Disposal of brackish water concentrate into depleted oil and gas fields: a Texas study

Jean-Philippe Nicot[a*] and Ali H. Chowdhury[b]

[a]Bureau of Economic Geology, John A. and Katherine G. Jackson School of Geosciences, The University of Texas at Austin, University Station Box X, Austin, Texas 78713-8924, U.S.A.; Tel. 512-471-1534; Fax: 512-471-0140; email: jp.nicot@beg.utexas.edu
[b]Texas Water Development Board, Stephen F. Austin Bldg., P.O. Box 1323, 1700 N. Congress Avenue, Austin, Texas 78711-3231, U.S.A.

Abstract

Disposal of concentrate from brackish water desalination plants by deep well injection into oil and gas fields is an attractive option in Texas. Underpressured depleted oil and gas reservoirs cover large areas of the state. Six areas were selected from across Texas for detailed analysis. These sites were characterized by abundant brackish groundwater, a projected shortage of freshwater, depleted oil and gas fields, and shallow injection wells. Information was collected on formation mineralogy, pressure history, geochemical attributes and flow parameters. Numerical modeling using SOLMINEQ, combined with a statistical approach, was used to assess the results of mixing desalination concentrate with formation water. Issues addressed include injection pressures required, the impact of down-hole conditions on mineral precipitation, and mobilisation of formation fines and clays. Numerical modeling found no technical problems outside the range commonly dealt with by the oil and gas industry. In addition, historically, most of the fields have received considerable volume of fresh and/or brackish waters. From a technological standpoint, injection of desalination concentrates into depleted oil or gas fields using existing wells is a highly feasible alternative. A brief look at the economics also suggests that this opportunity is highly advantageous.

Keywords: concentrate, oil and gas fields, disposal, scaling, clay sensitivity

1. Introduction and background

Demand for fresh water in Texas will increase in the future owing to population growth. Because conventional sources will be insufficient to cover needs, desalination of brackish water is an alternative being actively pursued by the State. A promising possibility for disposing of concentrates is deep well injection. Formation pressures in reservoirs have been greatly lowered because of past oil and gas production, creating an opportunity for injecting a large volume of foreign fluids at lower cost. Legal and, to a lesser degree, technical issues can nevertheless arise

[1]. This paper focuses on the technical issues. Injection of concentrate into the subsurface can potentially lead to formation damage because of scaling and clay mobilization. When concentrate is injected into the subsurface, it is subject to an increase in temperature and pressure. It mixes with the resident formation water as well, and both processes can lead to scaling. Another relevant concern is clay sensitivity to fresher water injection. Clayey material and fines can be mobilized and plug pores when they come in contact with a water of lower ionic strength and/or different ionic makeup. A third concern is the possible upper limit on the injection rate at which a formation is able to accept the concentrate stream.

Oil fields are plentiful in Texas (Fig. 1), with a cumulative production of approximately 60 billions barrels (9.5×10^{12} m^3) since the late 19th century. Because of its long history, the oil and gas industry in Texas has a great deal of experience in injecting fluids. When oil is produced, as much as 10 times more formation water may be produced than oil, particularly in mature fields. Most of the co produced saltwater is injected back into producing horizons as part of pressure maintenance or secondary recovery (waterflooding) operations. The remainder is reinjected in saltwater disposal wells into either productive or nonproductive horizons. Fresh and brackish water from local aquifers could also be used for pressure maintenance or secondary recovery, which was mostly the case until the middle of the 20th century. In Texas, over 31,000 injection wells are active in oil and gas fields. Approximately 0.9×10^9 m^3 of liquids are injected annually through these wells.

Of the more than 100 desalination plants currently operating in Texas, over 95 percent use reverse osmosis (RO). Nearly 83 percent of the plants use brackish groundwater, whereas 17 percent use brackish surface water. Currently no seawater desalination plants for public water supply exist in Texas. Current total capacity of desalination facilities for public water supply systems in Texas is approximately 0.15×10^6 m^3/day. They produce a waste stream in the vicinity of 38-57 $\times 10^3$ m^3/day, which is small compared with the produced water injection stream and smaller yet compared with the total fluid volume already removed from the subsurface.

2. Methodology

To address the technical issues of concentrate injection in the deep subsurface, several analysis areas from different geologically defined basins across Texas were selected according to intersection of the following criteria: (1) areas had to have a shortfall of water supply over the next 50 years' planning time frame, (2) areas had to be overlying abundant and relatively shallow brackish groundwater resources, (3) areas had to have depleted oil/gas fields with large oil and gas productions, and (4) they had to be areas where injection wells are not too deep. We examined scaling, clay mobilization/sensitivity to water, and injectivity issues. We also compiled practical solutions routinely used by the oil and gas industry to solve these problems. Succinct historical injection data were also assembled.

Information was first collected on formation mineralogy, pressure history, geochemical attributes, and flow parameters, such as permeability and porosity. A hypothetical concentrate chemical composition was then computed from that of the likely brackish water source overlying the pressure depleted formation. Brackish water composition was modified using standard water treatment additives and applying a concentration factor of 4. The high level of this work did not justify going into the specifics of a given membrane. A survey of concentrate from several Texas RO facilities and other brackish water facilities around the world determined that the concentrate enriched in all ions by a factor of 4 relative to the feed water is an appropriate representation of a facility having a high rejection rate. Acidification by sulfuric acid of either the feed water or the injectate is a common practice for limiting calcium carbonate scaling. We assumed a pH of 6 for the treated concentrate just before injection in the disposal formation and a generic antiscalant. The system was assumed fully closed from the time feed water was retrieved from the brackish aquifer to injection of concentrate into the subsurface.

Subsurface scaling assessment requires a geochemical code that can handle changes in pressure and temperature, as well as mixing of waters of high salinity. SOLMINEQ [2] is a batch geochemical code developed by the U.S. Geological Survey that assumes complete mixing of waters. We used a statistical approach combined with Monte Carlo trials to analyze the results of mixing formation water and concentrate, assuming that spatial variability in the composition of the formation water translates into temporal variability of the feed water. Additionally, relative locations of the brackish water well field and the concentrate disposal well are obviously unknown, justifying the random pairing of concentrate and formation samples.

The main difference between surface and subsurface processes is the possible mobilization of fines, in particular clays, in the subsurface. Clay material is often a minor component of those formations, but its mineralogy is crucial because of possible negative impact on injection well performance. Thermodynamics dictates what clays in equilibrium with a given water will be mobilized. We used plots of total cations to divalent cations developed by Scheuerman and Bergersen [3] to assess the likelihood of this happening. Problems, such as cation stripping, can also appear during the transient stage when the formation water is replaced by the concentrate. Such a tendency is characterized by the Mass Action Ratio (MAR) ratio linked to the cation exchange capacity of the clay. Cation exchange tendency of a solution can be characterized by the mass action ratio, defined as the ratio of sodium activity squared to that of calcium ($[Na]^2/[Ca]$). The MAR ratio (MAR of concentrate / MAR of formation water) allows quantification of the amount of cation stripping. We used a statistical approach to analyze the issue by randomly pairing MAR values of the concentrate and formation water multiple times. Comparison of MAR ratios with the guidelines presented in Scheuerman and Bergersen [3] allows for an assessment of the need for pretreatment.

Injectivity was modeled by calculating the flow rate (Eq. 1) that would result from combining formation characteristics (porosity, permeability, and compressibility) and pressure requirements (surface pressure, well depth, and head loss). Multiple combinations of these parameters allied with a Monte Carlo analysis provide some understanding of the likelihood of finding high performing injection wells and the number of wells needed to meet facility concentrate output. Parameters were varied randomly (except porosity and log permeability, which were varied according to their linear correlation coefficient). The response of a confined aquifer to injection pressure is given, in a consistent system of units, by Warner and Lehr [4]:

$$\Delta P = \frac{Q\mu}{4\pi kb}\ln\left(\frac{2.25k\rho gt}{\mu r^2 S}\right) \tag{1}$$

where P is pressure, Q is flow rate, k is permeability, b is assumed equivalent to pay thickness, ρ is water density, g is acceleration of gravity, t is time since injection began, μ is water viscosity, r is radial distance from well to point of interest, and S is storativity or storage coefficient. Parameter S is a function of formation porosity and of both compressibility of water and of rock. The equation is applied for tubing radius $r=r_w$.

In Texas, the maximum surface injection pressure allowed is ½ psi per foot (11.3 kPa/m) to top of injection interval unless results of a fracture pressure step rate support a higher pressure. Higher pressure tends to open fractures possibly detrimental to production and safety. Sandface pressure is surface pressure added to pressure due to weight of the injected fluid minus head losses through the tubing. Because maximum ΔP, pressure difference between well sandface and formation, is imposed, maximum flow rate Q can be computed when other parameters are known. Statistical distribution of permeability and porosity, as well as pay thickness b, was extracted mostly from proprietary databases.

3. Results and discussion

We will focus on the Woodbine Formation of Cretaceous age in the East Texas Basin and on the San Andres Formation of Permian age in the Permian Basin (Fig. 1) but also citing results for all analysis areas when appropriate. Because these formations have heavily produced oil and gas, they are most likely to have a dense infrastructure able to carry fluids at the surface. Depressurization resulting from hydrocarbon production is common in those long producing formations (e.g., Fig. 2). The Woodbine Formation is composed mainly of sandstones, with an occasional large fraction of feldspars and/or volcanic rock fragments. The sandstones have high porosity and permeability and a significant amount of clay (mainly smectites and chlorites). The San Andres Formation is composed of carbonates with low porosity and permeability and with none to little clay. The brackish water source is the Ogallala and Dockum aquifers and Carrizo-Wilcox aquifer for the Permian and East Texas Basins, respectively. Analyses of representative samples of the brackish water source, hypothetical concentrate, and formation water are presented in Table 1. Feed water TDS is mostly in the range 1,000 to 3,000 mg/L, while that of the concentrate is approximately 4 times higher. Brackish waters, and thus concentrates, are dominated by sodium chloride and bicarbonate, with a smaller input of calcium, magnesium, and sulfate for the Ogallala-Dockum aquifers. Formation waters are primarily sodium chloride, with some calcium, magnesium, and sulfate, particularly in the San Andres Formation. Potential feed waters are mainly undersaturated relative to calcite, gypsum, and silica, as well as to barium and strontium minerals. The median TDS is 56,000 mg/L for the Woodbine Formation water, with little dispersion around it, whereas the median TDS for the San Andres Formation water in the analysis area is 72,000 mg/L, with a larger variance. Formation water from all analysis areas shows supersaturated calcite, sometimes by one order of magnitude. It is common for calcium carbonate to be supersaturated.

3.1 Scaling issues

Common scales in the subsurface are composed of calcium carbonate, calcium and barium sulfates, and silica. Results of geochemical model runs are reported in histograms after multiple random pairings between acidified concentrate and formation water (Fig. 3). Mode of gypsum and calcite saturation index (*SI*) distribution is -1 and 0, respectively. Barite has a multimodal distribution with *SI* modes around 0.4, 0.8 and 2.7. The theoretical threshold for precipitation is *SI*=0. Addition of generic commercial antiscalants will increase the precipitation threshold to approximately 2 for carbonate and sulfates. It is nevertheless important to remember that the computed *SI* values result from the assumption of total mixing. In the subsurface, formation water and injected concentrate will not mix as much as assumed in this section. The concentrate will displace mostly resident formation water. This assumption yields a conservative estimate of the likelihood of scaling.

The amount of acid added is consistent with desalination industry usage (<300 ppm of sulfuric acid). If the increase in sulfate concentration leads to a barite scaling problem, hydrochloric acid can be used instead or, possibly doing away with acid, a targeted antiscalant. Figure 4 displays saturation indices concisely for all analysis areas. It suggests that no site is superior relative to scaling tendency. According to modeling results of this study, calcite and gypsum scales will not cause problems. Barite may form locally, especially in the East Texas Basin, that includes the highest computed barite *SI*. Silica (not displayed) seems unable to produce significant scaling, on average. In short, scaling will not generate problems outside of the range typically encountered, and dealt with, by both oil and gas and desalination industries.

3.2 Clay sensitivity issues

Fines, mainly clay particles, originating from within the formation can be mobilized by physical or chemical processes. Numerous experiments and field studies have shown that a significant reduction in permeability can occur when a fluid different from that of the formation is injected. Formation fines are typically attached on walls of larger grains and can sometimes be mechanically mobilized, but more often a change in chemical environment will deflocculate them. They can then be entrained by moving fluids and be immobilized in pore throats. Studies on clay sensitivity to water require knowledge of the nature of the clay material present in the formation and of the ionic composition of the injection water. Kaolinite clay, one endmember of the clay behavior spectrum, stays firmly attached to the pore walls for almost any ionic makeup. At the other end of the sprectrum, smectite deflocculation can occur if either solution ionic strength or percentage of divalent cations falls below some threshold. Other clay types, such as vermiculites and illites, have intermediate behaviors—except for chlorite, which is not water sensitive.

Sensitivity of clay bearing formations to water increases with decreasing water salinity, decreasing valence of the cations in solution, and increasing pH in the water. Two factors control whether injected waters 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 divalent cation concentration. On the basis of clay types commonly encountered in the reservoirs, Scheuerman and Bergersen [3] developed compatibility guidelines for injection water by plotting total cations against divalent cations (Fig. 5). Injection water and formation clay compatibility, at equilibrium, is then determined on the basis of positions of water composition on the diagram. 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.

In Permian and East Texas Basins (Fig. 5a and b), most formation water data points fall outside the smectite salinity line, suggesting that the formation contains smectite in contact with flowing water and that they are at equilibrium. On the other hand, injected concentrate is likely not at equilibrium with formation clays if its composition falls within the clay salinity lines. This is the case for approximately 25 percent of the concentrate data points in the Permian Basin (Fig. 5a). This basin should be easily amenable to concentrate injection, especially because of its paucity in clay minerals. The East Texas Basin could present a challenge for concentrate injection, unless the injection is carefully thought out, because most Carrizo-Wilcox data points fall within the smectite salinity line, and 35 percent falls within the illite salinity line (Fig. 5b). Other analysis areas have intermediate conclusions.

However, even seemingly compatible waters 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 shifts from outside to inside the deflocculation line as it moves downgradient. 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. If the MAR of the injection water is higher than that of the formation water, no clay mobilization is likely. Results of random pairing of MAR values are presented as histograms (Fig. 6) for comparison with guidelines presented in Scheuerman and Bergersen [3]. With a MAR ratio below 0.5 [3], a pretreatment of the formation is recommended. Table 1 suggests that, because MAR of the Ogalalla and Dockum aquifers is typically two orders of magnitude smaller than that of the San Andres Formation, a pretreatment would seem inevitable. However, one has to keep in mind that the amount of clay in the formation is small to start with and may not warrantee a pretreatment. MAR values for the East Texas Basin are of the same order of magnitude for formation water and concentrate (Table 1), the ratio could then be larger than 0.5 in many combinations. It follows that, in that basin, a pretreatment is needed only for some combinations of concentrate / formation water.

3.3 Historical perspective

Relevant knowledge about water injection, directly applicable to concentrate injection, can be gained by examining the field injection history. Soon after initial production of an oil reservoir with no natural water drive, water is injected for pressure maintenance. A natural water drive occurs when the hydrocarbon volume removed by oil production is occupied 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 occurs when light hydrocarbons in solution in the oil outgas to maintain pressure, whereas the latter occurs when a free gas cap is present on top of the oil. For example, most Permian Basin fields were under solution gas drive and have been good candidates for waterfloods. Most fields of the East Texas Basin were under natural water drive. Consequently, waterflooding has not been as widespread. The external water source could be surface waters, a fresh or brackish water aquifer, or produced water. History of Texas oil fields shows that targeted formations can take fresh water with no major problem, and injection of concentrate resulting from these same fresh waters will probably not generate more problems. Figure 7 presents the historical perspective of injection and demonstrates that, up to 1981, waters with a TDS<3,500 ppm made up more than 40% of the total injected volume.

We also gathered current maximum rate of injection per well from the administrative information collected by the responsible Texas State agency. Analysis shows that data could vary considerably and range from less than 100 bbl/d to more than 5,000 bbl/d (0.2 l/s to more than 9 l/s) (Fig. 8). Figure 8 shows an aggregated distribution across analysis areas of reported average and maximum injection rates, whose median is 1.9 l/s (30 gpm) and 3.8 l/s (60 gpm), respectively, whereas the 95th percentiles are approximately 9 l/s (150 gpm) and 14.5 l/s (230 gpm), respectively.

3.4 Injection rate issues

Porosity and permeability values are required to explore the capacity of a formation to accept desalination concentrate. In the San Andres Formation, porosity ranges from 2 to more than 20 percent, with most values falling between 5 and 10 percent. Intrinsic permeability ranges from 1 to more than 100 md. In the Woodbine Formation, porosity varies from less then 20 to more than 35 percent, with most values between 25 and 30 percent. Intrinsic permeability covers a large range, from approximately 10 to more than 5,000 md.

The number of wells needed to meet requirements of a typical desalination facility depends not only on facility size but also on the average injection rate that can be sustained by the formation, which is itself a function of permeability. Computed injection rates were plotted on histograms (Fig. 9). Distribution is likely biased toward low injection rates because higher performing wells will generally be used to inject fluids. The median injection rate is about 0.6 l/s (10 gpm) in the Paleozoic basins that include the Permian Basin, whereas it reaches 29 l/s (466 gpm) in the East Texas Basin. In all formations, the rate could also be increased by screening more intervals and performing well stimulation.

3.5 Practical solutions

In the past century or so of oil and gas production, the oil and gas industry has come up with solutions for most of the operational problems that they have encountered. The oil and gas industry has the option of using more aggressive methods than those in use in the drinking water industry to deal with scaling and other problems. They can be sorted into chemical and physical and operational solutions.

Acidizing (by injection of hydrochloric acid or sulfuric acid) is used to stimulate production in carbonates and to treat carbonate scales in all formations. Hydrofluoric acid will dissolve siliceous materials, especially clays and feldspar, but not quartz, whose dissolution kinetics is slower. Strongly alkaline agents (NaOH or KOH) are widely used to remove calcium sulfate deposits. $CaCl_2$ brine pretreatment before concentrate injection reduces water sensitivity of the clay minerals and eliminates cation stripping. Ca from the brine will saturate sensitive clays, preventing cation stripping and deflocculation [3]. Farther from the well bore, mixing with resident formation water will limit cation stripping. A buffer of NaCl or KCl is also used to eliminate fine deflocculation and migration. Clay stabilizers, which irreversibly bind clay particles and other fines to the substrate or to each other, are also used. Hydraulic fracturing is used to treat damaged wells and improve performance of low permeability wells.

If no clay stabilizers are used, 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. Common practice in the field of deep well injection of hazardous wastes is also to include a buffer waste injected between two chemically incompatible wastes. Even if fine mobilization does occur, lowering fluid velocity could help keep particles from bridging pores, which can be accomplished by decreasing flow rates or increasing number of perforations or shot density at the well.

3.6 Legal and Economic Considerations

Ability to use previously completed wells, as well as surface infrastructure, is the main advantage in using depleted oil and gas fields. However, the legislative environment, still in a state of flux, remains the biggest unknown for a well located in the United States. If in need of make up water and if a fit is found, an operator could presumably accept or even buy the concentrate from a nearby desalination facility [1] ("class II injection wells"). There is no legal obstacle to such a case. However, a desalination plant would need assurances that an oil-field operator could consistently accept the volume of concentrate for a set period of time for this to be a realistic option. Legal issues complicate the injection of concentrate into oil and gas fields when the injection is not directly related to oil and gas production. Using Mickley's cost estimation worksheet [5], new wells completed to a depth of 1300 m and 1150 m –average for the Permian and East Texas Basins, respectively,- and handling a concentrate stream of 7.6×10^3 m^3/day could cost as much as 4.5 and 4.0 million dollars, respectively, including a monitoring well, if the most stringent regulations ("class I injection wells"), also applicable to hazardous wastes, are used. On the other hand, because the concentrate is not hazardous in most cases, simpler regulations may be acceptable ("class V injection wells").

Following methodology developed by the U.S. Department of Energy [6], we suggest that initial capital cost for an injection well to a depth of 1220 m (4,000 ft) is approximately $375,000. Annual operating costs, including labor, are about $21,000 per well. Workover operations and energy for pumps comprise most of the non-labor operating costs. As suggested by Mickley [5] and in [6], chemical costs are typically a small fraction of operating costs. A *very* conservative injection rate (Fig. 9) of 545 m^3/day (100 gpm) requires 14 wells to meet the disposal requirement of a sizable facility (30×10^3 m^3/day). The operating costs for disposal are then a very reasonable \$0.027/m^3 (\$0.10/1,000 gallons). The main benefit of this approach is that the injection wells are already in place and that disposal costs consist mainly of operating costs.

4. Conclusions

Despite some differences, six analysis areas show a consistent picture relative to desalination concentrate injection into depleted oil and gas reservoirs. All areas have a promising history of fresh waterflooding, especially during early production in the first half of the 20th century, suggesting a very favorable outlook for concentrate injection. Injection rates are not on average historically high in Paleozoic formations such as in the Permian Basin, but can easily be improved. The East Texas and Gulf Coast reservoirs have higher permeability and very high potential injection rates. However, in most cases, multiple wells will be needed to accommodate the concentrate stream of a typical plant. Scaling tendency by common minerals, such as calcite and gypsum, is not outside of that typically encountered and dealt with by the oil and gas industry. The greatest risk for formation damage may be changing the ionic ratio of formation water or the selectivity of ion exchange between water and clay minerals, although water sensitivity of the clayey material can be accommodated using operational solutions such as pretreatments with appropriate chemicals or buffer solutions. Technical challenges of injecting desalination concentrates into oil producing formations are very much like those dealt with successfully by the oil and gas industry in the past decades. This work demonstrates that injection of desalination concentrates in the formation water will not be a problem if the injection water and the formation are appropriately pretreated, as is done routinely in the oil industry.

Acknowledgments

This study was funded by the Desalination and Water Purification Research and Development Program, U.S. Bureau of Reclamation (USBR) (Agreement No. 03-FC-81-0846) and the Texas Water Development Board (TWDB). We thank Bill Mullican from TWDB for the original research idea. Several people contributed to this project, in particular Robert Mace, from TWDB, and Katie Kier and Alan Dutton, both at the Bureau of Economic Geology. We also thank an anonymous reviewer who helped improve the manuscript. The paper was edited by Lana Dieterich. Views and conclusions contained in this report reflect those of the Bureau of Economic Geology and should not be interpreted as necessarily representing the opinions, either expressed or implied, or official policies of the USBR or TWDB.

References

1. R.E. Mace, J.-P. Nicot, A.H. Chowdhury, A.R. Dutton, and S. Kalaswad, 2004. Please, Pass the Salt: Using Oil Fields for the Disposal of Concentrate from Desalination Plants, in The Future of Desalination in Texas Volume II: Technical Papers, Case Studies and Desalination Technology Resources, J.A. Arroyo, Editor, Report No 363, Texas Water Development Board, 2004.

2. Y.K. Kharaka, W.D. Gunter, P.K. Aggarwal, E.H. Perkins, and J.D. DeBraal, SOLMINEQ88: A Computer Program for Geochemical Modeling of Water-Rock Interactions, U.S. Geological Survey Water Resources Investigation Report, 88-4227, 1988.

3. R.F. Scheuerman and B.M. Bergersen, Injection water salinity, formation pretreatment, and well operations fluid selection guidelines, in: Society of Professional Engineers SPE Reprint Series No. 29, SPE Paper No. 18461, 1990, pp.154–170.

4. D.L. Warner and J.H. Lehr, An Introduction to the Technology of Subsurface Wastewater Injection, Final Report, Jul 75-Jul 77, Missouri Univ.-Rolla., Robert S. Kerr Environmental Research Lab., Ada, Okla.; Municipal Environmental Research Lab., Cincinnati, Ohio; Report No. EPA/600/2-77/240 <NTIS> PB-279 207/5, 1977.

5. M.C. Mickley, Membrane Concentrate Disposal: Practices and Regulation, Desalination and Water Purification Research and Development Program Report No. 69, U.S. Department of the Interior, Bureau of Reclamation, Technical Service Center, 2001.

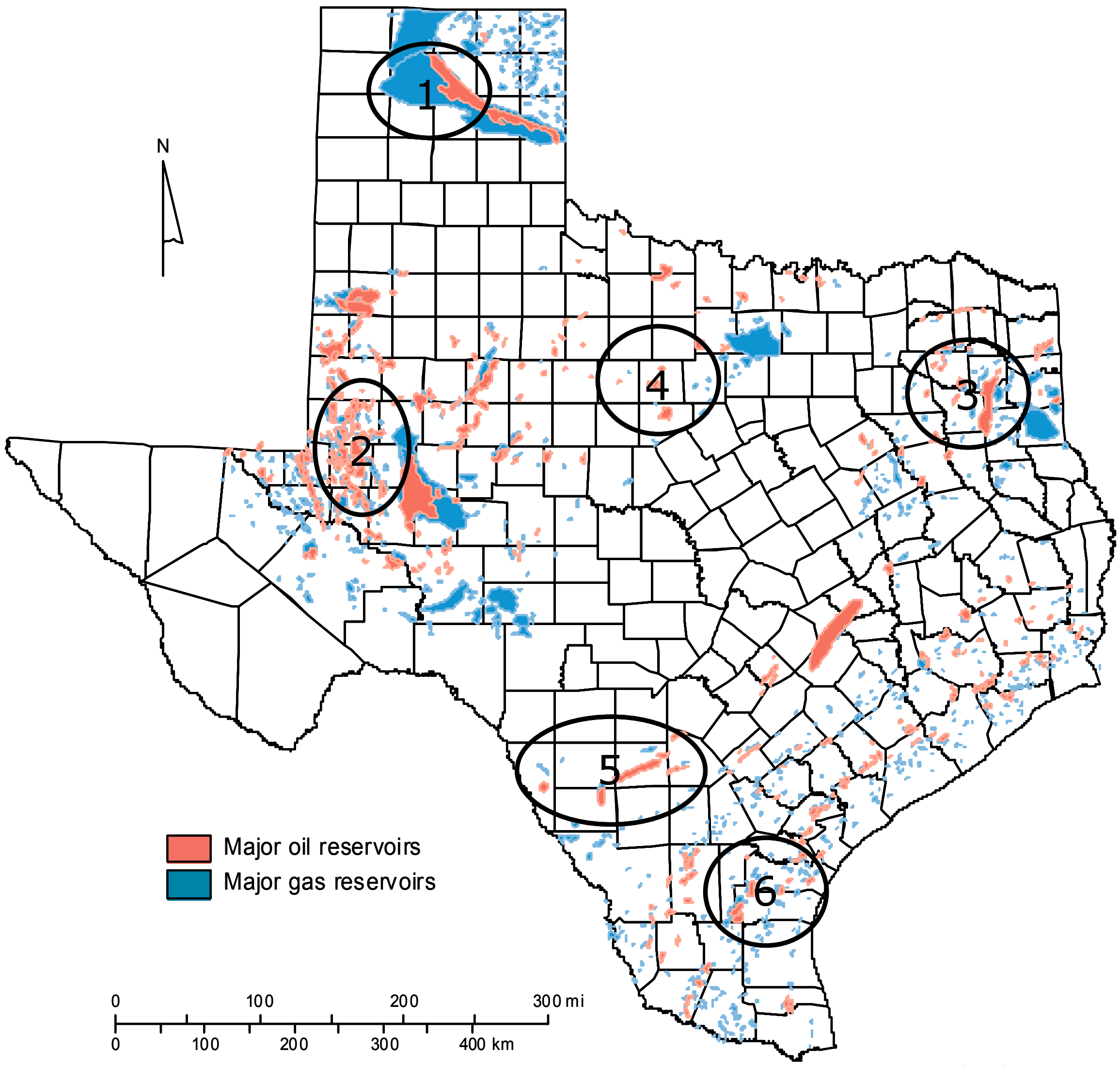
6. Energy Information Administration, Office of Oil and Gas. Costs and indices for domestic oil and gas field equipment and production operations, DOE/EIA-0185(2000) [online document] Jan. 2005,. Available: http://tonto.eia.doe.gov/bookshelf/SearchResults.asp

Table 1

Formation water, untreated feedwater and hypothetical concentrate composition. The concentrate is acidified with sulfuric acid to a pH of 6.

	Na	K	Ca	Mg	SiO_2	Cl	SO_4	HCO_3	pH	TDS	MAR
Permian Basin Formation Water (San Andres Formation)											
25^{th}	11,463	NM	2,272	684	NM	21,289	2,917	420	7.5	39,049	3.1
50^{th}	23,745	NM	2,693	792	NM	40,501	3,530	1,001	6.5	72,263	11.4
75^{th}	30,634	NM	3,254	1,198	NM	53,212	3,519	966	8.2	92,783	14.5
Permian Basin Feed Water (Ogallala and Dockum Aquifers)											
25^{th}	173	13	78	70	1	227	308	277	8.0	1,161	0.01
50^{th}	310	4	102	78	18	283	535	299	8.3	1,738	0.03
75^{th}	589	NM	263	141	70	670	1,329	227	7.4	3,314	0.06
Permian Basin Hypothetical Concentrate (from Ogallala and Dockum Aquifers)											
25^{th}	692	52	312	280	4	909	1,643	1,109	6.0	5,021	0.05
50^{th}	1,242	16	408	312	72	1,133	2,578	1,197	6.0	6,963	0.14
75^{th}	2,363	NA	1,055	565	281	2,688	5,647	910	6.0	13,532	0.23
East Texas Basin Formation Water (Woodbine Formation)											
25^{th}	19,788	NM	858	247	NM	32,375	38	654	7.5	53,984	25.0
50^{th}	20,400	NM	1,030	297	NM	33,600	215	540	7.5	56,000	22.1
75^{th}	21,991	NM	1,120	280	NM	36,120	323	607	7.4	60,441	24.6
East Texas Basin Feed Water (Carrizo-Wilcox Aquifer)											
25^{th}	440	2.2	3	1	10	450	2	420	8	1,330	3.4
50^{th}	498	NM	7	1	12	480	6	525	8	1,530	2.3
75^{th}	672	NM	12	6	41	699	23	580	NM	2,051	1.7
East Texas Basin Hypothetical Concentrate (from Carrizo-Wilcox Aquifer)											
25^{th}	1,761	9	12	4	40	1,801	635	1,681	6.0	5,948	13.5
50^{th}	1,994	NA	28	4	48	1,922	802	2,102	6.0	6,903	9.3
75^{th}	2,692	NA	48	24	164	2,800	935	2,323	6.0	8,986	6.7

NM: Not Measured; NA: Not Applicable
Note: percentile represent true samples and not compounded median value of each ion.



The threshold value for a reservoir to be mapped is 10 million barrels (15.9×10^6 m^3) of cumulative production of oil or 30 billions cubic feet (850×10^6 m^3) of gas.

Fig. 1. Map of major oil and gas fields in Texas. Analysis areas are numbered: 1. Anadarko Basin, 2. Permian Basin, 3. East Texas Basin, 4. Fort Worth Basin, 5. Maverick Basin, and 6. Southern Gulf Coast Basin.

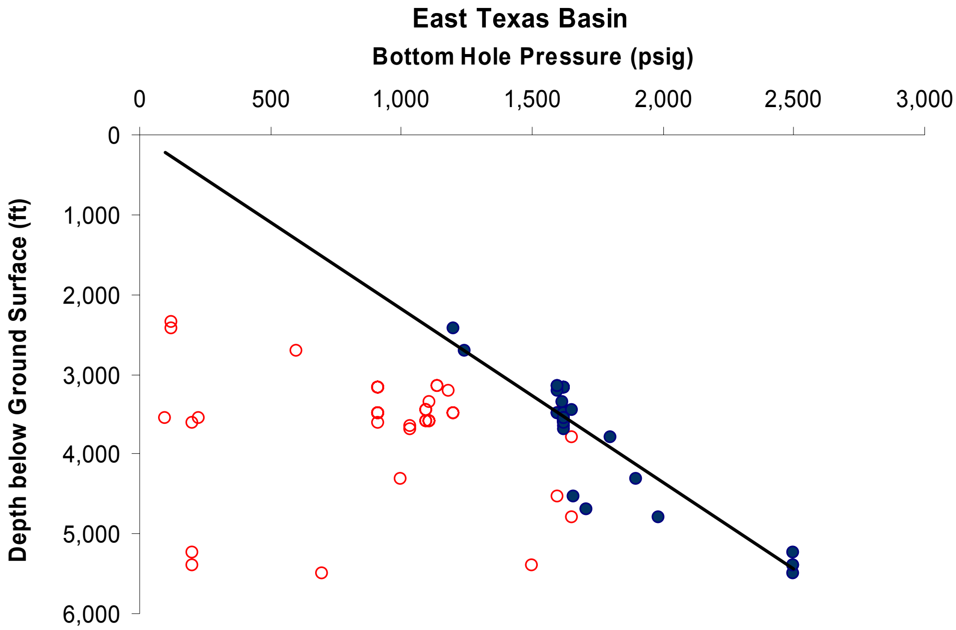


Fig. 2. Reservoir pressure as a function of depth. The straight line represents hydrostatic pressure. Open and full circles represent current and initial pressures, respectively. Only a few representative wells are shown for clarity (1ft = 0.305 m; 1 psi = 6895 Pa).

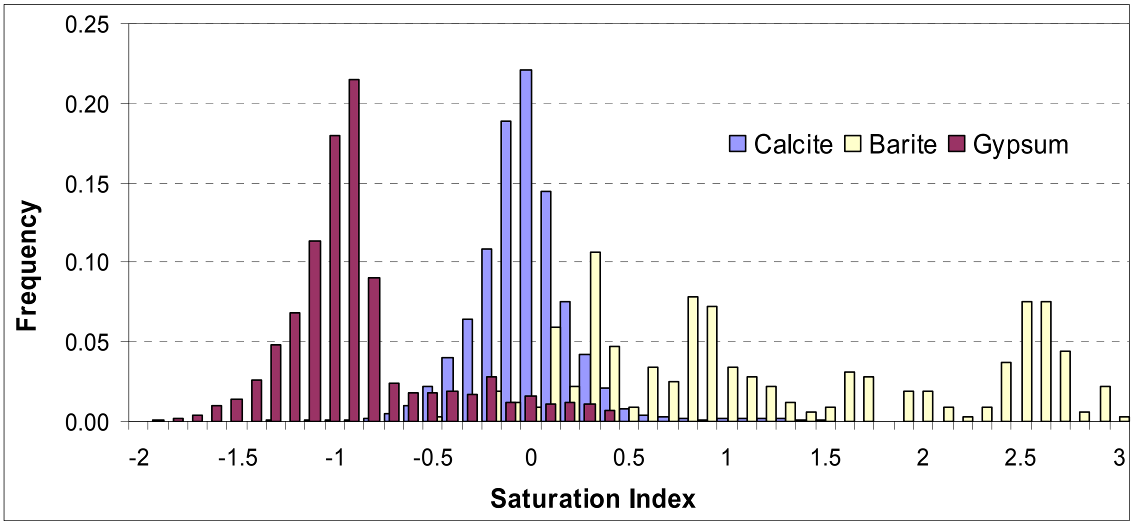


Fig. 3. Selected histograms of computed saturation index of scale forming minerals for mixing of acidified concentrate and formation water in the East Texas Basin (Number of bins: 51; Bin size: 0.1; Number of data points for calcite: 19,580; gypsum: 19,349; barite: 320).

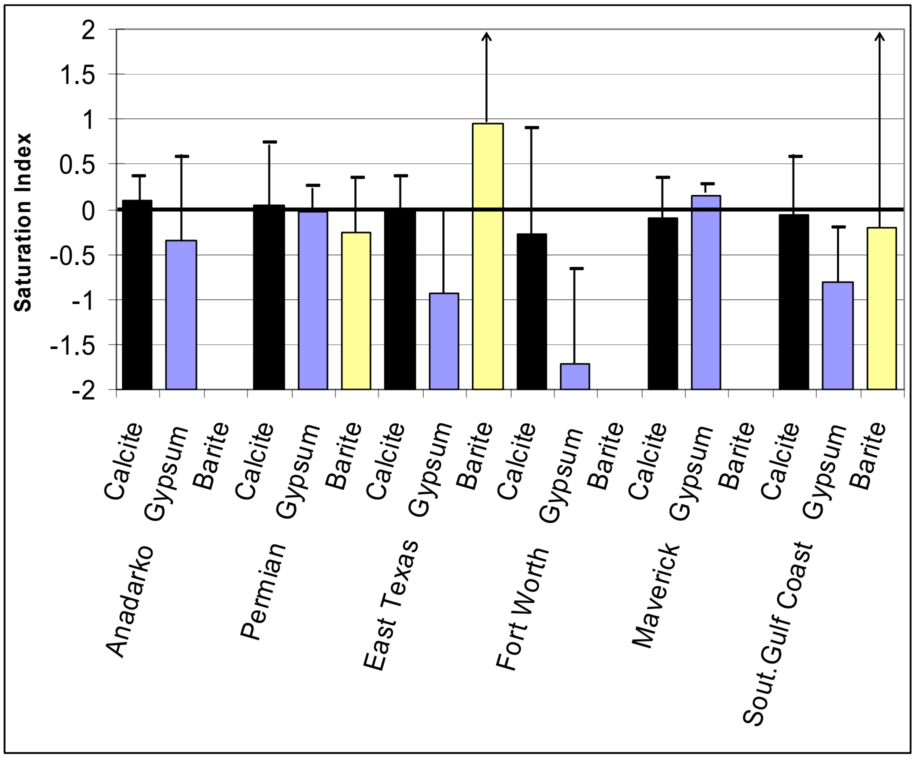
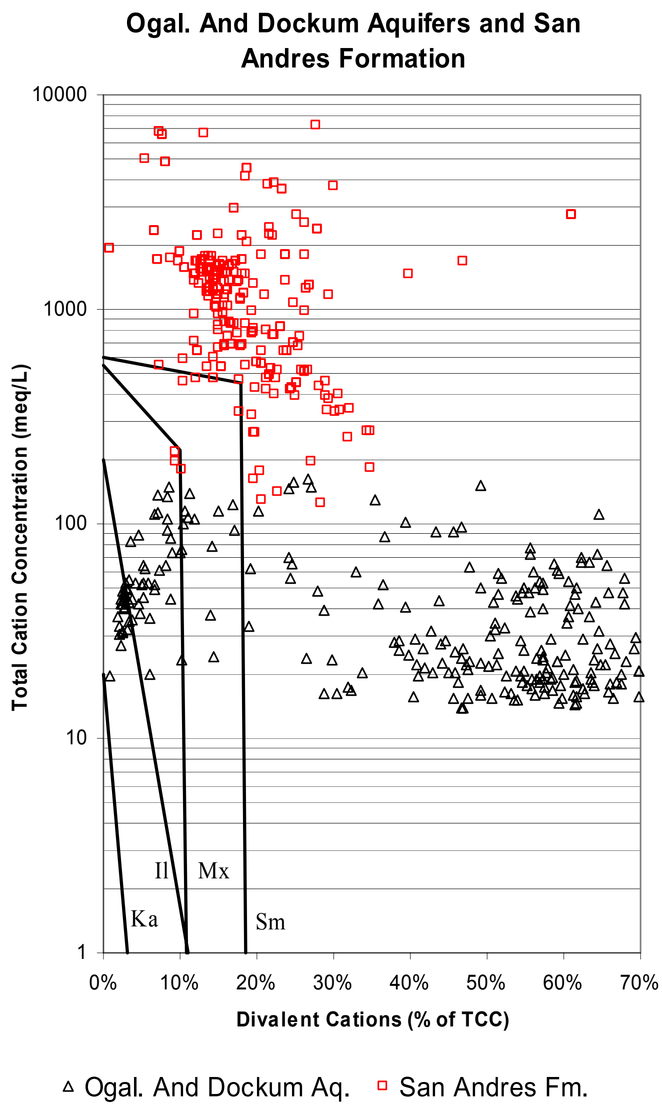


Fig. 4. Summary of computed median values and 95th percentile of saturation index (mixture of formation water and concentrate in different proportions). Arrows indicate saturation index values larger than 2 which is retained as the value beyond which recurrent scaling problems could occur during the injection. Basin locations are displayed in Figure 1.



Ka=kaolinite; Il=illite; Mx=mixed layers; Sm=smectite
TCC=Total Cation Concentration
Note: any water inside the delineated domain will deflocculate the corresponding clay.

Fig. 5a. Plot of total cation concentration and divalent cations percent for concentrate and formation water (Permian Basin).

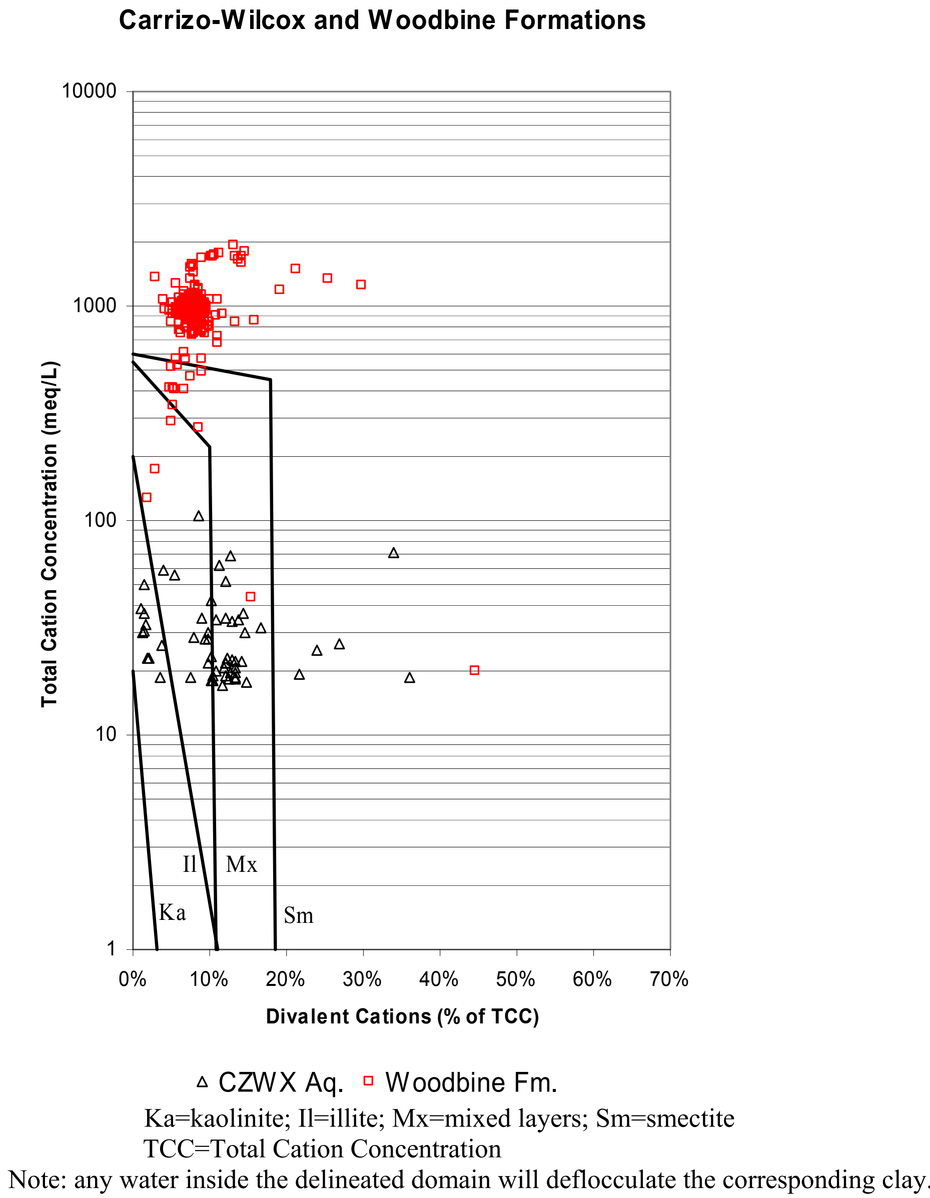


Fig. 5b. Plot of total cation concentration and divalent cations percent for concentrate and formation water (East Texas Basin).

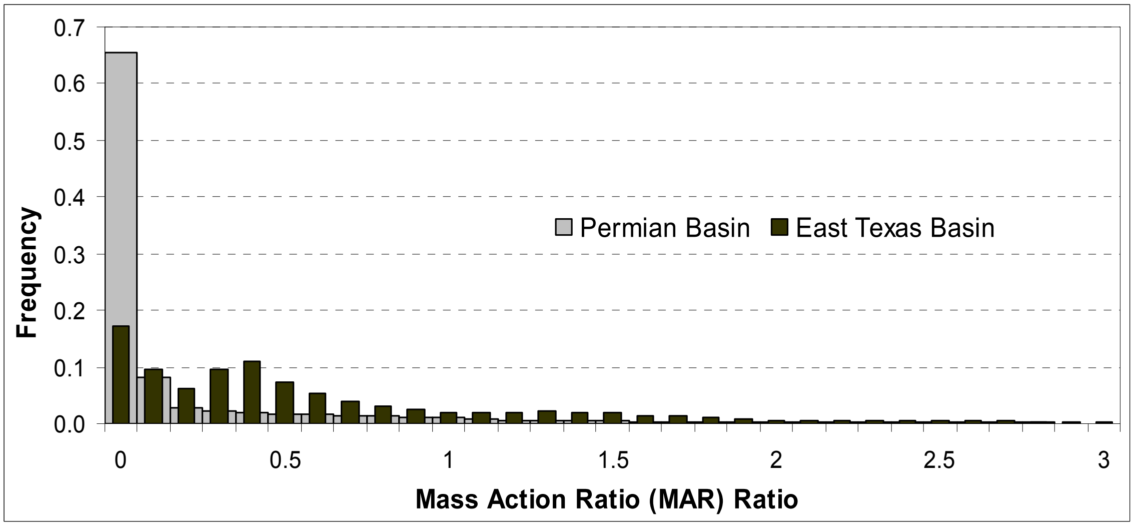


Fig. 6. Computed MAR ratio distributions for the Permian Basin (concentrates from Ogallala and Dockum waters injected into the San Andres Formation) and East Texas Basin (concentrates from Carrizo-Wilcox waters injected into the Woddbine Formation) (Number of bins: 31; Bin size: 0.1; Number of trials: 100,000)

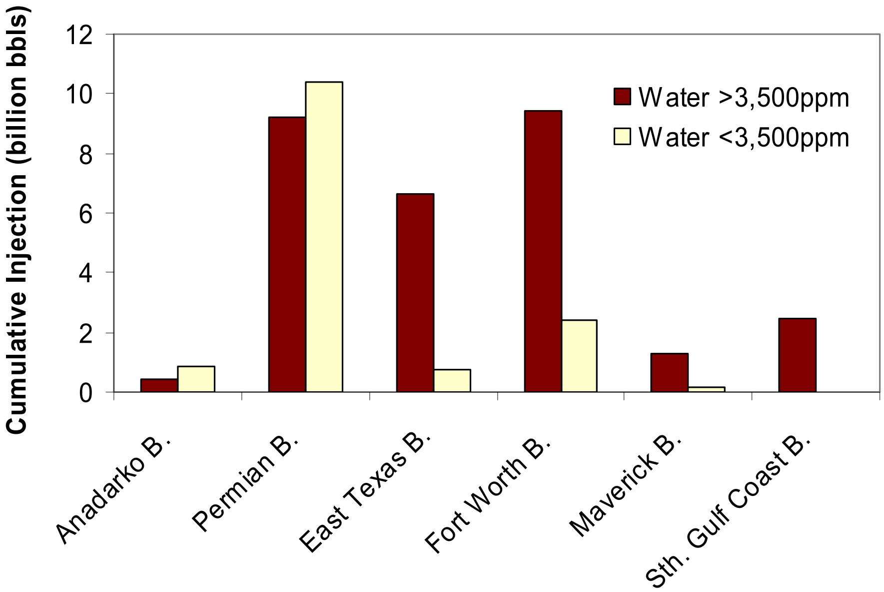


Fig. 7. Cumulative volume of injected water up to 1981 in administrative districts that include analysis areas (1 bbl= 0.159 m^3).

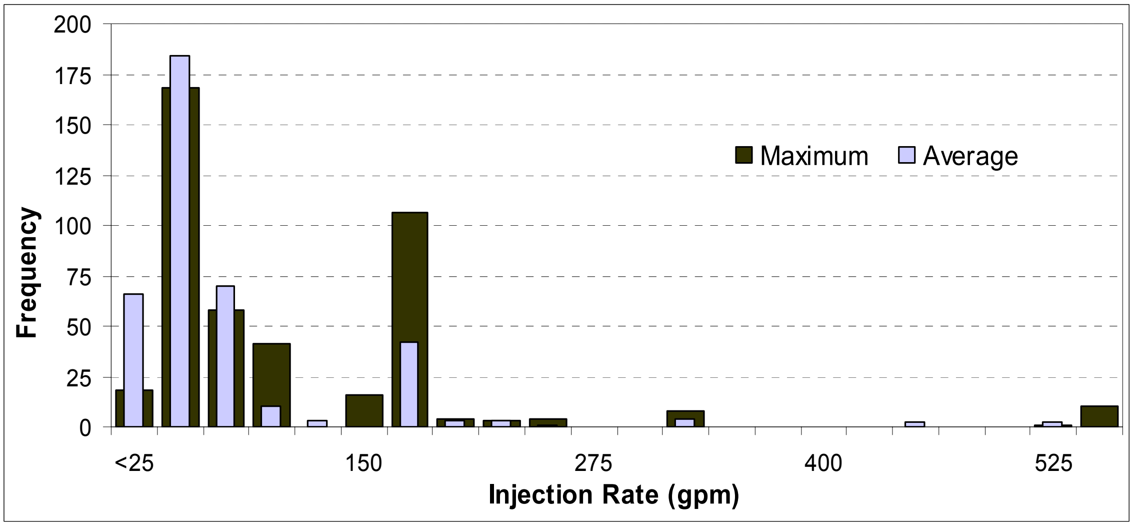


Fig. 8. Reported maximum and average injection rate distribution (from examination of administrative forms H1 – from the Railroad Commision, responsible state agency in Texas) for all analysis areas combined (100 gpm = 0.0063 m^3/s).

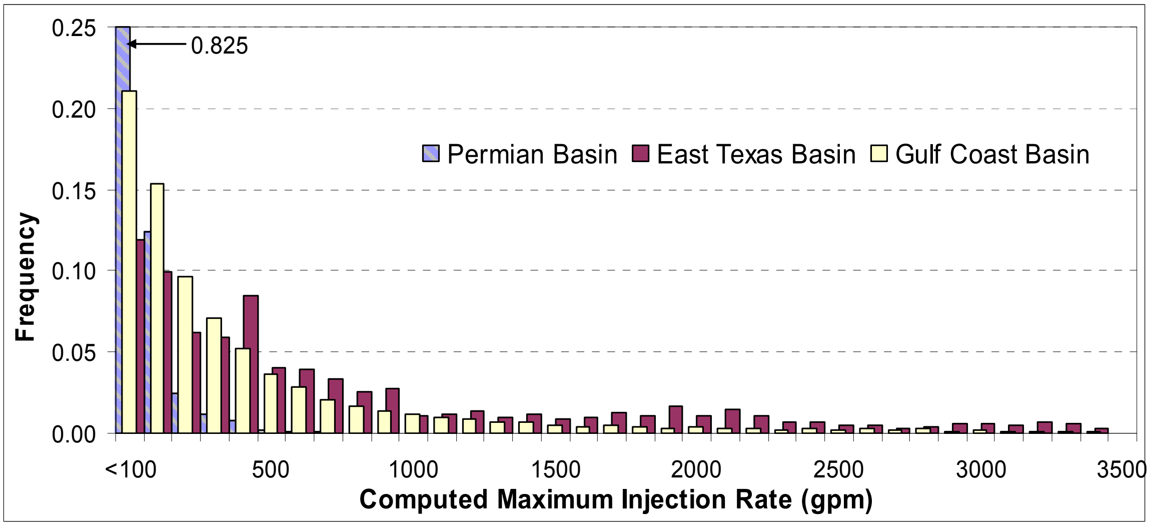


Fig. 9. Distribution of computed maximum injection rates for selected basins (Number of bins: 36; Bin size: 100 gpm; Number of trials for each basin: 10,000). Note that most of the rates computed for the Permian Basin are less than 100 gpm (100 gpm = 0.0063 m^3/s).