Comments on the Scientific Basis, or Lack Thereof, for Hydraulic Fracturing Fault Respect Distances

Dr. James P. Verdon

School of Earth Sciences,

University of Bristol

Report Commissioned by the Oil and Gas Authority

July 2018

Summary

- Several recent studies have proposed the application of a "horizontal respect distance" to be maintained between hydraulic fracturing (HF) sites and known faults. In this report we assess the scientific evidence underpinning these arguments.
- Wilson et al. (2018) use a statistical analysis of collated microseismic datasets as proxy evidence for fault reactivation distances. However, their interpretation of the data is flawed, because many of the datasets show evidence for fault reactivation, and/or inter-well fracture interference. In such cases, the relevant distance is not the largest extent of microseismicity, but the initial distance at which a hydraulic fracture first begins to reactivate a fault (or interfere with another well). Their failure to recognise this distinction means that Wilson et al.'s analysis produces a systematic overestimate of respect distances, and so cannot be used as the basis for regulation.
- Westwood et al. (2017) build generic geomechanical models to simulate the distance of influence of hydraulic fractures. These models are simple in nature, and fail to account for important physical processes that occur during HF. Moreover, the models are not ground-truthed or benchmarked in any way. As such, there is no way of assessing whether the models are producing a reasonable representation of reality, and so they do not provide a robust basis for regulation. Moreover, Westwood et al. fail to investigate the sensitivities of their model to many key parameters, which could have a major impact on their model results. If anything, these sensitivities demonstrate the impracticability of applying a single universal respect distance to a wide area that has variable *in situ* geomechanical properties and may be subjected to varying injection and stimulation programs.
- Styles et al. (2018a,b) argue for a respect distance of 850 m, but do not provide any scientific basis for this value. Our understanding is that this value is based on work performed at Keele University that was shown to be incorrect due to errors in the setup of the modelling code. This value should not be given further consideration.
- All of the above studies refer to the Poland Township induced seismicity sequence (Skoumal et al., 2015), where events occurred up to 850 m away from the well. However, these interpretations of the Poland Township sequence again confuse the distance required for fault reactivation, with the distance events can occur once a fault has been reactivated. A simple re-interpretation of the results presented by Skoumal et al. (2015) indicates that the re-activated fault probably passed directly through or very close to the stimulated wells. While events were then able to propagate out 850 m along the fault, the actual fault reactivation distance is much smaller.
- The flaws in the above studies means that there is no robust scientific basis on which to define or regulate a fault respect distance. Our view is that this is not an effective approach to regulate the induced seismicity issue. The existing regulatory approach applied in the UK requires operators to identify nearby faults, and to develop site-specific models of the expected vertical and lateral extent of their hydraulic fractures. This requirement, combined with real-time seismic monitoring that allows operators to mitigate any seismicity that does occur, is a more appropriate approach.

Introduction

The issue of seismicity induced by hydraulic fracturing (HF) continues to have an impact on the nascent U.K. shale gas industry. At present, regulations pertaining to induced seismicity are enforced by the Oil and Gas Authority (OGA) via the submission by operators of a Hydraulic Fracturing Plan (HFP). In an HFP, an operator is expected to take steps to mitigate the possibility of induced seismicity (OGA, 2017). This includes the following:

- Characterise the geomechanical conditions at the site, including *in situ* stresses and material properties.
- Identify any nearby faults using prior geological information and reflection seismic surveys, and assess the *in situ* stresses acting on these faults.
- Provide information about past seismicity (natural and/or induced) in the area.
- Model the expected HF growth distances.
- Assess the potential impact of induced seismicity via a seismic hazard assessment.
- Implement a Traffic Light Scheme (TLS) to mitigate seismicity in real time during operations. At present, the amber and red levels are set at magnitudes M_L = 0.0 and M_L = 0.5 respectively.

In addition to these existing regulations, there have been calls for the OGA to apply a "Horizontal Respect Distance", a minimum lateral distance that must be maintained between HF locations (i.e. the position in the subsurface of the well perforations through which the HF fluids enter the shale formation) and any known faults (e.g., Figure 1).

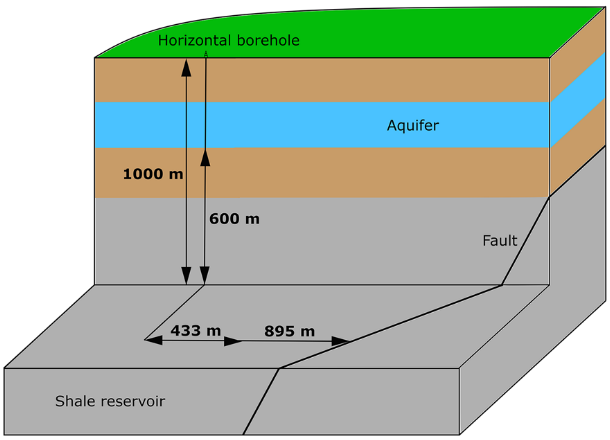

Figure 1: Schematic diagram illustrating proposed hydraulic fracture respect distances (from Wilson et al., 2018). The infrastructure act mandates that hydraulic fracturing can only take place below 1000 m depth, while Davies et al. (2012) suggests a vertical separation of at least 600 m between hydraulic fracturing and sensitive aquifers. Wilson et al. (2018) propose a lateral respect distance between hydraulic fracturing and faults of 895 m, while Westwood et al. (2017) suggest a distance of 433 m.

The calls for a HF respect distance have come via the academic literature (e.g., Westwood et al., 2017; Wilson et al., 2018), via public-facing documents (e.g. Styles, 2018a), and through direct correspondence with the OGA (Styles, 2018b). Proposed respect distances have varied between 433 m (Westwood et al., 2017), 895 m (Wilson et al., 2018), and 850 m (Styles, 2018a,b).

However, none of these proposed values have a sound scientific footing, being based either on a flawed interpretation of observed microseismicity in the field (Wilson et al., 2018); on very limited, simple modelling (Westwood et al., 2017); or without any apparent scientific basis at all (Styles, 2018a,b).

The primary purpose of this report is to describe in detail the limitations of the above studies. We conclude that the OGA should not consider implementing additional regulations in the form of HF respect distances. We contend that a more appropriate approach is for operators to develop models that simulate the expected geometries of their stimulated fractures, based on planned injection parameters and *in situ* geomechanical conditions, and to assess these simulations with respect to the positions of known faults. We note that this is already a regulatory requirement in the UK via the implementation of the HFP (OGA, 2017).

Using microseismic observations

Wilson et al. (2018) use microseismic observations collated from academic and industry literature to constrain the lateral growth of stimulated fractures. They argue that largest distance between the perforations and observed microseismic events represents the extent of HF influence, and therefore the minimum required separation distance to any faults. Wilson et al. collate a dataset of approximately 100 HF stages, performing a statistical analysis to conclude on a respect distance of 895 m.

We have identified two major flaws in the method used by Wilson et al., described in a comment currently under review for the same academic journal (Verdon et al., 2018) that we reproduce in part here. These flaws are that (i) Wilson et al. fail to account for the fact that some of their datasets may already be showing fault interaction, and (ii) that Wilson et al. fail to account for interference between HF wells. Both of these flaws will lead to a systematic overestimation of the distance of influence of a HF propagating into previously unstimulated rock.

Intersection of hydraulic fractures with faults

It is relatively common for hydraulic fractures to intersect faults in the subsurface (e.g., Warpinski, 2014). Typically, microseismic monitoring observations can be used to identify fault intersection by a HF via an increase in event magnitudes (e.g. Maxwell et al., 2008); a reduction in the Gutenberg-Richter b-value of the event population (e.g. Verdon and Budge, 2018); or a deflection in the direction of fracture growth (e.g. Warpinski, 2014). We note that many of the papers collated by Wilson et al. explicitly discuss the interactions between hydraulic fractures and faults (e.g., Wolhart et al., 2006; Maxwell et al., 2008; Warpinski and Du, 2010; Neuhaus and Miskimins, 2012; Neuhaus et al., 2013; Warpinski, 2014) in their datasets, while others acknowledge the presence of faults in the area of interest, even if HF-fault interactions are not explicitly discussed (e.g., Malone et al., 2009; Williams-Stroud and Billingsley, 2010; Konopelko et al., 2015).

Once a fault has been intersected, microseismic activity across a larger portion of a fault is commonly observed. This reactivation may be generated by (i) propagation of HF fluids along the fault; (ii) propagation of fluid pressure fronts along the fault; or (iii) static stress transfer associated with deformation along the fault (e.g., Sumy et al., 2014); or some combination of these effects. This means that once a fault has been encountered, the lateral extent of microseismic events will be determined by the dimensions of the fault. Therefore the lateral extent of microseismic events does not delineate the distance at which the HF was able to reactivate the fault, but the dimensions (or a part thereof) of the reactivated fault.

We demonstrate this flaw in Wilson et al.'s analysis via an imagined scenario in Figure 2. Three hydraulic fracture stages are conducted, each of the same size. The first two do not intersect any faults, and the microseismic events do represent the extent of the HF. However, the third stage intersects a fault, and as a result microseismicity is generated along the length of the fault. The hydraulic fracture propagation distance measured by Wilson et al. would be the distance to the furthest event. However, it should be immediately apparent that this distance would be far in excess of the actual distance at which the fault was reactivated, and a significant overestimation of the actual respect distance required to avoid fault reactivation.

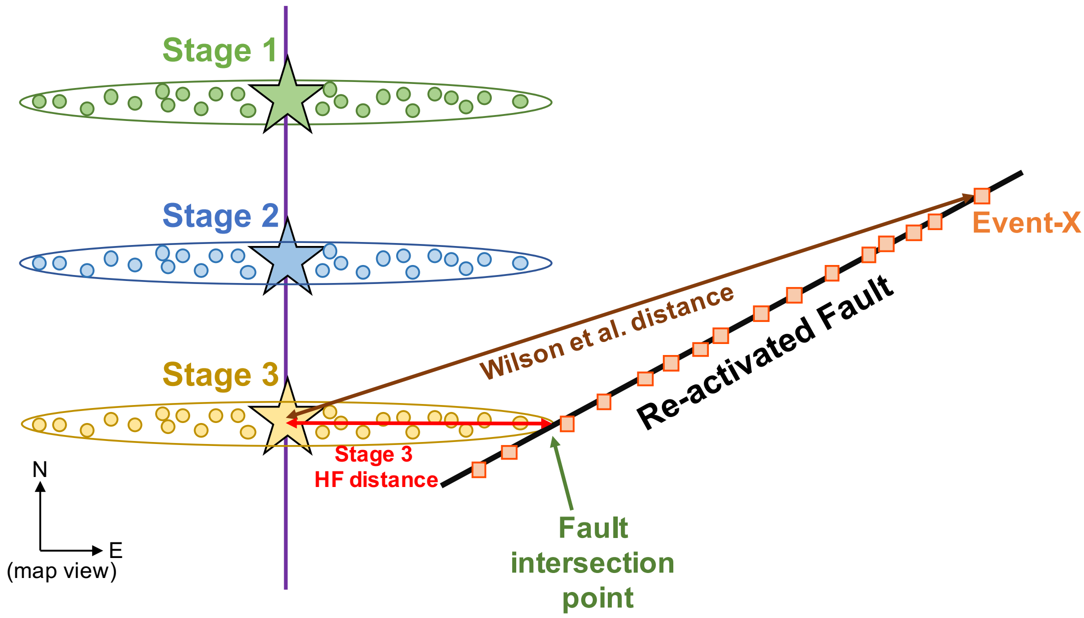

Figure 2: Schematic diagram demonstrating the first flaw in the analysis used by Wilson et al.. In this schematic, 3 HF stages are imagined, with perforation locations indicated by the stars. For the first 2 stages, HF proceeds as normal, and microseismic events (circles) are used to represent the extent of the HF (coloured ellipses). In the third stage, the HF intersects a fault. The HF fluids (or the pressure fronts associated with them) cause the fault to re-activate, generating fault-related microseismic events along its length (orange squares). Because they do not attempt to differentiate between events related to normal HF propagation and fault-reactivation events, Wilson et al. are measuring the distance between the perf position and the furthest fault-reactivation event (so-called "Event-X" in this figure). This will almost always be a significant overestimation compared to the actual distance that is of relevance for their stated aims, which is the distance between the perf and the point at which the HF first intersects the fault.

In other words, the relevant fault reactivation distance is the nearest distance at which a hydraulic fracture is observed to reach and reactivate a fault, not the distance reached by the microseismicity along a fault once it has been reactivated. Therefore the presence of any intersected faults in any of the datasets presented by Wilson et al. would render their analysis invalid. As noted above, many of the papers referenced by Wilson et al. explicitly discuss or implicitly suggest the presence of faults, while Wilson et al. have not attempted to rule out the presence of pre-existing faults in any of the datasets used.

Interference between hydraulic fracturing wells

Interference between hydraulic fractures from adjacent wells is commonly observed in many HF operations, known by the industry as “frac hits” (e.g. Jacobs, 2017). The failure of Wilson et al. to account for the possible presence of inter-well interference represents a second potential flaw that would lead to the overestimation of HF propagation distances.

We again demonstrate this flaw using an imaginary scenario, shown in Figure 3. Two wells are imagined, one of which has already undergone hydraulic fracturing, producing high-permeability fractured zones. When the second well is stimulated, the first two stages do not intersect the pre-fractured zones, and so the observed microseismicity represents the zone of influence of the HFs (as per Wilson et al.’s analysis). However, the third stage intersects a pre-fractured zone. This zone would allow the HF fluids, and the elevated pressure fronts associated with them, to quickly propagate to greater distances from the well. This results in microseismicity that is further from the well than would otherwise be the case had the first well not already been drilled and stimulated. The distance to the furthest microseismic event, as measured by Wilson et al., would again therefore represent an overestimation of the actual HF propagation distance.

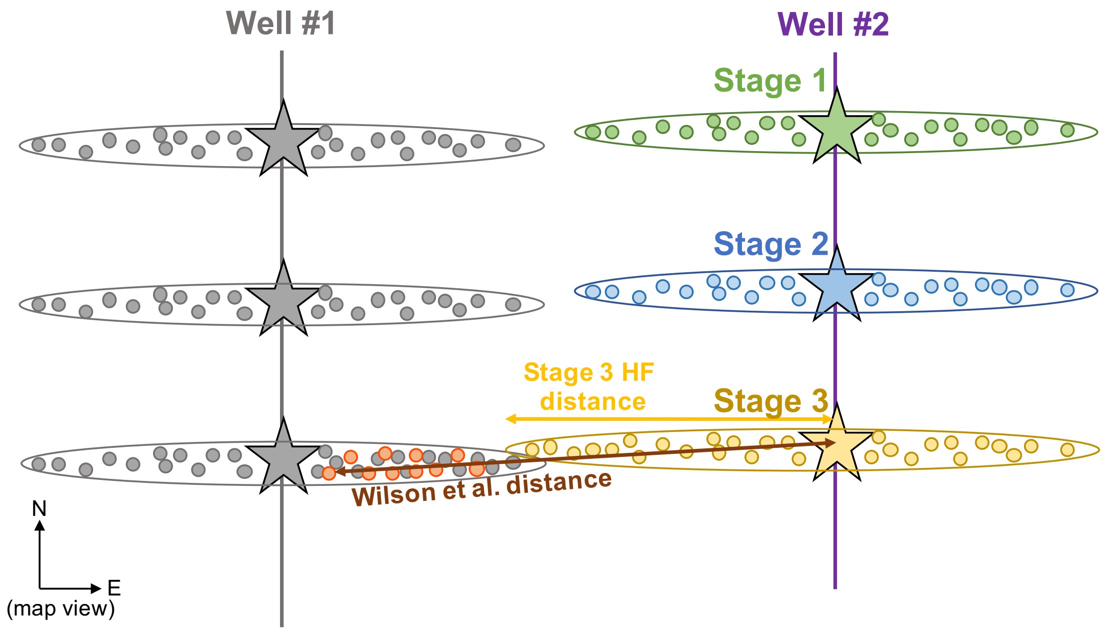

Figure 3: Schematic diagram demonstrating the second flaw in the analysis used by Wilson et al.. In this scenario, a first horizontal well has already been stimulated, with the HF extents (grey ellipses) being delineated by the associated microseismicity (grey circles). A second, adjacent horizontal well is then stimulated. The HFs during the first two stages do not intersect the HF zones from Well 1, and so the microseismicity can be used to delineate the HF extent. However, the third HF stage intersects an adjacent HF zone from Well 1, allowing the HF fluids (and associated pressure fronts) to move quickly along the now highly-permeable Well 1 HF zone, producing additional microseismicity that is much further from the Stage 3 perf position that would have been the case had Well 1 not existed. By failing to investigate interference between wells, in such cases the Wilson et al. approach may significantly overestimate the distances reached by hydraulic fractures.

In North America in particular it is common practice to drill and stimulate wells in close proximity to each other to minimise the volume of reservoir that is not reached by the HFs (see Figure 8 of Nicot et al., 2012 for an example showing the subsurface spacing of shale gas wells in northeast Texas). Note that here we are referring to the positions of wells within the reservoir: horizontal drilling may be used to access adjacent parts of a reservoir from drilling pads that are much more widely spaced. Many of the papers referenced by Wilson et al. do not discuss the presence or absence of existing stimulated wells adjacent to the ones stimulated, and so it is not possible to preclude whether this issue has impacted the datasets used (and if so, which).

However, two of the papers referenced by Wilson et al. explicitly discuss the presence of HF interference between wells (Wolhart et al., 2006; Mayerhofer et al., 2011), and this phenomenon is immediately apparent in the figures within several of the papers used, for example: Figure 20 of Wolhart et al. (2006), Figure 3 of Malone et al. (2009), Figure 6 of Mayerhofer et al. (2011), Figure 3 of Neuhaus et al. (2013), and Figure 3 of Warpinski (2014).

It is therefore evident that the interpretations applied by Wilson et al. to their collated datasets will produce a systematic overestimation of the respect distance. As such, their results do not provide a suitable basis for the development of robust regulations.

Using geomechanical models

Westwood et al. (2017) use geomechanical models to estimate respect distances based on the extent of stress transfer from stimulated fractures. They use a commercial numerical simulation tool, FracMan® (Golder Associates 2015), to model a generic HF operation, and then use Mohr-Coulomb modelling (e.g. King et al., 1994) to simulate the changes in stress in the surrounding rock mass that result from the opening of these fractures.

Westwood et al. examine the model sensitivities to a limited range of parameters, including the initial *in situ* fracture density, the proportions of different fracture slip mechanisms assumed, and the Coulomb stress change needed to reactivate faults. They find that the resulting respect distances are highly dependent on these parameters, with values ranging from as low as 15 m to as high as 433 m, with most results ranging either between 170 – 320 m for scenarios with a very low (0.001 MPa) fault reactivation threshold, or between 20 – 80 m for higher (0.1 – 0.5 MPa) fault reactivation thresholds. Taking the worst case scenario, Westwood et al. settle on a respect distance of 433 m. Note that this value is approximately 50% less than those proposed by Wilson et al. (2018) and Styles (2018a,b).

However, these results are based purely on generic modelling, with only superficial attempts to establish whether the models are providing a reasonable representation of reality. Uncertainties in geomechanical models stem primarily from two sources. Firstly, a model may not simulate all the physical processes that actually affect the real system. Secondly, geomechanical models require many input parameters that can have a complex and nonlinear impact on the results (e.g., Price et al., 2018). As such, unless a model has been calibrated or ground-truthed in a meaningful way, any results should be taken with a significant degree of scepticism (and certainly cannot provide the basis for robust regulation).

In the following paragraphs we present some specific examples that illustrate the above criticisms. At the outset of their modelling, Westwood et al. make the assumption that it is Mohr-Coulomb stress transfer, rather than any other mechanism, such as elevated pore pressures, or poroelastic stress transfer, that is causing faults to reactivate during hydraulic fracturing. Westwood et al. argue that poroelastic effects will have a 2nd or 3rd order effect, but do not present any scientific basis for making this claim. Given the large pore pressure changes that occur during HF (typically several MPa or more), whereas Westwood et al. are concerned with Mohr-Coulomb effects of the order 0.1 MPa, this unsubstantiated claim seems tenuous at best.

Westwood et al. do not investigate the influence of either the rock mechanical properties or the injection parameters on the result. Rock mechanical parameters such as Young's modulus will significantly affect the distances to which stress changes can be transferred, and therefore would have a major control on the result. The distances at which stresses are transferred will scale with Young's modulus, with larger values producing larger respect distances, and vice-versa.

There is significant variability in mechanical properties of the prospective shales both across the various Bowland sub-basins, and with depth within sub-basins. For example, Westwood et al. assume a relatively high value of Young's modulus (42.5 GPa), whereas Westaway and Younger (2014) assume a much smaller value (10 GPa).

In general, use of core samples can lead to overestimates of Young's modulus, because core samples tend to be taken from the most intact portions of drill cores, and because they cannot account for the presence of larger-scale discontinuities and fractures that act to soften the overall effective rock mass. Gudmundsson (2011) suggests that core sample tests can result in modulus values that can be anywhere from 1.5 – 5 times larger than *in situ* values. Verdon et al. (2011) found similar results when attempting to ground-truth geomechanical models to field observations of geomechanical behaviour. As outlined above, smaller Young's modulus values could result in significant reductions in the modelled respect distance.

Injection parameters would also have a major influence on the result for obvious reasons – a lower volume and/or lower pressure injection program would produce fewer and smaller fractures, and therefore have a smaller region of influence. Indeed, one might expect operators to design and adjust their injection programs to take into account the presence of known faults. Submitted HFPs have already indicated that there will be significant differences in injection programs (e.g., Cuadrilla Resources, 2017; Third Energy, 2017) both between sites, and even within individual wells.

Given the expected variabilities both in geomechanical properties, and in planned injection operators, defining a universally-applied respect distance based upon the outcome of a single modelling instantiation is spurious.

Respect distances that do not have any verifiable basis

Styles (2018a,b) cites a respect distance of 850 m. No scientific basis for this value is provided: the only reference is to personal communications between Profs Styles and Davies.

However, our understanding is that this value is derived from an early draft of the modelling work that was eventually presented in Westwood et al. (2017). This draft work, with a respect distance of 850 m, was shared by Prof. Styles with the U.K. Onshore Operators Group (UKOOG) Working Panel on Microseismic Monitoring and Fracture Mapping. The methods used were the same as described above. However, errors were made by the research group at Keele in transposing the FracMan® model results into the USGS Mohr-Coulomb modelling package, as these two packages use different coordinate systems.

These modelling errors were identified by the UKOOG Working Group, and communicated in a meeting with the Keele researchers on August 6th 2015. Subsequent correspondence confirmed these errors (R. Westwood *pers. comm.*, 2015), and that they had had a significant impact on the results. The reformulated models with this error corrected became the work presented in Westwood et al. (2017) as discussed above, with a much-reduced distance of 433 m.

In continuing to cite the 850 m respect distance value, Styles (2018a,b) is making use of a value that has been accepted as erroneous, and based on faulty modelling, by his own research team over 2 years ago.

Inappropriate use of Poland Township (Ohio) events as a benchmark

The case of induced seismicity near to the Poland Township, Ohio (Skoumal et al., 2015) is cited as evidence by each of Westwood et al. (2017), Wilson et al. (2018) and Styles et al. (2018a,b). Skoumal et al. (2015) observed events associated with hydraulic fracturing at distances of up to 850 m from the wells. This has been taken by all the respect distance studies to imply that the respect distance must be at least 850 m. In doing so, the authors have failed to take into account two things, (i) realistic event location errors, and (ii) that events do not necessarily delineate a fault in its entirety.

Skoumal et al. (2015) locate events via a two-step procedure: absolute locations are determined for a handful of master-events, and then relative locations are computed via double-differencing (Waldhauser and Ellsworth, 2000) for the remaining events. The double-differencing algorithm produces very small relative location uncertainties (i.e. locations of each event relative to the other events in the sequence), as small as ± 10 m as stated by Skoumal et al. (2015). However, the absolute event location uncertainties (i.e. the position of the entire event sequence within the subsurface) will be larger. These absolute location errors are not listed by Skoumal et al. (2015), but the nearest monitoring station is over 10 km distant, with other stations over 30 km away, so uncertainties will be large. For example, using a similar setup, in a similar area, Friberg et al. (2014) produced absolute location errors of ±400 m. If the absolute location errors for Skoumal et al. (2015) are similar, then these events could in fact be anywhere from 400 m to 1.2 km from the well.

More importantly, the event locations are unlikely to delineate the fault plane in its entirety. This is the same issue as described in our criticism of Wilson et al. (2018)'s approach. The key distance is that at which the HF first intersects the fault, not the distance travelled by events once the fault has been reactivated. The fault plane is unlikely to be entirely delimited by the observed events, especially given the poor detection thresholds that result when the nearest monitoring stations are tens of km distant. In Figure 4 we adapt the results presented by Skoumal et al. (2015) extending the observed fault trace and adding reasonable HF propagation distances. This shows that the extrapolated fault trace passes through or very close to all the HF stages that experienced seismicity.

The distance at which the fault at Poland Township was reactivated is therefore very probably much less than 850 m. Once the fault had been reactivated, events were then able to extend to 850 m distance, but this is not the distance at which the fault was reactivated. It is therefore incorrect to argue that the observations of Skoumal et al. (2015) provide evidence for a minimum fault reactivation distance of over 800 m.

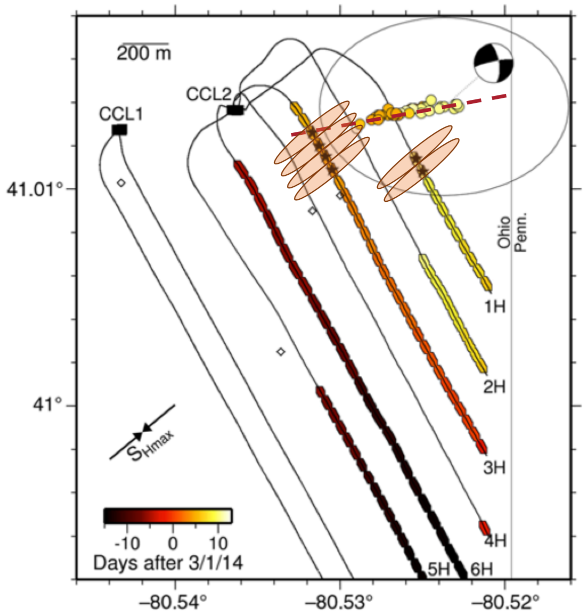

Figure 4: Map view of seismicity associated with hydraulic fracturing in Poland Township, Ohio (adapted from Skoumal et al., 2015). Coloured circles show the event positions, to the east and north of the HF wells (black lines). Each HF stage is demarcated by the small coloured rectangles, with the HF stages that induced seismicity marked by black stars. We have overlain on this diagram an extended fault trace (red dashed line) and reasonable expectations of HF propagation (red ellipses, which extend roughly 250 m on either side of the well, in the S_{Hmax} direction). Rather than being 850 m from the wells, the reactivated fault most likely passes through or very close to the HF stages that generated seismicity. The initial fault reactivation distance is therefore probably much smaller than the 850 m used by all of the fault respect distance studies.

Conclusions, and comments on the U.K.'s existing regulatory Approach

All of the fault respect distance studies discussed above begin with the aim of defining a single fault respect distance that can be applied to all HF operations in the U.K.. Notwithstanding the obvious issue of trying to base regulations and/or operational decisions on studies that contain the limitations and flaws outlined above, it is our view that mandating a single respect distance is not an appropriate mechanism to regulate this issue.

It is of interest to compare the proposed respect distances against the regulations already being applied to the industry. As described above, U.K. regulations for hydraulic fracturing require an operator to submit a hydraulic fracturing plan (HFP) prior to being given permission to operate. The HFP must describe measures taken by the operator to mitigate the risks posed by induced seismicity. Such measures include the requirement of an operator to identify the presence of faults in the vicinity of a proposed well, to assess the *in situ* stress state on these faults, and to assess the distances between such faults and the expected hydraulic fracture growth as modelled prior to the start of operations (e.g., Third Energy, 2017; Cuadrilla Resources, 2017). These hydraulic fracture models should be based upon site-specific geological and geomechanical conditions (stress state, rock geomechanical properties, rock permeability, the presence of existing fracture networks, *et cetera*), combined with the planned operational parameters (injection rates, volumes and pressures, and fluid viscosities, *et cetera*). It is our contention that a site-specific, risk-based approach such as this is the more appropriate basis for regulation, since the specific conditions, geo-hazards and planned operations at a particular site are explicitly taken into account.

Styles (2018a,b) notes that existing seismic reflection survey methods are not capable of resolving smaller faults that could still produce seismicity that exceeds the TLS thresholds (as has been noted previously by e.g., Westaway and Younger, 2014). We concur with this assessment: irrespective of precautions taken regarding fault respect distances, small faults may still be present that are too small to detect using reflection seismic surveying methods (e.g. Maxwell, 2013). So-called “sub-seismic” faults may still be large enough to produce felt seismic events. As such, any pre-emptive measures to mitigate induced seismicity cannot provide an absolute guarantee that seismicity will be prevented. As such, it is important that real time seismicity monitoring continues to be deployed during future HF operations, such that induced events can be identified immediately, allowing mitigating actions, such as those proposed in various Traffic Light Schemes, to be taken immediately, preventing the possibility of larger events capable of causing damage to buildings or infrastructure.

Conflicts of Interest

Given the potential significance of these issues with respect to the regulation of hydraulic fracturing, we note that J.P. Verdon has and continues to provide consulting services and advice regarding induced seismicity to shale gas operating companies in North America, the UK, and around the world. The views presented in this article are solely those of the author, who has received no input or contribution from shale gas operating companies in the writing of this report.

References

Cuadrilla Resources, 2017. Preston New Road 1z Hydraulic Fracture Plan: accessed at https://consult.environment-agency.gov.uk/onshore-oil-and-gas/information-on-cuadrillas-preston-new-road-site/supporting_documents/Preston%20New%20Road%20HFP.pdf.

Davies R.J., S.A. Mathias, J. Moss, S. Hustoft, L. Newport, 2012. Hydraulic fractures: how far can they go? *Mar. Pet. Geol.* 37, 1-6.

Friberg P.A., G.M. Besana-Ostman, I. Dricker, 2014. Characterization of an earthquake sequence triggered by hydraulic fracturing in Harrison County, Ohio: *Seis. Res. Lett.* 85, 1295-1307.

Golder Associates, 2015. FracMan® User’s Manual Release 7.5 Reservoir Edition.

Gudmundsson A., 2011. *Rock Fractures in Geological Processes*, Cambridge University Press

Jacobs T., 2017. Oil and gas producers find frac hits in shale wells a major challenge: *J. Pet. Tech.* 69, 29-34.

Konopelko A., V. Sukovatyy, A. Mitin, A. Rubtsova, 2015. Microseismic monitoring of multistage hydraulic fracturing in complex reservoirs of the Volgo-Urals region of Russia: *SPE Russian Petroleum Technology Conference*, SPE 176710-MS.

Malone W.S., M.G. Turner, M.J. Mayerhofer, N. Northington, L. Weijers, 2009. Development of a calibrated fracture-growth model and automated staging routine for the Jonah Field: *SPE Rocky Mountain Petroleum Technology Conference*, SPE 116304.

Maxwell S.C., 2013. Unintentional seismicity induced by hydraulic fracturing: *Canadian Society of Exploration Geophysicists Explorer* 38, 40-49.

Maxwell S.C., J. Shemeta, E. Campbell, D. Quirk, 2008. Microseismic deformation rate monitoring: *SPE Annual Conference and Exhibition*, SPE 116595.

Mayerhofer M.J., N.A. Stegent, J.O. Barth, K.M. Ryan, 2011. Integrating fracture diagnostics and engineering data in the Marcellus shale: *SPE Annual Technical Conference and Exhibition*, SPE 145463.

Neuhaus C.W. and J.L. Miskimins, 2012. Analysis of surface and downhole microseismic monitoring coupled with hydraulic fracture modeling in the Woodford Shale: *74th EAGE Annual Conference Expanded Abstracts*, G030.

Neuhaus C.W., C. Telker, M. Ellison, K. Blair, 2013. Hydrocarbon production and microseismic monitoring – treatment optimization in the Marcellus Shale: *AAPG Annual Convention*, Article #80310.

Nicot J-P., R.C. Reedy, R.A. Costley, Y. Huang, 2012. Oil and gas water use in Texas: Update to the 2011 mining water use report: *Bureau of Economic Geology, University of Texas at Austin*. Accessed at https://www.twdb.texas.gov/publications/reports/contracted_reports/doc/0904830939_2012Update_MiningWaterUse.pdf

Oil and Gas Authority, 2017. Guidance for EWTs and HFPs. Accessed at https://www.ogauthority.co.uk/media/3168/onshore-ewt-and-hfp_january-2017.pdf

Price D.C., D.A. Angus, A. Garcia, Q.J. Fisher, S. Parsons, J. Kato, 2018. A multimethod global sensitivity analysis to aid the calibration of geomechanical models via time-lapse seismic data: *Geophys. J. Int.* 212, 2031-2046.

Skoumal R.J., M.R. Brudzinski, B.S. Currie, 2015. Earthquakes induced by hydraulic fracturing in Poland Township, Ohio: *Bull. Seis. Soc. Amer.* 105, 189-197.

Styles P., 2018a. Fracking and historic coal mining: their relationship and should they coincide? Accessed at https://www.keele.ac.uk/media/keeleuniversity/facnatsci/schgge/news/2018/Fracking%20and%20Mining-%20Styles%202018.pdf

Styles P., 2018b. Shale gas fracking beneath worked coal seams? *Report presented to the OGA, July 2018.*

Sumy D.F., E.S. Cochran, K.M. Keranen, M. Wei, G.A. Abers, 2014. Observations of static Coulomb stress triggering of the November 2011 M_w 5.6 Oklahoma earthquake sequence: *J. Geophy. Res.* 119, 1904-1923.

Third Energy, 2017. Hydraulic fracture plan for Well KM-8, Kirby Misperton Alpha wellsite: accessed at https://consult.environment-agency.gov.uk/onshore-oil-and-gas/third-energy-kirby-misperton-information-page/user_uploads/pre-op-2-hydraulic-fracture-plan-sept-17.pdf.

Verdon J.P., and J. Budge, 2018. Examining the capability of statistical models to mitigate induced seismicity during hydraulic fracturing of shale gas reservoirs: *Bull. Seis. Soc. Amer.* 108, 690-701.

Verdon J.P., J-M. Kendall, D.J. White, D.A. Angus, 2011. Linking microseismic event observations with geomechanical models to minimise the risks of storing CO_2 in geological formations: *Ear. Plan. Sci. Lett.* 305, 143-152.

Verdon J.P., T. Kettlety, N. Igonin, 2018. Comment on "Fracking: how far from faults?" by M.P. Wilson et al.: *Submitted to Geomech. Geophys. Geo-energ. Geo-resour.*

Waldhauser F. and W.L. Ellsworth, 2000. A double-difference earthquake location algorithm: method and application to the Northern Hayward Fault, California: *Bull. Seis. Soc. Amer.* 90, 1353-1368.

Warpinski N.R., 2014. A review of hydraulic-fracture induced microseismicity: *48th US Rock Mechanics/Geomechanics Symposium, American Rock Mechanics Association*, ARMA 14-7774.

Warpinski N.R. and J. Du, 2010. Source-mechanism studies on microseismicity induced by hydraulic fracturing: *SPE Annual Technical Conference and Exhibition*, SPE 135254.

Westaway R. and Younger P.L., 2014. Quantification of potential macroseismic effects of the induced seismicity that might result from hydraulic fracturing for shale gas exploitation in the UK: *Quart. J. Eng. Geol. Hydrogeol.* 47, 333-350.

Westwood R.F., S.M. Toon, P. Styles, N.J. Cassidy, 2017. Horizontal respect distance for hydraulic fracturing in the vicinity of existing faults in deep geological reservoirs: a review and modelling study: *Geomech. Geophys. Geo-energ. Geo-resour.* 3, 379-391.

Williams-Stroud S. and R.L. Billingsley, 2010. Techniques to estimate fracture effectiveness when mapping low-magnitude microseismicity: *SEG Annual Conference Expanded Abstracts*, 2075-2079

Wilson M.P., F. Worrall, R.J. Davies, S. Almond, 2018. Fracking: how far from faults? *Geomech. Geophys. Geo-energ. Geo-resour.* 4, 193-199.

Wolhart S.L., T.A. Harting, J.E. Dahlem, T. Young, M.J. Mayerhofer, E.P. Lolon, 2006. Hydraulic fracture diagnostics used to optimize development in the Jonah field: *SPE Annual Technical Conference and Exhibition*, SPE 102528.