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Ellenburger wastewater injection and seismicity in North Texas

Matthew J. Hornbach [a,*], Madeline Jones [a], Monique Scales [a], Heather R. DeShon [a], M. Beatrice Magnani [a], Cliff Frohlich [b], Brian Stump [a], Chris Hayward [a], Mary Layton [a]

[a] Huffington Department of Earth Sciences, Southern Methodist University, Dallas, TX, United States
[b] University of Texas Institute for Geophysics, University of Texas at Austin, Austin, TX, United States

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ABSTRACT

North Texas has experienced a roughly exponential increase in seismicity since 2008. This increase is primarily attributable to wastewater injection into the Ellenburger Formation—a carbonate formation located within and just above seismically active zones. To our knowledge, there has been no previous comprehensive ~10 year analysis comparing regional seismicity with basin-wide injection and injection pressure of wastewater into the Ellenburger, even though monthly injection/pressure records have been made publically available for nearly a decade. Here we compile and evaluate more than 24,000 monthly injection volume and pressure measurements for the Ellenburger formation. We compare Ellenburger injection pressures and volumes to basin-wide injection pressures and volumes, and to earthquake locations and rates. The analysis shows where cumulative injection volumes are highest, where injection pressures and formation pressures are increasing, how injection volumes have changed regionally with time, and how Ellenburger injection volumes and pressures correlate in space and time with recent seismicity in North Texas. Results indicate that between 2005 and 2014 at least 270 million m^3 (~1.7 billion barrels) of wastewater were injected into the Ellenburger formation. If we assume relative homogeneity for the Ellenburger and no significant fluid loss across the 63,000 km^2 basin, this volume of fluid would increase pore fluid pressure within the entire formation by 0.09 MPa (~13 psi). Recent spot measurements of pressure in the Ellenburger confirm that elevated fluid pressures ranging from 1.7 to 4.5 MPa (250–650 psi) above hydrostatic exist in this formation, and this may promote failure on pre-existing faults in the Ellenburger and underlying basement. The analysis demonstrates a clear spatial and temporal correlation between seismic activity and wastewater injection volumes across the basin, with earthquakes generally occurring in the central and eastern half of the basin, where Ellenburger wastewater injection cumulative volumes and estimated pressure increases are highest. The increased seismicity correlates with increased fluid pressure, which is a potential cause for these earthquakes. Based on these results, we hypothesize it is plausible that the cumulative pressure increase across the basin may trigger earthquakes on faults located tens of kilometers or more from injection wells, and this process may have triggered the Irving-Dallas earthquake sequence. We use these results to develop preliminary forecasts for the region concerning where seismicity will likely continue or develop in the future, and assess what additional data are needed to better forecast and constrain seismic hazard.

1. Introduction

The Bend Arch-Fort Worth Basin in North Texas has experienced a rapid increase in the number of earthquakes beginning in 2008 (Fig. 1). This basin includes the largest metropolitan area in the southern United States–the Dallas-Fort Worth Metroplex. Prior to 2008, no confirmed felt earthquakes had occurred in the basin despite more than 160 years of settlement and more than 40 years of seismic monitoring (Frohlich and Davis, 2002; Frohlich et al., 2011, 2016). Since 2008, however, earthquakes in the Fort Worth Basin have generally increased in number, magnitude, and hence moment release, with the basin experiencing its largest (M4.0) earthquake in 2015 (Fig. 2).

There have been numerous investigations concerning the cause of recent earthquakes in North Texas and most conclude that the injection of oil and gas flowback brine water into deep sedimentary formations is probably responsible for reactivating faults and causing seismicity in the basin (Frohlich et al., 2011, 2016, 2012; Justinic et al., 2013; Gono et al., 2015; Hornbach et al., 2015). All

* Corresponding author.
E-mail address: mhornbach@smu.edu (M.J. Hornbach).

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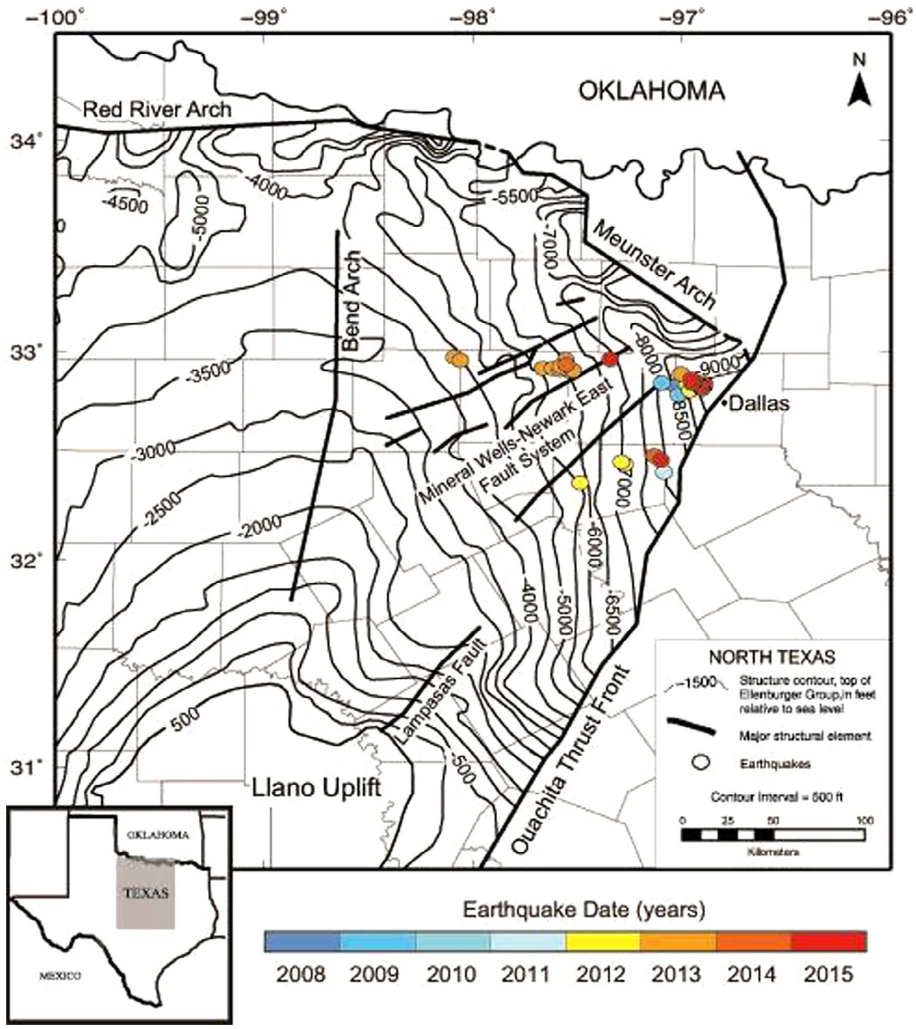

Fig. 1. Map of the Bend-Arch Fort Worth Basin showing earthquake epicenters reported in the USGS ANSS Catalog (location uncertainty of ~10 km). Contours indicate the top of the Ellenburger formation based on Pollastro et al. (2007). The basin depocenter is below the cities of Irving and Dallas in western Dallas County, where a significant increase in seismicity occurred in the past 3 years.

of these investigations focus on discreet relationships between regional wastewater injection sites and earthquakes. An important unanswered question is why some high volume injection sites induce earthquakes while others do not. Fully addressing the induced seismicity hazard requires understanding not only subsurface pressure changes but also the local stress regime. Although the stress regime in the Fort Worth Basin is only marginally constrained, published earthquake focal mechanism across the basin (e.g. Justinic et al., 2013; Hornbach et al., 2015) suggest the maximum principal stress direction extends in a northeast to southwest direction consistent with regional stress studies (e.g. Zoback and Zoback, 1980).

Two of the investigations assessing the cause of earthquakes in the Fort Worth basin (Gono et al., 2015; Hornbach et al., 2015) modelled subsurface permeability, pressure, and structure to estimate pore fluid pressure changes over time. Although both studies concluded regional seismicity is most likely induced by wastewater injection, a limitation of these modeling studies is their inability to fully account for subsurface complexity, and thus to constrain completely how pressures and volumes of injected wastewater influence subsurface stress. Specifically, significant uncertainties concerning fault locations, fault orientations, fault permeability, fluid flow paths, and regional stress regimes often limit the applicability of such modeling investigations. Limitations of these studies, combined with a decade of pressure and injection data made available by the Texas Railroad Commission, motivate us to explore alternative methods for forecasting where future seismicity might occur as wastewater injection continues in the basin.

In the present investigation we apply an alternative statistical approach that avoids the uncertainties associated with detailed 3D fluid flow modeling; we make straightforward statistical comparisons between wastewater injection practices, subsurface pressures, and regional seismicity. Statistical methods comparing seismicity and injection have found a correlative relationship in other large basins, especially in Oklahoma (e.g. Walsh and Zoback, 2015; Weingarten et al., 2015). In the Fort Worth Basin, Frohlich (2012) compared wastewater injection locations with regional seismicity during the two years when the US Earthscope Transportable Array was deployed across the area. Additionally, for 13 of the 28 counties located in the Fort Worth Basin, Gono et al. (2015) produced a nearly basin-scale fluid model noting the relationship between modeled subsurface pressure in the Ellenburger and regional seismicity. While both of these investigations found a spatial association between wastewater injection, subsurface injection pressure, and regional seismicity, neither evaluated the complete publically available pressure/volume data for all wastewater injection wells in the Ellenburger for the entire ~ 10 year period when seismicity has increased significantly (Fig. 2).

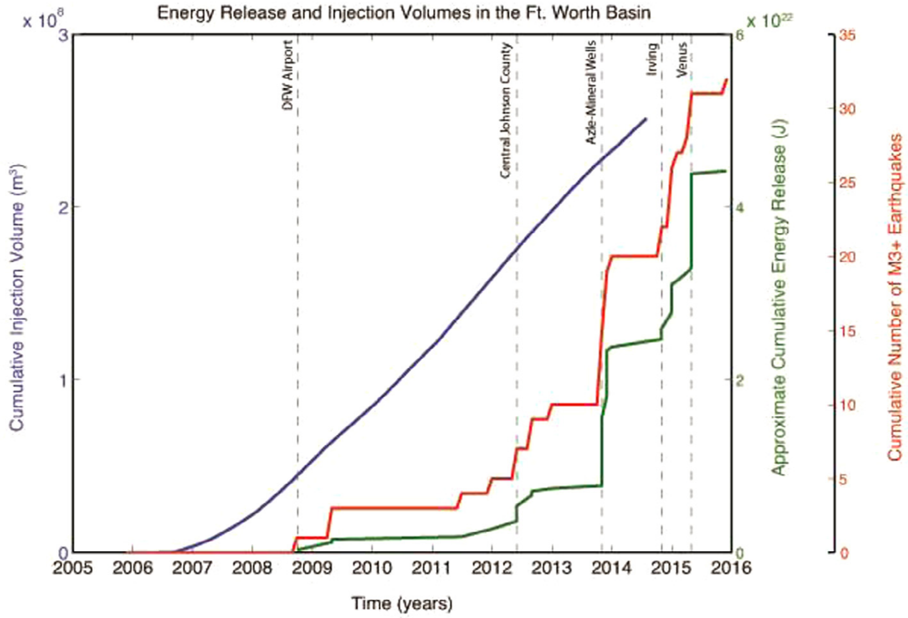

Fig. 2. Cumulative injection volumes, number of earthquakes at magnitude 3 and greater, and scalar moment which we use as a proxy for seismic energy release in the Ft. Worth Basin since 2005. Injection data were taken from the Texas Railroad Commission and earthquakes are M3.0 and above from the USGS Catalog. The energy is calculated by multiplying the scalar moment by a constant using the approach of Hanks and Kanamori (1979). Dashed lines represent the beginning of a sequence containing two or more magnitude 3 earthquakes.

For all 28 counties within the Fort Worth Basin, the present investigation compiles and analyzes earthquake locations for all USGS-reported earthquakes of magnitude 3 or greater, as well as more than 24,000 monthly injection volume and pressure measurements for the years 2005–2014 using data available online and archived by the Texas Railroad Commission. We use these data to assess the relationship between wastewater injection, time, pressure, and seismicity in North Texas over a ~10 year period and to generate forecasts for seismicity in the region.

2. Geologic background

2.1. Tectonic setting

The Bend Arch-Fort Worth Basin is an Ordovician age (greater than400 Ma) sedimentary basin covering an area of ~63,000 km^2 in North Central Texas. The basin is an asymmetric feature bounded by the Ouachita thrust and fold belt to the east, the Muenster Arch and Amarillo Uplift to the north, the Bend Arch structural fold belt to the west, and the Llano uplift to the south (Fig. 1) (e.g. Montgomery et al., 2005; Pollastro et al., 2007). Sediments in the basin dip east-northeast with the deepest part of the basin located below the city of Dallas at a depth of ~3700 m below sea level (Fig. 1) (Core Laboratories Inc, 1972; Pollastro et al., 2007). Although only a few large faults are mapped in the basin, nearly all follow a similar strike that extends along a southwest-northeast trend (e.g. Budnik et al., 1990; Ewing, 1991), consistent with regional seismic reflection studies (e.g. Sullivan et al., 2006) and the estimated current maximum horizontal stress direction (e.g. Zoback and Zoback, 1980; Huffman, 2003; Heidbach et al., 2008). Regional fault studies indicate the basin has not experienced widespread or significant tectonic activity for the past ~300 Ma (e.g. Muehlberger, 1965; Rozendal and Erskine, 1971; Huffman, 2003). Thus considering these observations, the occurrence of frequent felt earthquakes since 2008 within the basin is highly anomalous (Sullivan et al., 2006; McDonnell et al., 2007; Frohlich, 2012; Hornbach et al., 2015).

2.2. Recent seismicity

In the Fort Worth Basin since 2008, the cumulative number of earthquakes having magnitudes of 3 or more increases roughly exponentially, with discreet increases associated with individual earthquake sequences (Fig. 2). Many North Texas earthquake sequences do not follow typical mainshock-aftershock patterns but consist of swarms of small earthquakes. These include sequences in eastern Tarrant County near the Dallas-Fort Worth (DFW) airport beginning in 2008 (Frohlich et al., 2011), in Johnson County near Cleburne beginning 2009 (Justinic et al., 2013), in central Johnson County in 2012 and near Venus in eastern Johnson County in 2011(Frohlich, 2012) and again in 2015, in Dallas and Irving beginning in 2012 and continuing intermittently up to the present, and in Parker and Palo Pinto Counties near Azle and Mineral Wells beginning in 2013 and continuing intermittently up to the present (e.g. Hornbach et al., 2015). All these earthquakes occur either within the deepest and oldest sedimentary formations of the basin (primarily the Ellenburger), or in the basement Precambrian granite immediately underlying, and likely in direct pressure communication with, the Ellenburger (Frohlich et al., 2011; Justinic et al., 2013; Hornbach et al., 2015). The published investigations of all these sequences concluded that it was plausible or probable that they were induced by increased subsurface fluid pressures associated with the injection of wastewater. These results are also consistent with numerous recent studies that suggests fluid injection into formations directly above basement faults, such as the Ellenburger, increases the likelihood of earthquake activity (e.g. Frohlich, 2012; Ellsworth, 2013; National Research Council, 2013; McGarr, 2014; Walsh and Zoback, 2015; Rubinstein and Mahani, 2015).

2.3. The source of wastewater injected into the Ellenburger

The wastewater injected into the Fort Worth Basin is a byproduct of gas production mostly from the Barnett Shale (Montgomery et al., 2005; Bowker, 2007; Jarvie et al., 2007), an organic rich but geologically tight formation. Although the Barnett has high hydrocarbon production potential, its low permeability (typically less than 10^{-18} m^2) makes it difficult to exploit using conventional methods. The Barnett Shale unconformably overlies the Viola limestone and Ellenburger dolomite/limestone formations and underlies the Marble Falls Limestone formation (Fig. 3). The low permeability of the Barnett forms a natural seal, separating the Marble Falls and Ellenburger limestone aquifers from each other. Gas production for the Barnett Shale requires hydraulic fracturing, and a byproduct of this practice is wastewater (also called brine) that usually contains high concentrations of total dissolved solids. This brine is produced as a result of both flowback from hydraulic fracturing and from extraction of naturally occurring formation water. Brine produced in typical oil and gas fields can have total dissolved solids in excess of 250,000 ppm (Gregory et al., 2011), $\sim$10x saltier than seawater. To avoid environmental surface damage, oil and gas companies typically reinject brines into deep, isolated saltwater formations that are not in communication with shallower, fresh water aquifers.

We estimate that a majority of the water being injected into the Ellenburger is flowback water associated with the hydraulic fracturing process. According to the Texas Railroad Commission website, at least 15,000 unconventional wells have been drilled in the Barnett Shale. The average well in the Barnett shale that is hydraulically fractured uses between 11,000 and 19,000 m^3 (69,000–119,000 bbls) of water (Nicot et al., 2014). If injected

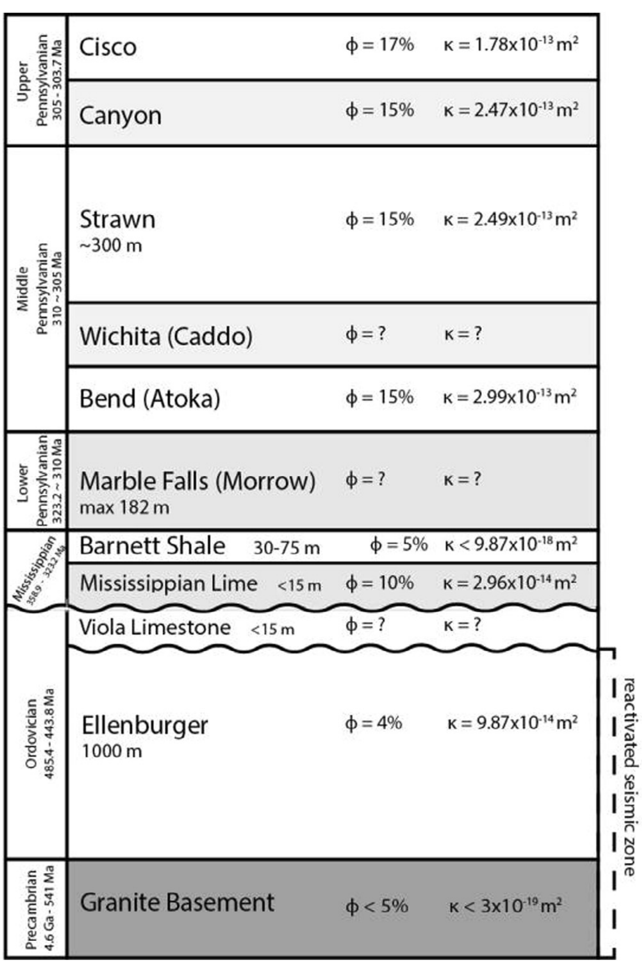

Fig. 3. The main formations used for wastewater injection in the Fort Worth Basin with respective porosities (ϕ) and permeabilities (κ). Figure shows approximate relatively thicknesses in the center of the basin. (Core Laboratories Inc. 1972; Gale et al., 2007; Montgomery et al., 2005; Loucks et al., 2009; Pollastro et al., 2003; Brace et al., 1968; Skoczylas and Henry, 1995; Geraud, 1994).

water is ultimately recovered from each well during production, then the total amount of flowback water from Barnett production ranges from 175 to 285 million m^3 (1.1–1.8 billion bbls). As we will show, this amount is equivalent to $\sim$65–106% of the total volume of water injected into the Ellenburger since 2005. Thus, the amount of water used to hydraulically fracture the Barnett from 2006 to 2014 is consistent to first-order with the amount of wastewater injected into the Ellenburger during that same time.

2.4. The fate of oilfield wastewater

Currently, oil and gas companies reinject wastewater into several different formations in the Fort Worth Basin. These formations, from shallowest to deepest, include (but are not limited to) the Cisco, Canyon, Strawn, Caddo, Atokan, Marble Falls, and the Ellenburger formations (Fig. 3). The age of the youngest formation outcropping at the surface of the basin is no younger than 65 Ma. The Ellenburger is the oldest (age >450 Ma), deepest, and thickest: it is a massive, $\sim$1 km thick karsted dolomite/limestone formation that extends across the entire basin (e.g. Core Laboratories Inc, 1972; Pollastro et al., 2007; see also Fig. 1). The Ellenburger overlies basement granite wash and unconformably underlies the Viola Limestone and Barnett Shale (Fig. 3) (e.g. Montgomery et al., 2005; McDonnell et al., 2007). The top of the Ellenburger formation is shallowest in the west, averaging a depth of $\sim$1000 m near the Bend Arch, but steadily deepens to the east, toward the formation depocenter and lowest potential drainage point at a depth of $\sim$2800 m below sea level under the cities of Irving and Dallas (Core Laboratories Inc, 1972) (Fig. 1).

The Ellenburger is the single largest aquifer in Texas, and it contains waters ranging in salinity from fresh at its shallow locations to hyper saline (150,000 ppm, $\sim$5x seawater) at greater depths (Core Laboratories Inc, 1972). Despite its significant volume, some physical properties of the Ellenburger are not ideal for wastewater storage: it has generally lower porosity (Φ) and permeability (κ) than other shallower Fort Worth Basin aquifers (Fig. 3), and although thick and therefore voluminous, regional seismic surveys indicate the Ellenburger is at many locations in direct contact with basement faults. Some of these basement faults extend through the Ellenburger and into the Barnett, providing connectivity between the units (e.g. Khatiwada et al., 2013). The Ellenburger formation porosity ranges between 2% and 12% but averages only 4% (Core Laboratories Inc, 1972). Regional studies combined with pressure fall-off tests indicate the formation has moderate permeability (0.1–500 mD) and, since it directly overlies the basement, fluids in the Ellenburger formation are likely in direct communication with basement faults at many sites.

The Ellenburger is largely a non-productive formation and, unlike many other formations in the basin where oil and gas have been produced extensively, has experienced only very limited fluid extraction for hydrocarbon production in the Fort Worth Basin. Some fluids have been intentionally extracted from the Ellenburger on the far western edge of the basin on top of the Bend Arch anticline or outside the basin entirely (e.g. Autry, 1940; Bradfield, 1964; Loucks and Anderson, 1985) and in limited instances, hydraulic fracturing has caused fracturing into the Ellenburger (Pollastro et al., 2007). For the vast majority of hydraulic fractures within the Barnett shale, however, there is little or no evidence of significant water flowback from the Ellenburger, with annual water production (G-1 and G-10) test reports provided by the Texas Railroad Commission typically indicating no significant flowback occurring within a year of the onset of production. Previous studies also suggest significantly more brine is injected into the Ellenburger than is produced from the Ellenburger in a particular region (e.g. Hornbach et al., 2015). Thus, while the Ellenburger is one of the largest brine sinks in the region, it has experienced only

Table 1
Total Ellenburger and total injection volumes by county, compiled from all available data accessible through the Texas RRC website, from December 2005 to November 2015.

County	County Area in Fort Worth Basin (sq.km)	Ellenburger - Total Volume (cubic m)	Total Volume (cubic m) *TRRC reports date back no further than 2005*	Ellenburger Volume/ Total Volume	Ellenburger - Total Volume per County Area (cubic m per sq. km)	Ellenburger - Total Volume per County Area (meters)	Total Volume per County Area (cubic m per sq.km) *TRRC reports date back no further than 2005*	Ellenburger Volume per Area/Total Volume per Area	# Inj Permits	# Inj Permits Ellenburger Only	# Inj Permits with H-10 data Ellenburger Only	# Inj Permits w/H-10 data in Ellenburger/ # Inj Permits
Archer	2357	43,147	2,17,31,269	0.199%	18	0.000018306	9220	0.199%	2716	5	2	0%
Bosque	2561	0	0	–	0	0.000000000	0	–	2	2	0	–
Brown	2445	0	16,49,521	0.000%	0	0.000000000	675	0.000%	540	0	0	0%
Burnet	2577	0	0	–	0	0.000000000	0	–	0	0	0	–
Clay	2683	1,35,601	96,30,627	1.408%	51	0.000050535	3589	1.408%	981	9	2	0%
Comanche	2429	0	34,031	0.000%	0	0.000000000	14	0.000%	43	0	0	0%
Coryell	2562	0	0	–	0	0.000000000	0	–	3	0	0	–
Dallas	801	0	0	–	0	0.000000000	0	–	0	0	0	–
Denton	1541	63,03,866	64,45,431	97.804%	4090	0.004089793	4182	97.804%	40	5	3	8%
Eastland	2398	8,81,730	1,80,92,628	4.873%	368	0.000367694	7545	4.873%	831	7	4	0%
Erath	2813	11,65,433	14,05,908	82.895%	414	0.000414302	500	82.895%	36	13	6	17%
Hamilton	2165	0	26,424	0.000%	0	0.000000000	12	0.000%	9	2	0	0%
Hill	1023	30,77,541	30,79,829	99.926%	3008	0.003007999	3010	99.926%	10	3	3	30%
Hood	1093	1,93,55,818	2,19,76,196	88.076%	17,709	0.017708891	20,106	88.076%	31	20	13	42%
Jack	2375	1,04,86,081	2,56,86,745	40.823%	4415	0.004415192	10,815	40.823%	1129	41	25	2%
Johnson	1888	11,22,01,133	11,38,80,566	98.525%	59,429	0.059428566	60,318	98.525%	39	39	27	69%
Lampasas	1844	0	0	–	0	0.000000000	0	–	0	0	0	–
Mills	1937	0	0	–	0	0.000000000	0	–	0	0	0	–
Montague	2107	1,32,58,069	6,83,20,137	19.406%	6293	0.006293035	32,429	19.406%	947	17	8	1%
Palo Pinto	2468	71,14,911	1,27,58,373	55.767%	2883	0.002882865	5170	55.767%	378	33	15	4%
Parker	2341	3,54,16,831	3,77,59,218	93.797%	15,129	0.015128933	16,130	93.797%	65	19	16	25%
San Saba	2937	0	0	–	0	0.000000000	0	–	0	0	0	–
Somervell	484	1,00,52,570	98,43,163	102.127%	20,770	0.020769772	20,337	102.127%	6	6	5	83%
Stephens	2318	14,93,560	30,66,97,456	0.487%	644	0.000644331	1,32,311	0.487%	1621	11	9	1%
Tarrant	2238	3,10,02,071	3,60,51,412	85.994%	13,853	0.013852579	16,109	85.994%	14	13	9	64%
Wichita	1462	46,338	10,25,40,669	0.045%	32	0.000031685	70,116	0.045%	4931	4	2	0%
Wise	2344	1,68,39,841	3,32,19,943	50.692%	7184	0.007184232	14,172	50.692%	287	18	8	3%
Young	2388	9,39,788	2,54,35,266	3.695%	394	0.000393546	10,651	3.695%	1938	23	10	1%
TOTAL	58,580	26,98,14,329	85,62,64,812	32%	1,56,682	0.15668226	4,37,410	36%	16,597	290	167	1%

limited fluid removal that might reduce formation pressures, particularly near the depocenter of the Fort Worth Basin.

3. Methodology

3.1. Data compilation

Wastewater injection/pressure data for Class II injection wells in Texas are collected and archived by the Texas Railroad Commission and publically available online. Since 2006, monthly pressure and injection volumes for each well site have been compiled annually at the end of each fiscal year on H-10 forms and provided publically online by the Texas Railroad Commission. Of a total of 290 verified disposal well permits for the Ellenburger in the Fort Worth Basin, we found 167 wells with H-10 reports, providing detailed injection volumes and well-head pressures from as early as late 2005 through September 2014 (Texas Railroad Commission, last accessed December 2015). To determine which formation wells inject into, we analyzed injection disposal permits. In instances where the injection formation is not specified explicitly, we identified it from the injection depth interval combined with regional subsurface formation tops (e.g. Pollastro et al., 2007). We compile and summed monthly Ellenburger injection volumes and pressures at all locations throughout the Bend-Arch Fort Worth Basin, spanning a total of 28 counties (Table 1).

We analyzed broad-scale pressure and injection trends by estimating (1) the volume injected per unit area, by county, over time, (2) the mean change in formation compressibility (see below), (3) the relative number and location of Ellenburger injectors, by volume, compared to the total number of injectors and the total injection volume in the basin, and (4) the spatial and temporal relationship between Ellenburger injection volumes, pressures/volume ratios, and regional seismicity. H-10 reports indicate how often pressure measurements were made at each well site. To ensure temporal consistency for injection pressure measurements, we only analyze pressures at wells where H-10 reports indicate daily pressure measurements were made to estimate an average monthly injection pressure. The full analysis, incorporating more than ~24,000 monthly data points, is used to make basic observations regarding wastewater injection, injection pressure, and seismicity in and below the Ellenburger.

3.2. Calculation of pressure and apparent compressibility

Assessing changes in relative formation compressibility provides important insight into subsurface fluid pressures changes, and in particular, allows us to identify locations where fluid pressure increases with time, promoting seismicity. For a given geological formation, if fluids are added faster than fluids leave, the formation pressure increases, and will continue to increase until there is failure via either plastic deformation, hydraulic fracture, or fault slip. It is well established that increasing fluid pressures increases the risk of seismicity and rock fracturing (e.g. Terzaghi, 1943; McLatchie et al., 1958; Zoback and Hickman, 1982), and that faulting may help relieve pressures in some areas, while increase stress in other areas (e.g. Stein, 1999). For each injector site where daily pressure measurements were made, we calculate changes over time in the formation as apparent compressibility, β

$$\beta = \frac{1}{V_e}\frac{\mathrm{dV}}{\mathrm{dP}} \tag{1}$$

here dV is the change in monthly volume injected at each injector site, dP is the change in mean monthly injector pressure at each injector site, and V_e is the approximate volume of the Ellenburger formation, which we estimate from isopach maps to be ~63,000 km^3 (Core Laboratories Inc, 1972). β represents an apparent compressibility and not a true compressibility because the calculation is local and uses pressures measured at the well head, not within the formation. Although this approach does not provide the true compressibility, the value calculated provides insight into whether compressibility, and therefore subsurface pressure, is increasing, decreasing, or holding steady with time at each injection site. One way to visualize or characterize what we are assessing is revealed in the $\frac{\mathrm{dV}}{\mathrm{dP}}$ term of the equation. If more pressure is required to inject the same volume of wastewater in a given time, then the pressure in the formation near the well site is increasing and the compressibility of the formation is decreasing.

We can calculate the average, basin-wide pressure change in the Ellenburger formation by recasting the compressibility equation in terms of a change in pressure, dP:

$$dP = \frac{1}{V_f}\frac{\mathrm{dV}}{\beta_f} \tag{2}$$

here dP is the average change in fluid pressure in the pores in the Ellenburger formation; V_f, the pore fluid volume for the Ellenburger for the basin, is calculated assuming an average porosity of 4% (Core Laboratories Inc, 1972) and a formation volume of 63,000 km^3, yielding an average pore volume of 2520 km^3; β_f, the average formation compressibility, estimated directly by studies commissioned by the Texas Railroad Commission for the Ellenburger, is 1.2×10^{-3} MPa^{-1} (http://www.rrc.state.tx.us/about-us/resource-center/research/special-studies/johnson-county/); and dV is the fluid volume injected as wastewater into the Ellenburger starting in 2006 and totaling 270 million m^3 through September, 2014. Using these data, we calculate an average increase in fluid pressure throughout the entire basin of 0.09 ± 0.02 MPa (~13 ± 3 psi), where uncertainties here are attributed only to uncertainties in basin formation area and volume (Pollastro et al., 2007; Core Laboratories Inc, 1972).

4. Results and analysis

4.1. Ellenburger injection volumes

As noted above, since 2006 approximately 270 million cubic meters (1.7 billion barrels) of wastewater have been injected into the Ellenburger formation in the basin (Fig. 2). The total volume of injected fluid increases between 2006 and 2009 and has since held relatively steady at approximately 35 million m^3 per year (Figs. 4A and 4B). Between 2006 and 2008, monthly volumes increased by more than a factor of 10, averaging less than 160 thousand m^3 a month in 2006 but more than 2 million m^3 per month by the end of 2008, with injection volume rates sustained near these values since 2009. Peak monthly injection of 3.5 million m^3 per month occurred at the end of 2011 and early 2012, and since then, injection volumes have sustained high values, typically exceeding 2.5 million m^3 per month through 2014 (see Table 2).

Geographically, the most significant injection occurs in the central-eastern half of the basin, near and surrounding the basin depocenter (Figs. 1 and 5). Ten of the 28 counties within the Bend-Arch Fort Worth Basin had no injection into the Ellenburger (Table 1). There is wide variability among the 18 counties with injection reports into the Ellenburger. The counties with the five highest Ellenburger injection volumes per unit area are, in decreasing order, Johnson, Sommervell, Hood, Parker and Tarrant counties, all in the central eastern portion of the Basin near the Dallas-Fort Worth-Arlington Metroplex. These counties, which represent only 12.75% of the surface area of the basin, accommodated more than 81% of all wastewater injected into the Ellenburger formation. In addition, the highest volume individual injectors are in these

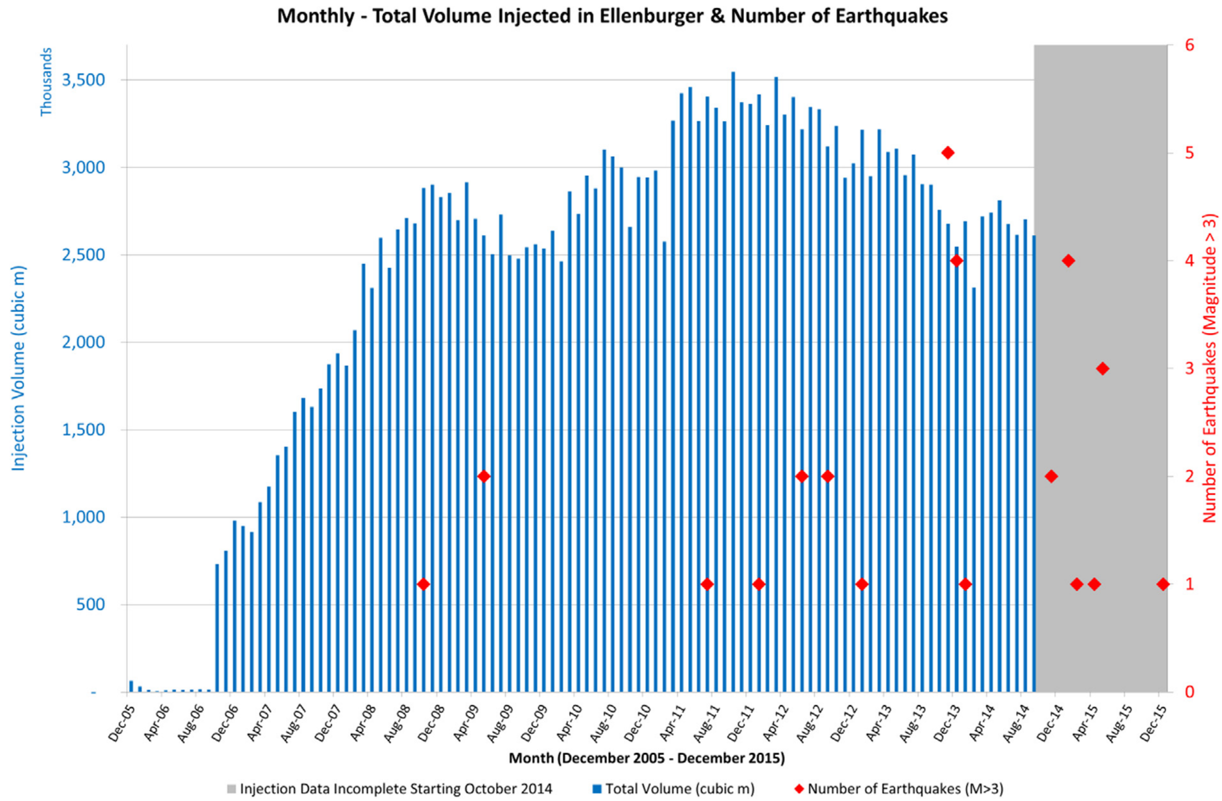

Fig. 4A. Earthquakes with magnitudes greater than 3 (red diamonds) and monthly injection rates into the Ellenburger in the Fort Worth Basin (blue bars) from December 2005 to October 2014. After October 2014 injection data is incomplete (gray box). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

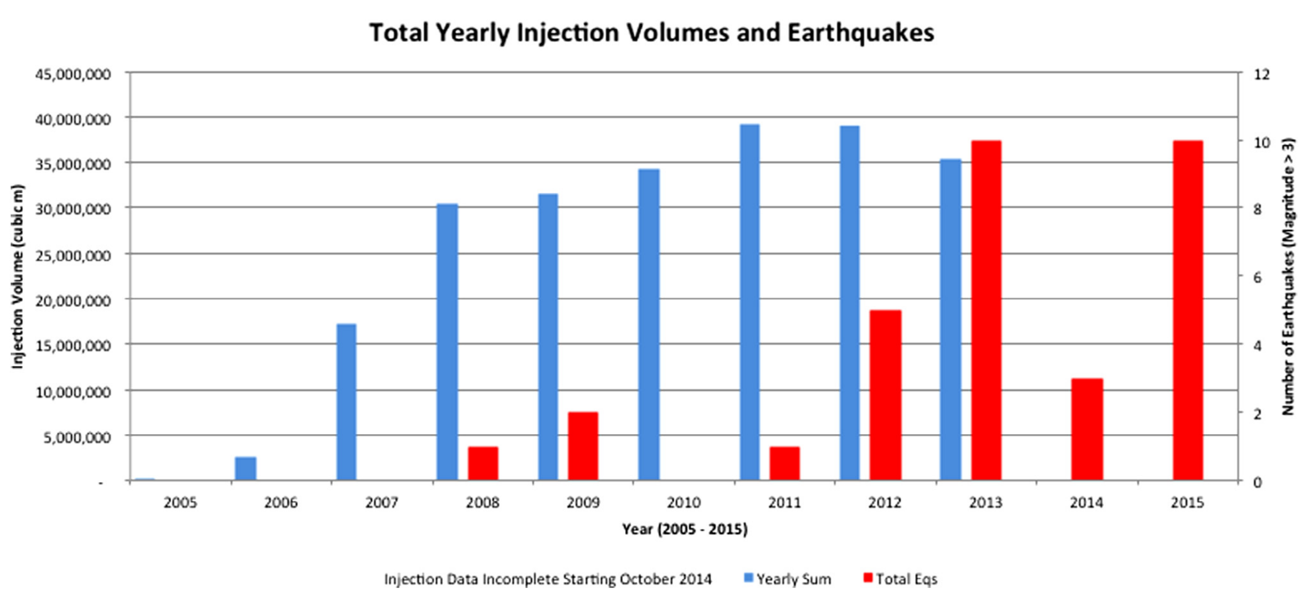

Fig. 4B. Bar chart showing the total yearly injection volume into the Ellenburger throughout the entire basin (blue) and the total number of earthquakes per year of magnitudes greater than 3.0 (red). Injection data is incomplete starting October 2014, so complete annual data are unavailable for 2014. The most rapid increases in injection volume occur from 2005 to 2008, and continues to steadily increase by 4–15% per year until 2011. From 2011 to 2013 yearly injection volumes decrease by 9–15% per year. A phase shift of two years gives the highest correlation coefficient (0.75) between annual seismicity and annual Ellenburger injection volume, however the analysis is clearly limited by available seismic data, as only earthquakes having magnitude 3.0 or greater are used. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

counties, with the largest (in Tarrant County) injecting approximately 8 million m^3 of brine into the Ellenburger between 2006 and 2014 (see Table 3). Of the 10 largest injectors, all are in three counties: Johnson (6), Tarrant (2), and Parker (2) (Table 3). These 10 wells represent only 6% of all wells in the basin injecting into the Ellenburger, but they accepted 25% of all Ellenburger

Table 2
Wastewater injection into the Ellenburger by year showing percent change and USGS reported seismicity for Magnitude 3 earthquakes by year. Annual injection volumes into the Ellenburger are based on all downloadable H-10 reports made publicly available on the Texas Railroad Commission web site.

Year	Total Injection Volume (cubic m)	% Change in Injection Volume	Total Eqs (M>3)
2005	62,627	–	0
2006	2,638,753.87	+4113%	0
2007	17,332,805.14	+557%	0
2008	30,363,307.59	+75%	1
2009	31,629,742.23	+4%	2
2010	34,244,309.21	+8%	0
2011	39,262,619.16	+15%	1
2012	39,090,310.47	-0.04%	5
2013	35,391,447.41	-9%	10
2014	–	–	3
2015	–	–	10

wastewater. If we interpolate injection volume for wells across the basin, we observe the highest injection volumes per unit area below the central and eastern portion of the basin (Fig. 6).

Temporal analysis of injection volume per unit area, aggregated by county, indicates the central-eastern half of basin experienced the highest cumulative injection volumes, and that only recently (2010–2014) has injection volume increased significantly to the north and west (Fig. 7). High injection volumes began in Johnson, Sommervell, Tarrant, Parker, and Hood counties in 2005–2008, and high annual injection volumes have since been generally sustained. From 2008 to 2010, Palo Pinto, Jack, Wise, and Denton Counties experienced significant increases in annual injection volume. More recently (from 2010 to 2014), these injection volumes increased in Wise and Montague Counties.

Although the Texas Railroad Commission does not provide total injection rates for individual formations, it does provide the total

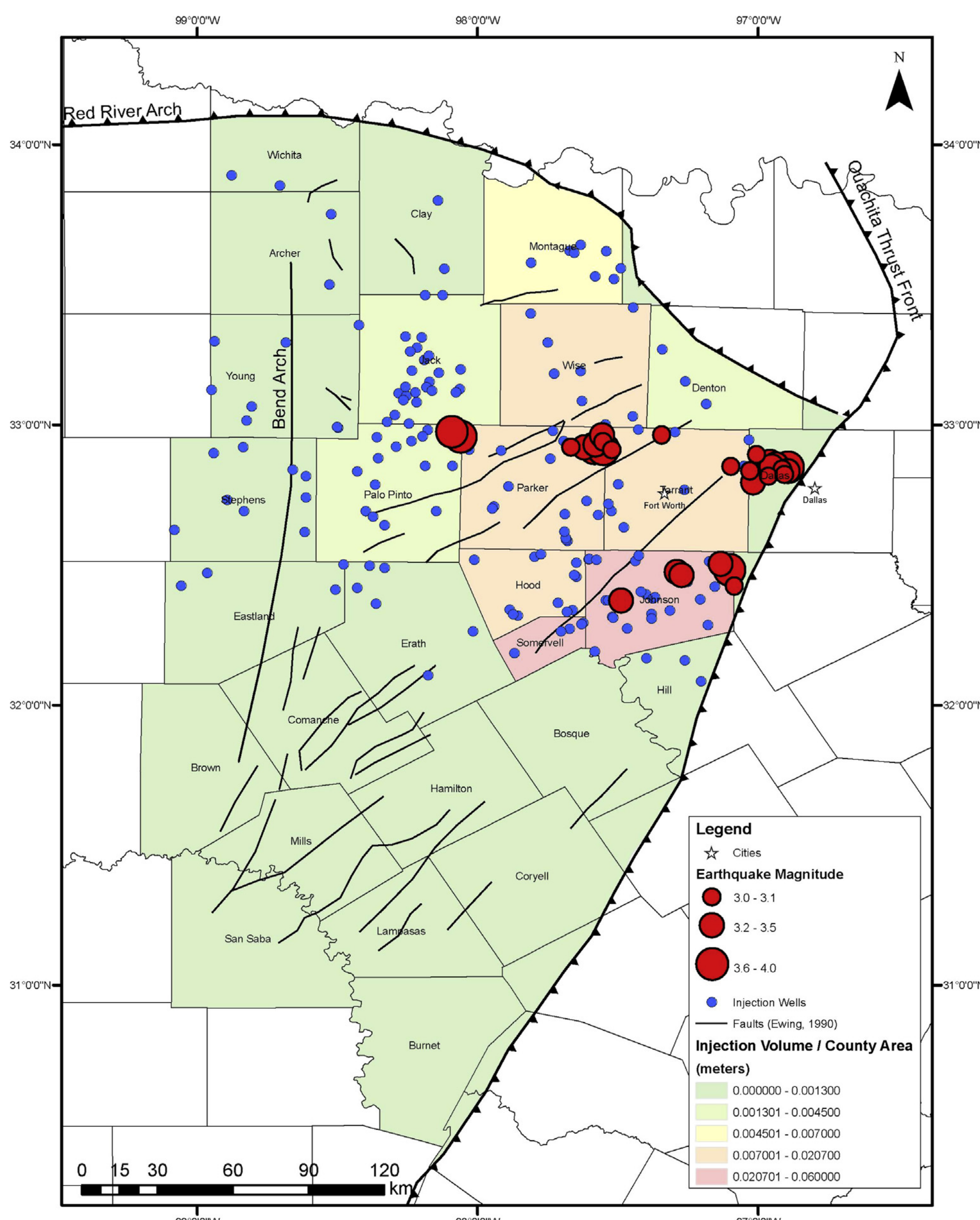

Fig. 5. The location of earthquakes (red) injection wells (blue) and injection volume per unit area, aggregated by county (colored counties). Earthquakes generally occur within or adjacent to counties where the injection volumes are highest. Our analysis of formation compressibility and subsurface pressures indicates the same areas where injection volumes are highest also experience the most significant subsurface pressure increases with time. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Table 3
Top 20 Ellenburger injectors by volume in the Fort Worth Basin from 2005 to 2014. Magnitude 3 or greater earthquakes have occurred within 10 km of 46% of the top 20 injectors, and 50% of the top 10 injectors. For the remaining 147 smaller volume injector wells in the basin, only 6% have experienced earthquakes within 10 km of their injection sites.

County	Total Volume (bbls)	Total Volume (cubic m)	No. EQs (M>3) within 10 km	Date of EQ
Tarrant	50,112,720	79,67,286.05	1	17-12-2015
Johnson	49,559,591	7,879,345.56	0	
Tarrant	47,269,368	7,515,229.19	0	
Parker	45,263,623	7,196,341.21	0	
Johnson	44,255,812	7,036,112.06	2	11/30/14, 5/7/15
Johnson	43,863,439	6,973,729.74	1	18-01-2012
Johnson	40,506,255	6,439,980.12	1	18-01-2012
Johnson	37,360,019	5,939,768.55	0	
Johnson	36,743,655	5,841,774.50	2	6–24-12, 6-15-12
Parker	35,559,264	5,653,471.37	0	
Johnson	34,468,836	5,480,107.17	0	
Johnson	33,551,658	5,334,287.52	3	5/7/15, 11/30/14, 7/17/11
Denton	33,459,656	5,319,660.37	0	
Johnson	32,680,831	5,195,837.08	0	
Tarrant	32,244,615	5,126,484.28	0	
Johnson	31,364,464	4,986,551.45	0	
Johnson	31,221,778	4,963,866.19	0	
Johnson	31,188,357	4,958,552.67	2	6/24/12, 6/15/12
Parker	29,689,424	4,720,241.36	2	11/25/13, 11/9/13
Johnson	29,076,663	4,622,820.14	2	11/30/14, 5/7/15

monthly wastewater volumes injected into all formations (not just the Ellenburger). The total volume injected for the entire basin 2006–2014 is 795 million m^3 ($\sim$5 billion barrels). Our analysis therefore indicates that approximately 1/3 of all wastewater injected into the Bend-Arch Fort Worth Basin is injected into the Ellenburger.

4.2. Comparison of Ellenburger injection volumes with basin seismicity

When earthquakes occur they generally have been in the counties with the highest injection volumes (Parker, Johnson or Tarrant Counties), or in counties immediately adjacent to these counties (Dallas, Ellis, and Palo Pinto counties). For example, Johnson, Tarrant, and Parker Counties, the three counties where wastewater disposal rates are highest, have also experienced a disproportionately large number of earthquakes, with 47% of all USGS-reported earthquakes greater than M3 occurring in these counties. Since 2005 the total volume of wastewater injected into the Ellenburger in these counties exceeds 178,600,000 m^3; this is $\sim$67% of all wastewater injected into the Ellenburger in the Fort Worth Basin. Thus, Counties that have experienced the highest injection rates since 2005 are also the counties with high earthquake concentrations. Although no wastewater injection occurs in Dallas and Ellis counties, both counties are immediately adjacent to two counties with very high wastewater injection rates (Johnson and Tarrant). Additionally, subsurface structural maps based on well logs show that in the Fort Worth basin the Ellenburger dips northward and eastward toward the Ouachita Front, reaching its deepest depth and largest thickness beneath Dallas and Ellis counties (Core Laboratories Inc, 1972; Fig. 1). Since the Ellenburger is a permeable formation, it is likely that heavier injection fluids will naturally gravitate eastward towards Dallas and Ellis counties, potentially increasing fluid pressure in this region.

Earthquakes also occur disproportionately near large injection wells, just as previous studies suggest (e.g. Frohlich, 2012). For example, of the 10 largest injection wells by volume in the basin, 50% have had a M3 or greater earthquake occur within 10 km (Table 3). Similarly, of the 20 largest injector wells by volume in the county, 46% have had a M3 or greater earthquake occur within 10 km. Indeed, the M 3.0 earthquake near Haslet, Texas, on December 17, 2015 represents the most recent example of this pheonomenon: the Haslet earthquake epicenter was within $\sim$1 km from the single largest injection well (by cumulative volume) in the entire basin. In contrast, if we exclude the top 20 injector wells by volume, only 6% of the remaining 147 injector wells have had a M3 or greater earthquake occur within 10 km. Thus, for areas within 10 km of a a large injector well, the earthquake probability appears significantly (nearly a factor of ten) greater. This result is consistent with previous investigations in the Fort Worth Basin noting spatial and temporal relationships between seismicity and wastewater injection (e.g. Frohlich, 2012).

4.3. Changes in Ellenburger compressibility with time

We calculated the monthly apparent compressibility for 84 wells where pressure measurements were made consistently on a daily basis. Of these, 43 (51%) showed evidence for reduced compressibility (increased formation pressure) with time, 21 (24%) showed evidence for increased compressibility (reduced formation pressure) with time, and 20 (24%) show no significant change in compressibility (no clear pressure change) with time. It is important to recognize that apparent reduction in compressibility (and increase in pressure) may simply be the result of increased friction as more fluids are injected into the well with time. We note however that 39 of the 43 wells (91%) with reduced compressibility have monthly injection volumes that remain either *constant* or systematically *decrease* with time while injection pressure increased. This implies that for at least 39 wells, reduced compressibility is not due to increased injection rates and that other factors must be involved. Increased compressibility (reductions in pressure) that we observe in 24% of the wells could be caused by fluid loss in the formation near a particular well due to natural fluid migration, unintentional removal by adjacent oil and gas production, or by fault reactivation that generates more accommodation space for fluids via increased fracture porosity. Currently, there is no significant oil and gas production in the Ellenburger in the central part of the basin. It is therefore perhaps more likely that pressure reductions are caused by natural fluid migration out of the formation. The analysis thus indicates that a majority of wells show an apparent reduced compressibility over time. Counties with the most wells showing reduced compressibility are Parker and Jack counties (6 wells each, 14% of the total), Johnson, Erath, and Hood counties (5 wells each, 12% of the total), followed by Palo Pinto (3 wells), Somervell (2 wells), and Tarrant county (2 wells). These counties are all located in or near areas of high seismicity (Fig. 5). These results therefore demonstrate that there is more than a simple correlation in time and space between high injection volumes and recent seismicity—the injection also provides a mechanism for triggering earthquake activity. Specifically, reduced formation compressibility and increased subsurface pressures below these well sites provide a clear and plausible cause for recent earthquakes: increased subsurface fluid pressures resulting from wastewater injection that is coincident in time and space with regional seismicity provide a simple, direct, observable, and easily explainable mechanism for triggering these seismic events.

4.4. Estimating the average change in Ellenburger formation pressure

For the entire Ellenburger formation, we calculate an average pressure change dP of 0.09 MPa (13 psi) attributable to wastewater injection totaling 270 million m^3 between 2006 and September 2014 (see methods section above). This value is consistent with pressures typically associated with seismic triggering (Reasenberg and Simpson, 1992; Stein, 1999). Our calculation

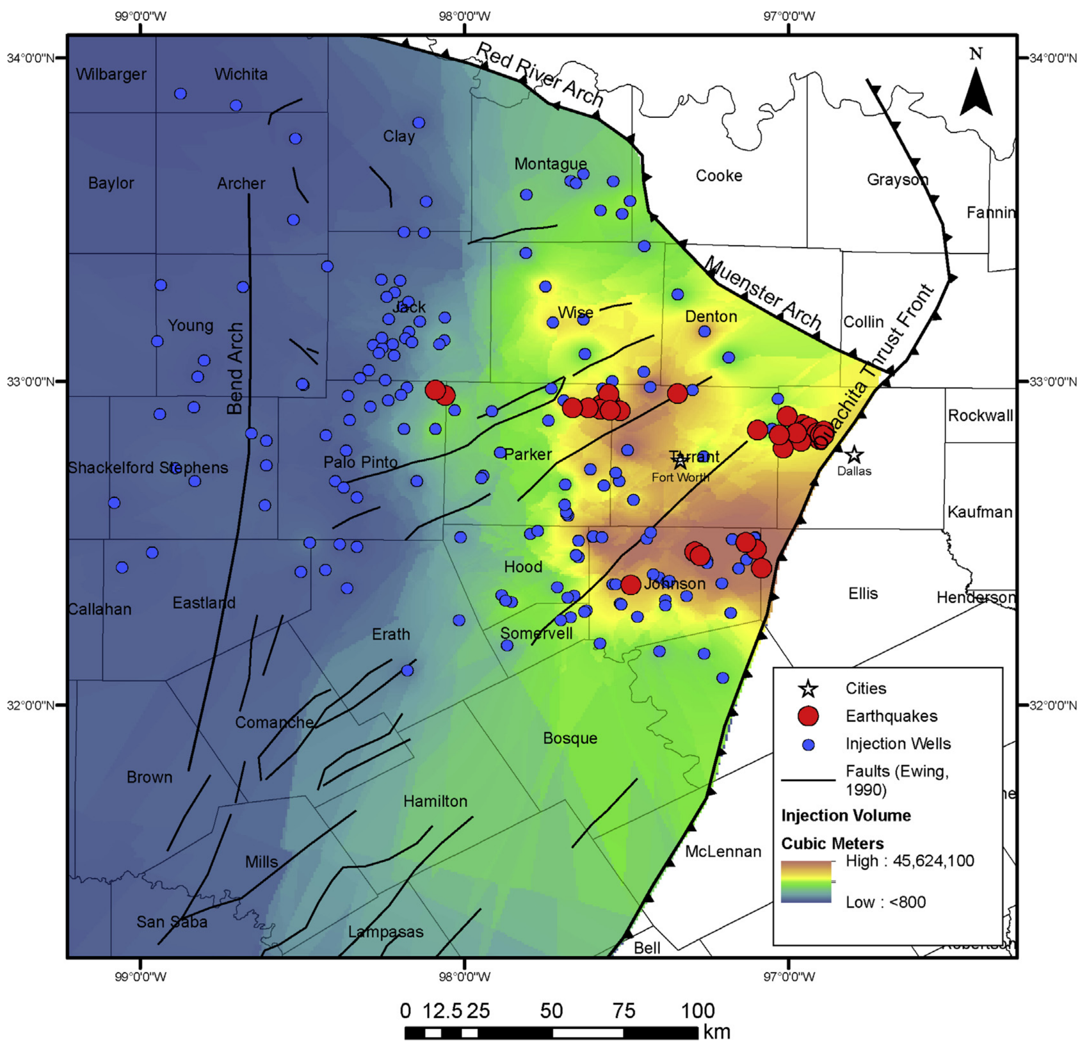

Fig. 6. Map showing an interpolated surface grid of injection volumes per unit area for Ellenburger wells, calculated using the inverse distance weighting (IDW) deterministic method. The interpolation uses the total injection volume of all 167 wells injecting into the Ellenburger formation. The interpolation consists of ~100,000 cells each with an area 817 × 817 m^2. Areas are assigned volumes calculated by a weighted average of the known volumes of the injection wells. Using the weighting approach, approximately 50% of the injected volume is accounted for within 25% of the distance to the next nearest well. The highest injection volumes are generally concentrated in the same regions where we see clusters of earthquakes. Additionally, the Dallas County earthquake sequence lies just southeast and down dip of the high injection volumes in Johnson county. Detailed fault maps will ultimately provide better constraints on how fluids might flow through the basin.

assumes uniform characteristics for the entire Ellenburger, when in fact there is undoubtedly significant heterogeneity (e.g. Core Laboratories Inc, 1972; Loucks et al., 2009). As a result, areas where the reservoir is confined and isolated from regions where injection occurs may have lower fluid pressure, at the expense of areas where wells inject into confined reservoirs that may have significantly higher pressure. For example, if fluids were confined by county, the highest pressure increases would generally occur in counties with the highest injection volumes per unit area (Fig. 8).

Compressibility will be higher (and pressures lower) if gas is present in the Ellenburger formation; however, it is unlikely that much free gas is present in the formation, particularly in the deepest part of the basin. Four lines of evidence support this conclusion. First, there is no significant oil or gas production from the Ellenburger in the basin. Second, the pressures at depths where the Ellenburger exists are not conducive to free gas, as natural gas is significantly more soluble at high pressure and is more dependent on pressure than temperature changes. This suggests that the lowest compressibilities (and the highest pressures) will preferentially occur in the deepest part of the basin, where pressure is highest, methane is more soluble, and the least amount of gas is present.

Third, if significant gas were present, the estimate of 0.09 MPa would be an over-prediction of subsurface pressure. To date, however, all measured pressures in the Ellenburger (provided by shut-in pressure tests) indicate excess fluid pressures higher than 0.09 MPa. For example, recent studies conducted by the Texas Railroad Commission to address the potential cause of recent seismicity in Johnson County, near Venus, Texas, indicate fluid pressures above hydrostatic in all wells tested across the region, with values ranging between 1.7 and 4.5 MPa (250–650 psi) above hydrostatic (http://www.rrc.state.tx.us/about-us/resource-center/research/special-studies/johnson-county/). Similarly, shut-in pressure measurements made at a well in Parker County near the Azle/Reno earthquake sequence also show pressures above hydrostatic (Hornbach et al., 2015). Fourth, it should be noted that the compressibility value used in the calculation is provided directly by engineers assessing subsurface pressures in the Ellenburger, and therefore, if accurate, should properly account for any free gas in the pore fluid. The Ellenburger pressure estimate presented here indicates elevated fluid pressures, just as spot measurements made at well sites suggest, but under-predicts actual observed subsurface pressures in the region. The analysis presented here is

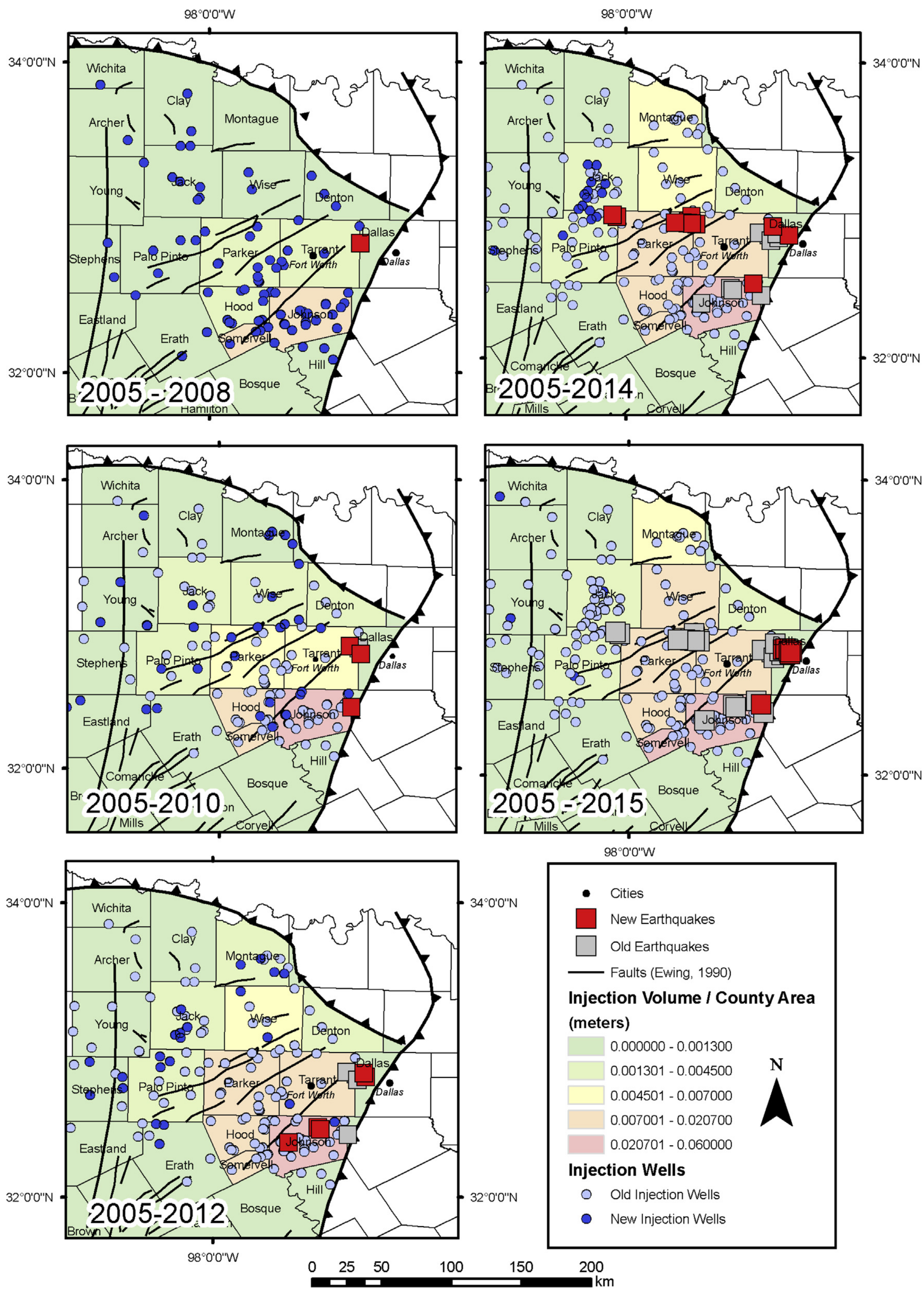

Fig. 7. Time lapse of injection volume per unit area, aggregated by county, and regional seismicity for events of magnitude 3 or greater. Seismicity begins in Eastern Tarrant and Johnson counties, both regions of initially high injection, and spreads both east and west into other areas where injection increases. Note in the last 4 years an increase in permitted injection wells to the north and west.

therefore consistent with regional observations indicating elevated fluid pressures exist and supports previous conclusions suggesting wastewater injection into Ellenburger elevates fluid pressures, promoting seismicity in the region.

4.5. Apparent seismic outliers

The previous investigations (Frohlich et al., 2011; Frohlich, 2012; Justinic et al., 2013; Hornbach et al., 2015) did not provide

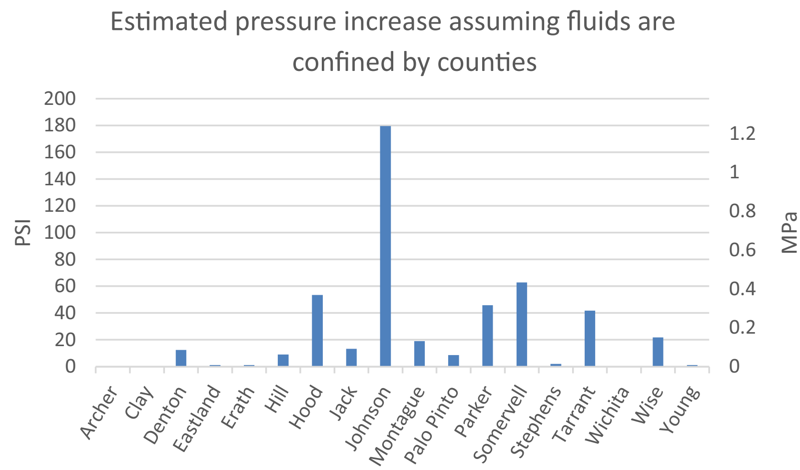

Fig. 8. Estimate of the expected pressure increase in the Ellenburger assuming all injected fluids are confined to the county of injection. In reality, fluid confinement is poorly constrained, and fluids are undoubtedly confined to larger or smaller volumes than those used here, with confinement often leaky. The analysis indicates fluid pressures are highest in Johnson County, but also high in Tarrant, Hood, Somervell, and Parker counties. The only regions where Ellenburger fluid pressures have been measured directly and made publically available are in Johnson and Parker Counties. In both instances, fluid pressures were elevated above values suggested here, with Johnson county measurements 250–650 psi above hydrostatic and Parker county measurements indicating ~70 psi above hydrostatic. Thus the elevated fluid pressures present here are consistent with, but lower than measured values.

an explanation for the occurrence of earthquakes in areas adjacent to, but more distant than a few km from higher-volume injection wells. These include earthquakes in Dallas and Ellis Counties, where no injection wells currently exist, and Palo Pinto County, where injection volumes are moderately low compared to adjacent seismically active counties. Although injection volumes are moderate in Palo Pinto County, the largest injector in the county is located near the two earthquakes in this region (Fig. 6). This, combined with regional fault maps indicating the Mineral Wells Fault may be optimally orientated for failure, with a similar strike to the Newark East Fault near Azle (Hornbach et al., 2015), may explain why earthquakes began in this region in 2013. For the Dallas and Ellis County earthquakes, there are several reasons why these events might not be natural, and instead, induced by wastewater injection:

1. The relatively shallow depths of the earthquakes (<8 km) placing them in the Ellenburger and underlying basement are similar to the depths of likely induced earthquakes near Azle, DFW, and Cleburne. In general, induced earthquakes have shallower hypocenters than natural earthquakes (e.g. Simpson et al., 1988; Ellsworth et al., 2015).
2. Often, induced earthquakes propagate away from an injection well over time, typically over the course of months to years (e.g. Ake et al., 2005; Keranen et al., 2014; Block et al., 2014; Hornbach et al., 2015), and there are documented cases of induced earthquakes more than 10–20 km distant from an injection site (e.g. Healy et al., 1968; Block et al., 2014). Earthquakes were first reported in the basin in 2008 and 2009 in eastern Tarrant and Johnson Counties, with seismicity occurring elsewhere across the region as time passed. The Dallas and Ellis county earthquakes are generally located 10 km or more away from the nearest injector well and did not begin until 6 years after large-scale injection commenced in the surrounding counties. Both counties are located just north and east of Johnson County— the county experiencing by far the largest volume of wastewater injection into the Ellenburger.
3. Large regional faults generally trend in a south-southwest to north-northeast direction across the basin, potentially providing direct pressure communication pathways from high injection zones in Johnson, Somervell, and Tarrant County to Dallas and Irving (Fig. 1, 6 and 7) (e.g. Rozendal and Erskine, 1971; Ewing, 1991; Pollastro et al., 2007; Hentz et al., 2012). Importantly, previous studies indicate critically stressed faults can act as long-distance fluid conduits that have higher permeability than the formation rock (e.g. Hsieh and Bredehoeft, 1981; Barton et al., 1995; Townend and Zoback, 2000). Thus, the idea of km-scale fluid flow along such fault systems is not new. Analysis of regional seismic reflection data revealing fault location and orientations combined with pressure/stress tests in regional wells could rule out or confirm this possibility.
4. Denser fluids will naturally gravitate towards the deepest accessible point, the basin structural axis or localized fault-bounded depocenters, increasing pressure in these areas. Dallas and Ellis counties rest directly above the Ellenburger's deepest point (Core Laboratories Inc, 1972) (Fig. 1). Thus it is plausible that denser brines injected in Parker, Johnson, and Tarrant counties will tend to migrate downslope to Ellis and Dallas counties, and over time increase fluid pressures in the Ellenburger formation there. These increased fluid pressures might trigger earthquakes on faults located in the deepest part of the basin. As noted above, it appears faults with the appropriate orientation already exist to provide high-permeability flow paths for these brines that generate pressure fronts towards Dallas and Ellis County.
5. Unlike the counties where the largest injections volumes occur (Johnson, Parker, and Tarrant counties), the Ellenburger in both Ellis and Dallas Counties is situated down-dip from injection, but is bounded to the east by the Ouachita fold and thrust belt, a massive, nearly impermeable geological boundary (Figs. 1, 5 and 6). The sediments in the Ouachita belt that the Ellenburger terminates against in the eastern edge of the basin consist of low-grade metamorphosed rock, most notably marble, metaquartzite, and quartz diorite (Rozendal and Erskine, 1971). These rocks are significantly less permeable than the Ellenburger. This suggests that fluids cannot easily migrate out of the depocenter below Dallas County since it is bounded by an impermeable feature to the east. Thus once fluids reach the deepest part of the basin below the Dallas-Irving area, they have nowhere else down-dip to migrate, except perhaps along faults. As a result, fluids injected into the Ellenburger in nearby counties may cause pressures to increase steadily over time in the Dallas/Irving area.

We can estimate the permeability necessary for more distant wastewater injection wells to affect faults below the city of Dallas and Irving. Felt earthquakes began in the Irving-Dallas area in early 2014, approximately six years after high injection rates began. We estimate the permeability necessary for the pressure wave to reach Dallas from injectors in both Johnson and Tarrant Counties by solving the characteristic time-pressure diffusion equation for permeability (e.g. Hettema et al., 2002):

$$k = \frac{d^2 \varphi \mu C}{t} \tag{3}$$

Here, d, the distance from a well in Johnson (or Tarrant) county to the center of Dallas county, is 40 (or 15) km; φ, the porosity of the Ellenburger is assumed 4% (Core Laboratories Inc, 1972), μ, the fluid viscosity of the brine, is 4×10^{-4} ($\pm 5 \times 10^{-3}$) Pa s (Texas Railroad commission website); C, the total compressibility of the Ellenburger, is 1.5×10^{-9} ($\pm 0.5 \times 10^{-9}$) Pa^1 (Texas Railroad commission website); and t, the characteristic time it takes for the pressure front to travel 40 and 15 km respectively, is 6 years. Using the 40 km distance for wells in Johnson county to earthquakes in Dallas County, we calculate a permeability of $1–3 \times 10^{-13}$ m^2 (100–300 mD) is necessary for fluid pressures to travel this distance over 6 years. If we use 15 km, the approximate distance from the Irving-Dallas earthquake sequence to the nearest active injection well in Tarrant county, a permeability of $1–4 \times 10^{-14}$ m^2 (10–40 mD) is necessary for the pressure wave to travel to the area of seismicity over six years. Measured permeability values for the Ellenburger vary greatly, but usually range between 5×10^{-13} and 1×10^{-15} m^2 (0.1–500 mD) (e.g. Archie, 1952; Core Laboratories Inc, 1972; Hornbach et al., 2015). Our estimated permeability values fall within observed measurements. It therefore is plausible that pressure fronts generated by injectors in neighboring counties could impact Dallas County.

5. Conclusions

Analysis of seismicity, injection volume and pressure measurements for the period 2005–2014 shows that within the Bend-Arch Fort Worth basin, areas where the largest fluid volumes were injected into the Ellenburger were also the areas where compressibility generally decreased, subsurface pressures increased, and earthquakes most often occurred (Figs. 2 and 5–7). The analysis shows not only correlation but causation: lower formation compressibility and higher pressures generally develop at the same time and location where earthquakes occurred. This interpretation is consistent with multiple previous studies conducted decades ago noting both correlation and causation between increased fluid injection volumes, increased pressures, and increased probability of structural failure and associated seismicity with time (e.g. Terzaghi, 1936; Kisslinger, 1976; Talwani and Acree, 1984; Ellsworth et al., 2015).

Of the eight counties in the basin where seismicity has occurred, two (Dallas and Ellis) have no reported injection wells. However, both counties (1) are immediately adjacent to counties where injection volumes are high, (2) are down-dip of the injection zone where denser fluids will flow, (3) are bounded by low permeability sediments of the Ouachita fold and thrust belt that prohibit fluid escape, (4) only began experiencing seismicity after injection began, and (5) are in areas structurally favorable (down-dip) for significant pressure increase. Furthermore, the timing and location of seismicity, developing several years after injection began and more than 10 km from the nearest injector, is similar to induced seismicity observed elsewhere attributed to pressure diffusion across a basin (e.g. Hsieh and Bredehoeft, 1981; Zoback and Hickman, 1982; Simpson et al., 1988; Block et al., 2014) and requires permeabilities consistent with values observed in the Ellenburger. Thus, it is plausible that the seismicity in Dallas and Ellis counties is induced.

In addition, we observe that (1) previous studies suggest the basin has been tectonically inactive for at least 250–300 million years, (2) no earthquakes had been reported in the Dallas-Fort Worth-Arlington area for the past 160 years prior to wastewater injection activity, (3) Dallas-Area earthquake focal depths are in the Ellenburger or the shallow basement beneath, and (4) the seismicity in the basin has spread with time. All these observations are consistent with the hypothesis that earthquakes in the Fort Worth Basin are induced by pressure changes linked to wastewater injection.

Because the subsurface pressure front continues to migrate even after injection ceases, past studies show that it often takes a significant amount of time (months to years) for pressure, and associated seismicity, to reduce to pre-injection levels (e.g. Hsieh and Bredehoeft, 1981; Zoback and Hickman, 1982; Block et al., 2014). Thus, if injection continues into the Ellenburger at rates observed from 2008 to 2014, the analysis broadly suggests that seismicity will continue to occur in Parker, Johnson, Tarrant, Ellis and Dallas Counties along faults optimally oriented for failure. Since not only this study but several others (e.g. Frohlich, 2012; Gono et al., 2015; Frohlich et al., 2016) show a correlation in space and time with large injection volumes and seismicity, one might anticipate seismicity to develop in other areas of the basin with time in locations where injection volumes have been recently increasing (such as Montague and Wise counties) or where the Ellenburger is down-dip of increasing injection volumes or bounded by the Ouachita fold and thrust belt, such as Denton county. Indeed, more detailed microseismicity studies in Montague, Wise, and Denton counties indicate earthquakes have already occurred that are too small to be felt or noticed by local residents (Frohlich, 2012). Nonetheless, injection that increase fluid pressures and reduce effective stress is only one factor influencing induced seismicity. To gain a better understanding of the link between wastewater injection and seismicity, it would be useful to have better information about the locations and orientations of subsurface faults across the basin, and the regional stress regime, especially in areas that are seismically inactive but where future injection is proposed. To assess future hazard, it would also be useful to have measurements of the stress on regional faults. Currently, the orientation of faults with respect to the subsurface stress regime in the basin is only marginally constrained in the public literature (Fig. 5) and this represents an important area of future research for further quantifying the induced seismicity hazard.

Finally, to assess regional seismic hazard—especially in dense urban environments like the Dallas-Fort Worth-Arlington Metroplex—it would be extremely valuable to closely monitor subsurface pressures with time, especially in areas where subsurface pressures may be increasing. As our analysis indicates, injected fluids have the potential to affect subsurface pressures at distances as great as tens of kilometers, with wells in different counties potentially impacting subsurface pressure under the cities of Dallas and Irving. Testing this hypothesis and determining the potential seismic hazard in the DFW area ultimately requires more detailed stress and fault maps combined with high-quality pressure monitoring within and below the Ellenburger formation. Currently, no standard or routine formation pressure monitoring program exists in the Ellenburger. Monthly well head injection pressures provided to the Texas Railroad Commission are only a rough proxy for understanding changes in formation compressibility, and currently, there are no baseline or time-dependent pressure measurements in the deepest part of the basin, directly below the cities of Dallas and Irving where seismicity could be most damaging. The recommendation to monitor subsurface pressure is a not a new idea; it was made nearly 50 years ago by both industry and academic researchers (e.g. Van Everdingen, 1968; Galley, 1968, and references therein) when injection strategies were first considered. It is a recommendation that remains even more valid and relevant today than it was 50 years ago.

Acknowledgments

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