# Texas Water Development Board

## Report 366

# Please Pass the Salt: Using Oil Fields for the Disposal of Concentrate from Desalination Plants

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| About the cover: | The map on the cover shows the location of about 30,000 Class III injection wells in Texas. |

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## Glossary

| | |
|---|---|
| AOR | Area of Review |
| API | American Petroleum Institute |
| bbl | barrels |
| Bcf | billion cubic feet |
| BUQW | base of usable quality water |
| Ca | calcium |
| CEC | cation exchange capacity |
| ED | electrodialysis |
| EDR | electrodialysis reversal |
| EPA | Environmental Protection Agency |
| Fm | formation |
| gpm | gallons per minute |
| HF | hydrofluoric acid |
| IAP | ion activity product |
| kPa | kiloPascals |
| $K_{sp}$ | solubility product |
| LSI | Langelier Saturation Index |
| $m^3$ | cubic meters |
| Mg | magnesium |
| MAR | mass action ratio |
| MCL | maximum contaminant level |
| mD | millidarcies |
| Na | sodium |
| MF | microfiltration |
| mg/l | milligram per liter |
| MGD | millions of gallons per day |
| MMbbl | million barrels (oil reserves) |
| µm | micrometers |
| NF | nanofiltration |
| % | percent |
| pH | hydrogen ion activity |
| ppm | parts per million |
| psi | pounds per square inch |
| PTTC | Petroleum Technology Transfer Council |
| RO | reverse osmosis |
| RCRA | Resource Conservation and Recovery Act |
| RRC | Railroad Commission of Texas |
| SEM | scanning electron microscope |
| *SI* | saturation index |
| $SO_4$ | Sulfate |
| TAC | Texas Administration Code |
| TCC | total cation concentration |
| TCEQ | Texas Commission on Environmental Quality |
| TDS | total dissolved solids |

| | |
|---|---|
| TIPRO | Texas Independent Producers and Royalty Owners |
| TOF | top of fluids |
| TSS | total suspended solids |
| TWDB | Texas Water Development Board |
| UF | ultrafiltration |
| UIC | Underground Injection Control |
| USDW | underground source of drinking water |
| VRF | volcanic rock fragments |

## SI Metric Conversion Table

### Length

1 inch = 0.0254 m
1 foot = 0.3048 m

### Volume:

1 bbl = 42 gallons = 159 liters = 0.159 $m^3$
1 gallon = 3.785 liters = $3.785 \times 10^{-3}$ $m^3$
1 acre-foot = 325,851.4 gallons = 1,233,482 liters = 1,233.5 $m^3$
1 cubic feet = 0.02832 $m^3$

### Flow rate:

1 gpm = 0.0631 liter/s = $6.31 \times 10^{-5}$ $m^3/s$
1 bbl/day = 0.0292 gpm = $0.184 \times 10^{-5}$ $m^3/s$
1 MGD = 694.4 gpm = 43.8 liter/s = 0.0438 $m^3/s$

### Pressure

1 psi = 0.068948 bar = 6894.757 Pa

### Permeability

1 mD = $1 \times 10^{-12}$ $m^2$

### Temperature

T in $^oF$ is such that T in $^oC = 5/9(T-32)$

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# 1.0 Executive Summary

With the advances and affordability of desalination technology, desalination is becoming a viable alternative for fresh-water supply. However, operators of desalination plants need a place to put the waste (concentrate) produced from their operations. One promising possibility is injecting concentrate into oil and gas fields where formation pressures have been greatly lowered due to past oil and gas production. Oil and gas fields are promising in Texas because they occur in many parts of the state, oil- and gas-field operators have considerable experience injecting oil field brines into these fields in more than 31,000 wells, and the impact to the environment is negligible to non-existent. The cost of concentrate disposal could be reduced even more if communities could dispose of concentrate down the same or similarly equipped wells that accept oil field brines. Unfortunately, the current permitting environment in Texas does not allow this option. Instead, desalination plant operators would be expected to apply for a Class I permit (millions of dollars and years to permit) instead of using a Class II permitted well (which only requires thousands of dollars and months to permit). The purpose of this study was to (1) show that oil and gas fields can physically and chemically accept concentrate from desalination plants and (2) recommend changes to statute and rules that would allow the disposal of concentrate in oil and gas fields.

To show that oil and gas fields can accept injected concentrate from desalination plants, we first identified depleted oil and gas fields in Texas and selected and characterized six areas for further analysis. These analysis areas in the Anadarko, Permian, East Texas, Fort Worth, Maverick, and Southern Gulf Coast basins are in areas where there are oil and gas fields, there are sources of brackish groundwater for desalination, and there are needs for additional fresh-water supplies. After we selected the analysis areas, we investigated (1) formation pressures, (2) modeled the interaction of concentrate and formation fluids, (3) analyzed water sensitivity effects on clays, and (4) modeled injectivity.

We found that many wells in oil and gas fields have formation pressures much lower than the lowest-most source of drinking water. This means that there is no hydraulic potential for fluids in the oil and gas to move into overlying aquifers. Many of the wells we investigated would qualify for an Area of Review variance, a variance that would remove the requirement for a survey of unplugged wells that might allow injected fluids to migrate upward and endanger overlying aquifers. This variance is granted when there is very little to no chance of upward migration of the fluids.

The mixing of waters of different chemical compositions can sometimes cause minerals to precipitate. If this happens when concentrate is mixed with formation fluids, the formation can be plugged. Therefore, we modeled the interaction of concentrate and formation fluids to assess if mineral precipitation would be a problem in our analysis areas. We found that concentrate could be injected into oil and gas fields without causing minerals to precipitate. However, in some cases, the concentrate would need a pre-treatment with anti-scalants to prevent mineral precipitation.

Oil and gas fields, like most geologic formations, contain clays. When water of a different composition moves into these formations, the clays may expand or separate from each other (deflocculate) and become mobile in the water. Expanding and mobile clays can plug the formation. Water sensitivity describes how clays respond to the water chemistry. We found that clays could probably deflocculate and mobilize if raw concentrate was injected in any of the basins that we investigated. However, pre-treatment and operational solutions (such as adjusting the injection rate, progressively mixing with formation water, and injecting a buffer) can be used to mitigate clay issues.

Injectivity is the physical ability of the oil and gas fields to accept fluids, including concentrate. We modeled injectivity for the six analysis areas by calculating the flow rate that would result from combining the formation physical characteristics (porosity, permeability, and compressibility) and pressure requirements (admissible surface pressure, well depth, and head loss). We found that the median injection rate for a single well is about 10 gallons per minute (gpm) in the Anadarko, Permian, Fort Worth, and Maverick basins and about 280 and 470 gpm in the southern Gulf Coast Basin and East Texas Basin, respectively. These rates could be increased by screening more intervals and stimulating the wells. A lower injectivity would require a larger number of injection wells for a formation to accept the same amount of concentrate.

The technical challenges of injecting concentrates into oil and gas producing formations are not unlike the challenges of injecting water from a source different from that of the formation water; a challenge the oil and gas industry has a long history of success addressing. This study suggests that injecting concentrates into oil and gas fields will likely not be a problem if the concentrate and the formation are appropriately pretreated, as is done routinely by the oil and gas industry when injecting produced waters. However, pre-treatment will add to the cost of concentrate disposal.

To recommend changes to statute and rules that would allow the disposal of concentrate in oil and gas fields, we reviewed current statute and rules and met with staff from the Texas Railroad Commission, the Texas Commission on Environmental Quality, and the U.S. Environmental Protection Agency (EPA) (headquarters and Region 6).

U.S. EPA classified underground injection control wells into five categories- I, II, III, IV, and V. Class I wells are designed to inject fluids of hazardous, industrial, and other domestic wastes beneath the lowermost formation containing an underground source of drinking water that lies within 0.25 miles of the well bore. Class II wells are designed to inject fluids that are brought to the surface in connection with the oil and gas exploration or storage of hydrocarbons. Class III wells are designed to inject fluids into formations for extraction of minerals and solution mining. Class IV wells are designed for disposal of hazardous or radioactive wastes. Class V wells are those not included in the above which are used for numerous purposes including artificial recharge, cesspools, drainage wells, and heat pump.

Depending on the specifics of the case, a desalination plant can obtain a Class I or Class V permit for concentrate disposal. The permitting process under Class I could be made easier if Texas followed EPA's minimum requirements for a Class I municipal (non-hazardous) disposal well. Texas currently requires that non-hazardous Class I wells meet the same permitting construction and reporting requirements as hazardous Class I wells. Recent state legislation has eliminated the contested case hearings from Class I injection wells disposing of concentrate from desalination operations.

Under the current regulatory climate, disposal of concentrate in a Class II well would require a dual permit: Class I/Class II or Class II/Class V. However, to attain a dual permit, the well would have to meet Class I or Class V requirements. Concentrate could be injected directly into a Class II well with no additional permits if the concentrate was used to enhance oil recovery. However, desalination plant operators would need assurances that oil field operators would take their concentrate over the life of the plant.

The permitting process under Class I could be made easier by using a general permit. The general permit would experience all of the public hearings and scrutiny of the Class I process. However, once TCEQ approves the general permit, permit applications that met the requirements of the general permit would only need an administrative review—a savings of years and perhaps millions of dollars. Because Texas has primacy of its underground injection control program, it may also be possible to create a special category of Class I permitting for the disposal of concentrate in Class II permitted wells.

Another permitting option is to change the permitting process at the federal level. These changes could include creating a special category under Class I, creating a special category under Class V, or allowing Class II disposal wells to accept concentrate. However, previous attempts to change these rules at the federal level have been an onerous and thus far unsuccessful task.

In short, our study shows that it is technically feasible to inject concentrate into oil and gas fields, and that there are several options for making the permitting of concentrate disposal wells easier and more affordable.

# 2.0 Introduction

Desalination of seawater or brackish groundwater is becoming a much more viable alternative for fresh-water supply in Texas and the rest of the United States. In arid parts of West Texas, desalination may be the only viable future water resource. Desalination technology has progressed considerably over the past ten years and become much more affordable. However, an important issue that remains for many communities is: Where do we put the concentrate resulting from desalination? This disposal issue is important because of environmental concerns and because of cost. Desalination concentrate is often detrimental to flora and fauna, and inland concentrate disposal can be 10 to 25 percent of the total cost of desalination projects amounting to over 100 million dollars on larger projects.

There are several alternatives for concentrate disposal from desalination activities. One promising possibility in Texas and elsewhere in the United States is deep-well injection in oil and gas fields where formation pressures have been greatly lowered due to past oil production. Oil and gas fields are promising targets for concentrate disposal in Texas because (1) they occur in many parts of the state, (2) oil and gas field operators already have considerable experience injecting liquids in these fields, (3) the costs are lower, and (4) the impact to the environment is negligible to non-existent.

Oil and gas fields occur in many parts of Texas including all of the Gulf Coast and much of the interior of the state (Figure 2-1). These oil and gas fields are near likely sources of water for

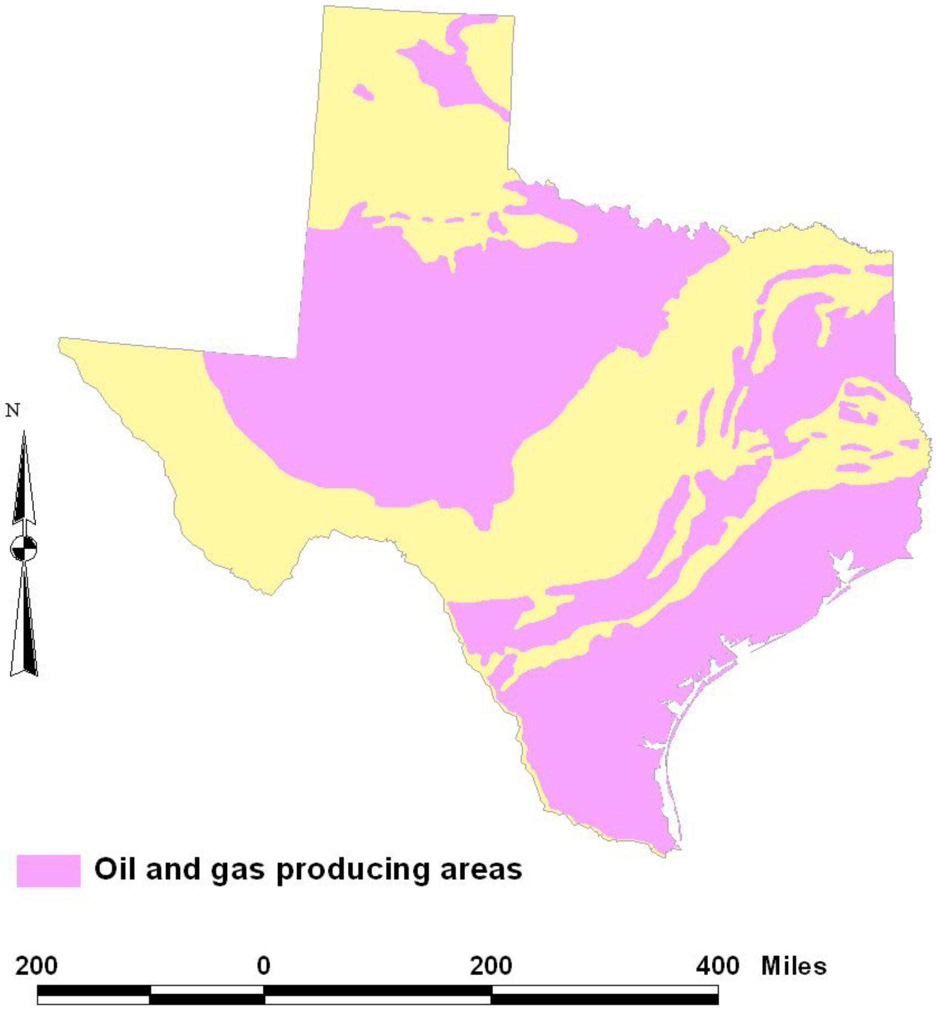


Figure 2-1. General location of oil and gas producing areas in Texas.

desalination: brackish groundwater (Figure 2-2) and saline water from the Gulf of Mexico. These fields are also near many small- to large-sized communities across Texas.

Texas has a growing interest in desalination as a source of potable water. There are currently a number of small desalination plants in the state (Figure 2-3; Table 2-1). The 2002 Texas State Water Plan (TWDB, 2002a) identifies several other possible plants across the state (Figure 2-3). Since publication of the 2002 Texas State Water Plan (TWDB, 2002a), additional communities have considered desalination more seriously due to decreasing costs, the success of other desalination project, and an initiative by Texas Governor Rick Perry to develop a large-scale demonstration seawater desalination project (TWDB, 2002b) (Figure 2-3).

The oil and gas industry in Texas has a great deal of experience in injecting fluids because a substantial amount of fluids are already being injected into oil and gas fields. When oil is produced from a field, brine is also brought to the surface. In mature producing fields, ten times more formation water may be produced than oil. Producers need to dispose of this brine and

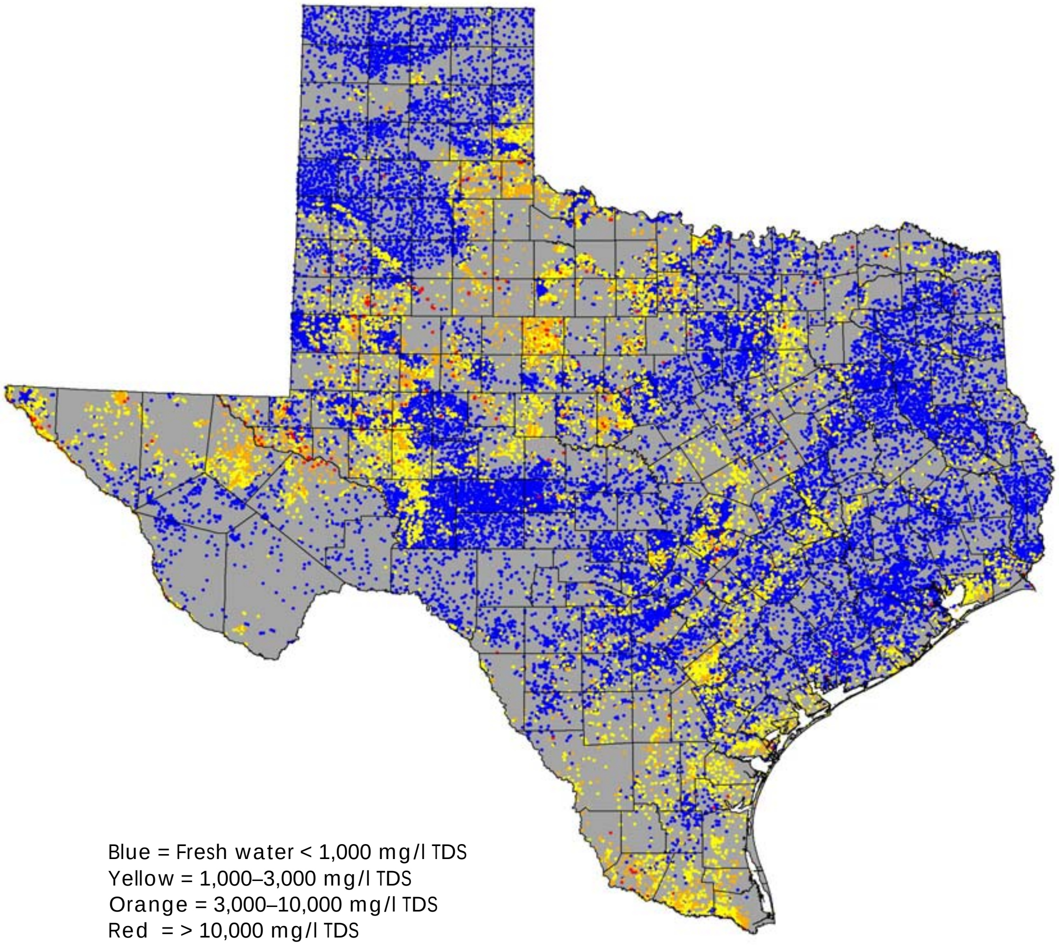


Figure 2-2. Location of brackish groundwater resources in Texas according to water-quality analyses in the Texas Water Development Board water well database (figure from LBG-Guyton and Associates, 2004).

therefore inject it back into the field. In Texas, there are over 31,000 active permitted injection wells in oil and gas fields. The depths of the injection wells in Texas for potential disposal of desalination concentrate range from about 250 feet to more than 13,000 feet with an average depth of 4,400 feet. More than 700,000 acre-feet of high-salinity brines per year are being injected through these wells. The costs of injecting concentrate into oil and gas fields will likely be lower than other disposal choices and deep well injection is likely to be much more cost effective than open-ocean discharge.

Properly sited, installed, and operated injection wells in oil fields will not adversely affect the environment. In many cases, the injected concentrate will represent an improvement in water quality in the oil fields. Along the Gulf Coast, deep-well injection would prevent the need for disposal of concentrate into environmentally sensitive bays and estuaries and into the Gulf of

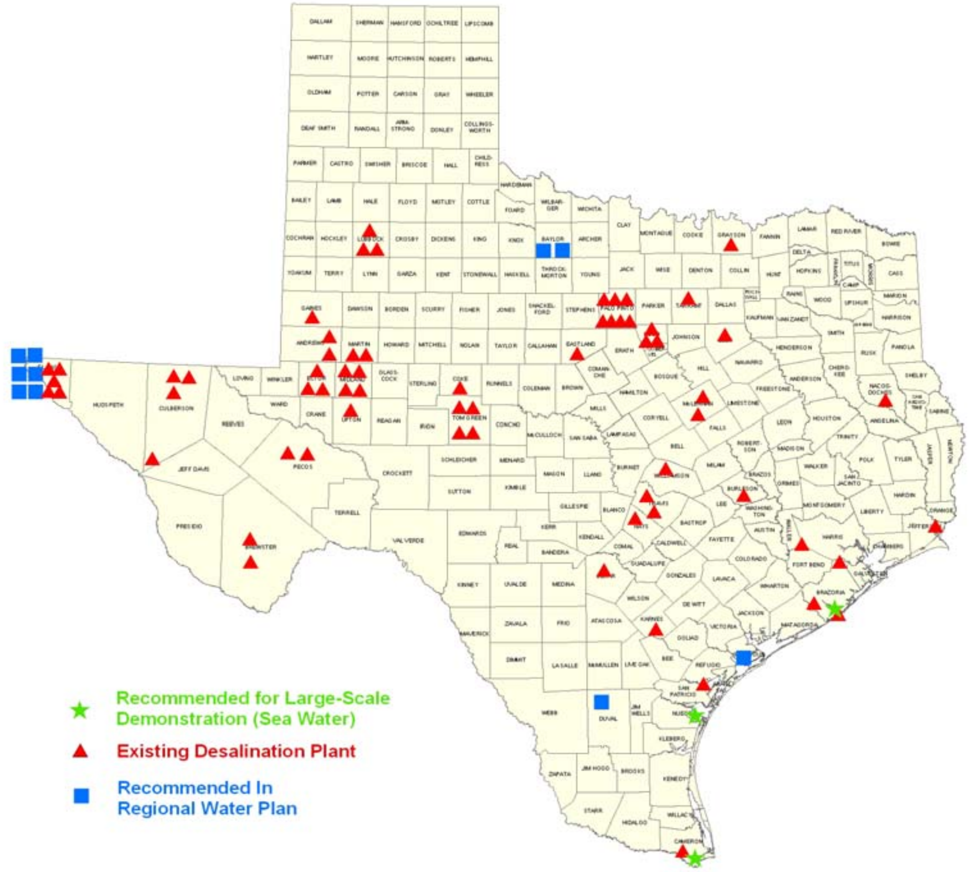


Figure 2-3. Location of existing and recommended desalination plants in Texas. Since the Governor's initiative, there is greater interest in desalination across Texas, including the Lower Rio Grande Valley, the Gulf Coast, and much of the central part of the state.

Mexico. Inland injection would prevent the disposal of concentrate in streams, rivers, and local water-treatment plants. Many people believe that oil fields will readily accept the quality and volume of concentrates from desalination plants. In some cases, operators would welcome the concentrate as 'make-up water' to help produce additional oil (Please pass the salt!).

The cost of concentrate disposal could be reduced even more if communities could dispose of this waste down the same or similarly equipped wells that accept oil field brines. However, current permitting in Texas essentially requires that concentrate be considered a hazardous waste, thus requiring considerably more expensive well construction and a considerably more expensive and lengthy permitting period. A hazardous waste disposal well requires millions of

Table 2-1. State of Texas desalination facilities operating in 1999 and with a design capacity greater than 0.05 MGD (from Mickley, 2001).

| Plant name | Disposal | Type | Category | Design capacity |
|---|---|---|---|---|
| Big Bend Motor Inn, Terlingua | Evaporation pond | Brackish reverse osmosis | DW | 0.05 |
| Dell City | Holding tank then irrigation | Electrodialysis reversal | DW | 0.10 |
| Esperanza | Small evaporation pond | Brackish reverse osmosis | DW | 0.06 |
| Ft. Stockton | City wastewater effluent lagoon | Brackish reverse osmosis | DW | 3.00 |
| Granbury | Into Lake Granbury | Electrodialysis reversal | DW | 0.62 |
| Haciendas Del Norte | Evaporation pond | Brackish reverse osmosis | DW | 0.08 |
| Harlingen Waterworks System | Receiving stream, tidal-affected | Brackish reverse osmosis | WW | 4.00 |
| Lake Granbury | Lake Granbury | Electrodialysis reversal | DW | 7.50 |
| Oak Trail Shores | 100 foot pipe into lake Granbury | Electrodialysis reversal | DW | 0.14 |
| River Oaks Ranch | Open pond | Brackish reverse osmosis | DW | 0.08 |
| City of Sherman | sewer | Electrodialysis reversal | DW | 6.00 |
| Sportsmans World | Back to Possum Kingdom lake | Brackish reverse osmosis | DW | 0.14 |

Design capacity is in millions of gallons a day (MGD)
DW=Drinking Water; WW=Waste Water

dollars and more than a year to obtain a permit. An oil field brine disposal well requires a couple months and a few thousand dollars.

The purpose of this study is two-fold: (1) to show that oil fields can accept injected concentrate from desalination plants and (2) to recommend changes to statute and rules that would allow the disposal of concentrate in oil and gas fields, thereby saving operators considerable money and making water more affordable to communities.

# 3.0 Background

This study required an understanding of the current permitting process, desalination technologies and concentrate, and deep-well injection. We discuss these topics in detail in the following sections.

## *3.1 The Current Permitting Process*

Concentrate from desalination operations can be disposed of in a number of ways. Common methods include discharging the concentrate into evaporation ponds, surface water bodies, or storm sewers; spreading it over the land surface; injecting it into deep wells; recycling the waste for beneficial purposes; or reusing it. Between 1993 and 2001, almost 72 percent of concentrate was disposed to surface water or storm sewers. Disposal in injection wells accounted for 17 percent of the total concentrate disposed in the same period, up from 12 percent before 1993 (Mickley, 2001).

### 3.1.1 History of the Federal Underground Injection Control Program

Underground injection of wastewater began in the 1930s when oil companies started disposing oil field brines and other oil and gas waste products into depleted reservoirs. Most of the early injection wells were oil production wells that were converted to wastewater disposal wells. Injection of hazardous chemical and steel industry waste started in the 1950s. During the 1950s, about four wells were reportedly used for hazardous waste disposal. Starting in the mid-1960s through the 1970s, the number of injection wells receiving hazardous waste grew at a rate of more than 20 wells per year (U.S. EPA, 2001).

When hazardous waste leaked from an abandoned injection well near Hammermill, Pennsylvania in the early 1970s, the Environmental Protection Agency (EPA) and the State of Pennsylvania tried to use the Clean Water Act to establish regulations to control underground injection. However, the courts decided in 1973 that the EPA did not have the authority under the Clean Water Act to regulate underground injection. In order to give the EPA the authority to regulate underground injection, the U.S. Congress passed the Safe Drinking Water Act in 1974 to protect underground drinking water sources (SDWA, Part C, Sections 1421-1426).

EPA published the final technical regulations for the Underground Injection Control (UIC) program in 1980. These regulations established minimum standards that the state programs needed to meet to receive primary enforcement responsibility (or primacy) as allowed under Safe Drinking Water Act (Section 1422). In 1981, Congress passed amendments to the Safe Drinking Water Act (Section 1425) that allowed the delegation of the UIC programs for oil and gas related injection wells to a state if the state's program was effective in protecting underground sources of drinking water (USDWs) and included traditional program components such as reporting, oversight, and enforcement. Between 1981 and 1996, the EPA granted primacy to 34 states for all injection wells. The EPA directly implements the UIC program in 10 states and shares responsibility in 6 other states.

In 1984, the EPA published special regulations for deep wells injecting hazardous waste as a result of the Hazardous and Solid Waste Amendments of 1984. In addition to making the requirements for these wells more stringent, the regulations require that each well operator demonstrate that the hazardous waste will not be released from the injection well zone for at least 10,000 years or will be rendered non-hazardous by natural processes.

### *3.1.2 Injection Well Classification*

The EPA divides injection wells into five classes: Class I through Class V (CFR 1989a, b).

**Class I injection wells** are used to inject hazardous waste beneath the lowermost formation containing a USDW. These wells also include industrial and municipal waste disposal wells and wells for disposing radioactive waste.

**Class II injection wells** are used to inject fluids brought to the surface in connection with oil and natural gas operations and the storage of hydrocarbons. The injected waste fluid (usually saltwater) can be commingled with wastewater from gas plants unless those waters are classified as hazardous waste at the time of injection.

**Class III injection wells** are used to inject fluids related to the extraction of minerals exclusive of oil and natural gas. This includes the mining of sulfur by the Frasch process, the in-situ production of uranium or other metals, and solution mining of salts or potash.

**Class IV injections wells** are used for the disposal of hazardous or radioactive waste in shallow wells. These wells are prohibited unless the injection wells are used to inject contaminated groundwater that has been treated and is being injected into the same formation from which it was drawn.

**Class V injection wells** are injection wells not included in Class I, II, III, or IV. This class includes a wide range of injection wells ranging from air conditioning return flow to wells used for controlling subsidence.

Of the five classes of injection wells, Class I wells are perhaps the most pertinent to the disposal of concentrate. To a lesser extent, Class V wells can also be used for concentrate disposal but are not as common. Class II injection wells have never been used for the disposal of concentrates from desalination operations and are authorized only for the disposal of fluids resulting from oil and gas operations. Some wells in Texas are dually permitted as Class I and Class II injection wells.

### *3.1.3 Texas Underground Injection Control Program*

The EPA granted Texas primacy for the UIC program in 1982. In a 1981 amendment of the Texas Water Code, the Texas legislature gave the Railroad Commission of Texas (RRC) jurisdiction of all Class II injection wells, Class V wells used for in-situ combustion of fossil fuels, Class V wells used for the recovery of geothermal energy to produce electric power, and Class V geothermal wells used in heating and aquaculture. The amendment gave the Texas Department of Water Resources jurisdiction over all Class I and Class IV injection wells and those Class III and Class V wells not under the jurisdiction of the RRC.

In 1985, the Texas Legislature amended the Texas Water Code and transferred the regulation of Class III brine mining injection wells for brine production from the Texas Department of Water Resources to the RRC. At the same time, the Legislature mandated the succession of the Texas Department of Water Resources by the Texas Water Commission for executive and judicial functions such as permitting, enforcement, and public hearings. The Texas Water Commission was replaced in 1993 by the Texas Natural Resource Conservation Commission by the merger of a number of state agencies. The Texas Natural Resource Conservation Commission was renamed the Texas Commission on Environmental Quality (TCEQ) in 2001.

The TCEQ’s UIC program is guided by both state and federal regulations and statutes for underground injection wells and the protection of groundwater. Three federal programs, the National Pollutant Discharge Elimination System permit program (under the Clean Water Act) for surface water protection, the UIC program (under the Safe Drinking Water Act) for control of well injections, and the pretreatment program (under the Clean Water Act) for discharge to the sewer, apply to the discharge of wastes from desalination. Texas was granted primacy for the UIC program in 1982 and for the National Pollutant Discharge Elimination System, pretreatment, and general permit programs in September 1998. Chapter 27 of the Texas Water Code (Injection Well Act) provides authority to the TCEQ for the Class I UIC program, and Chapter 331 of the Texas Administrative Code (relating to underground injection control) contains rules for the classification of injection wells and wastes associated with each class, corrective action standards and well closure requirements, and the permitting process for underground injection wells. Since 1982, Texas has issued approximately 270 Class I UIC permits for injection of industrial and municipal waste under the Texas Water Code and the Texas Health and Safety Code.

Under the Texas Water Code, the TCEQ's regulation of underground injection is directed toward the protection of "fresh water," defined in the Texas Water Code as "…water having bacteriological, physical, and chemical properties which make it suitable and feasible for beneficial use for any lawful purpose" (Section 27.002). As stated in Section 27.003 of the Texas Water Code: "It is the policy of this state and the purpose of this chapter to maintain the quality of fresh water in the state to the extent consistent with the public health and welfare and the operation of existing industries, taking into consideration the economic development of the state, to prevent underground injection that may pollute fresh water, and to require the use of all reasonable methods to implement this policy."

The term fresh water as defined in Texas Water Code and USDW as defined in 40 CFR is not strictly synonymous and clarification is required regarding the use of these terms. TCEQ defines fresh water in the broad statutory sense of the definition in Chapter 27 of the Texas Water Code. Because the definition of fresh water is conceptually based on beneficial use rather than on measurable physical characteristics, the boundaries of fresh water aquifers cannot be defined spatially or temporally. Thus, any water can be defined as fresh water provided it has a beneficial use. Texas' UIC program interprets fresh water as water having total dissolved solids (TDS) less than 10,000 milligrams per liter (mg/l) with the understanding that the broader statutory definition may be strictly applied whenever necessary to protect water containing more than 10,000 mg/l of TDS (30 TAC 331.2).

Because of the ambiguities of what constitutes fresh water in Texas, the TCEQ's UIC program has elected not to specifically designate or geographically delineate aquifers as underground sources of drinking water (USDWs). Any aquifer or a portion of an aquifer that fits the definition is considered a USDW even if it is not identified as such by the TCEQ. Nevertheless, the major and minor aquifers of Texas (Ashworth and Hopkins, 1995) contain a significant portion of the state's USDW as defined by 40 CFR 144.3 or 30 TAC 331.2.

The 78th Texas Legislature amended Chapter 27 of the Texas Water Code by adding Section 27.021 (relating to Permit for Disposal of Brine from Desalination Operations). With this amendment, the TCEQ was given authority to issue permits to dispose brine produced by a desalination operation in a Class I injection well if the applicant for the permit met all the statutory and regulatory requirements for the issuance of a Class I injection permit. Furthermore, the TCEQ was directed to develop a rule to provide for public notice and comment on an application for a permit. Hearing requirements of Chapter 2001, Government Code were waived for such permits. These new rules were still awaiting final approval at the time we were writing this document.

### *3.1.4 Overview of Class I Injection Wells*

By definition, Class I injection wells inject industrial or municipal wastewater beneath the lowermost USDW. Under federal definition, a USDW is an aquifer or a portion of an aquifer that supplies a public water system or contains enough water to supply a public water system, supplies drinking water for human consumption, contains water with a TDS of less than 10,000 milligrams/liter, and is not exempted by EPA or state authorities from protection as a source of drinking water (U.S. EPA, 2001).

Class I injection wells are classified as hazardous or non-hazardous depending on the characteristics of the injected wastewater. Class I injection wells permitted to inject hazardous wastewater are referred to as hazardous wells, and those that inject non-hazardous wastewater are known as non-hazardous wells. Industrial wells can be either hazardous or non-hazardous. Class I injection wells used for disposal of treated municipal waste are referred to as Class I municipal injection wells. Class I municipal injection wells are, by definition, non-hazardous wells. Class I municipal wells are not as numerous as Class I industrial wells and are currently found only in Florida. Class I municipal wells inject sewage effluent that has been treated to at least secondary treatment levels. This class of wells is not subject to the same strict requirements as other Class I wells.

Currently, there are 473 Class I injection wells in the United States, of which 123 are hazardous and 350 are non-hazardous or municipal wells. Texas has the largest number of hazardous wells (64) followed by Louisiana (17). The greatest number of non-hazardous wells is in Florida, followed by Texas and Kansas (U.S. EPA, 2001).

The EPA has not established regulations specifically for the disposal of water treatment plant residuals (Mickley, 2001). There are, however, federal regulations that apply to membrane wastes, some of which serve as guidelines to the states while others are mandatory. The EPA has essentially delegated the responsibility of regulating membrane wastes to the states giving them primacy over these programs provided the states meet all EPA requirements. The states with delegated authority continue to interact with the EPA in terms of reporting and communicating status, but the decisions are made at the state level (Mickley, 2001).

#### Class I Injection Well Design and Siting

UIC regulations require that all Class I injection wells be cased and cemented to prevent the movement of fluids into or between each USDW. Class I injection wells typically consist of three or more concentric layers of pipe: surface casing, long string casing, and injection tubing (U.S. EPA, 2001). The casings are generally constructed from corrosion-resistant materials such as steel or fiberglass-reinforced plastic and prevent the borehole from caving in and collapsing. The surface casing is the outermost of the three layers and extends from the surface to or below the lowermost USDW. The long-string casing extends from the surface to the injection zone with a screened, perforated, or open-hole completion. The well casing design and material depend on the chemistry of the injected wastewater, the receiving water, and the characteristics of the surrounding rock units.

The innermost layer of the injection well, the injection tubing, conveys injected wastewater from the surface to the injection zone. The tubing is generally constructed of corrosion-resistant materials since it is in constant contact with the wastewater. This tubing is typically made of steel, high-nickel alloys, fiberglass-reinforced plastic, alloy steel, or from other exotic elements such as zirconium, tantalum, or titanium.

The annular space between the injection tubing and the long string casing is sealed at the bottom by a packer (a space-sealing mechanical device) and at the top by the wellhead to create a fluid-tight seal. Constant pressure is maintained in the annular space and is monitored continuously to ensure the mechanical integrity of the well.

As mentioned previously, Class I injection wells include both industrial and municipal wells. The construction requirements for municipal wells are somewhat less stringent than those for industrial wells. One important difference is that municipal wells are not required to meet the tubing and packer requirement. Under UIC regulations "All Class I injection wells, except those municipal wells injecting non-corrosive wastes, shall inject fluids through tubing with a packer set immediately above the injection zone, or tubing with an approved fluid seal as an alternative. The tubing, packer and fluid seal shall be designed for the expected service" (CFR 1989b, p. 374).

According to Mickley (2001), the tubing and packer represent additional direct and indirect capital costs, the largest by far being that of the tubing string. Larger well casings, and therefore larger costs, are required to accommodate the tubing. However, the bulk of the capital costs of a deep well is in labor and testing and not in materials. The solution in the annulus between the tubing and the final casing is monitored 24 hours per day for pressure. Either a surface air compressor or source of nitrogen is used to keep the annulus at a pressure higher than the typical working pressure. In general, this requires more maintenance than other injection wells and thus more cost.

Site selection for Class I injection wells is probably one of the most important steps in the development of an injection well (Mickley, 2001). According to UIC regulations "All Class I wells shall be sited in such a fashion that they inject into a formation which is beneath the lowermost formation containing, within a quarter mile of the borehole, an underground source of drinking water."(40 CFR Part 146.12 relating to Construction requirements in Criteria and Standards Applicable to Class I wells). Class I injection wells are sited so that the underground formation has the natural ability to contain and confine the injected waste from migrating into nearby USDW (Mickley, 2001). Federal and state regulations require a vertical minimum separation of a quarter mile (1,320 feet) between the lowermost USDW and the well bore. Other requirements, such as geologic stability of an area with no transmissive fractures or faults, and areas that do not have wells or other artificial pathways between the injection zones and different USDW, also apply.

Typically, Class I injection wells are thousands of feet deep. In the Gulf Coast, Class I injection wells can range in depth from 2,000 to 12,000 feet or more. At these depths, fluids move very slowly, on the order of a few feet per hundred years or even thousand years (U.S. EPA, 2001) and are likely to remain confined for a long period of time.

## Class I Permitting Process in Texas

TCEQ's permitting process for Class I injection wells involves a pre-application meeting with its Waste Permit UIC staff. Applicants receive an application packet containing all necessary application forms with detailed instructions, information on obtaining copies of all applicable rules and statutes, and procedural information.

On receiving an application, TCEQ staff date stamp it, make sure the appropriate fees have been submitted, and then forward it to the administrative review team which reviews the application for administrative completeness. TCEQ may contact the applicant at any time during the administrative review process for clarification or more information.

Within 30 days of the date that TCEQ determines that the application is administratively complete, TCEQ's Chief Clerk mails Notice of Receipt of Application and Intent to Obtain Permit to the applicant, to potentially affected persons, and to others. The applicant is then responsible for publishing the notice in a newspaper and also placing the notice in a public location.

TCEQ's UIC staff begins a technical review as soon as the application is administratively complete. The applicant may be contacted at any time during this process for more information or clarification. Once a technical review is completed, the TCEQ's Executive Director makes a preliminary decision to issue a permit or recommend denial of the permit. The Preliminary Decision and draft permit are filed with the chief clerk. The Chief Clerk mails the Preliminary Decision concurrently with the Notice of Application. The applicant publishes the Notice of Application and Preliminary Decision.

Public comments must be filed with the Chief Clerk within 30 days after the last publication of the Notice of Application and Preliminary Decision. If comments are received, the Executive Director prepares a response within 60 days following the close of the comment period. The Chief Clerk mails the Executive Director's decision, response to public comments, instructions for requesting that TCEQ reconsider the Executive Director's decision, and instructions for requesting a contested case hearing.

The Executive Director may act on an uncontested application if public notice requirements have been satisfied and the application meets all relevant statutory and administrative criteria. The Chief Clerk mails the notice of the action and an explanation of the opportunity to file a motion to overturn the Executive Director's action on the application. A motion to overturn must be filed within 20 days after the signed permit is mailed to the applicant.

The typical amount of time required to process and obtain a non-hazardous injection well permit from the TCEQ ranges from one to three years. Hazardous well permits take even longer. Legislation passed by the Texas Legislature in 2003 exempts applicants for a Class I injection well permit for the disposal of concentrates from desalination operations from the requirements of a contested case hearing (Chapter 27.021, Texas Water Code, relating to Permit for Disposal of Brine from Desalination Operations). This can save up to three months in processing time for the permit.

Chapter 331 of the Texas Administrative Code (relating to Underground Injection Control) which implements the provisions of the Injection Well Act (Texas Water Code, Chapter 27) provides details on construction (Chapter 331.62), operating (Chapter 331.63), monitoring (Chapter 331.64), reporting (Chapter 331.65) and record keeping (Chapter 331.67) requirements for all injection wells (including Class I injection wells) under the jurisdiction of TCEQ.

Receiving a Class I permit is a long, arduous process that requires one year to attain and requires fees as high as $5,750. In addition, assembling the information required for a Class I permit application involves the collection and processing of a substantial amount of technical information and posting public notices. Collection of this technical information that may include regional evaluation of injection sites, surface characterization and well inventory, exploratory drilling and coring, and permit application may run into millions of dollars. For example, El Paso has currently received 1,550,000 in Federal money to seek a Class I injection well permit.

### 3.1.5 Overview of Class II Injection Wells

Class II injection wells are wells that are used for the injection of water produced from or for oil and gas operations. Typically, when oil and gas are extracted, large amounts of saltwater (brine) are also brought to the surface. This saltwater can produce adverse environmental impacts if discharged to the surface. Instead, all states require that this brine be injected into underground formations similar to the ones from which the oil and gas were extracted. Over two billion gallons of brine are injected daily into injection wells in the United States. The largest proportion of these brines is injected into formations that contain trace portions of extractable oil and gas (Veil and others, 2004).

Class II injection wells exist where there is production of oil and gas. There are approximately 167,000 Class II injection wells in the United States with most of them located in the southwest. Texas has the largest number of these wells (over 53,000, although only about 31,000 are active) followed by California, Oklahoma, and Kansas. Most Class II injection wells are used for the secondary recovery of petroleum (Class II-R). In this process, water is pumped into a formation containing some residual hydrocarbons. A portion of this hydrocarbon is recovered along with the injected water by extraction or production wells. Another type of oil and gas well is a disposal well (Class II-D). In this type of injection well, excess fluids from production and some other activities directly related to the production process are injected solely for the purpose of disposal.

Class II injection wells are required to follow strict construction standards except where historical practice in the state allows for different standards. A Class II injection well that follows EPA standards is built very much the same way as a Class I injection well. In 1980, Congress added Section 1425 to the Safe Drinking Water Act (controlling underground injection) relieving Class II well programs in the states from having to meet the technical requirements of UIC regulations. Instead, states can make a demonstration that they have an “effective program (including adequate record keeping and reporting) to prevent underground injection which endangers drinking water sources.”

## Class II Injection Well Siting and Design

In Texas, Class II injection well siting and construction standards are governed by regulations in Chapter 27 of the Texas Water Code (relating to Injection Wells) and by RRC Statewide rules 9 and 13 (relating to Disposal Wells, and Casing, Cementing, Drilling, and Completion Requirements, respectively).

In general, Class II injection wells are required to be cased and cemented in such a manner that the injected fluids do not endanger usable-quality groundwater resources as defined by the TCEQ. In no case can surface casing be set deeper than 200 feet below the specified depth without prior approval from the RRC. Cement is required to be circulated to the surface by the pump and plug method and the specifications for cement quality and casing integrity are outlined in RRC Statewide Rule 13. Injection wells must also meet UIC criteria for adequacy of cement to confine injected fluids.

Additionally, wells drilled or converted for disposal are required to be equipped with tubing that is set on a mechanical packer unless an exception is granted by the RRC for good cause (tubing is defined as a string of pipe through which injection of fluids occurs and which is neither wholly nor partially cemented in place). Packers cannot be set higher than 100 feet above the top of the permitted interval. Pressure observation valves are required on the tubing and each annulus.

The RRC has developed maximum injection pressure limitations which are required conditions of each injection well permit. Pressure limitations are established to assure that injection will not cause fracturing of the confining zone. Ordinarily, the maximum injection pressure is not allowed to exceed 0.5 pounds per square inch per foot of depth to the top of the authorized injection or disposal interval.

All injection wells are required to be pressure tested after construction and at least once every five years thereafter unless any workover occurs that disturbs the seal between the packer, tubing, and casing. Older wells that do not have tubing and packer may require special down-hole surveys to demonstrate mechanical integrity. The operator of each Class II injection well is required by the RRC to monitor the injection pressure and volume on a monthly basis and to report the results annually.

The EPA and the RRC require that the authorized injection or disposal strata in all Class II injection wells be isolated from overlying usable quality water by a sufficient thickness of impermeable strata of at least 250 feet of clay or shale. Injection is not permitted where faults, fractures, or other geologic structures might be present. Furthermore, RRC rules require that an applicant for a Class II injection well perform an area of review (AOR) study. An AOR study involves identification of unplugged wells that could allow injected fluids to migrate upward from the production zone and contaminate aquifers within a quarter mile radius of a proposed well. If an operator or group of operators in a field can document sufficient separation between the pressure head on a production zone and the base of useable quality water (BUQW), the RRC may issue a field-wide variance to the AOR requirement.

The main differences between the EPA's UIC program requirements and RRC's requirements pertain to the AOR and mechanical integrity testing. While the EPA prescribes checking all plugging and completion reports for cement across the injection zone, the RRC does not typically require full AORs, restricting itself to specific problem areas. Also, the RRC's mechanical integrity testing requirement is generally based on a five-year interval except in the case of old wells that do not meet new construction requirements.

RRC's regulations for Class II-Disposal (Class II-D) and Class II-Recirculation (Class II-R) injection wells are similar except for slight differences relating to the groundwater depth jurisdiction language in the Texas Water Code for Class II-D and the Texas Natural Resources Code for Class II-R wells. All groundwater depth recommendations are made by the TCEQ. In the case of Class II-D wells, the TCEQ recommendations include a review of geologic separation for shallowest allowed disposal of 250 feet of cumulative clay or shale between the disposal zone and the deepest usable water unit. In the case of Class II-R wells, the RRC considers the geological separation issue.

An additional difference between Class II-D and Class II-R injection well requirements involves the depth of the packer. Packers for Class II-D injection wells are required to be set within 100 feet of the disposal zone whereas packers for Class II-R injection wells, although usually subject to the same 100-foot limit, may be set farther away if well construction, groundwater proximity, and intervening impermeable strata allow (Veil and others, 2004).

### Class II Injection Well Permitting Process in Texas

In Texas, the RRC has primacy over the UIC Class II injection well program. The EPA approved the RRC's UIC program for Class II injection wells on April 23, 1982. Within the RRC, the Environmental Services Section evaluates and processes all Class II injection well applications. All applicants for new Class II injection well permits must obtain a permit from the RRC prior to starting disposal.

The RRC has adopted Practice and Procedure Rule 201 which sets specific time limits for RRC staff to act on permit applications. Under this rule, staff has 30 days to complete an initial review of the application. UIC staff must either notify the applicant that the application is administratively complete or request additional information if the application is incomplete. If the application involves the injection of fresh water, an additional 30 days is required to allow the TCEQ to review the application. UIC staff has 15 days to complete the final review and either issue or deny the permit.

When an incomplete application is received, staff mail out a letter requesting additional information. Staff then has 30 days to evaluate additional information submitted by the applicant. If a response is not received within 30 days of the first request, staff will send out a second request. The Practice and Procedure Rule 201 limits subsequent filing on incomplete applications to two filings of additional information. After the second filing of additional information, staff is required to either approve the application or deny a permit.

A permit denial letter is sent to the applicant if the proposed well completion or operating conditions do not meet minimum standards. The applicant's revisions to the application are reviewed by staff and, if found lacking, the permit application is denied. The applicant then has two options: the applicant can request a hearing once the application is administratively complete, or the denial letter may include instructions for modifying the application to allow approval. An applicant who wishes to protest an RRC decision can do so anytime before a permit is issued. RRC rules provide a minimum 15-day opportunity for protest. The steps in this process include a notification of protest, request for a hearing, transmittal to docket services, and the hearing itself. At the conclusion of the hearing process, the RRC can either issue a permit or deny the application.

The entire Class II-D permitting process can be completed within 30 to 45 days from the date of the RRC receiving an administratively complete application. The typical fee for a Class II permit ranges from approximately $250 to $400.

### 3.1.6 Overview of Class V Injection Wells

Class V injection wells are, by definition, injection wells that are not Class I, II, III, or IV wells or single family residential cesspools or septic systems (TCEQ, 2004). Class V wells generally are shallow waste disposal wells, septic systems, storm water and agricultural drainage systems, or other devices used to release fluids either directly into USDWs or into near-surface sediments that overlie USDWs (EPA, 1999). In order to qualify as a Class V injection well, the fluid released cannot be a hazardous waste as defined under the Resource Conservation and Recovery Act (RCRA). Frequently, Class V injection wells are designed as no more than shallow holes or septic tank and leachfield combinations intended for sanitary waste disposal. The EPA currently recognizes 23 types of Class V wells and 3 other types that include motor vehicle waste disposal wells, cesspools, and industrial wells used to inject non-hazardous industrial or commercial fluids (EPA, 1999). The EPA estimates that there are currently over 650,000 Class V injection wells through the United States. In Texas, there are approximately 14,000 Class V injection wells (TCEQ, 2004).

Under the EPA UIC program, Class V injection wells are currently authorized by rule, which means that they do not have to obtain an individual permit unless specifically required to do so. Under 40 CFR 144.12(a), owners or operators of all injection wells are prohibited from engaging in any injection activity that allows the movement of fluids containing any contaminants into USDWs if the presence of that contaminant can cause a violation of any primary drinking water regulation or may adversely affect human health. Sections 144.12(c) and (d) specify actions to be taken by the UIC Program Director if a well is not in compliance with section 144.12(a).

Owners or operators of Class V injection wells are also required to submit basic inventory information under 40 CFR 144.26. In addition, Class V injection wells are subject to the general program requirements of section 144.25 under which the UIC Program Director may require a permit, if necessary, to protect USDWs. Moreover, under section 144.27, the EPA may require owners and operators of any Class V injection well, in EPA administered programs, to submit additional information deemed necessary to protect Underground Sources of Drinking Water. Owners or operators who fail to submit the information required under sections 144.26 and 144.27 are prohibited from using their wells (EPA, 1999).

## *3.2 Desalination Technologies and Concentrate*

There are two main types of technology available to desalinate water: membrane-based and evaporation-based technologies. Evaporation-based technologies such as multistage flash or multiple-effect distillation are more suited for sea-water desalination and/or larger plants because energy requirements are almost independent of the source water salinity (Table 3-1). They also have a small recovery translating into a large waste stream which may be hard to dispose of short of sending it to a large body of water. Membrane-based technologies are more widely used in smaller plants and/or for the treatment of brackish water. In this study we focus on the membrane-based technologies because they are the only ones currently used in the continental United States. These membranes are also called semi-permeable membranes because they are selective in what can flow through them.

Membrane processes can be described according to the mechanisms involved and the size of the particles they allow through. The two mechanisms, which are described in more detail later, are pressure-driven and electro-potential driven processes. Pressure-driven membrane processes are further described as microfiltration (MF), ultrafiltration (UF), nanofiltration (NF), and reverse osmosis (RO). MF and UF act only mechanically, blocking bacteria and suspended particles (10 to 0.1 µm) because they cannot flow through the membrane pores. UF also blocks colloids and macromolecules (0.05 to 0.005 µm). In contrast, NF (0.005 to .0005 µm), which blocks solutes down in size to small organic molecules and divalent ions, and RO (0.001 to 0.0001 µm), which

Table 3-1. Characteristics of major desalination technologies.

| | Reverse osmosis (RO) | Electrodialysis reversal (ED/EDR) | Multistage flash (MSF) | Multiple-Effect Distillation (MED) |
|---|---|---|---|---|
| Energy cost | moderate | high | high | very high |
| Energy/Salinity | increases with salinity | increases fast with salinity | independent of salinity | independent of salinity |
| Applicable to | all water types | brackish | seawater - brine | seawater - brine |
| Plant size | modules | modules | large | large |
| Bacterial contamination | possible | post-treatment always needed | unlikely | unlikely |
| Final product salinity | on demand | on demand | can be <10 mg/l TDS | can be <10 mg/l TDS |
| Complexity | easy to operate, small footprint | easy to operate, small footprint | only large complex plants | only large complex plants |
| Susceptibility to scaling | High | low | low | low |
| Recovery | typically 30-50% for seawater and up to 90% for brackish water | | poor (10-25%) | low but better than MSF |

blocks solutes down to monovalent ions, operate mainly through diffusion and chemical interaction between the membrane and the solutes. NF is also called low-pressure RO or water softening. NF removes more Ca and Mg than Cl resulting in softer waters. NF also removes more $SO_4$ and $HCO_3$ than Cl. The two electro-potential driven processes are electrodialysis (ED) and electrodialysis reversal (EDR).

RO plants are most widely used in the nation for desalination with 72 percent of plants using brackish water RO, 2 percent using seawater RO, 15 percent using ED-EDR, and 11 percent using NF (Mickley, 2001). Of the approximately one hundred desalination plants operating in Texas, over 95 percent of plants use RO with the remaining 5 percent using ED-EDR. Nearly 83 percent of the desalination plants in Texas use brackish groundwater while 17 percent use surface water.

### 3.2.1 Summary of Technologies

Because most desalination plants in Texas employ RO and EDR, only these technologies are discussed below.

#### RO Technology

A solute in water tends to migrate until it reaches a chemical equilibrium with its surroundings. Osmosis is defined as the flow of a solute through a semi-permeable membrane in response to a concentration gradient across the membrane. A solute flows from lower to higher chemical concentrations to achieve chemical equilibrium. The flow will stop when the activities on both sides of the membrane are equal. The flow may be reversed by applying external pressure on the side of higher concentration. In such a case the phenomenon is called reverse osmosis. RO is a pressure-driven process and the pressure requirements increase as the salinity of the feed water increases. High pressures are needed to overcome the high osmotic pressure of seawater (375 to 500 psi) compared to low pressures (less than 100 psi) needed for desalination of brackish water. The source water is termed feed water while the resulting fresh water is called the permeate and the waste is called the concentrate.

The first RO membranes were made of cellulose acetate. Limitations due to the stability of cellulose restrict the use of this membrane to pH between 3 and 6 and temperature around 30ºC (HDR Engineering Inc., 2000, p. A3.1). They are also subject to biodegradation, but they tolerate chlorine added to the feedwater. Numerous polymeric membranes are now on the market (for example, polyamide, polysulfone, polyhydrazide, and polyurea). Although they are not tolerant of chlorine, they are not subject to biodegradation. In addition, they can operate in a wider range of temperature and pH conditions.

#### ED/EDR Technology

Both ED and EDR processes differ from the pressure-driven membrane processes. These processes employ both cation and anion selective-membranes between electrodes that allow cations to migrate toward one electrode and anions toward the other. Due to this migration, the central feed stream is relatively depleted in ions and the other two steams more concentrated. To inhibit fouling and scale growth on the membranes in the EDR process, electrode polarity is periodically reversed, hence the name of electrodialysis reversal. ED and EDR systems are used to treat brackish water for potable use or to desalt and concentrate wastewater effluents for reuse (Mickley and others, 1993). Most of the ED plants are EDR types. They are typically used for feed water on the low end of the brackish water range (<2,000 mg/l).

In the ED-EDR processes, there is less behavior difference between monovalent and divalent ions. Thus the concentrate in the EDR process generally contains a higher proportion of sodium chloride than the concentrate from an equivalent RO system. Recoveries in the ED-EDR processes can reach up to 90 percent. Unlike the RO processes, the ED water does not pass through the membrane. Thus, if colloids, viruses or organics are present in the feed water, they must be removed during pre-treatment. Turbidity criteria for the EDR processes are less stringent than for the RO membranes. Higher concentrations of calcium and carbonate species are acceptable in the EDR systems compared to the RO processes. If high concentrations of hydrogen sulfide are present in the water, the EDR systems may be designed for its removal prior to the process unlike RO systems (Mickley and others, 1993).

### 3.2.2 Concentrates

Desalination concentrates are produced during removal of salts from low quality water in RO and ED-EDR plants. The amount of concentrate as a percentage of feed water varies depending on the desalination method used, percent recovery, and the chemical additives used. In RO systems that produce drinking water, a typical pretreatment consists of acidification and addition of antiscalant chemicals (see next section). In general, membrane concentrate is essentially a concentrate of the feed water plus the chemical added for pre-treatment purposes; however, there are a few water quality constituents that are rejected by the membranes to a lesser extent than the others. Watson (1990) made the following observations from desalination of brackish groundwater in Fort Meyers, Florida: (1) heavy metals (for example, silver and mercury) are rejected at the same ratio as calcium and magnesium; (2) if anaerobic condition and hydrogen sulfide occur in groundwater then the concentrate will also be equally anaerobic containing hydrogen sulfide; and (3) concentrate pH is generally higher than the feed water pH due to the concentration of bicarbonate ions.

The degree of concentration, also called the concentration factor (CF), is defined as:

$$CF = 1/(1-R_w) * [1-R_w(1-R_s)] \qquad 3.1$$

where $R_s$ is the fractional salt rejection and $R_w$ is the fractional product water recovery (Glater and Cohen, 2003). Therefore, the concentration factor can be readily calculated knowing the composition of the feed water and expected recovery rate. Assuming a 100 percent salt rejection, a recovery of 75, 85, and 95 percent would yield a concentration factor of 4, 6.67, and 20, respectively. In general, divalent ions are rejected at a higher rate than monovalent ions. However, the error introduced by considering that they have the same rejection rate of 100 percent is minimal as illustrated in Mickley and others (1993, Chapter 5). There is no more than a few percent difference between monovalent and divalent ion rejection for typical rejection values of 90 to 100 percent.

Major ion ratios of the desalination concentrates and feed water from Texas and elsewhere (Tables 3-2 and 3-3) indicate that the ion ratios largely depend on the feed water composition (Ahmed, 2000). Feed water and concentrate compositions collected from four desalination facilities in Texas do not have a complete list of chemical parameters (Table 3-2). Some of the chemical parameters were measured for the feed water but not for the corresponding concentrate. Most of the chemical parameters in the concentrate have higher values than the feed water composition as would be expected during concentration of dissolved salts in the reverse osmosis process. Overall, salt concentration ratios (concentrate/feed water) for brackish water vary from 1.55 to 3.62 for TDS, 1.6 to 3 for $SO_4^{2-}$, and 1.26 to 3.77 for $Cl^-$. These variations in the salt concentration ratios are due to differences in pre-treatment and initial compositions of feed water. When the TDS in the feed water approaches seawater composition, salt concentration ratios for all chemical parameters are considerably reduced (Table 3-3). Major ion ratios of the desalination concentrates and the feed waters from Texas and elsewhere indicate that the ion ratios largely depend on the feed water composition.

TDS of the feed water has a good correlation to the concentrates ($R^2 = 0.98$) (Figure 3-1a). At lower TDS (<10,000 mg/l), desalination concentrates are approximately four times more enriched than the feed water composition. Nearly all Texas samples with TDS values of less than 10,000 mg/l fall in this category. For produced water at TDS values approaching that of seawater, recovery rate is significantly reduced. $Na^+$ and $Mg^{2+}$ of the feed water has a good correlation to the concentrates ($R^2 > 0.96$) (Figure 3-1b and c). Cross-plots of $Ca^{2+}$ and $SO_4^{2+}$ compositions of the desalination concentrates and feed waters show poor correlations ($R^2 = 0.57$ and 0.5, respectively) probably because acidification during pre-treatment perhaps unevenly affect these ions at varying salinities (Figure 3-1d and e). Membrane desalting technologies allow the dissolved gases, typically $O_2$, $CO_2$ and $H_2S$, to go through the membrane and be mostly depleted in the concentrate.

### 3.2.3 Changes Due to Pretreatment

Since feed water undergoes numerous transformations during the desalination process, it is important to understand and describe those changes.  As mentioned above, for operational reasons, the feed water needs to be pretreated (for example, Wilbert and others, 1998, Chapter 6). This generally entails (1) acidification to reduce the alkalinity of the raw water and prevent scaling by calcite and (2) addition of antiscalant(s) to prevent scaling by other minerals, particularly sulfates. If the source water is groundwater, pretreatment is often limited to pH adjustment, scale control, and cartridge filtration. Surface waters and some ground waters may require a more complex pretreatment process that could include coagulation, media filtration and clarification to remove suspended solids and bacteria. A typical biocide pretreatment could also involve chlorination and subsequent dechlorination with activated carbon or may be addition of sodium bisulfite because of the low tolerance of most modern membranes to chlorine.

Table 3-2. Comparison of feed water and concentrate compositions from desalination facilities in Texas.

| Facility | As | Al | Ba | Fe | Mn | Ca | Mg | Na | Cl | F | Nitrate as N | $SO_4$ | TDS | TSS | pH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **El Paso (ground water)** | | | | | | | | | | | | | | | |
| FW | 0.01 | ND | 0.02 | 1.05 | 0.04 | | | | 374 | 0.85 | 0.92 | 592 | 1,540 | | 7.70 |
| Conc | 1.38 | <0.08 | 0.03 | | | | | | 1,410 | | | | 5,101 | 10 | 8.11 |
| C/FW | 98.21 | | 1.30 | | | | | | 3.77 | | | | 3.31 | | |
| **City of Sherman (surface water)** | | | | | | | | | | | | | | | |
| FW | | 32.00 | 120.00 | 0.04 | 31.00 | | | 220 | 280 | | <0.5 | 220 | 980 | | |
| Conc | 0.09 | 0.09 | 0.22 | | | | | 609 | 1,005 | | | 668 | 3,548 | 6 | |
| C/FW | | 0.0028 | 0.0018 | | | | | 2.77 | 3.59 | | | 3.04 | 3.62 | | |
| **Dell City (ground water)** | | | | | | | | | | | | | | | |
| FW | <0.02 | <0.05 | 0.01 | <0.010 | <0.008 | 205 | 61 | 16.50 | 19 | | | 588 | 753 | | |
| Conc | | | | | | | | | 24 | | | 968 | 1,170 | | |
| C/FW | | | | | | | | | 1.26 | | | 1.65 | 1.55 | | |
| **City of Seadrift (ground water)** | | | | | | | | | | | | | | | |
| FW | | | | | | 115 | 48 | 468 | 875 | | | 34 | 1,699 | | 8.20 |
| Conc | | | | | | | | | | | | | 4,710 | | |
| C/FW | | | | | | | | | | | | | 3 | | |

Units are mg/l; FW = feed water; Conc = concentrate; C/FW = ratio of concentrate to feed water; TSS = total suspended solids; TDS = total dissolved solids.

Table 3-3. Comparison of feed water and concentrate compositions from desalination facilities in the United Arab Emirates (Ahmed, 2000).

| Facility | Ca | Mg | Na | Cl | K | $SO_4$ | Sr | Alkalinity | Hardness | Bicarbonate | pH | TDS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Adam** | | | | | | | | | | | | |
| FW | 103 | 70 | 410 | 506 | 12 | 773 | 3 | 195 | 548 | 230 | 8 | 2,000 |
| Conc | 417 | 280 | 1,670 | 1,964 | 43 | 4,336 | 13 | 30 | 2,211 | 37 | 6 | 8,747 |
| C/FW | 4.05 | 4.00 | 4.07 | 3.88 | 3.72 | 5.61 | 3.95 | 0.15 | 4.03 | 0.16 | | 4.37 |
| **Haima** | | | | | | | | | | | | |
| FW | 652 | 267 | 3,340 | 1,697 | 125 | 2,037 | 16 | 62 | 2,748 | | 7 | 8,217 |
| Conc | 1,020 | 406 | 406 | 9,090 | 174 | 3,881 | 24 | | | | 3 | |
| C/FW | 1.56 | 1.52 | 0.12 | 5.36 | 1.39 | 1.91 | 1.54 | | | | | |
| **Esherja** | | | | | | | | | | | | |
| FW | 496 | 1,100 | 8,630 | 15,868 | 355 | 4,104 | 11 | 114 | 5,785 | 139 | 7 | 30,638 |
| Conc | 841 | 1,900 | 14,800 | 24,062 | 631 | 6,139 | 18 | 181 | 9,951 | 221 | 7 | 48,510 |
| C/FW | 1.70 | 1.73 | 1.71 | 1.52 | 1.78 | 1.50 | 1.63 | 1.59 | 1.72 | 1.59 | | 1.58 |
| **Sowqrah** | | | | | | | | | | | | |
| FW | 404 | 1,170 | 9,360 | 16,193 | 415 | 3,310 | 8 | 136 | 5,845 | 153 | 8 | 30,955 |
| Conc | 625 | 1,830 | 14,600 | | 668 | 4,824 | 12 | 203 | | 173 | 7 | |
| C/FW | 1.55 | 1.56 | 1.56 | | 1.61 | 1.46 | 1.52 | 1.49 | 0.00 | 1.13 | | |
| **Hitam** | | | | | | | | | | | | |
| FW | 563 | 382 | 3,400 | 7,483 | 124 | 2,366 | 13 | 125 | 2,996 | 135 | 8 | 14,451 |
| Conc | 665 | 448 | 4,250 | 8,118 | 145 | 2,466 | 15 | 142 | 3,526 | 125 | 8 | 16,142 |
| C/FW | 1.18 | 1.17 | 1.25 | 1.08 | 1.17 | 1.04 | 1.20 | 1.14 | 1.18 | 0.93 | | 1.12 |
| **Madrakh** | | | | | | | | | | | | |
| FW | 429 | 1,390 | 11,200 | 17,999 | 483 | 3,161 | 8 | 111 | 6,809 | | 8 | 34,744 |
| Conc | 611 | 1,980 | 15,300 | 24,802 | 685 | 3,846 | 1 | 102 | 9,698 | | 7 | 47,305 |
| C/FW | 1.42 | 1.42 | 1.37 | 1.38 | 1.42 | 1.22 | 0.17 | 0.92 | 1.42 | | | 1.36 |

Units are mg/l; FW = feed water; Conc = concentrate; C/FW = ratio of concentrate to feed water; TDS = total dissolved solids.

Table 3-3. Continued.

| Facility | Ca | Mg | Na | Cl | K | $SO_4$ | Sr | Alkalinity | Hardness | Bicarbonate | pH | TDS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Zahar** | | | | | | | | | | | | |
| FW | 179 | 95 | 746 | 1,408 | 28 | | 5 | 244 | | | 7 | |
| Conc | 612 | 315 | 1,980 | 4,367 | 95 | 1,143 | 16 | 704 | 2,846 | | 7 | 8,990 |
| C/FW | 3.42 | 3.32 | 2.65 | 3.10 | 3.36 | | 3.47 | 2.89 | | | | |
| **Assadanat** | | | | | | | | | | | | |
| FW | 367 | 174 | 1,290 | 2,160 | 12 | | 30 | 196 | | | 8 | |
| Conc | 923 | 413 | 2,780 | 4,532 | 82 | 1,552 | 28 | 380 | 4,041 | | 7 | 10,553 |
| C/FW | 2.51 | 2.37 | 2.16 | 2.10 | 7.03 | | 0.93 | 1.94 | | | | |
| **Abu-Mudhaibi** | | | | | | | | | | | | |
| FW | 294 | 137 | 1,360 | 2,151 | 29 | 515 | 8 | 200 | 1,309 | 245 | 7 | 4,651 |
| Conc | 962 | 448 | 4,630 | 7,335 | 101 | 3,296 | 27 | 168 | 4,281 | 205 | 7 | 16,960 |
| C/FW | 3.27 | 3.27 | 3.40 | 3.41 | 3.47 | 6.40 | 3.34 | 0.84 | 3.27 | 0.84 | | 3.65 |
| **Qidfa I** | | | | | | | | | | | | |
| FW | 464 | 1,640 | 11,900 | 23,149 | 574 | 2,787 | 5 | 111 | 7,922 | 136 | 8 | 40,592 |
| Conc | 617 | 2,150 | 15,100 | 30,540 | 767 | 3,931 | 7 | 96 | 10,409 | 117 | 7 | 53,177 |
| C/FW | 1.33 | 1.31 | 1.27 | 1.32 | 1.34 | 1.41 | 1.58 | 0.86 | 1.31 | 0.86 | | 1.31 |
| **Qidfa II** | | | | | | | | | | | | |
| FW | 533 | 1,620 | 12,200 | 23,484 | 581 | 3,181 | 7 | 82 | 8,015 | 100 | 7 | 41,661 |
| Conc | 730 | 2,240 | 15,800 | 32,004 | 805 | 4,500 | 7 | 102 | 11,067 | 125 | 7 | 56,158 |
| C/FW | 1.37 | 1.38 | 1.30 | 1.36 | 1.39 | 1.41 | 0.99 | 1.24 | 1.38 | 1.25 | | 1.35 |
| **Kalba** | | | | | | | | | | | | |
| FW | 446 | 245 | 536 | 2,103 | 11 | 265 | 5 | 109 | 2,130 | 133 | 7 | 3,700 |
| Conc | 1,180 | 644 | 1,170 | 5,413 | 34 | 756 | 11 | 285 | 5,615 | 347 | 8 | 9,432 |
| C/FW | 2.65 | 2.63 | 2.18 | 2.57 | 3.09 | 2.85 | 2.12 | 2.61 | 2.64 | 2.61 | | 2.55 |
| **Umm-Al-Qwain** | | | | | | | | | | | | |
| FW | 49 | 110 | 775 | 1,182 | 19 | 562 | 5 | 226 | 581 | 275 | 8 | 2,851 |
| Conc | 202 | 510 | 3,190 | 4,108 | 85 | 2,444 | 21 | 538 | 2,630 | 656 | 8 | 10,923 |
| C/FW | 4.12 | 4.64 | 4.12 | 3.48 | 4.36 | 4.35 | 4.23 | 2.38 | 4.53 | 2.39 | | 3.83 |

Table 3-3. Continued.

| Facility | Ca | Mg | Na | Cl | K | $SO_4$ | Sr | Alkalinity | Hardness | Bicarbonate | pH | TDS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Jabal al-Dhana** | | | | | | | | | | | | |
| FW | 636 | 2,140 | 14,200 | 27,098 | 661 | 3,121 | 10 | 113 | 474 | 138 | 8 | 47,941 |
| Conc | 760 | 2,660 | 17,700 | 34,839 | 950 | 4,602 | 10 | 96 | 10,418 | 117 | 6 | 61,587 |
| C/FW | 1.19 | 1.24 | 1.25 | 1.29 | 1.44 | 1.47 | 1.04 | 0.85 | 21.98 | 0.85 | | 1.28 |
| | | | | | | | | | | | | |
| **Hamriyah** | | | | | | | | | | | | |
| FW | 48 | 85 | 498 | 779 | 13 | 407 | 4 | 177 | 474 | | 7 | 1,949 |
| Conc | 173 | 311 | 1,930 | 2,933 | 51 | 1,537 | 14 | 617 | 1,730 | | 8 | 7,350 |
| C/FW | 3.60 | 3.66 | 3.88 | 3.77 | 3.84 | 3.78 | 3.81 | 3.49 | 3.65 | | | 3.77 |

Units are mg/l; FW = feed water; Conc = concentrate; C/FW = ratio of concentrate to feed water; TDS = total dissolved solids.

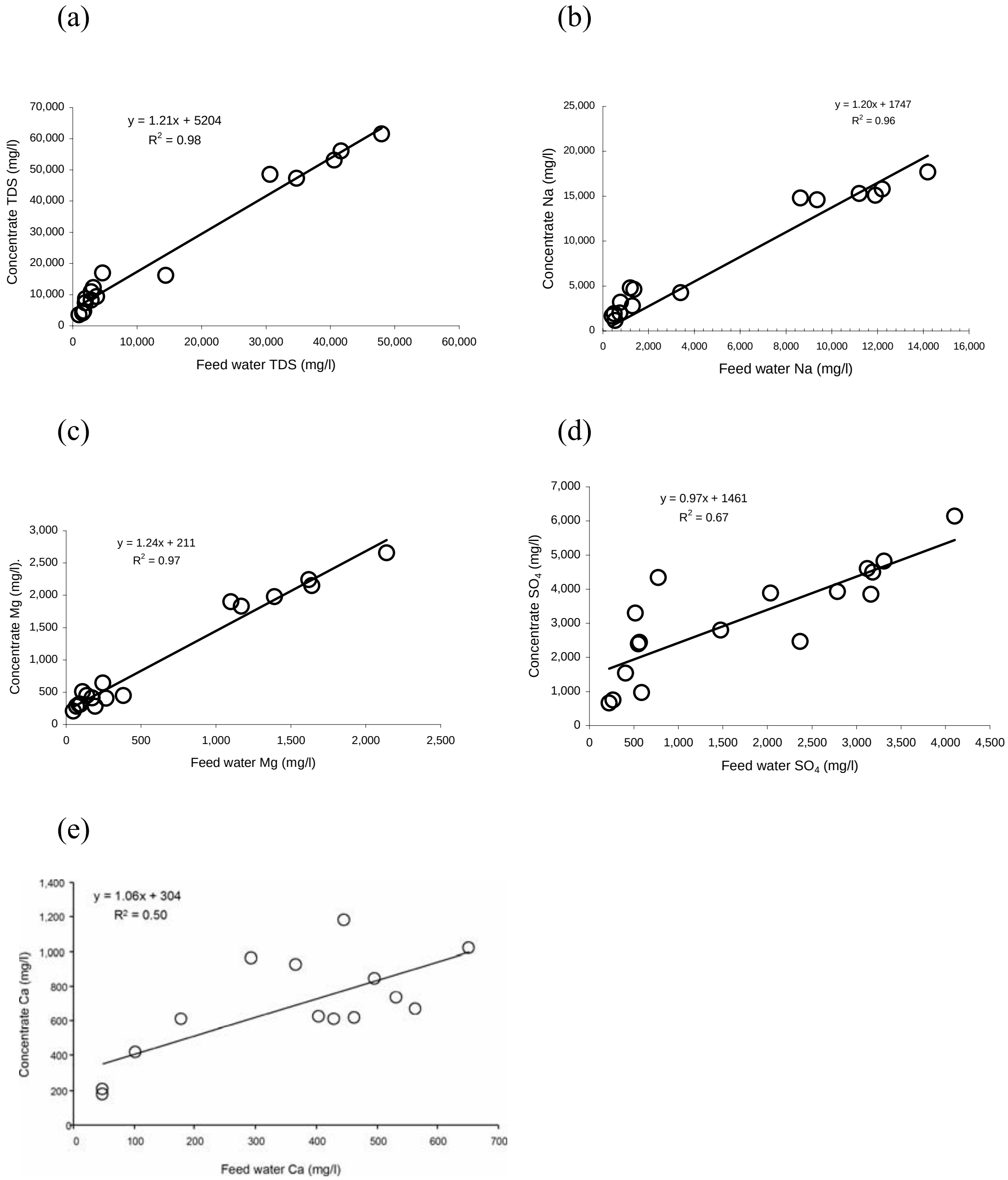


Figure 3-1. Comparison of feed waters and concentrates.

Bisulfite reacts with chlorine to generate chloride and sulfate. An alternate biocide such as ozone may be used in place of bisulfite. However, this may entail an extra degasification treatment of the feed water.

Acidification is generally done with sulfuric acid (dosage of <300 mg/l) and sometimes hydrochloric acid. Among the 33 drinking water RO, EDR, and NF facilities described in Mickley (2001) that adjust pH, all but 5 use sulfuric acid. Three use hydrochloric acid and two use sodium hydroxide. Sulfuric acid is cheaper but might generate sulfate scaling problems in feed water already high in sulfate while the addition of the chloride ion in hydrochloric acid enhances corrosion. Decreasing pH to less than 7.0 will also decrease solubility of silica, encouraging its precipitation onto the membrane. The 18 MGD Hollywood, Florida membrane softening and reverse osmosis plant injects a scale inhibitor and sulfuric acid into the feed water before the pretreatment cartridge filter. The design pH for the membrane softening and RO are 6.0 and 6.5, respectively (Bloetscher and Ortiz, 1999). The raw water supply comes from the Biscayne and Floridan aquifers. Another surficial calcium carbonate water with a high iron concentration (4 to 6 mg/l) is brought to a pH of 5.2 to 5.6 by adding sulfuric acid before a NF or membrane softening process (Messner and others, 1999). Acid addition increases solubility of calcium carbonate and prevents scaling. Hydrochloric acid is added at the feed water to the Port Hueneme, California EDR brackish water facility (AWWA, 2004, Case Study 2) to reduce scaling potential. The facility also operates parallel NF and RO modules which do not require acid addition. Mickley and others (1993, Chapter 3) report a study of 12 brackish water desalination plants where the amounts of acid added ranged from 40 to 300 ppm in Florida.

Antiscalant treatment involves the addition of a small amount of chemical (<10 mg/l) that does not modify the chemical characteristics of the concentrate. The antiscalants typically delay the scale formation process when the water is in contact with the membrane. Antiscalants are often made up of polyphospates, phosphonates, or polycarboxylates (Cowan and Weintritt, 1976). There are many antiscalant manufacturers, each with an assortment of products according to the facility needs. Makers of some antiscalants claim that their product can inhibit the precipitation of $CaCO_3$ at a Langelier Saturation Index (LSI) of up to +2.3 and $CaSO_4$ of up to 1.8 times supersaturation. Experiments have in general proven those claims to be accurate (Matty and Tomson, 1988; He and others, 1994). He and others (1994) report that the effectiveness of antiscalants (for $CaSO_4$ and $BaSO_4$) is a function of temperature, pH, ionic strength, as well as the nature of other divalent ions. They report that $CaSO_4$ and $BaSO_4$ precipitation in NaCl solutions can be inhibited at least to a saturation index of 0.7 and 2.9 (if temperature is less than $50^o$ centigrade), respectively. Matty and others (1985) reported a probable value of 2.3 for $CaCO_3$ saturation index for the inhibitor action under in-situ conditions.

Additional pre-treatment techniques can also be used as in any water treatment plant for water softening, Fe/Mn removal, and silica removal, although at an added cost. These techniques have the advantage of targeting one troublesome element or compound. Scale-forming material can be removed or their concentration decreased by ion-exchange techniques on special resins or ultrafiltration. Some form of chemical precipitation used in conventional water treatment plants can also be used although they are typically costly. For example, alum coagulation/flocculation and filtration could also be used to prevent the fouling and clogging of membranes by suspended solids. Adding lime to the feed water would raise the pH and precipitate calcium carbonate and magnesium hydroxide, softening the water. Aluminium sulfate (alum) also reacts with alkalinity and softens the feed water. NF and cation exchange treatments also soften the water. Iron and manganese can be removed from the solution by flowing it through a “greensand” system (mainly glauconite clay). All of the above processes decrease feedwater TDS and consequently the concentrate TDS.

A related issue is whether or not the flow system is open or closed to the atmosphere. Dissolved $O_2$ and $CO_2$ increase the corrosiveness of water and may need to be removed before they reach the membranes. Because gases go through RO membranes and are unaffected by ED-EDR, they are not present in the concentrate if the system operates in a closed-loop.

### 3.2.4 Post Treatment of Concentrate

The permeate often needs to be treated before it is suitable for human consumption typically by adding lime and increasing its pH. Depending on the disposal method, the concentrate also needs to be treated. Only one of the 10 desalination facilities described in Mickley (2001) that dispose of the concentrate through deep-well injection does some kind of pretreatment before injection. The Mabry Carlton EDR Facility (design capacity of 12 MGD) adds an antiscalant for gypsum (that would work for water with a *LSI* of less than 1.5). Sometimes cartridge filtration has to be performed to remove total suspended solids (TSS) added when backwash from UF pretreatment and other cleanup residues are added to the concentrate stream. An upper limit of 1 ppm TSS is generally accepted before injection. As a reference, typical TSS values in sea water are about 50 mg/l. Anticorrosion products are sometimes added to the concentrate stream. A more thorough description of possible pre-injection treatment is given in Section 3.3.1.

## *3.3 Deep-Well Injection*

Currently, deep injection wells are used to dispose of municipal wastes (for example, Florida), hazardous wastes (for example, Texas and Louisiana), and produced waters (oil-producing regions). Deep-well injection disposal of RO and EDR concentrates is currently done in Florida (Table 3-4).

Table 3-4. Locations of deep-well injection disposal of RO and EDR concentrates as of 1999.

| Plant name | State | Type | Design capacity (MGD) |
|---|---|---|---|
| Burnt Store RO Plant | FL | Brackish Reverse Osmosis | 0.56 |
| Englewood Water District RO Plant | FL | Brackish Reverse Osmosis | 3.00 |
| Knight Island Utilities Inc. | FL | Brackish Reverse Osmosis | 0.90 |
| Marco Island RO Plant | FL | Brackish Reverse Osmosis | 6.00 |
| Miramar West Plant | FL | Nanofiltration | 4.50 |
| North Collier County, FL | FL | Brackish Reverse Osmosis | 20.00 |
| Plantation, FL WTP | FL | Nanofiltration | 12.00 |
| Plantation, FL, City of | FL | Brackish Reverse Osmosis | 6.00 |
| Sanibel Island WTP | FL | Brackish Reverse Osmosis | 4.70 |
| T. Mabry Carlton EDR Facility | FL | Electrodialysis Reversal | 12.00 |

From Mickley (2001)
MGD = millions of gallons a day

However, the analogy with Texas is limited since the concentrate is injected in the often cavernous Lower Floridan aquifer (Mickley, 2001, Chapter 9). There is no recorded instance of injection of desalination concentrate into oil-bearing formations to our knowledge. Injection wells of all types share the same potential problems of formation damage when injecting a foreign fluid into a deep formation and also of plugging and tubing corrosion when injecting corrosive liquids.

### 3.3.1 Deep-Well Waste Injection

In 1985, about 5.1 billion gallons of Class I waste were injected through about 100 disposal wells in Texas (Capuano and others, 1989 p. 5). On average, this amounts to a rate of about 100 gpm or 3,400 bbl/day per well. The injection rate can be seven times greater for the most efficient wells (Capuano and others, 1989, Table 1). Most operators inject in the sandy aquifers along the Gulf Coast, namely the Frio, Yegua, Catahoula, Oakville, Wilcox, and other Miocene sandstones (Capuano and others, 1989, p. 53). Injection depth ranges from 2,000 to 8,500 feet but mostly from 4,000 to 7,000 feet (Capuano and others, 1989, p. 53) primarily against a hydrostatic formation pressure.

To ensure an optimal injection process and avoid corrosion, preliminary steps need to be taken. Injection of fines, compatibility issues, and corrosion concerns need to be addressed. Surface filtration and injectate conditioning are paramount to keep the injection well in good condition. Pretreatment processes include all or some of the following: addition of anti-corrosion additives to limit corrosion, filtering of suspended solids (to 1 µm and sometimes to 0.2 µm), pH adjustment to assure compatibility with formation fluids, and possible flocculation additives to limit clay migration and swelling. Pretreatment could also include degasification of the injectate by addition of chemical scavengers, vacuum deaeration, or counterflow gas stripping. The target gas is $O_2$ since lowering pH will make the water more aggressive, hence the necessity to deoxygenate the water before injection. Other gases that need to be stripped from the injection stream are $CO_2$ and $H_2S$. Records show that in Texas typical pre-treatment of Class I waste before injection consists of the addition of scale inhibitor and/or of pH adjustment by addition of acid or base (Capuano and others, 1989, p. 4). Those pre-injection treatment steps are very similar to those taken before undergoing membrane desalination suggesting that any pretreatment before injection may not be warranted.

As in the pre-treatment of desalination feed water, economic benefits of addition of chemicals must be seriously considered. For example, counter-flow gas stripping columns are more expensive than addition of sodium bisulfite (~10 mg for each ppm of $O_2$). However, bisulfite reacts with oxygen to produce sulfate which might be detrimental to injection if barium is present in the formation waters because of the very low solubility of barium sulfate.

### 3.3.2 Operational Characteristics of Oil and Gas Reservoirs

Early after the initial production of an oil reservoir, water is injected for pressure maintenance if the reservoir does not have a natural water drive (note that gas reservoirs are generally not waterflooded). A natural water drive occurs when the hydrocarbon volume removed by oil production is replaced by water moving in, keeping the reservoir under pressure and the production going with minimal assistance. Other common types of production drive are solution gas drive and gas cap drive. The former happens when light hydrocarbons in solution in the oil outgas to maintain pressure while the latter occurs when a free gas cap is present on top of the oil. Waterfloods occur later in the life of a field. For example, most of the West Texas fields were under solution gas drive (Galloway and others, 1983, Plate 5) and have been good candidates for water floods. The Permian Basin area is still being heavily waterflooded.

Most fields were under natural water drive in East Texas. Consequently water flooding has not been as widespread. However, East Texas well fields have an extensive reinjection program where the produced waters are typically disposed of in the same formation but further downdip. The southern Gulf Coast Frio fields have seen little water flooding, although salt water disposal wells are frequent. Solution gas and gas cap expansion drives are common in this basin. Information about water injection can be gained by looking at the injection history of the fields.

Depressurization resulting from hydrocarbon production is common in long-producing formations such as the San Andres in the Permian Basin, the Woodbine in the East Texas Basin, and the Frio in the Gulf Coast Basin. Natural recovery can be a long process. Senger and others (1987) estimated that it would take 10,000 years for a hypothetical field in the Palo Duro basin in the Texas Panhandle to return to 90 percent of the original pressure. The recovery rate is dependant upon permeability and storativity, but the order of magnitude of the recovery time interval suggests that the fields will stay underpressured for a long time.

The RRC delivers injection permits through H1 forms and tracks the injection history. Recently completed H1 forms are available on the RRC site on the Web while forms filled before 2000 can be reviewed at the RRC in Austin, Texas. The latest compilation of injection operations in Texas dates back to 1982 (RRC, 1982). Form H1 provides information into the type of fluid to be injected (for example, salt water, brackish water, fresh water, air, gas, $CO_2$, and polymer), the purpose of the injection (disposal or secondary recovery), and formation characteristics such as depth, perforated interval, porosity, and permeability. Volume of water needed is in general 150 to 170 percent of the targeted pore volume (Thomas and others, 1987, p. 41 - 44). The largest demand for external water is at the beginning of the water flood before breakthrough at the producing wells. Return water will progressively be re-injected unless precluded by the treatment cost of the produced water. It is common in the industry to convert a production well into an injection well as the water flood front passes by. The external water source could be surface waters (rivers and lake), a fresh-water aquifer, a brackish-water aquifer, or produced water possibly from the same formation. Typically, when water of different sources must be mixed, the mixing is done at the surface rather than down hole. The injection system can be closed or open to the atmosphere. A closed system limits pre-treatment and allows ferrous iron to stay in solution. Ferric iron is insoluble except at low pH. Exposing a solution with ferrous iron to oxygen would mean certain iron oxide precipitation somewhere in the system. Water with a high content of corrosive dissolved gases such as $H_2S$ or $CO_2$ may have to be thoroughly treated before injection. Dissolved $O_2$ is introduced by opening the system to the atmosphere. Dissolved $O_2$ is costly to remove from water and may have deleterious effects.

From a review of the H1 forms, we found that most of the fields have significant potential to accept considerable volumes of water. Forms H1/H1A are required when proposed injection will take place within two miles of a past or current productive reservoir (RRC Rule 46). Operators need to provide area of review (AOR) data as part of the application. Injection of fresh water as makeup fluid is restricted to cases where there is no technically or economically viable alternative. In that case, Form H7 must be provided. The oil industry is using various sources of water that include salt water (produced water), brackish water, fresh water from lakes, commercially available fresh water, and gas plant waste water for water-flooding reservoirs. In essence, convenience, economics, and availability of water determine the type of water being used in water-flooding operations. Estimated maximum daily rate of injection per well could vary considerably and ranges from less than 100 bbl per day to more than 5,000 bbl per day (3 gpm to more than 150 gpm). A rule of thumb generally applied in the industry is to limit injection pressure at the sandface to 1 to 1.5 psi/foot of depth. Higher pressure tends to open fractures, which may be detrimental to production and safety.

### 3.3.3 Area of Review Principles

The UIC regulations of the EPA require an AOR for newly drilled or converted Class II salt-water injection well. The permitting process requires operators to file with the RRC an AOR study. Applicants are required to submit a map showing all wells within a 0.25 mile radius of a proposed well in addition to well characteristics for those wells penetrating the formation of interest (drilling date and well status among other parameters). The purpose of an AOR study is to identify unplugged wells that may allow injected fluids to migrate upward and endanger the overlying underground sources of drinking water. The RRC states that a variance of an AOR request can be granted by demonstrating either that reservoir pressure is insufficient to raise fluids into underground sources of drinking water, that geologic conditions preclude upward movement of fluids, or that there is other compelling evidence that would warrant a variance.

If wells of unknown conditions are encountered, corrective action may be necessary to meet UIC requirements. Performing this study can be a hindrance to small operators because of the administrative search and field work it entails. However, it is permissible to ask for a variance to the AOR permitting process on the following bases (Warner and others, 1997):

- Variance based on absence of aquifer with water of good quality (<10,000 mg/l). The UIC program defines an Underground Source of Drinking Water (USDW) as an aquifer that contains fewer than 10,000 mg/l of TDS.

- Variance based on negative flow potential between injection-zone fluid levels and base of drinking water. If the injection zone pressure head is sufficiently below the stratigraphic base of useable quality drinking water (BUQW), then there is little potential for the injection fluids to migrate upwards and contaminate the drinking water even if some unplugged wells were unnoticed. A separation of 500 feet between the injection zone fluid level and BUQW is recognized as acceptable (Smyth and others, 1998) (Figure 3-2).

- Variance based on lack of intersection. No adjacent well is drilled to the depth of the injection zone.

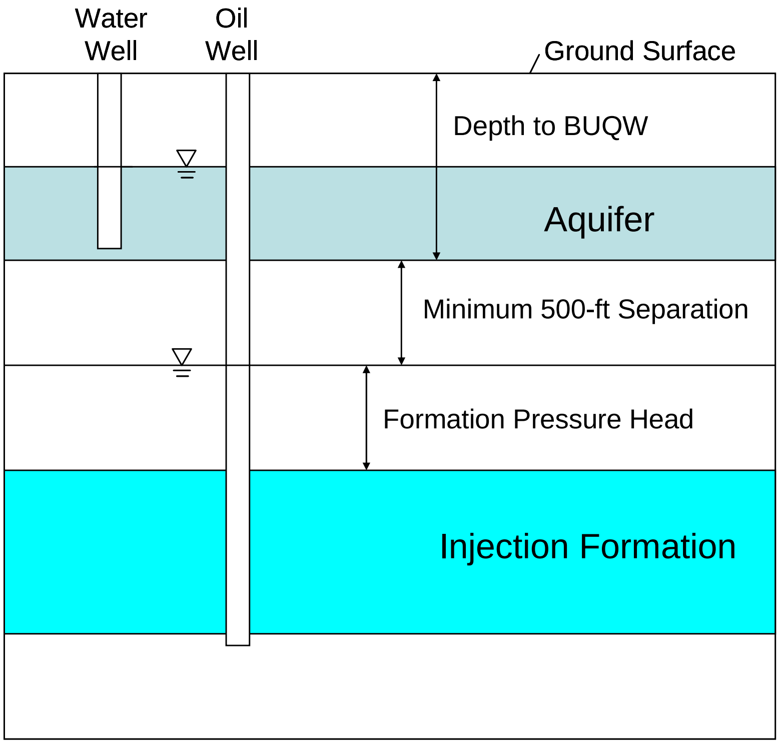


Figure 3-2. Diagram of area of review (AOR) principles.

- Variance based on mitigating geological factors. There could be the presence of a thief zone that would divert most of upward flowing fluid or of an incompetent formation that tends to cave into the wellbore. Warner and others (1997) suggest that 100 feet of continuous shale/mudstone or 250 feet of cumulative thickness may be enough to justify a variance.

- Variance based on well construction and abandonment methods. For example, for oil or gas fields developed after adequate regulations were promulgated (that is, after 1982 according to Warner and others, 1996).

- Variance based on other compelling evidence.

A previous state-wide study by the Bureau of Economic Geology (Smyth and others, 1998) co-funded by the U.S. Department of Energy and the RRC provided a field-level basis for operators to request a variance from the AOR permitting requirement. The RRC has adopted a procedure in their review of injection permits to consider an AOR variance if fluid levels reported on H15 forms as measured in shut-in wells can be shown to be well beneath the level of the BUQW. Warner and others (1996) did a study of selected fields in the Permian Basin; Warner and others (1997) did a study of the Frio Formation in South Texas; and Smyth and others (1998) investigated 113 fields in 36 counties across Texas to see if any fields could get variances. Warner and others (1996) used the second-to-last type of variance described above in their study. Warner and others (1997) studied the shale/mudstone abundance in the interval between injection formation and BUQW while Smyth and others (1998) quantified the separation between formation head and BUQW (the second type of variance described above). The interest of focusing on depleted oil and gas fields is that the separation between formation head and BUQW has been potentially increased by removing hydrocarbons.

Warner and others (1996) concluded that most wells abandoned after 1967, and even more so for those abandoned after 1982, were protective of usable quality water. They showed that the 78 Permian Basin injection fields analyzed could qualify for a variance of AOR. Warner and others (1997) also reported that sloughing shales are common along the Gulf Coast and that an open wellbore will quickly be sealed. They concluded that most Texas Gulf Coast Frio Formation well fields can be considered for variance of AOR on the basis of either well completion or presence of shales. Smyth and others (1998) concluded that 42 fields out of 113 could be recommended for variance of AOR.

### 3.3.4 Pressure Studies and Deep-Well Injection

Pressure studies require information on formation pressures, deep-well injection technology, and injection pressure and flow rates.

#### Formation Pressures

Formation pressure is critical to our understanding of the economic potential of a reservoir. Distribution of oil and gas is related to regional and local subsurface pressure and temperature environments. Knowledge of the expected pore pressure gradients helps with (1) efficient drilling of wells with correct mud densities, (2) proper engineering of casing programs, and (3) proper well completion without causing excessive formation damage. Normal or hydrostatic pressures have gradients in the range of 9.8 to 11 kPa/m (~0.433 psi/ft). The hydrostatic pressure is the pressure executed by the weight of a column of fluid. Hydrostatic pressure varies with the density of the fluid and the height of the column. Normally pressured formations are considered “open systems,” which permit hydraulic communication of interstitial fluids with the ground surface. Within a lithified formation there will be a number of pressures that individually tend to either lend support to, or attempt to further compact, the formation. The main pressures are: the pore pressure; the rock grain pressure (matrix stress); and the total overburden pressure, which is supported by the pore and rock grain pressures.

When the gradients are outside the stated range the reservoir is exhibiting abnormal pressures. Abnormally pressured formations are usually “closed systems” which have been geologically pressured. In that case, a permeability barrier acts as a pressure seal. In a geo-pressured sequence of shales and sands, the shales are composed primarily of platy clay minerals that fill the role of the permeability barrier. Overpressures are developed and maintained by restriction of pore fluid movement in the reservoirs. In such a sequence the ratio of shale to sand must be fairly high in order to increase the possibility of a sand unit being completely isolated and encapsulated by the surrounding shales. The creation of an over pressured formation is related to many physical, geochemical, and mechanical processes. For example, several kinds of stress changes can lead to abnormal pore fluid pressures: (1) rapid geologic loading or unloading creating compaction disequilibrium, (2) thermal expansion of fluids, (3) regional compressive or tensile tectonic stresses, and (4) generation of oil and gas from organic matter. However, this is a transient phenomenon at the geological time scale and typically occurs at deeper depths than those considered in this study. Some deep formations (>10,000 feet) of the Texas Gulf Coast are geopressured. Underpressured reservoirs are common in rocks that have been subjected to recent uplift and erosion. Most commonly, underpressure is subsequently developed when a reservoir is depleted of all its fluids.

The hydrostatic pressure $p_f$ at depth $D$ assuming water continuity from the surface is given by:

$$p_f = \int_0^D \rho_w(x) g dx \approx \rho_{w,aver} g D \qquad 3.2$$

where $\rho_w$ is the water density varying with depth. Water density at 20°C is given as a function of the TDS by (Kharaka and others, 1988):

$$\rho_w = 1 + 0.000688 \text{x} TDS \text{ with } TDS \text{ in g/L} \qquad 3.3$$

Seawater with a salinity of ~35 g/L would have a density of 1.024 kg/L at $20^0$C according to this formulation.

## Deep-Well Injection Technology

The technology for deep-well injection is similar for both Class I and Class II wells. Injection wells are typically completed according to either one of the three following modes: open hole in competent formations; fully screened in incompetent sand and gravel formations; and fully cased and cemented with the casing perforated, valid for both competent and incompetent formations.

A statistical analysis of the form H1 dataset (heavily biased towards Permian Basin wells) shows that half of the currently operating Class II injection wells in the analysis areas are cased and perforated with the remainder being open hole well. Less than ten percent of the injection systems are open; therefore, most injection systems are closed to the atmosphere. More than half of the wells have a borehole size of 7 7/8 inch and 85 percent of them are between 7.5 and 9.5 inches in diameter. In most cases, the tubing size is between 2 3/8 or 2 7/8 inch (97 percent of wells in the data set). An analysis of the reported maximum injection pressure gradient (injection pressure/tubing depth) showed that all (except some outliers probably representing bad data) of them are less than or close to hydrostatic. The maximum injection pressure is a function of the tubing diameter: the smaller the diameter, the higher the head loss.

## Injection Pressure and Flow Rates

Movement of the injectate into the formation requires a pressure high enough to overcome the resistance of the resident water. The response of an aquifer to the injection pressure is given, in a consistent system of units, by (Warner and Lehr, 1977, p. 104):

$$\Delta h = \frac{\Delta P}{\rho g} = \frac{Q}{4\pi T} \ln\left(\frac{2.25Tt}{r^2 S}\right) \qquad 3.4$$

where $h$ is the head, $P$ is the pressure, $Q$ is the flow rate, $T$ is the transmissivity ($T$=$Kb$ where $K$ is the conductivity and $b$ is the aquifer thickness), $t$ is the time since injection began, $r$ is the radial distance from well to point of interest, and $S$ is the storativity or storage coefficient. The parameter $S$ is related to both the compressibility of water and of the rock by:

$$S = S_c b = \rho g(\phi\beta + \alpha)b \tag{3.5}$$

where $S_c$ is the specific storage, $\beta$ is the compressibility of water, $\alpha$ is the compressibility of the rock skeleton, and $\phi$ is the rock porosity (Warner and Lehr, 1977, p. 41). Equation 3.4 is derived with the Theis assumptions (for example, Domenico and Schwartz, 1990). In terms of pressure and using the relationship between conductivity $K$ and permeability $k$ ($K=k/\rho g\mu$ where $\mu$ is the water viscosity), Equation 3.4 becomes:

$$\Delta P = \frac{Q\mu}{4\pi k\mathrm{b}} \ln\left(\frac{2.25kt}{\phi c\mu r^2}\right) \tag{3.6}$$

where $c$ is the compressibility of the aquifer. The parameter $c$ is typically unknown, but its lower limit is the compressibility of water (~$3\times10^{-6}$ $\mathrm{psi}^{-1}$). That same equation is also written in customary oilfield units as:

$$\Delta P = \frac{162.6Q\mu}{k\mathrm{b}} \left[\log\left(\frac{kt}{\phi c\mu r^2}\right) - 3.23\right] \tag{3.7}$$

where $Q$ is in bbl/day, $\mu$ is in centipoises, $k$ is in millidarcy, $t$ is in hours, $c$ is in $\mathrm{psi}^{-1}$, and $r$ is in feet. The equation is then solved for the tubing radius $r=r_w$. Results are not very sensitive to this parameter because its range of values is small and it appears in a log term. The expressions do not take into account the skin factor, a parameter that measures variations from the theoretical formulation. Skin factors can vary from about -5 when there is less pressure drop than expected (that is, when completion interval crosses a fracture or after stimulation) to more than 10 when the well or formation is damaged. Another parameter not explicitly taken into account is relative permeability. Even after a waterflood or tertiary recovery processes, there is still some residual saturation of oil and also very likely some flowing oil.

RRC requires that the injection pressure does not exceed the formation fracture gradient. Generally, the maximum surface injection pressure is 1/2 psi per foot to the top of the injection interval unless the results of a fracture pressure step-rate support a higher pressure. The sandface pressure is the surface pressure added to the pressure due to the weight of the injected fluid minus head losses through the tubing. Since maximum $\Delta P$, pressure difference at the well sandface and in the formation, is imposed, the maximum flow rate $Q$ can be computed when the other parameters are known.

$$Q = \frac{4\pi k\mathrm{b}\Delta P}{\mu} \left[\ln\left(\frac{2.25kt}{\phi c\mu r^2}\right)\right]^{-1} \tag{3.8}$$

with $\Delta P \approx 0.5D + 0.4D - P_f$ where $D$ is the depth to the injection level and $P_f$ is the formation pressure. Another approach can be used that assumes a steady-state system.

The equation in customary oil units is:

$$Q = \frac{0.00708 k b \Delta P}{\mu} \left[ \ln\left( \frac{5.61 Q t}{\pi \phi b S_w r_w} \right) \right]^{-1/2} \qquad 3.9$$

where $S_w$ is the water saturation (assumed at 0.7) (Thomas and others, 1987). Because $Q$ (in bbl/day) appears on both sides of the equation, an iterative solution is needed. The steady-state approach yields a flow rate 1.5 to 2 times higher than the transient approach. Given the approximations done during the computation and the use of average values possibly not representative of a given injection site, the flow rate obtained by this method cannot be known by less than a factor of 2.

### 3.3.5 Formation Damage

Formation damage can be defined as any process that leads to a reduction in production or injection rate. In the case of injection, injectivity $I$ is defined as follows:

$$I = \frac{Q}{P_{wf} - P_r} \qquad 3.10$$

where $Q$ is the flow rate, and $P_{wf}$ and $P_r$ are the flowing and formation pressures, respectively. Injectivity decline can lead to economic problems. One of the most important processes leading to injectivity decline is the filtration of suspended solids. Formation damage can also be due to chemical processes, that is, plugging of pores by minerals or precipitates, or to physical processes, in particular fine behavior. Fines are broadly defined as particles that can be put in motion by a flowing fluid. Suspended solids are a major factor in reducing injectivity. They can originate from solids put in suspension but also from nuclei of precipitating minerals. As such, they can appear in a solution even after going through a filtration process designed to remove them.

Formation damage is modeled by adding a “skin factor” to theoretical or ideal conditions. However, skin factor is truly a fudge factor that includes a lot of different processes including formation damage but also damage to the well. As discussed in the previous section, a positive skin indicates some damage while a negative skin indicates an enhancement in production typically due to well stimulation (that is, fracturing or acidization). Formation damage can be generated by scaling, migration of fines or precipitated material, clay swelling, emulsion block, or other mechanisms.

There are several numerical codes able to help in predicting well behavior to injection of various fluids. UTWID (Saripalli and others, 2000; Pang and Sharma, 1994), developed by the Department of Petroleum and Geosystems Engineering at The University of Texas in Austin, is one of them. The code requires facility-specific information about suspended solid concentration and their size-distribution. However, we were unable to collect the necessary information needed to use the software in a meaningful way.

## Scaling

Scaling occurs either when a change in environmental conditions (temperature, pressure, pH, and gas partial pressure) occurs or during mixing of incompatible solutions. Cations that frequently occur in formation waters and that can cause problems are calcium ($Ca^{2+}$), strontium ($Sr^{2+}$), barium ($Ba^{2+}$), and iron ($Fe^{2+}$). The most common scales are calcium carbonates (mainly calcite) and calcium sulfates (gypsum [$CaSO_4.2H_2O$] and anhydrite [$CaSO_4$] (Table 3-5). A particularly troublesome compound is barium sulfate ($BaSO_4$) because it is very insoluble. Strontium sulfate ($SrSO_4$) is also insoluble but to a lesser degree. Ba and Sr can also co-precipitate with Ca to form a mainly calcic solid solution carbonate. Silica, calcium fluoride, and phosphates could also hinder operations. In distilled water at 25°C, gypsum has a solubility of 2,080 mg/l, calcite has a solubility of 53 mg/l, $BaSO_4$ has a solubility of 2.3 mg/l, $SrSO_4$ has a solubility of 114 mg/l, and amorphous silica has a solubility of 110 mg/l (Heitman, 1990, Chapter 6). In distilled water in equilibrium with atmospheric gases at 25°C, calcite solubility climbs to more than 100 mg/l whereas the others are unaffected. Iron compounds (ferrous carbonate, ferrous sulfide, ferrous hydroxide, ferric hydroxide, ferric oxide) (Patton, 1986; Cowan and Weintritt, 1976) can also cause problems even if they exist naturally at very low concentration in natural waters (<100 µg/L) because corrosion of pipes and other devices can increase their concentration to much higher levels.

Table 3-5. Impact of environmental parameters on solubility of scale-forming minerals.

| | **Increasing temperature** | **Increasing pressure** | **Increasing salinity** | **Increasing pH** | **Increasing $P_{CO2}$** |
|---|---|---|---|---|---|
| Calcite ($CaCO_3$) | decrease | increase | increase | decrease | Increase but less pronounced as Ture increases |
| Gypsum ($CaSO_4.2H_2O$) | increase up to 38°C then slightly decrease | increase | increase up to 150 g/L | none | none |
| Barite ($BaSO_4$) | increase up to 100°C | increase | increase | none | none |
| Celestite ($SrSO_4$) | decrease | increase | increase up to 175 g/L | none | none |
| Silica ($SiO_2$) | Increase | increase | decrease | increase | none |

The degree to which a chemical compound is close to saturation is given by the saturation index *SI*. *SI* is defined as the logarithm of the ratio of the ion activity product (*IAP*) to the solubility product ($K_{sp}$)

$$SI = \mathrm{Log}\left(\frac{IAP}{K_{SP}}\right) \qquad 3.11$$

A negative *SI* indicates that a mineral will not precipitate. However, a positive index does not necessarily means that a mineral will precipitate – the kinetics of the precipitation might be too slow for the considered timeframe. Precipitation kinetics are influenced by a variety of factors (presence of particulates, total area, chemical and physical state of solid surfaces, chemistry of the solution, temperature, and pressure). *SI* can become positive because of mixing of different solutions but also because of pressure or temperature changes. Scaling tendency may be different depending on the technology used. Lozier and others (1992) report that during pilot studies, $CaSO_4$ scales were produced on the RO membranes while $CaCO_3$ were produced on the EDR membranes.

*SI* values are not unique for a given mineral—they are a function of many parameters including temperature, pressure, solution ionic strength, and pH. There are general rules such as solubility increasing with temperature. However, they are not valid for the most common scales. Calcium sulfate and calcium carbonate are characterized by a reverse solubility where their solubility decreases with temperature. Solubility also generally increases with pressure and is a more complex function of ionic strength or salinity. For example, gypsum is more soluble at high salinity but only at low pressure. This statement is not true at higher pressure. The solubility increase with pressure is a favorable parameter for injection. Ionic strength, a parameter related to salinity, also generally has a positive impact of solubility. However, non-charged species, such as silica, may be unaffected or negatively affected by an increase in salinity.

Before the advent of computers and numerical geochemical models, many empirical relationships developed to estimate precipitation tendency were based on limited information. Those relationships cannot account for all the factors as well as geochemical models do except in the simplest systems. An example of such an empirical index is the Langelier Saturation Index (*LSI*), widely used in the water treatment field. The Stiff and Davis index is another example that applies to oilfield brines. The Langelier index also helps in characterizing the corrosive character of a given water. As a general rule, scaling occurs more often in producing wells than in injection wells because of thermodynamics. Pressure increases with depth have a beneficial effect on solubility of most compounds. Temperature also increases with depth, but the effect is not as useful in typical cases because most carbonates have a retrograde solubility.

Calcium carbonate solubility is a function of partial pressure of $CO_2$. Its main mineralogical form is calcite. Calcium carbonate is very susceptible to precipitation during a pressure drop (that leads to a concomitant release of $CO_2$) whether it happens in an enclosed space for hydrodynamics reasons (such as at a valve or at a well screen) or in the open atmosphere. During an injection operation, the reverse might be true because solubility increases with $CO_2$ partial pressure and also for the simple thermodynamic rule of solubility increase with pressure increase (Patton, 1986). However, temperature increase has a negative impact on calcium carbonate solubility.

Most calcium sulfate scales are made up of gypsum. Anhydrite or hemihydrate ($CaSO_4$:0.5$H_2O$) could form at higher temperatures, but they typically result from gypsum dehydration. Gypsum solubility increases slightly with temperature up to ~40°C and then decreases (Patton, 1986). Both an increase in salinity, up to a value not reached in this study, and an increase in pressure favor an increase in solubility of gypsum. The solubility of barium sulfate increases with temperature, pressure, and salinity. However, barium sulfate solubility at surface temperature and pressure is low. If there is no scaling tendency of the concentrate at the surface, deep well injection should not present a problem until possibly the injectate meets the formation water.

Silica ($SiO_2$) exists under many mineralogical forms. A common crystallized form, quartz, has a solubility of ~10 mg/l, but amorphous silica solubility is more than 100 mg/l. Silica exists in water as neutral $SiO_2$ ion or in colloidal form. Silica solubility increases with temperature and pressure and dramatically increases with pH (from 110 mg/l at pH 5 to 300 mg/l at pH 9 in fresh water at 25°C). However, in contrast to other minerals resulting from the association of charged ions, an increase in salinity decreases silica solubility from 110 mg/l in fresh water to 85 mg/l in sea water.

Iron is another common element found in water at low concentration. A high iron concentration generally suggests corrosion. In contrast to other elements described above, iron can commonly exist in two valence states, ferrous ($Fe^{2+}$) and ferric ($Fe^{3+}$). Iron oxides—goethite (FeOOH), hematite ($Fe_2O_3$), or their hydrated form—and iron sulfides—pyrite ($FeS_2$)—are common iron scales. Iron sulfides can appear in reducing environments when the formation contains large amounts of $H_2S$ or when sulfate-reducing bacteria are present. Iron carbonate—siderite ($FeCO_3$) —has a limited solubility of ~70mg/l at 25°C and can be locally a problem on sites with high concentrations of $CO_2$. However, $Fe^{2+}$ would usually precipitate within the calcite structure.

Magnesium and strontium usually precipitate with calcium. Magnesium can also precipitate as hydroxide—brucite ($Mg(OH)_2$) —but precipitation occurs at higher temperatures than those considered in this study.

Physical forms of the mineral precipitates vary. Precipitates of some minerals are colloids (iron oxides and silica) and can quickly plug pores with flowing water. Others (calcite, gypsum, and barite) are crystalline, feed already existing crystals, and may take a longer time to plug pores since the growth is spread over a larger surface area.

### Fines

Fine particulates, called fines, could generate problems in injection and production wells. Three different origins/categories for fines have been suggested. (1) They could originate within the formation and be mobilized by physical or chemical processes; (2) they could be injected with the water stream (suspended solids); and (3) they could appear within the formation as free-floating particles resulting from material precipitated in the bulk water. The second and third categories can be dealt with through appropriate operational management. The first category, named here formation fines, is more problematic, although operational solutions to reduce their impact also exist.

Numerous experiments and field studies have shown that a significant reduction in permeability can occur when a fluid of a nature different from that of the formation is injected. This is because formation fines are typically attached on walls of larger grains. A change in chemical environment can modify the binding between the fines and the larger grains or deflocculate them and have them move and then immobilized in pore throats. Another way to plug pores is for fines of a clayey nature to swell and obstruct pores in place. However, formation fines are not all clay; their mineralogical composition is variable.

Muecke (1978) presented results of X-ray analysis of formation fines in the Miocene section of five Gulf Coast wells. Clay minerals (montmorillonite, illite, and chlorite/kaolinite, in decreasing order of importance) represent about 12 percent of the total weight of the fines on average. The most abundant mineralogical form of formation fine is quartz (~40 percent), followed by amorphous materials (~32 percent), and other minerals (~16 percent) such as feldspar, muscovite, sodium chloride, calcite, dolomite, and barite. Thomas and Crowe (1978) reported that two Texas Gulf Coast formations in Bee (Wilcox Formation) and Milam ("Green Sand") counties were in the 9 to 29 and 11.2 to 15 percent clay range, respectively, with 1.4 to 6 and 7.2 to 11.9 percent montmorillonite, respectively.

Sharma and Yortsos (1986) stated that fines can be detrital or diagenetic. Diagenetic clays are often present at the solid-fluid interface and are much more of a problem than detrital clay, which is often removed from the flowing fluid. It is thus important to determine not only the overall mineralogy of the formation but also the spatial location of the mineral grains.

If non-clayey fines of diverse origin act mainly in a mechanical fashion by bridging pore throats when put in motion, clay movement in the formation results from more complex causes because it also involves chemical interactions between the clay mineral and the bulk water. Clay minerals, especially montmorillonites and smectites, have the ability to exchange ions with the surrounding water. In a pristine formation at thermodynamic equilibrium, most clay particles are attached to larger particles and bound together in clumps or sheets. They may also hold other particles in a loose network. A change in the environmental conditions will move clay particles towards a new equilibrium which may include deflocculation, also called dispersion, of the clay masses. A change in environmental conditions can also cause swelling of the clay sheets and subsequent closing of pore throats. However, this latter effect is now recognized as secondary in most instances (Sharma and Yortsos, 1986; Scheuerman and Bergersen, 1990).

Minerals of the clay family can be categorized into five main groups (Table 3-6): smectites, vermiculites, chlorites, illites, and kaolinites (for example, see Brady, 1990). They all share a similar sheet-like crystallographic structure. An elementary layer of a clay mineral consists of either silicon tetrahedrons or aluminum octahedrons with oxygen atoms at the corners. Because of electrical imbalances, cations ($Ca^{2+}$, $Mg^{2+}$, $Na^{+}$, $K^{+}$, $H^{+}$) are attached to the silicon (Si) or aluminum (Al) elementary layers. Substitution of Si or Al by Mg or other cations is possible. The clay group is determined by the way Si-Al layers are organized, type of substitutions are made, and type of cations that charge-balance the elementary layers. The elementary pattern (called 1:1) of kaolinites is a stack of single Si and Al layers with no associated cations. Neither water nor cations can penetrate the interlayer space. In illite clays, two elementary Si layers sandwich an elementary Al layer (pattern 2:1). Some Al is substituted for Si, and K ions glue the multiple Si-Al-Si sheets together.

Table 3-6. Physical characteristics of clay minerals.

| Clay type | CEC[1] | Expansion[2] | Reactivity[3] | Causes for formation damage |
|---|---|---|---|---|
| Kaolinite | Very low | None | Low | Fine migration |
| Illite | Low | None | Low | Fine migration |
| Chlorite | Low | None | Low | Fine migration |
| Vermiculite | Very high | High | High | Swelling, deflocculation |
| Smectites | High | High | High | Swelling, deflocculation |

1 – Cation exchange capacity
2 – Expansion of mixed layer clays
3 – Reaction with the clay minerals

Smectites also have 2:1 pattern but with some substitution of $Mg^{2+}$ for $Al^{3+}$. The stacked sheets are held together by weakly adsorbed $Ca^{2+}$, $Mg^{2+}$, or $Na^+$ cations. The particularity of smectites (also called montmorillonites) is their ability to absorb water between the sheets, the molecular origin of so-called swelling. Vermiculites have a crystallographic structure similar to that of smectites but do not allow as much swelling. Chlorites have an extra sheet of Mg octahedrons (pattern 2:1:1) that, in essence, locks the structure. Chlorites cannot undergo layer expansion. Mixed-layer clay minerals are materials in which different kinds of clay layers alternate with each other. The mixing in vertical stacking can be regular or random. Commonly described mixed-layer clays include illite-vermiculite, illite-smectite, chlorite-vermiculite, chlorite-smectite, and kaolinite-smectite.

All clays can be subjected to deflocculation and put in motion. When solution salinity decreases, the exchange cations have tendency to diffuse into the bulk solution. Below some salinity threshold, diffuse forces overcome attractive Van der Waals forces and clay particles disperse (Scheuerman and Bergersen, 1990). At a given molar concentration, potassium cations are more effective than sodium cations at holding the clay particles together. Calcium cations are even more effective at holding the clay particles together ($Ca^{2+} >> K^+ > Na^+$).

Kaolinite is formed by the degradation of feldspars, especially K-feldspars, particularly at low pHs. Illite also results from the degradation of K-feldspar and other K-rich alumino-silicates but at higher pHs. Glauconite, an iron-rich clay sometimes abundant in marine formations, can be considered part of the illite family. Smectites commonly results from the alteration of silicates rich in Ca and Mg. The geological occurrence of smectites is noteworthy. They are mainly connected to volcanic material and are found in abundance in the Mesozoic and Cenozoic stratigraphic sections in Texas. Smectites are converted to illite with depth. A limit of 10,000 to 15,000 feet for complete conversion is often cited. They rarely exist in rocks older than late Mississipian (Dunoyer de Segonzac, 1970). Thin section studies can help in understanding the spatial distribution of clays, especially clays in direct contact with flowing fluids.

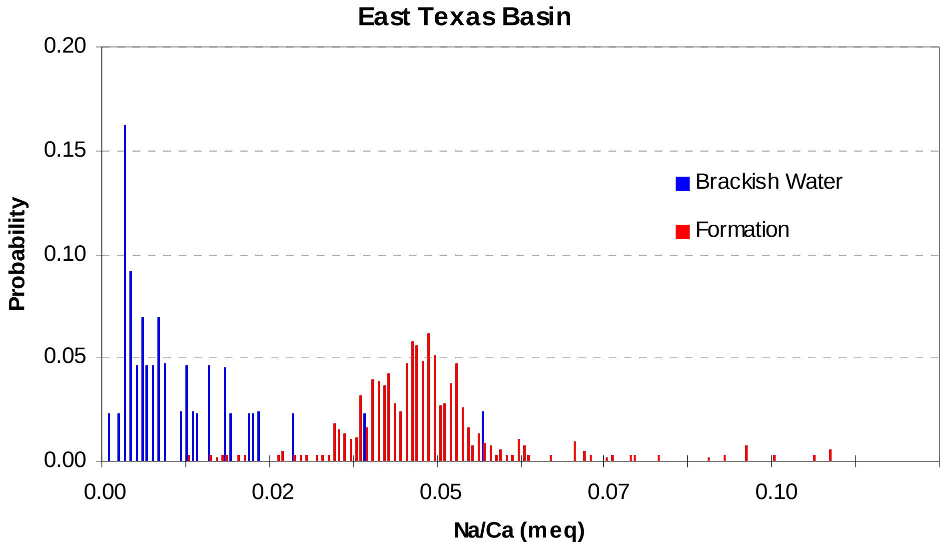


Figure 3-3. Na/Ca ratios in the East Texas Basin.

Smectite and vermiculite clays can exchange adsorbed cations with their environment, typically $H^+$, $Na^+$, $K^+$, $Ca^{2+}$, and $Mg^{2+}$. Their ability to exchange cations—their reactivity—is measured by the cation exchange capacity (CEC). Smectites have a CEC an order of magnitude higher than that of illites (~1 and 0.1 to 0.2 moles/kg, respectively). Illites can have a CEC about an order of magnitude higher than that of kaolinites (0.01 to 0.1 moles/kg). CEC is thus a measure of the possible problems generated by the injected fluids.

There are several general rules that determine the likelihood of a cation to be accepted in a clay interlayer: the highest charge density is selected, but only if it is not overwhelmed by a higher concentration of an ion with a smaller charge density. For example, $Na^+$ will be the most frequent cation in the interlayers if the smectite is in equilibrium with a NaCl solution with minor $CaCl_2$. The percentage of exchange sites occupied by divalent ions increases with decreasing salinity. In general, Na/Ca increases with depth (Figure 3-3). The exchange reaction can be written:

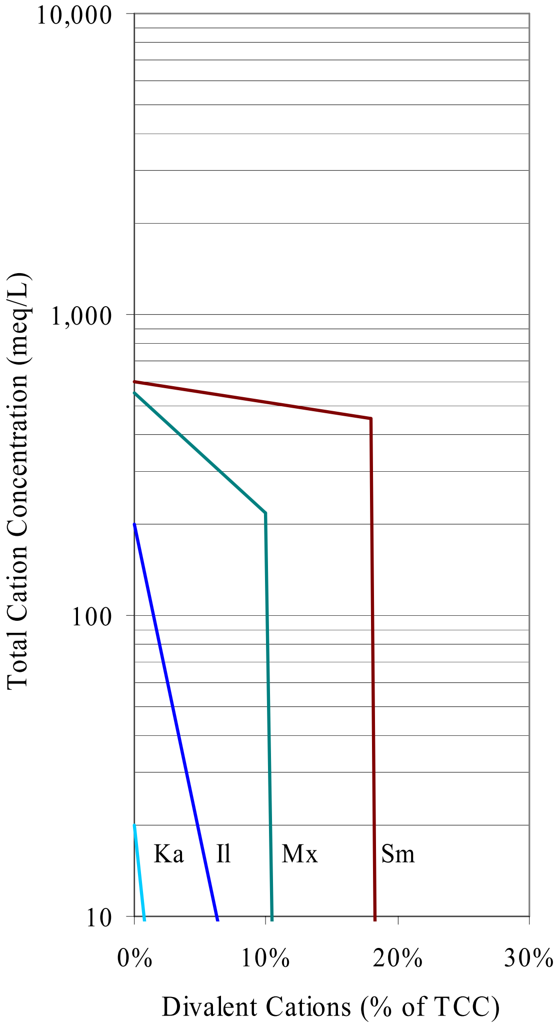
$$\text{Na-Clay} + Ca^{++} = \text{Ca-Clay} + 2Na^+ \qquad 3.12$$

The equilibrium reaction constant can be written as:

$$K = (Na^+)^2(\text{Ca-Clay})/(Ca^{++})(\text{Na-Clay})^2 \qquad 3.13$$

where ( ) represents the activity of the reactants. Given the importance of the $(Na^+)^2/(Ca^{++})$ ratio, it is called the mass action ratio (MAR).

In general, high salinity, high charge density, and low pH (specific case of high charge density) favor clay flocculation while low salinity and low charge density with high pH favors deflocculation. Because divalent cations are much more effective at keeping clays flocculated,



Ka=kaolinite; Il=illite; Mx=mixed layers; Sm=smectite
TCC=Total Cation Concentration

Figure 3-4. Template for water sensitivity analysis (Note: any water inside the delineated domain will deflocculate the corresponding clay).

increasing $Ca^{++}$ sharply reduces flocculation salinity (also called the critical salt concentration, which is the salinity at which a given type of clay stay flocculated). Figure 3-4 displays a simplified diagram from Scheuerman and Bergersen (1990). Flocculation salinity lines are displayed for four clay types: smectites, mixed layers smectite-illite, illites, and kaolinite. The slopes of the lines show that increasing total cation concentration can reduce the flocculation salinity. A solution with a fraction of calcium ions higher than 20 percent of the divalent cations will not generate any common clay dispersion at equilibrium. Since a formation water is in equilibrium with the solid phases present in the formation, all formation water chemical analyses should fall either in the vicinity of the salinity line or clearly outside of it. The location of these analysis points is a useful indication of the nature of the clays in equilibrium with the formation water. If, for example, a lot of the data points fall inside the smectite salinity line, it suggests that the formation water is not in contact with smectite clays in the formation.

When injecting fresher water, two things need to be appraised: position of the injected water relative to the flocculation salinity line (Figure 3-4) and availability of Ca cations. Fresh water is typically Ca-rich and clays at equilibrium with dilute water tend to incorporate a higher proportion of divalent cations into their exchange sites. Thus, clay will tend to strip Ca from the water to incorporate it into its mineral structure. However, by doing this, the Ca concentration in the water is reduced, and the injected water position on the salinity plot may be considerably shifted to the left in the deflocculation and permeability impairment zone (Scheuerman and Bergersen, 1990). How much Ca will be stripped from the solution before clay and solution are at equilibrium depends on the cation exchange capacity of the formation. Scheuerman and Bergersen (1990) mentioned a study of a Maverick Basin core where 400 pore volumes of water from the Carrizo-Wilcox water were needed before reaching equilibrium. During that transient phase, clays were deflocculated and mobilized. However, a simple $CaCl_2$ pretreatment before injection of the Carrizo-Wilcox water prevented any detrimental effect by saturating the clay exchange sites and avoiding cation stripping.

The impact of cation stripping can be estimated by computing the ratio of the formation water MAR to that of the injection water (Table 3-7). If the MAR of the injection water is higher than that of the formation water, no clay mobilization is likely (Scheuerman and Bergersen, 1990). Otherwise, pretreatment is suggested or recommended. It can be easily determined that the MAR of a concentrate is four times (as four is the RO concentration factor used in this study) that of the initial feed water:

$$\left(MAR_{i/f}\right)_{fresh} = \frac{\left(Na_{fresh}\right)_i^2 / \left(Ca_{fresh}\right)_i}{\left(Na\right)_i^2 / \left(Ca\right)_i} \tag{3.14}$$

$$\left(MAR_{i/f}\right)_{conc} = \frac{\left(Na_{conc}\right)_i^2 / \left(Ca_{conc}\right)_i}{\left(Na\right)_i^2 / \left(Ca\right)_i} = \frac{\left(4Na_{fresh}\right)_i^2 / \left(4Ca_{fresh}\right)_i}{\left(Na\right)_i^2 / \left(Ca\right)_i} = 4\left(MAR_{i/f}\right)_{fresh} \tag{3.15}$$

This suggests that, relative to clay sensitivity, if no problem was encountered during historical injection of fresh water, none will be when injecting concentrate. This may not be true relative to the scaling problem.

### Organic Material

Organic deposition leading to formation damage can be generated by mechanical accumulation and filtering if the injectate is mixed with produced waters containing hydrocarbons (that is, paraffins and asphaltenes). Organic deposition can also occur by growth of microorganisms. Microorganisms act by live or dead cell accumulation and help in precipitating bacterial by-products. To survive and multiply, microorganisms need a source of food (to build more of themselves), a source of energy (to fuel the redox chemical reactions needed to move and grow), an electron acceptor (to perform the chemical reactions), and some nutrients and trace elements. The food source will usually include local hydrocarbons, lignin, and other decayed vegetal material, and possibly migrating methane. The energy source is also typically the same as the

Table 3-7. Criteria for requiring formation pretreatment (from Scheuerman and Bergersen, 1990, Table 3).

| Clay type | Treatment recommended if $MAR_{i/j}$ | Treatment suggested if $MAR_{i/j}$ |
|---|---|---|
| Kaolinite | <0.15 | <0.3 |
| Illite | <0.3 | <0.5 |
| Chlorite | N/A | N/A |
| Smectites | <0.5 | <1.0 |

$MAR_{i/j}$=Mass action Ratio of injection water / Mass injection Ratio of formation water

food source. The electron acceptor, typically $O_2$ for aerobic bacteria at the surface, is either sulfate, ferric iron, or $CO_2$ in the subsurface. A common group of deep-formation dwelling anaerobic bacteria are sulfate-reducing bacteria. The waste product from sulfate reduction is $H_2S$ or one of its ionic forms, $S^{2-}$ or $HS^-$. Sulfide can then react with iron to precipitate poorly soluble iron sulfides. Even if a biocide is added to the concentrate waste stream to kill microorganisms injected along with the water, resident bacteria can still be active in the formation. Some sulfate-reducing bacteria are salt-tolerant. They can be active at salinities as high as 100,000 mg/l and temperatures above the maximum considered in this study ($60^oC$).

## Formation Damage Control and Solutions

In the past century or so of oil and gas production, the oil and gas industry came up with solutions for most of the operational problems they encountered. The following subsections describe a few approaches taken by the industry to deal with the problems described above. The solutions described below are not exhaustive but demonstrate capability of the industry to address formation damage. We did not investigate the cost of the different treatment methods and how they may affect the price of treated drinking water.

Acidizing (by injection of hydrochloric acid or sulfuric acid) is used to stimulate production in carbonates and to treat formation damage (particularly carbonate scales) in all formations. Hydrochloric acid (HCl) has the drawback of adding corrosion-enhancing chloride ions, unless corrosion inhibitors are added, while sulfuric acid could increase scale-prone sulfate ion concentration, which might be a problem, especially if barium is present. As a general rule sulfuric acid is used for scale control while scale removal is done with hydrochloric acid. Hydrofluoric acid (HF) will dissolve siliceous materials, especially clays and feldspar, but not quartz, whose dissolution kinetics are lower. HF is typically mixed with HCl to keep the pH low, thereby preventing precipitation of carbonates. The mixture is called “mud acid.” Strongly alkaline agents (NaOH or KOH) are widely used to remove calcium sulfate deposits.

$CaCl_2$ brine treatment reduces water sensitivity of clays. The Ca from the brine will saturate the sensitive clays and prevent cation stripping and deflocculation (Scheuerman and Bergersen, 1990). Further away from the wellbore, mixing with the resident formation water will limit cation stripping. A buffer of NaCl or KCl is also used to eliminate fine deflocculation and migration. Clay stabilizers (for example, Zr salt, hydroxy aluminum, and dimethyldicocoammonium $Cl^-$) that irreversibly bind clay particles and other fines to the substrate or to each other are also used. Tang and Morrow (2002) state that the presence of crude oil reduces fines production and limits permeability loss. Hydraulic fracturing is also used to treat damaged wells and improve performance of low-permeability wells (for example, Reynolds and Kiker, 2003, p. 8).

Some operators perform surface treatment of injected fluids with filters and flocculating chemicals (cut-off size typically around 2 to 4 microns) to prevent plugging. Some operators find this to require too much maintenance and therefore regularly backflow injection wells to remove impurities (Reynolds and Kiker, 2003, p. 45). $O_2$ scavengers are also used at the surface to avoid oxidation of reduced material downhole (if the system is open). A typical scavenger used in water treatment is sodium sulfite ($Na_2SO_3$). Sodium sulfite must be carefully considered because it could create sulfate-related problems downhole. There are hundreds of scale inhibitors marketed by oil field service companies. Biocides are also used to kill bacteria but may be effective only in killing bacteria injected from the surface with the water and not the indigenous bacteria within the formation further away from the well.

If no clay stabilizers are used, as advised by some consultants and service companies, salinity shock and fine deflocculation can be reduced by a gradual change in the salinity and ionic makeup of the invading water. Injecting a buffer solution compatible with both formation water and injectate is also an approach that works. Kharaka and others (1997, p. 1016) and Rosenbauer and others (1992) described the case where injection of a brine with a high sulfate concentration and low calcium concentration into a formation water with the reverse characteristics could be avoided by injecting a buffer of surface water. Common practice in the field of deep well injection of hazardous wastes is also to inject a buffer waste between two chemically incompatible wastes.

Even if fine mobilization occurs, lowering fluid velocity could help keep particles from bridging pores. This can be accomplished by decreasing flow rates or increasing the number of perforations or shot density. Fines will squeeze one by one through the pore throats and not bridge pores.

# 4.0 Approach

To complete this study, we needed to:

- communicate with regional and local stakeholders interested in desalination;
- identify depleted oil and gas fields in Texas and their proximity to areas in the state amenable to desalination;
- evaluate the impact of concentrate injection on selected oil and gas fields;
- evaluate the current process for permitting concentrate injection wells, and
- recommend changes to the permitting process.

Each of these tasks is described in more detail below.

## *4.1 Communicate with Stakeholders*

The purpose of this task was to communicate with appropriate stakeholders about the project. In this case, appropriate stakeholders included Regional Water Planning Groups, other state agencies, federal agencies, and private industry. To communicate with stakeholders, we created Web pages, talked to several industrial groups, spoke with Regional Water Planning Groups in Texas, interviewed desalination plant operators about concentrate disposal, and presented at several conferences around the state (Mace and others, 2004; Nicot and others, 2005). We also sent a questionnaire to members of the Texas Petroleum Technology Transfer Council (Appendix 5).

## *4.2 Identify Depleted Oil and Gas Fields*

The purpose of this task was to create a map of depleted oil and gas fields in Texas to identify possible locations that may be candidates for injection of concentrate from desalination operations. To do this, we (1) reviewed past studies and current information to map the distribution of depleted oil and gas fields around Texas and (2) plotted the location of oil field injection and disposal wells.

We digitized current paper atlases of major oil and gas fields in Texas from *Atlas of Major Texas Oil Reservoirs* by Galloway and others (1983) and *Atlas of Major Texas Gas Reservoirs* by Kosters and others (1989). The atlases contain reservoirs that produced at least 10 million barrels ($15.9 \times 10^6$ $m^3$) of cumulative production of oil or 30 billions cubic feet ($850 \times 10^6$ $m^3$) of gas. Many more oil and gas fields exist in Texas but those represented in the atlases have been in production for decades or historically produced large amounts of oil and/or gas. Because they have had large production, they are pressure-depleted and likely able to receive large amount of fluids.

Oil fields are already used by the oil industry to dispose of oil-field wastes, primarily oil-field brines. The Railroad Commission of Texas (RRC) currently permits and monitors over 31,000 oil-field injection and disposal wells. We used RRC information to develop a map showing the location of these wells across Texas. Because these permitted wells have already met the requirements to be Class II injection wells in the state, we used them as a proxy for locating oil fields that may be likely targets for the disposal of concentrate from desalination plants. We used this map to compare possible desalination plant locations as described in the regional water plans of Texas to oilfield locations. These maps, in conjunction with a study just completed by the Texas Water Development Board (TWDB) on the location of brackish ground-water resources for desalination (LBG-Guyton Associates, 2003), were also used to identify additional areas not considered by regional and local entities.

## *4.3 Select and Characterize Analysis Areas*

We chose six analysis areas based on the location of:

### Mature Oil and Gas Fields

Mature oil and gas fields are pressure-depleted due to extensive production of hydrocarbons. Depletion of the formation pressure could subsequently create enough room to accept large amounts of fluids, such as concentrates.

### Oil and Gas Fields from Various Geological Basins

We selected oil and gas fields located across the state in different geological basins representing varying reservoir rocks. We did this to include analysis areas from across the state and to observe whether analysis areas from different basins containing different reservoir rocks (carbonates and siliciclastics) and formation water composition produced results that favor their selection as candidate sites for the disposal of desalination concentrates. We also reviewed the stratigraphy of major reservoirs and oil and gas production zones across the State to confirm that we targeted the appropriate stratigraphic sections for additional study.

### Class II Injection Wells

We selected areas with Class II injection wells that target shallow formations for injection. We preferred shallower reservoirs because start-up and injection costs increase with depth. However, deep-seated injection wells have an advantage of being cheaper in the long run because concentrate can be injected by gravity drainage.

### Areas with Demonstrated Water Needs

We selected the oil and gas fields from areas that are also located in counties with demonstrated unmet water-supply needs now or in the future as reported in the State Water Plan (TWDB, 2002a). These are the general areas where there will be potential for locating a desalination plant in the future.

### Available Brackish Groundwater Resources

We also considered the availability of brackish groundwater in sufficient quantity for use in potential desalination plants. We reviewed the literature on brackish groundwater availability, depth and distribution, and chemical composition (LBG-Guyton Associates, 2003). This was important because, in addition to the quantity of brackish water available, brackish water-quality determines the concentrate composition.

### Characterize Analysis Areas

For each analysis area, we characterized the general geology, petrology and mineralogy, porosity and permeability, aquifers and brackish water sources, and additional parameters of interest such as average variation of temperature and pressure with depth, and formation compressibility. This was accomplished with a number of published and purchased sources of data and a review of the literature for each analysis area.

## 4.4 Conduct Area of Review (AOR) Variance Studies

We followed the methodology presented in Smyth and others (1998) in analyzing the separation between formation head and BUQW. We queried the RRC H15 database such that both BUQW and Top of Fluids (TOF) were available. Because of their variability, we were not able to define a potentiometric surface for either parameter in each field. For each of the six analysis areas, the separation $Sep_w$ (Figure 3-2) was calculated and plotted as a histogram for individual wells:

$$Sep_w = TOF_w - BUQW_w \tag{4.1}$$

Then the separation $Sep_f$ was computed on a field basis:

$$Sep_f = TOF_f - BUQW_f \tag{4.2}$$

where $Sep_f$ is, for a given field, the separation between the 95th percentile TOF and 5th percentile BUQW of all TOF and BUQW recorded for that field. For a given field, we presented the separation between the 95th percentile TOF and 5th percentile BUQW. We used 95th and 5th percentile in lieu of the usual two standard deviations to avoid giving outliers an undeserved weight.

## 4.5 Model Interaction of Concentrate and Formation Fluids

The injection of concentrate into an oil and gas reservoir may cause some unwanted side effects such as formation damage. As discussed in Section 3.3.5, formation damage occurs by a number of processes that include scale formation and migration of fines from mixing of desalination concentrates and oil-field waters in the subsurface. This may lead to a reduction in reservoir production or injection rate of the concentrate. This reduction occurs by plugging of pores from scaling minerals, precipitates, or fines. Fines are broadly defined as particles that can be put in motion by a flowing fluid. To assess the potential for scale formation from chemical interactions between desalination concentrates and oil-field waters, we evaluated the brackish and formation water compositions and used geochemical models.

We characterized the brackish and the formation water compositions for each of the analysis areas. We used the conventional batch geochemical code PHREEQC developed by the United States Geological Survey (USGS) (Parkhurst and Appelo, 1999)to determine the desalination concentrate composition. PHREEQC is applicable in this case because the ionic strength of the concentrate is typically below that of seawater. We determined the chemical composition of the concentrate by simply multiplying the concentration values of the brackish groundwater by a factor of four as is observed from many desalination plants. This was done by using the "REACTION" keyword in PHREEQC, which in this study removed 75 percent of the water initially present. We reviewed the literature for information on brackish water compositions (for example, LBG-Guyton, 2003) and compiled additional brackish water information from the TWDB's Groundwater Database.

We used the geochemical code SOLMINEQ developed by the USGS (Kharaka and others, 1988) to calculate the saturation indices (*SI*) of a batch mixture of formation water and concentrate in four proportions (0.2/0.8, 0.4/0.6, 0.6/0.4, and 0.8/0.2). The degree to which a chemical compound is close to saturation is given by the saturation index. *SI* is defined as the logarithm of the ratio of the ion activity product (*IAP*) to the solubility product ($K_{sp}$). A negative *SI* indicates that a mineral will not precipitate, but a positive index does not necessarily mean that a mineral will precipitate. We developed a script, written in Visual Basic and launched from an Excel© spreadsheet, to allow multiple runs without the user's intervention.

We used two sets of concentrates for mixing with the formation water: (1) concentrate with no treatment and (2) concentrate with acid added so that it had a pH of 6. Acidification of the concentrate drops the saturation index with respect to most of the minerals and is a standard practice followed in industry. We chose a pH value of 6 to be consistent with values reported in the literature (Section 3.2.3). We collected formation water composition data from the USGS produced water database and purchased additional information from IHS Energy, a private vendor. All geochemical calculations were done at the sampling temperature of the water. We assumed that the acid added was sulfuric acid.

SOLMINEQ required several input data sets. Concentrate composition was internally recomputed at a temperature of 25°C before being mixed with the formation water. The final temperature of the mixture was a direct function of the proportion of each water in the mixture. Temperature of the formation water was determined according to the thermal gradient and not from the so-called sampling temperature, which may not be representative of downhole conditions. When average screen depth was not available, we used the average of the available samples instead. Since pressure has an impact on mineral solubility, SOLMINEQ also requires pressure data. Because pressure data is typically not available at the same location where sampling was done, we inferred pressure using a linear relationship we developed between depth and pressure (Figure 4-1). Although there was a lot of variability in pressure distributions with depth, we were conservative in using the linear relationship rather than hydrostatic pressure because subsurface pressure provides significant control on precipitation of scale forming minerals.

As in all geochemical modeling, the choice and accuracy of the thermodynamic database is important. This is especially true for modeling brines. The database provided with PHREEQC, used to model solutions with ionic strength less than that of sea water, has been tested across the country in numerous projects. Therefore, we had high confidence in the accuracy of the program. On the other hand, in addition to the sampling inaccuracies, there is limited information on the interaction coefficients used in the Pitzer formulation, particularly ion-exchange reactions. SOLMINEQ is also limited to equilibration with one mineral. For these reasons, we did not attempt to quantify the amount of material that could precipitate. Instead, we focused on what minerals could precipitate.

We used a statistical approach combined with Monte Carlo trials to analyze the results of mixing formation water and concentrate based partly on temporal and spatial variability in the composition. We did this for two reasons. The first reason is that water-quality variations are generally related to permeability variations in the formation. As time goes on, brackish groundwater pumping draws additional water from low-permeability pockets and from the surrounding layers confining the aquifer. These waters are typically more saline and possibly of a different ionic composition. There are numerous local and regional examples of saline water

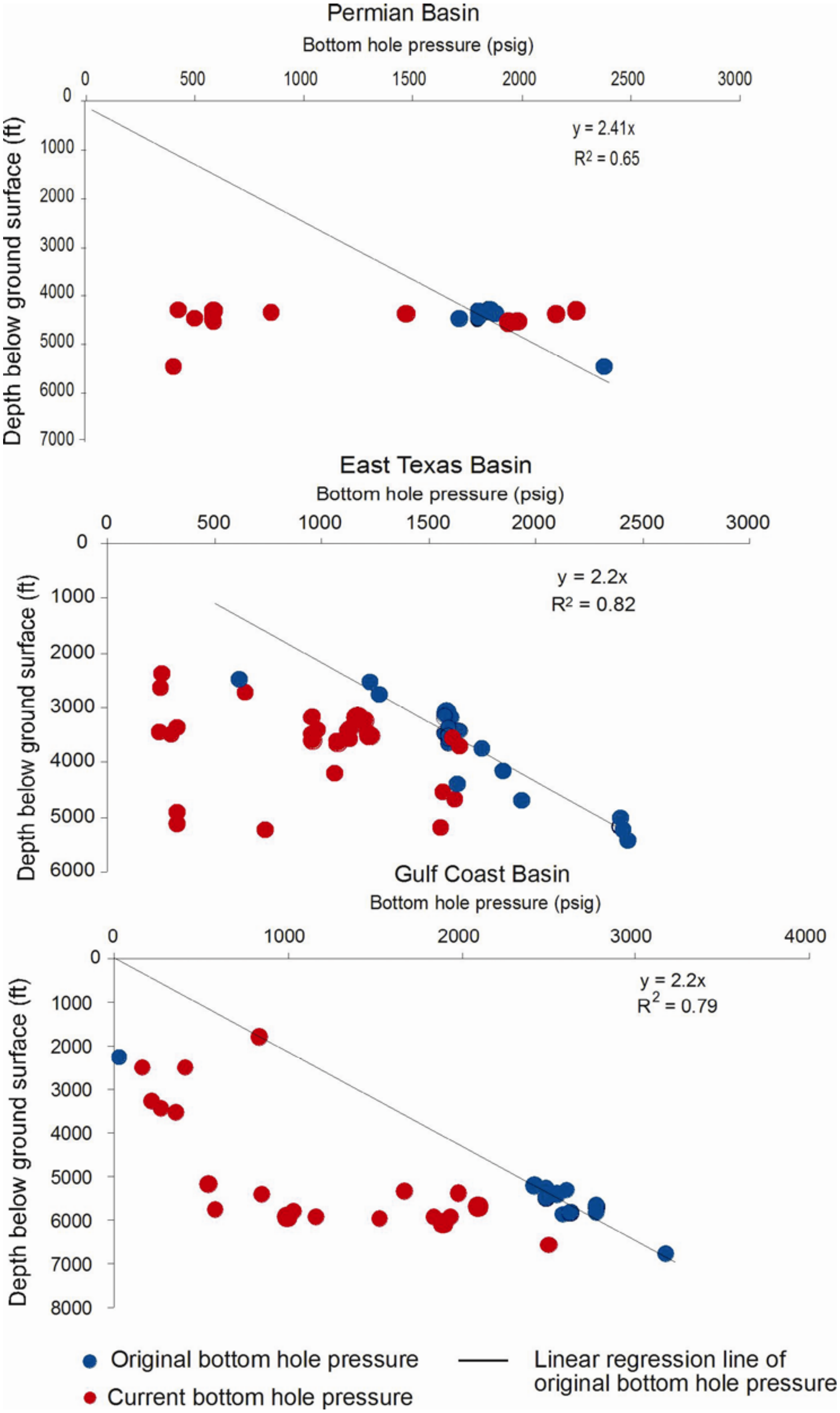


Figure 4-1. Reservoir pressure as a function of depth (from RRC H1 forms).

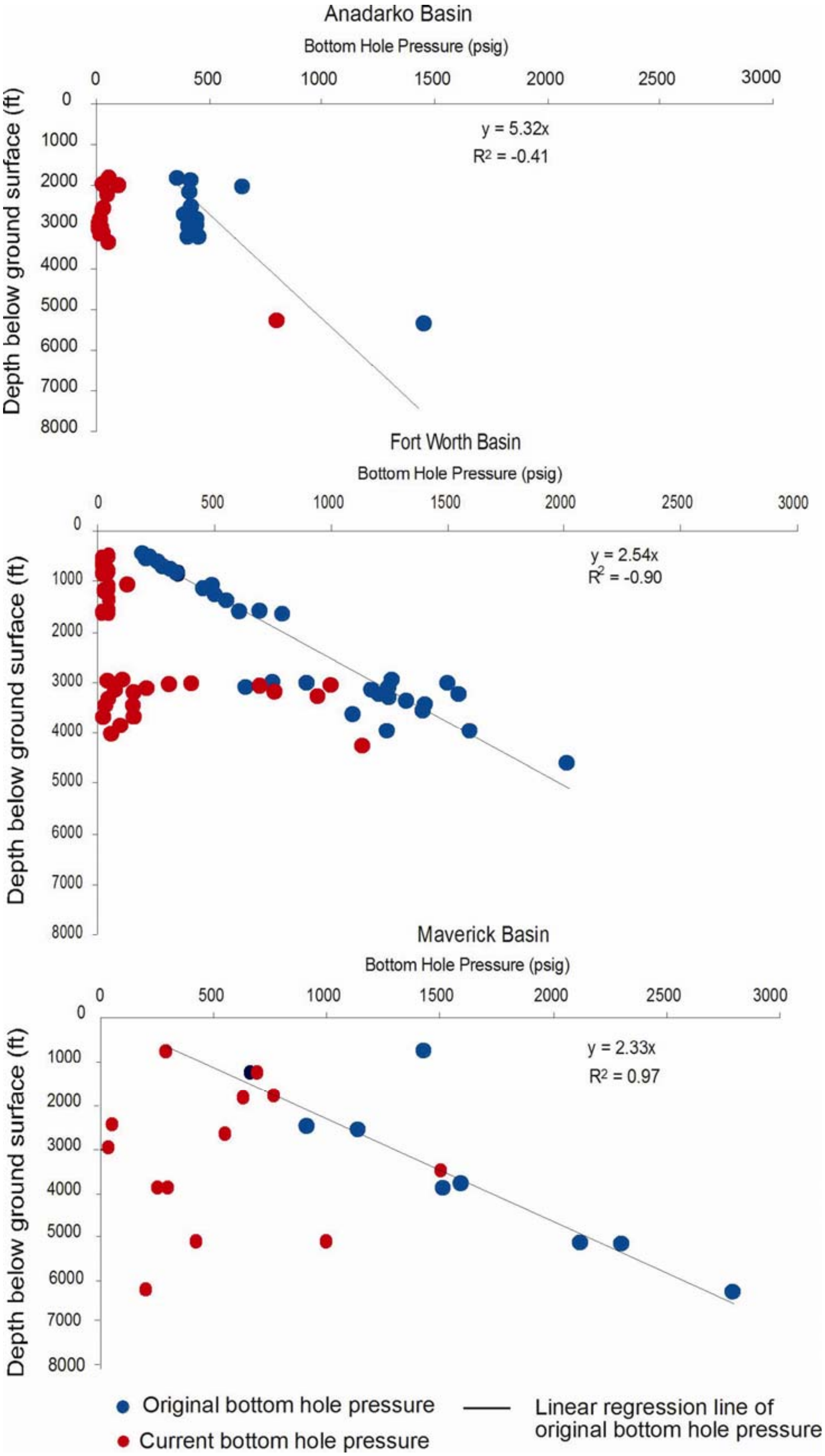


Figure 4-1. Continued.

Table 4-1. Total number of formation and brackish waters sampled from each of the basins for geochemical analyses.

| Basin | Formation water (Fm) | Concentrate (Conc.) | Number of possible combinations (Fm x Conc.) |
|---|---|---|---|
| Anadarko | 113 | 59 | 6,667 |
| Permian | 260 | 297 | 77,220 |
| East Texas | 381 | 52 | 19,812 |
| Fort Worth | 20 | 462 | 9,240 |
| Maverick | 131 | 150 | 19,650 |
| Southern Gulf Coast | 654 | 525 | 343,350 |

migration into the cone of depression of a well field and degrading the water quality. The second reason is that, in this screening study, the location of the brackish water well field and of the concentrate disposal well is not known, therefore justifying the random pairing of concentrate and formation samples. The total number of combinations varies from less than 10,000 in the Forth Worth Basin to almost 350,000 in the southern Gulf Coast Basin (Table 4-1). It should be noted that the number of potential combinations is not related to the actual variability in the field. We used a subset of 5,000 combinations, selected at random, after checking that the salient features of the results were reproduced for the Permian Basin data sets.

## *4.6 Analyze Water Sensitivity*

Water sensitivity studies require knowledge of the nature of the clay material present in the formation and of the ionic composition of the injection water. Kaolinite clays stay firmly attached to the pore walls for almost any ionic makeup while smectite deflocculation can occur if either the solution ionic strength or the percentage of divalent cations falls below some threshold. Other clay types have intermediate behaviors except chlorite, which is not water sensitive. If thin sections and X-ray studies can determine the precise location and nature of the clay minerals, a more expedient approach, supported by a general knowledge of the mineralogy of the formation, uses the assumption of equilibrium between the formation water and the formation clays. Plotting of formation water compositions on the diagram developed by Scheuerman and Bergersen (1990) shows the likely nature of the clay controlling formation water composition.

Plotting of the concentrate compositions on these same diagrams help to understand possible responses to concentrate injection. If all or a large number of samples fall outside the salinity line delineated by the controlling clay, clays will not deflocculate at equilibrium. On the other hand, concentrate injection could be a challenge if most samples fall inside the salinity line. Operational solutions must then be found to address the problem (for example, gradual changing the salinity of the invading water).

However, even seemingly compatible water can generate problems owing to cation stripping when, before reaching equilibrium, the injectate is so stripped of its cations by ion exchange that the solution moves from outside to inside the deflocculation line. Cation stripping can be eliminated by appropriate pretreatment (for example, injection of a slug of $CaCl_2$). The MAR ratio (MAR of concentrate/MAR of formation water) quantifies the amount of cation stripping. Comparison of MAR ratios to the scale established by Scheuerman and Bergersen (1990) allows an assessment of the need for pretreatment.

### *4.7 Evaluate Historical Water Injection*

We interviewed commercial disposal services and reviewed RRC H-1 forms to determine existing practices of water flood operations, sources and volumes of water used, and capacity of the oil and gas fields to accept concentrate. We collected information on the type of injected fluid (for example, salt water, brackish water, fresh water, air, gas, $CO_2$, and polymer) and the purpose of the injection (disposal, secondary recovery). Secondary recovery is the process of injecting fluids into the reservoir to "flush out" more oil. The volume of water needed for secondary recovery is in general 150 to 170 percent of the targeted pore volume (Thomas and others, 1987, p. 44-41). Highest demand for external water occurs at the beginning of the water flood before breakthrough at the producing wells. Return water is progressively reinjected unless precluded by the treatment cost of the produced water. It is common in the industry to convert a production well into an injection well as the water flood front passes by. The external water source could be surface water (rivers or lakes), fresh-water aquifer, brackish-water aquifer, or produced water from the same formation.

### *4.8 Model Injectivity*

We modeled injectivity by calculating the flow rate (Equations 3.4 to 3.9) that would result from combining the formation physical characteristics (porosity, permeability, and compressibility) and pressure requirements (admissible surface pressure, well depth, and head loss). Multiple combinations of these parameters allied with a Monte-Carlo analysis provided an understanding of the likelihood of finding high performing injection wells and of the number of wells needed to inject concentrate volumes.

### *4.9 Possible Permitting Paths*

Under current law in Texas, deep-well injection of concentrate is permitted using a Class I injection well. Class I injection wells are primarily for the disposal of hazardous waste. Obtaining a Class I underground injection well permit is a lengthy and expensive process. Wells drilled for Class I permits are drilled and completed specifically for this purpose and may be cost prohibitive for many desalination projects. The objective of this task was to identify an easier and less expensive process for permitting deep-well injection of concentrate from desalination operations. To do this, we first reviewed federal and state regulations and discussed the process with appropriate staff and officials from the different agencies. Once we evaluated the permitting process, we investigated the different ways we could change the process to allow the disposal of concentrate into Class II disposal wells.

## 5.0 Analysis Areas

Based on atlases of major oil and gas fields in Texas by Galloway and others (1983) and Kosters and others (1989), we developed a detailed map of major oil and gas fields of Texas (Figure 5-1). With some overlap, the atlases describe a total of 450 and 868 oil and gas reservoirs, respectively. In addition, we linked complementary information (production, depth, net pay, and average permeability and porosity) already in digital form (Holtz and others, 1991; Garrett and

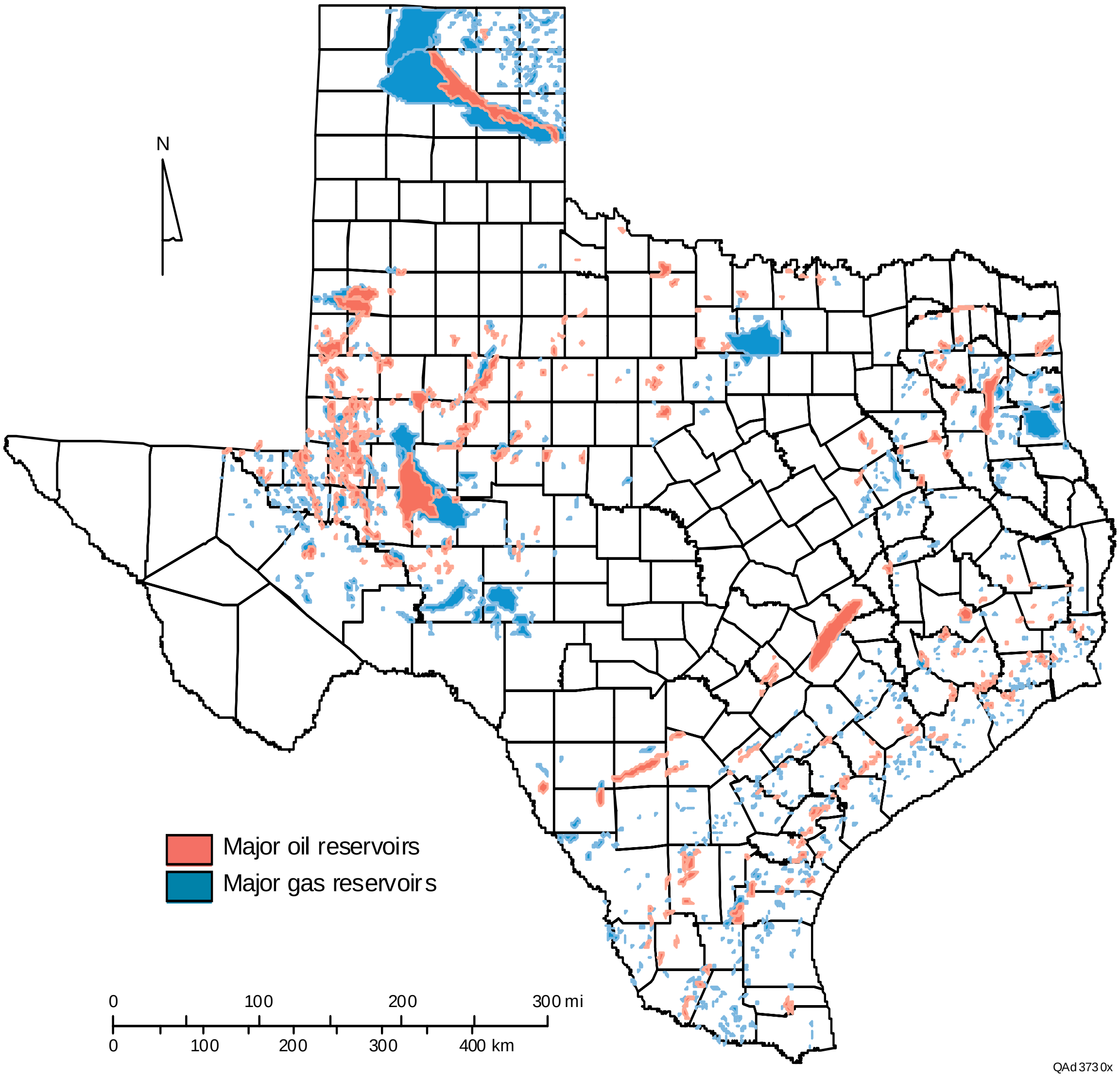
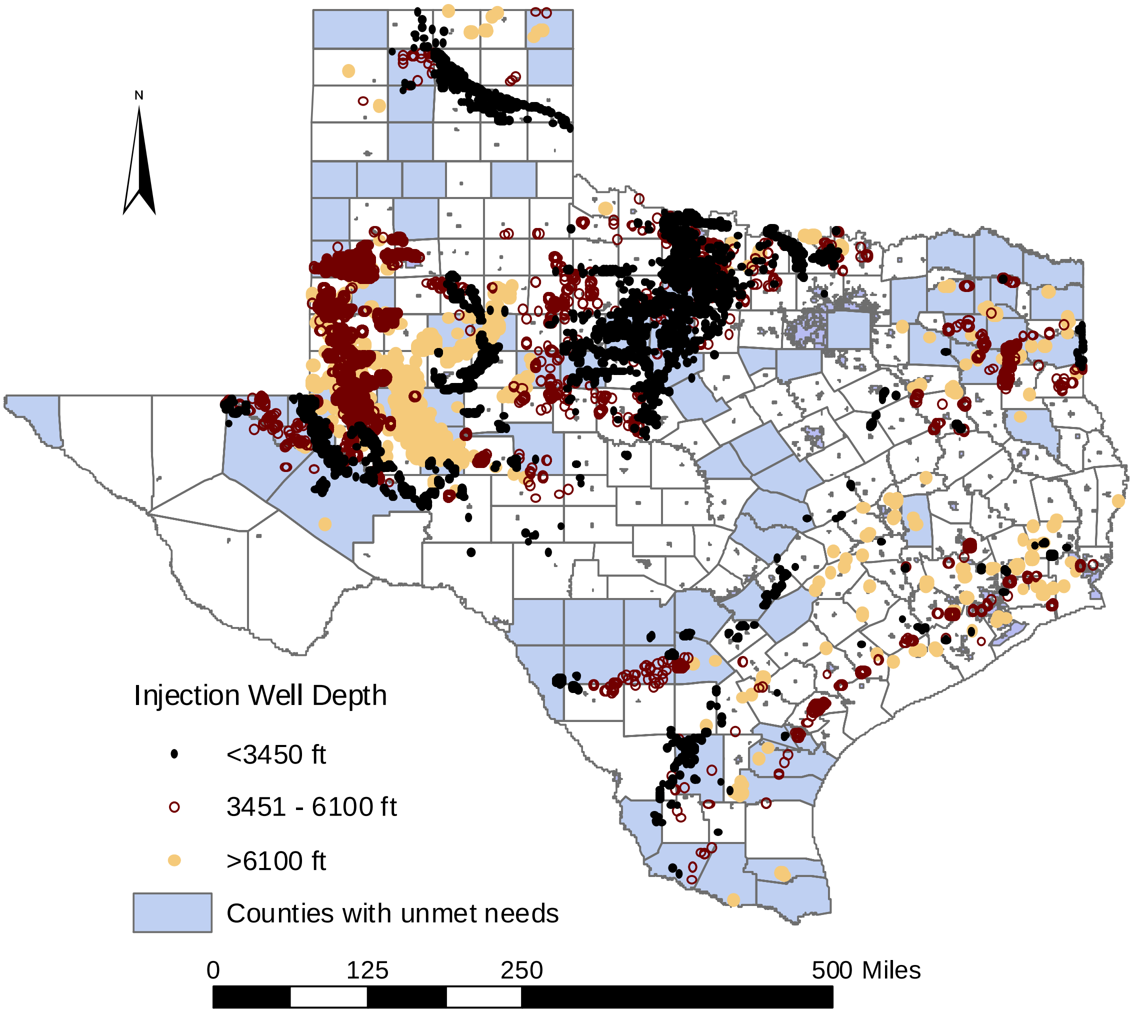


Figure 5-1. Location of major oil and gas reservoirs in Texas.

others, 1991) to the scanned map data for use in other parts of the study. The cumulative production of these reservoirs is large enough to take up concentrate produced in the 20+ years of a desalination plant's life. A quick computation shows that 4 MGD of drinking-quality water translates into at most 1 MGD of concentrate, that is, 695 gallons per minute or about 8.7 million bbl/year. The oil and gas producing regions of the state are along the Gulf Coast, in north-east Texas, in the Permian Basin area of Texas near Midland-Odessa, in the Texas Panhandle, and in north-central Texas (Figure 5-1). The Class II injection wells for the injection and disposal of oil field brines are closely associated with these oil and gas fields (Figure 5-2).



Note: Class II injection wells split into 3 depth groups of equivalent size (~25,000 points with depth information out of ~30,000 active injection wells).

Figure 5-2. Locations of Class II injection wells in Texas with corresponding completion depths. Counties with water-supply needs are shown in blue.

We based the selection of our six analysis areas on the location of (1) mature oil and gas fields (Figure 5-1), (2) oil and gas fields from various geological basins (Figure 5-3), (3) Class II injection wells (Figure 4-2), (4) areas with unmet water needs (Figure 5-4) or an interest in desalination to meet future water needs (Figure 2-3), and (5) available brackish groundwater resources (Figure 2-2). Based on these maps and the criteria discussed in Section 4.3.1, we identified the six analysis areas from different basins across the state (Figure 5-5). The basins considered include the Anadarko basin, the East Texas basin, the Permian basin, the Gulf Coast basin, the Fort Worth basin, and the Maverick basin. These analysis areas are representative of Texas basins, reservoirs, and brackish and formation waters and are representative of typical scenarios in the rest of the state.

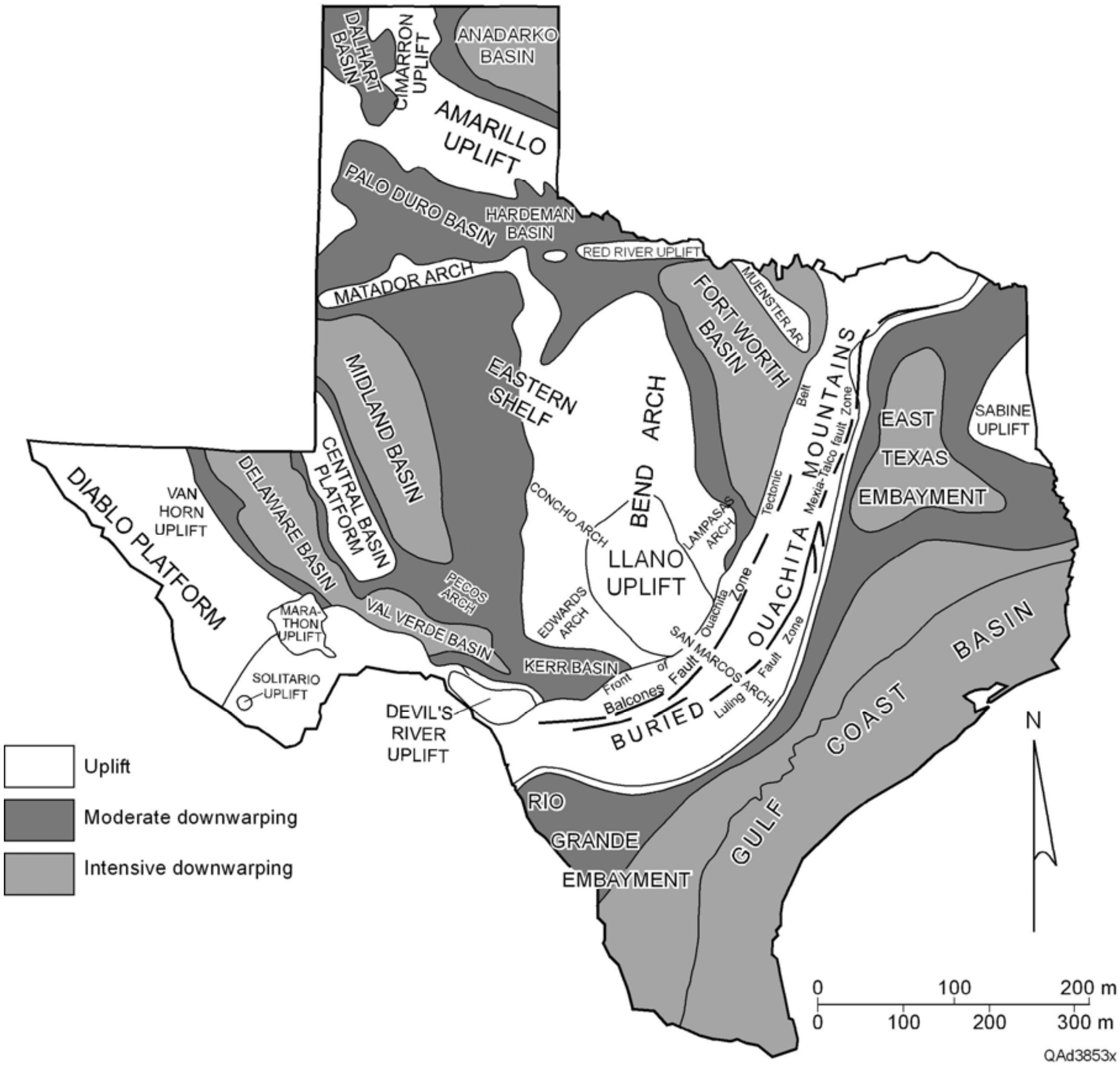


Figure 5-3. Generalized tectonic map of Texas showing location of sedimentary basins (modified from Kreitler, 1989).

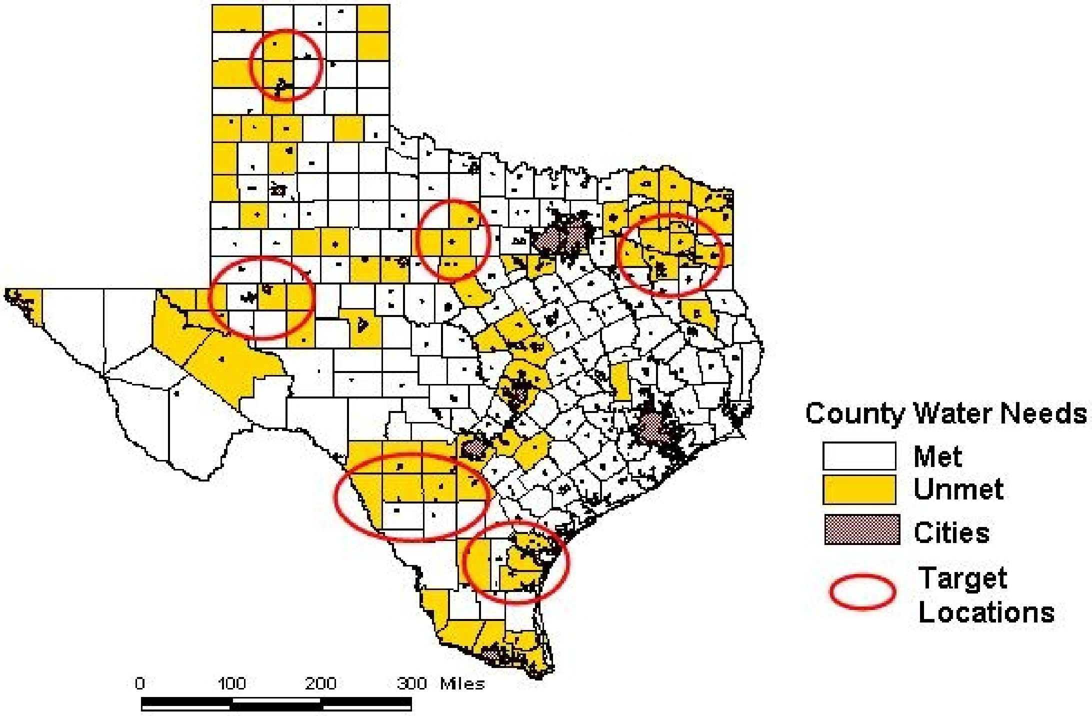


Figure 5-4. Texas counties with water-supply needs in 2050 (data from TWDB, 2002a). The general location of analysis areas are circled in red.

The reservoirs in these analysis areas are the most prolific in their respective areas and are thus most likely to have the highest pressure depletion (Figures 5-6, 5-7, 5-8, and 5-9). Because these reservoirs have also been heavily produced, they are most likely to have a dense infrastructure able to carry fluids at the surface through pipes.

The Granite Wash Formation is the most important oil producing unit of the Anadarko Basin and also yielded significant amounts of gas (Figures 5-8 and 5-9). The San Andres-Grayburg of the Permian Basin is the shallowest major oil producing unit of the basin (Figure 5-8) and still contains non-negligible amounts of gas (Figure 5-9). The Woodbine Formation in the East Texas Basin similarly produced huge amounts of oil (Figure 5-6). The Fort Worth Basin in the study area produces relatively minor amounts of oil from the Bend Conglomerate and Atoka formations (Figure 5-8) while the Maverick Basin yielded relatively large amounts of oil from the San Miguel and Olmos formations (Figure 5-6). The Frio Formation in the southern Gulf Coast is also a prolific gas and oil producer (Figures 5-6 and 5-7).

The analysis areas have a range of brackish groundwater available for desalination (Table 5-1). Although the Anadarko, Fort Worth, and Maverick basin analysis areas have a low availability of brackish groundwater as defined by LBG-Guyton Associates (2003), a low availability may be sufficient for a relatively modest desalination facility with a feed water stream of 5 MGD. Productivity is a function of transmissivity and other aquifer parameters while production cost is mainly a function of depth to water. These parameters are variable across the six analysis areas as they are for the brackish aquifers of Texas.

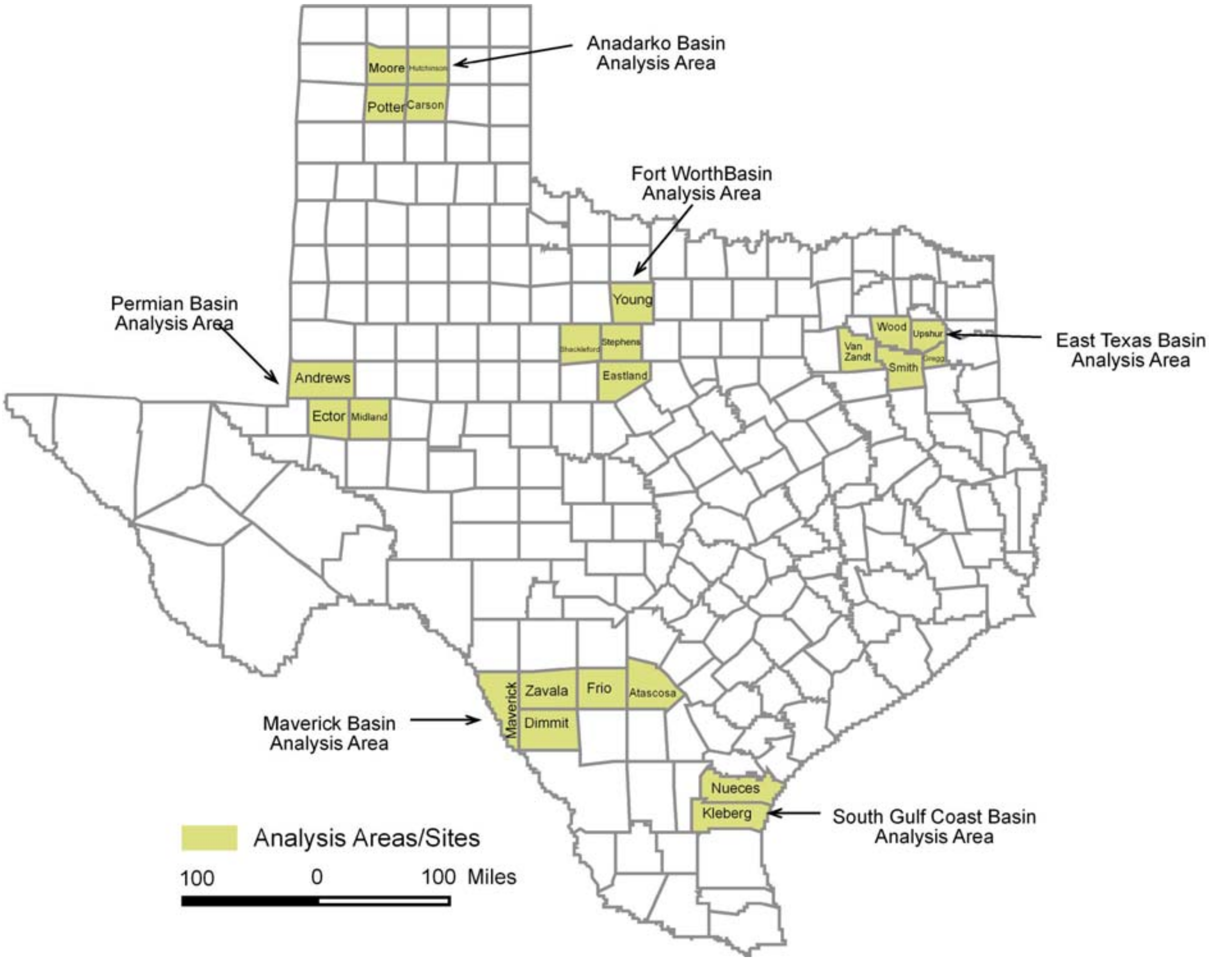


Figure 5-5. Locations of analysis areas.

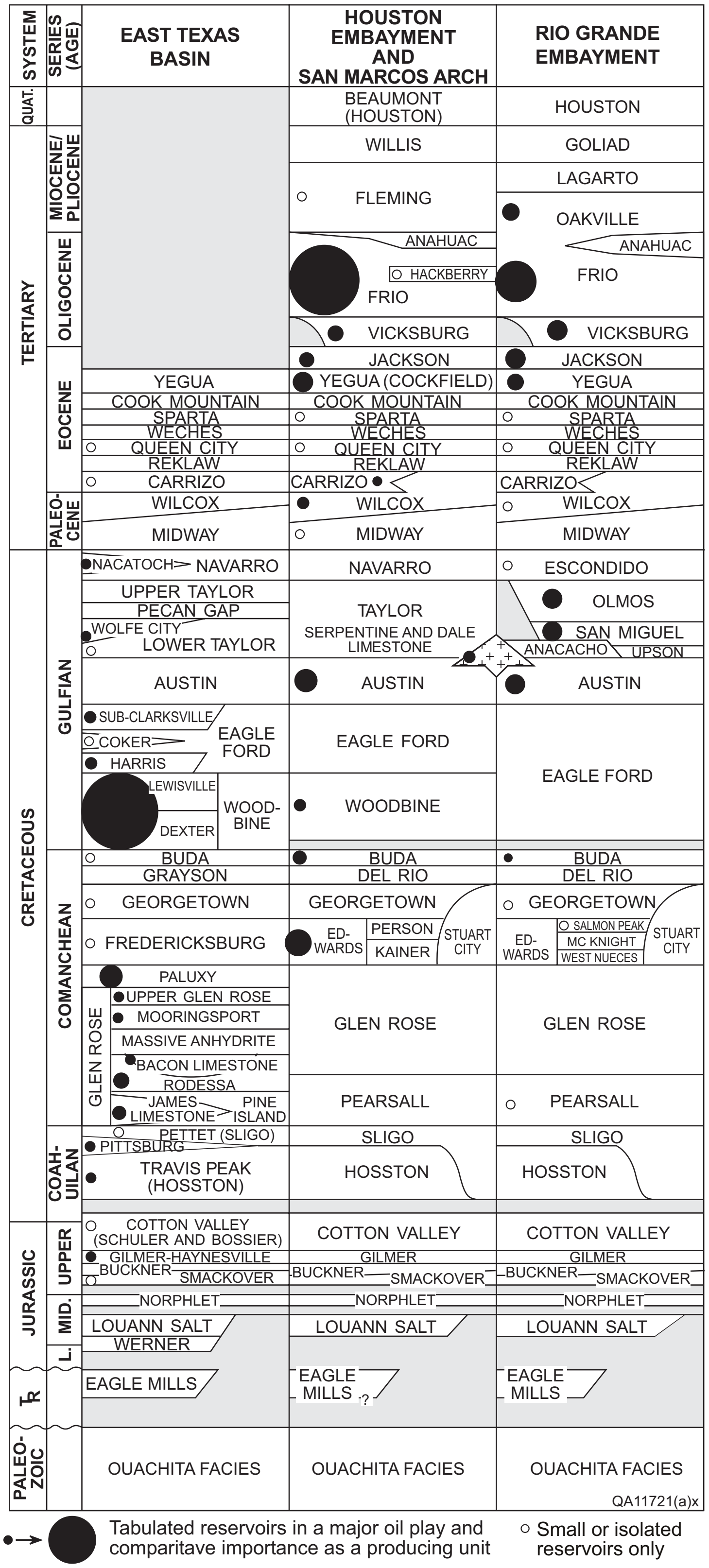


Figure 5-6. Stratigraphic column and relative oil production for the Gulf Coast and East Texas Basins (after Galloway and others, 1983).

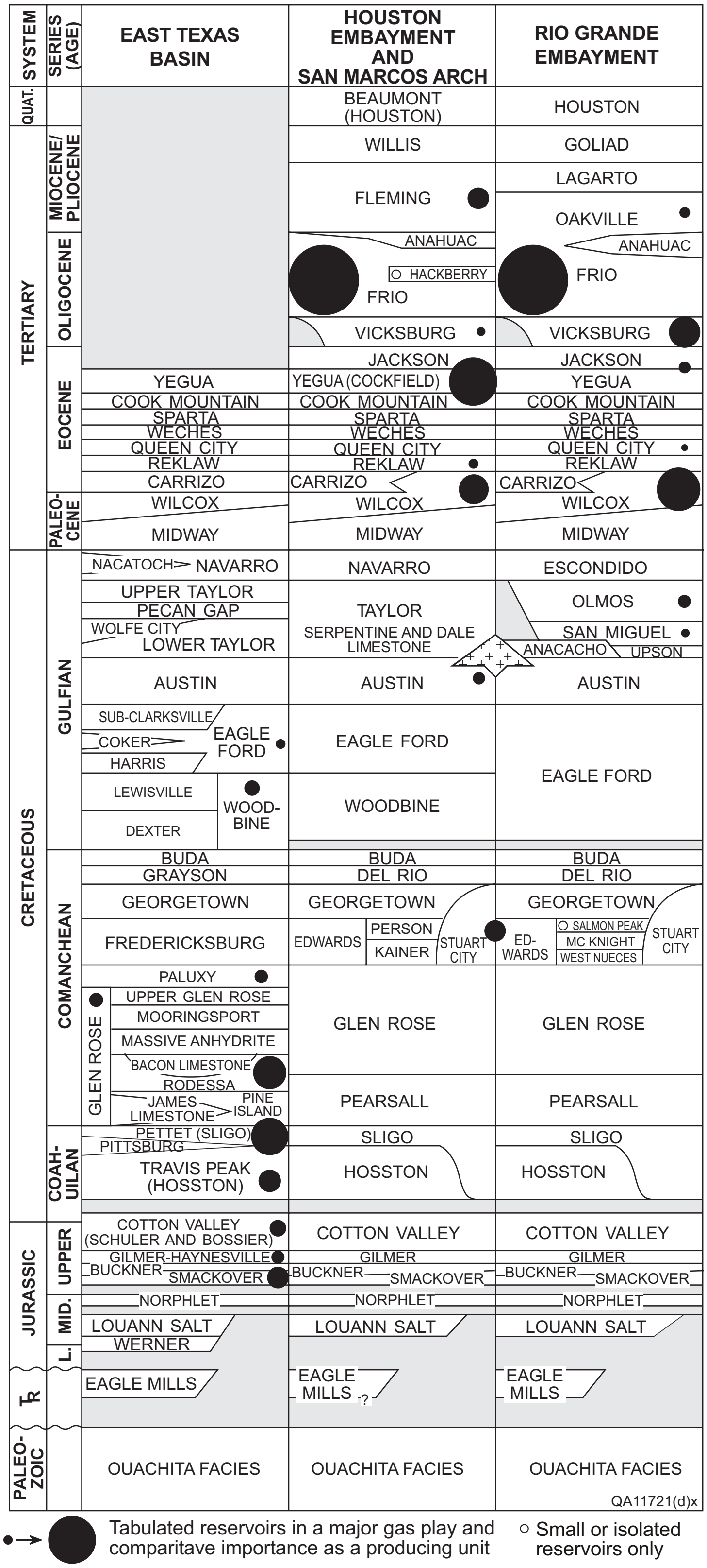


Figure 5-7. Stratigraphic column and relative gas production for the Gulf Coast and East Texas Basins (after Galloway and others, 1983).

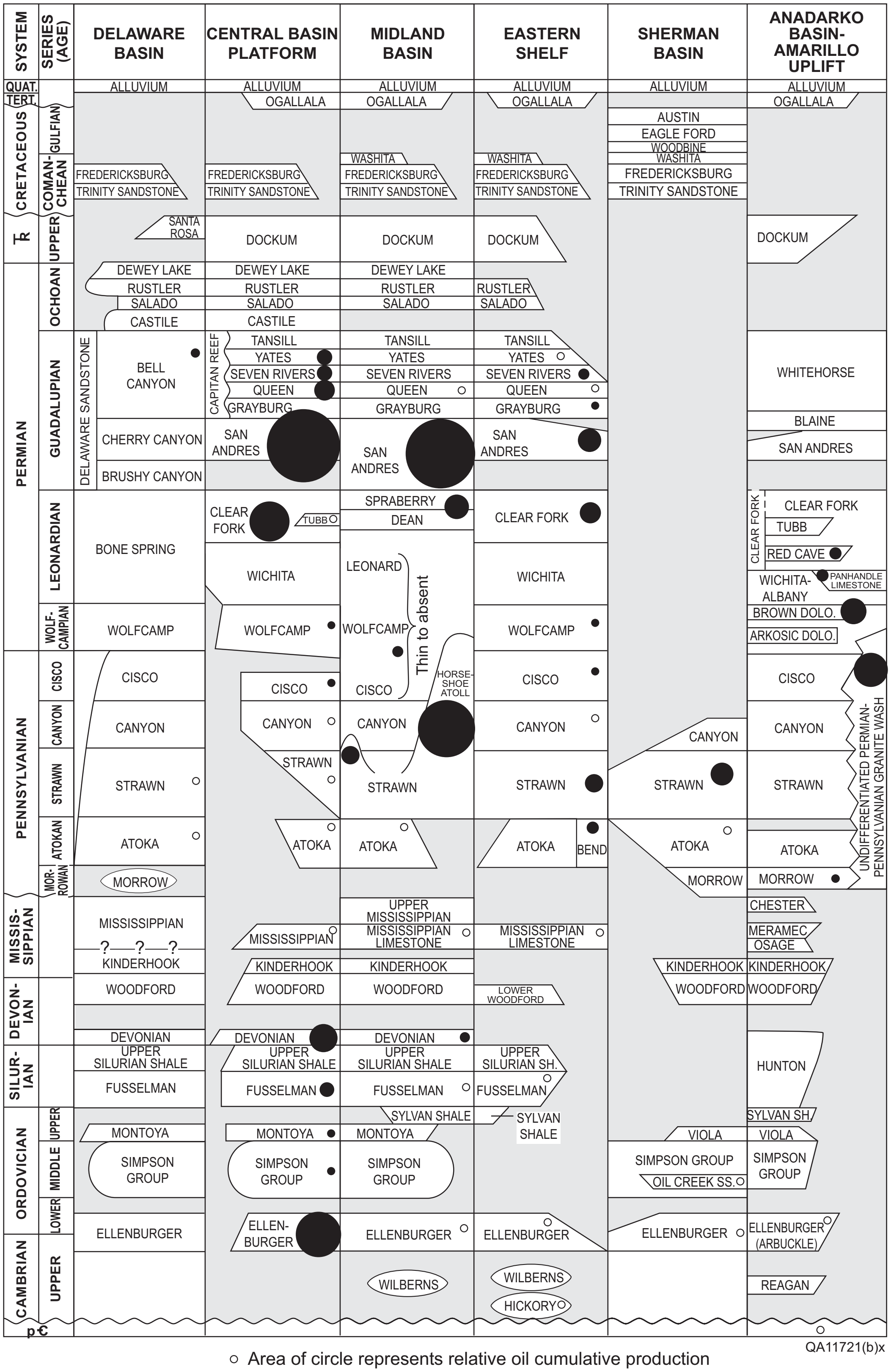
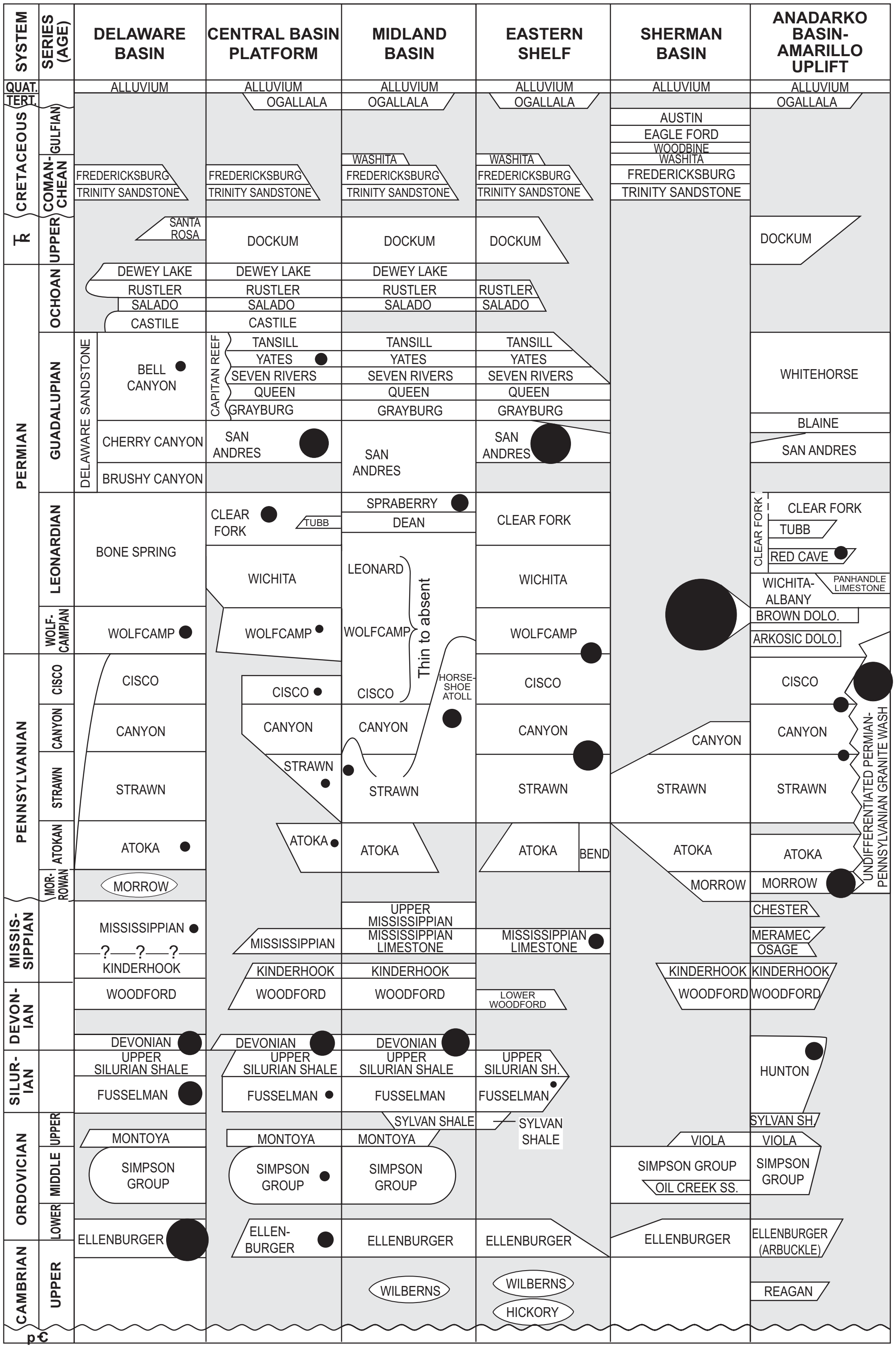


Figure 5-8. Stratigraphic column and relative oil production for the North-Central and West Texas Basins (after Kosters and others, 1989).



Area of circle represents relative gas cumulative production

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Figure 5-9. Stratigraphic column and relative gas production for the North-Central and West Texas basins (after Kosters and others, 1989).

Table 5-1. Brackish water availability in the six analysis areas (LBG-Guyton Associates, 2003).

| Water planning region | Aquifer | Availability | Productivity | Production cost |
|---|---|---|---|---|
| **Anadarko Basin** | | | | |
| A – Panhandle | Ogallala | Low | High | Low to Moderate |
| | Dockum | Low | Low | Low |
| **Permian Basin** | | | | |
| Region F | Ogallala | Moderate | High | Low to Moderate |
| | Dockum | High | Low to Moderate | High |
| | Rustler | Moderate | Low | High |
| **East Texas Basin** | | | | |
| D - Northeast Texas | Carrizo-Wilcox | High | Moderate | Moderate to High |
| **Fort Worth Basin** | | | | |
| G – Brazos | Trinity | Low | Low | Low |
| **Maverick Basin** | | | | |
| L – South Central Texas | Carrizo-Wilcox | Low | Low | Moderate to High |
| **Gulf Coast Basin** | | | | |
| N – Coastal Bend | Gulf Coast | Moderate | Moderate to High | Low |

Some analysis areas have multiple possible targets for disposal of concentrate (Table 5-2). Within a given analysis area, there are also a number of potential oil and gas fields for disposal (Figures 5-10, 5-11, 5-12, 5-13, 5-14, and 5-15).

## *5.1 General Geology*

The following section gives an overview of Texas geology summarized from Ewing (1991). 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, about 550 millions years ago, failed continental rifting resulted in widespread deposition of shelf sediments on a stable craton (that is, the Ellenburger Group). Carbonate and clastic deposition continued until late Devonian, 375 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 northwest-southeast on Amarillo-Llano uplift axis.

Table 5-2. Feed water source, injection formation, counties, and major oil and gas fields for the analysis areas.

| Basin | Brackish water source | Formation | Counties | Major fields |
|---|---|---|---|---|
| Anadarko | Ogallala and Dockum aquifers | Panhandle (granite wash /dolomite) | Carson<br>Armstrong<br>Moore<br>Potter | Panhandle |
| Permian | Ogallala, Dockum, and Rustler aquifers | San Andres (carbonate) | Ector<br>Midland<br>Andrews | Cowden North<br>Cowden South<br>Goldsmith<br>Mabee<br>Midland Farms |
| East Texas | Carrizo-Wilcox aquifer | Woodbine (sandstone) | Van Zandt<br>Wood<br>Smith<br>Gregg<br>Upshur | Van<br>and<br>Hawkins |
| Fort Worth | Trinity aquifer | Bend Conglomerate, Caddo Reef; and Glen Rose carbonates | Shackelford<br>Young<br>Stephens<br>Eastland | Boonsville<br>Breckenridge<br>Kildare Rodessa |
| Maverick | Carrizo-Wilcox aquifer | San Miguel and Olmos Delta Sandstone | Maverick<br>Zavala<br>Frio<br>Dimmit<br>Atascosa | Sacatosa<br>Big Wells Chittim<br>Big foot<br>Catarina |
| Southern Gulf Coast | Gulf Coast aquifer | Frio Sandstone | Nueces<br>Jim Wells<br>Kleberg | TCB<br>Seelington<br>Borregos<br>Stratton<br>Brayton |

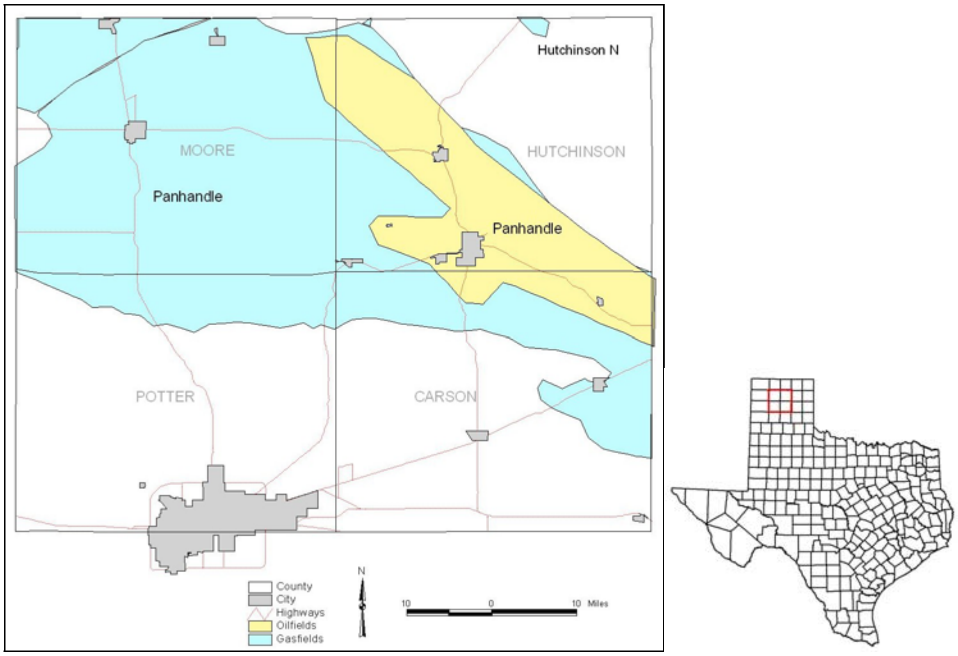


Figure 5-10. Major oil and gas fields in the Anadarko Basin analysis area.

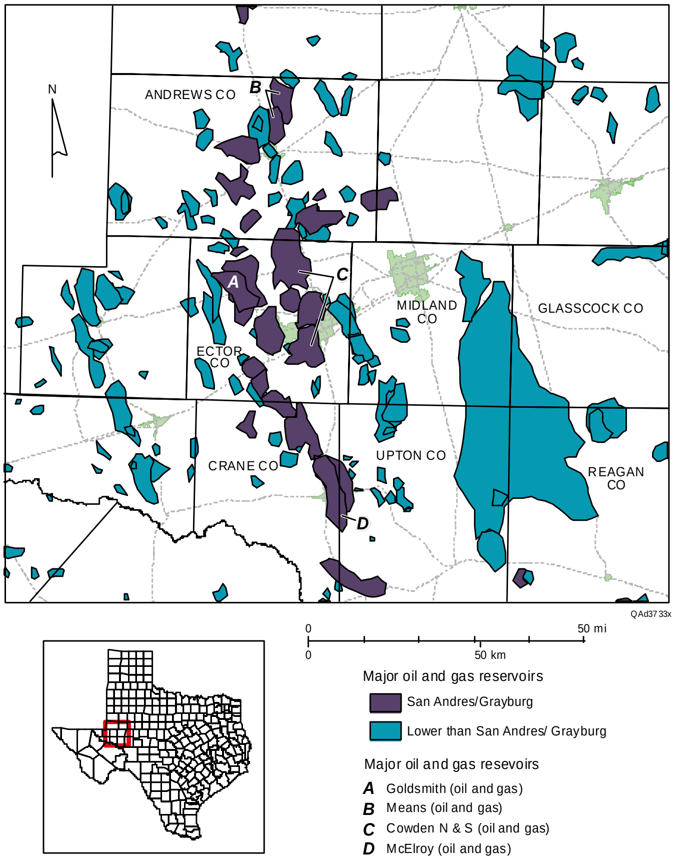


Figure 5-11. Major oil and gas fields in the Permian Basin analysis area.

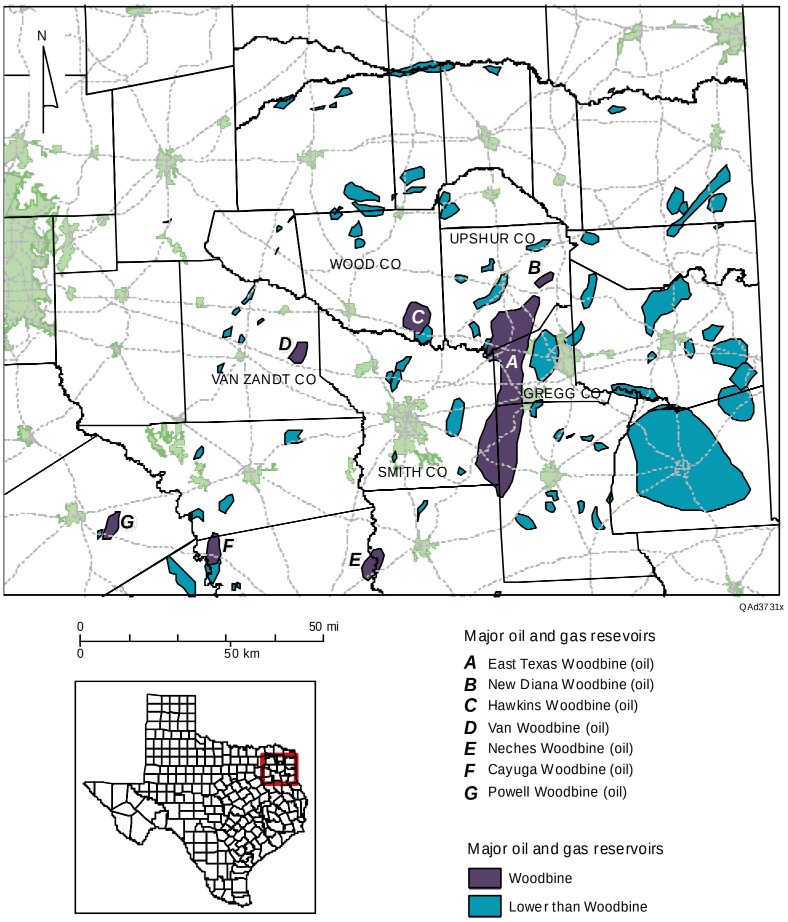


Figure 5-12. Major oil and gas fields in the East Texas Basin analysis area.

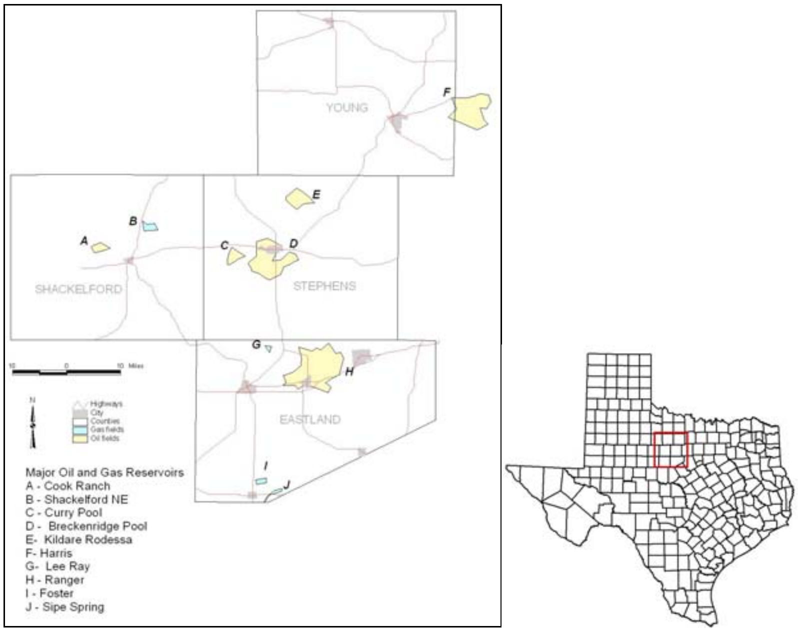


Figure 5-13. Major oil and gas fields in the Fort Worth Basin analysis area.

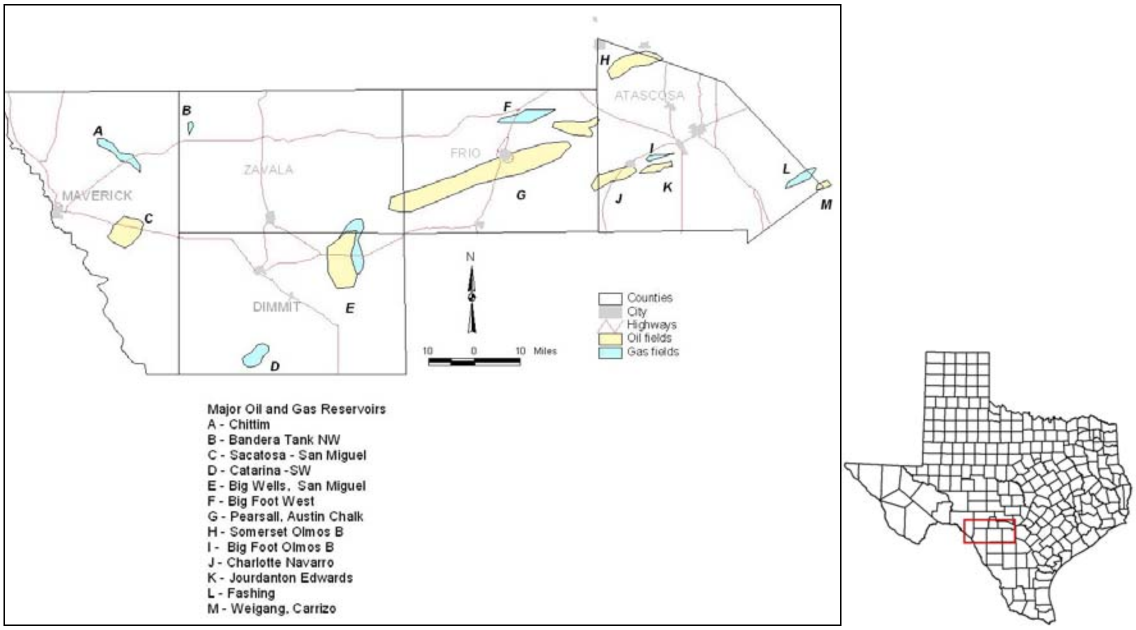


Figure 5-14. Major oil and gas fields in the Maverick Basin analysis area.

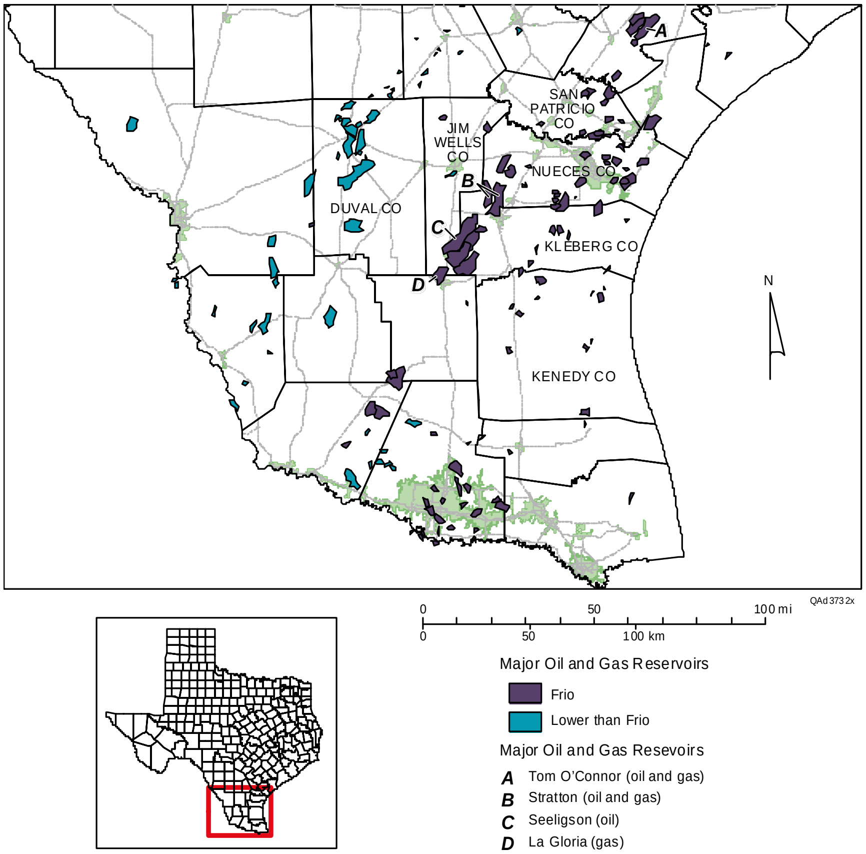


Figure 5-15. Major oil and gas fields in the Southern Gulf Coast Basin analysis area.

Beginning in the Mississippian period (starting 360 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 developed the 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 to 270 million years ago), major subsidence and sediment accumulation, partially fed by the erosion of the Ouichita Mountains, occurred in the Permian Basin, including the Delaware and Midland Basins separated by the Central Platform Uplift. Further 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 the 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 upwards in diapirs, a phenomenon still partly 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 rivers systems flowed towards the Gulf of Mexico carrying an abundant sediment load similar to today's Mississippi River. All of the area west of the old Ouachita Mountains range was also lifted and generated a local sediment source, including 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, include the Frio deltaic and strandplain sedimentation.

From a more hydrogeologic perspective, Kreitler (1989) presented an overview of Texas sedimentary basins as well as a summary of basin-scale hydrological processes. In a regional investigation on $CO_2$ injection for geological sequestration, Hovorka and others (2000) studied representative formations from several sedimentary basins across the United States that include the Frio, the Woodbine, and the Granite Wash formations.

## *5.2 Petrography and Mineralogy*

The formations of the analysis areas can be divided into two groups according to their petrographic and lithologic composition: carbonate or silici-clastic (Table 5-3). The San Andres Formation in the Permian Basin is mainly composed of carbonate while the other five formations generally consist of "clean" silici-clastic sands. The range of sands goes from nearly pure sand

Table 5-3. Petrography and mineralogy for the analysis areas.

| Basin | Main composition of matrix | Cement | Additional authigenic material in minor amounts |
|---|---|---|---|
| **Anadarko** | | | |
| quartz, feldspar, clay | | dolomite, calcite, siderite | chlorite, illite, kaolinite |
| **Permian** | | | |
| calcite, dolomite, anhydrite | | rare cement: chalcedony and kaolinite | |
| **East Texas** | | | |
| quartz, feldspars, volcanic rock fragments; more quartz to the south | | calcite, dolomite, ankerite, quartz | smectite, chlorite |
| **Fort Worth** | | | |
| plagioclase, organic matter, quartz, clay | | quartz, calcite, ankerite, siderite | chlorite, Illite, kaolinite, pyrite |
| **Maverick** | | | |
| quartz, clay, feldspar, rock fragments | | calcite and quartz overgrowths | kaolinite, feldspar, illite, pyrite, hematite |
| **Southern Gulf Coast** | | | |
| quartz, feldspars, volcanic rock fragments sometimes altered to chlorite, carbonate rock fragments | | calcite, ankerite | kaolinite, smectite |

with little non-silica grains to terrigenous sands mainly made of feldspars and rock fragments and their alteration products such as clay and carbonates. According to Folk's (1980) classification, if a sample has more than 25 percent rock fragments and almost 75 percent quartz grains, the sample is a litharenite. If a sample has more than 25 percent feldspar crystals and almost 75 percent quartz grains, the sample is an arkose. If a sample has more than 95 percent quartz crystals, the sample is a quartz arenite.

All gradations exist between quartz arenite, arkose, and litharenite (lithic arkose = arkose with non negligible fraction of rock fragments, feldspathic litharenite = litharenite with non negligible fraction of feldspars, subarkose = sand with some feldspar, and sublitharenite = sand with some rock fragments). The petrography and mineralogy of the formations are important considerations because they impact directly the potential chemical reactions during the injection process. Feldspars are much more reactive than quartz. The focus of the following descriptions is on the cement and authigenic mineral in potential physical contact with the formation fluid and the injected fluid.

### 5.2.1 Anadarko Basin

The Anadarko Basin is the deepest Phanerozoic sedimentary basin within the North American craton (Ham and Wilson, 1967). During the Pennsylvanian orogenic period, the Wichita and the Amarillo uplifts (Figure 5-3) were separated from the Anadarko Basin by a series of faults that resulted in subsidence along the southern margin of the Anadarko Basin and accumulation of coarse arkosic granite wash materials from the uplifts (Dutton and others, 1993). Two main oil- and gas-bearing formations occur in the Anadarko Basin: the Granite Wash and the Cleveland formations. Most of the Granite Wash reservoirs range in age from Desmoinesian to Virgillian.

Most of the tight gas occurs in the Granite Wash Formation. The fluvial deltaic Cleveland Formation was derived from the western margin of the basin that prograded eastward. The prolific Morrow Sandstone is derived from the source terrain to the northwest and sedimentary cover overlying the Amarillo uplifts (Dutton and others, 1993). Most of the oil and gas fields within the analyses area occur in Moore and Hutchinson counties (Figure 5-10). A north-south cross-section shows stratigraphic distribution and geometry of the units (Figure 5-16).

## Depositional Setting

The Granite Wash Formation is areally restricted close to the northern flank of the Amarillo Uplift (Dutton and others, 1993). These sediments were deposited in braided-stream, alluvial fan, and fan-delta complexes (RRC, 1982). Local occurrences of interbedded marine shales and limestones indicate marine transgression interrupted episodes of fan-delta deposition (Dutton, 1982, 1990). Tongues of tight gas of the Granite Wash Formation in the north were probably part of distal-fan deposition in near-shore marine bars (Dutton and others, 1993). The upward-coarsening log character of many tight gas bearing units indicate progradation. An upward-fining

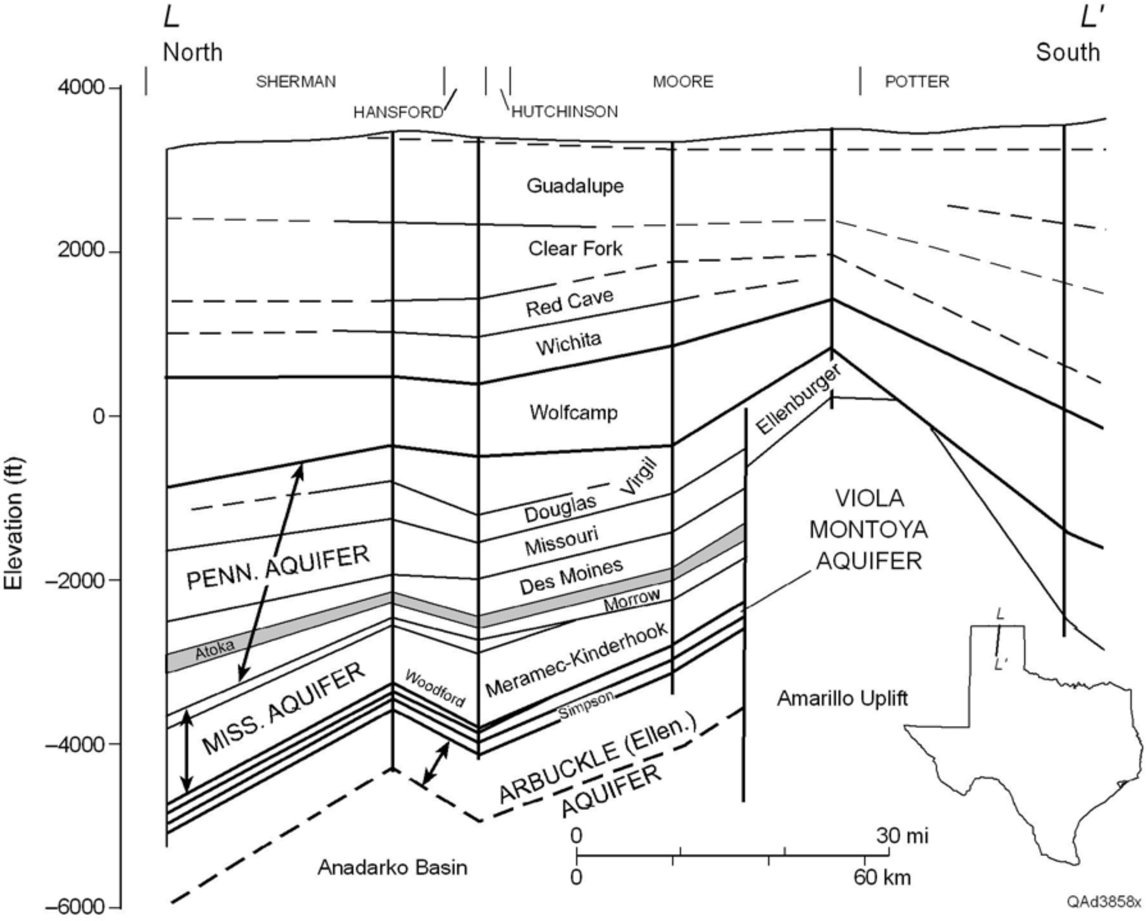


Figure 5-16. Simplified cross-section across the Anadarko Basin analysis area (modified from Core Laboratories Inc., 1972).

trend and blocky intervals suggest aggradational processes, and thinner zones with spiky log expressions represent cyclically repeated deposits (Dutton and others, 1993).

The Cleveland Formation is a prolific natural gas producer, and stratigraphic boundaries of the formation are marked by regionally correlative high-gamma-ray correlative shales. The Cleveland Formation extends from the western terminus of the Anadarko Basin at least as far as the west-central Oklahoma. The Cleveland Formation mostly contains sandstone and shale with carbonates restricted only in the upper part of the unit. Siliciclastics of the Cleveland Formation form mostly stacked, upward coarsening deltaic facies.

The Morrow Sandstone has been divided into Lower and Upper Morrow. The Lower Morrow contains a sequence of onlapping marine limestone, shale and sandstone. Thickness of the Lower Morrow is largely determined by the paleotopographic relief. The Upper Morrow was deposited by fluvial-deltaic systems. Chert eroded from the Meramec and Osage limestones contributes to individual chert beds.

## Reservoir Description

The tight Granite Wash section contains nine informal stratigraphic intervals that range in thickness from about 860 feet to 3,170 feet (RRC, 1982). Shale sections as much as 30 to 40 feet thick occur in the deep Anadarko Basin. Individual sections of the Granite Wash occur in intervals of 10 to greater than 120 feet. The log expressions in the nine stratigraphic units are variably upward coarsening, upward fining, blocky, and spiky. The trapping mechanism is stratigraphic locally modified by anticlines. Reservoir pressures range from 1,800 to 2,000 psi. Formation temperature ranges from 160 to 210$^{o}$ F.

Gas reservoirs in the Cleveland Formation are about 25,700 acres in areal extent (Kosters and others, 1989). Reservoir sandstones are as much as 65 ft thick but are locally 90 to 100 feet thick. Reservoir sandstones are generally continuous with sheetlike geometries. Reservoir thickness increasingly varies northward and westward. Bounding facies of the reservoirs are well-indurated, calcite-cemented pro-delta and distal-front shale and silty/sandy shales that are less than 25 ft (Dutton and others, 1993). Reservoir pressures in the Cleveland ranges from 2,200 to 2,700 pounds per square inch and reservoir temperature ranges from 145 to 160$^{o}$ F.

A total of 78 reservoirs have produced more than 10 Bcf of gas from the Morrow Sandstone in the Texas part of the Anadarko Basin (Dutton and others, 1993). Lower Morrow reservoirs are 15 to 20 ft thick, coarsen upward at the base, and fine upward at the top so that the cleanest most porous sandstone lies near the middle of the unit (Dutton and others, 1993). Stratigraphic traps occur due to lateral pinchout of the sandstones, postdepositional tilting to the southeast that has resulted in downdip water in each sandstone bar. Porosity in the sandstones is highly variable, typically about 14 percent and permeability about 35 mD (Dutton and others, 1993). Point-bar and deltaic channel-mouth-bar are the most prolific reservoirs with the bars 1 to 5 miles wide and 30 to 120 ft thick. Porosity averages about 12 percent and permeability 30 mD.

## Mineralogy and Diagenesis

Sandstone compositions of the Granite Wash range from 50 percent potassium feldspar, 24 percent quartz, 16 percent clay (mostly sericite), 7 percent dolomite (as a cement), and 3 percent other. Other cements include calcite and siderite. As much as 35 to 40 percent of the feldspar grains are highly altered to sericite. High clay content, dolomite cement, poor sorting, and grain angularity contributes to significant reduction in porosity and permeability (RRC, 1982).

Reservoir sandstones in the Cleveland Formation are feldspathic litharenites and lithic arkoses. Porosities in the Cleveland Formation range from 4 to 14 percent. Permeability values of the core samples range from 0.0033 to 4.55 mD with an average of 0.15 mD or less. The permeability of the sandstones is affected by large amounts of clay. Diagenetic cements and replacement minerals constitute between 10 and 34 percent of the rock volume. Illite, kaolinite, and chlorite are the main detrital clay minerals. Quartz comprises an average of 7.3 percent of the whole rock volume; calcite, ankerite, and siderite comprise an average of 6.2 percent of the whole-rock volume; and authigenic clay (chlorite, illite, and kaolinite) comprises an average of 3 percent of rock-volume (Dutton and others, 1993).

Reservoirs in the Morrow Sandstone are mainly composed of quartz-rich sandstone. It typically includes about 85 percent quartz, is fine-grained, and contains primarily quartz overgrowths and/ or carbonate cement. Clay matrix is comprised of illite, chorite, and/ or altered glauconite. This lithology chiefly characterizes the Lower Morrow reservoirs and most of the Upper Morrow marine sands. Chert conglomerate mainly occurs in the Upper Morrow where it comprises basal zones of channel sandstones and braided-channel sediments of fan delta plain origin.

Many parts of the Morrow play have little calcite or dolomite cement. Authigenic kaolinite and chlorite in Morrow Sandstones are common. Kaolinite content decreases into the deeper part of the Anadarko Basin. Chlorite is the most abundant authigenic clay in Morrow Sandstones (PTTC, 2000).

### 5.2.2 Permian Basin

We chose the San Andres Formation of Guadalupean/Permian age because of its high cumulative production. The part of the San Andres Formation included in the analysis area mainly lies along the eastern side of the Central Basin Platform and the western side of the Midland Basin (Figure 5-3). The Central Basin Platform is an elongate carbonate platform that covers structurally positive basement rocks during the Permian Period (Ruppel and Candor, 1988). To the east of the platform, predominantly deeper-water siliciclastics and carbonates were deposited in the Midland Basin (Ruppel and Candor, 1988). The San Andres Formation on the Central Basin Platform is the fourth largest oil play in the Permian Basin and has produced more than 2,150 MMbbl of oil from 52 reservoirs (Dutton and others, 2004). Most of the oil and gas fields within the analyses area occur in Crane, Ector and Andrews counties (Figure 5-11).
A northwest–southeast cross-section shows stratigraphic distribution and geometry of the units (Figure 5-17).

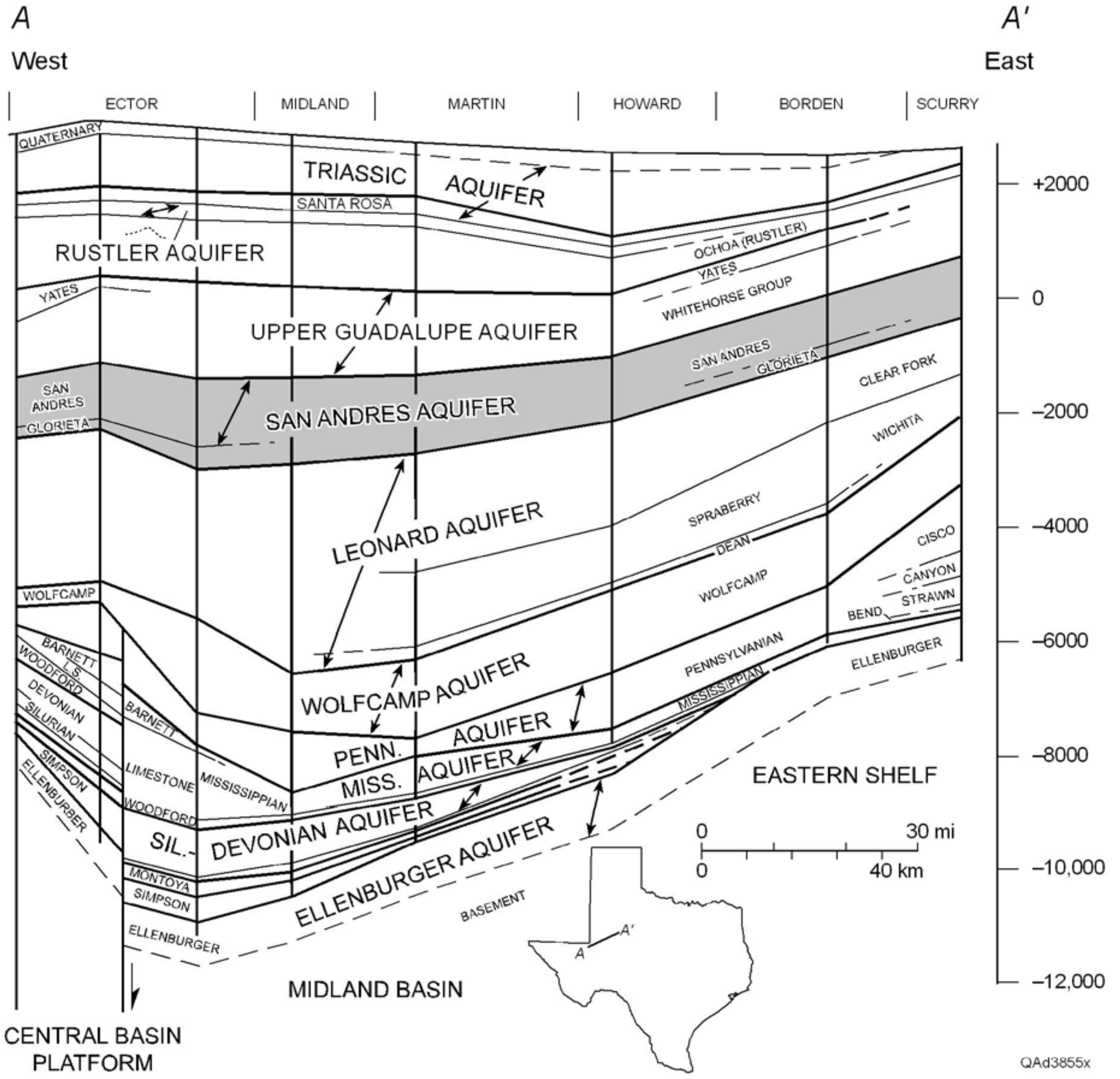


Figure 5-17. Simplified cross-section across the Permian Basin analysis area (modified from Core Laboratories Inc., 1972a).

## Depositional Setting

Carbonates and evaporates of the San Andres Formation of the Central Basin Platform were deposited on a shallow-water shelf. Depositional environments varied from bar and bank complexes along the shelf edge to restricted subtidal lagoons and arid tidal flats toward the interior of the platform. Overall, depositional facies are locally distributed, resulting in highly heterogeneous reservoirs.

### Reservoir Description

The San Andres-Grayburg Formation of the central platform of Texas and New Mexico has produced approximately 10 billion bbl of oil which accounts for approximately 40 percent of the Permian Basin production. The McElroy field has produced about 0.7 billion bbl of oil. Solution gas is the primary drive mechanism, and most reservoirs underwent water flood. Carbon dioxide is also commonly injected in the Permian Basin for tertiary recovery.

### Mineralogy and Diagenesis

The dominant minerals of this carbonate-rich formation in the Central Basin Platform area are calcite, dolomite, and anhydrite. The main detrital rock types include fusulinid packstone and wackestone, skeletal grainstone, burrowed mudstone and skeletal wackestone, pisolite grainstone, cryptalgal mudstone, and fine-grained (siltstone and mudstone) siliciclastics (Ruppel and Candor, 1988). Episodes of pervasive dolomitization affected texture and fabric of the rock. Anhydrite was emplaced after dolomitization. Chalcedony and kaolinite form rare cements (Ruppel and Candor, 1988). To the north, where more highly evaporatively concentrated brines formed, diagenesis formed a range of clay mineral compositions (Palmer, 1987).

## 5.2.3 East Texas Basin

The oil reservoirs in the Woodbine Formation of Cretaceous age included in this analysis area lie in the salt structure province of the East Texas Basin on the northern flank of the Sabine uplift. The Woodbine Formation was deposited in a complex of fluvial, deltaic, and strandplain depositional systems (Galloway and others, 1982). Of the many reservoirs in the Woodbine play, five have each produced more than $1.6\times10^6$ $m^3$ of crude oil (Galloway and others, 1983). Most of the oil and gas fields are widely scattered throughout the analysis area (Figure 5-12). The East Texas basin was extensively studied in the 1980s when it was considered for deep geological disposal of high-level nuclear waste. A northwest-southeast cross-section shows stratigraphic distribution and geometry of the units (Figure 5-18).

### Depositional Setting

The East Texas Basin is located between the Muenster Arch/Ouachita Fold Belt to the West and the Sabine Uplift to the east. It is comprised of Cretaceous platform deposits transitioning to alternating delta/fluvio-deltaic deposits of Paleocene/Eocene and deep-sea deposits. The Woodbine Formation consists of sediments deposited in many varied environments: fluvial, deltaic, shelf, and deep-marine.

### Reservoir Description

The Woodbine Formation in the East Texas Basin contains one of the world's most prolific plays (Galloway and others, 1983). The East Texas field in Upshur, Gregg, Smith, and Rusk counties has produced about 5 billion bbl of oil with an excellent recovery due to a strong water drive, early pressure maintenance by injecting water below the oil-water contact line, and good management practices enforced early on by the RRC. The Hawkins field in Wood County and the Van field in Van Zandt County produced 0.8 and 0.5 billion bbl, respectively.

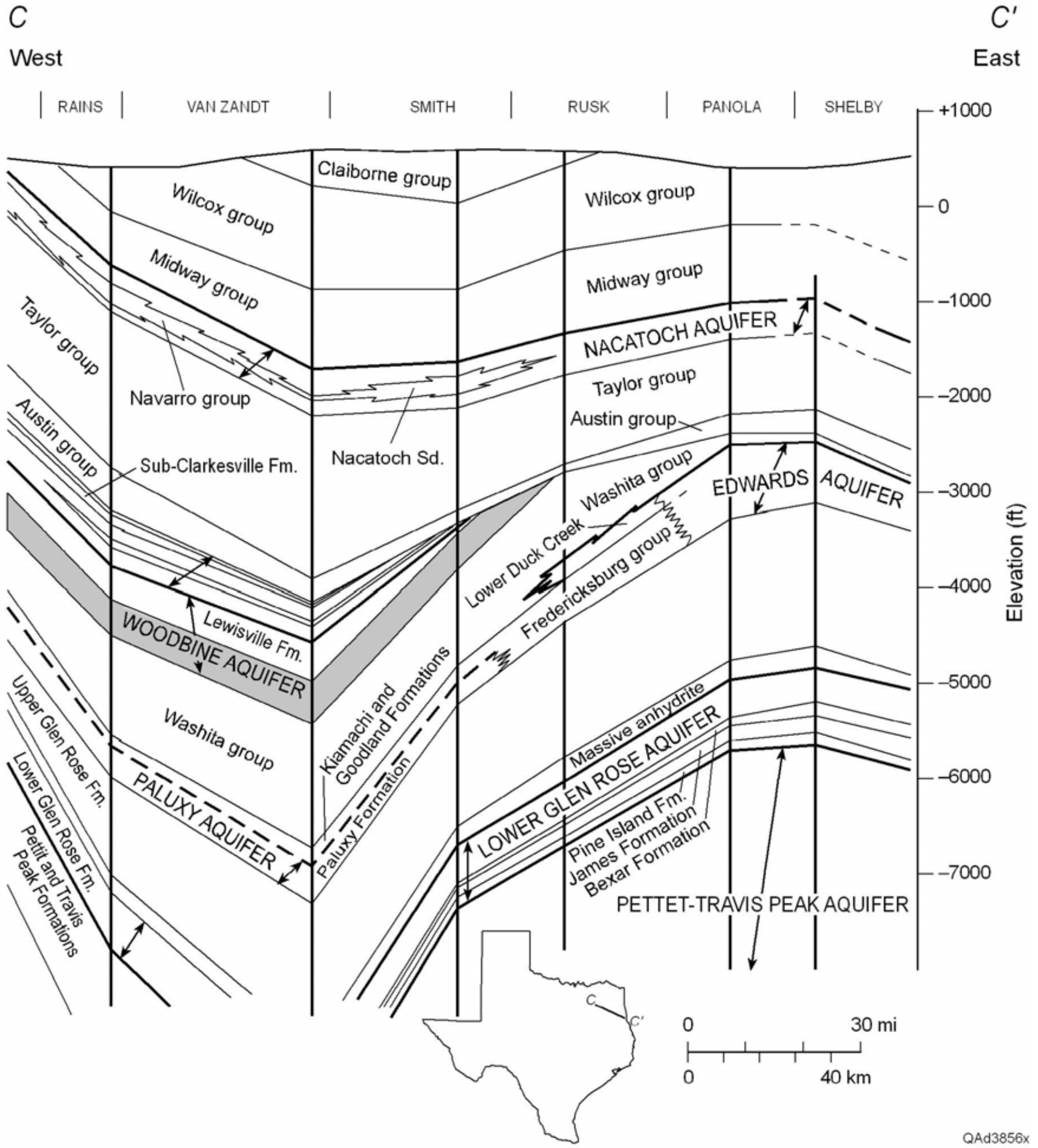


Figure 5-18. Simplified cross-section across the East Texas Basin analysis area (modified from Core Laboratories Inc., 1972a).

## Mineralogy and Diagenesis

The Woodbine Formation includes volcaniclastic sandstones with interbedded shale and conglomerate with igneous and volcanic rock fragments (Belk and others, 1986). Sands may have been derived from the Paleozoic sediments of the Ozark Uplift in Oklahoma and Arkansas with a secondary source of volcanic material in southwestern Arkansas (Beall, 1964). Igneous material is much more common in the upper Woodbine Formation but is found throughout the Woodbine section in Texas (Belk and others, 1986).

The following mineralogy summary is mostly from Belk (1986) who describes the formation close to the sediment source areas. Most sandstones have less than ten percent quartz but abundant oligoclase feldspar, Ti-rich pyroxene, and magnetite. Volcanic rock fragments (VRFs) comprise 49 percent of sand grains. Volcanic arenites and feldspathic volcanic arenites are interbedded with siltstones and conglomerates. The sand fraction consists of volcanic rock fragments, feldspar, quartz, chert, clay clasts, and heavy minerals such as hematite, magnetite, zircon, leucoxene tourmaline, apatite, and amphiboles. The most common detrital VRF is trachytic-textured igneous rock. Feldspars are probably oligoclase and some sanidine. Common authigenic cements include calcite, dolomite, ankerite, and quartz (Uziemblo and Petersen, 1983). The gravel fraction includes novaculite (variety of chert), clay clasts, and volcanic cobbles totally altered to smectite. The volcanic components include pheno-nepheline tephrites, pheno-nepheline basanites, and pheno-andesites (Belk, 1986).

The silt- and clay-sized fraction consists of feldspar, quartz, VRFs, clay clasts, smectite from diagenetic alteration of VRFs, and detrital calcite and biotite (Belk, 1986). Uziemblo and Petersen (1983) identified clay minerals including kaolinite, chlorite, illite, and smectite. Beall (1964) described varying sodium and calcium ratios in smectites across the western flank of the East Texas Basin. The higher Na-smectite composition toward the center of the basin probably reflects the distribution of formation water composition (Kreitler and others, 1987). Beall (1964) also found illite clay in the Woodbine Formation.

Wagner (1987) described the mineralogy of the Woodbine Formation in the giant Hawkins oil field (Figure 5-12) as fine to coarse-grained, moderately sorted sandstones with abundant quartz grains with secondary overgrowths, varying amounts of clay, including authigenic chlorite and kaolinite, and minor amounts of feldspar.

### 5.2.4 Fort Worth Basin

The Fort Worth Basin is an asymmetric foreland basin located in North Texas that formed during the Early to Middle Pennsylvanian Period in response to tectonic stresses that also produced the Ouachita Thrust Belt (Thompson, 1982). The basin has an axis about 200 miles long and a maximum width of 100 miles. It is bounded by the Red River Arch and Muenster Arch to the north, by the Broad Bend Arch to the west, and by the Llano Uplift to the south. The basin covers about 20,300 square miles with the deepest sections in the east-northeast and shallowest in the west. Paleozoic rocks in the Fort Worth Basin have a maximum thickness of 12,000 feet. Most of the oil and gas fields are located in Eastland and Stephens counties (Figure 5-13). East-west cross-sections show the stratigraphic distribution and geometry of the units (Figure 5-19).

#### Depositional Setting

The Atoka Group was deposited in three distinct packages of terrigneous deposits: (1) the lower Atoka formed from a fluvially dominated fan delta system, (2) the upper Atoka "Davis" formed from a coalesced wave-dominated deltas, and (3) the upper Atoka "post-Davis" is a thin, poorly integrated, fluvially dominated fan-delta system. The Atoka Group does not outcrop in the Fort a.)

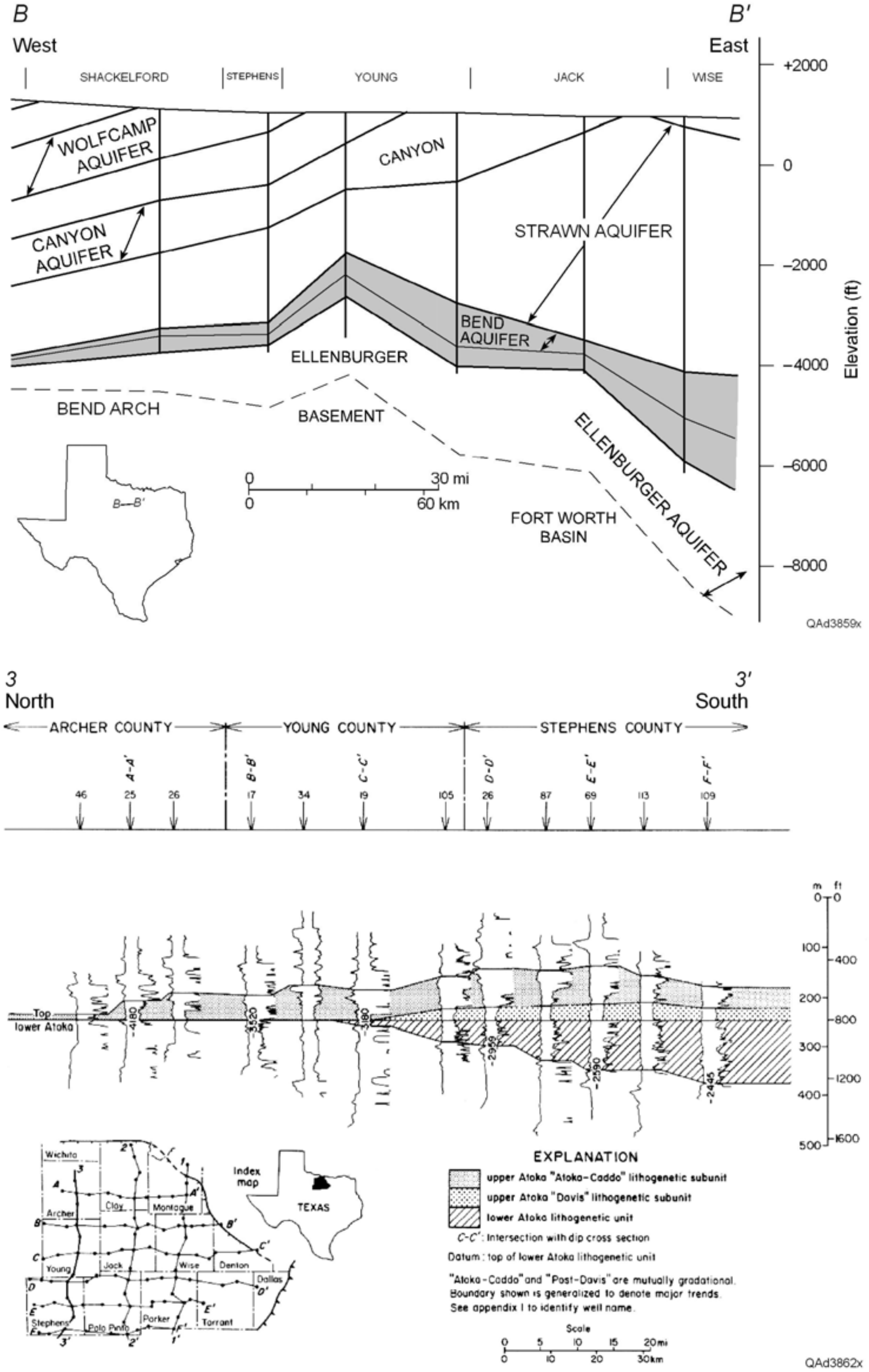


Figure 5-19. (a) Simplified cross-section across the Fort Worth Basin analysis area (modified from Core Laboratories Inc., 1972 a) and (b) cross-section through Young and Stephens counties showing distribution and geometry of the Atoka reservoir units (adapted from Thompson, 1982).

Worth Basin. Subsurface Atokan strata have been variously known as “Bend Conglomerate,” “Big Saline,” “Caddo Conglomerate,” “Lampasas Series,” “Marble Falls Conglomerate,” and “Atoka Group” (Thompson, 1982). The Atokan Group of sediments is as much as 5,900 feet thick near the leading edges of the Ouachita Thrust Belt (Johnson and others, 1988).

The Lower Atoka is characterized by highly digitate and elongate net sandstone geometry, extensively interfingered terrigeneous and carbonate units, and progradation facies sequences in which contemporaneous faulting influenced facies distribution. The upper Atoka “Davis” is characterized by a thick and strike-oriented sandstone geometry that suggests concurrent progradation and aggradation in a system of coalesced wave-dominated deltas. The upper Atoka “post-Davis” is also characterized by highly digitate sandstone geometry and a progradational facies sequence that suggests resumption of fluvially dominated fan-delta deposition (Thompson, 1982).

### Reservoir Description

The individual sandstone units in the Lower Atoka are thicker in the east and are characterized by blocky electric log patterns (Thompson, 1982). To the west the sandstone units progressively break up into a series of thin, discontinuous beds averaging ten feet thick. The primary source of the Lower Atoka was the Ouachita Thrust Belt.

The upper Atoka “Davis” is characterized by a thick, strike-oriented sandstone geometry and maximum thickness trends concentrated along a narrow zone. Individual sandstone units average 30 feet thick and are separated by thick shale sequences (Figure 5-19). The Davis Sandstone thickens southeastward from less than 20 feet along the northern and western flanks of the Fort Worth basin to as much as 1,200 feet in Parker and Dallas counties (Thompson, 1982). In Palo Pinto and Parker counties, the unit is about 50 to greater than 100 feet thick. Sandstone packages in the upper Atoka “post Davis” are thicker in the east and break up westward into thin stringers. In the west (Archer, Young, and Stephens counties) sandstone units average 5 feet thick. In the production zones, the reservoir pressures range from 200 to 2,000 psi with considerable variation among zones suggesting that the individual zones act as individual reservoirs with little intercommunication between zones (Thompson, 1982).

Three styles of reservoir compartmentalization occur in the Fort Worth Basin: structural, stratigraphic, and a combination of the two (Thompson, 1982). Structural compartments are caused by low-displacement faulting, most commonly associated with karst collapse in deeper carbonate rocks, which produces structurally isolated fault blocks. The faulting is widespread, but subtle, and neither vertical displacements nor fault-block geometries can be mapped without three-dimensional seismic data. Stratigraphic compartments may be bounded laterally by facies transitions or complete porosity occlusion caused by diagenetic processes and vertically by the impermeable surface or sequence boundaries. Combination-style compartments have both structural and stratigraphic elements (Hamilton and others, 1997).

### Mineralogy and Diagenesis

Davis reservoir sandstones are quartz-rich feldspathic litharenite (Thompson, 1982). Typical sandstones contain abundant shale interbeds. Plagioclase is the most abundant feldspar, and detrital organic matter is as much as eight percent of the volume of mudstones and muddy sandstones. Detrital clay is composed of illite, chlorite, kaolinite, and clay-size quartz. Porosity development is primarily controlled by depositional environment. Highest porosity occurs in chert conglomerates deposited under high-energy conditions. Porosity includes original porosity remaining between quartz overgrowths and secondary porosity produced by dissolution of chert grains. Pore spaces are angular, moderately interconnected, and 0.04 to 2 mm wide with an average width of 0.8 mm. Secondary pore spaces are slightly interconnected and range from 0.6 mm to 3 mm with an average width of 1 mm. Porosity in the medium- to fine-grained sandstones range between 8 and 12 percent. Chert conglomerates show permeability that averages between 2,000 to 3,000 mD. The medium- to fine-grained sandstones have permeability of typically less than 1 mD because of lack of interconnection between the dominantly secondary pore spaces.

Basic diagenetic sequence in the sandstones is (1) compaction resulting in stylolitization and development of pseudomatrix, (2) quartz overgrowth, and (3) dissolution of chert, feldspar, and metamorphic and volcanic rock fragments. Diagenetic minerals include replacement cements that may comprise as much as 25 percent of the whole rock volume that include quartz, calcite, ankerite, siderite, chlorite, illite, kaolinite, and pyrite. Quartz cement consists of up to about 11 percent sandstone volume in clean sandstones. Chlorite cement volume averages three percent and carbonate cement two percent of rock volume (Thompson, 1982).

### 5.2.5 Maverick Basin

The Maverick Basin of southwest Texas forms the easternmost part of the Rio Grande Embayment of the Gulf Coast Basin. The Maverick Basin is separated from the East Texas Embayment by the San Marcos Arch, which trends southeastward from the Llano Uplift (Figure 5-3). The Maverick Basin is bounded on the north by the Balcones Fault Zone and on the northwest by the Devils River Uplift. On the west, the basin is separated by the southeastward-trending Salado Arch. Smaller structural features include the Chittim Anticline and the Pearsall Ridge. No large growth faults occur in the basin. Numerous basaltic volcanic plugs occur in the northern part of the basin (Simmons, 1967). The Cretaceous San Miguel and the Olmos formations are the most prolific reservoirs in the Maverick Basin. The oil and gas fields within the analyses area roughly follow the southeastward structural trend (Figure 5-14). Cross-sections illustrate the stratigraphic distribution and geometry of the units (Figure 5-20).

The San Miguel Formation is predominantly an oil play (Galloway and others, 1983). It contains only three large gas reservoirs with a cumulative production of 81.8 billion cubic feet (Bcf) or 2.9 percent of the total production from Texas Gulf Coast Cretaceous gas plays (Kosters and others, 1989). Catarina southwest is a major gas play with a total production of 51.4 Bcf in 1978. Big Wells oil reservoir is relatively tight and wells require hydraulic fracturing to stimulate production. The reservoir shows minimal interwell variability, excellent internal continuity and maximum recovery efficiency (Tyler and others, 1986).

The Olmos Formation overlies the lowermost clastic wedge, the San Miguel Formation, and is overlain by the uppermost clastic wedge, the Escondido Formation (Figure 5-20). Tight gas sandstones occur within the Olmos Formation with 973 tight completions, with a cumulative production of 298.6 Bcf and an estimated ultimate recovery of 408 Bcf (Hugman and others, 1992).

(a)

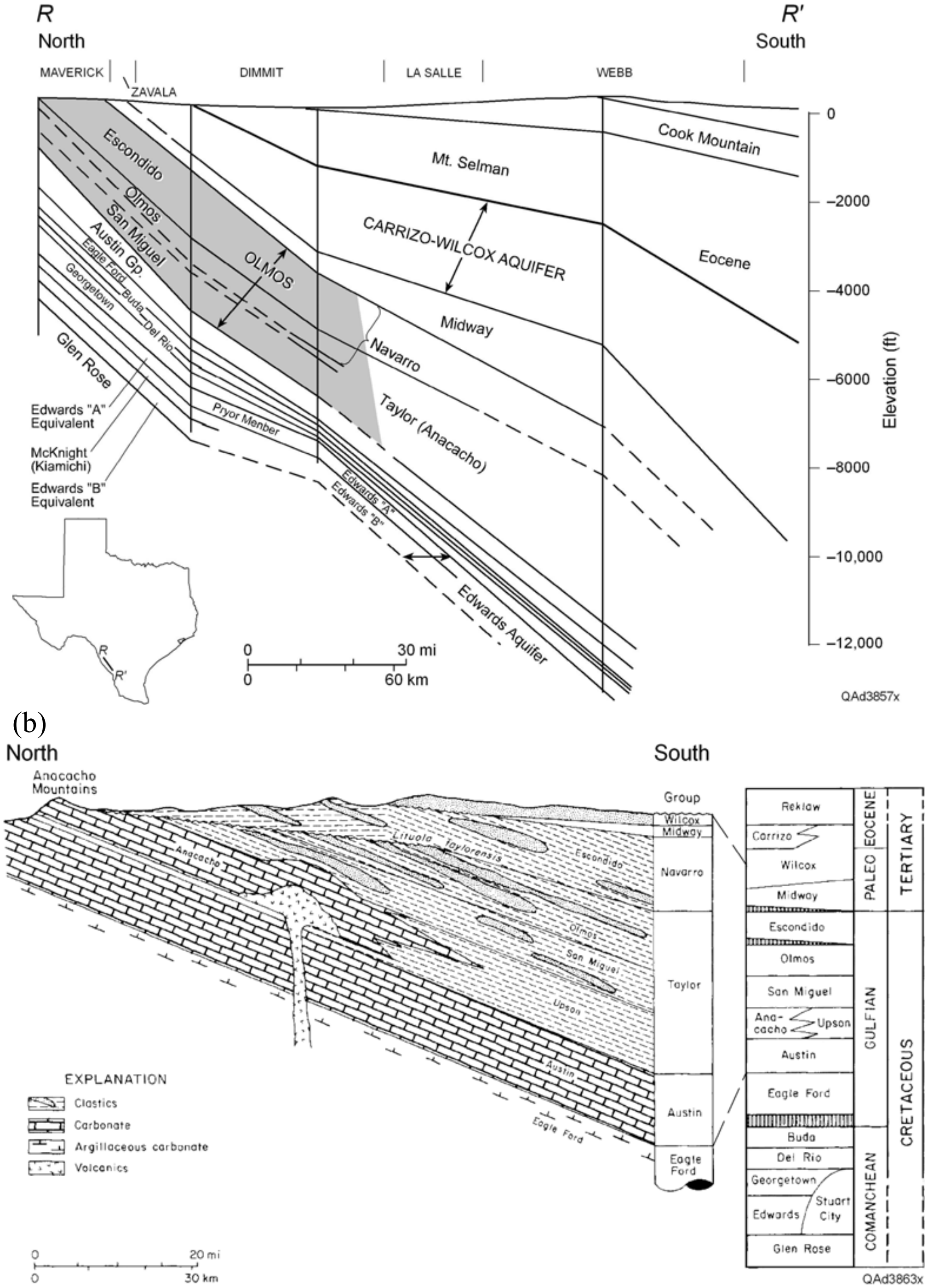


Figure 5-20. (a) Simplified cross-section across the Maverick Basin analysis area (modified from Core Laboratories Inc., 1972a) and (b) stratigraphic-cross section showing in detail distribution and geometry of the Olmos and the San Miguel reservoir sandstones. Location of the volcanic plug is also shown (adapted from Weise, 1980).

## Depositional Setting

The San Miguel sandstones were deposited in a wave-dominated delta that was reworked along strike by wave or tidal processes (Galloway, 1975). Nine major deltaic sandstone units (A to I from oldest to youngest), each representing a progradational sequence, were formed during marine transgression (Weise, 1980). More than half of the total oil production from the San Miguel Formation is derived from sandstone E (Figure 5-20).

The Olmos Formation is exposed around the Chittim anticline in Maverick County, and the formation extends in the subsurface to the southeast in Webb and La Salle counties. Olmos deposition occurs in two main depocenters: (1) the western depocenter (Catarina Delta System) where there is a highly wave-reworked, strike-elongated delta complex (Unit A) followed by more fluvially dominated delta systems (Units B and C) and (2) the eastern depocenter (Rocky Creek Barrier/Strand Plain System) where there is a wave-dominated delta complex (Unit F) followed by wave modified deltaic sedimentation (Units G and H) (Tyler and Ambrose, 1986). Units D and E form thick retrogradational coastal interdeltaic complexes (Figure 5.20). Sand bodies are composed of sharply based, thin-bedded sandstones that are massive, horizontally-laminated, or, more rarely, low-angle crossbedded. Sandstones grade upward into thoroughly bioturbated silty sandstones and sandy mudstones that are laid down by storm deposits derived from the nearby deltaic headland (Weise, 1980).

## Reservoir Description

The sandstones of the San Miguel Formation are dominated by upward coarsening cycles, are very fine-grained, and range from coarse siltstone to fine sandstone. Sandstone A is up to 43 miles long and 8 to 14 miles wide centering at the corner of Zavala, Frio, Dimmit, and La Salle counties. Sandstone A is concentrated in three main "pods" or depocenters with a thickness of 130 feet. Sandstone B is strike aligned, similar to A, and is up to 54 miles long. Sandstone C, better known as the Atlas or Elaine Sandstone, is 45 miles long and 30 miles wide with a net sandstone of 130 feet (Weise, 1980). Sandstone D, better known as the "basal San Miguel" sandstone, forms an arcuate trend with the net sandstone section reaching a maximum of up to 95 feet. Sandstone E, known as the "Big Wells" Sandstone, is 35 miles long and 18 miles wide with a net sandstone thickness of 90 feet. Sandstone F is at least 60 miles long and lays up-dip of Sandstone E with a net sandstone thickness of 90 feet. Sandstone G, known as the "torch," the "King," or the "Second Sand Miguel," is up to 60 miles long with a net sandstone thickness of 140 feet. The youngest of the units, Sandstone I, is 60 miles long and 22 miles wide with a maximum net sandstone thickness of 80 feet. Two types of hydrocarbon traps are common in the San Miguel sandstones: (1) structural traps over volcanic plugs and (2) stratigraphic traps formed by up-dip pinchout of porous sandstones.

Downdip from the Lower Cretaceous shelf edge, the Olmos sandstones are informally designated as Olmos "A" and underlying Olmos "B." Barrow and Asquith (1992) showed that Olmos Sandstone contains at least nine individual sandstone bodies. Unit A sandstones are as much as 60 feet thick, display upward-coarsening SP log patterns, and are arranged in a 75 mile long, strike elongate sandstone-rich trend. Unit B sandstones are lobate and digitate and have axes that are as much as 120 feet thick. Potential reservoirs are dip-elongate, upward-fining channel sandstones (70 to 100 feet thick), upward coarsening channel-mouth-bar sandstones (20 to 50 feet thick), and thin, muddy delta-front sandstones. Unit C contains a maximum of 80 feet of sandstone in southern Dimmit County and, as a strike-oriented system, has as much as 100 feet of sandstone in northwestern Webb County (Dutton and others, 1993). Unit D is centered in northwestern Webb County and consists of a major strike-elongate belt with as much as 90 feet of sandstone.

Unit E was deposited as a marine onlap with small scale (ten feet thick) sandstones of reservoir potential. In the updip trend, the net pay thickness ranges from 50 to 250 feet with net pay thickness of 50 feet in the downdip trend. Net pay thickness ranges from 12 to 82 feet for the Olmos Sandstone overall (Finley, 1984). Strike-oriented belts of high production are parallel to trends in sand thickness. However, the highest production occurs in the longshore-distal part of the trend, where sand thicknesses are generally lower than in the area proximal to the delta. This may be due to increased concentrations of calcite in proximal areas. Hydrocarbon pore volume corrected for volume of clay has been calculated from available log suites and compared with cumulative gas production. Gas recovery efficiency varies across the trend—significant reserves remain in areas where average drainage radius is much less than regulated well spacing.

## Mineralogy and Diagenesis

The sandstones of the San Miguel Formation are dominantly arkosic in composition. Calcic-plagioclases are most abundant compared to potassium feldspars and albite. Higher percentages of quartz are found in the coarsest parts of the sandstone. Sandstones of the Olmos Formation are subarkose to sublitharenite in composition and are composed of quartz, clay, feldspar, and rock fragments. The clay minerals are mainly detrital and include sub-equal amounts of mixed layer illite-smectite and Fe-rich chlorite. These minerals may comprise up to 30 percent of some of the sandstones (Snedden and Jumper, 1990).

Porosity determined from thin sections of the San Miguel Formation shows an upward increase due to a decrease in the clay content ranging from 10 to 30 percent. Highest porosity occurs in areas where feldspar and shell fragments have been leached. Original porosity is destroyed in some zones due to calcite cementation. The cemented zones exhibit low spontaneous potential (SP) and high resistivity values on electric logs. Thin limestone beds that are silty to sandy micrites are non-porous (Loucks and others, 1979; Weise, 1980).

Permeability ranges from 0.1 to 65 mD with an average of 6 mD. Core, SEM, and petrographic analyses of the Olmos Formation indicate that porosity, which ranges from 6 to 16 percent and averages slightly under 10 percent, is 80 percent primary macroporosity, 10 percent secondary macroporosity, and 10 percent primary microporosity (Loucks and others, 1979; Weise, 1980).

The most common cements in the San Miguel Formation are calcite and quartz overgrowths. Other diagenetic minerals are kaolinite, feldspar, illite (clay rims), pyrite, and hematite (Loucks and others, 1979). Diagenetic kaolinite occupies some primary intergranular pore spaces as well as central parts of larger cavities (Weise, 1980). The very fine-grain size and high clay content results in low permeability, which ranges from 0.01 to 8 mD (Snedden and Jumper, 1990). Finley (1984) documented median permeabilities ranging from 0.034 to 0.072 mD from 149 wells with lower permeabilities in the downdip sandstones.

Olmos reservoirs are overpressured, and fractures and faults may define pressure compartments in this unit. Dissolution of feldspar, calcite cement, and shale clasts in the Olmos Formation contributes to secondary porosity. Secondary calcite further reduces porosity and forms the updip trapping mechanism.

### *5.2.6 Southern Gulf Coast Basin*

The southern Gulf Coast Basin includes six major progradational sedimentary packages of Tertiary and Quaternary age and is underlain by older Mesozoic formations that record the early evolution of the basin (Galloway and others, 2000). Zones of growth faulting mark the basin-ward movement of the shelf edge. Fault-bounded reservoir compartments create many structural traps in the Cenozoic stratigraphic section of the southern Gulf Coast Basin. Numerous oil and gas fields occur in the analysis area of the southern Gulf Coast Basin (Figure 5-15). Stratigraphic cross-sections show abrupt thickening of the units towards the southeast, depths to the base of potable water, top of geopressure, and growth fault patterns (Figure 5-21).

#### Depositional Setting

The Frio Formation comprises one of the major progradations into the Gulf of Mexico (Figure 5-21). In the Frio Formation, hydrocarbons are trapped in the downthrown side of down-to-the-basin faults along the Vicksburg-Frio Fault Zone (Galloway and others, 1983). The Frio Formation of south Texas was deposited in a complex of fluvial, deltaic, strandplain, and barrier depositional systems (Galloway and others, 1982). Vertically stacked reservoirs in multiple horizons of permeable deposits are typical of the Frio Formation.

#### Reservoir Description

The sheer number of attractive targets makes an overview study such as this incomplete. The Frio Formation in Texas has produced 6 billion bbl of oil and 60 trillion cubic feet of gas. Shallow saline sections of the Gulf Coast basin are hydrostatic. Beyond depths of 8,000 to 10,000 feet, the formations become overpressured in the so-called geopressured zone.

#### Mineralogy and Diagenesis

Capuano and others (1989, p. 53), citing different sources, summarized the petrography of the Frio and other Gulf Coast sandstones. Quartz is a major component followed by feldspar and rock fragments, which generally make up 5 to 50 percent of the total rock. Clay content increases with depth and also undergoes a mineralogical change as smectite gives way to illite at depth of about 9,000 feet (Loucks and others, 1979). Carbonate cementation is also common and occurs predominantly as calcite. Calcite cement averages five percent in volume (Land, 1984). The lower Gulf Coast sandstones in the analysis area have a higher proportion (about 60 to 80 percent) of volcanic rock and carbonate rock fragments and plagioclase and orthoclase feldspars than their northern counterparts (Loucks and others, 1977, Figure 5) because of their proximity to the then-active volcanic areas in Mexico and West Texas. Rock fragments compose half to more than 75 percent of the non-quartz grains. Consolidation history includes a reduction in porosity (that can rebound with a leached secondary porosity but only beyond depths considered

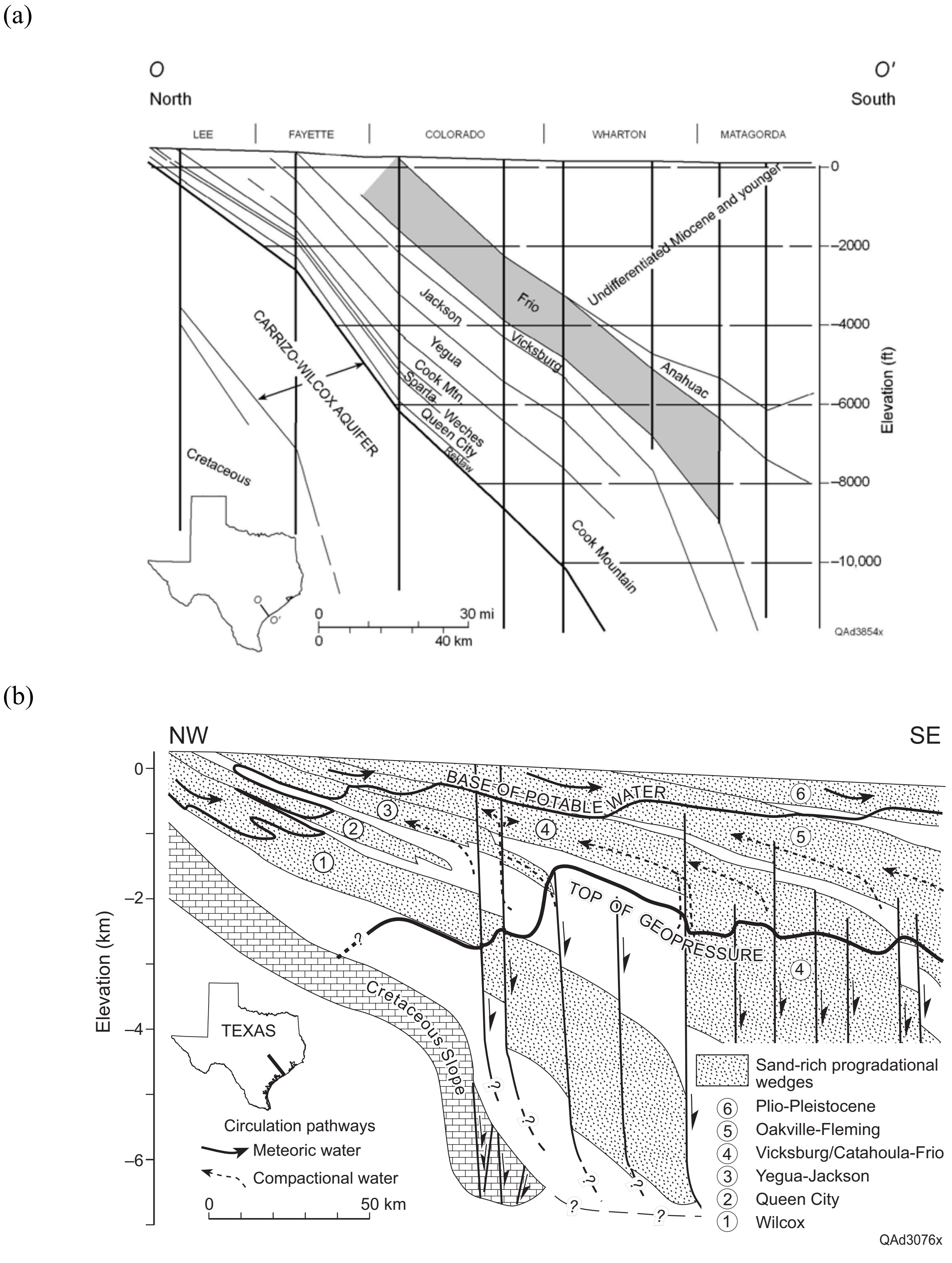


Figure 5-21. (a) Simplified cross-section of Southern Gulf Coast Basin analysis area (modified from Core Laboratories Inc., 1972a) and (b) major sand-rich progradational packages and growth fault zones beneath the Texas coastal plain (adapted from Galloway, 1982 and Galloway and others, 1982).

in this study), feldspar leaching, creation of some quartz and feldspar overgrowth, formation of clay coats and rims, and production of a calcite cement.

In a more detailed analysis, Lindquist (1977) completed a classic study of the mineralogy and diagenesis of reservoir sandstones in the Frio Formation. Lindquist (1977) focused on an analysis area in Nueces, Willacy, and Hidalgo counties that probably is representative of the Frio Formation in the southern Gulf Coast Basin. Texture and mineralogy varies with depositional system. In the depocenters of deltaic and nearshore coastal complex environments, the sandstones are mineralogically immature, fine-grained, and moderately well sorted. Feldspathic litharenites to lithic arkoses near the depocenters are low in quartz (20 to 30 percent) and rich in feldspar and VRF (up to 50 percent VRF) (Lindquist, 1977; Loucks and others, 1986). VRFs are predominantly rhyolites and trachytes and are normally silicified or altered to chlorite (Lindquist, 1977; Loucks and others, 1986; Grigsby and Kerr, 1991). Carbonate rock fragments, mainly from caliche deposits, are also frequent (Loucks and others, 1986). The diagenetic sequence is well established (Lindquist, 1977; Loucks and others, 1986):

- At shallow to moderate depth of burial in normal pressure regime: cementation by micrite replacing feldspar, feldspar overgrowths on feldspar, quartz overgrowths, sparry calcite replacing feldspar; and some pyrite; primary porosity is reduced to several percent and permeability reduced to less than several tens of millidarcies.

- At greater depth in the transition zone at the top of geopressure (about 10,000 feet): dissolution of calcite increases porosity to more than 30 percent and increases permeability to several hundred millidarcies.

- At greater depth in the geopressure zone: post-dissolution re-cementation by kaolinite, ferroan calcite and dolomite cements, ankerite, analcime, zeolite (laumontite?), and more pyrite, which cause reduction in secondary porosity and permeability.

Lindquist (1977) also found that porosity and permeability in the depocenter areas depend on the extensiveness of early cementation. Grigsby and Kerr (1991) found that the middle Frio Formation is composed mainly of lithic arkoses to feldspathic litharenites with abundant glass shards and volcanic-ash-rich matrix. Devitrification yielded analcime and mixed layer illite-smectite minerals (Kerr and Grigsby, 1991). Galloway (1977) also suggested that alteration of volcanic clasts yielded montmorillonite. In the middle Frio much of the higher porosities are ineffective owing to authigenic cementation. Morton and Land (1987) point out that the formation waters in the Frio Formation are mainly Na-Cl along the San Marcos Arch but Ca-Cl to the south in the Gulf Basin.

## *5.3 Porosity and Permeability*

Permeability and porosity data are extremely variable within the same formation with values that are a function of the depositional setting. Sources for porosity and permeability data included a Core Laboratories report (1972b), digital compilation of the oil and gas atlases published by the BEG by Holtz and others (1991) and Garrett and others (1991), and data from H1 forms downloaded from the RRC Web site or gathered from older paper copies. We also merged porosity and permeability data from oil and gas fields. Holtz and McRae (1995) showed that, in

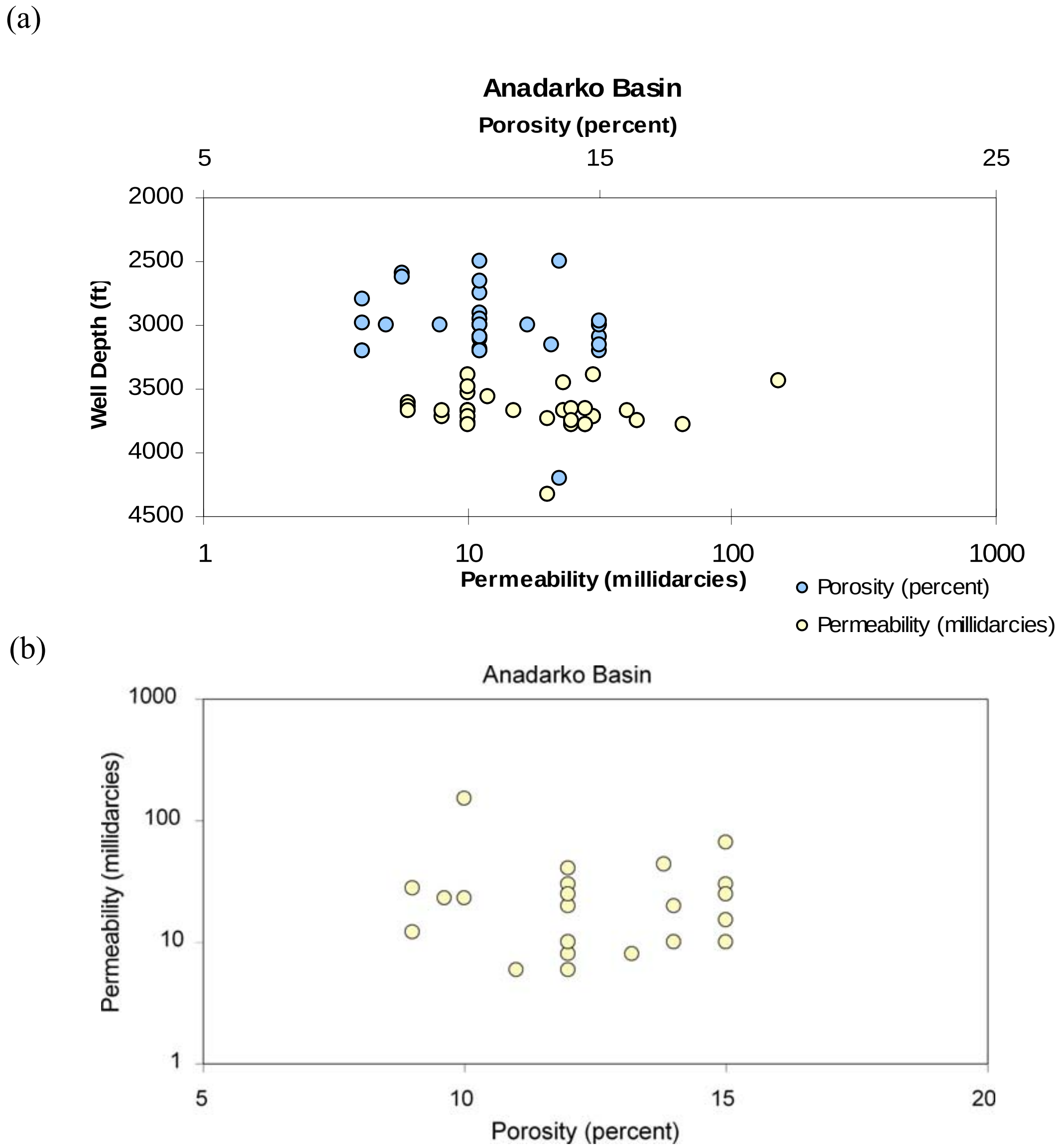


Figure 5-22. (a) Porosity and permeability with depth and (b) relationship between porosity and permeability in the Anadarko Basin.

the southern Gulf Coast, there is no difference in permeability and porosity statistical attributes between oil and gas fields. We only made a minimal effort to ensure there was no data duplication when we merged the different data sets.

Permeability distribution is very dependant upon the depositional pattern. A map of permeability values appears random until depositional system contours are superimposed onto the map. Porosity and permeability values are generally lower in the Paleozoic basins than in the Cretaceous and Tertiary basins. The porosity-permeability cross-plots show that these two parameters are linearly correlated in the analysis areas with a linear correlation coefficient of 0.5 or higher. We used these correlation coefficients when we computed the distribution of flow rates (Section 6).

It is beyond the scope of this study to do a thorough analysis of the spatial distribution of the permeability. However, we believe that, as a first approximation, the data gathered from various sources represent the permeability variability of a standard field. The concept of relative permeability is also very important in multiphase flow systems such as injection of water into oil and gas reservoirs. However, it is beyond the scope of this study to do a thorough analysis of relative permeability.

### 5.3.1 Anadarko Basin

Porosity in the Granite Wash ranges from 4 to 20 percent with an average of 8.5 percent. Permeabilities are moderate varying from about 9 to 100 mD with a mean of 23 mD. Porosity and permeability show poor correlation (Figure 5-22). At high porosity some of the sandstones have very low permeability, presumably due to an absence of interconnection between the pore spaces due to alteration of framework detrital minerals and formation of cements bridging the pore spaces.

### 5.3.2 Permian Basin

Porosity for the San Andres-Grayburg Formation ranges from 2 to more than 20 percent with most of the values between 5 and 10 percent (Figure 5-23). Permeability ranges from 1 mD to more than 100 mD with a mean value of about 5 mD. Permeability does not show a good correlation with porosity because of an absence of interconnection between the pore spaces (Figure 5-24).

### 5.3.3 East Texas Basin

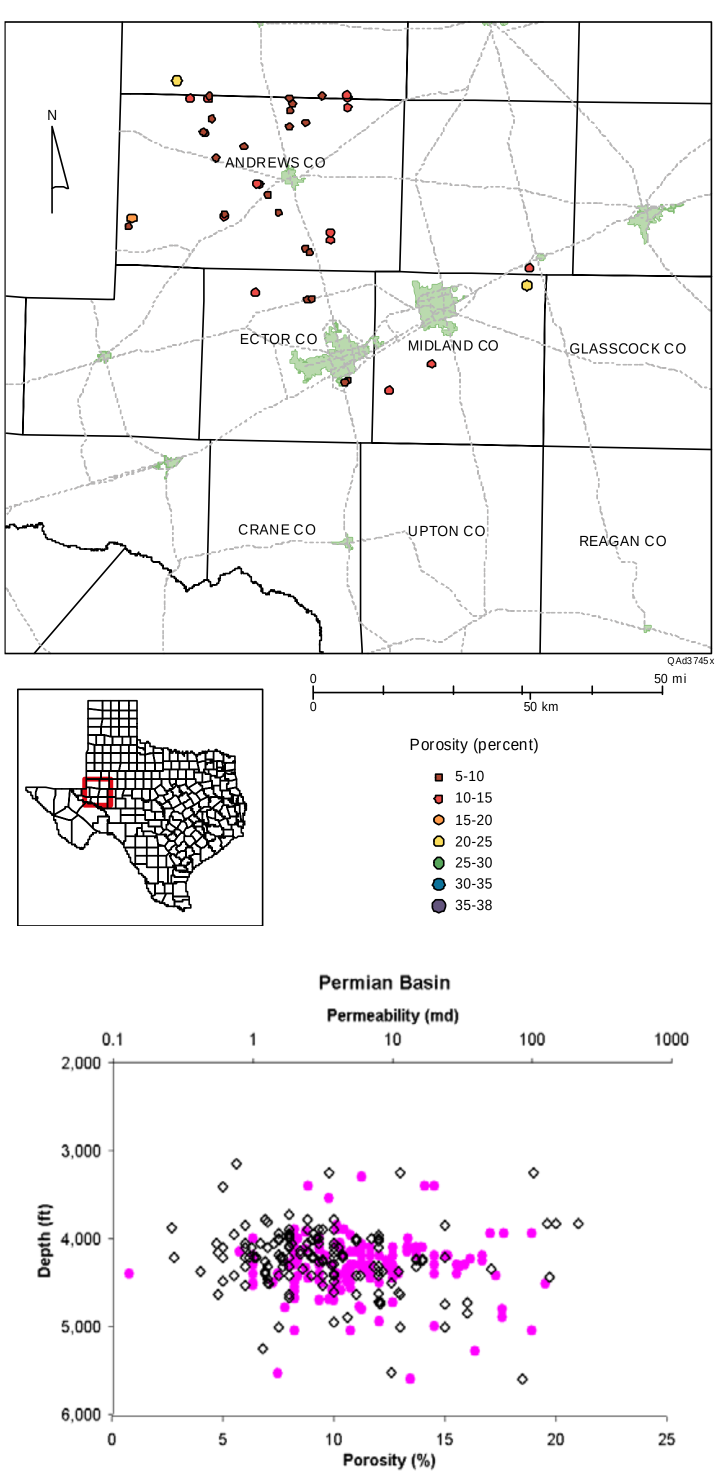
Porosity varies from less than 20 percent to more than 35 percent with most of the values between 25 and 30 percent (Figure 5-25). Permeability range from approximately 10 mD to more than 5,000 mD with a mean of about 500 mD (Figure 5-25). Porosity and permeability may be slightly correlated (Figure 5-26b). At the scale of the sampling, no correlation with depth is observed (Figure 5-25b).

### 5.3.4 Fort Worth Basin

Porosity in the Fort Worth Basin remains uniform at about 10 to 12 percent throughout the plotted depth intervals (Figure 5-27). Permeability varies orders of magnitude with the more permeable units occurring at depths between 3,000 to 4,000 feet (Figure 5-27). Permeability ranges from about 1 md to 10,000 md with a mean value of about 170 mD. A slight increase in permeability is observed with an increase in porosity (Figure 5-27).

### 5.3.5 Maverick Basin

Porosity of the San Miguel and the Olmos formations shows no trend with depth (Figure 5-28). Porosity ranges from about 20 to 32 with a mean value of 32. High porosity values exist at both shallow and deeper intervals (Figure 5-28) indicating their development due to secondary porosity along discrete reservoir intervals. Permeability ranges from about 1 to 2,400 mD with a



open diamonds = porosity; circles = permeability

Figure 5-23. (a) Spatial distribution of porosity and (b) variation between permeability and porosity with depth in the San Andres Formation of the Permian Basin. CO = County.

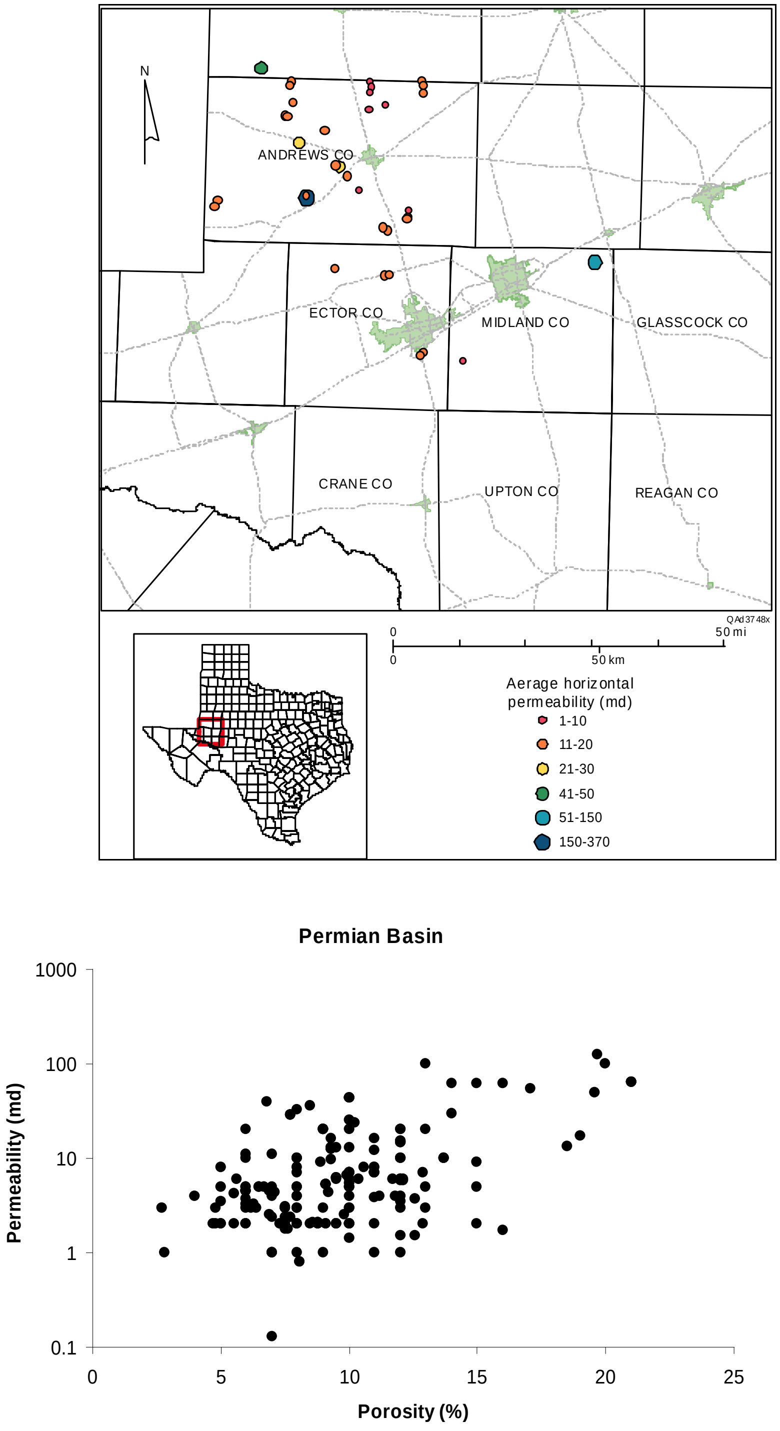
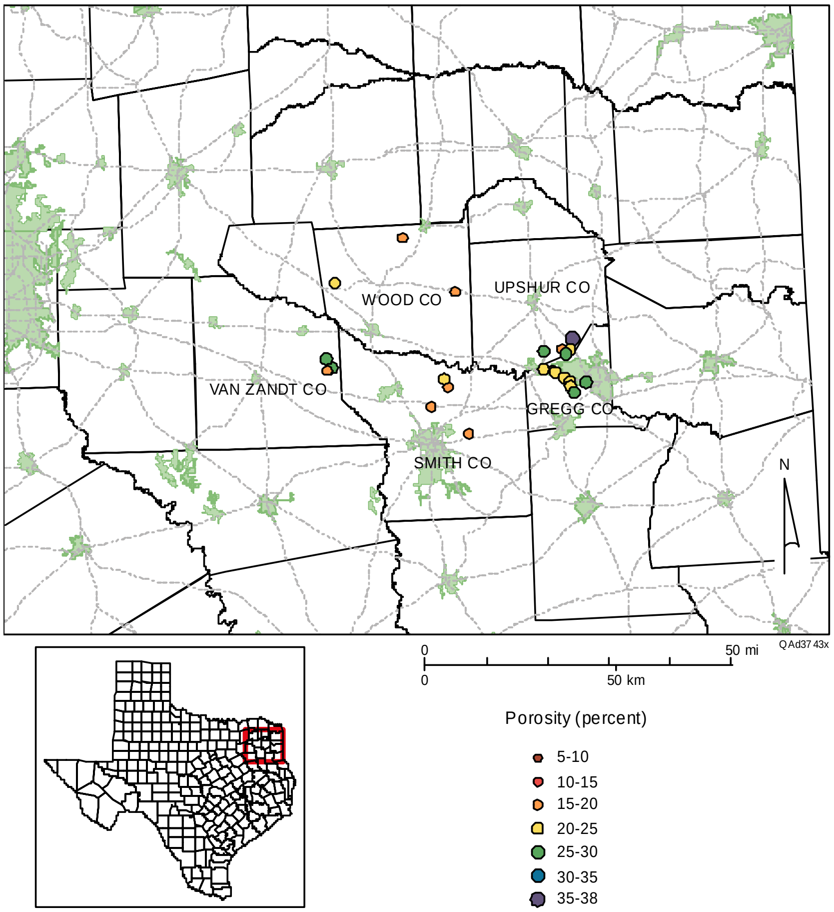
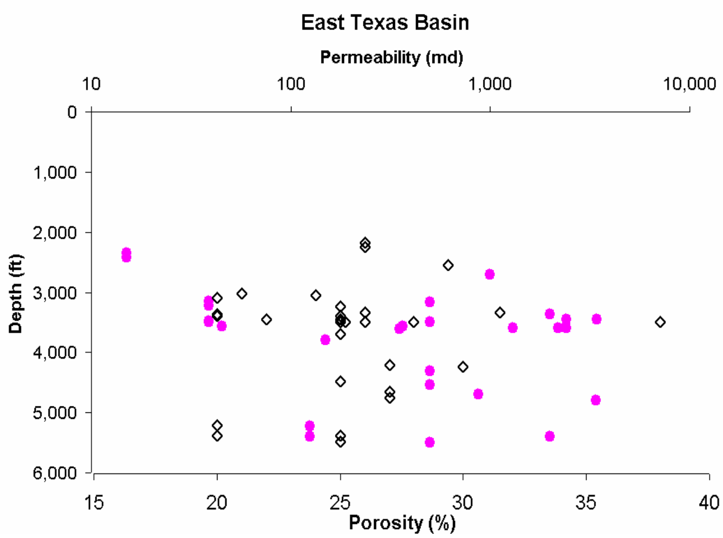


Figure 5-24. (a) Spatial distribution of permeability and (b) relationship between permeability and porosity for the San Andres Formation of the Permian Basin.

(a)



(b)



open diamonds = porosity; circles = permeability

Figure 5-25. (a) Spatial distribution of porosity and (b) variations of permeability and porosity with depth for the Woodbine Formation of the East Texas Basin.

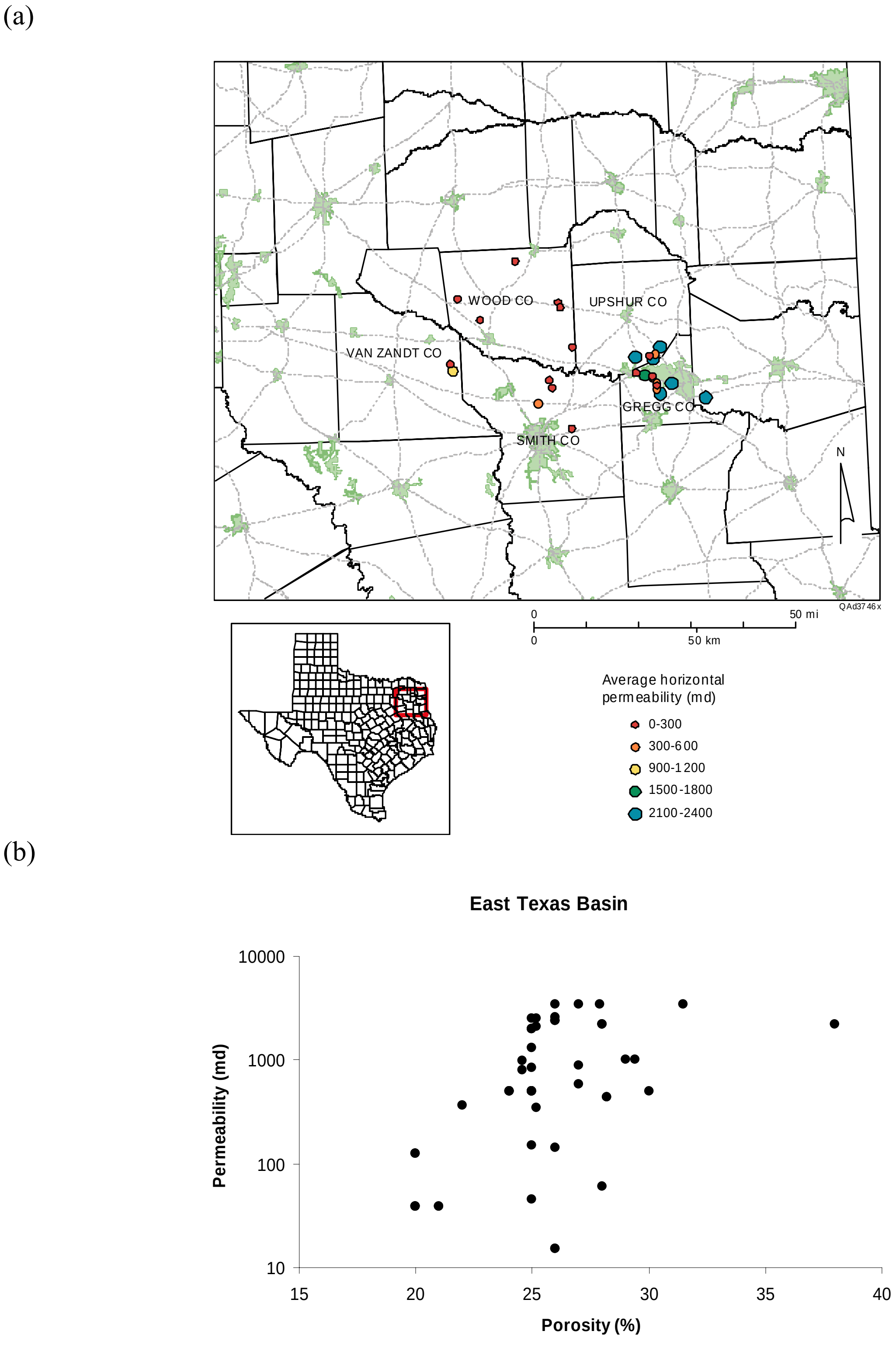
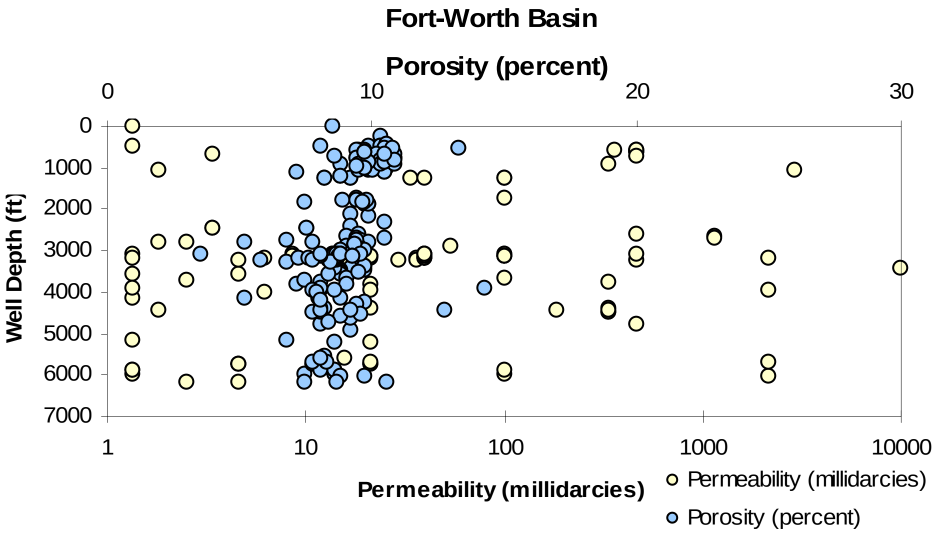


Figure 5-26. (a) Spatial distribution of permeability and (b) relationship between permeability and porosity for the Woodbine Formation of the East Texas Basin.

(a)



(b)

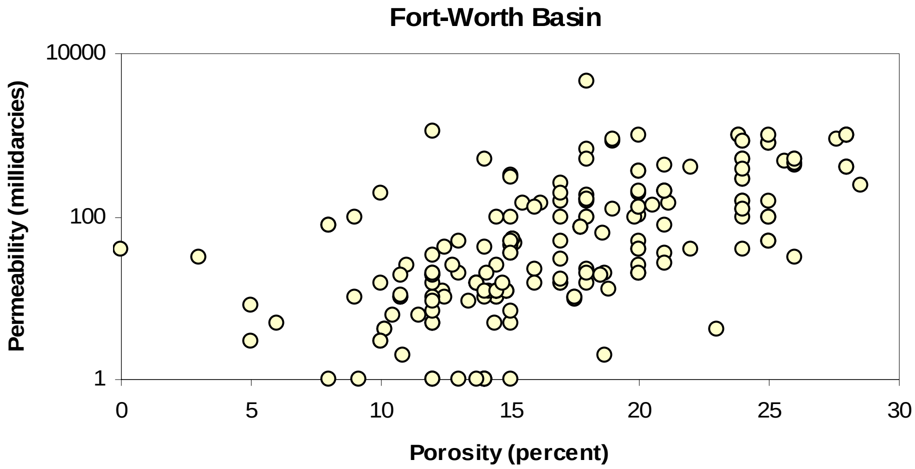
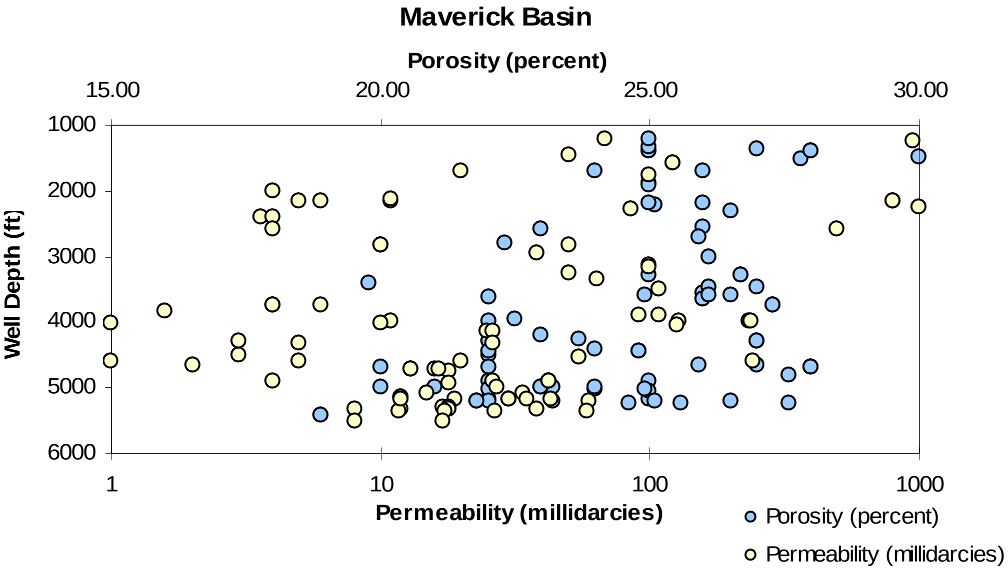


Figure 5-27. (a) Porosity and permeability with depth and (b) relationship between porosity and permeability in the Fort Worth Basin.

(a)



(b)

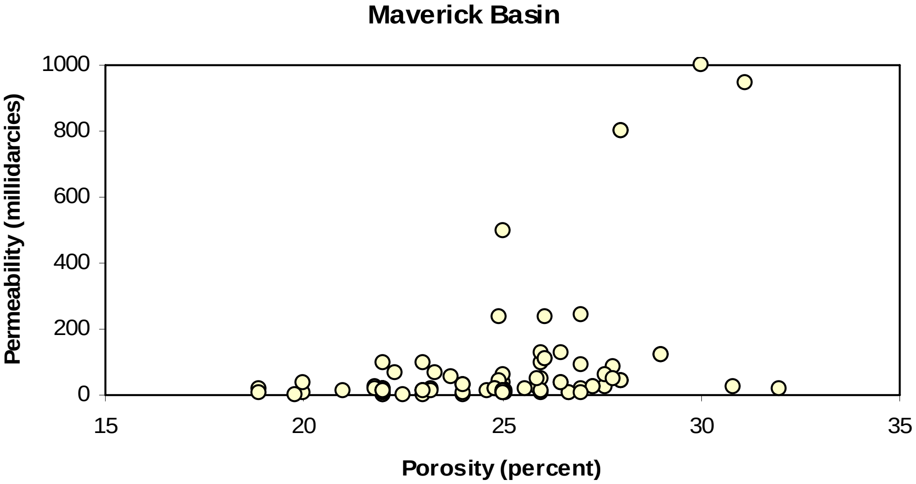


Figure 5-28. (a) Porosity and permeability with depth and (b) relationship between porosity and permeability in the Maverick Basin.

mean value of 105 mD. Porosity and permeability is poorly correlated (Figure 5-28). At high porosity some of the sandstones have low permeability. This is presumably caused by an absence of interconnection between the pore spaces and formation of cements that bridged the pore spaces.

### 5.3.6 Southern Gulf Coast Basin

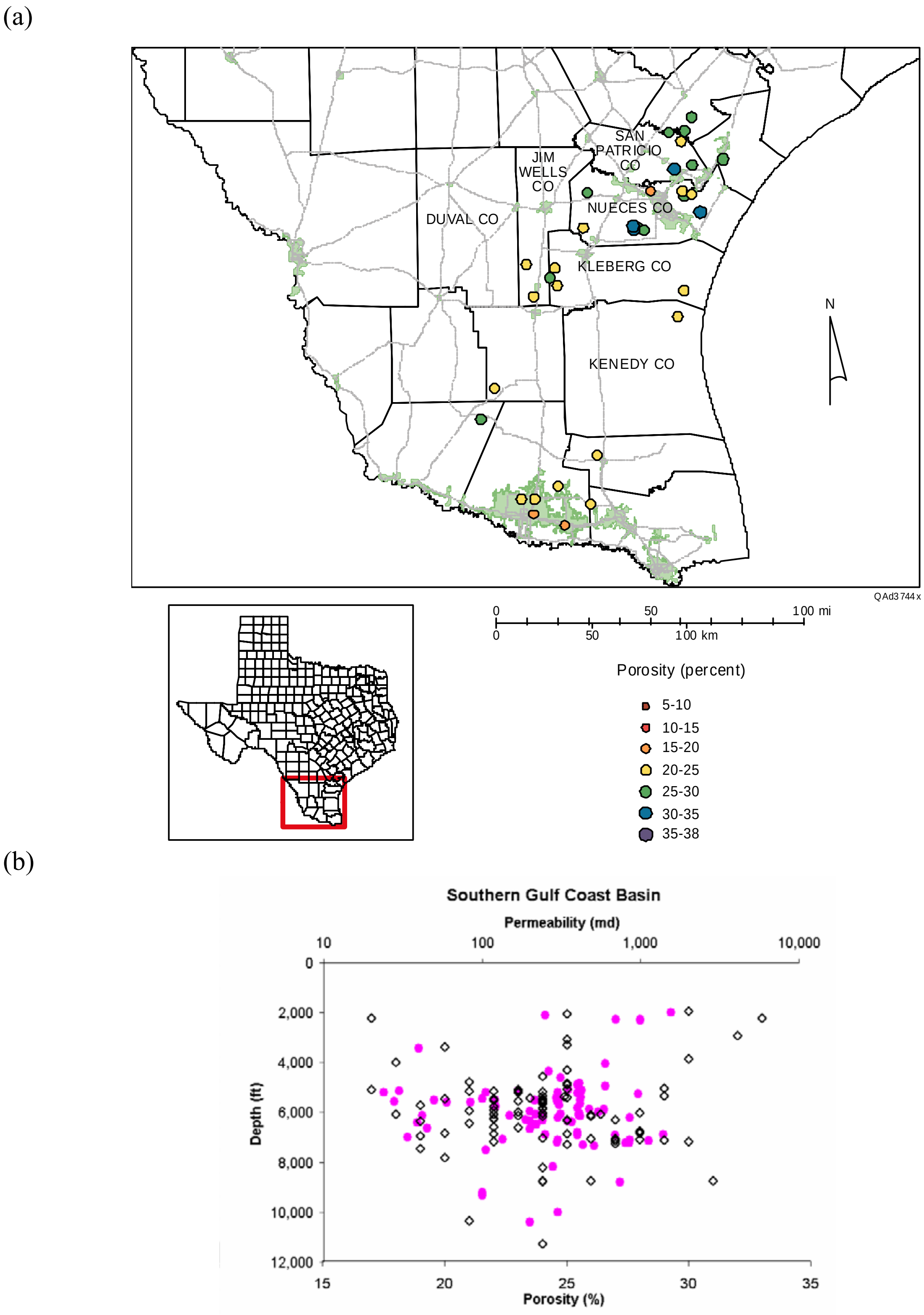
Controls on the distribution of permeability and porosity in the Frio Formation have been extensively studied. Porosity is primarily related to depositional facies with very high permeability in clean sandstones. There does not appear to be a relationship of porosity and permeability with depth (Figure 5-29) although Loucks and others (1986) discerned one for a larger depth range. Holtz and McRae (1995) studied the porosity, permeability, and other parameters of the Frio Formation in the southern Gulf Coast Basin analysis area. They used a data set similar to ours. They concluded that permeability and porosity are strongly correlated with the depositional facies. They also developed statistical distribution functions for permeability and porosity. However, although we made use of the porosity and permeability distributions, we randomly sampled the data set rather than fitting it to a functional statistical distribution. There appears to be a slight relationship between porosity and permeability in the analysis area (Figure 5-30).

## *5.4 Formation Waters*

Collins (1987) presented a condensed summary of produced waters in the U.S. and their properties. Collins (1975) presented a more detailed analysis. The major anion in most oil fields is chloride. Other anions include bicarbonate, sulfate, carbonate, fluoride, and organic acids. The major cations are sodium, calcium, and magnesium. Minor cations are potassium, strontium, and barium. The pH of produced waters is typically controlled by the carbonate system. The redox potential Eh of produced waters is often reducing/negative. If the produced waters are exposed to the atmosphere, the Eh becomes positive. The Eh status is important for understanding the solubility of sulfur and metals such as iron. Dissolved gases are frequent in formation waters and can easily volatilize if no precautions are taken. These gases are $CH_4$, $CO_2$, $N_2$, and $H_2S$ in addition to hydrocarbons.

There are many potential sources of error in the collection and analysis of formation water samples (Appendix 2). pH and Eh are the two most difficult parameters to measure accurately in situ. Measured pH and temperature may be inaccurate. Outgassing, particularly of carbon dioxide, is another concern. The presence of dissolved hydrocarbons in the water also contributes to the sampling difficulties because organic acids play a role in alkalinity determination. Barite is used in drilling mud and can lead to sample contamination. We examined barite concentrations and did not find any contamination of drilling mud. Formation waters are close to chemical equilibrium with the minerals composing the rock framework or are undergoing slow-kinetics reactions. Ca concentrations are likely determined by equilibrium with calcite, ubiquitous in the formations. Dissolved silica is controlled by amorphous silica solubility.

We used three types of sources to access information about formation waters: the USGS produced waters database (USGS, 2002), data ordered from IHS Energy Group (formerly



open diamonds = porosity; circles = permeability

Figure 5-29. (a) Spatial distribution of porosity and (b) variation between permeability and porosity with depth in the Frio Formation of the Southern Gulf Coast Basin.

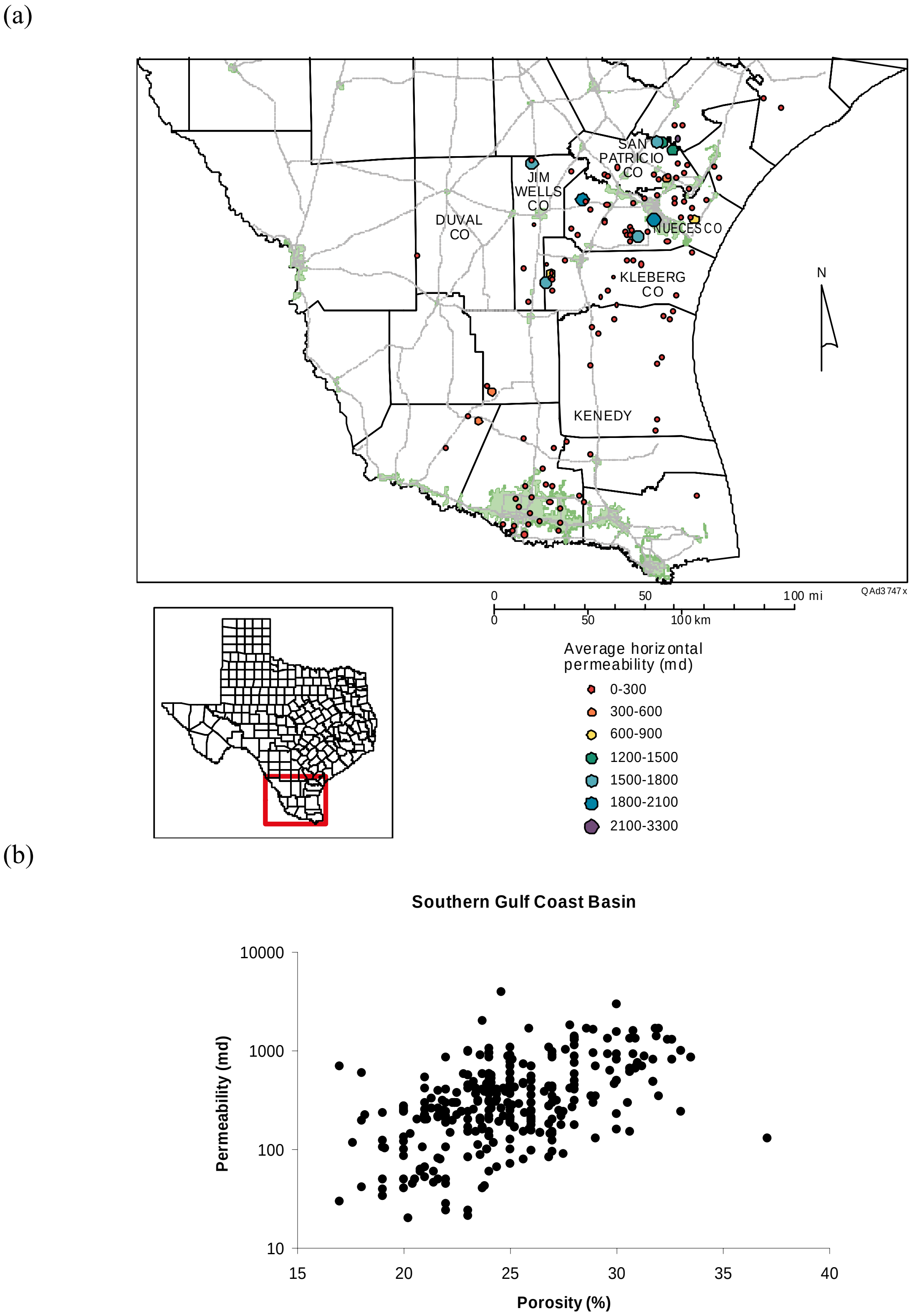


Figure 5-30. (a) Spatial distribution of permeability and (d) relationship between permeability and porosity for the Frio Formation of the Southern Gulf Coast Basin.

Petroleum Information/Dwights), and data gathered from publications, particularly BEG publications (Table 4-1). A major issue was determining field locations of samples with chemical analysis information. We did additional work to obtain locational coordinates for as many of these analyses as possible. Locational data came from both a cross-listing of American Petroleum Institute (API) well numbers and from field, lease, and well data obtained from a commercial license of data at drillinginfo.com.

The USGS database contains a total of 14,059 records for the state of Texas (Figure 5-31). It provides major ion concentration ($Ca^{2+}$, $Mg^{2+}$, $Na^{+}$, sometimes $K^{+}$, $Cl^{-}$, $SO_4^{2-}$, and $HCO_3^{-}/CO_3^{2-}$), TDS, and pH in addition to location and reservoir information. The USGS database also provides an indicator about the quality of the analysis (Appendix 3). Since we used the information for geochemical modeling, we needed data with the highest possible quality. However, no information was provided for important minor elements such as Ba or Sr. Chemical analysis for Fe and $H_2S$, which could be significant in the success of an injection well, was also lacking.

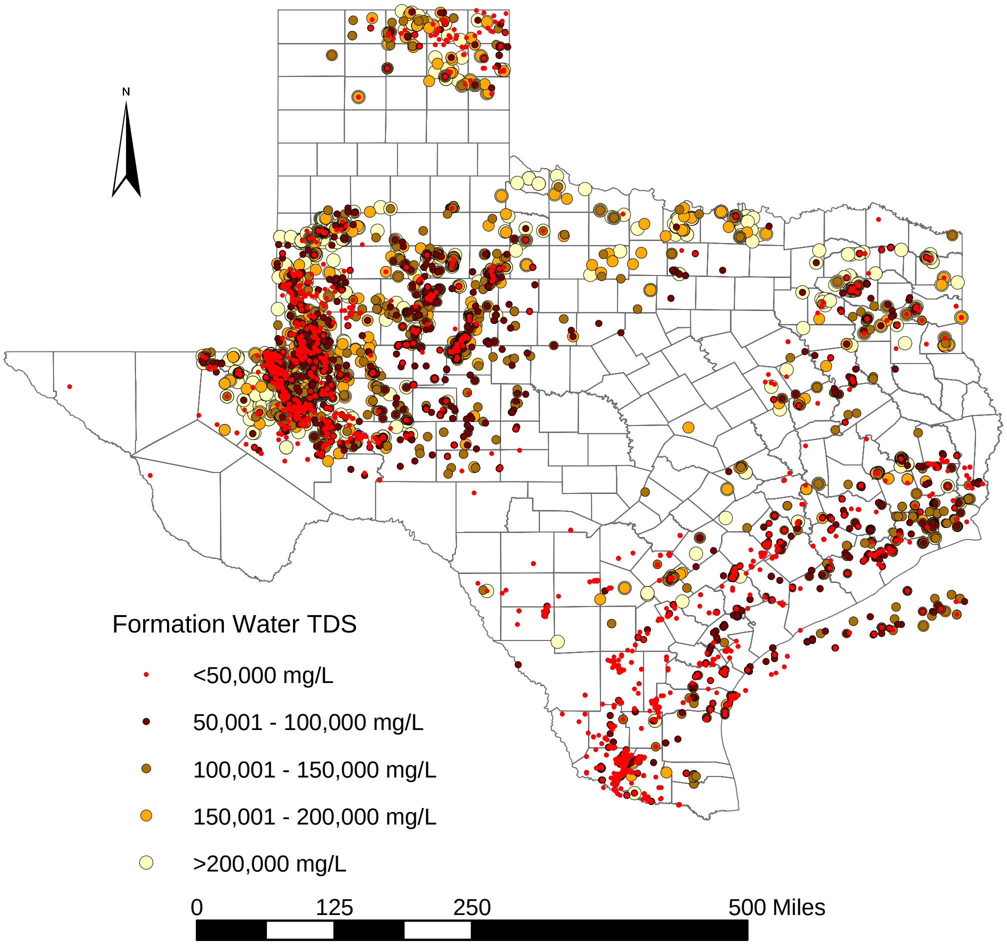


Figure 5-31. TDS of formation waters in Texas (USGS, 2002).

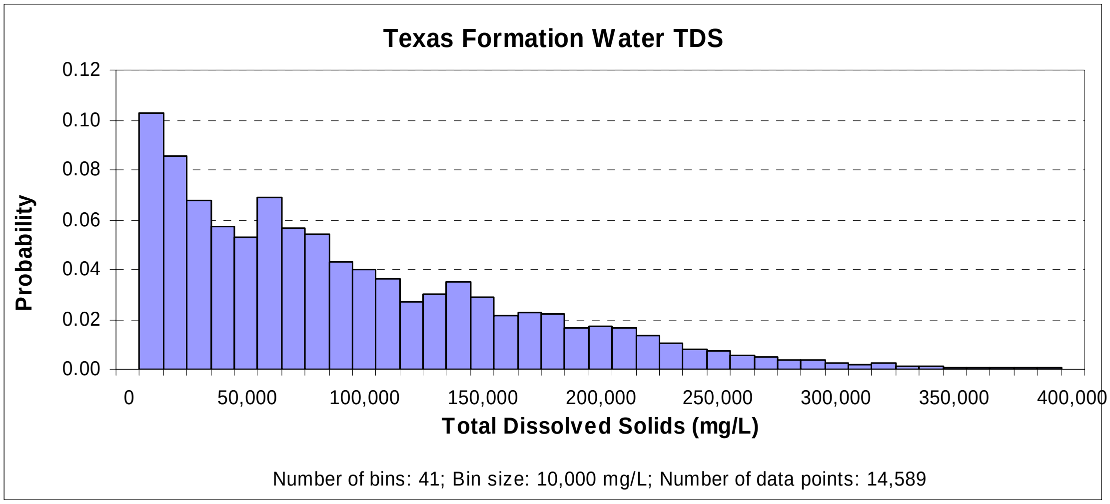


Figure 5-32. Histogram of the TDS of formation waters in Texas (USGS, 2002).

Table 5-4. Average TDS of formation waters.

| Basin | Average TDS (g/L) | Average Density* |
|---|---|---|
| Anadarko | 104 | 1.071 |
| Permian | 82 | 1.056 |
| East Texas | 57 | 1.039 |
| Fort Worth | 136 | 1.093 |
| Maverick | 33 | 1.023 |
| Southern Gulf Coast | 51 | 1.035 |

*from Kharaka and others (1988) formula for density as a function of TDS

TDS of produced waters are highly variable (Figure 5-32 and Table 5-4) ranging from less than that of sea water (35,000 mg/l) in the San Miguel and Olmos formations in the Maverick Basin to more than 130,000 mg/l in the Atoka Group in the Fort Worth Basin. We used average TDS values to compute density for the AOR calculations.

### 5.4.1 Anadarko Basin

We purchased most of the composition data from the IHS Energy Group. Formation waters in the analysis area show considerable variability in chemical composition (Figure 5-33). TDS of the formation waters that we analyzed have values that range from less than 1,500 mg/l to as much as 224,000 mg/l with a mean value of about 87,000 mg/l. The formation waters have pH values that lie between 3.21 and 8.4. The formation waters analyzed for this study mainly consist of sodium-chloride and calcium-chloride-sulfate type water (Figure 5-33). High variability in the formation water compositions between samples probably suggests influences of different source water, variability in formation lithology, and/or varying rates of chemical reactions between the matrix and the formation water.

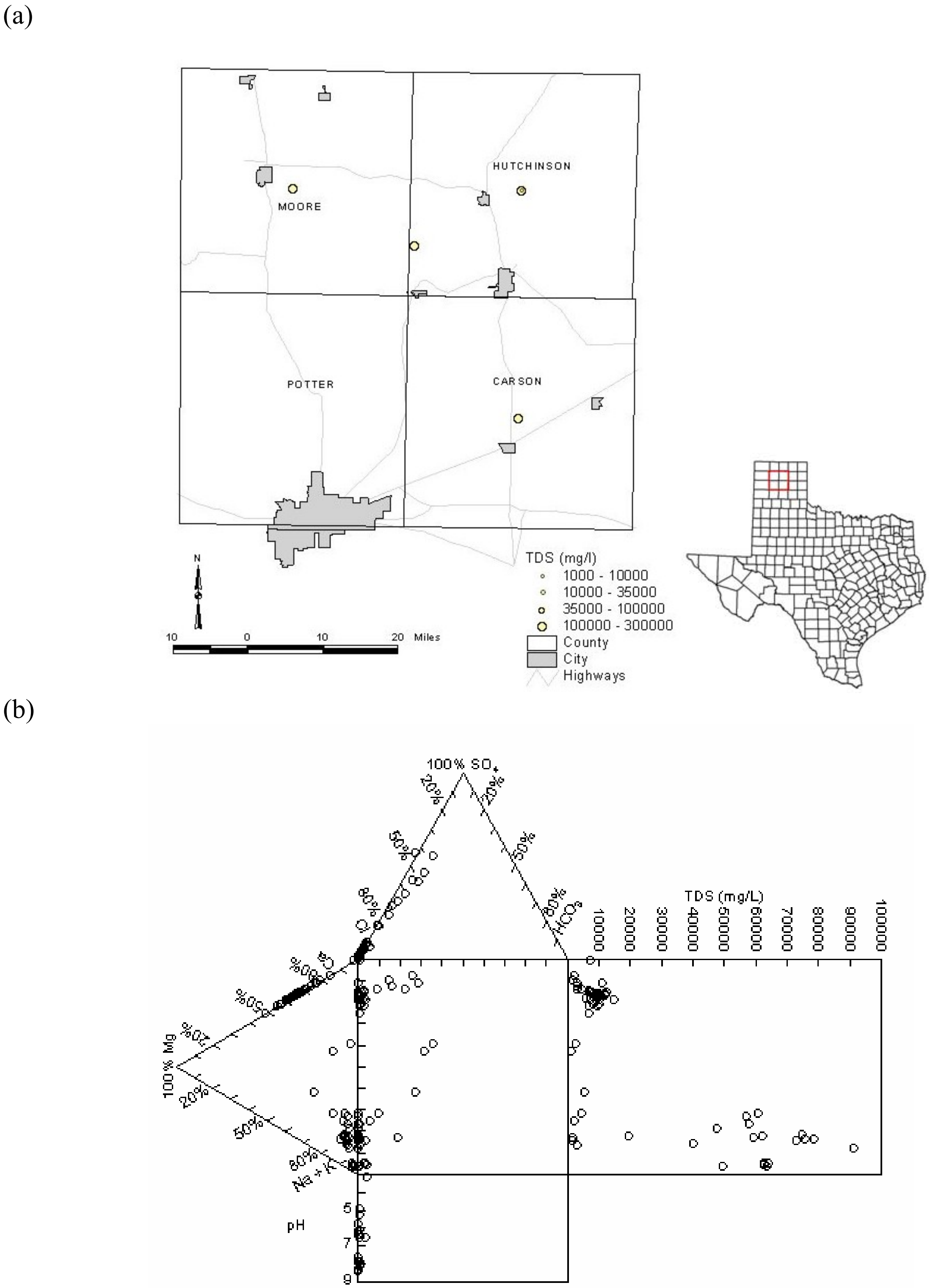


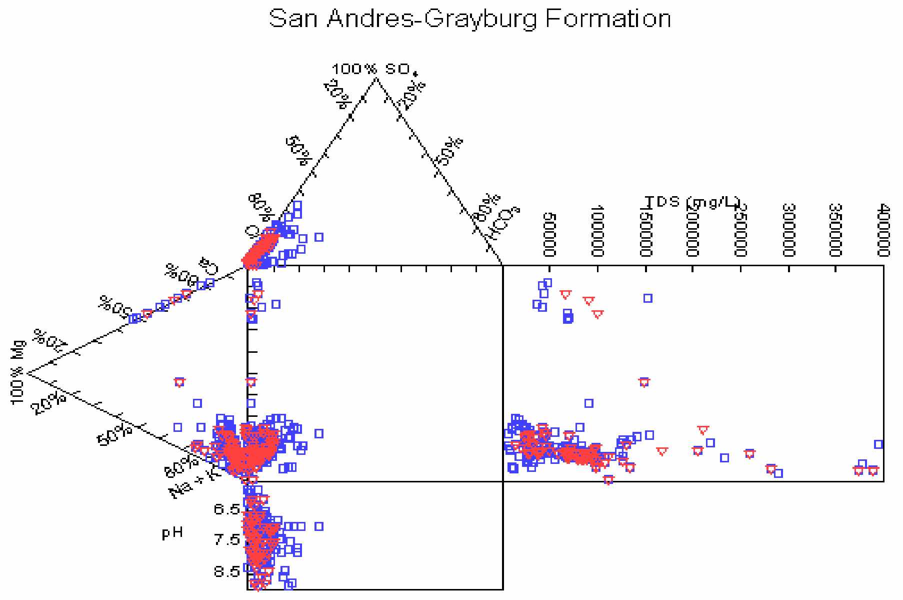
Figure 5-33. (a) Spatial distribution of TDS of formation water samples with known locations and (b) Durov plot of formation water from the Anadarko Basin.

### 5.4.2 Permian Basin

We used data from Dutton and Orr (1986) and Bein and Dutton (1993) to characterize formation waters from the San Andres Formation in the Permian Basin. These data included chemical analyses of more than 160 formation-water samples from San Andres oil fields and included data from the northern shelf of the Midland Basin. To extend these data farther south along the Central Basin Platform, we also purchased data from IHS Energy Group. We complemented the data asset with relevant samples from the USGS database. IHS Energy Group and USGS data sets appear to belong to the same population (Figure 5-34). TDS varies from 10,000 mg/l (sample likely contaminated and diluted by condensed water) to almost 400,000 mg/l. The average TDS is 82,000 mg/l. Values for recorded pH vary between 6 and 9. The formation waters analyzed for this study mainly consists of sodium-chloride type water. It is well known that the San Andres Formation is $H_2S$-rich. However, none of the analyses used in this study report $H_2S$ concentrations, casting doubt on the accuracy of the analyses for pH and other volatiles.

### 5.4.3 East Texas Basin

We used data from Kreitler and others (1987) to characterize formation waters from the East Texas Basin. Kreitler and others (1987) lists data by well in various oil fields but lacks locational



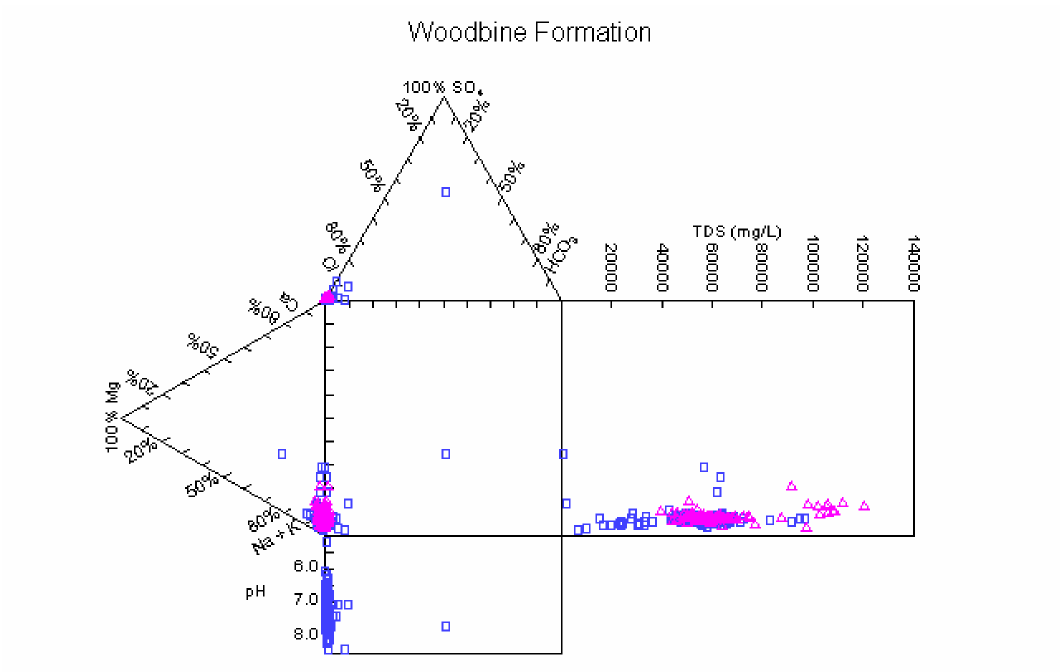
(squares = USGS data; triangles = IHS data)

Figure 5-34. Durov plot of samples from the San Andres-Grayburg Formation of the Permian Basin.

information on the wells. We acquired locations for 47 fields from www.drillinginfo.com available under license to the Bureau of Economic Geology. These 47 fields correspond to chemical-composition data for 131 samples. We complemented the dataset with information from the USGS database. The Kreitler and others (1987) and USGS datasets appear to be from the same population (Figure 5.35), although data from Kreitler and others (1987) have consistently higher TDS despite a commingled spatial origin. TDS varies from less than 10,000 mg/l to almost 120,000 mg/l with an average of 57,000 mg/l. The formation waters mainly consist of sodium-chloride water, and their pH varies from 6 to 8.

### 5.4.4 Fort Worth Basin

We purchased most of the data from the IHS Energy Group. Most of the formation waters we analyzed from the analysis area are brine in composition. Most of the formation waters are sodium-chloride type with minor concentrations of calcium, bicarbonate, and sulfate (Figure 5.36). TDS of the formation waters varies considerably in composition–from about 1,200 mg/l to about 224,000 mg/l with a mean value of 85,000 mg/l. The formation waters have pH values that lie between 2.6 to 7.9.



squares = USGS data; triangles = Kreitler ([1987) data

Figure 5-35. Durov plot of samples from the Woodbine Formation of the East Texas Basin.

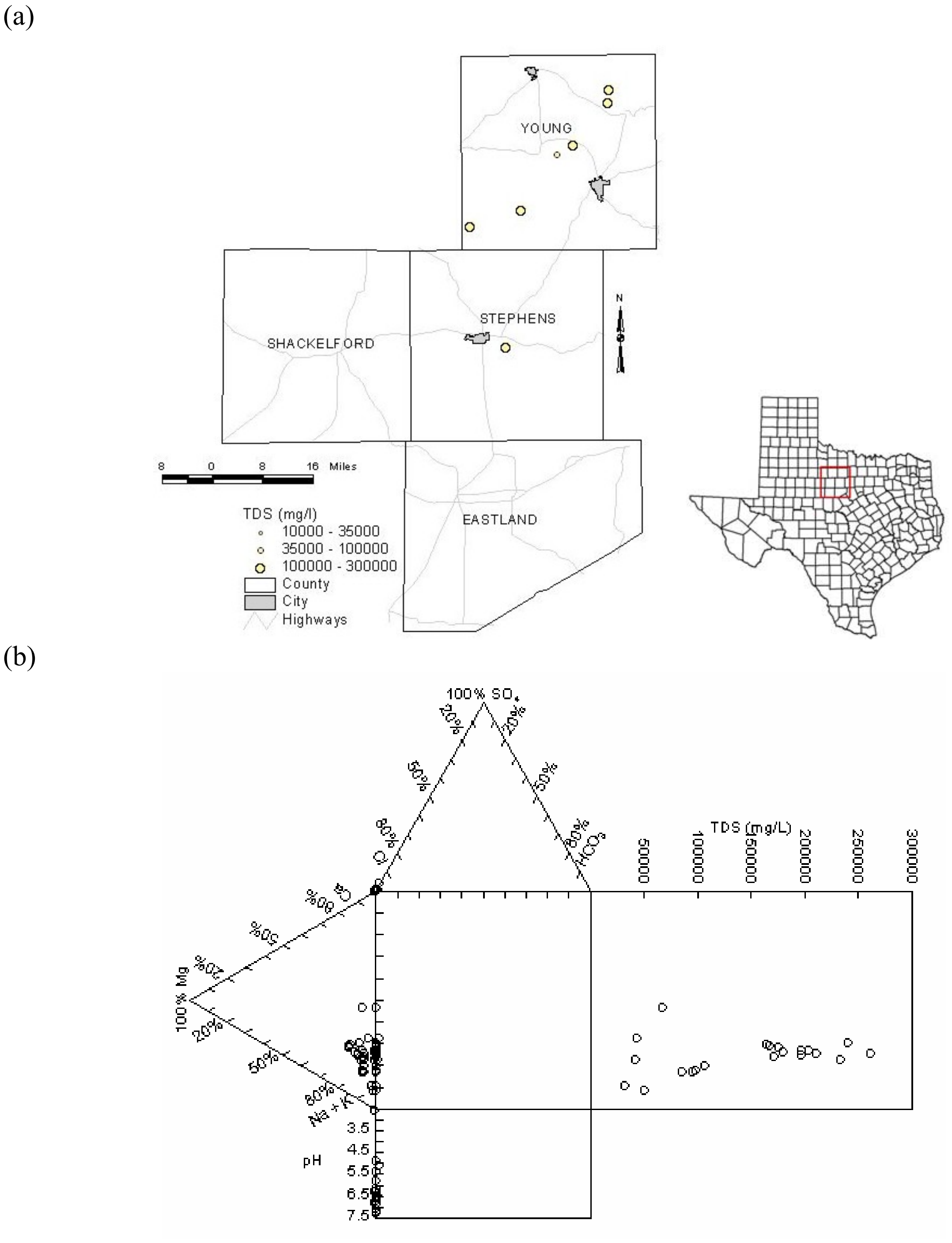


Figure 5-36. (a) Spatial distribution of TDS of formation water samples with known locations and (b) Durov plot of formation water samples from the Fort Worth Basin.

### 5.4.5 Maverick Basin

We purchased most of the data from the IHS Energy Group to characterize formation waters from the Maverick Basin. The formations waters in the Maverick Basin are mostly very saline to brine in composition (Figure 5-37). Most of the formation waters mainly consist of sodium-chloride type water with minor concentrations of calcium. TDS of the formation waters ranges from less than 1,200 mg/l to about 224,000 mg/l with a mean value of about 85,000 mg/l. The formation waters have pH values that lie between 3.7 and 8.2.

### 5.4.6 Southern Gulf Coast Basin

We used data from Kreitler and others (1988) and Kreitler and Richter (1986) to characterize formation waters from the Southern Gulf Coast Basin. These data include 186 samples from Jim Wells, Nueces, Kleberg, and San Patricio counties and additional data for the Frio Formation in other surrounding counties for statistical comparison. We complemented the dataset with information from the USGS database. Morton and Land (1987) did an extensive study on the chemical variations of Frio brines along the Texas Gulf Coast. Our analysis (Figure 5-38) and theirs shows variability in the chemical composition of the brines, although the formation waters are dominantly sodium chloride with a strong calcium and bicarbonate component. TDS varies from approximately 10,000 mg/l to almost 250,000 mg/l with an average of 51,000 mg/l. Values of pH range from 5 to more than 9.

## *5.5 Aquifers and Brackish Groundwater Sources*

We downloaded relevant brackish groundwater composition information from the TWDB online Groundwater Database with the guidance of the brackish groundwater report by LBG-Guyton Associates (2003). We checked the internal consistency of the water analyses according to the guidelines outlined in Appendix 2. As a general rule, ground water TDS increases with depth and distance from the recharge areas as observed on the maps of major and minor aquifers in Texas (Ashworth and Hopkins, 1995). Residence time increases along flowpaths and allows for the initially fresh recharging water to dissolve more solutes. However, groundwater composition can be and generally is considerably more complex with mixing of water of different sources, including deep brines. Brackish groundwaters are also typically found in the confined section of the aquifer. Man-made or natural (for example, halite outcrops or subcrops) surface contamination could also occur as observed along the Canadian and Red rivers. Typical ion compositions reported in chemical analyses are for $Ca^{2+}$, $Mg^{2+}$, $Na^{+}$, $Cl^{-}$ $HCO_3^{-}$, and $SO_4^{2-}$. The cation $K^{+}$ is sometimes reported either as Na + K or independently. Other cations such as $Fe^{2+}$, $Ba^{+}$, and $Sr^{2+}$ are also sometimes reported, especially when they might cause water quality problems. For the most part, the feed waters are typically undersaturated relative to the scale-forming minerals such as calcite, gypsum, barite, and silica (Table 5-5).

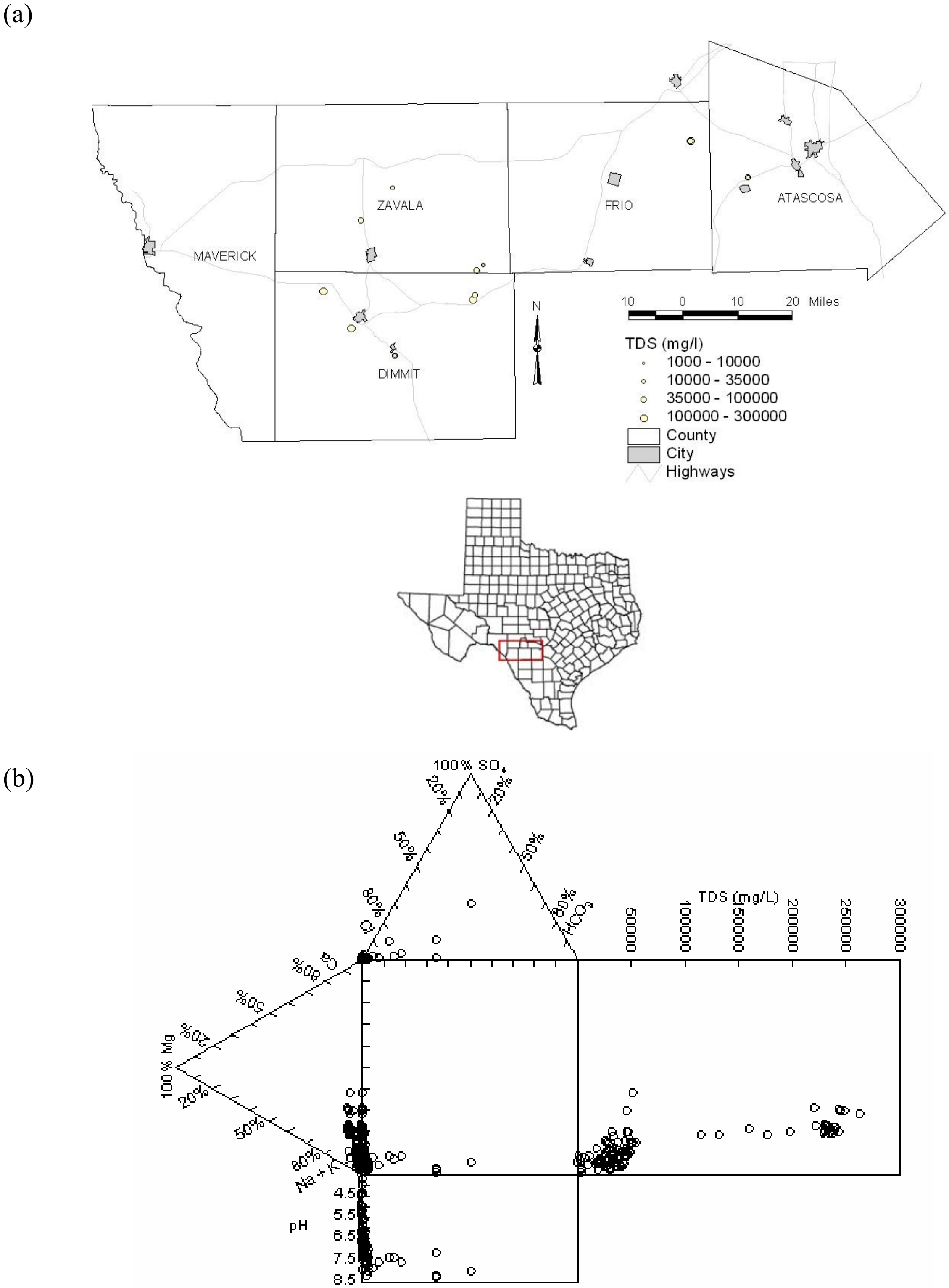
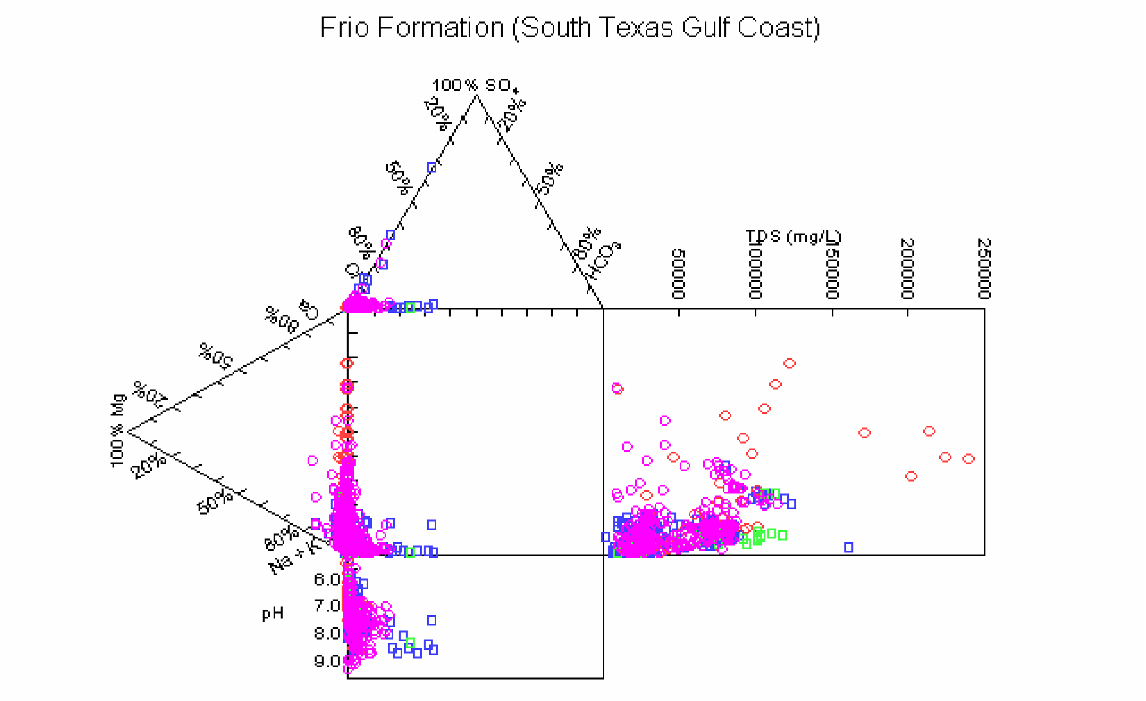


Figure 5-37. (a) Spatial distribution of TDS of formation water samples with known locations and (b) Durov plot of formation water samples from the Maverick Basin.



Southern Gulf Coast Basin (Frio Formation) (blue squares = USGS data; orange diamonds = Kreitler et al., 1988; green squares =; Kreitler et al., 1988; pink circles = Kreitler and Richter, 1986)

Figure 5-38. Durov plot of samples from the Frio Formation of the Southern Gulf Coast Basin.

Table 5-5. Saturation indices of scale-forming minerals in feed waters.

| | | Calcite SI | Gypsum SI | Barite SI | Silica SI |
|---|---|---|---|---|---|
| **Anadarko Basin** | | | | | |
| Raw feed water | Nb | 57 | 57 | 9 | 55 |
| | 5th | -0.84 | -1.91 | 0.15 | -0.95 |
| | Med | -0.49 | -0.96 | 0.31 | -0.63 |
| | 95th | -0.05 | -0.01 | 0.86 | -0.36 |
| **Permian Basin** | | | | | |
| Raw feed water | Nb | 297 | 297 | 35 | 262 |
| | 5th | -1.02 | -1.81 | -0.23 | -1.13 |
| | Med | -0.28 | -0.98 | -0.03 | -0.71 |
| | 95th | 0.07 | -0.23 | 0.40 | -0.20 |
| **East Texas Basin** | | | | | |
| Raw feed water | Nb | 52 | 43 | N/A | 39 |
| | 5th | -1.57 | -4.49 | N/A | -1.04 |
| | Med | -1.18 | -3.32 | N/A | -0.94 |
| | 95th | 0.04 | -0.15 | N/A | -0.32 |
| **Fort Worth Basin** | | | | | |
| Raw feed water | Nb | 460 | 457 | 3 | 427 |
| | 5th | -1.34 | -3.21 | -3.21 | -0.31 |
| | Med | -0.06 | -1.52 | -1.52 | -0.11 |
| | 95th | 0.35 | -0.69 | -0.69 | -0.02 |
| **Maverick Basin** | | | | | |
| Raw feed water | Nb | 148 | 148 | N/A | 144 |
| | 5th | -1.45 | -3.31 | N/A | -1.07 |
| | Med | -0.23 | -1.32 | N/A | -0.83 |
| | 95th | 0.30 | -0.47 | N/A | -0.42 |
| **South Texas Fields** | | | | | |
| Raw feed water | Nb | 525 | 525 | 69 | 462 |
| | 5th | -1.31 | -3.06 | -0.21 | -1.00 |
| | Med | -0.69 | -1.87 | -0.05 | -0.79 |
| | 95th | 0.07 | -1.01 | 0.34 | -0.17 |

Nb = number of data points; 5th = 5th percentile; Med = median; 95th = 95th percentile.

Table 5-6. Major and trace element compositions of groundwater in the Anadarko Basin analysis area.

| Analyses Areas | Parameters | Major Elements (mg/l) | | | | | | | | Trace Elements (ug/l) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | TDS | Ca | Mg | Na | HCO3 | SO4 | Cl | SiO2 | Ba | Fe | Cu |
| Anadarko Basin | | | | | | | | | | | | |
| Alluvium Aquifer | Average | 1553 | 235 | 95 | 131 | 232 | 297 | 527 | 30 | NA | NA | NA |
| | Standard Deviation | 2563 | 394 | 188 | 235 | 29 | 622 | 1115 | 12 | NA | NA | NA |
| | Maximum | 6136 | 940 | 432 | 550 | 267 | 1410 | 2520 | 51 | NA | NA | NA |
| | Minimum | 305 | 52 | 5 | 12 | 192 | 12 | 2 | 22 | NA | NA | NA |
| Ogallala Aquifer | Average | 1492 | 142 | 45 | 271 | 225 | 295 | 403 | 25 | 110 | 33 | 110 |
| | Standard Deviation | 473 | 106 | 37 | 136 | 47 | 254 | 352 | 3 | 54 | 38 | 54 |
| | Maximum | 2816 | 360 | 188 | 600 | 301 | 1090 | 1540 | 35 | 352 | 430 | 352 |
| | Minimum | 1013 | 24 | 13 | 72 | 89 | 9 | 27 | 19 | 25 | 0 | 25 |
| Ogallala and Dockum Aquifer | Average | 464 | 28 | 46 | 25 | 1 | 42 | 24 | 28 | 69 | 146 | 69 |
| | Standard Deviation | 114 | 5 | 15 | 9 | 0 | 22 | 64 | 5 | 26 | 208 | 26 |
| | Maximum | 1304 | 43 | 140 | 83 | 2 | 180 | 580 | 43 | 137 | 673 | 137 |
| | Minimum | 329 | 17 | 23 | 7 | 1 | 6 | 5 | 17 | 37 | 0 | 37 |
| Dockum Aquifer | Average | 1912 | 142 | 75 | 355 | 285 | 637 | 357 | 35 | 59 | 196 | 101 |
| | Standard Deviation | 2246 | 176 | 105 | 517 | 106 | 1059 | 565 | 21 | 28 | 369 | 109 |
| | Maximum | 8224 | 566 | 525 | 1880 | 473 | 3840 | 1879 | 83 | 124 | 1363 | 352 |
| | Minimum | 442 | 8 | 5 | 17 | 55 | 24 | 16 | 8 | 15 | 4 | 25 |

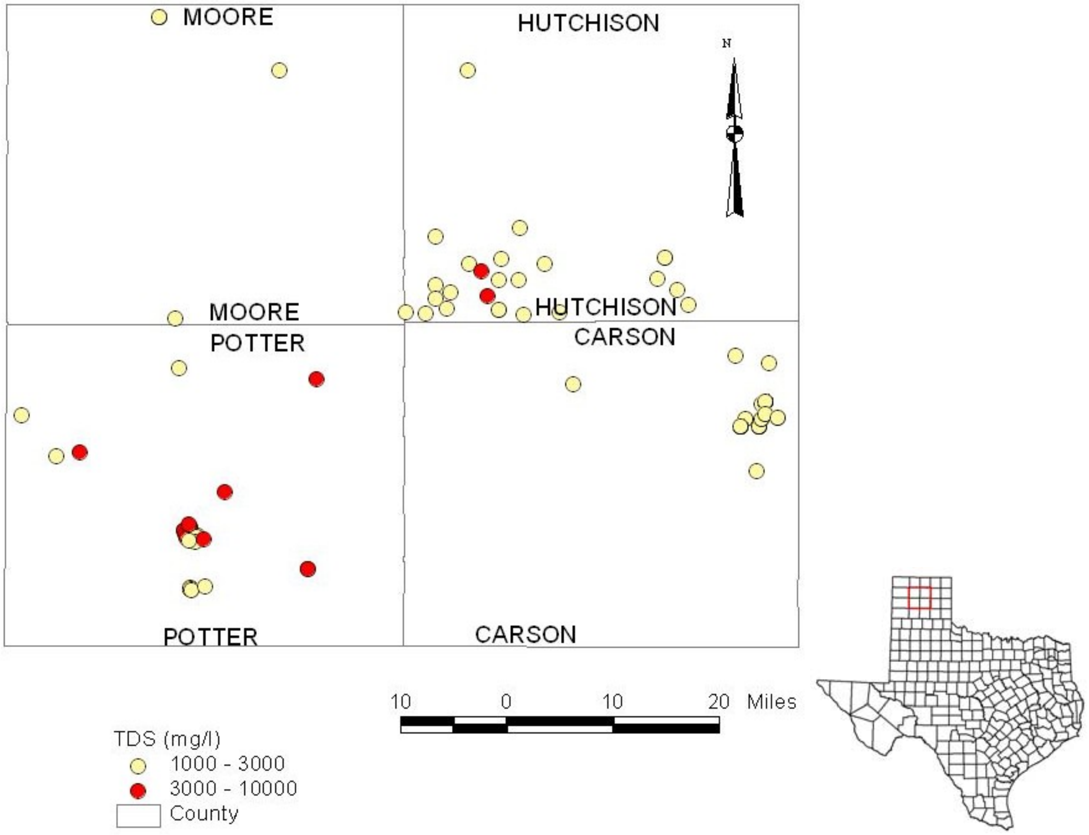
### 5.5.1 Anadarko Basin

The main aquifer in the analysis area of the Anadarko Basin is the Ogallala aquifer, the major water-bearing unit of the High Plains of Texas. The Ogallala aquifer is composed of sand, gravel, clay, and silt deposits (Ashworth and Hopkins, 1995). Groundwater moves slowly southeastward to the caprock edge or eastern escarpment of the High Plains. Coarse-grained sediments in the channels have the greatest permeability and supply water to wells of up to 2,000 gpm (Ashworth and Hopkins, 1995). Average yield of the Ogallala aquifer is 500 gpm. Chemical quality of the water in the aquifer is generally fresh; however, both chloride and total dissolved solids increase from north to south.

The Dockum aquifer also occupies the western portion of the analysis area and underlies much of the Ogallala aquifer. The primary water-bearing zone in the formation, the Santa Rosa, consists of up to 700 feet of sand and conglomerate interbedded with layers of silt and shale. Concentrations of dissolved solids in the groundwater range from less than 1,000 mg/l near the eastern outcrop to more than 20,000 mg/l in the deeper parts of the aquifer to the west (Ashworth and Hopkins, 1995).

Brackish groundwater occurs in the analysis area of the Anadarko Basin (Figure 5-39a). The alluvium and the Dockum aquifers are more saline than the Ogallala aquifer (Table 5-6). Concentrations of chloride are higher than concentrations of sodium and sulfate in these groundwaters. Most of the brackish groundwater in the analysis area has Ca-$HCO_3$ to Na-Cl chemical composition (Figure 5-39c). TDS of the brackish waters range from 1,000 mg/l to about 7,000 mg/l. The pH of the waters ranges from 7 to 9. Brackish groundwater is readily available at shallow to moderate depths in this area suggesting no additional cost of pumping (Figure 5-39b). Trace concentrations of $Ba^{2+}$, $F^{-1}$, $Fe^{2+}$, and $SiO_2$ occur in this groundwater with potential for scale formation during desalination unless appropriately treated.

(a)



(b)

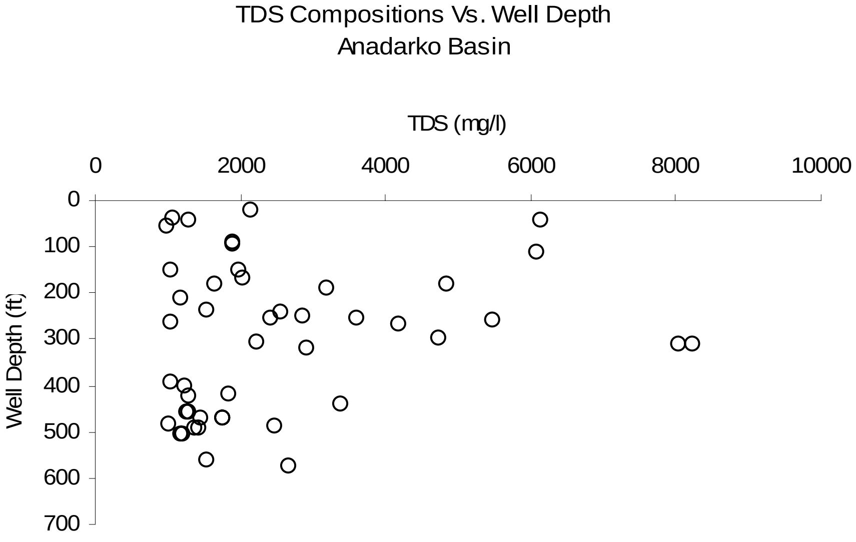


Figure 5-39. (a) Location of brackish water samples with TDS concentrations, (b) TDS versus depth, and (c) Piper and Durov plots of feed water for the Anadarko Basin.

(c)

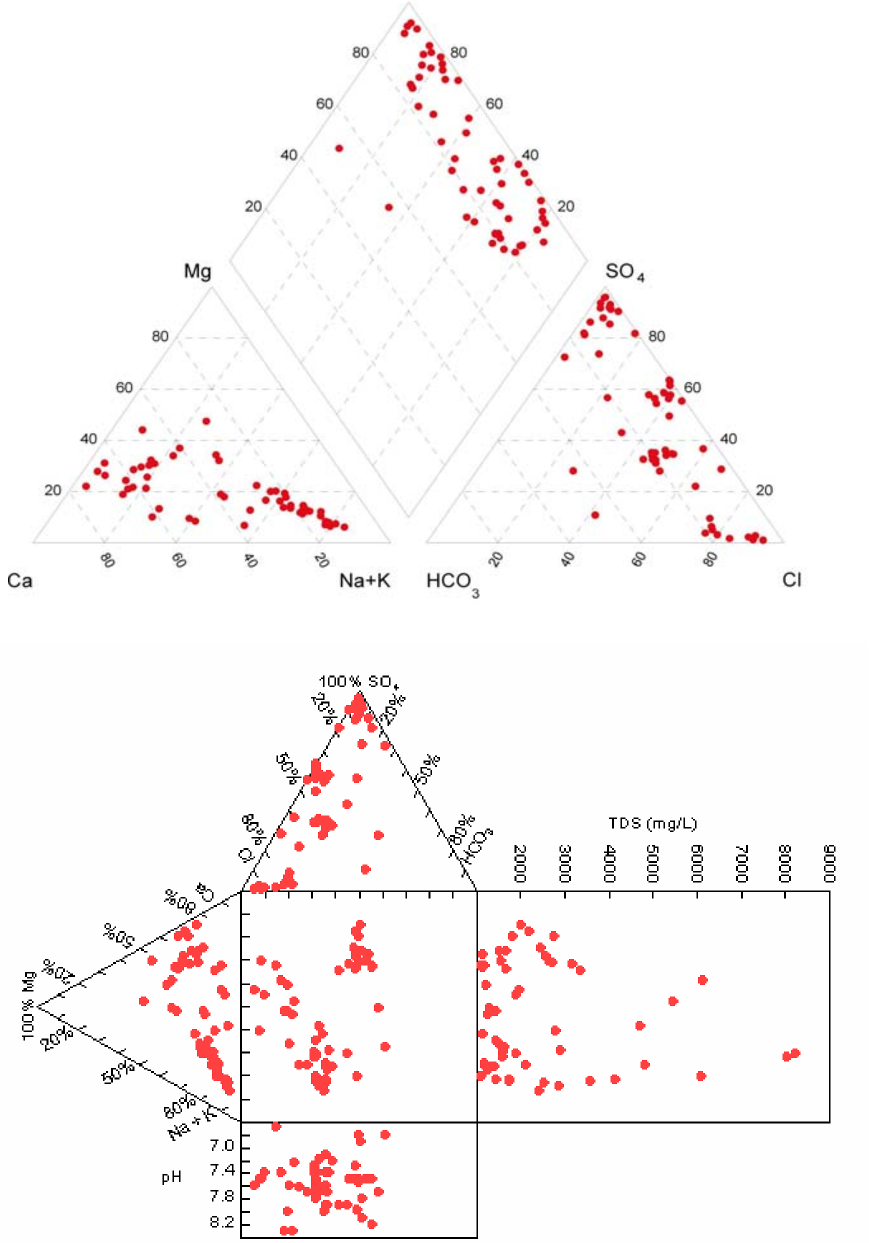


Figure 5-39. Continued.

### 5.5.2 Permian Basin

Aquifers covering all or part of the Permian Basin analysis area are the Ogallala aquifer, the Dockum aquifer, and, to a lesser extent, the Rustler aquifer. The Rustler aquifer underlies the Dockum aquifer and consists mainly of limestone, dolomite, and gypsum beds. Salinity information on the Rustler aquifer is scarce, but its salinity is likely the same or higher than that of the Dockum aquifer. Only one sample of the Rustler aquifer is included in the analysis (Figure 5.40a). We offset the low sample density in the analysis area by adding samples from neighboring counties. TDS values vary from 1,000 to 10,000 mg/l but cluster between 1,000 and 4,000 mg/l (Figure 5.40b). The samples show a wide variability in chemical composition.

### 5.5.3 East Texas Basin

The East Texas Basin includes several aquifers from the Claiborne and Wilcox groups: the Sparta, Queen City, Nacatoch, and Carrizo-Wilcox aquifers. The main Cretaceous water-bearing formations are, starting from the youngest: the Nacatoch Formation, the Sub-Clarksville Formation corresponding to the Eagle Ford Formation; the Woodbine Formation; and the Paluxy Formation, which laterally transitions into the Edwards Formation.

The Queen City aquifer does not seem to have a salt water disposal problem, probably because recharge rates are high. The Nacatoch aquifer is a minor aquifer in Texas. The Mexia-Talco Fault Zone interrupts the normal down-dip flow of groundwater from the outcrop area. The segment underlying the East Texas basin is beyond the fault zone and is likely saline (>10,000 mg/l), although little data have been reported (LBG-Guyton Associates, 2003).

The Carrizo-Wilcox aquifer is a major aquifer in Texas whose water availability has been recently described through construction of a groundwater availability model (Fryar and others, 2003). The Carrizo-Wilcox aquifer provides large volumes of fresh water but also contains abundant volume of brackish water in deeper sections (Table 5-1) within the TWDB-defined limits of usable water (<3,000 mg/l) (Figure 5-41b).

### 5.5.4 Fort Worth Basin

The Trinity aquifer is the primary aquifer in the analysis area of the Fort-Worth Basin. Formations in the Trinity Group (from youngest to oldest) are the Paluxy, Glen Rose, and Twin Mountains-Travis Peak (Ashworth and Hopkins, 1995). Where the Glen Rose Formation is thin or missing, the Paluxy and the Twin Mountains formations coalesce to form the Antlers Formation. The Antlers Formation consists of up to 900 feet of sand and gravel and is used for irrigation. The Twin-Mountains Formation is the most prolific part of the Trinity aquifer in North-Central Texas; however, the water quality is not good. Extensive development of the Trinity aquifer has occurred in the Fort Worth-Dallas region where water levels have dropped as much as 550 feet (Ashworth and Hopkins, 1995).

(a)

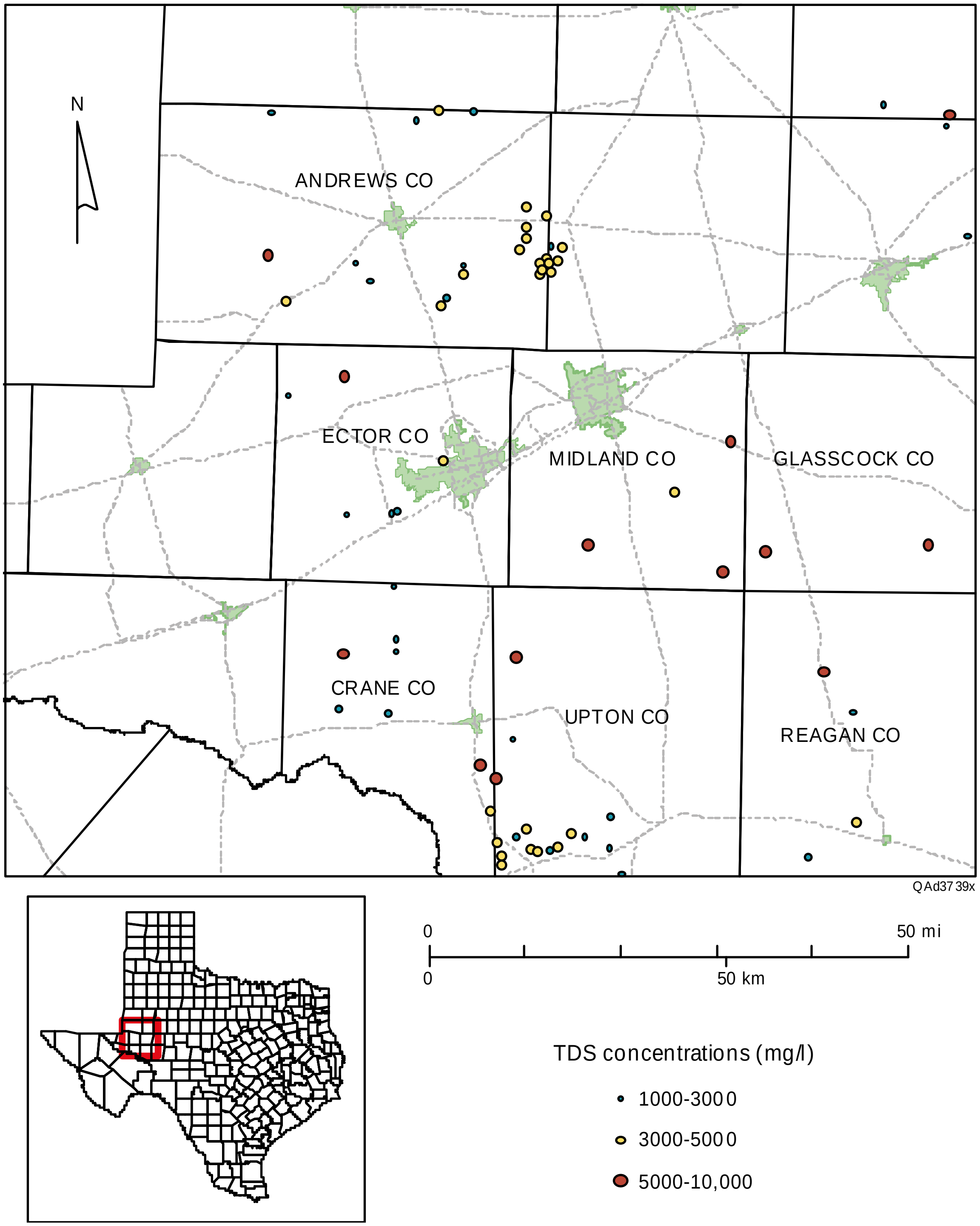
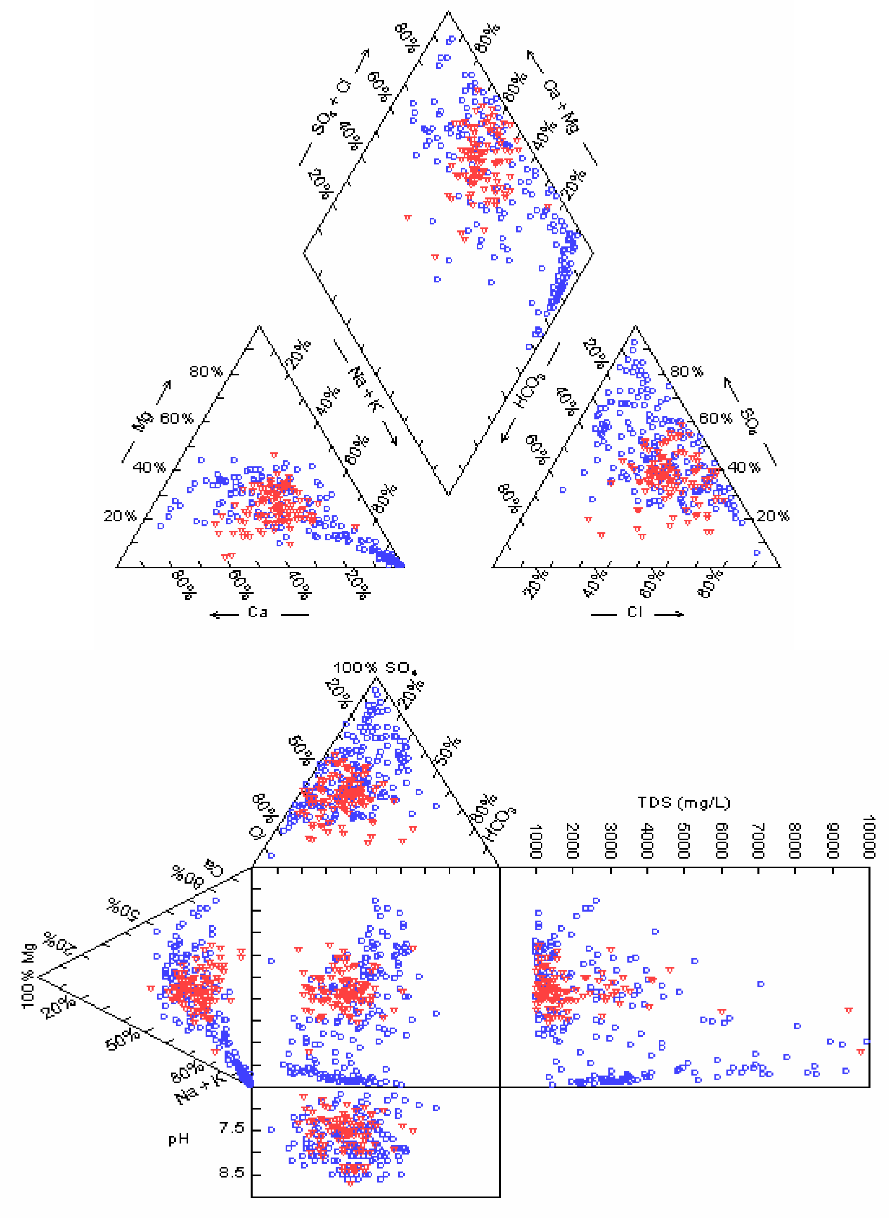


Figure 5-40. (a) Location of brackish water samples with TDS concentrations and (b) Piper and Durov plots of feed water for the Permian Basin (feed water is from the Ogallala and Dockum aquifers).

(b)



blue circles = Dockum aquifer; red triangles = Ogallala aquifer

Figure 5-40. Continued.

(a)

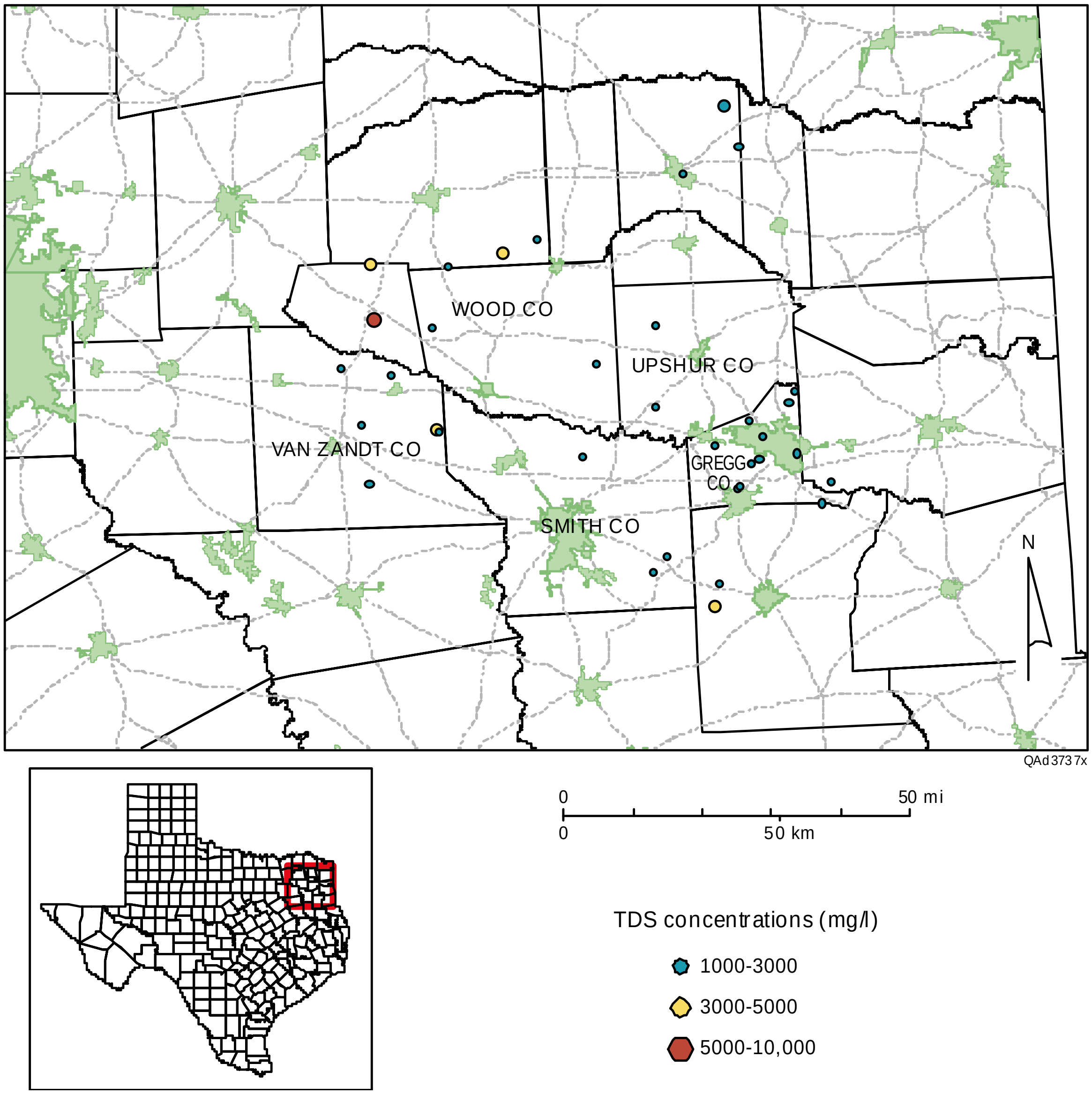


Figure 5-41. (a) Location of brackish water samples with TDS concentrations and (b) Piper and Durov plots of feed water for East Texas Basin (feed water from the Carrizo aquifer).

(b)

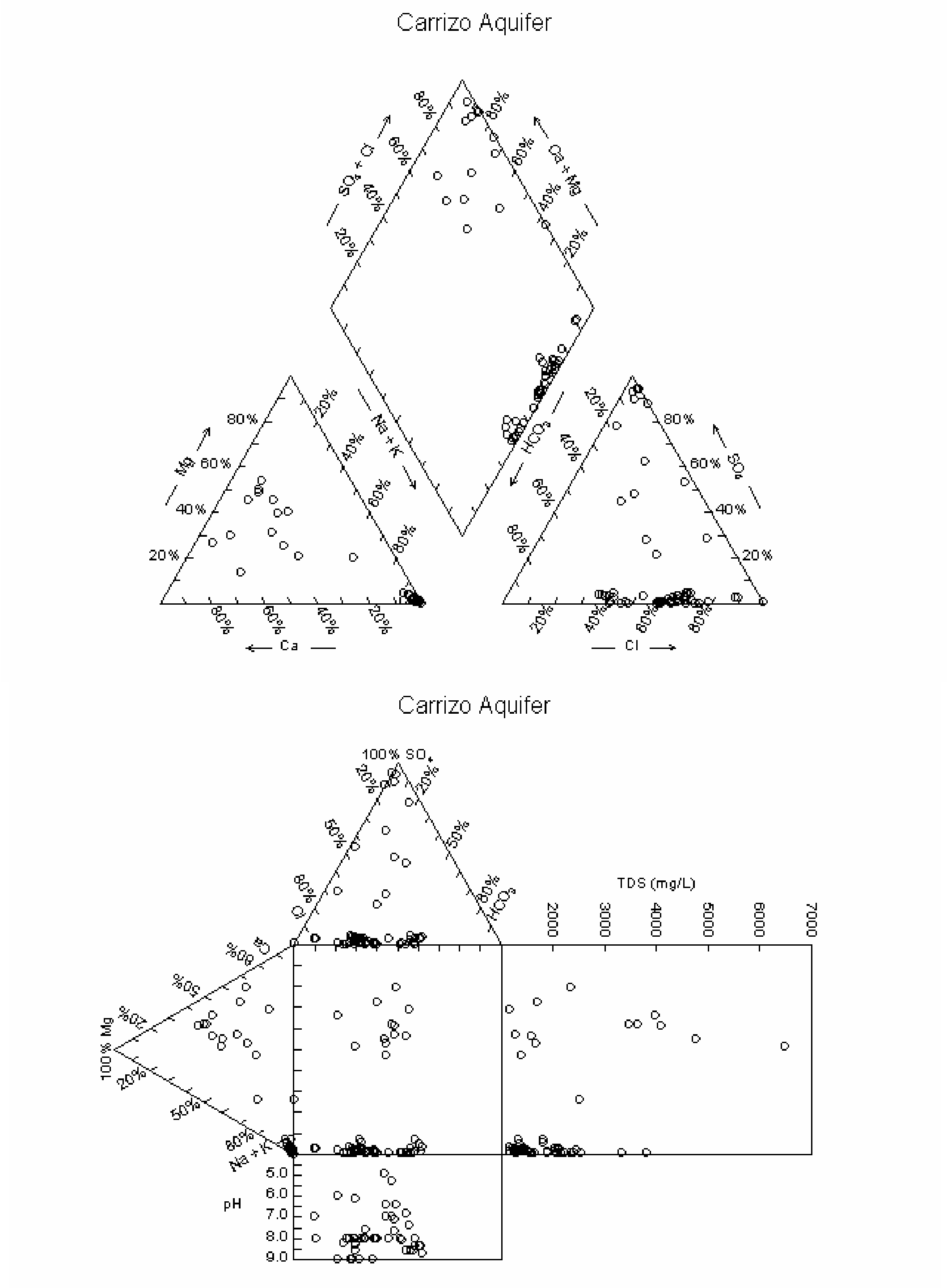


Figure 5-41.	Continued.

Brackish to slightly-saline groundwater occurs widely in the analysis area of the Fort Worth Basin (Figure 5-42a). Considerably more chloride occurs in the Trinity, Graham, and Alluvium aquifers than sodium and sulfate (Table 5-7). Groundwater in the analysis area has Ca- $HCO_3$ to Na-Cl composition (Figure 5-42c). TDS of the waters range from about 1,000 mg/l to 8,000 mg/l. Brackish groundwater is readily available at shallow to moderate depths in this area suggesting no additional cost of pumping (Figure 5-42b). Trace concentrations of $Ba^{2+}$, $F^-$, $Fe^{2+}$, and $SiO_2$ occur in this groundwater with potential for scale formation during desalination unless appropriately treated.

### 5.5.5 Maverick Basin

The main aquifer in the Maverick Basin analysis area is the southern part of the Carrizo-Wilcox aquifer. The Carrizo-Wilcox aquifer consists of fluvial-deltaic sediments of the upper Paleocene and Lower Eocene Wilcox Group and Carrizo Sand. The aquifer is bounded below by the marine clay deposits of the Midway Group and above by the Reklaw and Bigford formations that form a semi-confining unit between the Carrizo Sand and the shallower Queen City aquifer. The depositional sequences, in ascending order, are the lower Wilcox, the upper Wilcox, the Carrizo, the Queen City, the Sparta, the Yegua-Cockfield, the Jackson, and the Vicksburg-Frio formations. Each of these sequences is bounded by marine shales (Galloway and others, 1994).

Table 5-7. Major and trace element compositions of groundwater in the Fort Worth Basin analysis area.

| Analyses Areas | Parameters | Major Elements (mg/l) | | | | | | | | Trace Elements (ug/l) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fort Worth Basin | | | | | | | | | | | | |
| | | TDS | Ca | Mg | Na | $HCO_3$ | $SO_4$ | Cl | $SiO_2$ | F | Ba | Cu |
| Alluvium Aquifer | Average | 1356 | 242 | 96 | 387 | 398 | 401 | 759 | 16 | 1 | 53 | NA |
| | Standard Deviation | 959 | 149 | 88 | 287 | 114 | 359 | 630 | 4 | 0 | 31 | NA |
| | Maximum | 5308 | 655 | 497 | 1480 | 615 | 1450 | 2700 | 27 | 2 | 97 | NA |
| | Minimum | 289 | 38 | 29 | 130 | 146 | 9 | 149 | 2 | 0 | 20 | NA |
| Trinity Aquifer | Average | 2469 | 102 | 27 | 724 | 506 | 219 | 872 | 13 | 1 | 87 | NA |
| | Standard Deviation | 6159 | 140 | 34 | 2519 | 173 | 235 | 3455 | 4 | 1 | 138 | NA |
| | Maximum | 58633 | 730 | 176 | 23754 | 1057 | 1504 | 32313 | 20 | 12 | 526 | NA |
| | Minimum | 1001 | 1 | 0 | 77 | 140 | 0 | 52 | 2 | 0 | 20 | NA |
| Graham Aquifer | Average | 2052 | 139 | 37 | 578 | 431 | 310 | 754 | 13 | NA | NA | NA |
| | Standard Deviation | 1165 | 143 | 37 | 473 | 104 | 343 | 744 | 4 | NA | NA | NA |
| | Maximum | 5851 | 800 | 248 | 2210 | 752 | 1870 | 3350 | 28 | NA | NA | NA |
| | Minimum | 1008 | 5 | 1 | 55 | 128 | 0 | 57 | 7 | NA | NA | NA |

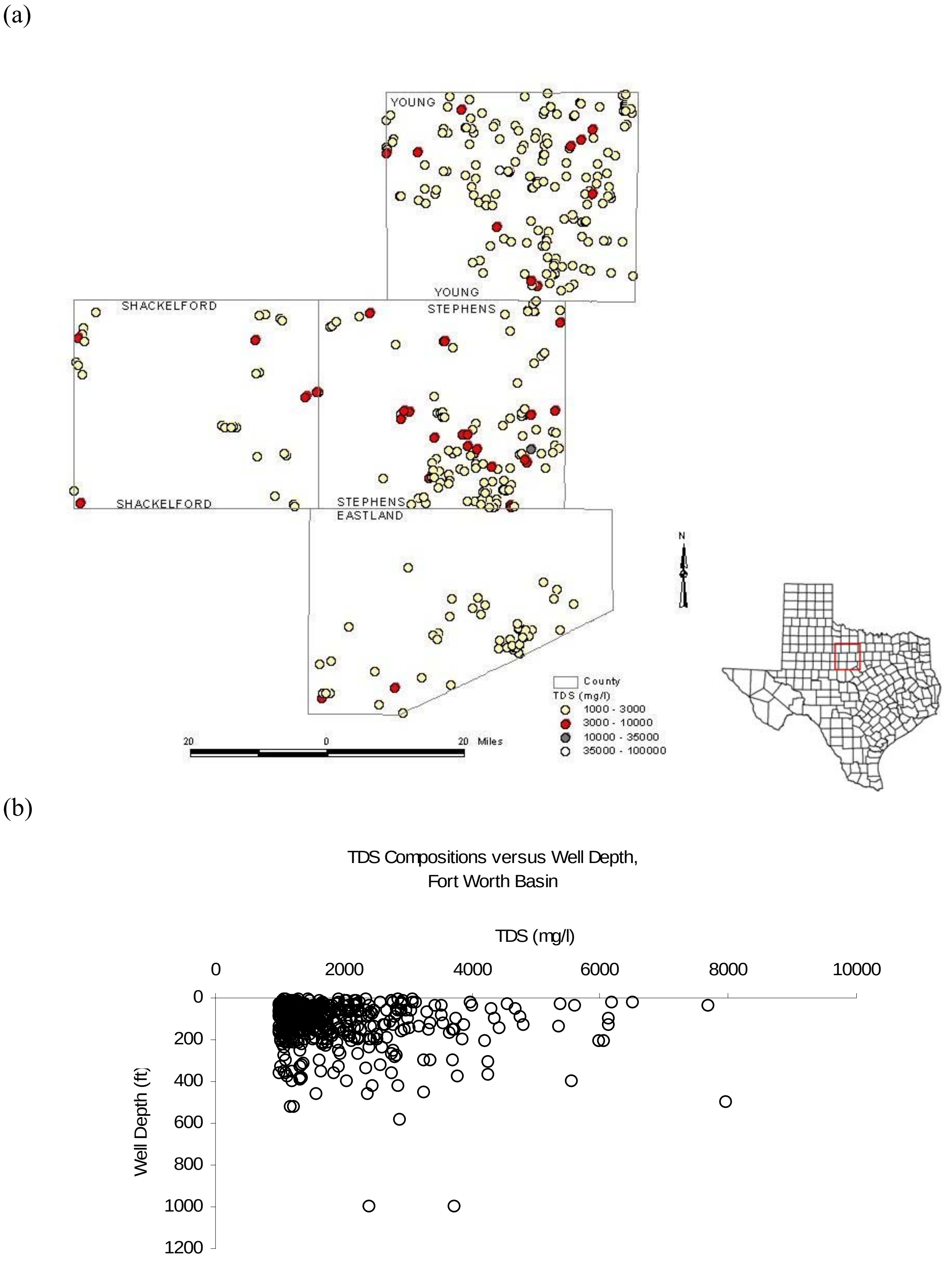


Figure 5-42. (a) Location of brackish water samples with TDS concentrations, (b) TDS versus depth, and (c) Piper and Durov plots of feed water for the Fort Worth Basin.

(c)

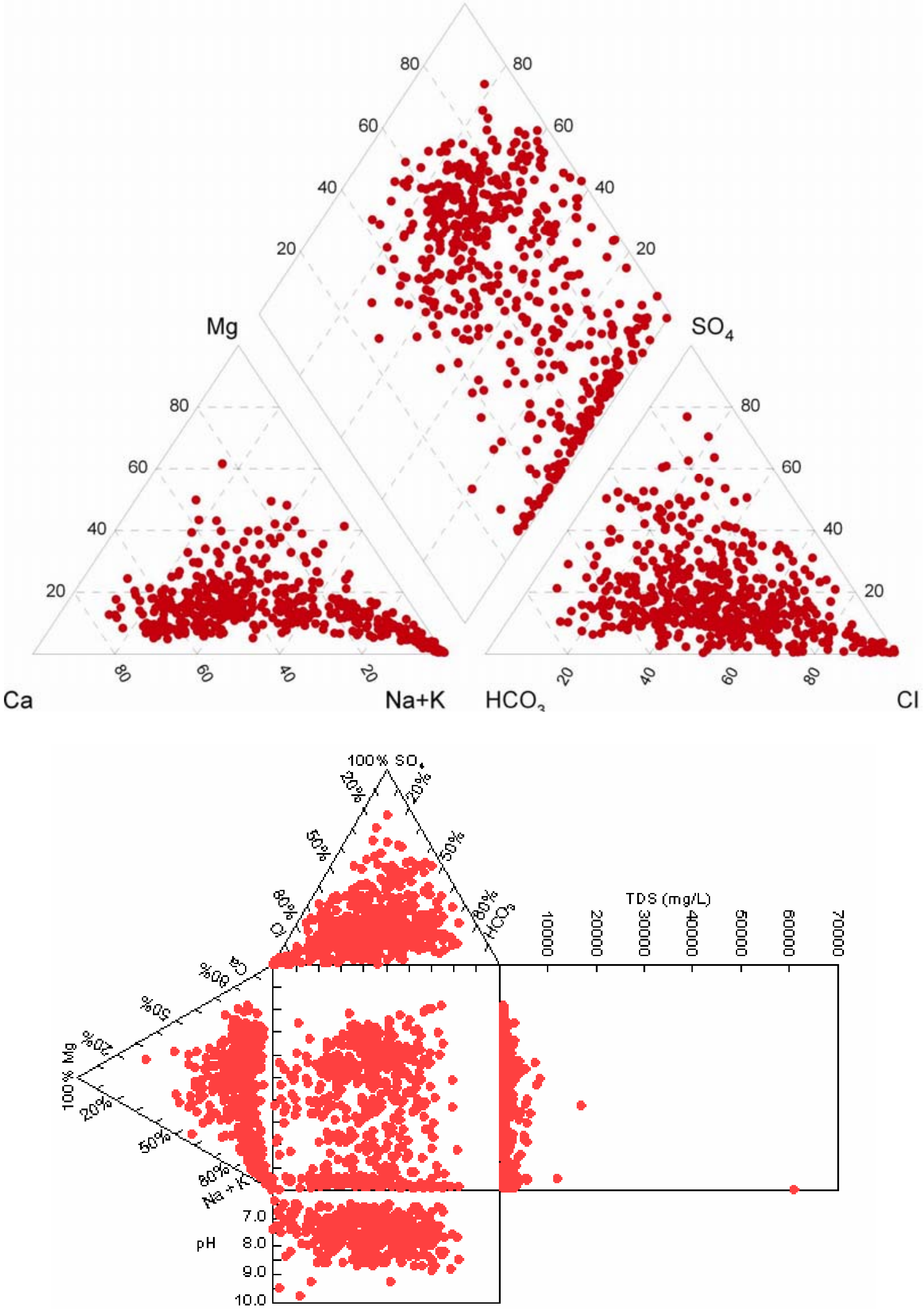


Figure 5-42. Continued.

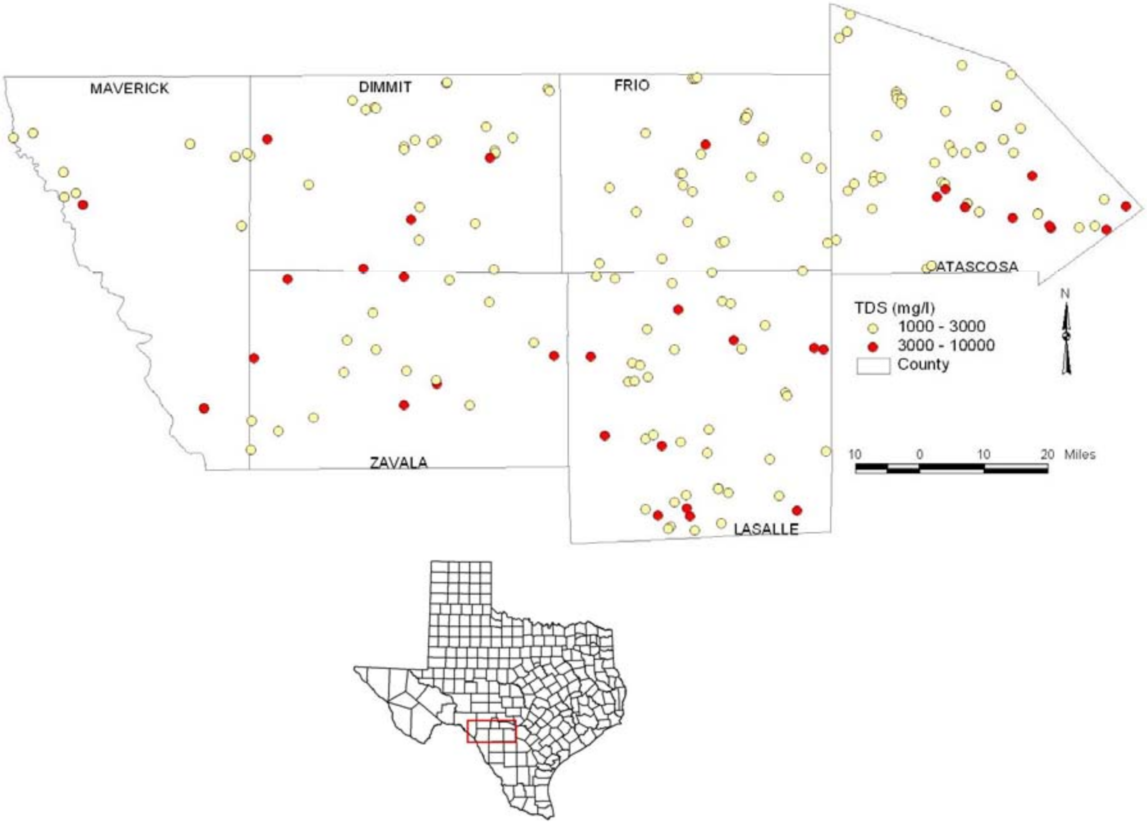
Brackish groundwater in the Carrizo-Wilcox, Queen City, Sparta, and alluvium aquifers in the analysis area are moderately saline in composition (Figure 5-43a). TDS range from 1,000 mg/l to about 7,000 mg/l with nearly equal concentrations of sodium (182 mg/l to 294 mg/l) and chloride (180 mg/l to 354 mg/l). Sulfate concentrations range from 122 mg/l to 183 mg/l (Table 5-8). Groundwaters in the analysis area have Ca-HCO$_3$ to Na-Cl composition (Figure 5.43c). Brackish groundwater is readily available at shallow to moderate depths in this area suggesting no additional cost of pumping (Figure 5.43b).

Trace concentrations of Ba$^{2+}$, F$^-$, Fe$^{2+}$, Cu$^{2+}$, and SiO$_2$ occur in the groundwater with potential for scale formation during desalination unless appropriately treated. Radium, a naturally occurring radionuclide, also occurs in the groundwater in the analysis area. Nearly 20 percent of the groundwater exceeds the primary MCL of 5 picoCuries per liter (pCi/L) for drinking water. Alpha particles exceed the MCL in seven percent of the wells (Deeds and others, 2003). Therefore, if these radionuclides are not removed by treatment prior to desalination, their concentration will likely increase in the concentrate which can pose additional disposal problems.

Table 5-8. Major and trace element compositions of groundwater in the Maverick Basin analysis area.

| Analyses Areas | Parameters | Major Elements (mg/l) | | | | | | | | Trace Elements (ug/l) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Maverick Basin** | | **TDS** | **Ca** | **Mg** | **Na** | **HCO3** | **SO4** | **Cl** | **SiO2** | **Ba** | **F (mg/l)** | **Fe** | **Cu** |
| **Alluvium aquifer** | Average | 1233 | 153 | 28 | 178 | 289 | 264 | 528 | 42 | 68 | 1 | 21 | 15 |
| | Standard Deviation | 781 | 67 | 17 | 209 | 76 | 221 | 357 | 15 | 76 | 0 | 16 | 9 |
| | Maximum | 3295 | 277 | 58 | 746 | 411 | 690 | 1159 | 57 | 327 | 1 | 80 | 42 |
| | Minimum | 439 | 74 | 6 | 19 | 207 | 88 | 202 | 22 | 19 | 0 | 10 | 3 |
| **Carrizo aquifer** | Average | 2027 | 86 | 21 | 538 | 543 | 250 | 557 | 20 | 92 | 0 | 374 | 9 |
| | Standard Deviation | 1044 | 118 | 28 | 417 | 363 | 204 | 528 | 7 | 69 | 1 | 682 | 10 |
| | Maximum | 5639 | 550 | 137 | 2040 | 1617 | 831 | 2609 | 36 | 802 | 4 | 6860 | 92 |
| | Minimum | 1034 | 2 | 0 | 64 | 43 | 1 | 76 | 2 | 0 | 0 | 0 | 0 |
| **Queen City aquifer** | Average | 1494 | 110 | 28 | 311 | 360 | 232 | 411 | 20 | 97 | 1 | 854 | 9 |
| | Standard Deviation | 900 | 170 | 23 | 145 | 98 | 193 | 449 | 13 | 160 | 1 | 1269 | 10 |
| | Maximum | 4285 | 713 | 81 | 565 | 505 | 872 | 1910 | 68 | 500 | 2 | 5330 | 35 |
| | Minimum | 437 | 4 | 3 | 29 | 189 | 34 | 12 | 10 | 15 | 0 | 15 | 1 |
| **Carrizo-Wilcox aquifer** | Average | 2017 | 145 | 33 | 466 | 352 | 333 | 645 | 22 | 54 | 0 | 214 | 12 |
| | Standard Deviation | 1322 | 152 | 29 | 453 | 151 | 315 | 598 | 13 | 32 | 1 | 298 | 20 |
| | Maximum | 6663 | 762 | 137 | 1933 | 976 | 1779 | 2609 | 68 | 105 | 1 | 920 | 57 |
| | Minimum | 1003 | 2 | 1 | 19 | 43 | 39 | 79 | 2 | 16 | 0 | 10 | 1 |
| **Wilcox aquifer** | Average | 2445 | 125 | 28 | 705 | 385 | 556 | 800 | 24 | 72 | 1 | 214 | 24 |
| | Standard Deviation | 2234 | 131 | 39 | 762 | 188 | 687 | 977 | 11 | 48 | 1 | 298 | 65 |
| | Maximum | 6663 | 353 | 121 | 1840 | 744 | 1779 | 2435 | 51 | 147 | 2 | 920 | 229 |
| | Minimum | 437 | 2 | 1 | 87 | 99 | 53 | 70 | 15 | 8 | 0 | 10 | 2 |

(a)



(b)

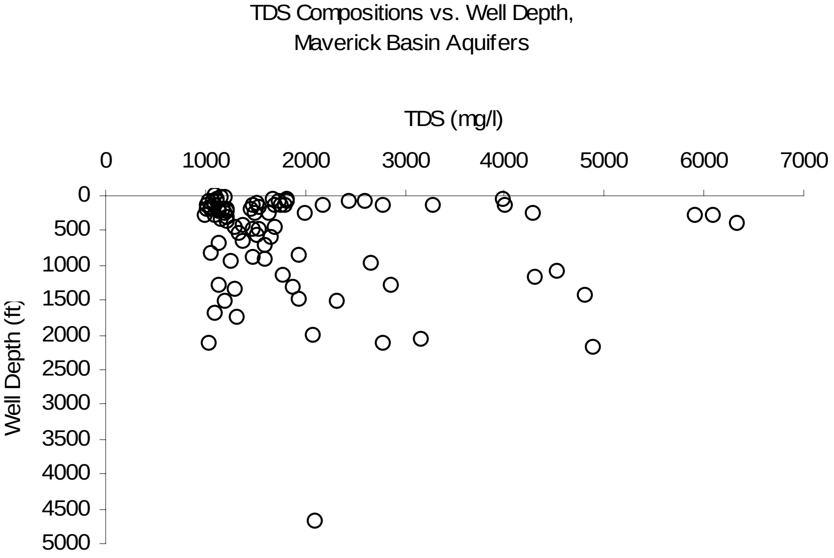


Figure 5-43. (a) Location of brackish water samples with TDS concentrations, (b) TDS versus depth, and (c) Piper and Durov plots of feed water for the Maverick Basin (feed water from the Carrizo-Wilcox aquifer).

(c)

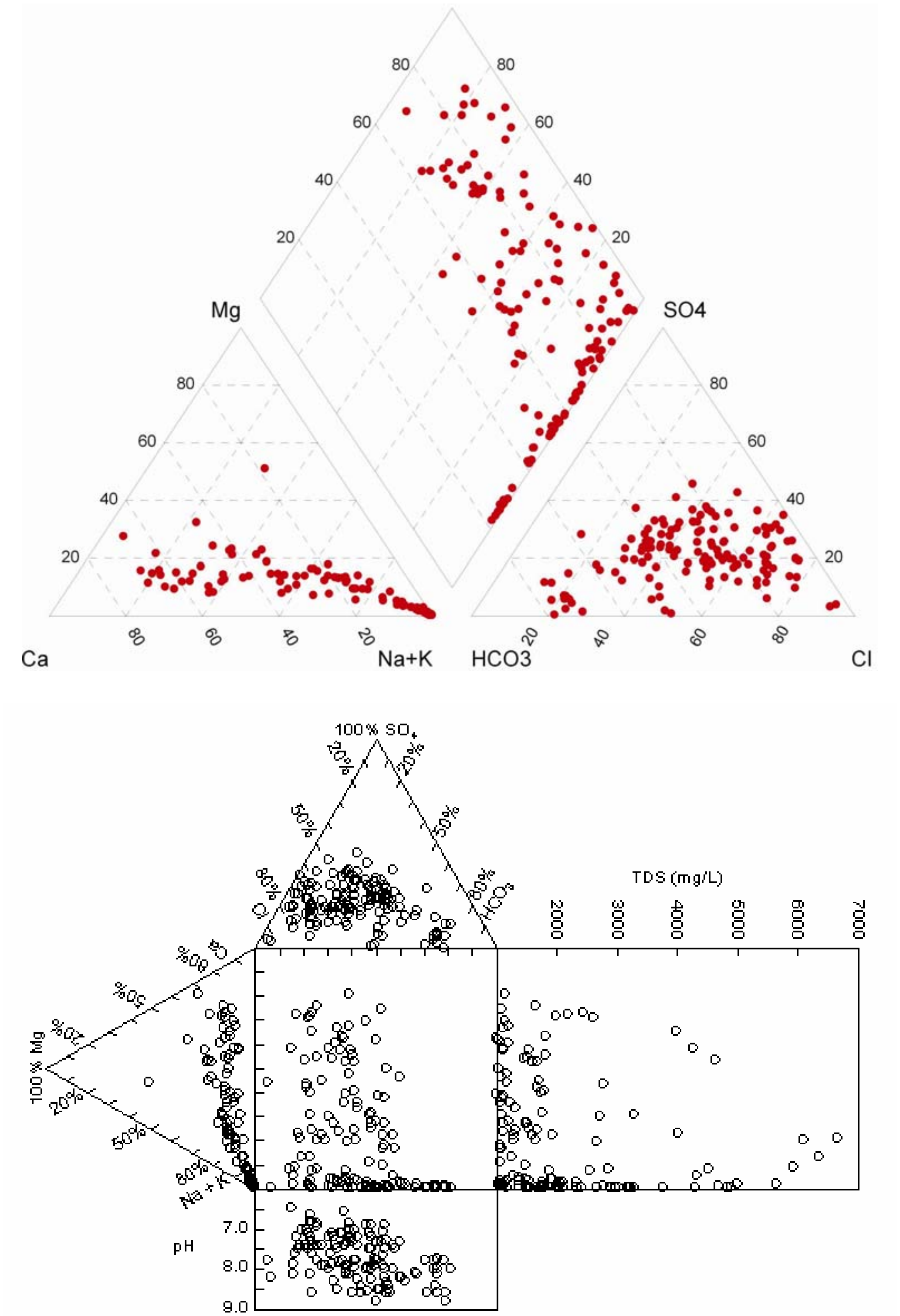


Figure 5-43. Continued.

### 5.5.6 Southern Gulf Coast Basin

The Gulf Coast aquifer is the primary aquifer in the Gulf Coast Basin. The Gulf Coast aquifer in the southern Gulf Coast Basin is composed of three sub-aquifers: the Chicot, Evangeline, and Jasper aquifers from the shallowest to the deepest (Ashworth and Hopkins, 1995). The aquifer is composed of interbedded silt, sand, and clay sediments of Cenozoic age. In the analysis area, the maximum sand thickness is approximately 700 feet. Brackish water is available at shallow depths (LBG-Guyton Associates, 2003) in significant volumes (Table 5-1) within the TWDB-defined limits of usable water (<3,000 mg/l) across much of the analysis area (Figure 5-44).

## 5.6 Additional Parameters

We compiled additional information on parameters needed for later calculations: average variations of temperature and pressure with depth, determination of a median sample for the formation waters, and formation compressibility. We also estimated concentrate compositions from an examination of brackish water compositions in the analyses areas and a review of the literature.

Temperature at depth can be measured or determined by the local geothermal gradient $g_T$ when no measurement is available or when the data are not reliable. We computed the average geothermal gradient by digitizing contour lines crossing relevant counties from a geothermal map of Texas (Woodruff and others, 1984). The contour lines were constructed mainly from the Woodbine and younger formations. We calculated average gradient within a county by integrating the gradient over the county with the Spatial Analyst tool featured in ArcInfo. We then averaged the county-averaged temperature gradients over the analysis area (Table 5-9).

We approximated surface temperatures at the analysis areas by average annual temperature at selected cities located in the chosen basin or close to it. Temperature, *T,* as a function of depth, *D,* is then expressed by:

$$T(^{0}\mathrm{C})=5/9(T_0+g_r D/100-32)\ (D\ \text{in ft},\ g_r\ \text{in}\ ^{\circ}\text{F/100ft}) \qquad 5.1$$

where $T_0$ is the surface temperature in $^{o}$F. We computed the depth as the midpoint between the upper and lower perforation or, when no depth is available, as the average depth of the available data points.

Since most geochemical samples did not provide pressure data and because pressure is important to estimate mineral solubility, we had to estimate pressure from depth. We did this by fitting a line through the H15 dataset. Pressure *P* as a function of depth is then expressed by:

$$P(\text{psi})=\alpha_P D\ (D\ \text{in ft}) \qquad 5.2$$

where $\alpha_P$ is the pressure slope (Table 5-9).

(a)

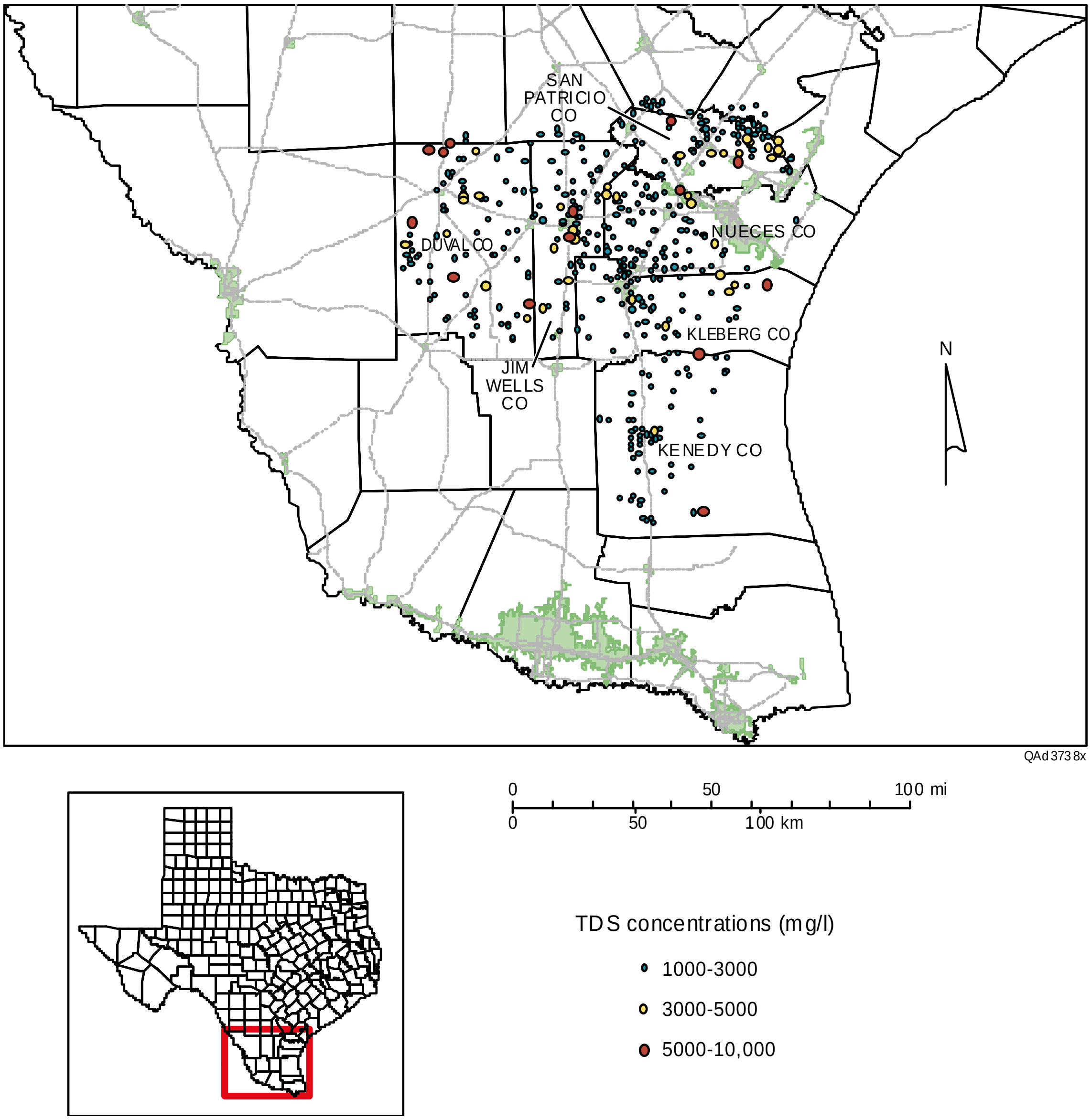
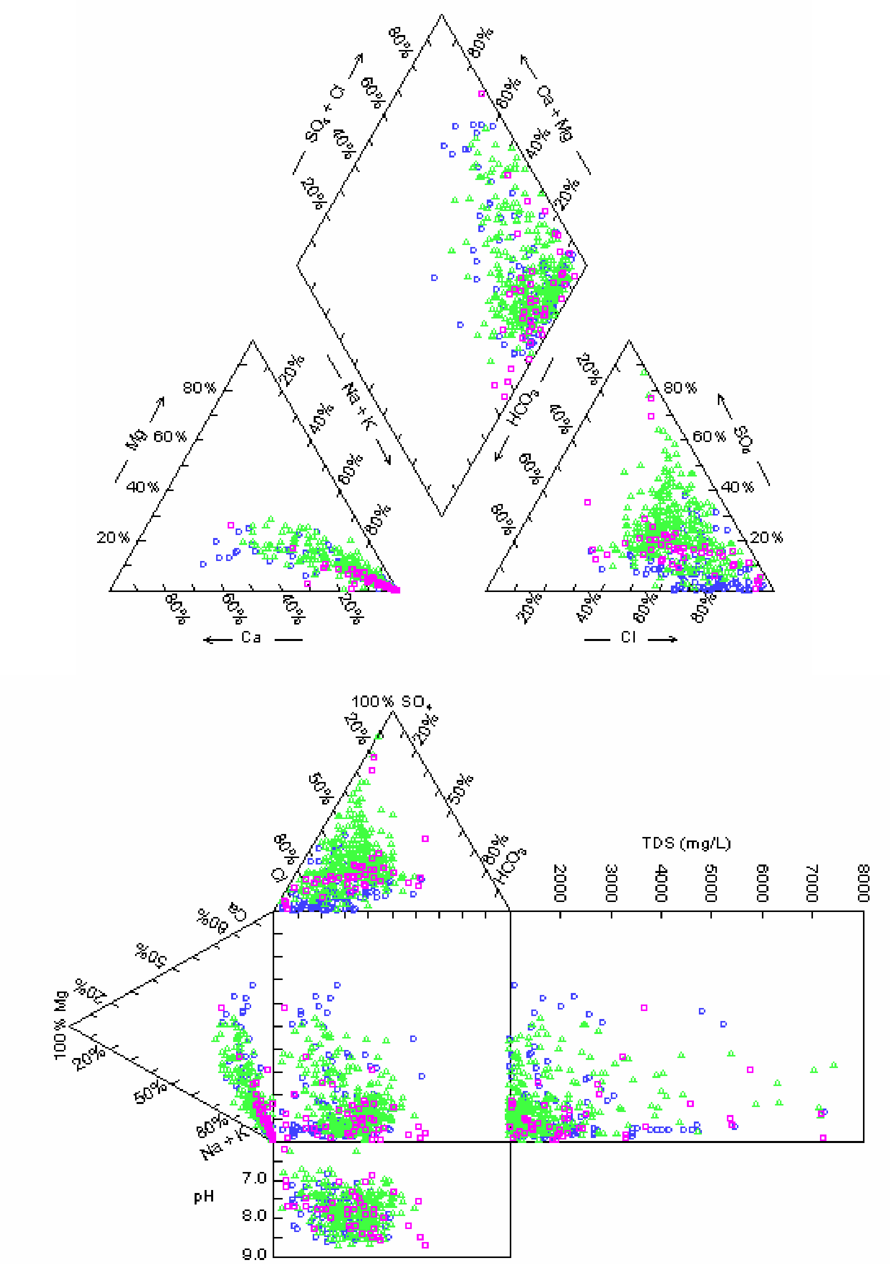


Figure 5-44. (a) Location of TDS samples and (b) Piper and Durov plots of feed water for the South Texas Basin (feed water from the Gulf Coast aquifer).

(b)



blue circles = Chicot aquifer; green triangles = Evangeline aquifer ; purple squares = Catahoula aquifer

Figure 5-44. Continued.

Table 5-9. Variation of temperature and pressure with depth.

| Basin | Mean surface temperature ($^oF$) | Temperature gradient ($^0F$/100 ft) | Pressure slope ($psi^{-1}$) |
|---|---|---|---|
| **Anadarko** | 63.5<br>(Wichita Falls) | 1.5 | 0.164 |
| **Permian** | 63<br>(Midland) | 1.180 | 0.312 |
| **East Texas** | 65<br>(Tyler) | 1.724 | 0.290 |
| **Fort Worth** | 67<br>(Waco) | 1.75 | 0.303 |
| **Maverick** | 72<br>(Brownsville) | 1.5 | 0.318 |
| **Southern Gulf Coast** | 72<br>(Brownsville – Corpus Christi) | 1.667 | 0.327 |

Note: hydrostatic pressure slope is 0.433 $psi^{-1}$.

Compressibility *c* is the specific change in volume, *V,* in response to a change in overburden pressure $\bar{\sigma}$ while the pore pressure *p* stays constant. Matrix and water compressibility are considered isotropic while only the vertical component of bulk compressibility is of interest in this study. Compressibility of the San Andres Formation and the Woodbine Formation are given as $9.5\times10^{-6}$ $psi^{-1}$ and $3.3\times10^{-6}$ $psi^{-1}$, respectively by Bass (1987, Figure 26.8). Bass (1987, Figure 26.8) also assumes a porosity of 24 percent for the Woodbine Formation and about 2 percent for the San Andres Formation, which is on the low side of the porosity range we report. Bass (1987) shows that compressibility loosely decreases with increasing porosity but only in consolidated materials. A lack of consolidation translates into a compressibility being independent of porosity.

Concentrate composition is a function of the feed water composition and scale of pretreatment. It is also a function of the membrane type and of the operational details. Almost every membrane vendor has proprietary software valid for their membrane that projects permeate and concentrate concentrations as a function of the feed water composition and operating parameters. It was beyond the scope of this study to determine the range of concentrate composition that could result from the large variety of membranes available on the market. Instead, based on analyses of brackish water samples from Texas and elsewhere, and information from the literature (Mickley and others, 1993), a uniform concentration factor of four was applied to all brackish water samples in determining the concentrate composition. We also assumed that the desalination process operates in a closed loop with no contact with the atmosphere between the time the water is retrieved from the brackish water aquifer and the time the concentrate is injected in the subsurface.

# 6.0 Results

We discuss the results of this study in the following sections: (1) communicate with stakeholders on disposal of desalination concentrates using existing oil and gas fields; (2) determine potential for area of review (AOR) variance for oil and gas wells located within the analysis areas; (3) determine potential chemical interaction between feed water and host formation water and their effects on reservoir performance; (4) determine levels of water sensitivity of clays from influx of feed water and their effects on reservoir performance; (5) review historical account of water injection and assess potential for water injection in the analyses areas; (6) perform injectivity modeling to determine injection rate and number of wells necessary to allow injection of concentrates; and (7) explore possible permitting paths to allow use of various injection wells for disposal of desalination concentrates.

## *6.1 Communicate with Stakeholders*

We developed two Web pages to inform stakeholders about the project, one for desalination and water interests:
http://www.twdb.state.tx.us/desalination/desal/Please%20pass%20the%20salt.asp
and another for oil and gas industry:
http://www.beg.utexas.edu/environqlty/grndwater/depletedoil.htm.

We also informed Regional Water Planning Groups in Texas about the project through TWDB's project managers. In addition, we gave presentations about the project at three conferences:

- "Please, Pass the Salt: Can the Oil Industry Benefit from Desalination Wastes?" *Presented at the TIPRO mid-winter policy meeting, January 13, 2004, Fort Worth, Texas*
- "Please pass the salt—Using oil fields for the disposal of concentrate—A progress report." *Presented at D-Salt Movers and Shakers—A TWDB workshop on desalination in Austin, Texas, March 25, 2004.*
- "Please pass the salt: Using oil fields for the disposal of concentrate." *Presented at the 2004 Biennial Conference and Exposition, "Water resource development using membranes," American Membrane Technology Association, San Antonio, Texas, August 5, 2004.*

We did not have much success with our survey of operators (only two responses). The responses were favorable to our project. Perhaps the resounding silence indicates that the disposal of concentrates in oil and gas fields would not be perceived as controversial by the industry.

Table 6-1. Percentage and number of fields with a separation greater than 500 feet.

| Basin | Percentage of fields with separation >500 ft | Number of fields |
|---|---|---|
| Anadarko | 66.7% | 18 |
| Permian | 50.5% | 436 |
| East Texas | 56.8% | 139 |
| Fort Worth | 62.8% | 285 |
| Maverick | 35.5% | 121 |
| Southern Gulf Coast | 56.2% | 356 |

Separation = difference in heads between the top of the fluids in the reservoir and the base of the usable quality water.

## *6.2 Area of Review (AOR) Variance Studies*

The AOR studies show that a significant portion of wells would qualify for a variance of AOR (Table 6-1), although reported fluid levels in shut-in wells and BUQWs are highly variable within the fields. Many wells would qualify because many fields have been pressure-depleted (Figure 6-1 and Table 5-10). For each analysis area (Figure 6-2 to Figure 6-7), we present three plots. The first plot shows the distribution of the depth to top of fluids (TOF) and the depth to the base of the usable quality water (BUQW). The second plot (“H15TOP-BUQW”) shows a distribution of the separation between the top of fluid and the base of the usable quality water and this on a well by well basis. The separation between the top of fluid and the base of the usable quality water is then averaged across a field. Those averaged field separations are used to build the histograms. The third plot (MinTOF-MaxBUQW) shows the difference between the lowest TOF of the field and the highest BUQW of the field, even if not from the same well.

The very large pressure depletion in the Anadarko Basin (Figure 6.2) indicates that a large fraction of the fields may qualify for a variance of AOR (~67 percent, Table 6.1). Between 50 to 60 percent of the fields from the Permian Basin (Figure 6.3), the East Texas Basin (Figure 6.4), and the Fort Worth Basin (Figure 6.5) may qualify for a variance of AOR. The Maverick Basin (Figure 6.6) is an anomaly among the 6 analysis areas because only 35.5 percent of its fields appear favorable for a variance of AOR. The percentage of fields with a separation greater than 500 feet falls in the main group at about 56 percent in the southern Gulf Coast Basin (Figure 6.7).

## *6.3 Interaction of Concentrate and Formation Fluids*

Some of the concentrate/formation water combinations produced above threshold saturation indices (Table 6.2, Appendix 4). The theoretical threshold for precipitation is a saturation index (SI) of 0, although kinetics may render the reaction so slow that it has no real impact. However, addition of anti-scalant solutions will increase the threshold to approximately 2. This threshold value is retained as the saturation index beyond which recurrent scaling problems could occur during injection. However, it is important to remember that the SI values result from the assumption of total mixing between the concentrate and the formation water.

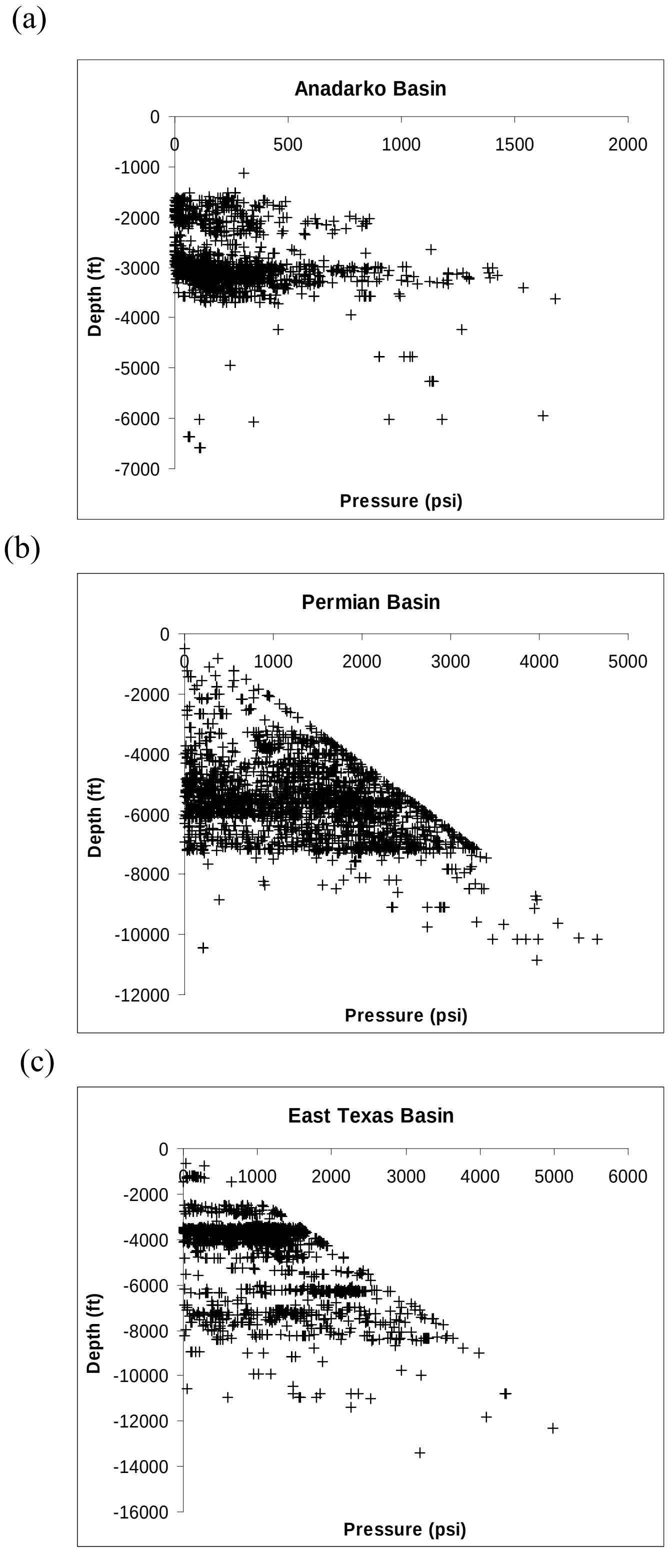


Figure 6-1. Pressure distribution in the (a) Anadarko, (b) Permian, (c) East Texas, (d) Fort Worth, (e) Maverick, and (f) southern Gulf Coast basins (data from RRC form H15).

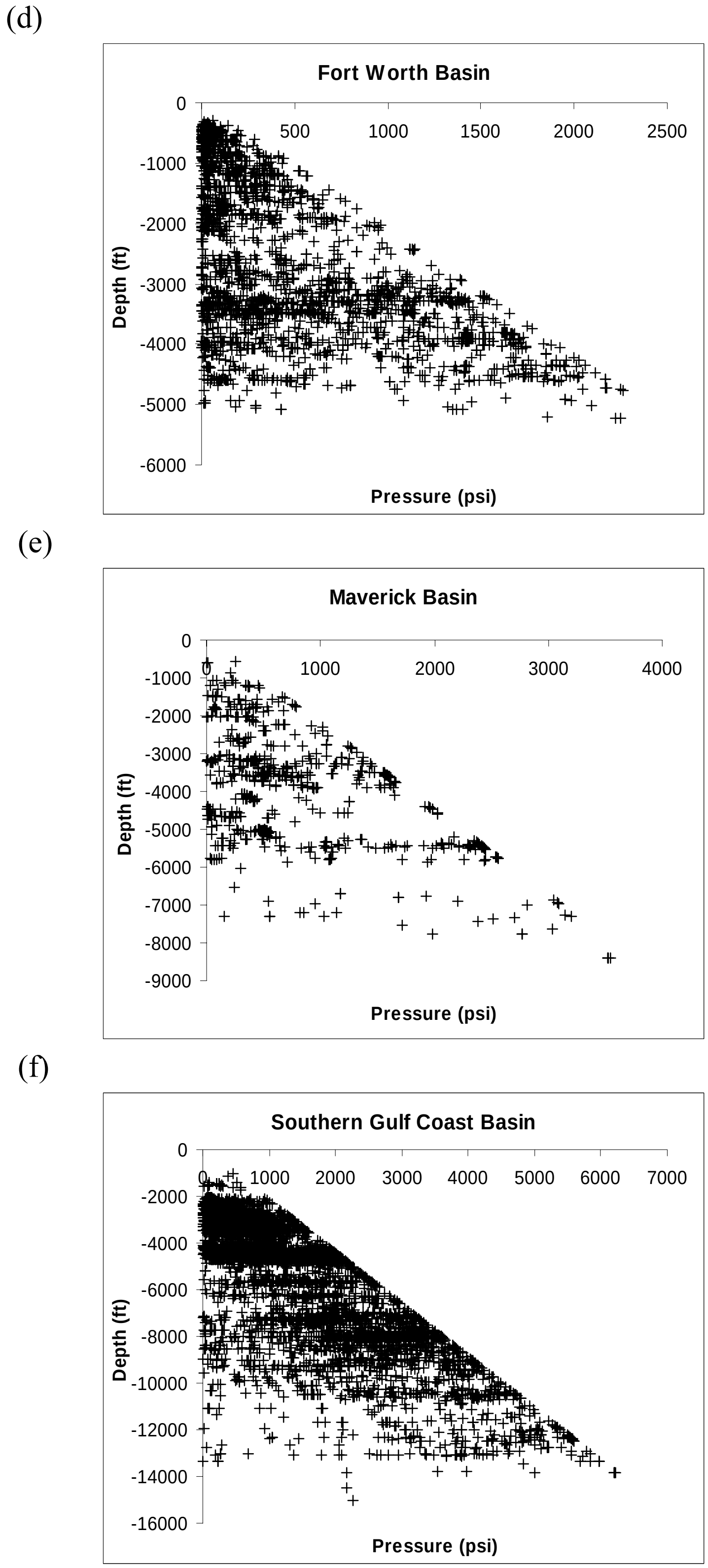


Figure 6-1. Continued.

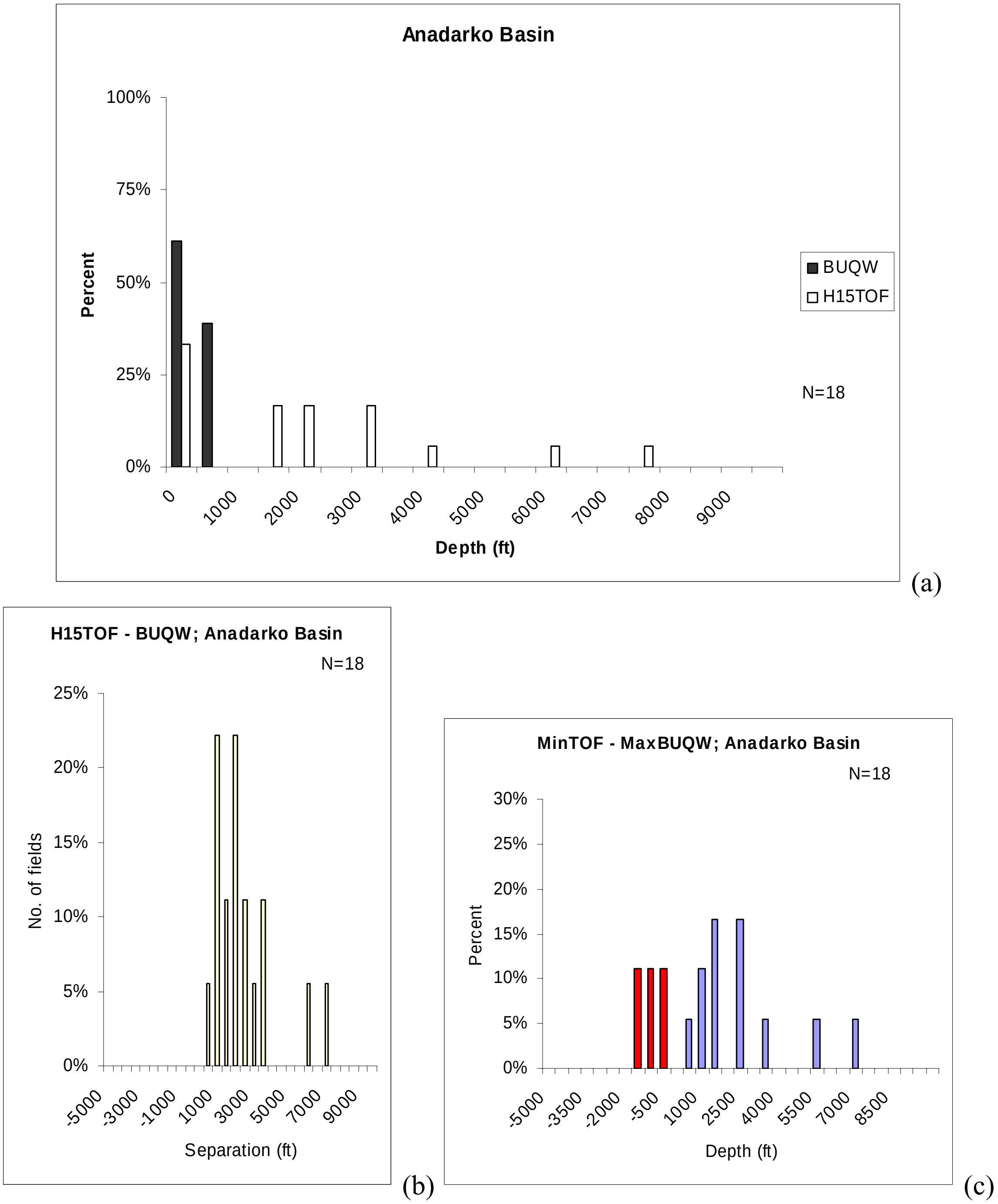


Figure 6-2. Variance of AOR study results for the Anadarko Basin.

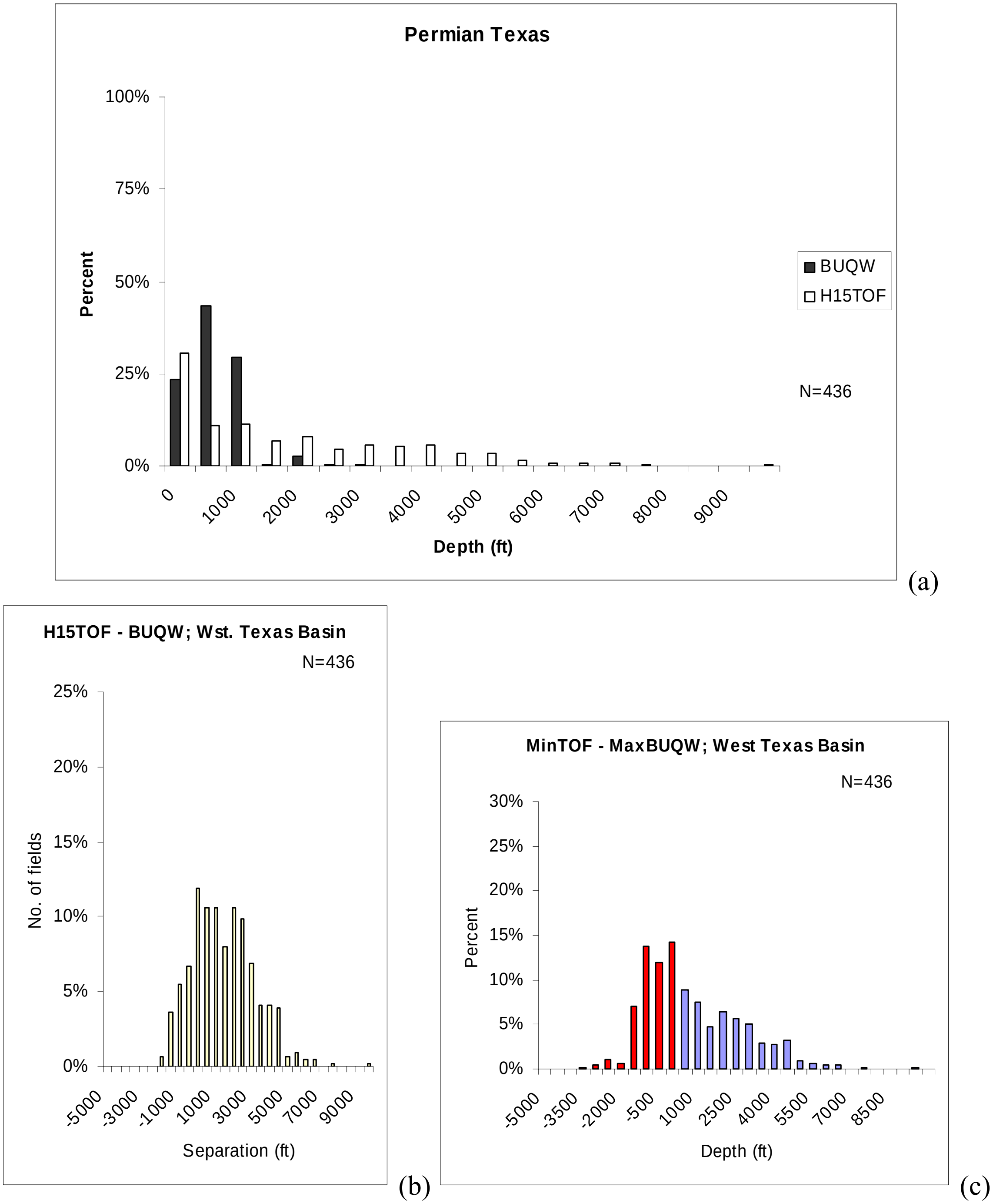


Figure 6-3. Variance of AOR study results for the Permian Basin.

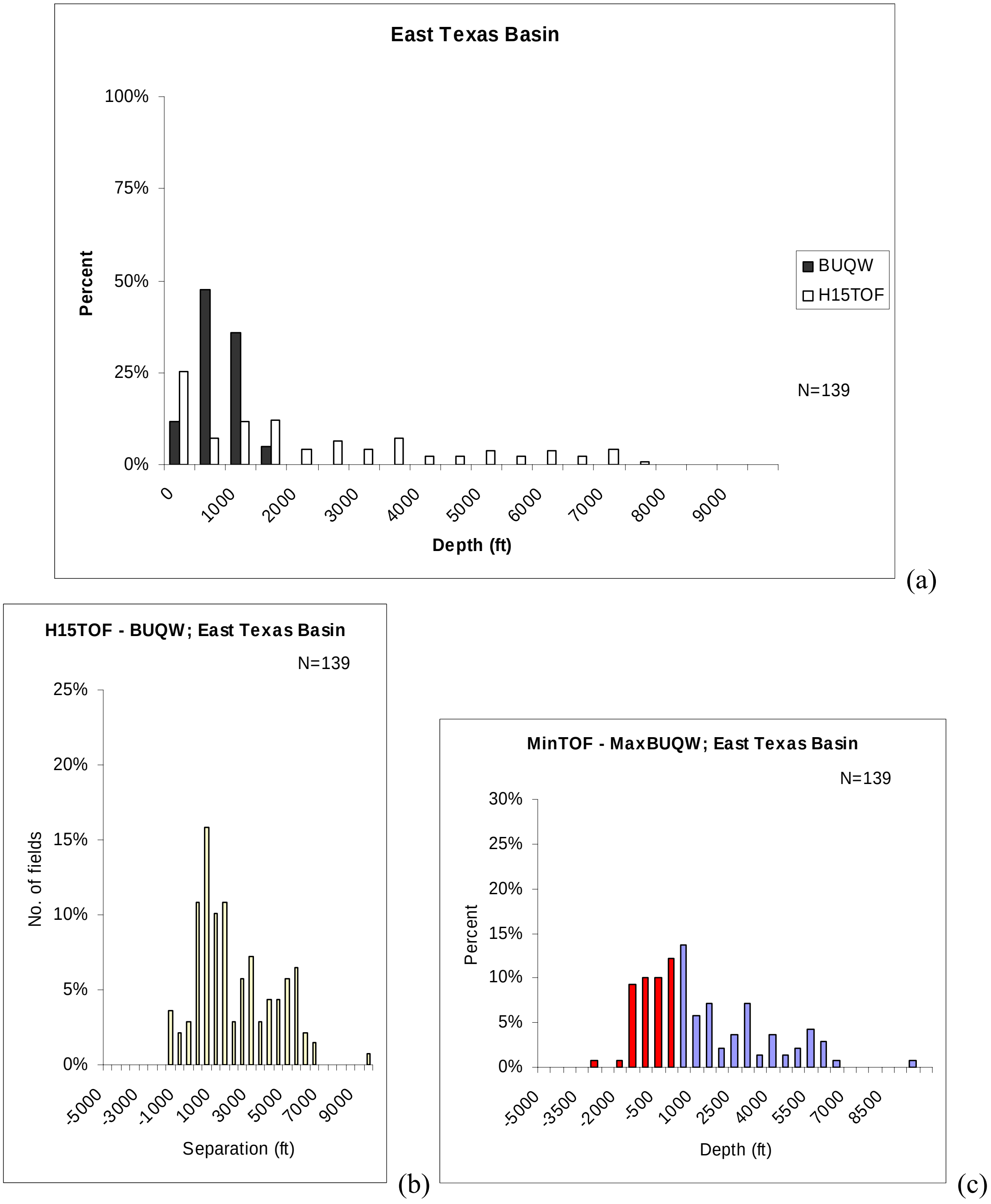


Figure 6-4. Variance of AOR study results for the East Texas Basin.

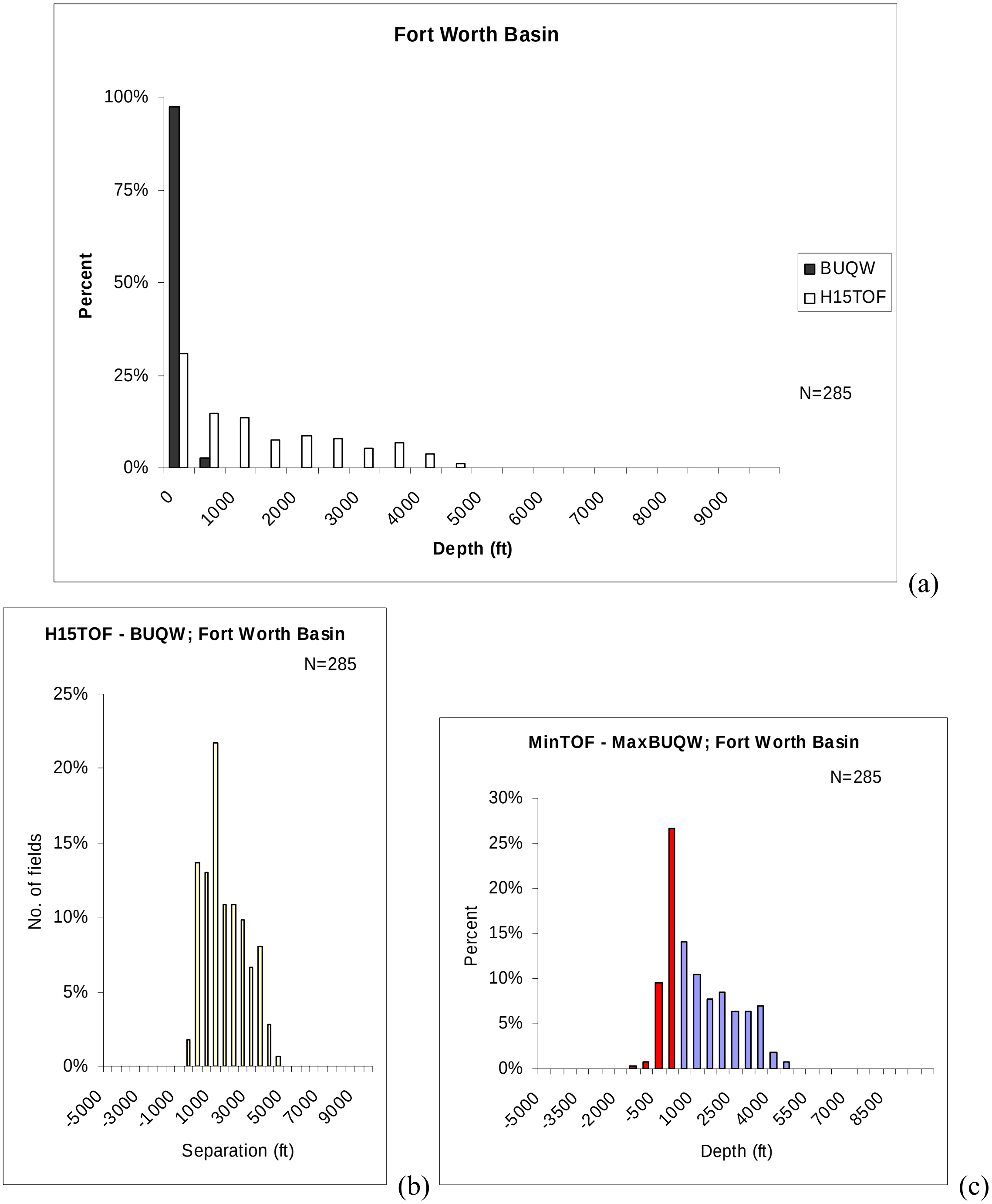
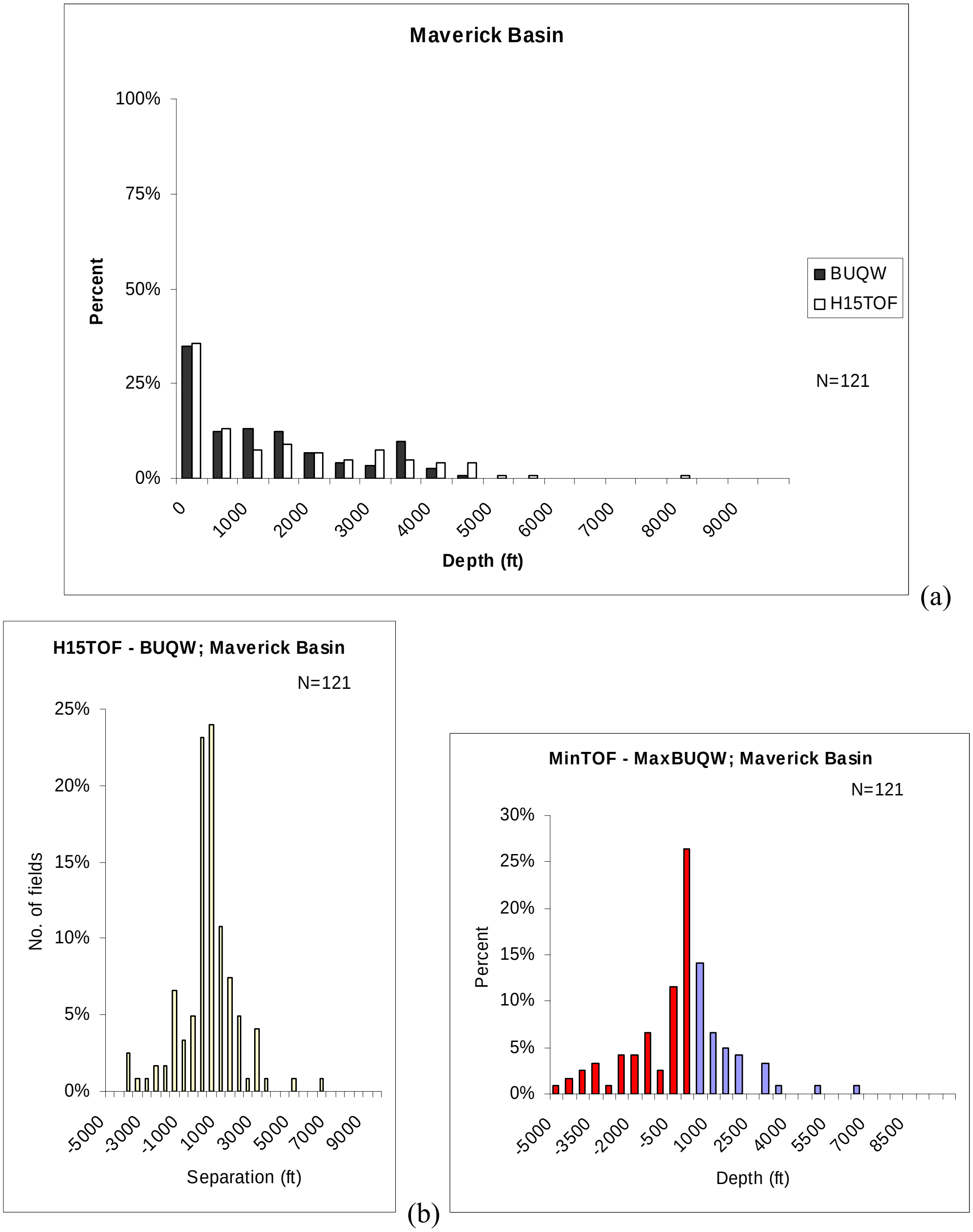


Figure 6-5. Variance of AOR study results for the Fort Worth Basin.



(a) (b) (c)

Figure 6-6. Variance of AOR study results for the Maverick Basin.

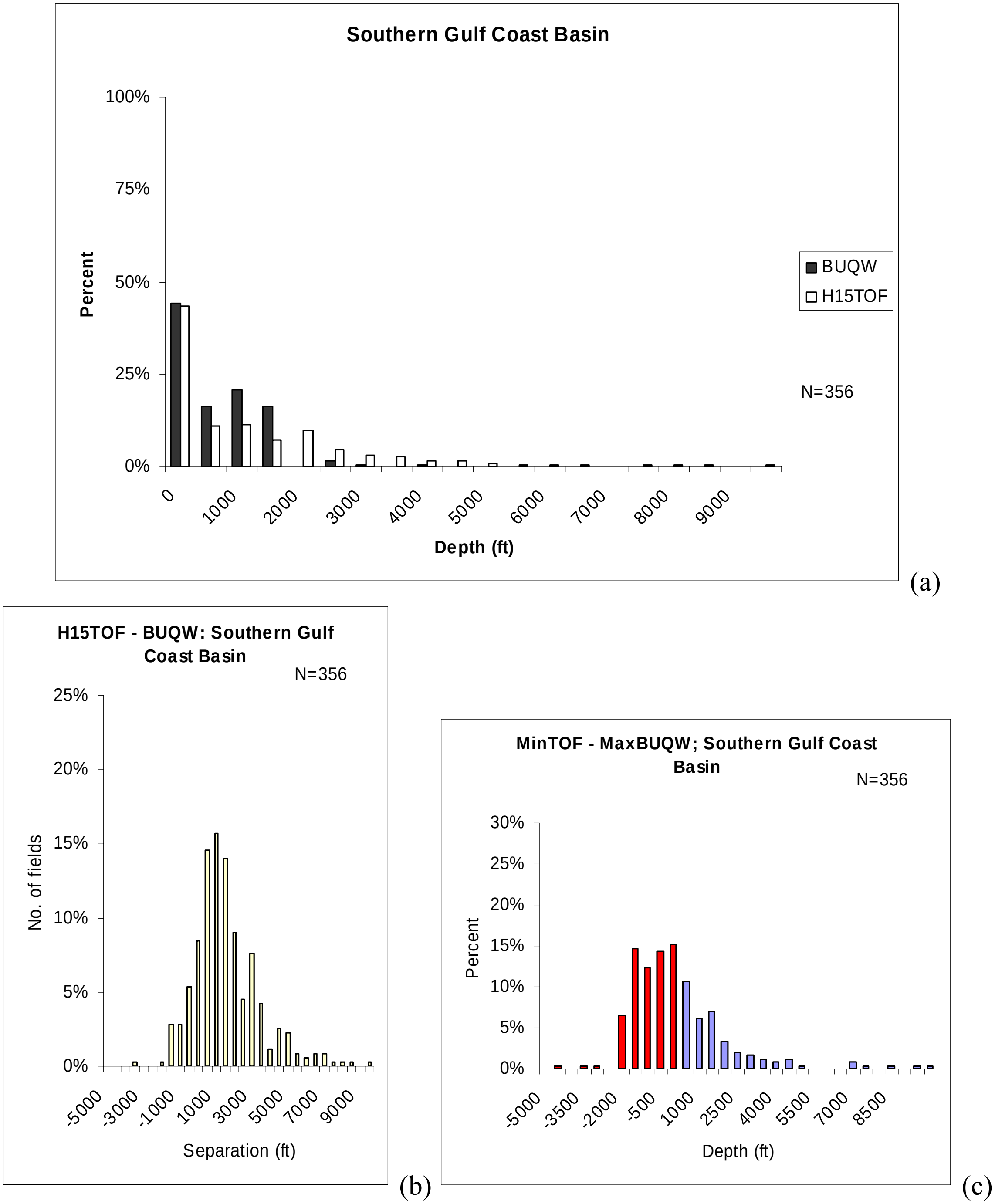


Figure 6-7. Variance of AOR study results from the Southern Gulf Coast Basin.

However, in the subsurface, formation water and injected concentrate may not mix completely because of lithologic heterogeneities. The concentrate will displace the resident formation water, and the injection front will be somewhat be blurred by diffusive forces.

The potential feed waters are mainly undersaturated relative to calcite, gypsum, and silica (Table 5-6). Barite saturation index from some basins, particularly Anadarko Basin, suggests that the water is supersaturated with respect to this mineral. However, given the low solubility of barite, it may also be due to erroneous field measurements of temperature.

Acidification of the concentrate drops the saturation index of calcite by one order of magnitude and brings it below a value of 0 in a majority of cases (Table 6-2; Appendix 4). The other minerals analyzed (gypsum, barite, and silica) show small variations in saturation index owing to the change in ionic strength by the addition of acid and of sulfate ions. This is more evident for gypsum and barite. The amount of acid added (<300 ppm of sulfuric acid) is consistent with desalination industry usage (Figure 6-8). If the increase in sulfate concentration leads to a barite scaling problem, hydrochloric acid can be used instead.

Table 6-2. Saturation indices for the analysis areas.

| | | **Calcite SI** | **Gypsum SI** | **Barite SI** | **Silica SI** |
|---|---|---|---|---|---|
| **Anadarko Basin** | | | | | |
| Concentrate (acidified) | Nb | 57 | 57 | 9 | 55 |
| | 5th | -1.28 | -0.67 | 0.90 | -0.32 |
| | Med | -0.92 | -0.13 | 1.15 | -0.02 |
| | 95th | -0.44 | 0.72 | 1.68 | 0.25 |
| Concentrate (no treatment) | Nb | 57 | 57 | 9 | 55 |
| | 5th | 0.02 | -1.16 | 0.15 | -0.32 |
| | Med | 0.36 | -0.18 | 0.31 | -0.02 |
| | 95th | 0.79 | 0.72 | 0.86 | 0.25 |
| Downhole batch mixture (with acidified concentrate) | Nb | 19,999 | 19,990 | N/A | 24,107 |
| | 5th | -0.72 | -0.68 | N/A | -1.03 |
| | Med | -0.11 | 0.14 | N/A | -0.45 |
| | 95th | 0.37 | 0.58 | N/A | 0.01 |
| Formation water | Nb | (1,572) | (1,659) | N/A | N/A |
| | 5th | -1.40 | -1.78 | N/A | N/A |
| | Med | 0.77 | 0.24 | N/A | N/A |
| | 95th | 1.84 | 0.78 | N/A | N/A |

Nb = number of data points; 5th = 5th percentile; Med = median; 95th = 95th percentile.

Table 6-2. Continued.

| | | Calcite SI | Gypsum SI | Barite SI | Silica SI |
|---|---|---|---|---|---|
| **Permian Basin** | | | | | |
| Concentrate (acidified) | Nb | 297 | 297 | 35 | 262 |
| | 5th | -1.45 | -1.02 | 0.49 | -0.52 |
| | Med | -0.69 | -0.13 | 0.70 | -0.10 |
| | 95th | -0.35 | 0.51 | 1.16 | 0.42 |
| Concentrate (no treatment) | Nb | 297 | 297 | 35 | 262 |
| | 5th | -0.18 | -1.09 | 0.45 | -0.52 |
| | Med | 0.59 | -0.23 | 0.67 | -0.10 |
| | 95th | 0.89 | 0.50 | 1.10 | 0.41 |
| Downhole batch mixture (with acidified concentrate) | Nb | 20,000 | 19,990 | 2,300 | 17,692 |
| | 5th | -0.50 | -0.48 | -1.01 | -1.22 |
| | Med | 0.05 | -0.03 | -0.26 | -0.57 |
| | 95th | 0.73 | 0.25 | 0.34 | 0.08 |
| Formation water | Nb | (4,878) | (5,000) | N/A | N/A |
| | 5th | 0.31 | -1.21 | N/A | N/A |
| | Med | 1.25 | 0.05 | N/A | N/A |
| | 95th | 1.91 | 0.20 | N/A | N/A |
| | | **Calcite SI** | **Gypsum SI** | **Barite SI** | **Silica SI** |
| **East Texas Basin** | | | | | |
| Concentrate (acidified) | Nb | 52 | 52 | N/A | 39 |
| | 5th | -2.01 | -2.10 | N/A | -0.43 |
| | Med | -1.59 | -1.74 | N/A | -0.33 |
| | 95th | -0.35 | 0.48 | N/A | 0.32 |
| Concentrate (no treatment) | Nb | 52 | 43 | N/A | 39 |
| | 5th | -0.65 | -3.73 | N/A | -0.43 |
| | Med | -0.29 | -2.52 | N/A | -0.33 |
| | 95th | 0.84 | 0.58 | N/A | 0.32 |
| Downhole batch mixture (with acidified concentrate) | Nb | 19,581 | 19,350 | 320 | 14,233 |
| | 5th | -0.44 | -1.39 | 0.07 | -1.28 |
| | Med | -0.03 | -0.94 | 0.96 | -0.79 |
| | 95th | 0.36 | -0.01 | 2.72 | -0.18 |
| Formation water | Nb | (4,980) | (5,000) | (84) | (11) |
| | 5th | 0.15 | -2.74 | -1.64 | -0.39 |
| | Med | 0.98 | -1.27 | 0.85 | -0.25 |
| | 95th | 1.33 | -0.89 | 2.22 | 0.16 |

Nb = number of data points; 5th = 5th percentile; Med = median; 95th = 95th percentile.

Table 6-2. Continued.

| | | Calcite SI | Gypsum SI | Barite SI | Silica SI |
|---|---|---|---|---|---|
| **Fort Worth Basin** | | | | | |
| Concentrate (acidified) | Nb | 427 | 460 | 3 | 427 |
| | 5th | -0.52 | -1.73 | 0.77 | -0.52 |
| | Med | -0.26 | -0.37 | 0.82 | -0.26 |
| | 95th | 0.00 | 0.15 | 0.84 | 0.00 |
| Concentrate (no treatment) | Nb | 460 | 460 | N/A | 427 |
| | 5th | -0.44 | -2.46 | N/A | -0.52 |
| | Med | 0.81 | -0.75 | N/A | -0.26 |
| | 95th | 1.19 | 0.06 | N/A | 0.00 |
| Downhole batch mixture (with acidified concentrate) | Nb | 26,875 | 26,876 | 16,684 | 85 |
| | 5th | -9.39 | -9.24 | -6.17 | -9.00 |
| | Med | -0.27 | -1.71 | -5.68 | -8.09 |
| | 95th | 0.89 | -0.66 | -5.32 | -6.89 |
| Formation water | Nb | (4,496) | (4,511) | (20) | (2,260) |
| | 5th | -9.01 | -8.86 | -8.26 | -6.17 |
| | Med | 0.02 | -1.38 | -7.54 | -5.63 |
| | 95th | 1.08 | 0.74 | -7.08 | -5.00 |
| | | **Calcite SI** | **Gypsum SI** | **Barite SI** | **Silica SI** |
| **Maverick Basin** | | | | | |
| Concentrate (acidified) | Nb | 148 | 148 | N/A | 148 |
| | 5th | -1.92 | -1.97 | N/A | -0.56 |
| | Med | -0.64 | -0.39 | N/A | -0.23 |
| | 95th | -0.07 | 0.30 | N/A | 0.20 |
| Concentrate (no treatment) | Nb | 144 | 148 | N/A | 144 |
| | 5th | -0.46 | -0.55 | N/A | -0.46 |
| | Med | -0.22 | 0.60 | N/A | -0.22 |
| | 95th | 0.20 | 1.13 | N/A | 0.20 |
| Downhole batch mixture (with acidified concentrate) | Nb | 28,738 | 28,178 | N/A | 28,179 |
| | 5th | -0.40 | -1.11 | N/A | -1.19 |
| | Med | 0.08 | -0.30 | N/A | -0.55 |
| | 95th | 0.35 | 0.27 | N/A | 0.26 |
| Formation water | Nb | (3,668) | (4,381) | N/A | (7) |
| | 5th | -1.50 | -3.29 | N/A | -5.19 |
| | Med | 0.37 | -1.61 | N/A | -5.03 |
| | 95th | 0.95 | -0.19 | N/A | -4.92 |

Nb = number of data points; 5th = 5th percentile; Med = median; 95th = 95th percentile.

Table 6-2. Continued.

| | | Calcite SI | Gypsum SI | Barite SI | Silica SI |
|---|---|---|---|---|---|
| **South Texas Fields** | | | | | |
| Concentrate (acidified) | Nb | 525 | 525 | 69 | 462 |
| | 5th | -1.73 | -1.52 | 0.67 | -0.39 |
| | Med | -1.11 | -0.87 | 0.83 | -0.18 |
| | 95th | -0.30 | -0.22 | 1.49 | 0.45 |
| Concentrate (no treatment) | Nb | 525 | 525 | 69 | 462 |
| | 5th | -0.43 | -2.30 | 0.52 | -0.39 |
| | Med | 0.19 | -1.08 | 0.70 | -0.18 |
| | 95th | 0.89 | -0.29 | 1.07 | 0.45 |
| Downhole batch mixture (with acidified concentrate) | Nb | 19,999 | 19,999 | 4,128 | 18,043 |
| | 5th | -0.77 | -1.55 | -1.70 | -1.38 |
| | Med | -0.07 | -0.81 | -0.20 | -0.79 |
| | 95th | 0.58 | -0.20 | 2.03 | -0.22 |
| Formation water | Nb | (2,656) | (5,000) | (400) | (779) |
| | 5th | -0.28 | -3.51 | -1.27 | -1.25 |
| | Med | 0.53 | -2.31 | 0.20 | -0.78 |
| | 95th | 1.06 | -0.97 | 1.38 | -0.39 |

Nb = number of data points; 5th = 5th percentile; Med = median; 95th = 95th percentile

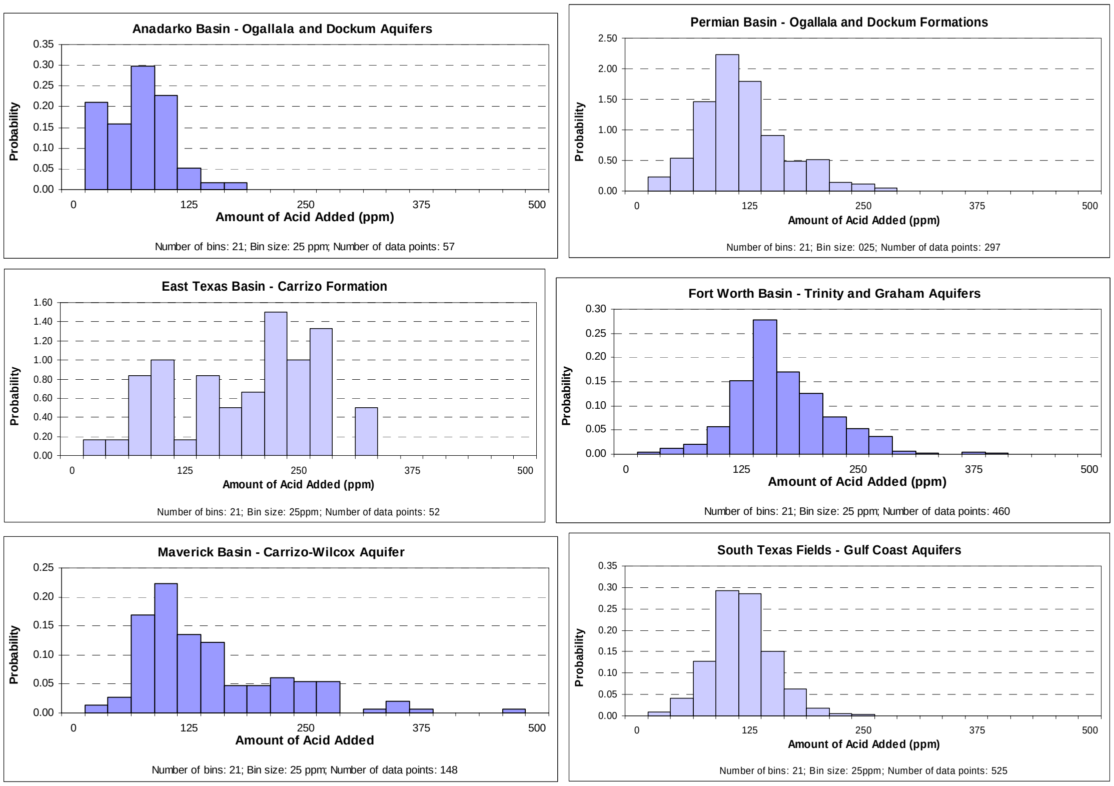


Figure 6-8. Amount of sulfuric acid added to the feed water from each basin to maintain pH of 6.

Formation water from all analysis areas shows that calcite is supersaturated, sometimes by one order of magnitude (for the median) (Table 6-2; Appendix 3). It is common for calcium carbonate to be supersaturated in solution, but it could also correspond for some samples to sampling problems such erroneous temperature or pH measurements. SOLMINEQ has the ability to equilibrate a solution with respect to a given mineral. Since calcite is widespread in the subsurface, this option could have been used. However, to allow for comparisons between analysis areas, we did not use this option.

Saturation indices for the mixing solutions are intermediate between those of formation water and acidified concentrate (Table 6-2; Appendix 3). All of the saturation indices, except for barite in one analysis area, are below the threshold of 2, which means that scaling would not likely occur with the addition of an antiscalant. There is no preferred site relative to scaling tendency (Figure 6-9). Calcite equally impacts all analysis areas. Gypsum may not be a problem, but the Anadarko and Permian basins are more prone than other basins. In general, silica does not seem to be able to produce a significant amount of scaling. Barite may be more of an issue, but data are insufficient to conclude with certainty.

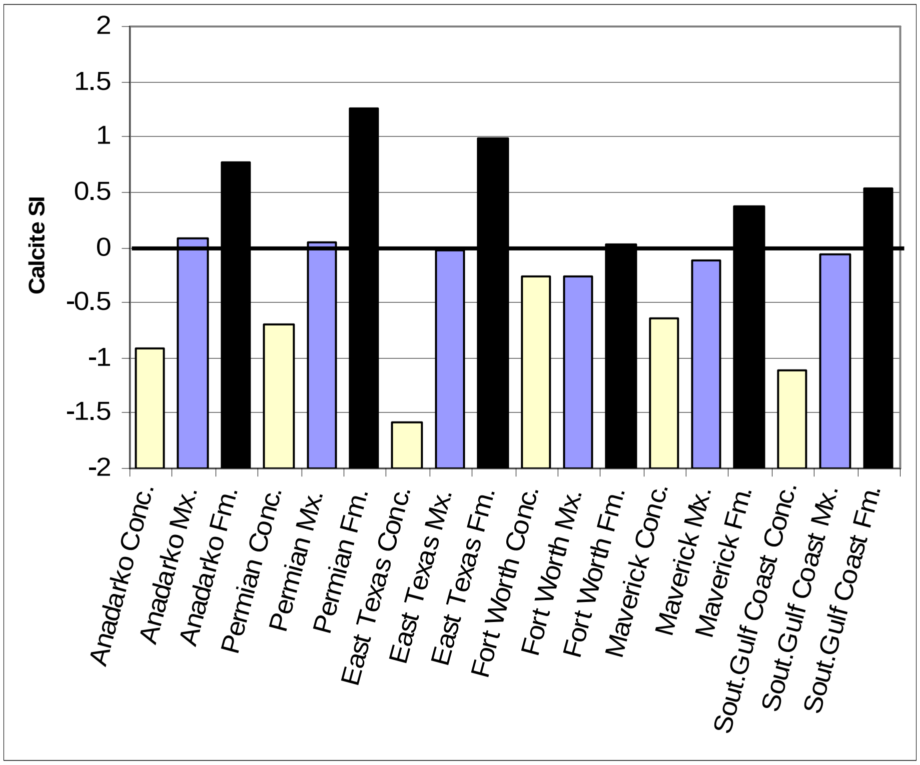
## *6.4 Water Sensitivity*

As described in Section 3.3.5 and emphasized by Warner and Lehr (1977, p. 174), water-sensitivity of clay-bearing sandstones increases with decreasing water salinity, decreasing valence of the cations in solution, and increasing pH in the water. Two factors control whether injected fluids will cause formation clay related impairment: (1) the water must have an adequate total cation and/or divalent cation concentration for prevention of clay deflocculation; and (2) cation exchange during mixing must not reduce the divalent cation concentration (Scheuerman and Bergersen, 1990). Based on the clay types commonly encountered in the reservoirs, Scheuerman and Bergersen (1990) developed compatibility guidelines for injection water. The most sensitive clay is montmorillonite followed by mixed layers clays and illite. Kaolinite is barely water sensitive and chlorite is not. The injection water and formation clay compatibility is then determined based on the positions of the water composition on the diagram.

In the Anadarko Basin (Figure 6-10), Permian Basin (Figures 6-11 and 6-12), East Texas Basin (Figures 6-13 and 6-14), Fort Worth Basin (Figure 6-15), and Maverick Basin (Figure 6-16), most of the data points fall outside the smectite salinity line suggesting that the formation contains smectite in contact with the flowing water and that they are at equilibrium. In the southern Gulf Coast (Figure 6-17a), data points reach the illite salinity line.

Because smectite clay is progressively transformed into illite with depth, we plotted some of the data by county with depth. The best example of this transformation occurs just outside the southern Gulf Coast Basin analysis area in San Patricio County (Figure 6-17g) where there is a large depth range in the Frio Formation. As the burial depth increases, so does the proportion of illite through conversion of mixed-layer illite-smectite. These mineralogical changes are indicated by the composition changes of the formation water. It was beyond the scope of this work to analyze the reactive transport phenomena leading to such changes. However, from a practical standpoint, it confirms that this type of analysis can help in determining the clay type controlling the water sensitivity of the formation.

(a)



(b)

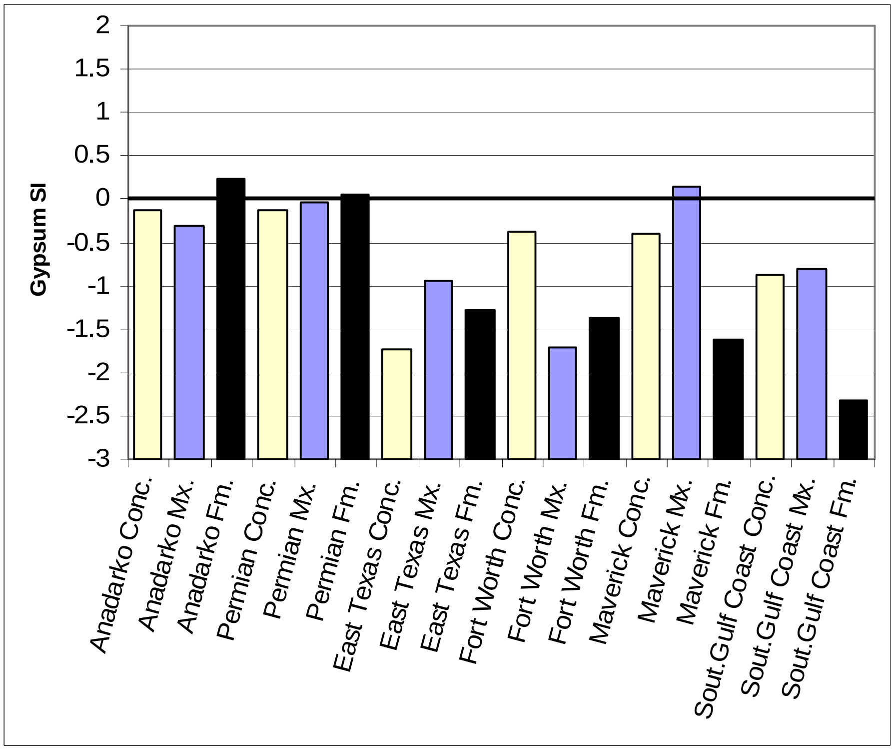
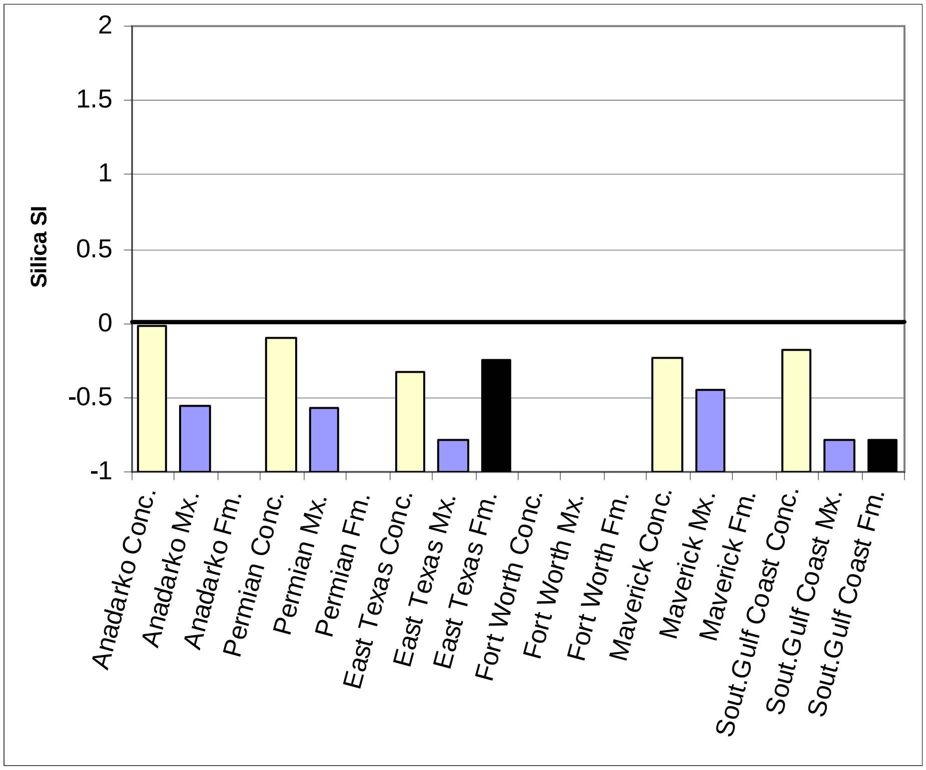


Figure 6-9. Median saturation indices (SI) for (a) calcite, (b) gypsum, (c) barite, and (d) silica for concentrate (conc.), formation water (Fm), and mixing solutions (Mx). Mineral precipitation is favored at SI values of 0.

(c)



(d)

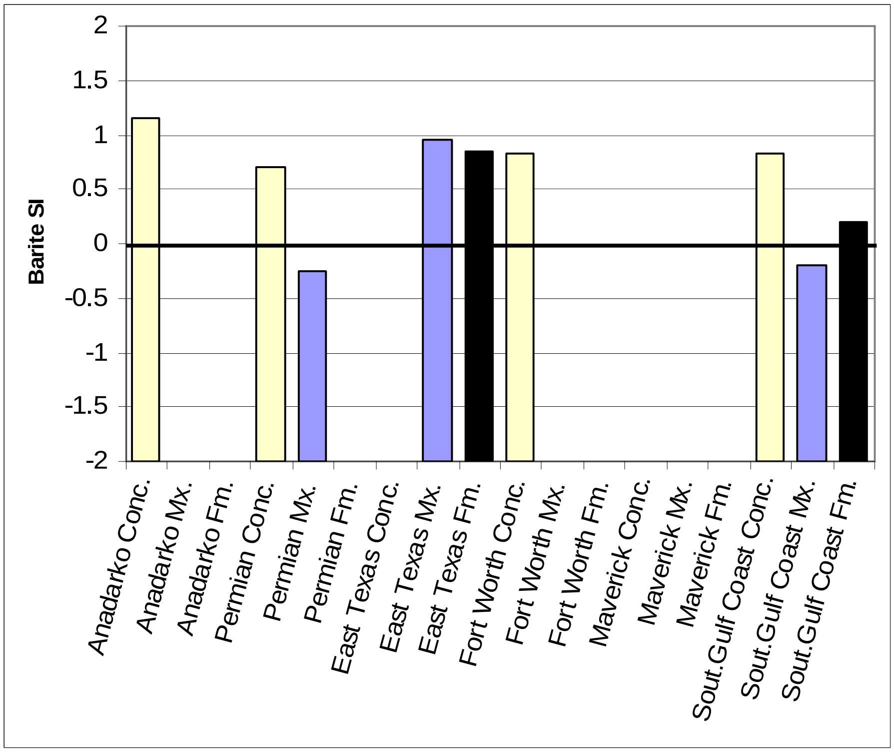
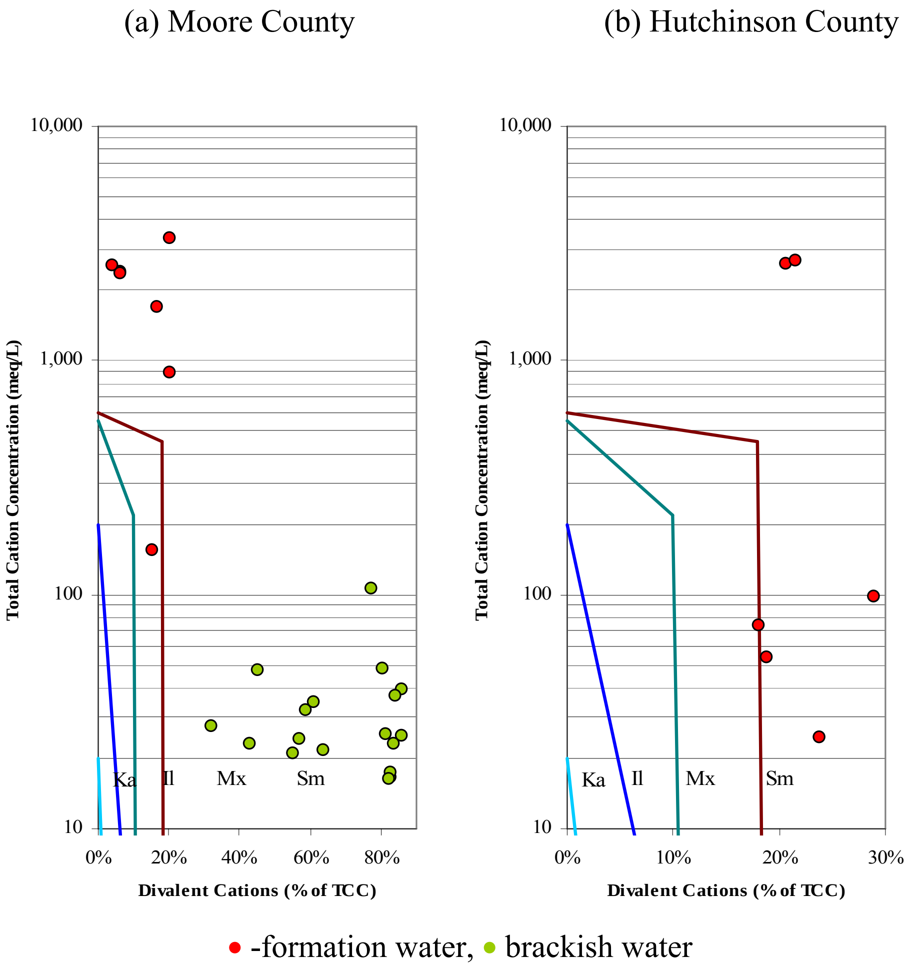
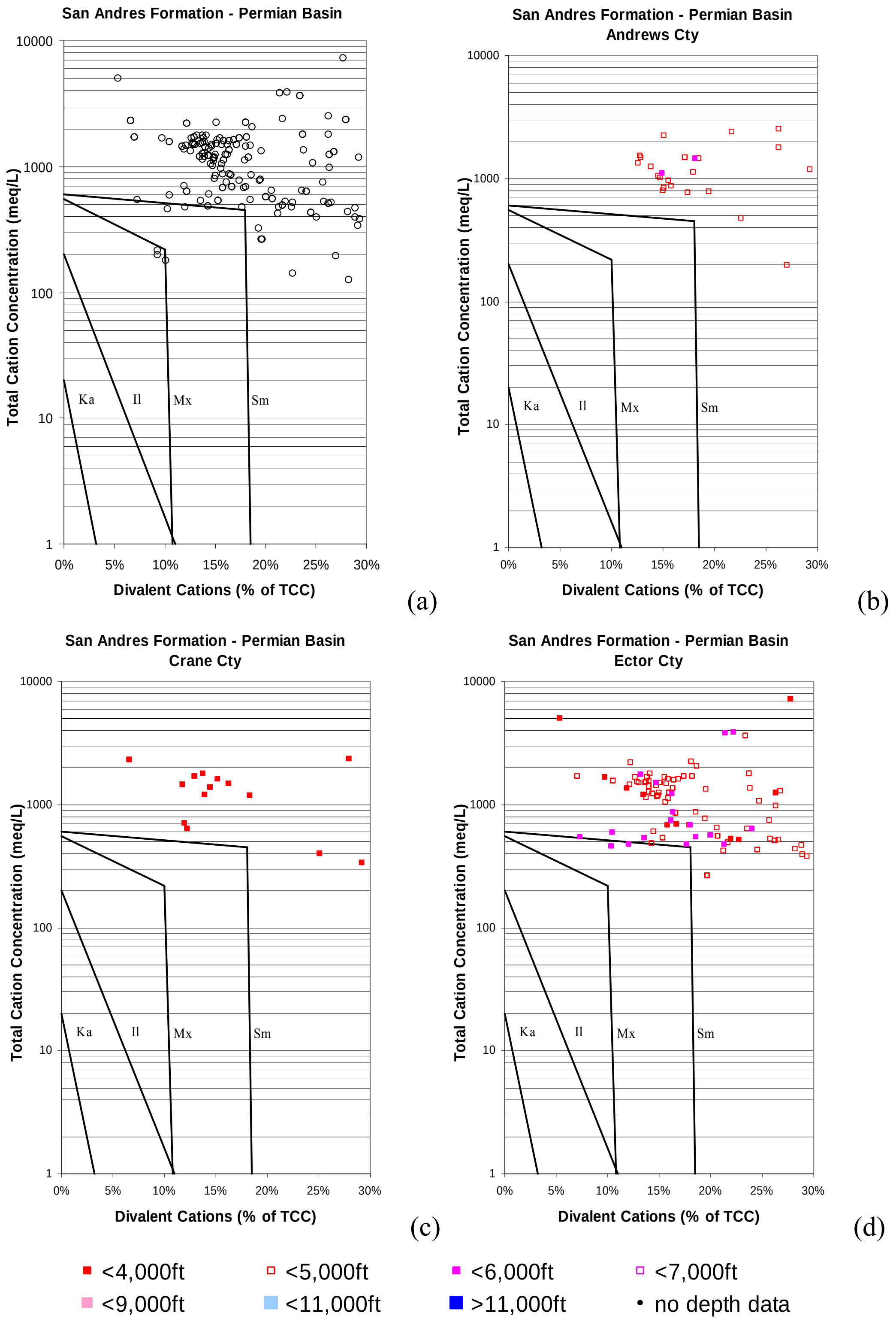


Figure 6-9. Continued.



Note: Most of the brackish waters have high divalent cations and fall to the right of the smectite boundary (not shown).

Figure 6-10. Total cation concentration and divalent cations for the brackish groundwater and formation water in the Anadarko Basin analysis area for (a) Moore County and (b) Hutchinson County.



Ka=Kaolinite; Il=Illite; Mx=Mixed layers; Sm=Smectite

Figure 6-11. Plot of total cation concentration and divalent cations for the formation water of the Permian Basin analysis area.

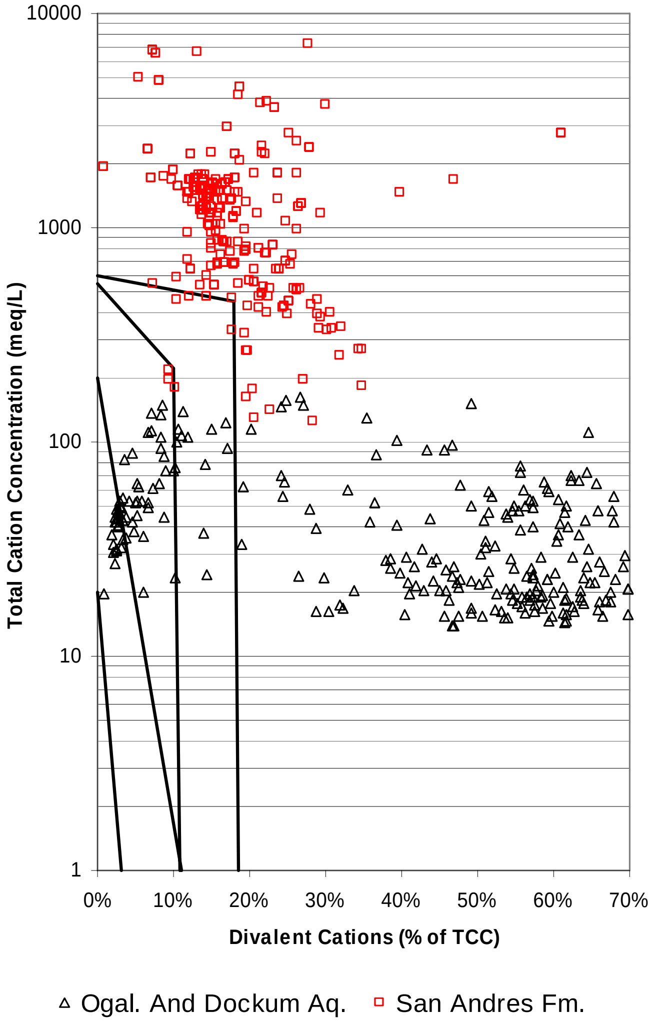
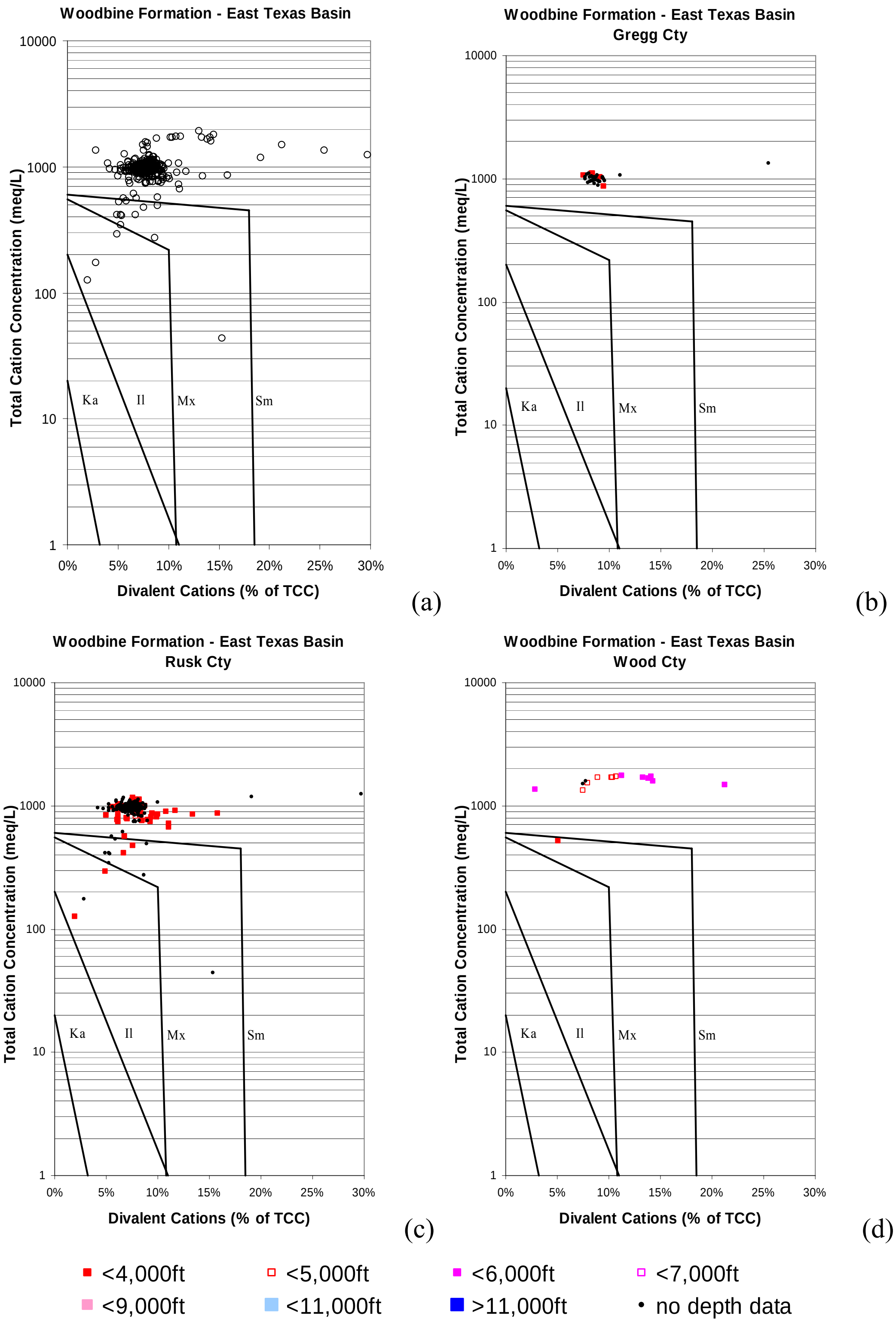


Figure 6-12. Total cation concentration and divalent cations for the concentrate and the formation water of the Permian Basin analysis area.



Ka=Kaolinite; Il=Illite; Mx=Mixed layers; Sm=Smectite

Figure 6-13. Cation concentration and divalent cations for the formation water of the East Texas Basin analysis area.

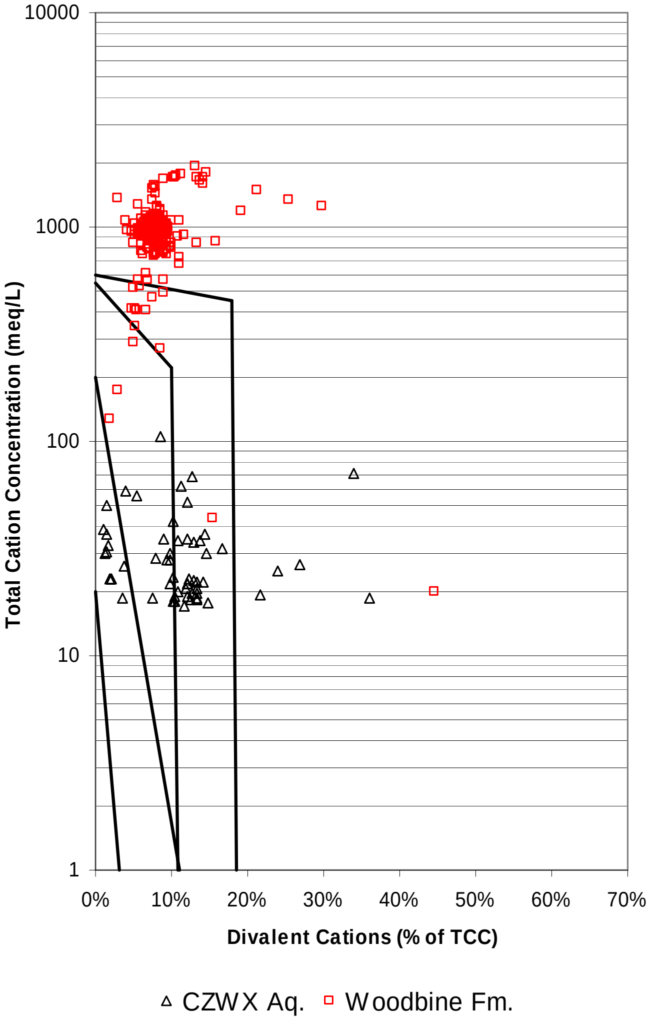


Figure 6-14. Total cation concentration and divalent cations for the concentrate and formation waters of the East Texas Basin analysis area. CZWX Aq = Carrizo-Wilcox aquifer, Woodbine Fm = Woodbine Formation.

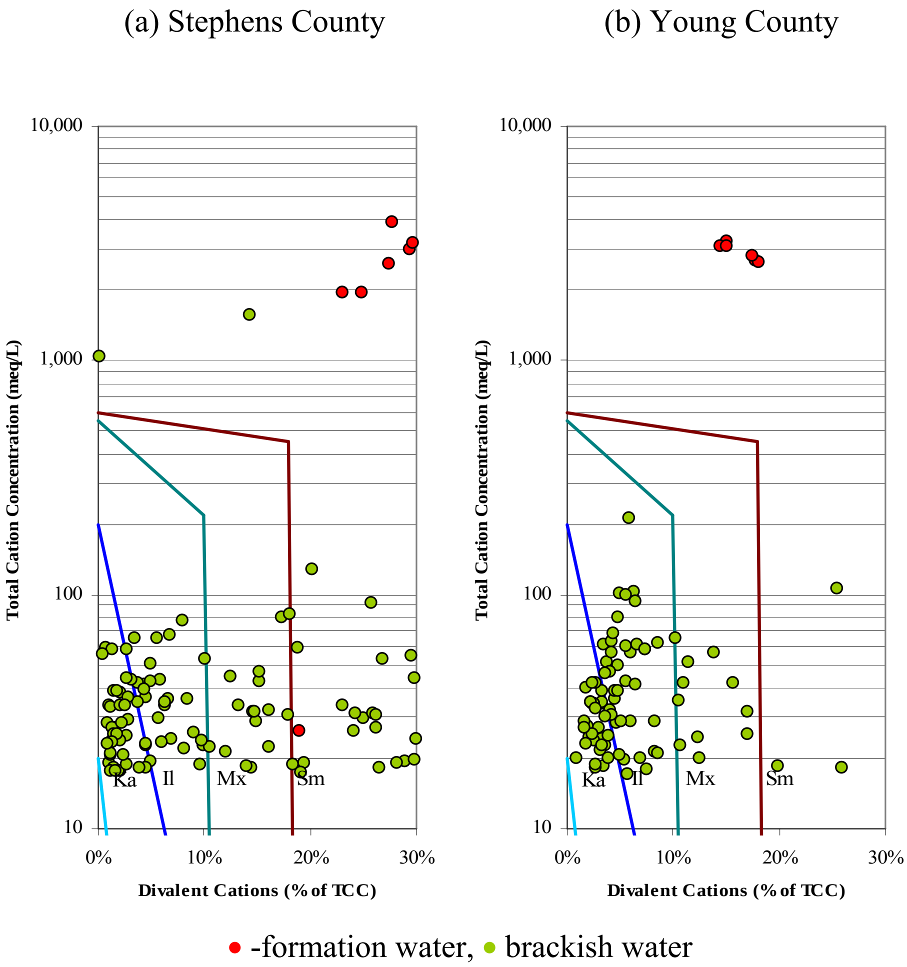
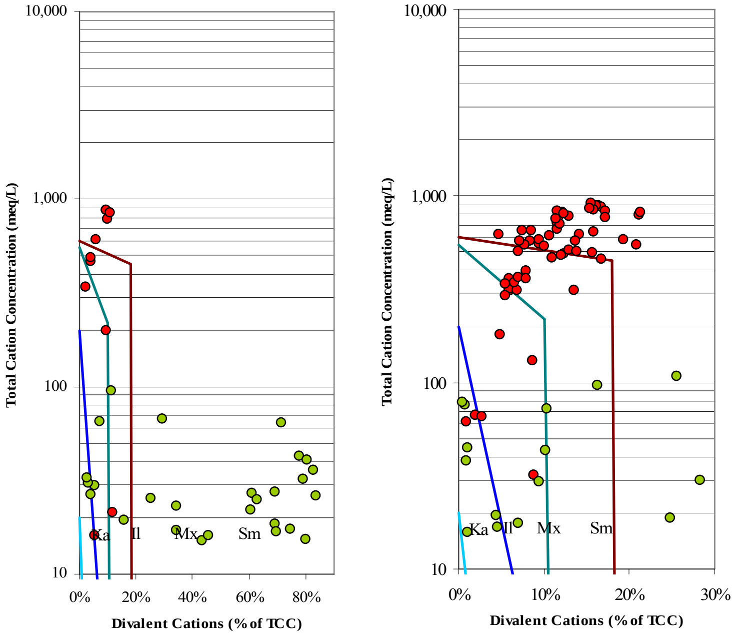
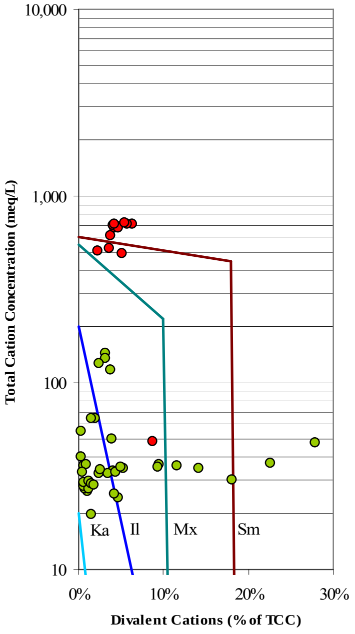


Figure 6-15. Total cation concentration and divalent cations for the brackish groundwater and the formation water of the Fort Worth Basin analysis area.



(a) Dimmit County (b) Zavala County

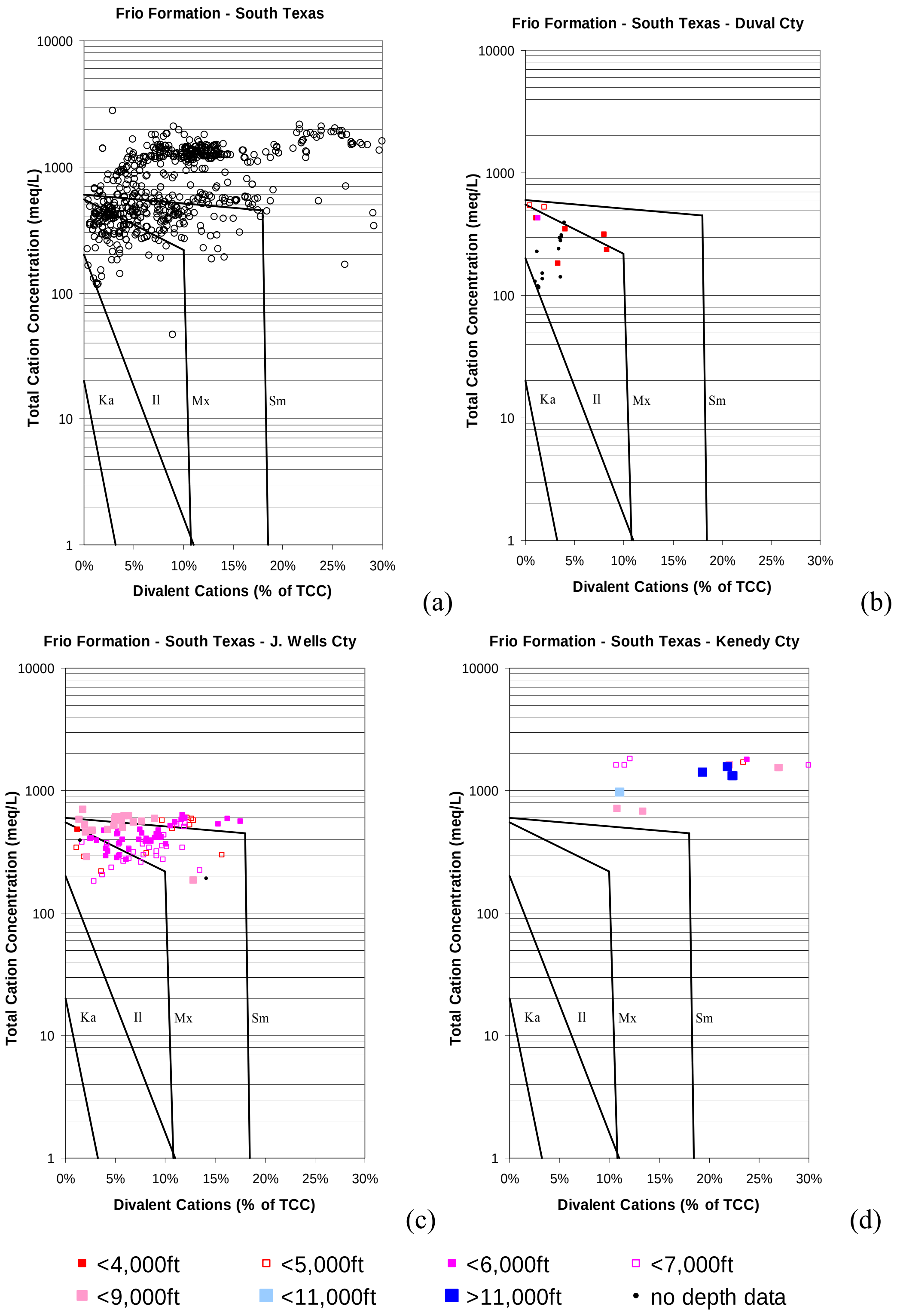
(c) Atascosa County



● -formation water, ● brackish water

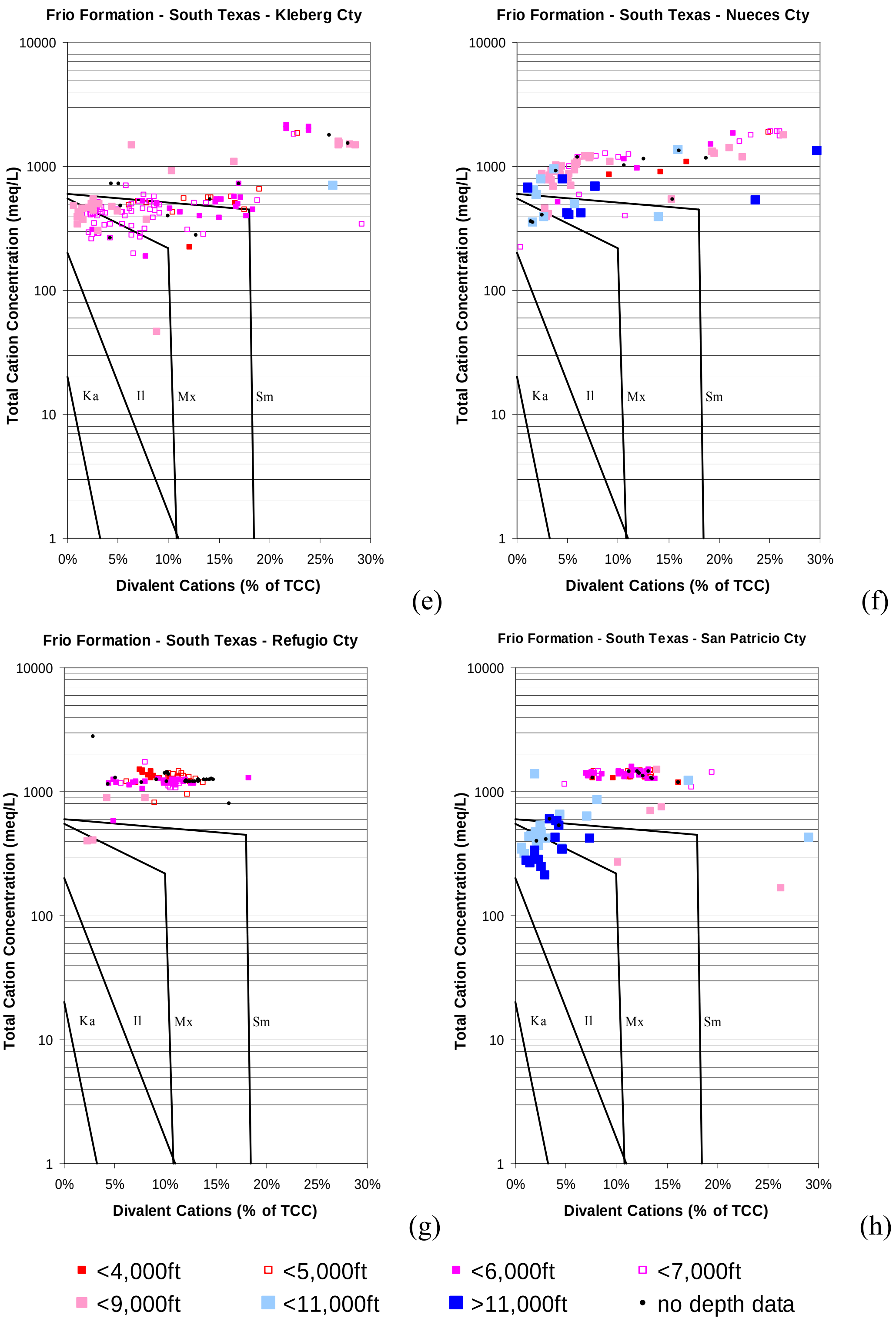
Note: Most of the brackish waters in Zavala County have high divalent cations and fall to the right of the smectite boundary (not shown).

Figure 6-16. Total cation concentration and divalent cations for the brackish groundwater and the formation waters of the Maverick Basin analysis area.



Ka=Kaolinite; Il=Illite; Mx=Mixed layers; Sm=Smectite

Figure 6-17. Total cation concentration and divalent cations for the formation water of the Southern Gulf Coast Basin.



Ka=Kaolinite; Il=Illite; Mx=Mixed layers; Sm=Smectite

Figure 6-17. Continued.

The depth range in the San Andres Formation in the Permian Basin is too narrow for this process to be viewed (Figure 6-11b, c, and d), although its initialization might be recognized in Ector County (Figure 6-11d). The same holds true for the Woodbine Formation in the East Texas Basin (Figure 6-13b, c, and d). Our data set for the Woodbine Formation contains a significant fraction of data points with no depth information. A trail towards the illite salinity line in Rusk County (Figure 6.13c) suggests that illite may be dominant in the southern part of the analysis area. Some other counties of the southern Gulf Coast analysis area are similar to San Patricio County (for example, Figure 6-17f for Nueces County). Other counties (for example, Figure 6-17c for Jim Wells County and Figure 6-17e for Kleberg County) may have formation waters that are at equilibrium with mixed-layer clays rather than smectite, even at shallow depths (<4,000 feet). In most cases, formation water sensitivity is likely controlled by smectite except in the southern Gulf Coast Basin where it may be controlled by mixed-layer clays and even possibly illite in the deeper sections of the Frio Formation.

The injected concentrate is likely not at equilibrium with the formation clays. However, all brackish water samples fall outside the smectite salinity line in the Anardarko Basin (Figure 6-10). Approximately 75 percent of the concentrate data points (measured as points with a divalent cations fraction of TTC of at least 20 percent) fall outside the smectite salinity line in the Permian Basin (Figure 6-12). Most of the Carrizo-Wilcox concentrate data points fall within the smectite salinity line, and only 65 percent fall outside the illite salinity line (Table 6-3). Similarly, the Fort Worth Basin analysis area contains more than half of the brackish water samples that fall inside the smectite salinity line (Figure 6-15). Most of the brackish water samples in the Maverick Basin analysis area fall outside the smectite salinity line (Figure 6-16). The southern Gulf Coast analysis area has 29 and 58 percent of the data points outside the illite and smectite salinity lines, respectively (Figure 6-18). Some basins, particularly the East Texas Basin and the Fort Worth Basin, could present a challenge for concentrate injection. The Anadarko Basin and Permian Basin analysis areas should be amenable to concentrate injection. The Maverick Basin and southern Gulf Coast Basin analysis areas may or may not be amenable to concentrate injection.

This first step of the water sensitivity approach eliminates those waters likely to generate formation damage. However, even seemingly compatible water can generate problems owing to cation stripping. The propensity of an injection water to undergo cation stripping is measured by the MAR ratio ($MAR_{i/f}$ = MAR of injected water / MAR of formation water). We used a statistical approach to analyze the issue. We determined the distributions of MAR of injection water and formation water. To calculate the distribution of the ratios, we sampled each MAR data set at random, computed the ratio, and plotted their statistical distribution. We used the risk-analysis package Crystal Ball® running under Excel (Crystal Ball, 2001) to do the analyses. We observed that a pretreatment of the concentrates is needed to avoid formation damage in nearly all mixing ratios of the concentrate and formation waters (Figure 6-19; Table 3-7).

## *6.5 Historical Account of Water Injection*

Economic factors often dictate the nature of the water selected for waterflood and pressure maintenance. Pumping and injecting fresh water may be cheaper than reinjecting produced waters or pumping water from saline aquifers, especially if they need treatment. In addition,

Table 6-3. Fraction of concentrate data points outside the smectite and illite salinity line.

| Basin | Fraction of concentrate data points outside the Smectite salinity line | Fraction of concentrate data points outside the Illite salinity line |
|---|---|---|
| Anadarko | 100% | 100% |
| Permian | 76% | 81% |
| East Texas | 9% | 65% |
| Fort Worth | 50% | 61% |
| Maverick | 50% | 58% |
| Southern Gulf Coast | 29% | 58% |

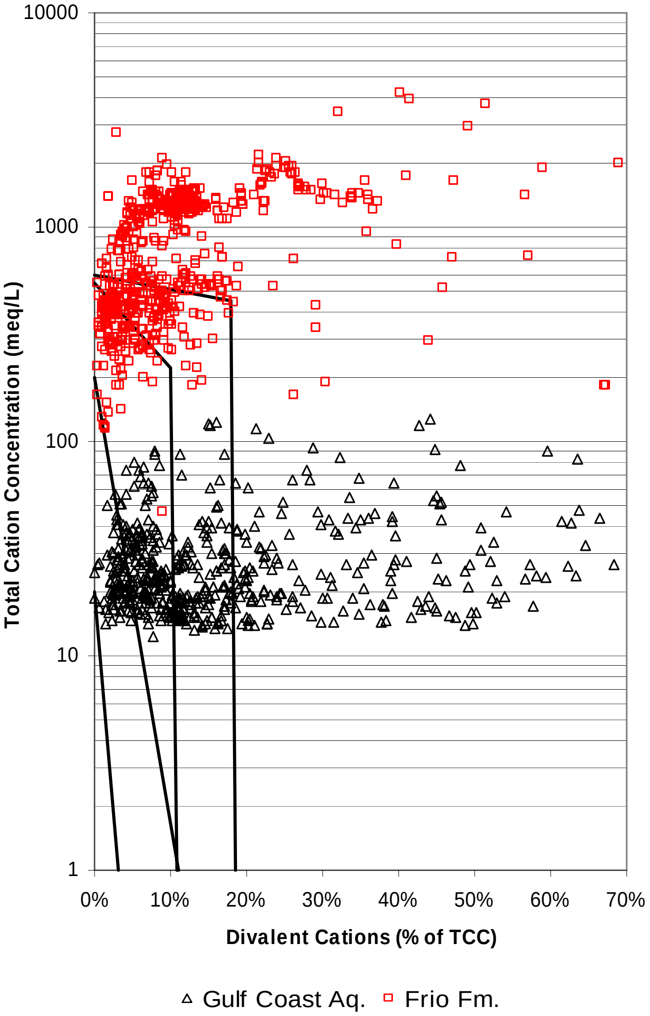


Figure 6-18. Total cation concentration and divalent cations for the concentrate and the formation waters of the Southern Gulf Coast Basin analysis area. Gulf Coast Aq = Gulf Coast aquifer, Frio Fm = Frio Formation.

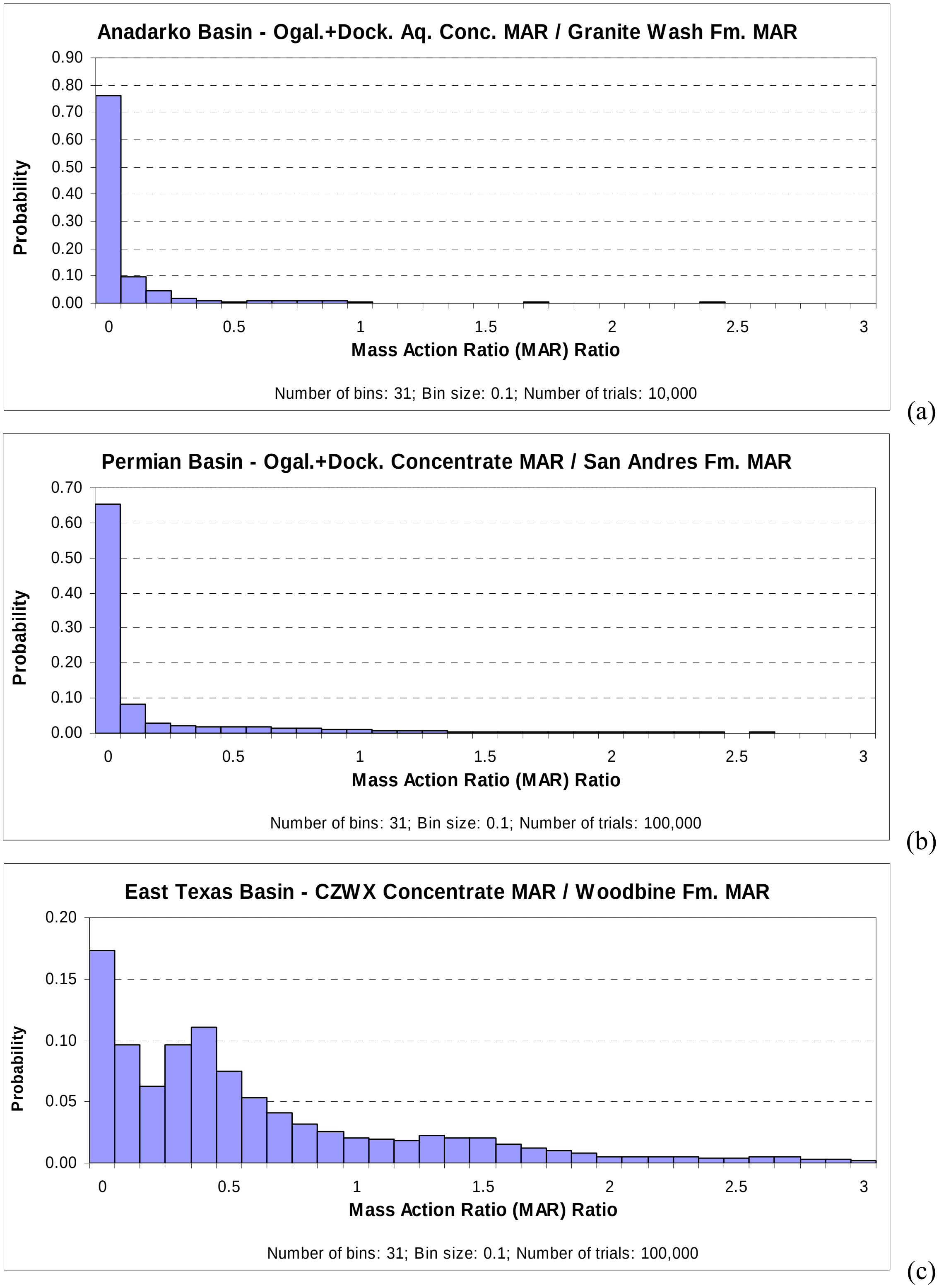


Figure 6-19. Distribution of mass action ratios for the analysis areas.

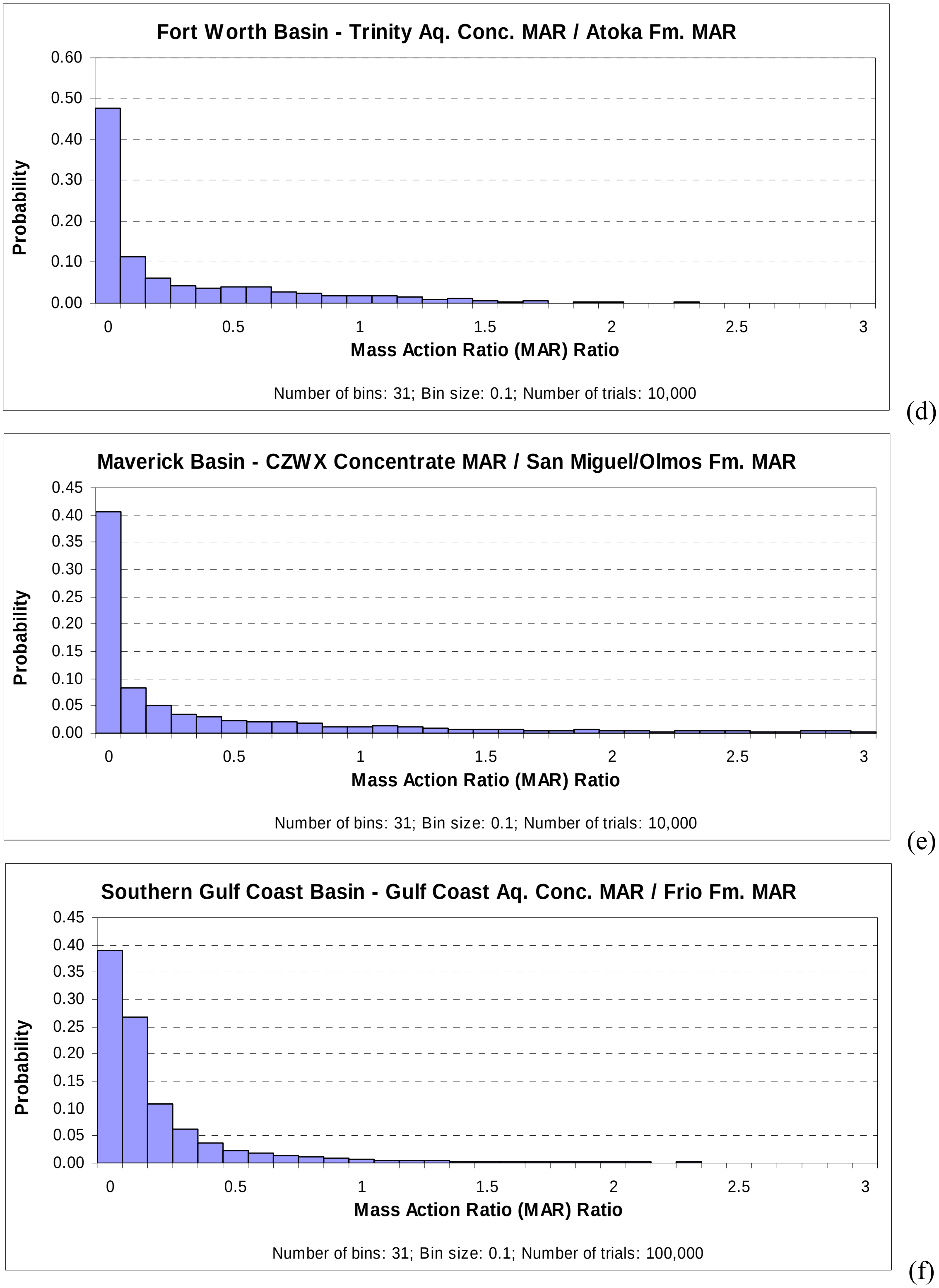


Figure 6-19. Continued.

fresh water does not generate as much corrosion and clogging on pipes and pumping equipment. It is also generally accepted that diluted brine leads to a higher oil recovery (for example, Tang and Morrow, 1997).

The last exhaustive compilation by the RRC of injection operations in Texas was done in 1982 (RRC, 1982). This document displays numerous tables with administrative as well as technical information on both active and abandoned projects. We compiled information from this document for the analysis areas. Although there is no information by producing formation, we believe that we can make conclusions on this information because (1) most of the depleted fields of the study area were already producing in the first half of the 20th century and (2) the depleted fields often account for a significant percentage of the basin cumulative production. In addition, fresh water aquifers were not as stressed by pumping in the past as they are today, and fresh water was more readily used for injection.

Different amounts of water have been injected into formations in the analysis areas (Figure 6-20 and Tables 6-4, 6-5). Injection of fresh water, mainly from the Ogallala aquifer, used to be very common in the Permian Basin. In the sixties, almost one percent of the fresh water produced from the Ogallala aquifer in Texas was used in waterflood and pressure maintenance operations. Anadarko Basin reservoirs were also heavily waterflooded with water from the Ogallala aquifer. A significant amount of fresh and brackish water was used in the Fort Worth Basin as well. The East Texas Basin also received some fresh water in addition to injecting produced water. The massive re-injection of produced waters from the East Texas field generated calcium sulfate, calcium carbonate, and silica in the treatment steps before entering the injection wells (East Texas Salt Water Disposal Company, 1958, p. 76). Aluminum and iron oxides were also precipitated, the former from alum added for coagulation of particulates and the latter from iron-based tubing. Average produced-water injection rate among about 75 wells active in the 1940s and 1950s varied between 150 and 200 gpm. In contrast, in the southern Gulf Coast, very little water injection was done. This is also true for the whole Texas Gulf Coast encompassing RRC districts 2, 3, and 4, including the Maverick Basin.

When we reviewed a smaller subset of H1 forms, we found that most of the injected water is produced water (Table 6-6). This smaller subset of H1 forms is a mix of more recent activity (from 2000) and older activity from the 1980s. We observe the same pattern as in district-wide numbers. there is major water injection in the Permian Basin, which was not under primary natural drive, and none in the southern Gulf Coast. Significantly, fresh water is often mixed with produced waters, presumably to limit formation damage. That same practice of blending water of different origins could also apply to desalination wastes. This historical perspective proves that at least some reservoirs in all analysis areas can accept fresh and brackish water in large amounts.

## *6.6 Injectivity Modeling*

Existing formation pressures in the study area are considerably lower than the hydrostatic pressure (Figure 4-1). The reported average and maximum injection rates for the analysis areas have medians of 30 gpm and 60 gpm, while the 95th percentiles are about 150 gpm and about 230 gpm (Figure 6-21). A rate of 60 gpm translates into a rate slightly smaller than 0.1 MGD. On the other end, Class I injection wells along the Texas Gulf Coast inject at an average rate of 100 gpm (Section 3.3.1) but could inject at a much higher rate.

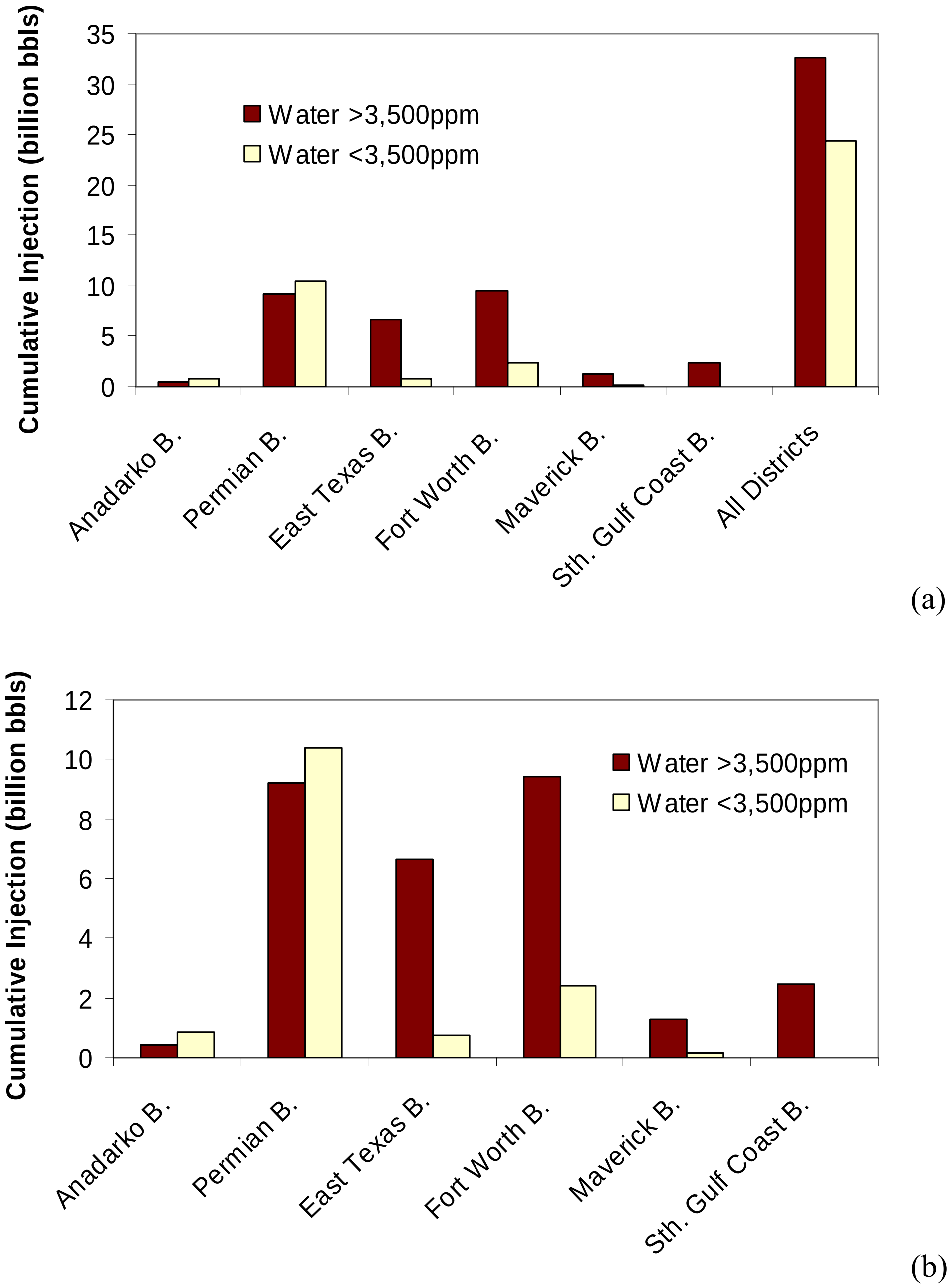


Figure 6-20. Cumulative volume of water injected up to 1981 (a) from districts including the study area and all districts in Texas and (b) only from districts including the analysis areas.

Table 6-4. Volume (thousand of bbls) of injected water in 1981 and cumulative volume up to 1981.

| RRC District (# of active wells) | Salt water >3,500 ppm* | Brackish water 1,000< - <3,500 ppm* | Fresh water <1,000 ppm* |
|---|---|---|---|
| **District 10 including Anadarko Basin** | | | |
| 1981 (758) | 20,492 | 0 | 14,480 |
| Cumulative | 403,859 | 0 | 835,682 |
| **District 8 including Permian Basin** | | | |
| 1981 (9,899) | 617,235 | 440,352 | 81,245 |
| Cumulative | 9,204,619 | 8,345,495 | 2,032,220 |
| **Districts 5 then 6 including East Texas Basin** | | | |
| 1981 (169) | 9,344 | 37 | 1,028 |
| Cumulative | 184,401 | 162 | 15,605 |
| 1981 (502) | 57,498 | 2,425 | 24,611 |
| Cumulative | 645,0997 | 70,512 | 663,108 |
| **Districts 7B then 9 including Fort Worth Basin** | | | |
| 1981 (1,654) | 133,453 | 1,423 | 41,533 |
| Cumulative | 2,826,445 | 74,583 | 788,338 |
| 1981 (4,683) | 292,279 | 3,264 | 12,117 |
| Cumulative | 6,605,868 | 152,478 | 1,369,369 |
| **District 1 including Maverick Basin** | | | |
| 1981 (1,162) | 12,409 | 17,264 | 3,367 |
| Cumulative | 1,297,012 | 78,666 | 56,453 |
| **District 4 including Southern Gulf Coast Basin** | | | |
| 1981 (424) | 79,645 | 0 | 0 |
| Cumulative | 2,440,605 | 11,211 | 1,910 |
| **All Texas Districts** | | | |
| 1981 (27,160) | 2,211,593 | 518,745 | 597,325 |
| Cumulative | 32,672,449 | 9,689,473 | 14,655,851 |

Source: Table 4, RRC (1982)
Notes: Cut-off values for brackish and saline waters from RRC (1982).

Table 6-5. District-wide average injection rates for active wells in 1981.

| RRC District (# of active wells) | Injected volume in 1981 (1,000 bbls) | Rate/well (bbl/day)* | Rate/well (gpm) |
|---|---|---|---|
| **District 10 including Anadarko Basin** | | | |
| 758 | 34,972 | 126.3 | 3.7 |
| **District 8 including Permian Basin** | | | |
| 9,899 | 1,138,832 | 315.0 | 9.2 |
| **Districts 5 then 6 including East Texas Basin** | | | |
| 671 | 94,943 | 387.4 | 11.3 |
| **Districts 7B then 9 including Fort Worth Basin** | | | |
| 6337 | 484,069 | 209.1 | 6.1 |
| **District 1 including Maverick Basin** | | | |
| 1,162 | 33,040 | 77.8 | 2.3 |
| **District 4 including Southern Gulf Coast Basin** | | | |
| 424 | 79,645 | 514.3 | 15.0 |
| **All Texas Districts** | | | |
| 27,160 | 3,327,663 | 335.4 | 9.8 |

Table 6-6. Selected injection information from RRC H1 form.

| Number of forms examined | Number of forms with relevant data | Number of forms with non-produced water sources | Source | # |
|---|---|---|---|---|
| **Anadarko Basin** | | | | |
| 34 | 34 | 0 | | |
| **Permian Basin (injection into the San Andres – Grayburg Formations** | | | | |
| 370 | 48 | 23 | Prod. water and Santa Rosa Fm | 9 |
| | | | Prod. Water, Santa Rosa, and Ogal. Fm | 1 |
| | | | Prod. Water and Ogal. Fm | 9 |
| | | | Ogallala Fm | 1 |
| | | | Surface water and unidentified source | 3 |
| **East Texas Basin (injection into the Woodbine Formation)** | | | | |
| 47 | 47 | 2 | Lower Wilcox Fm for polymer floods | 2 |
| **Fort Worth Basin** | | | | |
| 43 | 43 | 4 | Formation water from Caddo Lime/Conglomerate, and brackish/fresh water | 4 |
| **Maverick Basin** | | | | |
| 38 | 38 | 3 | Formation water, Olmos/ San Miguel Formation, and commercially available fresh water | 3 |
| **Southern Gulf Coast Basin (injection into the Frio Formation)** | | | | |
| 41 | 41 | 0 | | |

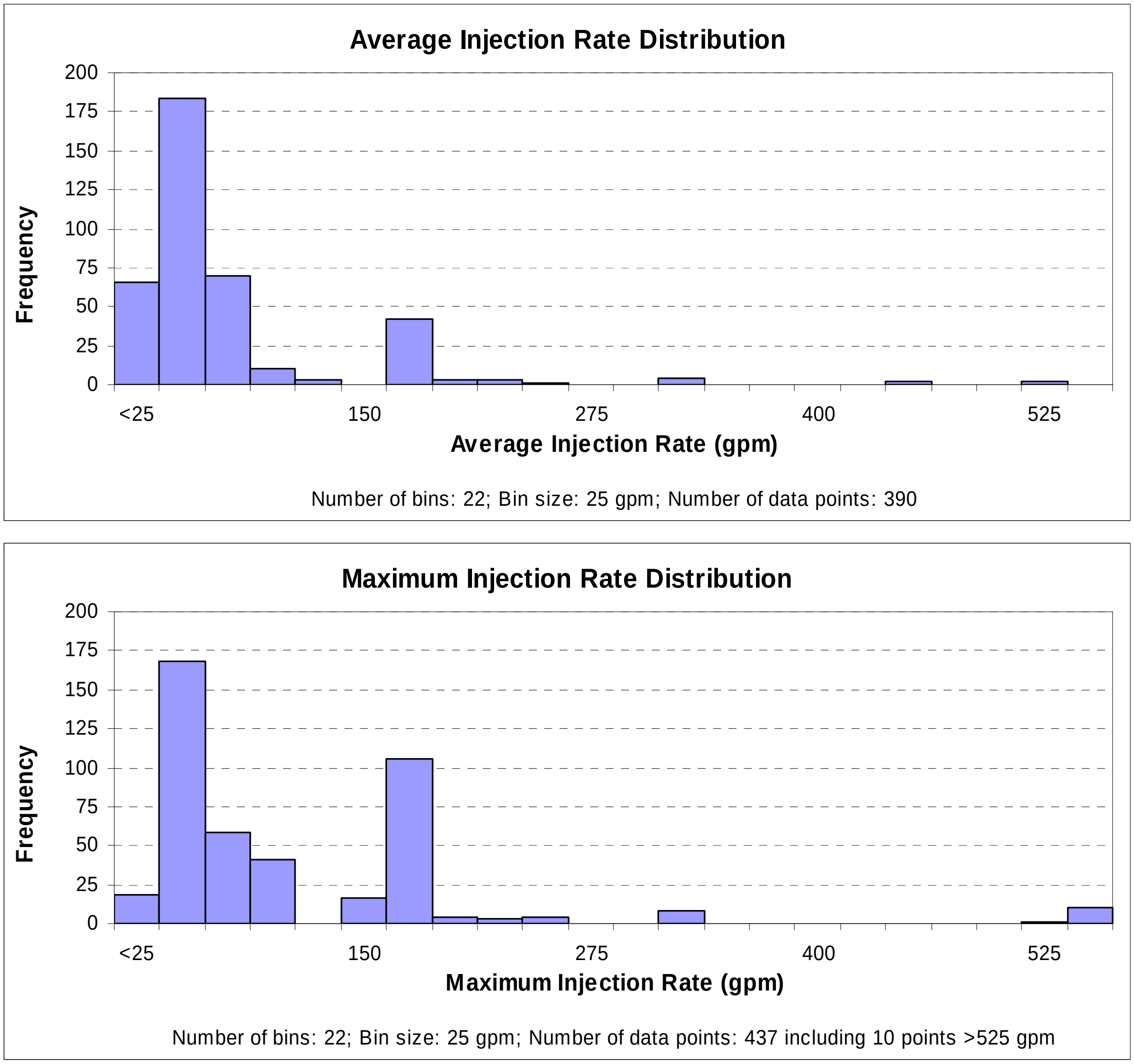
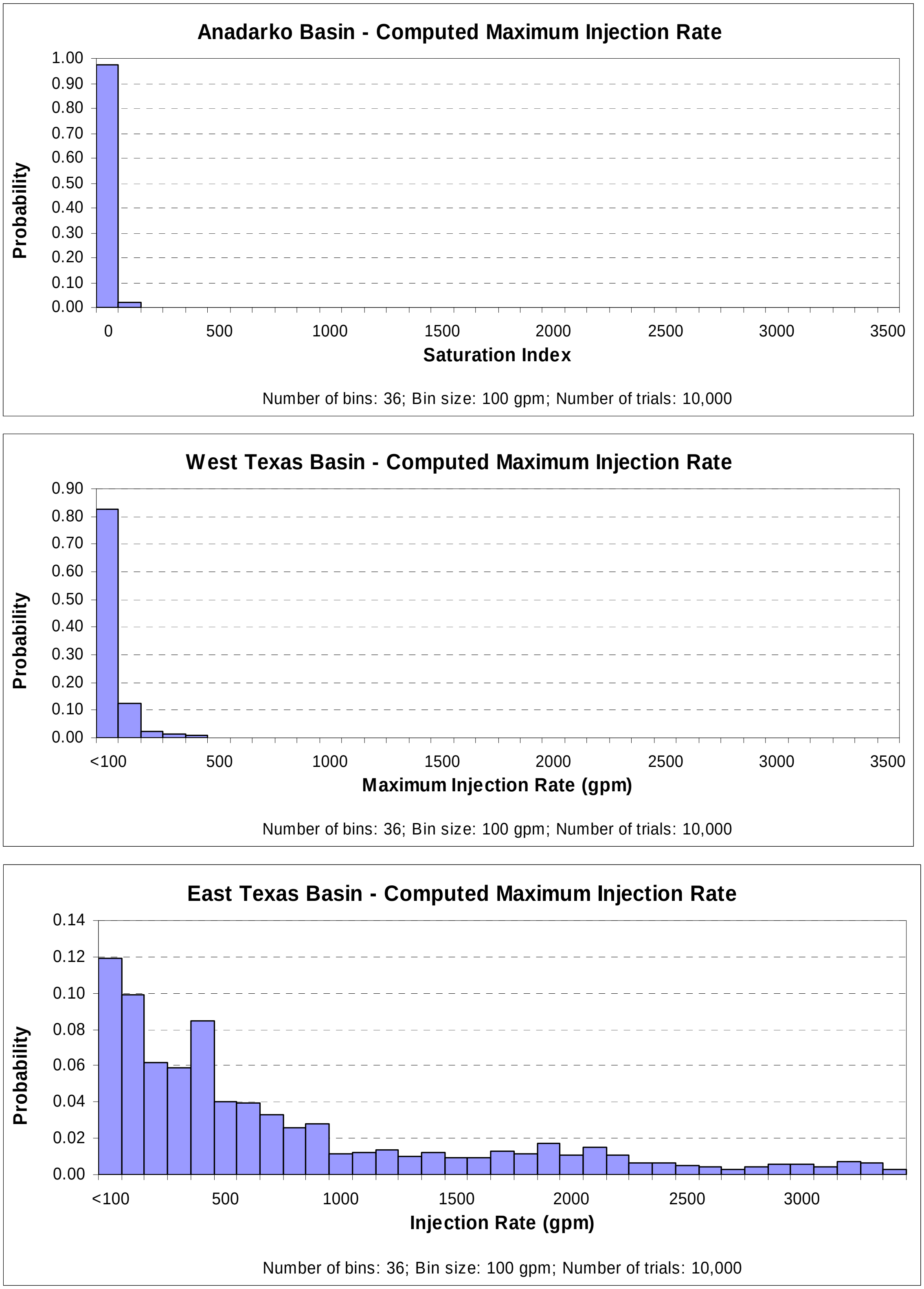


Figure 6-21. Distribution of injection rate (data from RRC form H1).

Depending on the facility size, a cluster or multiple clusters of wells may be needed. A facility generating 1 MGD of concentrate would need a least 10 injection wells as currently operated.

The number of injection wells needed to dispose desalination concentrates depends on the facility size as well as the average injection rate, a function of formation permeability (Section 3.3.4). We completed the statistical analyses with the risk-analysis package Crystal Ball® running under Excel (Crystal Ball, 2001) to generate the possible range of injection rates. We randomly varied the parameters (except porosity and permeability, which we varied according to their linear correlation coefficient) to calculate injection rates (Figure 6-2; Table 6-7). The distributions of injection rates include all collected porosity and permeability data and are therefore biased towards low injection rates. They may not be representative of the set of higher performing wells that will likely be used to inject fluids. The median injection rate is about 10 gpm in the Paleozoic basins while it reaches 278 and 466 gpm in the southern Gulf Coast and

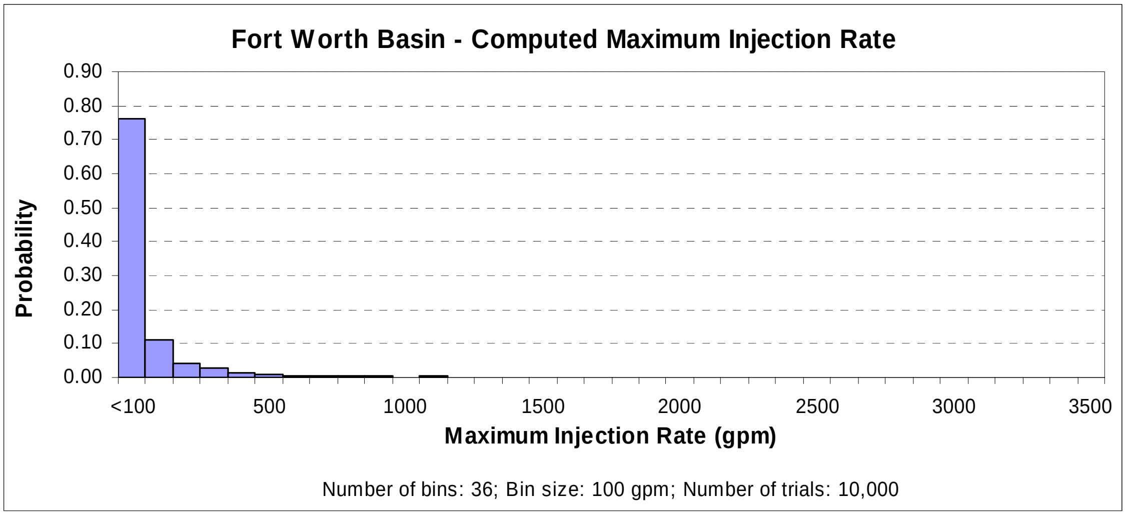


Number of bins: 36; Bin size: 100 gpm; Number of trials: 10,000

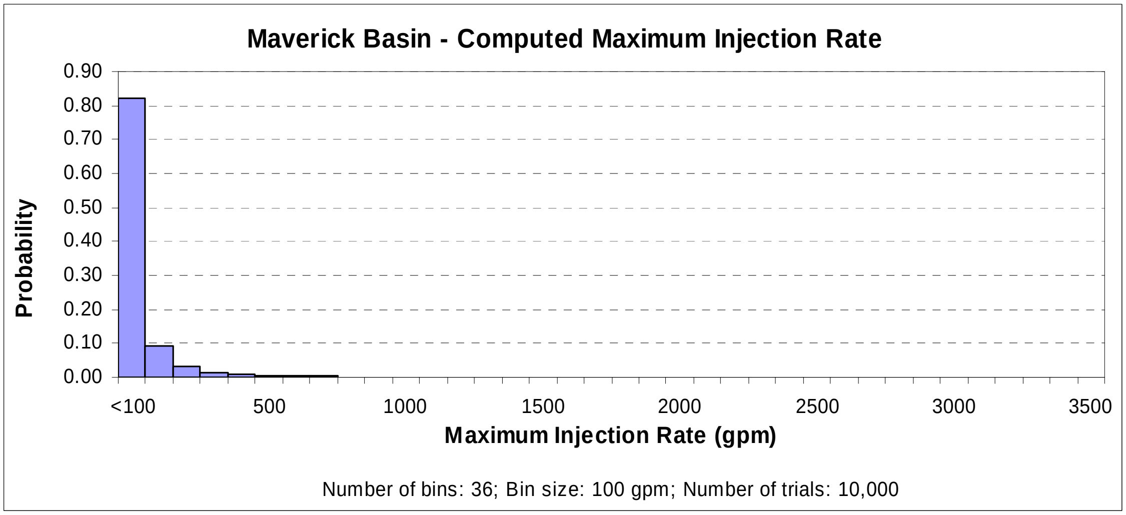
Number of bins: 36; Bin size: 100 gpm; Number of trials: 10,000

Number of bins: 36; Bin size: 100 gpm; Number of trials: 10,000

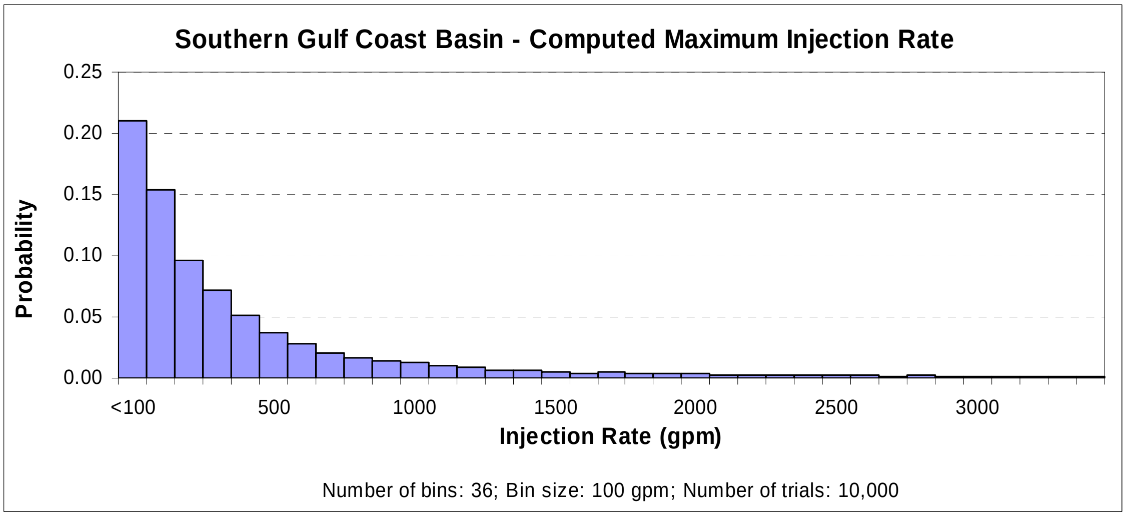
Figure 6-22. Distribution of computed maximum injection rate (no skin effect).


Fort Worth Basin - Computed Maximum Injection Rate

Number of bins: 36; Bin size: 100 gpm; Number of trials: 10,000


Maverick Basin - Computed Maximum Injection Rate

Number of bins: 36; Bin size: 100 gpm; Number of trials: 10,000


Southern Gulf Coast Basin - Computed Maximum Injection Rate

Number of bins: 36; Bin size: 100 gpm; Number of trials: 10,000

Figure 6-22. Continued.

Table 6-7. Computed injection rate statistics.

| Basin | 5th Percentile injection rate (gpm) | Median computed injection rate (gpm) | 95th percentile injection rate (gpm) |
|---|---|---|---|
| **Anadarko** | | | |
| | 2.3 | 7.3 | 22.8 |
| **Permian** | | | |
| | 1.5 | 13.2 | 152.7 |
| **East Texas** | | | |
| | 16.1 | 466 | 3,347 |
| **Fort Worth** | | | |
| | 0.3 | 9.8 | 376.4 |
| **Maverick** | | | |
| | 0.3 | 6.3 | 269.9 |
| **Southern Gulf Coast** | | | |
| | 29.8 | 278 | 9,038 |

East Texas Basins, respectively. The rate could also be increased by screening more intervals and performing well stimulation.

## *6.7 Possible Permitting Paths*

The EPA did not specifically consider the injection of concentrate from desalination operations when they published their final technical regulations for the UIC program in 1980. This is because injection of concentrate was not an issue when they wrote the regulations. Many believe that concentrate disposal wells logically fall under Class I because Class I includes municipal waste in its definition. However, others believe that concentrate disposal wells could also be permitted under Class V.

The options discussed below source from discussions with permitting experts at the EPA, EPA Region 6, TCEQ, and RRC (Appendix 3). Our lawyers also reviewed federal and state statute and rules. The first four options can be achieved now with current EPA and TCEQ regulations, although in some cases the process could be made easier. The last three options would require memos of agreement, changes in regulations, and/or changes in statute.

### 6.7.1 Non-Hazardous Class I

In Texas, the requirements for a non-hazardous municipal Class I injection well are similar to the requirements for a hazardous Class I injection well. These requirements are more stringent than EPA regulations. Permitting concentrate injection wells could be made easier in Texas if the state adopted minimum EPA standards for permitting non-hazardous Class I injection wells. Recent state legislation (House Bill 2567 of the 78th Texas Legislature) eliminated the contested case hearings from Class I injection wells disposing of concentrate from desalination operations.

TCEQ could make permitting, construction, and operation easier and less expensive by adopting EPA minimum requirements for municipal non-hazardous Class I injection wells.

### 6.7.2 Class II

There is a way to inject concentrate in an existing Class II well without having to acquire a Class I permit: injecting the concentrate as 'make-up' water as part of enhanced recovery operations. Oil-field operators often flood their reservoirs with water to liberate additional oil. While water produced from the formation may be enough for these enhanced recovery operations, operators may need water in addition to that produced from the formation, what operators call 'make-up' water. If concentrate was the source of make-up water, there would be no need for any additional permitting. However, a desalination plant would need assurances that an oil operator could consistently accept the volume of concentrate for a set period of time for this to be a realistic option.

### 6.7.3 Class V

Depending on the quality of the concentrate and formation water, it may be possible to permit a concentrate disposal well as a Class V injection well. El Paso Water Utilities (EPWU) is considering this option for the disposal of their concentrate (Bill Hutchison, EPWU, personal communication). In EPWU's case, the formation in question has a TDS less than 10,000 ppm, and their concentrate is expected to be of better quality than the formation water. Therefore, because they are disposing concentrate in an underground source of drinking water (USDW), something not considered in the other injection well classes, they may be eligible for a Class V permit. A Class V permit is desirable in this case because the permit can be granted by rule with a turnaround time of about 60 days. The EPA could consider creating a special sub-class of Class V injection wells for the disposal of concentrate.

### 6.7.4 Dual-Permitted Wells

One way to dispose of concentrate in a Class II injection well is to also permit that injection well as Class I or perhaps also as a Class V. However, for a Class I/Class II well, the well would have to meet TCEQ's construction requirements for a Class I well and follow the TCEQ Class I process in acquiring a permit. A dual-permitted well would then be able to accept Class I and Class II fluids. Texas currently has some Class I/Class II permitted wells (Steve Seni, RRC, personal communication, 2004).

### 6.7.5 General Permit for Class I Concentrate Injection Wells

A general permit would greatly simplify and decrease the time to attain a Class I permit. A general permit would involve getting a permit for a general class of injection wells. In this case, the general class of wells would be concentrate injection wells. Approval of the general permit requires going through the full approval process of a Class I injection well. Once a general permit is attained, anyone can apply for a permit under the general permit. If those permits meet the requirements set forth in the general permit, then the permit is granted. The advantage of the general permit is that it reduces the permitting process to an administrative review. If the application meets the requirements set forth in the general permit, the permit is granted. Therefore, instead of taking one to three years to attain a Class I permit, it might take as little as 60 days for a complete application. Implementation of a general permit would require approval of the concept of general permitting by TCEQ.

### 6.7.6 Special Class I for Concentrate Disposal in Class II

Because most of the UIC program is a legacy program, that is, under the control of the state, some believe that the state can create its own category under Class I for the disposal of concentrate in Class II wells. Under this scenario, TCEQ, in cooperation with RRC, would create a special Class I category that would grant a Class I permit to a well for concentrate disposal if the well already has a Class II permit. This process would only require an administrative review, a review that could be completed within 60 days. However, this approach may require that candidate wells meet Class I construction requirements. This requirement would decrease the number of qualified Class II wells. As a result of this study, the TWDB, TCEQ, EPA, and RRC are considering this option.

### 6.7.7 Change the Federal Regulations

The federal regulations could be changed in a number of ways to assist in the disposal of concentrate. However, EPA seems to be reluctant to open up its rules to accommodate desalination operations. Regardless, changing EPA’s rules is likely to be a long and onerous process. The desalination industry has attempted to induce wholesale changes to EPA’s rules concerning concentrate disposal with little success. Nevertheless, changes in the EPA’s rules could include a special category of Class V injection wells for desalination that considers the specifics of concentrate disposal. EPA could also change the definition of what is allowed to be injected into Class II wells to include desalination concentrates. Another option is to create a special category of Class I injection wells for concentrate disposal considering the special concerns of the disposal.

# 7.0 Conclusions

Based on our study, we developed conclusions on (1) formation pressure conditions in depleted oil and gas fields and implications for area of review (AOR) variance, (2) potential for scale formation due to mixing of desalination concentrates and formation water using PHREEQC and SOLMINEQ geochemical codes, (3) water sensitivity of fines and clays in the formations of depleted oil and gas fields to injected waters, (4) injection rate, which we calculated for each site on the basis of local porosity and permeability conditions, and (5) permitting options.

Formation pressure conditions of the depleted oil and gas fields indicate that a significant number of the wells would qualify for an AOR variance. A high percentage of wells could potentially receive the variance because the analysis areas are largely pressure-depleted. For each analysis area, we examined distribution of pressure conditions with depth relative to the base of usable quality water (BUQW) on a well-by-well and field-by-field basis. Large pressure depletions in the Anadarko Basin, where 67 percent of the fields could potentially receive an AOR variance, are very favorable. In the Permian, East Texas, and Fort Worth basins, between

50 to 60 percent of the fields could potentially receive an AOR variance. The Maverick Basin is an anomaly among the six analysis areas because only 35.5 percent of the fields appear favorable for an AOR variance. In the southern Gulf Coast Basin, about 56 percent of the fields have a separation greater than 500 feet between the top of the fluid in the formation and the BUQW.

We used PHREEQC and SOLMINEQ geochemical codes along with a Monte Carlo statistical approach to analyze the results of mixing formation water and concentrate. Results are reported in terms of saturation indices (*SI*) of the scale-prone minerals calcite, gypsum, barite, and silica. Potential feed waters are mainly undersaturated relative to calcite, gypsum, and silica. The barite saturation indices for some basins, particularly the Anadarko Basin, suggest that the basins are supersaturated with respect to barite. However, given the low solubility of barite, the high saturation indices may also be due to erroneous temperature field measurements. In most cases, acidification of the concentrate drops the calcite saturation index by an order of magnitude, bringing it below a value of 0. The other minerals analyzed (gypsum, barite, and silica) show small variations in *SI* due to the changes in the ionic strength with the addition of acid and sulfate ions (more evident for gypsum and barite). Formation waters from all analysis areas show supersaturation with respect to calcite and, to a much lesser degree, gypsum. It is common for calcium carbonate to be supersaturated.

Saturation indices for the mixing solutions fall between those of the formation water and acidified concentrate. *SI* values of several samples exceed the theoretical threshold for precipitation (*SI*=0) for the various combinations of mixing of concentrate/formation water. However, addition of anti-scalant products will increase the threshold to a value of approximately 2. This value is retained as the saturation index beyond which recurrent scaling problems could occur during the injection. The threshold value of 2 is exceeded only in the East Texas Basin for barite where the 95th percentile is 2.7. Nonetheless, it is important to note that the *SI* values obtained from batch modeling are based on the assumption that there is total mixing between the formation water and the concentrate. In reality, the injected concentrate may simply displace the resident formation water with little mixing.

Water sensitivity is of considerable importance in formation evaluations because deflocculation of clay can severely reduce permeability of the reservoirs and cause a reduction in injection flow rate. We used water compatibility guidelines for injection water following methods developed by Scheuerman and Bergersen (1990). Most of the data points for all the basins investigated except for the southern Gulf Coast Basin fall outside the smectite salinity line, suggesting that smectite in the formation is in equilibrium with the formation water. In the southern Gulf Coast Basin, most of the data points reach the illite salinity line. Occurrences of samples near the illite salinity line in Rusk County in East Texas Basin suggest that illite may be controlling clay deflocculation. Smectite clay is transformed progressively into illite with increasing depth and temperature. These mineralogical changes are highlighted by composition changes of the formation water. Therefore, we can conclude that water sensitivity in the formations are controlled by smectite except for the southern Gulf Coast, where mixed-layer clays and illite control water sensitivity in the deeper sections.

Injected concentrate derived from the overlying brackish water aquifer is unlikely to be at equilibrium with the formation clays in the reservoirs. However, all brackish water samples fall outside the smectite salinity line in the Anardarko Basin. Approximately 75 percent of the concentrate data points fall outside the smectite salinity line in the Permian Basin. Most of the Carrizo-Wilcox data points fall within the smectite salinity line and only 65 percent outside the illite salinity line. Similarly, more than half of the brackish water samples from the Fort Worth Basin analysis area fall inside the smectite salinity line. Most of the brackish water samples in the Maverick Basin analysis area fall outside the smectite salinity line. The southern Gulf Coast analysis area has 29 and 58 percent of the data points outside the illite and smectite salinity line, respectively. Concentrate injection in the East Texas and Fort Worth basins could present a challenge if operational solutions are carefully devised. Concentrate injection may not pose a problem in the Maverick and southern Gulf Coast basins. The Anadarko and Permian basins should be easily amenable to concentrate injection.

However, even apparently compatible water can generate problems owing to cation stripping. We used the mass action ratios ($MAR_{i/f}$ = MAR of injected water/MAR of formation water) of the different waters involved to assess cation stripping. Results of these analyses suggest that concentrate would need pretreatment for most combinations of concentrate and formation water.

We modeled injectivity variation by calculating the flow rate that would result from combining the formation physical characteristics (porosity, permeability, and compressibility) and pressure requirements (admissible surface pressure, well depth, and head loss). Multiple combinations of these parameters allied with a Monte-Carlo analysis using Crystal Ball® (Crystal Ball, 2001) show that the median injection rate for a single well is about 10 gpm in the Paleozoic basins and is about 280 and 470 gpm in the southern Gulf Coast and East Texas basins, respectively. It should be noted that the calculation includes all porosity and permeability values. The distribution is biased towards lower flow rates. An actual injection well will likely be located where permeability is higher. The rate could also be increased by screening more intervals and stimulating the well.

Based on the above results, we made a qualitative score table (Table 7-1) that lists high, medium, and low values for scaling tendency, water sensitivity, injection rate, and magnitude of pressure depletion. The score relative to scaling for all analysis areas was set at medium because barium scaling could not be ruled out with available data and information is missing for several important scale-forming minerals such as iron compounds. We rated the analysis areas in three groups according to their water sensitivity. The Anadarko and the Permian basins scored high because most of the concentrate samples fall outside the salinity line (that is, injection is sustainable with pretreatment). The Fort Worth, Maverick, and southern Gulf Coast basins received a medium score because a significant number of concentrate data points fall on the wrong side of the smectite salinity line. The East Texas Basin has very few concentrate samples located beyond the smectite salinity line and may require periodic stimulations. The injection parameter criterion places the analysis areas in two groups: Paleozoic basins (Anadarko, Permian, Fort Worth, and Maverick Basins) with potentially low injection rates and more recent basins (East Texas and southern Gulf Coast Basins) with much higher potential injection rates. All analysis areas rate favorably relative to pressure depletion criteria.

A general observation is that very few problems occur in an injection well owing to water incompatibility. This is because injectate (desalination concentrate) miscibly displaces the formation water. A sharp interface could exist between the injected and resident fluids. However, the interface is somewhat smoothed by diffusion and dispersion. Mixing calculations in this study are done assuming complete mixing (batch runs) and describe one end member of what is actually occurring, the other end member being where no mixing occurs at all. Batch modeling represents an upper limit on the amount of precipitation that can occur during the injection process.

Table 7-1. Summary of conclusions.

| Basin | Score relative to scaling | Score relative to water sensitivity | Score relative to injection rate | Score relative to pressure depletion |
|---|---|---|---|---|
| **Anadarko** | | | | |
| | Medium | High | Low | Very High |
| **Permian** | | | | |
| | Medium | High | Low | High |
| **East Texas** | | | | |
| | Medium | Low | High | High |
| **Fort Worth** | | | | |
| | Medium | Medium | Low | High |
| **Maverick** | | | | |
| | Medium | Medium | Low | High |
| **Southern Gulf Coast** | | | | |
| | Medium | Low-Medium | High | High |

Technical challenges of injecting desalination concentrates into oil-producing formations are not unlike those of injecting water from a source different from that of the formation water. The oil industry has a long history of dealing with such issues. This work suggests that injection of desalination concentrates in the formation water will likely not be a problem if the injection water and the formation are appropriately pretreated, as is done routinely by the oil industry in the application of produced waters.

To recommend changes to statute and rules that would allow the disposal of concentrate in oil and gas fields, we reviewed current statute and rules and met with staff from the Texas Railroad Commission, the Texas Commission on Environmental Quality, and the U.S. Environmental Protection Agency (headquarters and Region 6).

Depending on the specifics of the case, a desalination plant can obtain a Class I or Class V permit for concentrate disposal. The permitting process under Class I could be made easier if Texas followed EPA’s minimum requirements for a Class I municipal (non-hazardous) disposal well. Texas currently requires that non-hazardous Class I wells meet the same requirements as hazardous Class I wells. Recent legislation has eliminated the contested case hearings from Class I injection wells disposing of concentrate from desalination operations.

Disposal of concentrate in a Class II well would require a dual permit: Class I/Class II or Class II/Class V. However, to attain a dual permit, the well would have to meet Class I or Class V requirements. Concentrate could be injected directly into a Class II well with no additional permits if the concentrate was used in enhanced oil recovery. However, desalination plant operators would need assurances that oil field operators would take their volume of concentrate over the life of the plant.

The permitting process under Class I could be made easier by using a general permit. The general permit would experience all of the public hearings and scrutiny of the Class I process. However, once the general permit was approved, permit applications that met the requirements of the general permit would only need an administrative review: a savings of years and perhaps millions of dollars. Because Texas has primacy of its underground injection control program, it may also be possible to create a special category of Class I permitting for the disposal of concentrate in Class II permitted wells.

Another option is to change the permitting process at the federal level. These changes could include creating a special category under Class V, or allowing Class II disposal wells to accept concentrate. However, attempts to change these rules at the federal level have been an onerous and so far unsuccessful task.

In short, it is technically feasible to inject concentrate into oil and gas fields and there are several options for making the permitting of concentrate disposal wells easier and more affordable.

# 8.0 Acknowledgments

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This project involved a number of personnel with different expertise from the Texas Water Development Board and the University of Texas at Austin, Bureau of Economic Geology. Bill Mullican came up with the original idea of pursuing this project. He and Dave Mitamura traveled to Washington, D.C. to investigate changing federal rules concerning concentrate disposal. Bill Mullican, and Jorge Arroyo met and talked with TCEQ, RRC, and EPA Region 6 staff a number of times concerning current permitting and possible changes. Srin Surapanani provided a review of federal statutes concerning disposal options. Brent Christian conducted a phone survey of desalination plant operators in Texas on their disposal methods. Randy Larkin provided insight into permitting and helpful reviews. Phyllis Thomas oversaw contracting.

We are also grateful for the time and patience of the ‘owners’ of the permitting process in assisting us in understanding the permitting process and identifying ways to facilitate concentrate disposal: Tony Bennett, Michael D. Cowan, Ben Knape, Bryan Smith, and Mark Vickery (Texas Commission on Environmental Quality); Fernando De Leon, Richard Ginn, Steve Seni, and Robert Traylor (Railroad Commission); Ben Grumbles (EPA); Philip Dellinger, Ray Leissner, and Gilbert Tellez (EPA Region 6); and Mike Slayton (St. Johns River Water Management District).

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# Appendix 1 – Chemical Analyses

Because chemical analyses are used in geochemical runs, it is important to ensure their consistency. Data used in this study come from different sources of variable quality. We checked the internal consistency of the water analyses by making sure that the sum of the ions was close to the TDS value and that the sample was charge-balanced. We took the following steps for each chemical data set as applicable:

- Retained the latest analysis if there were more than one analysis.
- Computed TDS from the sum of ions and compared this sum to the given TDS. The TDS given in older databases or older samples in newer databases are often lower than the sum of ions. This is because, in past decades, TDS was often measured as the weight of the residue after total water evaporation. However, about half of the bicarbonate would be converted into gas during calcite precipitation. This results in a true TDS higher than the reported TDS. The formula is:

$$Ca + 2HCO_3^- \Longrightarrow CaCO_3 + H_2O + CO_2$$

- More recent analytical techniques report the true TDS.
- Deleted analyses with an electrical balance outside the permissible range.
- Deleted analyses showing “red flags” as shown in Table A1-1.
- Retained only those samples with a TDS>1,000 mg/l and <10,000 mg/l.
- If no temperature given, used the median of given temperature.

Our approach follows the general rules of the Quality Assurance tests from the American Water Works Association “Standard methods” reference (Clesceri and others, 1998). Other criteria are discussed in Hitchon and Brulotte (1994) and Collins (1975, Chapters 2 and 3).

Table A1-1. Criteria for assessing quality of chemical analyses.

| Criteria | Action if met | Rationale |
|---|---|---|
| TDS=Σ(ions) | suspicion | Non-analysis of Na. Na could be backcalculated from TDS. This would yield a perfect charge balance |
| Σ(ions+)= Σ(ions-) | suspicion | non-analysis of Na |
| TDS>>Σ(ions) or TDS<<Σ(ions) | deletion | Incomplete analysis |
| Σ(ions+)>> Σ(ions-) or Σ(ions+)<<Σ(ions-) | deletion | Incomplete analysis |
| Ph<4 or Ph>9 | deletion | likely contamination by acid wash or cement wash |
| K>Na | deletion | likely contamination by KCl mud in oil wells |
| K missing | suspicion | Incomplete analysis or K grouped with Na |
| Mg>Ca | deletion | Signifies loss of $CO_2$ and calcite precipitation |
| OH or $CO_3$ reported | suspicion | Equivalent to a high pH |
| High Fe | suspicion | Pipe or other material corrosion |
| Ba missing | | |
| High $NO_3$ | deletion | Surface contamination for oil wells, probably located in an otherwise fresh water zone |

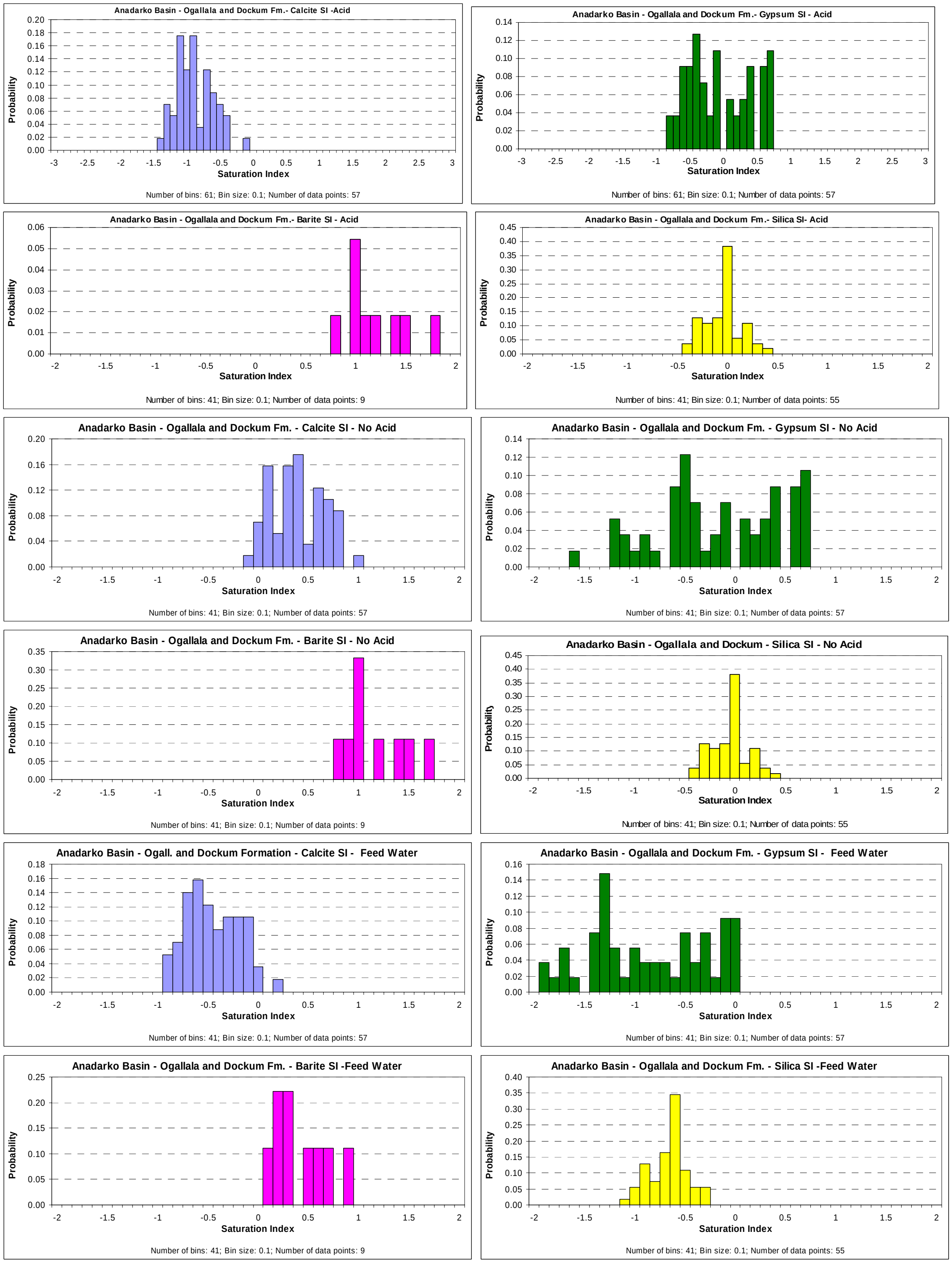
# Appendix 2 – Formation Water Sampling

Given the complexity of sampling formation water, collected samples may not always accurately reflect the chemistry of the formation. Formation waters can be sampled at different locations on the production line following different procedures. Reliability of the different sampling techniques can vary (USGS, 2002) (Table A2-1). Those sampling methods are discussed in API (1998, 2003). We only used analyses with grades of A or B in this study. The best analyses are those samples taken during production (but not too soon because of the influence of drilling mud and other testing materials). Fluids recovered during tests can also be usable. All other modes of sampling are only marginally useful. There are two main problems during sampling: loss of dissolved gas ($CH_4$, $CO_2$, $H_2S$, $O_2$) and carbonate precipitation. Those losses occur mainly due to change in temperature/pressure and lack of data for the temperature and pressure conditions of the analysis. The pH of the formation will change because of oxidation of reduced species and release of dissolved gas. We assumed that all pHs were determined in the lab at $20^oC$ and that no $CO_2$ loss occurred.

Table A2-1. Grading of formation water sampling methods.

| Location | Possible Problems | USGS Grade |
|---|---|---|
| Production | | B |
| Well head | | B |
| Bomb | | C |
| Drill Stem Test (DST) | Improper sampling | C |
| Formation Test | | C |
| Production Test | | C |
| Bailer | evaporation | D |
| Swab | contamination | D |
| Bleeder | | E |
| Heater/Treater | Gas venting, multiple wells, corrosion | E |
| Open Hole | Gas venting, mixing with condensed water | E |
| Separator | Gas venting, multiple wells, corrosion | E |
| Tank | Gas venting, evaporation, corrosion | E |
| Unknown | | F |

# Appendix 3 – Histograms of Saturation Indices



Anadarko Basin - Ogallala and Dockum Fm.- Calcite SI -Acid

Number of bins: 61; Bin size: 0.1; Number of data points: 57

Anadarko Basin - Ogallala and Dockum Fm.- Gypsum SI - Acid

Number of bins: 61; Bin size: 0.1; Number of data points: 57

Anadarko Basin - Ogallala and Dockum Fm.- Barite SI - Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 9

Anadarko Basin - Ogallala and Dockum Fm.- Silica SI- Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 55

Anadarko Basin - Ogallala and Dockum Fm. - Calcite SI - No Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 57

Anadarko Basin - Ogallala and Dockum Fm. - Gypsum SI - No Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 57

Anadarko Basin - Ogallala and Dockum Fm. - Barite SI - No Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 9

Anadarko Basin - Ogallala and Dockum - Silica SI - No Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 55

Anadarko Basin - Ogall. and Dockum Formation - Calcite SI - Feed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 57

Anadarko Basin - Ogallala and Dockum Fm. - Gypsum SI - Feed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 57

Anadarko Basin - Ogallala and Dockum Fm. - Barite SI -Feed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 9

Anadarko Basin - Ogallala and Dockum Fm. - Silica SI -Feed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 55

Figure A3-1. Saturation indices of scale-forming minerals for the concentrate with and without acidification and for the feed water (Anadarko Basin).

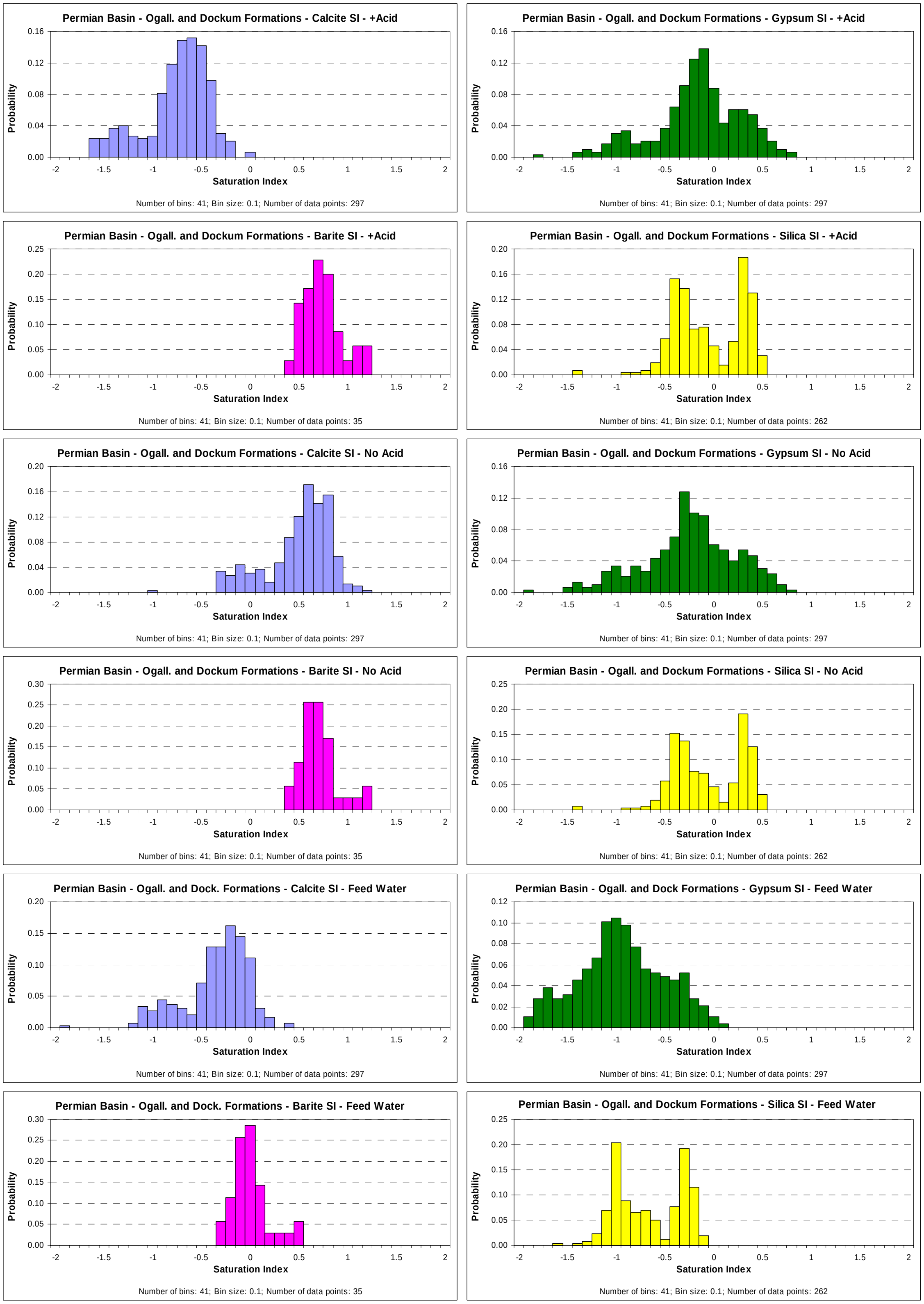


Figure A3-2. Saturation indices of scale-forming minerals for the concentrate with and without acidification and for the feed water (Permian Basin).

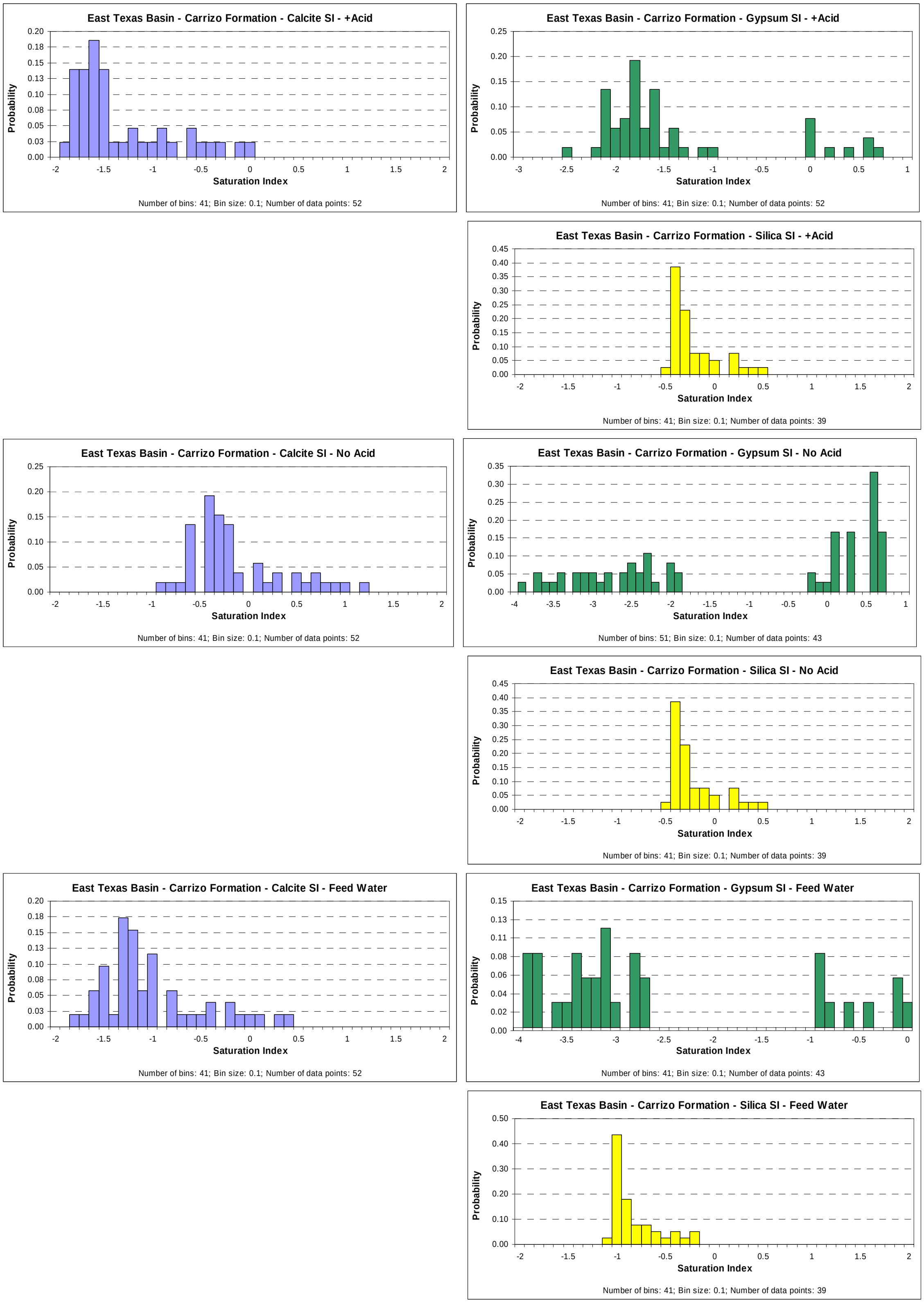


Figure A3-3. Saturation indices of scale-forming minerals for the concentrate with and without acidification and for the feed water (East Texas Basin).

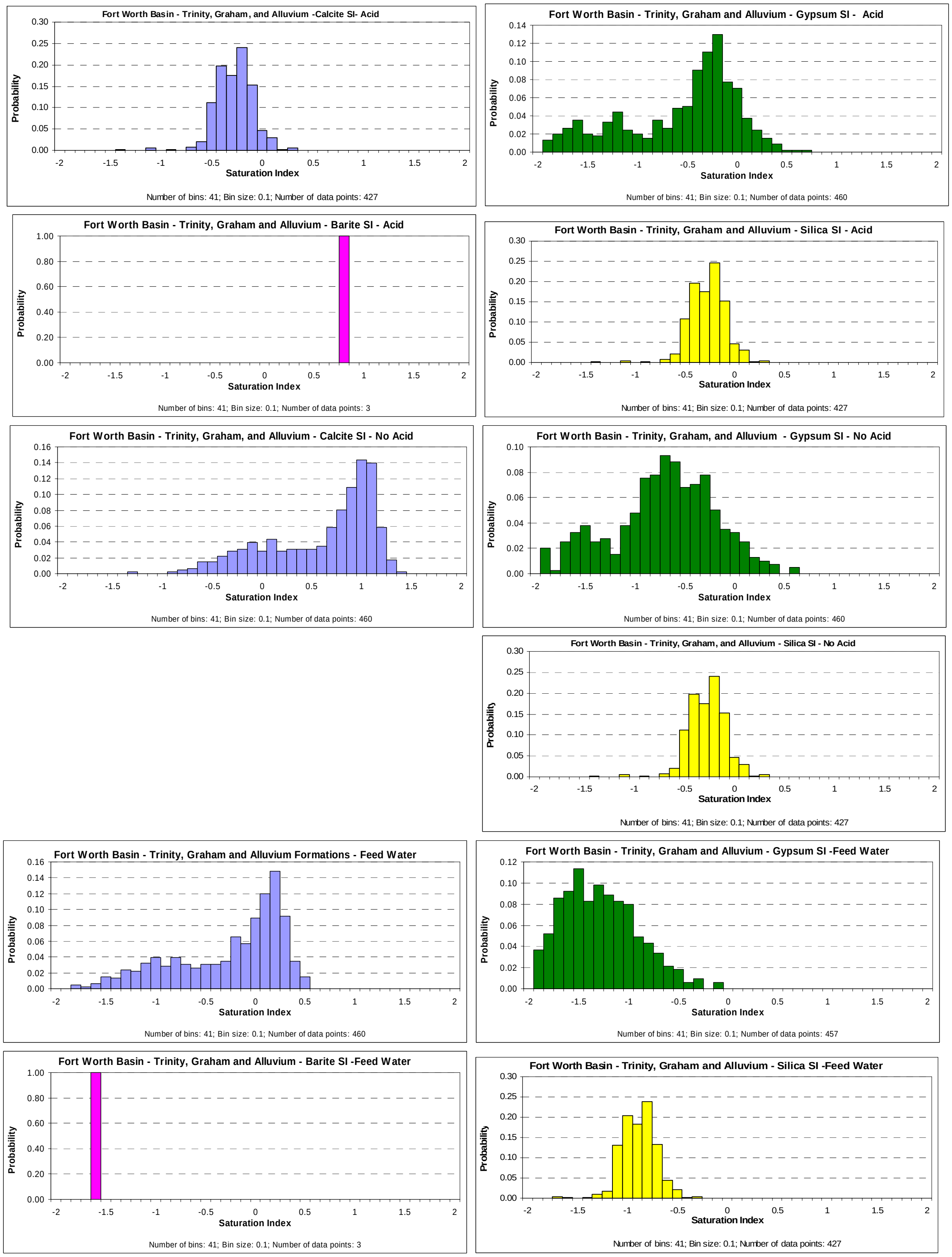


Figure A3-4. Saturation indices of scale-forming minerals for the concentrate with and without acidification and for the feed water (Fort Worth Basin).

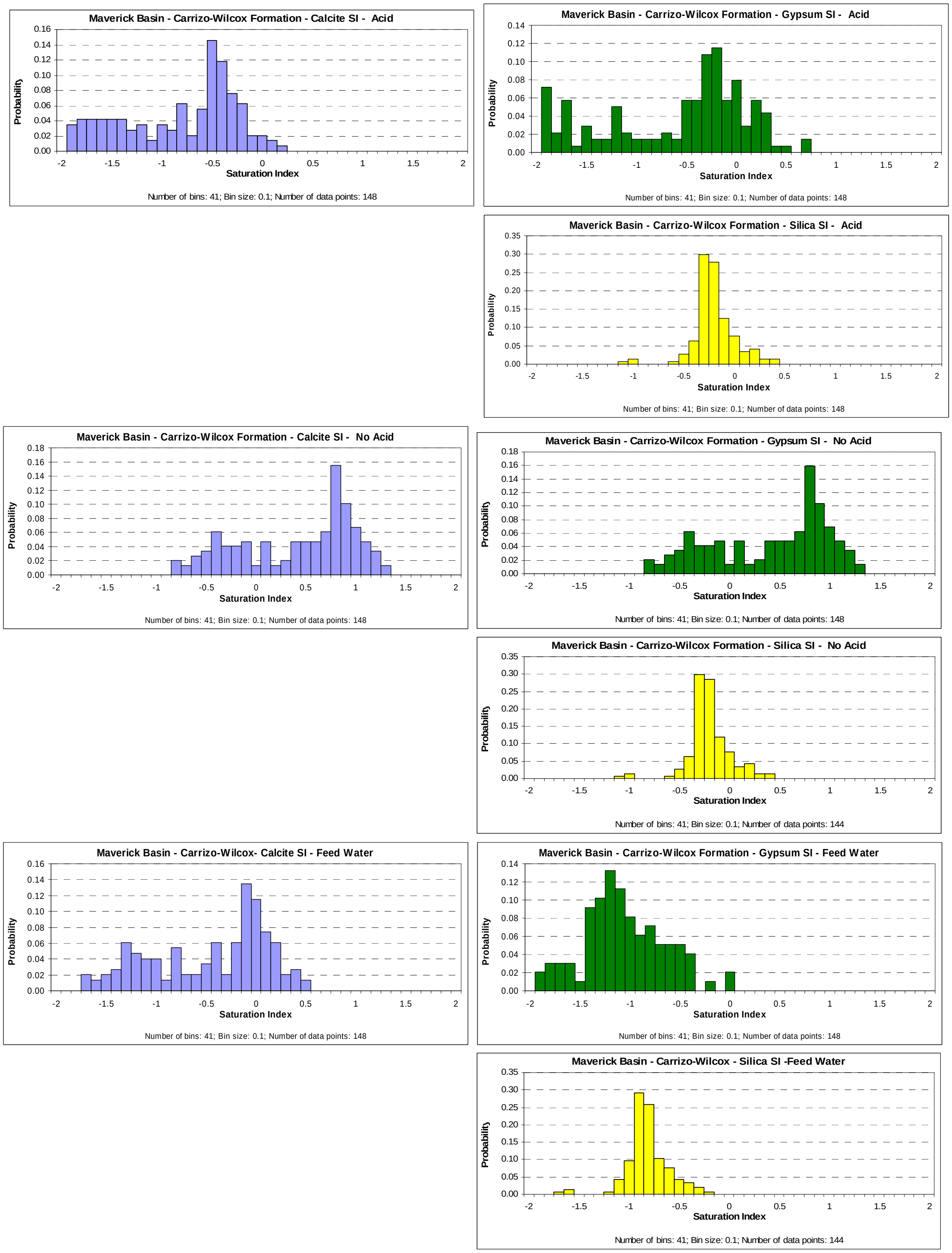
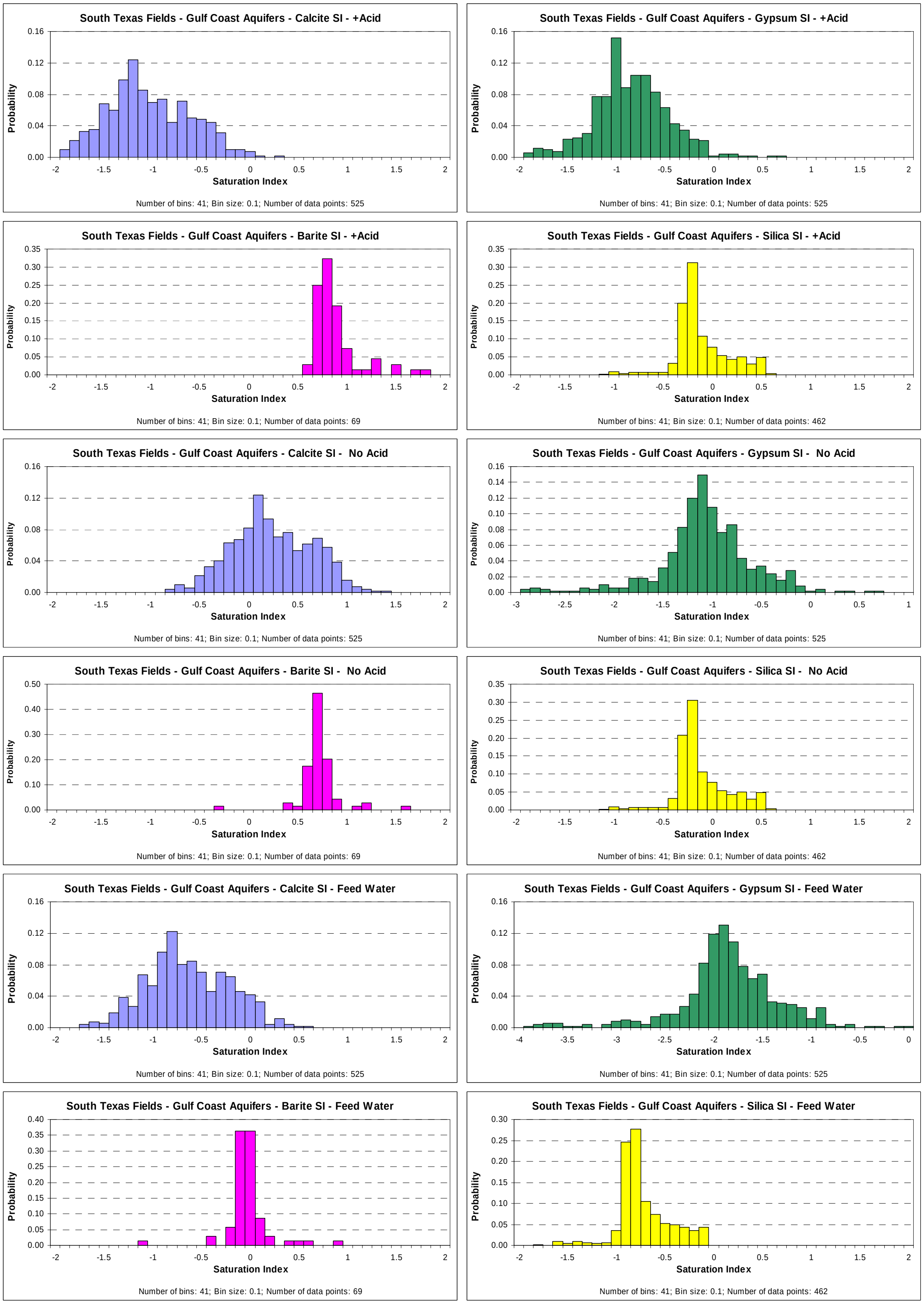


Figure A3-5. Saturation indices of scale-forming minerals for the concentrate with and without acidification and for the feed water (Maverick Basin).



South Texas Fields - Gulf Coast Aquifers - Calcite SI - +Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 525

South Texas Fields - Gulf Coast Aquifers - Gypsum SI - +Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 525

South Texas Fields - Gulf Coast Aquifers - Barite SI - +Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 69

South Texas Fields - Gulf Coast Aquifers - Silica SI - +Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 462

South Texas Fields - Gulf Coast Aquifers - Calcite SI - No Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 525

South Texas Fields - Gulf Coast Aquifers - Gypsum SI - No Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 525

South Texas Fields - Gulf Coast Aquifers - Barite SI - No Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 69

South Texas Fields - Gulf Coast Aquifers - Silica SI - No Acid

Number of bins: 41; Bin size: 0.1; Number of data points: 462

South Texas Fields - Gulf Coast Aquifers - Calcite SI - Feed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 525

South Texas Fields - Gulf Coast Aquifers - Gypsum SI - Feed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 525

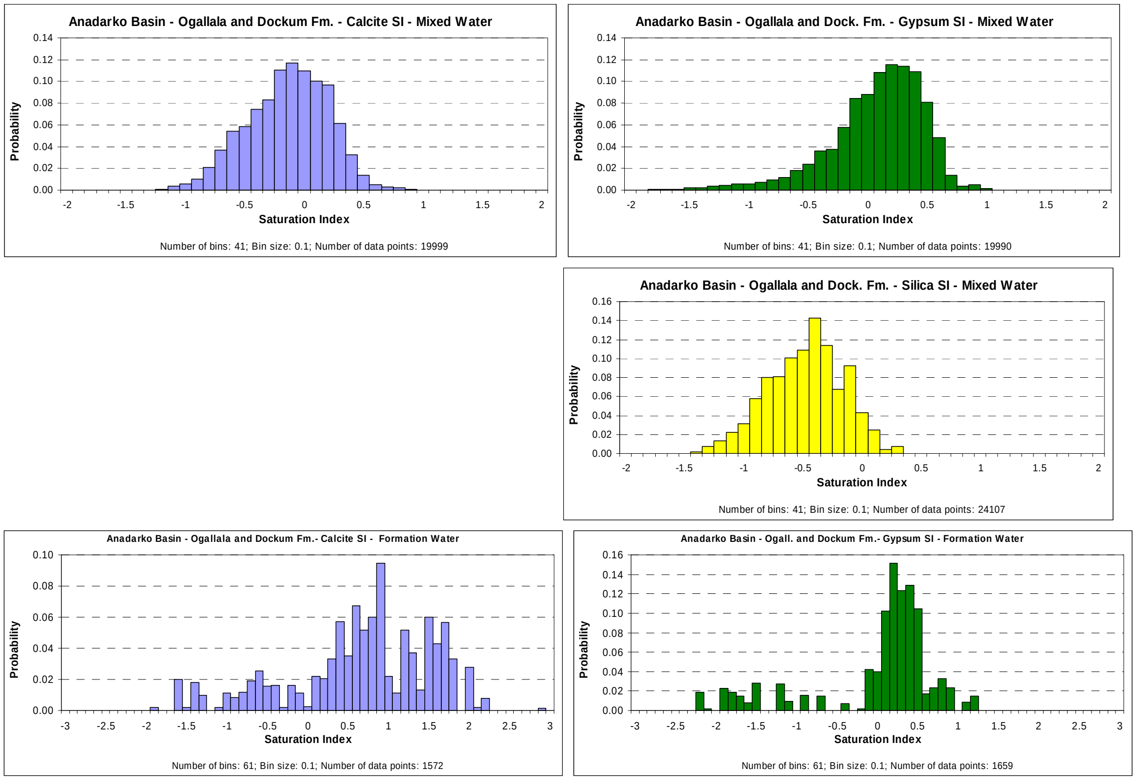
South Texas Fields - Gulf Coast Aquifers - Barite SI - Feed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 69

South Texas Fields - Gulf Coast Aquifers - Silica SI - Feed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 462

Figure A3-6. Saturation indices of scale-forming minerals for the concentrate with and without acidification and for the feed water (Gulf Coast Basin).


Anadarko Basin - Ogallala and Dockum Fm. - Calcite SI - Mixed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 19999

Anadarko Basin - Ogallala and Dock. Fm. - Gypsum SI - Mixed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 19990

Anadarko Basin - Ogallala and Dock. Fm. - Silica SI - Mixed Water

Number of bins: 41; Bin size: 0.1; Number of data points: 24107

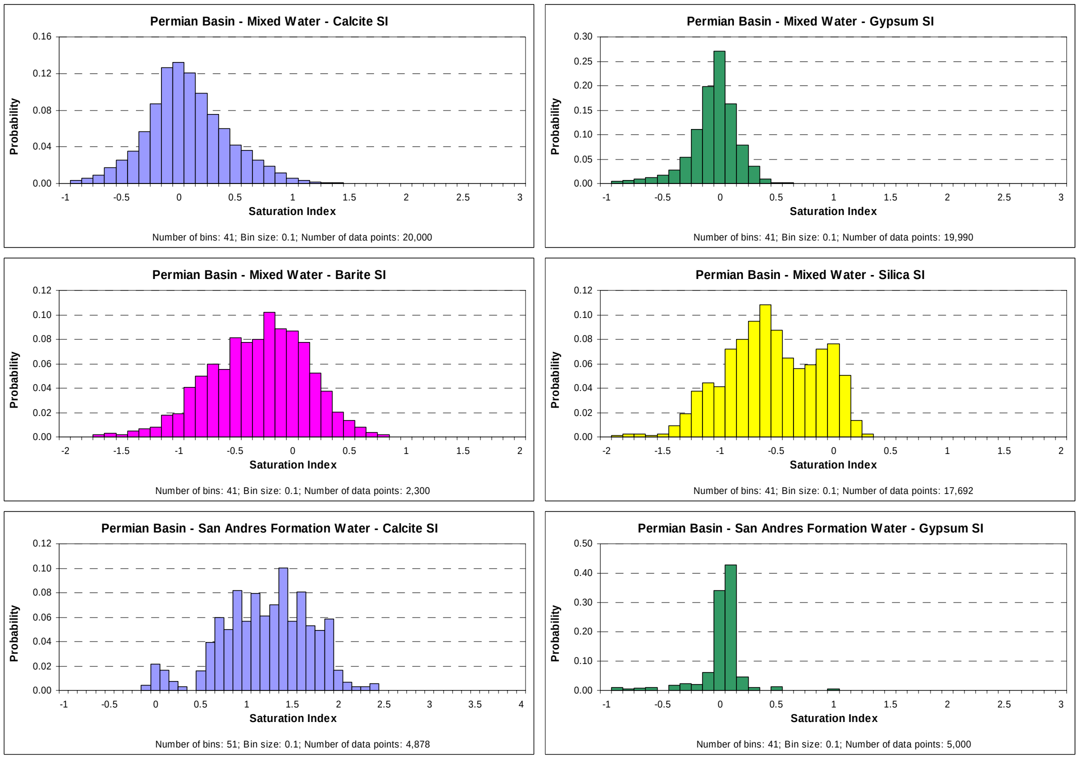
Anadarko Basin - Ogallala and Dockum Fm.- Calcite SI - Formation Water

Number of bins: 61; Bin size: 0.1; Number of data points: 1572

Anadarko Basin - Ogall. and Dockum Fm.- Gypsum SI - Formation Water

Number of bins: 61; Bin size: 0.1; Number of data points: 1659

Figure A3-7. Saturation indices of scale-forming minerals for the mixed solution (with acidified concentrate) and for the formation water (Anadarko Basin).



Permian Basin - Mixed Water - Calcite SI

Number of bins: 41; Bin size: 0.1; Number of data points: 20,000

Permian Basin - Mixed Water - Gypsum SI

Number of bins: 41; Bin size: 0.1; Number of data points: 19,990

Permian Basin - Mixed Water - Barite SI

Number of bins: 41; Bin size: 0.1; Number of data points: 2,300

Permian Basin - Mixed Water - Silica SI

Number of bins: 41; Bin size: 0.1; Number of data points: 17,692

Permian Basin - San Andres Formation Water - Calcite SI

Number of bins: 51; Bin size: 0.1; Number of data points: 4,878

Permian Basin - San Andres Formation Water - Gypsum SI

Number of bins: 41; Bin size: 0.1; Number of data points: 5,000

Figure A3-8. Saturation indices of scale-forming minerals for the mixed solution (with acidified concentrate) and for the formation water (Permian Basin).

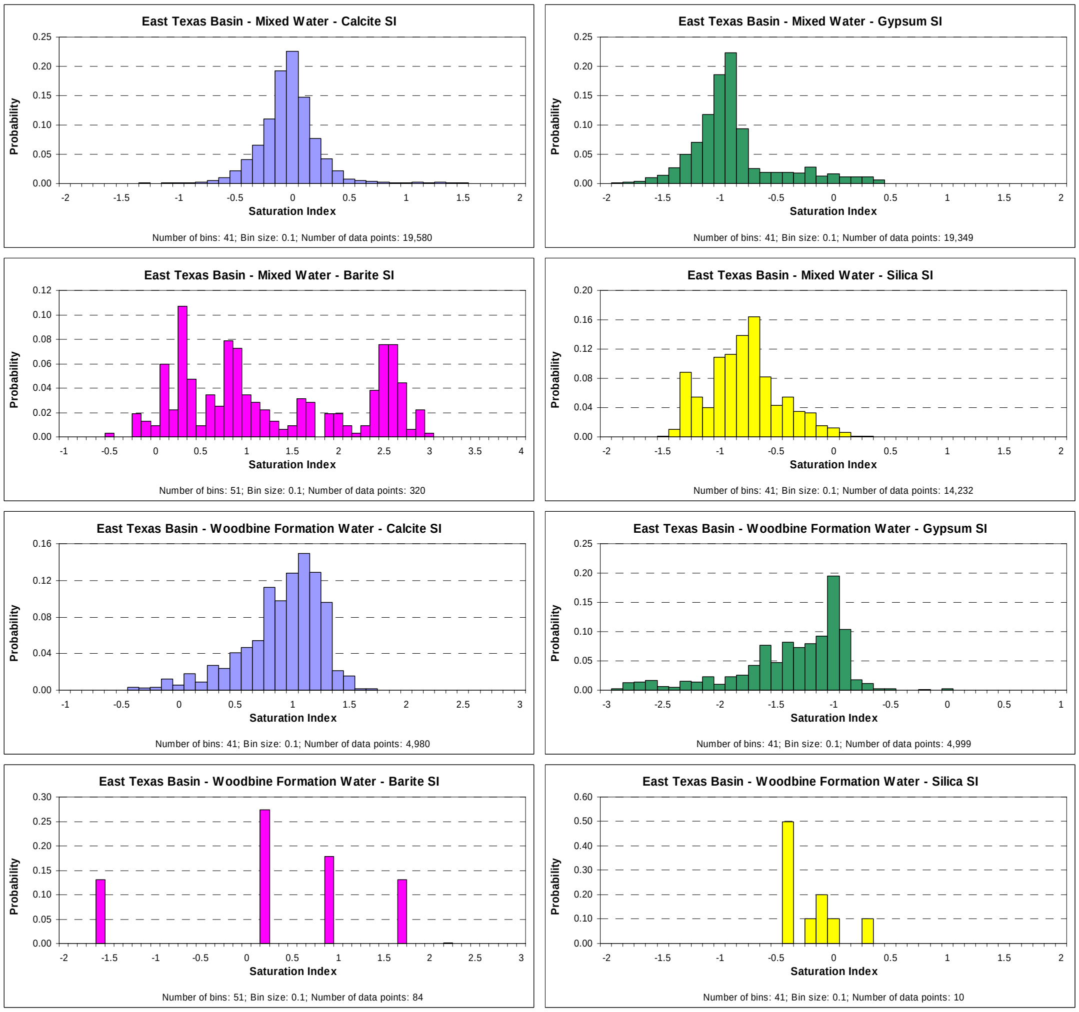


Figure A3-9. Saturation indices of scale-forming minerals for the mixed solution (with acidified concentrate) and for the formation water (East Texas Basin).

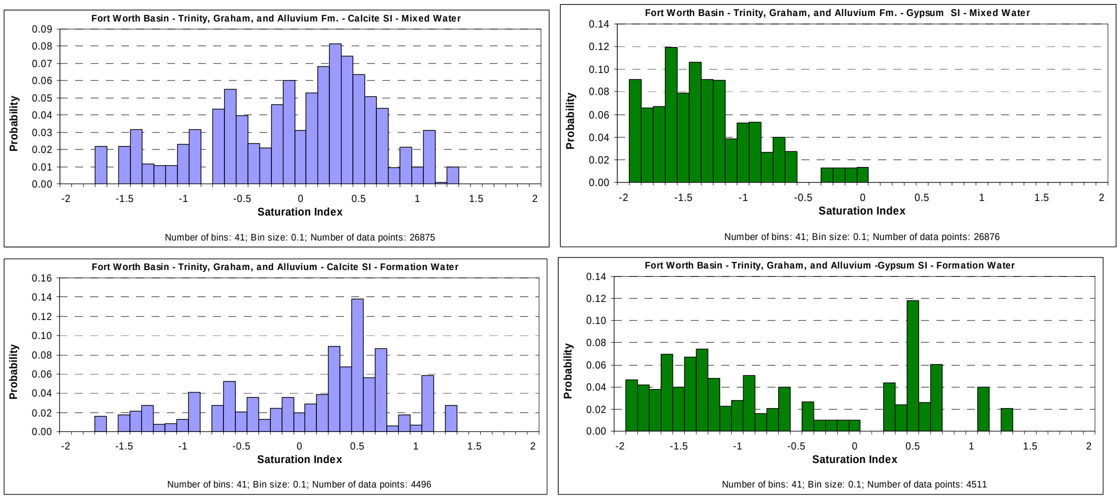


Figure A3-10. Saturation indices of scale-forming minerals for the mixed solution (with acidified concentrate) and for the formation water (Fort Worth Basin).

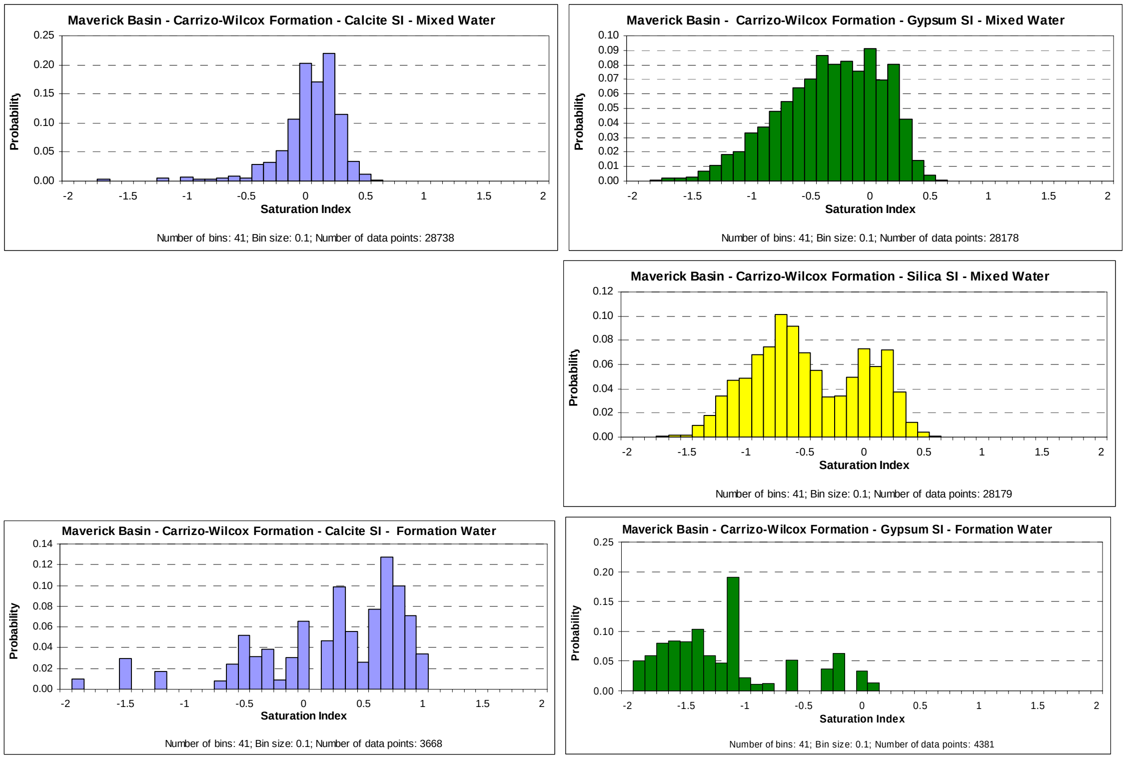


Figure A3-11. Saturation indices of scale-forming minerals for the mixed solution (with acidified concentrate) and for the formation water (Maverick Basin).

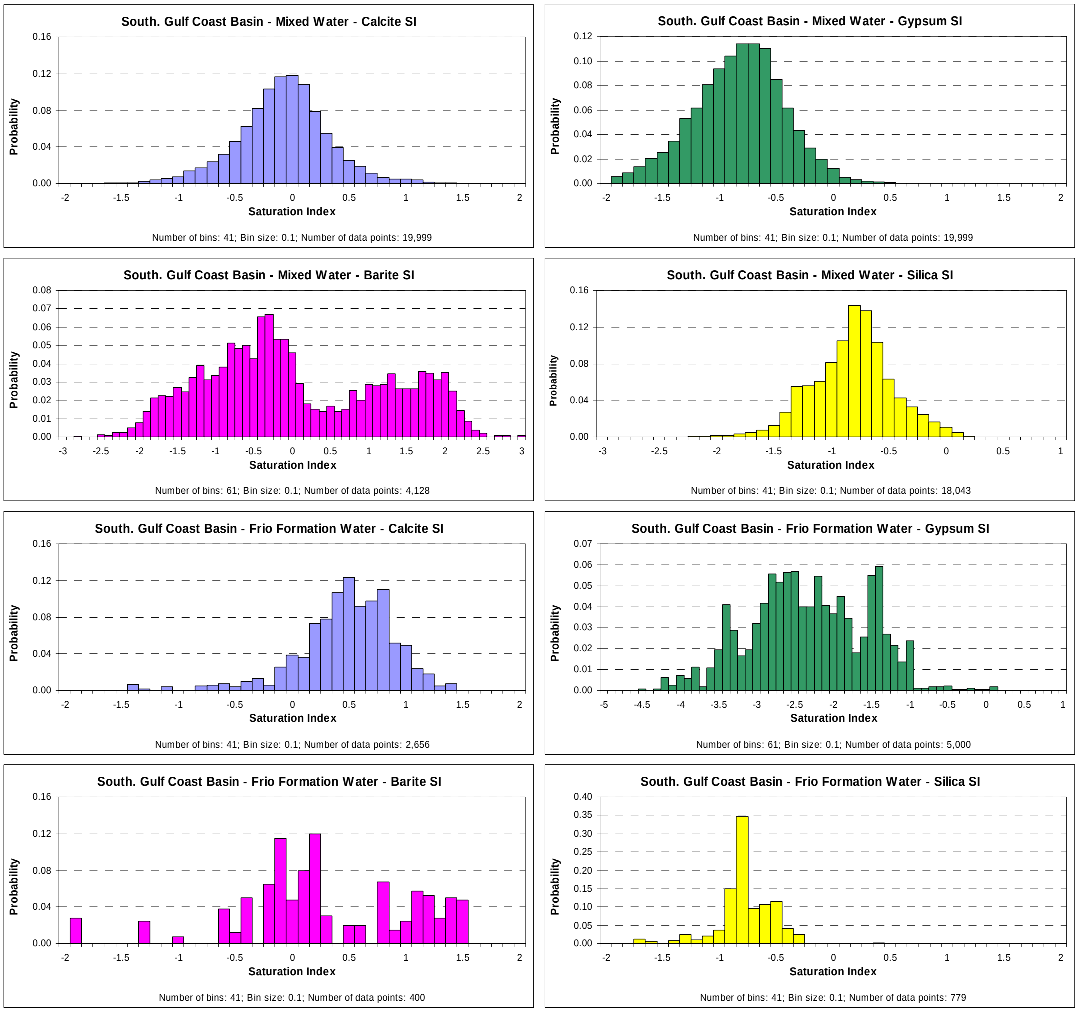


Figure A3-12. Saturation indices of scale-forming minerals for the mixed solution (with acidified concentrate) and for the formation water (Southern Gulf Coast Basin).

# Appendix 4 – Contacts

We met with the following people to discuss permitting issues:

| | | |
|---|---|---|
| Tony Bennett | | TCEQ |
| Michael D. Cowan | | TCEQ |
| Fernando De Leon | UIC | RRC |
| Philip Dellinger | Chief, Ground Water/ UIC Section | EPA Region 6 |
| Richard Ginn | | RRC |
| Ben Grumbles | Assistant Administrator for Water | EPA |
| Ben Knape | | TCEQ |
| Ray Leissner | Ground Water/ UIC Section | EPA Region 6 |
| Steve Seni | Assistant Director, Environmental Services | RRC |
| Mike Slayton | Deputy Executive Director | St. Johns River WMD, FL |
| Bryan Smith | UIC Permits Team | TCEQ |
| Gilbert Tellez | | EPA Region 6 |
| Robert Traylor | Geologist, Surface Casing | RRC |
| Mark Vickery | Deputy Executive Director | TCEQ |

EPA = Environmental Protection Agency

FL = Florida

RRC = Railroad Commission

TCEQ = Texas Commission on Environmental Quality

UIC = underground injection control

WMD = Water Management District

# Appendix 5 – Communication with Petroleum Technology Transfer Council

Early in the project, at the end of 2003, the BEG put together a roadmap for communicating with oil and gas operators including arranging a presentation at the Texas Independent Producers and Royalty Owners (TIPRO) meeting in January 2004, coordinating with Texas Petroleum Technology Transfer Council (PTTC) and TIPRO staff on how to contact operators, and setting up a web site directed to answering specific operator concerns and to collecting their comments.

In order to gain feedback from the Oil and Gas industry, BEG gave a short presentation on the concept of the project at the TIPRO mid-winter policy meeting in January 2004 in Fort Worth, Texas. As a follow-up to the meeting and the presentation, we posted a companion text file and a questionnaire (Table A1.1) on the PTTC Web site (http://www.energyconnect.com/pttc/) as well as on the BEG Web site. The PTTC sent an email to its 1,200 members giving information on the project and encouraging them to fill out the on-line questionnaire.

**Table A5-1: Text of the stakeholder questionnaire posted on the web**

The Texas Water Development Board and the Bureau of Economic Geology are soliciting input from the industry relative to the acceptance of desalination concentrates in Class II injection wells. The following questionnaire is meant to gauge the industry interest in the project. For additional information, view the slides, and accompanying text, presented at the TIPRO Mid-Winter Policy Meeting in Fort Worth, TX in January 2004.

**Question 1**: Assuming that the concentrate is delivered to your injection well head, there are no compatibility issues and no adverse effects to the formation and adjacent aquifers and assuming that the entire process is margin neutral at minimum, how likely would you be to accept the concentrate for injection?

Very likely / Somewhat likely / Neither likely or unlikely / Somewhat unlikely / Very unlikely

**Question 2**: If you agree taking the concentrate at the conditions outlined in Question 1, what volume would you most likely be willing to accept?

Less than 100 gpm (~3,500 barrel/day)
From 100 to 299 gpm (~3,500 and ~10,000 barrel/day)
From 300 and 699 gpm (~10,000 and 20,000 barrel/day)
700 gpm or more (20,000 barrel/day +)
Do not know

**Question 3**: How much would you be likely to charge per 1,000 gallons of concentrate?

**Question 4**: What, if any, concerns might you have in accepting desalination concentrates?

**Question 5**: Additional comments

Optional Information:
Name:
Company:
Address:
Phone:
Email: