

## Article

# A Passive Wellhead Pressure Monitoring Framework for Fracture Network Evaluation and Refracturing Design in Multi-Well Hydraulic Systems <sup>†</sup>

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## Abstract

This study presents an integrated workflow to characterize and optimize hydraulic fracturing operations in horizontal shale reservoirs using passive wellhead pressure monitoring (PWPM). Pressure data from offset wells in the Horn River Shale Basin were analyzed to identify passive pressure responses and distinguish between direct hydraulic communication and stress-induced behavior, providing insight into fracture dynamics and inter-well connectivity. A multivariate sensitivity analysis was performed to evaluate how key fracture and reservoir mechanical properties, fracture orientation, and in situ stresses govern passive pressure signatures. A fully coupled hydro-mechanical model, implemented using a distinct element formulation, was developed based on the observed passive pressure and microseismic data to generate a physics-based representation of fracture propagation and fluid migration. The modeling framework enables forward prediction of passive pressure responses during future stimulation stages, supporting improved treatment design, real-time operational adjustments, and more reliable refracturing strategies under evolving subsurface conditions. By enhancing fracture network characterization and complementing microseismic monitoring, PWPM demonstrates strong diagnostic value for supporting safer and more efficient injection practices in unconventional reservoir development, as well as broader sustainable energy applications.

**Keywords:** passive wellhead pressure monitoring (PWPM); hydraulic fracturing; fracture network; pressure interference; hydro-mechanical modeling; refracturing design



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## 1. Introduction

### 1.1. Background and Motivation

The development of unconventional shale reservoirs increasingly depends on accurately characterizing the geometry, connectivity, and evolution of stimulated fracture networks created during multi-stage hydraulic fracturing. As operators adopt tighter well spacing, more aggressive completion designs, and refracturing strategies in mature developments, understanding inter-well communication and fracture-driven interactions is essential for optimizing production and maintaining operational safety [1]. Traditional diagnostic tools, such as microseismic monitoring, fiber-optic sensing, and downhole pressure

gauges, provide valuable information, but they are often constrained by cost, deployment complexity, or limited spatial coverage [2,3]. In contrast, passive wellhead pressure monitoring (PWPM) has emerged as a cost-effective, scalable, and operationally simple technique capable of capturing real-time pressure responses across multi-well pads. These passive pressure signatures, commonly referred to as pressure hits, offer a unique window into fracture propagation behavior, stress shadow evolution, and inter-well connectivity, particularly in naturally fractured shale formations such as the Horn River Basin [4–6]. However, despite its growing adoption, PWPM lacks a standardized framework for interpreting passive pressure responses and linking them to fracture network evolution in complex geological settings.

The Horn River Shale Basin in northeastern British Columbia is one of Canada's most extensively developed unconventional gas plays, with production strategies relying heavily on multi-stage hydraulic fracturing of long horizontal wells. Its geological complexity, characterized by multiple brittle shale formations, abundant natural fractures, and variable mechanical properties, creates conditions contributing to the formation of intricate stimulated fracture networks [7]. These networks frequently extend across multiple wells and formations, generating pressure interactions detectable at the well surface [8]. Interpreting these interactions in real time provides operators with a diagnostic tool for assessing stimulation effectiveness; identifying fracture-driven well interference; and informing decisions related to well spacing, completion sequencing, and refracturing design.

PWPM has gained increasing traction as a practical alternative or complement to microseismic monitoring. Recent studies have expanded the use of pressure-based diagnostics for evaluating fracture connectivity, stress shadow development, and stimulation effectiveness in multi-well pads [9–12]. While microseismic data offer insights into fracture geometry and event distribution, their interpretation is often complicated by location uncertainty, limited resolution, and difficulty distinguishing hydraulic from shear-induced events [13,14]. PWPM, by contrast, directly measures the pressure response of offset wells to stimulation, capturing the integrated hydro-mechanical effects of fracture propagation, fluid migration, and stress redistribution [15]. When analyzed systematically, passive pressure responses can reveal whether communication is driven by direct hydraulic connectivity, stress-induced deformation, or a combination of both, an essential distinction for understanding fracture growth mechanisms and predicting interactions during future stages or well stimulations.

This study advances PWPM interpretation by integrating field pressure responses with a fully coupled DFN-DEM hydro-mechanical modeling workflow, enabling direct comparison of observed and simulated passive pressure signatures. It introduces multi-variate pressure catalogues that link geological variability, natural fracture attributes, and operational parameters to the expected passive pressure behavior, providing a structured basis for diagnosing fracture connectivity and complexity. These elements extend prior PWPM studies in the Horn River Basin by establishing a unified, mechanistic interpretation system for multi-well stimulation diagnostics.

### *1.2. Technical Rationale and Study Objectives*

Understanding passive pressure behavior requires a physics-based interpretation of hydraulic fracture propagation and natural fracture interactions. These processes are strongly influenced by in situ stress anisotropy, fracture orientation, mechanical properties, and bedding plane characteristics, often producing complex geometries that deviate from idealized bi-wing fracture models [16–23]. As a result, PWPM interpretation benefits from analytical and numerical approaches capable of linking observed pressure signatures to plausible subsurface mechanisms. A sensitivity-based evaluation of geological and engineering

parameters further supports the identification of dominant controls on passive pressure responses and enhances the diagnostic value of PWPM in multi-well environments.

The geological setting of the Horn River Basin underscores the importance of such integrated diagnostic approaches, as it exhibits distinct lithological and mechanical characteristics, with varying degrees of natural fracturing, mineralization, and brittleness. These formations are interbedded with carbonates and clay-rich shales, creating a heterogeneous environment in which hydraulic fractures may propagate differently depending on local conditions [7]. Understanding how hydraulic fractures interact with these natural features is essential for interpreting PWPM data and for constructing representative models of fracture network evolution [23–25].

Operationally, the “frac-wave” completion design used in the Horn River Basin provides an ideal setting for PWPM analysis. By fracturing wells in a uniform, progressive sequence from toe to heel and from well to well, operators ensure that pressure interactions can be observed consistently across a pad [8]. High-resolution surface pressure gauges capture passive pressure responses with sufficient precision to infer downhole behavior, provided the wellbores remain liquid filled. These early-time interactions, often coinciding with microseismic activity across multiple formations, indicate the establishment of fluid-filled, hydraulically connected fracture networks. While pressure interactions can also be observed during flowback and production, the pre-flowback stimulation phase offers the clearest insights into fracture propagation dynamics [4].

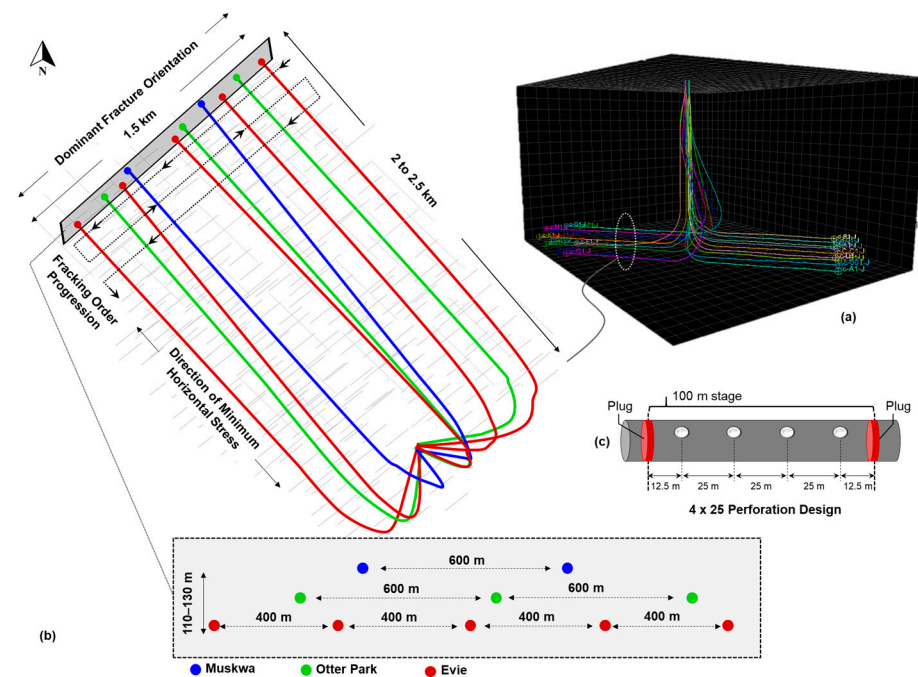
This study addresses the need for a framework to interpret passive wellhead pressure responses and link them to fracture network evolution in multi-well hydraulic systems. The framework establishes a basis for interpreting pressure-driven fracture interactions across multi-well systems, enabling diagnosis of inter-well communication and supporting future refracturing design.

## 2. Materials and Methods

The methodological framework developed in this study integrates passive wellhead pressure monitoring, analytical modeling, and fully coupled hydro-mechanical simulations to characterize fracture network complexity and inter-well connectivity during multi-stage hydraulic fracturing in the Horn River Shale Basin. The workflow includes four steps: (i) extraction of PWPM attributes; (ii) building of fracture network realizations from formation-specific statistics; (iii) simulation of hydro-mechanical fracture propagation using DEM; and (iv) comparison of simulated and observed pressure responses to assess fracture complexity and connectivity. This integrated approach provides a physics-based basis for interpreting fracture propagation and fluid migration behavior in naturally fractured formations.

### 2.1. Field Setting and PWPM Data Acquisition

Development of the Horn River shale resources relies on multi-stage hydraulic fracturing in horizontal wells drilled from multi-well pads. The half-pad examined in this study consists of approximately ten horizontal wells with lateral lengths of 2000–2500 m. Wells targeting the Muskwa and Otter Park formations were spaced at roughly 600 m laterally, whereas wells landed in the Evie were spaced more tightly, at approximately 400 m, reflecting its higher stress state and greater inter-well communication potential. The vertical separation between the Muskwa and Otter Park laterals was 50–60 m, and between the Otter Park and Evie it was 60–70 m. Each well was completed using a plug-and-perf design with 100 m stages containing four perforation clusters spaced 25 m apart, resulting in 20–25 stages per well (Figure 1). The individual stages were stimulated with 2000–2500 m<sup>3</sup> of slickwater (water with friction reducer) and 150–250 tons of sand proppant, pumped at rates of up to 20 m<sup>3</sup>/min [26].



**Figure 1.** Conceptual multi-well hydraulic fracturing pad layout and completion configuration. (a) 3D view of the full pad showing numerous horizontal wells drilled parallel to the minimum horizontal stress direction. (b) Plan-view (bird's-eye) schematic of the half-pad layout, illustrating the well spacing and an example of the “frac-wave” completion sequence, where the stages progress pad-wide in a uniform, well-to-well and toe-to-heel manner. This schematic is conceptual and does not represent the exact field treatment. (c) Example of a single 100 m plug-and-perf stage,  $4 \times 25$  m cluster design, consisting of four perforation clusters spaced 25 m apart.

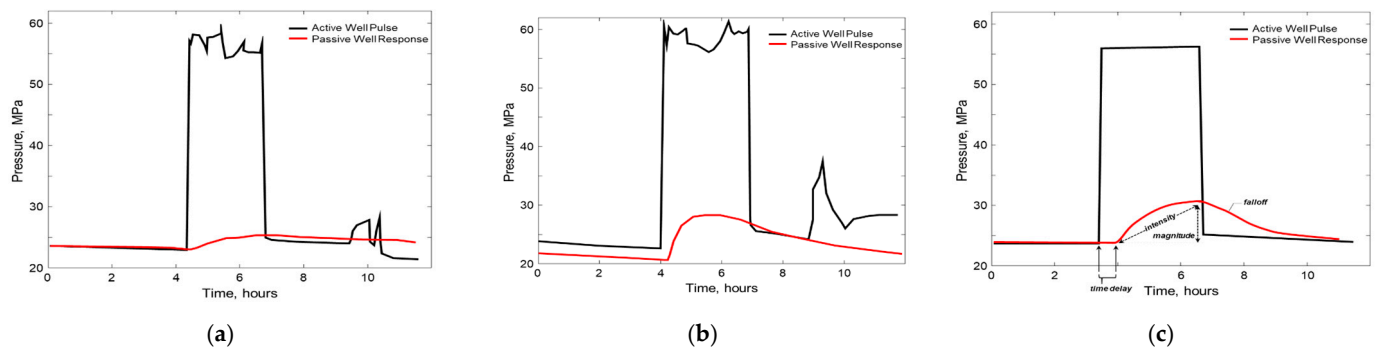
Hydraulic fracturing operations were carried out using a frac-wave completion sequence in which the stages were stimulated individually across the pad, enabling the offset wells to remain open and record the passive pressure responses. The wellhead pressure data were continuously collected from both the active and passive wells throughout each stage. The passive pressure signals were catalogued and grouped according to their timing, magnitude, and rate characteristics, allowing for the subsequent identification of two dominant response types: (i) direct hydraulic communication, marked by short delays and high-magnitude, rapid pressure increases; and (ii) hydro-mechanical or stress shadow effects, which produce lower-magnitude, quickly decaying responses associated with stimulation-induced deformation of nearby natural fractures [27]. Both mechanisms provide valuable diagnostic information about fracture connectivity, stress redistribution, and reservoir heterogeneity.

## 2.2. Passive Pressure Detection and Interference Analysis

Each passive pressure response was quantified using four primary attributes. The time delay was defined as the interval between hydraulic fracturing in the active well and the first sustained deviation in the passive well pressure exceeding background variability. The intensity was quantified as the initial pressure rise rate (kPa/min) computed over the steepest portion of the early-time response. The magnitude was defined as the peak pressure increase relative to the pre-stimulation baseline. The falloff was characterized using the early-time pressure decline rate (kPa/min) following the peak response, measured over the interval where the decline remained approximately linear. The pressure travel speed, calculated as the perforation-to-perforation distance divided by the time delay, was used as a supplementary indicator of inter-well hydraulic communication. These

definitions provide a reproducible basis for comparing the passive pressure signatures across wells and stages.

Figure 2a,b show, respectively, field examples of typical and significant passive pressure responses: in the typical case, approximately 6% of the active well pressure pulse is transmitted to the offset well (35.9 MPa active increase producing a 2.1 MPa passive response), whereas in the second case, representing the upper bound of field observations, approximately 20% of the active well pressure pulse is transmitted (yielding a 6.9 MPa passive response for the same active well pressure increase). Figure 2c presents a schematic passive pressure response that visually defines the four diagnostic attributes described above.



**Figure 2.** Pressure responses during hydraulic fracturing, showing the active well signal (black) and the corresponding passive pressure response in an offset well (red). (a) Typical passive response, in which approximately 6% of the active pressure pulse is transmitted to the passive wellbore, and a 35.85 MPa pressure increase in the active well produces a 2.07 MPa response in the passive well. (b) Significant passive response, in which approximately 20% of the active pressure pulse is transmitted, and the same 35.85 MPa active pressure increase results in a 6.89 MPa passive response, based on the data reported in [8]. (c) Characterization of passive pressure illustrating the active well pressure pulse and passive well response, with the four diagnostic attributes of time delay, intensity, magnitude, and falloff, as defined in Section 2.2.

Scatterplot matrices were used to examine the relationships among the passive pressure attributes. The inter-well connectivity was then quantified using a pressure interference workflow based on an interaction matrix representation. For each active stage, the passive well responses were encoded into a stage-by-well matrix using their constituent attributes, enabling rapid identification of directional communication pathways, under-stimulated zones, and cross-formation hydraulic interactions. Aggregating these matrices across stages and grouping wells by landing zone provided a systematic assessment of zone-specific stimulation efficiency. Limited radioactive tracer surveys independently corroborated these interpretations [28].

### 2.3. Geological and Geomechanical Characterization

The Horn River shales in northeastern British Columbia comprise three main reservoir intervals: the Muskwa, Otter Park, and Evie formations. The Muskwa consists of thinly bedded siliceous mudstone and argillaceous claystones and overlies the more thickly bedded Otter Park, which contains siliceous mudstone, argillaceous claystones, and argillaceous–calcareous claystones of variable thickness. The deepest interval, the Evie shale, is composed of thinly bedded siliceous and calcareous mudstone, laminated biomicrites, and argillaceous claystones [29]. These brittle formations occur at depths of approximately 2200–2700 m, with a total thickness of 140–210 m, and exhibit an average effective porosity of about 3%, matrix permeability near 200 nD, and residual TOC of 3–4%. The shales rest on limestones and dolomites and are overlain by clay-rich shales,

forming a mechanically layered system that influences fracture containment and vertical growth [4,8,30].

The Horn River shales host multiple natural fracture sets with variable intensity and mineralization. The fractures trending northeast, subparallel to the maximum horizontal stress, are typically open and minimally cemented, whereas the fractures in other orientations are commonly cemented, silica-rich in the Muskwa and calcite-rich in the Otter Park and Evie. Field observations indicate that fractures in the Muskwa are the most intensive, those in the Otter Park are less frequent but longer, and those in the Evie exhibit intermediate fracture intensity. Natural fractures range from microscopic fissures to meter-scale corridors, creating highly heterogeneous hydraulic and mechanical pathways that deform under coupled pressure–stress interactions [31]. Their presence, orientation, and connectivity are therefore critical for interpreting the passive pressure responses and constructing representative numerical models of fracture propagation and inter-well communication.

Elastic and in situ stress properties further govern the fracture behavior. Laboratory measurements indicate Young’s modulus values of approximately 37.9–38.6 GPa for the Muskwa, 40.4 GPa for the Otter Park, and 46.1–48.9 GPa for the Evie, with a representative Poisson’s ratio of 0.20. The vertical, maximum horizontal, and minimum horizontal stress gradients are approximately 25.2 kPa/m, 18.1 kPa/m, and 13.1 kPa/m, respectively [4,7]. These parameters define the stress anisotropy that controls fracture initiation, containment, and the relative contributions of tensile and shear deformation.

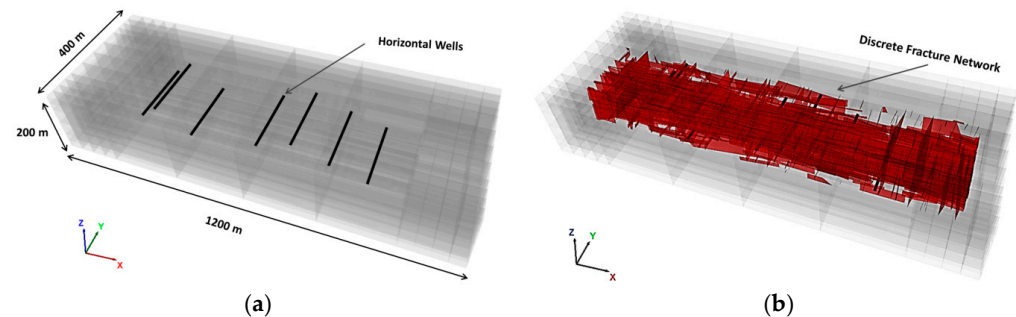
Fracture aperture evolves dynamically with changes in fluid pressure and stress. For modeling purposes, the maximum allowable apertures are taken from the upper tail of the distribution to represent the most conductive fractures. The reported average maximum apertures (derived from borehole image log interpretations supplemented by laboratory measurements of core samples) are approximately 2.6 mm in the Muskwa, 1.2 mm in the Otter Park, and 1.5 mm in the Evie, with the image logs indicating absolute maxima near 3.2 mm [7]. Stress–conductivity and displacement experiments on the Horn River shale samples [32] show that fracture stiffness decreases with increasing aperture and normal stress. Ref. [7] demonstrates that joint normal stiffness is well described by a negative exponential function of the rock matrix’s Young’s modulus, while the joint shear stiffness follows a similar trend and is approximately 0.42 of the normal stiffness. These relationships provide a physically grounded basis for modeling fracture compliance and conductivity evolution in coupled hydro-mechanical simulations.

#### 2.4. Hydro-Mechanical Modeling Framework

A fully coupled three-dimensional distinct element model (DEM) was constructed using 3DEC Version 7.0 [33] to capture the complex hydro-mechanical behavior of natural and induced fractures. The model domain measured  $1200\text{ m} \times 200\text{ m} \times 400\text{ m}$ , with an enlarged inner region to minimize boundary effects (Figure 3). The rock mass was represented as an assemblage of discrete blocks separated by discontinuities. Deformable blocks were discretized into finite-difference meshes, and discrete fractures were represented as joint elements [25,34,35].

Multiple discrete fracture network (DFN) realizations were generated to capture the geological uncertainty and to span the plausible range of fracture orientations, apertures, and mechanical properties inferred for the Horn River formations. Because the DFN ensemble is diagnostic rather than statistical, representative realizations were selected based on their ability to reproduce characteristic passive pressure responses rather than through formal convergence or uncertainty quantification criteria. Filters were applied to remove small or unfavorably oriented fractures and to prevent the formation of excessively thin blocks during the cutting process. Fluid flow was restricted to the fractures, and Newtonian

fluid behavior was assumed. Proppant transport and matrix imbibition were not explicitly modeled, although a limited number of constant pressure sinks were introduced to loosely mimic imbibition effects. Boundary conditions were applied by fixing the outer boundaries in all directions. Maximum and minimum horizontal stresses were applied along the x- and y-axes, respectively.



**Figure 3.** 3DEC distinct element model used for multi-stage hydraulic fracturing simulations: (a) model domain (1200 m × 200 m × 400 m) with an enlarged inner region to reduce boundary effects; (b) one realization of the pre-existing discrete fracture network incorporated into the model (reproduced from [26] with permission).

A single-fracture model was first used to verify fracture opening under injection, pressure propagation toward observation points, and fracture closure (i.e., falloff behavior) after pumping. Microseismic event locations were then incorporated into the modeling workflow by converting the event coordinates into fracture half-height distributions so they could be used as fracture set input for the 3DEC model. Multiple simulations were used to generate probabilistic fracture height distributions, which were combined with analytical solutions to estimate the equivalent fracture aperture and conductivity. These probabilistic attributes were subsequently integrated into full DFN models, which were then used to build the 3DEC simulations and were checked against observed passive pressure responses, stress shadow signatures, and microseismic event distributions to ensure that the models reproduced the dominant physics governing inter-well pressure interactions.

### 2.5. Sensitivity Analysis and Passive Pressure Responses

A multivariate sensitivity analysis was conducted to evaluate the influence of key geological and operational parameters, including fracture permeability, intact rock stiffness, natural fracture orientation, and in situ stress contrast, on the passive pressure behavior. Parameter variations were used to generate a suite of simulations that captured a wide range of plausible fracture network configurations. The objective was to develop a physics-based interpretation of passive pressure behavior rather than a statistical optimization framework. Table 1 summarizes the model's properties for the base case and the uncertainty ranges used in the coupled simulations. For each simulation, the passive pressure attributes were extracted and compared with field observations. The simulation outputs were grouped into characteristic pressure signatures that link the observed PWPM responses to the underlying fracture mechanisms. The probabilistic fracture height distributions derived from the microseismic data were incorporated to constrain vertical fracture growth, while analytical diffusivity solutions were used to estimate the equivalent fracture aperture and conductivity. These combined constraints ensured that the pressure catalogue reflected both the geometric and hydraulic variability observed in the field.

Although parameter variations were applied individually, each sensitivity realization was conducted within a fully coupled hydro-mechanical DEM framework. The fracture dilation, shear activation, stress redistribution, and fluid flow evolve simultaneously in the model, ensuring that the resulting passive pressure responses reflect the coupled

interaction of multiple geological and mechanical factors. Thus, the sensitivity analysis captures the multi-factor coupling effects through the physics-based modeling environment, even without performing a full factorial or multi-parameter statistical sweep.

**Table 1.** Input parameters and associated uncertainty ranges used to calibrate and evaluate fully coupled hydro-mechanical model for interpreting passive wellhead pressure responses.

| Category                         | Parameter                          | Base Value | Uncertainty Range      |
|----------------------------------|------------------------------------|------------|------------------------|
| Intact Rock and Joint Properties | Young's modulus (GPa)              | 26         | 19–40                  |
|                                  | Poisson's ratio                    | 0.2        | 0.14–0.25              |
|                                  | Density (kg/m <sup>3</sup> )       | 2600       | 2450–2650              |
|                                  | Joint normal stiffness (GPa)       | 18         | 6–25                   |
|                                  | Joint shear stiffness (GPa)        | 7.56       | 0.42 * j <sub>kn</sub> |
|                                  | Joint cohesion (MPa)               | 0.054      | 0–1                    |
|                                  | Joint friction (°)                 | 25         | 29–54                  |
|                                  | Joint tension (GPa)                | 1.25       | 0–2.5                  |
|                                  | Initial joint aperture (m)         | 0.0001     | 0.0001–0.002           |
|                                  | Max. allowable aperture (m)        | 0.003      | 0.003–0.005            |
| In Situ Stresses                 | Depth to center (m)                | 2600       | 2600                   |
|                                  | Vertical stress (MPa)              | 66.31      | 66.31                  |
|                                  | Max. horizontal stress (MPa)       | 47.7       | 47.7–62.3              |
|                                  | Min. horizontal stress (MPa)       | 34.4       | 34.4–47.7              |
|                                  | $\sigma_{Hmax}/\sigma_{Hmin}$      | 1.4        | 1.1–1.5                |
| Fluid and Operational Properties | Fluid pressure (MPa)               | 25.5       | 25.5                   |
|                                  | Fluid density (kg/m <sup>3</sup> ) | 1000       | 1000                   |
|                                  | Fluid viscosity (mPa·s)            | 0.89       | 0.89–15                |
|                                  | Injection rate (m <sup>3</sup> /s) | 0.4        | 0.20–0.66              |
|                                  | Injection time (min)               | 160        | 127–195                |

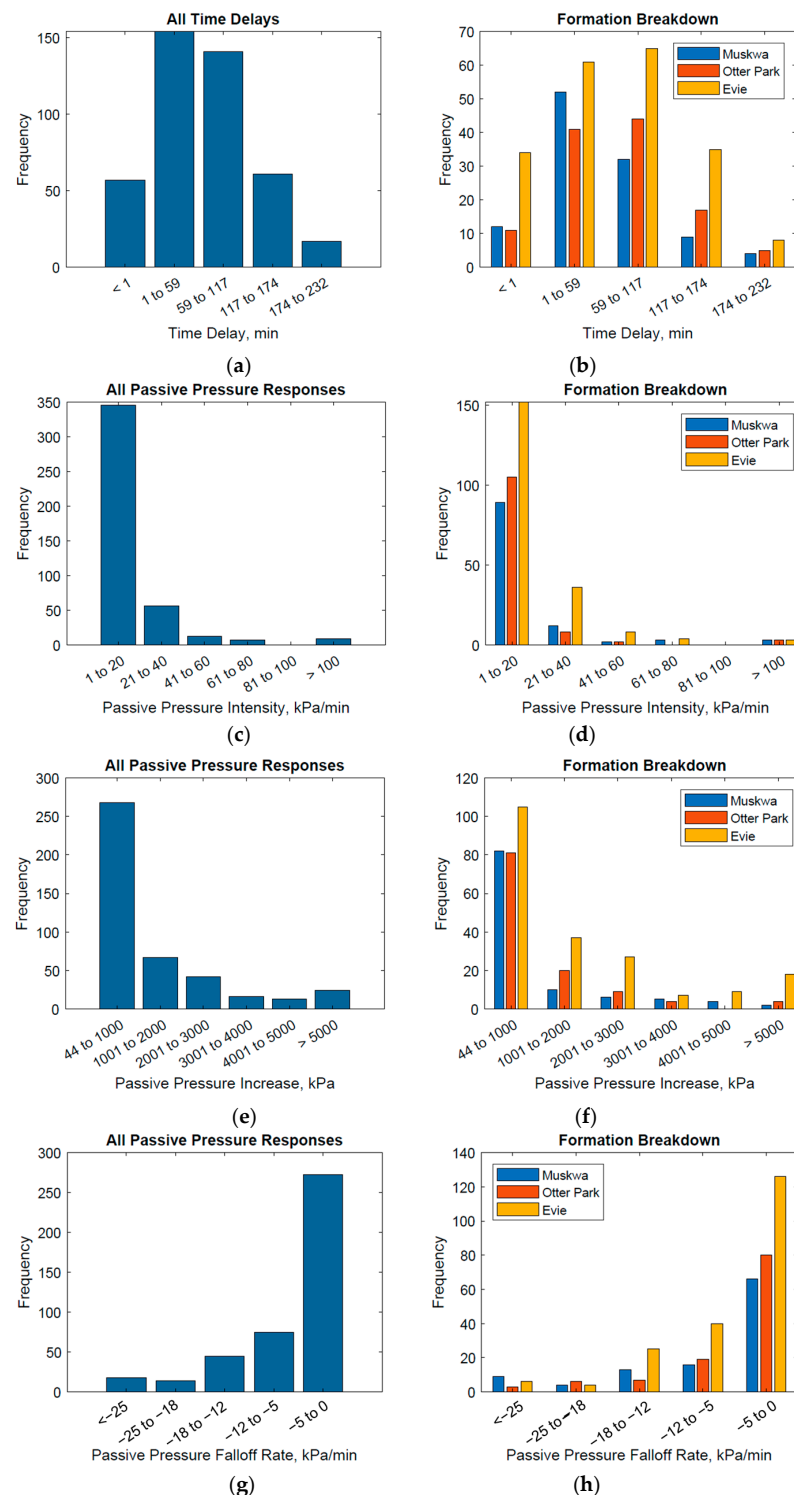
### 3. Results

#### 3.1. PWPM Field Observations and Attributes

The PWPM data acquired during the frac-wave stimulation revealed two dominant classes of passive pressure responses across the half-pad. Direct hydraulic hits were characterized by sharp, high-magnitude pressure increases occurring almost immediately after pumping began, indicating rapid fluid transfer through highly conductive fracture pathways (Figure 2a). In contrast, stress shadow-dominated responses exhibited moderate pressure increases that decayed rapidly once pumping ceased, reflecting deformation-induced compression of dense-phase fluid-filled natural fractures surrounding passive wells (Figure 2b). In some cases, small-magnitude, long-duration responses were recorded, consistent with pressure shadowing through tortuous fracture pathways containing mixtures of fracturing fluid and compressible gas. These response types also varied systematically with the frac-wave stage sequence, with the early stages typically producing sharper, higher-magnitude hydraulic hits and the later stages exhibiting more attenuated or stress shadow-dominated signatures as stimulation progressed toe-to-heel across the pad.

More than 450 satisfactory passive pressure interactions were documented (Figure 4). For each interaction, the distance between the perforation midpoints, in addition to the passive pressure response, was recorded. The four primary attributes exhibited systematic spatial and geological trends. The time delays ranged from near-instantaneous arrivals to several minutes, with the Evie formation showing the highest number of passive pressures with delays  $\leq 1$  min, indicating strong inter-well connectivity in this zone. The passive pressure intensities varied widely, with values exceeding 100 kPa/min often associated with direct hydraulic communication. The passive pressure magnitudes reached more than

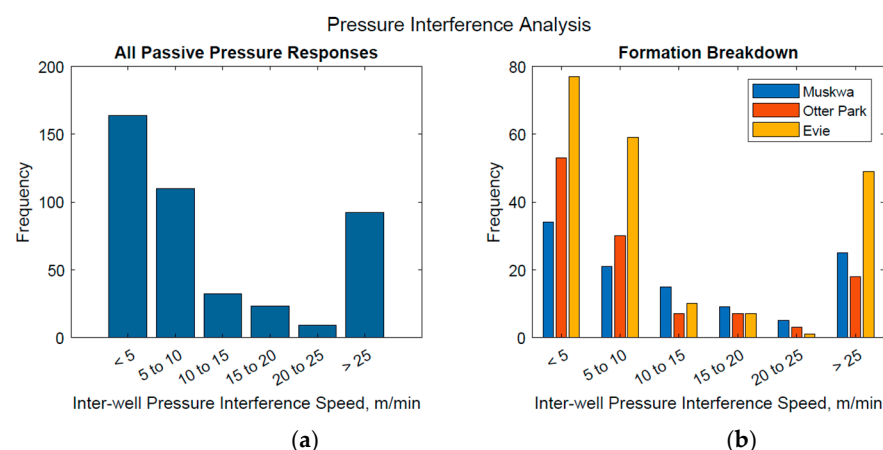
5 MPa in the Evie, where closer well spacing (400 m) and higher in situ stresses promoted stronger pressure transfer. The falloff behavior differed by formation; the Muskwa exhibited more pronounced falloff, suggesting greater fluid migration into smaller fractures and enhanced matrix imbibition.



**Figure 4.** Distributions of PWPM attributes across half-pad and by formation: (a) time delay distribution for all wells; (b) time delay distribution separated by formation (Muskwa, Otter Park, Evie); (c) passive pressure intensity distribution for all wells; (d) intensity distribution by formation; (e) passive pressure magnitude distribution for all wells; (f) magnitude distribution by formation; (g) falloff rate distribution for all wells; (h) falloff rate distribution by formation.

It is important to note that these formation-dependent differences also reflect the influence of well spacing across the half-pad. The Evie wells, spaced at approximately 400 m, consistently exhibited shorter time delays, higher passive pressure magnitudes, and higher travel speeds, indicating more efficient hydraulic communication. In contrast, the wider spacing of roughly 600 m to 800 m in the Muskwa and Otter Park formations contributed to longer delays and lower-magnitude responses, consistent with reduced pressure transfer efficiency at larger offsets. This natural spacing contrast provides a field-scale basis for interpreting how inter-well distance governs passive pressure propagation without requiring synthetic spacing scenarios.

The travel speed, computed as the ratio of inter-well perforation spacing to time delay, provided an additional diagnostic indicator of fracture network connectivity (Figure 5). High travel speeds correspond to short-delay, high-intensity responses, and are characteristic of direct hydraulic communication through conductive fracture pathways, consistent with observations of the Barnett, Eagle Ford, and Horn River shales [36–38]. Lower travel speeds reflect delayed responses associated with stress shadow propagation, fracture network tortuosity, or poroelastic diffusion. Positively skewed travel speed distributions therefore indicate more complex or heterogeneous fracture networks, where pressure propagates through combinations of natural fractures, partially connected pathways, and matrix-dominated diffusion. In the present dataset, the Evie formation exhibited the highest travel speeds, consistent with its short time delays, high pressure intensities, and more conductive fracture system.



**Figure 5.** Distributions of PWPM travel speed across the half-pad and by formation: (a) travel speed distribution for all wells; (b) travel speed distribution according to formation (Muskwa, Otter Park, Evie).

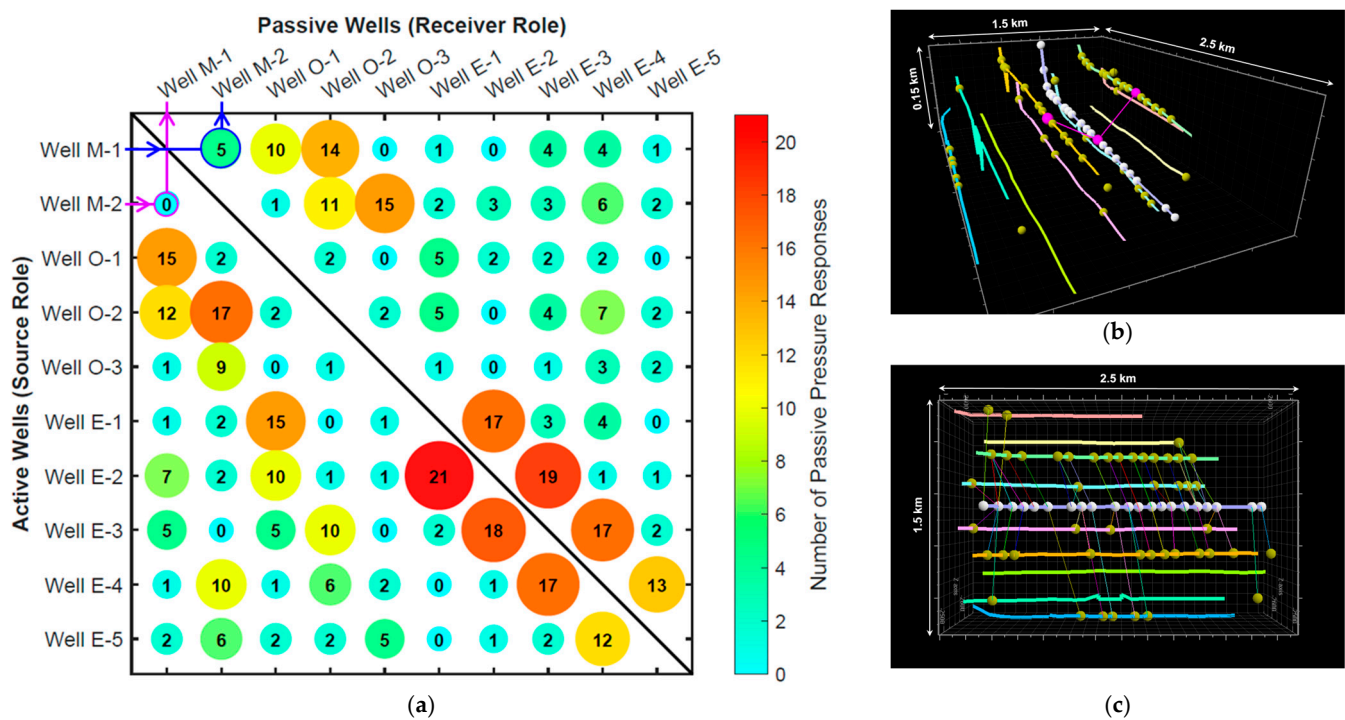
Because travel speed is derived from the time delay and spacing, it does not have a universal threshold; its diagnostic value lies in its relative magnitude and distribution shape, which reflect the underlying fracture transmission mechanisms. The distributions in Figure 5 illustrate this distinction for the present dataset. Direct hydraulic communication produces comparatively high travel speeds associated with short delays and conductive pathways, whereas stress shadow or deformation-driven responses exhibit lower travel speeds consistent with longer delays and more tortuous transmission paths. These ranges are formation-specific and are presented solely as empirical observations from the Horn River dataset rather than as generalized limits.

The time delay showed a weak correlation with distance beyond approximately 400 m, suggesting that fracture complexity increasingly governs pressure propagation at larger offsets. The passive pressure magnitude and intensity exhibited a strong positive correlation, while the magnitude showed no meaningful correlation with the time delay. The travel

speed displayed the expected inverse relationship with the time delay, confirming its utility as a first-order indicator of fracture conductivity and network efficiency. Collectively, these PWPM observations provide high-resolution, field-scale insights into fracture propagation and inter-well communication. The variability in the passive pressure attributes across the formations and well pairs reflects the combined influence of fracture geometry, natural fracture connectivity, and local stress conditions, forming the empirical foundation for the connectivity analysis and modeling presented in subsequent sections.

### 3.2. Inter-Well Connectivity and Interference Patterns

Inter-well connectivity refers to the degree to which stimulation in one well induces measurable pressure responses in neighboring wells. The connectivity was evaluated using a pressure interference analysis in which the number, strength, and attributes of passive pressures were catalogued for each active–passive well pair. Recording the interactions across the half-pad enabled construction of pressure interference matrices that summarized the connectivity at both the well and zone levels. A stage-by-well interaction matrix (Figure 6a) was used to encode the passive well responses for each active stage, with the rows representing active wells and columns representing passive wells. Each cell contains the passive pressure counts or attribute-level statistics, enabling rapid identification of directional communication pathways, under-stimulated wells, and cross-formation hydraulic interactions.



**Figure 6.** (a) Overview of the number of passive pressure responses among horizontal wells; the bubble size reflects the number of passive pressure responses, as indicated by the value shown inside each bubble.; (b) 3D mapping of passive pressure responses to identify stage-by-stage directional bias for a single fracturing well; (c) corresponding two-dimensional projection. The white spheres represent the fracturing stages in the active horizontal well, and the green spheres represent the passive pressure responses recorded in nearby wells. The lines connecting the white and green spheres trace each passive pressure response back to its originating fracturing stage, forming a simplified hydraulic fracture geometry reconstructed solely from the passive well pressure observations (reproduced from [26] with permission).

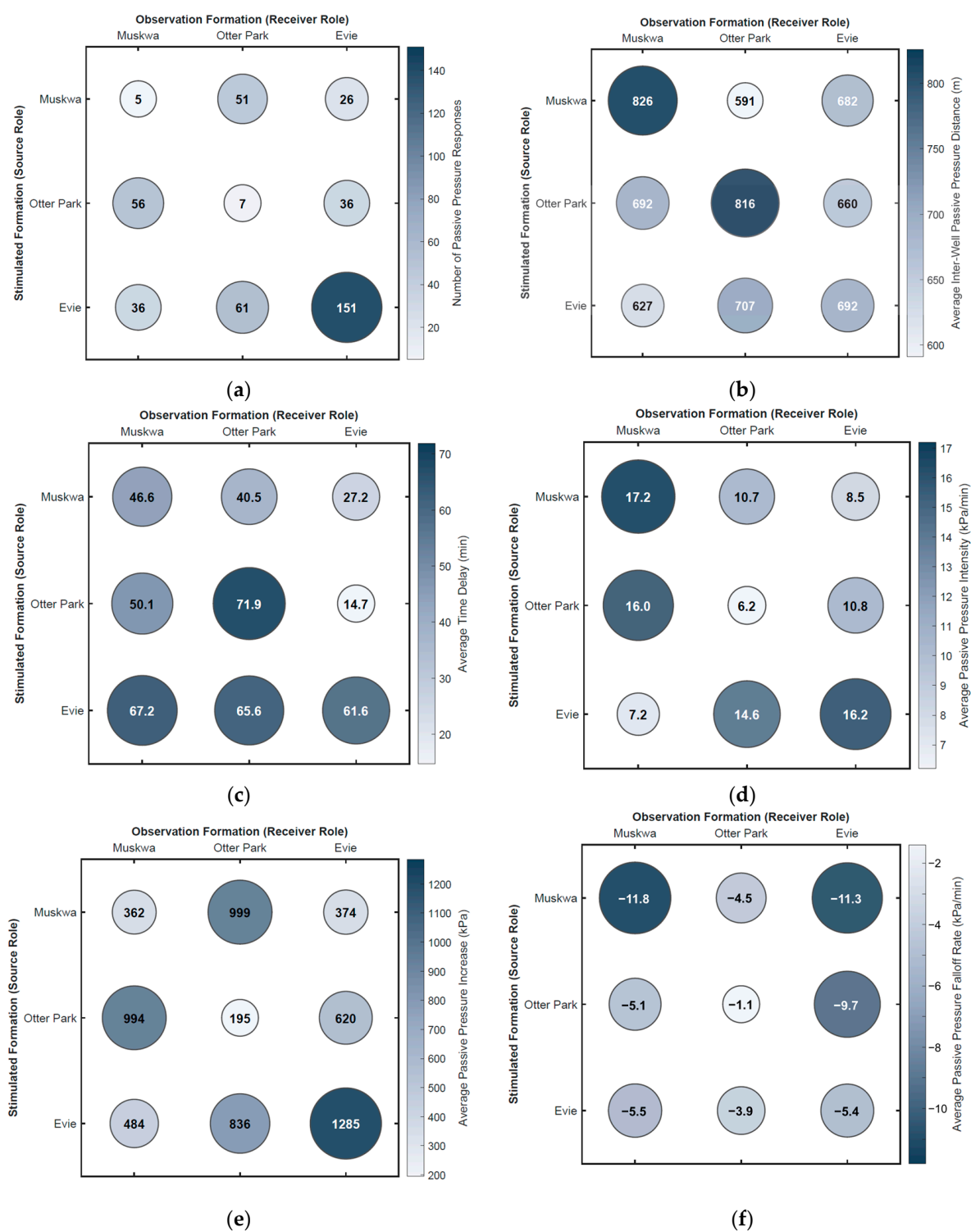
The warmer colors and larger bubbles in Figure 6a correspond to a higher number of passive pressures and, therefore, stronger hydraulic or hydro-mechanical communication. Because each well alternated between active and passive roles during the frac-wave sequence, the matrices capture the bidirectional nature of inter-well interactions. Contrary to the intuitive expectation of reciprocal behavior, asymmetry in the passive pressure counts between wells was common; for example, stimulation of Well M-1 produced five pressure responses in Well M-2, whereas stimulation of Well M-2 generated no measurable response in Well M-1, even though both wells are landed in the Muskwa formation. Such asymmetry reflects directional fracture propagation and the influence of local stress conditions and natural fracture architecture. The field records indicate that the pump schedules and perforation efficiency were comparable between the two wells during the frac-wave sequence, and no operational irregularities were identified that could account for the directional bias. These similarities suggest that the asymmetric inter-well communication was primarily governed by stress-driven fracture propagation and local fracture network architecture rather than differences in treatment execution, although operational factors could influence inter-well behavior in other settings.

The spatial and temporal mapping of passive pressures provided additional insight into the directional bias of fracture propagation (Figure 6b,c). The stage-by-stage visualization showed that the fractures preferentially propagated upward and toward specific offset wells, consistent with the regional stress regime and the orientation of dominant natural fracture sets. The three-dimensional mapping further revealed clear out-of-zone growth, with passive pressures from lower formations (Otter Park and Evie) frequently observed in the overlying Muskwa. These observations indicate that stimulated fractures commonly extend vertically across the formation boundaries, accessing natural fracture corridors with varying intensities.

While Figure 6 provides a qualitative structural overview of communication pathways, Figure 7 quantifies the inter-well connectivity strength using multiple diagnostic attributes. This multi-attribute, formation-level summary complements the interaction matrix by providing a more comprehensive characterization of connectivity without requiring a formal weighting scheme. Muskwa, the shallowest formation, exhibited the fewest passive pressure responses when its own wells were stimulated (only five), indicating limited independent stimulation (Figure 7a). However, Muskwa recorded substantial responses when the Otter Park and Evie wells were stimulated (56 and 36, respectively), demonstrating significant upward fracture growth from deeper formations. In contrast, Evie, the deepest formation, showed strong intra-zone connectivity, with 151 passive pressure responses among its wells. This behavior reflects both the closer well spacing in Evie and the higher in situ stresses that promote more direct fracture propagation (Figure 7b).

The formation-level averages of passive pressure attributes reinforce these connectivity trends. Muskwa exhibited the shortest time delays, highest intensities, and more pronounced falloff, reflecting greater fluid migration into smaller fractures and enhanced matrix imbibition. Evie displayed longer delays, yet the largest pressure magnitudes, consistent with efficient hydraulic communication (Figure 7c–f). Otter Park showed intermediate behavior, with moderate connectivity and attribute values.

A comparison with limited radioactive tracer data independently validated the PWPM-derived connectivity patterns. The stages that produced strong direct hits in the PWPM exhibited tracer breakthrough in the corresponding offset wells, whereas stages with weak or absent passive pressure responses showed limited tracer movement [28]. Overall, the connectivity patterns reveal a vertically integrated fracture system with strong upward and downward communication across the three formations.



**Figure 7.** Intra- and cross-formation passive pressure responses, shown as (a) number of responses across the three formations; (b) average distance; (c) average time delay; (d) average intensity; (e) average magnitude; (f) average falloff rate. Muskwa is the shallowest formation, underlain by Otter Park, and Evie is the deepest.

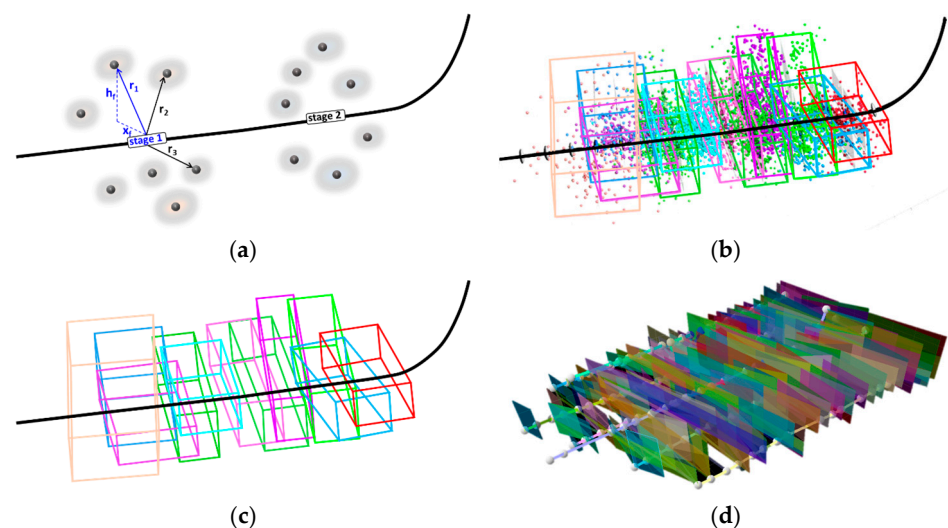
### 3.3. Analytical and Probabilistic Modeling Results

Given the ultra-low permeability of the Horn River shales, the magnitude and timing of passive pressures are strongly controlled by the conductivity and aperture of the stimulated fracture network. To obtain first-order estimates of these properties, the passive pressure attributes were interpreted using one-dimensional diffusivity solutions derived from the

continuity equation for isothermal, single-phase, incompressible flow between two impermeable fracture walls. Although hydraulic fracturing generates complex fracture networks, simplifying assumptions, such as treating fracture planes as smooth two-dimensional surfaces and neglecting roughness, enable rapid analytical evaluation prior to implementing fully coupled hydro-mechanical simulations.

Closed-form transient solutions for constant-rate and constant-pressure boundary conditions were applied to the observed time delays and pressure increases. Dimensionless variables were used to generalize the solutions, following [39]. For each active–passive well pair, the analytical solutions were inverted to back-calculate the equivalent fracture conductivity and aperture. The conductivity estimates were highest along the dominant fracture propagation direction, consistent with the high passive pressure magnitudes observed in the Evie formation. In contrast, the wells located obliquely to the principal fracture orientation exhibited lower inferred conductivities and longer delays, reflecting more tortuous or less conductive pathways. Larger fracture heights reduce the conductivity required to match observed delays, whereas smaller heights require higher conductivities.

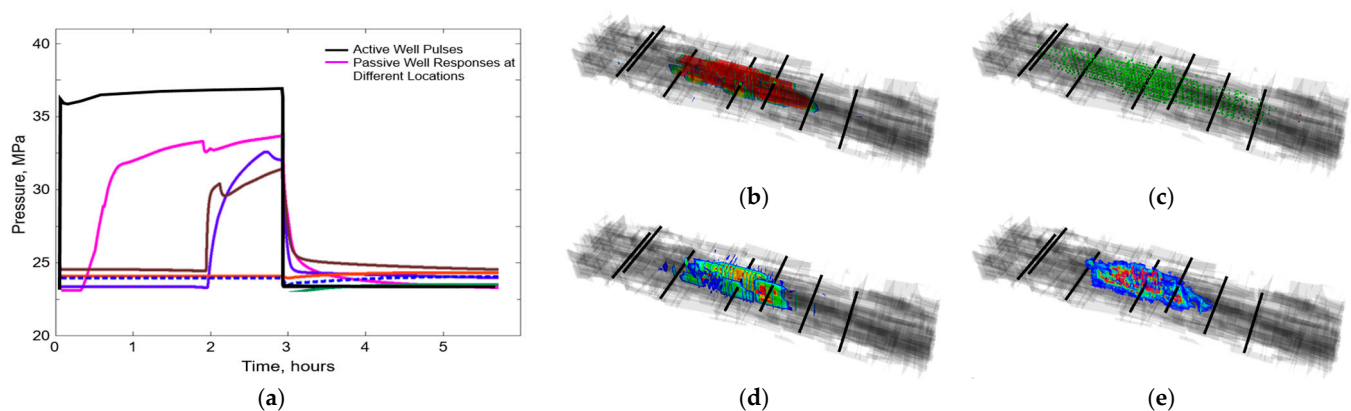
This dependency motivated the integration of analytical modeling with probabilistic fracture height distributions derived from the microseismic data. Each event was represented by an ellipsoidal uncertainty volume whose size increased with its distance from the receiver array (Figure 8a), and the coordinates were converted into radial, horizontal, and vertical distances relative to each stage’s perforation midpoint to reconstruct the stimulated fracture geometry [28]. The fracture height realizations were generated by sampling these ellipsoids (Figure 8b,c), and combined with analytical diffusivity solutions to estimate plausible fracture conductivities and apertures for each active–passive well pair. The resulting connectivity probabilities (Figure 8d) reveal strong spatial variability, with the high-probability corridors aligning with the dominant propagation direction and matching the passive pressure responses characterized by short delays and high intensities. Vertical connectivity is particularly pronounced between Otter Park and Evie, and the microseismic-derived fracture network aligns closely with that inferred from the passive pressure observations.



**Figure 8.** (a) Uncertainty associated with geometric interpretation of microseismic events during hydraulic fracturing stimulation, represented using ellipsoidal location-uncertainty volumes; (b) reconstruction of equivalent stimulated fracture geometries for several stages of single horizontal well based on recorded microseismic events; (c) estimated fracture height and width derived from probabilistic sampling of microseismic uncertainty; (d) fracture network realizations generated by integrating passive pressure responses with estimated fracture heights and widths. Interested readers are referred to [28] for methodological details.

### 3.4. DEM Simulation Results and Model Calibration

The distinct element simulations reconstructed the hydro-mechanical processes governing fracture propagation and inter-well communication during multi-stage hydraulic fracturing. Using the properties in Table 1, the base 3DEC model with a single major fracture reproduced the key features of the field pressure responses, with the qualitative comparison focused on timing, magnitude, and falloff trends rather than on formal goodness-of-fit metrics. The model captured the four main passive pressure attributes across multiple observation points, effectively representing the behavior recorded at the offset wells. It demonstrated that the dominant physics of fluid flow, fracture dilation, and stress-induced deformation were correctly reproduced (Figure 9a). The pore pressure front advanced preferentially along the fracture oriented perpendicular to the minimum horizontal stress, producing early, high-intensity signals at observation points aligned with the dominant propagation direction. This is consistent with the stress-controlled behavior inferred from the PWPM.

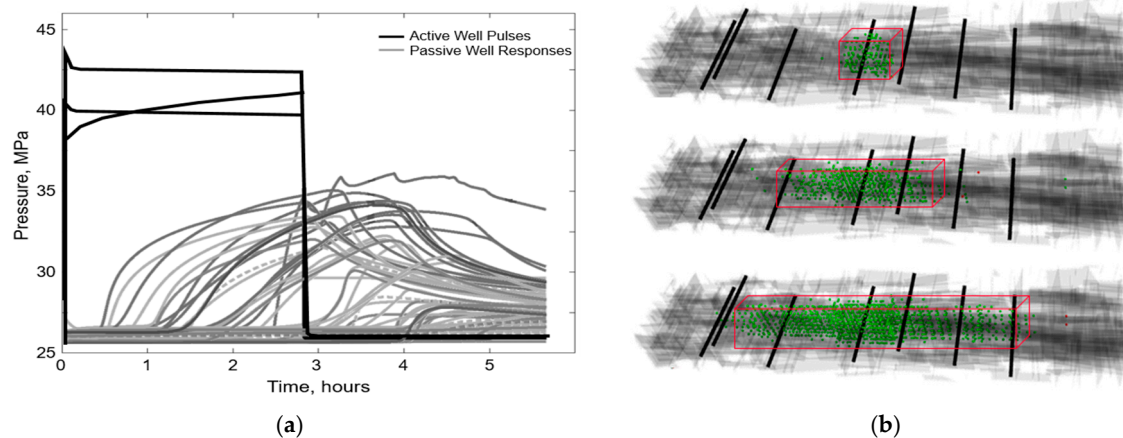


**Figure 9.** (a) Reproduced passive pressure responses during multi-stage hydraulic fracturing in the base case with a single major hydraulic fracture. Illustration of spatial distribution of (b) pore pressure, (c) microseismic events, (d) joint aperture, and (e) shear displacement during the fracturing stimulation. The bold black lines denote segments of the horizontal wells drilled parallel to the minimum horizontal stress. The gray background shows the pre-existing natural fracture network, consisting of two principal sets oriented with respect to the in situ stresses (reproduced from [26] with permission).

The evolution of microseismicity in the simulations provided insight into the development of the stimulated fracture network [40]. Early in the injection, tensile failures dominated as fractures opened under elevated pore pressure, while shear failures became increasingly prevalent as fluid entered natural fractures aligned with the maximum horizontal stress. Although tensile failures can generate microseismic events, their energy is often too low to be detected [25]. The 3DEC framework distinguishes between tensile and shear modes, allowing for event magnitudes to be correlated with joint properties, such as plastic slip. The resulting spatial patterns of microseismicity, together with changes in the joint aperture and shear displacement, illustrate the progressive formation of a complex fracture network (Figure 9b–e). The tensile failures concentrate along the primary hydraulic fracture plane, whereas the shear failures occur mainly within the intersecting natural fractures, a mixed-mode opening behavior consistent with observations from the Horn River Shale Basin.

The multivariate simulations generated catalogues of passive pressures that summarize the expected ranges of time delay, intensity, magnitude, and falloff for various geological and operational parameter combinations (Table 1). These catalogues serve as diagnostic references for interpreting pressure transfer behavior and identifying the fracture

mechanisms responsible for the observed responses, capturing the influence of fracture orientation, aperture, rock stiffness, joint properties, stress anisotropy, and injection conditions. Because they span the uncertainty ranges of reservoir properties, the catalogues can be used to estimate the expected responses at other well locations, with interpolations reliable in homogeneous intervals, while geostatistical methods are required in heterogeneous zones. Sensitivity analyses further examined how parameter variations shaped pressure transfer behavior and associated microseismicity. Figure 10 shows several realizations of simulated pressure response curves and the corresponding evolution of microseismic clouds for different fracture and reservoir properties at neighboring wells during a single fracturing stage.

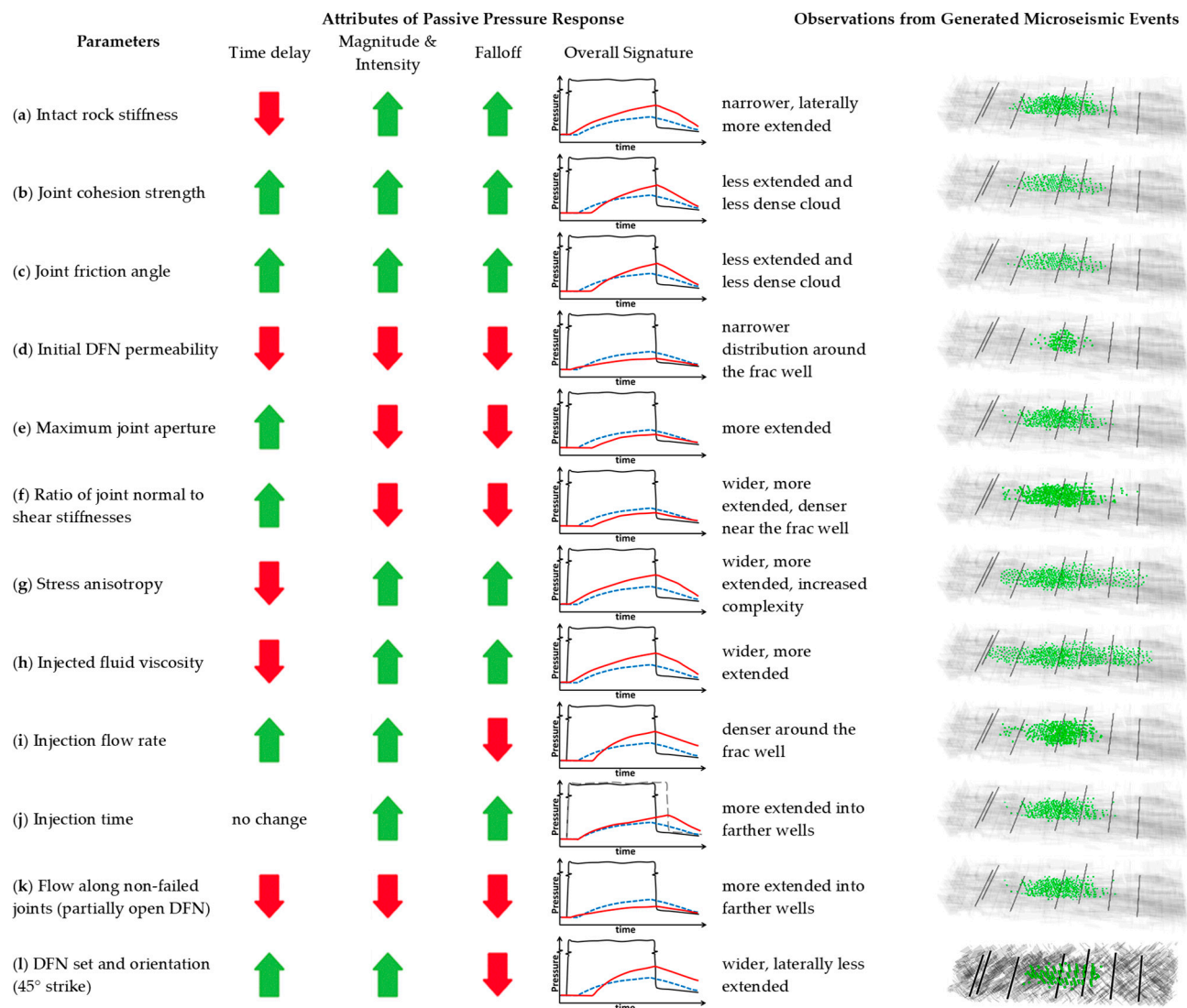


**Figure 10.** (a) Several realizations of simulated passive pressure responses and (b) the evolution of microseismic clouds for different combinations of fracture and reservoir properties at neighboring passive wells during a single hydraulic fracturing stage. Each realization illustrates how variations in fracture orientation, aperture, joint mechanical properties, and stress anisotropy influence passive pressure attributes as well as the spatial extent and character of microseismicity.

**Influence of Fracture Network Orientation and Stress Field Alignment:** The orientation of the discrete fracture network relative to the in situ stress field was one of the most significant controls on the passive pressure behavior. When the DFN was aligned with the principal horizontal stresses, the stimulated zone was narrow and elongated, dominated by tensile failures, and characterized by short time delays and a steep falloff. Rotating the DFN by approximately  $45^\circ$  relative to the stress field produced a markedly different response in which the stimulated fracture network became wider and more tortuous, with a greater proportion of shear failures. This configuration generated longer time delays, higher pressure magnitudes due to increased flow resistance, and less steep falloff curves, reflecting enhanced permeability retention associated with shear activation [41]. The broader microseismic cloud in this case indicated a more complex fracture network with a larger number of activated fracture planes (Figure 11). In contrast, the DFN sets aligned parallel to the maximum horizontal stress produced predominantly tensile failures that closed rapidly after pumping ceased, resulting in steep falloff signatures and limited microseismic extent. A detailed parametric analysis of fracture orientation angle would require a broader modeling campaign.

**Influence of Intact Rock and Joint Mechanical Properties:** Increasing Young's modulus, representing a stiffer and more brittle rock mass, elevated the wellbore pressure and produced longer, narrower fractures with higher conductivity. These conditions led to shorter delays, higher pressure intensities and magnitudes, and steeper falloff curves, especially at observation points within  $\sim 200$  m of the active stage, while more distant wells showed a less steep but still clear decline. This behavior reflects the constitutive link

between pore pressure and fracture dilation; stiffer rocks require higher pressure to open, but transmit pressure more efficiently once dilation occurs. The simulations also showed that stiffer formations concentrate deformation along fewer, more dominant fracture planes, reducing the lateral spread of microseismicity (Figure 11a).



**Figure 11.** Qualitative summary of passive pressure behavior from fully coupled hydro-mechanical simulations. Each row (a–k) illustrates the effect of a positive perturbation in a single uncertain variable on the passive pressure attributes and microseismic response. The green upward arrows (↑) and red downward arrows (↓) indicate the direction of change in the passive pressure attributes relative to the base case. The blue and red curves are schematic representations of the base case and perturbed passive pressure responses, respectively, and are included to highlight the general trends rather than exact model values; the black line represents the schematic pressure in the active fracturing well. The microseismic clouds are shown as green points, and the gray background depicts the pre-existing natural fracture network with two principal sets aligned with the in situ horizontal stresses. The rows correspond to changes in: (a) intact rock stiffness, (b) joint cohesion strength; (c) joint friction angle; (d) initial DFN permeability; (e) maximum joint aperture; (f) joint normal/shear stiffnesses; (g) stress anisotropy; (h) injected fluid viscosity; (i) injection flow rate; (j) injection time; (k) flow along non-failed joints (partially open DFN); (l) DFN set and orientation (45° strike).

Increasing the joint cohesion or friction angle stabilized natural fractures and reduced their tendency to slip under elevated pore pressure, leading to longer time delays, lower

pressure intensities and magnitudes, and steeper falloff curves. Larger joint stiffness similarly restricted fracture opening and limited conductive flow paths, producing longer delays, lower intensities, and more linear decline profiles; the associated microseismicity was more diffuse and spatially extended (Figure 11b,c). The joint tensile strength had little influence because fluid flow in the DEM model was confined to already-failed sub-contacts; unfailed fractures remained sealed. This restriction reflects the mechanical aperture thresholds expected under the in situ stress conditions of the Horn River formations, where unfailed joints typically remain closed and non-transmissive. Field observations and laboratory studies indicate that pressure transmission is dominated by dilation-activated fractures, and the sensitivity tests confirmed that enabling flow along unfailed joints produced overly diffuse pressure responses inconsistent with the observed PWPM behavior. Allowing flow along initially open or partially open fractures generated very short delays, lower intensities, extended falloff, and a more expansive microseismic cloud (Figure 11k), underscoring the importance of initial fracture openness in pressure propagation.

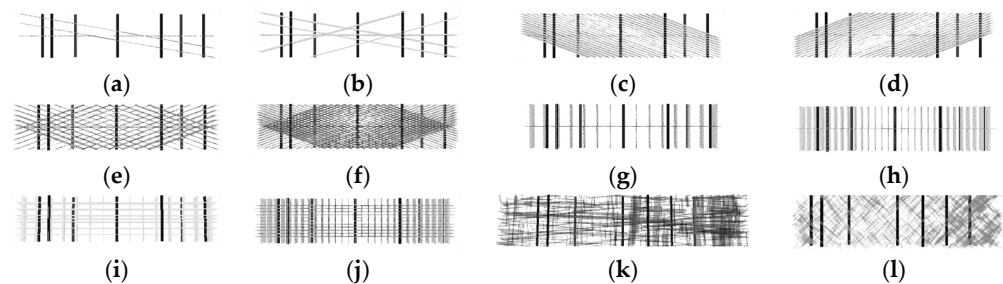
The initial aperture of natural fractures strongly influenced the pressure transfer behavior. Smaller apertures increased the flow resistance and delayed pressure arrival, producing higher magnitudes and broader microseismic distributions (Figure 11d). Larger apertures reduced arrival times and dampened pressure intensity and magnitude as fluid preferentially followed the most conductive pathways. The maximum allowable aperture, which sets the upper limit on dilation, also shaped the pressure signatures; increasing this parameter enhanced fracture storativity, delayed the pressure front, and produced a more linear falloff in distant wells (Figure 11e). These trends reflect the greater storage capacity of wider fractures and the sensitivity of pressure responses to fracture dilation limits.

**Effects of Stress Regime and Operational Parameters:** Decreasing the stress anisotropy ( $\sigma_{Hmax}/\sigma_{Hmin}$ ) by increasing the minimum horizontal stress caused the primary hydraulic fracture plane to resist opening, resulting in higher wellbore pressures, narrower apertures, longer time delays, and reduced passive pressure intensities and magnitudes. The overall complexity of the stimulated fracture network diminished, as evidenced by the contraction of the microseismic cloud (Figure 11g). Changes in Poisson's ratio altered the distribution of passive pressure responses among the passive wells and occasionally produced inflection points in the passive pressure curves, reflecting the complex interactions between stress redistribution and fracture dilation.

The operational parameters, including fluid viscosity, injection rate, and injection time, affected the passive pressure behavior. Higher fluid viscosity enhanced stimulation of fractures perpendicular to the minimum horizontal stress and triggered more tensile failures, producing shorter delays and higher passive pressure intensities and magnitudes. Because proppant transport was not included in the simulations, tensile-dominated fractures closed rapidly after pumping ceased, resulting in steep falloff [42]. The shear-dominated fractures, in contrast, retained permeability longer and produced longer delays, lower intensities, and more gradual falloff (Figure 11h). Increasing the injection rate elevated the wellbore pressure and altered the sequence in which the passive wells displayed pressure responses, reflecting increased fluid leakoff into crossing fractures (Figure 11i). The injection time had a minimal effect on the time delay but allowed the pressure front and microseismic activity to extend farther into the reservoir (Figure 11j).

**Increasing Fracture Network Complexity:** An increasing fracture network complexity consistently reduced the pressure transfer efficiency. The simulations incorporating additional DFN sets produced longer time delays, lower passive pressure intensities and magnitudes, and less steep falloff, accompanied by broader and more diffuse microseismic clouds. The cloud of microseismic events can be used to characterize the stimulated network complexity through the fracture complexity index (FCI), defined as the ratio of

microseismic image width to image length [43]. For example, the FCI increased from 0.124 in the three-fracture case to 0.211 in the five-fracture case, reflecting greater network tortuosity and reduced hydraulic connectivity (Figure 12). These increases in the FCI corresponded to broader, more diffuse microseismic clouds and more dampened pressure responses. The simulations demonstrated that increasing the fracture complexity impedes pressure propagation, reduces the amplitude of passive pressure responses, and prolongs pressure decline due to fluid migration into smaller fractures and the ultra-low-permeability matrix.



**Figure 12.** Various fracture patterns used to generate passive pressure responses, along with their corresponding fracture complexity indices (FCIs). Panels (a–j) show distinct DFN realizations with increasing structural complexity: (a) FCI = 0.124; (b) FCI = 0.211; (c) FCI = 0.231; (d) FCI = 0.224; (e) FCI = 0.286; (f) FCI = 0.303; (g) FCI = 0.407; (h) FCI = 0.611; (i) FCI = 0.334; (j) FCI = 0.502. Panels (k,l) illustrate more complex DFN sets with a 0° and 45° strike, respectively, representing the two principal natural fracture orientations relative to the in situ horizontal stresses.

## 4. Discussion

### 4.1. Geological and Mechanical Insights into Passive Pressure Responses

The workflow developed in this study shows that passive wellhead pressure monitoring is a robust, physics-based, though inherently limited, diagnostic tool for characterizing fracture propagation, inter-well connectivity, and stimulated reservoir volume in multi-well hydraulic fracturing. Integrating field-scale pressure observations with analytical modeling, probabilistic interpretation, and coupled hydro-mechanical simulations enables reconstruction of the fracture dynamics governing pressure transmission in the Horn River Shale Basin. The agreement between the simulated and observed responses indicates that PWPM captures the essential processes of fracture dilation, shear activation, stress redistribution, and preferential flow through conductive natural fractures, despite relying solely on surface measurements.

A key insight is that passive pressure signatures encode fracture network architecture. Rotating the DFN produced large changes in fracture complexity, failure mode distribution, and pressure propagation behavior. The networks aligned with the principal stresses formed narrow, tensile-dominated corridors, whereas the rotated networks generated broader, more tortuous, shear-dominated pathways. These differences appeared directly in the pressure response attributes, demonstrating that PWPM can infer the fracture geometry and failure mode from temporal and amplitude characteristics.

The mechanical properties further shaped the pressure transfer behavior. Stiffer formations transmitted pressure more efficiently once the fractures dilated, while a higher joint stiffness or friction angle suppressed the shear slip and reduced hydraulic connectivity. The natural fracture aperture, both the initial and dynamically evolving, was a dominant control. Wider apertures accelerated propagation and reduced pressure intensity, whereas narrower apertures delayed arrival and amplified buildup. These trends highlight the need for mechanically consistent representations of fracture conductivity and storativity.

The stress regime and anisotropy also influenced pressure communication. Increasing the minimum horizontal stress reduced the anisotropy and impeded the opening

perpendicular to  $\sigma_{\text{hmin}}$ , attenuating the responses and reducing fracture complexity. The sensitivity to Poisson's ratio shows how elastic properties govern stress redistribution and dilation [44], suggesting that PWPM can help refine mechanical earth models when direct measurements are limited. Operational parameters, such as viscosity, injection rate, and injection time, shaped the pressure behavior predictably, indicating PWPM's potential as a real-time indicator of stimulation effectiveness.

Finally, the fracture network complexity strongly governed the passive pressure attenuation. As the fracture count increased, the networks became more tortuous, complexity indices rose, and the pressure responses became more dampened and delayed. This relationship provides a measurable basis for using PWPM as a proxy for stimulated reservoir volume, especially where microseismic monitoring is impractical or cost prohibitive. The DFN realizations and their corresponding pressure signatures illustrate how increasingly tortuous fracture geometries consistently produce more attenuated and delayed PWPM signatures.

#### 4.2. Understanding Passive Pressure Attributes Across Mechanisms and Formations

The time delay clusters identified in this study align with the fundamental pressure propagation mechanisms described in hydraulic fracture diagnostics. Near-instantaneous responses ( $\leq 1$  min) indicate direct hydraulic communication through conductive fractures intersecting offset wells, consistent with observations from the Horn River Basin and other shale plays [7,37,45]. Intermediate delays reflect hydro-mechanical or stress shadow effects caused by stimulation-induced deformation of fluid-filled natural fractures near passive wells [38,46], while longer delays correspond to far-field poroelastic diffusion through a low-permeability matrix or distant fracture networks [47]. Their distribution across the Muskwa, Otter Park, and Evie formations therefore captures the expected transition from hydraulic to diffusion-dominated propagation.

The pressure rise rates provide an equally good diagnostic indicator of the underlying transmission mechanism. High rise rates ( $10^2$ – $10^3$  kPa/min) are a mark of direct hydraulic connectivity, as documented in multiple shale basins [37,43,45]. In this dataset, intensities exceeding  $\sim 10^2$  kPa/min consistently correspond to short-delay, high-magnitude events, reinforcing that this threshold reflects the physics of rapid pressure transfer rather than an imposed classification. Lower rise rates (on the order of  $\sim 10$  kPa/min) align with stress shadow or poroelastic responses, where the pressure evolves more gradually due to elastic deformation or diffusion-controlled propagation.

The peak-pressure magnitude is similarly governed by inter-well spacing, fracture conductivity, and in situ stress conditions. Large-magnitude hits ( $>3$ – $5$  MPa) occur when hydraulic fractures directly intersect offset wells or when conductive natural fractures provide efficient transmission pathways [37,46]. The strong ( $>5$  MPa) responses observed in the Evie formation are consistent with its higher stiffness, higher horizontal stress, and tighter well spacing, all of which indicate direct hydraulic connectivity [7,32]. In contrast, the Muskwa and Otter Park formations, characterized by wider spacing and more heterogeneous natural fracture systems, exhibit lower-magnitude responses ( $<2$ – $3$  MPa), consistent with diffusion-dominated or stress shadow mechanisms.

The formation-dependent falloff behavior provides additional insight into fracture conductivity and fluid migration pathways. The Muskwa's more pronounced falloff suggests enhanced fluid exchange with smaller fractures and greater matrix imbibition, consistent with prior observations in formations with dense, fine-scale natural fracture networks or higher clay content [38,46]. In contrast, the weaker falloff in the Evie and Otter Park formations reflects more conductive fracture pathways, where the pressure dissipates rapidly once pumping ceases [37,43]. These formation-specific falloff signatures

reinforce the interpretation that attributes of passive pressures indicate fracture conductivity, storativity, and network architecture.

#### *4.3. Implications, Applications, and Limitations*

This study has several direct implications for PWPM deployment and stimulation design. PWPM enables real-time fracture diagnostics by identifying fracture mode dominance and evolving connectivity during pumping, supporting dynamic adjustments of injection parameters. Pressure catalogues improve child well planning by predicting the inter-well communication risk and informing decisions based on spacing and stage placement. PWPM also guides refracturing by identifying depleted or overstimulated zones, helping operators avoid ineffective intervals or pre-pressurize them before treatment. Operational risks can be reduced through early detection of anomalously strong passive pressure responses, which may signal unintended fracture growth toward offset wells or surface infrastructure. In addition, PWPM offers a cost-effective alternative to microseismic monitoring, providing scalable diagnostics while maintaining high interpretive value.

In the context of refracturing design, PWPM's attributes provide qualitative indicators of zones that may benefit from re-stimulation. High falloff rates and muted pressure rise intensities commonly reflect depleted or pressure-drained intervals where fracture conductivity has diminished, making these zones potential refracturing candidates. Conversely, very low falloff rates and high magnitudes may indicate overstimulated or highly conductive regions where additional treatment would yield limited benefit. The time delay behavior also contributes diagnostic value. Short delays associated with weak passive responses can signal previously stimulated pathways that have become inefficient, whereas long delays paired with low magnitudes may reflect isolated or poorly connected intervals. These attribute combinations offer a practical, formation-specific framework for identifying refracturing targets without relying on universal quantitative thresholds.

Beyond unconventional reservoir development, the broader implications of this work extend to CO<sub>2</sub> sequestration and geothermal operations using horizontal wells [48]. The ability of PWPM to detect subtle changes in fracture connectivity, fluid migration pathways, and stress redistribution makes it a valuable potential monitoring tool for subsurface injection processes, where real-time diagnostics can enhance injection safety and reduce the risk of unintended fracture propagation or leakage.

Despite its strengths, this study has several limitations. The DEM framework restricts the flow to failed sub-contacts, potentially underestimating the contributions from partially open fractures. Proppant transport is not modeled, and the DFN statistics may miss small-scale heterogeneity. The model represents only part of a single half-pad, so the quantitative results reflect the specific geology and stress regime of the studied case. The analysis focuses on the injection time dynamics; long-term diffusion and production time connectivity are not evaluated. These limitations suggest future work incorporating proppant transport, partially open fractures, and multi-pad datasets.

Lastly, the applicability of PWPM is strongest in formations where pressure transmission occurs primarily through dense-phase fluid-filled fractures and where lithological variability remains moderate. In reservoirs with a high gas content, strong heterogeneity, or densely developed natural fracture systems, the passive pressure signals may become more diffuse or more strongly attenuated, reflecting a combination of hydraulic connectivity, gas compressibility, and localized deformation. These conditions do not prevent the use of PWPM, but require careful contextual interpretation, as pressure responses may integrate multiple competing mechanisms.

## 5. Conclusions

This study shows that passive wellhead pressure monitoring, when combined with analytical modeling, probabilistic interpretation, and fully coupled hydro-mechanical simulations, provides a robust and cost-effective approach for diagnosing fracture propagation and inter-well connectivity in multi-well hydraulic fracturing. The passive pressure data from the Horn River Shale Basin contain sufficient information to reconstruct the key hydro-mechanical processes governing fracture growth and fluid migration. The agreement between the simulated and observed passive pressures confirms that the essential physics of pressure transmission can be captured, enabling PWPM to support both diagnostic interpretation and predictive modeling.

The passive pressure behavior reflects the combined influence of fracture orientation, rock stiffness, joint mechanics, and fracture aperture, each of which shapes the transmissivity, deformation style, and pressure transfer efficiency. The operational parameters further modulate the response timing and magnitude, underscoring PWPM's utility as a real-time measure of stimulation effectiveness and fracture mode dominance. These sensitivities allow PWPM to inform stimulation design by clarifying how existing parameters control hydraulic connectivity and fracture network development. Fracture network complexity exerts a clear influence on passive pressure attenuation. The pressure catalogues capture this behavior by linking the geological and operational conditions to the expected signatures, enabling predictive assessment of inter-well connectivity for child well development, refracturing, and real-time decision-making.

Overall, this work establishes a coherent interpretation framework in which PWPM provides a practical diagnostic tool for fracture propagation and stimulation effectiveness. The results show that passive pressure signatures encode geological, mechanical, and operational controls on fracture network evolution, and that the attenuation trends offer a quantitative proxy for stimulated reservoir volume and fracture complexity. The broader applicability of PWPM to subsurface injection processes highlights its value as a pressure-based monitoring tool for improving operational safety.

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