How did hydraulic-fracturing operations in the Horn River Basin change seismicity patterns in northeastern British Columbia, Canada?

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Abstract

An increase in regional seismicity has been documented for the Horn River Basin (HRB) since the development of shale gas began in late 2006. Operational parameters of all hydraulic-fracturing (HF) treatments in the HRB between November 2006 and December 2011 were compiled from completion reports collected by the British Columbia Oil and Gas Commission (BCOGC). This database was compared with regional earthquake catalogs to delineate a quantitative relationship between the observed variation of regional seismicity and local HF operations. Taking the HRB as a whole, results suggest that the total injected volume from hydraulic fracturing is a more significant factor in affecting the pattern of local seismicity than injection pressure is. However, no clear change in background seismicity can be observed when the total monthly injected volume is less than ~20,000 m3. The initial effect of increasing injected volume is an increase in earthquake frequency but not magnitude. Relatively large seismic-moment release (>10^14 N m) occurred only when the monthly injected volume exceeded ~150,000 m3. Variable time lags, from days to four months, are observed between intense HF and the occurrence of a significant local earthquake. The hydrologic properties of the source formations and local geologic conditions (such as distribution, geometry, and dimension of preexisting faults) also might play important roles in induced seismogenesis, in addition to the total volume of injection.

Introduction

Northeastern British Columbia, Canada, is one of the most productive regions of shale gas in the world. Major geologic structures with high shale–gas potential include the Horn River Basin, the Liard Basin, the Cordova Embayment, and the Montney Trend (Figure 1). Of those locations, large-scale shale–gas production first was developed in the HRB in 2006 (British Columbia Oil and Gas Commission Report, 2012).

The occurrence of induced seismicity in northeastern British Columbia has been well documented since the 1970s (e.g., Milne and Berry, 1976). The number and size of induced seismicity reached a new level in the 1980s when hydrocarbon production expanded significantly (Horner et al., 1994). Local earthquakes with magnitude (M,) as large as 4.3 were observed near Fort St. John in northeastern British Columbia and appeared to be associated with the large cumulative volume of hydrocarbon extraction as well as the practice of fluid injection for enhanced recovery (Horner et al., 1994). As the hydrocarbon production in the Fort St. John area declined in the late 1980s, the level of local seismicity gradually decreased accordingly.

In contrast, very few earthquakes were reported in the Horn River Basin before 2010 (Figure 2). A recent study of historical seismograms recorded at the Canadian National Seismograph Network (CNSN) station FNBB, at Fort Nelson, south of the HRB (Figure 1), suggested that the apparent lack of reported seismicity was probably an artifact resulting from sparse CNSN station distribution in the continental interior of British Columbia (Farahbod et al., 2015). An important conclusion of Farahbod et al. (2015) is that the level of local seismicity in the shale–gas production area clearly has increased, both in number of events and in magnitude, as the scale of HF operations expanded from late 2006 through 2011.

In this study, we attempt to describe a more quantitative relationship between the observed variation of regional seismicity in the HRB and local HF operations. Specifically, a database containing operational parameters of HF at each production site is compiled from completion reports submitted to the BCOGC. Taking the HRB as a whole, our analysis suggests that the increasing level of local seismicity appears to be related to the volume of fluid used in the HF treatments and not to the pressure. Our results also indicate that the initial effect of local HF operations was probably an artifact resulting from sparse CNSN station distribution in the continental interior of British Columbia (Farahbod et al., 2015).

Figure 1. Map showing the locations of major productive regions of shale gas in British Columbia, including the Horn River Basin, Liard Basin, Cordova Embayment, and Montney Trend. CNSN: Canadian National Seismograph Network. ATSN: Alberta Telemetered Seismograph Network. Black triangles mark the locations of new broadband seismograph stations established in the region after 2012.

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HF operations resulted in an increase in earthquake frequency. As HF operations continued to expand, not only the number of events but also the magnitude of induced seismicity increased.

**Earthquake data and operational parameters of hydraulic fracturing**

Our earthquake database consists of two major parts. The first comes from the earthquake catalog reported by Natural Resources Canada (NRCan), compiled from routine analysis of CNSN records. From 2002 through 2011, 44 local earthquakes have occurred in the Horn River Basin (shown by red crosses in Figure 2). The temporal distribution of these events is irregular, with only one event in 2004, four in 2009, and the remaining events observed after 2010 (Figure 2).

The second part of our earthquake data comes from the catalog compiled by Farahbod et al. (2015). This catalog shows 365 events that occurred within 100 km of seismonograph station FNBB (Figures 1 and 2). The catalog is based on a single-station relocation method and has the advantage of including smaller events that fell below the detection threshold of the CNSN catalog because of sparse station density in northeastern British Columbia. Because of the extensive labor required by the single-station relocation process, Farahbod et al. (2015) focus on a specific 12-month time period (July 2002 through July 2003; Figure 2) before November 2006 when shale-gas development started in the HRB. The magnitude of completeness for this catalog is 2.4 for the post-HF era.

We compiled a database summarizing the operation parameters of all HF treatments in the HRB from November 2006 through the end of 2011. Paper copies of completion reports that local HF operators were required to submit by BC OGC regulation were collected and examined. Information on some of the more recent HF operations was available in digital form. The database consists of the HF treatment location, start and end times, injection pressure, and injection rate. The injected fluid volume was calculated by multiplying the average injection rate by the duration of operation.

**Analysis and results**

For each month from November 2006 through December 2011, we calculated the average treating pressure and the total injected volume of all HF operations in the Horn River Basin (Figure 3). Local HF operators tried a variety of injection pressures during the early phases of shale-gas development in the HRB (2006–2008), ranging from ~ 44 MPa to as high as ~ 66 MPa (Figure 3a). However, during the peak production period (2010–2011), the treating pressure was kept mostly below 60 MPa, with a mean value of ~ 52 MPa (Figure 3a).

In contrast, the amount of fluid used in hydraulic fracturing increased dramatically from the initial period of development in the HRB to the time of peak production of shale gas (Figure 3b). Specifically, the total injected volume was on the order of $10^3$ to $10^4$ m$^3$ per month for most of the time before 2010, with the minimum and maximum values being 384 (one well, November 2006) and 115,445 (seven wells, March 2009), respectively. In 2010–2011, the monthly injected volume jumped by almost two orders to as high as 689,495 m$^3$ (21 wells, July 2010; Figure 3b). Only three months had a total injected volume less than 100,000 m$^3$ (May and December 2010, October 2011; Figure 3b).

For earthquake data, we estimated the scalar seismic moment of each event from its local magnitude ($M_L$). The $M_L$ value was converted to the moment magnitude ($M_W$) based on the empirical relationship determined by Kao et al. (2012) for earthquakes in the British Columbia interior. The seismic moment was calculated using the relationship defined in Hanks and Kanamori (1979).

In Figure 4, we show the monthly variation of total seismic moment released, i.e., the sum of scalar seismic moment of all events (Figure 4a) and the maximum magnitude, $M_L$ (Figure 4b), for the same time period of our database of HF operation parameters. Both the total seismic moment and the maximum magnitude of earthquakes in the Horn River Basin increased in
2010–2011, which is contemporaneous with the peak in shale-gas production. Given that no clear increase in moment release or maximum magnitude was found in late 2008 when injection pressure was highest (Figure 3a), the total injected volume appears to be a more significant factor in affecting seismicity than injection pressure is.

To better illustrate the relationship between injected volume and variation of local earthquakes, the monthly seismic-moment release and the corresponding maximum earthquake magnitude are compared with the monthly injected volume (Figure 5). For months with a total injected volume less than ~20,000 m$^3$, the monthly seismic-moment release was < $10^{13}$ N m (Figure 5a), and no earthquake was > M$_L$ 3 (Figure 5b). When the monthly injected volume increased to > ~20,000 m$^3$ but was < ~150,000 m$^3$, about half of the months had total seismic-moment release > $10^{13}$ N m. Notice, however, that the corresponding maximum earthquake magnitude appeared to remain below 2.6 except in one sample (Figure 5b).

These two observations suggest that the moderate increase of injected volume seems to cause more frequent events initially, resulting in a higher total seismic-moment release, but it does not necessarily result in individual large-magnitude events.

When the monthly injected volume exceeded ~150,000 m$^3$, the increase in seismic-moment release and the maximum magnitude is obvious (Figure 5). Only ~25% of those months had total seismic-moment release less than $10^{13}$ N m. Meanwhile, ~70% of them had local earthquakes with M$_L$ ≥ 2.7 (Figure 5b). In other words, both the earthquake frequency and maximum size of local earthquakes increased significantly for most cases once the total injected volume was above the level of ~150,000 m$^3$.

We derive a relationship between the cumulative total of seismic moment in the HRB and the injected volume (Figure 6). For the five-year study period (November 2006 through December 2011), the logarithm of cumulative seismic moment is approximately linear with respect to the logarithm of the total injected volume:

$$\log(Mo) = 0.5482 \log(V) + 11.6170,$$

where seismic moment (Mo) and volume (V) are in the units of newton meters (N m) and cubic meters, respectively. The observed relationship appears as a series of steps rather than a linear slope (Figure 6). The steps suggest that the seismic response of the geologic system in the HRB might lag behind injection. The deviation of all sample points from the best-fitting linear trend is ±0.3, which implies a limit in the time lag between injection and induced seismicity. This means that more and/or larger earthquakes eventually will occur if the total volume of injection continues to increase.

Finally, to confirm the robustness of our statistics, we have repeated the analysis using different time intervals, including biweekly, monthly, bimonthly, and seasonal. Although the detailed numbers are different, the overall trends shown in Figure 3 through Figure 6 remain unchanged. The monthly results appear to have the best balance between the number of samples and data resolution.

**Discussion**

In a recent study, McGarr (2014) compiled case histories of earthquake sequences induced by fluid injection at depth (including hydraulic fracturing, wastewater disposal, and development of enhanced geothermal systems) to study factors...
that control the maximum magnitude. Based on the theoretical relationship between seismic deformation (i.e., seismic-moment tensor) and the volume change of the injected rock formation, the study suggests that the maximum seismic moment is limited to the volume of injected fluid times the modulus of rigidity, if the Gutenberg-Richter magnitude is limited to the volume of injected fluid times the rock formation, the study suggests that the maximum seismic moment being related to larger injected volumes is observed in this study and in that sense is consistent with the observations of McGarr (2014).

It is important to point out that the reverse statement (i.e., a higher volume of injection is associated with more release of seismic moment) is not always true. In fact, our results show that 25% of the months with intense HF operations (monthly injected volume exceeding 150,000 m$^3$) had total seismic moment less than 10$^{13}$ N m (Figure 5a), which is comparable to the level of background seismicity during the pre-HF era. In other words, a higher volume of injected fluid is a necessary but not a sufficient condition to induce larger earthquakes.

One possible explanation to the wide scattering of seismic moment (over a range of 2.5 orders; Figure 5) during months of intense hydraulic fracturing is the local geologic condition surrounding each HF site. The chance of inducing an earthquake becomes much higher if a preexisting fault system is located near the injection and its stress state has been affected significantly by the increase in pore pressure. In such a scenario, the geometry and dimension of the fault and/or its distance to the injection site might be the most important factors in determining the amount of seismic moment. Furthermore, if the fault is highly stressed, the size of the induced event might increase. More research into the geologic background of known induced earthquakes is needed to establish a comprehensive model for induced seismogenesis.

The importance of a possible time effect on the occurrence pattern of induced seismicity also should be considered. In the HRB, the seismic response to HF injection clearly showed variable time lags. Examining the data after January 2008, when sustained HF operations were carried out, suggests that it can take from days to as much as four months for the geologic system to respond with significant seismic events as predicted by the moment-volume relationship (Figure 6). Based on the HRB data set, it is unclear what factors and physical mechanisms control the time lag. Given that seismogenesis is related directly to the fluctuation of pore pressure at the source, we speculate that the hydrologic properties of the rock matrix, which ultimately control the diffusion process of underground fluids, might play an important role in controlling the number and size of events of induced seismicity.

### Conclusion

An increase in regional seismicity has been documented for the Horn River Basin since the development of shale gas began in late 2006. We compiled operational parameters of all hydraulic-fracturing treatments in the HRB between November 2006 and December 2011 from completion reports collected by the British Columbia Oil and Gas Commission. This database was compared with regional earthquake catalogs to delineate a quantitative relationship between the observed variation of regional seismicity and local HF operations. Results suggest that the total injected volume from hydraulic fracturing is a more significant factor in affecting the pattern of local seismicity than injection pressure is. However, no clear change in background seismicity can be observed when the total monthly injected volume is less than ~20,000 m$^3$. Relatively large seismic-moment release occurred only when the monthly injected volume exceeded ~150,000 m$^3$. Variable time lags are observed between intense HF and the occurrence of a significant local earthquake. The hydrologic properties of the source formations and local geologic conditions also might play important roles in induced seismogenesis, in addition to the total volume of injection.

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**Figure 6.** Relationship between the cumulative seismic moment ($M_o$) and cumulative injected volume ($V$) of hydraulic fracturing in the Horn River Basin since December 2006. Sample interval is one month. The observed relationship appears as a series of steps, suggesting that the seismic response of the geologic system might lag behind injection. The generally increasing trend can best be fitted by a line as log($M_o$) = 0.5482 log(V) + 11.6170. The range of data scattering is ±0.3 logarithm unit, as shown by the upper and lower dashed lines.
References


