

## Review Article

# Advancement of Hydraulic Fracture Diagnostics in Unconventional Formations

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Received 12 August 2021; Accepted 19 October 2021; Published 2 November 2021

Academic Editor: Qingwang Yuan

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Multistage hydraulic fracturing is a technique to extract hydrocarbon from tight and unconventional reservoirs. Although big advancements occurred in this field, understanding of the created fractures location, size, complexity, and proppant distribution is in its infancy. This study provides the recent advances in the methods and techniques used to diagnose hydraulic fractures in unconventional formations. These techniques include tracer flowback analysis, fiber optics such as distributed temperature sensing (DTS) and distributed acoustic sensing (DAS), tiltmeters, microseismic monitoring, and diagnostic fracture injection tests (DFIT). These techniques are used to estimate the fracture length, height, width, complexity, azimuth, cluster efficiency, fracture spacing between laterals, and proppant distribution. Each technique has its advantages and limitations, while integrating more than one technique in fracture diagnostics might result in synergies, leading to a more informative fracture description. DFIT analysis is critical and subjected to the interpreter's understanding of the process and the formation properties. Hence, the applications of machine learning in fracture diagnostics and DFIT analysis were discussed. The current study presents an extensive review and comparison between different multistage fracture diagnostic methods, and their applicability is provided. The advantages and the limitations of each technique were highlighted, and the possible areas of future research were suggested.

## 1. Introduction

Hydraulic fracturing is a well stimulation technique for enhancing hydrocarbon production from reserves. It relies on creating high-conductivity fractures propagated from the wellbore out into the formation [1]. The proppant fills the created fracture so that the fracture remains open when the fluid's pressure is reduced. As a result, a conductive path for hydrocarbons to flow from the reservoir into the wellbore is created. Hydraulic fracturing treatment, while appearing to be simple, offers many complications. Uncertainties exist regarding reservoir characteristics, fracture growth patterns, and fluid and proppant placement, which jeopardize the treatment's effectiveness [2, 3]. Fracture diagnostic techniques have proven to be effective in addressing

difficulties related to the design, execution, and monitoring of the fracture stimulation treatments [4]. There are several techniques for obtaining subsurface understanding into fracture dimensions, growth behavior, and interactions with the surrounding reservoir following treatment [5]. The crucial economic assessment of the potential outcomes is conducted based on the information received from these diagnostics, and optimal treatments are achieved [6].

Technological advances in well drilling, completion, and stimulation have resulted in record production and considerable growth in unconventional global markets. While these advancements are already having an impact, there is still a lack of understanding of important subsurface information, such as the created hydraulic fracture shape near and beyond the wellbore [7]. Hydraulic fracture diagnostics,

visualization of the created hydraulic fractures, and identifying proppant deep in the formation, further from the wellbore, are likely to be game-changers in releasing more hydrocarbons from unconventional reservoirs and improving well economics [8].

Unconventional resources expansion has made considerable strides in recent decades, thanks to game-changing advances in horizontal drilling and hydraulic fracturing. These previously uneconomic tight, low-permeability oil, and gas reservoirs are now an essential element of the energy mix necessary to meet the world's energy demands. Increased contact of fracture surface area and formation through innovative horizontal drilling and multistage fracturing completion method is a significant contributor to the success of unconventional hydrocarbon production [9]. Regions rich in conventional resources are actively exploring methods to demonstrate the potential for unconventional resources for future generations. Despite the availability of various diagnostic tools, the problems remain, particularly with the advancement of horizontal drilling and growing interest in the exploitation of unconventional [10, 11]. Hence, novel diagnostic methodologies are required to address the emerging challenges. This research discusses different diagnostic techniques and recent changes made to the conventional methods for application in unconventional reservoirs.

## 2. Literature Review

**2.1. Fracture Diagnostics Using Tracers.** The application of radioactive tracers combined with spectral gamma ray logging for fracture diagnosis is well established [12, 13]. Tracers that emit gamma rays are either injected into the fracturing fluids or coated on the proppant. Following the completion of the hydraulic fracturing treatment, logging is conducted to establish the near-wellbore fracture propped and unpropped heights. Radioactive (R/A) proppant tracers provide an approximation of the fracture height near the wellbore. RA tracers use embedded tracers, which can be ceramic materials, and provide quantitative information when assessing critical characteristics around the wellbore using gamma ray [5, 14]. There are different R/A tracers available that can be distinguished from one another using the logging tools; hence, by employing different tracers at different periods throughout the treatment, it may be possible to determine which perforations were receiving fluid at a given point in the treatment. These instruments have been widely used in both offshore and onshore applications to improve perforation efficiency and optimal proppant placement [15]. This technique has several advantages, including its relatively low cost, low reactivity with the reservoir fluids and rocks, similar transport behavior with the injected fluids, and ease of measuring with a high accuracy detection level [16]. However, the use of radioactive tracers raises environmental and safety problems for operators. Tracers are also restricted in their ability to provide information for regions far from the wellbore and fracture height in highly deviated wells [14, 17]. Radioactive tracers are being phased out in favor of chemical tracers, which are more environ-

mentally friendly and allow for longer-term data collection of in-well tracer flowback and communication within reservoir wells.

Chemical tracers are compounds that are either liquid or solid and are soluble in water, oil, or gas. The best chemical tracers must possess the following characteristics: be stable under reservoir conditions, have minimum partitioning into the nonsoluble phases, no adsorption on the reservoir rock, have a very low limit of detection, and have minimal to no environmental impacts [18]. Tracers used in multistage hydraulic fracturing are often classified as emulsion tracers, perforation tracers, and controlled release tracers. Tracer types and characteristics are summarized in Table 1.

[20] described the use of a nonradioactive tracer to assess the fracture height. The authors presented case studies as well as a comparison of nonradioactive and radioactive tracers. The nonradioactive tracer presented is a high thermal neutron capture cross-section tracer (HTNCC) that is placed into ceramic proppant grains during manufacture [21]. The HTNCC is added at very low concentrations that there is no noticeable change in the mechanical or physical properties of the proppant as a result of the addition. These tracers can be placed in either every grain for treatments that use 100% ceramic proppant or in treatments that use sand or other nonceramic proppant, ceramic grains having higher concentrations of the HTNCC can be mixed in and replace a small portion (5%) of the designed proppant. A pre- and postfrac neutron log is run across the zones of interest in both cases, and the difference in neutron response gives an estimate of proppant location. The primary advantage of this method is that the tracer is not radioactive; therefore, no special handling is required. Furthermore, because the tracer is a component of the proppant grains, the well can be logged at any time in the future. The cost may be higher depending on the fracture design and corresponding proppant requirements. Furthermore, this method is dependent on the depth of investigation of the logging tools. The radius of investigation is usually limited to no more than 24 in. from the wellbore, which means that the propped fracture profile outside 18-24 in. remains unknown. The accuracy of these methods is limited to a positive response only—if the proppant is not detected in a set of perforations or is not seen near the wellbore in a vertical well, it does not necessarily mean the proppant did not enter that set of perforations, or that the fracture did not grow higher. The fracture and proppant may be merely outside the radius of investigation. The inability of tracers to provide information on fracture dimensions far from the wellbore (greater than 24 in. from the wellbore) has been highlighted by Palisch et al. [22]. The authors described a method for far-field detection of the placed proppant. The method relies on electromagnetic technology to locate a detectable proppant.

In unconventional reservoirs, tracer flowback analysis is frequently used to determine hydraulic stimulation effectiveness, understand fracture communication with offset wells, and estimate fracture volume, correlate relative fracture contribution to the overall flow, and the connectivity of the fractured matrix created, etc. The combination of horizontal well drilling and multistage hydraulic fracturing treatment

TABLE 1: Tracers types and their characteristics modified after [19].

Tracer type	Uses	Advantages	Disadvantages
Perforation	1 Understanding the effectiveness of perforation.	1 The effectiveness of perforation treatment. 2 Inflow attributes.	1 Tracer volume restrictions.
Emulsion	1 Interwell communication. 2 Determining the strength of the fracture. 3 Evaluating the flow patterns.	1 Completion and zonal purposes. 2 Migration of fracturing fluids.	1 Possibility for faulty readings. 2 Tracer volume restrictions. 3 Short life period.
Controlled release	1 Inflow assessment.	1 Long-term inflow monitoring. 2 Accurate representation of zonal inflow.	1 Single-well characterization.

is widely used to increase production in unconventional and tight reservoirs. It is critical to evaluate the fracture networks developed to accurately predict hydrocarbon production. Several advantages have been found for fracture characterization using tracer flowback. Firstly, injecting different tracers into each fracture can effectively distinguish individual stages. Because these tracers will not become reactive with each other, the trace flowback analysis may be utilized to predict the fracture parameters at each stage. Secondly, since only a limited amount of tracers are injected, the concentration of tracers produced decreases over time, and the best tracer analysis would occur at the start of production. As a result, the collected tracer flowback data will most likely provide the earliest opportunity to evaluate a single-stage fracture network that contributes to the production of hydrocarbon (production allocation per stage). Finally, the tracer flowback test is fairly cost-effective, and its data is very multifunctional [23].

The general procedure for performing tracer flowback in a multistage hydraulically fractured well mainly consists of four steps, as shown in Figure 1 [23].

- (1) Tracer is injected with the fracturing fluid down into the reservoir
- (2) Tracer-free fracturing fluid is injected into the reservoir to drive the tracer slug into the fractures and matrix further (also known as the chase period).
- (3) During flow shut down, a downhole packer is introduced into the well to prop the next fracture
- (4) Opening the well (injector is being changed into a producer), the tracer can now be flown back with the fracturing fluid

Salman et al. [19] discussed the analysis of chemical tracers in flowback samples from unconventional reservoirs to determine the effectiveness of the treatment. They presented the flowback results for a multistage completion and concluded that tracer analysis can be used to assess the fractured system in the stimulated reservoir volume (highly fractured vs. sparsely fracture). [24] provided an analytical approach for quantifying fractures in a tight oil reservoir by using an early-time tracer poststimulation flowback profile. The authors determined that tracer dispersion,

adsorption, and the difference between the injection and flowback rates affect tracer flowback profiles (TFPs). Tian et al. [25] used synthetic numerical simulation to examine the chemical tracer selection criteria for fracture volume diagnosis in a shale gas reservoir. The authors found that the tracer partitioning coefficient had a considerably greater influence on fracture volume calculation than the tracer adsorption rate. As a result, the tracer adsorption effect on fracture volume calculations is dismissed, and the partitioning coefficient is the most important factor for tracer selection in fracture volume diagnosis. Based on the tracer data, the increase of the tracer partitioning coefficient will improve the accuracy of the estimated swept volume. [26] proposed a new numerical simulation method for analyzing chemical tracer data to help in estimating connectivity between the wellbore and the open connected fractures. As the fracture pressure falls during flowback, the induced unpropped (IU) fracture will close over time, causing the tracer to remain in the reservoir and the fractures. Based on the tracer response curve (TRC), it is clear that the IU fracture closure has a significant impact on the recovery of the tracer. The multiple peaks in the TRC can be explained by the closure of IU fractures during flowback. Early peaks in the production profile can be attributed to fracture closure near the wellbore, while late time peaks are due to the flowback of tracers from fractures connected to the wellbore through IU fractures. The area under the early time peak is directly related to the sections of fractures that are well hydraulically connected to the wellbore, while the area under the later peaks is related to the part of the fracture connected to the wellbore through IU fractures.

*2.2. Fracture Diagnostics Using Fiber Optics.* The use of fiber optics in well stimulation treatments has increased recently. The optical cable is deployed downhole, allowing for continuous monitoring of the treatment. Depending on the application, the cable installation can be temporary (coiled tubing or wireline conveyed) or permanent (installed behind the casing), and multiple sensors can be distributed along with the cable Figure 2. DTS and DAS are the two most common measuring techniques used with fiber optics. Monitoring the acoustic and temperature-related activity from an offset well-instrumented with a fiber optic cable in a multi-well hydraulic fracture stimulation can provide valuable

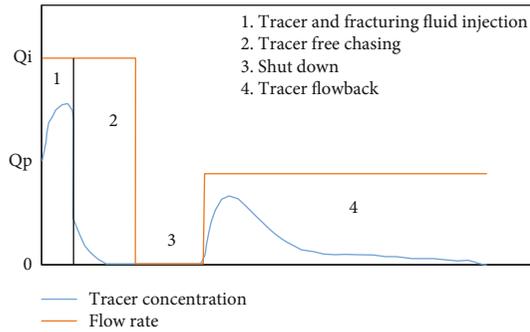


FIGURE 1: Schematic of the general process for performing tracer flowback in a multistage hydraulically fractured well modified after [23].

insight into fracture diagnostics for stimulated wells. Due to the reservoir complexity, determining the optimal completion and stimulation design to enhance fracturing efficiency and production performance in unconventional reservoirs remains difficult. Unconventional fiber optic applications have focused on fiber-based pressure gauges and cluster efficiency calculations using near-wellbore DAS and DTS obtained via permanent casing installations or DTS wireline logs run after treatment [27–30]. Fiber optics technology has been recognized as a potential option for establishing consistent production profiles in unconventional wells [30]. Fiber optics have brought new insights through real-time monitoring and integrated diagnostics in this aspect.

**2.2.1. Distributed Temperature Sensing (DTS).** DTS monitors wells by measuring wellbore temperature fluctuations. Whether gas, oil, or water enters the wellbore, a particular heat signature will be generated [32]. DTS can also be used for well integrity diagnostics. Fluid entering a wellbore can be quantified; fluid leaving or entering from a nonproductive zone can also be detected using temperature readings. Sierra et al. [31] described the details of the data acquisition and interpretation of the DTS results during fracturing treatments. The temperature profile can be used to monitor the cooling during injection and the warm-back during shut-in Figure 3. The authors highlighted the advantages of the permanent installation of the cable. Furthermore, they suggested the use of thermal tracers with faster interpretation capabilities in situations when cables are installed in flow paths. DTS has shown to be a successful method for injection/production allocation in unconventional wells. It can be used to evaluate fluid distribution across several clusters during fracturing stimulations and to monitor inflow distribution along the horizontal producer using absolute temperature data [33–35] and to track the distribution of inflows along with the horizontal producer [36–38]. DTS has also been used in assessing production from fractured wells during production [39]. Holley et al. [40] described the specific application of DTS in open hole packer completion for a tight gas reservoir. With the challenge of low permeability in tight gas reservoirs, the open hole completion is expected to provide greater access to the reservoir. Based on the case studies, the authors demonstrated the value of DTS monitor-

ing in providing insight into treatment effectiveness, the number, the location of initiation of fractures, and postfracture crossflow. Yoshida et al. [41] developed a two-phase linked wellbore and reservoir model that numerically simulates temperature throughout the injection, warm-back, and production phases. By using DTS data, they evaluated the cluster efficiency for one stage during the warm-back time. [38] established a black-oil thermal model that provides the cluster efficiency for a horizontal well with multistage fractures by evaluating DTS data during oil-water production. Aljawad [42] showed that DTS could be used after acid stimulation to identify a layered formation mineralogy. Another issue addressed by DTS is zonal isolation. In most cases, these reservoirs are accessed through multistage horizontal wells where zonal isolation between different stages is imperative. Several published case studies [36, 43–45] demonstrate how DTS was able to diagnose a failure in isolation in horizontal wells. DTS is useful for identifying communication between stages. During hydraulic fracture stimulation, the entire well cools down to the last perforation taking fluid [46].

**2.2.2. Distributed Acoustic Sensing (DAS).** This technology, which is relatively recent in comparison to DTS, is based on the measurement of the acoustic energy emitted during the treatment [47]. DAS surveys record the acoustic activity at various stages of the well's life. These recordings can then be used to provide information such as fluid and proppant distributions for different perforation clusters along the wellbore during stimulation [8]. DAS applications such as ball tracking, injection/production profiling, cluster efficiency evaluation, and interstage communication rely on signal intensity in high-frequency bands [44, 48, 49]. DAS may also be used to conduct time-lapse vertical seismic profiles [50–52], to monitor microseismic events [53–55], and to measure cross-well strain variations [56]. One of the most important applications of DAS technology is the diagnosis of multistage fracture treatment in horizontal wells [57]. DAS can also be used to conduct time-lapse vertical seismic (VSP) profiles [50–52] and to monitor microseismic events [53–55]. These findings have been used to quantify and estimate the geometry of far-field hydraulic fractures. DAS can provide production allocation estimates for specific types of unconventional wells over the life cycle of the well [30, 58]. DTS can be utilized to determine stage isolation and plug integrity during stimulation. It may also be used to forecast production allocation during peak periods [59]. By monitoring formation warmback after stimulation, DTS data can also help to restrict the geometry of near-wellbore fractures [30, 60]. DAS enabled the prediction of dominant fractures locations to optimize and improve future treatments [46, 57]. Compared to DTS, DAS has the advantage of faster diagnosis of immediate changes in the flow [61]. Furthermore, the thermal conductivity of the tubular and the fiber does not affect DAS measurements. [62] discussed the application of real-time DAS measurement for fracturing a horizontal well in tight sand. In gas-producing wells, successful production profiling using DAS has been reported by [30] presented DAS strain front analysis from hundreds

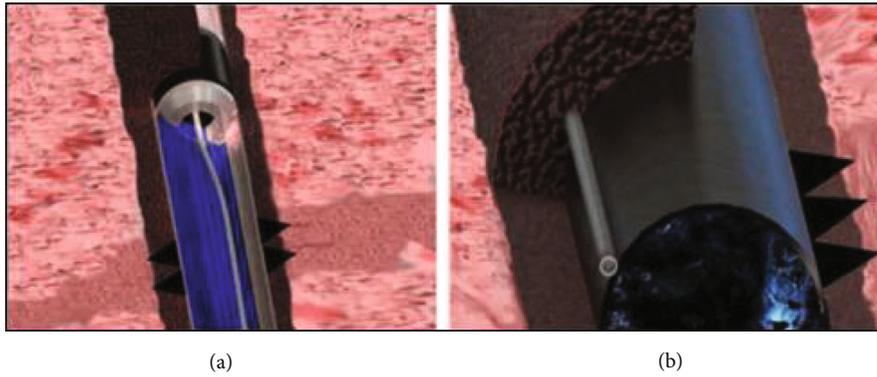


FIGURE 2: Installation of the optical cable (a) along the flow path (b) and behind the casing modified after [31].

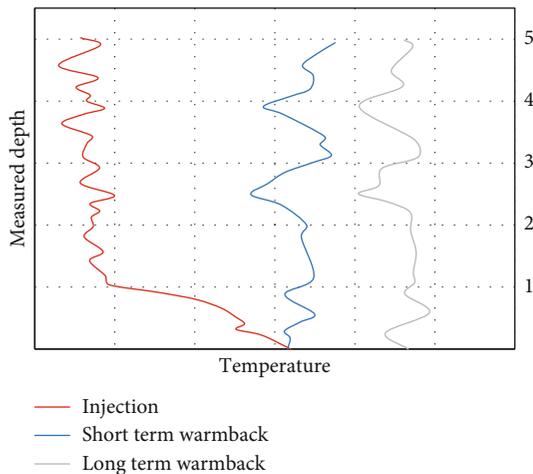


FIGURE 3: DTS measured temperature profile during injection and shut-in, indicating the flow distribution across the stage modified after [44].

of stages across a range of completion systems, with the results allowing for improved well azimuth techniques and stage offsetting. DAS is frequently used to integrate with other diagnostic tools, such as downhole pressure gauges. DAS responses often indicate fluid communication between current treatment stages and those previously stimulated, and bottom hole pressure gauges provide the ability to determine how far the current stage may be propagating. Figure 4 shows the pressure response of the pressure gauge due to several approaching stages (i.e., hydraulic connection). Monitoring the acoustic, temperature, and strain-related activity from an offset well-instrumented with a fiber optic cable can provide valuable insight into fracture diagnostics for stimulated wells. In unconventional reservoirs, DAS is utilized in time-lapse VSP seismic monitoring [63]. One challenge of DAS is the huge amount of data collected during the measurements. The discovery of low-frequency DAS (LF-DAS) of correlating fracture contacts from offset completions has increased the industry's use of fiber optics [56, 64, 65]. Jin and Roy [56] showed the application of an LF-DAS to monitor strain perturbation caused by hydraulic fracture propagation at offset monitor wells. The authors demonstrated the application of LF-DAS to monitor pro-

gressive strain perturbations caused by fracture propagation during hydraulic stimulation of a plug and perf (PnP) well. The spatial resolution of LF-DAS is limited by the system's gauge length configuration, which is generally more than a meter to offer a suitable signal-to-noise ratio and signal quality. The vast majority of LF-DAS studies in unconventional reservoirs have focused on strain changes at offset monitor wells during stimulation. The present interpretation of LF-DAS data is primarily concerned with mechanically induced rock deformation (i.e., fracture opening/closing). In contrast, LF-DAS signals are sensitive to both mechanical and thermal strains. It is critical to measure the influence of temperature changes on LF-DAS data [56].

DAS coupled with DTS has been used to evaluate completions parameters to save future expenses and improve well plans by optimizing injection profiles during treatment. [67] discussed the application of both techniques in a horizontal tight gas well with multiple clusters and stages. The measured data revealed that fracture initiation does not occur in all the clusters. The number of clusters that receive fluid is determined by stress interference and near-wellbore and tortuosity friction. Using multiple short-duration transient DTS and DAS signals, generating clusters may be identified and production profiles can be created [68, 69]. Diversion treatments can be used in multistage fracturing to ensure uniform distribution of the fracturing fluid and proppant. Fiber optic measurements can also provide information on the success of different treatments [43, 45, 57]. Fiber optics are generally much more expensive than other diagnostic methods. Furthermore, the fluid and proppant profiles are limited to near-wellbore measurements. However, the fiber optic glass crystals along the fiber make it ideal to understand well conditions in real time and allow for near-wellbore fracture quantification analysis. Jin et al. [58] generated a production allocation profile across an entire well using a combined inverted DTS transient temperature signal and DAS flow-velocity data.

Although the mechanism behind fiber optics makes it very effective for accessing the fracturing fluid taken by each cluster, its ability to evaluate proppant distribution is still under debate. Fluid transport is not the same as proppant transport. Proppant has been shown to only reach a portion of the induced fracture, which is dependent on many parameters including injection rate and fluid rheology [70]. In

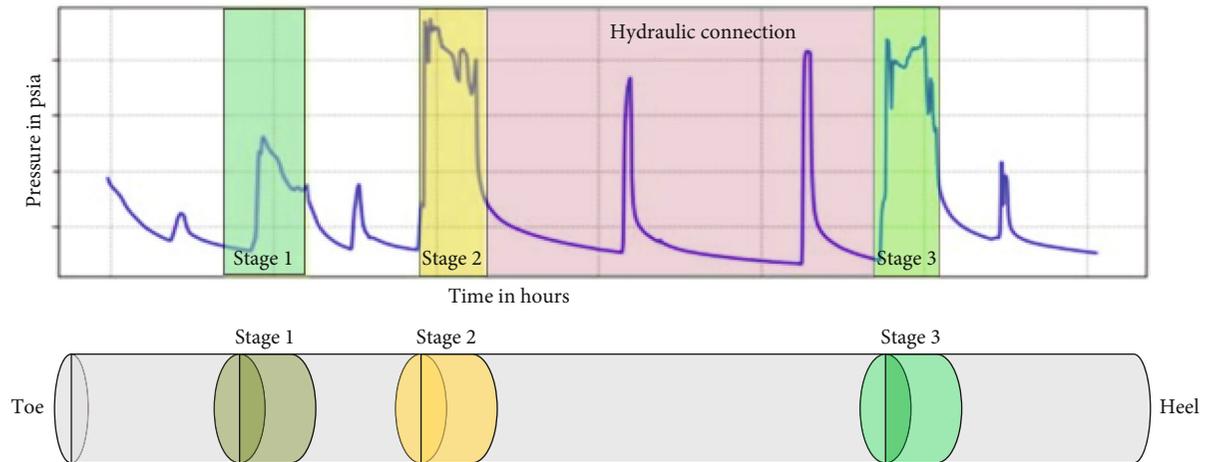


FIGURE 4: Gauge pressure recordings showing the hydraulic connection between stages modified after [66].

addition, simulations reveal a substantial heel bias in proppant distribution in the majority of the stages [23, 71]. Furthermore, DTS and DAS are unable to track the lateral extension of the proppant. As a result, fiber optic monitoring is ineffective for direct far-field mapping of the proppant distribution.

**2.3. Fracture Diagnostics Using Tiltmeters.** When a hydraulic fracture forms, the parting along the fracture causes deformation. These deformations are measured as tilt fields and can be utilized to diagnose fractures using inversion methods (Figure 5). Surface tiltmeters can be used to determine the azimuth, dip, and complexity of a fracture. The fracture dimensions can be determined using downhole tiltmeters.

**2.3.1. Surface Tiltmeters.** The depth of the fracture, as described by [17], was regarded as a major challenge for the application of the surface tiltmeters. Initially, the limitations were thought to be around 5,000 ft. However, recent advancements, as mentioned by [73], have overcome these challenges significantly, and measurements for depths greater than 10,000 ft have been reported. The limitations were attributed to the resolution of the instruments and the noise in the background, which were solved using improved instrumentation.

The data inversion process is an important aspect of tilt field diagnosis. The mathematical geophysical inversion is based on obtaining the best fit from the minimization of the difference between the forward model predictions and measured data. The residual error in the best fit can be representative of secondary fractures [73]. This is an important finding for the fracture diagnosis. One of the most distinguishing features of hydraulic fracturing in unconventional reservoirs is the growth of complex fracture networks, different from conventional treatments that create planar biwing fractures are formed and unconventional reservoirs have many intersecting nonplanar fractures. Furthermore, the network can contain both natural and induced fractures. The interaction of the hydraulic fracture with preexisting rock-fabric heterogeneity, such as natural fractures, fissures,

or cleats, is usually linked with complexity. Understanding and modeling the process of hydraulic-natural fracture interactions is critical for explaining fracture complexity and microseismic events seen during hydraulic fracturing treatments, therefore correctly predicting fracture geometry and, ultimately, reservoir production [7, 74–78]. Dahi-Taleghani and Olson [79] developed a numerical model to study the interactions between tensile fractures, induced shear fractures, and preexisting natural fractures in multi-stage hydraulic fracturing operations. The authors concluded that the fracture complexity was controlled by the geometry of the natural fractures, as well as the magnitudes, directions, and anisotropy of the principal stresses. An important application example for Eagle Ford shale formations has been discussed by [80] where an approach is described for determining the fracture network growth. They reported expanded steps in the geomechanical inversion technique for determining the areal extent of the fracture network. Similarly, [81] presented a case study for a tight gas reservoir with a cluster of horizontal wells. They found that the tiltmeter could monitor the fracture network growth during synchronous fracturing across multiple wells. [82] reported a new technique for assessing fracture complexity using surface tiltmeters, in which three additional parameters are specified to characterize the complexity in shale, coalbed, and sandstones.

Another application that benefits from surface tiltmeter diagnostics are reorientation refracturing [83–85]. The direction of the maximum principal stress changes in depleted reservoirs, causing fracture growth during refracturing to occur in a different direction from the original fracture. The change in the orientation of the fracture leads to more reservoir contact. Since the tiltmeter can monitor the azimuth of the fracture growth, the reorientation during treatment, and the additional reservoir contacted can be estimated.

**2.3.2. Downhole Tiltmeters.** Surface tiltmeters cannot provide information about the fracture dimensions because the dimensions cannot be resolved using the fields when the distance between the point of measurement and the

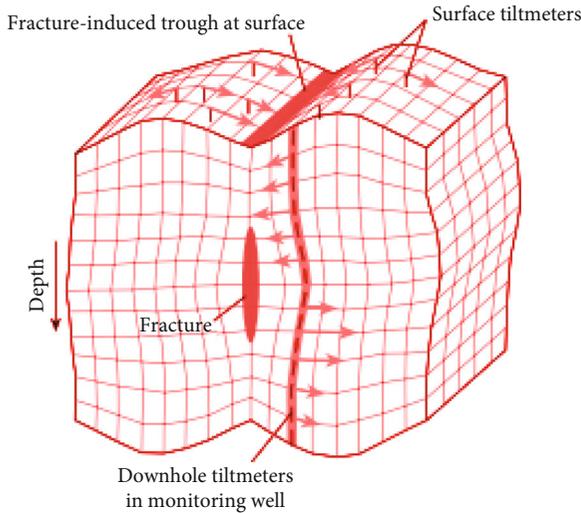


FIGURE 5: Schematic of tilt fields generated from deformation during fracturing modified after [72].

fracture is much larger than the fracture dimension. Downhole tiltmeter mapping is used to overcome this limitation. Tiltmeters are installed in offset wells rather than on the surface. The downhole tiltmeter and its implementation were reported by [73]. The downhole tiltmeter's fracture mapping principle is similar to that of a surface tiltmeter. Deformation fields are generated as a result of the induced fractures and are analyzed using inversion methods.

Figure 6 shows the influence of fracture length on deformation magnitude. The downhole tiltmeter arrays were previously installed in an offset observation well. Later advancements, however, were made to obtain data from the treatment well itself using tiltmeters. Although downhole tiltmeters are significantly more sensitive to fracture dimensions than surface tiltmeters, they do not offer direct information regarding proppant distribution [73]. As a result, they are rarely the primary choice to infer propped fracture geometries [84, 86] described the treatment well tiltmeters concept. They presented case studies in which the fracture height and width in deviated wellbores were measured in real-time. However, the technique was limited to treatments without proppants. Mayerhofer et al. [87] evaluated and used downhole tiltmeters in the treatment well to map fractures for propped treatments.

The ability to assess the vertical evolution of fracture-induced stresses and quantify fracture height is an advantage of downhole tiltmeters [88–92]. The tilt gradient displacement is orthogonal to the direction of displacement and can be used to identify how the rock formation is distorting [93]. Tiltmeters are also subjected to external disturbance, such as noise which can corrupt the data collected from the tiltmeters and distort the data of the actual fracture [94]. Surface tiltmeters are primarily used to determine fracture azimuth, dip, and complexity whereas downhole tiltmeters are used to obtain fracture dimensions. Furthermore, using the fracture mapping results, over a specified time interval, a deformation map can be generated outlining how the fracture network is formed and couple the results

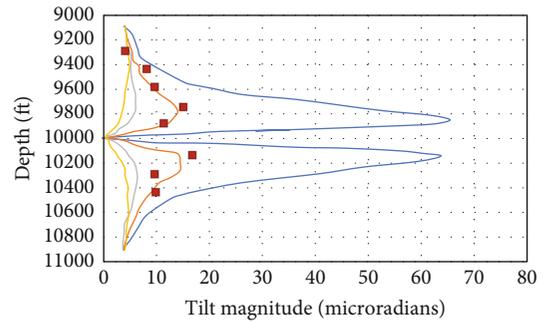


FIGURE 6: Effect of fracture length on the tilt magnitude modified after [73].

with a specified forward model will allow for approximation regarding the orientation of the fracture, the fracture volume, and the potential understanding of the fracture geometry by an inversion process [95]. Inverse problems with multiple solutions can be ill posed, and determining fracture properties such as width and shape can be difficult if the tiltmeters are located far away from the fracture plane [96].

#### 2.4. Fracture Diagnostics Using Microseismic Monitoring.

This approach for fracture mapping is based on the measurement of the seismic waves generated as a result of a hydraulic fracturing treatment. Microseisms emit elastic waves of two types: p waves (compressional) and s waves (shear). The emissions are attributed to the changes in pore pressure and stress during the treatment.

Microseismic monitoring is a common hydraulic fracturing surveillance technique that detects and records small earthquakes caused by hydraulic stimulation using surface, shallowly buried, or downhole geophones [97]. The magnitude and frequency of microseismic events are utilized to assess the growth of hydraulic fractures. Microseismic monitoring of a fracturing treatment yields information on fracture length, height, azimuth, and location around the wellbore [75]. According to [98], understanding fracture networks and growth allows for a more efficient treatment. Furthermore, tight reservoirs that have extremely low permeabilities will not be economical to recover, which is why understanding fracture propagation is critical to economic success [99].

The application of microseismic monitoring in modeling in the Barnett Shale has been discussed by [100–103] detailed the results of the stimulation treatment monitoring, as well as the resulting fracture network and stimulated reservoir volume (SRV) in the Sichuan shale. Accurate determination of far wellbore fracture geometry is an advantage of this approach. As a result, diversion treatments aiming at inducing far-field fracture complexity can also be monitored. Waters et al. [104] discussed the use of real-time monitoring for restimulation and far-wellbore diversion in Barnett Shale. East et al. [105] reported the use of this technique combined with net pressure analysis to monitor real-time far-field diversion and modify the treatment to achieve high complexity and maximum reservoir contact.

The data acquisition of the microseisms is an essential aspect of this method. Initially, measurements were obtained

using sensors installed downhole in an offset well. According to [5], the observation is reliant on the ability of the formation to transmit acoustic energy. It is preferable to have the measurements as close to the center of the fracture as possible. An offset well, on the other hand, may not be within the visible limits; therefore, new observation wells might not be desirable. Peyret et al. [106] discussed the possibility of monitoring from the surface. The authors compared the surface and downhole observations. They reported that by using surface and shallow grid observations, they were able to identify microseismic events with high accuracy. Similarly, [107] compared the downhole deployment in the treatment and offset wellbores. They discussed the triaxial borehole seismic technique for monitoring treatment wells. The authors reported that the treatment well monitoring system was able to record more data compared to the remote observation well. This treatment well recording, however, could only be done during the shut-in period following the injection treatment.

Recent advances in complex fracture modeling using microseismic modeling have enabled the prediction of fracture propagation in unconventional reservoirs using sophisticated models [75, 78, 108–110]. [111, 112] developed a fully coupled flow and geomechanics model was to identify the poroelastic behavior of multiphase fluid diffusivity and rock deformation of interwell fracturing interference in Eagle Ford unconventional reservoirs using the finite-element method (FEM) and multifracture propagation using the displacement discontinuity method. Nagel et al. [113] conducted studies on fracture complexity using higher viscosity fracture fluids, different proppant sizes, and natural fractures to investigate the interaction between a single dominant vertical hydraulic fracture and preexisting fracture networks.

Microseismic modeling is not without difficulties and geophone placement, monitoring array, is critical in the location selection of the monitoring array, how to deal with noise, and determining the suitable velocity structure ([114]. The seismic signal received by geophones are typically very weak and exhibit a low signal-to-noise ratio, introducing significant uncertainty about the location of the events, which is typically calculated by time separation of the P (primary) wave and S (secondary) wave, and these wave signals can also aid in rock formation identification [106]. The spatial distribution of microseismicity reveals information on fracture geometry and fracture development; however, it does not provide detailed information about the fracturing process, other than what is determined from the locations of the microseismic events [115]. Furthermore, microseismic measurements capture only a portion of the rock failure events and the results can be easily biased by adopting inaccurate velocity models. Moreover, this technique solely considers seismic events associated with shear failure [114, 116], without considering fluid and proppant transport. As a result, this technique provides very limited information into the propped fracture geometry, which is the primary factor controlling the effectiveness of a hydraulic fracturing job.

*2.5. Diagnostic Fracture Injection Tests (DFITs).* Diagnostic fracture injection tests (DFITs) basically comprise pump-

ing fluids into the subsurface formations to create a hydraulic fracture whereby important data can be gathered to help design hydraulic-fracturing treatments and characterize the subject reservoir as well. Historically, DFITs in conventional reservoirs focused on acquiring specific data that are essentially required for the treatment design, i.e., leak-off coefficient values and fluid efficiencies [3, 117]. This role has been then extended to acquire more data such as formation stresses, leak-off mechanisms, closure pressure, and transmissibility that can be correlated to reservoir permeability. More value was added to DFITs; when it comes to unconventional reservoirs characterization, it is found that most of the information obtained from such tests are comparable to those gained from the traditional pressure tests that are usually impractical to implement in tight, unconventional reservoirs [118]. Therefore, DFITs are recently employed to get an analyzable pressure response from such tight formations and characterize its in situ stresses.

DFITs are pump-in treatments in which small volumes of slick-water (usually KCl water) are pumped at constant low rates for a short time, creating a small fracture after exceeding the formation breakdown pressure [119]. After pumping for a certain time, the well is shut-in, and the pressure starts to fall off. After the well shut-in, the collected pressure transient data (PTA) are analyzed to identify the fracture closure pressure that is typically considered the formation minimum horizontal stress (Shmin). Figure 7 shows a typical bottom-hole pressure vs. time profile for the DFIT test.

*2.5.1. Common Data Acquisition Issues.* There are some common issues associated with DFITs either in the data acquisition stage or the analysis process. Regarding the data acquisition process, Newtonian, nonwall-building fluid should be used while pumping the treatment to get some other properties of the reservoir from the test. On the other hand, the after-closure pressure gradient can be disrupted, and the formation flow capacity can be masked in case of using gelled or other non-Newtonian fluids. While dealing with low-permeability formations, DFITs should be conducted as a pulse test which will not allow the superposition of multiple injections to have a valid analysis. In other words, if the first treatment is not pumped properly, there will be no point in injecting a second immediate attempt because the reservoir conditions have been altered by the first treatment. In such a condition, it is recommended to wait for a sufficient time for the reservoir to dissipate the pressure transient and reach unperturbed conditions [118].

Another common acquisition issue is not recording the falloff data for enough time. Depending on the type of the reservoir, the falloff recording period would differ but generally, it would be longer than the period that the pumping equipment could be available on site. After the pumping equipment move, the pumping gauges are usually replaced by secondary gauges to record the pressure. However, being calibrated in a different way than the primary pumping gauges, the secondary gauges could cause a difference in

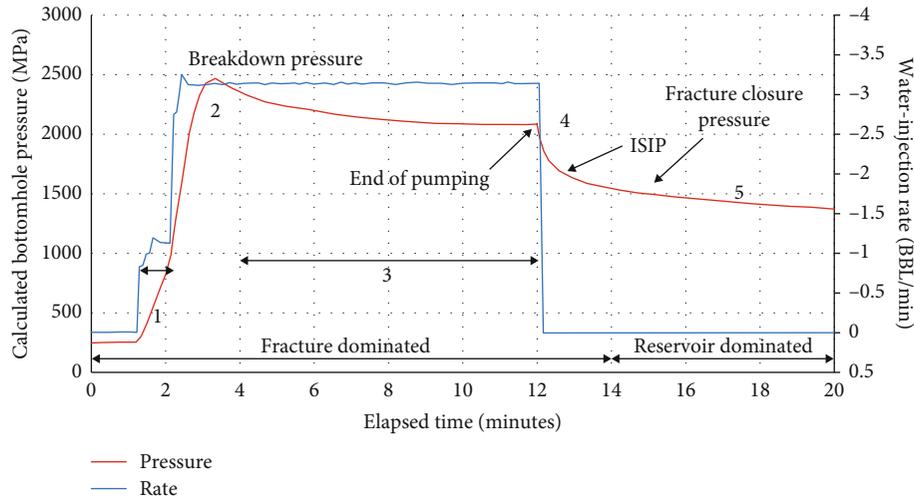


FIGURE 7: Typical bottom-hole pressure vs. time for DFIT test. The plotted lines represent the surface pressure (red line) and the injection rate (black line) modified after [120].

the readings which in turn affects the pressure derivatives and slopes [118, 121]. This may lead to false interpretation results while analyzing the recorded data. Generally, the pressure gauges should be adjusted in the way that it is highly sensitive and only reflects the response of the fracture and the formation.

**2.5.2. DFIT Data Analysis.** DFIT pressure data after shut-in can be categorized into two main groups: before and after the fracture closure (closure pressure). Nolte (1979, 1986, 1988) pioneered the before closure analysis (BCA) by introducing a dimensionless function called “G-function” that represents the elapsed time after shut-in normalized to the fracture extension duration. The G-function concept was developed based on Carter’s (1957) leak-off model and the material balance to build his approach for interpreting the data to get the fracture closure pressure, fluid efficiency, and fluids leak-off coefficients. In 1987, Castillo used the developed G-function to introduce a plot of the pressure vs. the G-function. In this plot, it is expected that the pressure data would form a straight line before deviation at the closure pressure. Often, pressure vs. G-function plot yields plots with multiple inflection points that interpret the pressure data difficult to identify the closure pressure. This can be attributed to nonideal leak-off behavior conditions, especially with unconventional reservoirs. [122] introduced two other plots including the first derivative ( $dP/dG$ ) and diagnostic derivative of the G-function ( $GdP/dG$ ) vs. the G-function. For the latter type, the ( $GdP/dG$ ) should yield a straight line passing through the origin before deviation at the closure pressure. The conventional analysis of the DFIT pressure decline data is ideally valid under some assumptions and simplifications that could introduce some errors when they are violated. Some of these assumptions are as follows:

- (i) Isotropic and homogenous reservoir
- (ii) Incompressible fracturing fluid

- (iii) Symmetric biwing fracture geometry
- (iv) Constant fracture height
- (v) Fracture growth stops immediately when pumping is stopped
- (vi) During DFIT, continuous stable fracture propagation is attained
- (vii) Constant pressure injection of a power law fluid
- (viii) Complete (unobstructed) closure of the fracture
- (ix) Constant fracture compliance (or stiffness) during closure

**2.5.3. Challenges with DFIT Data Analysis in Unconventional Reservoirs.** Being petrophysical complex systems, variations in the DFIT pressure decline behavior in the unconventional reservoirs compared to the conventional ones. In the case of unconventional reservoirs, it is not common to have such symmetric biwing fractures. Also, the fracture extension does not necessarily stop after pumping because of the accumulated pressure in the fracture during injection that may be released after pumping. This accumulation may occur due to the low fluids leak-off and the extremely low matrix permeability [120]. Consequently, the implementation of the DFIT pressure decline based on the standard assumptions makes it susceptible to noticeable errors in the interpretation of the fracture closure pressure and the formation properties as well.

For such nonideal leak-off behaviors with unconventional reservoirs, Barree et al. [123] introduced signature G-function plots considering different nonideal leak-off cases such as pressure-dependent leak-off, fracture tip extension, closing of secondary transverse fractures, and fracture height recession.

For unconventional reservoirs, it is common to have continued fracture extension or natural fracture activation. This is due to the stored pressure in the fracture, as a result

of extremely low leak-off coefficient for such reservoirs, during injection that tends to be redistributed toward the fracture tip and may cause fracture extension. Such extension may increase the fluid loss rate in such cases and can be observed as a steeper slope of the  $G$ -plot compared to the constant leaking-off area cases. Such considerations should be considered during the estimation of the fluid loss parameters using basic pressure decline analysis.

McClure et al. [124] investigated the fracture closure behavior using numerical simulation and concluded that the application of the conventional  $G$ -function diagnostic plot (the tangent line technique) underestimates the closure pressure. Therefore, they introduced another approach called the “compliance method” for interpreting the DFIT data to identify the closure pressure on the  $G$ -function plot at the point at which the fracture stiffness starts to increase. The fracture compliance can be defined as the derivative of fracture closure with respect to effective normal stress or pressure [125]. The fracture compliance is equal to the reciprocal of the fracture stiffness. This method is based on understanding how fracture stiffness (compliance as well) change due to fracture closure.

Another fracture model was then introduced by [126] to investigate the behavior of the fracture closure. They confirmed the observation of McClure et al. [124] which states that the fracture closure pressure may be underestimated when the DFIT data are interpreted using the tangent line method, and they recommended the compliance method as a more reliable approach. However, closes from its edges to the center in a progressive way, the fracture compliance keeps changing since it does not close all at once [119]. In such a case, the fracture closure pressure interpreted using this method might be larger than the minimum principal stress. Wang and Sharma [127] proposed the “variable compliance method,” and they suggested to pick an average of the dimensionless  $G$ -time of the tangent line method and compliance method as a reliable way for estimating the minimum in situ stress when a concave pressure derivative exists.

Generally, after conducting DFITs, the collected data are then analyzed to characterize the reservoir. Fracture closure pressure is one of the main objectives of such analysis to optimize the hydraulic fracturing treatment and its execution as well. Different analytical methods are commonly used for determining the closure pressure such as  $G$ -function plot,  $G$ - $dP/dG$  plot, and square-root of time approach, and fracture compliance method. However, one of the main issues associated with the data analysis process is the pressure curve interpretation especially in the case of unconventional reservoirs. Solid experience and good understating of the process is an essential requirement for identifying the straight-line sections for plotting slopes. Being solely based on human decision, such analysis is more likely to be subjective. Therefore, such analysis is very critical, and it might be sometimes biased by the human interpreter’s understanding of the process and the formation properties [128].

*2.5.4. Machine Learning (ML) Applications.* Given such criticality and importance of accurate fracture closure pressure

makes it is worthwhile for continued improvements for the followed analysis techniques to reduce the subjectivity of the analysis. Therefore, new approaches were introduced to implement the machine learning approaches to help analyze the DFIT data and identify the fracture closure pressure more accurately. Such machine learning-based approaches are recently supported by the availability of a huge amount of data besides the powerful capabilities of computers nowadays. Such models basically learn from the patterns observed in the input data to create the optimized network that can accurately predict the desired output, i.e., the fracture closure pressure. Having such models does not mean replacing the existing analytical methods but it could help identify the different fracture properties, i.e., fracture closure pressure.

Nande [128] introduced a new model to predict the fracture closure pressure ( $P_c$ ) using a supervised learning technique: artificial neural network (ANN). The proposed model was developed based on field data measured during in situ minifrac tests, from several wells within the same field. Linear regression and multilayer perceptron (MLP) algorithms were also presented as viable ML approaches to predict  $P_c$  based on field DFIT test results [129]. For such approaches, the data collected from the field tests, i.e., DFIT and mini-fract test, were analyzed carefully using different analytical techniques, i.e.,  $G$ -function and the squared-time plot, to assure the accuracy of the interpreted  $P_c$  values before being fed as output features for the ML models [128, 130].

Moreover, the ML applications are extended to detect the fracture hits at offset monitoring wells based on optical fiber-based distributed acoustic sensors (DAS) signals [58]. The developed model fitted the manually picked fracture hits using ANN to eventually result in fracture-hit probability in unconventional reservoirs. ML approaches could also help boost the event detection accuracy upon microseismic monitoring for hydraulic fracturing. Zhang et al. [131] developed a neural-network-based microseismic event detection model combined with a convolutional neural network (CNN), long short-term memory (LSTM), and a probability inference. The model was able to improve the efficiency of real-time microseismic monitoring significantly even in case of poor signal-to-noise ratio (SNR). Generally, it should be highlighted that the larger the field data available for developing such ML models are, the better the expected reliability and robustness of such models are for interpreting fracture diagnostic data with accepted accuracy. This in turn could help overcome the limitation of the subjectivity and personal biases and avoid misleading conclusions.

### 3. Comparative Analysis

Different fracture diagnosis techniques have been successfully applied to fracture treatment. However, each of them has certain advantages and disadvantages. Depending on the quality and type of information required for treatment, appropriate techniques should be evaluated and used. Analyses of the fracture diagnostic methods have also been performed previously [5, 17, 132, 133]. These studies have detailedly compared the characteristics and limitations of

TABLE 2: Application of fracture diagnostics for characterizing fracture parameters.

Parameter	High applicability	Limited applicability
Created length	Surface microseismic	When installed downhole can measure created length; the observation well monitoring should be within three times the fracture length
	Downhole microseismic	
Height	Downhole microseismic	DTS
	Surface tiltmeter	Data acquired during and after treatment; applicable to the vertically oriented wellbore
	Downhole tiltmeters	
Width	Downhole tiltmeter	DAS
		Diagnostic DAS data combined with fracture model to estimate fracture growth
Complexity	Surface tiltmeter	Pressure diagnostics
		Net pressure data and minifrac decline can also give estimates of fracture complexity when the maximum stress is known
Cluster efficiency	DTS	Information obtained posttreatment; real-time diagnosis cannot be performed to modify the treatment on-the-fly
	DAS	
Azimuth	Surface tiltmeter	Provides estimates of fracture azimuth when employed in the offset well
	Surface microseismic	
	Downhole microseismic	
Proppant distribution	RA tracers	Provides an estimate of proppant distribution in multiple fractures from different clusters assuming relative fluid and relative proppant distribution are the same
	HTNCC proppants	
	EM-based detectable proppants	
Asymmetry	Surface microseismic	The tiltmeter arrays should be in proximity to the propagating fracture
	Downhole microseismic	

the techniques for fracture dimensions, azimuth, and dip. For unconventional reservoirs, the fracture growth is not a planar fracture, but a complex fracture network. Therefore, in the case of unconventional reservoirs, it is necessary to characterize the complexity of the fracture. Warpinski et al. [11] compared different techniques, including the parameters of fracture complexity and multistage effectiveness and isolation. Table 2 presents a similar summary, comparing different diagnostic methods and their applicability to determine the important parameters of different stimulation treatments.

Through this analysis, it is obvious that no single diagnostic provides enough information to fully understand and optimize fracturing. Therefore, the combined application of multiple diagnostic methods may be the most appropriate strategy to characterize the fracturing treatment.

#### 4. Integration of Different Diagnostic Methods

[134] presented an example of integrating different diagnostic methods. The authors reported a case study in which DTS technology and microseismic mapping were used for the diagnosis of shale fractures. The limitation of microseismic mapping in resolving the near-wellbore fluid distribution is highlighted. In the case of multiple clusters, it can be assumed that the distribution of fluids among all clusters is equal. However, due to factors such as near-hole friction, in situ stress heterogeneity, and stress interference, all clusters might not receive fluid and fracture initiation might

not occur in all clusters. The assumption of equal distribution can lead to misunderstandings about microseismic events. The real-time fluid distribution monitoring using DTS can provide a better near-wellbore resolution and thus can provide more accurate information about fracture initiation. Examples of fluid entry through perforations, flow behind casing, fault reactivation, and stage isolation highlight the benefits of applying DTS and microseismic mapping at the same time.

Holley et al. [40] combined microseismic mapping and DTS to diagnose hydraulic fracturing networks. Microseismic usually cannot capture near-well fractures and reservoir conditions, while DTS can only obtain information from near-well formations. The integration of these two methods can provide real-time and comprehensive monitoring of hydraulic fracturing operations, as well as interpretation and analysis after fracturing. In addition, these two fracture diagnosis tools are linked with production log data to obtain accurate flow distribution results.

McCullagh et al. [135] discussed the application of the microseismic data to improve the results obtained through the DTS surveys for Eagle Ford shale. The far-field information obtained from the microseismic data is used to calibrate the fluid distribution and related thermal models to accurately determine fluid distribution.

The application of the microseismic mapping of the fracturing treatment in the Biyang shale in China was discussed by Yang et al. [136]. In an attempt to improve the accuracy of the estimated SRV, they used a reservoir model based on

geological logs and well log data. Based on the model, the areas with high probability and low probability of forming fractures in the near-wellbore area are determined. When the uncertainty is high, model-based indexing is used to filter the microseismic monitoring data.

The combined application of surface and downhole microseismic monitoring along with surface tiltmeters to monitor the fracturing treatment in Eagle Ford shale was described by [137]. The purpose of the monitoring was to determine the SRV and the fracture network geometry. The results of each of the diagnostic led to a more conclusive interpretation. The tiltmeter results showed the horizontal fractures dominate the near-wellbore fracture network. The difference in microseismic activity between the early and late periods was observed. The comprehensive interpretation of surface and downhole microseismic events refutes the assumptions of observation bias and background noise and points out that changes in geomechanical properties are possible causes. To determine the advantages of the combined application of tiltmeters and microseismic monitoring, [138] described the hybrid downhole tiltmeter and microseismic array. The authors also discussed the method for the inversion of the acquired data.

As a cost-saving advantage, it is mentioned that a single well is used to monitor and obtain a single result instead of two separate results. The literature also describes the application of various diagnostic methods, including RA tracers and chemical tracers [14]; [10], demonstrating the advantages of integrated fracture diagnosis.

Rate transient analysis (RTA) and pressure transient analysis (PTA) are indirect methods that can be used for fracture diagnostics and estimate the fracture and formation parameters. RTA has been used to estimate the stimulated surface area in many multistage fractured horizontal wells. Different authors combined the chemical tracer analysis with RTA to convert the producing SRV for the whole well to SRV for each stage. This combination helps to allocate the production at the stage level, in addition, to investigate the fracture operations for each stage [139]. Lately, PTA was conducted in readily available fall-off data after each stage completion to estimate the created SRV during the fracturing process. This method provides a free and real-time investigation method to estimate the fracture geometry and a measure of completion efficiency [140, 141]. However, the results from these techniques are still under debate and open more room for research.

## 5. Conclusions

- (i) Individual methods have limitations preventing a thorough characterization of the fracture network created. Using multiple diagnostic techniques (pressure diagnostics, microdeformation monitoring, microseismic monitoring, DTS/DAS fiber optics, and tracers) at the same time might result in synergies, leading to a more informative fracture description

- (ii) When utilized for diagnostic design and interpretation, advanced mathematical modeling can be useful. Data inversion for fracture asymmetry from surface tiltmeter monitoring, reservoir geomechanical model for complementing mitigating uncertainties in microseismic monitoring, and DTS inversion for real-time fluid distribution monitoring are some examples
- (iii) DFIT is one of the common fracture diagnostic tools. However, its results might be biased by the human interpreter's understanding of the process and the formation properties
- (iv) The main issue associated with the data analysis process is the pressure curve interpretation especially in the case of unconventional reservoirs due to the complex fracture matrix created and the associated nonideal leak-off behavior. Therefore, solid experience and good understating of the process is an essential requirement for identifying the fracture closure pressure accurately. Such an issue can be quietly resolved by implementing more than one technique while interpreting the pressure decline data to confirm the value of the interpreted
- (v) AI and machine learning can play a significant role in the digital transformation of the oil and gas industry which includes the improvement of pre-existing diagnostic techniques by overcoming previous limitations by utilizing the wealth of data available from field operations
- (vi) The automation of the operations using intelligent methods that exist in AI can lead to dramatically reduce the costs incurred by the personnel and equipment in the field operations, hence improving the economics of the service providers

## Conflicts of Interest

The authors declare that they have no conflicts of interest.

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