

## Human-induced seismicity and large-scale hydrocarbon production in the USA and Canada

Mirko van der Baan\* , Frank J. Calixto

Dept. of Physics, Univ. of Alberta, Edmonton, AB, T6G 2E1, Canada.

\*Correspondence to: E-mail: [Mirko.vanderBaan@ualberta.ca](mailto:Mirko.vanderBaan@ualberta.ca)

### Abstract

We compare current and historic seismicity rates in six States in the USA and three Provinces in Canada to past and present hydrocarbon production. All States/Provinces are major hydrocarbon producers. Our analyses span three to five decades depending on data availability. Total hydrocarbon production has significantly increased in the past few years in these regions. Increased production in most areas is due to large-scale hydraulic fracturing and thus underground fluid injection. Furthermore, increased hydrocarbon production generally leads to increased water production, which must be treated, recycled or disposed of underground. Increased fluid injection enhances the likelihood of fault reactivation, which may affect current seismicity rates.

We find that increased seismicity in Oklahoma, likely due to salt-water disposal, has an 85% correlation with oil production. Yet, the other areas do not display State/Province-wide correlations between increased seismicity and production, despite 8-16 fold increases in production in some States. However in various cases seismicity has locally increased.

This article has been accepted for publication and undergone full peer review but has not been through the copyediting, typesetting, pagination and proofreading process which may lead to differences between this version and the Version of Record. Please cite this article as doi: 10.1002/2017GC006915

© 2017 American Geophysical Union

Received: Mar 10, 2017; Revised: Mar 10, 2017; Accepted: Jun 01, 2017

Multiple factors play an important role in determining the likelihood of anthropogenic activities influencing earthquake rates, including (i) the near-surface tectonic background rate, (ii) the existence of critically stressed and favorably oriented faults, which must be hydraulically connected to injection wells, (iii) the orientation and magnitudes of the in situ stress field, combined with (iv) the injection volumes and implemented depletion strategies. A comparison with the seismic hazard maps for the USA and Canada shows that induced seismicity is less likely in areas with a lower hazard. The opposite however is not necessarily true.

## Introduction

The turnaround in hydrocarbon production in North America in the last few years is generally attributed to two key technological innovations, namely horizontal drilling and multi-stage hydraulic fracturing, employed in both unconventional tight plays (mainly shale resources, Figure 1) and for redevelopment of mature conventional hydrocarbon fields (*Van der Baan et al., 2013*). For instance, in 2013 the USA became the largest hydrocarbon producer in the world, up from number 3 only a few years before. The USA produced on average 12.4M barrels/day in 2013 (petroleum and other hydrocarbon liquids but excluding dry gas), surpassing Saudi Arabia with 11.7M barrels/day. Likewise, the USA surpassed Russia's dry gas production in 2011. See Table 1 for accessed sources of production information.

Large-scale hydraulic fracturing involves large-scale underground injection of fluids. Furthermore, increased hydrocarbon production generally leads to increased water production. This water is either treated, recycled (e.g., via hydraulic fracturing treatments), or disposed of in underground saline aquifers via salt water disposal wells (*Clark et al., 2013; Rubinstein and*

*Mahani, 2015; Horner et al., 2016*). Both hydraulic fracturing treatments (*Davies et al., 2013; Atkinson et al., 2016*) as well as salt water disposal (*Weingarten et al., 2015; Atkinson et al., 2016*) may increase local seismicity rates, for instance, due to fault reactivation. The physical mechanism how increased pore pressures (e.g., due to fluid injection) can facilitate slip on pre-existing faults is well understood (*Ellsworth, 2013*). Figure 2 shows known salt-water disposal wells in the Central and Eastern USA, including those thought to be associated with induced seismicity (*Weingarten et al., 2015*).

We investigate whether a relationship exists between seismicity rates and hydrocarbon production in major onshore producing regions in the USA and Canada over the last few decades. Specifically we ask the question: Does large-scale increases in production lead to increased seismicity rates?

## **Methods**

We examine first the seismicity rates for the years 1965-2014. We consider only events with magnitudes larger than three, the minimum magnitude that can be reliably detected by the often sparse seismological networks used in the past (*Ellsworth, 2013; Schultz et al., 2015b*). For each region the exact spatial coordinates are specified in the Figure captions. We discard all events deeper than 15km since we are only interested in seismicity that may be triggered due to human activities at the surface. We use a maximum depth of 15km since depths of shallow events are generally ill constrained in regional networks due to their spatially sparse density, with increasing depth uncertainty for older data. It is not uncommon for a shallow event to be assigned a depth by an interpreter given a fixed set of predefined depth levels. Similar seismicity patterns are obtained if a shallower depth is used of say 10km.

Next we compare these seismicity patterns with published production information for the same time period. Specifically we look at natural gas gross withdrawals (total gas produced from both oil and gas wells) and crude oil production. For fairness of comparison between seismicity and production, we outline the spatial extent of the major oil and gas plays in each considered State and Province.

Within Canada, we consider the provinces of Alberta (renewed oil production from existing conventional plays and new tight plays such as the Montney and Duvernay shales), British Columbia (increased hydrocarbon production from tight Horn River and Montney shales) and Saskatchewan (tight oil from Bakken shale), and within the USA, Pennsylvania, West Virginia (tight gas from Marcellus shale), Oklahoma (Woodford shale, Hunton and Mississippi Lime dewatering plays), North Dakota (tight oil from Bakken shale), and on-shore Texas (tight oil from Eagle Ford shale and Permian basin, tight gas from Barnett and Haynesville-Bossier shales). See Figure 1 for geographic locations.

## **Data and Resources**

The seismicity rates for the years 1965-2014 are obtained from the IRIS catalogue for the United States ([http://ds.iris.edu/wilber3/find\\_event](http://ds.iris.edu/wilber3/find_event)) and from a merged Earthquakes Canada-IRIS catalogue for Canada (<http://www.earthquakescanada.nrcan.gc.ca/stndon/NEDB-BNDS/bull-eng.php>). For the Canadian regions, we used the catalogue from Earthquakes Canada as a base and added events from the IRIS catalogue if not found in the Earthquakes Canada database. In all cases, only events with magnitudes  $M \geq 3$  and depths less than 15km are extracted. No further screening was implemented, since both agencies have stringent reporting and quality assurance standards.

For additional scrutiny, we compared our merged catalogue for Canada with the one used by *Atkinson et al. (2016)* for Alberta and British Columbia, available on <http://www.inducedseismicity.ca>, covering mostly the period 1985 through present, and found identical patterns.

The hydrocarbon production information comes from a variety of sources (Table 1). For the continental USA, we use data from the U.S. Energy Information Administration (<http://www.eia.gov>), which publishes monthly oil and gas production per state since 1981, as well as rig counts for various plays since 2007. Canadian production statistics come from the Canadian Association of Petroleum Producers (<http://www.capp.ca>) and the National Energy Board (<http://www.neb-one.gc.ca>) who publish respectively monthly and yearly statistics per Province since 1998 and 1947. Oil and gas production statistics for Canada are converted to thousands of barrels (oil) and to MMcf (gas), respectively, to facilitate comparison. Again no further screening was implemented and statistics are reproduced as reported by the agencies.

Outlines of producing formations were obtained from maps produced by IHS PacWest (<http://pacwestcp.com>; last accessed January 2016) for the Woodford, Bakken, Barnett, Marcellus, Eagle Ford, Permian Basin and Haynesville-Bossier shales; from ShaleExperts (<http://www.shaleexperts.com>; last accessed October 2015) for the Mississippi Lime formation; from Natural Gas Intel (<http://www.naturalgasintel.com/international-resources/>; last accessed October 2015) for the Montney (Alberta side), Duvernay and Viking formations; and from *BCOGC (2014b)* for the Horn River basin and the Montney formation (British Columbia side).

## Results

## *Oklahoma, USA*

The change in earthquake rates in Oklahoma has drawn widespread attention (*Keranen et al., 2013; Keranen et al., 2014; Walsh and Zoback, 2015*; Figures 3a-c). In 2014, the rate of occurrence of earthquakes with magnitudes of three and greater in Oklahoma exceeded that in California (*Keranen et al., 2014; McGarr et al., 2015*). Overall, the seismicity shows sporadic activity between 1966 and 1976 (9 events), two peaks between 1977 and 1983 (275 events), then a quiet period with 45 events until 2008, when seismicity rate strongly increased: 42 events in 2012, 115 events in 2013 and 607 events in 2014.

Oil production in Oklahoma peaked in 1984 (168M barrels), declined steadily until trend reversal in 2010 (69M barrels), returning to 115M barrels in 2013. Gas production steadily increased from 1967 through 1990, and then declined rapidly, until 2003 when trend reversal occurred (2003:  $1.6 \times 10^6$  MMcf, 2014:  $2.3 \times 10^6$  MMcf; Figures 3d,e). The increased hydrocarbon production since 2008, specifically in oil, coincides with increased seismicity rates. This region has experienced a total of 28 years with no to very low seismicity as compared to 12-15 years of moderate to large seismicity. The seismicity between 1977 and 1983 (275 events) occurs across the entire State of Oklahoma but with the largest concentration within the Western outline of the Woodford shale play (Figure 3a).

New production comes largely from wells targeting the Mississippi Limestone and Hunton formations. These are conventional and often very mature reservoirs, also known as dewatering plays, where significantly more water than hydrocarbons are produced (*Murray, 2013, 2015*). Hydraulic fracturing is not thought to play an important role within these two formations (*Murray, 2013; Walsh and Zoback, 2015*); yet current water use for hydraulic

fracturing in the Woodford shale is among the highest averages per well for the USA (*Gallegos et al., 2015*).

Recent seismicity is mostly concentrated within the region containing most salt-water disposal wells (that is, class II injection wells), which are largely related to production from the central part of the Mississippi Lime and Hunton formations (Figure 3a). Indeed, the change in seismicity in Central and Northern Oklahoma is thought to be caused by increased salt-water disposal (*Keranen et al., 2014; Walsh and Zoback, 2015; Weingarten et al., 2015*), particularly in deep formations (Arbuckle Group) which are directly above crystalline basement rock, possibly reactivating critically stressed faults (*McNamara et al., 2015*). See also Figure 2.

#### ***Pennsylvania, West Virginia and Ohio, USA***

Oil production has been historically larger in Oklahoma than in Pennsylvania and West Virginia. However, current gas production, mostly from the Marcellus shale, exceeds Oklahoma production due to a 16-fold increase since 2010 (Figures 4d,g). Like in most of North America, Pennsylvania's oil production peaked in the early 80s (4.9M barrels), then declined until a trend reversal from 2000-2005 onward. Oil production quadrupled from 2000 (1.5M barrels) to 2014 (6.4M barrels). Gas production was minimal until 2008 ( $2.0 \times 10^5$  MMcf) when a sixteen fold increase occurred through 2013 ( $3.3 \times 10^6$  MMcf; Figures 4d,e). West Virginia's production also experienced recent increases (Figures 4f-g).

Seismicity rates within the Marcellus play between 1995 and 2015 may be slightly higher than before 1995; yet annual seismicity is approximately constant (Figures 4a-c), as shown by the constant slope in the cumulative seismicity plot. Seismicity surrounding the Marcellus shale area shows a similar pattern with a subtle but more pronounced break in slope around 1995. It is also fairly constant since 1995 (Figures 4a-c). The break in slope in both cases may be due to

increased seismometer density which would imply that the magnitude of completeness lies somewhat above  $M=3$  in this area. Yet, the steeper slope for the entire area indicates that increased observed seismicity is not constrained to the Marcellus shale play.

Only a single injection-related cluster is known with seismicity in excess of magnitude 3. *Kim (2013)* reports 12 events of magnitudes  $M_w > 1.8$  in Youngstown, Ohio (Figure 4a) during January 2011 to February 2012 associated with salt-water disposal. Only a single event exceeds magnitude 3 during the time frame of their study ( $M_{4.0}$  on 2011-12-31). A second event occurs in 2014 ( $M_{3.0}$  on 2014-03-10).

Closer inspection shows another cluster with a peak of 13 events in 2011 (Figure 4b), 6 of which belong to a swarm of aftershocks from the Mineral, Virginia,  $M_{5.7}$  earthquake (2011-08-23). This is a known tectonic (natural) event outside of the Marcellus shale area (*Chapman, 2013*).

Finally, some seismicity within the Appalachian region may be due to coal mining. For instance, *Bollinger (1989)* finds up to magnitude 2 events above an active coal mine in Virginia, with seismicity rates proportional to volume of rock removal.

Contrary to Oklahoma, there is no evidence for increased regional seismicity rates between 2008 and 2014 within the Marcellus shale play, despite the 16-fold increase in gas production, largely attributed to substantial hydraulic fracturing with associated increases in underground fluid injection (*Ellsworth, 2013; Lutz et al., 2013*). Hydrocarbon production in Ohio is also on the rise with 15M barrels of oil and  $5.2 \times 10^5$  MMcf of gas in 2014, representing respectively 2.9 and 6.2 fold increases from 2012. New production comes mainly from the Utica shale formation (Figure 1).



Few hydrocarbon-related salt-water injection wells (that is, class II injection wells) exist in West Virginia and Pennsylvania (Figure 2). It is not uncommon for Pennsylvanian produced water to be trucked to Ohio for disposal (*Lutz et al., 2013*), including the cluster examined by *Kim (2013)*. Estimates for the amount of produced water that is recycled in Pennsylvania, via new hydraulic fracturing treatments, vary considerably with assessments of 6-27% between 2009 and 2014 (*Chen and Carter, 2016*) versus 13% prior to 2011 and 56% in 2011 (*Lutz et al., 2013*). Like the Woodford shale, current water use for hydraulic fracturing in the Marcellus shale is among the highest averages per well for the USA (*Gallegos et al., 2015*).

Differences in geology and production practices thus play an important role in determining the likelihood for fluid-induced seismicity. At first sight, analysis of Marcellus-shale production versus seismicity rates in the area may give the impression that large-scale hydraulic fracturing is less likely to lead to locally changed seismicity patterns, contrary to large-scale salt-water disposal; yet both types of underground fluid injection may affect seismicity (*Atkinson et al., 2016*) as will be shown when discussing Alberta and northeast British Columbia.

### ***On-shore Texas, USA***

Texas has only experienced 187 events of magnitude 3 or higher during 1964-2014, including 15 events deeper than 15km (Figure 5). The region is mostly seismically quiet. However, half of the events occurred in a relative short time: 95 during 2010-2014 as compared to 92 during 1964-2009.

The State of Texas is responsible for 37% of the US 2014 crude oil production. Most onshore oil production comes from the Permian Basin and the Eagle Ford shale formation

(Figure 5). The Barnett and Hayneville-Bossier shales are responsible for the recent rise in produced on-shore gas in Texas. Onshore oil production declined from 1981 through 2004, was flat until 2010 when it doubled from 427M barrels in 2010 to 924M in 2013. Natural gas withdrawals in on-shore Texas, which were first reported in 1992, remained relatively constant until 2005, when it increased from  $6.0 \times 10^6$  MMcf to  $8.2 \times 10^6$  MMcf in 2013. The current Texas gas production still exceeds that for the Marcellus shale with a combined Pennsylvania and West Virginia output of around  $4.0 \times 10^6$  MMcf in 2013 (Figures 5e,g). Increased oil and gas production is again generally attributed to hydraulic fracturing (*Gallegos et al., 2015*). Also numerous salt-water disposal wells exist in Texas (Figure 2). Offshore production as well as federal Gulf of Mexico production is excluded in our analysis since off-shore seismicity ( $M \geq 3$ ) is negligible (only 6 events during 1966-2015).

The recent increase in seismicity correlates visually with increased oil production in onshore Texas. However, unlike Oklahoma (Figures 2 and 3), seismicity in on-shore Texas is spatially constrained to local areas (clusters), whereas increased production comes from large regions. For instance, hydraulic fracturing (*Gallegos et al., 2015*) and salt-water disposal (Figure 2) occur across most of the Barnett shale area; yet seismicity is strongly clustered (*Frohlich, 2012*).

There are five known clusters: four in the last decade and one during 1975-1982 in the Cogdell field. The latter cluster is attributed to enhanced oil recovery (*Davis and Pennington, 1989*) and overlaps with a more recent cluster in the area, attributed to CO<sub>2</sub> storage (*Gan and Frohlich, 2013*). The other recent clusters are located in the Barnett shale (*Frohlich, 2012*), Eagle Ford shale (*Frohlich and Brunt, 2013*) and the Timpson sequence in the Haynesville-Bossier

shale (*Frohlich et al., 2014*). Most of these are also detected by *Weingarten et al. (2015)*, as shown in Figure 2.

In other words, recent changes in seismicity only occur locally, despite substantial increases in large-scale underground fluid injection across the State of Texas due to hydraulic fracturing and salt-water disposal. This raises the question what differentiates these specific local areas? Closeness to favorably oriented faults is likely to play an important role; yet *Frohlich (2012)* shows that seismicity in the Barnett area is not necessarily constrained to known faults. Likewise, published fault maps for Oklahoma (*Darold and Holland, 2015*) do not show a clear correlation with observed seismicity (Figure 3a).

#### ***North Dakota, USA (Bakken shale)***

Seismicity in North Dakota with magnitude 3 or greater is very rare. Likewise only individual events occur in Eastern Montana. On the other hand, hydrocarbon production in North Dakota increased strongly (Figure 6), again generally attributed to hydraulic fracturing treatments and horizontal drilling (*Gallegos et al., 2015*). Oil production was constant from 1981 through 2005. It then increased from 36M barrels in 2005 to 314M in 2013, an 8.7 fold increase. Likewise, gas production was constant from 1967 through 2005, then jumped from  $5.6 \times 10^4$  MMcf in 2005 to  $3.5 \times 10^5$  MMcf in 2013, a six fold increase. These growths are attributed mainly to multi-stage hydraulic fracturing treatments in the Bakken formation and they made North Dakota the second largest oil-producing State in the USA in 2013.

Like Pennsylvania and West Virginia, North Dakota is a State with significantly increased oil and gas production but no noticeable change in seismicity. Contrary to

Pennsylvania and West Virginia, numerous salt-water disposal wells exist in North Dakota within the Bakken production zone (Figure 2), yet few injection wells are thought to be associated with seismicity in North Dakota (*Weingarten et al., 2015*). North Dakota is thus an example of a State with substantially increased underground fluid injection, yet no concurrent change in regional seismicity rates.

### ***Saskatchewan, Canada (Bakken shale)***

The Bakken shale play from North Dakota (USA) continues north into the province of Saskatchewan, Canada. Figure 7 shows the southern part of the province has experienced only 29 events since 1970. Only 2 of these occur within the Bakken outline. An isolated pocket of 15 events exists in south-east Saskatchewan (black dots in inset of Figure 7a). This area also experienced a swarm of 8 events during the early 1980's (red dots). This specific cluster is likely induced by potash mining near Esterhazy (*Hasegawa et al., 1989; Verdon et al., 2016*).

Total crude oil production was mostly constant between 1970 and 1990 (77M barrels), rapidly increased until 1997 (148M barrels) and has since again been essentially constant with a moderate increase in 2013 (177M barrels) due to increasing light oil production. Light oils are mainly produced from the Bakken, Lower Shaunavon and Viking formations. The outline of the Lower Shaunavon formation partially overlaps with the Western portion of the Bakken. The Viking formation extends from Western Saskatchewan to Alberta (Figure 8a). The Lower Shaunavon and Saskatchewan Viking outlines are devoid of seismicity ( $M \geq 3$ ).

Heavy oil production, mainly from Western Saskatchewan, contributes significantly to total crude oil production (Figure 7d), but again no known seismicity occurs near these fields.

Only total crude oil production is reported prior to 1997. Gas production has been mostly in line with the oil production, except that the increase happened in the late 80s instead of early 90s. Production has been declining since 2006 (Figure 7e).

Like its southern counterpart in North Dakota, seismicity is and remains rare in the Canadian part of the Bakken formation. See also *Verdon et al. (2016)* for a more in-depth analysis of net fluid injection and seismicity in Southeast Saskatchewan. Saskatchewan is thus another example of a region with increased underground fluid injection, yet no concurrent change in seismicity rates.

### ***Alberta, Canada***

The province of Alberta, Canada (Figures 8a-c) has experienced 211 events of magnitude three or larger during 1965-2014. The seismic activity shows four noticeable peaks: eighteen events in 1996, thirteen in 2000, eleven in 2001 and fifteen in 2013.

Production of light oil has been steadily decreasing since 1973 (522M barrels) with a moderate trend-reversing increase since 2010 (168M barrels) to 212M barrels in 2013 (Figure 8d). Production of heavy oils and bitumen is shown separately. Most commonly, heavy oils are either mined at the surface or recovered via steam injection to enable in situ drainage. No known seismicity occurs near these fields, yet it dominates increasingly total Albertan oil production (*NEB, 2013*). Gas production steadily increased since 1970, peaking in 2000 ( $5.9 \times 10^6$  MMcf), then decreasing (Figures 8d,e).

Hydrocarbon recovery occurs essentially along the entire southwestern section of the foothills bordering the Rocky Mountains (e.g., Figure 1 in *Atkinson et al., 2016*). The change in

light-oil production is generally attributed to multi-stage hydraulic fracturing treatments allowing (re)-development of tight-oil fields (*NEB, 2013*) such as the mature Cardium and Viking formations and the more recently targeted Montney and Duvernay shale plays (Figure 8a). Indeed, the number of disposal and hydraulically fractured wells has respectively steadily and substantially increased within Alberta and British Columbia in the period 2010-2015 (*Atkinson et al., 2016*).

The increase in seismic activity in the late 1970's and early 1980's as well as the peak in 1996 is thought to be associated with gas extraction in and near the Strachan field, Rocky Mountain House (*Wetmiller, 1986; Baranova et al., 1999*). Both production and seismic activity have decreased since 1995 beneath the Strachan field (*Stern et al., 2013*). Seismicity rates in Alberta are also influenced by the local increase in seismic activity in the Cordell field during 1995-2012, linked to salt-water disposal (*Schultz et al., 2014*).

The peak of seismicity in 2013 is attributed to a swarm of 25 events around Fox Creek of magnitudes 2.5-3.5 near hydraulic fracturing treatments in the Duvernay shale (*Schultz et al., 2015c*). On January 22 and again June 13, 2015, this same area experienced respectively M4.4 and M4.1 events about 30 km NNW of Fox Creek, two of the largest events worldwide thought to be associated with hydraulic fracturing (*Atkinson et al., 2016*). The first event led to new monitoring regulations (*Alberta Energy Regulator, 2015*) including a stop-light system (*Gaucher et al., 2015*) with shut in for magnitudes in excess of 4. See also *Bao and Eaton (2016)* and *Schultz et al. (2017)* for more background on the induced seismicity in the Duvernay area.

In southern Alberta, near the U.S. border, *Schultz et al. (2015a)* correlate a cluster of seismic events between Dec 2011 and March 2012 with a hydraulic fracturing treatment near Cardston. The largest event has a magnitude of 3.0 (2011-12-03). Various other events in the

area at minimum distances of 15km from the injection site occur near known faults (e.g., the Livingstone thrust) and may be tectonic.

*Atkinson et al. (2016)* find that dozens of disposal and hydraulically fractured wells may be associated with  $M \geq 3$  seismicity in Alberta and British Columbia. The Province of Alberta is thus an example where both hydraulic fracturing and salt-water disposal may be associated with induced seismicity.

### ***British Columbia, Canada (Montney and Horn River shales)***

For the province of British Columbia, we have excluded all events at its West Coast which are related to the Juan de Fuca, Explorer and Pacific plates subsiding underneath the Canadian Craton (*Price, 1994*). In its intercratonic region, British Columbia has experienced relatively few events of  $M \geq 3$  between 1970 and 2005 (55 total), but a steady increase in seismic activity occurs since 2005 (Figure 9).

Oil production peaked in 1971 (25M barrels), was constant between 1975 and 1995 (~13M barrels), peaked again between 1997 and 2004 (15.6M barrels) and has steadily decreased since then (Figure 9.d). Gas production, on the other hand, was relatively flat between 1971 and 1986 ( $\sim 4.0 \times 10^5$  MMcf), but has been steadily increasing ever since, with a reported current production of  $1.6 \times 10^6$  MMcf in 2013 (Figure 9e), mostly attributed to exploitation in the Horn River Basin and the Montney shale formation accompanied by substantial increases in hydraulic fracturing treatments in the period 2008-2015 (*BCOGC, 2014a; Atkinson et al., 2016*). Moreover, annual water disposal volumes in Northeast British Columbia (*BCOGC, 2014b*) are visually strongly correlated to reported annual gas production since 1971 (Figure 9.e).

The peak in seismicity in the early 1990s has been attributed to water injection in the Eagle field (Montney shale) near Fort St John (*Horner et al., 1994; BCOGC, 2014b*). The regulator of British Columbia has declared that fluid injection during hydraulic fracturing in the Horn River basin is responsible for the recorded events in 2009-2011 (*BCOGC, 2012; Farahbod et al., 2015*). Seismicity in the Horn River area has decreased since 2012, mainly due to falling gas prices and associated reduction in gas production and hydraulic fracturing treatments (*BCOGC, 2014b*).

Various seismic clusters within the Montney production zone (Figure 9a) are thought to be associated with either hydraulic fracturing or salt-water disposal (*BCOGC, 2014b; Atkinson et al., 2016*). This includes an estimated M4.6 event which occurred on August 17, 2015.

*Atkinson et al., (2016)* analyze 12,289 hydraulically fractured wells and 1,236 salt-water disposal wells in Alberta and northeast British Columbia in the period 1985-2015. They conclude that in the entire period only 7% of all recorded seismicity with magnitudes  $M \geq 3$  is clearly of tectonic (natural) origin, 31% of the seismicity may be associated with hydraulic fracturing and 62% with salt-water disposal. However, in the tail end 2010-2015, these numbers are reversed; 62% of the seismicity may be associated with hydraulic fracturing and 31% with salt-water disposal. The possible reversal is caused by the significantly increased number of hydraulic fracturing treatments in Alberta and Northeast British Columbia since 2010, whereas the number of salt-water disposal wells has only steadily increased.

However, the vast majority of wells have no associated seismicity (*Atkinson et al., 2016*). Only 1.3% of the disposal wells and 0.3% of the hydraulically treated wells may have associated seismicity. One possible explanation for the different percentages is that salt-water disposal wells operate for long periods (often years), whereas hydraulic fracturing treatments last generally only



a few days per well. This limits the likelihood of injected fluids hydraulically connecting to a nearby fault.

## Discussion

We started with the question: Does large-scale increases in production lead to increased seismicity rates? Our observations show quite a diverse picture (Figures 3-9). Either no visual correlation exists in the period 2008-2014 between seismicity rates and changes in production (Pennsylvania, West Virginia, North Dakota and Saskatchewan) or it is limited to small areas (local clusters in Texas; Youngstown, Ohio; Cardston, Cordel, Fox Creek, and Strachan fields in Alberta; several clusters in the Horn River and Montney plays in British Columbia). Conversely, the state of Oklahoma shows a clear visual correlation between increased production and seismic activity at the regional scale (Figure 3).

*Correlations* – Is it possible to quantify correlations? Figure 10 shows daily averages of oil production (green) versus seismicity rates ( $M \geq 3$ , red) in Oklahoma for the months of January 2007 through November 2016. Daily averages are shown in each month instead of monthly quantities to correct for the different number of days per month. An 85% correlation exists between seismicity and production in Oklahoma in this period. The maximum correlation is obtained at zero lag; yet the onset of the increased production is approximately 1.5-2 years ahead of the increase in seismicity. Their respective peaks are 10 months apart. If pore pressure diffusion due to salt-water disposal triggers induced seismicity in Oklahoma (Keränen *et al.*, 2013; Keränen *et al.*, 2014; Walsh and Zoback, 2015), then one would indeed expect a delay between production and seismicity trends. Seismicity in Oklahoma is declining since the start of 2016, whereas production is essentially constant. At its height, 113 events ( $M \geq 3$ ) occurred in

January 2016. Notable is also the large number of events in November 2011 when the Prague event ( $M=5.6$ ) occurred on 2011-11-05.

We did not compute correlation coefficients for the other regions. Estimation variances are inversely proportional to the number of samples in a time series (*Mendel, 1991*). In other words, use of the annually reported statistics within the period of increased production (for most States/Provinces 2008-2015 or 2010-2015) does not lead to a meaningful correlation coefficient. See *Opřsal and Eisner (2014)* for more background on this issue. Unfortunately, for all considered States/Provinces but Oklahoma, the seismicity rates are such that using monthly instead of annual occurrences is not meaningful as too few events occur. We anticipate that correlations will be low since trends are visually dissimilar at the regional scale.

In this paper, hydrocarbon production is used as a proxy for fluid injection volumes since pore pressure increases and thus fluid injection increases the likelihood of fault reactivation and therefore the probability of felt seismicity (*Ellsworth, 2013*). Ideally, net volumes would have been used (that is, injection minus extraction volumes). Unfortunately, hydraulic-fracturing and salt-water-disposal volumes are rarely fully disclosed, hence the necessity to use production as a proxy. Yet is it a fair proxy since many factors affect the performance of a reservoir over time? For instance, with increasing age a reservoir tends to produce more water. Likewise, are hydraulic fracturing volumes proportional to production?

These questions are difficult to answer conclusively because of the lack of hard data for most considered Provinces/States. Annual water disposal volumes in Northeast British Columbia (*BCOGC, 2014b*) are visually strongly correlated to reported annual gas production since 1971 (Figure 9.e). Likewise, Figure 10 shows that oil production for the entire State of Oklahoma is strongly correlated with salt-water injection volumes into the Arbuckle formation for central and

western Oklahoma (*Langenbruch and Zoback, 2016*), with essentially constant production, injection data between 2008 and 2011, strong increases starting early 2012, and both peaking in March 2015. The regulator introduced mandated restrictions on injection rates in 2015, causing a sharp decline in injection volumes into the Arbuckle formation (*Langenbruch and Zoback, 2016*), whereas production has been essentially constant since 2015 (Figure 10).

Some injection occurs in other formations but the Arbuckle formation is by far the most important formation in Oklahoma for salt-water disposal. Likewise, some Arbuckle injection occurs outside of central and western Oklahoma but the majority of wells are within this zone (*Langenbruch and Zoback, 2016*). See also Figures 2 and 3.

At its height, in March 2015, the daily injection rate into the Arbuckle formation amounted to 3.23M barrels/day for an oil production of 0.48M barrels/day. To put this in perspective, the USA, currently the world's largest hydrocarbon producer, extracted on average 15.1M barrels/day in 2015 of petroleum and other hydrocarbon liquids but excluding dry gas. On average, in the period 2008-2014, 6.98 times more salt water was disposed into the Arbuckle formation in central and western Oklahoma than oil was produced in the entire State of Oklahoma. In July 2016, this ratio changed to 3.55, likely due to a combination of mandated injection restrictions by the State regulator and changed depletion strategies by operators, focusing on the economically most profitable wells due to the strong decline in oil prices since 2014.

Figure 10 shows the following correlations: 92% between production and injection (5 months lag), 89% between injection and seismicity (9 months lag), and 85% between production and seismicity (no lag). Production is 5 months ahead of injection, and injection is 9 months ahead of seismicity. Seismicity trailing injection data is supportive of pore pressure diffusion due

to salt-water disposal triggering induced seismicity in Oklahoma (*Keranen et al., 2013; Keranen et al., 2014; Walsh and Zoback, 2015; Langenbruch and Zoback, 2016*).

The observed strong correlations between disposal volumes and hydrocarbon production for North-East British Columbia and Oklahoma strengthen our base assumption that hydrocarbon production is representative of trends in disposal volumes at the regional scale. Are hydraulic fracturing volumes also proportional to production?

Even less hard data are published on regional hydraulic fracturing volumes. However, we can use another source of information, namely rig counts, that is, the number of drilling rigs that are operational in an area. Figure 11 shows rig counts versus oil and gas production in the Bakken (North Dakota and part of Montana), Eagle Ford (Texas), Haynesville (Texas), Marcellus (Pennsylvania and West Virginia), Permian Basin (Texas) and Utica (Ohio). See Figure 1 for geographic locations. Together with the Niobrara (Colorado and Wyoming) these plays accounted for 92% of oil production growth and all natural gas production growth in the USA during 2011-2014. See Table 1 for sources.

Much of the increased production in these areas is attributed to horizontal drilling and hydraulic fracturing with above-average volumes (*Gallegos et al., 2015*). An increased rig count thus indicates increased drilling activities within an area and by association a likely increased number of hydraulic fracturing treatments. Figure 11 shows that rig counts are correlated to production but with peaks leading by one or more years. This gives credence to our assumption that production can be used as a proxy for hydraulic fracturing volumes at the scale of these regional plays. The trend in the last couple years has been to increase both the number of hydraulic fracturing stages (that is, treatment points) per well and the fluid volumes per stage, indicating a shorter time separation between hydraulic fracturing volumes and production than

between rig counts and production. The strong decline in rig counts in 2015 is due to the fall in oil and gas prices in 2014.

If pore pressure diffusion due to hydraulic fracturing triggers induced seismicity, then increased production and seismicity rates could coincide, lead or trail depending on the well-head-to-hypocenter distances involved and time lags between treatment and production. In most case histories however the seismicity occurs during treatment or in the flowback period and thus ahead of production (*Bao and Eaton, 2016; Schultz et al., 2017*). *Causality* – A natural tendency exists to focus attention on areas where seismicity patterns have changed; however, it is equally important to understand why this is not the case elsewhere. *Davis and Frohlich (1993)* pose several questions to establish if a causal link exists between fluid injection and observed earthquake patterns, as well as to determine the likelihood of inducing future earthquakes due to injection. They recommend investigating (1) the background seismicity (does historic seismicity exist?), (2) the local geology (are there known faults in the area?), (3) the current state of stress (are the rocks close to being critically stressed?), (4) the actual injection practices (is sufficient fluid injected to create shear failure at the well head and the location of observed seismicity?). At the scale of this investigation it is not possible to isolate individual causes and factors of what is clearly a multi-faceted problem. However it is possible to draw various general conclusions.

*Injection volumes* – Both hydraulic fracturing volumes and salt-water disposal volumes vary substantially from play to play (*Clark et al., 2013; Gallegos et al., 2015; Chen and Carter, 2016*). For instance, disposal volumes in Oklahoma grew from 849M to 1,538M barrels annually between 2009 and 2014 (*Murray, 2015*, and Figure 10), whereas the annual disposal volume for Northeast British Columbia was 35M barrels in 2013 (*BCOGC, 2014*). The vast volume of the injected fluids in Oklahoma must play a role in explaining the observed regional change in

earthquake patterns, compared with only locally observed changes in Northeast British Columbia (Figures 3 and 9).

Full information on injection volumes for hydraulic fracturing treatments is at best only partially disclosed. Substantial data mining is required to obtain estimates at a regional or play-sized scale (*Gallegos et al., 2015; Chen and Carter, 2016*). *Horner et al. (2016)* estimate that for North Dakota (Bakken) water use for hydraulic fracturing increased 5.6 fold from 18.3M barrels/year in 2008 to 102M barrels/year in 2012. These numbers remain more than an order of magnitude smaller than the disposal volumes in Oklahoma; yet it is 3 times the estimated disposal volume in Northeast British Columbia for 2013. Conversely, seismicity in North Dakota is and remains rare (Figure 7). This demonstrates that although the likelihood of induced seismicity rises with increased injection volume in general, the required volumes for triggering seismicity vary substantially both locally and regionally.

*Current state of stress* – The likelihood of inducing seismicity is also related to the differential stress state (that is, largest minus smallest principal stress), and in particular how close an area is to the critical shear stresses (*Davis and Frohlich, 1993; Zang et al., 2014*). Both the stress magnitudes and orientations are important (*Sibson, 1985, 1990*).

The vertical stress magnitude is commonly derived from density logs. The minimum horizontal stress magnitude and the orientation of the maximum horizontal stress can be obtained using a variety of means such as extended leak off tests, borehole breakout or hydraulic fracturing treatments. Unfortunately, it is typically measured only at a few depths. Obtaining estimates of the maximum horizontal stress magnitude is much more challenging (*Schmitt et al., 2012*). All three principal stresses are required to find the likelihood of shear reactivation of a

pre-existing fault of a given orientation, for instance, using slip tendency analysis (*Morris et al., 1996*). The pore pressure regime also plays an important role (*Sibson, 1985, 1990*).

Furthermore, numerical simulations show that the magnitude of both horizontal stresses can vary significantly with depth (*Roche and Van der Baan, 2015*), because material and stress heterogeneity are likely to be coupled. Understanding the regional and local variability in induced seismicity thus requires an improved knowledge of the orientation and magnitude of all components of the in situ stress field. For instance, are all rocks critically stressed? Variations in local effective stress magnitudes and orientations across the USA and Canada combined with different fluid injection volumes are likely to explain many of the observed seismicity patterns.

*Local geology and existing faults* – The likelihood for induced seismicity also increases if injected fluids and resulting pore pressure perturbations intersect pre-existing and favorably oriented faults (*Sibson, 1985, 1990; Ellsworth, 2013; Zang et al., 2014*). Knowledge of the existence, orientation and mechanical properties of reactivated faults is often incomplete and insufficient. *Frohlich (2012)* shows that seismicity in the Barnett area only occasionally occurs near known faults. Likewise, published fault maps for Oklahoma (*Darold and Holland, 2015*) do not show a clear correlation with observed seismicity (Figure 3a). In the Horn River area (British Columbia), reactivation occurred in nearly all cases on faults that are not visible on reflection seismic data, whereas intersected known faults only rarely created induced seismicity (*BCOGC, 2012*). A strike-slip regime exists locally in the Horn River basin. Strike-slip faults are difficult to detect on reflection seismic data because of the lack of fault offset in the dip direction. Lack of knowledge on the presence and properties of nearby faults clearly poses a conundrum for assessing reactivation and thus induced-seismicity potential.

*Historical background seismicity* – Finally, *Davis and Frohlich (1993)* recommend examining the historic seismicity in order to determine if anomalous trends exist. This is done in Figures 3-9. Seismic hazard maps may provide additional insight into historic seismicity patterns (*Evans et al., 2012*). Probabilistic seismic hazard analysis aids in assessing the risk to infrastructure and humans caused by earthquake shaking. It estimates the probability that ground motion exceeds a certain level at a site within a predefined timeframe (*Cornell, 1968*). Hazard assessment is based on historic seismicity and takes both the number and magnitude of events into account.

Figures 12 and 13 provide the two-percent probability of exceedance in 50 years of peak ground acceleration (PGA) in the United States (*Peterson et al., 2014*) and Canada (*Earthquakes Canada, 2005*). An inferred low PGA implies a historically low seismic hazard. In all the States and Provinces with exceedance PGA below 0.06g, either no visual correlation exists in the period 2008-2014 between seismicity rates and changes in production (Pennsylvania, West Virginia, North Dakota and Saskatchewan) or it is limited to local areas (local clusters in Alberta, British Columbia, Ohio, Texas). Conversely, the state of Oklahoma, with the significantly higher exceedance PGA of 0.2-0.3g, shows a clear regional correlation between increased production and seismic activity (Figure 10).

Two different conclusions can be drawn from this observation. Seismic hazard maps are an indicator of existing tectonic background rates and natural seismic activity if human-induced seismicity is negligible or has been excluded from the computations. Indeed efforts are made to exclude events suspected to be of nontectonic origin in the USA hazard calculations (*Petersen et al., 2015*). However, there is a growing recognition that historic human-induced seismicity may be more important than previously thought as seen in Oklahoma [Figure 3a and *Hough and Page*



(2015)], Alberta and Northeast British Columbia [Figures 8a, 9a and *Atkinson et al. (2016)*]. For instance, the peak in Oklahoma oil production in the early 80s coincides with increased seismicity between 1977 and 1983 with numerous epicenters in known producing areas (Figure 3). See also *Hough and Page (2015)*. This in turn affects seismic hazard predictions.

The first possible conclusion is that if historic human-induced seismicity in Oklahoma, Alberta and British Columbia is relatively prevalent then the seismic hazard maps simply reflect this. The alternative conclusion is that the likelihood of anthropogenic activities creating induced seismicity is proportional to the near-surface tectonic background rate and the amount of natural seismicity. This would then help explain why for instance North Dakota and Pennsylvania show little evidence for induced seismicity. Either conclusion implies that induced seismicity is less likely in areas with low seismic hazard. Similarly, *Evans et al. (2012)* find that the likelihood for the occurrence of felt or damaging events due to CO<sub>2</sub> or geothermal fluid injection seems to be smaller in areas with low seismic hazard (10% likelihood of a GPA of 0.07g or smaller within 50 years). Note however that they state explicitly that the opposite is not necessarily true. Induced felt seismicity is not more likely in areas with higher seismic hazard (*Evans et al., 2012*).

## Conclusions

Large-scale underground fluid injection, because of hydraulic fracturing treatments and/or salt-water disposal, may affect local and regional seismicity rates. A scrutiny of six States in the USA and three Provinces in Canada shows however regional responses vary significantly with several States/Provinces showing no change in recorded seismicity despite 8-16 fold increases in production. Conversely, in Oklahoma, there is an 85% correlation between oil production and

seismicity ( $M \geq 3$ ), and a 92% correlation between salt-water disposal into the Arbuckle formation and recorded seismicity.

Our observations raise the question of contributing factors and underlying causes. Why do some regions/local areas show positive correlations between seismicity rates and recent production increases (with associated large-scale fluid injection), whereas most areas seem insensitive to ongoing anthropogenic activities?

Ultimately, a combination of the depletion strategy, injection volumes plus the local and regional-scale geology and tectonics determine susceptibility to increased earthquake hazard; current state of stress, proximity to critically stressed faults and the seismic history are all factors determining the risk that a given region may experience human-induced seismicity. A comparison with the seismic hazard maps for the USA and Canada shows that induced seismicity is less likely in areas with a lower hazard. The opposite however is not necessarily true.

## **Acknowledgments**

The authors thank the sponsors of the Microseismic Industry Consortium and the Natural Sciences and Engineering Research Council for financial support, Gail Atkinson, David Eaton and Ryan Schultz as well as the numerous individuals who have provided feedback on this study but requested anonymity. Data and resources used in this study are detailed in Table 1 and in the section ‘Data and Resources’ including website links. We thank all data providers (Canadian Association of Petroleum Producers, Earthquakes Canada, Energy Information Administration, IHS PacWest, IRIS, National Energy Board, Natural Gas Intel, ShaleExperts) for collecting,

screening and publishing these resources. Finally we would like to thank Cornelius Langenbruch for providing collected data on salt-water disposal into the Arbuckle formation in Oklahoma.

## References

- Alberta Energy Regulator (2015). Subsurface Order No 2: Monitoring and Reporting of Seismicity in the Vicinity of Hydraulic Fracturing Operations in the Duvernay Zone, Fox Creek, Alberta. AER Bulletin 2015-07 3 pp., URL <<https://aer.ca/documents/orders/subsurface-orders/SO2.pdf>>.
- Atkinson G. M., D.W. Eaton, H. Ghofrani, D. Walker, B. Cheadle, R. Schultz, R. Shcherbakov, K. Tiampo, J. Gu, R. M. Harrington, Y. Liu, M. van der Baan and H. Kao (2016). Hydraulic fracturing and seismicity in the Western Canada sedimentary Basin. *Seismological Research Letters*, **87**(3), 631-647.
- Bao W and D. W. Eaton (2016) Fault activation by hydraulic fracturing in western Canada: *Science*, 354, 6318, 1406-1409.
- Baranova V., A. Mustaqeem, S. Bell (1999). A model for induced seismicity caused by hydrocarbon production in the Western Canada Sedimentary Basin. *Canadian Journal of Earth Sciences*. **36**, 47-64.
- BCOGC (2012). Investigation of observed seismicity in the Horn River basin. Tech. Rep., BC Oil and Gas Commission, Victoria, British Columbia, Canada, 2012; [www.bcogc.ca/node/8046/download](http://www.bcogc.ca/node/8046/download).

BCOGC (2014a). Horn River Basin Unconventional Shale Gas Play Atlas. BC Oil and Gas Commission, Victoria, British Columbia, Canada, 2014; <http://www.bcogc.ca/node/11238/download>. [Last accessed October 2015].

BCOGC (2014b). Investigation of observed seismicity in the Montney Trend. Tech. Rep, BC Oil and Gas Commission, Victoria, British Columbia, Canada, 2014; <http://www.bcogc.ca/node/12291/download>.

Bollinger G.A. (1989) Microearthquake activity associated with underground coal-mining in Buchanan County, Virginia, U.S.A, *Pure and Applied Geophysics*, **129** (3/4), 407-413.

Chapman, M.C., (2013). On the Rupture Process of the 23 August 2011 Virginia Earthquake, *Bulletin of the Seismological Society of America*, **103**, 613-628.

Chen, H. and K. E. Carter (2016) Water usage for natural gas production through hydraulic fracturing in the United States from 2008 to 2014. *Journal of Environmental Management*, **170**, 152-159.

Clark, C. E., Horner, R. M., Harto, C. B. (2013) Life cycle water consumption for shale gas and conventional natural gas. *Environmental Science and Technology*, **47**, 11829–11836.

Cornell, C. (1968) Engineering seismic risk analysis, *Bulletin of the Seismological Society of America*, **58**, 1583-1606.

Darold A.P., Holland A.A. (2015) Preliminary Oklahoma optimal fault orientations. Oklahoma Geological Survey Open-File Report (OF4-2015). Norman, OK. pp. 1.

Davies R., G. Foulger, A. Bindley, P. Styles (2013). Induced seismicity and hydraulic fracturing for the recovery of hydrocarbons. *Marine and Petroleum Geology*. **45**, 171-185.

Davis S.D. and C. Frohlich (1993) Did (or will) fluid injection cause earthquakes? – Criteria for a rational assessment. *Seismological Research Letters*, **64** (3-4), 207-224.

Davis S. D., W.D. Pennington (1989). Induced seismic deformation in the Cogdell oil field of west Texas. *Bulletin of the Seismological Society of America*, **79**(5), 1477-1495.

Earthquakes Canada (2005). Seismic hazard map for Canada. [www.earthquakescanada.nrcan.gc.ca/hazard-alea/zoning-zonage/NBCC2005maps-eng.php](http://www.earthquakescanada.nrcan.gc.ca/hazard-alea/zoning-zonage/NBCC2005maps-eng.php). (Last accessed October 2015).

Ellsworth W.L. (2013). Injection-induced earthquakes. *Science*. **341**, no. 6142, 1225942.

Evans, K.F., Zappone, A., Kraft, T., Deichmann, N., Moia, F. (2012) A survey of the induced seismic responses to fluid injection in geothermal and CO<sub>2</sub> reservoirs in Europe. *Geothermics* **41**, 30-54.

Farahbod A.M., H. Kao, J.F. Cassidy, D. Walker (2015). How did hydraulic-fracturing operations in the Horn River Basin change seismicity patterns in northeastern British Columbia, Canada? *The Leading Edge*, **34**(6), 658-663.

Frohlich C. (2012). Two-year survey comparing earthquake activity and injection-well locations in the Barnett shale, Texas. *Proceedings of the National Academy of Sciences*. **109**, no. 35, 13934-13938.

Frohlich C., M. Brunt (2013). Two-year survey of earthquakes and injection/production wells in the Eagle Ford Shale, Texas, prior to the Mw4.8 20 October 2011 earthquake. *Earth and Planetary Science Letters*, **379**, 56-63.

Frohlich C., W. Ellsworth, W. A. Brown, M. Brunt, J. Luetgert, T. MacDonald, S. Walter (2014).

The 17 May 2012 M4.8 earthquake near Timpson, east Texas: An event possibly

- triggered by fluid injection. *Journal of Geophysical Research: Solid Earth*. **119**, no. 1, 581-593.
- Gallegos, T.J., B. A. Varela, S. S. Haines and M. A. Engle (2015) Hydraulic fracturing water use variability in the United States and potential environmental implications. *Water Resources Research*, **51**(7), 5839–5845.
- Gan W., C. Frohlich (2013). Gas injection may have triggered earthquakes in the Cogdell oil field, Texas. *Proceedings of the National Academy of Sciences*, **110**(47), 18786-18791.
- Gaucher E, Schoenball M, Heidbach O, Zang A, Fokker PA, van Wees J-D, Kohl T (2015) Induced seismicity in geothermal reservoirs: A review of forecasting approaches. *Renewable and Sustainable Energy Reviews*, **52**, 1473-1490.
- Hasegawa, H.S., Wetmiller, R.J. and Gendzwill, D.J. (1989) Induced seismicity in mines in Canada - an overview: *Pure and Applied Geophysics*, **129**, no. 3-4, 423-453.
- Horner R. B., J. Barclay, J. MacRa (1994). Earthquakes and hydrocarbon production in the Fort St. John area of northeastern British Columbia. *Canadian Journal of Exploration Geophysics*. **30**, no. 1, 39-50.
- Horner R.M., C. B. Harto, R. B. Jackson, E. R. Lowry, A. R. Brandt, T. W. Yeskoo, D. J. Murphy and C. E. Clark (2016) Water use and management in the Bakken shale oil play in North Dakota. *Environmental Science and Technology*, **50**, 3275–3282.
- Hough, S. E., Page, M. (2015). A century of induced earthquakes in Oklahoma? *Bulletin of the Seismological Society of America*, **105**(6), 2863-2870.

- Keranen K. M., H. M. Savage, G. A. Abers, E. S. Cochran (2013). Potentially induced earthquakes in Oklahoma, Usa: Links between wastewater injection and the 2011 Mw 5.7 earthquake sequence. *Geology*. **41**, no. 6, 699–702.
- Keranen K. M., M. Weingarten, G. A. Abers, B. A. Bekins, S. Ge (2014). Sharp increase in central Oklahoma seismicity since 2008 induced by massive wastewater injection. *Science*. **345**, 448-451.
- Kim W. Y. (2013). Induced seismicity associated with fluid injection into a deep well in Youngstown, Ohio. *Journal of Geophysical Research: Solid Earth*. **118**, no. 7, 3506-3518.
- Langenbruch C. and M. D. Zoback (2016) How will induced seismicity in Oklahoma respond to decreased saltwater injection rates? *Science Advances*, 2, e1601542.
- Lutz B.D., A.N. Lewis and M.W. Doyle (2013) Generation, transport, and disposal of wastewater associated with Marcellus Shale gas development. *Water Resources Research*, **49** (2), 647–656.
- McGarr A., B. Bekins, N. Burkardt, J. Dewey, P. Earle, W. Ellsworth, S. Ge, S. Hickman, A. Holland, E. Majer, J. Rubinstein, A. Sheehan (2015). Coping with earthquakes induced by fluid injection. *Science*, **347**, 6224, 830-831.
- McNamara D. E., H. M. Benz, R. B. Herrmann, E. A. Bergman, P. Earle, A. Holland, R. Baldwin, A. Gassner (2015). Earthquake hypocenters and focal mechanisms in central Oklahoma reveal a complex system of reactivated subsurface strike-slip faulting. *Geophysical Research Letters*, **42**(8), 2742-2749.

- Mendel, J. M., 1991, Tutorial on higher-order statistics (spectra) in signal processing and system theory: *Proceedings of the IEEE*, 79, 278–305.
- Morris, A., Ferrill, D. A., and Henderson, D. B. (1996) Slip tendency analysis and fault reactivation: *Geology*, **24**(3), 275–278.
- Murray K.E. (2013). State-scale perspective on water use and production associated with oil and gas operations, Oklahoma, US. *Environmental Science and Technology*, 47(9), 4918-4925,
- Murray K.E. (2015) Class II Saltwater Disposal for 2009–2014 at the Annual-, State-, and County- Scales by Geologic Zones of Completion, Oklahoma. Oklahoma Geological Survey Open-File Report (OF5-2015). Norman, OK. pp. 18.
- NEB (2013). Canada’s Energy Outlook 2013: Energy supply and demand projections to 2035. <https://www.neb-one.gc.ca/nrg/ntgrtd/ft/2013/2013nrgftr-eng.pdf>
- Opršal, I., and Eisner, L. (2014). Cross-correlation—an objective tool to indicate induced seismicity. *Geophysical Journal International*, 196(3), 1536-1543.
- Petersen M. D., M. P. Moschetti, P. M. Powers, C. S. Mueller, K. M. Haller, A. D. Frankel, Y. Zeng, S. Rezaeian, S. C. Harmsen, O. S. Boyd, N. Field, R. Chen, K. S. Rukstales, N. Luco, R. L. Wheeler, R. A. Williams, A.H. Olsen (2014). Documentation for the 2014 update of the United States national seismic hazard maps, Open-File Report, 1091 (USGS). <http://pubs.usgs.gov/of/2014/1091/>.
- Petersen M.D., C.S. Mueller, M.P. Moschetti, S.M. Hoover, J.L. Rubinstein, A.L. Llenos, A.J. Michael, W.L. Ellsworth, A.F. McGarr, A.A. Holland and J.G. Anderson (2015). Incorporating Induced Seismicity in the 2014 United States National Seismic Hazard



Model – Results of the 2014 Workshop and Sensitivity Studies, Open-File Report 2015-1070.

Price R. (1994). Cordilleran tectonics and the evolution of the Western Canada Sedimentary Basin, in Geological Atlas of the Western Canada Sedimentary Basin. [www.ag.gov.ab.ca/publications/wcsb\\_atlas/A\\_CH02/CH\\_02.html](http://www.ag.gov.ab.ca/publications/wcsb_atlas/A_CH02/CH_02.html).

Roche V., Van der Baan M. (2015) The role of lithological layering and pore pressure on fluid-induced microseismicity. *Journal of Geophysical Research: Solid Earth*, **120** (2), 923-943.

Rubinstein J.L., A.B. Mahani (2015). Myths and facts on wastewater injection, hydraulic fracturing, enhanced oil recovery, and induced seismicity. *Seismological Research Letters*, 86(4), 1060-1067.

Schmitt, D.R., Currie, C.A., Zhang, L., 2012. Crustal stress determination from boreholes and rock cores: fundamental principles. *Tectonophysics* **580**, 1–26.

Schultz R., V. Stern, Y.J. Gu (2014). An investigation of seismicity clustered near the Cordell field, west central Alberta, and its relation to a nearby disposal well. *Journal of Geophysical Research: Solid Earth*. **119**, no. 4, 3410-3423.

Schultz, R., S. Mei, D. Pana, V. Stern, Y. Gu, A. Kim, and D. Eaton (2015a). The Cardston Earthquake Swarm and hydraulic fracturing of the “Alberta Bakken” play, *Bulletin of the Seismological Society of America*, 105, 2871–2884.

Schultz, R., Stern, V., Gu, Y. J., & Eaton, D. (2015b). Detection threshold and location resolution of the Alberta Geological Survey Earthquake Catalogue. *Seismological Research Letters*, 86(2A), 385-397.

- Schultz, R., Stern, V., Novakovic, M., Atkinson, G., & Gu, Y. J. (2015c). Hydraulic fracturing and the Crooked Lake sequences: Insights gleaned from regional seismic networks. *Geophysical Research Letters*, **42**(8), 2750-2758.
- Schultz, R., R. Wang, Y. J. Gu, K. Haug, and G. Atkinson (2017), A seismological overview of the induced earthquakes in the Duvernay play near Fox Creek, Alberta, *J. Geophys. Res. Solid Earth*, 122, doi:10.1002/2016JB013570.
- Sibson, R.H. (1985) A note on fault reactivation: *Journal of Structural Geology*, 7 (6), 751-754.
- Sibson, R.H. (1990) Rupture nucleation of unfavorably oriented faults: *Bulletin of the Seismological Society of America*, 80 (6), 1580-1604.
- Stern, V.H., Schultz, R.J., Shen, L., Gu, Y.J., Eaton, D.W. (2013): Alberta earthquake catalog, version 1.0: September 2006 through December 2010; Alberta Energy Regulator, AER/AGS Open File Report 2013-15, 29 p.
- Van der Baan M., D. Eaton and M. Dusseault (2013). Microseismic monitoring developments in hydraulic fracture stimulation, in *Effective and sustainable hydraulic fracturing*, A.P. Bunger, J. McLennan and R. Jeffrey, eds., Intech, 439-466.
- Verdon, J. P., Kendall, J. M., Horleston, A. C., & Stork, A. L. (2016). Subsurface fluid injection and induced seismicity in southeast Saskatchewan. *International Journal of Greenhouse Gas Control*, in press, available on line.
- Walsh F. and M. Zoback (2015). Oklahoma's recent earthquakes and saltwater disposal. *Science Advances*, 1(5), e1500195.

Weingarten M., S. Ge, J. W. Godt, B.A. Bekins & J.L. Rubinstein (2015). High-rate injection is associated with the increase in US mid-continent seismicity. *Science*, **348** (6241), 1336-1340.

Wetmiller R.J. (1986). Earthquakes near Rocky Mountain House, Alberta, and their relationship to gas production facilities. *Canadian Journal of Earth Sciences*. **23**, no. 2, 172-181.

Zang A, Oye V, Jousset Ph, Deichmann N, Gritto R, McGarr A, Majer E, Bruhn D (2014) Analysis of induced seismicity in geothermal reservoirs - An overview. *Geothermics* **52**, 6-21.

## List of Tables

**Table 1. Production-related web addresses used in this study**

Web addresses	Comments
<a href="http://www.eia.gov/beta/international/index.cfm">http://www.eia.gov/beta/international/index.cfm</a>	International energy data and analysis.
<a href="http://www.eia.gov/dnav/ng/ng_prod_sum_a_epg0_fgw_mmcf_a.htm">http://www.eia.gov/dnav/ng/ng_prod_sum_a_epg0_fgw_mmcf_a.htm</a>	U.S. Natural gas gross withdrawals and production
<a href="http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_a.htm">http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_a.htm</a>	U.S. Crude oil production
<a href="http://www.eia.gov/petroleum/drilling/">http://www.eia.gov/petroleum/drilling/</a>	U.S. Rig counts
<a href="http://www.capp.ca/publications-and-statistics/statistics/statistical-handbook">http://www.capp.ca/publications-and-statistics/statistics/statistical-handbook</a>	Production information for Canada
<a href="https://www.nrb-one.gc.ca/nrg/sttsc/crdlndptrlmprdct/stt/stmtdprdcn-eng.html">https://www.nrb-one.gc.ca/nrg/sttsc/crdlndptrlmprdct/stt/stmtdprdcn-eng.html</a>	Production information for Canada

## List of Figures

**Fig. 1. Shale plays in Canada, the United States and Mexico.** The Marcellus shale in Pennsylvania, the Bakken shale in North Dakota, and the Barnett, Eagle Ford and Haynesville-Bossier shales in Texas are among the most important shale plays. Source: U.S. Energy Information Administration.

**Fig. 2. Active and associated class II injection wells in the Central and Eastern United States.** (A) Active and associated class II injection wells. Associated means that the well was active and within 15 km distance of a co-temporal seismic event. (B) Percentage of associated injection wells by State. From: *Weingarten et al. (2015). Reproduced with permission of Science.*

**Fig. 3. Seismicity and hydrocarbon production for Oklahoma, USA:** (A) Seismicity in Oklahoma state during 1965-2014. 1164 events ( $M \geq 3$ ) occurred within the coordinates: 103°11'-94°41'W, 33°47'-37°08'N. Solid line shapes: Outlines of Woodford shale and Mississippi Lime plays. Thin dashed line: region containing salt-water disposal wells (*Walsh and Zoback, 2015*). Thick dashed line: region with high density of disposal wells (*Walsh and Zoback, 2015*). The Hunton play is located just south of the Mississippi Lime within the bold dashed contour. (B) Annual seismicity rates. (C) Cumulative seismicity over time. (D) Oklahoma annual production of crude oil in thousands of barrels. (E) Oklahoma annual natural gas gross withdrawals in million cubic feet (MMcf).

**Fig. 4. Seismicity and hydrocarbon production for Marcellus shale and surrounding areas, USA:** (A). 158 events occurred from 1964 to 2014 within the coordinates: 83.01°W-73.74°W, 43.97°N-36.36°N. 110 events occurred within the Marcellus shale play (red curved line). The seismicity in Youngstown, Ohio, may be associated with fluid injection (*Kim, 2013*). (B) Yearly seismicity rates for the study region (black curve) and the Marcellus shale area (red dotted line). (C) Cumulative seismicity over time. Annual production of (D) Pennsylvania crude oil (thousands of barrels), (E) Pennsylvania natural gas gross withdrawals (MMcf), (F) West Virginia crude oil, (G) West Virginia natural gas gross withdrawals.

**Fig. 5. Seismicity and hydrocarbon production for on-shore Texas, United States:** (A) Seismicity during 1965-2014. 172 events occurred within the coordinates: 106.68-93.58°W, 25.89°-36.46°N. The Barnett, Eagle Ford, Haynesville-Bossier shales and the Permian Basin plays are outlined. Five clusters are highlighted (large circles). These include two overlapping clusters in the Cogdell field during 1975-1982 due to enhanced-oil recovery (*Davis and Pennington, 1989*) and a recent cluster due to CO<sub>2</sub> storage (*Gan and Frohlich, 2013*). (B) Yearly seismicity rates. (C) Cumulative seismicity over time. Annual production of (D) on-shore crude oil (thousands of barrels) and (E) on-shore natural gas (MMcf).

**Fig. 6. Seismicity and hydrocarbon production for North Dakota, United States:** (A) Seismicity during 1965-2014. 12 events occurred within the coordinates: 109.47°W-99.62°W,

49.00°N-46.17°N (North Dakota and eastern Montana). The Bakken shale play is outlined by the curved line. (B) Yearly seismicity rates. (C) Cumulative seismicity over time. Annual production of (D) crude oil (thousands of barrels) and (E) natural gas (MMcf).

**Fig. 7. Seismicity and hydrocarbon production for Saskatchewan, Canada:** (A) Seismicity during 1965-2014. 29 events occurred within the coordinates: 109.97°W-101.49°W, 51.10°N-49.03°N. Bakken formation is shown in red outline. Note that only 2 events occurred within the Bakken area. The cluster north east of the Bakken formation is not related to oil activities but thought to be related to potash mining activities. (B) Yearly seismicity rates. (C) Cumulative seismicity over time. Annual production of (D) continuous line: total crude oil, dashed line: heavy crude oil, dotted line: light crude oil production (thousands of barrels) and (E) natural gas (MMcf).

**Fig. 8. Seismicity and hydrocarbon production for Alberta, Canada:** (A) Seismicity during 1965-2014. 211 events occurred within the coordinates: 120.37°-110.08°W, 60.09°-48.96°N. The mature Viking formation and newer Montney and Duvernay shale plays are shown in red outlines. Cardston and Fox Creek (hydraulic fracturing), Cordel (disposal) and Strachan (production) field clusters are identified by blue circles. (B) Yearly seismicity rates. (C) Cumulative seismicity over time. Annual production of (D) continuous line: crude oil, dashed line: heavy oil (thousands of barrels) and (E) natural gas (MMcf).

**Fig. 9. Seismicity and hydrocarbon production for British Columbia, Canada:** (A) Seismicity during 1965-2014. 128 events occurred within the coordinates: 129.51°-120.19°W, 57.95°-52.76°N. Horn River and Montney formations are shown in curved outlines. Known seismic clusters are shown as larger circles. (B) Yearly seismicity rates. (C) Cumulative seismicity over time. Annual production of (D) crude oil (thousands of barrels) and (E) natural gas (MMcf).

**Fig. 10. Seismicity, salt-water disposal and oil production for Oklahoma: January 2007 through November 2016.** Daily averages per month of oil production (green, million barrels/day), salt-water disposal into the Arbuckle formation (blue, million barrels/day) and earthquakes (red,  $M \geq 3$ ). Large correlations exist between all displayed quantities: 92% between production and injection (5 months lag), 89% between injection and seismicity (9 months lag), 85% between production and seismicity (no lag). Earthquakes of  $M \geq 5$  are also indicated.

**Figure 11. Rig counts and hydrocarbon production** for Bakken (North Dakota, Montana), Eagle Ford (Texas), Haynesville (Texas), Marcellus Shale (Pennsylvania, West Virginia), Permian Basin (Texas), Utica (Ohio) from January 2007 through January 2017. Red: oil production (barrels/day). Green: gas production (Mcf/day). Blue: rig counts. Rig counts and production tend to be strongly correlated but with time shifts of 1-3 years. Note different vertical scales in all cases.



**Fig.12. 2014 Seismic hazard map for the United States**, showing 2% probability of exceeding a given ground acceleration in 50 years. **Top insets:** Annual oil (solid lines) and gas (dashed lines) production for North Dakota (ND), Oklahoma (OK), Marcellus shale area (Pennsylvania-PA, West Virginia-WV), Texas (TX). **Bottom insets:** seismicity rates (solid lines) and cumulative seismicity (dashed lines) for Bakken shale, Oklahoma, Marcellus shale, Texas. Symbols: areas with locally changed seismicity rates thought to be associated with fluid injection, with exception of the Virginia tectonic swarm. Modified after *Peterson et al. (2014)*.

**Fig. 13. Seismic hazard map for Canada** showing the peak ground acceleration at a probability of 2% in 50 years. Source: *Earthquakes Canada (2005)*. **Top insets:** Annual oil (solid lines) and gas (dashed lines) production for the provinces of British Columbia (BC), Alberta (AB) and Saskatchewan (SK). **Bottom insets:** seismicity rates (solid lines) and cumulative seismicity (dashed lines) for British Columbia, Alberta and Saskatchewan.

Figure 1.

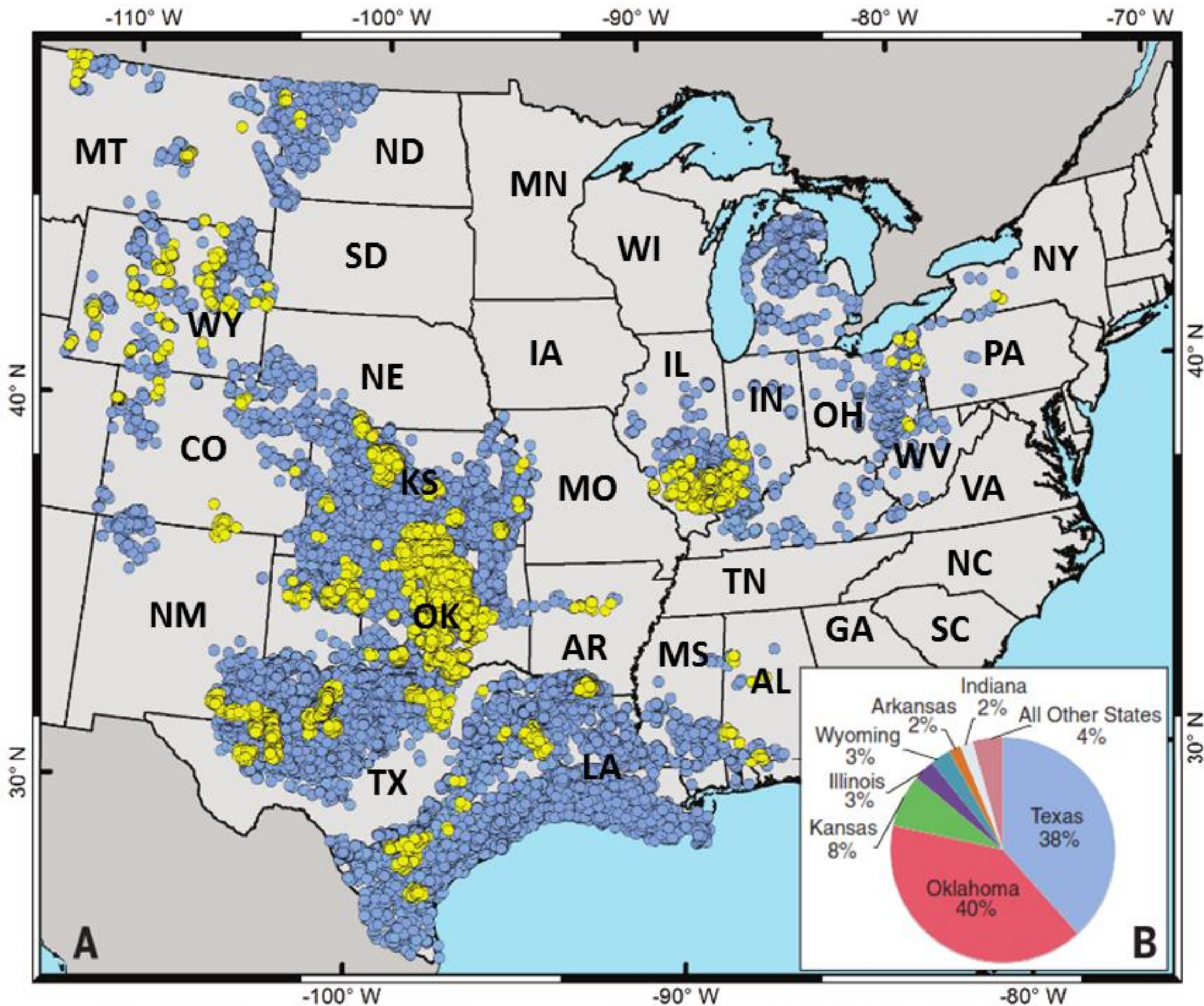


# North American shale plays (as of May 2011)





Figure 2.



● Active Injection Wells  
 27,102 - Salt Water Disposal  
 78,968 - Enhanced Oil Recovery

● Associated Injection Wells  
 6,961 - Salt Water Disposal  
 11,796 - Enhanced Oil Recovery

Figure 3.



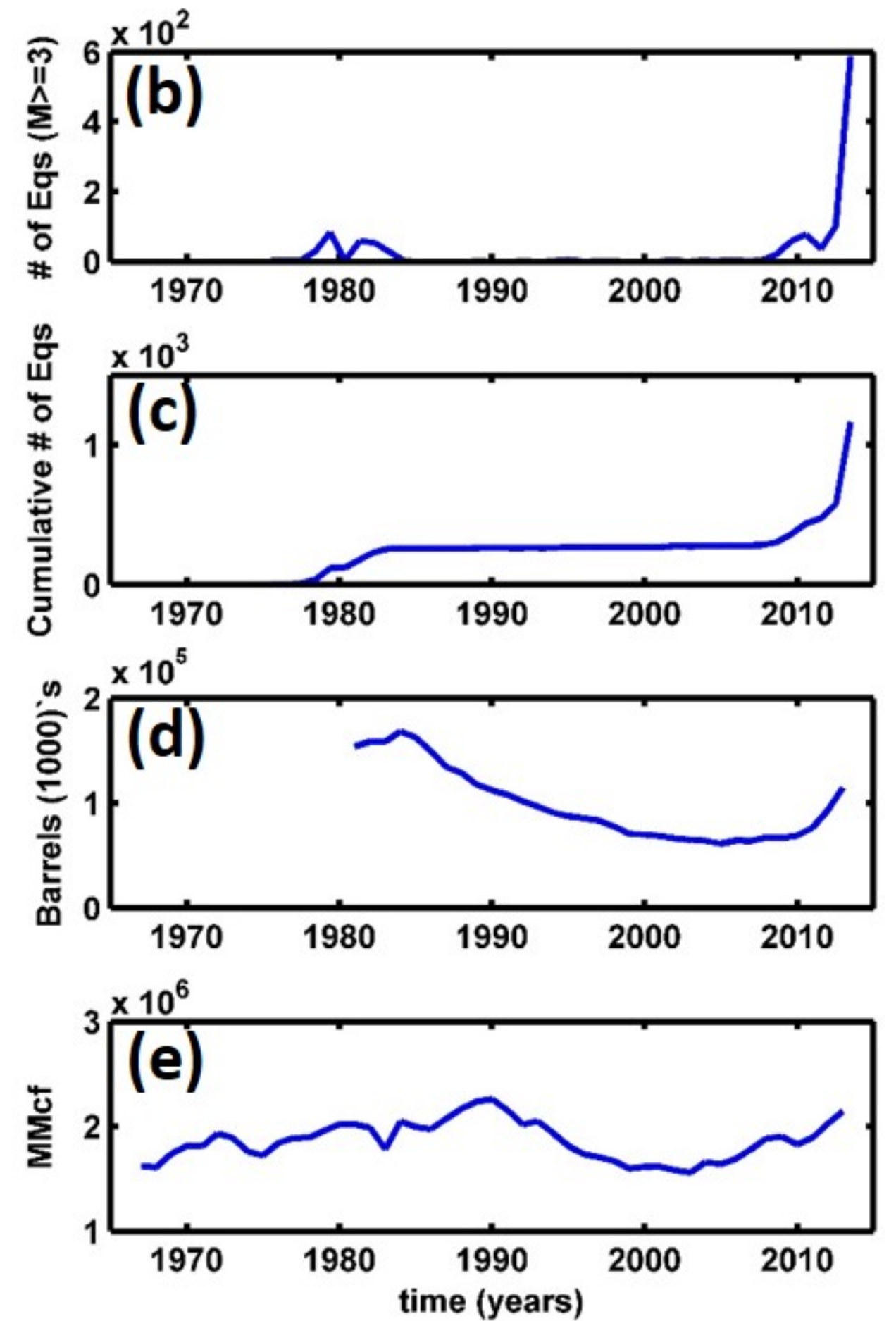
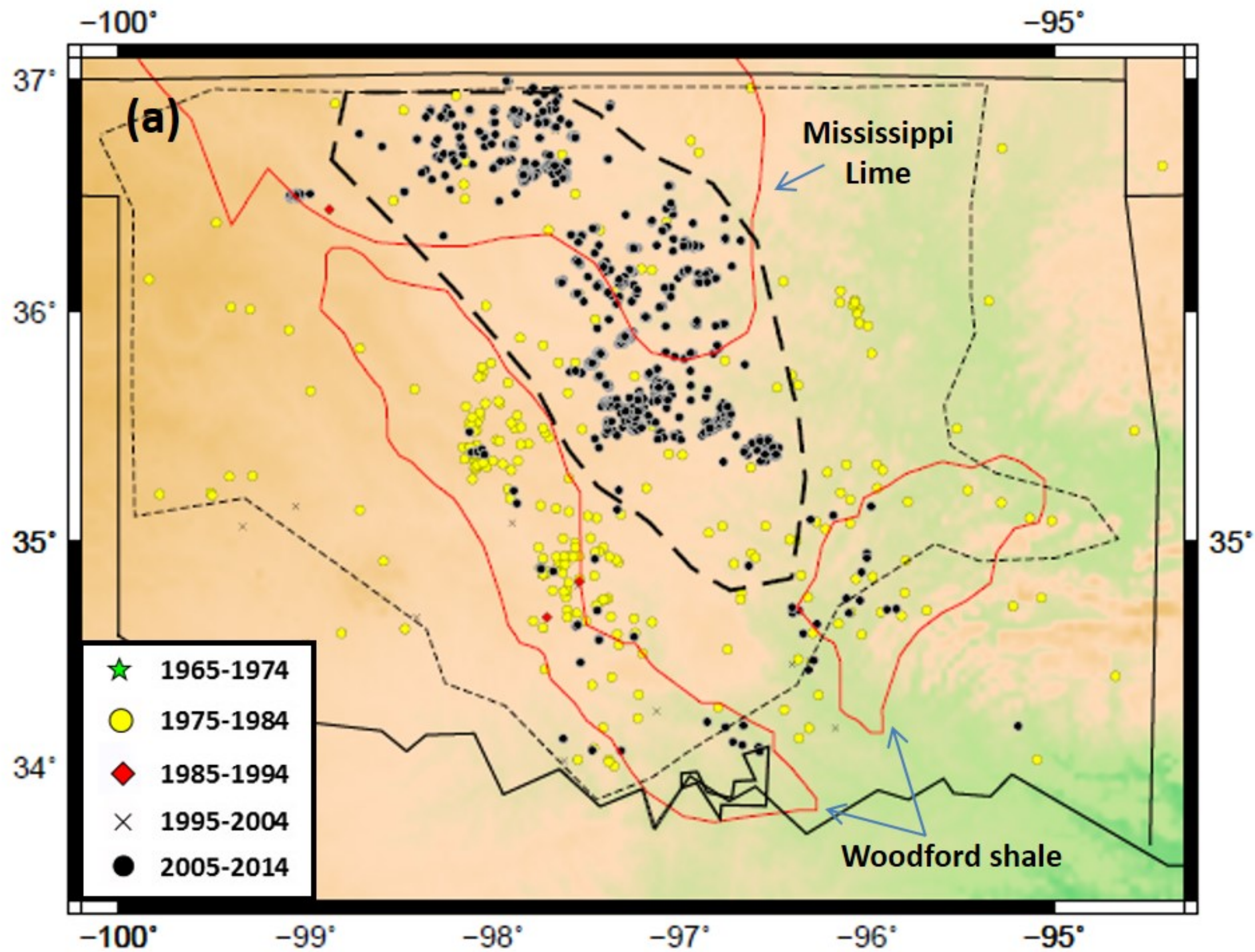


Figure 4.



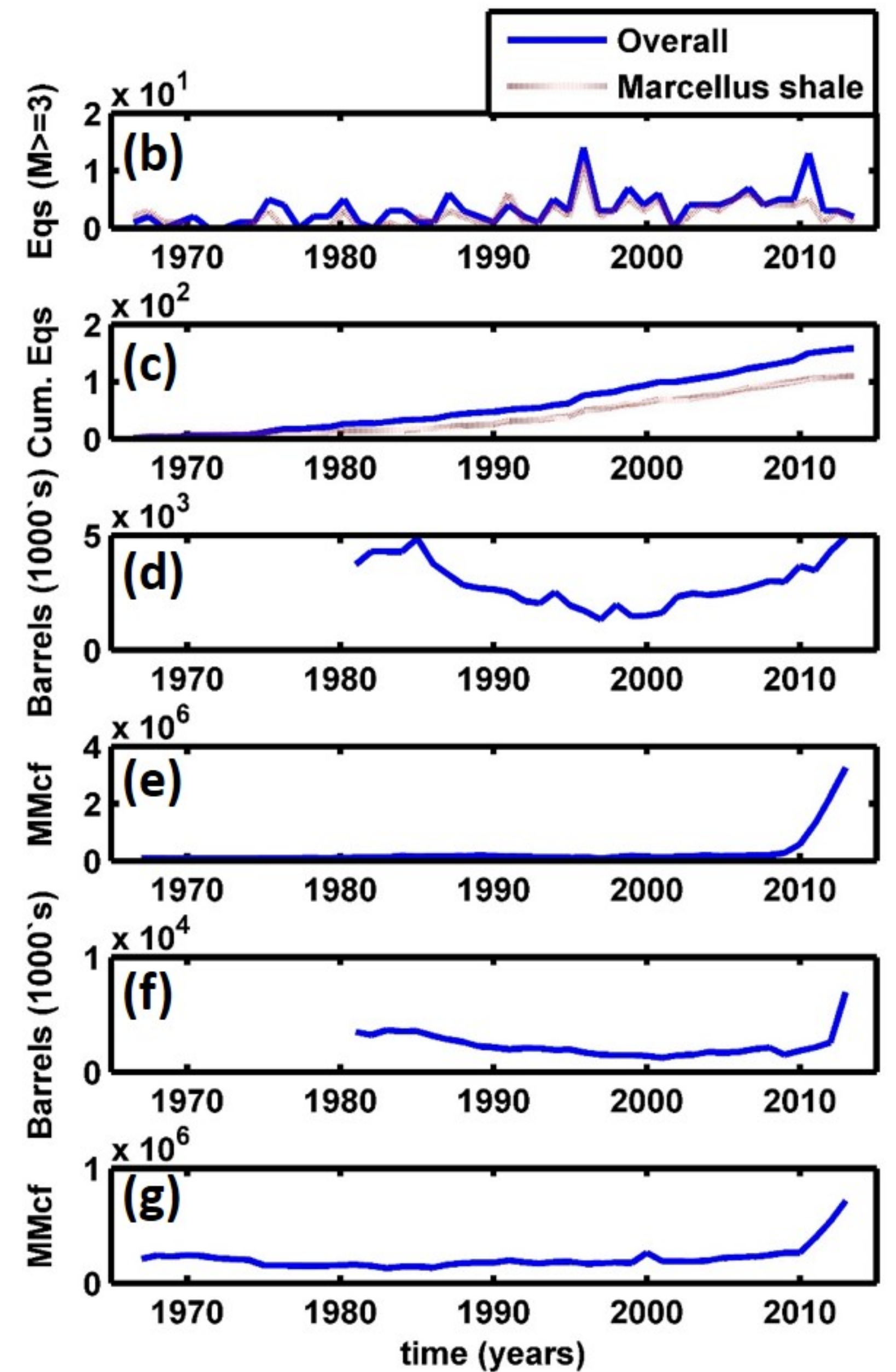
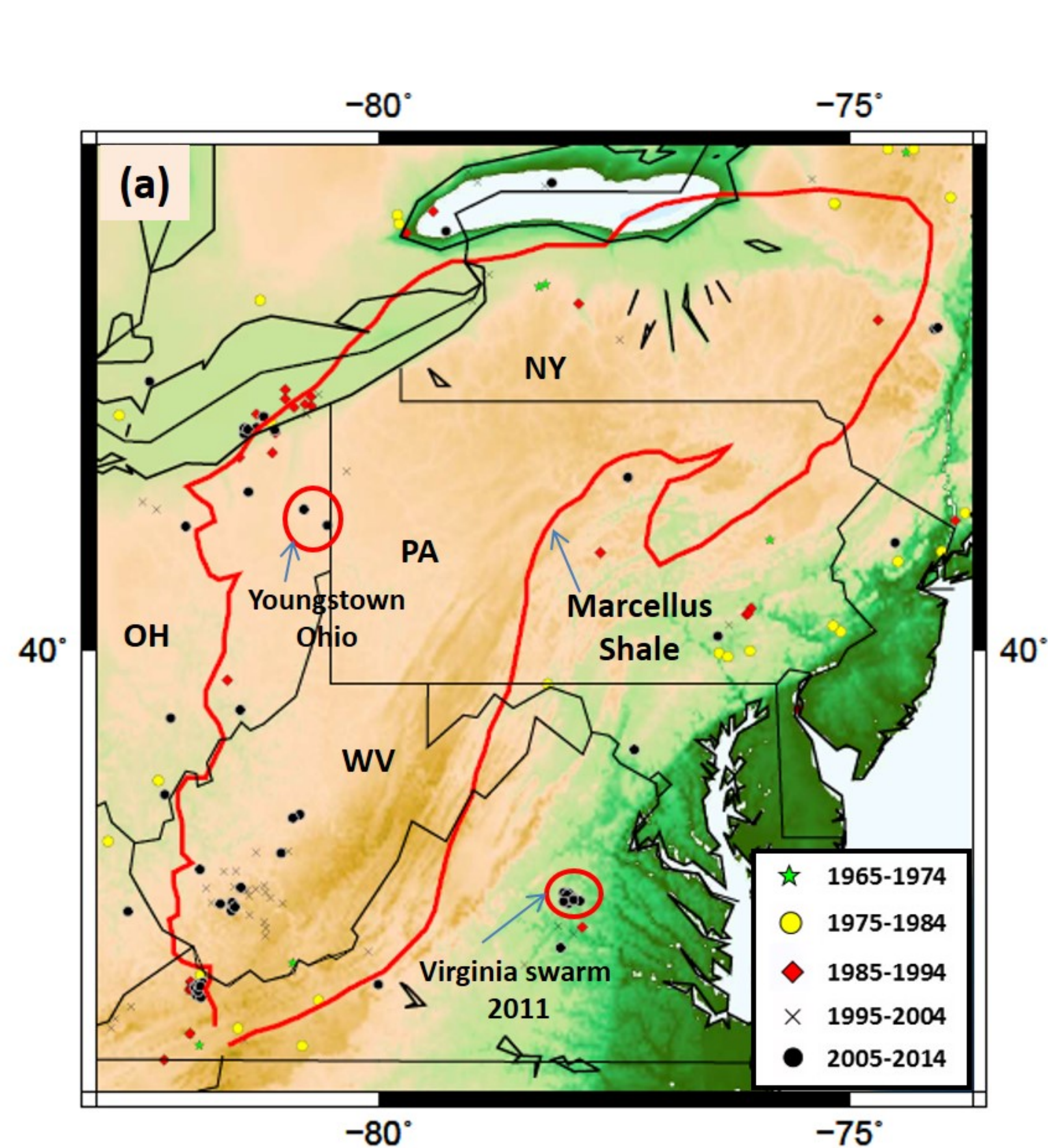




Figure 5.

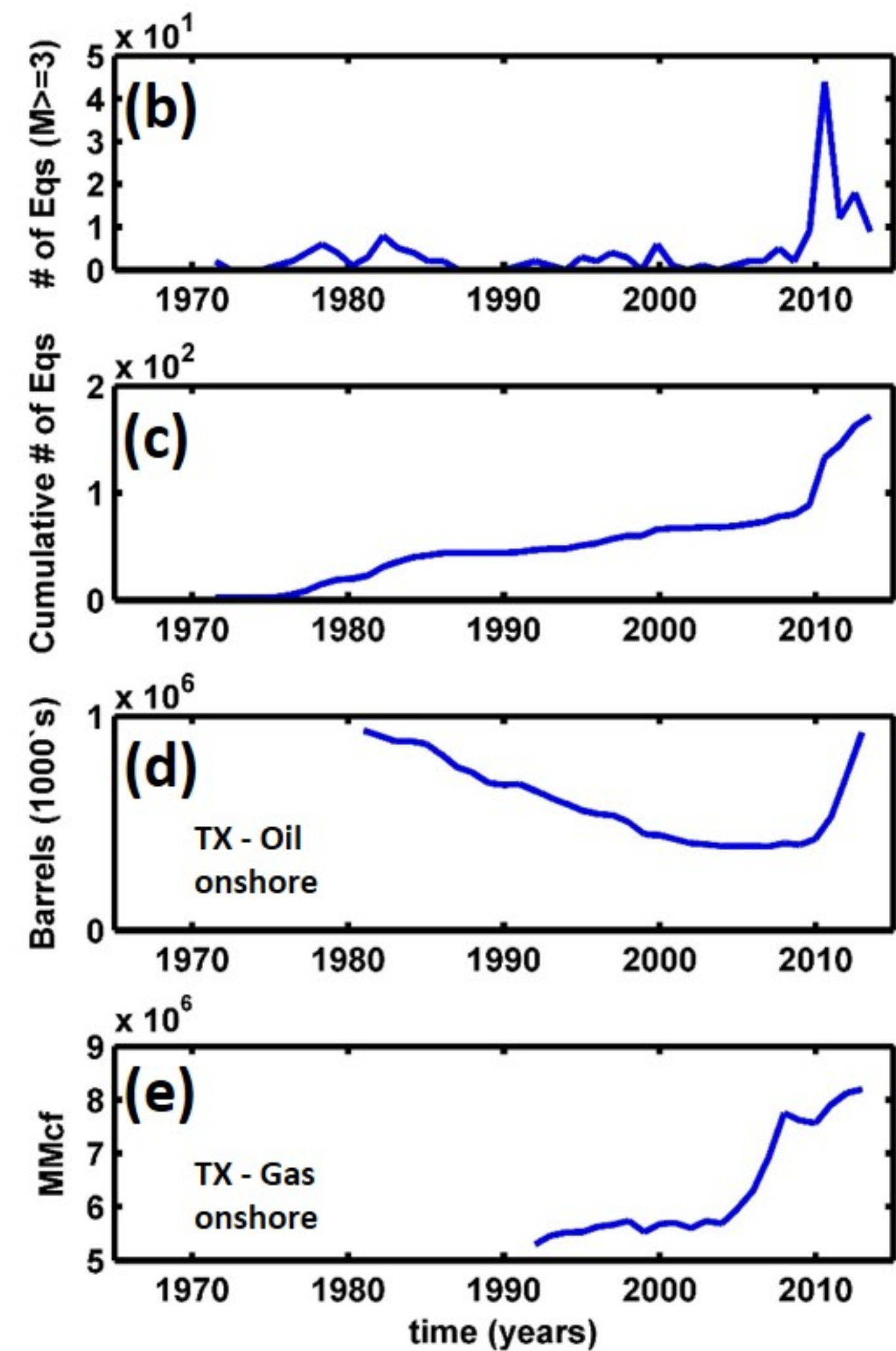
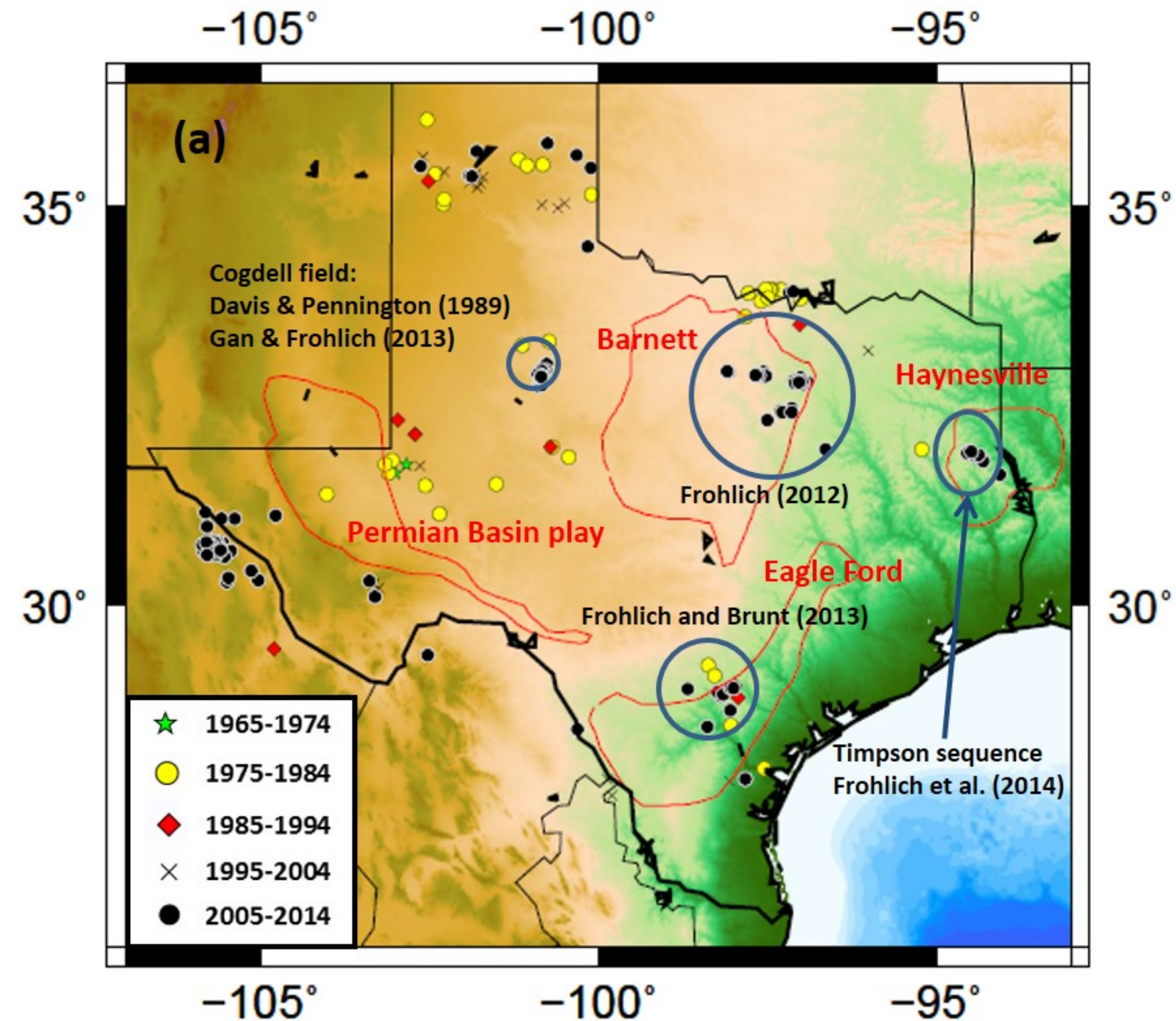


Figure 6.



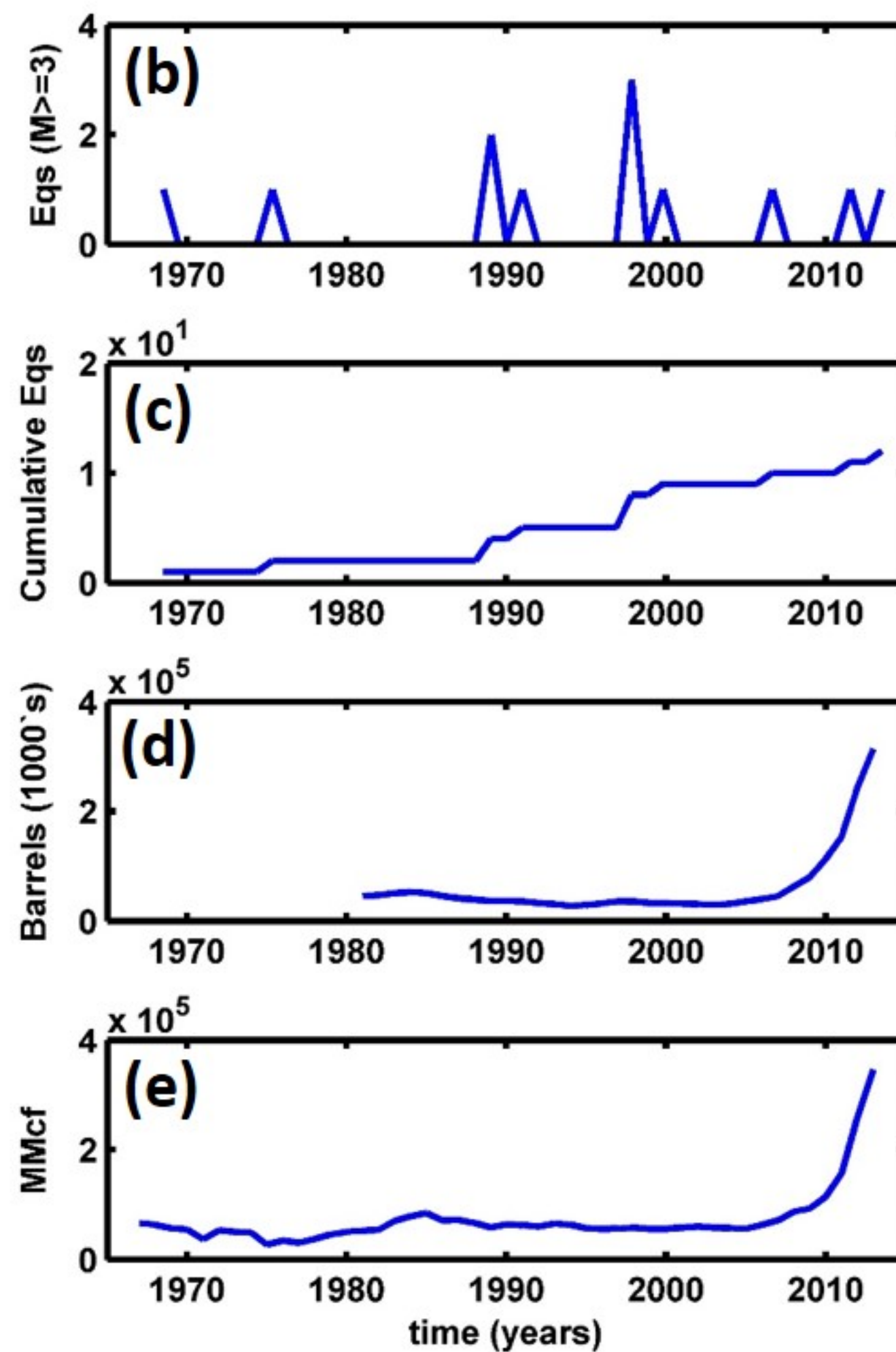
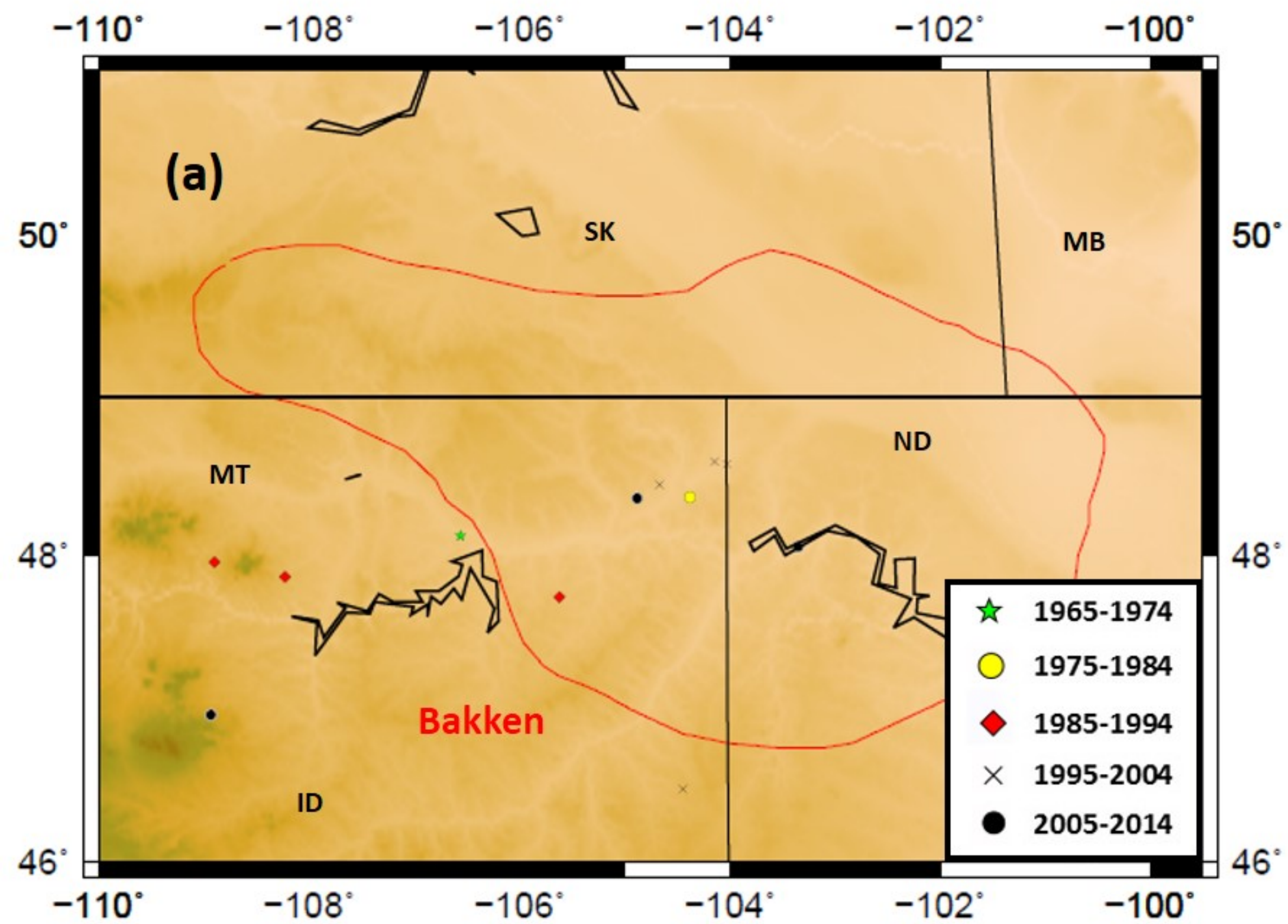


Figure 7.



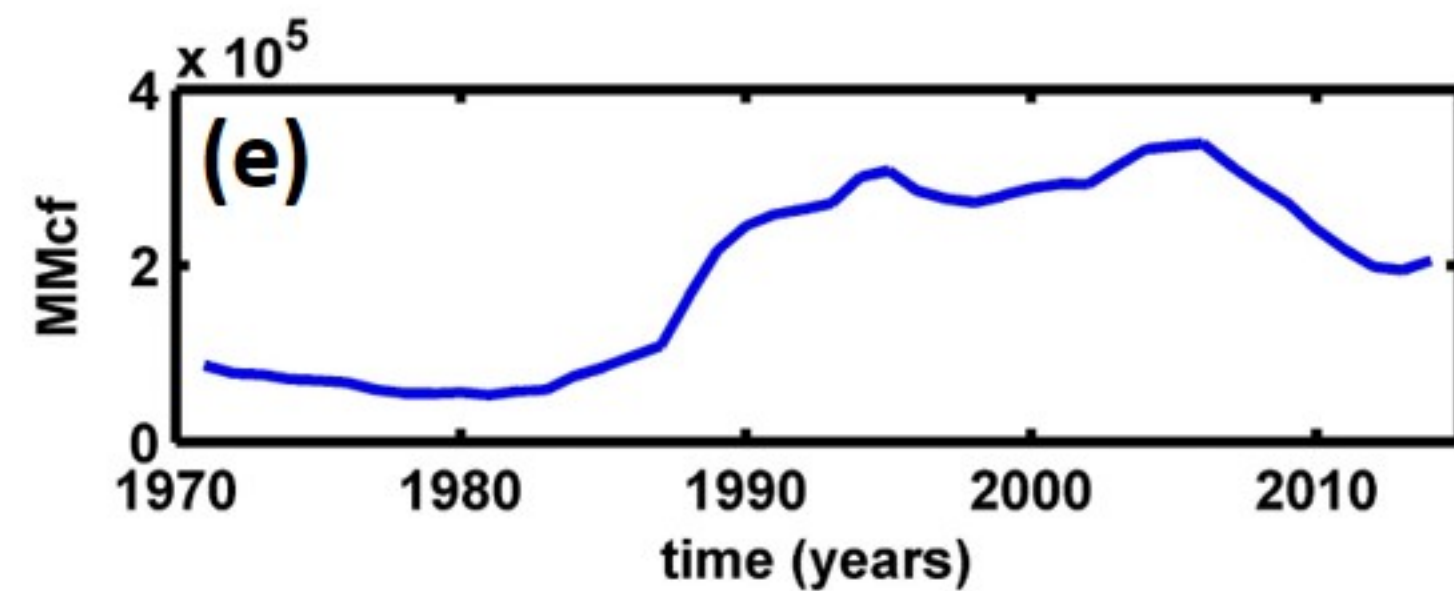
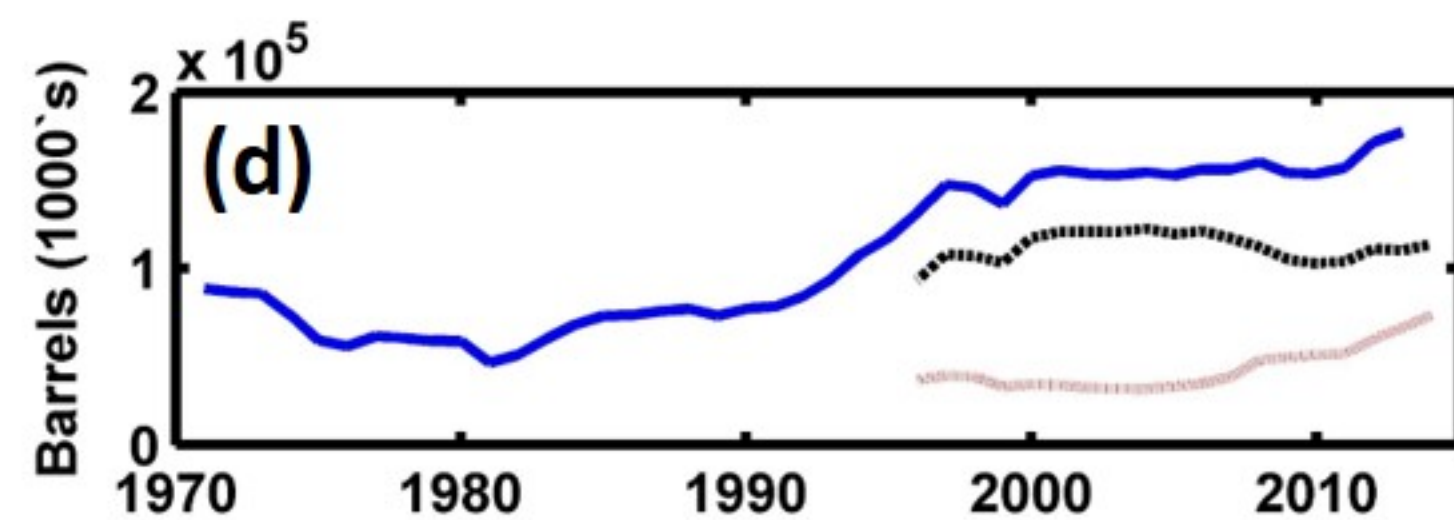
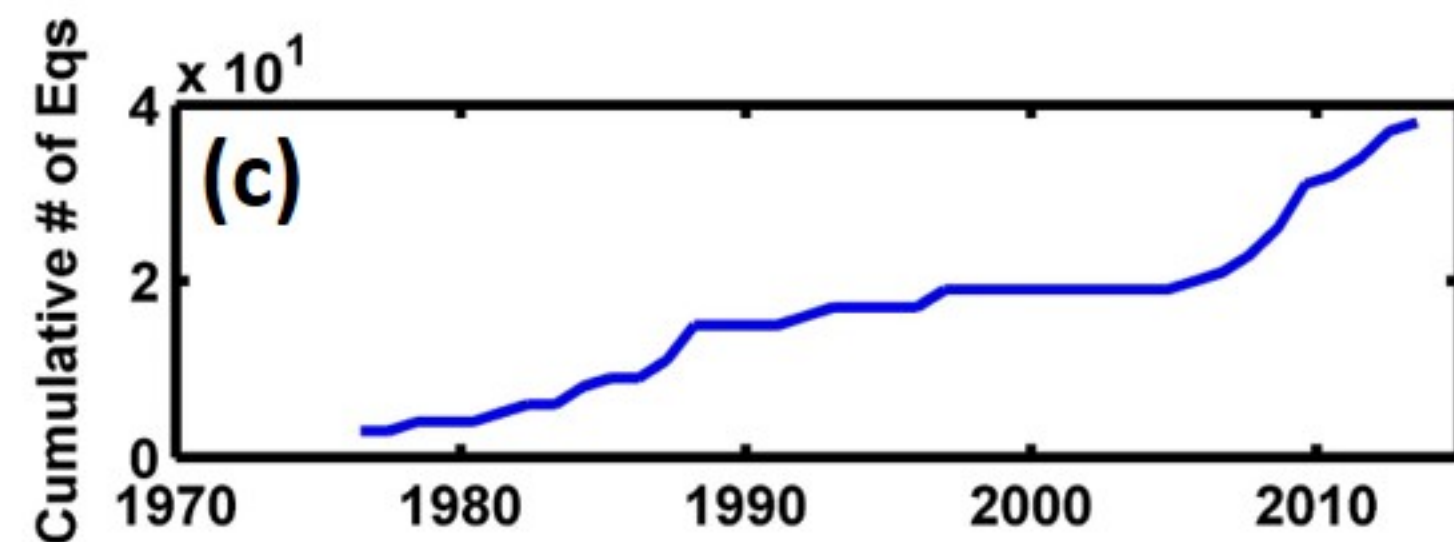
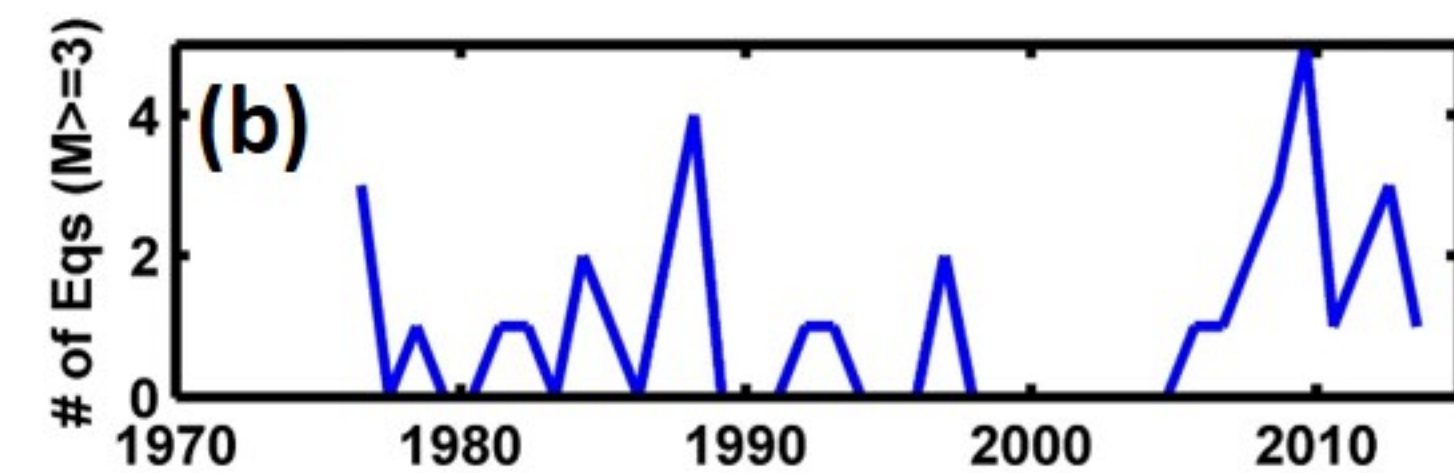
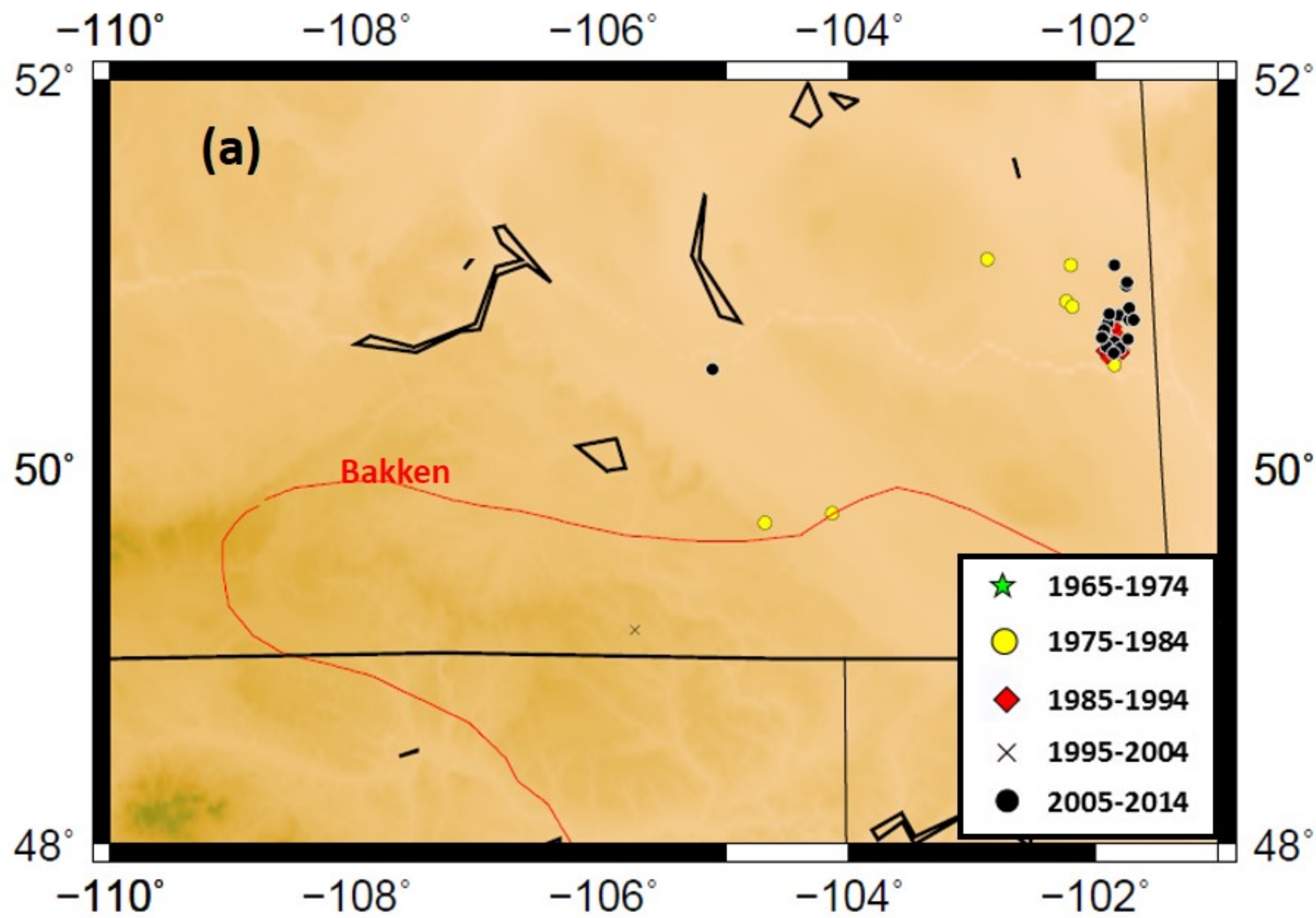


Figure 8.



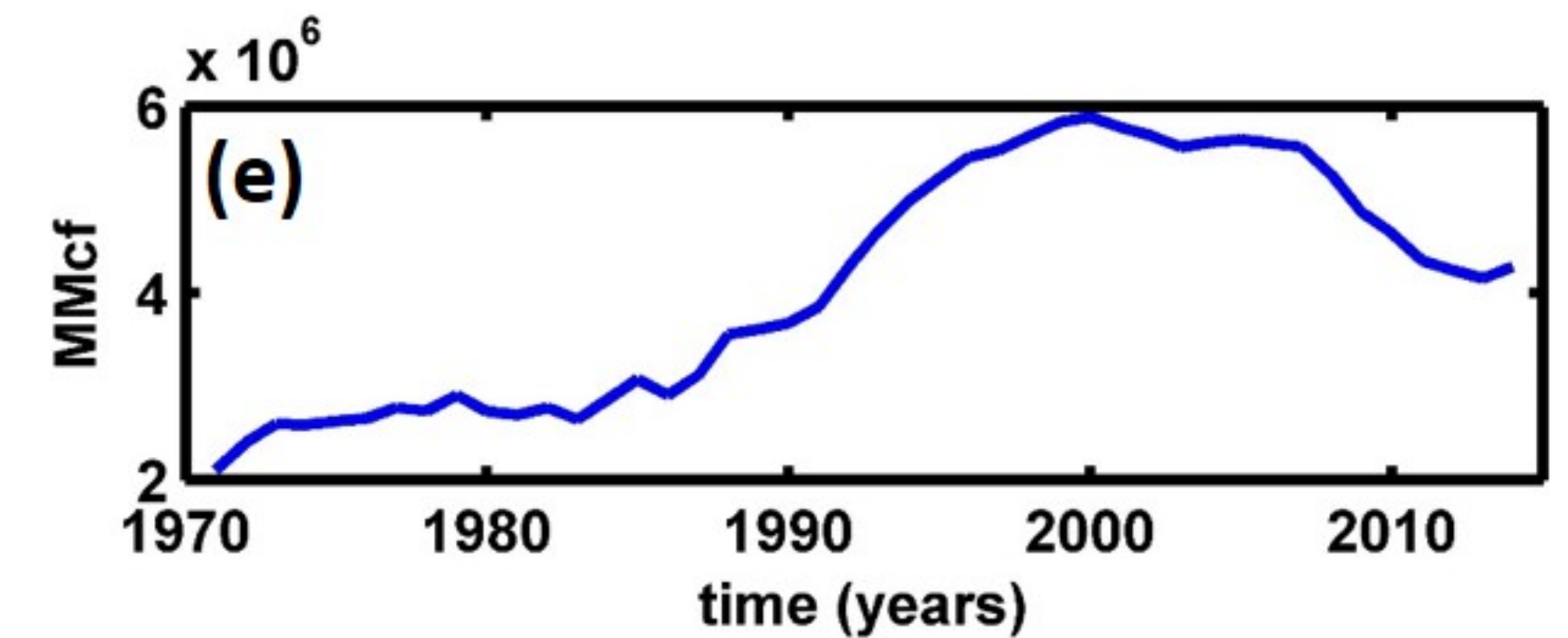
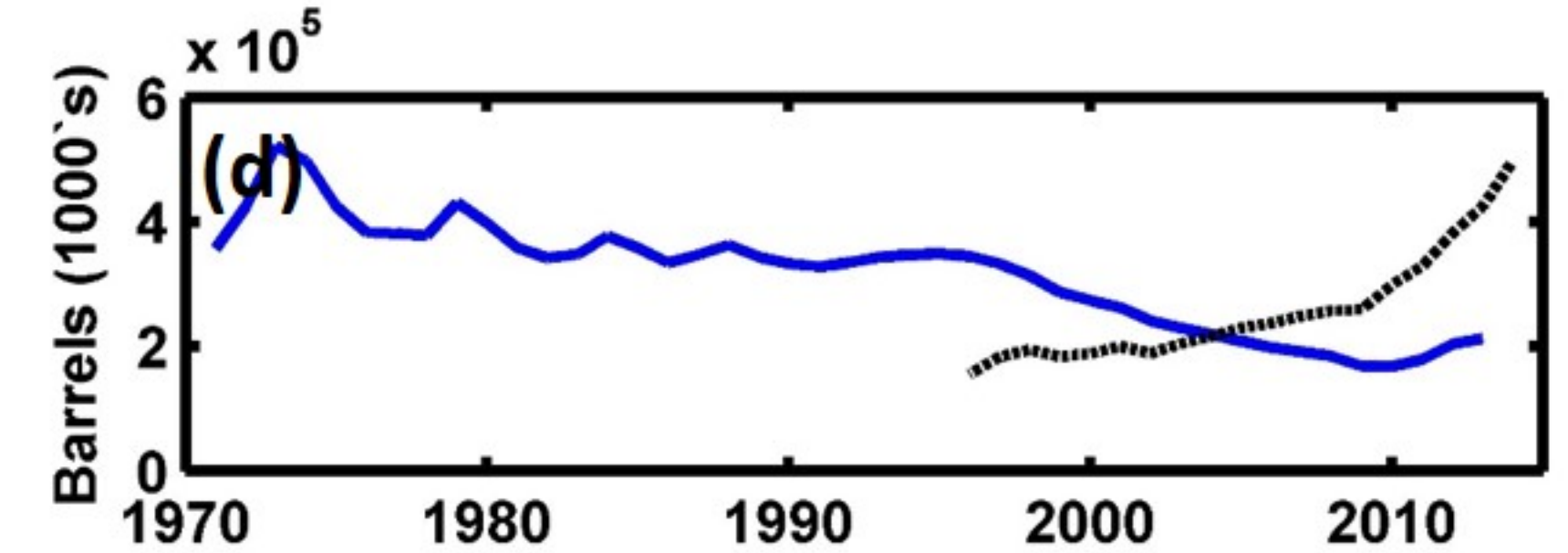
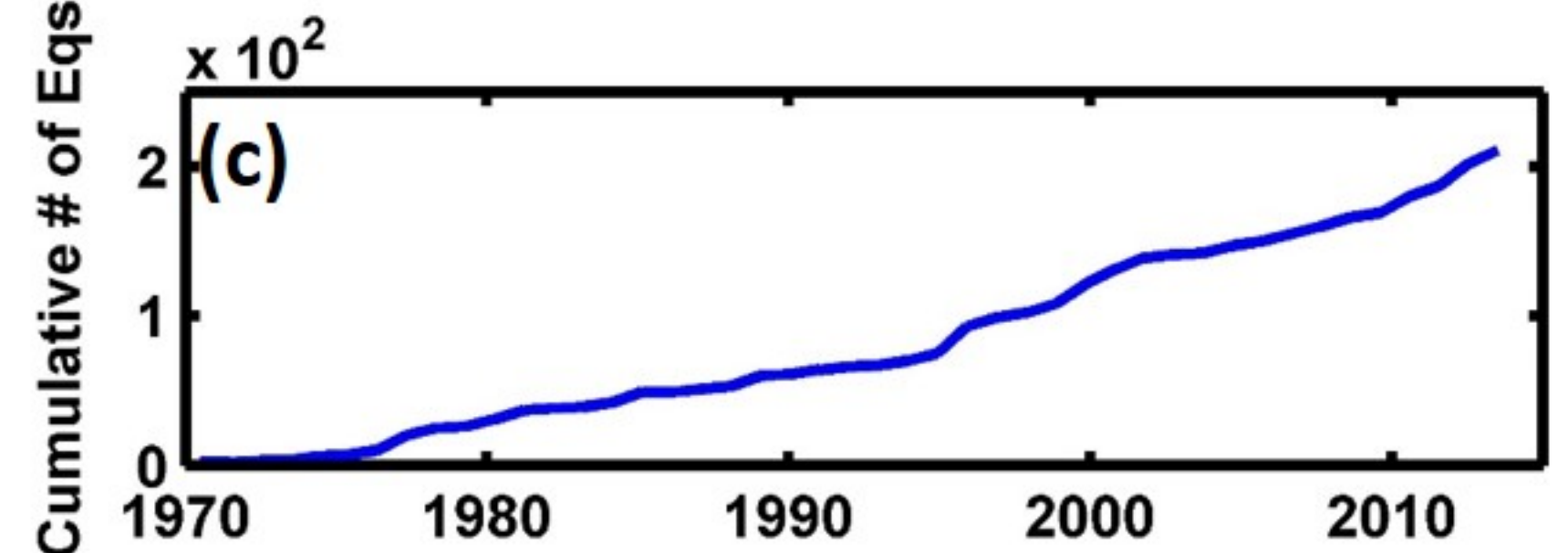
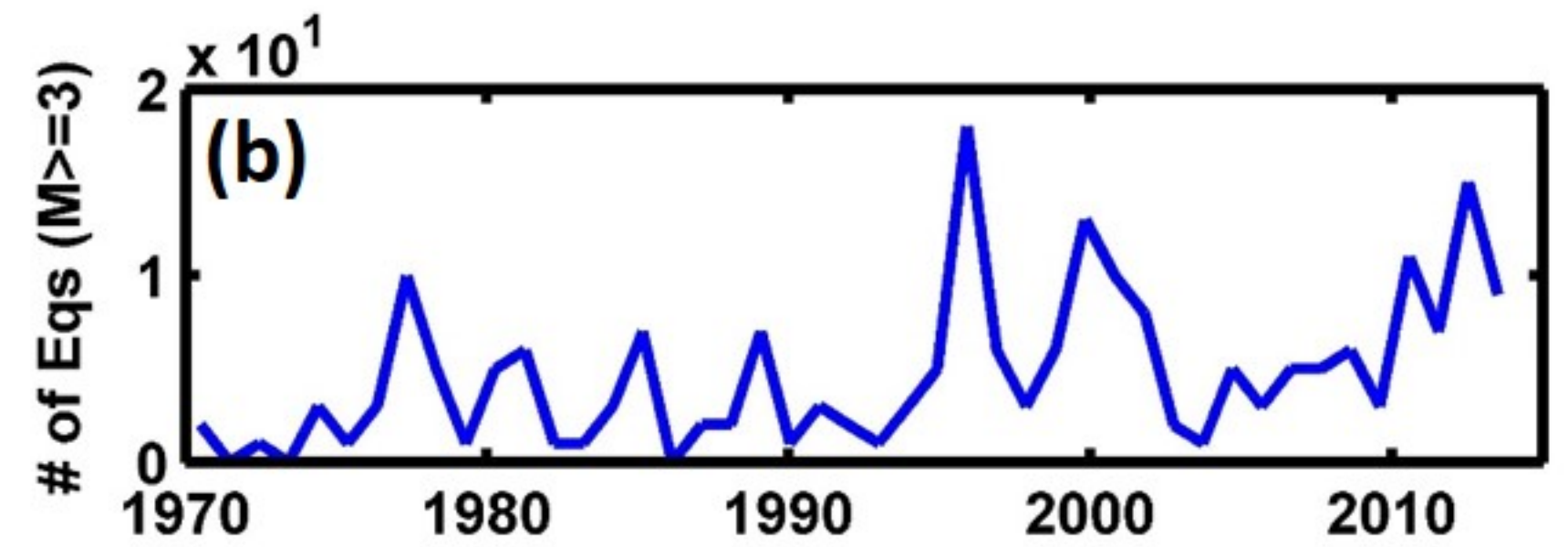
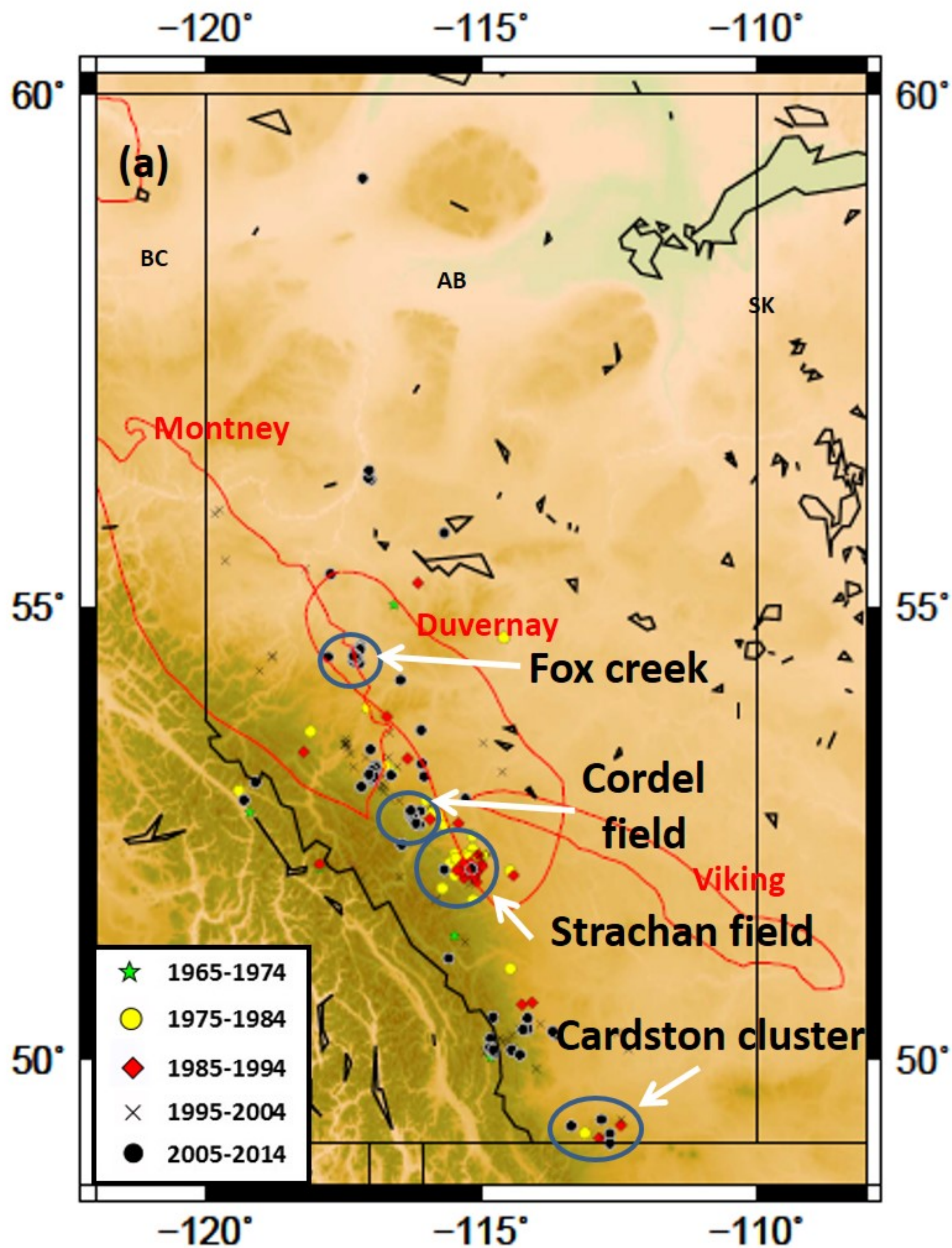




Figure 9.



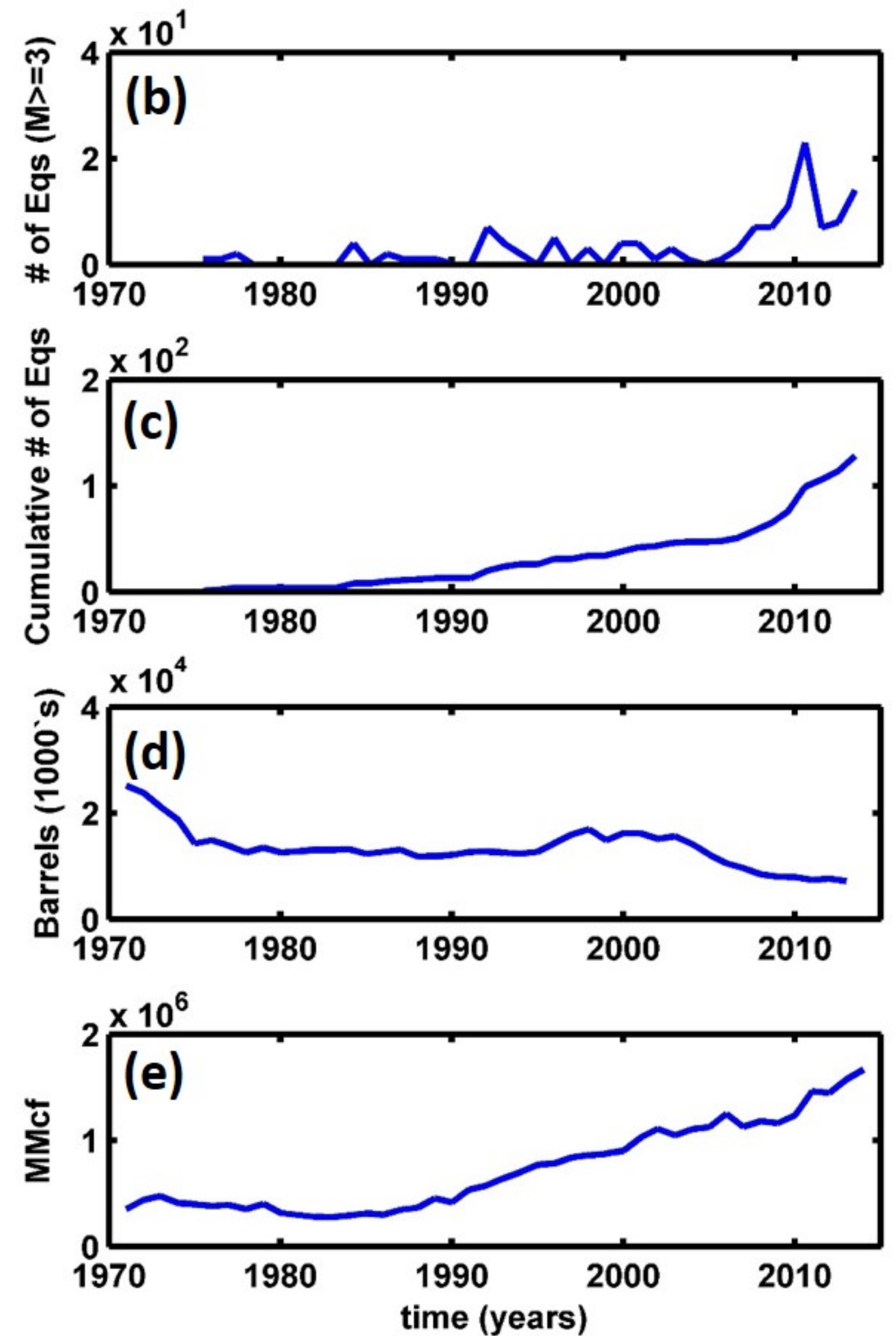
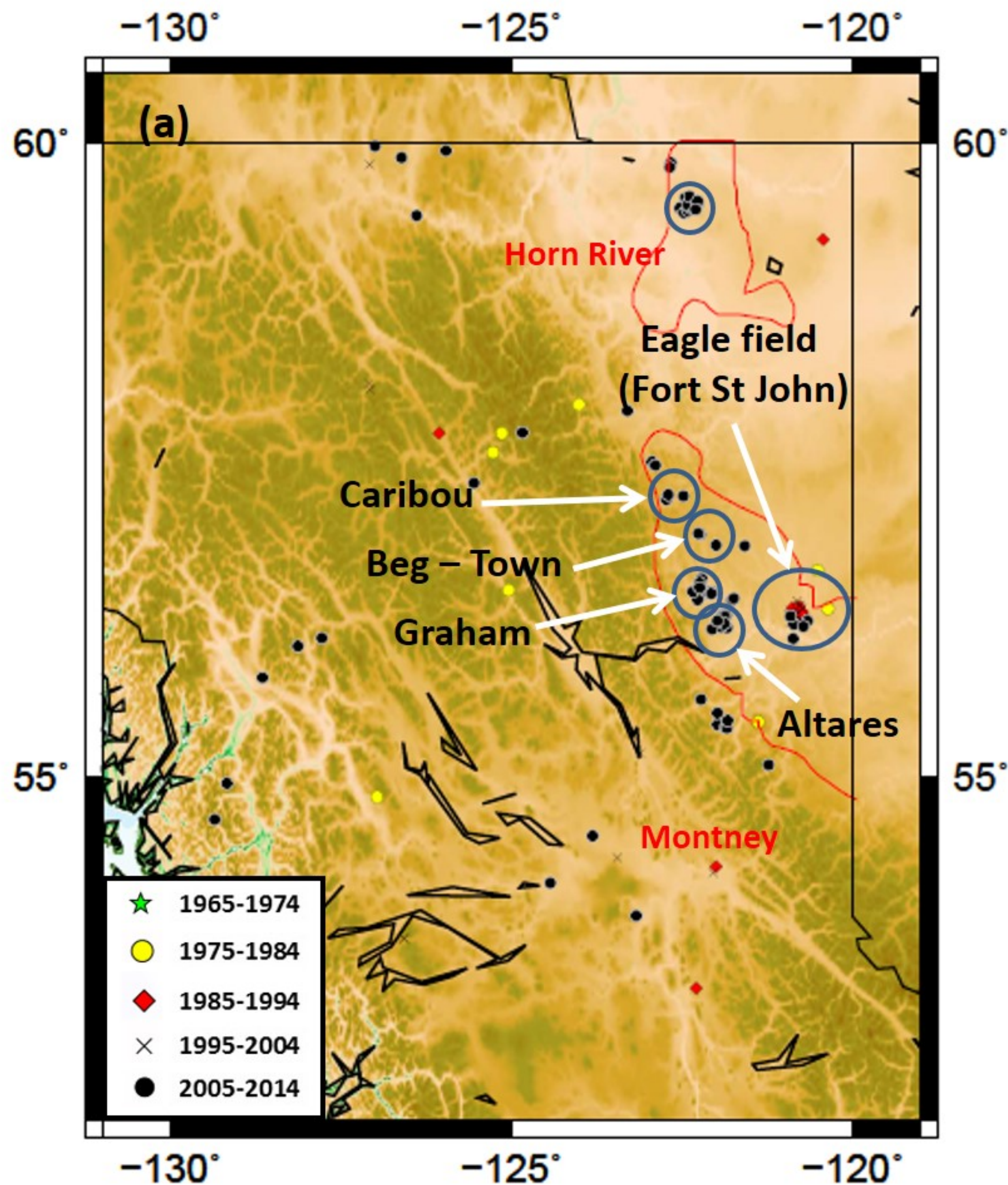




Figure 10.

# Oklahoma: Oil production, salt-water disposal and seismicity

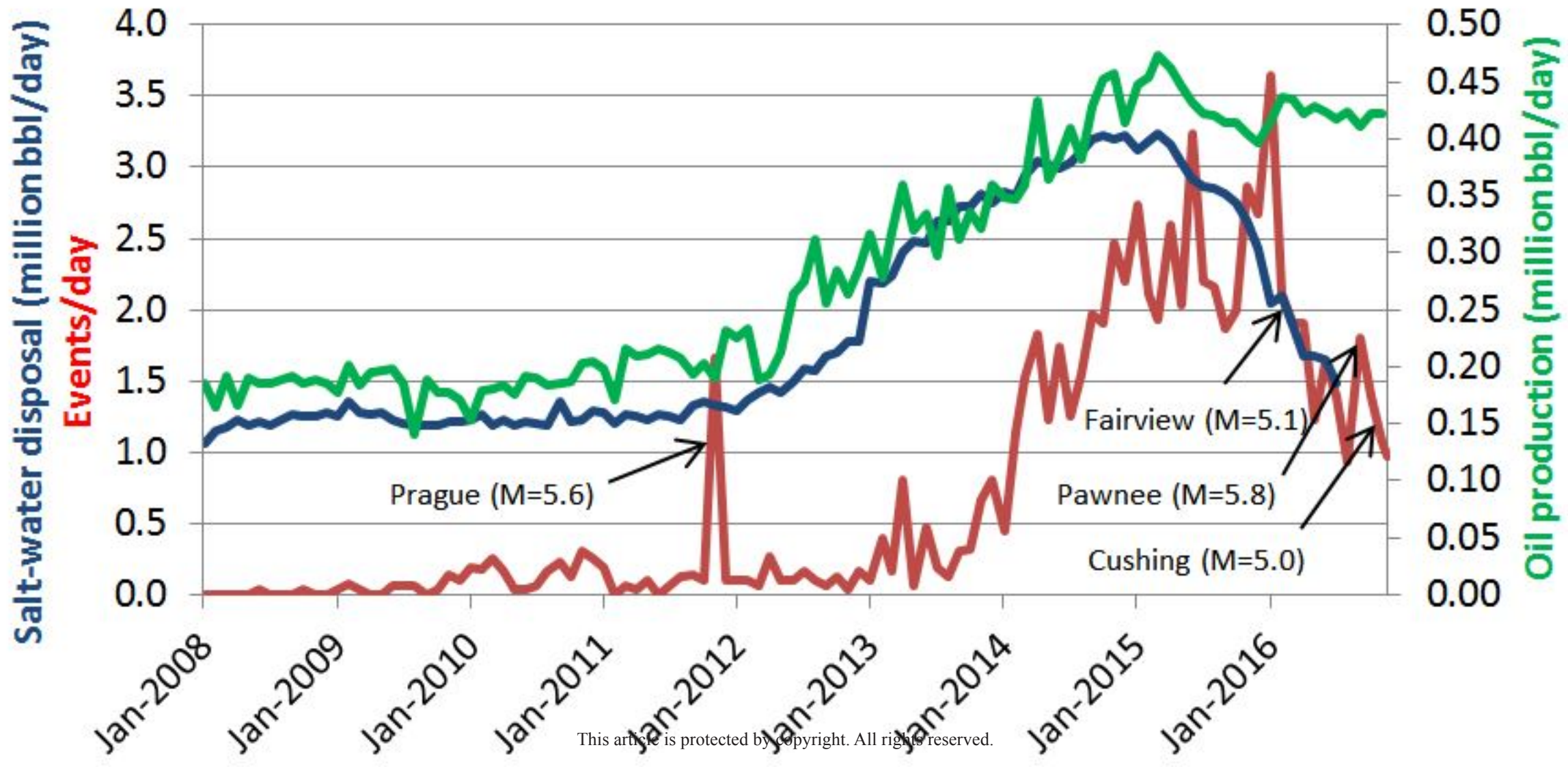


Figure 11.



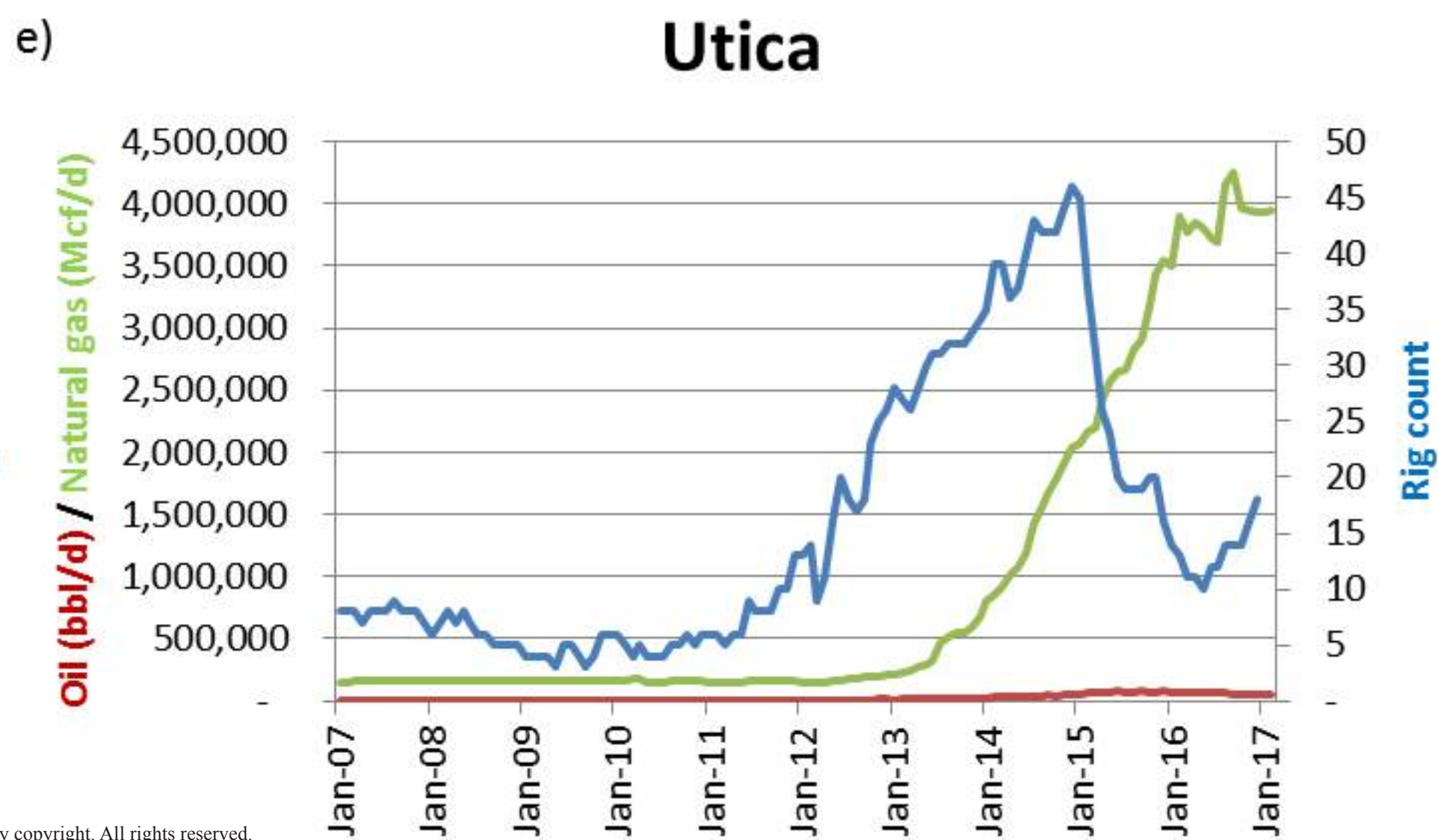
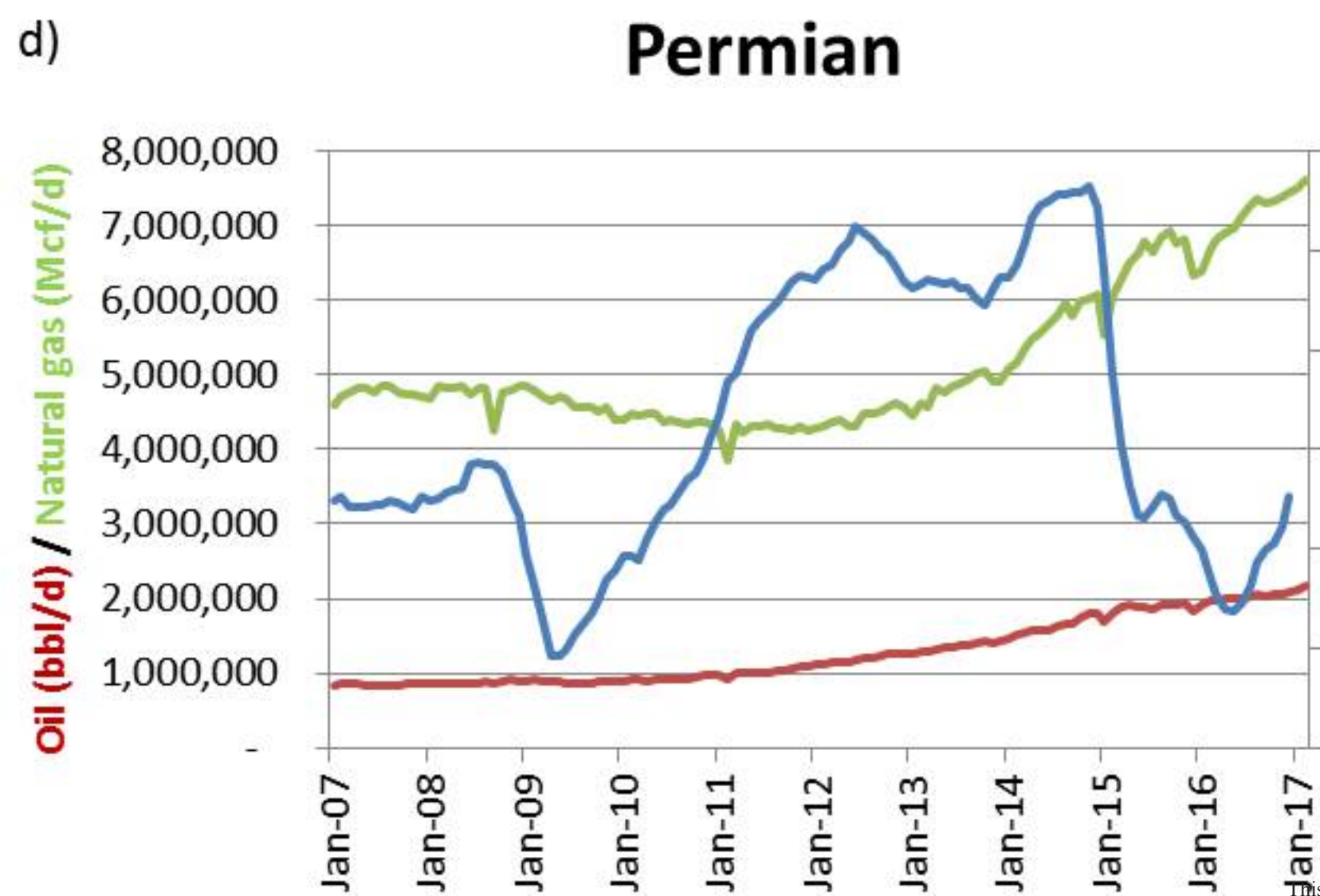
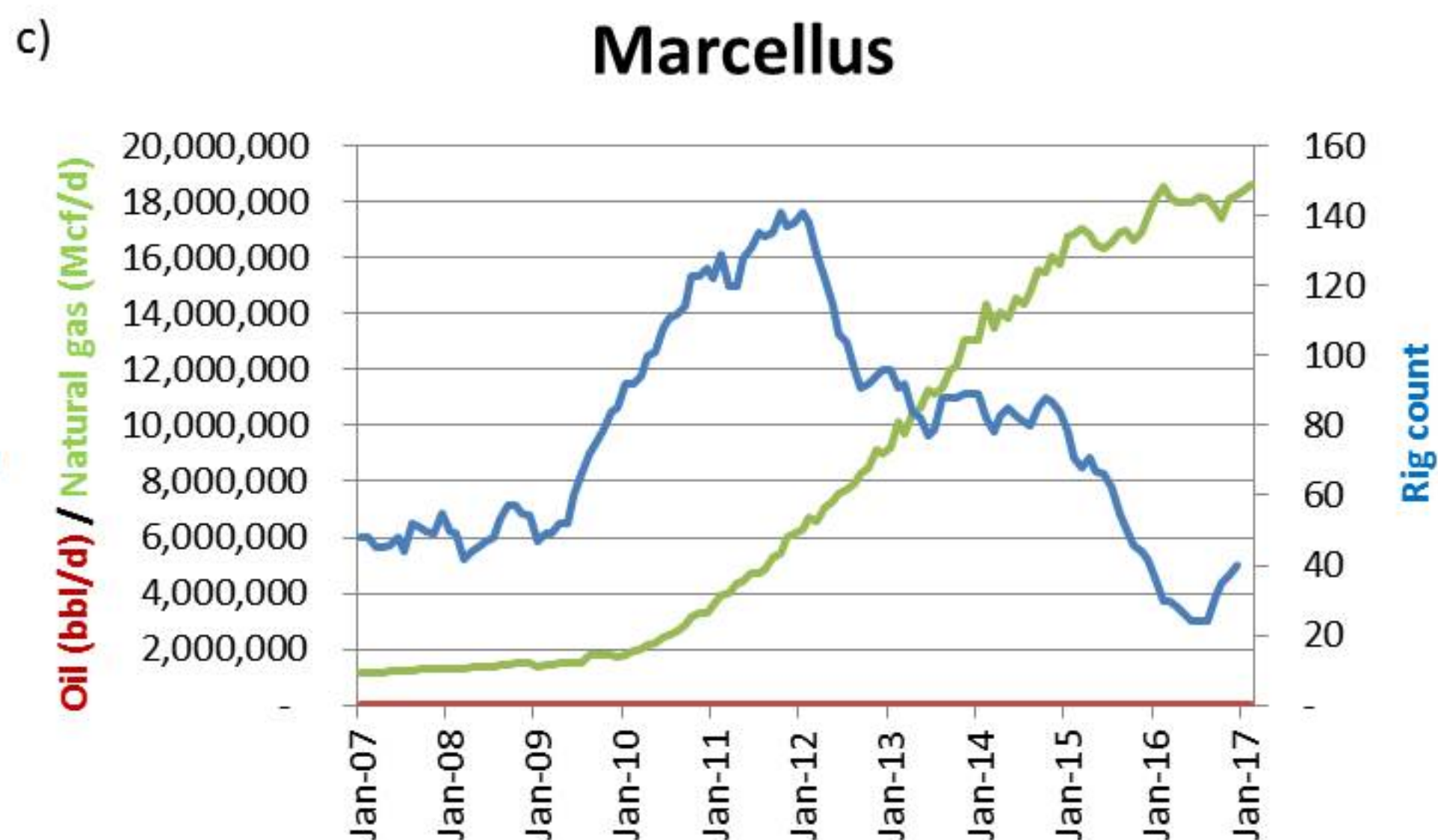
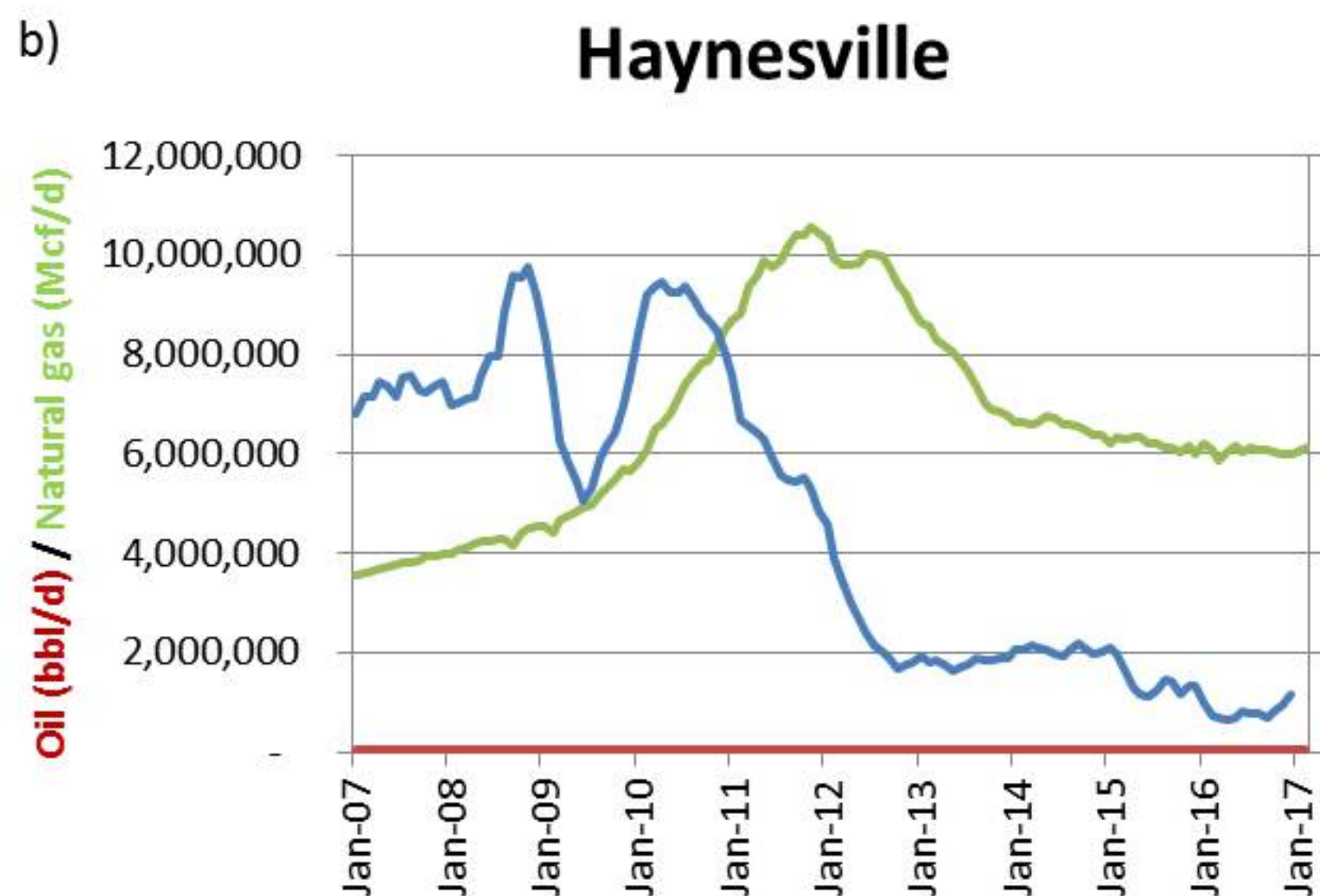
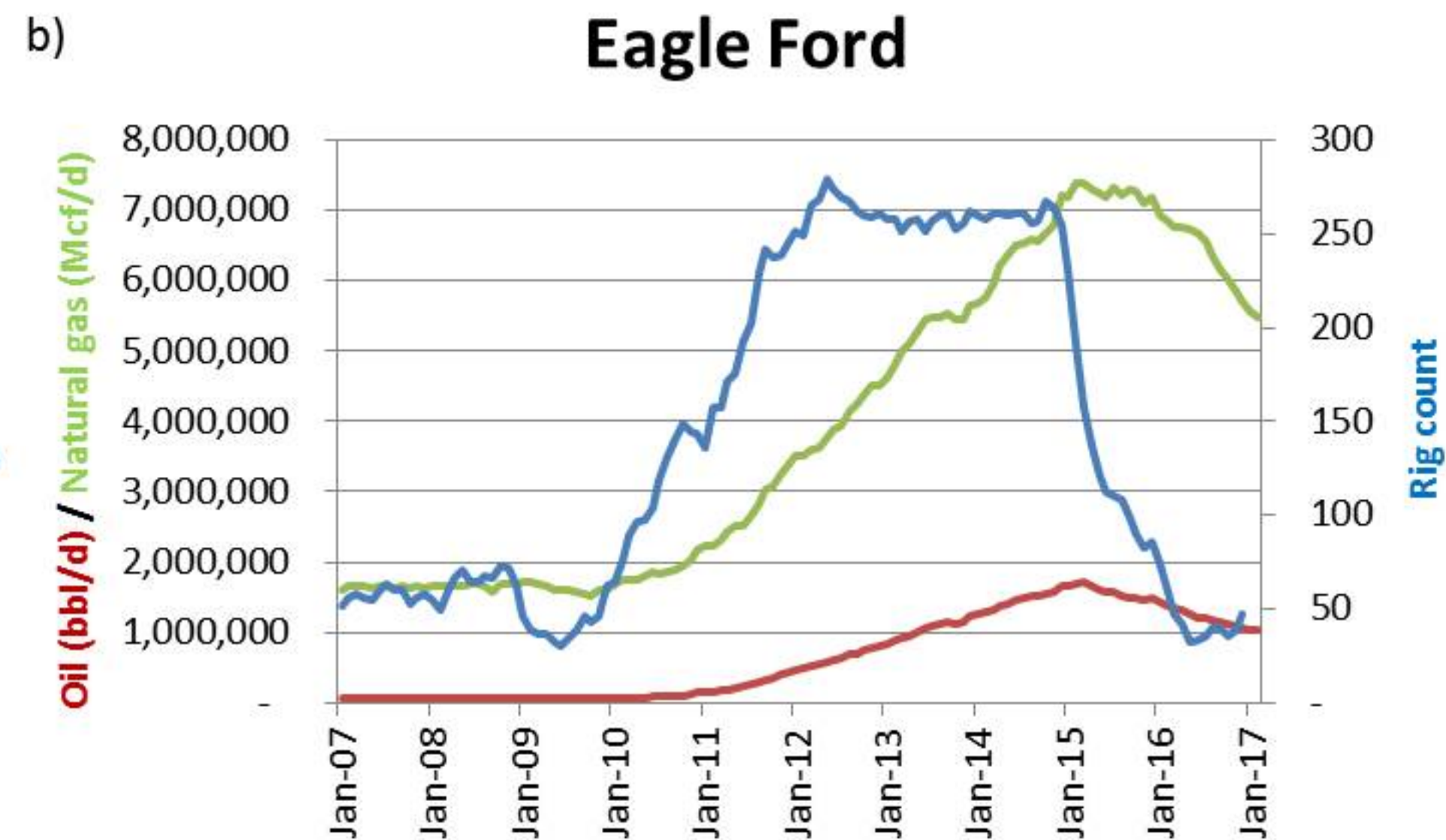
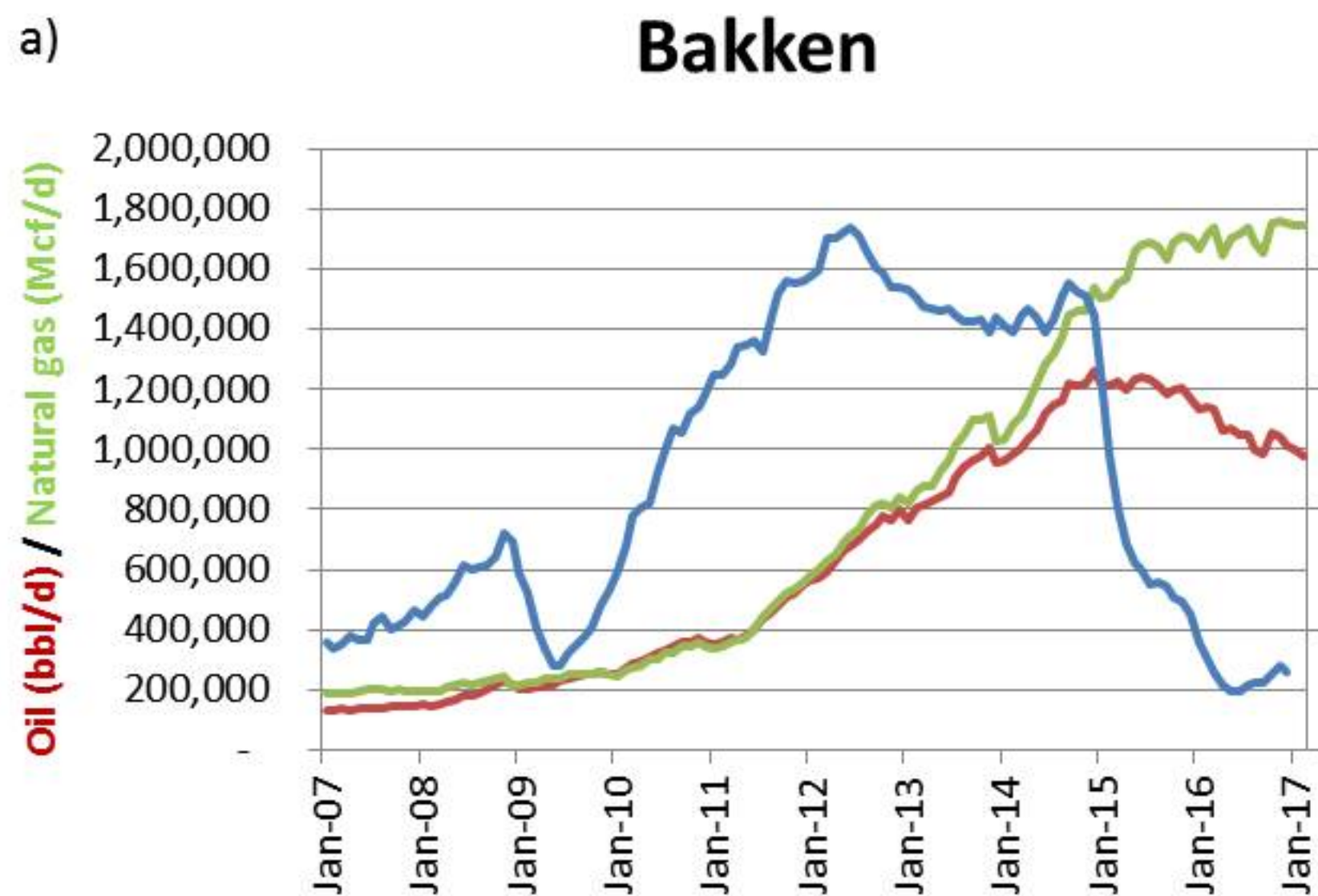
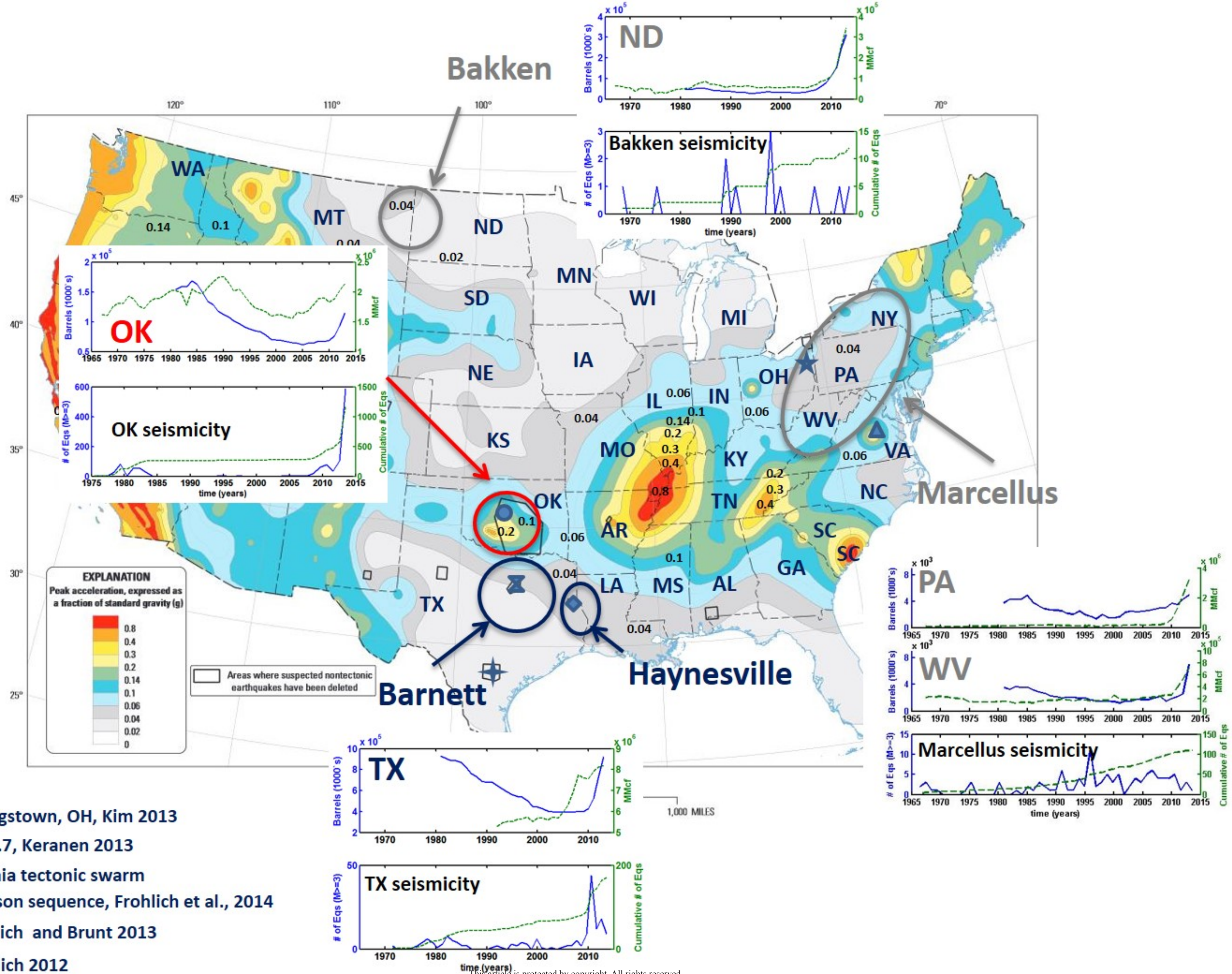




Figure 12.

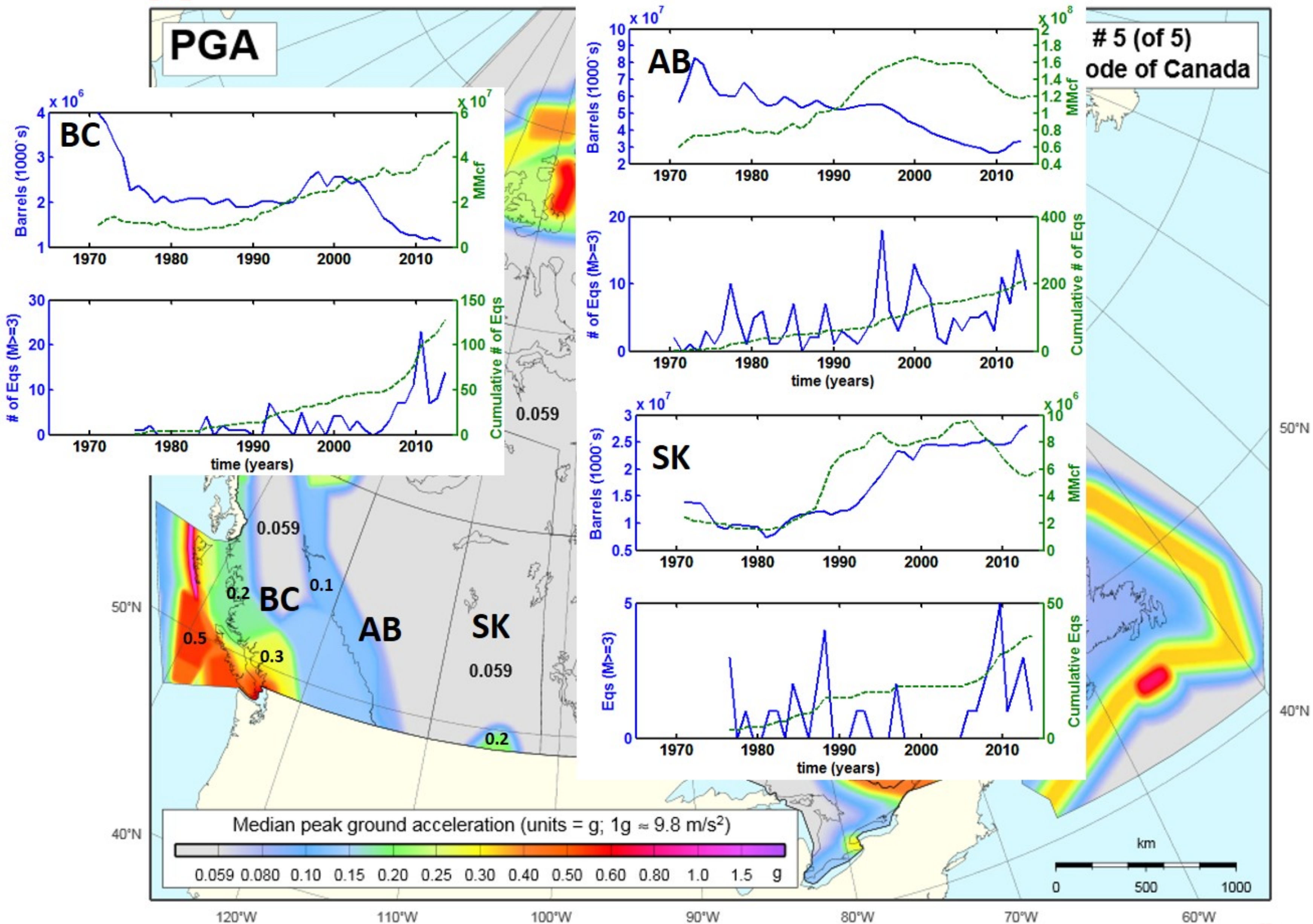






**Figure 13.**

Accepted Article



Peak ground acceleration at a probability of 2%/50 years for firm ground conditions (NBCC soil class C).