Comparison of class II injection well area of review requirements with area of evaluation for hydraulically fractured wells

Yashesh Jitendra Panchal
COMPARISON OF CLASS II INJECTION WELL AREA OF REVIEW REQUIREMENTS WITH AREA OF EVALUATION FOR HYDRAULICALLY FRACTURED WELLS

by

YASHESH JITENDRA PANCHAL

A THESIS

Presented to the Faculty of the Graduate School of the

MISSOURI UNIVERSITY OF SCIENCE AND TECHNOLOGY

In Partial Fulfillment of the Requirements for the Degree

MASTER OF SCIENCE IN PETROLEUM ENGINEERING

2013

Approved by

Dr. Shari Dunn-Norman, Advisor
Dr. Ralph Flori
Dr. Runar Nygaard
Since 2010 the US Environmental Protection Agency (EPA) has been proposing plans to study, and has now initiated research regarding the potential impact of hydraulic fracturing processes on drinking water sources. Their work refers to an ‘Area of Evaluation’ around a hydraulically fractured well, inferring that the wells immediately around hydraulic fractured wells should be studied, to evaluate the conditions of these wells and their potential to contaminate overlying USDWs.

Class II injection wells must have a minimum ¼ mile radius area of review to determine the condition of wells surrounding the proposed injection well. All wells within this AOR are evaluated, although wells that intersect the zone of injection are of greatest interest.

This study examines publically available micro seismic data for multi-stage hydraulic fractured horizontal wells in various shale plays. A ¼ mile AOE is inscribed on each stage the microseismic to determine if all microseismic events fall within this criteria. The study also investigates current state practices with respect to AOE.

Results of this study indicate that most wells have hydraulically fractures that fit within current ¼ mile AOR criteria. While this may not be the only aspect to consider with respect to these types of wells, it is a good starting point for additional study.
ACKNOWLEDGMENTS

This thesis would not have been possible without the help and support of my advisor Dr. Shari Dunn-Norman. I thank her for accepting me as one of her graduate students, being so patient and pushing me to be a better engineer.

I am thankful to my committee members Dr. Runar Naygaard and Dr. Ralph Flori for providing their timely guidance.

I am thankful to all the Oil and Gas State Regulatory Board for providing the data regarding the practice followed in their respective states.

I am grateful to my friends Anuroop, Siddharth, Ananth, Vibhuti, Aditi Mishra, Palak, Sachin, Sahil and Soham for motivating me and creating a fun environment around me that helped me release my tension at times. I would also like to thank Aditi Sharma, Deepak and Ishan for being with me when I needed support.

I am grateful to my friends back home in India, Harshit, Apurv, Darshan, Chintan, Sagar, Nishtih, Yatri, Miten, Mansi, Fenil, Poojan, Komal, Priyank and Suril for constantly forcing me to concentrate on my research work. This thesis would not have been possible without the continuous support of my friends. I would like to thank Apoorva, because of whom I am in United States and pursuing my higher education.

It was a pleasant experience to work in the University library. I would thank the Staff of library to encourage me. Special thanks to Dawn Mick, Dan, Scott, Marsha, June and all fellow students working in library.

And finally I would like to acknowledge the trust and support of my PARENTS and my FAMILY members.
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<tr>
<td>σ&lt;sub&gt;v&lt;/sub&gt;</td>
<td>Vertical principal stress</td>
</tr>
<tr>
<td>ρ</td>
<td>Density of the fluid</td>
</tr>
<tr>
<td>z</td>
<td>Height</td>
</tr>
<tr>
<td>g</td>
<td>Gravitational acceleration</td>
</tr>
<tr>
<td>σ&lt;sub&gt;v&lt;/sub&gt;'</td>
<td>Effective vertical stress</td>
</tr>
<tr>
<td>P&lt;sub&gt;p&lt;/sub&gt;</td>
<td>Pore pressure</td>
</tr>
<tr>
<td>σ&lt;sub&gt;Hmax&lt;/sub&gt;</td>
<td>Maximum horizontal stress</td>
</tr>
<tr>
<td>σ&lt;sub&gt;Hmin&lt;/sub&gt;</td>
<td>Minimum horizontal stress</td>
</tr>
<tr>
<td>σ&lt;sub&gt;H '&lt;/sub&gt;</td>
<td>Effective horizontal stress</td>
</tr>
<tr>
<td>P&lt;sub&gt;bd&lt;/sub&gt;</td>
<td>Break down pressure</td>
</tr>
<tr>
<td>T&lt;sub&gt;o&lt;/sub&gt;</td>
<td>Tensile strength of rock</td>
</tr>
<tr>
<td>p</td>
<td>Reservoir pressure</td>
</tr>
<tr>
<td>σ</td>
<td>Stress</td>
</tr>
<tr>
<td>E</td>
<td>Youngs modulus</td>
</tr>
<tr>
<td>P&lt;sub&gt;net&lt;/sub&gt;</td>
<td>Net treating pressure</td>
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<td>K&lt;sub&gt;lc-app&lt;/sub&gt;</td>
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<td>Fracture height</td>
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<tr>
<td>E'</td>
<td>Plain strain modulus</td>
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<td>σ&lt;sub&gt;c&lt;/sub&gt;</td>
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<tr>
<td>q</td>
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<tr>
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<tr>
<td>--------</td>
<td>------------</td>
</tr>
<tr>
<td>ν</td>
<td>Poisson ratio</td>
</tr>
<tr>
<td>μ</td>
<td>Viscosity</td>
</tr>
<tr>
<td>T</td>
<td>Time</td>
</tr>
<tr>
<td>r</td>
<td>Radius of endangering influence</td>
</tr>
<tr>
<td>K</td>
<td>Hydraulic conductivity of the injection zone</td>
</tr>
<tr>
<td>H</td>
<td>Height of Injection zone</td>
</tr>
<tr>
<td>T</td>
<td>Time of injection</td>
</tr>
<tr>
<td>S</td>
<td>Storage coefficient</td>
</tr>
<tr>
<td>Q</td>
<td>Injection rate</td>
</tr>
<tr>
<td>$h_{bo}$</td>
<td>Observed original hydrostatic head of injection zone measured from the base of USDW</td>
</tr>
<tr>
<td>$h_w$</td>
<td>Hydrostatic head of USDW (length) measured from the base of the lowest USDW</td>
</tr>
<tr>
<td>$S_p G_b$</td>
<td>Specific gravity of the fluid in the injection zone</td>
</tr>
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1. INTRODUCTION

Over the past two decades the oil and gas industry has learned how to combine horizontal drilling techniques with rapid methods of emplacing large, multi-stage hydraulic fracturing (also referred herein as ‘HF’) treatments to extract natural gas/oil from unconventional shale plays. Although the technical success of this enterprise is irrefutable, environmentalists have questioned the use of multi-stage hydraulic fracturing citing that this process is a danger to underground sources of drinking water (USDWs).

Since 2010 the US Environmental Protection Agency (EPA) has been proposing plans to study, and has now initiated research regarding the potential impact of hydraulic fracturing processes on drinking water sources. While a complete review or summary of the EPA hydraulic fracturing study plan is beyond the scope of this study, historical work and a progress report of their efforts is available at www.epa.gov/hfstudy.

The 2011 EPA study plan called for research in a number of areas comprising the hydraulic fracturing ‘life cycle’. One part of this life cycle is ‘well injection’ and the main question posed therein is, “What are the possible impacts of the injection and fracturing process on drinking water resources?” Among the various details and sub-questions is: identification of the area of evaluation for a hydraulically fractured well (Section 6.3.3.1, EPA 2011)

The phrase ‘area of evaluation’ is noted in several places throughout the well injection portion of the EPA study. The ‘area of evaluation’ is also given an abbreviation in nomenclature (AOE) but is not strictly defined. However, the implication of AOE is that there is some distance around a hydraulically fractured well that requires study for
potential effects of the fracturing operation to drinking water. At the time of this study, the manner of defining the HF AOE has not yet been defined by the EPA.

Class II injection wells are subject to Area of Review (AOR) studies as part of routine permitting processes. An AOR is a defined study of wells surrounding the proposed injection well, most typically within ¼ mile radius. The AOR process provides a logical analogy for the HF AOE process, but it should be kept in mind that hydraulic fracturing is not the same process as Class II disposal or injection. A permitted Class II well injects fluids continuously, for years, provided the well satisfies regular mechanical integrity testing. Hydraulic fracturing is a very short term injection of fluids and proppant, albeit at high pressure. A fracturing treatment is typically pumped for hours per single stage, and less than a week for multiple stages along a horizontal wellbore. Hence the AOR analogy is believed to be a good starting point for addressing potential HF AOE’s, realizing that other phenomenon, such as induced hydraulic fractures intersection existing fractures, may also affect the HF AOE.

This study compares AOR distance criteria applied by each state, to microseismic responses obtained from hydraulically fractured wells within several shale plays throughout the United States, to determine if hydraulic fracture treatments fall within AOR criteria. The study also summarizes state practices with respect to AOE’s for hydraulic fractured wells, and some industry practices regarding state AOE’s.
2. AREA OF REVIEW (AOR)

By federal law, all wells injecting or disposing fluids into the subsurface must have a valid permit and pass periodic testing to ensure protection of underground sources of drinking water (USDW). A USDW is defined as any aquifer that contains less than 10,000 mg/l total dissolved solids and is currently being used as a drinking water source or which is of sufficient volume and adequate quality to be a future source for twenty-five or more connections (EPA, http://www.epa.gov/region6/water/swp/uic/faq2.htm).

Although there are a number of steps required to obtain a Class II injection permit, the most important aspect to this work is the ‘Area of Review’ study requirement, or AOR. This section presents important aspects of well classification and construction related to the AOR process, and compares state AOR requirements.

2.1. FUNDAMENTALS OF CLASS II INJECTION/DISPOSAL WELLS

All wells in the United States that dispose of fluids in the subsurface must be permitted to do so according to the Safe Drinking Water Act (SDWA). The SDWA designated that each state permits such wells under an Underground Injection Control (UIC) program, overseen either by the state or by the federal government (Environmental Protection Agency, EPA). Wells permitted under the UIC are classified according to common uses and referred to as injection ‘classes’ as shown in Figure 2.1.

In oil and gas operations, salt water disposal wells and water injection fall under the designation of Class II wells, and may be permitted either as commercial or non-commercial disposal wells. The term Class II disposal well is normally used for wells injecting produced oilfield brines, flowback waters, or other associated waters into a
porous subsurface formation that does not produce oil/gas. The term Class II injection well is normally used for wells that inject oilfield waters (and perhaps make up fresh water) into a porous formation that produces oil/gas. These wells are commonly called enhanced oil recovery water injection wells. Class II injection wells also include underground hydrocarbon storage wells. Throughout this thesis, the term Class II injection well has been used, broadly referring to disposal as well as all injection situations.

Figure 2.1 is a typical classification for class II injection wells according to UIC. A schematic diagram of a typical class II injection well is shown in Figure 2.2. Although
each state has its own regulations with respect to wellbore construction, all wells inject fluids through tubing, and with the use of a packer or other barrier that protects the casing annulus.

All states also required casing to be set through the lowest known source of drinking water, and for that casing string to be fully cemented to surface. A pressure test is conducted to verify the pressure integrity of the casing and cement job. (Arthur et al., 2011) summarizes and compares some state practices with respect to shallow casing construction.

There are more variations in Class II construction practices around the injection zone, but in general the injection zone is normally cased and perforated, and the casing string is cemented to some level above the top of the injection formation. The Texas Railroad Commission (RRC) provides specific guidance on packer setting depth and top of cement (TOC) determined by either cement bond logs (CBL) or temperature survey (Figures 2.3 and 2.4). Many states strive to follow the RRC well construction and testing practices.
Figure 2.2. Class II injection facts (Oil Conservation Division)
Figure 2.3. Texas RRC well construction packer rules for class II injection

Figure 2.4. Texas RRC cementing guide for class II injection
Figure 2.5 provides details regarding cementing operations, and each State provides such information for operators (D.L. Warner et al. 1994). Class II injection wells must meet their respective state’s minimum construction standards, regardless of whether the well is newly drilled for injection, or an existing producing well converted to injection.

![Figure 2.5. Example of well construction standard](image)

1. Circulation of cement is must around surface pipe.
2. The casing strings should be cemented, at least 100 feet into next shallowest string.
3. If wells are drilled in valley areas then surface pipe must be set minimum 50 feet below the fill.
4. If there is an intermediate casing, then it should be cemented following procedure of #2.
5. Production casing can be set anywhere, either on the top or through the formation.

In addition to following the well construction guidelines, operators must also pressure test the production casing cement to a certain pressure, and for a prescribed time to assure a seal. (Arthur et al., 2011) provides a comparison of some state’s testing practices.

While the permitting process ensures a high level of protection to USDWs within the injection well, there will likely be many other wells surrounding the injection well,
and their wellbores may not have been constructed to a standard that would protect an overlying USDW. Fluids injected under pressure will flow through the porous media, and may flow into adjoining wellbores, reaching the overlying USDW if the adjoining wells have inadequate wellbore construction. For this reason, it is necessary to study wells within a prescribed radius of the injection wells, referred to as an area of review, or AOR.

2.2. CONCEPT OF AREA OF REVIEW (AOR)

Area of review is the area surrounding an injection well or wells defined by either the radial distance within which pressure in the injection zone may cause migration of the injection and/or formation fluid into an underground source of drinking water or defined by a fixed radius of not less than one-fourth mile (D. L. Warner et al., 1994). Where the radial distance of the AOR is calculated from injection pressure and reservoir properties, it is also known as "zone of endangering influence." Figure 2.6 depicts an AOR with one production well and one abandoned well near the Class II injection well.

 Wells that intersect the active injection formation are of greatest concern in the AOR process, however all wells of record within the prescribed distance must be included. Contamination of the USDW through the wellbore may occur in two different ways:

1) In a producing well, there can be a leakage in the casing which may lead to the inflow of the produced water to enter the USDW. This can be avoided by following the construction standards and testing the mechanical integrity of the wells.

2) There may be a pressure difference between the injection zone and USDW, which may lead to the flow of water from reservoir to the USDW due to improper plugging of an
abandoned well. This can be avoided by understanding the potential of flow (hydraulics), using adequate abandonment plugs, and the presence of conduits.

Figure 2.6. AOR showing one producing well (solid dot) and one abandoned well

Figure 2.7 depicts a producing well, and an abandoned well which provide pathways for contamination of USDWs, provided that injections pressure is sufficient for this to occur.
Where the radius of the AOR is determined by injection pressure, the following equation is used to calculate what is referred to as the “zone of endangering influence” (40 CFR § 146.6.)

\[
\begin{align*}
    r &= \frac{2.25 \, KHt}{S \, 10^x} \\
    X &= \frac{4\pi KH(hw - hbo \times SpGb)}{2.3 \, Q}
\end{align*}
\]  

Figure 2.7. Potential USDW contamination from wells surrounding the class II injection well
where \( r \) is the radius of endangering influence, \( K \) is the hydraulic conductivity of the injection zone, \( H \) is the height of the injection zone, \( T \) is the time of injection, \( S \) is the storage coefficient, \( Q \) is the Injection rate, \( h_{bo} \) is the Observed original hydrostatic head of injection zone measured from the base of USDW, \( h_{w} \) is the hydrostatic head of USDW (length) measured from the base of the lowest USDW, \( S_G \) is the Specific gravity of the fluid in the injection zone. The above equation is based on the following assumptions:

- The injection zone is homogenous and isotropic
- The injection zone has infinite area extent
- The injection well penetrates the entire thickness of the injection zone
- The well diameter is infinitesimal compared to “\( r \)” when injection time is longer than a few minutes and
- The emplacement of fluid into the injection zone creates instantaneous increase in pressure.

Although it was not possible to obtain release of industry data for a full AOR industry example application to be included with this thesis, the Texas RRR and California Conservation provide many details regarding the full requirements for submitting an AOR.

(Refer: [http://www.conservation.ca.gov/dog/general_information/Pages/UIC ApplicationGuidance.aspx](http://www.conservation.ca.gov/dog/general_information/Pages/UIC ApplicationGuidance.aspx))

Table 2.1 summarizes the radial distance required for an AOR within each state. The agency abbreviation refers to the organization which oversees the AOR process. As shown most states have adopted the minimum \( \frac{1}{4} \) mile radius, but some states use a larger
AOR because, in those cases, a different conductivity, storage coefficient and hydrostatic head have been used to determine the zone of endangering influence.

Table 2.1. Summary of AOR within each state

<table>
<thead>
<tr>
<th>Region/State</th>
<th>Agency</th>
<th>Well Class</th>
<th>Fixed Radius</th>
<th>Verified by Calculation</th>
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<tbody>
<tr>
<td><strong>II</strong>NY</td>
<td>USEPA</td>
<td>IIR,IID</td>
<td>1/4 mi</td>
<td>Yes</td>
</tr>
<tr>
<td><strong>III</strong>PA/VA</td>
<td>USEPA</td>
<td>IIR,IID</td>
<td>1/4 mi</td>
<td>Yes, IID</td>
</tr>
<tr>
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<td>USEPA</td>
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<tr>
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</tr>
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<td>No</td>
</tr>
<tr>
<td>V MI</td>
<td>USEPA</td>
<td>I</td>
<td>2 mi</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>USEPA</td>
<td>IIR,IID</td>
<td>1/4 mi</td>
<td>No(c)</td>
</tr>
<tr>
<td></td>
<td>IEPA</td>
<td>I</td>
<td>2.5 mi</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>IDNR</td>
<td>IIR,IID</td>
<td>1/4 mi</td>
<td>No(c)</td>
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Table 2.1. Summary of AOR within each state (continue)

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<thead>
<tr>
<th>State</th>
<th>Agency</th>
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<td>2 mi</td>
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<td></td>
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<td>No(c)</td>
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<tr>
<td></td>
<td>OEPA</td>
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<td>OH</td>
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<td>1/4 mi if q&lt;200 bbl/d/yr</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>1/2 mi if q&gt;200 bbl/d/yr</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>III</td>
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</tr>
<tr>
<td>VI</td>
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<td>1/4 mi</td>
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<td>1/2 mi</td>
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<td>I HAZ</td>
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<td></td>
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<tr>
<td></td>
<td>AOGC</td>
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</tr>
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<td>2.5 mi or 1/4 mi if Calc=0</td>
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<td>(g)</td>
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<td></td>
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<td>1/4 mi</td>
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<td></td>
<td></td>
<td>III</td>
<td></td>
<td></td>
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<td>OCC</td>
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</tr>
<tr>
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<td></td>
<td></td>
<td>(non-com)</td>
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</tr>
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<td></td>
<td></td>
<td></td>
<td>1/2 mi</td>
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<td>NA</td>
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<td>2 1/2 mi</td>
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</tr>
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<td></td>
<td></td>
<td>III, V</td>
<td>1/4 mi</td>
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</tr>
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<td>VII MO</td>
<td>MDNR</td>
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<td>1/2 mi</td>
<td>No</td>
</tr>
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<td>KS</td>
<td>KCC</td>
<td>I, IID</td>
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<td></td>
<td>KDHE</td>
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<td>1 mi (I non-haz)</td>
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<td></td>
<td>I, III, V</td>
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<td>NOGCC</td>
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<td>COGCC</td>
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<td>WOGCC</td>
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<td>III</td>
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<tr>
<td>X AK</td>
<td>AOGCC</td>
<td>I, IID</td>
<td>1/4 mi</td>
<td>No</td>
</tr>
</tbody>
</table>
2.3. AREA OF REVIEW VARIANCE

The Area of Review requirement can be waived by applying for a variance. In order to obtain variance from well by well AORs, five different methods are proposed. To provide variance for some or all wells these five methods can be used in any order or in any combination. The five methods are as follows:

- Variance based on absence of USDW.
- Variance based on lack of intersection.
- Variance based on negative flow potential.
- Variance based on mitigating geological factors.
- Variance based on well construction and abandonment methods.

It is believed that all five methods can be used for large geographic areas but the first four methods are based upon geologic and hydrologic criteria and are most easily visualized as "global" methods. This is because they are considered to be broadly effective in protecting USDWs irrelevant of the presence of individual wells that are not properly constructed or abandoned. The fifth method requires complete details of the methods for construction and abandonment of the wells that are present in that area. (D. L. Warner et al., 1994).
3. METHODOLOGY

The objective of this work was to characterize the extent of pressure/fracturing surrounding a typical hydraulic fractured well, and to determine if AOR criteria were a good criteria. The research focused on unconventional reservoirs, since hydraulic fracturing in these reservoirs is of greatest concern.

At the outset of this work it was expected to use reservoir simulation to model a zone of influence around the hydraulically fractured well, and to compare the radial distance of pressure from simulation results to AOR criteria for Class II injection wells. However, this approach proved impractical because reservoir simulators cannot easily model flow from nano-darcy shales, unless fractures are ‘introduced’ into the model. Adding fractures manually would invalidate the research method.

Since reservoir simulation could not be used to calculate a zone of influence, it was decided to use microseismic data as indication of the fracture extent and orientation (azimuth). This approach has been taken previously in determining the vertical extent of hydraulic fracture in unconventional resources (Fischer, 2011) shown in Figure 3.1.
A complete set of all microseismic data was requested from industry, in an attempt to study once complete shale play. Although this information is available through a single service provider, releases were required from all companies. As this was felt to be too difficult, it was decided to use microseismic data available in the literature. The analyses of those data are considered to be the principle literature search, as there are no published papers on AOE for hydraulically fractured well.
4. HYDRAULIC FRACTURING

This section reviews basic information on hydraulic fracturing and presents a discussion of fracture diagnostics in support of the microseismics used in the work.

4.1. BASIC OF HYDRAULIC FRACTURING

Hydraulic fracturing has helped in increasing the production of hydrocarbon and thus made a significant contribution in the oil and gas industries. According to a survey done in 1991 by a French Petroleum Institute, (Larry et al., 2009) almost 71% of all completed wells were hydraulically fractured.

The purpose of creating a fracture is to allow the flow of the reservoir fluid to the wellbore surface by creating a path from the reservoir rock that extends beyond the layer of the wellbore skin damage. The schematic diagram showing the surface operations of a hydraulic fracture operation is shown in Figure 4.1

![Figure 4.1. Surface preparation before the start of fracturing (FracFocus)](image-url)
Hydraulic fracturing is performed in a following manner:

- It is made sure that the wellbore construction is completed according to the standards. The casings are cemented properly in such a way that there should be no contact between drilling fluid/fracturing fluids with the formation fluid (aquifer).

- The fracturing fluid is pumped inside the wellbore. The fracturing fluid is basically a mixture of 99.5% water and sand or ceramics along with some additives.

- The fracturing fluid is injected with a pressure to crack the formation. The pump trucks are used to provide sufficient pressure to the fracturing fluid that is greater than the fracture gradient of the rock.

- Once the initial break down is achieved, an initial volume of fluid is pumped in formation. This fluid is called pad.

- The pad propagates the fracture and serves as a cooling agent for the rock face as the fracture is created.

- The pad fluid may leak off into the surrounding formation. When the pad fluid leaks off the fracture stops growing.

- The proppant is added immediately after the pad volume. The function of the proppant is to keep the fracture open and to create a permeable flow path.

The Figure 4.2 shows a schematic of hydraulic fracturing process.
As discussed the propped fracture functions as a conductivity pathway for the migration of fluid (hydrocarbon) from the formation to the wellbore.
4.2. HORIZONTAL FRACTURING

Horizontal drilling is the process of drilling a well in such a way that the drilling process reaches the top of the formation i.e. kick off and deviates in such a way that it becomes parallel to the plane of the reservoir. For drilling the vertical portion i.e. till the kick off point same procedure is followed as for the vertical wells. From the kick off point to the entry point the drilling process is done using the hydraulic motor that is mounted just above the bit and it is powered by the drilling mud. The curved section has 300 - 500 feet of radius. Figure 4.3 shows a horizontal well within a reservoir, with multiple states of fractures along the wellbore.

Figure 4.3. Horizontal drilling (Sheila Foran, 2011)
4.3. HYDRAULIC FRACTURING FLUID

The main purpose of the hydraulic fracturing fluid is to initiate and/or expand the fracture, it also helps in the transportation of the proppant in the fracture in the formation. There are various kinds of fracturing fluid water based and oil based. The selection of these fluids is done by the service companies in order to induce and maintain permeable and productive fracture. Each of these fracturing fluids has its own use and its use is decided by the service companies. In order to achieve the most productive fracture, the fracturing fluid must contain certain properties. The properties are as listed,

- It should be viscous in such a way that it should transport the proppant inside the fracture.
- It should extend the fracture length by maximizing fluid travel distance.
- It should be able to carry large amount of proppant into the fracture.

As far as viscosity of fracturing fluid is concerned, it has very contradictory requirement. The fracturing fluid should be less viscous so that it can travel easily through the well bore, but it should be viscous enough to carry and travel the proppant inside the fracture and again it should be less viscous so that it can come out of fracture and return to the formation. In order to make this possible there are different types of additives used along with the fracturing fluids. The most common additives are breakers, biocides, fluid loss additives like 100 mesh sand, silica flour etc, and friction reducers like latex polymers or copolymers.

4.4. FRACTURE ORIENTATION

In-situ stress determines fracture morphology. The rocks that are present in the formation are subjected to in-situ stress at each and every point. These stresses are
resolved into three principal stresses. The principal stresses are the vertical stress \( \sigma_v \), the maximum horizontal stress \( \sigma_{H\text{max}} \) and the minimum horizontal stress \( \sigma_{H\text{min}} \). In most oilfield situations the maximum principal stress is the vertical stress which is equal to the overburden stress. Fracture will always try to propagate in the direction of least principal stress. So in a three dimensional regime a fracture will propagate in such a way that it can avoid greatest stresses and create a width in the direction of least stress. This means that fracture will develop in a direction parallel to maximum horizontal stress and perpendicular to minimum horizontal stress. Figure 4.4 shows all the three stresses.

Figure 4.4. State of stress
In a majority of the unconventional shale plays, vertical stress is the maximum principal stress, minimum horizontal stress is the minimum principal stress and maximum horizontal principal stress is the intermediate stress. Wells are drilled horizontally, in the direction of the minimum horizontal stress. As discussed at depths where formation which can be produced is found, the stress field may lead to a hydraulic fracture which is normal to the minimum horizontal stress. Thus the two main things that govern the well orientation in the horizontal wells is fracture direction and azimuth. Two cases can exist longitudinal or transverse fracture. For the transverse fracture intersecting a well the possibility of multiple fracture exists but with a proper zone isolation. Longitudinal fractures are used when the formation has higher permeability. (Vilegas et. al) compares the performance of longitudinal fractures over the transversely fractured horizontal wells.

It was found that for a constant fracture volume transverse fractures can outperform the longitudinal fractures. Transverse fractures have potential to activate natural fractures. In recent days most of the industries prefer the transverse fracture technique in order to gain more benefits. Figure 4.5 shows the transverse and the longitudinal fractures.

Fractures pumped along the wellbore are then transverse fractures, as shown in Figure 4.5
Subsurface stress and formation pore pressure are linked, and it is useful to review this here.

Density logs are useful for the calculation of vertical stress. Vertical stress can be calculated using following formula,

$$\sigma_v = \int_0^Z H \rho(z) g dz$$ \hspace{1cm} (3)

Here H is the depth of the formation where stress is calculated, \( \rho \) is the density of the overlying formation and \( g \) is the gravitational acceleration which is mostly considered constant.

If there is a porous media then the pressure in the pore space should be taken in count and thus the effective vertical stress \( \sigma_v' \) will be calculated using following formula,

$$\sigma_v' = \sigma_v - Pp$$ \hspace{1cm} (4)
The propagation of fracture will normally take place in the direction parallel to the maximum horizontal stress ($\sigma_{H\text{max}}$) and perpendicular to the minimum horizontal direction ($\sigma_{H\text{min}}$). The horizontal stress is calculated using following formula,

$$\sigma_H = \left( (\sigma_v - Pp) \left( \frac{\nu}{1-\nu} \right) \right) + Pp$$

(5)

The effective vertical stress is used to calculate the horizontal stress using following formula,

$$\sigma_{H}' = \left( \frac{\nu}{1-\nu} \right) \sigma_v'$$

(6)

Here $\sigma_H'$ is the effective horizontal stress and $\nu$ is the Poisson ratio. In many cases the horizontal stress will be different in all directions. If we consider the various geological conditions and tectonic stress, then maximum horizontal stress ($\sigma_{H\text{max}}$) and minimum horizontal ($\sigma_{H\text{min}}$) stress can be approximated.

The breakdown pressure (i.e. the pressure at which the formation rock fractures and allows the fluid to enter in) is calculated using following formula,

$$P_{bd} = 3\sigma_{H\text{min}} - \sigma_{H\text{max}} + T_o - p$$

(7)

Here $P_{bd}$ is the breakdown pressure, $T_o$ is the tensile strength of rock and $p$ is the reservoir pressure.

According to the Hooke's Law, under uniaxial compression stress must be proportional to the strain,

$$\sigma = E \varepsilon$$

(8)
Here $\sigma$ is stress, $E$ is Young's Modulus and $\varepsilon$ is the strain. Rocks have different values of Young's Modulus. Fracture propagation and growth is affected by Young's Modulus.

4.5. PRESSURE ANALYSIS OF HYDRAULIC FRACTURE

The pressure in the fracture is the function of the stresses in the formation and the fluid that is used to create the fracture in the formation. Pressure can be compared with all the factors that control the fracture growth. If the in-situ properties of the rock, fluid properties and the pressure can be defined than it is easy to understand the fracture geometry and fracture growth. Different fracture models have different formulas for calculating the net treating pressure. The net treating pressure ($P_{\text{net}}$) is basically the difference between the bottom hole treating pressure (BHTP) and closure stress. The formula for $P_{\text{net}}$ is as follows,

$$P_{\text{net}} = (P - \sigma_c) \alpha \left\{ \left( \frac{E'}{h^4} \right) \left( \frac{\mu q x_f}{E'} \right) + \left( \frac{K_{lc-app}}{h^4} \right) \right\}^{1/4} $$

(9)

Here $\sigma_c$ is the closure stress, $E'$ is the plain strain modulus, $\mu$ is the viscosity of fracturing fluid, $q$ is the pump rate, $K_{lc-app}$ is the apparent fracture toughness, $h$ is the fracture height.

Equation 9 shows us that $P_{\text{net}}$ is directly proportional to the ratio of plain strain modulus and fracture height and also to the product of viscosity, flow rate and fracture half length raise to the $1/4$ power. So it can be understood from the relation that the net treating pressure increases with an increase in fracture length but with the condition that fracture height should remain constant or increase very less. So if the height of the fracture is increasing with a constant flow rate and constant fluid viscosity than the net
treatting pressure will not increase because from equation it is clear that fracture height is to power four.

Nolte and Smith (1981) developed the net treating pressure analysis methodology used for the fracture simulation (Larry Britt et al., 2009). He prepared a log-log graph of net treating pressure versus the pumping time which is useful in understanding the fracture propagation. This plot shows different modes in fracturing process. This plot shows us the period of confined height extension, constant height growth (stable growth), restricted height (screen out) and controlled height growth. Figure 4.6 shows the relationship between net treating pressure and the pumping time.

Figure 4.6. Nolte Smith interpretation guide (Britt et al., 2009)
Figure 4.6 shows different modes,

I - Contained Height (Unrestricted extension)

II - Stable Growth (Natural fracture opening)

III - Restricted Extension (Screenout)

IV - Unstable height growth

This plot is a result of the work by Perkins and Kern (1961) and Nordgren (1972), which focused on the fact that net pressure is proportional to time raised to some power (n).

\[ \Delta P = T^{(n)} \]  

(11)

For the fluids which are used in fracturing treatment the exponent (n) can be defined in some range for high and low fluid loss. The exponent factor varies from \( n = 1 \) for Newtonian fluid to \( n = 0.5 \) for non-Newtonian fluid.
5. FRACTURE DIAGNOSTICS

It is important to understand the fracture morphology (height, length and azimuth) in order to develop a low permeability reservoir with horizontal drilling and hydraulic fracturing. The development of fracture is longitudinal or horizontal will depend on the orientation of the fracture. There are different methods for determining the fracture azimuth. The common methods used are Induction logs, tilt meters, microseismic mapping etc.

5.1. INDUCTION LOGS

This method is based on the principal that if the fracture is created in the formation then the resistivity of that fracture will be different compared to the surrounding formation. The induction log is distorted by the resistivity difference between the fractured area and surrounding formation. If the formation is deeper it will tend to alter the resistivity over a large volume compared to the shallower formation. This may influence the reading of induction logs for deeper formation more compared to the shallower formation. Thus for distinguishing the deeper and shallower formation, array induction logs with multiple depths is used.

The fundamental property due to which the material opposes the flow of current is resistivity. It is a wireline log of the formation resistivity. It is based on the principle of inducing the alternating current loops in the formation and then measure the received signal in the receiver. The alternating current of some frequency is allowed to pass through the transmitter coil and it induces an alternating magnetic field inside the formation. This helps in creating current loops in the formation. These current loops will form its own magnetic field and gives out current while crossing the receiver coil. In
majority of cases arrays of several coils are used. Either these arrays are hardwired or it may consist several simple arrays that are connected to software in order to give appropriate readings. The induction (resistivity) log is shown in Figure 5.1.

Figure 5.1. Resistivity log showing change in resistivity at a certain depth
5.2. TILTMETER

A tiltmeter is an instrument designed to measure very small changes from the horizontal level, either on the ground or in structures. The tiltmeter is used to monitor changes in the inclination of a structure. Tiltmeter data can provide an accurate history of movement of a structure and early warning of potential structural damage. Typical applications include: Monitoring rotation caused by mining, tunneling, soil compaction.

The tiltmeter is a device that works on measuring the angular rotation with respect to the gravity vector. It has a signal conditioning electronics that is helpful in producing stable output signal for a different and wide range of input voltages. This helps in knowing the actual movement and not just the power supply variations.

The tiltmeter instrument is sensitive it is like a carpenter’s bubble level instrument (carboceramics). It is a tube made up of quartz and this tube is filled with some conductive fluid with a bubble of gas. In case when the tiltmeter moves the gas bubble present in the tube will try to maintain its alignment with the gravity vector. The electrode’s area that is in contact with the conductive fluid will determine the amount of electrical current that flows between excitation electrode and the pickup electrode. This generates a difference in electrical current between these two electrodes. This difference is amplified, digitized and used to understand how far the sensor has tilted. Figure 5.2 shows the basic principle on which the tiltmeter works.
Generally, two different tiltmeters are used depending on the information needed,

- Surface tiltmeter
- Downhole tiltmeter

5.2.1 Surface Tiltmeter. This tiltmeter is used to study the hydraulic fractures. It can monitor the fracture as deep as 12000 feet. This works on the assumption that for the deformation created by the fractures, the earth will behave in an elastic manner.

The well is surrounded radially by a typical array of large number of tiltmeter. The distance is about 0.4 times the depth of the fractured zone. All this tiltmeters are installed in small holes with depth of around 10 to 20 feet and packed with sand. This is done to insulate the apparatus from the surface weather conditions and noise effects.
5.2.2 Working of Surface Tiltmeter. As discussed earlier the surface tiltmeter has an array of certain number of tiltmeter surrounding the wellbore. The tiltmeters are self contained, it communicates with the site through high gain-radio telemetry links. There is a predetermined cycle period during which a central computer polls each tiltmeter periodically or downloads the tilt data that are collected. This is automatically transferred to the computer automatically once the information is collected and it is converted into graphical data. Figure 5.3 shows an example of a typical tiltmeter site outfitted with radio telemetry for long term fracture modeling.

![Figure 5.3](image-url)
The monitoring job also involves measuring the tilt induced by production and/or injection induced tilt. The same procedure is followed in an inverse manner to determine fracture parameters and delta-pore-pressure induced parameters that produce the deformation field. Highly sensitive device is required to measure the magnitude of induced surface deformation as it is quite low.

The surface tiltmeter is generally used for:

- In determining the fracture azimuth and dip.
- Discern fracture growth in multiple plains.
- Approximation of fracture centre (depth to centre and lateral centre shift).

5.2.3. Downhole Tiltmeter. The working principle of downhole tiltmeter is same as the surface tiltmeter. The downhole tools are run into offset wells on wireline with the standard oilfield centralizer. The offset wells are drilled at a certain distance to the injection well. It is really important to consider the distance as the distance influences the reliability and predicted length of a fracture. The distance between this tools and fractures is short compared to the surface tiltmeter. There is a signal to noise ratio because of this short distance between tool and fracture. Typically 6 to 18 tiltmeters are placed in the offset wells in an array. The depth of instrument is decided on the interval to be fractured and the instrument is centered on it. Figure 5.4 shows a downhole tiltmeter installation.
A downhole tiltmeter is used for:

- Determining fracture azimuth and dip
- Detection of out of zone fracture growth and/or unstimulated pay
- Approximate hydraulic fracture width
- Help in calibrating fracture growth models

The downhole tiltmeters are not much effective for horizontal fractures though. This is the limitation of downhole tiltmeter. It is designed for a tolerance of 8 to 10° but
there few tiltmeters with a tolerance that can handle the tolerance of plus or minus 30º are available now a day (Advantek International).

The downhole tiltmeter is compared with the surface tiltmeter in Figure 5.5. As it can be seen that the information regarding the direction of the fracture can be obtained using surface tiltmeter and the information regarding created fracture height is provided by downhole tiltmeter.

![Figure 5.5. Comparing downhole and surface tiltmeter (Viola Rawn - Schatzinger, 2009)](image)

5.3. MICROSEISMIC MAPPING

Microseismic mapping works on the principle of earthquake seismology. Similar to earthquakes, the events of microseismic also emit elastic P (compressional) and S (shear) waves. The microseismic events are at much higher frequencies compared to earthquake although its elastic in nature. Similar to the downhole tiltmeter there are offset
wells to monitor the fracture near the injection well. This can be around 1000 ft to 1500 ft away from the injection well. The location and the direction of the fracture can be determined using the P and S waves and plotting them on the X, Y and Z components. Figure 5.6 shows the microseismic event and function.

![Figure 5.6. Microseismic event and function (IPAA)](image)

It can be seen from the figure that the signals are generated from the fracture tip. An increase in the formation stresses is created by hydraulic fracture and this stress are
proportional to the net fracturing pressure. This stresses are also proportional to the increase in pore pressure due to fracturing fluid leak off. The result in shear slippages around the hydraulic fracture is due to the tip process and pore pressure. This shear slippage act as a mini earthquake and it has its epicenter within and/or near the hydraulic fracture. The microseismic mapping technology is much easier to use compared to the downhole tiltmeter.

5.4. SUMMARY OF FRACTURE DIAGNOSTIC TECHNOLOGIES AND THEIR LIMITATIONS

Table 5.1 gives an idea of the limitations of all fracture diagnostic methods.

Table 5.1. Fracture diagnostic technologies and its limitations (Pinnacle Technologies)

<table>
<thead>
<tr>
<th>DIAGNOSTIC</th>
<th>MAIN LIMITATIONS</th>
<th>ABILITY TO ESTIMATE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface Tilt Mapping</td>
<td>Resolution decreases with depth</td>
<td></td>
</tr>
<tr>
<td>DH Offset Tilt Mapping</td>
<td>Resolution decreases with offset well distance</td>
<td></td>
</tr>
<tr>
<td>Microseismic Mapping</td>
<td>May not work in all formations</td>
<td></td>
</tr>
<tr>
<td>Treatment Well Tiltmeters</td>
<td>Frac length must be calculated from height and width</td>
<td></td>
</tr>
<tr>
<td>Radioactive Tracers</td>
<td>Depth of investigation 1'-2'</td>
<td></td>
</tr>
<tr>
<td>Temperature Logging</td>
<td>Thermal conductivity of rock layers skew results</td>
<td></td>
</tr>
<tr>
<td>HIT</td>
<td>Sensitive to I.D. changes in tubulars</td>
<td></td>
</tr>
<tr>
<td>Production Logging</td>
<td>Only determines which zones contribute to production</td>
<td></td>
</tr>
<tr>
<td>Borehole Image Logging</td>
<td>Run only in open hole information at wellbore only</td>
<td></td>
</tr>
</tbody>
</table>
6. MICROSEISMIC MAPPING

Microseismic mapping is a technique to understand the fracture propagation and keeps a track of the fracture propagation as it advances through the formation. Microseismic mapping works on the principle of earthquake seismology. Similar to earthquakes, the events of microseismic also emit elastic P (compressional) and S (shear) waves. The microseismic events occur at much higher frequencies compared to earthquake although it is elastic in nature. The frequency range may be as high as 200 to 2000 Hz. The science of microseism is based on micro-earthquake. These micro-earthquakes are too small to be felt on the surface, so it should be measured from the underground itself. These micro-earthquakes are measured or sensed using the sensors called the Geophones or Accelerometers. This event is called microseismic event.

Figure 6.1 explains the working procedure of how microseismic events of the fractured zone can be recorded using the P and S waves velocity model combined with the downhole array of the seismic sensors present in the nearby offset wells. Microseismic interpretation consists of following observations,

- Fracture height
- Fracture length
- Fracture azimuth
- Fracture or fault activation
- Fracture behavior
6.1. MICROSEISMIC EVENT

When the energy is emitted as a result of rock failure due to shear, the possibilities of large earthquake can occur. In similar way microseismic events occurs due to the activities like oil and gas production, creating fractures in the formation or mining that may change the stress distribution of the formation and change the volume of the rockmass. The formation or the rock will possess the elastic property, due to which it will try to redistribute the stress within the rockmass. During this process the rock will shear or slip along the preexisting zones of weakness as a fault or fracture network. The
energy is released in the form of seismic waves during this fault/fracture generation and this is called the Microseismic event.

6.2. MICROSEISMIC EVENT DETECTION

Microseismic events lead to the emission of elastic P (compressional) and S (shear) waves which reaches the installed receivers (geophones). These waves are recorded and transmitted in the form of signal, this signal is registered as an increase in amplitude compared to the other background level (background noise). Depending on this signal quality the peaks are formed whether high or low in the signal amplitude that is associated with the P and S waves arrivals. It is hard to achieve a true microseismic signal because of the background noise that is created. When true signal is detected it is called triggered. Different methods are used for detecting the true event signal and differentiate it with respect to the background noises. The common methods used for identifying true microseismic event are Threshold triggering and STA/LTA ratio.

6.2.1. Threshold Triggering. A user defined threshold limit is set as a break up point. Threshold limit detects the microseismic event based on this user defined limit. There are different channels for receiving the signals. The amplitude of signals on each channel will be identified and compared with the threshold limits, the channels which will exceed the threshold value will be recognized. A condition is usually set in order to ensure that in more than one sensor microseismic event should be detected. To ensure this a condition is set to trigger an event on system only when the set number of channels individually trigger within a given period of time.

The configuration of threshold triggering can be done in such a way that it automatically responds to the changing noise condition. If there is a fluctuation in the
signal the threshold trigger will still consider the change rather than giving an erroneous noise signals triggering. Figure 6.2 shows an example of threshold triggering.

Figure 6.2 shows that there are 6 different channels. The used defined limit is 100 mV. The signals on the channels 1 - 5 are exceeding the user defined threshold limit but the signal on channel 6 is not exceeding the user defined threshold limit. The microseismic event will be triggered when all the set channels will trigger within a given period of time.
6.2.2. STA/LTA Ratio. STA is the Short Term Average and LTA is the Long Term Average. The average energy in STA leading window and the LTA trailing window are compared in STA/LTA ratio method. In this method the ratio of STA and LTA should be greater than the specific user defined value. If the value greater than the user defined value is obtained the signal will be triggered. Similar to the threshold triggering method, when the set number of channels individually trigger within a given period of time the data acquisition system will trigger. Figure 6.3 shows example showing the function of STA/LTA ratio method.

![Figure 6.3. Example showing the function of STA/LTA ratio method (ESG Solutions)](image)

Figure 6.3 shows the STA/LTA ratio for different channels. The blue window is the STA region and the green window is the LTA region. In channel A and B the ratio
(STA is small as well as LTA is small) is small/small so it is equal to 1. In channel C the ratio is big/small so it is greater than 1. In channel D the ratio is big/big so it is equal to 1. So the signal will be triggered for channel C. The benefit of the STA/LTA ratio method over threshold trigger method is that the amplitude will not be triggered if amplitude is not increased significantly.

6.3. WAVEFORM

The seismic waves are released into the surrounding rocks if the microseismic event occurs. The elastic deformation takes place when the seismic waves travels through a rock. This is called body waves and are totally different from the surface waves. This waves applies longitudinal stress i.e. compression or shear stress on the rocks. The elastic property of rock will try to bring back the rock in its original condition once the force is removed. The type of propagating waves governs the type of stress or strain in the body of rocks. There are two types of waves P (compressional) and S (shear) waves.

6.3.1. P Waves. P waves are the compression seismic waves that travel very fast. As it moves through the medium it pushes and pulls it. It passes very smoothly like the flow of water on the surface. The particles in the medium experiences vibrations and it is in direction parallel to the propagating wave. Figure 6.4 shows the direction of P wave and its effect on medium.
6.3.2. **S Waves.** S waves are the shear waves that travels with a low speed compared to the P waves. This waves can pass through the rock body only. It can move the particles inside the rock in up-down or side-side position. Particles in the medium experiences perpendicular vibration to the direction of wave propagation. Figure 6.5 shows the direction of S wave and its effect on medium.

![Figure 6.4. P wave propagation (ESG Solutions)](image1)

![Figure 6.5. S wave propagation (ESG Solutions)](image2)

6.3.3. **Moveout.** If the separation between the P wave and S wave is more than the distance between the source and the sensor than the effect of the distance between the source and the receiver on the recorded time is described by Moveout. The sensor that is
nearest to the source will detect the arrival time and the delay will be noticed by the extra
distance that the waves have to travel from source to the farther receivers.

6.3.4. Use of P and S Waves in Event Location. Event location is the location
where the microseismic event has occurred i.e. either the fracture is generated or the
fracture is reactivated. The velocity of the medium through which the waves are passing
and the distance between the event and the sensor governs the traveling time taken by the
P and the S wave to travel of that distance. The speed with which the microseismic event
radiates from the event source through the rocks can be determined using sonic logs. This
is helpful in creating a velocity model.

The event location can be determined using following methods,

- P and S waves picks: to determine the distance between event and sensor.
- The orientation using the hodogram analysis.

6.3.4.1. Event location using P and S waves. The principle of moveout is used
here. The array of sensors are sent inside the offset well. The distance between this sensor
is known. The difference in the arrival time of both P and S waves is noted. This is called
moveout and it will give information regarding the distance on the sensor array. The
velocity of both the waves are used to determine the event location. The difference will be
created between the P wave and the S wave as the P waves travel faster than the S wave,
this is used to determine the event location. There will be a wider separation between P
and S waves for the sensors that are far away from the event compared to the sensor that
are near the event. Figure 6.6 shows the P and S waves separation.
Figure 6.6. P and S wave separation (ESG Solutions)

Figure 6.6 shows the P and S wave propagation with respect to time. It can be seen that the time when P wave is observed is earlier than that of the S wave.

6.3.4.2. Orientation using hodogram analysis. Hodogram analysis is the cross plot of the particle motion having two components for a time window. It is used to understand the directions of waves from where they are coming and to detect the shear wave splitting. The data is recorded along the axes of the geophones and it is displayed as a function of time.

6.4. MOMENT MAGNITUDE

Magnitude is one of the most important output of the microseismic monitoring. Seismic moment is defined for shear dislocation as shear modulus multiplied by area of slip multiplied by the displacement.

\[ Mo = \mu \cdot AD \]  

(12)
In majority cases the seismic moment is calculated from the moment magnitude which is nothing but the log of the moment. Following formula is used to calculate the seismic moment from the microseismic event.

\[ Mo = \frac{4\pi \rho c^3 R \Omega_o}{F} \]  

(13)

where \( \rho \) is the density, \( R \) is the distance between source and sensor, \( \Omega_o \) is the low frequency level of displacement and \( F \) is the radiation pattern, average if the mechanism pattern is unknown 0.52 P or 0.63 S.

The size of event in terms of amount of energy released is known by the moment magnitude (ESG Solutions). It works on the principle of Richter Scale, in order to calculate the strength of the event, the amplitude of waveform is recorded with Seismograph at known distance from the source.

Moment magnitude basically relates to the rock movement, which is the distance of the movement along the fracture and the area of fault or fracture surface. Moment magnitude is considered among the most accurate methods for understanding the size of event. It is used to describe the physical activity of the event, this values can be used to compare the magnitude values for different events. The moment magnitude values are logarithmic values. So the increase in amplitude recorded in the seismograph is around 10 times more for every increase in one unit of the magnitude. The Table 6.1 shows us the Moment magnitude with respect to the slip area, moment, range, and equivalent explosive charge (Pinnacle Technologies).
Table 6.1. Example of the moment magnitude

<table>
<thead>
<tr>
<th>Moment Magnitude</th>
<th>Comments</th>
<th>Recording Range (feet)</th>
<th>Moment (MNm)</th>
<th>Slip and Area</th>
<th>Equivalent Explosive Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>-4</td>
<td>Smallest we can record</td>
<td>&lt;100</td>
<td>0.01</td>
<td>10 μm / 0.003 m²</td>
<td>1 mg</td>
</tr>
<tr>
<td>-3</td>
<td></td>
<td>~1500</td>
<td>0.04</td>
<td>40 μm / 0.03 m²</td>
<td>30 mg</td>
</tr>
<tr>
<td>-2</td>
<td>Big for Barnett</td>
<td>~2500</td>
<td>1</td>
<td>0.1 mm / 0.3 m²</td>
<td>1 g (blasting cap)</td>
</tr>
<tr>
<td>-1</td>
<td>Biggest in Barnett</td>
<td>~5000</td>
<td>40</td>
<td>0.4 mm / 3 m²</td>
<td>30 mg</td>
</tr>
<tr>
<td>0</td>
<td>Limit of “microseismic”</td>
<td>&gt;10000</td>
<td>1,000</td>
<td>1 mm / 30 m²</td>
<td>1 kg stick of explosive</td>
</tr>
<tr>
<td>1</td>
<td>Largest event Habanero geothermal</td>
<td>-</td>
<td>40,000</td>
<td>4 mm / 300 m²</td>
<td>30 kg</td>
</tr>
<tr>
<td>2</td>
<td></td>
<td>-</td>
<td>1,000,000</td>
<td>1 cm / 3,000 m²</td>
<td>1 ton</td>
</tr>
<tr>
<td>3</td>
<td>Felt earthquake</td>
<td>-</td>
<td>40,000,000</td>
<td>4 cm / 0.03 km²</td>
<td>30 ton</td>
</tr>
</tbody>
</table>

6.5. UNCERTAINTIES IN LOCATING MICROSEISMIC EVENTS

It is necessary to understand the uncertainties in the microseismic events before interpreting the microseismic patterns. This is done in order to avoid the erroneous results in getting the microseismic patterns. Following are the uncertainties observed,

6.5.1. Travel Time of P and S Waves. It is necessary to match the arrival time of the P and S waves in order to understand the microseismic event location. There are certain conditions like surface pumping operations, wellbore condition, production, drilling etc which may cause different types of background noises which will affect the signal quality of these waves. The Signal to Noise ratio (SNR) is the key function to measure the signal in an accurate manner. The uncertainties in the arrival of P and S waves may decreases with an increase in SNR. The arrival times may not be detected in all the sensors.
In order to understand this signals an evaluation of event quality is included. In majority of cases when events are reported, the SNR with values between two and three is taken as a cutoff value. Figure 6.7 shows the impact of SNR quality on the microseismic pattern.

![Figure 6.7. Impact of SNR on fracture pattern (C. Cipola et al. 2011)](image)

Figure 6.7 shows the plan view of the microseismic pattern with different values of SNR. The figure on left is with SNR value greater than 2.5 in which the pattern looks uncertain and shows a complex fracture growth whereas the figure on right shows the SNR value greater than 5 and the pattern in this figure is certain and shows the planar fracture growth. The best SNR values obtained depends on the number and quality of events and source to sensor distance.
6.5.2. Velocity Model. The uncertainty in the velocity model may lead to error in event location. The sonic logs are used to measure the P and S waves. The sonic log measures the vertical velocities but the ray paths for most microseismic are horizontal. The vertical and horizontal velocities may vary because of the rock fabric, deposition, layering etc. Calibration of sensor orientation in the wellbore is one of the most important things to study microseismic operation. The sensor orientation is determined by monitoring the location of the perforation shots which is pre decided. If this orientation is perfect then the chances of uncertainties in the velocity model can be reduced if the velocity model has proper P and S waves. Figure 6.8 gives an idea for this.

Figure 6.8. Uncertainty in velocity model and the impact of depth of sensor array (C. Cipola et al. 2011)

Figure 6.8 show the depth of sensor arrays can impact the uncertainty in the velocity model. For this particular example the location uncertainty is less when sensor array is at depth.
### 6.5.3. Distance Effects

This is typically a observation well bias, the location of the observation wells can create certain kinds of uncertainties. The strength of the microseismic event can be calculated using the seismic moment. It is difficult to detect an event due to attenuation of the signal if the seismic amplitude decreases. In order to get the accurate Estimated Stimulated Volume (ESV) and Stimulated Reservoir Volume (SRV) it is important to know whether the entire fracture geometry was mapped. This is because microseisms can be detected only to a certain distance from the observation (offset) wells. Due to this detection limits wrong fracture geometry is considered or wrong estimation of SRV is done.

In order to avoid such uncertainties following exercise should be practiced, Plot a graph of event magnitude versus distance from sensor array and plot all the events on that graph. This graph can be used to check if the entire fracture geometry was mapped by measuring the lowest detectable event which is farthest from the sensor array. Now if the measured events are larger in number than it is possible that entire fracture was mapped because the higher magnitude event at even greater distance would have been detected if it has occurred. This is shown by an example in Figure 6.9

![Magnitude versus distance graph](image.png)

**Figure 6.9.** Magnitude versus distance graph (C. Cipolla et al. 2011)
Figure 6.9 shows us the magnitude versus distance graph in which the graph on left shows the graph of entirely fractured event and the graph on right shows us the normalized events. In order to normalize these events a cutoff point is selected. The cutoff point is the point where the lowest magnitude event is noticed from the farthest distance from the sensor array, which represents the fracture extremities. Eliminating all the events that lie below this threshold limit will help in getting more accurate results as there will be more events detected as the distance to sensor array decreases.

6.5.4. Effect of Location of Observation Well. The location of the observation well from the treatment well is also source of concern when considering the results for event patterns. Considerable variations can occur in the calculation of distance, depth and azimuth for each event. This type of uncertainties is very common in multifractured horizontal wells. Figure 6.10 shows the impacts of observation well bias on the multifractured horizontal wells. The fracture growth may appear complex or planar depending on the orientation and location of the observation well. In the example well considered in Figure 6.10 the fracture is planar in both cases but it can be misinterpreted as complex because of different effect of azimuth uncertainty between this two stages. For the stage farthest from the observation well the fracture height might be interpreted wrongly and for the fracture near to observation well the its complexity can be wrongly interpreted.
Figure 6.10. Effects of observation well location bias on the microseismic event patterns for multifractured horizontal wells (C. Cipolla et al. 2011)

Figure 6.10 shows the hypothetical events that may be misinterpreted, the figure below it shows the uncertain ellipsoids that may occur due to wrong interpretation because of location bias.
6.6. INTERPRETATION OF MICROSEISMIC DATA

There are several interpretation tools that are used in order to evaluate the microseismic pattern. For this discussion we will be using spatial and temporal application of an event histogram, ESV and event count as shown in Figure 6.11. Considering an example of a re-fracture in horizontal shale gas completion (C. Cipolla et al. 2011).

For evaluating the fracture growth, Histograms with event count versus the position can be a really important tool. As shown in Figure 6.11 the histograms are used to understand the fracture location along the horizontal lateral at different stages of the
treatment. The left most portion of the figure is the event locating histograms, the graph in the centre is the spatial distribution of ESV and the right most graph is the treatment data integrated with ESV and event count. The topmost graph shows the initial stage of the re-fracturing treatment which shows that the fracture is extending in the similar fashion as the initial treatment. It can be seen that ESV is not increasing and the event counts are decreasing. The middle graphs shows that the diversion stage and the diversion stage is not successful. This can be seen from the overlapping in the histogram. In this case there is a limited increase in the ESV and event counts are decreasing. After evaluating the stage 2 design, stage 3 design was modified, and the bottom graph shows the results for diversion. No overlapping can be seen in this stage in the histogram and a large increase in the ESV and events is noticed.

ESV calculation provides real time evaluation tool to identify the effectiveness of the fracture and the re-fracturing behavior. Comparison of the ESV graphs in Figure 6.11 it can be clearly seen that while moving from stage 1 to stage 3 the fracture location was unchanged after the initial diversion stage.
7. ANALYSIS OF HYDRAULICALLY FRACTURED WELL DATA

The analysis for hydraulic fracture is done by understanding the areal view of the fractures. Figure 7.1 shows the Lateral view (left side) of the fracture and Areal view (right side) of the fracture. The lateral view is useful in understanding the height of fractures whereas areal view is used to understand the height and azimuth of the fracture. This section describes the evaluation of well microseismic data, taken from the literature for well within several different shale plays.

Figure 7.1. Comparison between lateral view and areal view (Travis Vulgamore et al., 2007)

7.1. AREA OF EVALUATION METHODOLOGY

Figure 7.2 shows us the areal view of the microseismic image for a multifractured horizontal well. Different stages are indicated with different colors. The straight line with
light grey color in the centre shows the centre of the wellbore. The curved lines passing through the centre shows the fractured zone. This is not seen in the microseismic image, this is for understanding the figure.

Figure 7.2. Example microseismic data for multi-stage HF horizontal well

For each stage of fracturing, a circle is inscribed with the center of the circle at the perforations (the point of fracture initiation), with a diameter of either ¼ mile for Class II injection criteria, or using a diameter according to State requirements as shown in Figure
7.3. Each state with significant production from a shale play was contacted to determine if their regulatory agency required a particular area to be studied.

![Diagram showing AOE carried out on the fractured area with reference of the microseismic image.]

Figure 7.3. AOE carried out on the fractured area with reference of the microseismic image

Table 7.1 summarizes state practices for studying wells around hydraulically fractured wells, and compares those criteria to Class II injection. Not all states responded to the survey, but for the responses obtained, it appears that a ¼ mile area of investigation is most commonly used.
Table 7.1. Comparison between AOR and AOE

<table>
<thead>
<tr>
<th>TATE</th>
<th>AOR DISTANCE</th>
<th>DISTANCE FROM PROPOSED FRAC JOB</th>
</tr>
</thead>
<tbody>
<tr>
<td>ALASKA</td>
<td>Quarter mile</td>
<td>Quarter mile</td>
</tr>
<tr>
<td>IDAHO</td>
<td>-</td>
<td>Quarter mile</td>
</tr>
<tr>
<td>COLORADO</td>
<td>Quarter mile</td>
<td>500 feet</td>
</tr>
<tr>
<td>NORTH DAKOTA</td>
<td>-</td>
<td>One mile</td>
</tr>
<tr>
<td>NEW MEXICO</td>
<td>2.5 mile or Quarter mile</td>
<td>Quarter mile</td>
</tr>
<tr>
<td>INDIANA</td>
<td>Quarter mile</td>
<td>500 feet</td>
</tr>
<tr>
<td>TEXAS</td>
<td>Quarter mile</td>
<td>Quarter mile</td>
</tr>
<tr>
<td>PENNSYLVANIA</td>
<td>Quarter mile</td>
<td></td>
</tr>
<tr>
<td>WYOMING</td>
<td>Quarter mile</td>
<td>Quarter mile</td>
</tr>
<tr>
<td>OKLAHOMA</td>
<td>Quarter mile (non com.)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Half mile (com.)</td>
<td>-</td>
</tr>
<tr>
<td>LOUISIANA</td>
<td>Quarter mile</td>
<td></td>
</tr>
<tr>
<td>KANSAS</td>
<td>Quarter mile</td>
<td></td>
</tr>
<tr>
<td>OHIO</td>
<td>Half mile (if Q&lt;200 bbl/d/yr)</td>
<td>Quarter mile</td>
</tr>
<tr>
<td></td>
<td>Quarter mile (if Q&gt;200 bbl/d/yr)</td>
<td></td>
</tr>
<tr>
<td>MONTANA</td>
<td>Half mile</td>
<td>Quarter mile</td>
</tr>
<tr>
<td>ARIZONA</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>NEW YORK</td>
<td>Quarter mile</td>
<td>-</td>
</tr>
<tr>
<td>MISSOURI</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>CALIFORNIA</td>
<td>Depends on geology</td>
<td>1000 feet</td>
</tr>
<tr>
<td>WEST VIRGINIA</td>
<td>Quarter mile</td>
<td></td>
</tr>
</tbody>
</table>
7.2. CASE STUDIES

The procedure noted here was applied to the microseismic data for wells found in the literature. A limited number of wells were found with areal seismic and a scale that would allow analysis. The cases found and analyzed are summarized here.

7.2.1. Case 1. Figure 7.4 is the Barnett shale formation in the Ft. Worth Basin which is located in the North Central part of Texas

![Microseismic mapping in North Central Texas on Barnett Shale formation (G waters et al., 2011)](image)

Figure 7.4. Microseismic mapping in North Central Texas on Barnett Shale formation (G waters et al., 2011)
The exploration of this well started back in 1981 and then certain service companies operating on this kept on changing. In 2003 Devon energy took the charge of the production here. There are more than 50 horizontal wells in this area.

It can be seen from the graph that all the frac stages are represented with different colored microseismic event, AOE is carried out around each stages and the area around the microseismic is covered with the same color in order to understand the evaluation easily. It is observed that for all the stages all microseismic events fall in their respective AOE circles.

7.2.2. Case 2. Figure 7.5 is the tight gas formation at West Tavaputs field in the Unita Basin, Utah.

Figure 7.5. Microseismic mapping in West Tavaputs field in the Unita Basin, Utah (J. E. Shemeta et al., 2007)
The experiment in this basin was carried out using 12 level receiver in which 3 of this 12 level receiver consisted of triple receiver stack. This was done to obtain the accurate microseismic images.

From the graph it can be clearly seen that the microseismic events are located near to the wellbore and they lie in the 300 feet radius around the fracture zone. In this case AOE was carried out around four different stages of fracture and it is observed that entire microseismic event falls in this four stages so there is no chance for fracture to extend beyond this area.

7.2.3. Case 3. Figure 7.6 shows an unconventional shale formation within the Fort Worth basin. The depth at which the horizontal drilling was carried out is about 10,000 feet. Permeability of the formation is in order of nanodarcies and the gas filled porosity is approximately 3% to 5%.

It is observed from the graph that four different stages are considered for AOE. The stages around which the AOE is carried out with colors orange and blue covers all the microseismic events in it. Stages having microseismic events with AOE colored yellow and red has few microseismic events falling outside the quarter mile radius. This events are not extended much farther than the AOE, but still this is a point of concern that what measures should be taken for this cases.
7.2.4. Case 4. Figure 7.6 shows the microseismic mapping in the Barnett shale formation located in the Mississippian marine. The permeability of the formation varies from 0.00007 to 0.00005 md and the porosity is in the range of 3% to 5%. The Barnett shale in this area is estimated to extend over 54,000 miles.
It is observed from the microseismic mapping shown in Figure 7.7 that all the microseismic events fall in the quarter mile radial distance for all the three stages that are considered in this graph for AOE. So the fractures are no longer than the quarter mile.
7.2.5. Case 5. Figure 7.8 shows the microseismic mapping in the tight gas reservoir located in North America.

Figure 7.8. Microseismic Mapping of a tight gas formation in North America (Jason Baihly et al., 2007)

The formation here is made up of sandstone. The permeability of the formation is less than 0.1 md.

Figure 7.8 shows microseismic mapping for two stages of fracturing. AOE is conducted on both of them. The quarter mile radial distance covers all the microseismic events in it.
7.2.6. Case 6. Figure 7.9 shows the microseismic mapping of the Barnett shale formation within the Fort Worth Basin.

Figure 7.9. Microseismic mapping in the Barnett Shale formation of Fort Worth Basin in Texas, (J. Daniels et al., 2007)
The matrix permeability is in the range of 0.00007 to 0.00005 md. Porosity range is 3% to 5%. The source rock is the Barnett and it is abnormally pressurized, it has a pore pressure gradient of approximately 0.5 psi/ft.

The figure shows us that there are few microseismic events that are not covered in the quarter mile radius around the well. The microseismic events that are not circumscribed in the AOR are just few feet away.

7.2.7. Case 7. Figure 7.10 shows microseismic mapping during the completion of two horizontal wells in the Marcellus shale formation located in the Tioga county of Pennsylvania. The estimated geologic transverse of the Marcellus shale was estimated to be about 90,000 square miles. The thickness increases as we follow the east direction due to change in characteristics.

The fracture half-length for well 1H was around 620 feet to 1125 feet and the fracture width was about 510 feet to 950 feet (Niel A. Stegent., SPE Pinnacle). The fracture half-length for well 2H was around 700 feet to 875 feet and the fracture width was about 370 feet to 620 feet.

The data from Pennsylvania is considered to be one of the most important reading, as there are lot of fracturing job carried out. It is really important to understand the fracturing treatment process going on and the area around the fractured zone that needs to be considered for AOE.
There are seven perforation stages for each well. The AOE is carried out around all the microseismic events for well 2H. The microseismic mapping shows that all the microseismic events fall in the 1000 feet radius. For well 1H the AOE was carried out for the third stage and it covered all the events of stage 2 and 4 so it can be said that for well 1H also the microseismic events will fall in AOE. The width and the half-length data calculated using the software also shows that the fracture does not exceed the 1000 feet radial distance.
7.2.8. **Case 8.** Figure 7.11 shows the microseismic mapping in the Barnett Shale formation in the Mississippian age marine shelf deposit. There are four different stages for the hydraulic fracturing process. All the stages are shown with different colors. It can be seen that few stages are overlapping each other.

![Microseismic mapping](image)

**Figure 7.11.** Microseismic mapping in the Barnett Shale formation (C. Cipolla et al., 2011)
The AOE is conducted on all the four different stages. It is observed that the microseismic events in all the stages fall inside the quarter mile radius from the wellbore. It can be seen that the events in stage 1 (i.e. the events with green color) falls just inside the quarter mile radius. Stage 2 and Stage 3 (i.e. the events with red color and yellow colors respectively) do not extend much and are sited well inside the AOE. For stage 4 (i.e. the events with blue color) it is observed that all microseismic events do not fall in the quarter mile radius and there are few events observed outside AOE, but they are very few in number and just few feet away from the circle.

7.2.9. Case 9. Figure 7.12 shows the microseismic mapping of the Barnett Shale formation in the Jonah field in Wyoming state.

Figure 7.12. Microseismic mapping of the Barnett Shale formation in Jonah field Wyoming (Fracture mapping, Pinnacle Inc)
The Jonah field is located in Green river Basin in Sublette County in Wyoming. The formation had low permeability and the gross pay interval varied from 2800 to 3600 feet.

The plot in this case is magnitude vs. distance. The AOR is calculated considering the distance on X-axis as reference. It is seen that all the events in this plot is inside the quarter mile radial distance from the wellbore. The events do not exceed more than 600 feet. So there is no possibility for fractures to exceed the quarter mile radius.

**7.3.10. Case 10.** Figure 7.13 shows microseismic mapping of a Barnett Shale formation in North central region of Texas State.

![Figure 7.13. Microseismic mapping of Barnett Shale formation (N. R. Warpinski et al., 2005)](image-url)
The initial fracture pressure gradient was 0.61 psi/ft and it rose to around 0.71 psi/ft after the completion of fracturing treatment.

It is observed from the plot above that almost all the microseismic events are present inside the quarter mile radial distance from the wellbore. There are different stages but here the AOR is carried out from the centre which covers almost all the events in the quarter mile radial distance from the wellbore.

7.3 EXAMPLES OF FORMATION THAT ARE OUTSIDE UNITED STATES

7.3.1. Case 1. Figure 7.14 shows the microseismic mapping in the eastern china oil field

![Microseismic mapping of Eastern China Oilfield](image)

Figure 7.14. Microseismic mapping in the Eastern China oil field (Licheng Ma et al., 2012)
7.3.2. **Case 2.** Figure 7.15 shows the microseismic mapping of Cretaceous age sandstone formation in Central Alberta for well 1.

Figure 7.15. Microseismic mapping of Cretaceous age sandstone formation in Central Alberta (well 1) (Murray Reynolds et al., SPE 2012)
7.3.3. **Case 3.** Figure 7.16 shows microseismic mapping of Cretaceous age sandstone formation in Central Alberta for well 2.

Figure 7.16. Microseismic mapping of Cretaceous age sandstone formation in Central Alberta (well 2) (Murray Reynolds et al., 2012)
7.3.4. **Case 4.** Figure 7.17 shows microseismic mapping in the Halfdan field in Danish sector of North sea having chalk formation of Cretaceous and Danian age.

Figure 7.17. Microseismic mapping in the Halfdan field in Danish sector of North Sea having chalk formation of Cretaceous and Danian age (M. H. Rod et al., 2005)
7.3.5. **Case 5.** Figure 7.18 shows microseismic mapping in Shale formation of the Horner river basin in Canada.

Figure 7.18. Microseismic mapping in shale formation of the Horner River basin in Canada (Alex Novlesky et al., 2011)
The AOE is conducted on the microseismic plots of different formation present in
different location of the world. Figures 7.14 to 7.18 shows the AOE results conducted on
it. It is observed that there are different stages of fracturing in Figure 7.15, Figure 7.16
and Figure 7.18. All those stages were covered with different AOR. The quarter mile
radius around the wellbore is considered in all this cases and for all different stages. It is
observed that the microseismic events in all this case is fitted comfortably inside the
AOE, except for Figure 7.18

It is observed in Figure 7.18 that there are few events in stage 3 that falls outside
AOE. These microseismic events are really less, and if the depth of the formation is deep
than those events can be neglected. Most of the events in this case are very well fitted
inside our AOE. Figure 7.14 and Figure 7.17 also shows that the microseismic events are
fitted inside the AOR.

The Table 7.2 summarizes all the microseismic events discussed above and shows
the extent of the fractures on both sides, it also shows whether the fractures are limited to
AOE or not.
Table 7.2. Details of formation and the fractures extensions

<table>
<thead>
<tr>
<th>Sr. no.</th>
<th>Formation</th>
<th>Stages</th>
<th>Midpoint</th>
<th>Range towards +ve X axis</th>
<th>Range towards -ve X axis</th>
<th>AO E radius</th>
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<td>1</td>
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<td>1370</td>
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<td></td>
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Table 7.2. Details of formation and the fractures extensions (Continue)

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<th>Stage 2</th>
<th>Stage 3</th>
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<td>Barnett shale formation (feet)</td>
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<td>Halfdan field in Danish sector of North sea (distance in miles)</td>
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8. CONCLUSIONS AND FUTURE WORK

This study has evaluated publically available microseismic data for multi-stage hydraulically fractured horizontal wells in shale plays, to determine if AOR criteria are applicable to hydraulically fractured wells. Currently some state requires that wells near hydraulically fractured wells be studied prior to stimulation, but not all states have these requirements. The following are conclusions of the work:

1. Wells evaluated in this study have microseismic responses that indicate their fracture lengths are well within ¼ mile AOR criteria.

2. Not all States currently require and AOE process around hydraulically fractured wells, but many States do have this requirement.

3. Barnett wells had events outside the standard ¼ mile radius, but not far outside. This may be due to inaccuracy of the microseismic measurements.

4. No conclusions can be drawn regarding the efficacy of the ¼ mile radius for hydraulically fractured wells but industry has accepted this requirement. Some companies queried in this research indicate they voluntarily study wells within a ½ mile radius, self-imposing a more rigorous standard than required.

While this study is helpful in examining how an AOE may be defined in the future, it is a limited study with public data. It is suggested that this work continue with a complete set of data for each of the major shale plays, and that those results be made available for the industry.
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Yashesh Panchal earned his undergraduate degree in Chemical Engineering from Institute of Technology, Nirma University, Ahmedabad, India in Spring 2008 and worked for Solvay Specialties India (Pvt) Ltd for one year prior to enrolling for Master's program in Petroleum Engineering in Missouri University of Science and Technology in Spring 2011. He earned his Master's degree in Petroleum Engineering in Spring 2013.