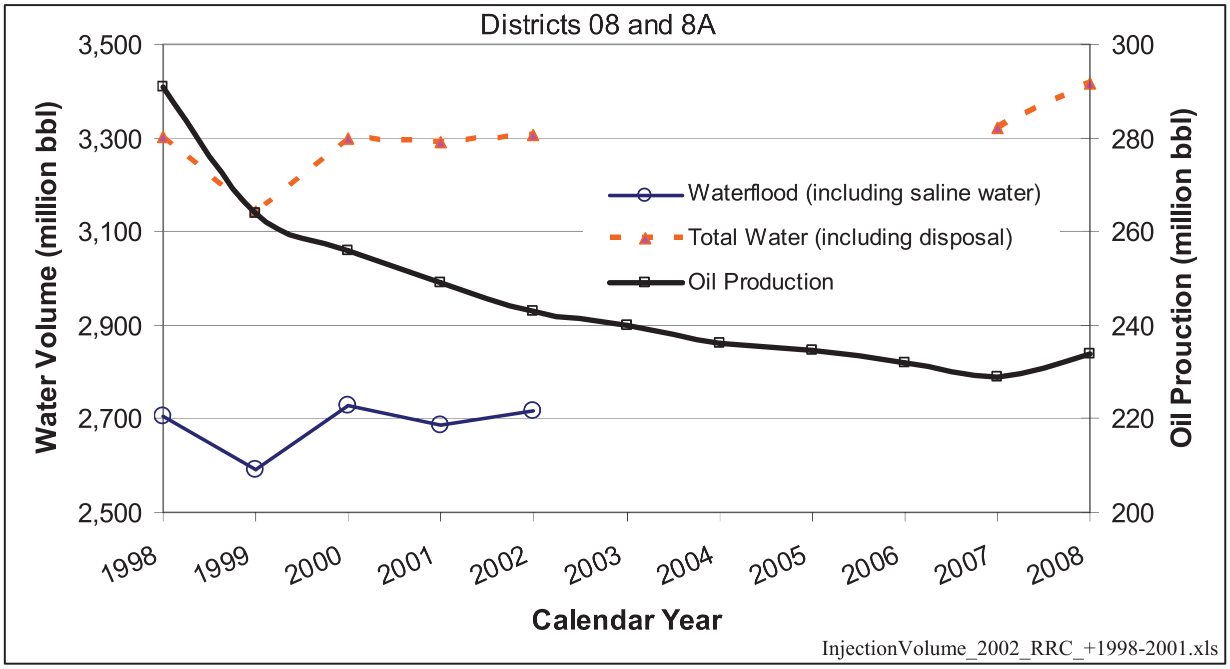
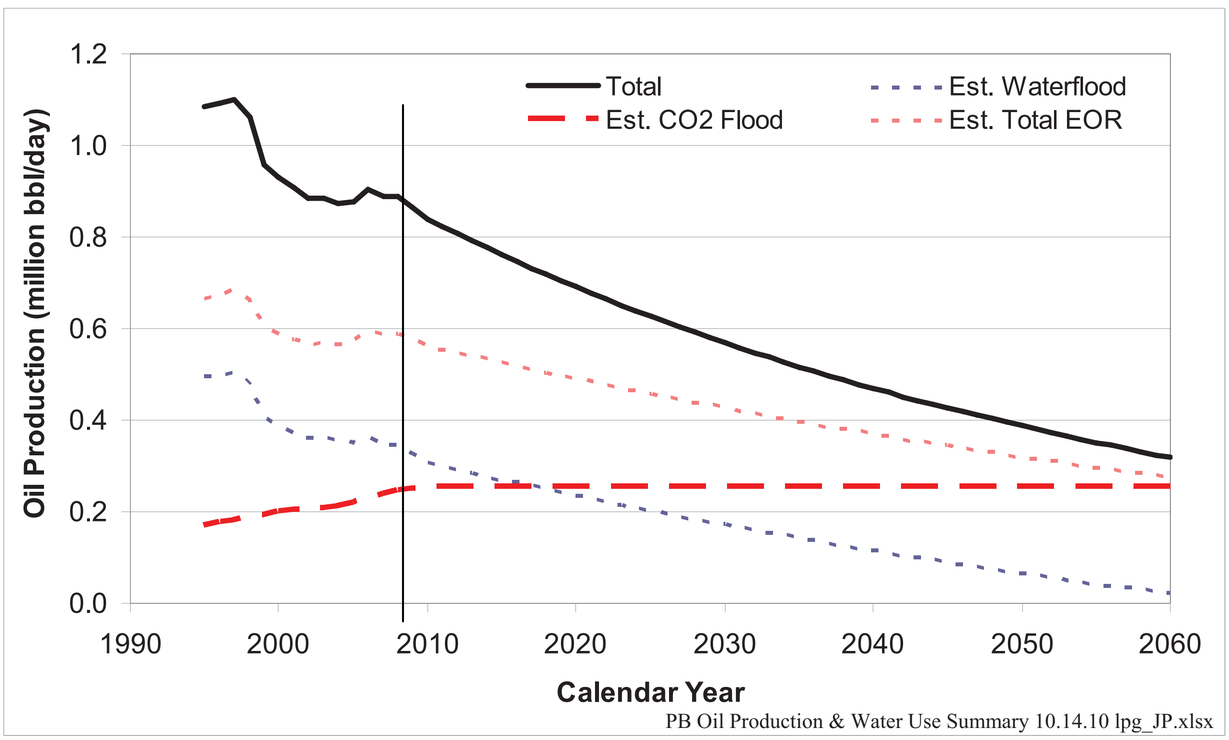
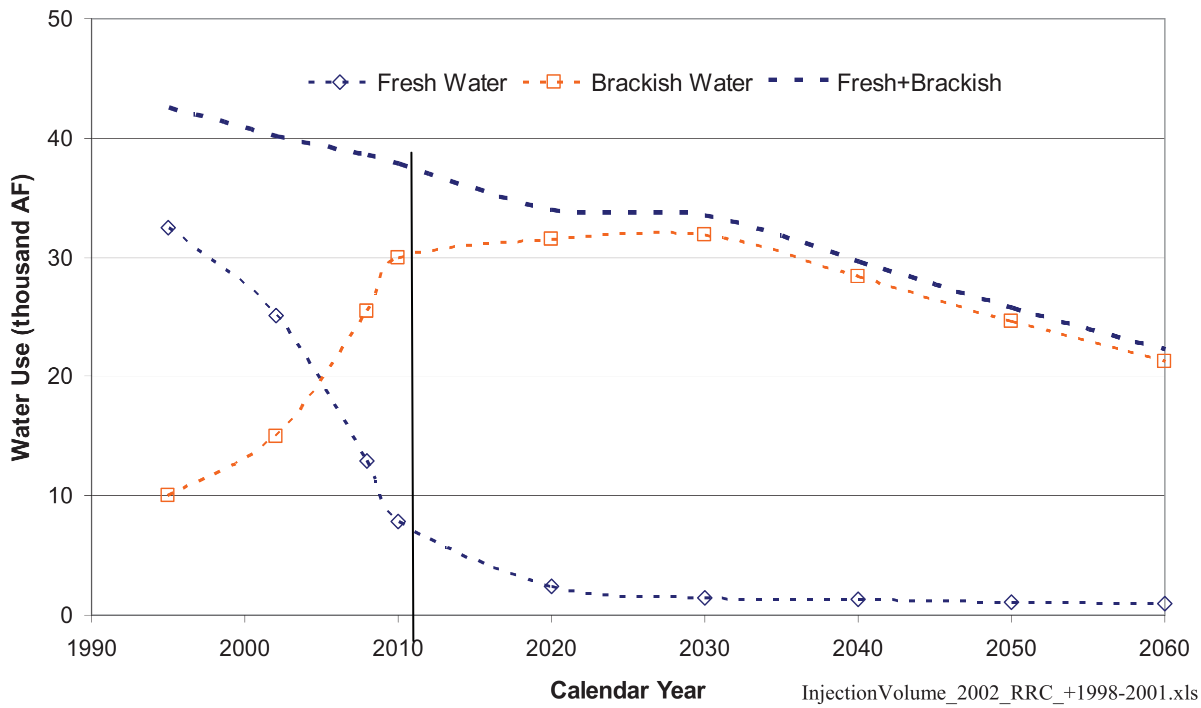


Figure 92. Comparison of oil production and water injection in RRC districts 08 and 8A (1998–2008)



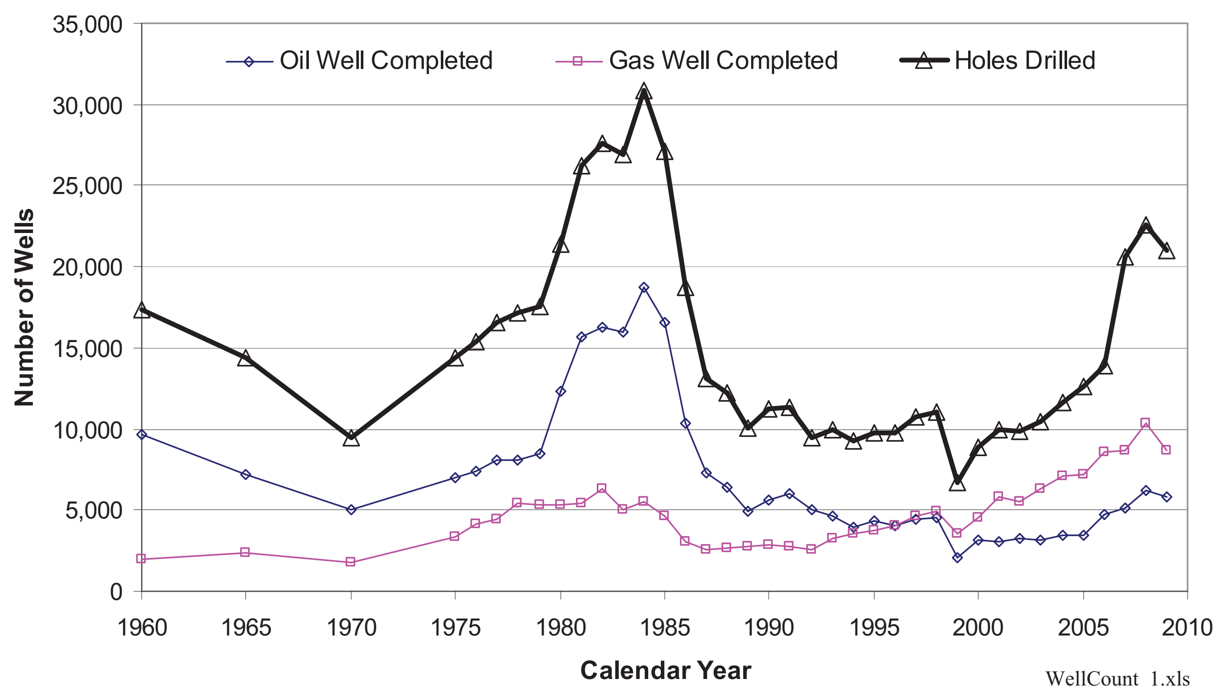
Note: data only for historical total production

Figure 93. Historical and forecast for oil production in districts 8, 8A, and 7C



Note: Only data points are from 1995 RRC survey

Figure 94. Estimated current and projected fresh- and brackish-water use for pressure maintenance and secondary and tertiary recovery operations



Source: RRC website http://www.rrc.state.tx.us/data/drilling/txdrillingstat.pdf
Note: completions include mostly new drills but also re-entered and recompleted wells (10-15% of total)

Figure 95. Number of holes drilled and of oil and gas wells completed in Texas between 1960 and 2009

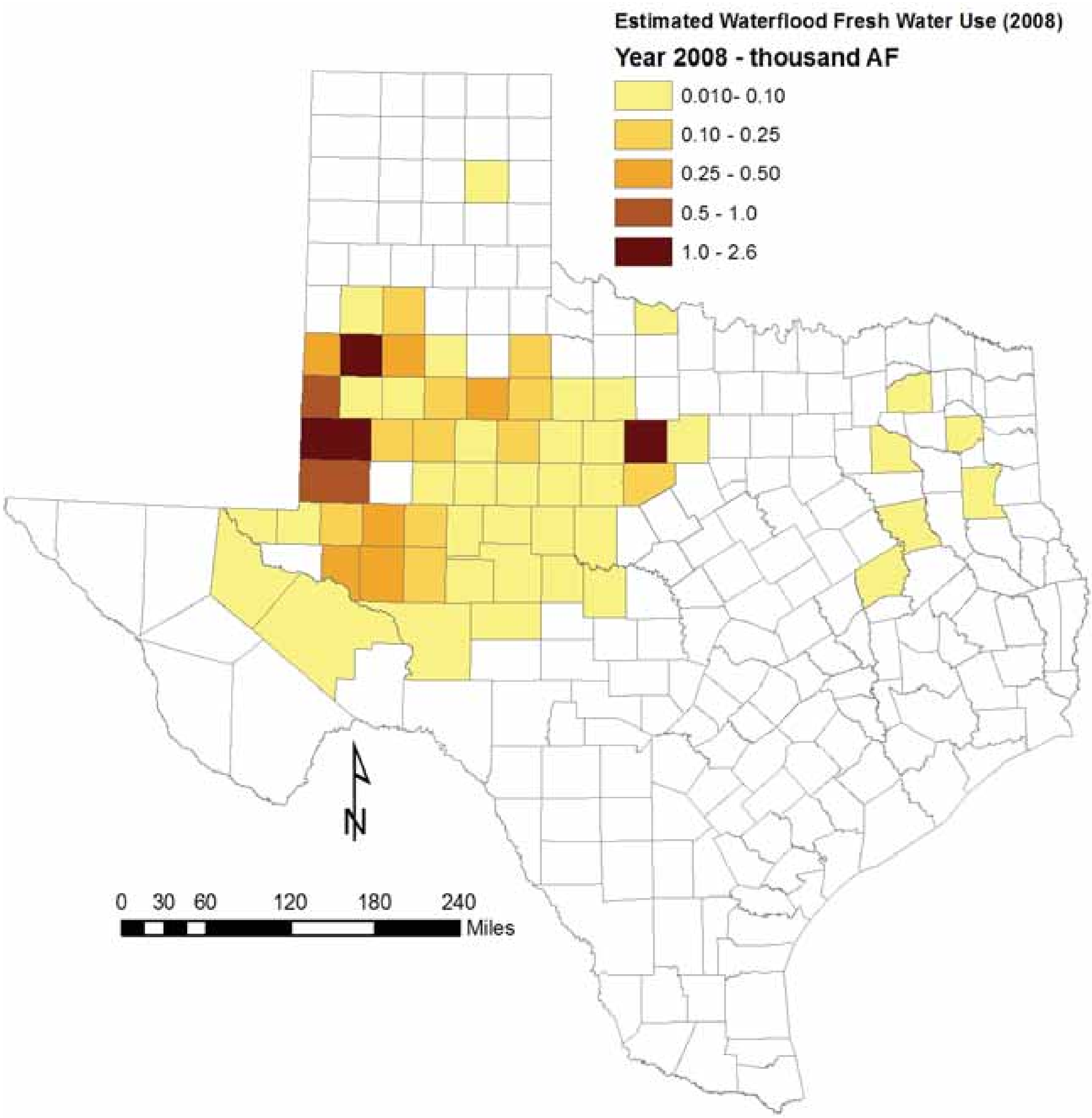


Figure 96. Estimated fresh-water use for waterfloods (2008)

4.3 Coal and Lignite

Total coal production for 2009 was >1 billion short tons for the country, 35+ million short tons of which the state of Texas produced (Table 1). Currently Texas has 11 active coal mines or groups of mines, with 2 mines (Kosse and Twin Oak mines) coming fully online in the next few years (Figure 97).Total production has been decreasing for 2 decades (Figure 98 with more details in Figure 100). All mines are above ground, mining lignite grade resources to a depth of 250 ft. All coal operations in Texas are currently mine-mouth, meaning the coal is used to power a power plant or other facility close to the mine. All mines with significant production in the past decades are still in operation, except for Sandow transitioning to the adjoining Three Oaks, both operated by ALCOA, Inc., (Williams, 2004) and the two Gibbons Creek locations (operated by the Texas Municipal Power Agency, TMPA–Bryan College Station), idle since 1996. The survey went only to current operators. From north to south, mines with recent activity as listed on the RRC website are given in Table 25.

In general, coal-mining processes require water during operations for activities such as dust suppression, waste disposal, reclamation and revegetation, coal washing, transportation, and drilling. In Texas, coal mining does not require drilling, coal washing, or transportation by slurry pipeline, and water use is limited to dust suppression and equipment washing. However, there is a need for dewatering and depressurization for most mines (Table 26). The water pumped is either discharged into a lake or stream or first discharged into a retention or sedimentation pond and then routed to a lake or stream. Therefore, once the water has been initially pumped from the ground to allow initial mining to occur, the water becomes available for use as surface water. Many mines also contract additional water from water-supply wells and water rights in order to supply fresh water to office operations (Table 27). Additionally, water for mining activities such as dust suppression and hauling activities may come either from these separate water-supply wells or from the retention ponds. Tracking where the water is routed, from where and what it is used, and the exact amount of consumption prove to be a difficult task. Whereas agencies track water pumped for operations and discharged into local surface waters, no central agencies tracks the entire operation when it comes to mining. The TWDB sends a survey to operators for groundwater pumped from water-supply wells, whereas the RRC tracks water pumped for depressurization and dewatering. Additionally, mining operators must report water-quality information on discharged water to lakes and streams to TCEQ. In order to further delineate the data, a questionnaire (Appendix D) was sent to mining operators regarding their water usage via TMRA.

In 2009, 37.1 million short tons of lignite was produced in the state, requiring production of 25.7 thousand AF of water and resulting in an average raw water use of 227.5 gal/st. However, including only consumption (and not dewatering), the same coal production required only 2.6 thousand AF or 22.8 gal/st. For comparison purposes, Chan et al. (2006) reported that, in 2003, given national coal-production statistics, a rough estimate of overall water required for coal extraction (mining and washing) ranged roughly from 86 to 235 million gal/day for an overall coal production of 1,071.7 million short tons, including 86.4 million short tons of lignite (EIA) (30 to 80 gal/st). These nationwide numbers represent a mix of uses, coal washing for Appalachian and interior coals, depressurization for lignite, and slurry pipelines.

The Sandow mine used to contribute a large fraction of total coal-mining water use (Figure 99), more than half of the ~40,000 AF/yr of produced groundwater until 2008. The current overall amount is <20,000 AF/yr. Currently no mine comes close to the threshold of 10 thousand AF/yr. However, surface water is also used in some mines, according to data we collected for the years 2009–2010. Overall, we assumed that the amount and distribution of the water used in 2009–2010 are very similar to those used in 2008 (year chosen as representative) in the coal industry.

Luminant mines in East Texas (Monticello Thermo, Monticello Winfield, Oak Hill, Martin Lake, and Big Brown) have a total water use of between 1 and 2.5 thousand AF/yr, which is mostly due to overburden dewatering, do not need to be depressurized (or very little), and have to pump supplementary (variable across mines) amounts of water to satisfy their operational needs. All of the water is fresh and is used mostly for dust suppression. An additional mine in the same Sabine Uplift area (South Hallsville in Harrison County operated by Sabine Mining Company) shows a larger water volume being processed at 5.8 thousand AF/yr, but that includes no groundwater pumping for overburden dewatering or for depressurization. The operating technique here appears to allow for overburden seepage to collect in the pit and mix with surface water.

Central Texas mines (including Jewett, Calvert/Twin Oak, Sandow/Three Oaks) are characterized by some depressurization pumping. Levels of depressurization and dewatering vary considerably across mines. Mines located in the Calvert Bluff Formation above the prolific Simsboro aquifer of Central Texas (between the Colorado and Trinity Rivers) are forced to produce large amounts of water to depressurize and avoid heaving of the mine floor (for example, Harden and Jaffre, 2004). The Sandow mine in Milam County used to pump large amounts of water from the Simsboro, in excess of 20 thousand AF/yr.

Gibbons Creek and San Miguel mines tap the Jackson Group lignite, not the Wilcox. The San Miguel mine does produce groundwater, but it is saline and is reinjected into the subsurface. For the purpose of this study, the San Miguel mine has zero water use. Two new mines will be developed in the future: Twin Oaks, next to the current Calvert mine in Robertson County and Kosse Strip in Limestone County. They will be discussed in the Future Use section.

Table 28 summarizes our findings: a total of 25.6 thousand AF is pumped, only 2.6 thousand AF of which is consumed. Most is groundwater (18.4 thousand AF), 1.1 thousand AF of which is consumed.

Table 25. Lignite and coal-mining operations in Texas

Name	County	Current Operator	Cumul. Prod. 1976–2007 (million st)[A]	Water-Use Range (thousand AF/yr)	Status
Monticello Thermo	Hopkins	Luminant	35.4	~0.9	Active in 2009
Monticello Winfield	Titus	Luminant	268.1	0.6–1.0	Active in 2009
Darco	*Harrison*	*Norit Americas Inc.*	*6.8*		*Not in operation 2001 last prod.*
Hallsville	Harrison	Sabine Mining Company	80.4	~5.8	Active in 2009
Oak Hill	Rusk	Luminant	101.2	1.2–1.7	Active in 2009
Martin Lake	Panola	Luminant	265.9	~1.0	Active in 2009
Big Brown	Freestone	Luminant	160.7	~2.5	Active in 2009
Jewett	Freestone/ Leon	Tx Westmoreland Coal Company (NRG)	167.7	~2.0	Active in 2009
Calvert	Robertson	Walnut Creek Company	32.6	7.2	Active in 2009
Sandow	*Milam*	*ALCOA Inc.*	151.0	*>25 1990–2008 average*	*Not in operation 2005 last prod.*
Three Oaks	Bastrop/Lee	ALCOA Inc.	13.7	4.0-5.0	Active in 2009
Gibbons Creek	*Grimes*	*TMPA*	*43.0*		*Not in operation 1996 last prod.*
Powell Bend		*LCRA*	*1.6*		*No longer permitted 1993 last prod.*
San Miguel	Atascosa/ McMullen	San Miguel Electric Cooperative	80.2	0.2 saline	No fresh or brackish water use
Little Bull Creek		*Amistad Fuel Company*	*0.43*		*No longer permitted 1987 last prod.*
Eagle Pass	*Maverick*	*Dos Republicas Resources Co., Inc.*	*0*		*Not (ever?) in operation.*
Palafos, Rachal, Trevino	*Webb*	*Farco Mining, Inc.*	*7.2*		*Not in operation 2004 last prod.*
Thurber		*Thurber Coal Company*	*0.46*		*No longer permitted 1983 last prod.*

Note: mine locations not in operation are in italics in smaller print
[A]: RRC website file tx_coal.xls

Table 26. Water fate for current lignite operations in Texas

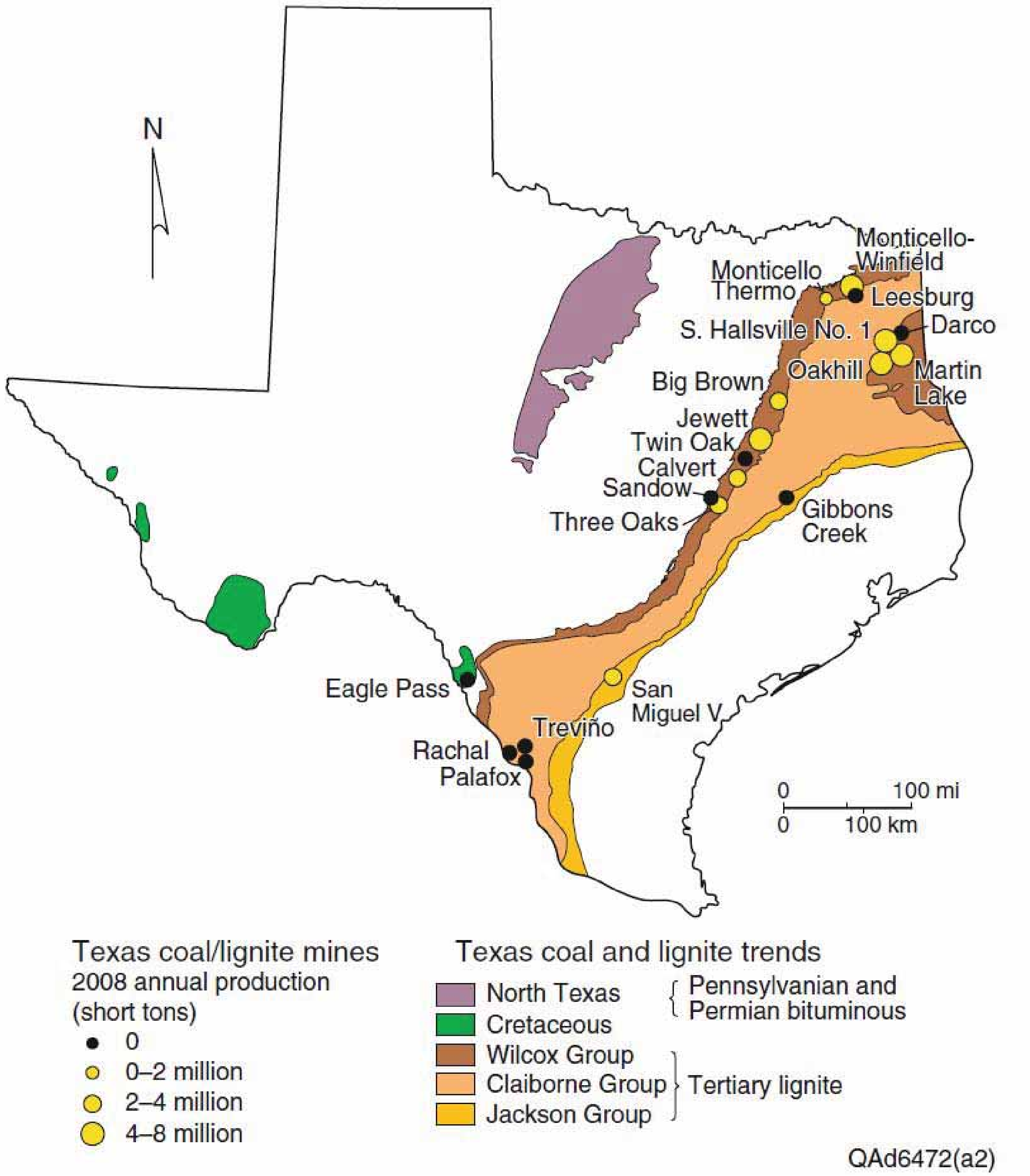
Name	County	Dewatering	Depress.	Other	Use
Monticello Thermo	Hopkins	77.7% overburden	0%	22.3% water supply	95% dust suppression 5% washing
Monticello Winfield	Titus	0%	0%	100% water supply	95% dust suppression 5% washing
Hallsville	Harrison	99.9% pit	0%	0.1% water supply	
Oak Hill	Rusk	54% overburden	0%	46% water supply	95% dust suppression 5% washing
Martin Lake	Panola	12.9% overburden	0%	87.1% water supply	95% dust suppression 5% washing
Big Brown	Freestone	92.5% overburden	3%	4.5% water supply	95% dust suppression 5% washing
Jewett	Freestone/ Leon	98% but mostly overburden dewatering		2% water supply	
Calvert	Robertson	2% overbrd. 2% pit	95%	1% water supply	Mine operations + discharge
Sandow	*Milam*		*100%*		
Three Oaks	Bastrop/ Lee		99%	1% water supply	
San Miguel	Atascosa/ McMullen	2% pit	98%	unknown	Discharge to Class V injection wells

Table 27. Water source for current lignite operations in Texas

Name	County	Fresh	Brackish	GW	SW
Monticello Thermo	Hopkins	100%	0%	80%	20% (water rights)
Monticello Winfield	Titus	100%	0%	50%	50%
Hallsville	Harrison	100%	0%		100% pit dewatering but also seepage (GW)
Oak Hill	Rusk	100%	0%	58.5%	41.5% (water rights)
Martin Lake	Panola	100%	0%	100%	0%
Big Brown	Freestone	100%	0%	100%	0%
Jewett	Freestone/ Leon	95%	5%	Unknown	Assumed all GW
Calvert	Robertson	100%	0%	100%	
Sandow	*Milam*	*100%*	*0%*		
Three Oaks	Bastrop/ Lee	100%	0%	100%	0%
San Miguel	Atascosa/ McMullen	0%	0%	100% saline	0%

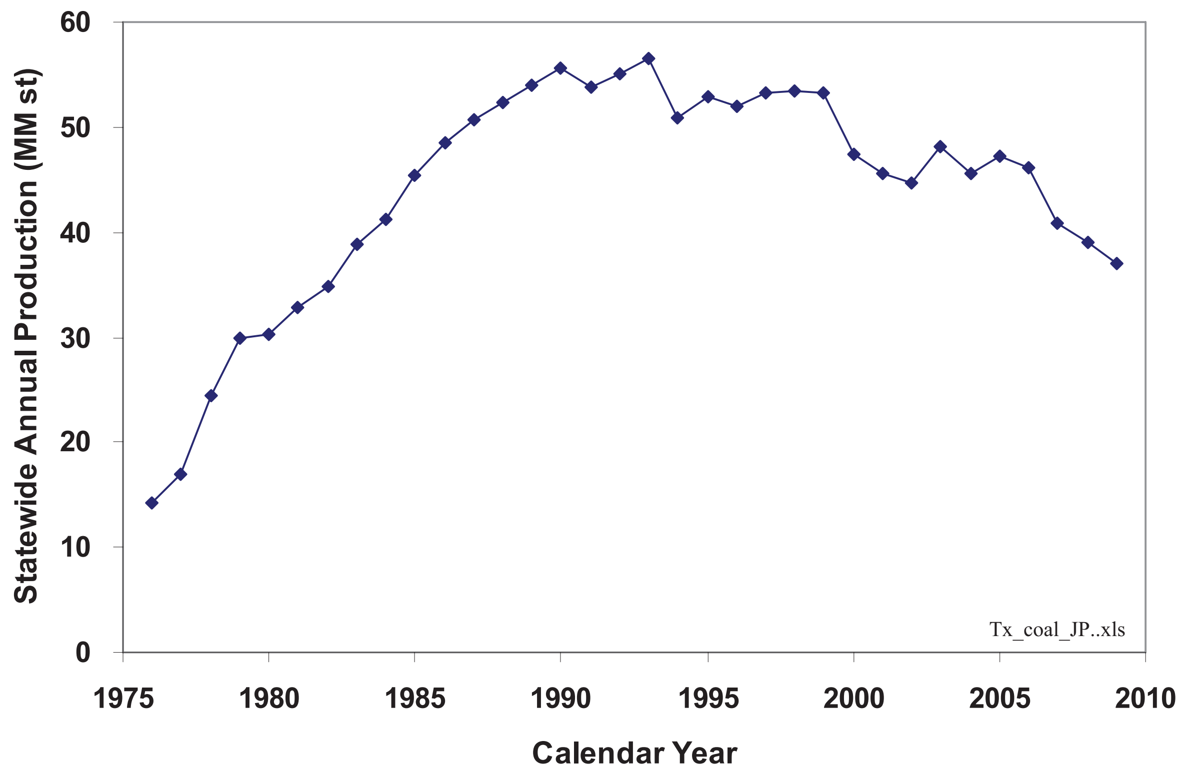
Table 28. Estimated lignite mine water use per county in AF/yr (2010)

Contributing Mine	County	Total Pumpage	Total Consumption	Pumpage Groundwater	Consumption Groundwater	Pumpage Surface Water	Consumption Surface Water	Pumpage Fresh Water	Consumption Fresh Water
San Miguel	Atascosa	0	0	0	0	0	0	0	0
1/2 Three Oaks	Bastrop	2,089	21	2,089	21	0	0	2,089	21
Big Brown, 1/3 Jewett	Freestone	3,129	124	3,129	124	0	0	3,095	124
South Hallsville	Harrison	5,800	6	6	6	5,794	0	5,800	6
Monticello Thermo	Hopkins	920	205	735	21	185	185	920	205
1/2 Three Oaks	Lee	2,089	21	2,089	21	0	0	2,089	21
1/3 Jewett	Leon	667	13	667	13	0	0	633	13
1/3 Jewett, Kosse Strip	Limestone	694	41	694	41	0	0	661	41
Martin Lake	Panola	982	855	554	428	428	428	982	855
Calvert, Twin Oak	Robertson	7,436	74	7,436	74	0	0	7,436	74
Oak Hill	Rusk	1,265	582	741	58	524	524	1,265	582
Monticello Winfield	Titus	619	619	310	310	310	310	619	619
TOTAL		**25,689**	**2,562**	**18,449**	**1,116**	**7,240**	**1,446**	**25,589**	**2,562**



Source: Ambrose et al. (2010)

Figure 97. Distribution of Texas lignite and bituminous coal deposits, coal mines currently permitted by the RRC with 2008 annual production in short tons



Source: RRC website file tx_coal.xls

Figure 98. Statewide coal/lignite annual production (1975–2009)

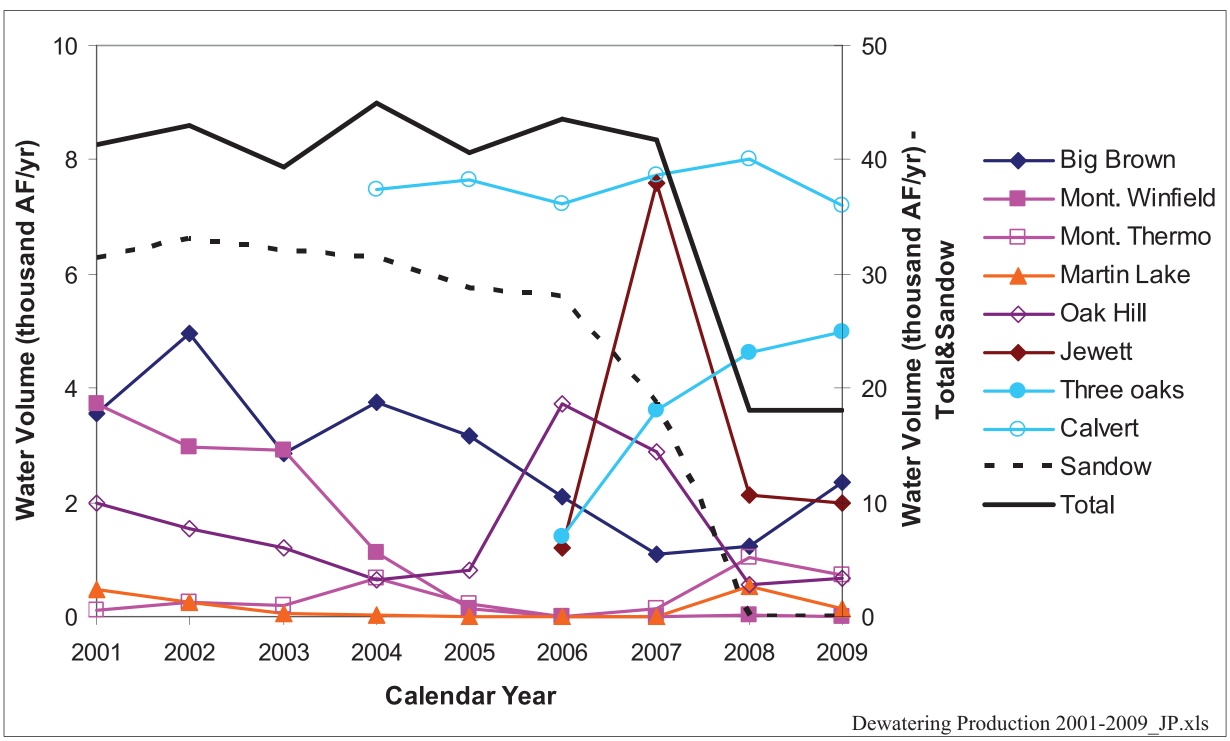
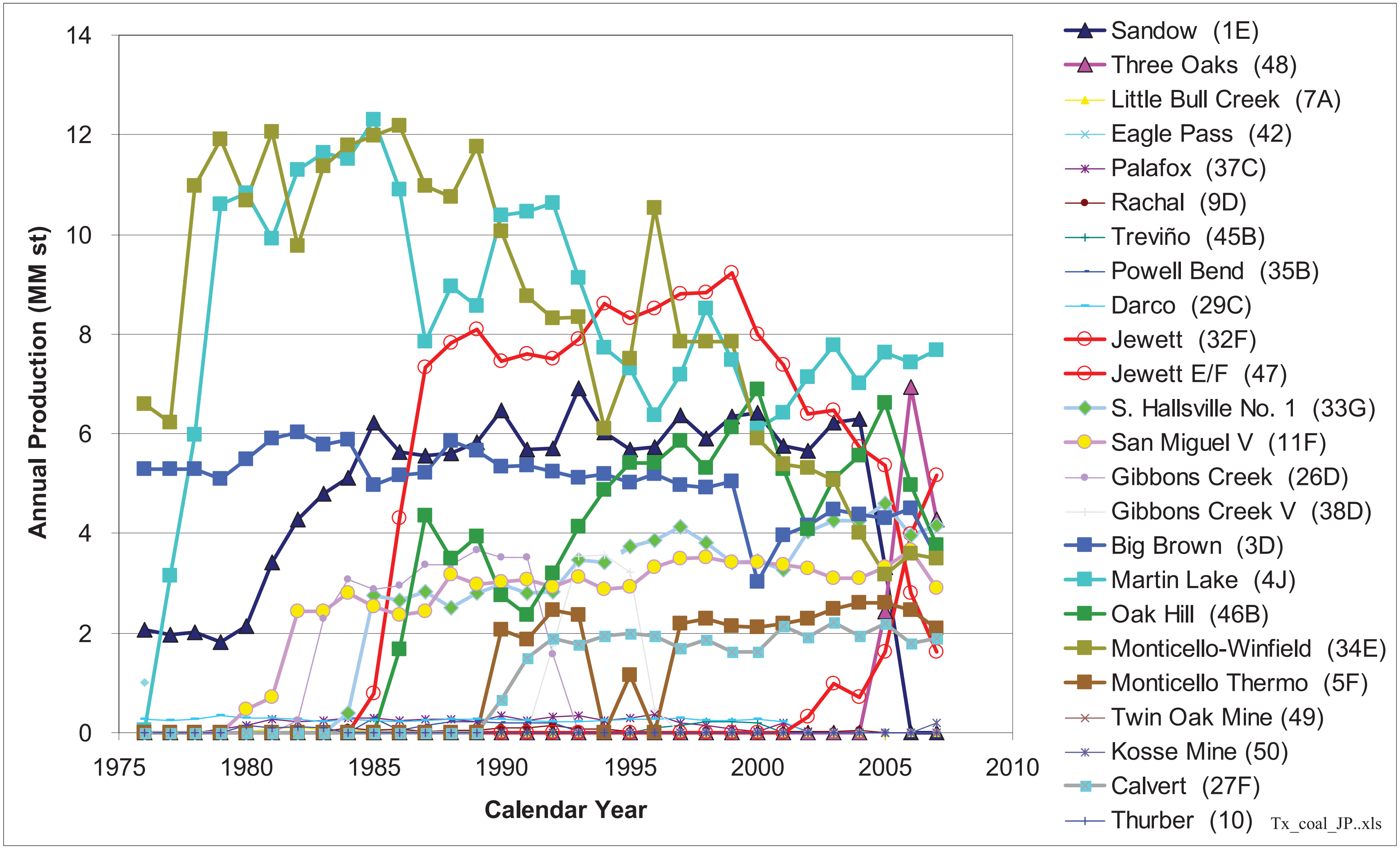


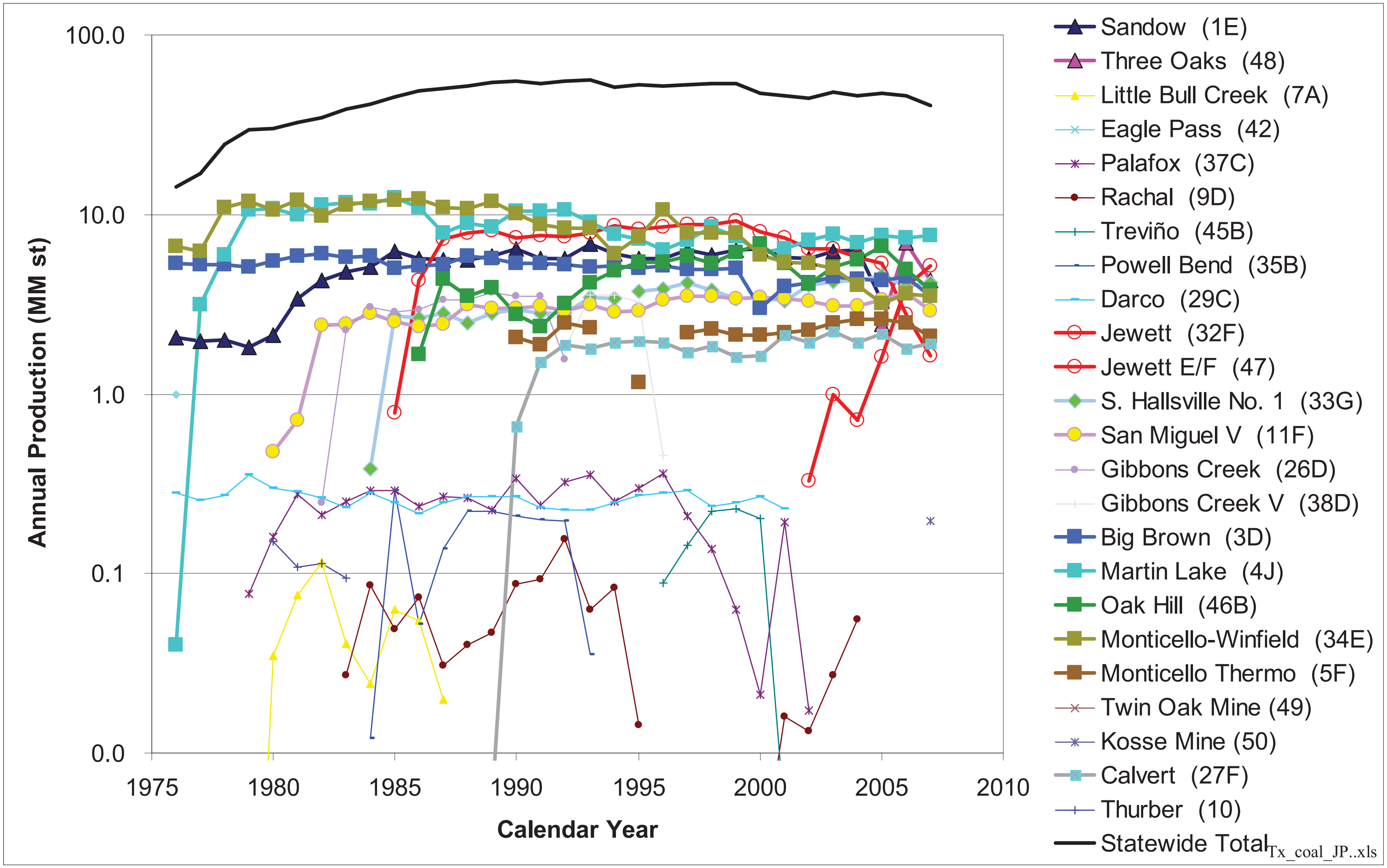
Figure 99. Lignite mine groundwater production 2001–2009



(a) linear scale

Note: permit numbers in brackets

Figure 100. Production of Texas coal mines (1976–2007)



(b) log scale

Source: RRC website file tx_coal.xls

Figure 100. Production of Texas coal mines (1976–2007) (continued)

4.4 Aggregates

This section summarizes work presented in Walden and Baier (2010) that addresses nonfuel industrial mineral mining, including aggregates, stone, clays, metals, and nonmetallic minerals. Most of the information focuses on crushed stone and construction sand and gravel, which make up the largest portion of the industrial mineral mining industry in Texas and constitute one of the greatest water users. As detailed in the methodology section (Section 3.3.3), the current TWDB data set is used as a basis and is compared with the newer BEG survey. In Section 4.4, we describe our efforts to bring in additional information, particularly confirmation of water-use coefficients.

4.4.1 General Aggregate Distribution

Aggregates fall into two major categories: crushed stone and sand and gravel, as well as a miscellaneous third category. Having a low value on a mass basis, aggregates tend to concentrate around urban areas because transportation costs can be prohibitive unless they possess an intrinsically higher value such as industrial sand (used in hydraulic fracturing) or igneous crushed stones (Figure 101). Aggregate products can be economically trucked up to 50 miles and can be shipped by rail up to 200–250 miles.

Carbonates (limestone and dolomites) for crushed rock exist in large quantities across most of the state but typically come from selected formations such as the Edwards Limestone (Garner, 1994), especially along the Balcones Fault Zone (west of San Antonio to south of Dallas). Overall, crushed stone consists mostly of limestones but also sandstones, as well as granitic rocks in the Llano area and volcanic rocks ("trap rock") in the Uvalde area. Carbonates, and more generally crushed stones, have several purposes, including concrete making, ballast, base material under foundations, roads, and railroads, but also manufacture of cement and lime. Sand and gravel facilities are located mainly along streams and rivers and in the Gulf Coastal Plains and tend to be smaller and sometimes intermittent.

Some facilities are located below the water table and need to pump seeping groundwater (as well as stormwater) from the exploitation pit. It is difficult to estimate the amount of groundwater (which should be counted toward withdrawal) relative to the amount of stormwater (which should not be counted as either groundwater or surface-water withdrawal) without undertaking a study of the local hydrologic system, unless a water-source breakdown is provided by the operator.

4.4.2 Description of Mining Processes

4.4.2.1 Crushed Limestone Mining

Hard-rock limestone is mined by blasting large sections of the quarry wall and extracting the shot rock with excavators, loaders, or other mechanical equipment. Large dump trucks transport the material to rock crushers, where it is reduced to a size that can be moved by conveyor belts to other parts of the operation. No water is used during extraction except for roadway watering and dust suppression, as needed. Initial rock crushing and separation are also performed dry except for dust suppression. Road-base products, which contain higher proportions of clay and pit fines, are produced in this dry section of the plant. Harder rock is passed sequentially through a series of crushers, shakers, and screens with a multistage washing system to produce a variety of product sizes. Amount of water used depends on how dirty the rock is and the number of products to be generated. Different sized products are separated and stockpiled for delivery to customers. Products can be mixed in various proportions to satisfy specific customer specifications. The wash water removes very fine particles and impurities from the larger aggregate products. These small particles are further separated from the wash water using cyclones, rotating screws, weirs, and fine screens to produce manufactured sand. Figure 102 represents a simple flow diagram of a typical crushed-stone mining process.

The remaining water is captured and typically routed to large settling ponds to allow super-fine particles of silt and clay to settle out of suspension before being pumped back to supply ponds to be recycled for reuse in the process. Smaller operations or quarries with limited available space may use closed filtration or similar equipment to further clean and recycle wash water. Discharge of water is rare and generally only occurs during seasonal, heavy rainfall events that overwhelm the retention ponds. As a result of the active water recycling and reuse efforts in place at most crushed-stone quarries, only ~20 to 30 percent of the water used in the operation is actually consumed and must be replaced. Water loss generally results in four ways: (1) retention of water in the moisture content of final product shipped to customers; (2) application of water on roadways, conveyor belts, and transfer points to suppress dust; (3) spillage and absorption of water from washing process equipment and pipes; and (4) evaporation from ponds and open equipment.

Rainwater, spillage, and drainage from stockpiles are collected and routed to settling ponds or other equipment to reduce the amount of makeup water required. Surface ponds that are below the local water table may also have significant groundwater seepage into the ponds. In some areas of the state, this seepage is often enough that active pumping from groundwater or surface-water sources is not required or may only be necessary during summer months or periods of extreme drought. Brackish or saline water cannot be used for aggregate mining because the salt will adversely impact the quality of the concrete, asphalt, and other products manufactured from the materials.

4.4.2.2 Sand and Gravel Mining

In open-pit sand and gravel mining, material is removed using excavators, front-end loaders, draglines, or shovels and transported by trucks for processing. Deposits are frequently located near streams or waterways and are mined moist. No water is required for extraction and, in some cases, water must be pumped away from the mining site to allow access by machinery, although some facilities with deposits below the water table use dredges. Dewatering of groundwater seeping into the mining site is often used as wash water but may also need to be supplemented by groundwater and surface-water sources.

In most dredge-type sand and gravel mining, materials are pumped from the bottom of a body of water and piped to the processing plant in a high volume of water. The sand and gravel are separated, and the bulk of the water is returned to the original location. This return water is critical to maintaining an adequate volume of water at the mine site to allow continued pumping. Some dredge mines use bucket dredges to load material onto barges or other means of transport to processing locations.

Sand and gravel are processed through a series of shakers, screens, and washers to size, separate, and clean different products. Larger rocks may be crushed or removed for other uses. Rotating screens with water sprays are used initially to treat wet materials before log washers or rotary scrubbers remove clays and organic materials. Screening is used to separate product by size. Products are dewatered with screw conveyors, cyclones, or other separators and then transported to stockpiles. Wash water is routed to stormwater retention ponds, where particles are allowed to settle out. It is then recycled as process water or applied on plant roadways for dust suppression, as needed. Because sand and gravel are typically wet, little if any water is required on conveyors or other equipment for dust suppression. The moisture content of sand and gravel can be ~5% to 6%, resulting in proportional loss of water.

4.4.3 External Data Sets

Several databases (MSHA, USCB) list aggregate facilities and related commodities but do not include information on their production (Table 2, Table 3). A trade association (NSSGA) in association with USGS also reports names and locations of aggregate facilities but, similar to USCB and MSHA, does not provide commodity production or water use. As described next, we investigated with little success the possibility that TCEQ own information about water use. TCEQ regulates surface-water rights. We also conducted a survey of GCDs to access information on groundwater use.

4.4.3.1 TCEQ Central Registry

TCEQ is responsible for the regulation and permitting of all sources of air and water pollution and has adopted rules that specify the control technologies and emissions limits that must be met by industries, including mining operations, in Texas. The TCEQ has established a Central Registry of all regulated entities, which contains information about the companies and specific locations of industrial sites. Each regulated site is issued a Registration Number or RN Number, which allows the agency and the public to readily access this information and links to other program records related to permitting, compliance, inspections, enforcement, and other actions taken by the TCEQ. The Central Registry database was queried to extract information on all active facilities with major, two-digit SIC Codes of 10, regarding metal mining, and 14, regarding mining and quarrying of nonmetallic minerals, except fuels. The numbers and types of facilities identified by this search were far larger than identified by MSHA and NCCGA and are shown in Table 29.

4.4.3.2 TCEQ Surface-Water Diversion

The TCEQ issues and regulates water-rights permits and withdrawals of most surface water in Texas including navigable waters, reservoirs, and major impoundments. Each water right holder must submit monthly reports indicating the amount of water diverted, amount returned, and the amount consumed. The TCEQ provided spreadsheet data on water-rights reports from entities identifying themselves as mining users for 2006–2008. The agency was unable to segregate the mineral-mining facilities from other mining interests, such as oil and gas or coal, so it was difficult to clearly differentiate the available data. Many of the companies that were clearly recognizable as mineral mining reported no surface-water diversions, or they indicated that they consumed 100 percent of the amount that they did divert. In some cases, companies did report significant return-flow quantities. However, there appeared to be some confusion on the appropriate reporting requirements because some companies reported that the sum of the amount returned and consumed exceeded the amount that was diverted throughout the year. Appendix F includes a table that provides all of the active water-rights holders in the mining industry, along with the amount of water they are authorized to withdraw in acre-feet per year. It also includes a table of the 2008 Water Rights Reporting Data.

Further evaluation of the TCEQ Water Rights data to identify and extract industrial mineral mining information and to resolve gaps and inconsistencies in the reported values may be worthwhile. However, most mineral mining operations do not depend on surface-water-rights diversions except to supplement captured stormwater and recycled water when needed.

The TCEQ does not regulate the extraction of groundwater. Local GCDs have been established to monitor and control the amount of water withdrawn from aquifers in many areas of the state. No centralized data are available for specific types of water use, and additional investigation would be required to survey GCDs to determine whether they maintain data on mining activities within their jurisdiction. Information gathered from GCDs is posted in Appendix E.

4.4.3.3 TCEQ TPDES

The TCEQ regulates wastewater from major industrial and commercial sources under the Texas Pollution Discharge Elimination System (TPDES) through permits that control the amount and quality of effluent discharged. Discharge of process water requires an individual, site-specific permit, whereas discharge of stormwater can often be authorized under the Multi-Sector General Permit (MSGP) for major industrial activities. All of the SIC code categories for mineral mining operations (major two-digit Groups 10 and 14) are subject to the MSGP. Facilities are required to monitor and report the quantity of discharges but do not need to report captured or recycled water if it does not leave their property. Because most mining operations actively recycle much of their water, they only discharge during periods of exceptionally heavy rain. Examination of individual TPDES permits and discharge-monitoring reports will be of limited value in quantifying water use or consumption.

The TCEQ regulates the emission of air pollutants to reduce or avoid the release of contaminants that could adversely affect public health or the environment. Mineral mining operations have the potential to emit particulate matter (PM) from a number of processes that require controls to be implemented. Rules and air-quality permit requirements most often direct mining operations to reduce these PM emissions by applying water sprays to crushers, conveyors, transfer points, stockpiles, and roadways to suppress dust. This application becomes a major source of water consumption because most or all of the water used for these purposes evaporates. TCEQ rules do not require sources to monitor or report the amount or frequency of water used for particulate controls. Although some facilities record some related activities, such as the number or frequency of water trucks used to spray roadways, for their own management needs, such data are not consistent and cannot be reliably used. Further evaluation of air permits or controls will have limited value in quantifying the amount of water used or consumed by the mining industry.

4.4.3.4 TCEQ SWAP Database

The federally mandated TCEQ Source Water Protection (SWAP) project database contains a wealth of information about current and past mining activities and is a good source to locate facilities. However, it does not provide information about water use.

4.4.4 BEG Survey Results

4.4.4.1 Survey of Facilities

Results of the BEG survey are summarized in Table 30 (without reference to specific facilities or their location). Total production for crushed stone from the surveyed facilities translates into ~35 million tons, or 22.5 % of state total production, and may be sufficient to imply some validity and predictive power to this aggregate category. On the other hand, sand and gravel survey results add up to only ~3.6 million tons, or 3.6% of the state total production, and thus provide more limited predictive power. Overall surveyed facilities are well distributed across the state and are located in areas where most of the population resides (Figure 103). The 26 facilities (18 crushed stone and 8 sand and gravel) show a large range in terms of production (<0.2 to >13 million tons per year), reported gross water use (a few AF/yr to >4,000 AF/yr), reported net water use (a few AF to >2,000 AF/yr), and in a category called groundwater and surface-water net water use (from 0 to >1,000 AF/yr). The last category does not consider stormwater in net water use and account only for so-called external sources (surface water or groundwater). Plotting the information (Figure 104) graphically illustrates the relationship between these types of water use.

The stormwater category is included because precipitation falling on the property is generally redirected to sumps and ponds to comply with TCEQ regulations. Often that stored stormwater alone can be sufficient to run aggregate operations. This study did not try to determine whether the drainage area and precipitation at a specific facility are consistent with the amount of stormwater reported to be used. Such a task goes beyond the scope of work, although data to perform it are readily available. Discriminating between stormwater and groundwater is difficult in a pit whose bottom might be deeper than the water table, but it is just as conceivable to think that the stored stormwater recharges the aquifer as to think the reverse.

Water-use statistics are computed with and without accounting for stormwater (Table 31): the crushed-stone water-use coefficient is either 64 gal/st (with all water sources) or 36 gal/st (without counting stormwater), and sand and gravel water-use coefficient is either 68 gal/t (all water sources) or 47 gal/st (without storm water). Excluding dry process facilities and facilities from a company that seems to have much lower water-use coefficients produces 151 and 66 gal/st for wet process and crushed stone facilities, respectively. However, we think that the fraction of dry vs. wet process facilities is representative of the state as a whole (because we obtained complete data from a large operator in the state) and that lower water-coefficient facilities should also be included in the average (because they come from several large facilities). Recall that in the methodology section we explained that averages were made on a production basis not as a simple average of each facility average.

The amount of reported recycling varies widely from none for dry-process crushed-stone facilities, which only consumes water for dust suppression and a few wet-process crushed-stone facilities, possibly because they have stormwater in excess, to almost 100% in some highly water-conscious facilities. A few wet-process crushed stone facilities also reported no recycling, possibly because they have excess storm water available or because they misinterpreted the question. Most facility recycling rates range from 65% to 90%. For the washed crushed-stone mining operations that reported recycling, rates were in the expected range of from 49% to 86%. Recycling at surveyed sand and gravel operations was reported at rates ranging from 74% to 99%.

Unexpectedly, five operations indicated that no recycling of water was conducted at the mines and that all of the gross water used was consumed. This may be due to a misunderstanding of the survey questionnaire rather than an unrealistic indication that all water is used only once at the facility and is lost to product or evaporation. A more probably interpretation is that no exceptional recycling activities have been implemented to increase water reuse. In these cases, the reported amounts should be considered net water use. This study focuses on the net water use and did not need knowledge of gross water use or recycling rate because, unlike oil and gas activities, recycling serves only one single facility. The large spread in net water use is illustrated in Figure 105, which displays histograms of water consumption. However, values cluster ~0 to

30 gal/t for dust control (roads and machinery) and show a bimodal distribution at <20 gal/t and ~50 gal/t for washing. Both distributions have very long tails. Gross-washing water use reportedly ranges from a minimum of 3.0 gpm/tph for very clean rock (rare) up to 15.0 gpm/tph for dirty rock (as sometimes seen in the Edwards Limestone), that is, 180 to 900 gal/t (Walden and Baier, 2010).

The source of consumed water (Table 32) is equally difficult to generalize because of the limited size of the analyzed sample, but it seems that on average more than half of the consumed water is groundwater. This figure, however, represents an average that matches only a few facilities (Table 30). Water for most operations come from only one of three possible sources (groundwater, surface water, or stormwater). It is thus impossible to attribute water source at a county level without specific knowledge of the water use at each facility.

4.4.4.2 Survey of GCDs

Survey results are described in detail in Appendices D and E and integrated within the body of the report. Overall, except for a few very responsive districts, most GCDs either did not respond to the survey or did not have access to the requested information. In summary, findings indicate that most groundwater conservation districts do not collect estimates of groundwater use by mining operations. The districts generally rely on information reported by the TWDB, even though they may not be able to confirm the information. Fewer than 50 percent of the districts surveyed replied with any information. Of the respondents, only 20 percent provided any quantitative volumetric estimate of use or permitted use of groundwater by mining entities. No districts reported having monitoring systems in place to measure groundwater use that was permitted for mining. Therefore, other than the reported current use data in Appendix D (Table 72), the districts were unable to provide better projections of water use by mining.

4.4.5 Historical and Current Aggregate Water Use

Table 33 summarizes some historical water-use coefficients, a parameter not easy to come by as discussed earlier. Old reports (for example, Quan, 1988, published by the Bureau of Mines) mention ~300 gal/st but variable across the years (470 to 220) (his Fig. 30) and probably across the country as well as a function of local conditions. About half is recycled water (Quan, 1988, Table 5). Crushed stone intensity of water use ranges from 60 to 150 gal/st (his Fig. 34). Quan (1988) presented data for 7 individual years between 1954 and 1984. The trend is towards reduction in water use but not in a regular fashion and actually shows an uptick in the last year (1984), amount of recirculated/recycled water increased from a small fraction in 1954 to 50% in 1984. Quan (1988, p.32) estimating future water use in 2000 for the U.S. Bureau of Mines also relied on intensity of use coefficients using them as multipliers to the projected mineral production. Norvell (2009, Table 3) calibrated USGS water-use coefficients from Quan (1988) to Texas water-use surveys done ca. 2000. He doubled water-use relative to the U.S. average and assumed 80% recycling. Mavis (2003, Table 6.1–2) provided figures in the following subcategories for the sand and gravel category: 1–6 gal/t for dust control of machinery (this is consumed), 60–180 gal/t for wet screening, ~60 gal/t for sand screw, and ~90 gal/t for gravity classifier. The last three categories are for gross water use.

Recent WUS surveys conducted by the TWDB have a small overlap with the BEG survey (Table 34) in terms of facility, with an approximate agreement in terms of net water use. TWDB results cannot be used to develop water-use coefficients because production values are not provided, but they were integrated into their specific counties, as described in the methodology section.

Overall, **~24,700 AF and ~18,300 AF (total of 43,000 AF)** was consumed across the state for aggregate production. Results for individual counties are listed in Table 35.

Table 29. TCEQ Central Registry records of mining facilities in Texas

SIC Code	Type of Mine	No. of Mines	SIC Code	Type of Mine	No. of Mines
Major Group 10: Metal Mining					
1011	Iron Ore	4	1081	Metal Mining Services	8
1044	Silver Ore	6	1094	Uranium–Radium–Vanadium Ore	52
1061	Ferroalloy Ore (except Vanadium)	4	1099	Misc. Metal Ore	18
Major Group 14: Mining and Quarrying of Nonmetallic Minerals, Except Fuels					
1411	Dimension Stone	118	1446	Industrial Sand	74
1422	Crushed and Broken Limestone	1285	1455	Kaolin and Ball Clay	14
1423	Crushed and Broken Granite	8	1459	Clay, Ceramic, and Refractory Minerals (not elsewhere classified)	
1429	Crushed and Broken Stone (not elsewhere classified)	296	1474	Potash, Soda, and Borate Minerals	8
1442	Construction Sand and Gravel	1041	1479	Chemical and Fertilizer Mineral Mining (not elsewhere classified)	60
			1481	Nonmetallic Minerals Services, Except Fuels	29
			1499	Misc. Nonmetallic Minerals, Except Fuels	100

Table 30. Water-use survey results from selected aggregate operations

Production (Mt/yr)	Gross Water Use (1000s AF/yr)	Net Water Use (1000s AF/yr)	GW &SW Net Use (1000s AF/yr)	Water Use (gal/st)	Recycle Rate (%)	Source Water		
						GW	SW	StW
Crushed stone (wet process)								
4.00	4.1	1.3	0.00	107	68%			100%
1.76	2.9	0.5	0.54	100	81%	100%		
0.80	1.1	1.1	1.10	450	0%	100%		
1.33	1.6	0.4	0.41	100	75%	100%		
0.85	1.2	0.2	0.09	65	86%		50%	50%
1.50	1.4	1.4	0.00	300	0%			100%
*0.20**	0.2	0.2	0.15	*est 250*	0%		100%	
*0.65**	0.1	0.1	0.03	*est 250*	0%	55%		45%
*0.18**	0.3	0.1	0.04	*est 250*	52%	30%		70%
*0.33**	0.3	0.3	0.00	*est 250*	0%			100%
3.50	1.1	0.3	0.33	31	70%	100%		
13.70	4.3	1.1	1.06	25	75%	100%		
0.60	1.1	0.2	0.14	92	84%	80%		20%

Production (Mt/yr)	Gross Water Use (1000s AF/yr)	Net Water Use (1000s AF/yr)	GW &SW Net Use (1000s AF/yr)	Water Use (gal/st)	Recycle Rate (%)	Source Water		
						GW	SW	StW
Crushed stone (dry process)								
0.29	0.01	0.01	0.01	9	0%	100%		
0.39	0.01	0.01	0.00	10	0%			100%
4.56	0.14	0.14	0.14	10	0%	100%		
2.28	0.07	0.07	0.00	10	0%			100%
5.00	0.02	0.02	0.02	2	0%	18%	82%	
Sand and gravel								
0.55	0.29	0.08	0.08	45	74%		100%	
0.52	0.12	0.04	0.04	26	67%		100%	
0.21	0.12	0.03	0.00	38	79%			100%
0.50	1.84	0.03	0.03	18	99%		100%	
0.50	2.00	0.35	0.35	228	83%	100%		
0.30	0.09	0.02	0.02	22	76%	100%		
0.52				0	Y			100%
0.48				0	Y			100%

*: estimated
Note: some facilities may underreport their stormwater use

Table 31. Aggregate net water use/consumption based on BEG survey results

	Number of Data Points - % of State Production	1000s AF /million tons	Gal/t
Crushed-stone water-consumption coefficient			
All water sources	17–22.5%	0.197	64
GW+SW only	17–22.5%	0.109	36
Wet process crushed large w/o low water-use coefficient facilities			
All water sources	10–~8%	0.465	151
GW+SW only	10–~8%	0.204	66
Sand and gravel water consumption coefficient			
All water sources	6–3.6%	0.209	68
GW+SW only	8–3.6%	0.143	47

Table 32. Net water-use breakdown by water source

		Groundwater	Surface water	Stormwater
Crushed Stone	Weighted by production	0.706	0.011	0.295
	Facility average	0.491	0.129	0.381
Sand and gravel	Weighted by production	0.689	0.291	0.020
	Facility average	0.250	0.375	0.250

Note: crushed stone survey represents ~22.5% of total production, whereas sand and gravel survey sample represents only 3.6% of production

Table 33. Historical water-use coefficients for aggregates (gal/st)

Withdrawal	Recycled	Total	Discharge	Consumption	Source
Sand and Gravel					
		220–470*			Quan (1988, Fig.30) 1954-1984
130	59	189	88	42	Quan (1988, Table C-5) 1984
260			52	208	Modified from Norvell (2009, p.13)
		211–336			Mavis (2003, Table 6.1-2)
Industrial Sands					
806	2891	3697	259	547	Quan (1988, Table C-5) 1984
1612			322	1290	Modified from Norvell (2009, p.13)
Crushed Stone					
		60–150			Quan (1988, Fig.34) 1954-1984
68	64	132	48	20	Quan (1988, Table C-5) 1984
136			27	109	Modified from Norvell (2009, p.13)

*including industrial sand

Table 34. Results from recent TWDB WUS

Sand and Gravel		Crushed Stone	
Year	Net Water Use (AF)	Year	Net Water Use (AF)
2007	72	2007*	1,058
2007	1,468	2007*	824
2005	3,020	2007*	1,196
2006	6	2007**	625**/0.9
2007	0	2002	625
2001	150	2007	4,822
2007	2	2007	1,787
2007	386	2007	185
2007	112	2007	341
2007	0	2007	0.6
2004	5	2007	0.3
2007	2,384		

*facility with water-use approximately confirmed by BEG survey
**consistent with BEG survey only for earlier years
Source: TWDB Office of Planning

Table 35. Estimated county-level crushed-stone and sand and gravel water use for 2008 (other counties are assumed to have zero water use)

County	CS	S&S	County	CS	S&S
Unit: 1000s AF					
Atascosa		0.350	Kaufman	2.063	0.195
Bastrop		0.063	Kerr		0.059
Bell	0.747	0.346	Lampasas	0.293	0.012
Bexar	3.108	1.028	Liberty		0.108
Borden		0.000	Limestone	0.210	
Bosque		0.013	Lubbock		0.415
Brazoria		0.565	Maverick	0.052	
Brazos		0.230	McLennan		1.025
Brown	0.000		Medina	0.287	0.063
Burnet	0.280	0.031	Montague	0.104	0.010
Callahan	0.131		Montgomery		0.028
Coke		0.003	Navarro		0.062
Colorado		1.540	Nolan	0.023	
Comal	3.634	0.099	Nueces		0.445
Cooke	0.818	0.026	Oldham	0.165	0.002
Coryell	0.275		Orange		0.136
Dallas		1.574	Parker	0.170	0.253
Denton		1.262	Potter	0.192	0.308
Duval		0.604	Reeves	0.014	0.008
Eastland	0.150		Sabine	0.053	
Ector	0.168		San Patricio	0.340	0.055
El Paso		0.581	Smith		0.106
Ellis	2.898		Somervell		0.386
Fannin		0.006	Starr		0.142
Fayette		0.082	Stonewall	0.019	
Floyd	0.169		Tarrant		1.093
Fort Bend		0.000	Taylor	0.000	
Galveston		0.282	Travis	0.135	0.718
Glasscock	0.095		Uvalde	0.055	
Grayson		0.041	Val Verde		0.031
Guadalupe		0.186	Victoria		0.000
Harris		2.494	Walker	0.454	
Henderson		0.115	Ward		0.016
Hidalgo	0.170	0.603	Washington		0.018
Hutchinson	0.127	0.023	Webb	0.226	0.005
Jack	0.238		Williamson	2.273	
Jefferson		0.131	Wise	1.422	0.229
Johnson	3.091	0.075	Young	0.035	
Jones		0.010	**TOTAL**	**24.7**	**18.3**

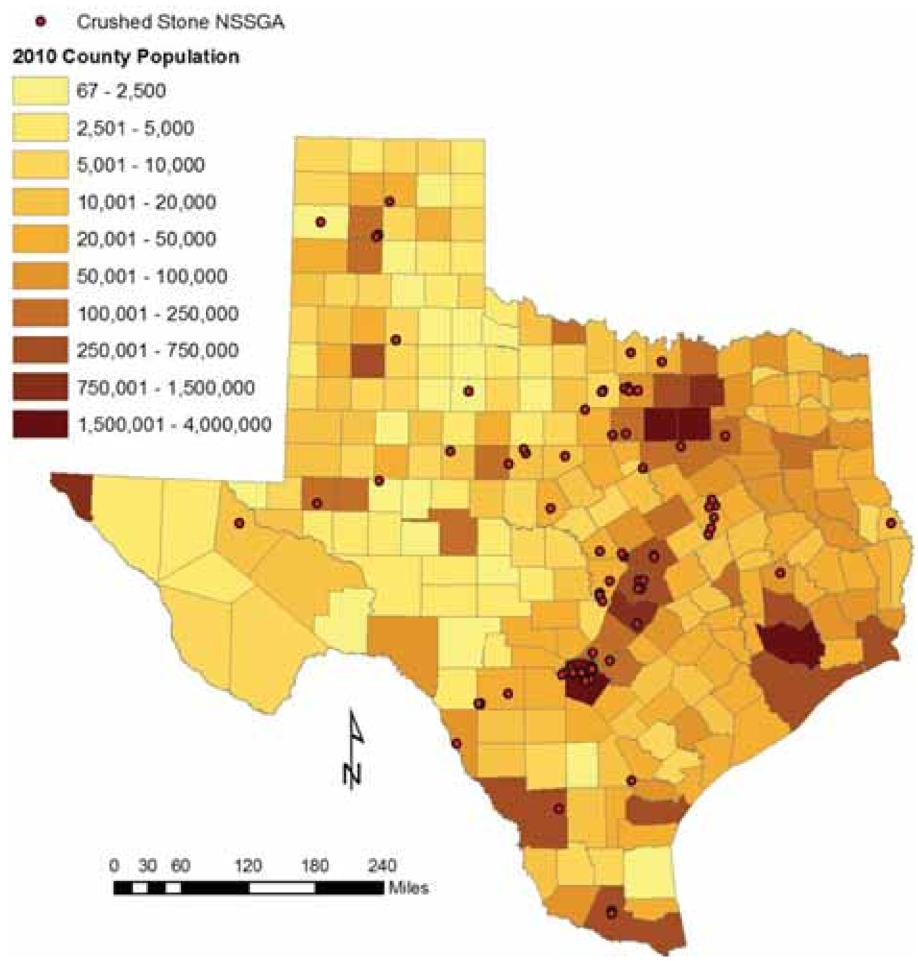


Figure 101. County population in 2010 (TWDB projection) and crushed-stone NSSGA facilities

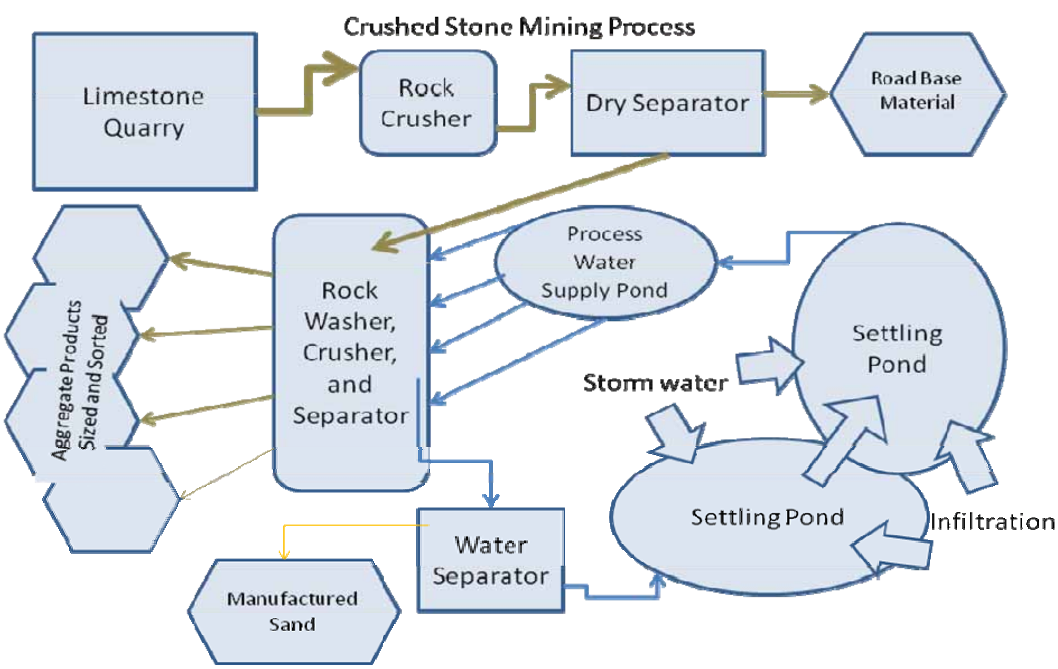
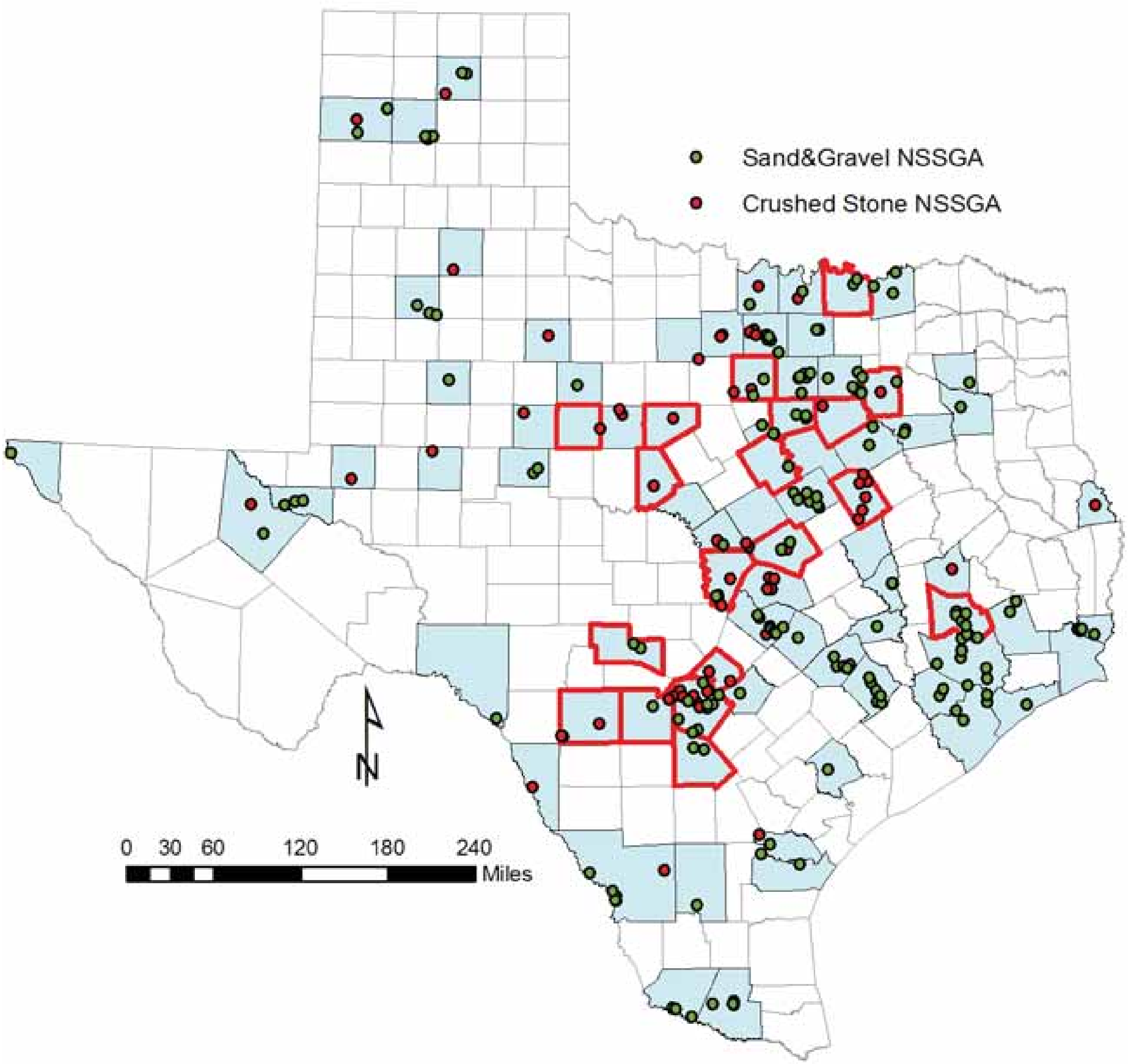
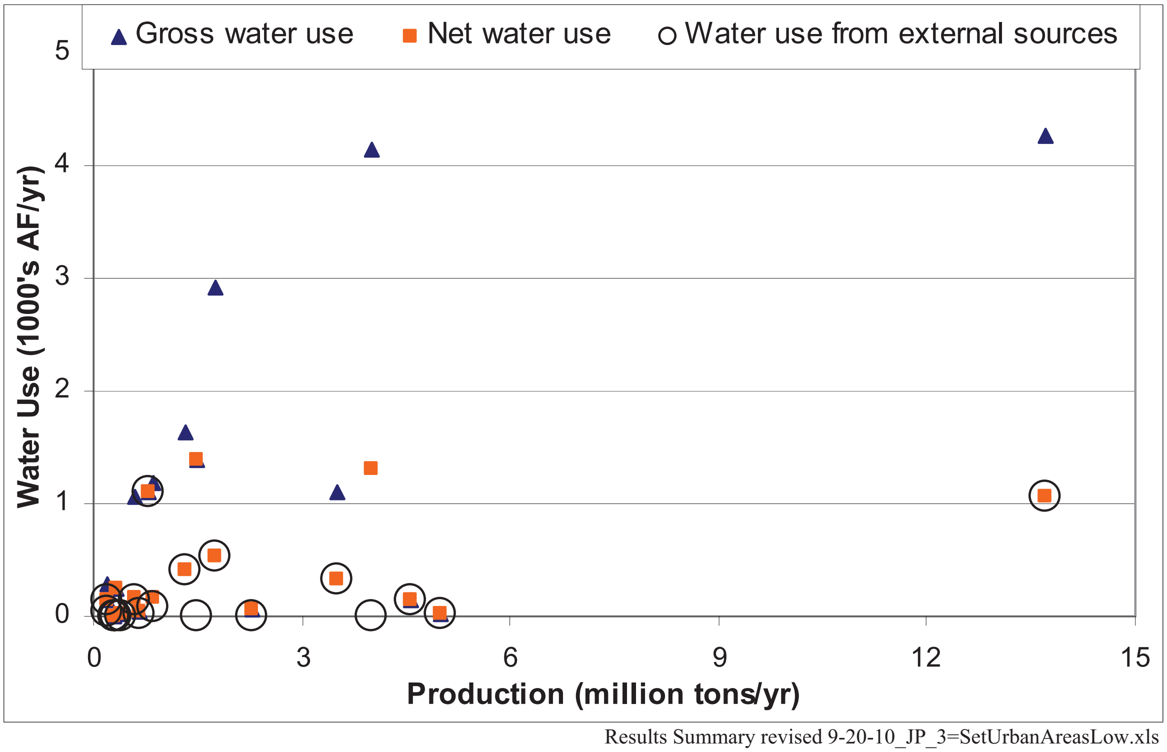


Figure 102. Flow diagram of typical crushed-stone process

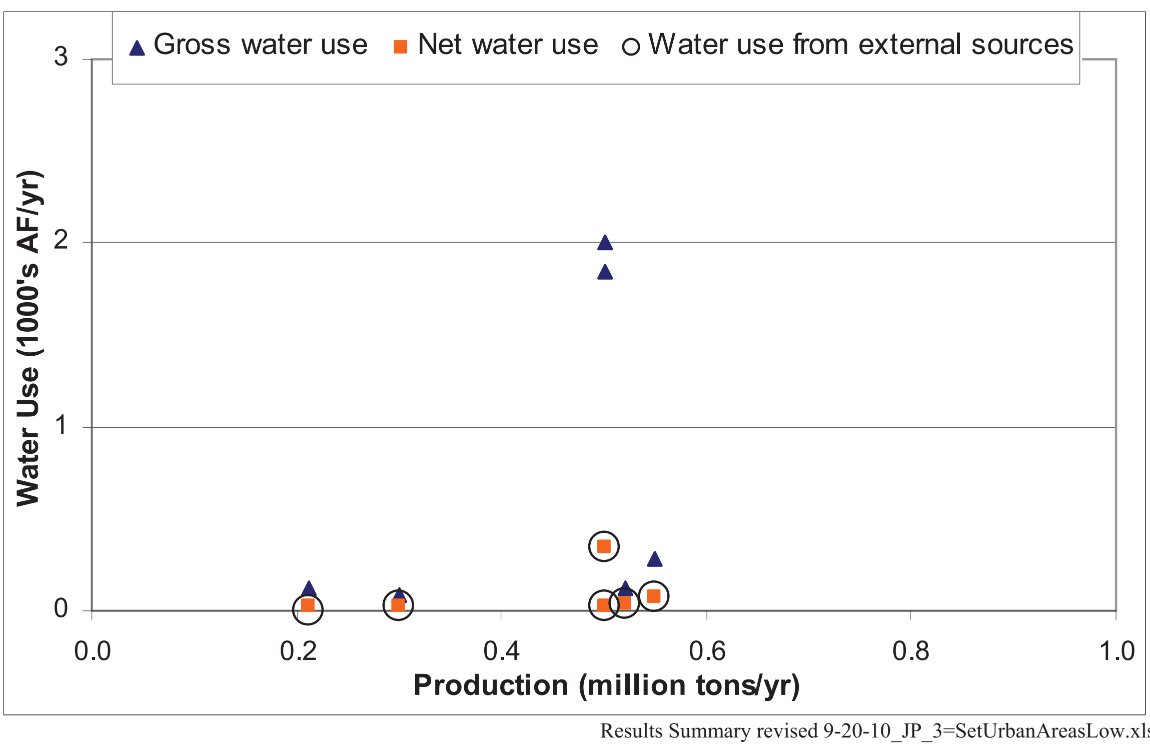


Source: NSSGA/USGS database

Figure 103. Counties with NSSGA-listed facilities; highlighted county lines represent those counties with information from the BEG survey

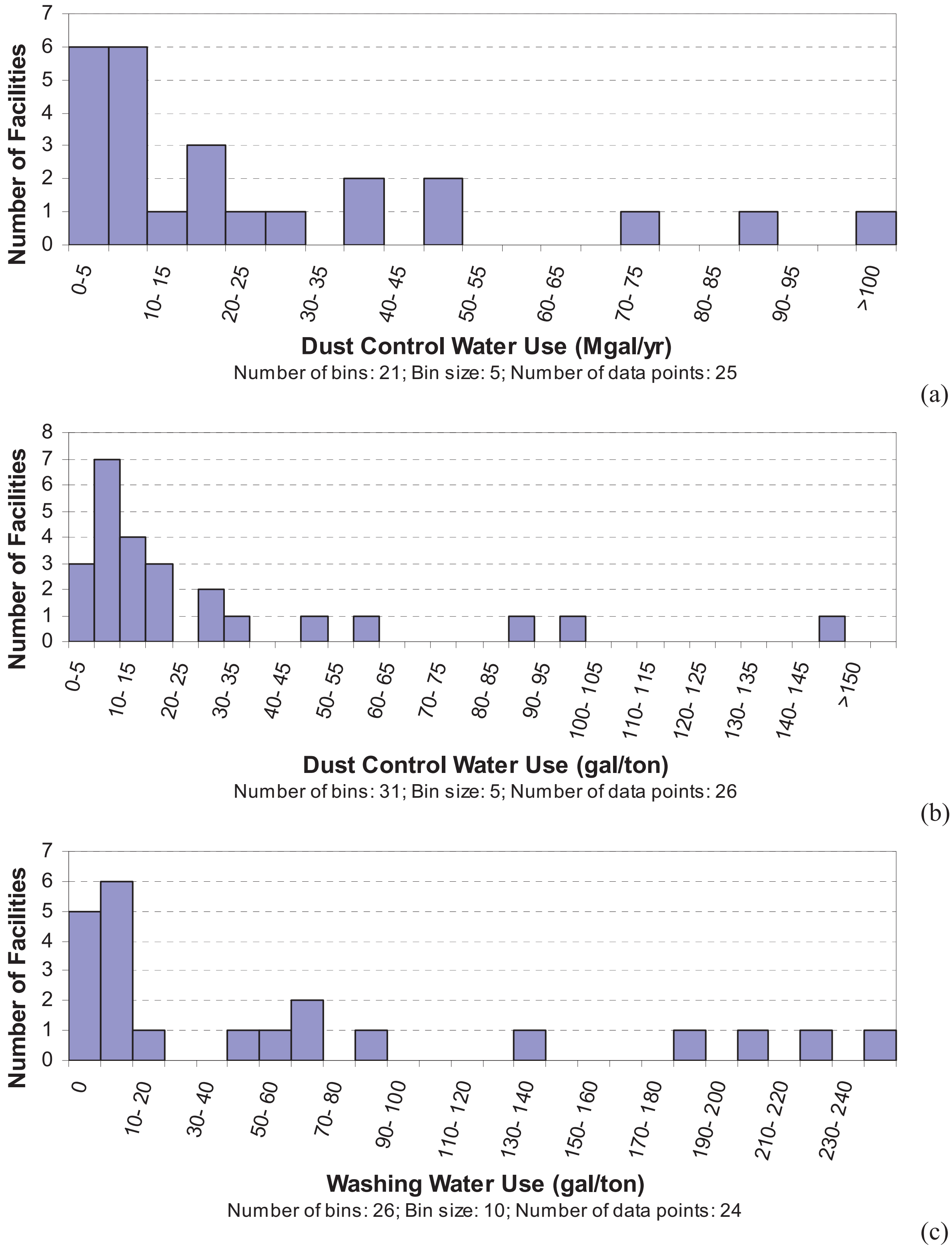


(a)



(b)

Figure 104. Water use from BEG survey for (a) crushed stone facilities; (b) sand and gravel facilities



Source: BEG survey

Figure 105. Histograms of aggregate net water use for washing and dust control: (a) per facility, (b) and (c) per unit production

4.5 *Other Nonfuel Minerals*

This section examines water in categories with smaller water use overall, although a few facilities may still use a significant amount of water. The dimension-stone category included many facilities, but other nonfuel facilities are too few to derive water use statistically, and they have to be analyzed individually.

Water use from the cement industry is not included in this section, not because mining of raw material is not mining, but because it is usually associated with a manufacturing SIC code (#3241). There are currently 12 cement plants, which are largely associated with the extensive Cretaceous limestones in Central Texas (Kyle and Clift, 2008). In surveys, it could be difficult to discriminate between water use in the cement plant proper and in the quarries, particularly because water use for most installations is likely to be related to dust suppression only, a small fraction of total usage overall. However, we can still infer an order of magnitude amount of water consumed in mining proper by applying values derived from crushed-rock aggregate installations. In 2009, Texas produced 11 million metric tons of cement (USGS commodity website); about half of it comes from limestone and the other half from clay material. Assuming 10 gal/t for dust control (Figure 105a) for limestone and half that value for clay rocks, yields an estimated total consumption of 250 AF (assuming no stormwater is used). This estimate is corroborated by a BEG survey returned by a large cement manufacturer in the state in which its water-use coefficient for dust suppression is even smaller.

Only one zeolite-producing facility is turning out perhaps 5,000 to 10,000 t of product per year, and total production for the nation is ~60,000 t from 10 mines. Texas is ranked third in terms of production (USGS commodity website, http://minerals.usgs.gov/minerals/). Using the earlier approach, we found the contribution of this mine to water use is negligible. Although minerals such as barite and alumina are also listed in the MSHA database, they correspond to processing facilities not mines.

We applied a similar approach for lime and gypsum, which, as raw materials, are typically transported dry to the processing plant. There is probably little washing of the material for cement, lime, or gypsum plants. Any water use past the quarrying stage would be considered part of the manufacturing process (for example, to soften the material), especially if the water is used within the processing-plant boundaries.

4.5.1 Dimension Stone

Dimension-stone facilities quarry their raw material mostly from Precambrian granites in Central Texas, Permian limestones in North-Central Texas, Cretaceous limestones in Central Texas, and Triassic Limestones in West Texas (Garner, 1992). The MSHA database lists 100+ facilities in this category, and the TWDB WUS survey lists only one facility with no recent water-use data. However, given the small production (44,000 tons in 2007, USGS *Texas Minerals Yearbook*) and assuming water use is related mostly to dust control and cutting, we tentatively based their water use on the highest water use coefficient for the crushed-stone aggregate (151 gal/ton, Table 31). This calculation results in a total water use of 18.5 AF/yr, with the additional assumption that the 10 largest dimension-stone facilities consume most of the water, each using on average 1.8 AF/yr. Even increasing the water-use coefficient by one order of magnitude yields values low enough to be neglected, given the uncertainty associated with larger uses such as aggregates, particularly because many of the counties with dimension-stone facilities also host crushed-stone or lime facilities (Figure 106).

4.5.2 Industrial Sand

Industrial sand, typically used in glass making, foundry molding, and blast sands, has seen an uptick in production and use, probably owing to the large increase in hydraulic-fracturing activities in which it is used as a proppant. Production is concentrated in only a few areas/counties (Figure 107). Texas industrial sand production has increased in sync with U.S. production but seems to be growing faster in the past few years (Figure 108). Some of the operations are owned by gas companies. Current production is likely ~4 million tons (3.28 and 3.58 million tons in 2007 and 2008, respectively, as given on the USGS website (http://minerals.usgs.gov/minerals/).

Industrial sand facilities are similar to aggregate facilities and would require a similar amount of water for dust suppression on roads and conveyor systems but require more water per unit product for washing. Historical water-use coefficients for industrial sands (Table 33) show a total water use ~20 times higher than for aggregates but a higher recycling rate as well (80% in the 1980s). Water consumption averaged across the U.S. was also 10+ times higher than that of crushed stone. The few data points collected for this study agree with this figure.

The Hickory UWCD near the Llano Uplift reported 4,212 AF and 559 AF permitted in McCulloch and Mason Counties, respectively, in a total of five operations most likely related to industrial-sand (proppant) production. The UWCD also stated that actual use and permitted amounts were very close and that plant consumption (manufacturing) was not included. Other sources of information suggest that these two counties produce >1 million tons of industrial sand, particularly the Carmeuse Industrial Sand facility, and perhaps up to one-third of the state output. Assuming the latter sand production value results in a high water-use coefficient of 1,200 gal/t. A facility in Limestone County reports on the TWDB WUS database (http://www.twdb.state.tx.us/wrpi/wus/wus.asp) a consistent ~650 AF/yr throughout the year. A facility responding to the TACA/BEG survey and located in a county north of Houston reported 0.2 million tons of production, water consumption of 315 AF/yr, and a significant fraction (~93%) of the water being recycled. A quick calculation yields a water-consumption coefficient of 514 gal/t for the latter facility, which reports no water use for dust suppression.

How much stormwater is used is unclear. Note that some of the industrial sand facilities are collocated with regular aggregate facilities and that their water consumption may already be included in this category. Overall, when no other information is available, we assumed a water-use coefficient of 600 gal/t, to which we added 20 gal/t for dust control, resulting in **9.7 thousand AF** (Table 36).

4.5.3 Chemical Lime

Lime (and cement) plants tend to be sited next to the raw material (Edwards Limestone, Austin Chalk, and other pure limestones) being quarried. The year 2009 saw a short drop in lime production (1.04 million metric tons; 1.5 million metric tons in 2008), deviating considerably from the trend of the past 2 decades (according to which, production should have been over 1.7 million tons) (Figure 109). According to USGS, as well as the MSHA website (http://www.msha.gov/drs/drshome.htm), there are five lime facilities in Texas, in Bosque, Burnet, Comal, Johnson, and Travis Counties. MSHA provided the annual number of employee-hours, and we assumed that production is proportional to the number of hours worked. Most of the water use in lime facilities is associated with manufacturing. There is typically no washing; operators tend to avoid adding water because of the cost of heating it. Water use is only for dust suppression and is likely hard to separate from overall plant use. We assumed that water consumption is due only to dust suppression at 10 gal/t (Figure 105a). The result is a small total water consumption of **46 AF** (assuming no stormwater is used) (Table 37), which can be neglected.

4.5.4 Clay Minerals

Clay minerals mined in Texas fall into two categories—common clay (brick making, cement component) and specialty clays (ball clay, bentonite, fire clay, Fuller's earth, kaolin). These five types' usage and mineralogical make-up are: ball clay (kaolinitic sedimentary clays that commonly consist of 20–80% kaolinite, 10–25% mica, 6–65% quartz), which is used for ceramics; bentonite, which is used for drilling mud, among many other uses; fire clay (all clay minerals but bentonite), which is used to make refractory products; Fuller's earth (montmorillonite or palygorskite or a mixture of the two), which is used as a adsorbent; and kaolin (kaolinite), which is used for porcelain and high-quality paper (Norvell, 2009, p.6).

Clay mining is generally performed by scrappers, which remove materials and transport it to stockpiles for use in manufacturing processes, such as brick making. In some mines, excavators are used to remove and load clay onto railcars, barges, or other transport to off-site manufacturing plants. Clay mines may be online for only a few months each year to provide raw materials sufficient to support manufacturing throughout the year. No water is used in the actual mining process, although water is added during most of the manufacturing processes. In fact, clay mines are bermed to minimize rainwater inflow and must be dewatered, if necessary, to allow access and prevent excess water from affecting clay quality. Water is discharged into retention ponds or nearby surface water, and some is used for dust suppression on plant roadways. Water can be used for conveyance as slurry but cannot be included as mining use; it is instead considered as manufacturing use.

Texas clay deposits are generally contained in Tertiary formations of the Gulf Coast. Brick-making operations often tap the common clay of the Calvert Bluff Formation in Central Texas (Hunt, 2004). Altered volcanic ash layers in South Texas provide bentonite, and kaolinite is produced from the Simsboro Formation in North Texas. The main clay producers are in Gonzales (bentonite), Navarro (common clay), Limestone (kaolin), and Fayette (bentonite) Counties. Clay is also mined in an additional 20 counties.

Texas mining production in 2008 was 2.14 million tons of various clay minerals, having remained relatively constant at that level during the past decade despite a bump of ~2.7 million tons in 2006 and 2005. Less water is probably needed for dust suppression in clay operations, and stormwater probably ponds more easily than in conventional aggregate operations. However, unlike for cement, lime, and gypsum operations, the clay washing step could be included as mining use, which we ultimately decided not to do. Assuming a water-use coefficient of 30 gal/t (Figure 105c) would have yielded only **~200 AF**, a low value that falls below the uncertainty level of major users and is distributed across various operations in several counties.

4.5.5 Gypsum, Salt, and Sodium Sulfate

Gypsum is produced mostly from Permian evaporitic strata of North-Central Texas in Nolan/Fisher/Stonewall Counties and Hardeman County, as well as in Gillespie, Kimble, Wheeler, and (perhaps) Harris Counties. Texas production in 2008 was ~1.04 million metric tons and has seen large variations in production in the past decades, although seemingly relatively stable at 1.8 million tons/yr on average (Figure 110). The number of mining facilities has also changed in sync with total production (four, five, or six facilities). The result is a small total water consumption of **32 AF** (assuming no stormwater is used) (Table 38).

There are only two salt mining operations in Texas: the Grand Saline Dome in East Texas in Van Zandt County and the Hockley Dome in the Houston area in Harris County, both of which use the classic room-and-pillar mining technique. The USGS commodity website (http://minerals.usgs.gov/minerals/) reports that the Hockley and Grand saline mines had a production capacity of 400,000 and 150,000 short tons of rock salt in 2008, respectively. Texas total salt production has ranged from 9 to 10 million metric tons/ yr in the past decade (9,080 metric tons in 2008), ~20% to 25% of national production. In 2006, Morton-Thiokol's salt mine in Grand Saline in Van Zandt County reported the use of self-supplied groundwater of 384.4 AF, diversion of 43.3 AF of surface water, and groundwater purchase of 43.5 AF, totaling 471 AF/yr (Table 39) (K. Kluge, TWDB WUS, personal communication, 2006). The Harris-Galveston Subsidence District reported that the Hockley mine in Harris County uses ~0.1 to 7.0 Mgal/yr from groundwater wells. The district is also purchasing surface water from the Gulf Coast Water Authority for ~150 to 200 Mgal/yr, which comes to a total of ~535 AF/yr and **1.0 thousand AF** overall (Table 39). However, solution mining is the most common method of obtaining salt. In theory, 800 gal of water is required to recover 1 metric ton of salt with little recycling. In Texas, salt is used mostly as a chemical feedstock for producing chlorine (a key ingredient in the production of plastics) and soda ash (a key ingredient in the manufacture of glass) and the salt-saturated brine is directed toward the manufacturing process. For example, Dow Chemical in Brazoria County uses water from the Brazos River and is injected onsite to recover salt for use in the chemical plant. The ~9 million tons of salt annually produced in the state minus underground mining production and minus 0.8 Mt evaporated at Baytown brings the total salt production through brine at 7,700,000 × 800 = ~19,000 AF. This use of feedstock in the chemical industry is considered manufacturing and is not included in the mining category tallied in this report.

Sodium sulfate mining is extracted from brines underlying alkaline lakes in West Texas (Kyle, 2008; Kyle and Clift, 2008), one of two such facilities in the U.S. The TWDB WUS survey shows annual groundwater withdrawals remaining consistently at ~400 AF in Gaines County in the past decade. Norvell (2009) noted that early in this decade the facility pumped 1,440 AF/yr, 1,092 AF of which was saline water, increasing our confidence that the earlier mentioned **400 AF** is fresh groundwater, not produced brine (which should not be counted toward water use). We assume that sulfate sodium production and concomitant water use remained stable in the study period. Growth of this commodity will be covered by sources other than mining natural accumulations.

4.5.6 Talc

National production of talc decreased from 0.85 million tons in 2005 to 0.51 million tons in 2009 (USGS website, http://minerals.usgs.gov/minerals/). It is produced from seven mines. Talc in the Allamoore district of Hudspeth and Culberson Counties in West Texas is produced from several quarries at ~100,000 t/yr. The most recent TWDB WUS (2003) reports a low water use of 1 AF. However, RWPG Region L (Far West Texas) initially prepared a report (2010) citing a value of 1,500+ for Culberson County, increasing to 1,600+ in 2060 (see their section 2.4.7). The quarries are apparently in Hudspeth County, whereas the wells appear to be in Culberson County. The water consumption value was derived using a water-use coefficient approach (from USGS) and not using direct metering. Whether this figure includes processes that would belong to the manufacturing category is unclear. We were unable to collect better information, and we expect no change in water use in the decades leading to 2060, assuming water consumption to be classified as mining ~0.

4.5.7 Uranium

Although uranium could be considered a fuel for nuclear power plants, its main use, for convenience, is treated in this section. Only in situ leaching (ISL) or in situ recovery (ISR) technology is currently used to mine uranium (Campbell et al., 2007). The two main kinds of water-use consumption are (1) active mine and (2) reclamation/restoration, the latter requiring more water by far, although overall, the uranium extraction industry uses little water. A typical operation consists of injecting water with oxygen into the ore zone and producing the uranium-laden water, removing the uranium in ion-exchange resin, and reinjecting the water at a high recycling rate (>97%). The restoration phase follows, in which other soluble elements are brought back close to initial concentrations. A reverse osmosis technology is generally used. The recycling rate is lower, perhaps 33%, at least initially. As trace-element concentrations decrease, the RO system can be pushed further, resulting in a decreased waste stream. Other technologies, such as bioremediation, could consume less water. A given ISR facility often produces uranium and restores the subsurface at different nearby locations simultaneously. We retained an average value of 250 gal/ lb of uranium as an overall representation of water consumption.

Uranium production is concentrated in South Texas (Blackstone, 2005; Carothers, 2008, 2009; Nicot et al., 2010). EIA reported (http://www.eia.gov/nuclear/) that in 2009 only two ISL operations were active in Texas: Alta Mesa (Brooks County) and Kingsville Dome (Kleberg County). In 2008 two more were operational: Rosita and Vasquez, both in Duval County. In the past few years uranium production in the U.S. has been close to 4 million lb U_3O_8 (Figure 111) and was 4.145 million lb U_3O_8 in 2009. These facilities have a nominal production of 1 million lb U_3O_8 each (except Vasquez, at 0.8 million lb U_3O_8). EIA reported only aggregated data to protect individual companies. With the additional help of survey returns, we estimated Texas production at ~28% of total production (that is, ~ 1.1 million lb U_3O_8). We reached this value by contrasting (1) production capacity in Texas (5.3 million lb U_3O_8 in 2009) with that of the U.S as a whole (20.45 million lb U_3O_8), that is 28%, with (2) employment numbers at 31% in Texas and Colorado the total number of employee-years. Clift and Kyle (2008) reported a total production of ~1.34 million lb U_3O_8 in 2007, more than two-thirds of it from Brooks County (Alta Mesa Project). This level of production results, in turn, in a water consumption of 275 million gal, or **840 AF,** for all producing mines in Texas. We assumed that restoration water consumption is combined with production. Because the number of operating mines is limited, actual water consumption can be much lower if no restoration is being done. For the purpose of this study, we attributed one-third of the estimated total to each county (Table 40). Reclamation by RRC of legacy open pits produced in the second half of the 20th century is not included in this count.

4.5.8 Other Metallic Substances

Texas has many other occurrences of metallic and industrial minerals, notably in west Texas and in the Llano Uplift of central Texas (e.g. Price et al., 1983; Price et al., 1985; Kyle, 1990; Kyle, 2000). Some of these deposits have had minor production, but most known deposits are currently inactive. The scale of known resources provides little encouragement that most could represent viable mining operations in the foreseeable future. On the basis of decades-long evaluation and development activities, three deposits seem to have potential for near-term mining: (1) Shafter silver deposit, Presidio County; (2) Round Top beryllium-uranium-rare earth element deposit, Hudspeth County; and (3) Cave Peak molybdenum deposit, Culberson County. They will be examined in the ‘Future Water Use” section.

Table 36. Estimated county-level industrial sand-water consumption

County	Estimated Number of Facilities	Estimated Water Use (1000s AF)
Atascosa	3	0.43
Colorado	3	0.43
Dallas	1	0.04
El Paso	1	0.04
Guadalupe	1	0.07
Harris	1	0.14
Hood	3	0.43
Hunt	1	0.07
Johnson	1	0.04
Liberty	2	0.14
Limestone	2	1.30
Mason	1	0.56
McCulloch	4	4.21
Montgomery	2	0.76
Newton	1	0.14
Orange	1	0.07
Robertson	1	0.04
San Saba	2	0.28
Smith	1	0.07
Somervell	1	0.14
Tarrant	3	0.21
Wise	1	0.07
Total	**23**	**9.68**

Table 37. Estimated county-level lime mining-water consumption (AF)

	Water Consumption (AF)
Bosque	8.5
Burnet	2.8
Comal	6.6
Johnson	13.1
Travis	15.1
Total	**46**

Table 38. Estimated county-level gypsum mining-water consumption (AF)

	Water Consumption (AF)
Fisher	3.3
Gillespie	3.3
Hardeman	6.6
Kimble	1.5
Nolan	14.8
Wheeler	1.2
Total	**32**

Table 39. Estimated county-level salt mining-water consumption (AF)

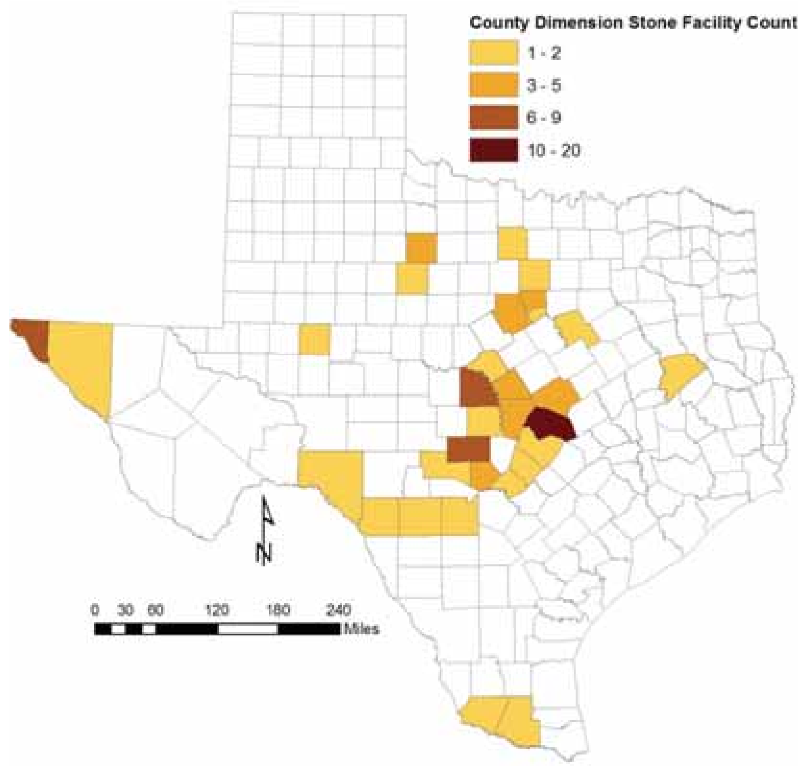
County	Water Consumption (1000s AF)
Harris	0.535
Van Zandt	0.471
Total	**1.01**

Table 40. Estimated county-level uranium mining-water consumption (2009)

County	Water Consumption (1000s AF)
Brooks	0.28
Duval	0.28
Kleberg	0.28
Total	**0.84**

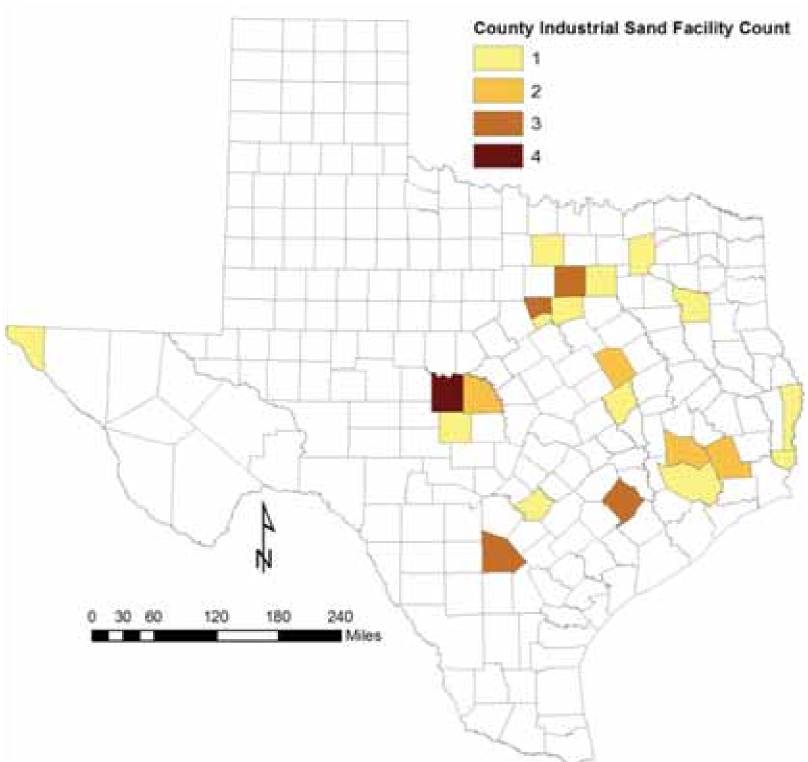
Table 41. Summary of water use not in the oil and gas, coal, or aggregate categories

Mined Substance	Estimated Water Consumption (1000s AF)
Dimension Stone	0.018
Industrial Sand	9.7
Chemical Lime	0.046
Clay Minerals	0.2
Gypsum	0.032
Salt	1.01
Sodium Sulfate	0.4
Talc	~0
Uranium	0.84
Zeolite	~0
Cement	N/A
Total	**12.25**



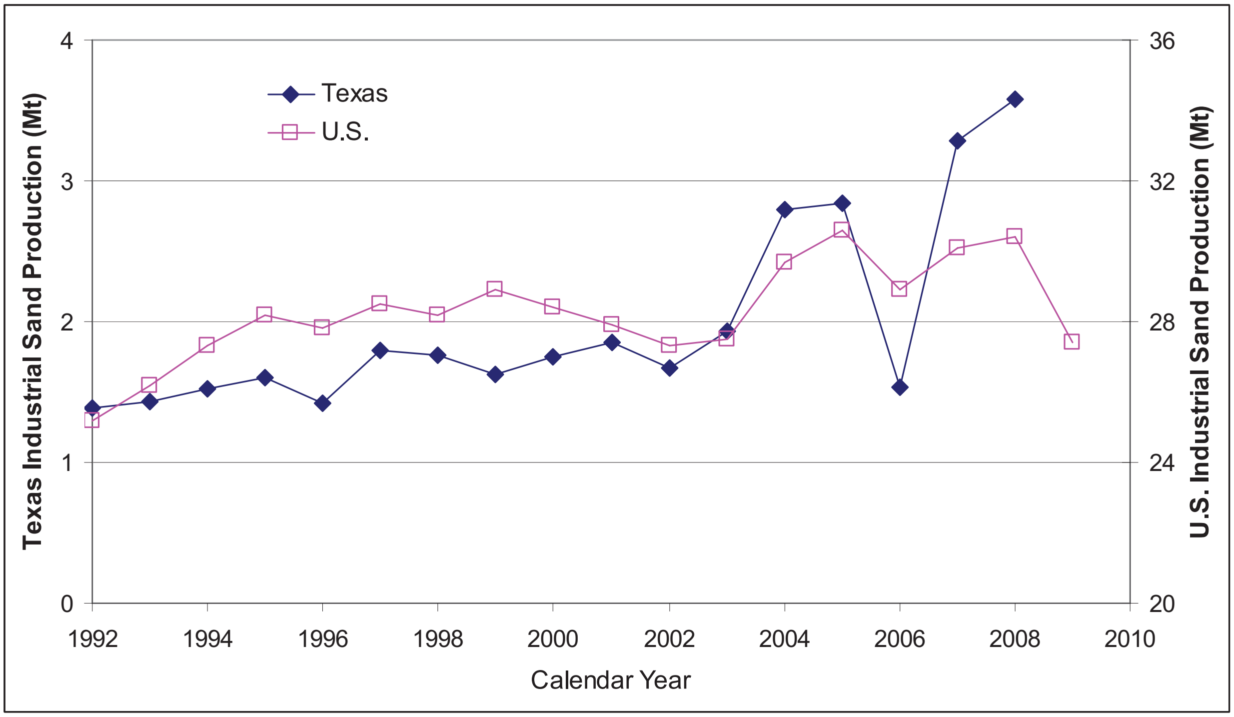
Source: MSHA database

Figure 106. County-level count of dimension-stone facilities



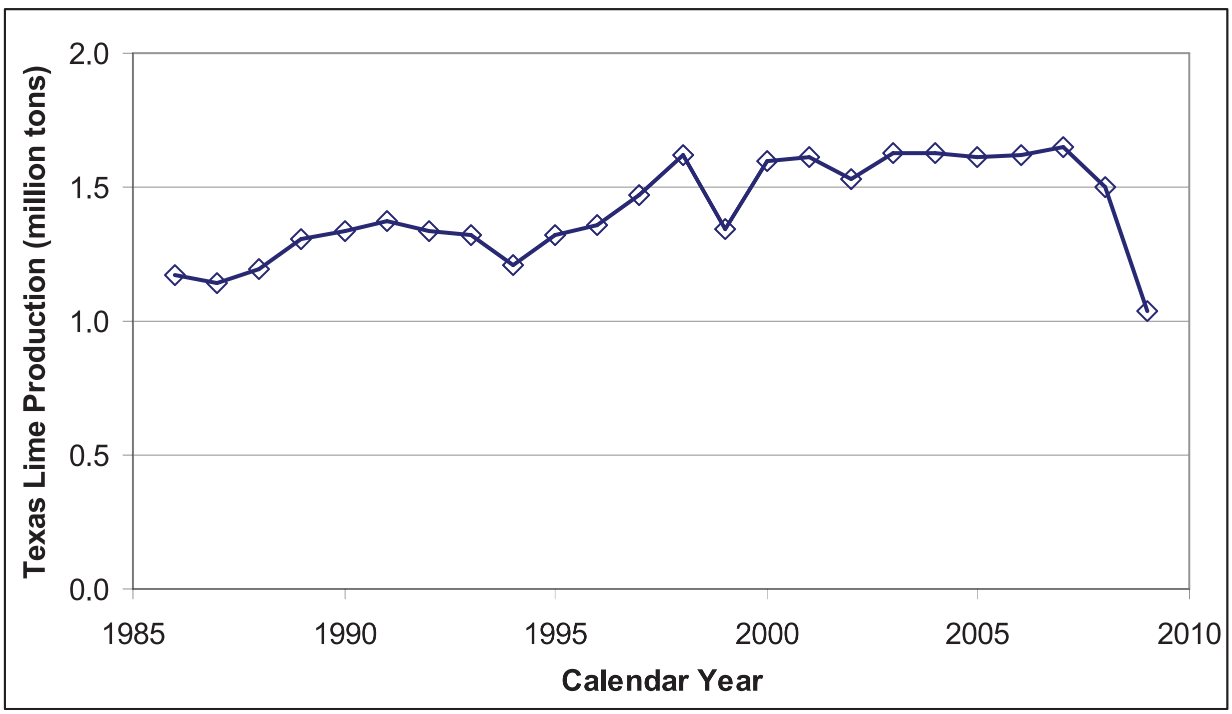
Source: MSHA database

Figure 107. County-level count of industrial-sand facilities



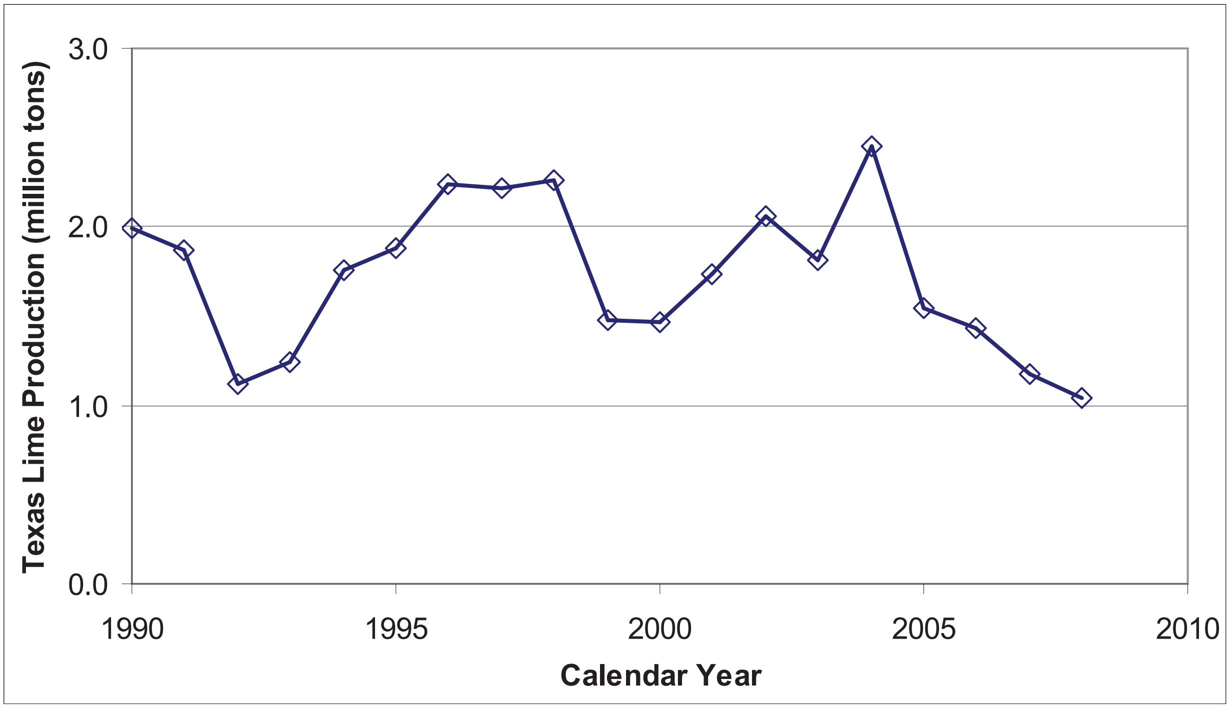
Source: USGS commodity website

Figure 108. Texas and U.S. industrial-sand production (1992–2008)



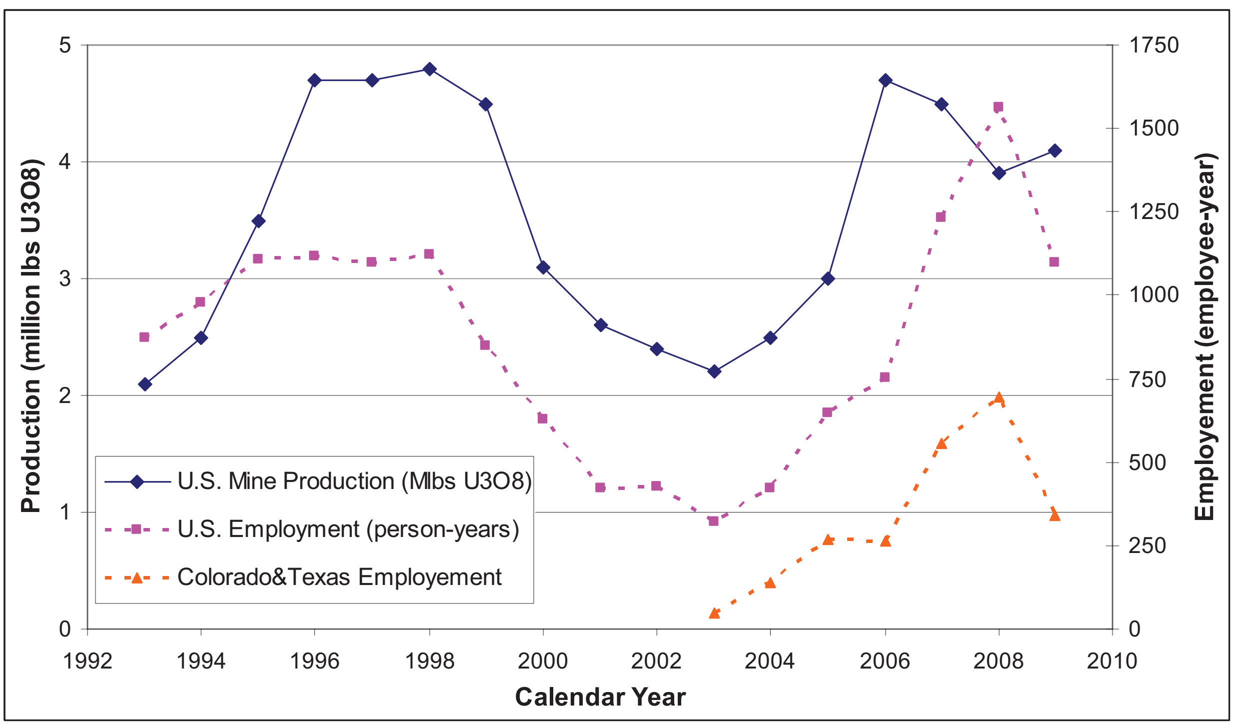
Source: USGS commodity website

Figure 109. Texas lime production (1986–2009)



Source: USGS commodity website

Figure 110. Texas gypsum production (1990–2008)



Source: EIA website

Figure 111. U.S. uranium production and employment (1993–2009)

4.6 Historical Mining with High Water Use

Although no longer active, mines once having high water use should be noted.

Sulfur

Once Texas was a major producer of Frasch sulfur from microbially altered evaporitic strata in west Texas (Hentz et al., 1989) and in salt dome cap rocks of the Gulf Coastal Plain (Kyle, 2002). More than 350 million tonnes of sulfur were produced using the Frasch process from these native sulfur deposits in Texas, Louisiana, and Mexico during the 20th century (Kyle, 2002). As recently as 1999, Frasch sulfur was produced from the Culberson deposit in Culberson County, one of the largest deposits of this type. Four smaller deposits in Pecos County had lesser amounts of Frasch sulfur production through the 1980s (Crawford, 1990).

The shallow salt domes of the Gulf Coastal Plain were the sites of significant historical sulfur production (Myers, 1968; Flawn, 1970; Greene, 1983, p. 10; Kyle, 2002). The Boling salt dome cap rock in Wharton County was the largest known Frasch sulfur producer in the United States, with more than 87 Mt of production from 1916 until 1993. Other Texas counties with multiple historical Frasch sulfur producers include Brazoria (4), Fort Bend (4), and Jefferson (2). Other counties with single producers include Chambers, Duval, Liberty, and Matagorda. Most of the economic sulfur concentrations seem likely to have been exhausted during the Frasch mining period.

The Frasch process requires extensive amounts of superheated water to inject into the native sulfur-bearing zone to melting the sulfur, allowing the pumping of liquefied sulfur to the surface (Ellison, 1971). The economics of the Frasch process dictate extensive recovery of water and its contained heat. Water usage in association with Frasch sulfur production at the Culberson deposit was nominally 2,000 gal per tonne of sulfur produced (J. Crawford, written communication, 2010), but with only 5% of the total water being "make-up" water for the sulfur extraction, i.e. 95% of the process water is recycled. Thus, using those figures, the water demand for the Culberson operation at a rate of ~2.5 million tonnes per year totaled about 900 AF per year (1990 case; Crawford, 1990). This make-up water was supplied from wells in Reeves County, 37 miles southeast of the sulfur production site (Crawford, 1990; Crawford et al., 1998).

Bituminous Coal

Texas bituminous coal occurs in six coalfields in North-Central Texas, Maverick County, and Webb County. More specifically, coal resources occur in the Eagle Pass, Santo Tomas, Eagle Spring, San Carlos, Big Bend, and west of Fort Worth in North-Central Texas. The largest annual production of bituminous coal occurred in 1917, with >1.25 million tons of bituminous coal produced in the state, followed by a steep decline in the early 1920s that was due to competition from oil and gas. Production of bituminous coal ended in 1943 after 15 yr of low production, <100,000 t/yr (Evans, 1974). Coal from these areas has been extensively mined, and we assume no further production through the next decades.

4.7 Conclusions and Synthesis for Historical Water Use

In 2008, the mining industry, defined as described in Section 4, consumed ~140 thousand AF of fresh water, distributed in a relatively balanced way between its main users (Figure 112). The oil and gas industry used ~57 thousand AF (41%), whereas the coal and aggregate industry used ~27 (19%) and ~43 (31%) thousand AF, respectively. The "other" category (~12 thousand AF, 9%) is dominated by industrial sands. A more detailed breakdown (Figure 113) shows that water use included 35.8 thousand AF for fracing wells (mostly in the Barnett Shale/Fort Worth area) and ~21.0 thousand AF for other purposes in the oil and gas industry. Aggregate industry water use is distributed between crushed stone (24.7 thousand AF) and sand and gravel (18.3 thousand AF). Remaining water use amounts to 12.2 thousand AF and is dominated by industrial sand production (~80% of total).

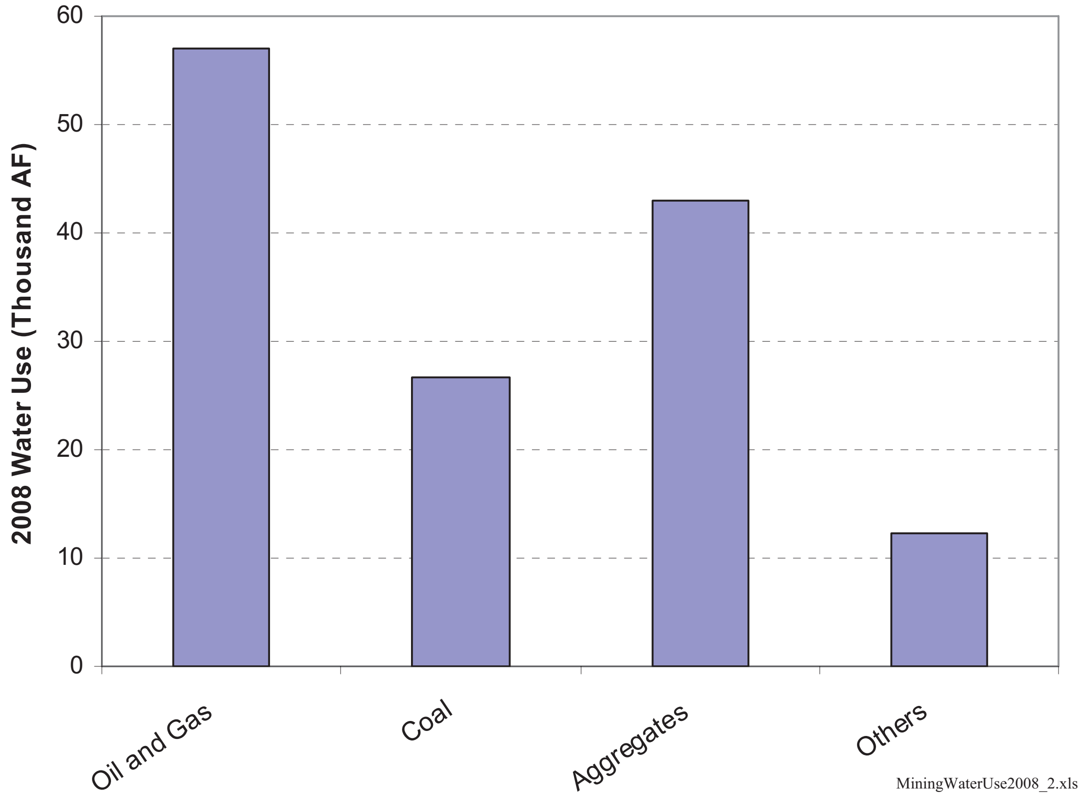


Figure 112. Summary of water use by mining industry segment (2008)

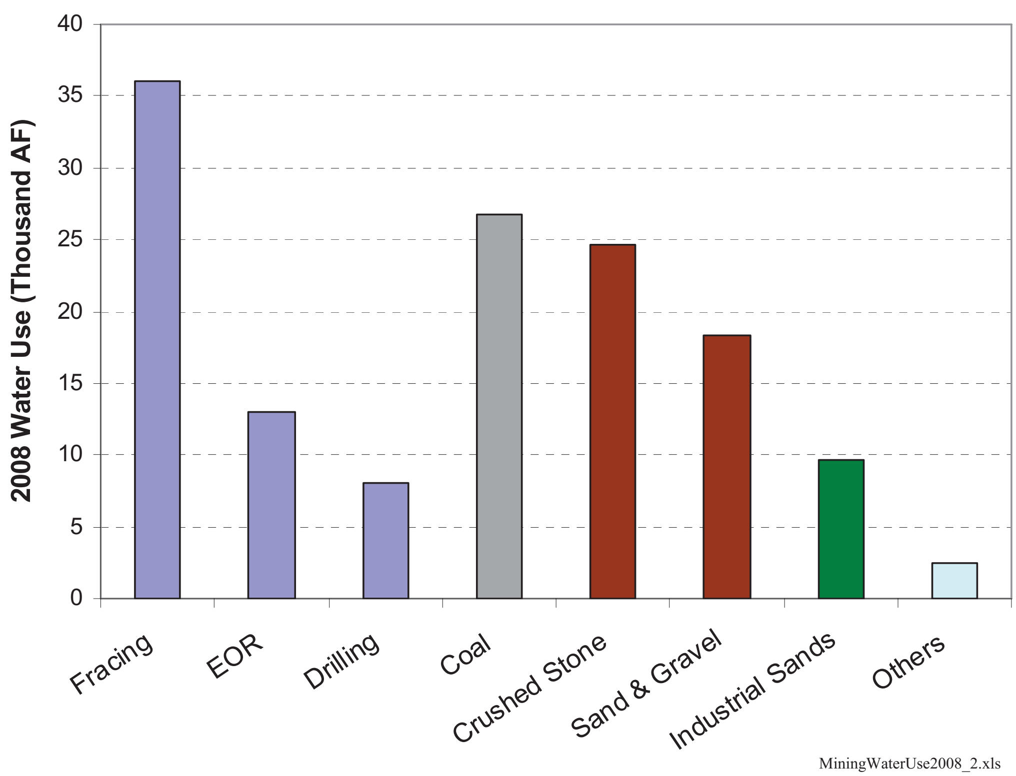


Figure 113. Summary of water use by category (2008)

5 Future Water Use

Most uncertainty about future water use in the mining category comes from unknowns in the rapidly evolving exploration of shales and tight formations, whose gas production is ultimately tied to national economic activity. Aggregates and coal-mining water use are better constrained and directly driven by local conditions, such as population growth, but are also connected to national economic activity. The latter is the most important driver for oil and gas long-term trends of interest to this study. An element strongly impacting future water use is the national energy policy, particularly the impact of any cap-and-trade legislation. The passage of some cap-and-trade or carbon-tax legislation during the next decade is likely to boost gas-fueled power plants, but it may also boost oil production through a greater availability of CO_2 needed for tertiary recovery of oil currently nonrecoverable (assuming the type of WAG CO_2 flood common in the Permian Basin).

In the short term, oil and gas operators are likely to focus on plays such as the Wolfberry or the combo play of the Barnett Shale or the Eagle Ford, all producing oil with significantly better economics than gas. Gas is typically a regional commodity and does not travel as well as oil, which is a world commodity. This fact is currently reflected in current oil and gas prices. In terms of BTUs contained, oil and gas prices have tracked each other fairly well until about a decade ago. It follows that variation/change in price will vary more wildly for gas. Unless lease agreements were made early in the history of the plays, Barnett Shale or Haynesville Shale operators are probably on the wrong side of the breaking even at current low gas prices. The economic slowdown has also impacted aggregate and other material demand, as well as power demand. However, overall, we refrained from trying to model this short-term episode.

5.1 Gas Shales and Tight Formations

Future water use depends on the amount of oil and gas still in the ground that is ultimately recoverable. Resources are enormous. Holditch and Ayers (2009) suggested that technically recoverable reserves in any basin are 5 to 10 times the amount of conventional gas produced and reserves are from >10 times in the Fort Worth Basin to less than the average in the Gulf Coast, and it is very likely that the industry will operate beyond the Barnett, Haynesville, and Eagle Ford shales, which it is currently focusing on. From a practical standpoint, however, this study had to rely on spatially defined resources from published information. The shale-gas industry agrees that there will be no major discovery of gas shales in Texas, whose geology is well known (e.g., Chesapeake CEO, 2010).

National organizations that develop, compile, and distribute national assessments of oil and gas reserves and resources (USGS, EIA, AAPG, PGC) have a hard time keeping up with rapid changes in the field. Figures provided by these organizations and others are not necessarily consistent as to the cutoff date for production, and other criteria may differ (resources and reserves vary through time as some are produced and additional ones are discovered), and the spatial footprint considered might be different or include areas outside of Texas. A compounding factor is that available data may not refer to a particular formation but simply a geographic area. Organizing such a large pool of information was a challenging endeavor, and we integrated the different and sometimes conflicting figures as best we could, given the time and budget constraints. As a comparison benchmark, state-level current gas production is ~7–8 Tcf/yr and increasing, whereas oil production is 0.3–0.4 Bbbl/yr. The latest figures from EIA are from 2008

(Table 43) and are categorized by RRC district (see map in Figure 9 for locations), as well as information on proved reserves. Speculative/undiscovered resources were provided by USGS (Table 43) and are not entirely consistent with data collected from other sources (Table 44). Overall, we assumed a total of 52 Tcf to be produced from the Barnett Shale. Eagle Ford and Haynesville-TX + Bossier-TX production potential is not included specifically but can be estimated at 161 Tcf and 28 + 21 Tcf, respectively. Permian Basin Barnett and Woodford USGS projections (Table 44; Schenk et al., 2008) seem optimistic and are assumed to be at ~20 Tcf. On the other hand, Wolfberry potential seems to be underestimated. Schenk et al. (2008) included only the Spraberry at a proposed ~510 million barrels of unconventional oil.

More generally, the Schenk et al. (2008) study is an example of a resource assessment performed periodically by the USGS. Unfortunately, information on other important basins in Texas has not been updated yet and the recent sharp increase in resources has not been taken into account. The Fort Worth Basin assessment (USGS, 2004) dates back to 2003, and work on the Cotton Valley and Travis Peak Formations was performed in 2002. USGS (Schenk et al., 2008) provided figures for undiscovered resources in the Permian Basin and divided them into conventional and "continuous" resources. Continuous undiscovered resources were estimated at 35 Tcf of gas and 1.3 Bbbl of oil and NGL. Overall the document may overestimate the potential of the Woodford and Barnett Shales and underestimate that of the Spraberry/Wolfberry. The same document assessed that 0.747 Bbbl oil, 5.2 Tcf gas, and 0.236 Bbbl NGL remain to be discovered, which is in addition to the ~5 Bbbl and ~0.3 Tcf of proven conventional reserves (Dutton et al., 2005b, p. 554). In the end, we estimated that the Wolfberry will produce ~1 Bbbl in the coming decades.

In general, we favor more optimistic predictions (more resources, more production, more water use) because predictions by EIA seem to have systematically underestimated actual production for the past decade because of unconventional gas. By combining proven and undiscovered recoverable resources (Table 43), we assume that the next 5 decades will see 10 Tcf produced from the Anadarko Basin, 16 Tcf from the East Texas Basin, 11 Tcf from the Gulf Coast Basin, and 15 Tcf from the Permian Basin (all tight gas and not necessarily all production).

5.1.1 Projected Future Water Use of Individual Plays

We next address gas shales individually (Barnett, Haynesville, Bossier, Eagle Ford, Pearsall, Woodford-PB and Barnett-PB) and basins with tight producing formations. Table 45 summarizes operational characteristics as collected from the literature to provide guidance for the parameters used in the production-based approach (see Methodology Sections 3.4.1.1 and 3.4.1.2). Parameters used for the production-based and resource-based projections are summarized in Table 46 (gas shales) and Table 47 (tight formations). Water use is contingent on the price of gas, and drilling activity is more sensitive to price than production. All gas plays, even with marginal permeability, will be fraced if gas prices reached $10/ Mcf, even more if the gas contains condensate, and development will be accelerated relative to that projected in this section. Conversely, if the price of gas stays below $5/Mcf for an extended period of time, projections may turn out to be too high in terms of water use.

Given the current low price of gas relative to oil in terms of BTU content, more companies have become interested in wet gas, that is, gas that contains significant amounts of ethane, propane, and butane (that can form liquid at surface conditions), whose price more closely follows that of oils. Alternatively, operators are moving altogether into the oil window of the shale. This business transition is occurring in the Barnett, Eagle Ford and Granite Wash. The net effect on water use will be to stabilize the amount used at the state level because companies will likely oscillate between dry and wet gas as a function of natural gas price.

All basins but the Gulf Coast Basin show an increase in gas production in the recent study by the PGC (PGC, 2009), in which the U.S. is divided into work areas that follow the general geology: P-320 (East Texas), P-330 (Gulf Coast), P-430 (Fort Worth Basin), and P-440 (Permian Basin, including New Mexico and West Texas) (Figure 115). The East Texas Basin has shown an increase in both production and well count in the past few years after a long period of stability. Between January 2004 and December 2008, production increased from ~3,000 to ~5,000 MMcfd, with ~10,000 incremental wells. The Fort Worth-Strawn Basins, after a slow decline in terms of production (~600 MMcfd) and well count since 1990, have shown a turnaround that started ca. 2000 and that corresponds to initial development of the Barnett Shale. Starting then, production increased to 2500 MMcfd in 2007 and increased faster to reach ~5000 MMcfd at the end of 2008. Gulf Coast production stayed more or less stable at 6,000 to 7,000 MMcfd but has been on a slow decreasing trend since 2000. The well count is stable as well. Production in the Permian Basin has remained stable at 4,000 MMcfd for the past 20 years (to the end of 2008), with an increase in well count showing the maturity of the plays and infill drilling.

Barnett Shale

The Barnett Shale represents a special case because a similar study was completed a few years ago (Nicot and Potter, 2007; Nicot, 2009a). Appendix B suggests that projections are correct so far. For the present study, we went back to initial projections at the county level (Bené et al., 2007, Table 8, Appendix 2; Nicot and Potter, 2007, Table 8), supplemented by the study by Tian and Ayers (2010), who presented an update on the prospectivity of the shale in both the oil and gas windows. We also noted that average water intensity seems to have decreased from the estimated 1.2 Mgal/1,000 ft of lateral in Nicot and Potter (2007) to ~1 Mgal/1,000 ft, despite (or thanks to) an increase in lateral length.

County-level results are presented in Table 48. Water use projections peak in 2017 at ~43 thousand AF and then decrease to almost nothing in 2040. High-water-use counties are outside the core area because it has already passed its peak of drilling activity. Parker, Tarrant, and Wise Counties, for example, have a high water use, although it will drop during the next decade as activity moves to Clay and Montague Counties in the oil window and more peripheral counties outside of the core area.

Haynesville/Bossier Shales

The part of the Haynesville/Bossier shales lying in Texas is estimated at ~35% of each play. We also added a few counties west of the salt basin slated to start producing at a later date. Projections suggest that water use will peak at 22 thousand AF around the 2020 (Table 49 and Table 50). As expected (as well as by construction), counties from the core area (Harrison, Panola, San Augustine, Shelby) are projected to peak at the same time and to contribute the most to total water use.

Eagle Ford Shale

Because of the relative lack of information on Eagle Ford wells, the Eagle Ford Shale decline curve is assumed to be similar to that of the Haynesville but scaled by a smaller EUR. Cusack et al. (2010) attempted a similar analysis in the Eagle Ford play and concluded that 50,000 wells would be needed. This study came up with twice as many wells but spread over a much larger area. The Eagle Ford Shale was projected to peak in 2031, with a water use of ~32 thousand AF (Table 51). Leading counties in terms of water use are such mostly because of their size because no core area has been delineated yet and water use is distributed over the whole play more or less evenly (but not entirely because of prospectivity variations still).

Permian Basin Barnett and Woodford Shales

Those two potentially gas-bearing shales cover large tracts of land in the Delaware Basin in West Texas and overlap (making them more attractive to operators). They have been tested several times, apparently with little success. Matthews et al. (2007) suggested that the lack of carbonates to the Barnett Permian Basin relative to the Fort Worth Basin subcrops is an unfavorable element. We also think that the level of interest is currently low. Mineral-rights owners would rather produce shallower oil with a more dependable worth. Similar to the Pearsall Shale, we assumed a delayed start of around 2020. Water-use is projected to peak at 9.8 thousand AF in 2031 (Table 52).

Pearsall Shale

The Pearsall play has not been very active in the past couple of years but has showed potential in the past. It was assumed that after a period of time, operators in the Eagle Ford would redirect their attention to this play, which is slated to use water in significant amounts around 2020 and peak in 2031 at ~8.1 thousand AF (Table 53).

Wolfberry Trend

The Wolfberry Trend is assumed continuous and is treated in a way similar to that of gas shales. Projections result in a 2023 peak year, with a water use of 11.7 thousand AF. Counties with the highest water use are Irion, Reagan, and Upton Counties (Table 54).

Tight-Gas Plays

Tight-gas plays are discontinuous and cannot be approached exactly as the gas shales were. In addition, most of them have been producing both conventional and tight gas for many years. Their water use is also smaller for these very reasons: less gas to recover and only a small fraction of a county is of interest. Water use in the East Texas Basin tight-gas plays (Table 55) is projected to peak in 2024 at 5.5 thousand AF, with no county dominating. Water-use projections for the Anadarko Basin (Table 56) peak at 3.1 thousand AF in 2020, with a strong contribution from Hemphill and Wheeler Counties. The south Gulf Coast Basin (Table 57) has a small projected water use of 2.4 thousand AF distributed over many counties at its peak (2027), in agreement with the low level of interest local plays have received in the past few years. The Permian Basin (Table 58), which has a higher potential, shows the highest water use in 2017 at 7.8 thousand AF, distributed over many counties as well.

5.1.2 Correcting Factors

Correcting factors include recycling, refracing/infill drilling, and potential development of new technologies.

5.1.2.1 Recycling

Recycling figures depend on two parameters: (1) how much of the frac water flows back and how soon after the fracing operation itself? and (2) what fraction of it is usable again with or without treatment? The amount of water ultimately flowing back from an average fraced shale-gas well is a strong function of the play. It can vary from three times the volume injected in the

Barnett Shale to a small fraction, as in the Marcellus in Pennsylvania. From a strictly operational standpoint, only the water flowing back early (10 days) in the history of the well is reusable, when all the water infrastructure is still in place (although a multiwall pad may mitigate this). The fraction of injected frac water satisfying this criterion is 16% and 5% in the Barnett and Haynesville Shales, respectively (Table 42). In addition, the quality of the such-defined flowback water is variable. Some initial flowback water can be reused with little treatment (filtration or/and mixing). Blauch (2010) stated that flowback water can be used without much treatment, mostly by straight blending with fresh water (5–10% flowback and 90–95% fresh water) and using new-generation chemical additives. However, Rimassa et al. (2009) suggested that full recycling will be hard to attain because degraded additives accumulate in the recycled water. At the other end of the spectrum, undergoing full recycling using more or less advanced treatments and producing distilled water can be expensive. However, a whole segment of the service industry has grown in the past decade to address the recycling needs of gas operators with the development of many mobile water-treatment units making use of different technologies (Horn, 2009), such as osmosis, reverse osmosis, and thermal processes.

The RRC website (http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php, accessed 10/11/2010) mentioned that a company specializing in recycling of industrial water has treated enough produced water (at 80% recovery) to generate 9.3 million barrels of fresh water thanks to several mobile units. This amount is equivalent to 1.2 thousand AF over the course of a few years (since 2005). The RRC website also announced that a stationary facility in Parker County with a capacity of 30,000 bbl/d received the go-ahead. This capacity amounts to a production of 1.13 thousand AF of recycled water a year, assuming no down time. Devon, using recycling mobile units, has recycled >400 million gallons, with an efficiency of ~80% (that is, >320 Mgal (~1 thousand AF), which was reused and >80 Mgal had to be disposed of (Devon website). This information has been reprised by RRC, as described earlier. It seems that only Devon has heavily invested in making use of flowback and treated produced water. According to the IHS database, Devon has drilled ~20% of the Barnett wells since 2005. The process did not seem competitive with new water and disposal of flowback water. It remains unclear how many operators follow a recycling program similar to that of Devon in the Barnett and elsewhere in Texas. Conservatively assuming that twice as many wells as involved in Devon's flowback recycling program have been treated results in 3% of the injected frac water having been treated (~70 thousand AF since 2005). Incorporating the fact that some flowback water was probably used without extensive treatment and not counted toward the figures presented earlier will increase this number. For example, reuse, although it probably depends on the operating company, can be as high as ~200,000 gal per well in Barnett wells with little treatment (M. Mantell, Chesapeake, personal communication, 2010), corresponding to a 6% reuse. Chesapeake does not typically reuse water from the Haynesville (too little and of poor quality). Overall, the recycling effort can be estimated in the 5–10% range in the Barnett and ~0% in the Haynesville.

The industry is bound to make tremendous technological progress in recycling, driven mostly by issues external to the state of Texas. When a critical mass of companies involved in recycling is reached, substantial progress in efficiency and rate is expected. Particularly because of specifics in the Marcellus Shale area, such as limited use of injection wells and municipal wastewater-treatment facilities, the industry will make progress in recycling (as long as there is material to recycle). In this study we assumed that a maximum of 20% of the water used for fracing will be used again.

5.1.2.2 Refracing

How much refracing of wells already fraced is taking place is unclear, and the information is conflicting. Vincent (2010) did a systematic study of restimulation from the origins of hydraulic fracturing and concluded that it works (as documented in the literature) and fails (as not documented as often). However, discussion with operators suggests that very little refracing of recent or future wells will take place. Refracing activities so far have been restricted to wells completed early in the development of the slick-water technology and, thus, may be more common for vertical wells. However, Potapenko et al. (2009, p. 2), looking back at Barnett recompletions, found that despite great success with refracing of vertical wells, little success has come from restimulation of horizontal wells. Gel fracs performed early in the history of the play perhaps somehow may have damaged the formation and that the new water fracs have restored it to its full potential (King, 2010, p. 24). Similarly, it was found that "*Some recent spacing between frac stages in horizontal wells by some operators are so close that it may be very difficult to refracture those wells as all the stages are communicated. Many earlier horizontal wells left large segments between stages unperforated for later refracturing development. Some now also believe that drilling horizontal well laterals close (250 ft.) and not simo-fracturing is leaving gas in place that may not be refractured successfully later on using current technology. Some of us believe that simo-fracturing provides gas today that might have been recovered years later through refracturing.*" (PBSN, Sept. 23, 2008). Simo-fracturing consists of fracing neighboring wells at the same time. However, the same newsletter (PBSN, May 5, 2008; Oct. 5, 2009) states "*We believe most Barnett Shale horizontal wells will be refractured within the first seven years of production.*"

This work assumes that all the possible restimulations have already been done and that there will be no need to refrac newer wells.

5.1.2.3 Infill drilling

Infill drilling takes advantage of the new technologies (horizontal drilling and hydraulic fracturing) that can then be applied to older plays and reservoirs. Infill drilling is an important factor but has no need to be included explicitly as a correcting factor. It is already implicitly part of the methodology.

5.1.2.4 New or Updated Technologies

New or updated technologies that could further decrease reliance on fresh water include use of fluids other than water (propane, N_2, CO_2), sonic fracturing with no added fluid, and other waterless approaches with specialized drilling tools. N_2 fracs may prove effective. Brannon et al. (2009) and van Hoorebeke et al. (2010) described a ~250,000-gal liquid N_2 for a multistage frac job with a 3,000-ft-long lateral. These workers noted that although this kind of frac is not widespread, Marcellus operators may find advantages in using N_2 fracs because of their limited need of water and lack of disposal issues. They went on to note that the Woodford and Barnett Shales present a favorable lithology for application of this technology. Other potential development includes cryogenic nitrogen or CO_2 and high-energy gas fracturing (Zahid et al., 2007). Friehauf and Sharma (2009) discussed the benefits of "energizing" frac fluids with gases such as N_2 or CO_2 (better). Gas addresses the water-trapping problem by creating high gas saturation in the invaded zone and facilitating gas flow. How this different approaches impact total water use is, however, unclear. As the cost of water increases, those methods potentially more expensive than water fracs could become more attractive and receive more attention. Some companies already seem to be using CO_2 fracs in the Barnett and Eagle Ford. Some technologies limit the amount to be disposed of but do not necessarily reduce the demand on local water resources, for example, using waste heat from compressors to evaporate (but not recover) water.

This work does not account for such technological progress and assumes that all plays will be produced thanks to technologies currently applied on a wide scale.

5.1.3 Conclusions on Fracing Water Use

Overall water use for fracing will increase from the current ~37 thousand AF to a peak of ~120 thousand AF by 2020–2030 (Figure 116). However, uncertainty is large. We assumed no major technological breakthrough in fracing technology and no more than small incremental annual increase in efficiency. Another way to measure uncertainty is to assess the two approaches used (production-based and resource-based approaches). Used independently, these would differ by a factor of two in terms of water use. In addition, there are still several other potential gas accumulations, particularly at larger depths than considered in this study—for example, Cotton Valley and pre-Pearsall Formations in South Texas (Ewing, 2010), Travis Peak potential tight-gas resources downdip of the current play (Li and Ayers, 2008), and Silurian, Ordovician (Simpson Group), or even Cambrian targets in the Delaware Basin or the Permian Basin (Dutton et al., 2005a)—but which are all too speculative to be included in this study. Production from these formations would mean that water use, instead of decreasing after the peak of ~120 thousand AF would stay at that level or possibly higher for a longer period of time.

Table 42. Flowback volume characteristics.

	Frac Water Volume (Mgal)	Flowback @ 10 Days (Mgal)	Ultimate Produced Water (Mgal)	Recovery Ratio
Barnett	3.8	0.6	11.730	3.1
Haynesville	5.5	0.25	4.475	0.9
Fayetteville	4.2	0.5	0.980	0.25
Marcellus	5.5	0.5	0.700	0.15

Source: M. Mantell, GWPC Annual UIC Conference, Austin, TX, January 26, 2010

Table 43. Compilation of published Texas oil and gas reserves

	Oil (Bbbl)	Gas (Tcf)	Source
Proved Reserves			
Texas	5.122 4.56	72.1 81.8	EIA (2008, Tables 4 & 5) RRC website (2010, data from 2008)
Districts 4+2 (South TXs)	0.092	0.00 Shale 10.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
District 6 (East TX)	0.16	0.16 Shale 11.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
Districts 8+8A+7C (~PB)	4.30	0.04 Shale 13.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
Districts 5+9+7B (~FWB)	0.23	21.4 Shale 26.8 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
District 10 (~An. B)	0.05	0.00 Shale 6.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
Undiscovered Recoverable Resources (Mean)			
Permian Basin, including New Mexico	0.75 Conv. 0.51 Cont. 1.26 Total	5.20 Conv. 0.26 Tight 35.13 Shale 40.58 Total	USGS – NOGA website 2010*
Anadarko (TX+OK+KS)	0.40 Conv. 0.00 Cont. 0.40 Total	14.20 Conv. 0.00 Tight 0.00 Shale 14.20 Total	USGS – NOGA website 2010*
Fort Worth Basin (>Texas)	0.10 Conv. 0.00 Cont. 0.10 Total	0.47 Conv. 0.00 Tight 26.23 Shale 26.70 Total	USGS – NOGA website 2010*
Western Gulf Coast (TX+LA)	2.29 Conv. 1.09 Cont. 3.38 Total	68.09 Conv. 2.63 Tight 0.00 Shale 70.72 Total	USGS – NOGA website 2010*
East Texas**	2.76 Conv. 0.00 Cont. 2.76 Total	0.00 Conv. 0.00 Tight 0.00 Shale 0.00 Total	USGS – NOGA website 2010*

*NOGA website http://energy.cr.usgs.gov/oilgas/noga/assessment_updates.html (updates)
**The only information for East Texas is commingled with Mississippi salt-basin data
Conv. = conventional; Cont. = continuous

Table 44. Compilation of published reserves for oil and gas shales and tight formations

Play	OOIP/OGIP (Tcf/Bbbl)	Produced Amount	Total Recoverable Reserves (variable unit)	Source
Barnett		7 Tcf*		RRC website – to 2009
		8.2 Tcf 23.6 million bbl		PBSN (Nov.1, 2010) to 09/01/2010
	250 Tcf		50-60 Tcf	
			33 Tcf	EIA (2008) from website
	327 Tcf		44 Tcf	U.S. DOE (2009, p. 17)
			26.2 / 1.0 Bbbl NGL	Coleman (2009, Table 3) - Pollastro (2007)
			36 Tcf (low); 59 Tcf (BG); 102 Tcf (high)	Mohr and Evans (2010)
Eagle Ford			150 / 25 Bbbl	Basin O&G, Nov. 2010, p. 10
			226 Tcfe**	Cusack et al. (2010, p. 172)
Haynesville (TX+LA)			Up to 100 Tcf	Spain and Anderson (2010)
	717 Tcf		251	U.S. DOE (2009, p. 17)
			73 Tcf (low); 131 Tcf (BG); 250 Tcf (high)	Mohr and Evans (2010)
			60 Tcf (for TX?)	Hammes (2009)
Bossier (TX+LA)			100 Tcf	Hanson and Lewis (2010)
Permian Basin (Woodford, Barnett, Wolfberry)			35 Tcf / 1.3 Bbbl oil+NGL	Coleman (2009, Table 3)
Woodford – Delaware Basin			Undisc.: 15.1 Tcf / 0.30 Bbbl NGL	Schenk et al. (2008)
Barnett – Delaware Basin			Undisc.: 17.2 Tcf / 0.34 Bbbl NGL	Schenk et al. (2008)
Woodford+Barnett – Midland B.			Undisc.: 2.8 Tcf / 0.11 Bbbl NGL	Schenk et al. (2008)
Spraberry			Undisc.: 0.26 Tcf /0.53 Bbbl Oil+NGL	Schenk et al. (2008)

*Through 2009, RRC website http://www.rrc.state.tx.us/barnettshale/index.php
**Undisc. = Undiscovered (mean); BG = Best Guess
1 bbl oil = 5.9 Mcf or 1 Bbbl = 5.9 Tcf

Table 45. Compilation of published operational characteristics for oil and gas shales and tight formations

Play	OGIP (Bcf/section)	EUR (Bcf/well)	IP (MMcfd)	Source
Barnett	140	2.65 Bcf		F. Wang, pers. comm. (2010)
	65			U.S. DOE (2009, p. 17)
	100150			Vassilellis et al. (2010)
		3.3 Bcf (core)		XTO Energy (2009)
		3.0 Bcf		Mantell (2010)
		3.0 Bcf (Hor.) 0.74 Bcf (Ver.)		Baihly et al.(2010) at 30 years
		1.25 Bcf		Jarvie (2009) at 30 years
		1.16 Bcf Hor.		SPEE-Anonymous (2010)
Haynesville	150–170	7.5 (4.5-8.5)		F. Wang, pers. comm. (2010)
	160–240			Vassilellis et al. (2010)
		3-6 Bcf	Up to 30	Spain and Anderson (2010, p. 657)
		6.5 Bcf		Hammes (2009)
		6.5 Bcf		XTO Energy (2009)
		6.5 Bcf		Mantell (2010)
	80			U.S. DOE (2009, p. 17)
		5.9 Bcf		Baihly et al. (2010) at 30 years
		3.42 Bcf		Jarvie (2009) at 30 years
		2.6 Bcf		SPEE-Anonymous (2010)
Eagle Ford	140–212			Cusack et al. (2010)
	40–223	5-6 Bcf		Vassilellis et al. (2010)
		5-6 Bcfe		DrillingInfo (2010)
		3.8 Bcf		Baihly et al. (2010) at 30 years
Pearsall	80–120			Vassilellis et al. (2010)
Woodford		3.8 Bcf		XTO Energy (2009)
Cotton Valley		1.9 Bcf (Hor.) 1.0 Bcf (Vert.)		Baihly et al.(2010) at 30 years
Cleveland (Hor.)		0.8 Bcf (Hor.) ~0.5 Bcf (Ver.)		Baihly et al.(2010) at 30 years

Note: 1 section = 640 acres = 1 mi^2.

Table 46. Summary description of parameters used in water-use projections (shale-gas plays)

	Barnett	**Haynesville**	**Eagle Ford**	**Bossier**	**Haynes. West**	**Pearsall**	**Woodford/Barnett Delaware Basin**
Resource-based Approach							
County Coverage	80%	80%	80%	80%	80%	60%	80%
Lateral Spacing (ft)	1000	1000	1000	1000	1000	1000	1000
Intensity-Mgal/1000ft	H.: 1.0	H.: 1.1	H.: 1.25	H.: 1.1	H.: 1.1	H.: 1.0	H.: 1.0
Uncorrected total water use (Th. AF)	1,020	440	1,513	225	37	358	434
Production-based Approach							
Play EUR (Tcf Equ.) from 2010 to 2060	61 52	44 28	250 161	33 21	2.2	25	25
Peak year after start End year after start (county level)	+8 +30	+11 +50	+16 +70	+10 +50	+15 +45	+15 +70	+15 +70
Overall peak year	2015	2031	2035	2020	2033	2031	2031
Average well EUR (BCF)	H.: 2 (core) H.: 1 (non-c.) V.: 0.8	H.: 2	H.: 1.3	H.: 1.2	H.: 2	H.:1.5	H.: 1.5
Average water use /well (Mgal)	3.3	6.1	6.2	3.3	6.1	3.3	3.3
Uncorrected total water use (Th. AF)	457	278	1897	356	23	193	193
Number of wells estimate	59,636	14,712	99,120	19,013	1,255	19,040	19,040
Reuse / Recycling	-1% / year <20%	-0.5% / year <3%	-1% / year <20%	-1% / year <20%	-0.5% / year <3%	-1% / year <20%	-1% / year <20%
Total water use (final results in AF)	750	426	1070	191	36	223	270

Table 47. Summary description of parameters used in water-use projections (tight formations)

	Anadarko Basin	**East Texas**	**Wolfberry**	**Gulf Coast**	**Other Permian Basins**
Resource-based Approach					
County coverage	20%	150%	80%	8%	8%
Lateral spacing (ft)	1000	n/a	n/a	n/a	n/a
Intensity (Mgal/1000 ft)	450	n/a	n/a	n/a	n/a
Vertical well (Mgal)	0.4	0.9	1.0	0.5	0.8
Uncorrected total water use (Th. AF)	50	189	314	76	145
Production-based approach					
Play EUR (Tcf Equ.) from 2010 to 2060	10	16	1070 Bbbl	11	15
Peak year after start End year after start (county level)	+6 +22	+12 +50	+15 +50	+18 +60	+8 +35
Overall peak year	2015	2022	2023	2027	2017
Average well EUR (BCF)	H : 1.2 (50%) V. : 0.6 (50%)	H.: 2 (25%) V. : 0.5 (75%)	H. : n/a V. : 0.06 MMbbl	H.: n/a V. : 0.4	H.: n/a V. : 0.3
Average water-use /well (Mgal)	H.: 1.3 V.: 1	H.: 3 V.: 0.9	H.: n/a V.: 0.9	H.: n/a V.: 0.5	H.: n/a V.: 0.8
Uncorrected total water use (Th. AF)	46	140	94	61	182
Number of wells estimate	13,197	33,961	34,031	33,650	71,513
Reuse / Recycling	-1% / year <20%	-1% / year <20%	-1% / year <20%	0%	-1% / year <20%
Total water use (final results in AF)	49	165	283	78	150

Table 48. Projected water use in the Barnett Shale (Fort Worth Basin)

County	2010*	2020	2030	2040	2050	2060
	AF					
Archer	0	1,618	1,292	369	0	0
Bosque	913	2,547	1,065	0	0	0
Clay	634	3,731	1,663	0	0	0
Comanche	429	2,524	1,125	0	0	0
Cooke	101	282	118	0	0	0
Coryell	0	1,793	1,140	263	0	0
Dallas	620	769	271	0	0	0
Denton	1,674	587	0	0	0	0
Eastland	0	1,127	1,157	386	0	0
Ellis	325	235	63	0	0	0
Erath	2,017	2,500	882	0	0	0
Hamilton	190	1,118	498	0	0	0
Hill	1,008	1,249	441	0	0	0
Hood	1,720	990	215	0	0	0
Jack	1,835	1,706	535	0	0	0
Johnson	3,308	1,537	241	0	0	0
McLennan	0	1,380	680	62	0	0
Montague	539	3,174	1,415	0	0	0
Palo Pinto	446	2,627	1,171	0	0	0
Parker	4,003	1,787	153	0	0	0
Shackelford	0	1,121	1,151	384	0	0
Somervell	771	443	96	0	0	0
Stephens	0	1,854	1,178	272	0	0
Tarrant	3,147	1,104	0	0	0	0
Wise	4,220	1,961	308	0	0	0
Young	0	563	578	193	0	0
Total (Th. AF)	**27.9**	**40.3**	**17.4**	**1.9**	**0.0**	**0.0**

*Projected value, not actual observed water use (see Current Water Use Section) MohrDataBarnett_3.xls FinalReport-Sept.10.xls

Table 49. Projected water use in the Haynesville Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Angelina	0	426	534	367	200	33
Gregg	0	245	435	307	179	51
Harrison	344	2,506	1,848	1,211	574	0
Marion	0	413	517	356	194	32
Nacogdoches	0	1,683	1,582	1,055	527	0
Panola	308	2,242	1,654	1,083	513	0
Rusk	0	1,841	1,730	1,153	577	0
Sabine	0	856	804	536	268	0
San Augustine	221	1,613	1,189	779	369	0
Shelby	314	2,284	1,685	1,104	523	0
Upshur	0	440	781	551	321	92
Total (Th. AF)	**1.2**	**14.5**	**12.8**	**8.5**	**4.2**	**0.2**
Leon	0	57	201	183	96	9
Freestone	0	69	243	221	116	11
Total (Th. AF)	**0.0**	**0.4**	**1.4**	**1.2**	**0.6**	**0.1**

MohrDataHaynesville.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 50. Projected water use in the Bossier Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Nacogdoches	116	2,379	1,599	1,083	567	52
Sabine	210	1,411	949	643	337	31
San Augustine	213	1,432	962	652	342	31
Shelby	302	2,028	1,363	923	484	44
Total (Th. AF)	**0.8**	**7.3**	**4.9**	**3.3**	**1.7**	**0.2**

MohrDataHaynesv.TemplateBossier.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 51. Projected water use in the Eagle Ford Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Atascosa	0	1,443	2,273	1,836	1,399	962
Austin	0	48	256	279	221	163
Brazos	0	519	1,132	922	712	503
Burleson	0	594	1,295	1,055	816	576
Colorado	0	859	1,874	1,527	1,180	833
DeWitt	0	1,067	1,681	1,357	1,034	711
Dimmit	218	2,155	2,327	1,852	1,377	902
Fayette	0	842	1,838	1,497	1,157	817
Frio	0	82	438	477	378	278
Gonzales	0	79	420	458	363	267
Grimes	0	59	314	342	271	200
Karnes	0	1,113	1,350	1,080	810	540

County	2010*	2020	2030	2040	2050	2060
	AF					
La Salle	242	2,390	2,581	2,054	1,528	1,001
Lavaca	0	571	1,776	1,591	1,245	899
Lee	0	47	249	272	215	159
Leon	0	635	1,976	1,771	1,386	1,001
Live Oak	0	79	420	458	363	267
McMullen	0	1,689	2,047	1,638	1,228	819
Madison	0	278	865	775	607	438
Maverick	0	430	1,338	1,199	938	678
Washington	0	366	1,139	1,021	799	577
Webb	138	1,369	1,478	1,177	875	573
Wilson	0	473	1,473	1,320	1,033	746
Zavala	0	434	1,352	1,211	948	685
Total (Th. AF)	**0.6**	**17.6**	**31.9**	**27.2**	**20.9**	**14.6**

MohrDataHaynesv.TemplateEagleFord.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 52. Projected water use in the Woodford and Barnett Shales in the Delaware Basin

County	2010*	2020	2030	2040	2050	2060
	AF					
Crane	0	20	63	50	39	28
Culberson	0	1,324	4,120	3,230	2,528	1,826
Pecos	0	666	2,071	1,624	1,271	918
Reeves	0	893	2,778	2,179	1,705	1,231
Ward	0	44	136	107	84	60
Winkler	0	30	92	72	56	41
Total (Th. AF)	**0.0**	**3.0**	**9.3**	**7.3**	**5.7**	**4.1**

MohrDataHaynesv.TemplateDelawareWoodford+Barnett.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 53. Projected water use in the Pearsall Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Atascosa	0	244	757	594	465	336
Dimmit	0	470	1,463	1,147	898	648
Frio	0	98	306	240	188	136
La Salle	0	521	1,622	1,272	995	719
Live Oak	0	94	294	231	180	130
McMullen	0	405	1,261	989	774	559
Maverick	0	458	1,427	1,119	876	632
Webb	0	48	149	117	91	66
Zavala	0	116	360	283	221	160
Total (Th. AF)	**0.0**	**2.5**	**7.6**	**6.0**	**4.7**	**3.4**

MohrDataHaynesv.TemplatePearsall.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 54. Projected water use in the Wolfberry play

County	2010*	2020	2030	2040	2050	2060
	AF					
Andrews	71	404	383	232	97	0
Borden	42	242	229	139	58	0
Dawson	42	241	228	139	58	0
Ector	42	242	229	139	58	0
Gaines	71	405	384	233	97	0
Glasscock	171	975	924	561	235	0
Howard	172	980	929	564	236	0
Irion	197	1,124	1,065	647	271	0
Martin	172	977	926	562	235	0
Midland	171	974	923	560	234	0
Reagan	223	1,273	1,206	732	306	0
Schleicher	22	128	121	74	31	0
Sterling	44	248	235	143	60	0
Upton	234	1,336	1,266	768	321	0
Total (Th. AF)	**1.7**	**9.5**	**9.0**	**5.5**	**2.3**	**0.0**

MohrDataHaynesv.TemplateWolfberry.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 55. Projected water use in East Texas tight-gas plays

County	2010*	2020	2030	2040	2050	2060
	AF					
Anderson	0	24	83	66	41	15
Cass	0	52	66	46	25	4
Cherokee	23	254	288	188	89	0
Freestone	636	856	670	439	208	0
Gregg	132	177	138	91	43	0
Harrison	900	532	395	259	123	0
Henderson	0	259	327	225	123	21
Limestone	279	375	293	192	91	0
Marion	23	252	210	138	65	0
Nacogdoches	321	321	245	160	76	0
Panola	805	476	354	232	110	0
Robertson	287	606	487	319	151	0
Rusk	51	563	468	307	145	0
Shelby	0	228	288	198	108	18
Smith	0	103	130	90	49	8
Upshur	0	163	206	141	77	13
Total (Th. AF)	**3.5**	**5.2**	**4.6**	**3.1**	**1.5**	**0.1**

MohrDataHaynesv.TemplateEastTexas.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 56. Projected water use in Anadarko Basin tight formations

County	2010*	2020	2030	2040	2050	2060
	AF					
Hansford	74	675	61	0	0	0
Hemphill	694	364	33	0	0	0
Hutchinson	6	59	6	0	0	0
Lipscomb	123	507	46	0	0	0
Ochiltree	73	671	61	0	0	0
Roberts	183	447	41	0	0	0
Sherman	7	61	6	0	0	0
Wheeler	697	365	33	0	0	0
Total (Th. AF)	**1.9**	**3.1**	**0.3**	**0.0**	**0.0**	**0.0**

MohrDataHaynesv.TemplateAnadarko.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 57. Projected water use in the South Gulf Coast Basin tight-gas plays

County	2010*	2020	2030	2040	2050	2060
	AF					
Aransas	9	17	22	16	11	5
Bee	23	47	58	43	29	14
Brazoria	37	75	94	70	46	21
Brooks	25	49	62	46	30	14
Calhoun	17	33	42	31	21	10
Cameron	25	50	62	46	30	14
Colorado	25	51	64	48	31	15
DeWitt	24	47	60	44	29	14
Duval	47	94	118	87	57	27
Fort Bend	23	46	58	43	28	14
Goliad	22	45	56	42	27	13
Hidalgo	42	83	105	78	51	24
Jackson	22	45	56	42	28	13
Jim Hogg	30	60	75	56	37	17
Jim Wells	23	45	57	42	28	13
Karnes	20	40	50	37	24	11
Kenedy	38	76	95	71	46	22
Kleberg	25	49	62	46	30	14
La Salle	39	77	97	72	47	22
Lavaca	25	51	64	47	31	15
Live Oak	28	56	70	52	34	16
McMullen	30	60	75	56	37	17
Matagorda	31	61	77	57	37	18
Nueces	22	45	56	42	28	13
Refugio	21	42	53	39	26	12
San Patricio	18	37	46	34	22	11
Starr	32	64	79	59	39	18
Victoria	23	46	58	43	28	14
Webb	88	177	222	165	108	51

County	2010*	2020	2030	2040	2050	2060
	AF					
Wharton	29	57	72	53	35	17
Willacy	16	31	39	29	19	9
Zapata	27	55	68	51	33	16
Total (Th. AF)	**0.9**	**1.8**	**2.3**	**1.7**	**1.1**	**0.5**

MohrDataHaynesv.TemplateGulfCoast.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 58. Projected water use in the Permian Basin tight formations

County	2010*	2020	2030	2040	2050	2060
	AF					
Andrews	231	509	297	85	0	0
Borden	68	157	91	26	0	0
Crane	121	277	161	46	0	0
Crockett	53	123	72	21	0	0
Dawson	68	156	91	26	0	0
Ector	265	328	191	55	0	0
Gaines	114	263	153	44	0	0
Garza	68	156	91	26	0	0
Glasscock	138	316	184	53	0	0
Howard	139	318	185	53	0	0
Loving	103	236	138	39	0	0
Lynn	68	157	91	26	0	0
Martin	342	285	166	48	0	0
Midland	341	284	166	47	0	0
Mitchell	68	157	92	26	0	0
Pecos	37	86	50	14	0	0
Reagan	446	371	217	62	0	0
Reeves	400	917	535	153	0	0
Scurry	69	158	92	26	0	0
Sterling	70	161	94	27	0	0
Sutton	108	248	145	41	0	0
Terrell	45	103	60	17	0	0
Terry	68	155	90	26	0	0
Upton	525	454	265	75	0	0
Val Verde	22	51	30	9	0	0
Ward	126	289	168	48	0	0
Winkler	133	307	179	51	0	0
Yoakum	61	140	81	23	0	0
Total (Th. AF)	**4.3**	**7.2**	**4.2**	**1.2**	**0.0**	**0.0**

MohrDataHaynesv.TemplatePB-TG.xls

*Projected value, not actual observed water use (see Current Water Use Section)

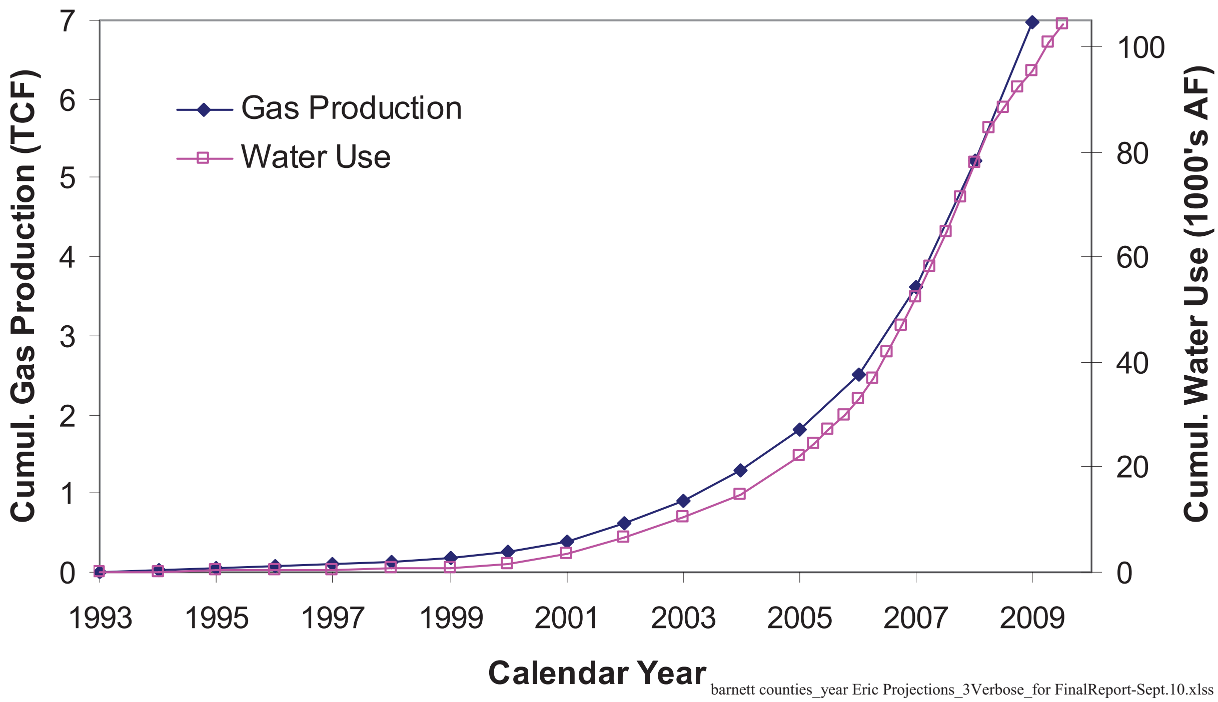
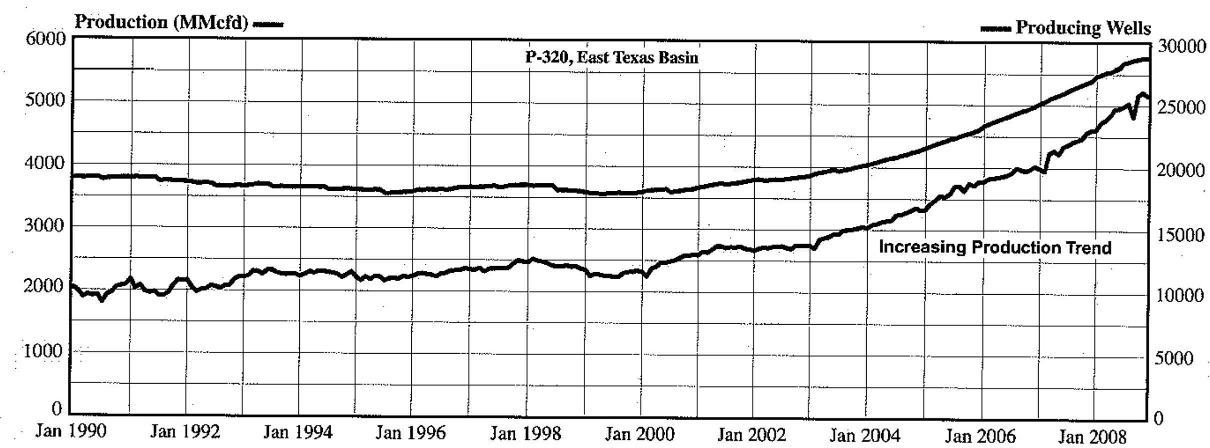
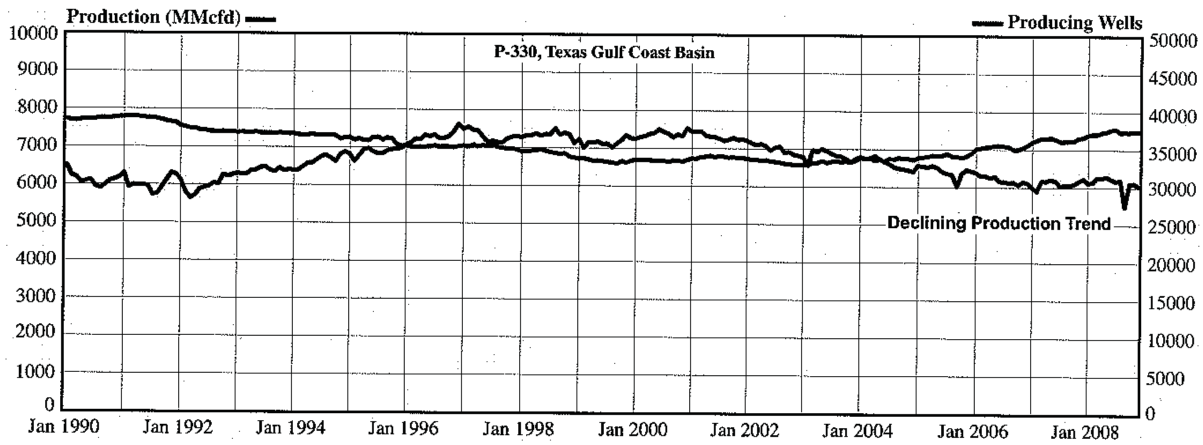


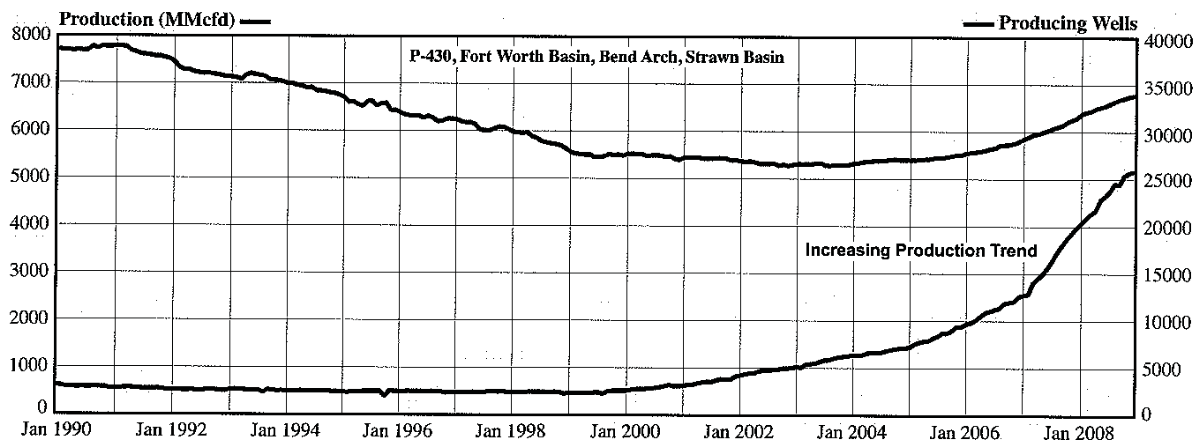
Figure 114. Cumulative gas production and water use in the Barnett Shale play from the origins



Source: PGC (2009); raw data from IHS Energy
Note: The most irregular curve represents gas production; a 1000-MMcfd unit in the production axis corresponds to 0.365 Tcf

Figure 115. Monthly wet-gas production and number of producing oil and gas wells (1990–2008)





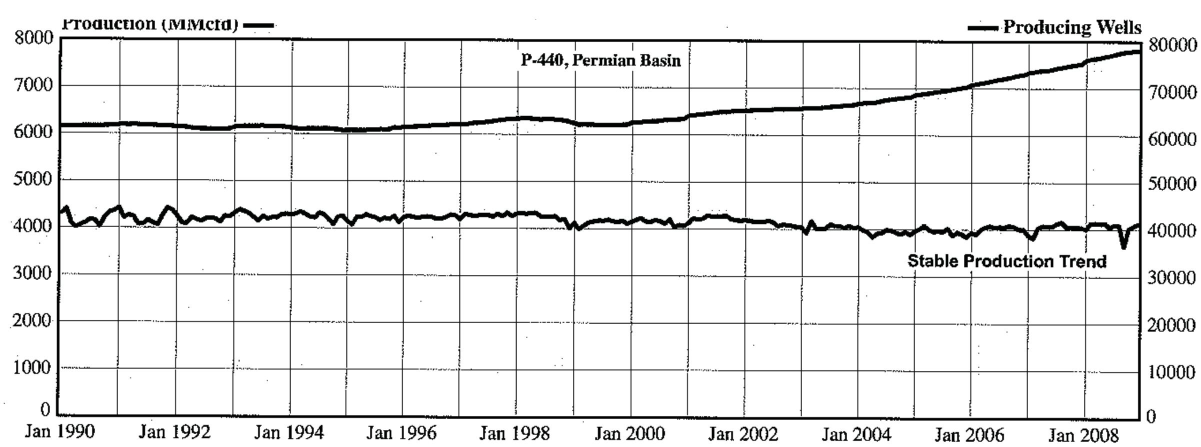


Figure 115. Monthly wet-gas production and number of producing oil and gas wells (1990–2008) (continued)

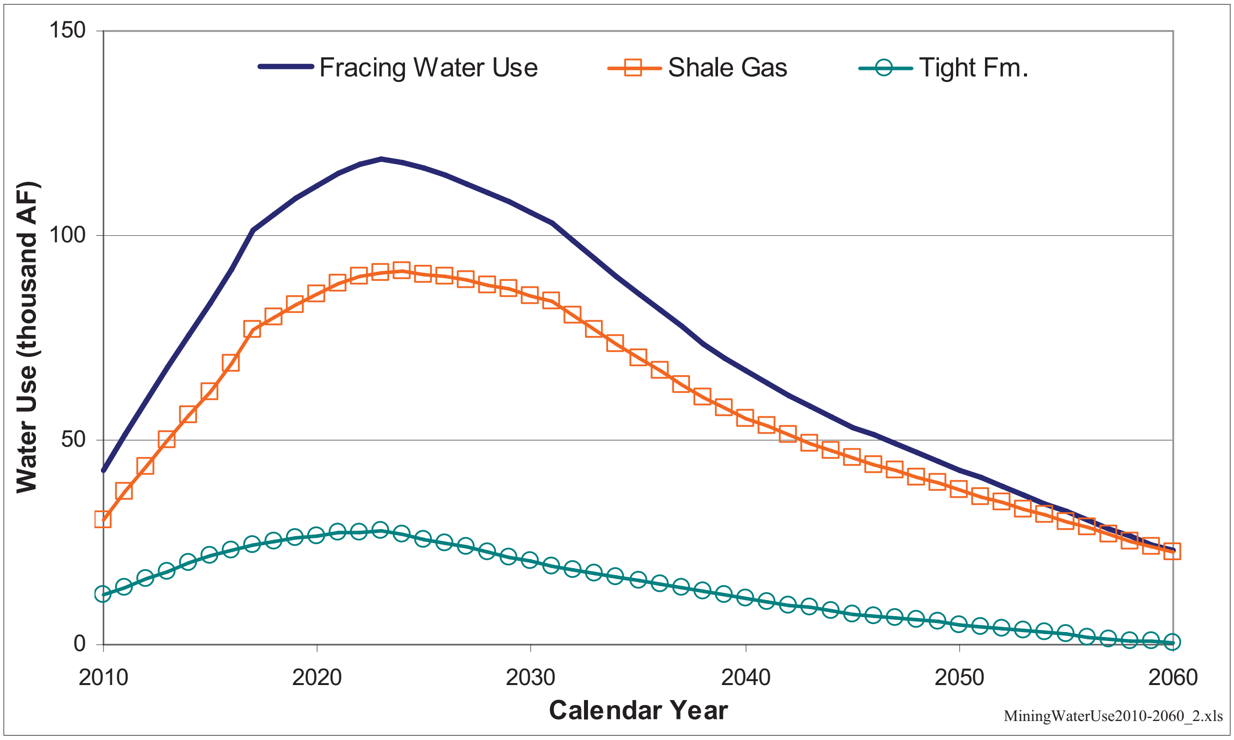


Figure 116. Projected state fracing water use

5.2 Conventional Oil and Gas

Conventional oil and gas, although beyond their peak production, are likely to remain significant for many decades as operators assess and put online new reservoirs. After peak oil in Texas in the early 1970s, the following years showed a slow, more or less linear decrease in production (despite an increase in producing wells). Starting in the late 1990s, though, a graph shows a clear leveling off of the decrease (Figure 117), one section of which can be used to extrapolate future production (Figure 118). Much anecdotal evidence suggests that conventional oil and gas resources in Texas are far from being exhausted. For example, Ewing (2010) listed several likely deep plays (>10,000 ft) in South Texas equivalent to productive formations in East Texas. And operators in the Permian Basin still have to explore for the gas that may lie deeper than current production horizons. As described earlier, USGS oil and gas assessments evaluate the resource that is deemed to be technically recoverable using current and projected techniques. Reserves are defined as a subset of the resources that can be produced economically. The USGS-based National Oil and Gas Assessments (NOGA) is tasked to evaluate those *undiscovered* petroleum resources. NOGA divides the continental U.S. into many provinces, including "West Gulf," "East TX, LA-MS Salt Basins," "Bend Arch-Fort Worth Basin," "Permian Basin," and "Marathon Thrust Belt." Except for the much smaller last province, all four other provinces go largely beyond Texas. The latest complete assessment of the U.S. was made in 1995, although updates of the assessment of some provinces were made very recently.

5.2.1 Water and CO_2 Floods

Conventional oil and gas production use water for two purposes: drilling and EOR. As seen in the current water-use section, water use for waterfloods has been decreasing steadily, and we assume that it will keep making up a smaller and smaller fraction of fluid injected for waterfloods. Fresh water use has been declining strongly in the past decades, and we expect the trend to continue (Figure 119). The general trend of oil production in West Texas has been one of more or less continuous decline since its peak in the early 1970s. Galusky (2010) produced what we think are relatively accurate numbers for the Permian Basin (~10 Bbbl to 2060). Schenk et al. (2008) estimated undiscovered resources of conventional oil in the Permian Basin at 747 million barrels. A study by the consulting firm ARI (Kuuskraa and Ferguson, 2008, Table 1) reports that Texas (including that portion of the Permian Basin in New Mexico) has >200 Bbbl of OOIP of which ~70 Bbbl is conventionally recoverable (primary and secondary recovery processes), an arguably optimistic projection. For comparison, Texas has produced ~60 Bbbl of oil since the origins.

Dutton et al. (2005a) presented a comprehensive study of all known oil and gas fields in the Permian Basin and included a section on production forecast to 2015. The lack of full overlap between the Permian Basin and Districts 08 and 8A (New Mexico had 15.6% of cumulative production through 2000, Dutton et al., 2005a, p. 351) carries some uncertainty but the error introduced by assuming the Permian Basin and RRC Districts 08 and 8A coincide is small compared to the other assumptions used in this section. Dutton et al. (2005a) projected a production of 3.25 Bbbl of oil through 2015 from which the 1.9 Bbbl produced through 2010 (since the publication of the Dutton et al., 2005a report) must be deducted yielding 1.35 Bbbl to be produced to 2015. This is consistent with Galusky (2010)'s projections at 1.44 Bbbl from 2011 to 2015. Both workers have in common the slow decline of conventional oil production at a similar rate.

The slow pace of this decline (~2% per year) reflects the steady increase in EOR production techniques (waterfloods and CO_2 floods). The general pattern of declining oil production has occurred through high-price as well as low price-intervals. It would thus seem reasonable to project this gradual decline through the forecast period of this study (2010– 2060). Oil drilling and completion activities and oil production are expected to be sustained at slowly declining levels in West Texas over the next 50 years. It is projected that EOR production methods will be responsible for 70% or more of total oil production by 2020 and beyond. Although EOR production requires copious quantities of water to sustain oil reservoir pressures, fresh water is expected to decline in use relative to brackish and saline (recycled produced) waters. Total brackish and saline water use is thought to have essentially peaked near the present estimated figure of ~38.5 thousand AF/yr and is then expected to decline over the coming decades. In contrast, total fresh-water use is expected to continue to decline from the present estimated figure of ~10,000 ac-ft/yr to less than half this level by 2020. In this study we did not investigate the possibility of having extensive waterfloods in the Gulf Coast area or elsewhere in the state. We did not include the real potential for extensive CO_2 floods as it is not clear whether operators would use a WAG technique with concomitant water use or simply inject CO_2 (which might be in abundance in the future, thanks to the presence of many coal-fired power plants along the Gulf).

Table 59 summarizes our findings per county. Projections of overall water use, estimated at ~8 thousand AF in 2010, is decreasing through time because of the built-in assumption of decreased fresh water use for the purpose of waterflood and other recovery processes.

Going back to historical reports (for example, Torrey, 1967) is insightful in the sense that it allows comparison of projections with actual production and water use. The 1967 report author makes the correct statement (p. 2) that no reasonable alternative but to extrapolate currents can be made in a 50-year projection period. The report predicts average water use in the 1990–2000 decade of ~220 thousand AF for much smaller oil production than actually occurred. Included in their water use is all nonproduced waters, of which it is unclear how much is fresh or brackish. The approach was to compute oil reserves amenable to water injection for pressure maintenance or waterflooding (25% increasing to 50% of projected production in 2010) and to apply a multiplier (average of 8.2 bbl of water used to produce 1 bbl of oil) corrected by the amount of produced water used (typically 10%– 20%, that is, most of water is makeup water, although the quality is not described).

5.2.2 Drilling

In general, drilling and completion activities are much more sensitive to short-term price cycles than production. Periods of relatively high oil prices tend to incentivize and support a proportionally greater level of drilling activity than do periods of low prices. It would be virtually impossible to predict oil prices many years into the future with any level of real confidence. Projections of water use for drilling are thus more perilous than price or production projections. Nevertheless, it seems reasonable to project a gradual decline in fresh water use for oil drilling in the coming decades, Even as oil fields become depleted, an increase in drilling activity for oil can be expected because of the renewed interest in plays similar to the Wolfberry in the Permian Basin and because of an increased interest in waterflooding, requiring drilling of new wells. This increase in drilling is likely to be more than balanced by a decrease in fresh-water use as the industry uses more and more brackish and saline water. Galusky (2010) proposed to assume that the fresh water use for drilling in the Permian Basin (which is more densely drilled than the rest of Texas) will stay relatively stable until 2020, and will gradually decrease below about half its present level by 2060. We assume that the pattern is applicable to the whole state. Despite the general decrease of fresh-water use in oil production, it is likely that the water use for drilling will keep increasing for the next few years because of shale-gas activity. The amount of fresh water used in drilling shale gas wells is variable and a function of the play (Section 4.2.2). Including water use from shale-gas activity yields a peak of 13 thousand AF within the current decade (Figure 120).

Table 59. County-level fresh and brackish water-use projections for waterflood

County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
State Total	**7.87**	**2.39**	**1.49**	**1.29**	**1.12**	**0.96**	**29.91**	**31.49**	**31.93**	**28.34**	**24.58**	**21.26**
Anderson	0.008	0.002	0.002	0.001	0.001	0.001	0.031	0.033	0.033	0.029	0.025	0.022
Andrews	0.384	0.117	0.073	0.063	0.055	0.047	1.457	1.534	1.556	1.381	1.197	1.036
Archer	0.003	0.001	0.001	0.000	0.000	0.000	0.010	0.011	0.011	0.010	0.009	0.007
Atascosa	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.003	0.003	0.002	0.002	0.002
Baylor	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001
Borden	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Brown	0.005	0.001	0.001	0.001	0.001	0.001	0.018	0.019	0.019	0.017	0.015	0.013
Callahan	0.018	0.005	0.003	0.003	0.003	0.002	0.067	0.071	0.072	0.064	0.055	0.048
Camp	0.003	0.001	0.001	0.000	0.000	0.000	0.010	0.011	0.011	0.010	0.008	0.007
Carson	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001
Clay	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.004	0.004	0.003	0.003
Cochran	0.005	0.002	0.001	0.001	0.001	0.001	0.020	0.021	0.021	0.019	0.016	0.014
Coke	0.109	0.033	0.021	0.018	0.016	0.013	0.416	0.438	0.444	0.394	0.342	0.296
Coleman	0.021	0.006	0.004	0.003	0.003	0.003	0.080	0.084	0.085	0.076	0.066	0.057
Comanche	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.002	0.002	0.001	0.001	0.001
Concho	0.108	0.033	0.021	0.018	0.015	0.013	0.412	0.434	0.440	0.390	0.338	0.293
Cooke	0.004	0.001	0.001	0.001	0.001	0.001	0.016	0.017	0.017	0.015	0.013	0.012
Cottle	0.007	0.002	0.001	0.001	0.001	0.001	0.026	0.027	0.027	0.024	0.021	0.018
Crane	0.027	0.008	0.005	0.004	0.004	0.003	0.101	0.106	0.108	0.096	0.083	0.072
Crockett	0.007	0.002	0.001	0.001	0.001	0.001	0.025	0.026	0.027	0.024	0.021	0.018
Crosby	0.228	0.069	0.043	0.037	0.032	0.028	0.866	0.912	0.925	0.821	0.712	0.616
Culberson	0.033	0.010	0.006	0.005	0.005	0.004	0.127	0.134	0.135	0.120	0.104	0.090
Dawson	0.039	0.012	0.007	0.006	0.005	0.005	0.146	0.154	0.156	0.139	0.120	0.104

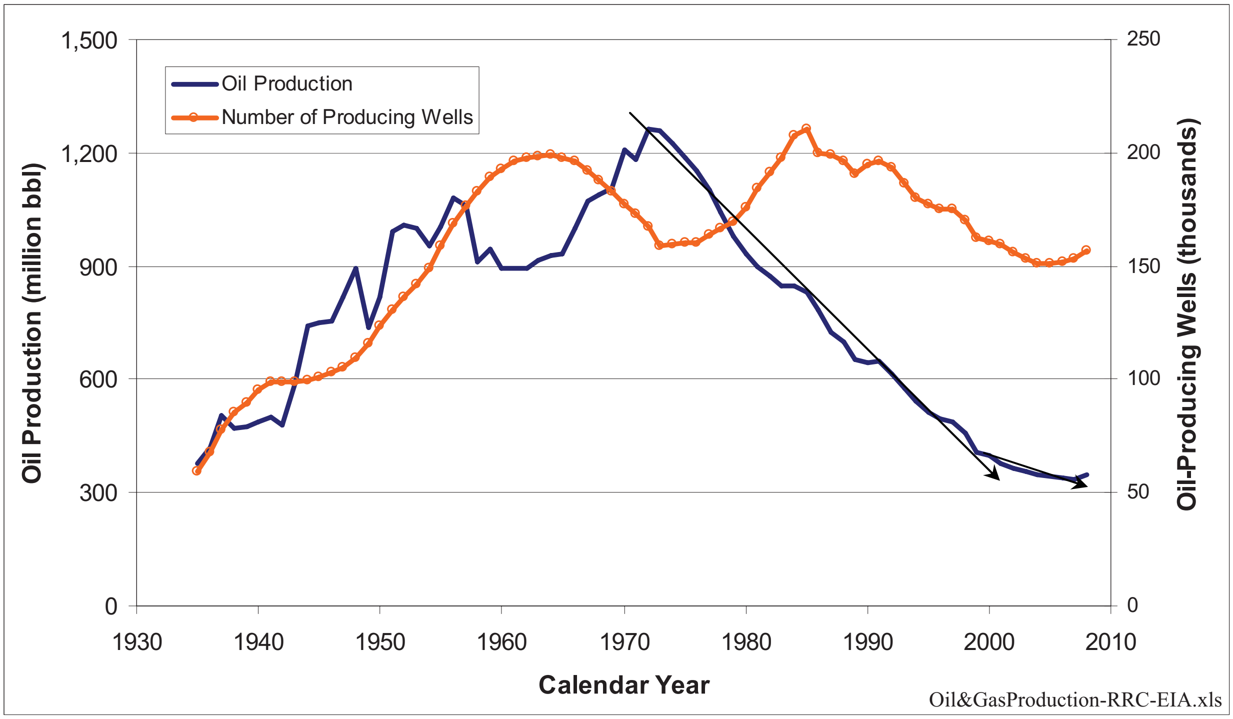
County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Dickens	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Dimmit	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Eastland	0.070	0.021	0.013	0.012	0.010	0.009	0.267	0.281	0.285	0.253	0.219	0.190
Ector	0.019	0.006	0.004	0.003	0.003	0.002	0.072	0.075	0.077	0.068	0.059	0.051
Fisher	0.091	0.028	0.017	0.015	0.013	0.011	0.345	0.364	0.369	0.327	0.284	0.245
Floyd	0.031	0.010	0.006	0.005	0.004	0.004	0.119	0.125	0.127	0.113	0.098	0.084
Foard	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.003	0.002	0.002	0.002
Franklin	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.005	0.004	0.004	0.003
Freestone	0.001	0.000	0.000	0.000	0.000	0.000	0.005	0.005	0.005	0.004	0.004	0.003
Gaines	0.002	0.001	0.000	0.000	0.000	0.000	0.008	0.009	0.009	0.008	0.007	0.006
Garza	0.011	0.003	0.002	0.002	0.002	0.001	0.042	0.045	0.045	0.040	0.035	0.030
Glasscock	0.085	0.026	0.016	0.014	0.012	0.010	0.324	0.341	0.346	0.307	0.266	0.230
Gray	0.014	0.004	0.003	0.002	0.002	0.002	0.055	0.058	0.058	0.052	0.045	0.039
Grayson	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.005	0.005	0.004	0.004	0.003
Hale	0.271	0.082	0.051	0.045	0.039	0.033	1.031	1.085	1.100	0.977	0.847	0.733
Hansford	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.004	0.004	0.003	0.003
Hartley	0.002	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.006	0.006	0.005	0.004
Haskell	0.019	0.006	0.004	0.003	0.003	0.002	0.072	0.075	0.076	0.068	0.059	0.051
Hockley	0.001	0.000	0.000	0.000	0.000	0.000	0.005	0.005	0.005	0.005	0.004	0.003
Hopkins	0.009	0.003	0.002	0.001	0.001	0.001	0.034	0.036	0.036	0.032	0.028	0.024
Howard	0.014	0.004	0.003	0.002	0.002	0.002	0.053	0.056	0.057	0.051	0.044	0.038
Hutchinson	0.004	0.001	0.001	0.001	0.001	0.000	0.015	0.016	0.016	0.014	0.012	0.011
Irion	0.169	0.051	0.032	0.028	0.024	0.021	0.642	0.676	0.685	0.609	0.528	0.456
Jack	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.002	0.002
Jones	0.025	0.008	0.005	0.004	0.004	0.003	0.094	0.099	0.100	0.089	0.077	0.067
Kent	0.006	0.002	0.001	0.001	0.001	0.001	0.023	0.024	0.024	0.022	0.019	0.016
King	1.818	0.553	0.345	0.299	0.258	0.223	6.907	7.271	7.373	6.546	5.676	4.909

County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Knox	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.003	0.003	0.002	0.002	0.002
Lamb	0.136	0.041	0.026	0.022	0.019	0.017	0.518	0.545	0.553	0.491	0.425	0.368
Leon	0.011	0.003	0.002	0.002	0.002	0.001	0.043	0.045	0.046	0.041	0.035	0.031
Limestone	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.003	0.003	0.002	0.002	0.002
Lipscomb	0.003	0.001	0.001	0.000	0.000	0.000	0.011	0.011	0.011	0.010	0.009	0.008
Loving	0.074	0.023	0.014	0.012	0.011	0.009	0.282	0.297	0.301	0.267	0.232	0.200
Lubbock	1.307	0.398	0.248	0.215	0.186	0.160	4.968	5.230	5.303	4.708	4.082	3.531
Lynn	0.207	0.063	0.039	0.034	0.029	0.025	0.785	0.826	0.838	0.744	0.645	0.558
Marion	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.002	0.001
Martin	0.084	0.026	0.016	0.014	0.012	0.010	0.320	0.337	0.342	0.303	0.263	0.227
Maverick	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.004	0.004	0.003	0.003	0.002
McCulloch	0.009	0.003	0.002	0.001	0.001	0.001	0.034	0.035	0.036	0.032	0.028	0.024
McMullen	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.002	0.001	0.001	0.001
Menard	0.250	0.076	0.047	0.041	0.035	0.031	0.948	0.998	1.012	0.899	0.779	0.674
Midland	0.035	0.011	0.007	0.006	0.005	0.004	0.134	0.141	0.143	0.127	0.110	0.095
Mitchell	0.003	0.001	0.001	0.000	0.000	0.000	0.011	0.011	0.011	0.010	0.009	0.008
Montague	0.004	0.001	0.001	0.001	0.001	0.000	0.014	0.015	0.015	0.014	0.012	0.010
Moore	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.003	0.004	0.003	0.003	0.002
Motley	0.027	0.008	0.005	0.005	0.004	0.003	0.104	0.110	0.111	0.099	0.086	0.074
Navarro	0.002	0.001	0.000	0.000	0.000	0.000	0.008	0.009	0.009	0.008	0.007	0.006
Nolan	0.045	0.014	0.009	0.007	0.006	0.006	0.171	0.180	0.183	0.162	0.141	0.122
Ochiltree	0.004	0.001	0.001	0.001	0.001	0.000	0.015	0.015	0.016	0.014	0.012	0.010
Oldham	0.003	0.001	0.001	0.001	0.000	0.000	0.012	0.012	0.013	0.011	0.010	0.008
Palo Pinto	0.018	0.005	0.003	0.003	0.003	0.002	0.068	0.071	0.072	0.064	0.056	0.048
Pecos	0.066	0.020	0.012	0.011	0.009	0.008	0.249	0.262	0.266	0.236	0.205	0.177
Potter	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Reagan	0.024	0.007	0.004	0.004	0.003	0.003	0.090	0.094	0.096	0.085	0.074	0.064

County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Red River	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.004	0.004	0.003	0.003	0.002
Reeves	0.019	0.006	0.004	0.003	0.003	0.002	0.071	0.075	0.076	0.068	0.059	0.051
Runnels	0.060	0.018	0.011	0.010	0.009	0.007	0.228	0.240	0.243	0.216	0.187	0.162
Rusk	0.011	0.003	0.002	0.002	0.002	0.001	0.044	0.046	0.046	0.041	0.036	0.031
Schleicher	0.030	0.009	0.006	0.005	0.004	0.004	0.112	0.118	0.120	0.106	0.092	0.080
Scurry	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Shackelford	0.046	0.014	0.009	0.007	0.006	0.006	0.173	0.182	0.185	0.164	0.142	0.123
Sherman	0.002	0.001	0.000	0.000	0.000	0.000	0.007	0.007	0.007	0.007	0.006	0.005
Smith	0.004	0.001	0.001	0.001	0.001	0.001	0.016	0.017	0.017	0.015	0.013	0.012
Stephens	1.086	0.330	0.206	0.178	0.154	0.133	4.126	4.343	4.404	3.910	3.390	2.932
Sterling	0.007	0.002	0.001	0.001	0.001	0.001	0.027	0.029	0.029	0.026	0.022	0.019
Stonewall	0.132	0.040	0.025	0.022	0.019	0.016	0.503	0.530	0.537	0.477	0.414	0.358
Sutton	0.001	0.000	0.000	0.000	0.000	0.000	0.005	0.006	0.006	0.005	0.005	0.004
Taylor	0.015	0.005	0.003	0.002	0.002	0.002	0.057	0.060	0.061	0.054	0.047	0.041
Terrell	0.106	0.032	0.020	0.017	0.015	0.013	0.401	0.423	0.429	0.380	0.330	0.285
Terry	0.019	0.006	0.004	0.003	0.003	0.002	0.072	0.076	0.077	0.068	0.059	0.051
Throckmorton	0.042	0.013	0.008	0.007	0.006	0.005	0.160	0.169	0.171	0.152	0.132	0.114
Titus	0.002	0.001	0.000	0.000	0.000	0.000	0.006	0.007	0.007	0.006	0.005	0.004
Tom Green	0.011	0.003	0.002	0.002	0.002	0.001	0.042	0.045	0.045	0.040	0.035	0.030
Upshur	0.007	0.002	0.001	0.001	0.001	0.001	0.028	0.030	0.030	0.027	0.023	0.020
Upton	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Van Zandt	0.012	0.004	0.002	0.002	0.002	0.001	0.044	0.047	0.047	0.042	0.036	0.032
Ward	0.003	0.001	0.001	0.000	0.000	0.000	0.012	0.012	0.012	0.011	0.009	0.008
Wheeler	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Wichita	0.012	0.004	0.002	0.002	0.002	0.002	0.047	0.050	0.050	0.045	0.039	0.033
Wilbarger	0.002	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.006	0.006	0.005	0.004
Wilson	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001

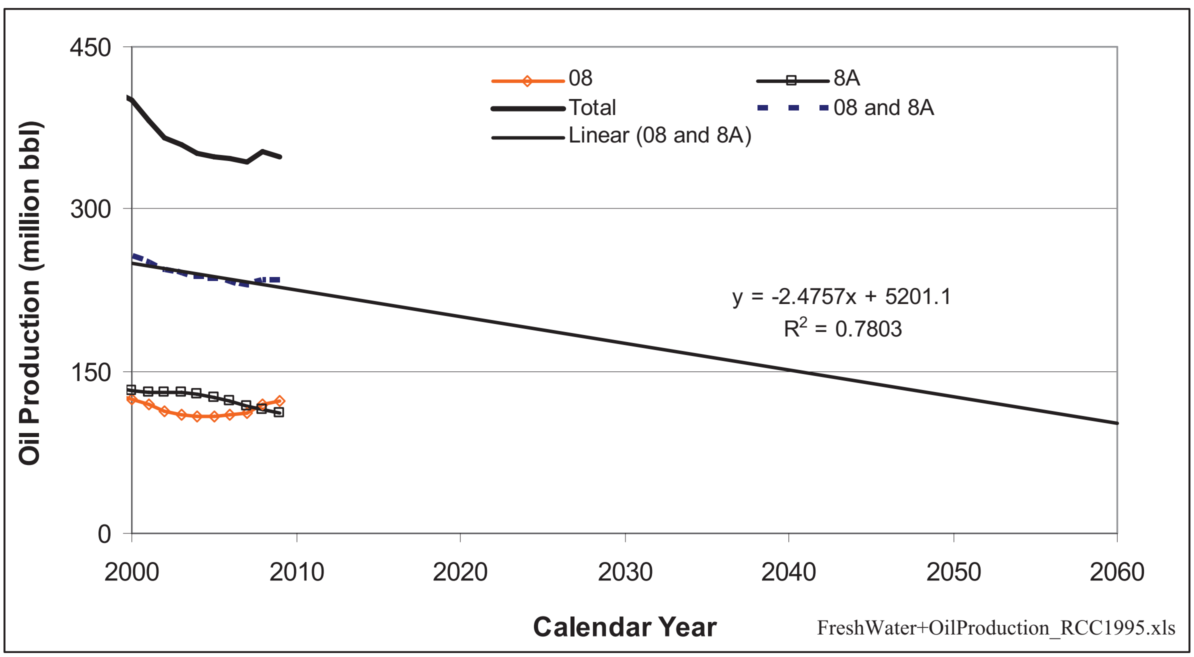
County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Winkler	0.022	0.007	0.004	0.004	0.003	0.003	0.083	0.088	0.089	0.079	0.069	0.059
Wood	0.004	0.001	0.001	0.001	0.001	0.000	0.014	0.015	0.015	0.013	0.011	0.010
Yoakum	0.219	0.067	0.041	0.036	0.031	0.027	0.832	0.875	0.888	0.788	0.683	0.591
Young	0.002	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.006	0.006	0.005	0.004

InjectionVolume_2002_RRC_+1998-2001_1.xls



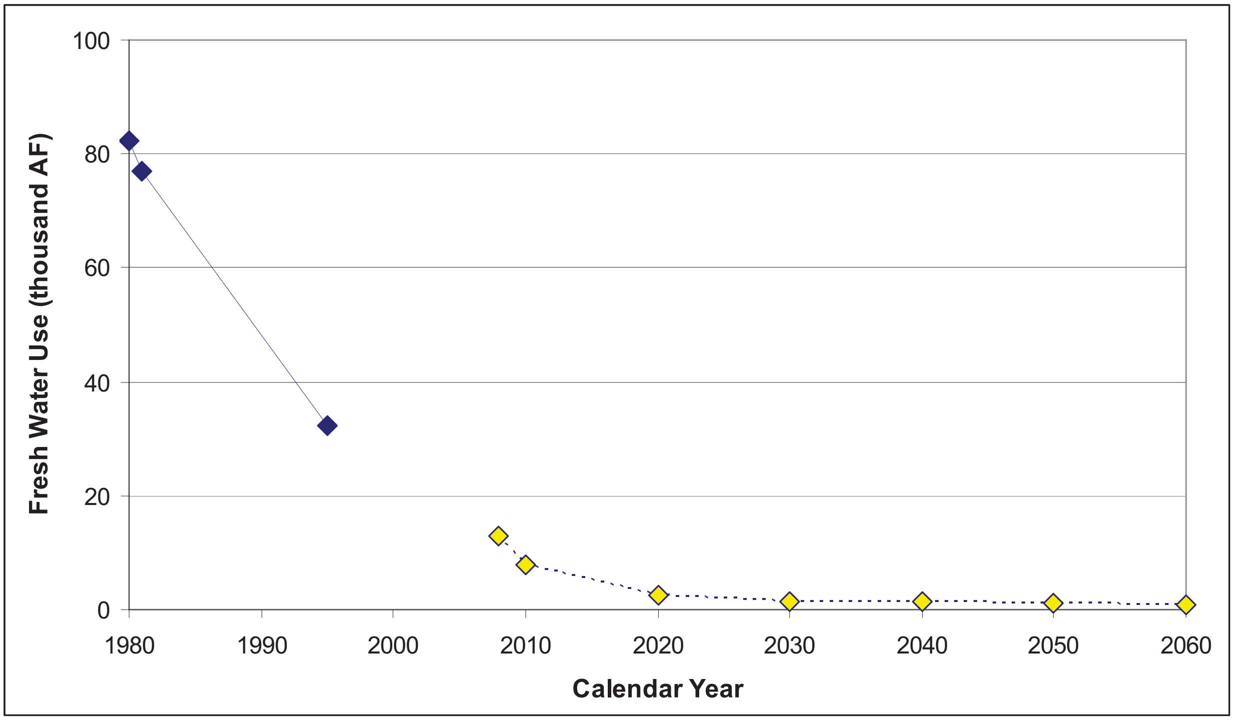
Source: EIA website

Figure 117. Annual oil production in Texas (1936–2009)



Source: RRC online system http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do (historical data)

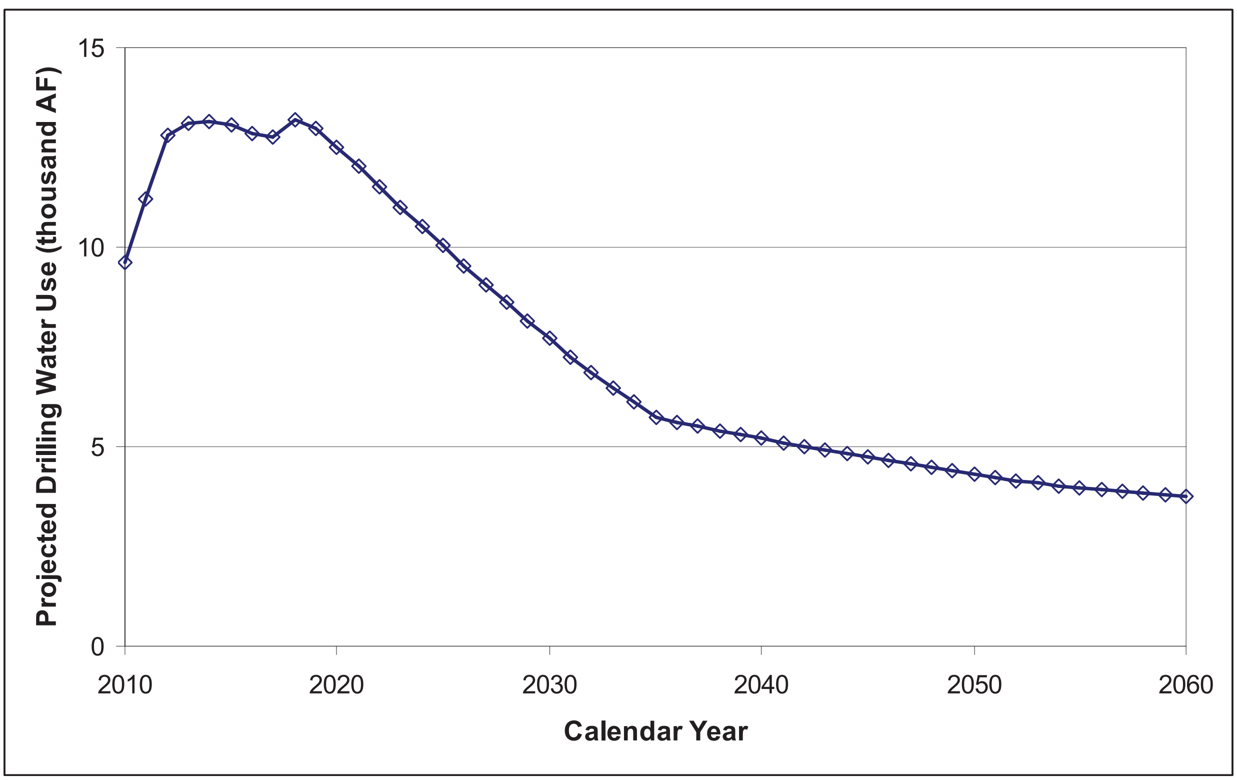
Figure 118. Future annual oil production, Districts 8, 8A, and Texas



Source: RRC (1982) and De Leon (1996) for historical data

Historical Injection 2=fromRRC1982Report.xls

Figure 119. Historical and projected fresh-water use in secondary and tertiary recovery operations



DrillingWaterUse.xls

Figure 120. Projected drilling-water use

5.3 *Coal*

Coal resources are plentiful in Texas and are unlikely to be exhausted within the next 5 decades at the current average production rate. Kaiser et al. (1980) gave an overview of the lignite resource in Texas and estimated reserves at >6 billion short tons. More recently, Warwick et al. (2002) identified 7.7 billion short tons of Central Texas lignite reserves, excluding resources within coal-mine lease areas. All mines currently in production, except Jewett mine, which is slated to end production around 2025, are assumed to keep producing at a rate similar to the current one. Three Oaks mine came on line recently (2005) after Sandow mine retired. Two new mines will come on line in the next few years: Kosse mine in Limestone County and Twin Oaks mine in Robertson County. Future water-use breakdown for these two mines was estimated from Jewett and Calvert mines, respectively. At the state level, water use is assumed to ramp up from ~25,000 AF/yr to 40,000 AF/yr, mostly because of Three Oak and Twin Oak mines (Figure 121). Other mines' water use remains relatively steady (Figure 122). Results per mine/per county are listed in Table 60. Robertson County exhibits higher water use, starting at ~7,500 AF currently and increasing to 10,000+ AF after 2040. All of the water is groundwater, very little of which is consumed and most of which is discharged to streams.

The scenario we favor is one in which potential increase in energy needs will be covered by western coal (which has been competing with local coal for decades, Figure 123), by other fossil fuels (gas?), or by a different energy source (nuclear?), but not by a massive extension of mouth-of-mine coal-fired power plants and concomitant increase in water use. In any case, a return to underground mining of subbituminous reserves is deemed unlikely.

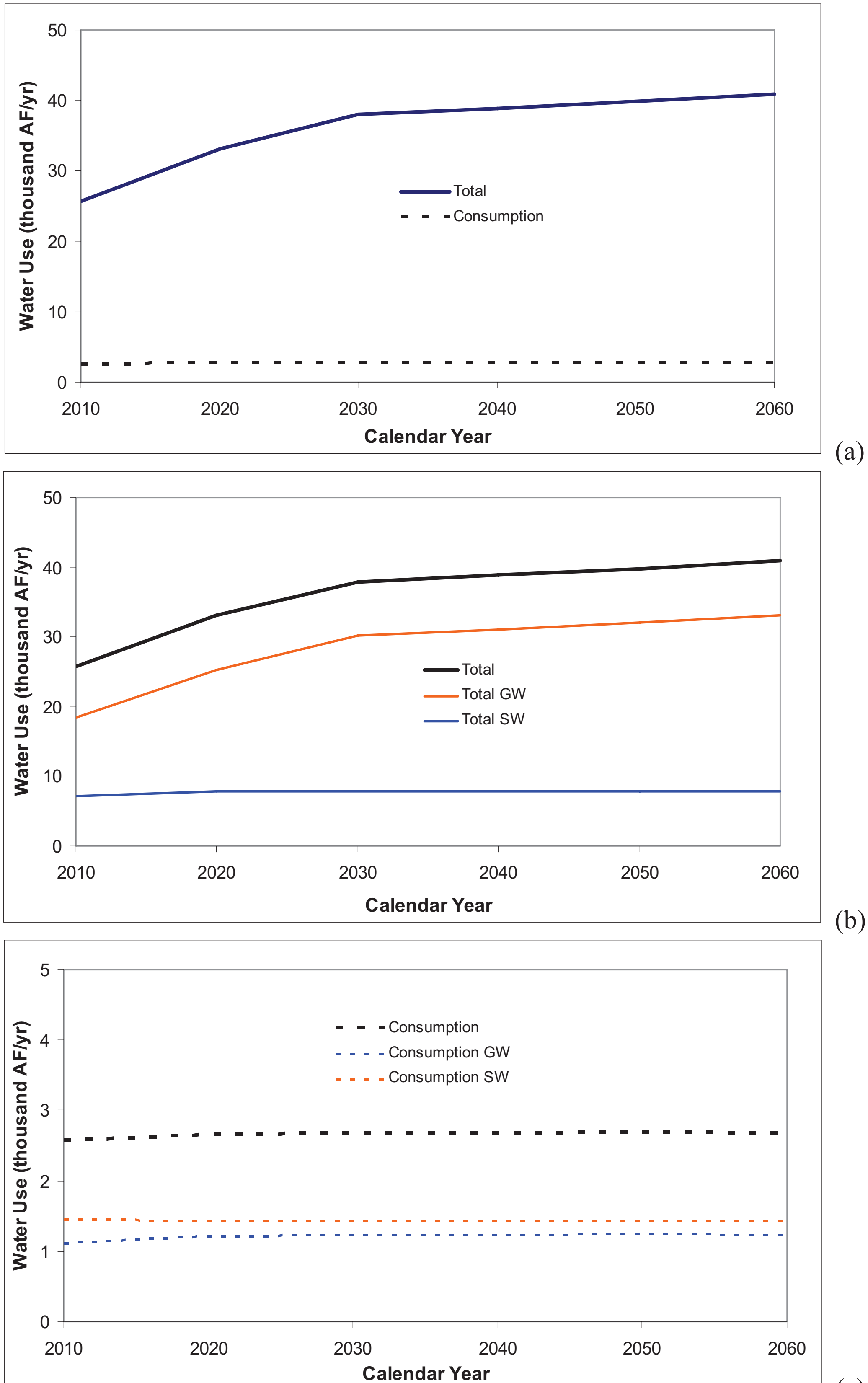
Table 60. Projected lignite-mine water use per county in AF/yr (2010–2060)

		TOTAL PUMPAGE						TOTAL CONSUMPTION					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
Big Brown, ⅓Jewett	Freestone	3,129	3,833	3,000	3,000	3,000	3,000	124	152	135	135	135	135
South Hallsville	Harrison	5,800	6,380	6,380	6,380	6,380	6,380	6	6	6	6	6	6
Monticello Thermo	Hopkins	920	900	900	900	900	900	205	201	201	201	201	201
½Three oaks	Lee	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
⅓Jewett	Leon	667	833	0	0	0	0	13	17	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	694	4,333	3,500	3,500	3,500	3,500	41	87	70	70	70	40
Martin Lake	Panola	982	982	1,500	1,500	1,500	1,500	855	855	855	855	855	855
Calvert, Twin Oak	Robertson	7,436	8,180	8,998	9,897	10,887	11,976	74	82	90	99	109	120
Oak Hill	Rusk	1,265	1,668	1,668	1,668	1,668	1,668	582	582	582	582	582	582
Monticello Winfield	Titus	619	1,000	1,000	1,000	1,000	1,000	619	619	619	619	619	619
TOTAL		**25,689**	**33,110**	**37,946**	**38,845**	**39,835**	**40,924**	**2,562**	**2,650**	**2,668**	**2,677**	**2,687**	**2,668**
		PUMPAGE GROUNDWATER						**CONSUMPTION GROUNDWATER**					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
Big Brown, ⅓Jewett	Freestone	3,129	3,833	3,000	3,000	3,000	3,000	124	152	135	135	135	135
South Hallsville	Harrison	6	6	6	6	6	6	6	6	6	6	6	6
Monticello Thermo	Hopkins	735	719	719	719	719	719	21	20	20	20	20	20
½Three oaks	Lee	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
⅓Jewett	Leon	667	833	0	0	0	0	13	17	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	694	4,333	3,500	3,500	3,500	3,500	41	87	70	70	70	40
Martin Lake	Panola	554	554	1,072	1,072	1,072	1,072	428	428	428	428	428	428
Calvert, Twin Oak	Robertson	7,436	8,180	8,998	9,897	10,887	11,976	74	82	90	99	109	120
Oak Hill	Rusk	741	1,144	1,144	1,144	1,144	1,144	58	58	58	58	58	58
Monticello Winfield	Titus	310	691	691	691	691	691	310	310	310	310	310	310
TOTAL		**18,449**	**25,294**	**30,130**	**31,030**	**32,020**	**33,109**	**1,116**	**1,209**	**1,227**	**1,236**	**1,246**	**1,227**

County+Pop_1-to-All(from Katy)_5.27.10_JP.xls

Table 60. Projected lignite-mine water use per county in AF/yr (2010–2060) (continued)

		PUMPAGE SURFACE WATER						CONSUMPTION SURFACE WATER					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	0	0	0	0	0	0	0	0	0	0	0	0
Big Brown, ⅓Jewett	Freestone	0	0	0	0	0	0	0	0	0	0	0	0
South Hallsville	Harrison	5,794	6,374	6,374	6,374	6,374	6,374	0	0	0	0	0	0
Monticello Thermo	Hopkins	185	181	181	181	181	181	185	181	181	181	181	181
½Three oaks	Lee	0	0	0	0	0	0	0	0	0	0	0	0
⅓Jewett	Leon	0	0	0	0	0	0	0	0	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	0	0	0	0	0	0	0	0	0	0	0	0
Martin Lake	Panola	428	428	428	428	428	428	428	428	428	428	428	428
Calvert, Twin Oak	Robertson	0	0	0	0	0	0	0	0	0	0	0	0
Oak Hill	Rusk	524	524	524	524	524	524	524	524	524	524	524	524
Monticello Winfield	Titus	310	310	310	310	310	310	310	310	310	310	310	310
TOTAL		**7,240**	**7,815**	**7,815**	**7,815**	**7,815**	**7,815**	**1,446**	**1,442**	**1,442**	**1,442**	**1,442**	**1,442**
		PUMPAGE FRESH WATER						**CONSUMPTION FRESH WATER**					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
Big Brown, ⅓Jewett	Freestone	3,095	3,792	3,000	3,000	3,000	3,000	124	152	135	135	135	135
South Hallsville	Harrison	5,800	6,380	6,380	6,380	6,380	6,380	6	6	6	6	6	6
Monticello Thermo	Hopkins	920	900	900	900	900	900	205	201	201	201	201	201
½Three oaks	Lee	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
⅓Jewett	Leon	633	792	0	0	0	0	13	17	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	661	4,292	3,500	3,500	3,500	3,500	41	87	70	70	70	40
Martin Lake	Panola	982	982	1,500	1,500	1,500	1,500	855	855	855	855	855	855
Calvert, Twin Oak	Robertson	7,436	8,180	8,998	9,897	10,887	11,976	74	82	90	99	109	120
Oak Hill	Rusk	1,265	1,668	1,668	1,668	1,668	1,668	582	582	582	582	582	582
Monticello Winfield	Titus	619	1,000	1,000	1,000	1,000	1,000	619	619	619	619	619	619
TOTAL		**25,589**	**32,985**	**37,946**	**38,845**	**39,835**	**40,924**	**2,562**	**2,650**	**2,668**	**2,677**	**2,687**	**2,668**



County+Pop_1-to-All(from Katy)_5.27.10_JP.xls

Figure 121. Projected lignite-mine water use (2010–2060)

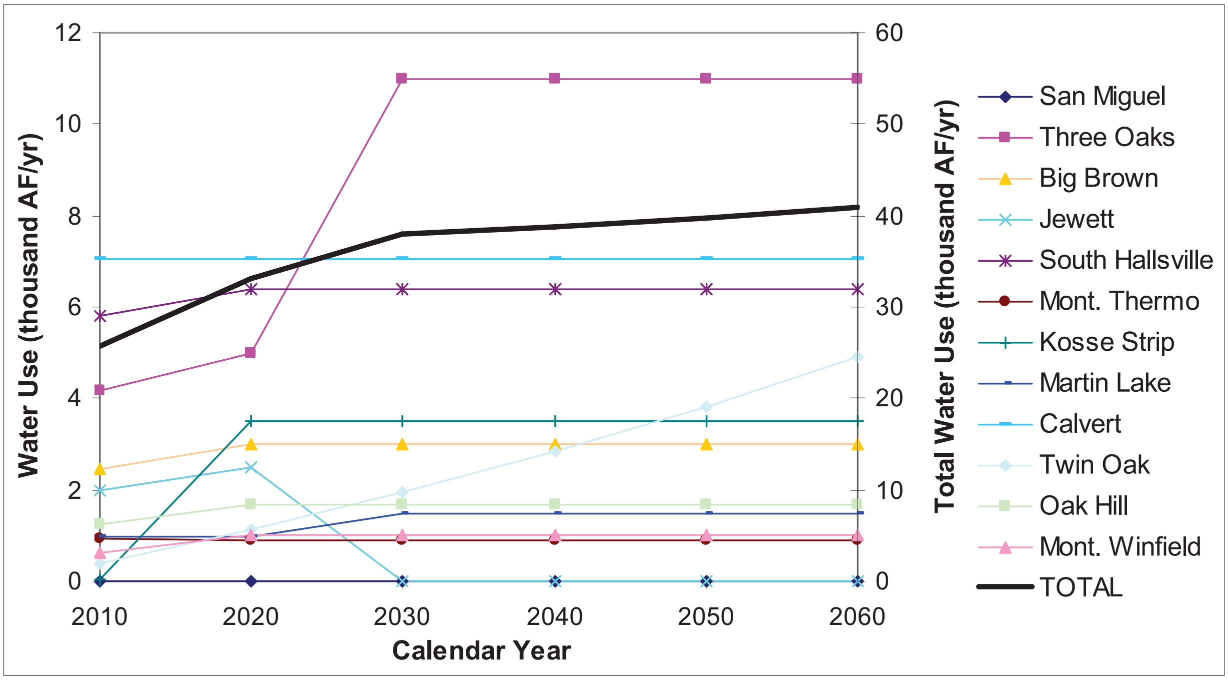


Figure 122. Total water use for each coal-mining facility

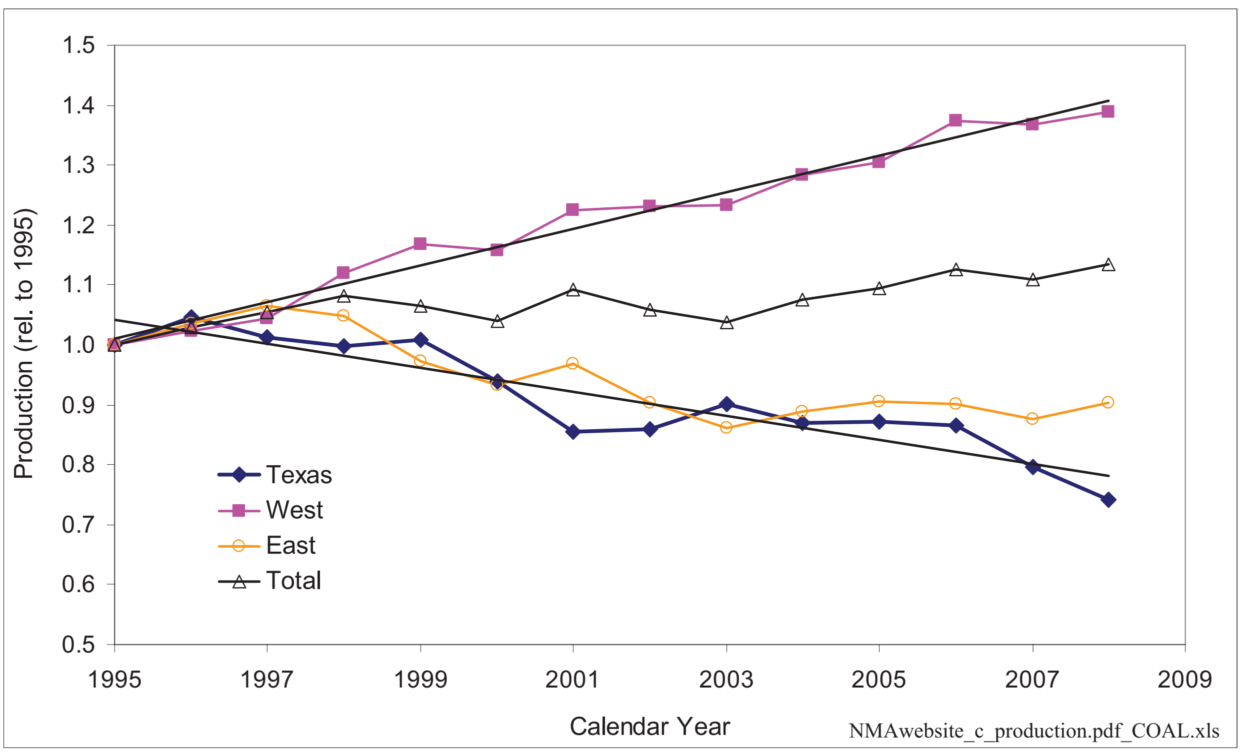


Figure 123. Relative growth of Texas (negative) and western (positive) coal

5.4 Aggregates

Key parameters for future aggregate water use relating population and aggregate production are presented in Table 61, Figure 124, and Figure 125. We assumed that crushed stone and construction sand and gravel will follow a trajectory similar to that of the past 2 decades. The production trajectory considered deviates from strict linear extrapolation of historical data and is somewhat flattened. The increased gap between crushed-stone and sand and gravel operations (Figure 125) is consistent with the societal trend of having large operations at one location for a long period of time, rather than having dispersed generally smaller sand and gravel operations. However, both categories are expected to grow in the future. The overall growth rate is 1.5%–2% (Table 61). Some analysts have projected an annual growth in the industry of 3%–5% (Walden and Baier, 2010). Although industry has been significantly impacted by the current economic recession, it is anticipated that demand for aggregate products will continue to grow with the population and the need for roadway and other building materials. It is not clear, however, how a 3% annual growth (translating into a production of ~1,200 million tons/yr in 2060) can be sustained in terms of water use without increasing water recycling or developing dry processes. The aggregate water use projections presented in this report can therefore be construed as either modest annual growth with no change from current practices or higher annual growth with concomitant decrease in water use. In addition, although most mining facilities are operated for at least 20 years, and although some larger operations have 100 years or more of reserves, small "mom & pop" quarries may be operated for as little as 5 years and are often associated with specific development projects or other short-term, localized demands. This observation carries the understanding that many small facilities could appear in counties not listed in Table 63, which shows sand and gravel water-use projections. Table 62 does the same for crushed stone. Table 64 summarizes projections displayed at the county level in Figure 126 and Figure 127. Overall aggregate will increase from ~50 thousand AF/yr in 2010 to ~100 thousand AF/yr in 2060.

Table 61. Historical and projected population and aggregate production

Year	Crushed Stone (million tons)	Sand and Gravel (million tons)	Population	Average Annual Population Change
1990	55	42	16,986,510	
2000	110	74	20,851,820	386,531
2010	164	105	25,388,403	453,658
2020	198	124	29,650,388	426,199
2030	232	144	33,712,020	406,163
2040	268	165	37,734,422	402,240
2050	307	187	41,924,167	418,975
2060	346	210	46,323,725	439,956

Table 62. Crushed-stone water use projections per county through 2060

County	2008	2010	2020	2030	2040	2050	2060
Bell	0.747	0.803	1.039	1.278	1.460	1.681	1.914
Bexar	3.108	3.341	4.051	4.603	5.038	5.502	6.070
Brown	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Burnet	0.280	0.301	0.384	0.460	0.535	0.598	0.678
Callahan	0.131	0.140	0.141	0.141	0.136	0.133	0.129
Comal	3.634	3.907	4.739	5.473	6.123	6.651	7.378
Cooke	0.818	0.880	1.133	1.349	1.576	1.893	2.181
Coryell	0.275	0.296	0.355	0.397	0.429	0.463	0.505
Eastland	0.150	0.161	0.168	0.178	0.211	0.213	0.225
Ector	0.168	0.181	0.196	0.212	0.218	0.229	0.240
Ellis	2.898	3.115	3.564	4.213	5.047	6.004	6.827
Floyd	0.169	0.182	0.190	0.195	0.202	0.208	0.213
Glasscock	0.095	0.102	0.107	0.112	0.114	0.117	0.121
Hidalgo	0.170	0.183	0.244	0.310	0.364	0.415	0.477
Hutchinson	0.127	0.137	0.152	0.172	0.186	0.193	0.207
Jack	0.238	0.256	0.302	0.322	0.363	0.405	0.450
Johnson	3.091	3.323	3.816	4.479	5.347	6.337	7.197
Kaufman	2.063	2.218	2.492	2.903	3.507	4.263	4.864
Lampasas	0.293	0.314	0.374	0.417	0.449	0.483	0.526
Limestone	0.210	0.226	0.250	0.280	0.294	0.332	0.359
Maverick	0.052	0.056	0.065	0.072	0.077	0.079	0.085
Medina	0.287	0.308	0.360	0.397	0.425	0.453	0.491
Montague	0.104	0.111	0.129	0.150	0.181	0.205	0.232
Nolan	0.023	0.025	0.025	0.025	0.024	0.023	0.022
Oldham	0.165	0.177	0.204	0.244	0.275	0.288	0.315
Parker	0.170	0.183	0.218	0.264	0.318	0.372	0.425
Potter	0.192	0.206	0.235	0.275	0.305	0.318	0.345
Reeves	0.014	0.015	0.016	0.016	0.017	0.018	0.019

County	2008	2010	2020	2030	2040	2050	2060
Sabine	0.053	0.057	0.060	0.063	0.066	0.069	0.072
San Patricio	0.340	0.366	0.419	0.464	0.491	0.510	0.546
Stonewall	0.019	0.021	0.020	0.019	0.019	0.018	0.017
Taylor	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Travis	0.135	0.145	0.188	0.230	0.272	0.310	0.355
Uvalde	0.055	0.059	0.072	0.078	0.081	0.086	0.093
Walker	0.454	0.488	0.660	0.842	1.086	1.337	1.572
Webb	0.226	0.243	0.331	0.435	0.521	0.611	0.710
Williamson	2.273	2.444	3.152	3.796	4.412	5.046	5.750
Wise	1.422	1.529	1.882	2.263	2.685	3.177	3.639
Young	0.035	0.038	0.040	0.043	0.045	0.049	0.052

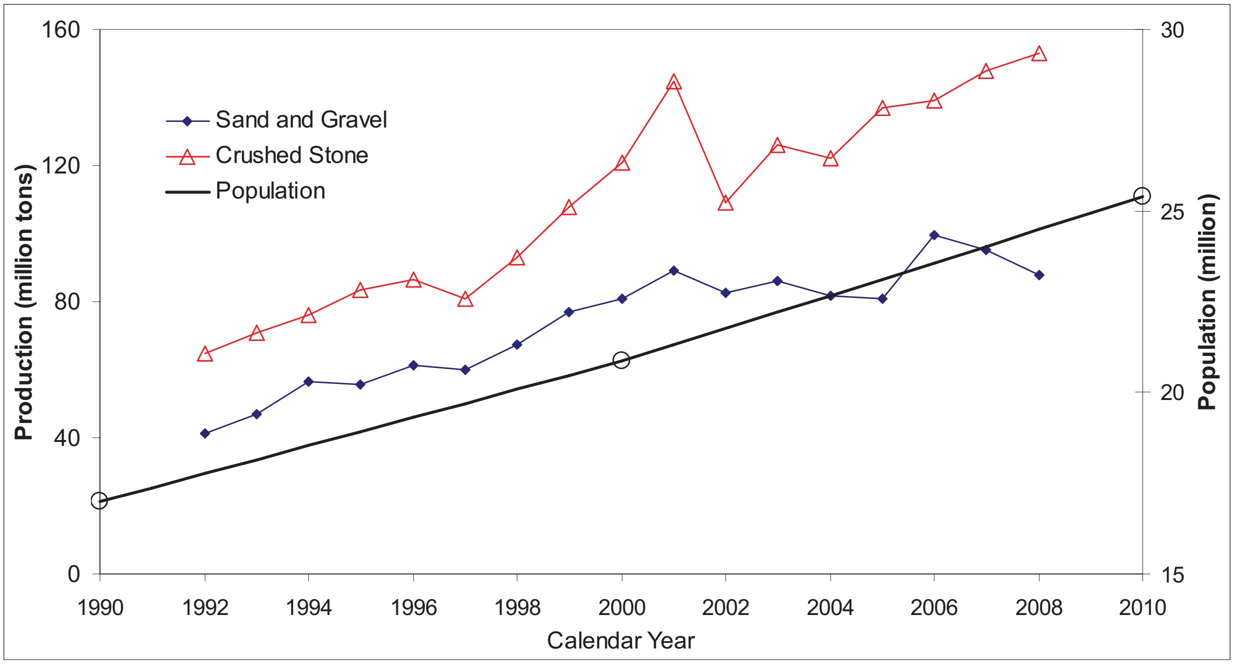
Table 63. Sand and gravel water-use projections per county through 2060

County	2008	2010	2020	2030	2040	2050	2060
Atascosa	0.350	0.420	0.526	0.615	0.698	0.755	0.846
Bastrop	0.063	0.076	0.113	0.162	0.225	0.310	0.387
Bell	0.346	0.415	0.523	0.622	0.710	0.800	0.907
Bexar	1.028	1.233	1.233	1.233	1.233	1.233	1.233
Borden	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Bosque	0.013	0.015	0.018	0.018	0.019	0.021	0.023
Brazoria	0.565	0.678	0.866	1.064	1.289	1.533	1.790
Brazos	0.230	0.276	0.347	0.403	0.495	0.474	0.521
Burnet	0.031	0.037	0.050	0.064	0.079	0.100	0.120
Coke	0.003	0.004	0.004	0.005	0.005	0.006	0.006
Colorado	1.540	1.848	2.033	2.190	2.372	2.440	2.543
Comal	0.099	0.119	0.180	0.242	0.305	0.382	0.464
Cooke	0.026	0.031	0.040	0.048	0.066	0.073	0.085
Dallas	1.574	1.889	1.889	1.889	1.889	1.889	1.889
Denton	1.262	1.514	2.106	2.678	3.332	4.293	5.191
Duval	0.604	0.725	0.796	0.846	0.810	0.748	0.713
El Paso	0.581	0.697	0.880	1.063	1.266	1.482	1.721
Fannin	0.006	0.007	0.011	0.016	0.023	0.027	0.033
Fayette	0.082	0.098	0.123	0.145	0.183	0.241	0.287
Fort Bend	0.000	0.000	0.000	0.000	0.001	0.001	0.001
Galveston	0.282	0.339	0.375	0.402	0.444	0.480	0.514
Grayson	0.041	0.049	0.061	0.073	0.089	0.106	0.125
Guadalupe	0.186	0.224	0.318	0.422	0.541	0.674	0.816
Harris	2.494	2.993	2.993	2.993	2.993	2.993	2.993
Henderson	0.115	0.138	0.181	0.235	0.304	0.395	0.477
Hidalgo	0.603	0.723	1.045	1.444	1.850	2.272	2.750
Hutchinson	0.023	0.027	0.028	0.027	0.026	0.027	0.026

County	2008	2010	2020	2030	2040	2050	2060
Jefferson	0.131	0.157	0.180	0.202	0.230	0.280	0.315
Johnson	0.075	0.090	0.121	0.162	0.214	0.281	0.342
Jones	0.010	0.012	0.013	0.013	0.013	0.013	0.013
Kaufman	0.195	0.234	0.296	0.386	0.491	0.646	0.783
Kerr	0.059	0.071	0.076	0.080	0.100	0.102	0.111
Lampasas	0.012	0.015	0.017	0.019	0.021	0.023	0.025
Liberty	0.108	0.129	0.165	0.206	0.253	0.310	0.365
Lubbock	0.415	0.498	0.554	0.601	0.676	0.745	0.807
McLennan	1.025	1.230	1.444	1.732	1.868	2.228	2.509
Medina	0.063	0.076	0.097	0.117	0.138	0.157	0.180
Montague	0.010	0.012	0.013	0.014	0.015	0.017	0.018
Montgomery	0.028	0.033	0.050	0.071	0.101	0.135	0.167
Navarro	0.062	0.075	0.096	0.123	0.155	0.198	0.236
Nueces	0.445	0.534	0.654	0.780	0.892	0.981	1.104
Oldham	0.002	0.002	0.002	0.001	0.001	0.000	0.000
Orange	0.136	0.163	0.176	0.191	0.220	0.238	0.256
Parker	0.253	0.304	0.393	0.424	0.503	0.580	0.674
Potter	0.308	0.370	0.456	0.583	0.711	0.790	0.909
Reeves	0.008	0.010	0.011	0.013	0.015	0.016	0.018
San Patricio	0.055	0.067	0.086	0.107	0.125	0.144	0.166
Smith	0.106	0.127	0.154	0.184	0.246	0.317	0.376
Somervell	0.386	0.463	0.552	0.613	0.636	0.668	0.715
Starr	0.142	0.170	0.229	0.296	0.357	0.418	0.491
Tarrant	1.093	1.312	1.312	1.312	1.312	1.312	1.312
Travis	0.718	0.862	0.862	0.862	0.862	0.862	0.862
Val Verde	0.031	0.037	0.046	0.054	0.060	0.065	0.072
Victoria	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ward	0.016	0.020	0.022	0.023	0.025	0.028	0.029
Washington	0.018	0.022	0.024	0.026	0.030	0.032	0.035
Webb	0.005	0.006	0.009	0.012	0.016	0.020	0.024
Wise	0.229	0.275	0.345	0.445	0.584	0.734	0.886

Table 64. Summary of aggregate water-use projections

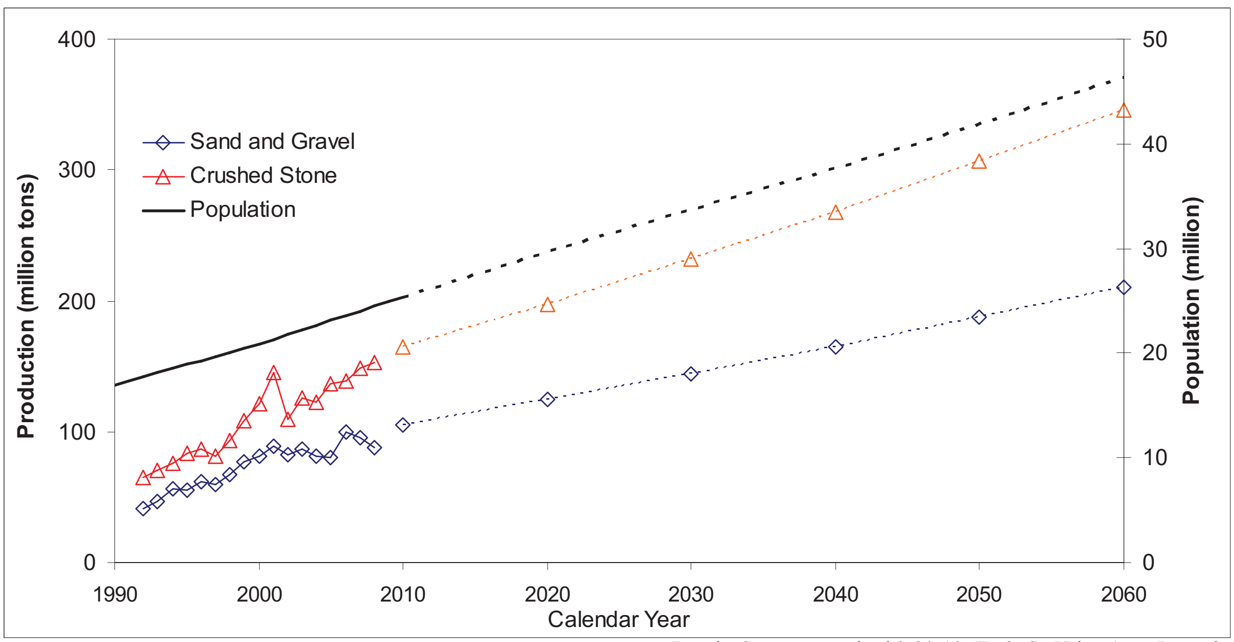
	2010	2020	2030	2040	2050	2060
Water-Use Projection (1000s AF)						
Crushed Stone	26.5	31.8	37.2	42.9	49.1	55.3
Sand and Gravel	22.0	25.2	28.6	32.1	36.1	40.3
Total	48.5	57.0	65.7	75.0	85.2	95.6



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Source: USGS (Aggregate production) and TWDB (population)

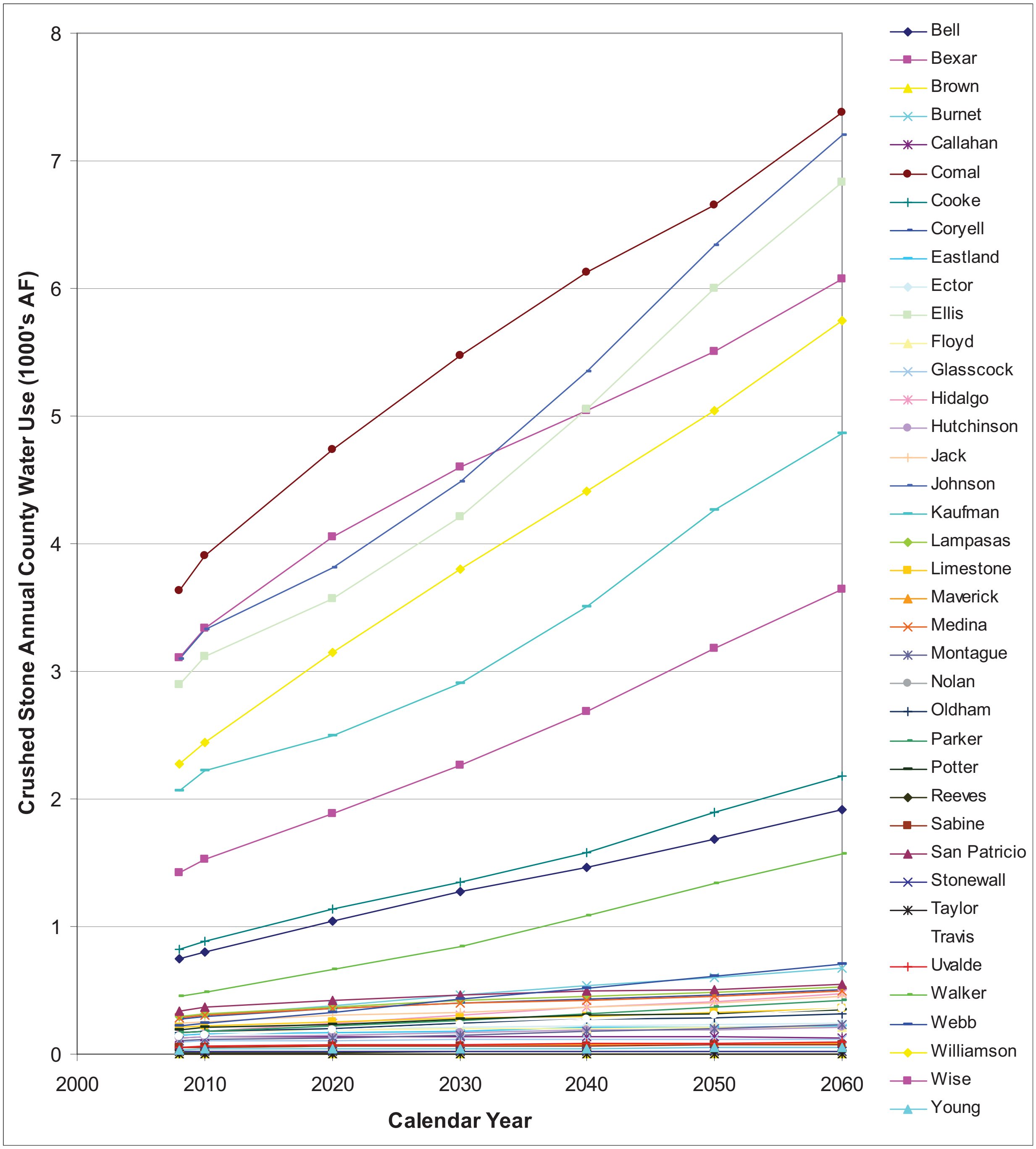
Figure 124. Historical population and aggregate production in Texas



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

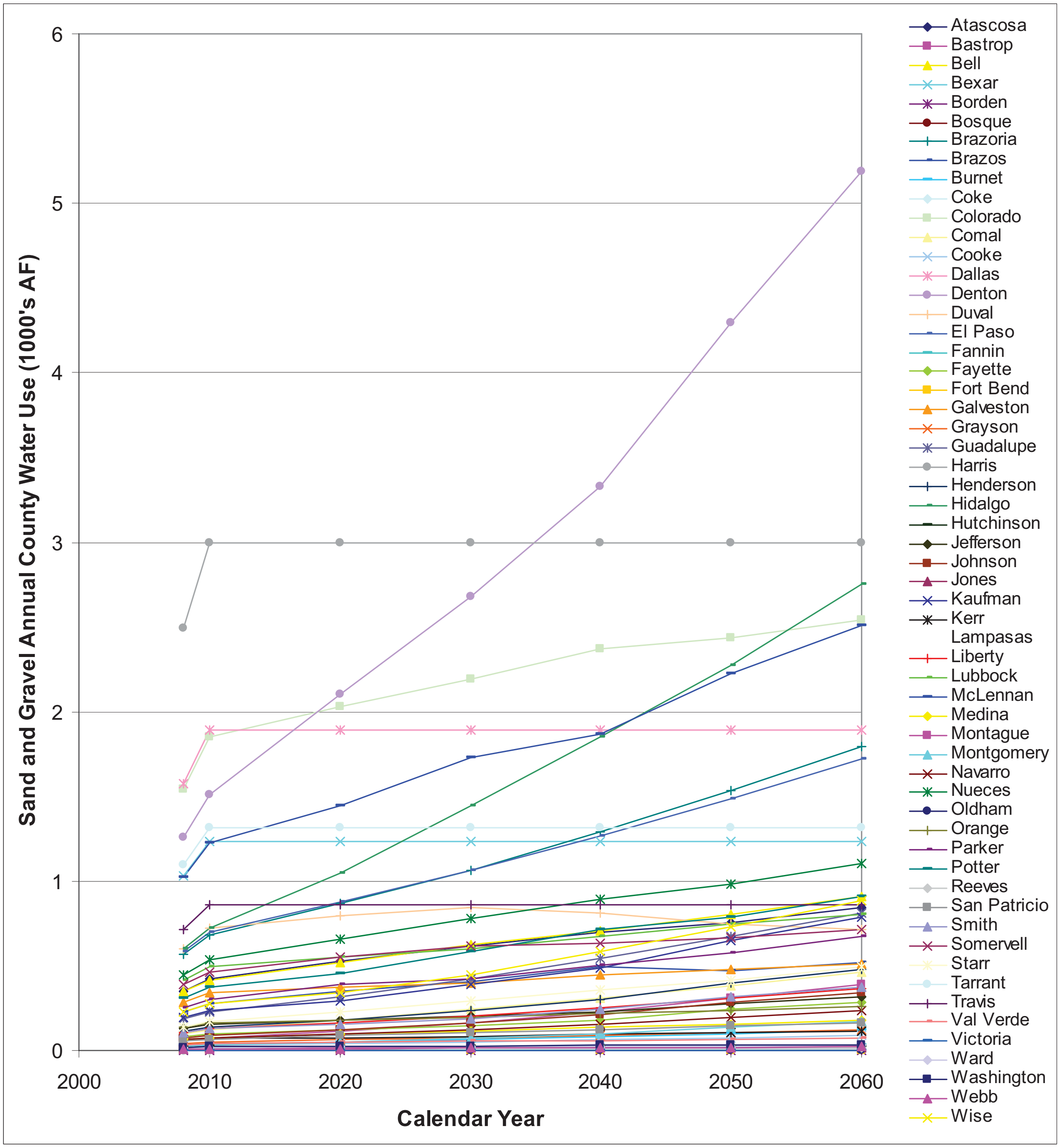
Source: USGS (aggregate production to 2008) and TWDB (population through 2060)

Figure 125. Historical population and projection for population and aggregate production in Texas



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Figure 126. Crushed-stone water-use projections per county through 2060



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Figure 127. Sand and gravel water-use projections per county through 2060

5.5 *Industrial Sand*

As seen in the Current Water Use section, industrial-sand mining is more water intensive than the closely related category of aggregate and consumes almost 10 thousand AF. Industrial-sand production is clearly connected to the increase in well stimulation/fracing through the use of proppants, although proppant sand used in Texas can be imported from out of state and sand produced in Texas exported out of state. There is no doubt that a significant fraction of the locally produced sand is used by the oil and gas industry. Assuming that a proppant loading of 1 lb/gal translates into 0.163 million tons/ thousand AF of frac water, then 35.8 thousand AF (2008 fracing water use) would correspond to 5.8 million tons. This figure is above the current Texas production of 3.58 million short tons in 2008 (Figure 128), suggesting that a significant fraction of the proppant is either not necessarily all natural sand or that it comes from out of state. A close examination of the production plot shows that departure from the background trend can be attributed to use to the oil and gas industry and that 1.5 million tons of industrial sand (only a fraction of the amount needed) was used, along with 38.5 thousand AF, to frac wells in Texas. We then assumed that this proportion stays constant in the next few decades (that is, that local production and imports from out of state grow at the same rate) and applied it to the water-use projections for fracing. We then distributed the results as they were distributed between counties and facilities in the Current Water Use section without incorporating important elements such as mining reserves or proximity to oil and gas plays. We assumed that the water coefficient would linearly improve from the current 620 gal/t to a value of 350 gal/t in 2060. The maximum water use close to 18 thousand AF is projected to be reached in the 2020–2030 decade (Table 65).

5.6 *Other Nonfuel Minerals*

In this section, we extrapolate from figures presented in the Current Water Use section. As we did previously, we neglect water use in the dimension-stone industry. We use extrapolation from current trends for lime and gypsum (Table 66 and Table 67) and expect no change in water use in clay, salt, sodium sulfate, or talc categories.

5.6.1 Uranium

The South Texas uranium province has already produced ~80 million lb U_3O_8. In 2003, EIA (2010) projected that 27 million lb U_3O_8 at 0.089% U_3O_8 on average and 40 million lb U_3O_8 at ~0.062% U_3O_8 on average remained in the ground in Texas, for a market price of \$50 and \$100/lb U_3O_8, respectively. As of January 2011, market price hovered at ~\$60/lb. These reserves are, however, dwarfed by reserves in the western states (Wyoming, New Mexico, Arizona, Colorado, Utah), with 462 and 1,034 million lbs U_3O_8, for the same price cutoffs of \$50 and \$100/lb, respectively. In addition to the three counties with permits active in 2010 (Brooks, Duval, Kleberg), a sixth permit is pending at TCEQ in Goliad County; it has generated vigorous public participation. The RRC website lists exploration permits as of January 2011 in nine counties: Atascosa, Bee, Brooks, Duval, Goliad, Jim Hogg, Karnes, Kleberg, and Live Oak (and an additional permit in Briscoe County in the Texas Panhandle), to which can be added DeWitt, Jim Wells, McMullen, and Webb Counties (Figure 129). However, we assumed no change in current water use or of its distribution.

5.6.2 Other Metallic Minerals

On the basis of decades-long evaluation and development activities, three deposits seem to have potential for near-term mining: (1) Shafter silver deposit, Presidio County; (2) Round Top beryllium-uranium-rare earth element deposit, Hudspeth County; and (3) Cave Peak molybdenum deposit, Culberson County.

5.6.2.1 Shafter Deposit

The Shafter deposit in Presidio County, 18 miles north of the Rio Grande, is the closest to actual production (http://www.aurcana.com/s/NewsReleases.asp?ReportID=439022), as plans for silver production by mid-2012 have been announced. This deposit is the downdip extension of the ore zone of the Presidio silver mine that was in production from 1883 until the early 1940s. The planned silver production follows a decade of activity by several predecessor companies, all building on an extensive exploration and limited development program in the late 1970s and early 1980s. The designed production rate for this underground mine is 1500 tons of ore per day, with measured and indicated reserves for more than 5 years of production, and additional resources for an additional 5 years of production, given favorable economic conditions. Burgess (2010) provided a detailed feasibility study for the Shafter mine, including plans for water management as: "*Two distinct phases in the water management plan are envisaged. The first phase will involve mining operations performed above the water table with no ground water being produced from this activity. During this phase, mining operations will be a small net consumer of water in the form of drill water and dust control water. Process plant make-up water will be obtained from the old underground workings in Block 1 which lie below the water table and are flooded with an estimated 20 million gallons of water. These old workings are recharged from a deep aquifer at a rate of 350 gpm, this figured being based on the inflows observed by Gold Fields when they were developing Block 1 in the early 1980's. During this first phase of operations, no excess water will be generated as only the net requirements of the process plant and the underground workings will be drawn from the old workings of Block 1.*" and "*The second phase is when the decline face encounters the water table at approximately 900 Level, prior to which the 20 million gallons of water standing in the test mine in Block 1 will be pumped out through the Gold Fields shaft. By dewatering the Goldfields Shaft and Block 1 test mine in this manner, the water table will be lowered in advance of the decline face to reduce the amount of ground water encountered. The second phase also entails mining operations simultaneously occurring above the water table in Blocks 2 to 5. Mining Block 1 entails removing standing water (estimated at 20 million gallons) and groundwater inflows. This phase will produce a net excess of water of 350 gpm from ground water flowing into the underground mine which will be clarified in underground settling sumps to reach compliance with EPA criteria and then disposed of by discharge to the environment in a dry creek at the south west corner of the property (Arroyo del Muerto).*"

The Shafter ore zone is below the water table, so dewatering of the ore zone prior to and during production will more than account for any water used in mining per se. Furthermore, a considerable excess of water required for all of the Shafter operation will be produced. For the stated rate of ore production for the 5-year period, Burgess' s analysis indicates that total water used by the operation will average 104 AF per year, of which less than 20 AF per year will be used in mining and surface use around the mine. Source water derived from pumping of the ore zone will average 565 AF per year for the designed ore production rate of 1500 tons per day (even accounting for a nominal 10% ore dilution and development headings). Thus, **excess water production for the five-year period will average more than 500 AF per year (groundwater)**. If the current silver resources prove economically viable to extend production beyond the initial five-year period, there is little reason to doubt that these relative figures would also apply to that extended amount and period of production.

5.6.2.2 Round Top Deposit

The Round Top beryllium-uranium-rare earth element deposit near Sierra Blanca in Hudspeth County is currently being reevaluated (http://www.standardsilvercorp.com/projects/round-top/), building on an extensive exploration program for beryllium in the 1980s (Rubin et al., 1990). The impetus for Round Top exploration has been boosted by the current emphasis on developing domestic REE sources to counter restricted supply from foreign sources, notably China. Although the mineralization controls at Round Top are only broadly understood, it is worth noting that this geologic environment is represented throughout a considerable portion of west Texas, suggesting regional potential for additional deposits. However, at this point, production even from the Round Top deposit would be hypothetical, and thus water needs are not possible to constrain.

5.6.2.3 Cave Peak Deposit

The molybdenum and associated metals deposit at Cave Peak in Culberson County has an exploration history also dating to the 1960s (Sharp, 1979). Following a considerable period of inactivity, the Cave Peak property has recently attracted renewed interest (http://www.quaterraresources.com/projects/cave_peak/). While geologically similar molybdenum deposits are sites of significant mining operations in other states, it is too early in the evaluation process to determine if Cave Peak represents an economically viable resource, let alone assess any potential water needs and impacts.

5.6.3 Conclusions

Uranium solution mining is likely to continue in Texas but a large increase in production and water use is not expected because of the competition of other deposits in the U.S. and elsewhere.

The planned Shafter mine has a life-expectancy in the decade range (currently 2012-2022), so barring discovery of substantial new resources locally, its water use (actually the mine's local supply of excess water) would not have a long term impact on regional water issues. Should any of the other metallic and industrial mineral deposits prove economically viable even at modest mining rates, even though the total water consumption likely would be relatively small, there could be significant impacts on local (ground)water supplies in the arid west Texas region.

Although Frasch sulfur is not produced anymore in Texas, sulfur remains a widely used industrial chemical, notably in the production of agricultural fertilizers, but the domestic and global sulfur supply currently is dominated by "nondiscretionary" sulfur recovery from refineries of sour crude oil and natural gas and from metal refineries as mandated by the Clean Air Act. Thus, it seems unlikely that Frasch sulfur production will ever return to economic viability in Texas, but should it do so, it could affect local water demand, particularly in west Texas. There are additional metal resources, namely zinc, lead, and silver, in association with some salt dome cap rocks that could represent a hypothetical mining activity over an extended timeframe (Kyle, 1999).

Table 65. Projected county-level industrial-sand water consumption

County	2008	2020	2030	2040	2050	2060
Atascosa	0.43	0.79	0.72	0.54	0.44	0.35
Colorado	0.43	0.79	0.72	0.54	0.44	0.35
Dallas	0.04	0.07	0.07	0.05	0.04	0.03
El Paso	0.04	0.07	0.07	0.05	0.04	0.03
Guadalupe	0.07	0.13	0.12	0.09	0.07	0.06
Harris	0.14	0.26	0.24	0.18	0.14	0.12
Hood	0.43	0.79	0.72	0.54	0.44	0.35
Hunt	0.07	0.13	0.12	0.09	0.07	0.06
Johnson	0.04	0.07	0.07	0.05	0.04	0.03
Liberty	0.14	0.26	0.24	0.18	0.14	0.12
Limestone	1.30	2.37	2.18	1.64	1.32	1.07
Mason	0.56	1.02	0.94	0.71	0.57	0.46
McCulloch	4.21	7.69	7.07	5.32	4.27	3.46
Montgomery	0.76	1.39	1.28	0.96	0.77	0.62
Newton	0.14	0.26	0.24	0.18	0.14	0.12
Orange	0.07	0.13	0.12	0.09	0.07	0.06
Robertson	0.04	0.07	0.07	0.05	0.04	0.03
San Saba	0.28	0.51	0.47	0.35	0.28	0.23
Smith	0.07	0.13	0.12	0.09	0.07	0.06
Somervell	0.14	0.26	0.24	0.18	0.14	0.12
Tarrant	0.21	0.38	0.35	0.27	0.21	0.17
Wise	0.07	0.13	0.12	0.09	0.07	0.06
Total	**9.68**	**17.68**	**16.26**	**12.24**	**9.82**	**7.95**

Table 66. Projected county-level lime-mining water consumption (AF)

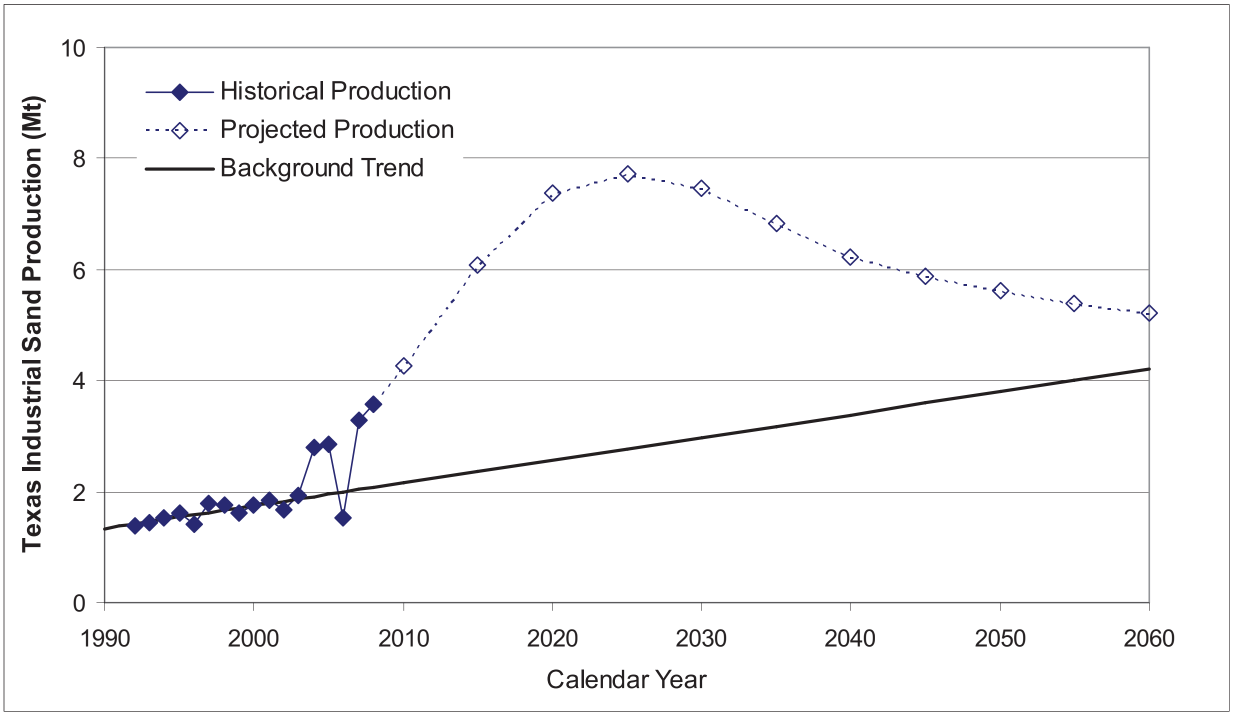
	2008	2020	2030	2040	2050	2060
Bosque	8.5	11.3	12.7	14.1	15.4	16.8
Burnet	2.8	3.7	4.1	4.5	5.0	5.4
Comal	6.6	8.7	9.8	10.8	11.9	12.9
Johnson	13.1	17.4	19.5	21.7	23.8	25.9
Travis	15.1	20.0	22.5	24.9	27.3	29.8
(AF)	**46**	**61**	**69**	**76**	**83**	**91**

Lime_count.xls

Table 67. Projected county-level gypsum-mining water consumption (AF)

	2008	2020	2030	2040	2050	2060
Fisher	3.3	4.0	4.0	4.0	4.0	4.0
Gillespie	3.3	4.0	4.0	4.0	4.0	4.0
Hardeman	6.6	8.0	8.0	8.0	8.0	8.0
Kimble	1.5	1.8	1.8	1.8	1.8	1.8
Nolan	14.8	17.8	17.8	17.8	17.8	17.8
Stonewall	1.2	1.4	1.4	1.4	1.4	1.4
Wheeler	1.2	1.4	1.4	1.4	1.4	1.4
(AF)	**32**	**38**	**38**	**38**	**38**	**38**

Gypsum_count.xls



IndustrialSand_count.xls

Figure 128. Projection of industrial-sand production

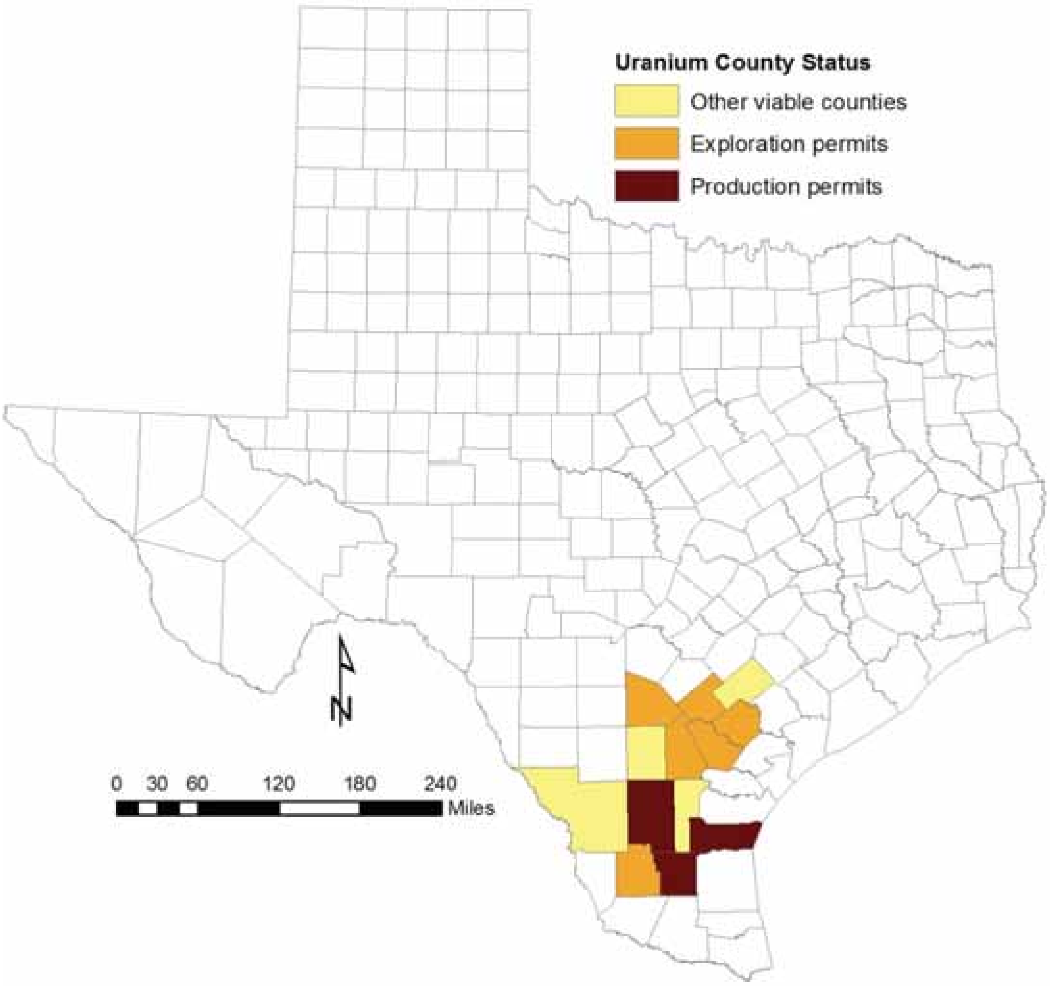


Figure 129. Counties prospective for uranium mining as of 2010

5.7 *Water Use for Speculative Resources*

Given that these resources are fairly speculative at this point and that even order-of-magnitude projections are impossible, their water use was not included in the projections. Information is provided, however, to alert stakeholders that it may be an option in the future when market conditions are favorable.

5.7.1 Heavy Oil

Large resources exist across the country and North America (for example, Veil and Puder, 2006; Veil and Quinn, 2008). Texas contains perhaps the largest heavy oil/tar sands reserves in the U.S after Utah. Heavy oil is generally defined as having an API density of between 10º and 20º. Below 10º API, the term *tar* (or *bitumen*) is generally used. Tar sands (called *oil sands* in Canada) of interest are San Miguel D and Anacacho of Cretaceous age in mostly Kinney, Maverick, Medina, Ulvalde, and Zavala Counties in the Maverick Basin. Asphaltic material (residue that occurs where a reservoir crops out after evaporation of the volatile or after water washing such as a reservoir subject to shallow groundwater systems) is still being produced in quarries operated by Vulcan Materials and by Martin-Marietta (Ewing, 2009, p. 27). Seni and Walter (1993) also mentioned heavy-oil deposits of Eocene age along the South Texas Gulf Coast (whether these accumulations have been or are currently produced through conventional means is unclear). Reserves of at least 3 Bbbl are reported (4.8 Bbbl in Kuuskraa et al., 1987), but they could be as high as 10 Bbbl (Ewing, 2009, p. 17). The *Oil&Gas Journal* (Moritis, 2010) claimed 7–10 Bbbl of OOIP. Heavy-oil deposits are different from oil shales, in which oil has not left the source rock and may still be in the form of kerogen, the chemical precursor to oil.

A typical production method consists of elevating the temperature of the deposits to lower the viscosity of the oil and allow it to flow to the production wells, which is done through steam injection or in situ combustion. Steam injection is used if the heavy oil is not too deep (<3,000 ft) because of heat loss along the well bores. Deposits, if shallow, can also simply be mined in open pits (as is done in Canada) and processed using steam. Stang and Soni (1984) mentioned a steam:oil ratio of 10.9 and 8.2 on two 1+-year-long test sites. U.S. DOE (ca. 2007) described the <3 ratio of Canada tar sands as being particularly favorable. Veil and Quinn (2008, p. 47) mentioned a ratio of 9 bbl/bbl for the Chevron operations in Kern River field in California, about half of the water being recycled. They also discussed other field-water use, ranging from 2 to 12 bbl/bbl. Figures in Torrey (1967, Table 6) projecting water use for the whole state of Texas suggest an average ratio of 3.9 bbl/bbl (for an oil production of ~2.7 Bbbl). The *Oil&Gas Journal* (Koottungal, 2010) reported that a steam flood is operating in Anderson County, although it is unclear what the target of the flood is. In a hypothetical case that 50% of the resource is recoverable (Tyler, 1984, p. 147; Stang and Soni, 1984), recovered solely through steam injection, and that it will be exhausted in 50 years, this scenario could be represented as 5×10^9 bbl /2 /50 yr × 5 bbl/bbl × 42 gal/bbl /325,851 gal/AF/1,000 = 32 thousand AF/yr, that is, 16 thousand AF/yr with a recycling of 50%. This amount does not include potentially needed dewatering of the shallow aquifers. Other much smaller deposits also exist across the state (Tyler, 1984), but their potential production contribution is dwarfed by the uncertainty of the South Texas deposits.

Cyclic interest (20–30 year cycle?) in these resources generally occurs when the price is oil is reasonably high—as it is currently (new tests were very recently performed) and as it was in the early 1980s. In the 1960s, although oil prices were stable, Texas underwent a steady growth in field development as well, interrupted by the 1971 RRC decision to lift the production limit (Nicot, 2009b).

5.7.2 Enhanced Coalbed Methane Recovery

Coalbed methane (CBM) is generally produced by depressurization (that is, water production) of the formation that the coal seams are part of. A drop in pressure releases some of the methane sorbed to the coal matrix. PGC (2010, Table 91 and p. 359) mentioned a figure of 3.4 Tcf of gas in the speculative category (compared with 156.2 Tcf in the combined probable, possible, and speculative categories) for Texas and Louisiana Gulf Coast Pliocene-Eocene lignites. These figures are not entirely accurate at present because CBM is currently produced from Louisiana coal (Echols, 2001; Clayton and Warwick, 2006; Foss, 2009), although they do underline the small potential. Louisiana and East Texas Wilcox coal seams have a low dip, resulting in a large economical surface footprint whereas Central Texas Wilcox has a steeper dip resulting in a smaller potential for economic production (P. Warwick, USGS, personal communication, 2010); that is, coal plunges quickly beyond economical depth. The coal may have been charged through local bioprocesses (MacIntosh et al., 2010) or by thermogenic gas migrating from deeper in the basin (Arciniegas, 2006; McVay et al., 2007). How much of that water required being extracted would be fresh, brackish, or saline is unclear.

In addition, a company has apparently successfully tested the gas potential of Olmos coals in the Maverick Basin (San Filipo, 1999; PGC, 2010, p. 359). PGC (2010, p. 360) pointed out that, despite the presence of Pennsylvanian-Permian coal, the Fort Worth/Strawn Basins do not seem to contain potentially recoverable resources, in disagreement with an interpretation by Hackley et al. (2009b).

5.7.3 Coal to Liquid

The production of coal and, thus, water through dewatering, may also be affected by an increasing interest in coal-to-liquids (or coal liquefaction) technologies (CTL). CTL involves the conversion of solid coal through direct or indirect coal liquefaction into liquid fuels and chemicals by breaking down coal’s molecular structure and adding hydrogen. Whereas no known pilot plants exist in Texas (one is planned in Natchez, Mississippi), future interest in the possibility of creating liquid fuel from lignite may increase coal production in the long term. Because lignite is cheap and abundant within Texas, its practical application is for mine-of-mouth operations. There are, therefore, no transportation costs, offsetting the cost of burning lower grade coal, a more dependable and local source of fuel. However, the need for liquid fuels to compete with oil and natural gas may increase the possibility that coal will be used for CTL production. A discussion of the implications, management strategies, and obstacles facing CTL production will provide insight into its application as a liquid fuel rather than a source of electricity.

Because the need for a nearby abundant water supply can be a problem for many CTL plants, it would be logical to mine lignite where depressurization is needed, that is, the Wilcox lignite of Central Texas. An estimate comes to ~5 to 8 bbl of water per barrel of CTL (this is, manufacturing water use) (Hebel, 2010, Chapter 3). An average of 1.5 to 1.8 bbl of CTL is produced per ton of coal. Full-scale CTL plants are expected to operate at 30,000 to 80,000 bpd. At the low end, a plant would consume ~6.5 million tons of coal per year (Hebel, 2010, Chapter 4), as well as 8.5 thousand AF/yr of water. The ability to use the water pumped from depressurization and dewatering needs of a coal mine would enhance the sustainability of a CTL plant by not putting additional pressure on the groundwater resources. Also, it is likely that a CTL would need deep water wells as the nearby coal-mine operations draw down the aquifer, which increases the amount of energy needed to pump the water. Overall, start of coal-to-liquid operations will increase coal mining and water use in both manufacturing and mining sectors.

5.8 Conclusions and Synthesis for Future Water Use

Combining all water uses, projections suggest that peak mining-water use will occur in the 2020–2030 decade at ~250 thousand AF, sustained by oil and gas activities (Figure 130). Hydraulic fracturing represents the most significant fraction of oil and gas mining use (Figure 131). Percentages of oil and gas water use currently below 50% of total water use, would reach its largest fraction at 50+% in 2015–2030. Fracing is dominant in that use (Figure 132). Eventually oil and gas water use will be slowly taken over by aggregate-water use, which is projected to constitute >50% of total mining-water use by 2050 (Figure 133).

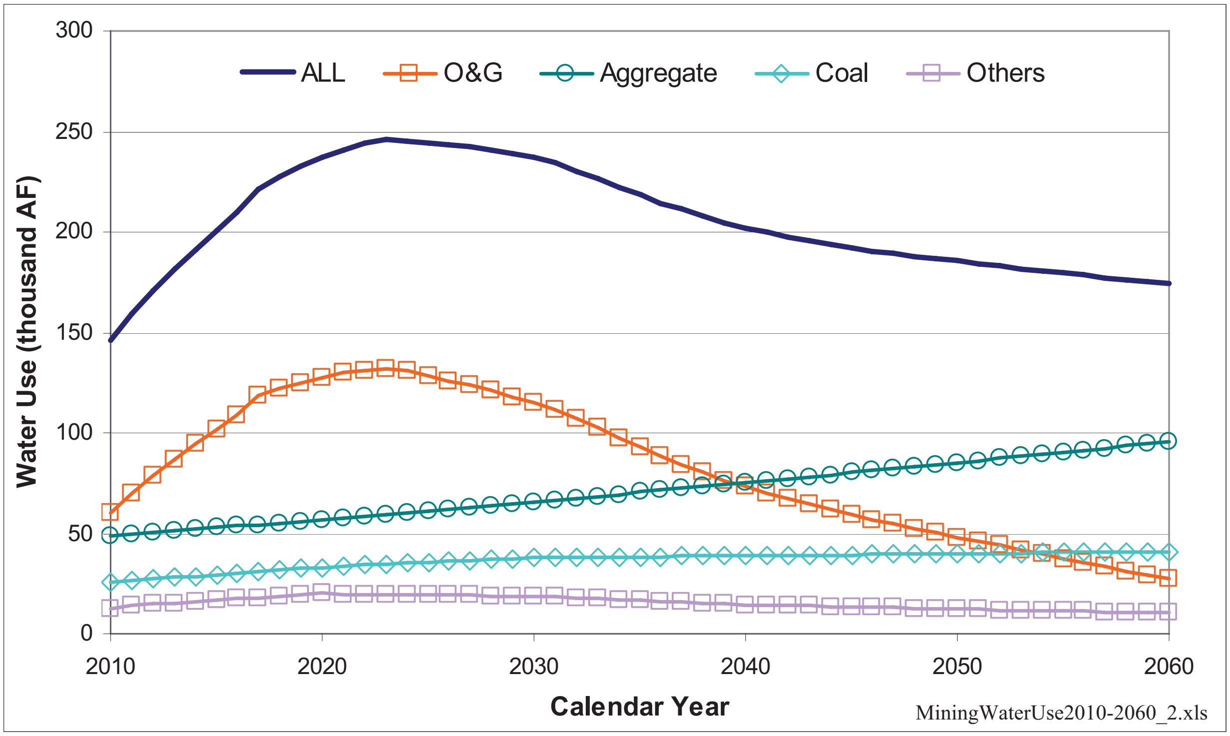


Figure 130. Summary of projected water use by mining-industry segment (2010–2060)

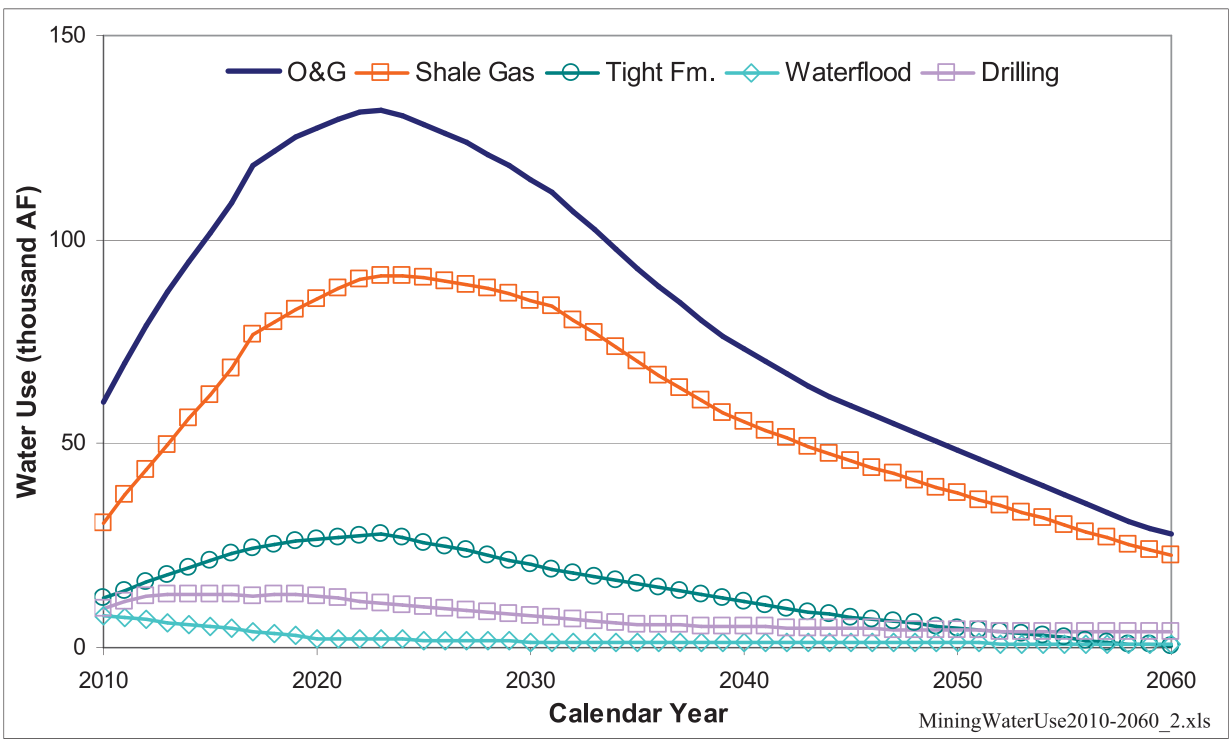


Figure 131. Summary of projected water use in the oil and gas segment (2010–2060)

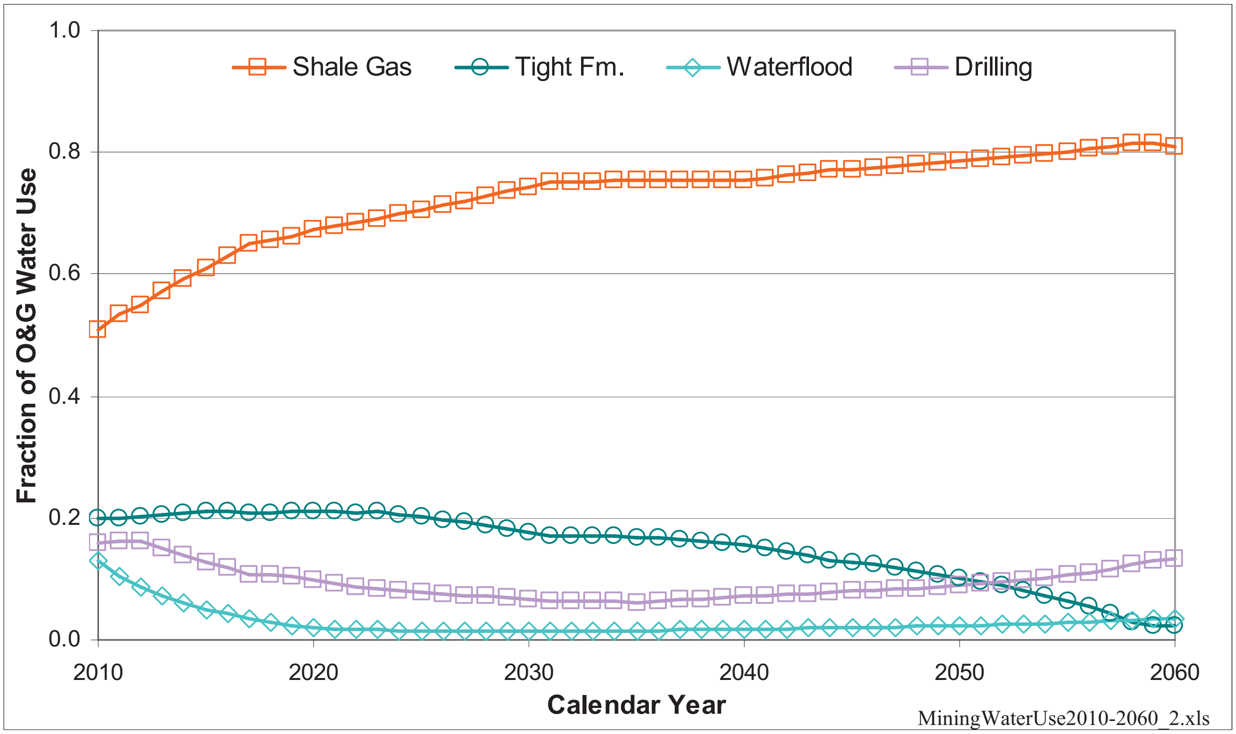


Figure 132. Summary of relative fraction of projected water in the oil and gas segment (2010–2060)

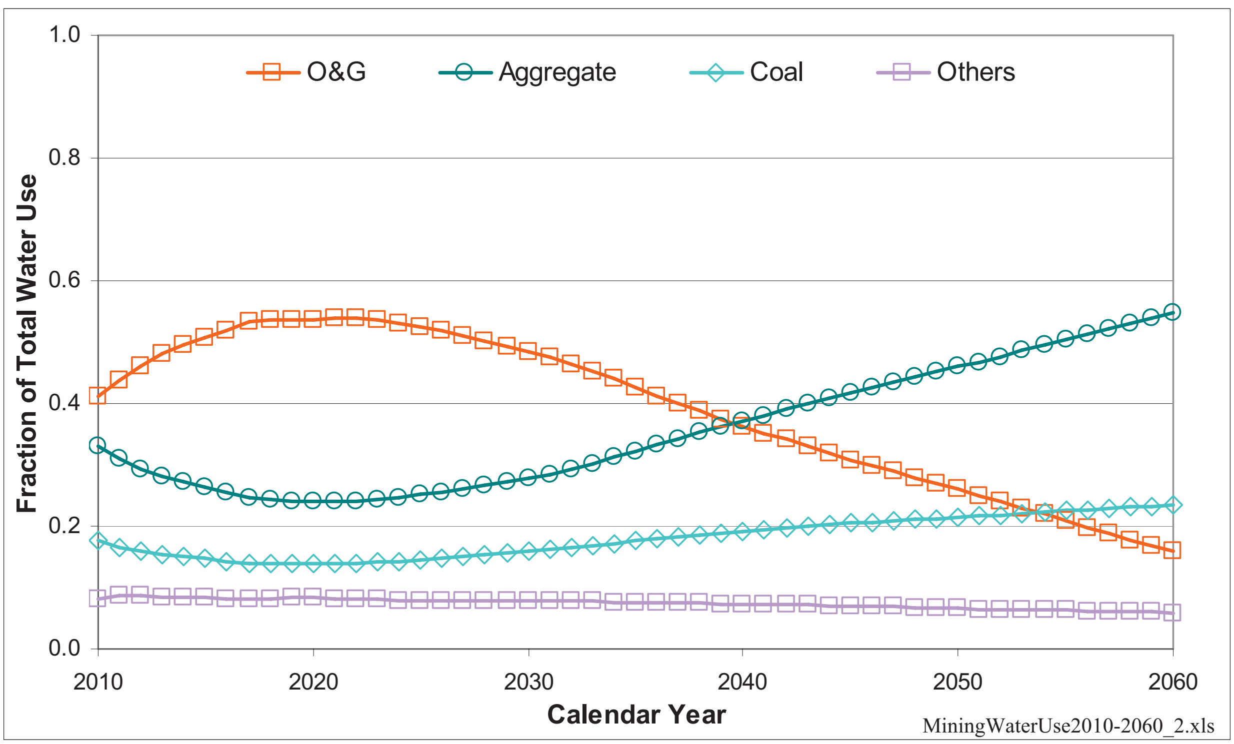


Figure 133. Summary of relative fraction of projected water use by mining-industry segment (2010–2060)

6 Conclusions and Recommendations

This study was undertaken to help in constraining water use in the mining industry. Overall in 2008, the industry as a whole consumed ~140 thousand AF of fresh water. The uncertainty associated with this value is relatively high as only figures from the coal industry (26.7 thousand AF) are well known because of legal requirements. Water usage for fracing in the oil and gas industry is also relatively well-constrained (35.8 thousand AF) because reported to the RRC with other parameters gathered during well completion. Other water uses in the oil and gas industry such as for drilling and waterfloods (21 thousand AF) are known by about a factor 2. Fresh water use for aggregate and similar commodities (lime, industrial sand, etc) production are not well-known and rely on educated guesses supported by limited survey results. We also estimate that fresh-water use is known by about a factor 2 for sand and gravel operations and maybe by a factor of 1.5 for generally larger crushed stone and industrial sand operations. Water use from some large facilities or some small contributors (uranium, metallic substances) are well documented but they make up only a small fraction of the total state water use. Applying those uncertainty factors implies that the true water use is within the 105-195 thousand AF range but those bounds are much less likely than the value of ~140 thousand AF derived in this document (Figure 134). Table 68 presents year 2008 overall water use results at the county leve. Clearly the uncertainty increases as the area of interest decreases in size, particularly if it contains unaccounted-for aggregate facilities or if the facility size has been overestimated. Comparison between published TWDB estimates and results of this work (Figure 135) shows that, by selecting the top 20 high water user counties in the mining category, only 10 of them overlapped.

County-level projections for the 2010-2060 period are given in Table 69. They suggest that peak mining-water use will occur in the 2020–2030 decade at ~250 thousand AF, decreasing to ~175 thousand AF by 2060. Many assumptions went into the building of the projections, in particular related to the activities of the oil and gas industry. Water use for those counties in which a large component of the mining water use is from shale gas fracing or those counties overlying currently little-known (mostly deep) oil or gas accumulations can deviate dramatically from the projections owing to political/legal and economic factors. Water use projections could be improved if the starting point, current water use, was better known.

This study emphasized the difficulties in gathering information on water use and the disappointing limitations of voluntary surveys, in particular whether the surveyed entities are representative of their respective mining segment as a whole. In other words, our survey sampling is likely biased. The low response rate may reflect the general reluctance of the mining industry to provide competitively sensitive information that is not required or to divert staff resources to obtain and submit data that is not routinely kept for business purposes.

Continuing to work with trade associations and expanding that cooperation to include other organizations appears to be necessary and appropriate to improve data collection. Lessons learned from this study can be used to develop refined, focused data collection, designed in consultation with a small workgroup of mining-industry representatives and related agencies and organizations, to effectively ground-truth water use/consumption and production assumptions in the industry and to calculate water-use coefficients on the basis of an acceptable, reproducible methodology. A useful alternative approach would be to make use of the recent progress in analyzing satellite imagery (in particular through time) to complement/confirm data obtained through surveys.

Table 68. County-level summary of mining water use (oil and gas drilling not included)

County	Mining Water Use (AF)	County	Mining Water Use (AF)	County	Mining Water Use (AF)
Anderson	13	Gillespie	3	Moore	1
Andrews	684	Glasscock	346	Morris	0
Angelina	90	Goliad	9	Motley	4
Aransas	0	Gonzales	0	Nacogdoches	384
Archer	7	Gray	24	Navarro	70
Armstrong	0	Grayson	43	Newton	141
Atascosa	781	Gregg	128	Nolan	112
Austin	0	Grimes	0	Nueces	453
Bailey	0	Guadalupe	256	Ochiltree	77
Bandera	0	Hale	109	Oldham	171
Bastrop	2,152	Hall	0	Orange	206
Baylor	0	Hamilton	0	Palo Pinto	235
Bee	6	Hansford	4	Panola	1,926
Bell	1,093	Hardeman	7	Parker	2,191
Bexar	4,136	Hardin	1	Parmer	0
Blanco	0	Harris	3,169	Pecos	238
Borden	126	Harrison	6,673	Polk	0
Bosque	21	Hartley	3	Potter	501
Bowie	0	Haskell	31	Presidio	0
Brazoria	568	Hays	0	Rains	0
Brazos	239	Hemphill	721	Randall	0
Brewster	0	Henderson	143	Reagan	460
Briscoe	0	Hidalgo	847	Real	2
Brooks	295	Hill	1,137	Red River	1
Brown	8	Hockley	1,881	Reeves	153
Burleson	34	Hood	2,584	Refugio	0
Burnet	314	Hopkins	935	Roberts	216
Caldwell	0	Houston	13	Robertson	7,684
Calhoun	3	Howard	56	Rockwall	0
Callahan	160	Hudspeth	0	Runnels	27
Cameron	0	Hunt	70	Rusk	1,836
Camp	4	Hutchinson	156	Sabine	53
Carson	1	Irion	105	San Augustine	88
Cass	0	Jack	323	San Jacinto	0
Castro	0	Jackson	4	San Patricio	398
Chambers	0	Jasper	0	San Saba	280
Cherokee	120	Jeff Davis	0	Schleicher	16
Childress	0	Jefferson	131	Scurry	39
Clay	22	Jim Hogg	2	Shackelford	75
Cochran	390	Jim Wells	0	Shelby	0
Coke	37	Johnson	11,678	Sherman	3
Coleman	35	Jones	51	Smith	235
Collin	0	Karnes	0	Somervell	697
Collingsworth	0	Kaufman	2,258	Starr	209

County	Mining Water Use (AF)	County	Mining Water Use (AF)	County	Mining Water Use (AF)
Colorado	1,972	Kendall	0	Stephens	1,786
Comal	3,740	Kenedy	27	Sterling	67
Comanche	1	Kent	297	Stonewall	238
Concho	27	Kerr	59	Sutton	1
Cooke	1,081	Kimble	1	Swisher	0
Coryell	275	King	121	Tarrant	6,450
Cottle	2	Kinney	0	Taylor	25
Crane	403	Kleberg	280	Terrell	12
Crockett	113	Knox	1	Terry	99
Crosby	20	Lamar	0	Throckmorton	69
Culberson	64	Lamb	13	Titus	622
Dallam	0	Lampasas	305	Tom Green	32
Dallas	1,690	La Salle	27	Travis	868
Dawson	250	Lavaca	18	Trinity	0
Deaf Smith	0	Lee	2,089	Tyler	0
Delta	0	Leon	740	Upshur	43
Denton	4,013	Liberty	248	Upton	1,313
DeWitt	13	Limestone	2,469	Uvalde	55
Dickens	9	Lipscomb	145	Val Verde	33
Dimmit	49	Live Oak	3	Van Zandt	492
Donley	0	Llano	0	Victoria	0
Duval	904	Loving	68	Walker	454
Eastland	277	Lubbock	774	Waller	0
Ector	509	Lynn	51	Ward	87
Edwards	2	McCulloch	4,220	Washington	18
Ellis	2,994	McLennan	1,025	Webb	349
El Paso	621	McMullen	44	Wharton	6
Erath	295	Madison	0	Wheeler	1,074
Falls	0	Marion	30	Wichita	20
Fannin	6	Martin	569	Wilbarger	3
Fayette	82	Mason	560	Willacy	5
Fisher	153	Matagorda	8	Williamson	2,273
Floyd	169	Maverick	75	Wilson	1
Foard	1	Medina	350	Winkler	30
Fort Bend	4	Menard	2	Wise	3,938
Franklin	2	Midland	700	Wood	6
Freestone	3,631	Milam	0	Yoakum	863
Frio	4	Mills	0	Young	38
Gaines	3,033	Mitchell	75	Zapata	107
Galveston	282	Montague	691	Zavala	0
Garza	196	Montgomery	788	**SUM**	**129,662***

*: oil and gas drilling not included

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Table 69. County-level summary of 2010-2020 projections for mining water use (oil and gas drilling not included)

County	2010	2020	2030	2040	2050	2060
Anderson	8	26	84	67	42	16
Andrews	678	1,014	743	377	152	47
Angelina	0	426	534	367	200	33
Aransas	9	17	22	16	11	5
Archer	3	1,619	1,293	370	0	0
Armstrong	0	0	0	0	0	0
Atascosa	851	2,998	4,368	3,672	3,055	2,497
Austin	0	48	256	279	221	163
Bailey	0	0	0	0	0	0
Bandera	0	0	0	0	0	0
Bastrop	2,164	2,613	5,662	5,725	5,810	5,887
Baylor	0	0	0	0	0	0
Bee	23	47	58	43	29	14
Bell	1,218	1,562	1,901	2,170	2,481	2,821
Bexar	4,574	5,284	5,836	6,271	6,736	7,304
Blanco	0	0	0	0	0	0
Borden	109	395	318	165	58	0
Bosque	937	2,576	1,096	33	37	40
Bowie	0	0	0	0	0	0
Brazoria	716	941	1,157	1,359	1,578	1,812
Brazos	276	865	1,534	1,418	1,187	1,024
Brewster	0	0	0	0	0	0
Briscoe	0	0	0	0	0	0
Brooks	305	329	342	326	310	294
Brown	5	1	1	1	1	1
Burleson	0	594	1,295	1,055	816	576
Burnet	341	437	528	619	704	804
Caldwell	0	0	0	0	0	0
Calhoun	17	33	42	31	21	10
Callahan	158	146	145	139	135	131
Cameron	25	50	62	46	30	14
Camp	3	1	1	0	0	0
Carson	0	0	0	0	0	0
Cass	0	52	66	46	25	4
Castro	0	0	0	0	0	0
Chambers	0	0	0	0	0	0
Cherokee	23	254	288	188	89	0
Childress	0	0	0	0	0	0
Clay	635	3,731	1,664	0	0	0
Cochran	5	2	1	1	1	1
Coke	114	38	26	23	21	20
Coleman	21	6	4	3	3	3
Collin	0	0	0	0	0	0
Collingsworth	0	0	0	0	0	0

County	2010	2020	2030	2040	2050	2060
Colorado	2,304	3,728	4,851	4,490	4,087	3,744
Comal	4,033	4,928	5,725	6,438	7,044	7,855
Comanche	429	2,524	1,125	0	0	0
Concho	108	33	21	18	15	13
Cooke	1,016	1,457	1,516	1,643	1,966	2,267
Coryell	296	2,147	1,537	692	463	505
Cottle	7	2	1	1	1	1
Crane	144	297	225	99	43	31
Crockett	58	121	71	21	1	1
Crosby	228	69	43	37	32	28
Culberson	33	1,334	4,126	3,236	2,533	1,830
Dallam	0	0	0	0	0	0
Dallas	2,549	2,731	2,227	1,940	1,930	1,922
Dawson	147	404	324	170	63	5
Deaf Smith	0	0	0	0	0	0
Delta	0	0	0	0	0	0
Denton	3,188	2,693	2,678	3,332	4,293	5,191
DeWitt	24	1,114	1,740	1,402	1,063	725
Dickens	0	0	0	0	0	0
Dimmit	218	2,625	3,790	2,999	2,275	1,551
Donley	0	0	0	0	0	0
Duval	1,052	1,170	1,243	1,177	1,085	1,020
Eastland	231	1,317	1,348	608	223	234
Ector	499	762	630	413	290	243
Edwards	0	0	0	0	0	0
Ellis	3,440	3,799	4,276	5,047	6,004	6,827
El Paso	737	953	1,131	1,317	1,523	1,754
Erath	2,017	2,500	882	0	0	0
Falls	0	0	0	0	0	0
Fannin	7	11	16	23	27	33
Fayette	98	965	1,982	1,680	1,398	1,104
Fisher	94	32	21	19	17	15
Floyd	213	200	201	207	212	217
Foard	1	0	0	0	0	0
Fort Bend	23	47	58	44	29	14
Franklin	1	0	0	0	0	0
Freestone	3,766	4,862	4,268	3,984	3,493	3,026
Frio	0	180	744	717	566	414
Gaines	584	1,060	933	676	498	400
Galveston	339	375	402	444	480	514
Garza	77	155	91	27	2	1
Gillespie	3	4	4	4	4	4
Glasscock	492	1,414	1,230	740	364	131
Goliad	22	45	56	42	27	13
Gonzales	0	79	420	458	363	267
Gray	14	4	3	2	2	2
Grayson	50	62	73	89	107	125

County	2010	2020	2030	2040	2050	2060
Gregg	132	422	573	398	222	51
Grimes	0	59	314	342	271	200
Guadalupe	294	446	540	629	745	873
Hale	271	82	51	45	39	33
Hall	0	0	0	0	0	0
Hamilton	190	1,118	498	0	0	0
Hansford	75	675	62	0	0	0
Hardeman	7	8	8	8	8	8
Hardin	0	0	0	0	0	0
Harris	3,668	3,784	3,763	3,705	3,670	3,643
Harrison	7,044	9,418	8,624	7,850	7,076	6,380
Hartley	2	0	0	0	0	0
Haskell	19	6	4	3	3	2
Hays	0	0	0	0	0	0
Hemphill	694	364	33	0	0	0
Henderson	138	440	562	529	518	498
Hidalgo	948	1,372	1,858	2,292	2,738	3,251
Hill	1,008	1,249	441	0	0	0
Hockley	1	0	0	0	0	0
Hood	2,150	1,775	937	544	436	353
Hopkins	929	903	902	901	901	901
Houston	0	0	0	0	0	0
Howard	321	1,293	1,111	618	238	2
Hudspeth	0	0	0	0	0	0
Hunt	70	128	118	88	71	58
Hutchinson	174	240	206	213	221	233
Irion	366	1,176	1,097	674	295	21
Jack	2,091	2,008	857	363	405	450
Jackson	22	45	56	42	28	13
Jasper	0	0	0	0	0	0
Jeff Davis	0	0	0	0	0	0
Jefferson	157	180	202	230	280	315
Jim Hogg	30	60	75	56	37	17
Jim Wells	23	45	57	42	28	13
Johnson	6,774	5,565	4,969	5,633	6,682	7,598
Jones	37	20	18	17	17	16
Karnes	20	1,153	1,399	1,117	834	551
Kaufman	2,452	2,788	3,289	3,998	4,908	5,648
Kendall	0	0	0	0	0	0
Kenedy	38	76	95	71	46	22
Kent	6	2	1	1	1	1
Kerr	71	76	80	100	102	111
Kimble	1	2	2	2	2	2
King	1,818	553	345	299	258	223
Kinney	0	0	0	0	0	0
Kleberg	305	329	342	326	310	294
Knox	1	0	0	0	0	0

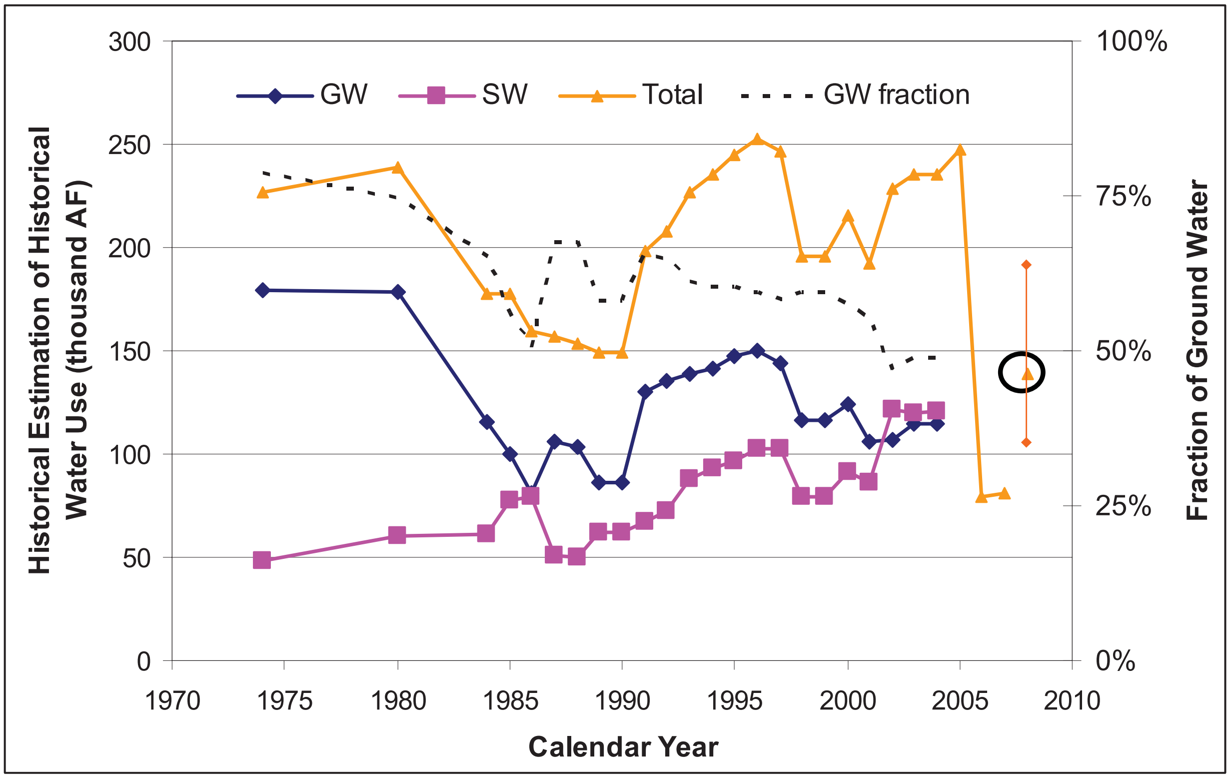
County	2010	2020	2030	2040	2050	2060
Lamar	0	0	0	0	0	0
Lamb	136	41	26	22	19	17
Lampasas	329	391	437	470	506	551
La Salle	280	2,989	4,300	3,398	2,570	1,742
Lavaca	25	621	1,839	1,638	1,276	914
Lee	2,089	2,547	5,749	5,772	5,715	5,659
Leon	678	1,680	2,701	2,431	1,732	1,034
Liberty	269	420	441	430	452	480
Limestone	2,500	7,333	6,258	5,630	5,242	4,928
Lipscomb	126	508	47	0	0	0
Live Oak	28	229	784	741	577	414
Llano	0	0	0	0	0	0
Loving	174	251	148	50	11	9
Lubbock	1,805	952	849	891	931	967
Lynn	273	214	128	59	29	25
McCulloch	4,219	7,690	7,073	5,324	4,274	3,460
McLennan	1,230	2,825	2,413	1,930	2,228	2,509
McMullen	30	2,154	3,383	2,682	2,038	1,395
Madison	0	278	865	775	607	438
Marion	24	665	728	494	259	33
Martin	588	1,279	1,103	622	247	10
Mason	560	1,023	941	708	568	460
Matagorda	31	61	77	57	37	18
Maverick	57	954	2,837	2,395	1,893	1,395
Medina	384	457	514	563	610	671
Menard	250	76	47	41	35	31
Midland	537	1,260	1,090	612	239	4
Milam	0	0	0	0	0	0
Mills	0	0	0	0	0	0
Mitchell	69	153	90	26	0	0
Montague	666	3,317	1,579	197	222	250
Montgomery	793	1,438	1,348	1,062	906	792
Moore	1	0	0	0	0	0
Morris	0	0	0	0	0	0
Motley	27	8	5	5	4	3
Nacogdoches	436	4,384	3,426	2,298	1,170	52
Navarro	77	97	124	156	198	236
Newton	140	256	235	177	142	115
Nolan	85	56	51	49	47	45
Nueces	556	699	837	934	1,009	1,118
Ochiltree	77	673	62	1	1	0
Oldham	182	207	246	277	289	315
Orange	233	304	309	308	309	314
Palo Pinto	464	2,632	1,174	3	3	2
Panola	2,095	3,700	3,507	2,815	2,123	1,500
Parker	4,489	2,398	840	821	952	1,098
Parmer	0	0	0	0	0	0

County	2010	2020	2030	2040	2050	2060
Pecos	102	769	2,132	1,648	1,280	926
Polk	0	0	0	0	0	0
Potter	576	692	859	1,016	1,108	1,254
Presidio	0	0	0	0	0	0
Rains	0	0	0	0	0	0
Randall	0	0	0	0	0	0
Reagan	679	1,640	1,420	796	310	3
Real	0	0	0	0	0	0
Red River	1	0	0	0	0	0
Reeves	431	1,815	3,330	2,362	1,742	1,270
Refugio	21	42	53	39	26	12
Roberts	183	447	41	0	0	0
Robertson	7,763	8,859	9,552	10,267	11,079	12,009
Rockwall	0	0	0	0	0	0
Runnels	60	18	11	10	9	7
Rusk	1,328	4,075	3,868	3,130	2,391	1,669
Sabine	268	2,327	1,816	1,244	674	102
San Augustine	435	3,044	2,152	1,431	711	31
San Jacinto	0	0	0	0	0	0
San Patricio	451	542	616	651	676	723
San Saba	280	511	470	354	284	230
Schleicher	52	137	127	78	35	4
Scurry	67	154	90	25	0	0
Shackelford	46	1,135	1,160	391	6	6
Shelby	616	4,540	3,335	2,225	1,114	62
Sherman	9	61	6	0	0	0
Smith	201	386	433	425	437	443
Somervell	1,373	1,251	945	813	810	830
Starr	202	292	376	416	456	510
Stephens	1,086	2,184	1,384	450	154	133
Sterling	119	406	328	170	61	1
Stonewall	154	61	46	42	38	34
Sutton	106	241	141	40	0	0
Swisher	0	0	0	0	0	0
Tarrant	4,669	2,799	1,665	1,577	1,525	1,484
Taylor	15	5	3	2	2	2
Terrell	149	132	78	34	15	13
Terry	84	156	91	28	3	2
Throckmorton	42	13	8	7	6	5
Titus	621	1,001	1,000	1,000	1,000	1,000
Tom Green	11	3	2	2	2	1
Travis	1,022	1,070	1,115	1,159	1,200	1,247
Trinity	0	0	0	0	0	0
Tyler	0	0	0	0	0	0
Upshur	7	605	988	694	400	105
Upton	744	1,776	1,522	842	321	0
Uvalde	59	72	78	81	86	93

County	2010	2020	2030	2040	2050	2060
Val Verde	59	96	83	68	65	72
Van Zandt	483	475	473	473	473	472
Victoria	23	46	58	43	28	14
Walker	488	660	842	1,086	1,337	1,572
Waller	0	0	0	0	0	0
Ward	145	347	323	179	112	90
Washington	22	391	1,166	1,051	831	612
Webb	475	1,934	2,296	1,995	1,705	1,425
Wharton	29	57	72	53	35	17
Wheeler	699	367	35	1	1	1
Wichita	12	4	2	2	2	2
Wilbarger	2	0	0	0	0	0
Willacy	16	31	39	29	19	9
Williamson	2,444	3,152	3,796	4,412	5,046	5,750
Wilson	0	474	1,473	1,320	1,033	746
Winkler	151	334	270	125	60	44
Wise	6,094	4,315	3,133	3,358	3,982	4,583
Wood	4	1	1	1	1	0
Yoakum	278	202	120	59	31	27
Young	40	604	621	238	49	52
Zapata	27	55	68	51	33	16
Zavala	0	550	1,712	1,494	1,169	845
SUM	**136,639***	**224,749***	**229,263***	**196,538***	**181,116***	**170,893***

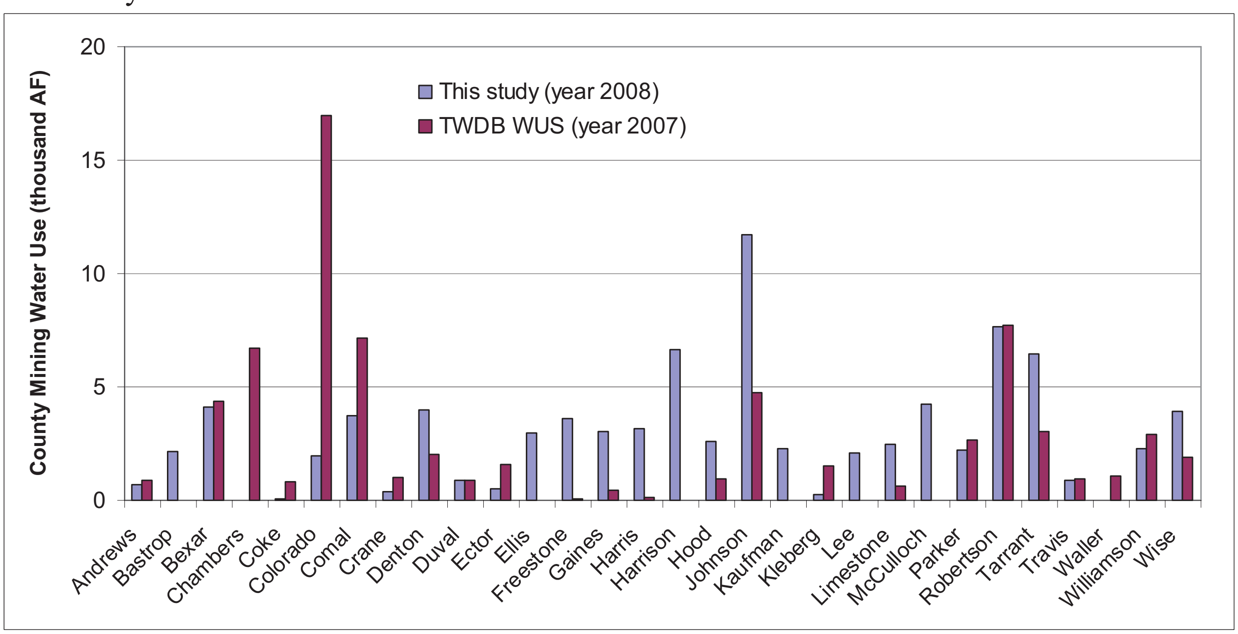
*: oil and gas drilling not included

MiningWaterUse2010-2060_2.xls



Source: TWDB website rptWaterUseSummaryByState_TWDB-WUS_1974-2004_+to 2007_JP.xls

Figure 134. Historical estimation of historical mining-water use
Most likely year 2008 water use is highlighted by the large circle. Also shown is the range of uncertainty.



MiningWaterUse2008_2.xls

Figure 135. Comparison of high mining water use

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8 Appendix List

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9 Appendix A: Relevant Websites

All categories
USGS mineral production: http://minerals.usgs.gov/minerals/
USGS water use: http://water.usgs.gov/watuse/
USGS e-library: http://pubs.er.usgs.gov/
U.S. Census Bureau: http://www.census.gov/econ/www/mi0100.html;
http://www.census.gov/mcd/
TWDB water use survey (WUS): http://www.twdb.state.tx.us/wrpi/wus/wus.htm
MSHA mine database (including abandoned mines): http://www.msha.gov/drs/drshome.htm
http://www.msha.gov/drs/asp/extendedsearch/statebycommodityoutput2.asp
EIA: http://www.eia.doe.gov/
BEG publications: http://www.beg.utexas.edu/publist.php

Aggregates:
Trade journals:
Aggregate Manager: http://www.aggman.com/
Pit & Quarry: http://www.pitandquarry.com/
Rock Products: http://rockproducts.com/
Mining Engineering: http://www.smenet.org/
Trade Associations:
National Stone, Sand, and Gravel Association (NSSGA): http://www.nssga.org/
TMRA: http://www.tmra.com/
TACA: http://www.tx-taca.org/

Oil and Gas:
Operators
Chesapeake: http://www.chesapeake.com/Pages/default.aspx
http://www.chk.com/Pages/default.aspx
Devon Energy: http://www.devonenergy.com
Barnett Shale Water Conservation & Management Committee:
http://www.barnettshalewater.org/
Trade Associations:
TXOGA: http://www.txoga.org/
Regulators:
RRC H10 query: http://webapps.rrc.state.tx.us/H10/h10PublicMain.do
Permit application: http://www.rrc.state.tx.us/forms/publications/HTML/index.php
All RRC forms: http://www.rrc.state.tx.us/forms/forms/og/purpose.php
Fresh-water questionnaire: http://www.rrc.state.tx.us/forms/publications/HTML/fw-ques.php
UIC query: http://webapps2.rrc.state.tx.us/EWA/uicQueryAction.do
RRC Barnett Sh.: http://www.rrc.state.tx.us/barnettshale/index.php
RRC Haynesville Sh.: http://www.rrc.state.tx.us/bossierplay/index.php
RRC Eagle Ford Sh.: http://www.rrc.state.tx.us/eagleford/index.php
USGS NOGA:
1995 assessment: http://energy.cr.usgs.gov/oilgas/noga/1995.html
Gulf Coast: http://energy.er.usgs.gov/regional_studies/gulf_coast/gulf_coast_assessment.html

Coal
CBM in Gulf Coast: http://energy.cr.usgs.gov/oilgas/cbmethane/pubs_data_gulf.html
RRC maps of coal resources: http://www.rrc.state.tx.us/forms/maps/historical/historicalcoal.php

RRC table of coal production: http://www.rrc.state.tx.us/data/production/index.php

Energy
Future of power generation in Tx: http://www.twdb.state.tx.us/RWPG/rpfgm_rpts.asp
Coal and uranium: http://www.rrc.state.tx.us/industry/smrd.php

Other useful sites:
Information about drilling rig count: http://www.rigdata.com/index.aspx;
http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm
IHS Energy: http://energy.ihs.com/
Drilling info: http://www.info.drillinginfo.com/
Aggregate industry: http://www.pitandquarry.com/pit-quarry-content/quarryology-101
IMPLAN by MIG, Inc.: http://implan.com/V4/Index.php

10 Appendix B: Postaudit of the 2007 BEG Barnett Shale Water-Use Projections

In the 2007 TWDB update of the Northern Trinity GAM (Bené et al., 2007), BEG (Nicot and Potter, 2007, summarized in Nicot, 2009a) proposed a methodology for estimating future water use related to Barnett Shale activities for 2 decades through 2025. The purpose of this appendix is to compare water-use projections with actual water use for the 2007–2009 (report used data through mid- to late 2006). At the October 2009 GSA meeting in New Orleans, Nicot and Ritter (2009) presented an initial postaudit, which is completed here.

2007 Report Methodology

The following steps are a summary of the methodology applied in the 2007 report:

Step 1: Derive the geographic extent in which frac jobs are likely to take place by integrating gas window, formation thickness, and well economics, defining high, low, and medium cases (somewhat subjectively).

Step 2: Use historical data to define average water use per well or per linear of lateral (Figure 136). Vertical well water use is nicely distributed along a normal distribution around a mean of 1.2 Mgal/well. Because defective database entries yielded unnatural water use at both low and high ends, averages used in the analysis are computed using data only 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 Mgal, respectively. The raw average for horizontal wells (2005–2006) is 3.07 Mgal/well, whereas the truncated average is 2.65 Mgal/well. The relatively more abundant frac jobs with low water use (Figure 136a), generating a dissymmetric histogram result from the addition of acid jobs and other common well-development and completion practices outside of strictly defined frac jobs. In contrast to vertical wells that have a relatively narrow range of lengths/depths, horizontal wells have laterals of very variable length (although the vertical sections, as for the vertical wells, belong to a relatively narrow range) that translates into a more uniform distribution (Figure 136b). Only those frac jobs performed in 2005 and 2006 were included in the histogram of Figure 136b to avoid bias due to early trials of the slick-water frac technology. Using water-use intensity (volume of water per linear of lateral) instead of absolute water use per well yields a better-defined histogram (Figure 136c). 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 2,400 gal/ft seems conservatively reasonable for the medium scenario. Values of 2,000 and 2,800 gal/ft were retained for low and high scenarios, respectively, for the 2007 report.

Step 3: Define a maximum water use at the county level by assuming that the county is drilled up and apply an average water use per vertical well or per linear of lateral. This step assumes a vertical well spacing of at least 40 acres (see Table 70 for details) and a constant distance between horizontal well laterals. All horizontal wells were assumed to be parallel to each other and to the main fault direction (under the assumption made at the time that operators would not want to drill through a large fault because of the risk of watering out the well). This assumption results in an extremely large water volume (Figure 137) that needs to be corrected and distributed through time.

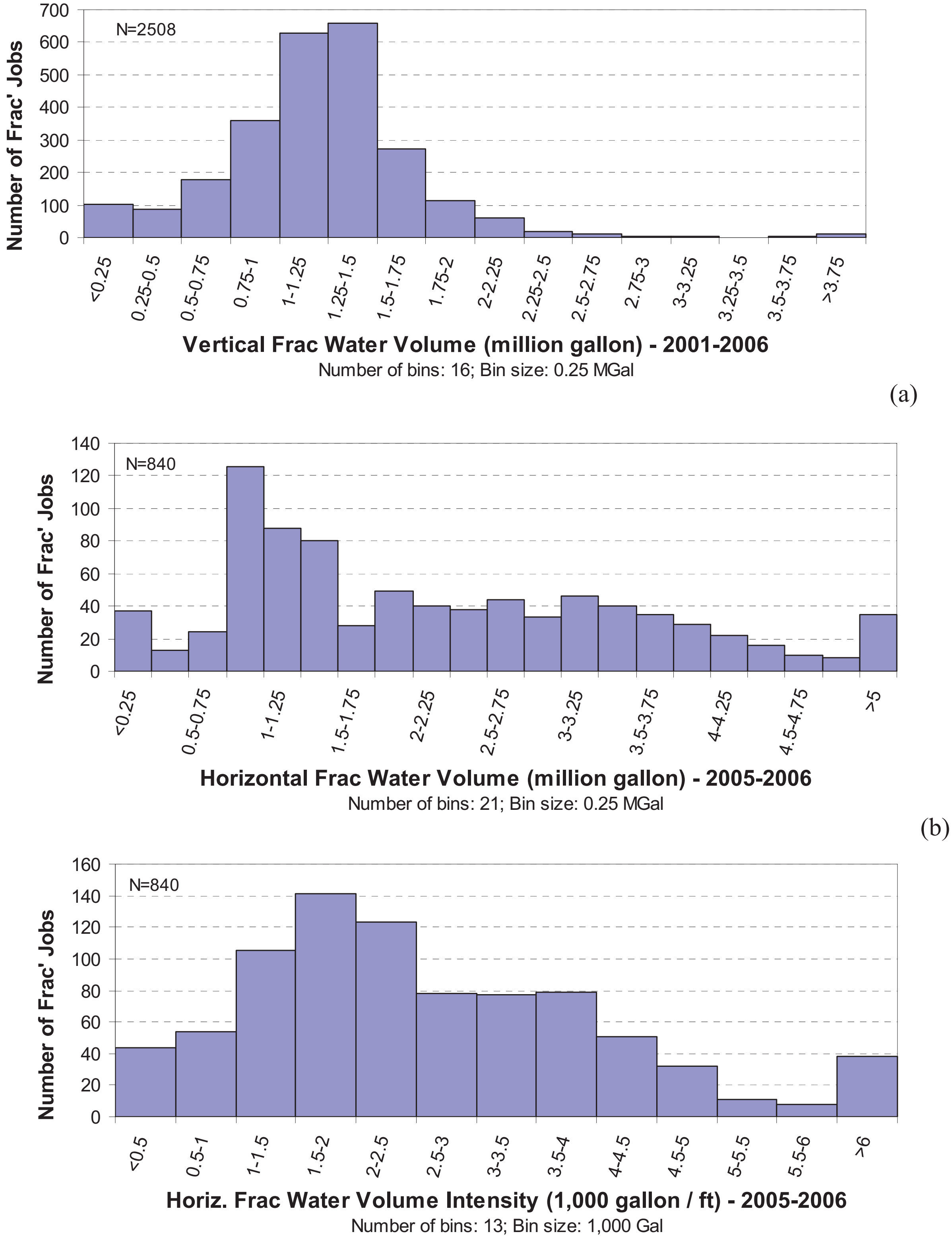
Step 4: Apply time-independent correction factors: karst, operations, prospectivity. The sag avoidance ("karst") correction factor was assumed to take into account some reluctance from the operators to drill through disrupted Barnett Shale strata that was due to karstic features in the underlying Ellenburger Formation. Early on, in the vertical well phase, drilling to and connection to the Ellenburger Formation was detrimental to operators because of excessive water production. The Ellenberger is a well-known regional (saline water) aquifer. It was thought at the time that operators would avoid karstic feature-rich areas because they were avoiding well-known faults. It turned out to be less of a concern than thought. Prospectivity represents the overall maturity of the shale and its likelihood to contain large economic resources in a given county or fraction of county. Prospectivity/risk factor can be understood either as a fraction of the area that will be developed or, more accurately, as the mean of the probability distribution describing the likelihood of having the county polygon developed (already given the high, medium, or low scenario condition). This factor is used simply as a multiplier of hypothetical maximum water use. The 2007 report used a prospectivity factor of 1 for core-area counties but one of 0.7 and 0.5 in Montague and Clay Counties, respectively. These oil-prone counties turned out to be more interesting than initially thought. The oil potential was thought to be not very prospective and, in fact, a hindrance to gas production.

Step 5: Add correction factors associated with time-dependent constraints. Growth of recycling techniques was assumed to reach a maximum of 20% of total water use in 2025. Recompletion/restimulation frequency remains unclear. The 2007 report assumes no recompletion for horizontal wells and that a large fraction of the vertical wells would be recompleted. The last and most controlling factor is the availability of drilling rigs. There are a limited number of active drilling rigs around the country, and their number at a given play is a complex function of play activity, oil/gas price, economic climate, relative location of other plays, etc. Galusky (2007) reported ~57 and ~93 active rigs in the Barnett Shale play in 2005 and 2006, respectively, resulting in 12 to 13 wells being drilled per year per rig, on average. The 2007 report assumes that there would be no more than 3,000 recompletions a year, starting in 2010 and ~2,400 in 2008, both in the "high" scenario case (Figure 138). This number turned out to be an underestimation in 2008. The actual number climbed to 2,500+ horizontal wells in 2008.

Step 6: Apply activity weighting curve to each county. This factor takes into account the life cycle of hydrocarbon production: initial production, relatively quick increase to peak production, peak sustained for a relatively short interval, relatively quick production, followed by a slow decrease. The 2007 report based the activity curve on that of Wise County that was on its past-peak decreasing limb in 2006 and applied it to all other counties or fractions of counties. Start date of each county activity was a function of geographic proximity to the core area and prospectivity.

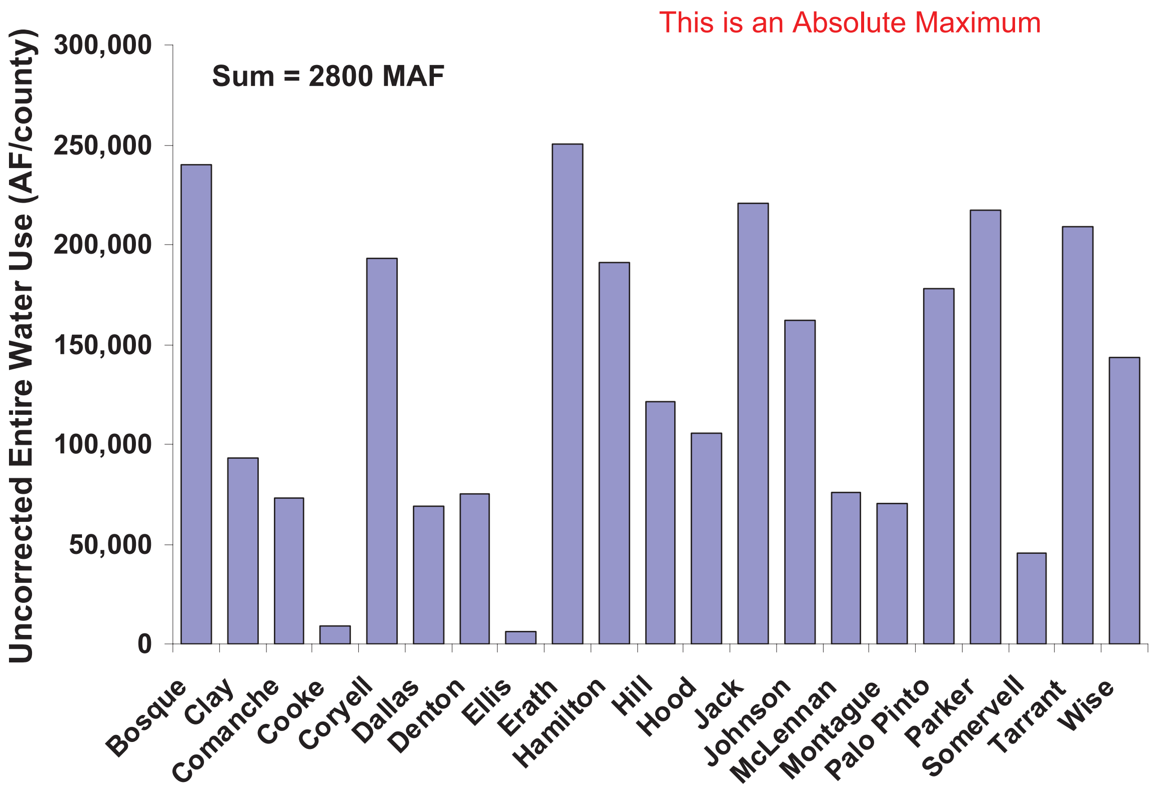
Step 7: Apply GW/SW split. The 2007 report assumes increased reliance on groundwater. Groundwater use would reach 60% to 100% of total water use in 2025.

Resulting final output of the 2007 report is presented in Figure 139. The high scenario yields a total groundwater use of 417,000 AF, an annual average groundwater use of 22,000 AF over the 2007–2025 period, and a cumulative areal groundwater use of 0.05 AF/acre. The medium and low scenarios utilize a total 183,000 and 29,000 AF of groundwater for an annual average of ~10,000 and 1,500 AF and a cumulative areal groundwater use of ~0.04 and 0.009 AF/acre, respectively. A survey completed in the same period (Galusky, 2007) showed that projections were accurate in the short term and were bounded by the high and medium scenarios. The next section analyzes medium-term projections to the 2010 horizon and compares them to actual figures.



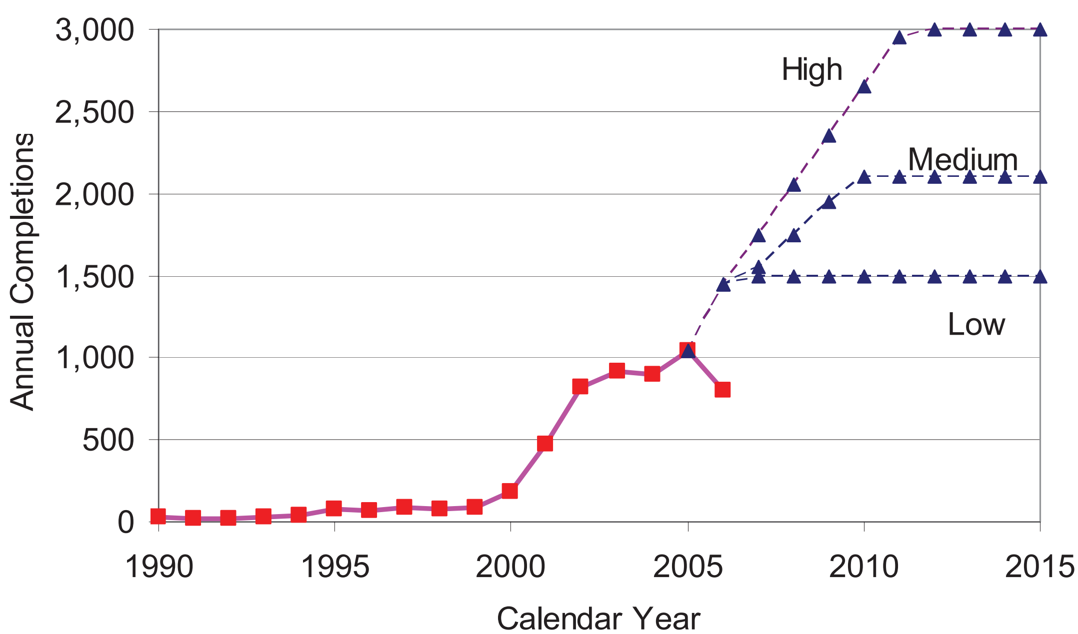
Source: Nicot and Potter (2007)

Figure 136. Distribution of water use for vertical wells (a), horizontal wells (b), and per linear of lateral of horizontal wells (c).



Source: Nicot and Potter (2007)

Figure 137. Uncorrected entire water use



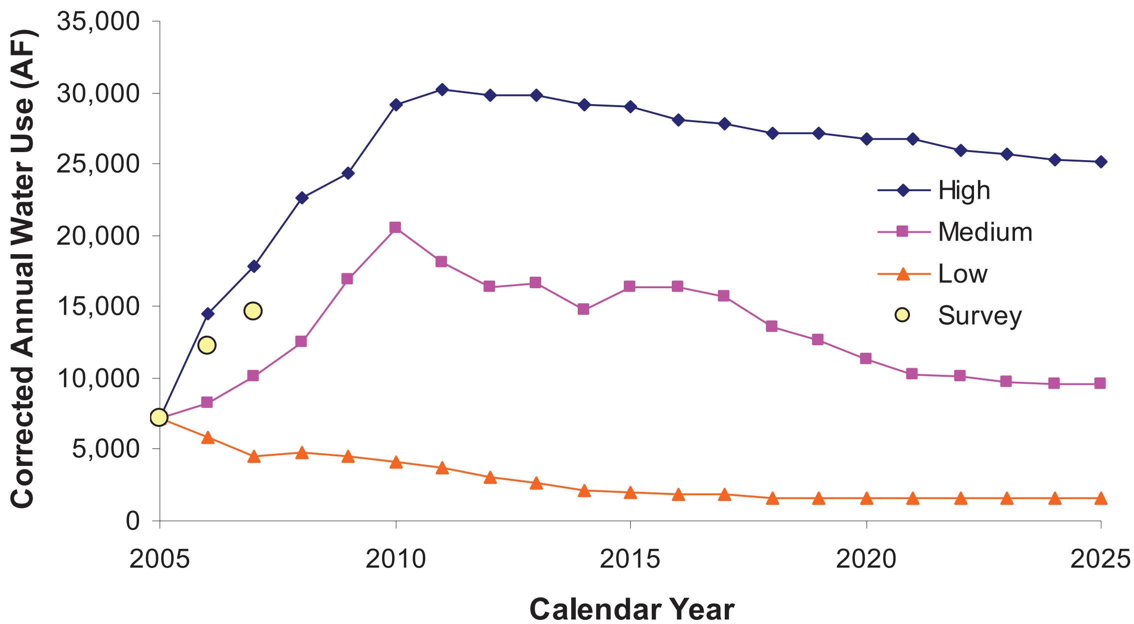
Source: Nicot and Potter (2007)

Figure 138. Projected annual completions

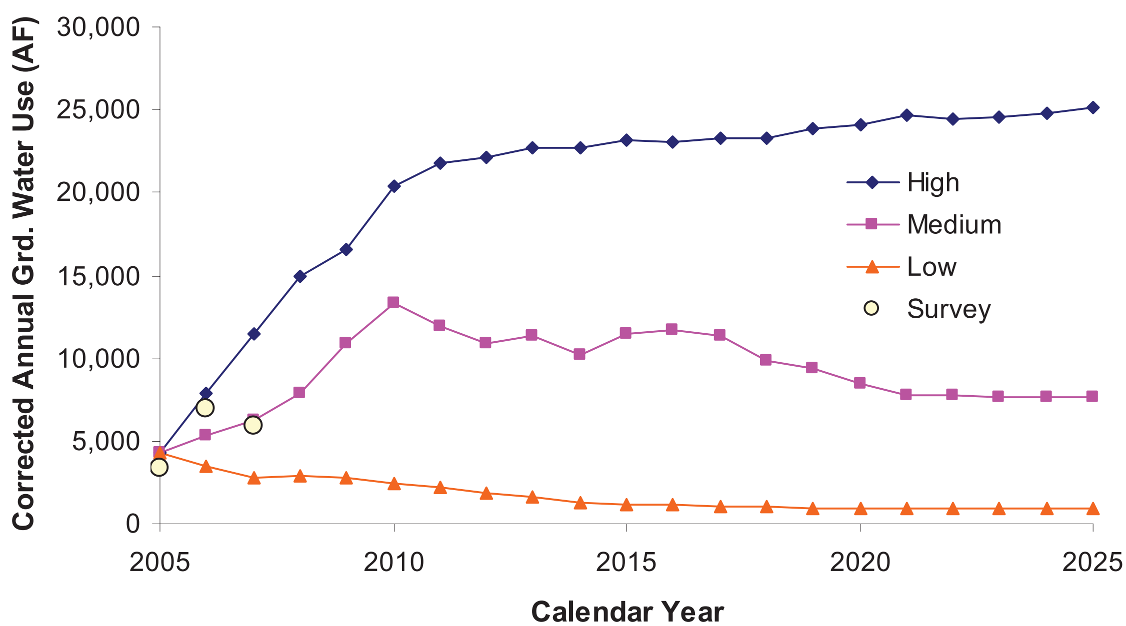
Table 70. Summary description of parameters used in 2007 report water-use projections

Category	Comment	High Water Use	Medium Water Use	Low Water Use
County Polygon	There are three binary variable couples: rural/urban—horizontal/vertical wells—within Viola footprint or not, resulting in four main categories: (1) Viola/urban (only horizontal wells), (2) Viola/rural (both horizontal and vertical wells), (3) no Viola/urban (only horizontal wells), and (4) no Viola/rural (only horizontal wells)			
Footprint Fraction	A county polygon cannot be covered by >90% (vertical wells) or 80% (horizontal wells) of the maximum possible well coverage.			
Vertical Well Spacing		1 well/40 acres	0.5 well/40 acres	0.25 well/40 acres
Horizontal Well Lateral Spacing	No Viola and/or urban	800 ft	1,000 ft	2,000 feet
	Viola rural	800 × 4 ft	1,000 × 4 ft	2,000 × 4 ft
Sag Feature Avoidance (“Karst”)	Vertical well	100%		
	Horizontal well	100%	75%	40%
Average Water Use	Vertical well	1.2 million gal		
	Horizontal well (spread reflects uncertainty)	2,800 gal/ft	2,400 gal/ft	2,000 gal/ft
Water-Use Progress Factor[A]	(variations reflect technological progress)	1%	0%	0%
		Water-use annual incremental improvement as a fraction of total water use, e.g., 100% of current use in 2005 with a 1% increment translates into 80% of water use in 2025 compared with the same frac job executed in 2005		
Recompletion	Vertical well	100%	50%	0%
		of initial completions executed 5 years before		
	Horizontal well	0%	0%	0%
Recycling[A]		1%	0.33%	0%
		Recycling annual increment as a fraction of total water use (e.g., 0% in 2005 with a 1% increment translates into 20% recycling in 2025)		
Maximum Number of Sustained Annual Completions		3,000 completions/year	2,100 completions/year	1,500 completions/year
Additional Water Use in Overlying Formations		0%	0%	0%
Barnett Groundwater Use Expressed as % of Total Barnett Water Use	In year 2005–2006	60%	60%	60%
	Annual increment in following years	2%	1%	0%
	In year 2025	100%	80%	60%

Note: [A] These parameters do not maximize water use, but the likely competition for water in the high scenario suggests that recycling and water-use intensity will get better through time.
Source: Nicot and Potter (2007)



(a)



(b)

Source: Nicot and Potter (2007) and Nicot (2009a); survey data points by Galusky (2007)
Note: The data points used in a previous version of the same plot (Nicot, 2009a) are slightly lower because Galusky (2007) included drilling-water use. Nicot (2009a) was estimated at 20% of total water use whereas in this document, it is estimated at only 10%. "Survey" point for year 2007 in Galusky (2007) is also a projection but directed by data from the first few months of the year.

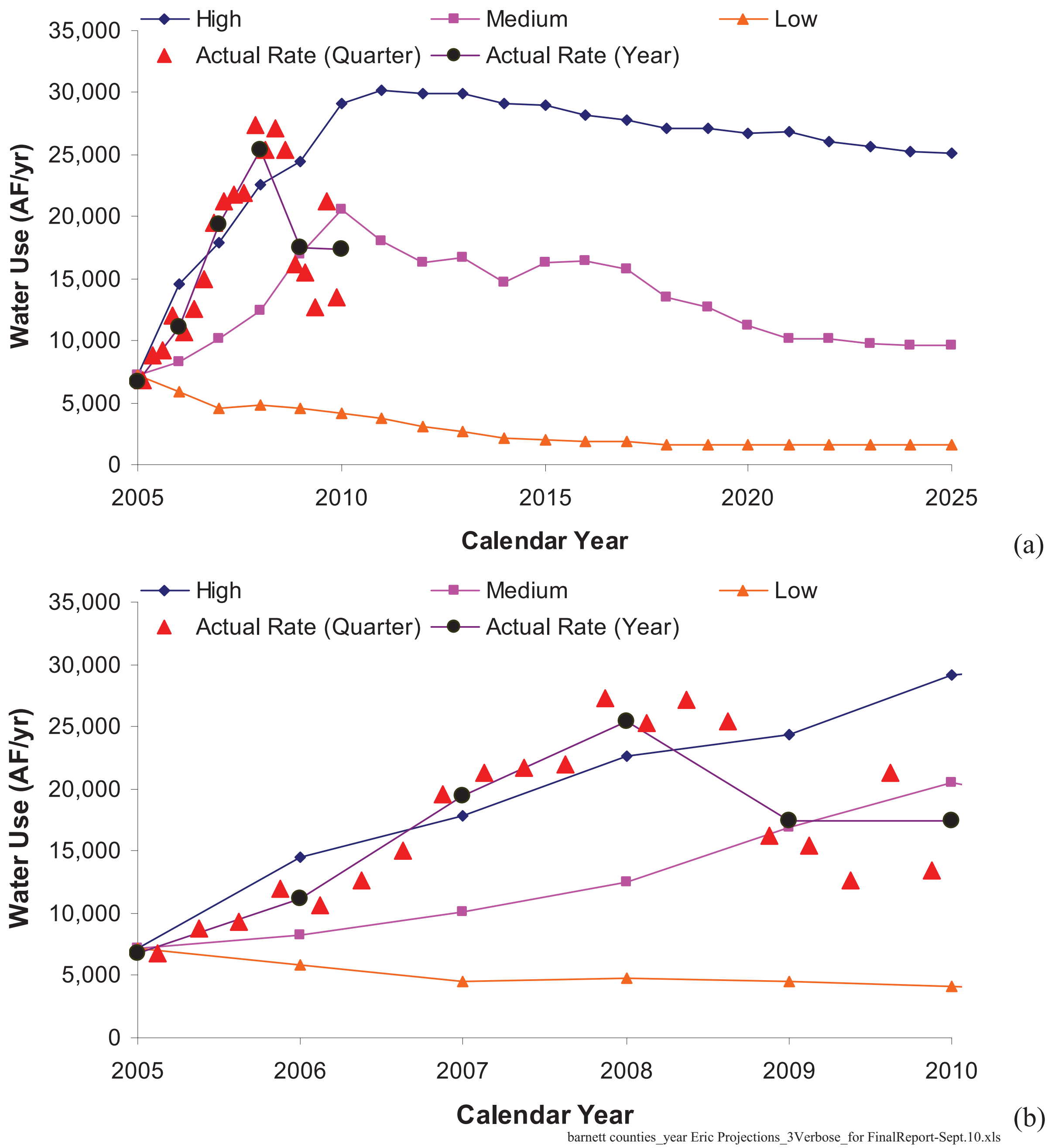
Figure 139. 2007 report projected frac total water use (a) and projected frac groundwater use (b)

Postaudit:

The recent downturn in gas prices has showed us that we cannot expect a linear development of the play but that it will go through periods of intense activity followed by calmer phases. I Because predicting these cycles is impossible in the long term, we only need to recognize that they exist and understand that actual water use will fluctuate around some projected average. Nicot and Potter (2007) suggested that peak water use (but not necessarily peak gas production) would occur around 2011 (Figure 140a, early years magnified in Figure 140b) after a quick ramp-up, followed by a slow decline. Superimposed on the projections are actual water-use figures as extracted from the IHS database in the summer of 2010. Initial growth overshot projections of the high scenario before crashing down below projected values of the medium scenario in 2009 because of the economic downturn. The figure depicts both quarterly water use (expressed in AF/yr) and annual values. Cumulative water use falls between high and medium scenarios (Figure 141).

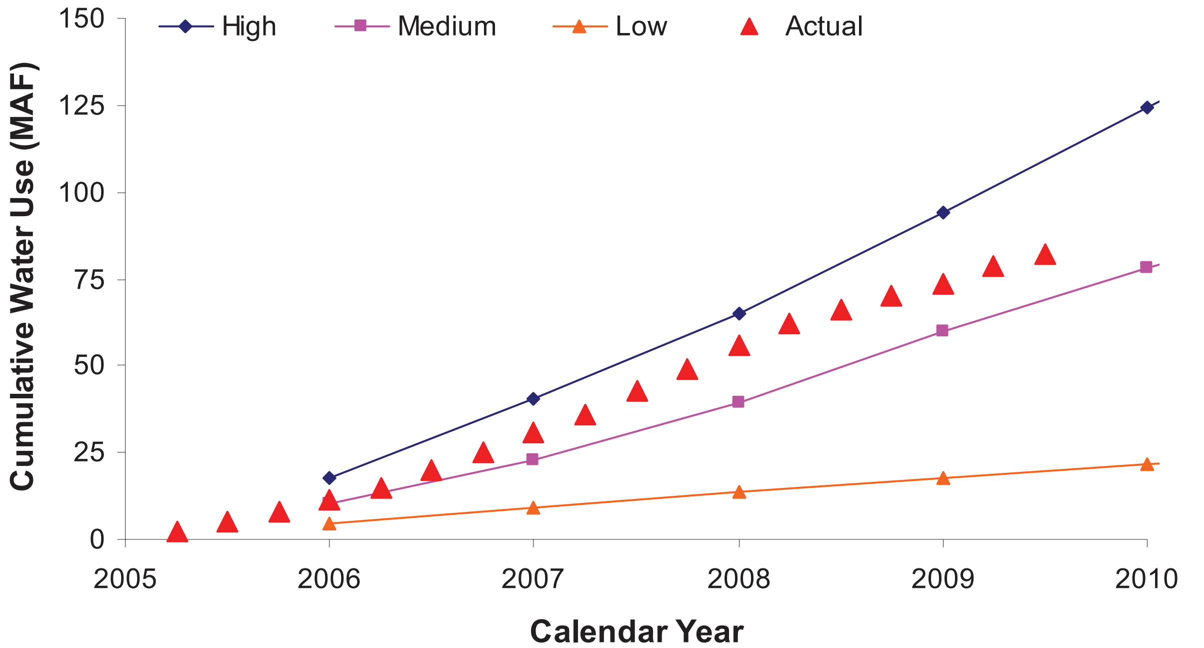
If the match between actual and projected numbers is good at the aggregate level, it is somewhat less so at the county level. Water use from four of the counties with significant figures (Denton, Johnson, Tarrant, and Wise) are plotted in Figure 142. Individual county matches are acceptable, but trends are better preserved by aggregating the four counties. A cross-plot comparison at the county level (Figure 143) also suggests that the general trend was well captured regionally but that deviations exist at the county level. Comparison of actual data is made against the high scenario in Figure 143a (linear scale) and Figure 143b (log scale). The high scenario was constructed as bounding—that is, most of the points should be below the unit slope line. Neglecting the 2009 points, they are for the most part. The 2009 points are located above the line (projected > actual) because of the economic downturn.

Several important conclusions can be drawn from this exercise: (1) it is possible to make sensible projections, at least at a 5-year horizon; (2) projections deviate from actual values as the size of the area of interest decreases— county-level projections seem to be noisy and more uncertain than projections made for larger geographic areas; (3) county-level projections can be off by a factor of 2 or more, even if projections are acceptable at the aggregate level.



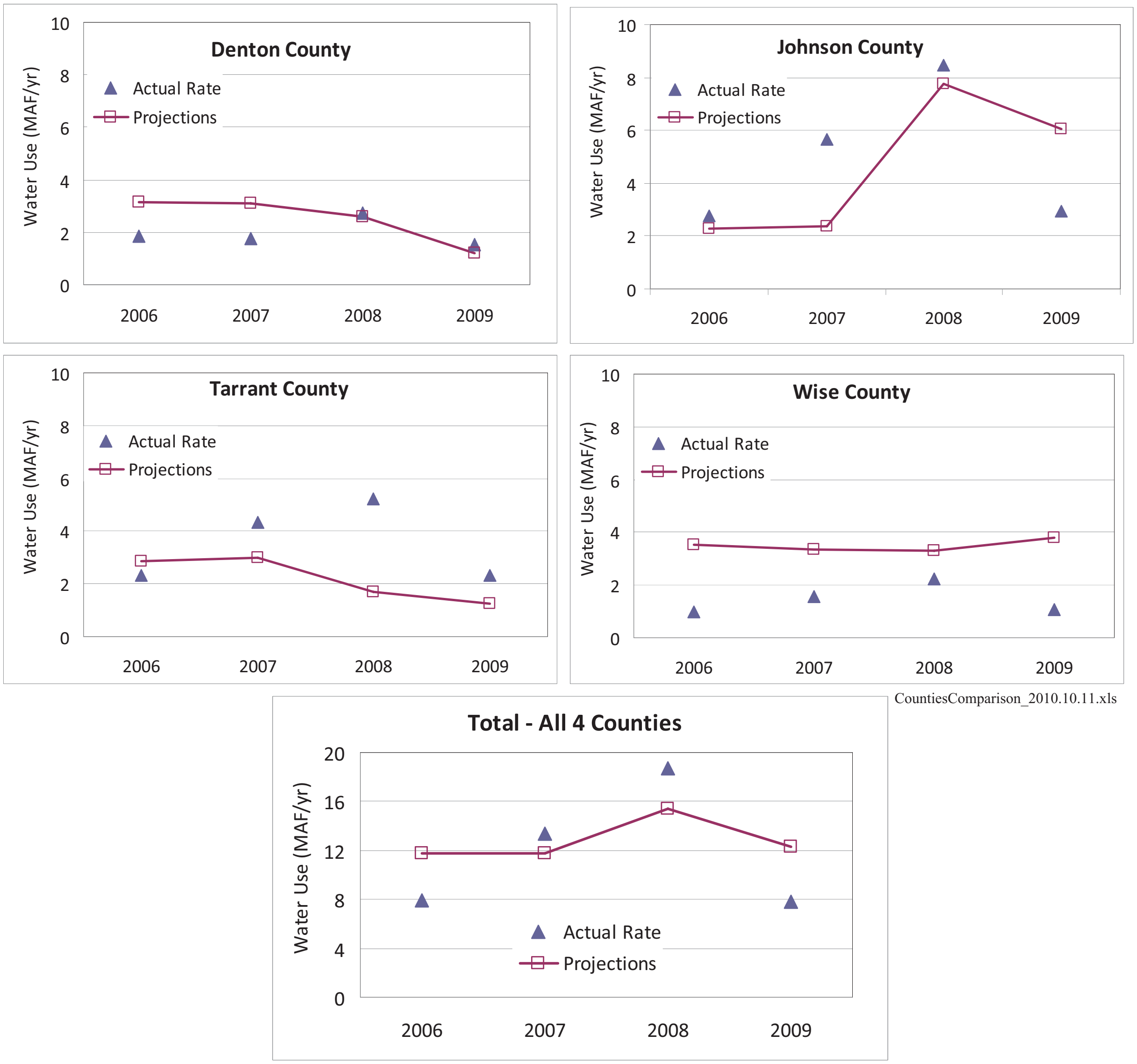
Source: Projections from Nicot and Potter (2007); actual water use from IHS database
Note: Tick for calendar year corresponds to the middle of the year (06/30); water use for each quarter (expressed in AF/yr) of a given year is on both sides of the calendar-year tick; 2010 yearly water use assumed that overall water use for the year will stay as in the first 2 quarters.

Figure 140. Comparison of water-use projections and actual figures in the Barnett Shale (2005–2010)



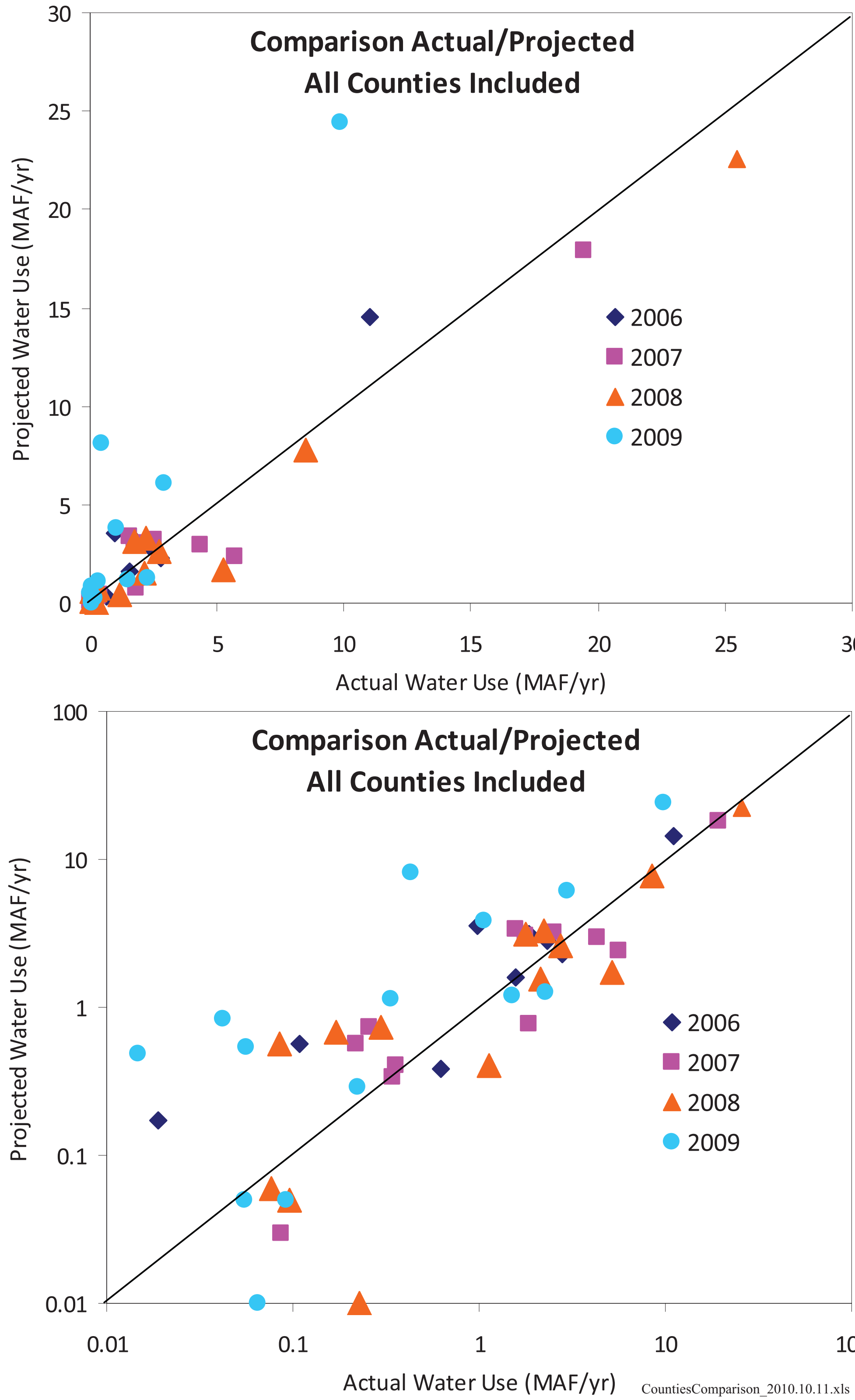
Source: Projections from Nicot and Potter (2007); actual water use from IHS database
Note: Tick for calendar year represents the end of the year (12/31); origin of both projection and actual water use is set on 01/01/2006; MAF = thousand AF

Figure 141. Comparison of cumulative water-use projections and actual figures in the Barnett Shale (2006–2010)



MAF = thousand AF

Figure 142. Comparison of actual vs. projected (high scenario) water use for four counties: Denton, Johnson, Tarrant, and Wise.



MAF = thousand AF

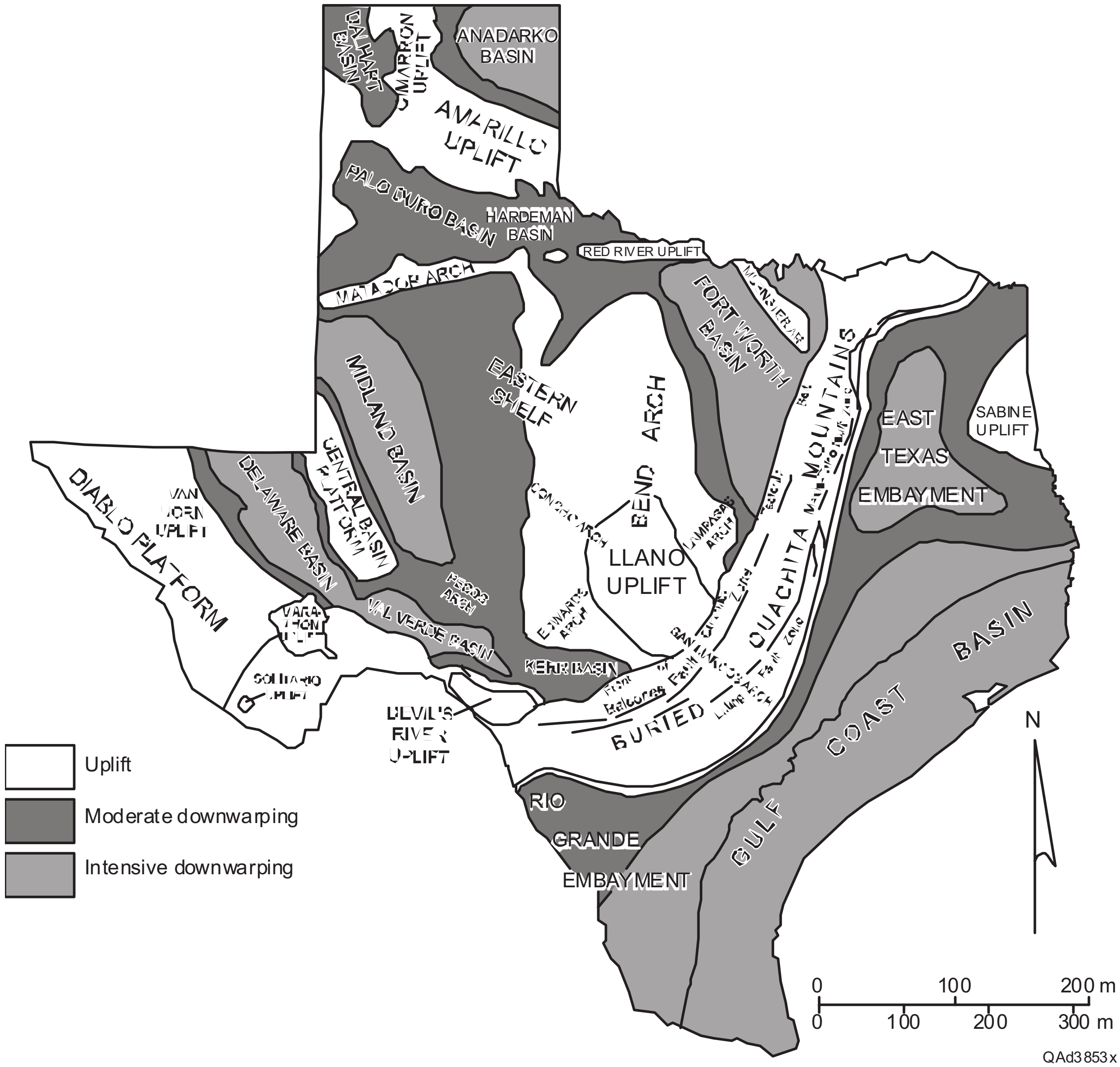
Figure 143. Comparison of actual vs. projected (high scenario) water use for all Barnett Shale counties

10 Appendix C:
Relevant Features of the Geology of Texas

This appendix provides an overview of the geology of Texas at it applies to hydrocarbon accumulations summarized from Ewing (1991). The state can be divided into basins (Figure 144). Most of West and Central Texas is underlain by Precambrian rocks that crop out mostly in the Llano Uplift in Central Texas and locally in the Trans-Pecos area. Starting in the Cambrian period, ~550 million years ago, failed continental rifting resulted in widespread deposition of shelf sediments on a stable craton (e.g., Ellenburger Group). Carbonate and clastic deposition continued until the late Devonian, 350 million years ago. Thickness of the deposits varies, with a maximum in the ancestral Anadarko Basin and total removal by erosion of some formations along a broad arch oriented NW-SE on the Amarillo-Llano Uplift axis. Beginning in the Mississippian period (starting 350 million years ago), the passive-margin history of rifting and subsidence was replaced by extensive deep-marine sedimentation and tectonic convergence on the eastern flank of the continental margin. This convergence episode yielded the so-called Ouachita Mountains, now eroded and buried, whose trace approximately follows the current Balcones Fault Zone that runs west from San Antonio and northeast through Austin to the east of Dallas. Behind the orogenic belt, during and after the compressive event, sedimentation continued in and around several inland marine basins, north and west of the current Balcones Fault Zone. Sedimentation was thicker in the basins and thinner or absent on platforms and arches. During these times (320– 270 million years ago) major subsidence and sediment accumulation, partly fed by the erosion of the Ouachita Mountains, occurred in the Permian Basin, including the Delaware and Midland Basins separated by the Central Platform Uplift. Farther north, the Anadarko Basin is separated from the Midland Basin by another basin and two structural highs. The Anadarko Basin also underwent abundant sedimentation during the Pennsylvanian and Permian and included coarse granitic detritus ("granite wash") from the Amarillo Uplift. The Fort Worth Basin is also filled with Pennsylvanian and Permian sediments.

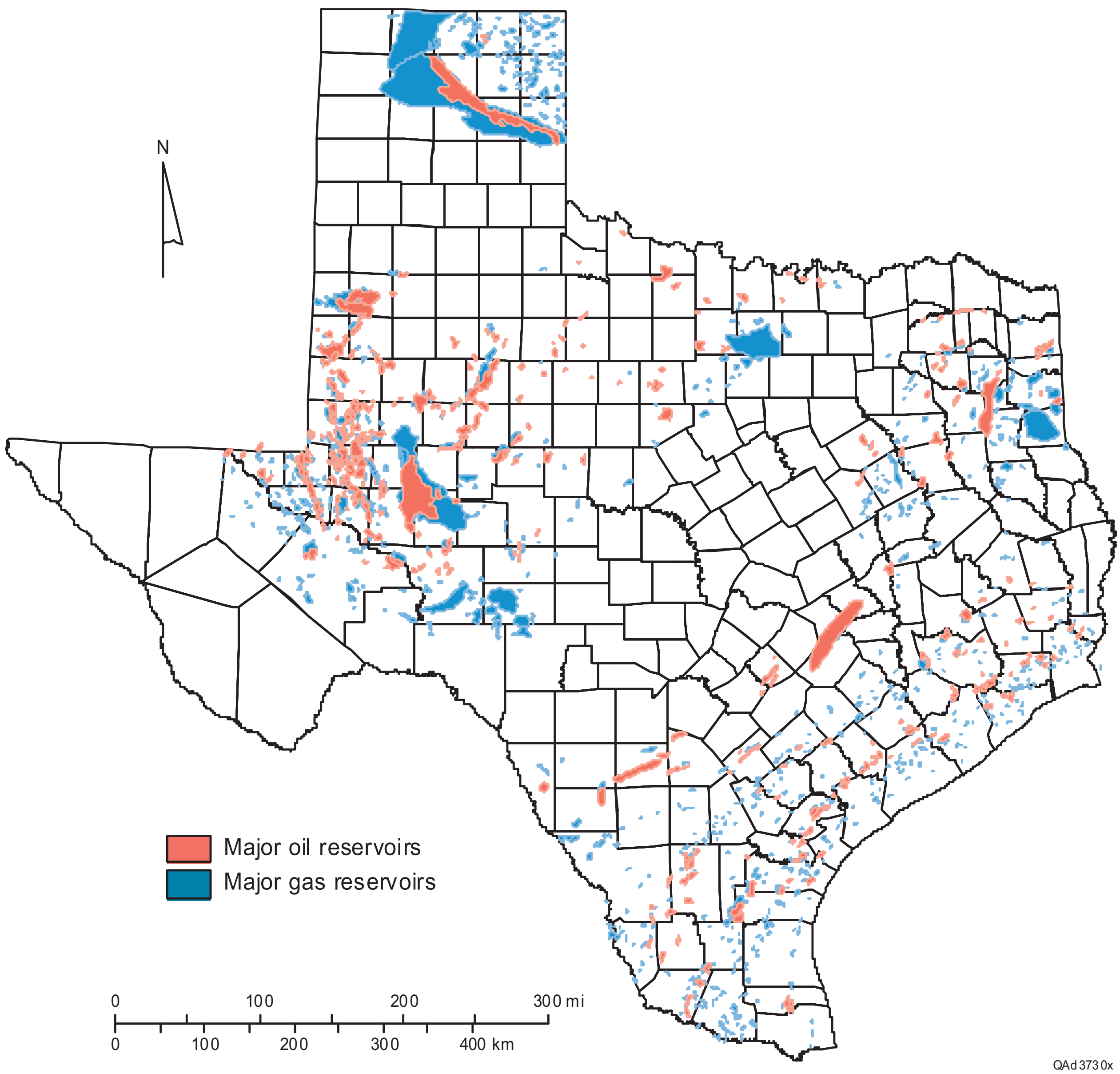
Beginning in Triassic time (250 million years ago), Texas was again subject to extension and volcanism, leading to Jurassic rifting of the continental margin and creation of the Gulf of Mexico and Atlantic Ocean. The focus of major geologic events shifted to the eastern part of the state. The small rift basins that initially formed were buried under abundant salt accumulation (Louann Salt). As the weight of sediments increased, the salt became unstable and started locally to move upward in diapirs, a phenomenon still locally active today. During the Cretaceous, sediments deposited from shallow inland seas formed broad continental shelves that covered most of Texas. Abundant sedimentation in the East Texas and Maverick Basins occurred during the Cretaceous. In the Tertiary (starting 65 million years ago), as the Rocky Mountains to the west started rising, large river systems flowed toward the Gulf of Mexico, carrying an abundant sediment load, in the fashion of today's Mississippi River. All the area west of the old Ouachita Mountain range was also lifted, generating a local sediment source, including erosional detritus from the multiple Tertiary volcanic centers in West Texas and Mexico. Six major progradation events, where the sedimentation built out into the Gulf Coast Basin, have been described.

Many Texas basins contain hydrocarbons (Figure 145). Their stratigraphy is detailed for oil and gas productive formations in Figure 146 and Figure 147 for the Gulf Coast and East Texas Basins and in Figure 148 and Figure 149 for the North-Central and West Texas Basins.



Source: modified from Kreitler (1989)

Figure 144. Generalized tectonic map of Texas showing location of sedimentary basins



Source: BEG map from Galloway et al. (1983) and Kosters et al. (1989)

Figure 145. Map of major oil and gas fields in Texas

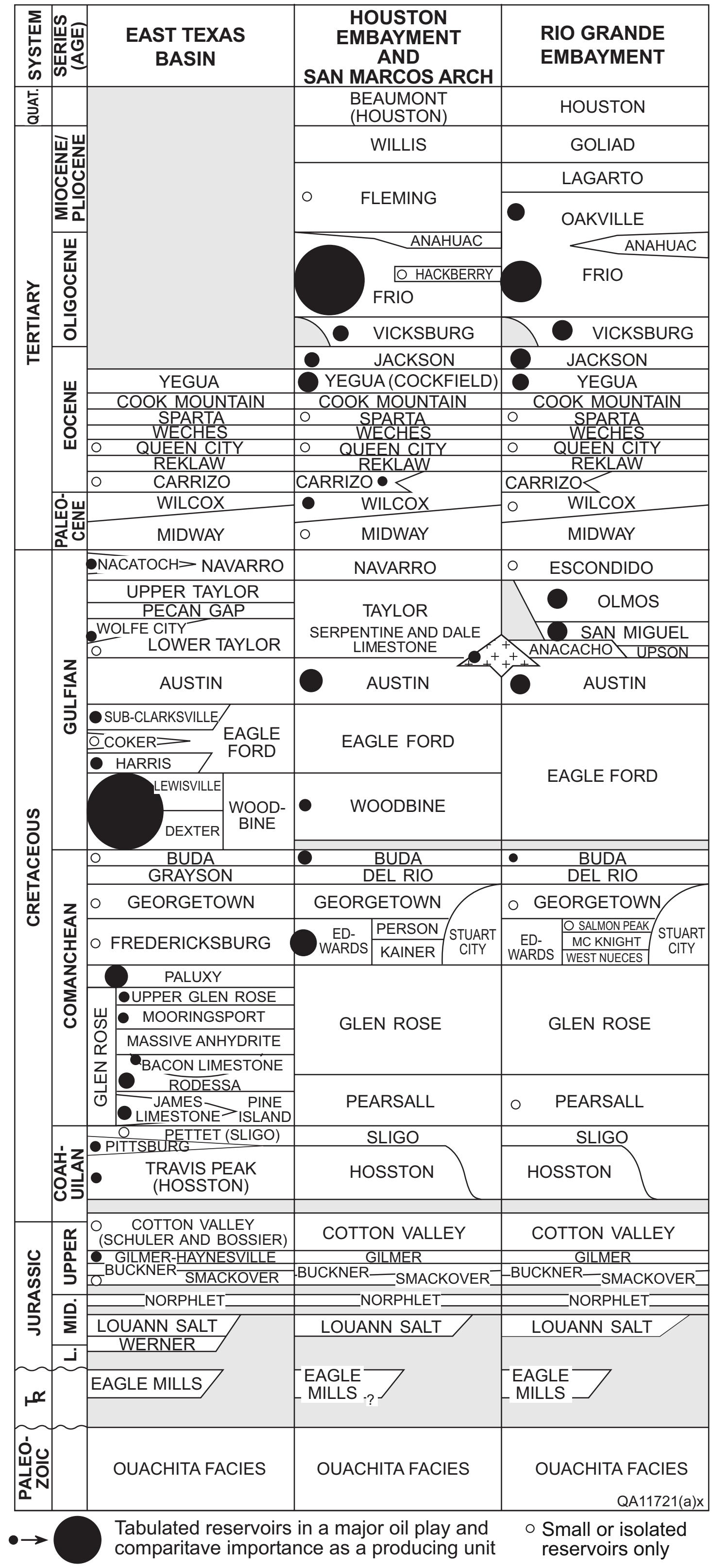


Figure 146. Stratigraphic column and relative oil production for the Gulf Coast and East Texas Basins (after Galloway and others, 1983)

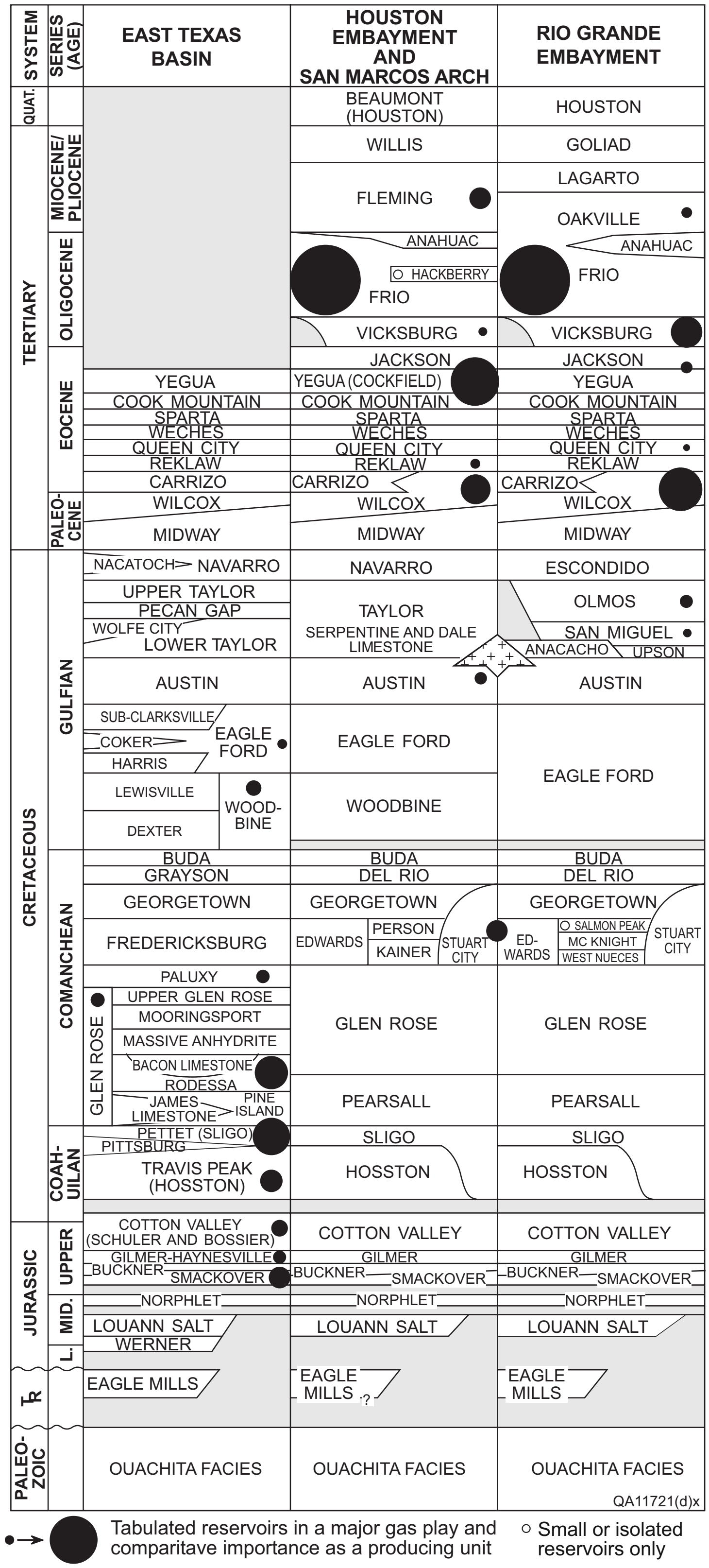


Figure 147. Stratigraphic column and relative gas production for the Gulf Coast and East Texas Basins (after Galloway and others, 1983)

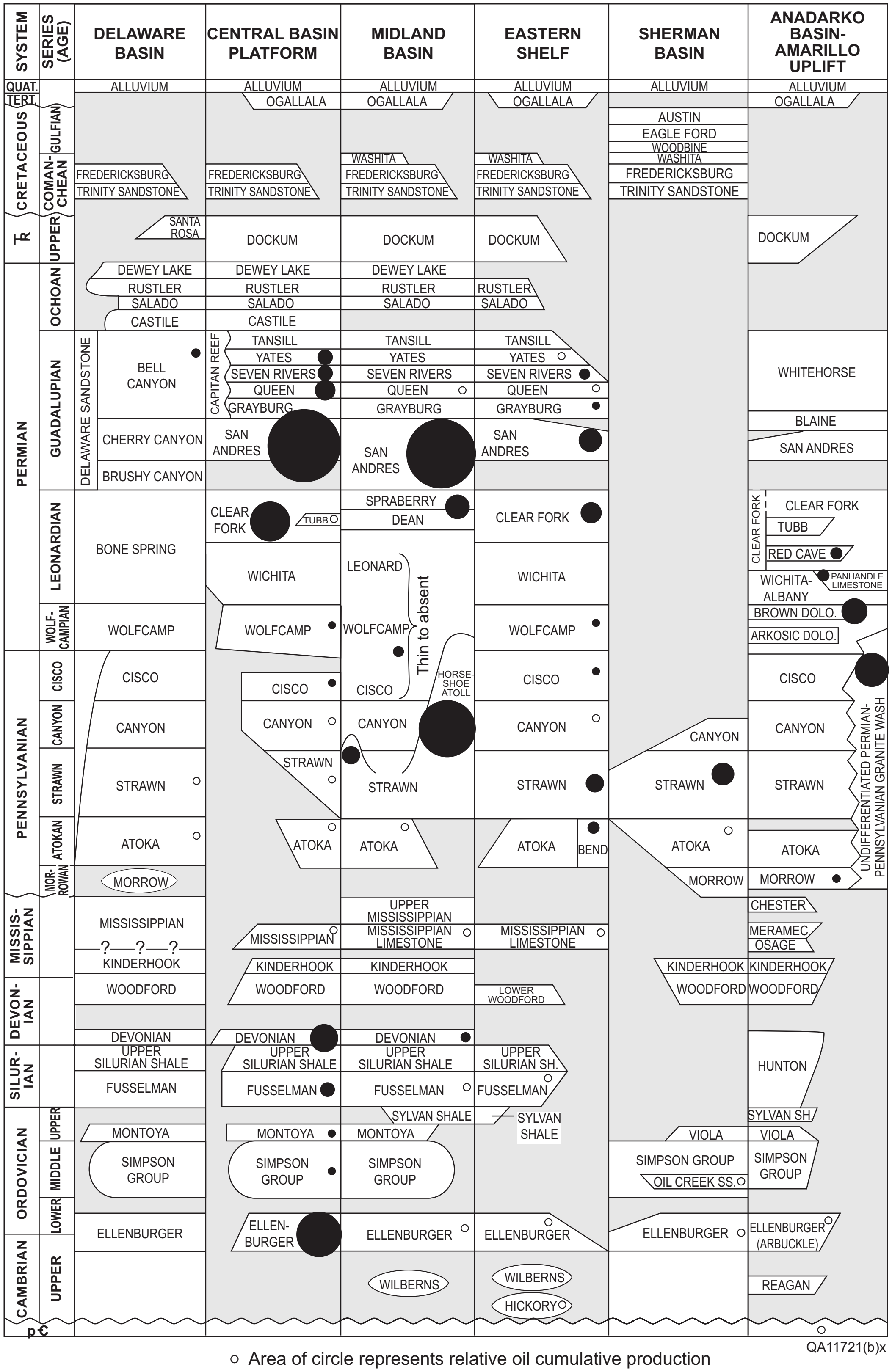
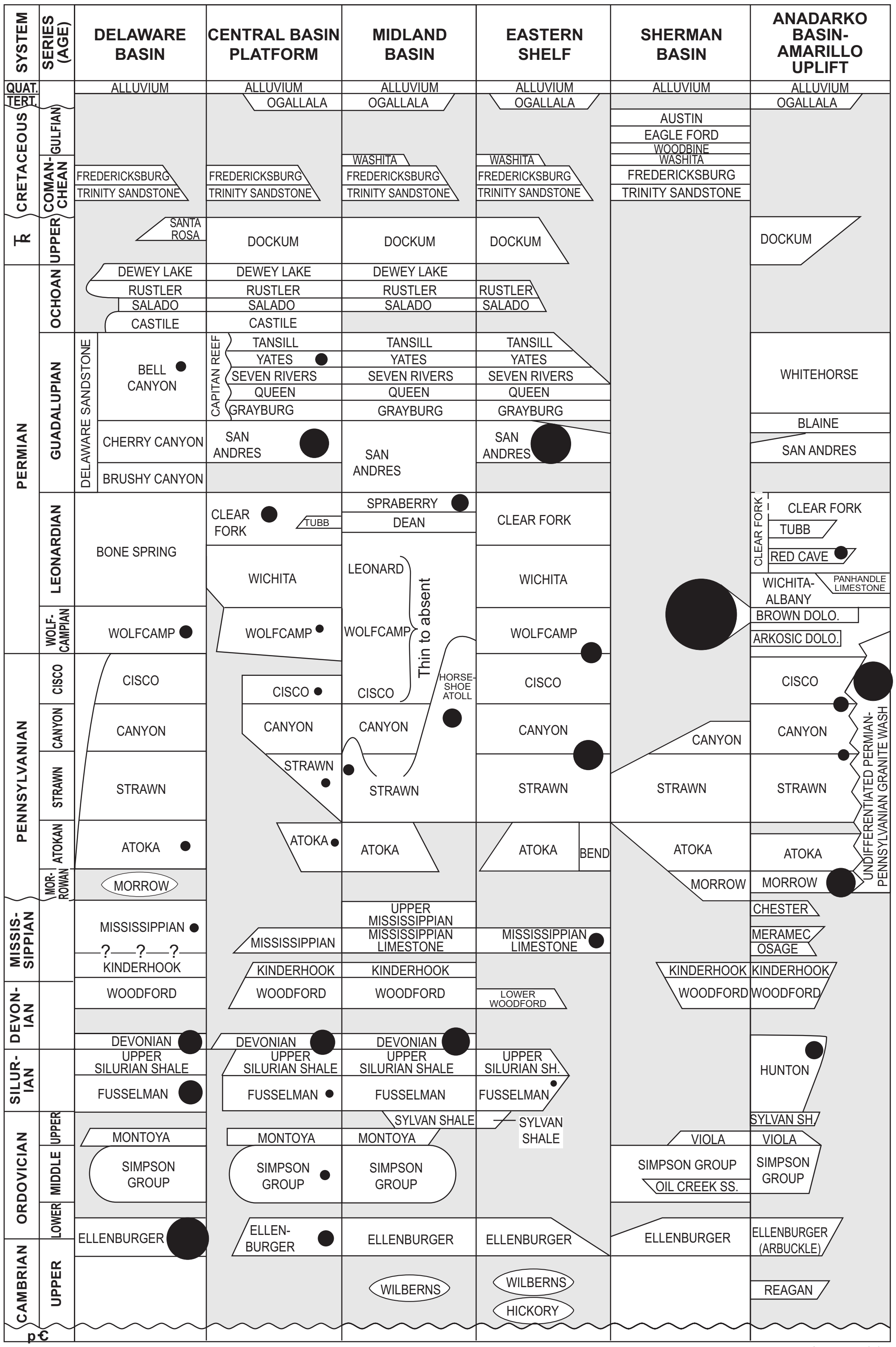


Figure 148. Stratigraphic column and relative oil production for the North-Central and West Texas Basins (after Kosters and others, 1989)



Area of circle represents relative gas cumulative production

Figure 149. Stratigraphic column and relative gas production for the North-Central and West Texas Basins (after Kosters and others, 1989)

11 Appendix D: Survey Questionnaires

During the course of this study, we performed two types of surveys: (1) one aimed at water users through trade associations: TMRA and TACA, and (2) one geared toward water suppliers/Groundwater Conservation Districts (GCDs). We performed an additional survey of oil operators in Texas to inquire about their waterflooding activities.

11.1 Survey of Facilities

As part of this study, we enlisted the assistance of two of the major associations representing the mining industry in Texas: the Texas Aggregate and Cement Association (TACA) and the Texas Mining and Reclamation Association (TMRA). With the endorsement of each association, letters were sent on behalf of the TWDB to all of the association member companies with a survey form. Forms were provided as both Word documents with narrative questions and as Excel documents in spreadsheet format. Examples of the forms are given at the end of this appendix. Survey questionnaires were sent to TMRA members in December 2009, and the association asked that all responses be returned for review of sensitive or proprietary information. Company survey questionnaires were sent to TACA members in February 2010 and handled the same way.

11.1.1 About the Trade Associations

The Texas Mining and Reclamation Association (TMRA) has a variety of members—in addition to individual members and consultancy, its membership includes the following companies: Clay Mining: Acme Brick Company, Boral Bricks, Inc., Elgin Butler Company, Southern Clay Products, U.S. Silica Company; Utilities/Lignite/Coal Mining: Luminant Mining, North American Coal Corporation, Texas Westmoreland Coal Company, Walnut Creek Mining Company, American Electric Power, NRG Energy, San Miguel Electric Cooperative, Inc., Texas Municipal Power Agency; Sand, Gravel and Stone Mining: Capitol Aggregates, LTD, Hanson Aggregates Central, Inc., Trinity Materials Company, Chemical Lime Company; and Uranium Mining: South Texas Mining Venture, Mestena Uranium, LLC, Rio Grande Resources Corporation, Signal Equities, LLC, Uranium Energy Corporation, Uranium Resources, Inc.
The Texas Aggregate and Cement Association (TACA) does not release the list of its membership but does include many small aggregate producers.

11.1.2 Response Rates

Aggregates: 6 companies representing 27 sites provided responses to the BEG. Complete responses are provided in Appendix G and include

Coal/Lignite: we received information back from all lignite mines in Texas (~100% success rate)

Uranium: we received information from several operators

11.2 Survey of GCDs

LBG-Guyton was charged with the task of researching and evaluating groundwater use for mining in Texas. We compiled a packet of the mine data that we were able to obtain through statewide public sources to send to all GCDs so that they might address any changes to water usage that they might be aware of. To begin with, a series of maps and tables of mineral mine data and locations throughout Texas were produced so that each district could see what data were available publicly. These maps and tables were included in a mailed packet, along with a survey requesting any mining information the district had available, an explanation of the data included in the packet, and a letter explaining the purpose of the study. The GIS maps contain all Texas GCDs and mine locations (active and inactive) in the TCEQ SWAP project database, and the data tables include mine data from MSHA and mining water-use projections from TWDB's 2007 *Water for Texas Report*.

Forty-seven (47) out of one hundred (100) questionnaires (47%) that were sent to GCDs were returned. Figure 150 is a map showing the districts that replied, as well as the mine sites that the TCEQ report lists as active in the state of Texas. Districts that replied to the survey are colored and labeled; all other districts are gray. Questions included in this packet are predominantly yes or no questions with requests for explanations of the answers if confirmed. The questions are listed in Table 71, with the answer percentage (using only those 47 GCDs that returned responses). In addition to the leading questions, explanation was requested if the answer was reported as yes. Studying these comments helped us discover some general findings among the survey questionnaires returned. In general, we found that few GCDs had extensive knowledge of mineral mining or mining water use within the district. Some districts had a general idea of what mining operations were active and inactive and could speculate as to how much water was being used according to permits, but none of the districts monitored actual water use.

Also, more districts thought that water use from mining data that had been reported in the TWDB report (such as presented in Table 75) was incorrect, excluding those that did not know. Few had contacted any of the mining entities, and even fewer had contacted the RRC to obtain data on mines. However, nine districts did report some quantitative knowledge of permitted volume of water use for specific mining entities. Table 72 details TWDB water use for mining WUG predictions from 2010 through 2060 and each of the district's own reported volumes for comparison.

Table 71. GCD mine-data questions and response percentages

Question	Total Answers	% Yes	% No	% Unk†	% >0
1. Does your district independently estimate water use by mining?	45	16 %	84 %		
2. Have you contacted Texas Railroad Commission to obtain data on mines?	45	4 %	96 %		
3. Do you have any way of validating the mining use estimates in Table 3?	45	18 %	82 %		
4. What portion of total water use in your district is used for mining?*	36			42 %	36 %
5. Have you contacted any of the entities listed in Table 1 or 2?	44	14 %	86 %		
6. Do you feel the data in Table 3 are accurate?	45	9 %	18 %	73 %	
7. Do you know of other mining facilities not included on the map?	43	9 %	91 %		
8. Do you have any additional information regarding groundwater or surface water use at the facilities?	40	15 %	85 %		

† Unknown—answered "Don't know"

*18 % reported 0 % water use for mining

Table 72. Mining water-use changes reported by certain GCDs

GCD	Volume (ac-ft)							Ratio of Reported/ Predicted 2010 Values	District Notes
	2010	2020	2030	2040	2050	2060	District Reported		
Barton Springs/Edwards Aquifer CD	1699	1821	1902	1982	2060	2116	826	49%	District-reported mine water use reported as industrial WUG.
Bee GCD	36	40	42	44	46	48	**105	292%	**% water use (201 ac-ft) split between Bee Co. and Live Oak Co. not specified so was assumed to be half for this exercise.
Harris-Galveston Subsidence District	1547	1713	1815	1917	2020	2112	25	2%	Other water use reported as commercial or industrial WUG.
Headwaters UWCD	167	165	164	163	162	161	109	65%	
Hickory UWCD No. 1	394	395	396	397	398	400	4771	1211%	
Live Oak UWCD	3894	4319	4583	4845	5108	5341	**105	3%	**% water use (201 ac-ft) split between Bee Co. and Live Oak Co. not specified so was assumed to be half for this exercise.
Lost Pines GCD	10483	10485	10486	5487	51	52	4410	42%	Reported use by ALCOA in 2009 for lignite mining.
McMullen GCD	195	203	207	211	215	218	1	1%	
Post Oak Savannah GCD	4025	4024	4024	3024	1524	1524	15000	373%	ALCOA water use reported as industrial WUG. Water rights end in 2038.

*Of those districts that replied with volume calculations, ⅔ reported lower volumes of mining water use than in the 2007 state water plan

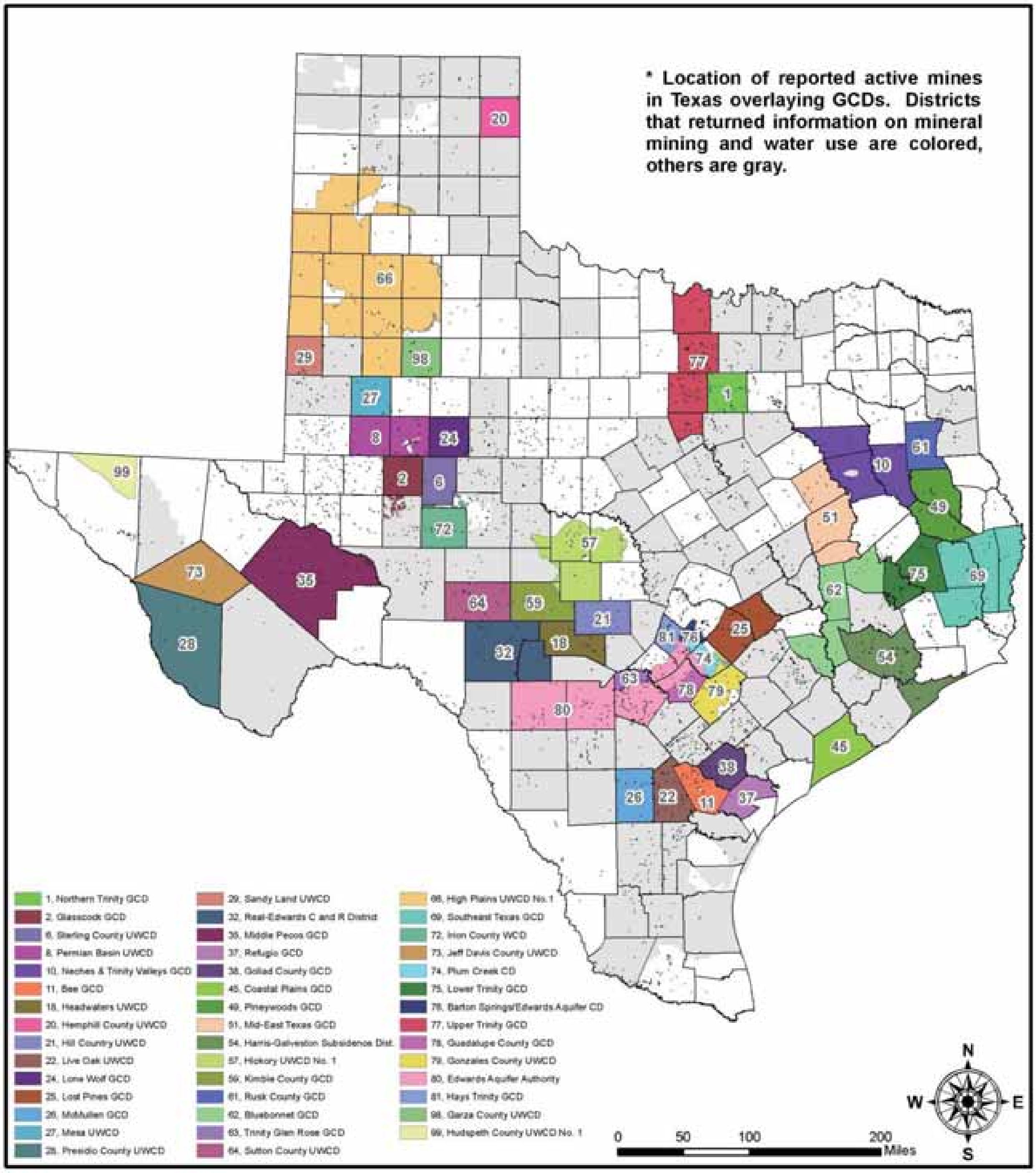


Figure 150. GCDs that have returned information on mineral mining water use in their district

11.3 Questionnaire Forms

To coal mining operators (modified to save space):

Date:

Name of Company and of Mining Operation (including SIC or SICs):

County of Mine Location:

Contact Name, Phone, E-mail, and Address:

Coal Production

1. Please rank factors affecting the amount of coal you produce from year to year in order from most (#1) to least important?

a. General economy (rank=)

b. Electricity demand projections (rank=)

c. Production capacity (rank=)

d. Other ________________________________ (rank=)

e. Other ________________________________ (rank=)

Water Source

1. Please indicate the approximate amount of water pumped each year as well as the unit used (acre-feet, gallons, etc.)

________________________ (unit: ___________)

2. Please circle the sources of the water pumped at your operations and indicate the approximate percentage of each applicable source:

a. Overburden dewatering (______%)

b. Pit dewatering (______%)

c. Depressurization (_____%)

d. Other ________________________ (______%)

Choice (d) is intended for facilities at which additional water not ultimately originating from dewatering or depressurization is needed (e.g., river, another aquifer)

3. Please circle factors affecting the amount of water pumped? (check all that apply)

Dewatering

a. The amount of coal to be produced

b. Proximity to surficial aquifer

c. Other _________________________________

Depressurization

a. The amount of coal to be produced

b. The safety factor to prevent floor heave

c. Proximity to aquifer

d. Other _________________________________

Other

a. The amount of coal to be produced

b. Other _________________________________

4. What is the quality (Total Dissolved Solids) of the water pumped at your operations for:

Dewatering

a. Fresh (<1000 mg/L)

b. Brackish (> 1000 mg/L and < 10,000 mg/L)

c. Saline (> 10,000 mg/L and < 35,000 mg/L)

d. Very Saline (> 35,000 mg/L)

Depressurization

a. Fresh (<1000 mg/L)
b. Brackish (> 1000 mg/L and < 10,000 mg/L)
c. Saline (> 10,000 mg/L and < 35,000 mg/L)
d. Very Saline (> 35,000 mg/L)
Other Source ____________________ *:*
a. Fresh (<1000 mg/L)
b. Brackish (> 1000 mg/L and < 10,000 mg/L)
c. Saline (> 10,000 mg/L and < 35,000 mg/L)
d. Very Saline (> 35,000 mg/L)

5. How often do you monitor the **rate and volume of water** pumped for depressurization/dewatering?
a. Daily
b. Monthly
c. Every 2-5 months
d. Yearly
e. Other:______________

6. How often do you monitor the **quality of water** pumped for depressurization/dewatering?
a. Daily
b. Monthly
c. Every 2-5 months
d. Yearly
e. Other:______________

7. Do you report the rate and quality of water pumped to a federal, state or local agency?
a. None
b. Texas Railroad Commission
c. Texas Water Development Board
d. Local Groundwater Conservation District
e. Other (please list) ______________

<u>Water Use</u>

1. For what specific mining activities do you consume the water pumped from dewatering/depressurization? (circle all that apply, provide approximate % if possible)
a. Dust suppression for mining (______%)
b. Dust suppression for hauling (______%)
c. Reclamation/revegetation (______%)
d. Coal washing (______%)
e. Transportation (______%)
f. Drilling (______%)
g. Other (please list) ______________ (______%)

2. Do you report the rate and quality of water consumed to a federal, state or local agency?
a. None
b. Texas Railroad Commission
c. Texas Water Development Board
d. Local Groundwater Conservation District
e. Other (please list) ______________

3. Do you supply water to other entities? Please circle all that apply.
a. None
b. Municipality (Name(s): ________________________)
c. Water supplier (other than municipality) (Name(s): _______________________)
d. Local farmers/ranchers/landowners

5. What factors affect whether or not pumped water is provided to these other entities? (circle all that apply)
a. Quality of water
b. Quantity and consistency of the amount pumped
c. Request from outside water users
d. Fee provided by outside water users
d. Other (please list) ______________________________

Water Discharge

1. Where do you discharge the water not consumed during operations? (provide approximate percentage as needed)

Dewatering

a. Freshwater lake or stream	(_______%)
b. Retention pond then lake or stream	(_______%)
c. Deep-well injection	(_______%)
d. Other _______________________	(_______%)

Depressurization

a. Freshwater lake or stream	(_______%)
b. Retention pond then lake or stream	(_______%)
c. Deep-well injection	(_______%)
d. Other _______________________	(_______%)

Other Source

a. Freshwater lake or stream	(_______%)
b. Retention pond then lake or stream	(_______%)
c. Deep-well injection	(_______%)
d. Other _______________________	(_______%)

2. Is the amount of water discharged monitored?
a. Yes
b. No

3. Do you report the monitored quantity to a federal, state or local agency?
a. None
b. Texas Railroad Commission
c. Texas Water Development Board
d. Local Groundwater Conservation District
e. Other (please list) _______________

Future of Lignite mining in Texas

1. Do you foresee any future developments in coal production that would make it more efficient or less water intensive? (Please list or describe any new technologies and the extent to which produced water would be decrease)

2. Do you expect water depressurization and dewatering pattern to remain the same over the short-term (1-9 years)?
a. Yes
b. No *If not, why?*

3. Do you expect water depressurization and dewatering pattern to remain the same over the long-term (10-50 years)?
a. Yes
b. No
If not, why?

To aggregate and other industrial mineral operators (modified to save space):

Date:
Name of Company & Mining Operation (including SIC or SICs):
County of Mine Location:
Contact Name, Phone, E-mail, and Address:

1) Please provide a brief description of your mining process, the ways that water is used at the facility, and the ways that water use is monitored or estimated (flow charts are OK). Please separate, if possible, the industrial mineral mining operations from other product manufacturing (cement, brick, etc.) that may occur on the same property.

2) Water Amount and Water Use. Please report the amount (specify unit: gallons, acre feet, etc.) of water used, the amount recycled (actual or percentage), and the net amount consumed in mining operations annually (or another time unit, in all cases, specify).

   Please break this into amounts for each type of use (extraction, rock washing, roadway watering, dust suppression on conveyor systems, etc.), if possible.

   Please break this into amounts obtained from surface water, groundwater, storm water, etc. and name the source water (stream, lake, aquifer, etc.). Please also note the water quality (fresh, brackish, saline)

   Please report the amount of water typically used in rock washing equipment in gallons per minute/ton per hour (gpm/tph) of mineral product processed.

   Is water discharge out of the facility boundaries sometimes needed? When? How much? Which water type?

   Are these monitored or estimated values? Based on what years?

3) Production. Please report maximum aggregate, sand & gravel, or other industrial mineral mining production (in tons) authorized per year, and an estimate of the range of typical production in recent years. Is production expected to increase, decrease, or remain unchanged in coming years?

4) Future Water Use. How many years has the mine been in operation and what is the projected life of the facility? Are any new industrial mineral mining operations by your company anticipated (if so, where and when)?

   What, if any, plans have been made to reduce water use or identify alternative water sources if water supply is reduced or becomes more expensive?

   What techniques or technologies could be utilized to reduce water use in the industrial mineral mining industry? Is use of saline or brackish water possible or likely to become more common?

   What are the key issues or challenges regarding water use being faced by your industry today or in the future?

To aggregate and other industrial mineral operators (alternate format in excel)

Name of Company & Mining Operation: Date:
County of Mine Location: Type of Mine/SIC:
Contact Name, Phone, E-mail, and Address:
Brief description of your mining process, the ways that water is used at the facility, and the ways that water use is monitored or estimated.

	Quantity of Water Used (Total)	Quantity of Water Recycled	Quantity of Water Consumed (Lost)	Quantity of Water Used in Extraction	Quantity of Water Used for Rock Washing
fresh					
brackish					
saline					
	Quantity of Water Used for Roadway Watering	Quantity of Water Used for Dust Suppression	Quantity of Water Discharged if any	Where? How often?	Rate of Wash Water Use (gpm/tph)
fresh					
brackish					
saline					
	Surface Water (%)	Name of Water Source(s) (lake X, river Y, storm water, etc.)	Groundwater (%)	Name of Water Source(s) (aquifer X, local alluvium, etc.)	
fresh					
brackish					
saline					
	Product Name	Typical Production (tpy)	Authorized Production (tpy)	Number of Years of Mine Operation	Projected Life of Facility
Product1					
Product2					
Product3					

Is water use estimated or monitored? Which is the base year?
Is production expected to increase, decrease, or remain unchanged in coming years?
Are any new mineral mining operations by your company anticipated (if so, where and when)?
What, if any, plans have been made to reduce water use or identify alternative water sources if water supply is reduced or becomes more expensive?
What techniques or technologies could be utilized to reduce water use in your industry? Is use of saline or brackish water possible or likely to become more common?
What are the key issues or challenges regarding water use being faced by your industry today or in the future?

To uranium operators (modified to save space):

Date:
Name of Company & Mining Operation (including SIC or SICs):
County of Mine Location:
Contact Name, Phone, E-mail, and Address:

1) Please provide a brief description of your mining process, the ways that water is used at the facility, and the ways that water use is monitored or estimated (flow charts are OK). Please separate, if possible, the mining operations from other operations that may occur on the same property.

2) Water Amount and Water Use. Please report the amount (specify unit: gallons, acre feet, etc) of water used, the amount recycled (actual or percentage), and the net amount consumed in mining operations annually.

   Please break this into amounts for each type of use (subsurface ISR operations, surface ion exchange operations, dust suppression, etc.), if possible.

   Please break this into amounts obtained from surface water, groundwater, storm water, etc. and name the source water (stream, lake, aquifer, etc.). Please also note the water quality (fresh, brackish, saline)

   Please report the amount of water typically used/consumed (specify) in gallons per pound of product (specify U, U_3O_8, yellow cake, etc.) if possible.

   Is water discharge out of the facility boundaries sometimes needed (deep well injection during restoration)? When? How much? Which water type?

   Are these monitored or estimated values? Based on what years?

3) Production. Please report production or an estimate of the range of typical production in recent years. Is production expected to increase, decrease, or remain unchanged in coming years?

4) Future Water Use. How many years has the mine been in operation and what is the projected life of the facility? Are any new uranium mining operations by your company anticipated (if so, where and when)?

   What, if any, plans have been made to reduce water use or identify alternative water sources if water supply is reduced or becomes more expensive?

   What techniques or technologies could be utilized to reduce water use in your industry? Is use of saline or brackish water possible or likely to become more common?

   What are the key issues or challenges regarding water use being faced by your industry today or in the future?

11.4 Survey of West Texas Oil Operators

For oil wells:

Water Use

		Fresh Water (<3,000 TDS)		Brackish Water (3,000–10,000 TDS)		Saline Water (>10,000 TDS)		
Item	**Unit**	**From GW**	**From SW**	**From GW**	**From SW**	**From GW**	**From SW**	**Notes/Explanation**
Water used in 2010 for well drilling	bbl							Project/estimate through 2010.
Water used in 2010 for well completion (& fracturing)	bbl							Project/estimate through 2010.
Water used in 2010 for waterflood operations	bbl							Project/estimate through 2010.
Water used for CO2 flood operations	bbl							Project/estimate through 2010.
Other substantial 2010 water use	bbl							Please note type of use and enter units as appropriate.

Operational Statistics				
Item	**Units**		**Notes/Explanation**	
No. **vertical** oil wells drilled in 2010	number		Estimate/project through year's end.	
Average well depth for **vertical** wells	ft		Estimate	
No. **horizontal** oil wells drilled in 2010	number		Estimate	
Average total lateral length for **horizontal** oil wells	ft		Estimate	
No. wells "fraced" in 2010	number		Estimate/project through year's end.	
Average depth/length of wells being "fraced"	ft		Estimate	
No. acres in active waterflood	number		Estimate	
No. acres in active CO2 flood	number		Estimate	
Estimated total 2010 oil production from waterfloods	bbl		Estimate	
Estimated total 2010 oil production from CO2 floods	bbl		Estimate	
Estimated total 2010 associated gas production from waterfloods	MMcf		Estimate	
Estimated total 2010 associated gas production from CO2 floods	MMcf		Estimate	

For gas wells

Water Use

Item	Unit	Fresh Water (<3,000 TDS)		Brackish Water (3,000–10,000 TDS)		Saline Water (>10,000 TDS)		Notes/Explanation
		From GW	From SW	From GW	From SW	From GW	From SW	
Water used for 2010 well drilling	bbl							Project/estimate through 2010.
Water used for 2010 well completion (& fracturing)	bbl							Project/estimate through 2010.
Other substantial 2010 water use	bbl							Please note type of use and enter units as appropriate.

Operational Statistics

Item	Units		Notes/Explanation
No. **vertical** gas wells drilled in 2010	number		Project/estimate through 2010.
Average well depth for **vertical** gas wells	ft		Estimate
No. **horizontal** gas wells drilled in 2010	number		Project/estimate through 2010.
Average total lateral length for **horizontal** gas wells	ft		Estimate
No. wells "fraced" in 2010	number		Estimate/project through year's end.
Average depth of vertical gas wells being "fraced"	ft		Estimate
Average total lateral length of horizontal gas wells being "fraced"	ft		Estimate

To GCDs:

Several figures and tables (following questionnaires) were sent to each GCD in Texas, along with the following questionnaire requesting information about the district's knowledge of mining operations within its borders.

When answering the following questions, we asked that GCDs not include water use for oil/gas activities.

1. Does your district independently estimate water use by mining?
    a. If yes – please describe
2. Have you contacted Texas Railroad Commission to obtain data on mines?
3. Do you have any way of validating the mining use estimates in Table 3? (*TWDB projections*)
    a. If yes – please describe method and result
4. What portion of total water use in your district is used for mining?
5. Have you contacted any of the entities listed in Table 1 or 2?
    a. If yes – please describe what you found
6. Do you feel the data in Table 3 are accurate?
    a. If yes – why?
    b. If no – why?
7. Do you know of other mining facilities not included on the map?
    a. If yes – do you have an estimate of the water use?
8. Do you have any additional information regarding groundwater or surface water use at the facilities?

In addition to figures similar to Figure 7 (Introduction section), we provided the GCDs with tables extracted from (1) the SWAP database (Table 73), (2) the MSHA database (Table 74), and (3) projections for the TWDB 2007 water plan for the counties included whole or in part in the GCD (Table 75). Only the last table gives some indication of mining water use.

Table 73. Example of information provided by the SWAP database (Lost Pines GCD)

Mine Sites in the Lost Pines GCD

PSOC ID	SITE ID	SITE NAME	LATITUDE (DD)	LONGITUDE (DD)	HORIZONTAL DATUM	LOCATION METHOD	AGENCY	ACTIVE	MINE TYPE	COMMODITY	GEOLOGIC FORMATION
4343	021BSW201		30.118900	-97.432800	27	MAP-M2	BEG	N		SAND, GRAVEL	WILLIS FORMATION
4344	021ELE301		30.363100	-97.268600	27	MAP-M2	BEG	Y		CLAY-COMMON	
4345	021ELE501		30.321899	-97.323303	27	MAP-M2	BEG	Y		CLAY-COMMON	
4346	021ELE502		30.332800	-97.292503	27	MAP-M2	BEG	Y		CLAY-COMMON	
4347	021ELE601		30.322201	-97.285301	27	MAP-M2	BEG	Y		CLAY-COMMON	
4348	021LAB401	Powell Bend	30.187500	-97.333336	27	MAP-M1	TNRCC	N	STRIP MINE	COAL-LIGNITE	CALVERT BLUFF FORMATION
4349	021LAB701		30.163601	-97.340797	27	MAP-M2	BEG	Y		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4350	021LAB702		30.156900	-97.339996	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4351	021PAI701		30.128300	-97.124199	27	MAP-M2	BEG	Y		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4352	021SMI201		30.091101	-97.200798	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4353	021SMI202		30.090000	-97.202202	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4354	021SMI901		30.015600	-97.164200	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4355	021SNW201		30.228300	-97.175598	27	MAP-M2	BEG	N		SAND, GRAVEL	REKLAW FORMATION
4356	021TOG201		29.988300	-97.169998	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4357	021TOG301		29.979200	-97.163300	27	MAP-M2	BEG	N		SAND, GRAVEL	WILLIS FORMATION
4359	021TOG303		29.988300	-97.129700	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4361	021TOG305		29.973600	-97.134697	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4362	021TOG306		29.975000	-97.137497	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4363	021UTY101		30.223600	-97.464699	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4364	021UTY401		30.208099	-97.490303	27	MAP-M2	BEG	Y		SAND, GRAVEL	ALLUVIUM
4365	021UTY601		30.175600	-97.413300	27	MAP-M2	BEG	Y		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4366	021WEP101		29.988100	-97.095802	27	MAP-M2	BEG	N	STRIP MINE	SAND, GRAVEL	ALLUVIUM
4367	021WEP102		29.987499	-97.099403	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
11080	287BEA701		30.411400	-97.250000	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	SIMSBORO SAND
11081	287BEA702		30.392799	-97.237503	27	MAP-M2	BEG	N	PIT	CLAY	SPARTA SAND
11082	287DIB201		30.343599	-96.805000	27	MAP-M2	BEG	Y	PIT	SAND, GRAVEL	YEGUA FORMATION
11083	287DIB202		30.343100	-96.796898	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	YEGUA FORMATION
11084	287DIB203		30.343300	-96.792503	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	YEGUA FORMATION
11085	287DIB204		30.342199	-96.795303	27	MAP-M2	BEG	Y	PIT	SAND, GRAVEL	YEGUA FORMATION

Table 74. Example of information provided by the MSHA database sent to GCDs

Texas MSHA Mine Database

Mine ID	Mine Name	Status	Type	Primary Commodity	Secondary Commodity	Operator Name	County	Street	PO Box	City	State	Zip	Nearest Town
4100249	Athens Plant & Pits	Intermittent	Surface	Common Clays NEC		Hanson Brick	Henderson	200 Athens Brick Road		Athens	TX	75751	Athens
4100252	Balcones Pit & Plant	Active	Surface	Common Clays NEC		Balcones Minerals Corp	Fayette	233 Balcones Lane		Flatonia	TX	78941	Flatonia
4100253	Barrett Base Plt	Active	Surface	Crushed, Broken Limestone NEC		Alamo Concrete Products Ltd	Bexar	6889 EAST EVANS ROAD		SAN ANTONIO	TX	782662813	San Antonio
4100262	Kosse Plant	Active	Surface	Common Clays NEC		U S Silica Company	Limestone	FM 2749		Kosse	TX	76653	Kosse
4100264	Standard Pit	Intermittent	Surface	Clay, Ceramic, Refractory Mnls.		Acme Brick Company	Bastrop	1776 Old McDade Road		Elgin	TX	78621	Elgin
				Common Clays		Elgin-Butler Brick							

Table 75. Example of information provided by the 2007 TWDB water plan sent to GCDs (Lost Pines GCD)

RWPG	County Name	WUG ID	WUG Name	Basin Name	TWD 2010	TWD 2020	TWD 2030	TWD 2040	TWD 2050	TWD 2060	Regional Comments
G	LEE	071003144	MINING	BRAZOS	5450	5450	5450	5450	13	13	
K	BASTROP	111003011	MINING	GUADALUPE	7	8	8	8	8	8	
K	BASTROP	111003011	MINING	COLORADO	5016	5018	5018	18	19	20	
K	BASTROP	111003011	MINING	BRAZOS	10	9	10	11	11	11	

12 Appendix E:
Supplemental Information Provided by GCDs

Some GCDs provided useful information. Some have already been mentioned in Appendix D (Table 72). As mentioned previously, few responses contained information useful to quantifying total groundwater usage by mining operations in Texas GCDs. However, a few are worth summarizing here because their account of groundwater usage varies from what is reported in the 2007 *Water for Texas Report*.

In addition, none of the GCDs located in the mining belt reported information regarding lignite mining. However, lignite mines and water use shown on the maps within these districts were not contested in any of the surveys we received. Five major areas in West Texas produce oil and/or gas: Andrews, Stephens, Hockley, Gaines, and Yoakum Counties. Three of these counties have a governing groundwater district: Hockley (High Plains UWCD), Gaines (Llano Estacado UWCD), and Yoakum (Sandy Land UWCD). We contacted these GCDs as well as Stephens and Andrews Counties' AgriLife Extension Offices. The three GCDs replied to our requests but let us know that they do not retain any records of oil/gas water use within their respective districts. The two county offices contacted did not reply with any information.

See Appendix A of LBG-Guyton (2010) for a more detailed summary table and scanned copies of responses received from the GCDs that were sent information.

- The Barton Springs/Edwards Aquifer Conservation District reported one limestone mining operation not listed, as well as one mining operation listed as an active quarry that is no longer in use.
- Bee County and Live Oak GCDs reported that they are unaware of any uranium mines that are using any water because the uranium mines have been closed, are still in reclamation phase, and should not use much or any water. It is conservatively reported that 201 ac-ft of groundwater is used for uranium mining between the two districts.
- Harris-Galveston Subsidence District reported back on five known mining operations and their permitted water use: Swiley and Pit Plant (est. use, 100,000 gal/yr), Hockley Mine (est. use, 1 million gal/yr), Densimix (est. use, 0.1 million gal/yr), Megasand Enterprises (est. use, 3,960 gal/yr), and Petroleum Coke Grinding (est. use, 0 gal/yr). See Appendix A f LBG-Guyton (2010) for details on these water users by HGSD.
- Headwaters UWCD provided a table of mine-water users and their information. It is noted in the table that the Wheatcraft pit has a groundwater permit for 62 ac-ft and that Martin Marietta has a groundwater permit for 47 ac-ft. See Appendix A of LBG-Guyton (2010) for details provided on these water users by HUWCD.
- Hickory UWCD seemed to have the largest discrepancy between permitted mine-water use and reported estimates of water use in the 2007 WFT report. In a table including all but two mining operations, permitted water use was reported for McCulloch and Mason Counties. The total water permitted for McCulloch County came to 4,212 ac-ft, and the total permitted in Mason County, 559 ac-ft. These estimates are much larger than the 171 and 6 ac-ft (respectively) reported in the 2007 WFT report.
- Lost Pines GCD reported use of groundwater for lignite mining only. It reported the groundwater use by ALCOA in 2009 to be 4,410 ac-ft.
- McMullen GCD reported that all sand and gravel pits in the district stopped operating and stopped using water 20 years ago. This fact may reduce assumed water use in this district

- Mesa UWCD reported very little water being used for mining currently.
- Neches and Trinity Valleys GCDs reported that the amounts reported by the 2007 WFT report may be excessive because they are ~6% of total current water production in the district.
- Post Oak Savannah GCD reported a 15,000-ac-ft permit for groundwater use by ALCOA that ends in 2038.
- Sutton County UWCD reported no mining operations in Sutton County and that there should be no water used for such operations.
- Red Sands GCD returned only a hand-drawn map showing known mining operations within the district, some of which were not shown on the GIS map that had been sent out.

13 Appendix F: Water-Rights Permit Data and 2008 Water-Rights Reporting Data

The following two tables (Table 76 and Table 77) list data dump from of the TCEQ database concerning surface-water rights.

Table 76. 2008 Water-rights reporting data

			Annual	Annual	Annual
		River	Diverted	Return	Consumed
Year	Name of Company	Basin	Amount	Flow	Amount
2008	AKIN	Sabine	0	0	0
2008	ALAMO CONCRETE PRODUCTS LTD	Brazos	165.424	150.205	15.219
2008	ALCOA INC	Brazos	0	0	0
2008	ALCOA INC	Brazos	0	0	0
2008	ALON USA REFINING INC	Colorado	21.3	0	21.3
2008	ASH GROVE TEXAS LP	Trinity	289.3	0	289.3
2008	BASELINE OIL & GAS CORP	Brazos	1000	0	82.61
2008	BELL SAND COMPANY	Neches	4.75	0	0
2008	BLUE SKY OILFIELD SERVICE LLC	Brazos	0	0	0
2008	BLYTHE	Colorado	0	0	0
2008	BOWIE, CITY OF	Trinity	1.3738	0	1.3738
2008	BRAZOS RIVER AUTHORITY	Brazos	5268	0	5268
2008	BRAZOS RIVER AUTHORITY	Brazos	426	0	426
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	13	0	13
2008	BRAZOS WATER STATION	Brazos	29.09	0	29.09
2008	BRECKENRIDGE GASOLINE CO	Brazos	0	0	0
2008	BURLINGTON RESOURCES OIL & GAS CO LP	Brazos	10	0	10
2008	BURLINGTON RESOURCES OIL & GAS CO LP	Brazos	10	0	10
2008	CAMPBELL CONCRETE & MATERIALS LP	Brazos	1135	997	140
2008	CAPITOL AGGREGATES LTD	Brazos	53.61	0	53.61
2008	CAPITOL AGGREGATES LTD	Colorado	0	0	0
2008	CARAWAY	Brazos	0	0	0
2008	CAVERN DISPOSAL INC	Trinity	36	0	36
2008	CERVENKA	Colorado	0	0	0
2008	CHAMBERS-LIBERTY COS ND	Trinity	0	0	0
2008	CHESAPEAKE ENERGY INC	Brazos	0	0	0
2008	CHEVRON PHILLIPS CHEMICAL CO LP	Brazos-Colorado	453.71	339.71	0

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	CITATION 1994 INVESTMENT LTD PARTNERSHIP	Brazos	0	0	0
2008	CITATION 1998 INVESTMENT LTD PARTNERSHIP	Brazos	0	0	0
2008	CITATION 1998 INVESTMENT LTD PARTNERSHIP	Brazos	58.4567	0	58.4567
2008	CLEBURNE, CITY OF	Brazos	0	0	0
2008	COLORADO RIVER MWD	Colorado	9	0	0
2008	COLORADO RIVER MWD	Colorado	843.2	0	0
2008	COLORADO RIVER MWD	Colorado	0	0	0
2008	COLORADO RIVER MWD	Colorado	0	0	0
2008	COLORADO RIVER MWD	Colorado	0	0	0
2008	CONOCOPHILLIPS CO	Brazos-Colorado	0	0	0
2008	DALLAS, CITY OF	Trinity	0	0	0
2008	DEVON ENERGY PRODUCTION CO LP	Brazos	0	0	0
2008	EASTLAND INDUSTRIAL FOUNDATION	Brazos	0	0	0
2008	EBAA IRON INC	Brazos	0	0	0
2008	EL PASO CO WID 1	Rio Grande	0	0	0
2008	ENCANA OIL & GAS USA INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	FAIR OIL LC	Cypress	0	0	0
2008	FRANKLIN LIMESTONE COMPANY	Brazos	0	0	0
2008	GEOCHEMICAL SURVEYS	Brazos	0	0	0
2008	GRAHAM, CITY OF	Brazos	0	0	0
2008	GREEN	Canadian	0	0	0
2008	GREENBELT M&I WA	Red	0	0	0
2008	GULF COAST WATER AUTHORITY	Brazos	0	0	0
2008	H R STASNEY & SONS LTD	Brazos	54.51	0	0
2008	HALLWOOD PETROLEUM	Brazos	0	0	0
2008	HANSON AGGREGATES CENTRAL INC	Trinity	2392.24	2221.34	2392.24
2008	HANSON AGGREGATES CENTRAL INC	Trinity	0	0	0
2008	HANSON AGGREGATES WEST INC	Trinity	0	0	0
2008	HANSON AGGREGATES WEST INC	Trinity	125.75	114.44	125.75
2008	HENRIETTA, CITY OF	Red	0	0	0
2008	HUDSPETH COUNTY CRD 1	Rio Grande	0	0	0
2008	INGRAM ENTERPRISES LP	Brazos	43.85	0	43.85

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	J & W SUPPLY INC	Brazos	30	0	30
2008	JACKSON SAND & GRAVEL INC	Trinity	0	0	0
2008	JANES GRAVEL CO	Brazos	446.23	0	0
2008	KEECHI VALLEY CATTLE CO	Brazos	0	0	0
2008	KERSH	Neches	4.75	0	0
2008	LATTIMORE MATERIALS COMPANY	Brazos	63.53	0	63.53
2008	LATTIMORE MATERIALS COMPANY	Brazos	572.14	0	572.14
2008	LEONARD WITTIG GRASS FARMS INC	Brazos-Colorado	0	0	0
2008	LOWER COLORADO RIVER AUTHORITY	Colorado	0	0	0
2008	LOWER COLORADO RIVER AUTHORITY	Colorado	0	0	0
2008	LUMINANT GENERATION CO LLC	Cypress	492	0	492
2008	LUMINANT MINING CO LLC	Sabine	376	0	376
2008	LUMINANT MINING CO LLC	Sabine	0	0	0
2008	MARTIN MARIETTA MATERIALS SOUTHWEST INC	Trinity	0.25	0	0.25
2008	MINERAL WELLS SAND & GRAVEL	Brazos	0	0	0
2008	MOBLEY COMPANY INC	Colorado	0	0	0
2008	MOBLEY COMPANY INC	Colorado	0	0	0
2008	MOBLEY COMPANY INC	Colorado	0	0	0
2008	MOHR	Colorado	0	0	0
2008	MORTON SALT COMPANY INC	Sabine	76.34	0	0
2008	NORTH CENTRAL TEXAS MWA	Brazos	0	0	0
2008	NORTH RIDGE CORPORATION	Brazos	0	0	0
2008	NORTH TEXAS LIVING WATER RESOURCES LLC	Brazos	0	0	0
2008	NORTH TEXAS LIVING WATER RESOURCES LLC	Brazos	0	0	0
2008	OCCIDENTAL PERMIAN LTD	Brazos	0	0	0
2008	PITCOCK BROTHERS READY-MIX	Brazos	0	0	0
2008	PLAINS PETROLEUM OPERATING CO	Brazos	0	0	0
2008	PREMCOR PIPELINE CO	Neches-Trinity	51.468	0	51.468
2008	PUMPCO INC	Brazos	2.7496	0.4677	2.7496
2008	QUICKSILVER RESOURCES INC	Brazos	1709.11	0	1709.11
2008	RED RIVER AUTHORITY	Red	0	0	0
2008	SABINE MINING COMPANY	Sabine	157.76	0	0
2008	SABINE MINING COMPANY	Sabine	0	0	0
2008	SAN JACINTO RIVER AUTHORITY	San Jacinto	0	0	0
2008	SAN JACINTO RIVER AUTHORITY	Trinity	0	0	0
2008	SANCO MATERIALS CO	Colorado	25.6	0	25.6

			Annual	Annual	Annual
		River	Diverted	Return	Consumed
Year	Name of Company	Basin	Amount	Flow	Amount
2008	SANCO MATERIALS CO	Colorado	8.76	0	8.76
2008	SCHKADE	Brazos	0	0	0
2008	SHUMAKER ENTERPRISES INC	Colorado	249.74	0	249.74
2008	SOUTHWESTERN GRAPHITE CO	Colorado	0	0	0
2008	SWANSON MULESHOE RANCH LTD	Brazos	0	0	0
2008	SWEPI LP	Brazos	0	0	0
2008	TARRANT INVESTMENT CO INC	Brazos	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	316	0	316
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TAYLOR	Colorado	0	0	0
2008	TERRY JACKSON INC	Colorado	0	0	0
2008	TERRY JACKSON INC	Colorado	0	0	0
2008	TEX IRON INC	Neches	0	0	0
2008	TEXAS INDUSTRIES INC	Trinity	0	0	0
2008	TEXAS INDUSTRIES INC	Colorado	0	0	0
2008	TEXAS MUNICIPAL POWER AGENCY	Brazos	0	0	0
2008	TEXAS MUNICIPAL POWER AGENCY	Brazos	0	0	0
2008	THISTLE DEW RANCH	Brazos	0	0	0
2008	TLC INVESTMENTS LLC	Brazos	0	0	0
2008	TRINITY MATERIALS INC	Brazos	0	0	0
2008	TRINITY MATERIALS INC	Trinity	0	0	0
2008	TRINITY MATERIALS INC	Trinity	51.9814	0	0
2008	TXI OPERATIONS LP	Brazos	0	0	0
2008	TXU BIG BROWN MINING CO LP	Trinity	0	0	0
2008	TXU MINING COMPANY LP	Sabine	0	0	0
2008	TXU MINING COMPANY LP	Sabine	307	0	307
2008	TXU MINING COMPANY LP	Brazos	0	0	0
2008	TXU MINING COMPANY LP	Cypress	0	0	0
2008	TXU MINING COMPANY LP	Sabine	0	0	0
2008	TXU MINING COMPANY LP	Cypress	0	0	0
2008	TXU MINING COMPANY LP	Sulphur	65	0	65
2008	TXU MINING COMPANY LP	Cypress	132	0	132
2008	TXU MINING COMPANY LP	Sabine	0	0	0
2008	TXU MINING COMPANY LP	Sulphur	0	0	0
2008	UNDERWOOD	Brazos	15.81	0	15.81

			Annual	Annual	Annual
		River	Diverted	Return	Consumed
Year	**Name of Company**	**Basin**	**Amount**	**Flow**	**Amount**
2008	UNION OIL COMPANY OF CALIF	Neches	0	0	0
2008	UNITED STATES DEPT OF ENERGY	Neches-Trinity	50.69	0	50.69
2008	UNITED STATES OF AMERICA	Rio Grande	0	0	0
2008	UPPER NECHES RIVER MWD	Neches	0	0	0
2008	US DEPARTMENT OF ENERGY	Brazos	81.06	0	81.06
2008	VULCAN CONSTRUCTION MATERIALS LLP	Brazos	139.34	0	0
2008	W F COMPANY LTD	Colorado	0	0	0
2008	WAGGONER	Red	0	0	0
2008	WALNUT CREEK MINING COMPANY	Brazos	0	0	0
2008	WEATHERFORD, CITY OF	Trinity	0	0	0
2008	WEIRICH BROTHERS INC	Colorado	0	0	0
2008	WEIRICH BROTHERS INC	Colorado	0	0	0
2008	WEST CENTRAL TEXAS MWD	Brazos	45.91	0	0
2008	WESTERN COMPANY OF TEXAS INC	Brazos	1031.33	0	1031.33
2008	WHARTON COUNTY GENERATION LLC	Brazos-Colorado	0	0	0
2008	WHITE RIVER MWD	Brazos	7.75	0	7.75
2008	WHITE RIVER MWD	Brazos	0	0	0
2008	WHITESIDE	Red	0	0	0
2008	WICHITA CO WID 2	Red	22	0	22
2008	WILLIAMS PRODUCTION GULF COAST LLP INC	Brazos	0.346	0	0
2008	ZEBRA INVESTMENTS INC	Brazos	53.4	0	53.4
	Totals		**564,147.36**	**259,933.12**	**168,660.45**

Source: TCEQ Central Registry database

Table 77. Water-rights permit data

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
UPPER NECHES RIVER MWD		Anderson			AM 10/14/92,9/28/99,3/1/00.MULTI-EVERYTH
SAN MIGUEL ELECTRIC COOP INC	SAN MIGUEL LIGNITE MINE	Atascosa	120.00		SEDIMENTATION CONTROL AND DUST SUPPRESSION PURPOSES
NORTH CENTRAL TEXAS MWA		Baylor	500.00		
BRAZOS RIVER AUTHORITY		Bell			MAX RATE "UNSPECIFIED"
BRAZOS RIVER AUTHORITY		Bell			
FRANKLIN LIMESTONE COMPANY		Bell	138.00	69.00	
CAPITOL AGGREGATES INC	CAGNON SAND & GRAVEL PLANT	Bexar	431.00	5.00	AMEND 2/93,7/94,9/96,10/98.SC,08/28/02
CAPITOL AGGREGATES INC	CAGNON SAND & GRAVEL PLANT	Bexar	769.00	10.00	AMEND 2/93,7/94,9/96,10/98.SC,08/28/02
CAPITOL AGGREGATES INC	CAGNON SAND & GRAVEL PLANT	Bexar	3,304.00	585.00	AMEND 2/93,7/94,9/96,10/98.SC,08/28/02
JOHN MCPHERSON ET AL		Bosque			AMENDED 5/15/2009: CHANGE TO MULTI-USE; ADDED MINING USE
CHEVRON PHILLIPS CHEMICAL CO LP	CLEMENS TERMINAL	Brazoria	3,000.00		
CHEVRON PHILLIPS CHEMICAL CO LP	CLEMENS TERMINAL	Brazoria	2,350.00		
UNITED STATES DEPT OF ENERGY	BRYAN MOUND SPR SITE NEAR FREEPORT	Brazoria	52,000.00		TOTAL 215K. AM 7/31/89, 3/26/2001
APACHE CORPORATION		Brazos	20.00		
LOWER COLORADO RIVER AUTHORITY		Burnet			SEE 5482-6.AM 10/89,3/90,3/96.AM C ABAND
SOUTHWESTERN GRAPHITE CO	DIV OF DIXON TICONDEROGA	Burnet	400.00		
GUADALUPE-BLANCO RIVER AUTHORITY		Calhoun			AM 4/91,5/04,9/04,5/1/2007:STAT DISTRICT
UNION CARBIDE CHEM & PLASTICS		Calhoun			AMEND 4/17/91.PART OWNER WITH GBRA
DOUGLAS M BRICE		Cameron			AMEND 3/13/95, 6/4/99
JOEL RUIZ ET UX		Cameron			RATE:23-2707.AMEND 10/30/84,7/2/99

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
MICHAEL A MACMAHON		Cameron	9.62		AMEND 6/6/97:DIVPTS 8 COS BELOW AMISTAD
PABLO A RAMIREZ INC		Cameron			" " .5 COUNTIES."
TXU MINING COMPANY LP	MONTICELLO-LEESBURG LIGNITE MINING AREA	Camp	685.00		SCs.DUST SUPPR,CNSTR,EQUIP.AM A:CORR DPs
CHAMBERS-LIBERTY COS ND		Chambers			AMEND 10/25/04:ADD USES & IBT TO 80000AF
CHAMBERS-LIBERTY COS ND		Chambers	800.00		
CITY OF HENRIETTA		Clay	1.00		
COLORADO RIVER MWD		Coke	8,427.00		MAY DIVERT 6000 AF IN CO 168. "
COLORADO RIVER MWD		Coke	1,000.00		MAY DIVERT 6000 AF IN CO 168. "
PATTY LOIS CERVENKA		Coke	100.00		& CO 200.AMEND 5/10/2007:ADD MINING USE
RAMONA A TAYLOR		Coke	40.00		& IRRIGATION. 3 DIVPTS. AMEND 11/12/99
SANCO MATERIALS CO		Coke	35.00		DIVERT 309 AF.AMEND 10/96,10/98.3 DIVPTS
SANCO MATERIALS CO		Coke	32.00		DIVERT 320 AF.SC.AM 10/98,9/99.2 DIVPTS
BRAZOS RIVER AUTHORITY		Comanche			
R E JANES GRAVEL CO		Crosby	450.00		
WHITE RIVER MWD		Crosby	2,000.00		
CITY OF DALLAS		Dallas			AM 84,85,86,1/96,3/1/96,6/02,11/04,10/06
H S JACKSON SAND & GRAVEL INC		Denton	3.00		8/07 MAIL RETD: RTS/BOX CLOSED/UTF
CHARLES LYDELL THALMANN		Dimmit	1.00		AMEND 2/26/90
GREENBELT M&I WA		Donley	750.00		
EASTLAND INDUSTRIAL FOUNDATION		Eastland	607.00		
EBAA IRON INC		Eastland	1,000.00		
EL PASO CO WID 1	MESILLA, AMERICAN, RIVERSIDE DIV DAMS	El Paso			ADJUDICATED FROM 5433-1
HUDSPETH COUNTY CRD 1		El Paso			& HUDSPETH CO. ADJUDICATED FROM 244/236-1 IN 2007
UNITED STATES OF AMERICA	MESILLA, AMERICAN, RIVERSIDE DIV DAMS	El Paso			ADJUDICATED FROM 5433-1
ASH GROVE TEXAS LP		Ellis	82.00	50.00	AMENDED 1/5/2001: INCREASE DIV RATE
TARRANT INVESTMENT CO INC		Erath	30.00		USE 1 UNDER ADJ 4026. "; 7/09 MAIL RTD;RTS/ANK/UTF
CAMPBELL CONCRETE & MATERIALS LP		Fort Bend	2,300.00	230.00	AMEND 4/12/2000:ADD DIVPT,IMPOUNDMENT

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
GULF COAST WATER AUTHORITY		Fort Bend			WHICH PRIORITY DATE?
CAVERN DISPOSAL INC		Freestone	31.00		129 AF USE 4 EXPIRED 12/92
TARRANT REGIONAL WATER DIST		Freestone			ALSO CO 175. AMEND 1/4/2000, 2/8/2005
TARRANT REGIONAL WATER DIST	DISTRICT RETURN FLOWS	Freestone			AMEND 2/8/05:DISTRICT RETURN FLOWS.2 DPs
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone	5.00		SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
CITATION 2002 INVESTMENT LP		Garza	200.00		AMEND 8/93; WITH WSC 2418
WHITE RIVER MWD		Garza	4,000.00		8/4/2005: CONSTR EXTENDED TO 7/24/2012. 1/21/2009: CONSTR EXTENDED TO 7/24/2016
WAYNE E MOHR		Gillespie	30.00		AMND 1/24/96:2ND DIV PT:30.272N/98.781W
WEIRICH BROTHERS INC		Gillespie	50.20		WASH GRAVEL. AMEND 8/25/95
RED RIVER AUTHORITY		Grayson	100.00		
G R AKIN ET AL		Gregg	5.20		
TEXAS MUNICIPAL POWER AGENCY	GIBBONS CREEK LIGNITE MINE	Grimes			AMEND 1/24/05:ADD USES 7, 8, 11
TEXAS MUNICIPAL POWER AGENCY	GIBBONS CREEK LIGNITE MINE	Grimes	200.00		AMEND 12/16/04:ADD USES
FAIR OIL LC		Harrison	165.21		& CO 158
SABINE MINING COMPANY	PIRKEY POWER PLANT	Harrison	200.00		
SABINE MINING COMPANY	SOUTH HALLSVILLE #1 SURFACE LIGNITE MINE	Harrison			REDIRECT ALL OF BRANDY BR TO HATLEY CRK
TARRANT REGIONAL WATER DIST		Henderson			AMEND 7/93, 1/4/2000, 2/8/05
TARRANT REGIONAL WATER DIST	DISTRICT RETURN FLOWS	Henderson			AMENDED 2/8/05:ADD DISTRICT RETURN FLOWS
TEX IRON INC		Henderson			STORED GROUNDWATER. CRUSHED STONE WASHING
DOUGLAS M BRICE		Hidalgo			AMEND 3/13/95, 6/4/99

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
HIDALGO CO IRR DIST 2		Hidalgo	100.00		7/14/81,6/10/87,5/15/90,5/8/95,4/13/2000
HIDALGO CO WID 3		Hidalgo	100.00		AMENDED 10/10/78, 9/8/95
HIDALGO COUNTY IRR DIST 16		Hidalgo	200.00		AMEND 8/11/95, 7/12/96
JOEL RUIZ ET UX		Hidalgo			RATE:23-2707.AMEND 10/30/84,7/2/99
LUCIO E GONZALEZ JR		Hidalgo	5.00		
PABLO A RAMIREZ INC		Hidalgo			" " .5 COUNTIES."
RUFINO GARZA ET AL		Hidalgo	125.00		AMENDED 11/1/93, 8/30/94, 1/8/99
SERGIO GALINDO		Hidalgo	100.00		AMENDED 4/25/2007:CHG IRR TO MINING
BRAZOS RIVER AUTHORITY		Hill			
CITY OF CLEBURNE		Hill			
BRAZOS RIVER AUTHORITY		Hood			
BURLINGTON RESOURCES OIL & GAS CO LP		Hood	600.00		AMMENDED 2/6/2009- INCREASED DIVERSION AMT FROM 400 AC-FT TO 600 AC-FT
CARRIZO OIL & GAS INC		Hood	15.00		
CHESAPEAKE ENERGY INC		Hood	2,000.00		
ENCANA OIL & GAS USA INC		Hood	17.00		REPLACED 12179-9
EOG RESOURCES INC		Hood	680.00		
EOG RESOURCES INC EASTERN DIVISION		Hood	300.00		
LOWELL UNDERWOOD		Hood	100.00		
QUICKSILVER RESOURCES INC		Hood	1,400.00		
WESTERN COMPANY OF TEXAS INC		Hood	1,000.00		SYSOP
WILLIAMS PRODUCTION GULF COAST LLP INC		Hood	86.00		
TXU MINING COMPANY LP	MONTICELLO-THERMO LMA	Hopkins	220.00		DUST SUPPR,CONSTR,MISC.4 DPS,3 RES.SCs
ALON USA REFINING INC		Howard	215.00		OIL WELL FLOODING; & USE 2
COLORADO RIVER MWD	BEALS CREEK PROJECT	Howard	2,200.00	2,000.00	& WATER QUALITY IMPROVEMENT
COLORADO RIVER MWD	NATURAL DAM LAKE PROJECT	Howard	2,500.00		&CO 159;& USE 8-WATER QUALITY CTRL; IMP
W F COMPANY LTD		Howard	800.00		NOTIFY CLEANRIVERS OF CHG.MAIL RETD 6/07

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TEXAS INDUSTRIES INC	BOONESVILLE PLANT	Jack			50 AF PURCHASED FROM TARRANT CO WCID 1
PREMCOR PIPELINE CO		Jefferson	76.70		
UNITED STATES DEPT OF ENERGY	BIG HILL SPR SITE	Jefferson	30,000.00		AMND 7/12/90.87291 AF ABANDONED 3/20/96
TRINITY MATERIALS INC	CLEBURNE PLANT	Johnson	125.00		CONSUMPTIVE USE UNDER WSC#2210
GEOCHEMICAL SURVEYS		Jones	40.00		2 LAKES.6/06 MAIL RETD:RTS/ANK/UTF
RICHARD SCHKADE		Jones	5.00		CLEANING AND REUSE IN ROCKSAW COOLING
TLC INVESTMENTS LLC		Jones	338.00		
TRINITY MATERIALS INC	SEAGOVILLE SAND & GRAVEL #280	Kaufman	100.00		WITH WSC 2300. AMEND 12/21/2006: MOVE DIVPT. MAIL RETD 3/09: RTS/NO MAIL RECEPTACLE/UTF
OCCIDENTAL PERMIAN LTD	COGDELL CANYON REEF UNIT	Kent	3,525.00		
OCCIDENTAL PERMIAN LTD	COGDELL CANYON REEF UNIT	Kent	2,375.00		
DARRELL G LOCHTE ET AL		Kerr	143.00		123 AF NONCONSUMPTIVE.9/07 MAIL RETD:RTS
WHEATCRAFT INC		Kerr			AM 8/7/2000:CONTRACT.10/04/2006:MU, DPs
WHEATCRAFT INC		Kerr			AMEND 4/18/2006: ADD MINING (MULTI-USE)
WEIRICH BROTHERS INC	KIMBLE CO PLANT	Kimble	60.00	6.00	
PLAINS PETROLEUM OPERATING CO		Knox	235.00		SECONDARY OIL RECOVERY. W/WSC _____
SAN JACINTO RIVER AUTHORITY		Liberty			MULTI-USES,COUNTY,PRI. AMEND 5/95, 10/3/06
TXU MINING COMPANY LP	KOSSE LIGNITE MINE	Limestone	1,000.00		DUST SUPPRESSION, CONSTRUCTION, & MISC MINING ACTIVITIES
COLORADO RIVER MWD	O H IVIE RESERVOIR	Martin			DIV 2500 AF TOTAL FROM EITHER RESERVOIR FOR INDUSTRIAL OR MINING USE
TERRY JACKSON INC		Mason			1.5 AF CONTRACT WATER. WITH WSC 12254-9
ALAMO CONCRETE PRODUCTS LTD		Maverick	78.00	15.00	AMEND 4/22/87,12/12/94.15 AF CONSUMPTIVE
DE LOS SANTOS READY MIX		Maverick	2.00		AMEND 1/24/91,3/14/01,4/18/01,11/03/03
DOUGLAS M BRICE		Maverick			AMEND 3/13/95, 6/4/99
EW RITCHIE III ET AL		Maverick			
KATHRYN RITCHIE COTTER ET AL		Maverick	10.00		AMEND 7/6/93
MILDRED GOODSON		Maverick			AMEND 3/27/02, SPECIAL COND

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
JIMMY A MUMME ET UX		Medina	15.00		AMENDED 10/20/04:ADD DIV PT,FLOW RESTRIC
MOBLEY COMPANY INC		Menard	3.00		
ALCOA INC	SANDOW MINE RECLAMATION PROJ	Milam			STORE GW IN RESERVOIRS.SEE 5816-1.SCs
ALCOA INC		Milam			STORE GW IN RESERVOIRS.SEE 5803-1.SCs
CITY OF BOWIE		Montague	200.00		
CLARICE BENTON WHITESIDE		Montague	9.00		
SAN JACINTO RIVER AUTHORITY		Montgomery	5,500.00		
CITY OF CORPUS CHRISTI		Nueces	12.00		TRANSBASIN TO BASINS 20, 22.ORDER 4/2001
CITY OF CORPUS CHRISTI	JC ELLIOTT LANDFILL & ADJACENT CITY PROP	Nueces			SC
TOM W GREEN		Oldham	30.00		
3 N1 WATER SOLUTIONS		Palo Pinto	250.00		
3 N1 WATER SOLUTIONS		Palo Pinto	250.00		
BASELINE OIL & GAS CORP		Palo Pinto	1,000.00		REPLACED 2420-9
BLUE SKY OILFIELD SERVICE LLC		PALO PINTO	15.00		
BRAZOS RIVER AUTHORITY		Palo Pinto			
BRAZOS WATER STATION		Palo Pinto	100.00		AMENDMENT CHANGES EXPIRE DATE TO 12/31/2009
BRAZOS WATER STATION		Palo Pinto	50.00		
BURLINGTON RESOURCES OIL & GAS CO LP		Palo Pinto	200.00		AMMENDED 2/6/09- CHANGE DIVERSION AMT FROM 400 AC-FT TO 200 AC-FT
CITATION 1998 INVESTMENT LTD PARTNERSHIP		Palo Pinto	175.00		GOES W/ APP#5359(UPSTREAM CONTRACT)
DART OIL & GAS CORP		Palo Pinto	10.00		
DEVON ENERGY PRODUCTION CO LP		Palo Pinto	100.00		
EOG RESOURCES INC		Palo Pinto	320.00		AMENDMENT ADDS A DIVERSION PT.
EOG RESOURCES INC WESTERN DIVISION		Palo Pinto	190.00		
INGRAM ENTERPRISES LP		Palo Pinto	50.00		
LATTIMORE MATERIALS COMPANY		Palo Pinto	300.00		

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
MINERAL WELLS SAND & GRAVEL INC		Palo Pinto	15.00		
NORTH RIDGE CORPORATION		Palo Pinto	235.00		
NORTH TEXAS LIVING WATER RESOURCES LLC		Palo Pinto	2,700.00		MULTIUSE=MINING & IRRIGATION
NORTH TEXAS LIVING WATER RESOURCES LLC		Palo Pinto	650.00		MULTIUSE=MINING & IRRIGATION
PIONEER NATURAL RESOURCES USA INC		Palo Pinto	129.00		REPLACED 12062-9
R J CARAWAY		Palo Pinto	41.00		
RANGE RESOURCES CORPORATION		PALO PINTO	90.00		
THISTLE DEW RANCH		Palo Pinto			
VULCAN CONSTRUCTION MATERIALS LLP		Palo Pinto	2,000.00		REPLACED 1315-9
LUMINANT MINING CO LLC	MARTIN LAKE LMA	Panola	250.00		3 RES, 3 DIV PTS. ALSO RUSK CO. MINING, D&L, SEDIMENT CONTROL. AMENDED 5/11/2009: COMBINE 5004 INTO 5889
TXU MINING COMPANY LP	MARTIN LAKE LIGNITE MINING AREA	Panola	600.00		21 DIV PTS.SCs.EXEMPT RES.AMN 3/30/07
TXU MINING COMPANY LP	MARTIN LAKE LIGNITE MINING AREA	Panola	400.00		AMEND 3/30/07:ADD 400AF,RESES,USES
TXU MINING COMPANY LP		Panola	150.00		11 DIV PTS. SCs
XTO ENERGY INC		Panola	720.00		
CITY OF WEATHERFORD		Parker			AMEND 9/8/04
TXI OPERATIONS LP	TIN TOP	Parker			
APACHE CORPORATION		Robertson	20.00		
BRAZOS RIVER AUTHORITY		Robertson			
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson	685.00	53.00	TOTAL OF 12 DIVPTS.SCs. GW FROM DEWATER
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson			TOTAL OF 12 DIV PTS.SCs
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson			TOTAL OF 12 DIV PTS.SCs

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson			TOTAL OF 12 DIV PTS.SCs
WALNUT CREEK MINING COMPANY		Robertson			LIGNITE MINE SEDIMENTATION POND
BONNIE JO BLYTHE ET AL		Runnels	70.00		2 TRACTS 531.4 ACRES, SC. "
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk	680.00		SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk	680.00		DP1. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP2.DUST SUPPR,CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP3. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP4. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP5. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP6. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP7. DUST SUPPR, CONSTR, EQUIP WASH,MISC
MOBLEY COMPANY INC		Schleicher	3.00		
COLORADO RIVER MWD		Scurry			&CO 17.AMEND 9/26/2001:DIV PTS, ADD IRR
H R STASNEY & SONS LTD		Shackelford			AMEND 5/13/2009: CHANGE TO MULTI-USE: LIVESTOCK, DOMESTIC, & MINING PURPOSES
BELL SAND COMPANY		Smith	60.00	6.00	SAND WASHING

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
R E KERSH		Smith	57.00	6.00	SAND AND GRAVEL WASHING
CLEMMACO LTD		Starr			AMEND 9/19/97, 7/30/2008: COMBINATIONS
DOUGLAS M BRICE		Starr			AMEND 3/13/95, 6/4/99
JOEL RUIZ ET UX		Starr			RATE:23-2707.AMEND 10/30/84,7/2/99
PABLO A RAMIREZ INC		Starr	30.00		" " .5 COUNTIES."
ROSITA GRAVEL INC		Starr	22.50		AMENDED 11/14/97: CHANGE USE 3 TO USE 4
BRECKENRIDGE GASOLINE CO		Stephens			6/06 MAIL RETD:RTS/NDAA/UTF
SWANSON MULESHOE RANCH LTD		Stephens	218.00		AMEND 8/12/86: REVERTS TO REC USE
WEST CENTRAL TEXAS MWD		Stephens			AMEND 3/6/91,10/11/2002
CITATION 1994 INVEST LTD PART		Stonewall	235.00		WITH CONTRACT #1995 (? CONTRACT EXPIRED)
MOBLEY COMPANY INC		Sutton	3.00		
TARRANT REGIONAL WATER DIST	TO FT WORTH HOLLY WWTP	Tarrant			B&B CONVEYANCE OF PIPELINE WATER. MAX RATE NOT TO EXCEED DISCHARGED RATE
TARRANT REGIONAL WATER DISTRICT		Tarrant			AMEND 5/14/85, 1/4/2000, 2/21/2005. MAX RATE UNSPECIFIED
LUMINANT GENERATION CO LLC	MONTICELLO STEAM ELECTRIC STATION	Titus			DUST SUPPRESSION,EQUIP WASHDOWN & MISC
TXU MINING COMPANY LP	MONTICELLO LIGNITE MINING AREA	Titus	50.00		SCs. 13 DIVPTS, 7 RESERVOIRS
TXU MINING COMPANY LP	MONTICELLO LMA	Titus	135.00		6 DPS, 2 RES. SCs.
TXU MINING COMPANY LP	MONTICELLO LIGNITE MINING AREA	Titus	200.00		3 DIV SEGMENTS & 5 RES. SCs
UPPER COLORADO RIVER AUTH		Tom Green			AMENDED 12/19/97, 5/30/2008, 6/13/2008
CAPITOL AGGREGATES LTD	AUSTIN SAND-GRAVEL PLANT READY MIX	Travis	2,540.00	340.00	AMENDED 8/15/97: COMBINED WITH 5378-6; PERMIT EXPIRES UPON PERMANENT CESSATION OF MINING OPS
CAPITOL AGGREGATES LTD	AUSTIN SAND-GRAVEL PLANT READY MIX	Travis	242.00	0.00	AMENDED 8/15/97: COMBINED WITH 5378-6. THIS IS NONCONSUMPTIVE MINING USE
LOWER COLORADO RIVER AUTHORITY		Travis			SEE 5478.AMEND 10/12/89,3/8/90,10/31/91
SHUMAKER ENTERPRISES INC		Travis	300.00		REPLACED 2208-9;AMENDED 11/01
TERRY JACKSON INC		Travis	1.50		1.5 AF CONTRACT WATER. SEE PERMIT 12244-1

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TEXAS INDUSTRIES INC	GREEN SAND AND GRAVEL PLANT	Travis	110.00	11.00	690 A/F EXP 12/31/93; ALL WATER RIGHTS EXPIRE WHEN MINING ENDS OR UPON EXPIRATION OF LEASE; FLOW RESTR ON EXPIRED WATER
TYLER SAND COMPANY		Upshur	200.00		1/99: SEE SC A, CO DEFUNCT; WUR/NOT N
CAPITOL AGGREGATES INC	DEL RIO PLANT	Val Verde	166.00	17.00	AM 11/2/87.6/28/2001:ADD DIVPT & PLACE
MORTON SALT COMPANY INC		Van Zandt	251.00		EXEMPT LAKE
UNION OIL CO OF CALIFORNIA		Van Zandt	400.00		
UNION OIL CO OF CALIFORNIA		Van Zandt	270.00		
UNION OIL CO OF CALIFORNIA		Van Zandt	500.00		
BRAZOS RIVER AUTHORITY		Washington			
ALBERT F MULLER JR		Webb	2.38		
ALICE SOUTHERN EQUIP SERVICE		Webb	145.00		AMEND 7 & 11/93,12/94,10/30/98
ALICE SOUTHERN EQUIP SERVICE		Webb	175.00		AMENDED 10/30/98
BARBARA T FASKEN	FARCO MINE DAM AREA	Webb	200.00		
BEN-HUR ENTERPRISES LTD		Webb			AMEND 1/24/91,3/14/2001,4/18/2001.2705-6
CHRISTINE MCKEE		Webb	1.00		AMEND 6/20/87. USE 4 IN ZAPATA & WEBB
CITY READY MIX INC		Webb	100.00		AMEND 10/15/91, 11/23/92
DOUGLAS M BRICE		Webb	131.56		AMEND 3/13/95, 6/4/99
H B O'KEEFE ESTATE		Webb	100.00		AMENDED 8/14/98: 100 AF USE 3 TO USE 4
HACHAR REAL ESTATE COMPANY		Webb	23.00		AMEND 6/30/86
J & B CONTRACTORS INC		Webb	2.00		AMEND 3/29/94
JOEL RUIZ ET UX		Webb			RATE:23-2707.AMEND 10/30/84,7/2/99
LAREDO SAND & GRAVEL CO		Webb	20.00		
LOUIS C LECHENGER ET AL		Webb	20.00		AMEND 4/14/88
MANDEL PROPERTIES LTD		Webb	100.00		AMEND 10/13/95
MICHAEL ALLEN MACMAHON		Webb	120.00		6/18/90
RANCHO BLANCO CORPORATION		Webb	300.00		AMEND 11/2/87,9/25/89,10/11/94,8/25/95
RODOLFO GARCIA		Webb	75.00	10.00	
RODOLFO GARCIA		Webb	62.00		
SAMUEL A MEYER ET AL		Webb	30.00		AMEND 10/17/94
SAN ISIDRO NORTH LTD		Webb			AMEND 12/18/91, 5/31/96. AMEND 3/19/2008: ADD MINING USE. AMEND 7/2/2008: ADD INDUSTRIAL USE

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
STEPHEN A MCKENDRICK TRUSTEE		Webb	2.38		W H MCKENDRICK TRUST
TOPAZ POWER PROPERTY MGMT II LP		Webb			AMEND 2/7/97.REUSE 731.5 OF THE 2194.5
UNION PACIFIC OIL & GAS CO		Webb	5.00		AMEND 6/16/92
WILLIAM H MCKENDRICK III		Webb	8.33		
CONOCOPHILLIPS CO		Wharton			
LEONARD WITTIG GRASS FARMS INC		Wharton	1,000.00		
WHARTON COUNTY GENERATION LLC	NEWGULF POWER FACILITY	Wharton			
WICHITA CO WID 2 ET AL		Wichita	2,000.00		
W T WAGGONER ESTATE		Wilbarger	30.00		FROM MIDWAY LAKE
JOEL RUIZ ET UX		Willacy			RATE:23-2707.AMEND 10/30/84,7/2/99
PABLO A RAMIREZ INC		Willacy			" " .5 COUNTIES."
ALAMO CONCRETE PRODUCTS LTD	WEIR PLANT	Williamson	300.00	30.00	AM 6/92,5/02.FORMERLY SOUTHWEST MATERIAL
BRAZOS RIVER AUTHORITY		Williamson			
BRAZOS RIVER AUTHORITY		Williamson			
CAPITOL AGGREGATES LTD	GEORGETOWN QUARRY	Williamson	118.00		AMENDED 8/15/97, 5/28/99: ADDED DIV PT
GENE H BINGHAM ET AL		Williamson	240.00	24.00	MAY CONSUMPTIVELY USE 24AFY
HANSON AGGREGATES CENTRAL INC	BRIDGEPORT STONE PLANT #2	Wise	345.00	69.00	
HANSON AGGREGATES CENTRAL INC	BRIDGEPORT STONE PLANT #2	Wise	1,505.00	301.00	
HANSON AGGREGATES CENTRAL INC	CHICO CRUSHED STONE PLANT	Wise	510.00		AMEND 5/7/91
HANSON AGGREGATES WEST INC		Wise	1,475.00		
HANSON AGGREGATES WEST INC		Wise	177.00	177.00	
MARTIN MARIETTA MATERIALS SOUTHWEST INC		Wise	1,200.00		
TARRANT REGIONAL WATER DIST		Wise	7,500.00		COS 249, 220
TARRANT REGIONAL WATER DIST		Wise			AMEND 5/5/89,1/4/2000. COS 249,119

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TRINITY MATERIALS INC	DECATUR PLANT #205	Wise	25.00		SC. W/WSC#1970
CITY OF GRAHAM		Young	500.00		
PITCOCK BROTHERS READY-MIX		Young	100.00		
ANTONIO R SANCHEZ SR ESTATE		Zapata	50.00		3/87,8/87,9/88,7/89,5/10/2000.9 COUNTIES
ANTONIO R SANCHEZ SR ESTATE		Zapata	50.43		3/87,8/87,9/88,7/89,5/10/2000.9 COUNTIES
DOUGLAS M BRICE		Zapata			AMEND 3/13/95, 6/4/99
EDWIN H FRANK III		Zapata	6.00		AMEND 1/4/90
EL CAMPO FARM COMPANY		Zapata	25.00		SEE 23-2787 FOR RATE
FENDER EXPLORATION & PRODUCTION CO LLC		Zapata	20.00		AMEND 10/25/2000:CHG 20 AF TO MINING USE
FLF LTD		Zapata	7.46		AMEND 1/4/90
GALBERRY PROPERTIES LLC		Zapata	5.60		AMEND 1/4/90
HERRADURA RANCH		Zapata	6.30		AMEND 1/4/90
JAMES C GUERRA ET AL		Zapata	12.50		AMEND 8/14/98: CHG POFD & USE 3 TO 4
JAVIER ZAPATA ET AL		Zapata	146.00		
JOEL RUIZ ET UX		Zapata	20.00		RATE:23-2707.AMEND 10/30/84,7/2/99
KCS RESOURCES INC		Zapata	25.00		
LARRY G HANCOCK		Zapata	6.10		AMEND 1/4/90
LONE STAR LA PERLA LP		Zapata	5.64		AMEND 1/4/90
MARIA EVA URIBE RAMIREZ		Zapata	10.00		AMEND 7/12/90
MARTINEZ QUARTER HORSE RANCH LTD		Zapata			AM 5/3/06:ADD MINING.6/13/07:ADD ACRES
MARTINEZ QUARTER HORSE RANCH LTD		Zapata	2.80		AMEND 1/4/90
MICHAEL T THRASHER		Zapata	6.10		AMEND 1/4/90
NEUHAUS & CO LTD		Zapata	17.10		AMEND 1/4/90
PABLO A RAMIREZ INC		Zapata			" " .5 COUNTIES."
RAMIRO V MARTINEZ		Zapata			AMEND 3/16/05:ADD IND & MINING USES
ROBERTO J VIDAURRI		Zapata			AM 5/92,6/93,08/02,9/26/02,7/31/2009:MULTI-USE,DIV
ROSEMARIE ANN GEARY		Zapata			AM 12/1/86,4/12/94,7/27/01,11/4/03:MULTI
SDK FARMS		Zapata	12.90		AMEND 1/4/90
SDK FARMS LLC		Zapata			AM 5/3/06:ADD MINING.6/13/07:ADD ACRES

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TECOMATE CAPITAL PARTNERS LTD		Zapata	4.00		AMEND 1/4/90
UNICO CONSTRUCTION CO		Zapata	11.24		AMEND 5/31/85,3/13/2003:CHG USE TO 4/AG
WICHITA PARTNERSHIP LTD		Zapata			AM 1/30/95.6/21/2007:MULTIUSE.3/13/08:CM
ZAVALA-DIMMIT CO WID 1		Zavala	4.00		
ZAVALA-DIMMIT CO WID 1		Zavala			
ZAVALA-DIMMIT CO WID 1		Zavala			
CITY OF HOUSTON					

Source: TCEQ Central Registry database

14 Appendix G:
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15 Appendix H:

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16 Appendix I: yyyyy

17 Appendix J:
List of Files Submitted to TWDB and Content

17.1 List of Files with Nonproprietary Content

17.2 List of Files with Proprietary Content

18 Appendix K: Responses to Review Comments

Responses to Review Comments
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