Chapter 6

Understanding Hydraulic Fracture Growth, Effectiveness, and Safety Through Microseismic Monitoring

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1. Introduction

Microseismic monitoring has become a valuable tool for optimizing stimulations, completions, and overall field development, particularly in unconventional reservoirs. This technology was initially rooted in geothermal energy [1,2], but subsequently was used for many years in research projects to understand fracturing in unconventional reservoirs, such as in the Multiwell Experiment [3,4], the M-Site fracture diagnostics laboratory [5-8], the Carthage Cotton Valley fracturing test [9,10], and for other processes, such as drill cuttings injection [11]. It finally reached a level of sophistication and reliability to function as a service technology in the early 21st century [12,13], and many thousands of hydraulic fractures have been monitored since that time. In addition to providing a "window" into the subsurface for fracture optimization and control, the large amount of microseismic data that has been gathered provides a significant database that can be used for environmental surety.

Microseismicity occurs because of geomechanical changes to the reservoir as a result of the fracturing process [14,15], and detection and location of these "events" provides a methodology to monitor fracture growth patterns and overall dimensions. One of the curious features of microseismic technology is that no one has ever seen the slippage plane of a microseism that was induced by a hydraulic fracture. As a result, the understanding of microseismicity has been through a down-scaling of earthquake seismology [16], examination of fracture behaviour in minebacks [17,18], comparisons with rock bursts and laboratory acoustic emissions [19,20], and geomechanics considerations of the way in which hydraulic fractures perturb a reservoir [21].

Nevertheless, there have been several validation experiments where other measurement technologies have been used to verify the accuracy and interpretation of microseismicity, and these have been very helpful in promoting an understanding of the process of microseismic activation during a fracturing treatment. The most comprehensive of these tests was the M-Site test funded by GRI and DOE; it was developed as a fracture diagnostics laboratory in the Piceance basin of Colorado [5-8]. Intersection wells, downhole tiltmeters, tracers, pressure interference, and other technologies were used to show the accuracy of determining the fracture azimuth, length, and height by these methods in typical sandstone reservoir rocks. In these tests, it became clear that microseismicity does not necessarily occur on the hydraulic fracture, but can develop along planes of weakness at an offset distance that depends on both the formation and the treatment.

While there have been no published tests about fracturing in shale reservoirs that provide the full detail available from M-Site, the project described by Fisher et al. [12] in the Barnett shale has many of the same elements as M-Site. Both downhole and surface tiltmeters were used to supplement the microseismic data, and numerous offset producing wells were used to monitor the movement of fracturing fluid during the treatment. Wells that were "bashed" (i.e., loaded up with fracturing fluids) provided direct evidence of actual fluid presence at that location that could be compared to the microseismicity. This comprehensive test verified the actual formation of a "network" in this reservoir.

With a reasonable level of accuracy and interpretability established by validation tests, such as those described, microseismicity can be used for field development, completion design, stimulation optimization, and addressing environmental concerns. The last aspect, with respect to aquifers and seismicity, is very important for current unconventional reservoir development throughout the world.

2. Microseismic applications

There are many case studies in the literature that illustrate how microseismicity can be used to aid in the exploitation of unconventional reservoirs. One very evident one was provided by Mayerhofer et al. [22] for a two-well, multi-stage, multi-perforation-clusters completion in the Marcellus. Figure 1 shows a plan view and side view of the microseismic data color coded by the well being stimulated. In these views, there is enough information to decide if the well trajectory is correct (assuming transverse fractures are desired), if the number of stages is sufficient to access all of the reservoir, if the number and spacing of perf clusters is giving the desired behaviour, if the treatment fluids, rates, and volumes are generating appropriate lengths without causing excessive height growth, and many other more subtle aspects of completion. This example shows the type of information that one should expect to obtain in such a monitoring project.

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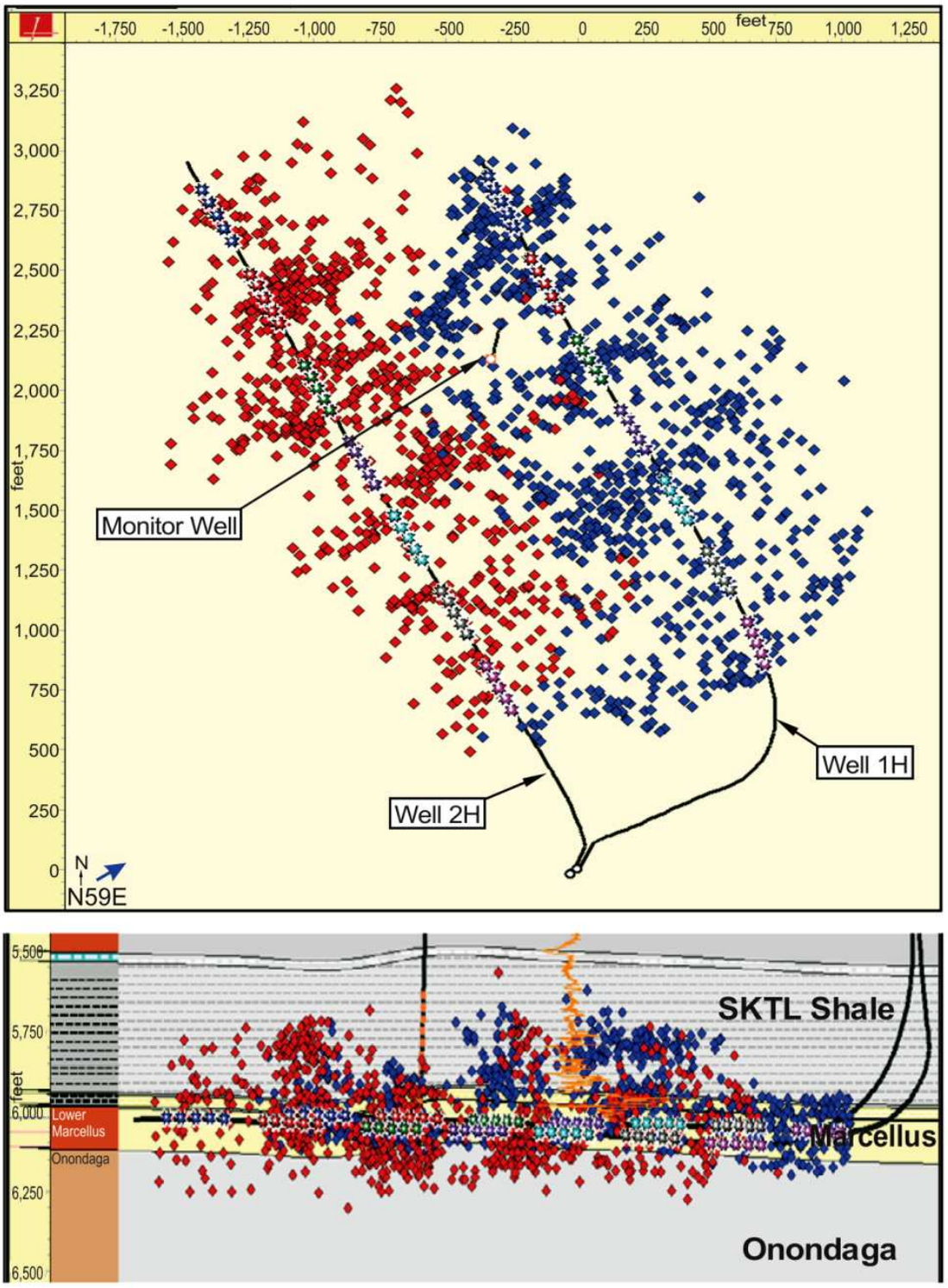

Figure 1. Example Marcellus microseismic maps for two adjacent wells.

While most interest about microseismicity tends to be focused within final dimensions of the fracture, the growth patterns often provide valuable information for designing fracture treatments. Many treatments show extremely rapid initial growth in either height or length,

followed by a highly reduced late-time development. Figure 2 shows an example of length development as a function of time, with each side of the y axis representing one wing of a planar fracture. The bounding dashed line is square-root-of-time behaviour, which is very common and would suggest high leakoff conditions, such as into natural fractures (e.g., [23]). The color coding represents tip-related events (green) and interior events (red). Generally, half or more of the microseismic events occur after the tip has passed the event location, again suggesting natural fracture interactions [15,21] as the source of much of the microseismicity.

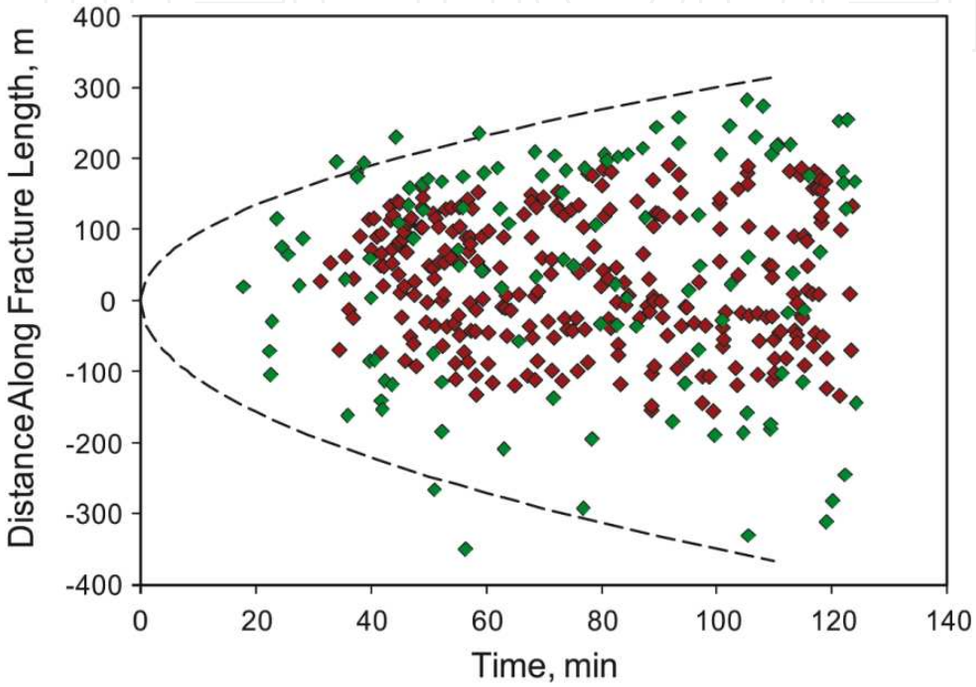

Figure 2. Fracture length development versus time and conditions.

3. Beyond dots, or beyond verification

It is well-understood that microseismicity is a scaled-down version of conventional seismicity and tools from earthquake seismology should be applicable in some sense for evaluating microseismic behaviour [16]. Certainly, the fault plane solutions that can be derived from a moment tensor inversion provide some information about the planes that are activated during fracturing. Unfortunately, there is no validation that such information can be taken much beyond a resolution of the fault planes, nor is it necessarily clear how the fault planes are being activated (stress effects, leakoff, actual tip extension processes, etc.).

To suggest that any change in behaviour of the source mechanism, such as a difference between pure shear and a large volumetric component, is somehow diagnostic of fracture behaviour is pure hypothesization without any supporting field, lab, or theoretical results. This type of theorizing is useless, and possibly deleterious, without validation because it could lead to

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actions that jeopardize the treatment. The remote likelihood that source mechanisms can be used to evaluate the hydraulic fracture behaviour (other than dimensions from the event locations) can be easily understood in terms of both energy and volumetric considerations. The total microseismic energy released (or at least what can be detected with current instrumentation) is typically on the order of one millionth or less of both the energy input into the treatment and the strain energy that would be calculated for the fracture based on microseismic dimensions and measured pressures [21]. Similarly, the volumes associated with the sum total of the microseismic displacements are generally on the order of a few liters or less compared to hundreds or thousands of cubic meters of fluid injected. This small volume cannot be representative of SRV or other fracture parameters.

Figure 3 shows a plot of the total seismic energy associated with microseismicity in a fracture as a function of the largest event and the "b" value. The b value is the negative slope of the Gutenberg-Richter frequency distribution for earthquakes in a region over some time period. For earthquakes, it is usually near 1.0. For microseisms associated with hydraulic fracturing, it is quite variable and often between 1.0 and 2.0. Given a b value, maximum magnitude event, and low end cutoff (in this case magnitude -4), the energy released can be found by integrating the energy as a function of magnitude over the distribution. For the overwhelming majority of treatments, the maximum magnitude is less than 0 (and often much less than 0), so the typical energy released is on the order of hundreds of kilojoules or less. Fracture injections in shale stimulations usually imparts hundreds of millions kilojoules of energy.

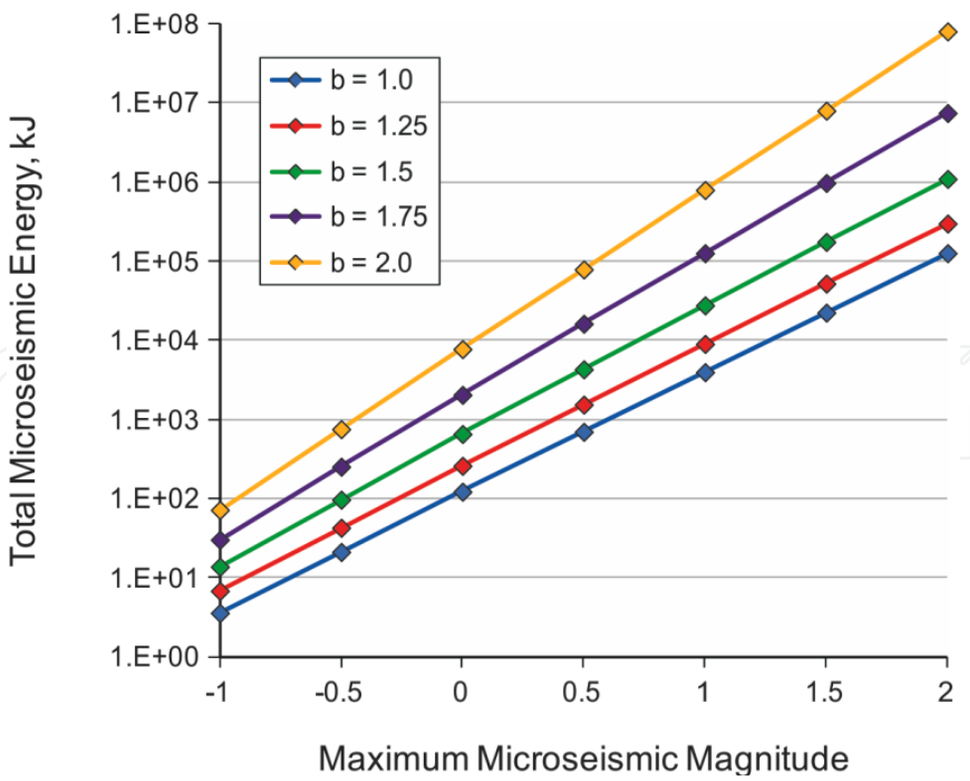

Figure 3. Seismic energy released as a function of magnitude and b value.

The actual source mechanism is a result of the geomechanical processes that occur during fracturing. There is a large perturbation in the stresses around a fracture and a bigger perturbation in pore pressure as the high pressure fracturing fluid leaks off into the reservoir through the pore space or into natural fractures. These changes alter the existing in situ conditions and impact the behaviour of any slippage or opening that might occur around the fracture. Geomechanical calculations can be useful to understanding these perturbations, and they can also provide improved understanding of the microseismic distribution by assessing the stress and failure conditions around the fracture [21, 25].

The linkage of geomechanics and source mechanisms should be helpful to understanding the reservoir and how it is impacted by the stimulation. The slippage planes that are activated should have higher permeability and could provide clues about the reservoir itself (e.g., natural fractures) and optimum methods to enhance permeability in the reservoir.

4. Environmental aspects

Proving the safety of hydraulic fracturing is a welcome side benefit of microseismic surveys. One of the issues fostered by fracturing opponents is that large shale treatments could contaminate aquifers by fracturing into near-surface water supplies. There is, first of all, a very large base of literature that demonstrates that fracture height growth is severely limited by geologic conditions; [26] provides a brief review of some of the pertinent literature. Factors such as stress changes and material property variations across layers, interface characteristics associated with the horizontal bedding, and higher-permeability layers that allow high levels of fluid leakoff are all commonly present in sedimentary basins where oil and gas are being exploited. These features cause fractures to propagate much farther laterally than vertically. There are also theoretical considerations that clearly demonstrate that fracturing volumes are smaller by an order of magnitude or more than the volumes that would be required to propagate fractures the multi-kilometer distances to approach the surface.

With the microseismic monitoring database that has been obtained throughout the last decade, there is now a large amount of information available that shows clearly that fracturing does not propagate the enormous distances required to cause contamination. Figure 4 provides an example of fracture height data from all monitored fractures in six major North American shale basins sorted by depth [26]. This plot shows thousands of fracture stages ordered by depth of the perforations. The fracture tops, as indicated by the shallowest microseism detected on each tests, are shown in red, while the fracture bottoms are green. While fractures occasionally exhibit significant vertical growth (both upward and downward), the distances are small compared to the distance required to approach typical water wells. The formations included in this data set are the Barnett, Marcellus, Woodford, EagleFord, Haynesville, and Muskwa/Evie.

It is also important to note that many of the "spikes" in the data of Figure 4 are attributed to fault interactions. There are many faults, some well below seismic detection, that can influence the behaviour of the fracture. As can be seen, many of these faults result in downward growth,

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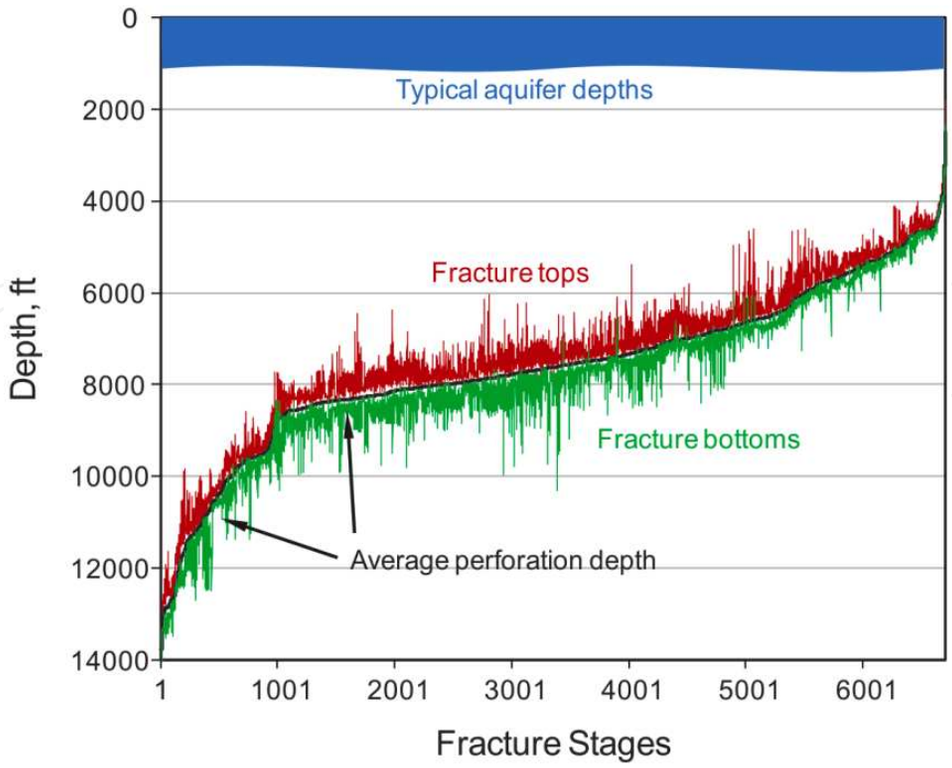

Figure 4. Hydraulic fracture height growth in shale basins of North America.

others result in upward growth, while others can veer in a different horizontal direction. These faults are easily detectable in the microseismic data because the magnitudes of the events are much larger than the magnitudes of normal reservoir events. Figure 4 shows that faults have only a limited effect on height growth. The behaviour of a hydraulic fracture when it intersects a fault is not an unanswered question. There could be some additional height growth, though all measurements show that it is limited.

Microseismic data, which is essentially the monitoring of micro-earthquakes, also provides information to show the extremely small likelihood of damaging seismic activity [27]. Figure 5 shows the maximum microseismic magnitude for all fracture treatments in major North American basins up to mid-year 2011, where each point is the maximum magnitude microseism obtained in a fracture stage. The largest monitored microseism found in several thousand stages has not exceeded +1.0, which is about 1,000 times less energy than the threshold that can just be felt at the surface.

The question of fault interaction comes into play with induced seismicity as well as height growth. Again, the data show what happens when faults are intersected. Most seismicity induced by shale stimulations, although somewhat variable across formations, is in the magnitude range of -4 to -1. Larger events are the direct result of interaction with faults, some of which are seismic and were known to exist, and others were subseismic prior to being marked by microseismicity. The general increase in magnitude that occurs as a result of fault interaction is usually one to two. The Bowland shale and Horn River basin experience suggest

that greater increases are possible, but they must be exceedingly rare given the common experience, as shown in Figure 5.

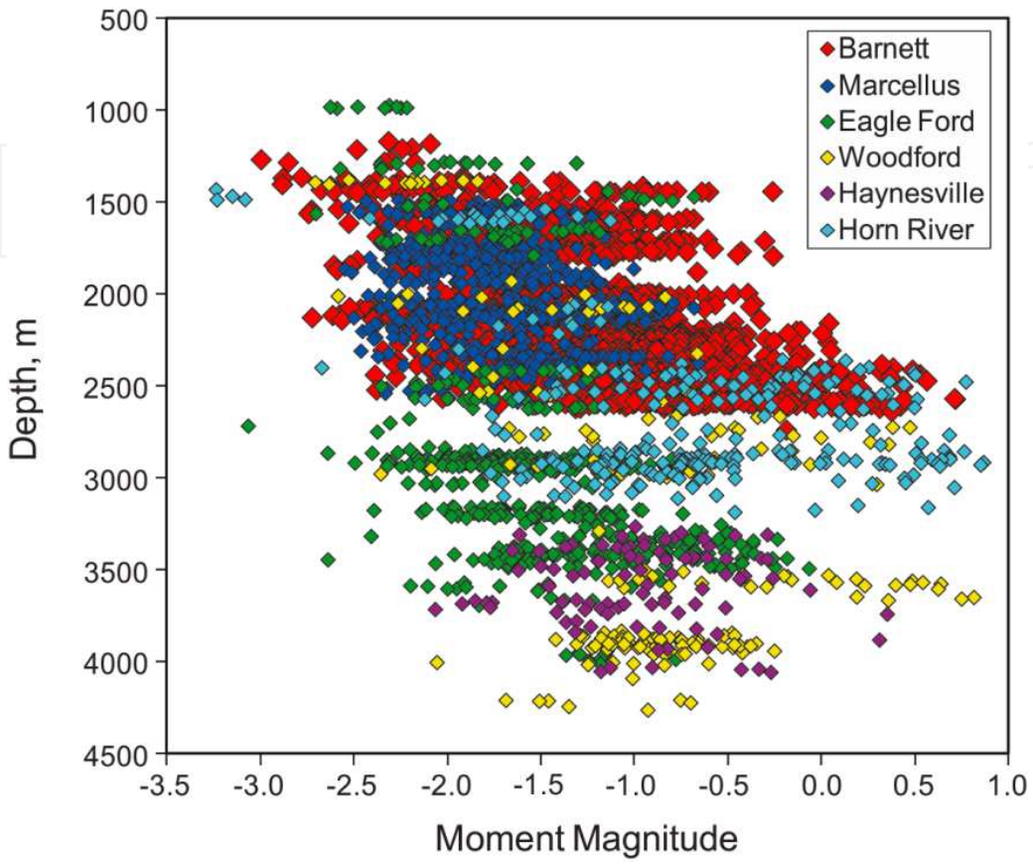

Figure 5. Microseismic magnitudes associated with fracturing in North American shale basins.

Although these results show that induced seismicity is not likely to be a problem in hydraulic fracturing, there likely will be rare cases (e.g., Bowland shale, Horn River basin) where the fracturing interacts with a major fault system that is critically stressed. In such a case, it could be possible to experience seismicity that is significant enough to be felt at the surface.

It is always useful to investigate how the seismicity might be mitigated so that development work can continue. Figure 6 addresses the issue of whether rate and volume adjustments might reduce the strength of the seismicity. These results show that the magnitudes generated by hydraulic fracturing, whether fault induced or not, is not generally a function of either rate or volume, for the range considered by this data. Data from three US basins are plotted and it can be seen that there is no definitive trend, except at very low rates and volumes. When considering the volumes necessary for effective fracturing of shale resources, the ability to influence the seismicity is very limited.

It should be noted that the maximum that occurs in each plot is most likely because most of the treatments are conducted at those particular rates and volumes. The likelihood of experiencing larger-than-normal events is predicated on the likelihood of intersecting a fault. Because

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most treatments are conducted within a fairly limited range, it stands to reason that the largest events will generally be found when treating under those conditions.

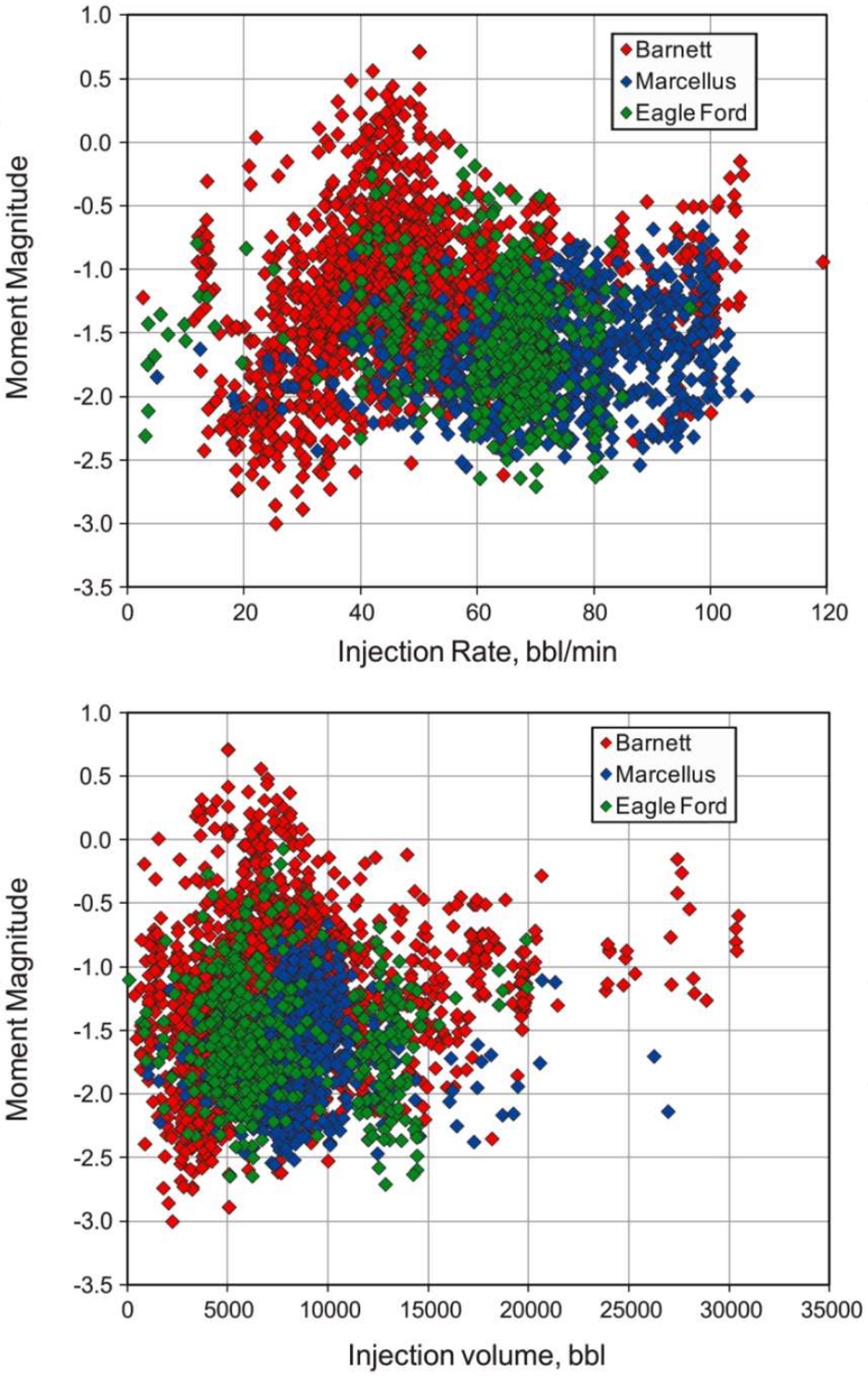

Figure 6. Effect of rate and volume on induced seismicity in three shale basins.

5. Summary

Microseismic monitoring is a very useful tool for optimizing fracture treatments, evaluating completion schemes, and assessing well layouts and spacing in unconventional reservoirs. The microseismicity is induced by the reservoir changes resulting from the hydraulic fracturing process. The dimensions and orientation of the fracture can usually be deduced from the microseismic distribution, and it is often possible to determine other features of the fracturing process, such as complexity, asymmetry, and interaction with geohazards.

It is important to understand the geomechanical process that occurs during fracturing to best interpret the microseismic distribution and to fully understand the value of any source analyses, such as moment tensor inversion. The perturbations imparted to the reservoir during fracturing are usually very large and can result in unexpected behaviour, if ignored.

Microseismicity monitoring has provided a very large data base from which environmental impacts of fracturing can be assessed. With thousands of fractures monitored, there is clear evidence that fractures do not extend the thousands of feet vertically to the shallow depths of typical aquifers. Fractures are generally much longer than they are tall as a result of the rock mechanic barriers that result from sedimentary structures.

Microseismicity monitoring has also provided evidence that hydraulic fractures are not likely to generate felt earthquakes in anything other than the rarest circumstances. Most of the seismic activity induced by a hydraulic fracture has energy levels that are 1,000 to 1,000,000 times smaller than events that would be felt at the surface, and even much farther below those that might cause damage.

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