Project Acronym and Title:
M4ShaleGas - Measuring, monitoring, mitigating and managing the environmental impact of shale gas

MODEL PREDICTIONS OF THE FRACTURE DISTURBED ZONE

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### Public introduction

M4ShaleGas stands for *Measuring, monitoring, mitigating and managing the environmental impact of shale gas* and is funded by the European Union’s Horizon 2020 Research and Innovation Programme. The main goal of the M4ShaleGas project is to study and evaluate potential risks and impacts of shale gas exploration and exploitation. The focus lies on four main areas of potential impact: the subsurface, the surface, the atmosphere, and social impacts.

The European Commission's Energy Roadmap 2050 identifies gas as a critical fuel for the transformation of the energy system in the direction of lower CO$_2$ emissions and more renewable energy. Shale gas may contribute to this transformation.

Shale gas is – by definition – a natural gas found trapped in shale, a fine grained sedimentary rock composed of mud. There are several concerns related to shale gas exploration and production, many of them being associated with hydraulic fracturing operations that are performed to stimulate gas flow in the shales. Potential risks and concerns include for example the fate of chemical compounds in the used hydraulic fracturing and drilling fluids and their potential impact on shallow ground water. The fracturing process may also induce small magnitude earthquakes. There is also an ongoing debate on greenhouse gas emissions of shale gas (CO$_2$ and methane) and its energy efficiency compared to other energy sources.

There is a strong need for a better European knowledge base on shale gas operations and their environmental impacts particularly, if shale gas shall play a role in Europe’s energy mix in the coming decennia. M4ShaleGas’ main goal is to build such a knowledge base, including an inventory of best practices that minimise risks and impacts of shale gas exploration and production in Europe, as well as best practices for public engagement.

The M4ShaleGas project is carried out by 18 European research institutions and is coordinated by TNO-Netherlands Organization for Applied Scientific Research.

### Executive Report Summary

It is often suggested that hydraulic fracturing may lead to contamination of shallow aquifers used for drinking water supplies due to the hydraulic fracturing process, e.g. by the creation of pathways for fracturing or formation fluids along hydraulic fractures that extend from deep shale formation all the way up to the shallow aquifers. This scenario is not supported by observations of the spatial distribution of micro-seismicity caused by hydraulic fracturing operations in shales from the United States and Canada. Instead, dedicated research shows that some cases of contamination near shale gas operations are related to improper well construction or surface spills, leaks or emissions. As shale gas basins in Europe are underexplored compared to basins in the United States and Canada, there is a general lack of data for shale gas operations in European shale basins. Modelling that can predict fracture dimensions or fracture disturbed zone around injection points at well perforations is therefore critical for upfront assessment of the risks and impacts associated with hydraulic fracturing. In this report, several modelling approaches, sources of data, application to field cases and model limitations are reviewed with a focus on (1) constraints on rock properties and stress conditions relevant to the development of induced or reactivated fractures, (2) prediction of the development of induced or reactivated fractures, (3) application of the modelling approaches to the Posidonia Shale Formation (PSF) in the Netherlands, (4) methods to evaluate model predictions using (micro-seismic) monitoring, and (5) examples of situations where model predictions might not be accurate. Overall, model predictions suggest that the extent of the fracture disturbed zone is limited (maximum few hundred meters around the injection point) for treatment schedules that are commonly used for hydraulic fracturing in shales, and that the extent of the fracture disturbed zone can be controlled by adjusting treatment schedules according to local geological settings and formation properties.
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1 INTRODUCTION

1.1 Context of M4ShaleGas

Shale gas source rocks are widely distributed around the world and many countries have now started to investigate their shale gas potential. Some argue that shale gas has already proved to be a game changer in the U.S. energy market (EIA 2015\(^1\)). The European Commission’s Energy Roadmap 2050 identifies gas as a critical energy source for the transformation of the energy system to a system with lower CO\(_2\) emissions that combines gas with increasing contributions of renewable energy and increasing energy efficiency. It may be argued that in Europe, natural gas replacing coal and oil will contribute to emissions reduction on the short and medium terms.

There are, however, several concerns related to shale gas exploration and production, many of them being associated with the process of hydraulic fracturing. There is also a debate on the greenhouse gas emissions of shale gas (CO\(_2\) and methane) and its energy return on investment compared to other energy sources. Questions are raised about the specific environmental footprint of shale gas in Europe as a whole as well as in individual Member States. Shale gas basins are unevenly distributed among the European Member States and are not restricted within national borders, which makes close cooperation between the involved Member States essential. There is relatively little knowledge on the footprint in regions with a variety of geological and geopolitical settings as are present in Europe. Concerns and risks are clustered in the following four areas: subsurface, surface, atmosphere and society. As the European continent is densely populated, it is most certainly of vital importance to understand public perceptions of shale gas and for European publics to be fully engaged in the debate about its potential development.

Accordingly, Europe has a strong need for a comprehensive knowledge base on potential environmental, societal and economic consequences of shale gas exploration and exploitation. Knowledge needs to be science-based, needs to be developed by research institutes with a strong track record in shale gas studies, and needs to cover the different attitudes and approaches to shale gas exploration and exploitation in Europe. The M4ShaleGas project is seeking to provide such a scientific knowledge base, integrating the scientific outcome of 18 research institutes across Europe. It addresses the issues raised in the Horizon 2020 call LCE 16 – 2014 on Understanding, preventing and mitigating the potential environmental risks and impacts of shale gas exploration and exploitation.

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1.2 Study objectives for this report

The United States and Canada have a long track record of successful hydraulic fracturing and shale gas production. Such track record is lacking in Europe, which means assessment of the impact of hydraulic fracturing needs to be performed upfront (i.e. before large-scale exploitation has commenced), and needs to be based on limited available data. Modelling approaches that can predict fracture dimensions or fracture disturbed zone aid in providing such impact assessment.

The main objective of this report is to provide a review of different modelling approaches that can simulate the dimensions of hydraulic fractures and fracture disturbed zone. In this report the theory behind fracturing, methods to constrain the input data, and sources of data are reviewed. In addition, modelling approaches are outlined that can be used to analyze fracture disturbed zone in case of combined tensile and shear fracturing in fractured reservoir with a population of natural faults. Some fracturing models are applied to the Posidonia Shale Formation in the Netherlands to demonstrate the applicability of the models to real field cases. Some methods are discussed that can be used to validate model predictions, as well as examples and settings are discussed that may be prone to larger fracture disturbed zone than predicted by the models. Overall, the research illustrates the predictive power of different modeling approaches and aids in assessing the risks associated with hydraulic fracturing with a focus on the subsurface impact of the fracturing process.

1.3 Aims of this report

This report aims to provide a public dissemination of modelling approaches and predictions of dimensions of fractures and fracture disturbed zone that adds to the scientific knowledge base for hydraulic fracturing. In particular, it aims to provide scientific knowledge on risks and impacts associated with the induction and reactivation of fractures due to hydraulic fracturing.
2 SCIENTIFIC BACKGROUND AND REPORT INTRODUCTION

While a long track record of successful hydraulic fracturing and shale gas production exists in the United States (EPA, 2016), such a record is lacking in potential shale gas basins in Europe. Hydraulic fracturing operations have now been performed in some shale gas wells in Poland and the United Kingdom (Clark et al., 2014; Hendel et al., 2015), but in general data on the impact of these operations is sparse. In underexplored European shale basins, upfront predictions of hydraulic fracturing need to be based on limited available data, i.e. before large-scale exploitation has commenced. One of the main public concerns in Europe regarding the impact of hydraulic fracturing is related to fracture containment. It is often suggested that hydraulic fracturing may lead to contamination of shallow aquifers used for drinking water supplies due to the hydraulic fracturing process itself. It is, sometimes implicitly, assumed that hydraulic fractures can extend from deep shale formation all the way up to the shallow aquifers, and that these fractures can act as pathways for migration of fracturing or formation fluids (King, 2012; Davies et al., 2012). Although hydraulic fracturing has been associated with contamination in some cases, mainly in relation to surface spills or improper well construction (Llewellyn et al., 2015), there is no clear evidence for contamination due to fluid migration along hydraulic fractures (EPA, 2016). This observation may be generally valid, provided there is ample separation between the shale and shallow aquifers. The presence of regional sealing formations and local subsurface conditions may also aid in inhibiting fluid migration over large distances along discontinuities such as fault zones. Hydraulic fracturing of the Bowland Shale at the Preese Hall 1 well near Blackpool in the United Kingdom has resulted in felt seismicity as well as some (non-critical) casing deformation (De Pater and Baisch, 2011; Green et al., 2012; Clark et al., 2014). Accordingly, fault reactivation associated with hydraulic fracturing may affect the integrity of wells. It is therefore important to study the impact of hydraulic fracturing operations in detail because it allows better mitigation measures to be implemented (i.e. focused on surface operations and well completion rather than on the hydraulic fracturing process) that reduce the impacts and risks associated with hydraulic fracturing. On the other hand, fault reactivation associated with hydraulic fracturing may affect the integrity of wells (De Pater and Baisch, 2011; Green et al. 2012). It is therefore important to develop best practice hydraulic fracturing operations that ensure fracture containment and mapping within a limited rock volume around wells, while achieving optimum stimulation of the target shale to ensure gas flow at commercial rates.

Modelling approaches that can predict fracture dimensions or fracture disturbed zone around injection points at well perforations are important for optimization of hydraulic fracturing. In particular, hydraulic fracturing models can aid optimization because (1) multiple hydraulic fracturing scenarios can be evaluated addressing variations in operational parameters such as injection volume as well as uncertainty in geological parameters such as mechanical rock properties, (2) simulations can be used to perform a risk and impact assessment upfront (i.e. before operations have commenced), and (3) they can aid in designing hydraulic fracturing operations so that both fracture containment and
commercial gas production is achieved (i.e. dual objective optimization of hydraulic fracturing).

In this report, we briefly review different modelling approaches that can be used to simulate dimensions of fractures and stimulated reservoir volume. In addition, we focus on the application of two approaches to an actual field case. First, an analytical approach is developed that can be used for fast screening of approximate dimensions of fractures and fracture disturbed zone. This approach requires a number of simplifying assumptions mainly regarding spatial variation in rock properties, characteristics of induced fractures and natural fracture populations, and mechanical and fluid flow processes. The spatial distribution of reactivated fractures and fracture permeability after stimulation are key controlling factors that determine the extent of fracture disturbed zone, stimulated reservoir volume, and hydrocarbon flow rates (Gale and Holder, 2010; King, 2010).

Although performed for one type of shale at rather large depth in one of many geological settings in Europe, simulations show limited upward growth (< 250 meter above well) of individual fracture and limited extent of fracture disturbed volume for treatment schedules that are commonly used for hydraulic fracturing in shales. The presence of natural fractures may lead to larger overall fracture disturbed zones, but the vertical extent of reactivated fractures unlikely extends beyond 250 m. Implications are given for the characteristics of induced or reactivated fractures that result from hydraulic fracturing if the distribution and properties of faults and fractures in shales is accounted for. The report acknowledges assumptions and limitations of the models by discussing some examples and settings that may be more prone to extension of induced fractures than predicted by the models.
### 3 MODELING APPROACHES

Hydraulic fracturing involves fluid injection that may lead to initiation and propagation of new (hydraulic) fractures as well as the reactivation of existing fractures. The combination of injection-induced fracture initiation and reactivation results in a fracture disturbed zone around the injection well. In this section, we describe different modelling approaches that can be used to predict dimensions of fractures or the fracture disturbed zone resulting from fluid injection during hydraulic fracturing operations. The aim is not to compile a comprehensive review of modelling approaches, but rather focus on some key approaches that can be readily applied to constrain the fracture disturbed zone. Accordingly, the focus is on (1) analytical models that allow screening of the fracture disturbed volume and provide a rough estimate or bounds on the volume affected by fractures, (2) semi-analytical models that incorporate some (vertical) heterogeneities of the fractured medium (i.e. layering) and are commonly used in commercial hydraulic fracturing simulators to design individual fracturing operations, and (3) a brief review of recent trends in developing numerical models that allow more in depth investigation of the fracturing process and its effect on shales. More detail overview of different hydraulic fracturing models can be found elsewhere, for example in Economides and Nolte (2000); Shahid et al. (2015), or in proceedings of recent conferences (e.g., 50th U.S. Rock Mechanics/Geomechanics Symposium, held 26-29 June 2016 in Houston, Texas). The input data for hydraulic fracturing models consist of geological data, such as in situ stresses and mechanical rock properties, and operational data, such as injection rate and hydraulic fracturing fluid composition. The section starts with an overview of general geomechanical theory and some key modelling approaches that can be used to constrain in situ stresses and mechanical rock properties.

### 3.1 Constraints on data controlling hydraulic fracturing

#### 3.1.1 Constraints on in situ stress from general geomechanical theory

The stress state at any location in the subsurface can be described by a second order (Cauchy) tensor (e.g., Jaeger et al., 2007; Fjaer et al., 2008):

\[
\sigma_{ij} = \begin{pmatrix}
\sigma_{11} & \sigma_{12} & \sigma_{13} \\
\sigma_{21} & \sigma_{22} & \sigma_{23} \\
\sigma_{31} & \sigma_{32} & \sigma_{33}
\end{pmatrix}
\]  

(1)

With the proper choice of coordinate system, shear stresses \((\sigma_{ij} \text{ with } i \neq j)\) vanish and the stress tensor can be described by 3 principal stresses \((\sigma_{11}, \sigma_{22}, \sigma_{33})\). In many cases (i.e. away from discontinuities such as salt domes, fault zones or boreholes), subsurface deformation can be described in terms of Andersonian faulting regimes where stresses are analyzed using a coordinate system where one of the principal stresses is vertical and the other two horizontal (Anderson, 1951). In this case, principal stresses are the vertical stress \((S_v)\), maximum horizontal stress \((S_{\text{Hmax}})\) and minimum horizontal stress \((S_{\text{Hmin}})\). As
a first approximation the total stresses in the rock formation at depth ($z$) can be calculated by (e.g., Jaeger et al., 2007; Fjaer et al., 2008; Zoback, 2007):

$$S_v = \int_0^z \rho(z) \cdot g \cdot zdz$$

(2)

$$S_h = \frac{V}{(1-v)} \left( S_v - \alpha P_p \right) + \alpha P_p$$

(3)

with formation density ($\rho$), gravitational acceleration ($g=9.8 \text{ m/s}^2$), Poisson ratio ($\nu$), Biot coefficient ($\alpha$), and pore fluid pressure ($P_p$). Alternatively, Eq. (3) may be written in terms of effective stress, yielding $\sigma_i' = K' \sigma_i'$. In this case, bounds on (isotropic) horizontal stresses are calculated using the Poisson effect of overburden weight, assuming the formation is laterally constrained (i.e. horizontal strain $\varepsilon_{h}=0$). As $\nu < 0.5$ for rocks, this approach assumes a normal faulting regime (i.e., $S_{hmin}<S_{Hmax}<S_{i}$). If instead, the formation is in a critical state with stresses controlled by the frictional strength of faults, bounds on maximum and minimum principal stresses ($S_1$ and $S_3$) can be determined by (Jaeger et al., 2007; Zoback, 2007):

$$\frac{\sigma_1}{\sigma_3} = \frac{(S_1-P_p)}{(S_3-P_p)} = \left[ (\mu^2 + 1)^{\frac{1}{2}} + \mu \right]^2$$

(4)

with friction coefficient ($\mu$) that describes the frictional strength of pre-existing faults. Eq. (4) can be used to determine stress bounds for normal ($S_1 = S_v$, $S_3 = S_{hmin}$, $S_{hmin}<S_{Hmax}<S_{i}$), strike slip ($S_1 = S_{Hmax}$, $S_3 = S_{hmin}$, $S_{hmin}<S_{i}<S_{Hmax}$) or reverse ($S_1 = S_{Hmax}$, $S_3 = S_{hmin}$, $S_{hmin}<S_{i}<S_{Hmax}$) faulting regimes. A lower bound on $S_{hmin}$ is given by the hydrostatic pore pressure gradient ($\Delta P_p/\Delta z \approx 10 \text{ kPa/m}$). Within these bounds, principal stresses may vary between an isotropic ($S_1 = S_2 = S_3$) and anisotropic ($S_1 \neq S_2 \neq S_3$) stress state. In most cases, the stress state in the subsurface is characterized by anisotropic stresses, and different ratios $K_{min} = \sigma_2/\sigma_1$ and $K_{max} = \sigma_3/\sigma_1$ may be introduced to describe the anisotropy (cf. ter Heege et al., 2017).

### 3.1.2 Constraints on rock mechanical properties

The most common methods to constrain mechanical rock properties are by well log interpretation or laboratory experiments. In many cases well logs are available, while laboratory experiments involve testing core of the rock formation of interest or comparison with analogue materials for which laboratory data is available. Availability of core material for laboratory experiments is often an issue, in particular considering appropriately curated bedrock material (either from core or outcrop material) of proper dimensions and without desiccation that is suitable for laboratory experiments addressing geomechanical properties.

A variety of well logs may be available to constrain rock properties (Crain and Holgate, 2014). Here, focus is on the most common logs that can be used to constrain the mechanical rock properties controlling hydraulic fracturing. Formation density (Eq. 2) can be determined using the RHOB log. If a dipole sonic log is available, dynamic
Young’s modulus \((E_{\text{dyn}})\) and Poisson’s ratio \((\nu_{\text{dyn}})\) can be derived that describe the elastic properties of the rock formation:

\[
E_{\text{dyn}} = \rho v_s^2 \frac{3v_p^2 - 4v_s^2}{v_p^2 - v_s^2}
\]

\[
\nu_{\text{dyn}} = \frac{v_p^2 - 2v_s^2}{2(v_p^2 - 2v_s^2)}
\]

with compressional \((v_p)\) and shear \((v_s)\) sonic wave velocities (in km/s). If only a monopole sonic log is available, \(v_s\) can be constrained using \(v_p\) based on empirical relations for specific rock types, e.g. for mudstones \(v_s = (v_p - 1.16)/1.36\) (Castanga et al., 1985). However, it remains subject to critical evaluation to what extent predictions based on these empirical relations are accurate (cf. Ter Heege et al., 2015).

Laboratory experiments can be used to obtain static elastic moduli \((E \text{ and } \nu, \text{ Eq. 5, 6})\) that are most relevant for hydraulic fracturing, and to relate dynamic to static elastic moduli (Eissa and Kazi, 1988; Sone and Zoback, 2010). In addition, laboratory experiments can be used to obtain properties that determine rock strength, such as tensile strength \((T_0)\), cohesion \((S_0)\), and friction coefficient \((\mu, \text{ Eq. 4})\).

### 3.2 Analytical fracturing models

A simple analytical approach to modelling the dimensions of fractures and fracture disturbed zone or stimulated reservoir volume can be based on modelling tensile (mode I) and shear (mode II) fractures as two end-members (Figure 1). As opposed to most (commercial) hydraulic fracturing simulators that use semi-analytical models of tensile fracturing or full 3D numerical models, the analytical approach is fast (i.e. computational inexpensive) and can account for both tensile and shear fracturing.

#### 3.2.1 Tensile (mode I) fractures

In general, tensile failure occurs when the effective minimum principal stress equals tensile strength (i.e. \(\sigma_3' = \sigma_3 - P_p = -T_0\) with \(P_p\) denoting pore pressure). For a vertical well and a stress field characterized by normal faulting, principal stresses are \(S_v > S_{H\text{max}} > S_{H\text{min}}\) and tensile fractures are vertical. In the case of wellbore injection pressure \((P_i)\) that exceed far field pore pressure, stress concentrations occur due to poroelastic effects which can be described by the poroelastic stress coefficient \((\xi = \alpha(1-2\nu)/2(1-\nu)\) with \(\alpha\) denoting Biot’s coefficient). Hence, the injection pressure at which tensile fractures initiate around the wellbore is given by (Economides and Nolte, 2000; Fjaer et al., 2008):

\[
P_i = \frac{3S_{H\text{min}} - S_{H\text{max}} + T_0 - 2\xi P_p}{2(1-\xi)}
\]

with minimum \((S_{H\text{min}})\) and maximum \((S_{H\text{max}})\) horizontal stresses.
Figure 1. Schematic Mohr circle diagram showing the potential effects of fluid injection during hydraulic fracturing on the local stress state for a normal faulting regime. For the initial stress state before injection, the effective stresses ($\sigma'_v$, $\sigma'_H$, $\sigma'_L$, thin black lines) driving deformation are determined by the total stresses ($S_v$, $S_H$, $S_L$, thick black lines), pore pressure ($P_p$) and the poroelastic behavior of the rock described by the Biot coefficient ($\alpha$). In this example, different Mohr failure criterion for fracture reactivation are indicated (red lines) with similar cohesion ($S_w$) and different friction coefficients ($\mu_w$), assuming existing natural fractures form planes of weakness (Fjaer et al., 2008). A Mohr failure criterion for intact rock with cohesion ($S_i$) and internal friction coefficient ($\mu_i$) is also indicated. Some fractures may be critically-stressed at initial stress conditions (red/black dot) due to a relatively low friction coefficient ($\mu_w = 0.44$ in this example) and a critical orientation (at angle $\lambda'_{inj}$ to $\sigma'_v$), and will be reactivated even for small variations in pore pressure at the start of injection. The critical angle $\lambda'$ is related to the friction angle $\phi_i = \arctan(\mu_i)$, i.e. $\lambda' = 45^\circ \pm \phi_i/2$ (Eq. 16, 17). Other fracture orientations (black dots) will be stable at initial stress conditions. During injection, effective stresses (in green) will be reduced, and the range of critical fracture orientations ($\lambda'_{inj}$) becomes larger and fractures with higher friction coefficient ($\mu_w = 0.6$ in this example) can become critically-stressed and may be reactivated (red/green dots). Due to the poroelastic behavior of the rock the decrease of $\sigma'_{Lmin}$ is less than the decrease of $\sigma'_v$ for increasing pore pressure, resulting in a small decrease of the Mohr circles during injection (mainly determined by the Poisson ratio $\nu$). If existing fractures at critical orientations within the prevailing stress state are absent or not hydraulically connected to the injection point, effective stresses may be reduced due to rising pore pressure until the minimum horizontal stress ($\sigma'_{Lmin}$) reaches the tensile rock strength ($T$). At this pressure, hydraulic fractures will initiate and continue to open and grow as long as $\sigma'_{Lmin} = -T_p$. Note that a Mohr-Coulomb type failure criterion may not generally apply to viscoplastic materials such as many shales (cf. TerHeege, 2016).

Considering material balance between injected volume ($V_i$), fracture volume ($V_f$) and leakoff volume that is lost to the formation ($V_l$) for a rectangular fracture yields (cf. Economides and Nolte, 2000):

$$V_i = Q_i t_i = V_f + V_l = H_f \bar{W}_f 2L_f + 6C_i H_i L_f \sqrt{t_i} + 4L_f H_i S_p$$

(8)
with injection rate \((Q_i)\), injection (pumping) time \((t_i)\), fracture height \((H_f)\), average fracture width \((W_f)\), fracture length \((L_f)\), fluid-loss height \((H_l)\) and spurt loss \((S_p)\). Several relations between fracture dimensions, local pressure conditions, and rock properties can be found for different assumptions for fluid flow and fracture mechanics (Economides and Nolte, 2000). A key relation for net pressure \((P_{net} = P_f - S_{min})\) with \(P_f\) the pressure in the fracture) includes a fluid mechanics component describing viscous flow through the fracture and a fracture mechanics component describing opening of fractures at the fracture tip (Economides and Nolte, 2000):

\[
P_{net} = \left[ \frac{c_p E^3 \eta Q_i L_f}{(1-v^2)^3 H_f^4} + \left( \frac{\pi}{\sqrt{48L_f^4}} \right)^4 \right]^{1/4}
\]

with constant \((c_p)\), Young’s modulus \((E)\), Poisson ratio \((v)\), fluid viscosity \((\eta)\), and critical stress intensity factor \((K_{ic})\). Analytical models of tensile fractures generally assume a specific fracture geometry. For a radial fracture with radius \((R_f)\), constant injection rate, negligible fluid friction in the fracture and no leakoff, the net pressure and fracture dimensions can be described in terms of operational parameters (i.e. injection volume rate \(Q_i\), and time \(t_i\) with \(Q_i = V_i/t_i\)) and rock properties (Sneddon, 1946; Perkins & Kern, 1961; Economides and Nolte, 2000):

\[
P_{net} = \left( \frac{2\pi^3 \gamma E^2}{3(1-v^2)^2 Q_i t_i} \right)^{1/5}
\]

\[
V_f = \frac{16(1-v)R_f^3}{3E} P_{net}
\]

\[
R_f = \left( \frac{9E Q_i t_i}{128\pi\gamma(1-v^2)} \right)^{1/5}
\]

\[
W(r) = \frac{8f R_f (1-v^2)}{\pi E} \sqrt{1 - \left( \frac{r}{R_f} \right)^2} P_{net}
\]

with radial distance from the center of the fracture \((r)\), and fracture surface energy \((\gamma)\). With these assumptions, Eqs. (12)-(14) give an upper bound to fracture dimensions as leakoff of fluids into the formation will lower the fluid volume available to open and propagate fractures.
3.2.2 Shear (mode II) fractures

The pressure at which shear fractures initiate movement can be based on Mohr-Coulomb failure criterion (e.g., Fjaer et al., 2008):

\[ P_i = \sigma_n - \frac{\tau - S_0}{\mu} \]  

(15)

with normal stress \( (\sigma_n) \), shear stress \( (\tau) \), cohesion \( (S_0) \) and friction coefficient \( (\mu) \). For the reactivation of shear fractures, the inherent shear strength of the rock can be significant \( (S_0 = S_i) \) and the coefficient of internal friction \( (\mu = \mu_i) \) should be used in Eq. (15). After reactivation, generally a drop in cohesion \( (S_0 = S_w \approx 0) \) and friction coefficient occur \( (\mu = \mu_w) \) with \( \mu_w \) the coefficient of frictional sliding along a weak plane, Figure 1). Normal and shear stress are related to in situ stresses by:

\[ \sigma_n = \frac{1}{2} (\sigma_1 + \sigma_3) + \frac{1}{2} (\sigma_1 - \sigma_3) \cos 2\beta \]  

(16)

\[ \tau = \frac{1}{2} (\sigma_1 - \sigma_3) \sin 2\beta \]  

(17)

with the angle between the normal to the fault plane and the maximum principal stress \( (\beta = \pi/4 + \varphi/2) \), and friction angle \( \varphi = \arctan(\mu) \). The fracture dimensions of a non-critically-stressed natural fracture that is present in the rock formation can be approximated by:

\[ V_f = c_g L_f S_f W_f \]  

(18)

with geometrical constant \( (c_g) \), average fracture length along strike \( (L_f) \), average fracture length along dip \( (S_f) \), and average fracture width \( (W_f) \). Constant \( c_g \) depends on the fault geometry, and may be chosen depending on the dimensions and detail of mapped fault geometries (e.g., \( c_g = 1 \) for large rectangular fault volumes that cut through the entire rock formation, or \( c_g = 1/6\pi \) for ellipsoidal fault volumes that are completely contained within the rock formation). The change in width or aperture due to reactivation of (critically-stressed) fracture \( (\Delta W_f) \) can be expressed as the combination of tensile- \( (\Delta W_n) \) and shear- \( (\Delta W_s) \) controlled opening (Wassing et al., 2014):

\[ \Delta W_f = \Delta W_n + \Delta W_s \]  

(19)

\[ \Delta W_n = \frac{c_{k0} \sigma_n}{1 + c_{k1} \sigma_n} \]  

(20)

\[ \Delta W_s = \Delta u_s \tan \psi \]  

(21)

with a constant \( (c_{k0}) \) for which \( 1/c_{k0} \) is related to the normal stiffness at \( \sigma_n = 0 \), a constant \( (c_{k1}) \) for which \( c_{k1}/c_{k0} \) is related to the maximum normal stiffness for a closed fracture, average shear displacement over the fracture surface \( (\Delta u_s) \), and dilatancy angle \( (\psi) \). For
ellipsoidal fractures, average displacement can be related to stress drop (Brune, 1970; Ellsworth, pers. comm.):

$$\Delta u_s = \frac{2}{3} \Delta u_{\text{max}} = \frac{2}{3} \frac{\Delta \tau}{k_s} = \frac{2R_f \Delta \mu \sigma'_n}{c_g G}$$

(22)

with stress drop ($\Delta \tau = \Delta \mu \sigma'_n$ with $S_0 = 0$, Eq. 15), shear stiffness of the fracture ($k_s$), average shear modulus of the fracture ($G$), and geometrical constant ($c_g = 7\pi/24$ for penny-shaped fractures). Average displacement (and hence stress drop) can also be used to calculate seismic moment ($M_0$), assuming that fracture reactivation releases seismic energy (Aki, 1966; Hanks and Kanamori, 1979):

$$M_0 = GA_f \Delta u_s$$

(23)

with (rupture) area of the fracture that is failing ($A_f$). Using Eq. (15)-(23), monitored seismicity can be related to dimensions of shear fractures and local stress state.

### 3.2.3 Fracture populations

The previous section analyses the reactivation of single shear fractures. The fracture disturbed zone will be dependent on the population of natural fractures that are present in the rock volume. The frequency distribution of fault properties or dimensions in a fracture population is often observed to follow power law distributions (Odling et al. 1999; Bonnet et al. 2001; Torabi and Berg 2011). If a population of faults or fractures is analyzed for an area of observation ($A_f$) crosscutting a rock volume ($V_r$), the number of faults of size $T$ can be described by considering the density or cumulative density function (e.g., Bonnet et al. 2001). If the distribution of fault sizes is characterized by a power law distribution, the number of faults of size $T$ ($n$) or the cumulative number of faults with size greater than $T$ ($N$) can be described by (TerHeege et al., 2016):

$$n(T) = c_{n1} T^{-c_{n2}} \quad \text{with} \quad c_{n1} = \frac{N_{\text{tot}} (c_{n2} - 1)}{T_{\text{min}}^{1-c_{n2}}}$$

(24)

$$N(T) = \int_T^{\infty} n(T) dT = c_{N1} T^{-c_{N2}} \quad \text{with} \quad c_{N1} = \frac{c_{n1}}{c_{n2} - 1} = \frac{N_{\text{tot}}}{T_{\text{min}}^{1-c_{n2}}} \quad \text{and} \quad c_{N2} = c_{n1} - 1$$

(25)

where $T$ can denote the fault length along strike ($L$) or along dip ($S$), or fracture width ($W_f$). $N_{\text{tot}}$ is the total number of faults observed in $A_f$, and can be calculated by taking $T = T_{\text{min}}$ in Eq. (25) with $T_{\text{min}}$ the minimum fault size. $T_{\text{min}}$ can either be the actual minimum fault size that can be observed (controlled by the resolution of the fault size analysis method), or a theoretical lower limit derived from using the power law fit to extrapolate fault sizes beyond the lower limit in data (for example, the minimum size of faults that significantly contribute to bulk permeability). Constants $c_{n1}$, $c_{n2}$, $c_{N1}$ and $c_{N2}$ can be derived from best fit of fault size distribution data to Eqs. (24) and (25). The constants are determined by the overall fracture density ($N_{\text{tot}}/V_r$) in the area (cf. TerHeege et al., 2016).
3.2.4 Permeability model for fractured reservoirs

In the previous sections the critical pressure for initiation of tensile fractures or reactivation of shear fractures is given. During injection of fluids for hydraulic fracturing, pressure will increase in the rock volume. Pressure increase at the well may lead to initiation of tensile fracture while pressure increase around natural fractures may lead to the reactivation of shear fractures. The temporal and spatial distribution of pressure during injection is determined by the permeability of the reservoir, which critically depends on the fracture distribution (cf. section 3.2.3). Anisotropic permeability in a fracture can be described by a 3D permeability tensors \( \mathbf{K}_F \) that is defined in terms of 3 orthogonal principal permeabilities in a coordinate system with axes parallel to the normal, strike and dip vector of the fracture, respectively, and principal permeabilities described by the harmonic and arithmetic means of fracture and matrix permeability (TerHeege et al., 2016):

\[
\mathbf{K}_F = \begin{pmatrix}
K_{F11} & 0 & 0 \\
0 & K_{F22} & 0 \\
0 & 0 & K_{F33}
\end{pmatrix}
\]

\( K_{F11} = \left( \frac{F_w \mathbf{W}_f}{K_{F11}} + \frac{1 - F_w \mathbf{W}_f}{\mathbf{K}_M} \right)^{-1} \)  
\( K_{F22} = F_w \mathbf{W}_f \mathbf{K}_{F22} + (1 - F_w \mathbf{W}_f) \mathbf{K}_{M22} \)  
\( K_{F33} = F_w \mathbf{W}_f \mathbf{K}_{F33} + (1 - F_w \mathbf{W}_f) \mathbf{K}_{M33} \)

with the density of fractures at similar orientation \( F_w \) and components of the matrix permeability tensor \( \mathbf{K}_M \). For fracture populations, the bulk permeability in a geographical coordinate system can be approximated by volume averaging the permeabilities of different fracture sets \( \mathcal{F} \) with similar orientation. A rotation of the fracture-based coordinate system using Euler angles needs to be applied to express the fracture permeability tensor in the geographical coordinate system (Fjaer et al., 2008). Average bulk permeability \( \overline{\mathbf{K}}_B \) is then given by (cf. TerHeege et al., 2016):

\[
\overline{\mathbf{K}}_{Bij} = \left( 1 - \frac{V_{\text{rot}}}{V_r} \right) \mathbf{K}_{Mij} + \sum_{\chi=1}^{N_F} \mathbf{R}_{ij} \frac{V_{\chi}}{V_r} \mathbf{K}_{Fij} \mathbf{R}^T_{ij} \quad \text{with } V_{\text{rot}} = \sum_{\chi=1}^{N_F} V_{\chi}
\]

with the (total) volume of fractures in the different sets \( V_r \), \( V_{\text{rot}} \), total number of fracture sets \( N_F \), and rotation matrix \( \mathbf{R} \). The volume of fractures in each set can be determined by combining Eq. (18) with (25) using proper classes in the power law distribution of fault sizes and fault scaling laws together with formation properties (cf. TerHeege et al., 2016).

3.2.5 Fractured reservoir model

The combination of analytical model describing fractured reservoir permeability, power law fracture size distributions for fracture populations, characteristics of tensile and
shear fractures, and seismic moment release can be used to determine fracture initiation and reactivation in a fractured rock volume. With the proper permeability model pressure due to fluid injection in a well that is arbitrarily placed in the fractured rock volume can be calculated at any location in the model. Eqs. (7), (15) and (23) can then be used to determine fracture disturbed volume and spatial distribution of micro-seismicity (Figure 2).

![Seismic moment magnitude and location](image)

**Figure 2.** Generic model of a fractured reservoirs with natural fractures (fracture strike is indicated by black lines) with a power law distribution of fault sizes (Eq. 24, 25) that are placed following a latin hypercube sampling (LHS) method to ensure that large faults are not located next to each other. Micro-seismicity (blue-yellow spheres with sizes according to seismic moment, Eq. 23) is indicated on reactivated faults that are optimally oriented for shear failure after fluid injection resulting in an 15 MPa pressure increase throughout the reservoir (S_v = 50MPa, S_hmin = 20MPa) and the pressure is increased throughout the reservoir by 15 MPa, resulting in failure on faults orientated optimally for failure (Ter Heege and Coles, 2017).

### 3.3 Semi-analytical well-based fracturing models

The analytical approach described in section 3.2.1 for tensile fracturing is often extended in hydraulic fracturing simulators to include (1) different fracturing models, (2) coupled proppant transport, heat transfer, fluid flow and fracture propagation, (3) leakoff of injected fluid into the formation, (4) height growth, and (5) rock properties based on well data. In general, a semi-analytical approach for solving equations that control fracture growth, fluid flow and proppant placement is used in hydraulic fracturing simulators with data from well logs and from databases with properties of hydraulic fracturing fluids and proppants. Depending on the required complexity, the models can be fully 3D, planar 3D or pseudo-3D (Economides and Nolte, 2000). Full 3D models can include variations in fracture orientation and heterogeneities in rock formations. Planar 3D assume a single
fracture orientation and may allow lateral and vertical heterogeneities in rock formations. Pseudo-3D (P3D) models assume a single fracture orientation and complex fracture shape (e.g., cell-based models) or a single fracture orientation and an elliptical fracture shape. Many (commercial) hydraulic fracturing simulators are based on elliptical P3D models and assume laterally homogeneous, vertically inhomogeneous (layered) rock formations. A key advantage of elliptical P3D models is that they generally require limited computation power, while including height growth and vertical variation in rock properties (layering). Compared to analytical models, the P3D models better predict the vertical extent of hydraulic fractures, and simulate vertical width profiles of fractures that control proppant placement and fracture conductivity (and hence flow of hydrocarbons).

In this report, focus is on the approach that is used in (commercial) hydraulic fracturing simulators (i.e. MFRAC, Meyer et al., 1989). This simulator incorporates different fracture models including leakoff (cf. Economides and Nolte, 2000), i.e. (1) the radial fracture model, (2) the Kristianovitch-Geertsma-DeKlerk (KGD) model which assumes horizontal plane strain and is applicable to tensile (hydraulic) fractures with $L/H << 1$, and (3) the Perkins-Kern-Nordgren (PKN) which assumes vertical plane strain and is applicable if $L/H >> 1$.

### 3.4 Numerical models for hydraulic fracturing

Numerical models are required for simulation of more complex 3D fracture patterns, or to study fracturing process in more detail. Some key examples of modelling hydraulic fracturing that commonly involved numerical models include (1) interaction of multiple fractures and their effect on the stress field (e.g., stress shadows around fractures, Wong et al., 2013), (2) interaction of induced and natural fractures (e.g., arrested or offset fractures, Lavrov et al., 2014), and (3) fracturing in near-well area (e.g., rotated fractures or effects of drilling-induced damage on the rock formation). Many examples exist but it may be useful to make the broad distinction between continuum, discontinuum or hybrid continuum-discontinuum models. In general, continuum models are preferred for large-scale models, for example simulating stress field disturbance or the effect of spatial variation in rock properties (e.g., Orlic et al., 2013). A disadvantage is that discontinuum features such as natural fractures may not be incorporated in detail. Discontinuum models are preferred if propagation of fractures through a porous medium need to be simulated in detail (e.g., Marani et al., 2014). A disadvantage is that models often require significant computational effort, and models are generally relatively small scale or 2D. The hybrid models attempt to overcome these disadvantages, in many cases by combining elastic behaviour modelled by continuum approaches and inelastic (fracturing) modelled by discontinuum approaches in a single model (Lavrov et al., 2014). Below, some examples are given of applications of numerical models to simulate hydraulic fracturing.

Hydraulic fracturing from deviated or horizontal wells often results in complex, three-dimensional fracture patterns. The fracture initiation at the borehole wall is determined by the local stress field. Since the orientations of the minimum principal stress near a high-angle well are, in general, different from those in the far field, the fracture will rotate during its propagation so as to become aligned with plane normal to the far-field minimum stress at some distance from the well. In the near-well area, the fracture
becomes therefore twisted. It assumes a complex three-dimensional shape as it continuously adjusts to the changing stress field while propagating away from the well. The twisted, near-well part of the fracture may reduce the conductivity of the fracture and thus the productivity of the stimulated well. In addition, pumping proppant through the twisted fracture may become a challenge due to proppant particles getting stuck in the near-well part of the fracture (the problem known as "proppant screen-out"). In order to optimize frac jobs in deviated and horizontal wells, truly three-dimensional fracturing models are needed (Alekseenko et al., 2012). Even though such models are less computationally efficient than their commonly-used two-dimensional (or "pseudo three-dimensional") counterparts, the computational burden can be reduced if the focus is on modelling the fracture growth only in the near-well area, i.e. where the twisting occurs. A conventional 2D or pseudo-3D simulator can be used outside the near-well area, once the fracture has assumed the orientation normal to the far-field in-situ stress.

Gas-bearing shales are naturally-fractured rocks. One of the goals of a frac job is therefore to stimulate the natural fracture network and improve the communication between this network and the well. When an induced fracture propagates in a naturally-fractured shale, its direction changes according to the local stress orientation. The latter is affected by the architecture of the natural fracture network. Moreover, the propagating fracture can be arrested or offset by the natural fractures (Figure 3, Lavrov et al., 2014). Natural fractures can be reactivated and may start propagating during a frac job. The propagation pressure of such fractures depends on their orientation, which can vary according to the tectonic conditions that prevailed at the time the natural fractures were created as well as the present-day stress state (Lavrov, 2017). This will further complicate the frac job and any attempt to numerically predict its outcome. Hydraulic fracturing simulators used to design frac jobs in gas-bearing shales should therefore account for the effect of natural fractures on the job outcome (Weng et al., 2011). Even in the near-well area, such fractures can strongly influence the induced fracture pattern, resulting in twisting of the induced fracture even when the frac job is performed from a vertical well (Figure 4, Lavrov et al., 2016, Zubkov et al., 2007). Moreover, since most frac jobs in shales are multistage, numerical models should account for the effect of the neighbouring fractures in the same stage or adjacent stages, and, in the case of e.g. zipper fractures, the effect of fractures propagating from neighbouring wells (Wong et al., 2013). The above arguments necessitate the development of computationally-efficient fracturing models for shale-gas stimulations that should be capable of modelling complex, three-dimensional induced-fracture patterns affected by pre-existing fractures and faults naturally occurring in shale.
Figure 3. (a) Fracture arrest and (b) fracture offset. Propagation direction of the hydraulic fracture is shown by arrows.

Figure 4. Fracture twisting caused by a natural fracture intersecting a vertical well. The induced fracture is initiated from the tip of the natural fracture and gradually aligns with the plane normal to the minimum in-situ stress, $S_{\text{min}}$, as it propagates away from the well (Lavrov et al., 2016).
4 MODEL DATA AND OBSERVATIONS FOR THE POSIDONIA SHALE FORMATION IN THE NETHERLANDS

The approach for determining dimensions of fractures and fracture disturbed zone for a realistic field case is illustrated for the Jurassic Posidonia Shale Formation (PSF) located in the West Netherlands Basin near the town of Waalwijk (Figure 5).

Figure 5. (a) Location of the Posidonia Shale Formation (PSF) in the subsurface of the Netherlands (red ellipse) and outcrops of time-equivalent depositional analogues in Germany and England, superimposed on a map with reconstructed Jurassic paleogeography in NW Europe (courtesy of Ron Blakey, University of Arizona). (b) Subsurface distribution and depth of the PSF. Note that areas with depths of the PSF below 5000 m, and in the NNW of the Dutch offshore sector are not shown. (c) Pictures of outcrops of the Whitby Mudstone Formation along the Yorkshire Coast (United Kingdom). (d) Subsurface distribution of the PSF with wells for conventional gas exploration and production drilled above (red dots) or through (green dots) the formation (purple shading according to depth with darker colors indicating deeper parts of the PSF). The 3D seismic survey (red box) and well WED-03 (red star) used in report are also indicated (TerHeege at al., 2014; Zijp et al., 2015).
The PSF is a grey to black shale of Toarcian age (182-180 Ma), found in a large part of the Southern Permian Basin reaching from the east coast of the United Kingdom in the West to central Germany in the East. In the United Kingdom, the formation is present as the Jet Rock Member (Whitby Mudstone Formation, Yorkshire Basin, in France as Schistes Cartons (Paris and Aquitaine Basin), and in Germany as the Posidonienschiefer or Ölschiefer. In the Netherlands, the PSF is found at 1800-3800 m depth, and is a potential target for shale gas exploitation. Several wells target deeper Triassic tight sandstone reservoirs and penetrate the PSF in the Netherlands, but the formation has not yet been drilled specifically for shale gas (TerHeege et al., 2015). Data for the PSF is available from these wells as well as some core data and 3D seismic surveys (Figure 5d). Moreover, Zijp et al. (2015) provided additional detailed insight in vertical heterogeneity and natural fractures of the PSF by studying outcrops of the Whitby Mudstone Formation around Whitby in the United Kingdom, which can be regarded as an analogue for the PSF. Geological and well-based fracturing models were constructed for a representative area in the South of the Netherlands (Noord-Brabant province) where the Posidonia Shale Formation is present in the subsurface (Figure 5d). The area was chosen based on (1) subsurface distribution, (2) coverage of 3D seismics, (3) accurate determination of formation depth and over-/underlying formations, (4) presence of wells with well logs suitable for rock property modeling, (6) availability of measurements on core samples (cf. Ter Heege et al., 2014; 2015; 2016).

4.1 In situ stress and rock properties from well logs

A single well-base model of well WED-03 was used to simulate hydraulic fracturing for the PSF in the South of the Netherlands (Figure 5d). The study in this report focuses on determining variations in fracture dimensions due to variations in mechanical rock properties and on sensitivity of fracture dimensions to varying treatment schedules based on data from well WED-03. Rather than providing a single prediction based on best practice methods to constrain rock properties, stress field and treatment schedules, a systematic range of input parameters is investigated. It may be regarded as a typical upfront analysis of hydraulic fracturing in an early exploration phase (i.e. in absence of well tests, etc.) to a shale gas target. Note that more well data is available for the Posidonia Shale Formation which allows determining spatial trends in geological settings, rock properties and fracture dimensions for the PSF in the Netherlands (Ter Heege and Coles, 2017). Gamma ray (GR), sonic (DT), bulk density (RHOB) and deep resistivity (RESD) logs are available for well WED-03 (Figure 6). For determining the variations in rock properties, the lithostratigraphy for depth between 1725 m (Brabant Formation) and 2360 m (Aalburg Formation) was divided into 5-meter thick zones close to the Posidonia Shale Formation. Rock elastic properties (Young’s modulus and Poisson ratio) are derived from the different logs using Eqs. (5)-(6). The elastic properties are used in Eqs. (2)-(3) to determine bounds on the minimum horizontal stress (Figure 7, see TerHeege et al. 2015 for more details on the other properties). Rock properties that critically influence the initiation, orientation, propagation and reactivation of fractures from well logs or other sources are summarized in Table 1.
Figure 6. Well logs from well WED-03 crosscutting the Posidonia Shale Formation in the Netherlands with bounds for different rock properties and minimum horizontal stress in each of the zones of the well-based hydraulic fracturing model. ATWDL- Lower Werkendam Formation, ATPO-Posidonia Formation, Aalburg Formation (TerHeege et al., 2014).

Figure 7. Bounds on the minimum horizontal stress based on rock properties from well WED-03 (Figure 6 and Eqs. 2-4, TerHeege et al. 2014).
### Table 1. Most important input parameters for hydraulic fracturing simulations (Ter Heege et al., 2014; 2016).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Value for low-base-high scenarios</th>
</tr>
</thead>
<tbody>
<tr>
<td>gas-filled porosity</td>
<td>%</td>
<td>1.0-6.2-12.5</td>
</tr>
<tr>
<td>permeability</td>
<td>μD</td>
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<tr>
<td>leakoff coefficient</td>
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<td>3.1-21.0-169.4</td>
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<tr>
<td>Young’s modulus</td>
<td>GPa</td>
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</tr>
<tr>
<td>Poisson ratio</td>
<td></td>
<td>0.34-0.39-0.41</td>
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<td>pay zone height</td>
<td>m</td>
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<td>proppant</td>
<td></td>
<td>70/140-20/40-20/40 (econo)</td>
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<tr>
<td>production time</td>
<td>year</td>
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<tr>
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<td>14-77-100</td>
</tr>
</tbody>
</table>

### 4.2 Outcrop data on natural fracture populations

Considering data on natural fractures from outcrops, the crucial difference in burial and uplift history of outcrops compared to subsurface formations should be emphasized, which hampers direct extrapolation of quantitative fracture data to subsurface conditions. In particular, additional populations of conductive fractures may develop during uplift to the Earth’s surface. For a qualitative comparison between outcrop fracture data and subsurface fault data, fracture populations in the Jet Rock Member of the Whitby Mudstone Formation have been analyzed (Zijp et al., 2015). The Jet Rock Member is a time-equivalent depositional analogue of the Jurassic Posidonia Shale Formation that outcrops in the United Kingdom. Outcrop locations are situated along the Yorkshire coast at Port Mulgrave, Runswick Bay and Kettleness (Figure 5c). The fracture analysis was done using the Digifract method developed by Hardebol and Bertotti (2013). With this method digital acquisition and characterization of natural fracture networks on outcrops is done by quantifying amount of fractures, fracture length and fracture orientation. Afterwards statistical calculations can be performed on the acquired fracture data. The results of the fracture analysis at the outcrop location near Port Mulgrave shows (1) a varying number of fractures in the top 4 meters of the Jet Rock Member with densities changing on a meter scale and an average fracture spacing of ~0.5 meters, (2) a dominate E-W fracture orientation, and (3) a relation between mineral composition and fracture characteristics (Figure 8, Zijp et al., 2015). In addition to the analysis of fractures, high resolution (10 cm) sedimentological, geochemical and geobiological sampling, and spectral gamma ray logging has been performed to study the relation between sedimentary and structural features. Outcrop studies are useful as trends in fracture characteristics can be observed in detail, and relations with rock properties can be determined that may aid in identifying zones that are prone to fracturing and fluid migration through interconnected fracture networks.
4.3 Fault population data from 3D seismic surveys

A 3D seismic survey near the town of Waalwijk (L3CLY1992A) was used to construct a geological model and to characterize the Posidonia Shale Formation (PSF) in terms of the occurrence of natural fault populations (Figure 9). Detailed seismic interpretation including attribute (coherence, variance) and structural analysis was performed. Length along strike and dip, and displacements of the main faults are analysed using vertical seismic sections and time maps of the base Tertiary (BTER, Figure 9a), the Jurassic Posidonia Shale Formation (ATPO, Figure 9b), and an apparent seismic reflector between ATPO and BTER. Based on the structural analysis of fault orientations it was concluded that a dominantly strike slip faulting regime (i.e. $S_{H\text{max}} > S_v > S_{H\text{min}}$, cf. section 3.1.1) was active during development of the main fault zones (Figure 9c). It suggests that the majority of the faults in the area preferentially developed along Riedel ($R$) and conjugate Riedel ($R'$) orientations, typical for early stages of fault development (e.g., Tchalenko, 1970). Fault length data can be used to calibrate theoretical relations describing the distribution for fault size, such as power law relations (Eqs. 24, 25). These relations can then be used to extrapolate fault size beyond the scale of observation and describe fracture densities at scales relevant for hydraulic fracturing (Figure 9d, Eq. 30). Odling et al. (1999) suggested that if data collected at different observation scales ($A_{obs}$) is combined, the part of the data representing large fault lengths at each scale can be described by a power law. A reliable power law fit to fault lengths cannot be derived from the PSF data within the investigated range of fault lengths (Figure 9d). It suggests that the dataset needs to be extended or should be combined with observations at a different measurement scale (e.g., core samples or thinsections) to reliably extrapolate the fault length distribution beyond the current scale of observation. It is well-known that analysis of fault lengths may be subject to truncation (i.e. underestimation of the frequency of small faults due to analysis-specific limitation of the fault length resolution) or sensoring (i.e. underestimation of the frequency of large faults due to limitation of the observation area).
effects (e.g., Torabi and Berg, 2011). A truncation effect seems to affect the PSF data at small fault lengths. Considering the relatively large scale of observation (i.e. a 3D seismic survey with $A_{\text{obs}} = 3.64 \times 10^6 \text{ m}^2$), it is unlikely that fault length data are significantly affected by a sensing effect (see TerHeege et al., 2016 for more details).

Figure 9. Seismic interpretation of 3D survey L3CLY1992A in the South of the Netherlands (Figure 5). Time map of the base Tertiary (a) and Posidonia Shale Formation (b) with the main interpreted faults used to determine fault length along strike. (c) Structural interpretation of the observed faults showing typical angular relations between different types of fracture (i.e. “Riedels”) that indicate a dominant strike slip faulting regime at time of fault development. Angles between different Riedels (R, R’ and P) and the maximum principal stress ($\sigma_1$) are expressed in terms of friction angle $\varphi$ (Eq. 16, 17). (d) Cumulative distribution of fault lengths along strike (L) and along dip (S). Fault length data from Odling et al., (1999) for Cambrian–Ordovician sandstones in the Tayma region of NW Saudi Arabia are indicated for comparison (Ter Heege et al., 2016).
5 MODEL PREDICTIONS OF FRACTURE DIMENSIONS FOR THE POSIDONIA SHALE FORMATION

A commercially available hydraulic fracturing simulator (MFRAC, MSHALE, Meyer, 1989; Meyer and Bazan, 2011) has been used to predict fracture dimensions for data from well WED-03 (cf. section 4.1). A model of a virtual horizontal well was constructed based on the WED-03 data and configuration of a well in the Marcellus Shale Formation (Jacot et al., 2010). The well-based model consists of a ~2100 m. long vertical section and a maximum horizontal section of 2300 m at ~92° inclination. Simulations were performed for varying rock properties and treatment schedules to address uncertainty in fracture dimensions due to variation in geological and operational parameters. The minimum, arithmetic mean and maximum values of rock properties for the different zones in the PSF are used in low, base and high case hydraulic fracturing scenarios, respectively (Table 1, Figure 6). In addition, different stress scenarios are tested (Figure 7). To analyze the sensitivity of hydraulic fracture properties to the treatment schedule, low, base and high case scenarios for injection rate and volume, number of injection stages, and total proppant mass are simulated. Four additional scenarios are simulated to test the effect of fluid and proppant type, and method of proppant injection (ramp and step). In all scenarios (except the stress scenarios for Poisson effect and friction fault theory, Eqs. 3, 4), the base case (Figure 10) was kept the same and only one parameters was changed to systematically investigate the sensitivity of fracture properties to the different input parameters. The range in treatment schedule parameters is based on hydraulic fracturing studies (mainly US shales), and existing information of the Posidonia Shale Formation (e.g., its small thickness). In total 31 hydraulic fracturing scenarios were simulated (see TerHeege 2014; 2016 for more details on the use of the simulator and model).

The shape, dimensions and conductivities of hydraulic fractures vary considerably, depending on input parameters. Largest variations are observed for injection volume and rate, leakoff coefficient, and fluid type (Figure 11), i.e. fracture length and width are promoted by (1) large injection volumes, (2) low leakoff rate, (3) low Poisson ratio, and (4) low viscosity fracturing fluids (i.e. slickwater mainly consisting of water and friction reducer as compared to gel-type fracturing fluids). Superposition of the virtual horizontal well and base case fracture on the geological model of the Waalwijk area shows the relative scale of the fracture and separation between the top of the fracture ($H_f = 166$ m) and base of aquifers used for drinking water (~2.2 km, Figure 12). As mentioned in sections 3.2 and 3.4, tensile fractures may interact with natural fractures so that fluid injection results in a network of induced or reactivated fractures rather than a single fracture. An orthogonal network of fractures can be introduced in the MSHALE simulator to investigate the effect of fluid injection on natural fractures. It should be noted that the approach implemented in the simulator has important shortcomings, so the results can only be used to investigate rough trends on the extent of the fracture disturbed zone resulting from hydraulic fracturing operations. For example, the natural fracture patterns are orthogonal with pre-defined regular spacing of fracturing. Moreover, only tensile (mode I) fracturing is considered while shear (mode II) fracturing may be the dominant fracturing mode for natural fractures (cf. section 3.2). The most important observations...
of introducing natural fractures are (1) lower fracture half lengths (~68 m for single fractures compared to 12-30 m for natural fracture networks, depending on stress anisotropy and fracture spacing) due to the partitioning of fluid in multiple fractures and increased leakoff for multiple fractures, (2) increasing maximum fracture half length and decreasing overall area of the fracture disturbed zone for increasing stress anisotropy ($S_{hmin}/S_{Hmax}$), and (3) increasing maximum fracture half length and overall area of the fracture disturbed zone for decreasing fracture spacing (Figure 13).

Summarizing, minor upward growth of fractures is predicted by the single fracture models for all scenarios, i.e. for the treatment schedules investigated fractures can be contained within a ~200 m. zone around the shale target, and >2 km below drinking water aquifers. Incorporation of an orthogonal fracture network with equally-spaced tensile fractures increases the lateral extent of the fracture disturbed zone but decreases the dimensions of individual fractures in the network. Important shortcomings of the analysis are model assumptions that only single fractures or orthogonal networks of equally-spaced tensile fractures are induced or opened.

Figure 10. Results for the base case hydraulic fracturing simulation of tensile (mode I) fractures (MFRAC). Variation of minimum horizontal stress with depth (a) calculated using the Poisson effect of overburden weight (Eq. 3), and vertical cross-sections along width at the well (b) and along fracture length (c).
Figure 11. Results for hydraulic fracturing simulations of tensile (mode I) fractures (MFRAC). Typical fracture profiles for different input parameters illustrated by plotting the vertical fracture cross-sections along fracture width at maximum fracture height (Figure 10, profiles or dash symbols, left vertical axis) versus maximum fracture half length (horizontal axis). Scaled fracture widths at the well are indicated (crosses), and shale pay zone (red dashed lines). Text indicates the different scenarios (Table 1).

Figure 12. Vertical profile of the base case hydraulic fracture (b, Figs. 10, 11) superimposed on a geological model (a) based on seismic interpretation and wells in the study area (Figure 5d). Note that the fracture is plotted at the right scale in (a) to illustrate the vertical extent of hydraulic fractures (166 m.) and separation (~2.2 km) between the top of the fracture and bottom of shallow aquifers used for drinking water supplies (at shallow depths above ~300 m in case of the Netherlands).
Figure 13. Results for hydraulic fracturing simulations of an orthogonal fracture network consisting of tensile (mode I) fractures (MSHALE). Map views (horizontal sections) of the variation of disturbed fracture zone with increasing anisotropy of the horizontal stresses (a) and with increasing fracture spacing (b).

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SHmax
SHmin
map views of fracture network
increasing stress anisotropy
wellbore

0.5 meter  2 meter  5 meter
map views of fracture network
(note different scales)
wellbore

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increasing fracture spacing

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6 DISCUSSION

In this report, modelling approaches are presented that can be used to simulate dimensions of fractures and stimulated reservoir volume. The models provide ways for upfront assessment of the potential risks associated with loss of fracture containment for a stimulated volume of shale around wells. As with any model, assumptions and simplifications are implicit in the analysis. These include characteristics of fractures and natural fracture populations as well as factors not accounted for in the models. To explore ways of evaluating the models, a summary with observations of characteristics and dimensions of fractures and stimulated reservoir volume is given, including some examples of cases where model predictions might not be accurate:

- **Micro-seismic monitoring to evaluate model predictions.** Micro-seismic monitoring during hydraulic fracturing is one of the key methods to monitor hydraulic fracturing operations and the spatial extent of induced fractures or stimulated fracture disturbed volume. Most observations of micro-seismicity seem to indicate that upward growth of hydraulic fractures or cases where fracture disturbed zone extends far beyond the target shales are limited (King 2012; Fisher and Warpinski 2012). These studies show (1) no evidence that induced fractures have reached shallow groundwater-bearing formations or aquifers, (2) a distance between the well and top of micro-seismic hypocenters of less than 350 meter in more than 99% of cases (based on a pure statistical analysis of mapped micro-seismicity), and (3) a maximum distance between the well and top of micro-seismic hypocenters of 536 meter for the Marcellus Shale and 588 meter for the Barnett Shale (Davies et al. 2012). Availability of micro-seismic data is an issue, i.e. it is estimated that 3-5% of hydraulic fracturing operations are monitored in the US and Canada (Van der Baan et al. 2013). Also, there is a strong bias in the data towards certain (deeper) shale formations, and in many cases (raw) data is not publicly available. Moreover, there is a tendency for hydraulic fracturing operations with increasing injection volumes per fracturing stage that would give rise to larger dimensions of fractures and fracture disturbed zone. Results of a survey of wells with shallow shale gas operations that include examples of distance between hydraulic fracturing and ground water resources below ~600 meter can be found in EPA (2016). Conservative design of hydraulic fracturing jobs (i.e. mainly in terms of injection volumes) is important to limit dimensions of fractures or fracture disturbed zone. Additional monitoring methods with added value are monitoring surface deformation using tiltmeters that monitor both seismic and aseismic deformation, or measurements using fibre optic cables permanently installed in wells that can monitor (long term) changes in the subsurface based on distributed temperature (DTS), acoustic (DAS) or strain (DSS) sensing.

- **Faults as natural pathways for fluid migration.** Examples of natural seepage of hydrocarbons (i.e. hydrocarbon occurrences at the surface in areas not affected by
hydrocarbon exploitation) show that under certain circumstances natural faults and fractures may act as migration pathways for hydrocarbons, even without stimulation (e.g., Leifer et al., 2010). An example of out-of-zone hydraulic fracturing due to migration of hydraulic fracturing fluids along natural faults is given by Sharma et al. (2004). Their study demonstrated that hydraulic fracturing of a tight sandstone reservoir at ~4 km depth resulted in smaller hydraulic fractures than predicted by models, enhanced leakoff and migration of fracturing fluids along an undetected fault, and out-of-zone fracturing in a shallower (~200 meter) formation than the target reservoir.

- Geological settings and rock properties that affect fluid flow. It is generally accepted that gas production from the US Barnett and Marcellus Shales is promoted by the combination of mineralogical composition and presence of natural fractures. Mineralogical composition affects the formation brittleness and stiffness, which is a proxy for its ability to be stimulated by hydraulically fracturing (e.g., Jarvie et al. 2007). The presence of natural fractures, in particular in combination with the tectonic evolution of the formation, that can result in critically-stressed or overpressured fractures (for example due to tectonic inversion). While these features may be beneficial for hydrocarbon production, they may also lead to larger dimensions of fractures or fracture disturbed zone. In contrast, clay-rich shales such as the Posidonia Shale Formation may be prone to fracture closure and proppant embedment due to creep (TerHeege et al., 2015). Mineralogical composition is affecting elastic moduli of formations which is accounted for in some of the fracture models, while the effect of creep is generally not accounted for. Accordingly, specific combinations of mineralogy and tectonic evolution may yield dimensions of fractures and fracture disturbed zone that deviate from model predictions.
SUMMARY AND CONCLUSIONS

Shale gas basins in Europe are underexplored compared to basins in the United States and Canada. Some of the main public concerns in Europe regarding the impacts of shale gas exploitation are related to hydraulic fracturing, in particular to processes related to fracture containment such as predictions of dimensions and migration directions of hydraulic fractures. Practices in the US and Canada has led to suggestions that hydraulic fracturing may lead to contamination of shallow aquifers used for drinking water supplies due to the hydraulic fracturing process itself. Numerous studies have addressed this issue based on data and practices in the US and Canada, which suggest that isolated cases of contamination result are related to surface spills or improper well construction rather than loss of fracture containment around the target shale. In Europe, there is a general lack of data for shale gas operations and observations of the subsurface perturbations due to hydraulic fracturing. Modelling that can predict fracture dimensions or fracture disturbed zone around injection points at well perforations is therefore critical for upfront assessment of the risks and impacts associated with hydraulic fracturing.

In this report, modelling approaches that can be used to simulate dimensions of fractures and stimulated reservoir volume are investigated. The research and findings can be summarized as follows:

- Modelling approaches are reviewed (cf. section 3) that can be used to (1) constrain rock properties and stress conditions relevant to the development of induced or reactivated fractures, and (2) predict the development of induced or reactivated fractures. A modelling approach is outlines that allows fast screening of approximate dimensions of fractures and fracture disturbed zone, including tensile (mode I) and shear (mode II) failure and predictions of induced seismicity.

- Sources of model data are explored (cf. section 4), focusing on the Posidonia Shale Formation (PSF) in the Netherlands and outcrops of time-equivalent depositional analogues. The data includes (1) in situ stresses and rock properties from well logs for well WED-03 that was drilled through the PSF in the South of the Netherlands, (2) fracture populations in the Jet Rock Member of the Whitby Mudstone Formation (PSF analogue) that is present in outcrops along the Yorkshire Coast in the United Kingdom, (3) fault populations in the PSF from interpretation of a 3D seismic survey in the South of the Netherlands.

- Predictions of fracture dimensions are performed using a commercially available hydraulic fracturing simulator (MFRAC, MSHALE, cf. section 5). Different hydraulic fracturing scenarios are simulated with different operational and geological parameters for a virtual horizontal well with a ~2100 meter long vertical section and a maximum horizontal section of 2300 m that was based on WED-03. Simulations show limited upward growth (< 250 m. above well) of individual fracture and limited extent of fracture disturbed volume for treatment schedules that are commonly used for hydraulic fracturing in shales. The presence of natural fractures may lead to larger overall fracture disturbed zones, but the vertical extent of reactivated fractures unlikely extends beyond 250 meter.
A discussion on modelling approaches is included (cf. section 5) that addresses (1) methods to evaluate model predictions using (micro-seismic) monitoring, including a summary of main observations from the US and Canada, (2) geological settings and formation properties that are key in controlling fault and fracture development, and (3) some examples of cases where model predictions might not be accurate.

- Overall, model predictions suggest that (1) the extent of fracture disturbed zones are limited (maximum few hundred meters around the injection point) for treatment schedules that are commonly used for hydraulic fracturing in shales, (2) the extent of the fracture disturbed zone can be controlled by adjusting treatment schedules according to local geological settings and formation properties, and (3) limitation of model prediction for specific settings should be taken into account in assessing the impacts and risks associated with fracture development during hydraulic fracturing.
REFERENCES


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