◀页岩气钻井完井技术专题▶

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大规模多级水力压裂技术在页岩油气藏开发中的应用

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摘 要:北美地区页岩气开发已经商业化,开发技术也逐步趋于成熟,而中国虽然有丰富的页岩气资源,但由于起步较晚,目前还处于探索阶段。有效开采页岩气通常需要在水平井中实施大规模的多级水力压裂,提出了低渗油气藏大规模水力压裂的关键岩石力学原则,介绍了微地震技术在水力压裂监测中的应用,并用离散单元法建立的数学模型对水力压裂的效果进行了评价,分析了中国页岩油气藏水力压裂方案优化的地质因素,并对大规模水力压裂的可持续性发展提出了一些建议。

关键词:多级水力压裂 岩石力学 页岩气 页岩油 低渗透油气藏 中国盆地

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Massive Multi-Stage Hydraulic Fracturing for Oil and Gas Recovery from Low Mobility Reservoirs in China

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Abstract: Production of gas and hydrocarbon liquids from low permeability shales has been established in North America; exploration and development has accelerated in Europe and in China, and generic opportunities in China are postulated. Currently, effective production requires multiple hydraulic fracturing stages usually in horizontally drilled wells. Key geomechanical principles relating to the response of these reservoirs to large volume hydraulic fracturing are presented. Geologic reasons why hydraulic fracturing treatment schedules may need to be refined for some shale plays in China are outlined. Finally, from a longer-term perspective, sustainability of these large volume treatments is considered and modifications and alternatives are suggested.

Key words: Massive multi-stage hydraulic fracturing; geomechanics; shale gas; shale oil; low permeability reservoirs; Chinese basins

1 Introduction

Production of gas and oil from shales is not new. In North America, Devonian shales, the Monterey shale and numerous other plays are well known and until fairly recently have been viewed as "fortunate oddities". Economics and technological advances have established gas-bearing shales as significant resource opportunities. In the last two decades effective directional drilling operations, successful implementation of reduced proppant volumes, concurrent reduction in viscosity requirements as well as improved methods for isolating zones have established shales as viable hydrocarbon resources. Dozens, if not hundreds, of technical papers have been published and presented to clarify the nature of these resources, the geologic criteria for successful production, and the stimulation protocols that are evolving for exploitation. This paper implicitly acknowledges these numerous publications and points out good review publications; for example, King's 2010 overview of stimulation of shales[1]. Geomechanical considerations related to large volume (massive), multi-stage hydraulic fracturing (MMHF) is identified.

International shale exploration and development has accelerated everywhere, particularly in China. Some of the geologic features that may require revised treatment philosophies in these Chinese basins are hypothesized. Finally, recognizing some of the geomechanical and socio-economic difficulties associated with MMHF, modifications and alternatives are discussed.

1.1 What is the interest in China?

Recoverable shale gas resources in China have been estimated to be at least 26×10^{12} m^3 (918 Tcf)[2-3]. There could also be tremendous untapped potential in ubiquitous marine and lacustrine shales. These shales span the Paleozoic (even Pre-Cambrian) to the Quaternary, e.g., the Cambrian Qiongzhusi Formation in the Sichuan Basin and the Quaternary Qigequan Formation in the Qaidam Basin, only recently considered as viable gas plays. Most potential Chinese shale plays are located in thinly populated areas, as compared with Europe

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or even North America. Thus, there is substantial shale gas and shale oil potential for Chinese and foreign oil companies, and effective stimulation becomes even more essential to offset transportation costs. Shale gas and shale oil will play a major role in China's future energy portfolio; according to the Strategic Research Center of Oil and Gas Resources, under the Ministry of Land and Resources, target production levels by 2020, encompassing ten to fifteen prominent Chinese shale gas fields, are between 15 and 30 Bcm(530－1 060 Bcf).

Prospective shales have formed in diverse paleogeographic settings in China, in a variety of basinal settings, with further variations due to varying tectonic imprints. China has more than 600 sedimentary basins, including more than 200 hydrocarbon basins (Fig. 1). Conservatively, more than ten basins have substantial commercial shale gas and shale oil potential (indicated by the red stars in Fig. 1). Table 1 lists the geological ages of these potential shale gas and shale oil plays-from Sinian-Cambrian to Tertiary. The shales include both marine shales(e. g. , Sichuan Basin) and lacustrine shales(e. g. , Ordos Basin and Bohai Bay Basin). These shales have been recognized for their source rock potential for hydrocarbons that migrated into higher permeabilitystrata, but have not previously been considered as gas reservoirs. Shales within the higher permeability strata are widespread and thick; some are buried deeply enough to generate dry gas, others are shallower and charged with biogenic gas, and many contain sufficient organic material and fractures to provide significant recoverable gas reserves. To produce the tremendous volumes of gas thought to be in these low to ultralow permeability shales, massive hydraulic fracturing is needed to create conductive pathways to the wellbore.

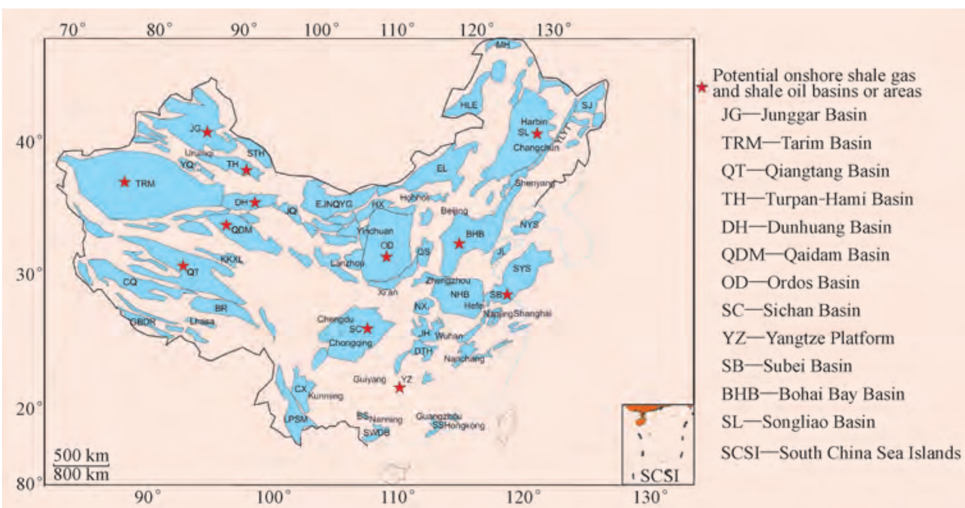

Fig. 1　Potential low mobility, onshore shale gas or shale oil basins in China

Table 1　High-grade shale gas or shale oil basins in China

Basin	Age	Formation	TOC, %	Ro, %	Thickness/m
Qaidam	Quaternary	Qigequan	0. 30–0. 60	0. 20–0. 50	0–800
Bohai Bay	Paleogene	Shahejie 3	0. 30–33. 00	0. 30–1. 00	230–1 800
Songliao	Cretaceous	Qing1	2. 20	0. 70–3. 30	＞100
Songliao	Cretaceous	Shahezi	0. 70–1. 50	1. 50–3. 90	100–350
Qiangtang	Mid Jurassic	Xiali	0. 30–6. 20	1. 40	400–600
Turpan-Hami	Mid and Earlier Jurassic	Shuixigou	1. 30–20. 00	0. 40–1. 10	50–600
Junggar	M Jurassic	Xishanyao	0. 20–6. 40	0. 60–2. 50	350–400
Ordos	Triassic	Yanchang	0. 60–5. 80	0. 70–1. 10	50–120
Ordos	Carboniferous-Permian	Shanxi	2. 00–3. 00	＞1. 30	50–180
Sichuan	Jurassic	Ziliujing	0. 51–2. 41	0. 87–1. 15	30–120
Sichuan	Lower Triassic	Xujiahe	1. 00–4. 50	1. 00–2. 20	150–1 000
YZ(include Sichuan)	Lower Permian	Longtan	0. 40–22. 00	0. 80–3. 00	20–2 000
YZ(include Sichuan)	Earlier Silurian	Longmaxi	1. 90–4. 40	2. 00–3. 00	50–500
YZ(include Sichuan)	Earlier Cambrian	Qiongzhusi	1. 00–4. 00	3. 00–6. 00	20–700
Tarim	Cambrian, Ordovician		0. 80–1. 56	0. 80–4. 00	＞3 000

1. 2　What are the key controlling factors?

In productive shales, it is well established that matrix permeability is low and that economic deliverability is contingent on minimizing the distance that gas or oil needs to move through the matrix before encountering higher permeability pathways connected to a producing wellbore. The generic steps in exploration and development need to encompass four domains, described below.

The four areas of concern in developing shale plays are:

1) Identification of the Resource Present-OGIP or OOIP.

a. How is the fluid stored?　Adsorption, compressible storage, solution, and absorption in kerogen are all feasible mechanisms. Insightful references include work by Curtis et al., 2010 [4], and Cui et al., 2010 [5]. Fig. 2 demonstrates the complex mineralogic assemblages and nanoporosity within and outside of kerogen acting to retain hydrocarbons in North American and Chinese shales. Since permeability is extremely low it is anticipated that hydraulic fracturing will be necessary to create large fracture surface areas.

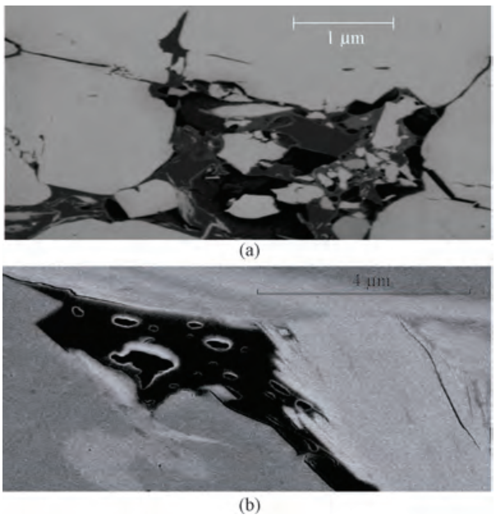

Fig. 2 Complex mineralogic assemblages and nanoporosity characteristics within and outside of kerogen in shale

a) is one scanning electron microscopy slice from an FIB-SEM Marcellus shale sample showing larger quartz grains (light gray), as well as clay (platelets) and smaller quartz grains with kerogen (medium gray) and gas-filled porosity (black) (courtesy Energy & Geoscience Institute, University of Utah); b) is intragranular organic matter and nanoscale pores in a Jiulaodong Formation shale, Wei-201 Well, Sichuan Basin, China (courtesy C. Zou).

b. Extent of the resource? Tradeoffs between thickness, areal extent and total organic content (TOC) are effectively appreciated. If the reservoir is lean, a resource play mentality is necessary to justify exploitation. Substantial volumetric extent (vertical and areal) has favored economics in many North American situations. Compartmentalization and tectonic history may be complicating factors in some other regions, e. g. the Sichuan basin has experienced many episodes of tectonic activity since the Paleozoic. It is speculated that this could require revised stimulation strategies in some Chinese basins.

c. Saturation? Water saturation is low in many prolific plays. Logging analysis for saturation forecasting remains difficult, particularly in clay-rich situations. However, gas-prone shales can have a tremendous capacity for imbibition or loss of water injected during stimulation. Fluid recovery is commonly low.

2) Identification of the role of fabric and fractures.

Assuming adequate gas or oil in place, the second criterion for success is that there must be textural features or fractures to carry hydrocarbons into larger scale engineered fractures. Depending on the specific shale, higher permeability streaks, microfractures associated with tectonic loading or expulsion, healed and reactivated or newly minted fractures can all contribute. Gale et al., 2008 [6], and Han, 2011 [7], provide a good perspective of the role of fractures and sedimentary fabric. Hydraulic stimulation is impacted by the lithologic character and by the nature of the fractures. Furthermore, anisotropy and heterogeneity issues in these reservoirs are well recognized [8].

3) Stimulation using multiple large-volume hydraulic fractures.

Given a resource with appropriate fabric that supplements the lower permeability matrix rock, drilling, completion and stimulation are carried out to develop an interconnected fracture network feeding into a production well. Stimulation usually entails pumping large volumes of water with low proppant concentrations at high rates through multiple isolated zones. Isolation technology advances allow carrying out multiple treatments in long wells over relatively short time frames, dramatically improving the potential viability of these plays. This technology advance is evolutionary and more developments will be made in the future to optimize treatments. Geomechanical aspects of these complex stimulation treatments are the focus of this paper.

4) Production and Reservoir Management.

While reading the review of MMHF for shales that follows, bear in mind the need for continuous evolution of stimulation programs. For example: optimizing treatment size in various situations, accommodating environmental restrictions and requirements, improving the economics related to treatment volumes and rates, intelligent use of monitoring based on induced seismicity.

Operating these reservoirs is as important as creating the interconnected fracture system to prevent development of "orphaned" fractures that were created during stimulation but which become isolated during production because connected fractures become closed or impaired.

2 Technology for Stimulating Shale Reservoirs

Implementation of massive, multi-stage hydraulic fracturing (MMHF) in long horizontal wells has changed the natural gas industry worldwide. Vast gas resources in low permeability strata-"shale"-are being unlocked in North America by installing large-drainage-volume wells in plays such as the Marcellus Shale, Pennsylvania, the Barnett Shale, Texas, the Horn River Shale, British Columbia, and so on. MMHF will also impact the oil industry in rocks such as the Monterey Formation ("shale" oil in California), the Eagle Ford shale (South Texas), the Wolfcamp shale oil (Permian Basin), and many tight oil reservoirs such as the non-fractured part of the dolomitic heavy oil carbonate Issaran field in Egypt which contains over 2.5 billion barrels of oil (e. g. references [9-11]). MMHF is intended to maximize drainage volume around a well. To this end, large volume hydraulic fracturing is usually executed at many perforated locations along a cased horizontal well, usually drilled parallel to σ_{hmin} to maximize fracture length extension normal to the well axis (Fig. 3). The differences between individual stages vary from play to play and operator to operator.

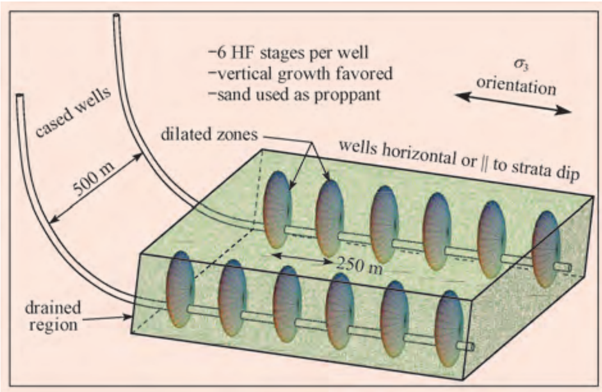

Fig. 3　This is a schematic of multiple hydraulic fracturing stages along the well axis for shale gas stimulation

Apparently, MMHF is something that cannot yet be realistically simulated—from a rock mechanics perspective. We will try to explain the difficulties and point to some things we can do, some we can't, and where we might go. Beyond this, we speculate on future improvements to stimulation activities.

In Fig. 3, the zone in which the global permeability has been enhanced (called the "stimulated zone"[12] or the "dilated zone") around each cluster of perforations is simplistically sketched as an ellipsoid with the short axis parallel to the σ_3 direction (σ_3 is the minimum total principal stress), as would be expected. The well, typically 1 000－2 000 m long, is often placed close to the base of the reservoir because fractures tend to preferably propagate upwards as they are formed by high-pressure fluid injection. This has misleadingly been called the "buoyancy effect"; actually, hydraulic fracture "rise" occurs when the fracturing fluid pressure gradient is less than the local σ_{hmin} gradient; i. e., if $\mathrm{d}\sigma_{\text{hmin}}/\mathrm{d}z > d\rho_{\text{f}}/\mathrm{d}z$ (z is the true vertical distance and the fracturing fluid density is ρ_{f})[13]. In situations where there is a weak lower barrier and where there is water below, alternative placement may be mandated. However, even "horizontal" fractures generated when $\sigma_{\text{v}} = \sigma_3$ will rise away from the injection point at a shallow rise angle (σ_{v} is the total vertical stress). This is an important observation because if fractures propagate at an angle to the principal stress directions, large shear displacements along the induced fracture planes can be expected[14,17].

The current "record" (likely eclipsed by the time this article is published) appears to be 45 separate fracturing stages along a horizontal well, each being a high-rate treatment to create a region of propped fractures-the "propped-zone" (Fig. 4), which is hopefully surrounded by a much larger region-the "dilated zone" (Fig. 4)-where natural fractures have been opened permanently by wedging and block rotation, or propped by shear displacements.

3　Geomechanics of MMHF

The rocks being stimulated by MMHF are stiff, low-permeability strata of low to moderate porosity (5%－15%).① They may be naturally fractured, but they also have diagenetic features we call "incipient

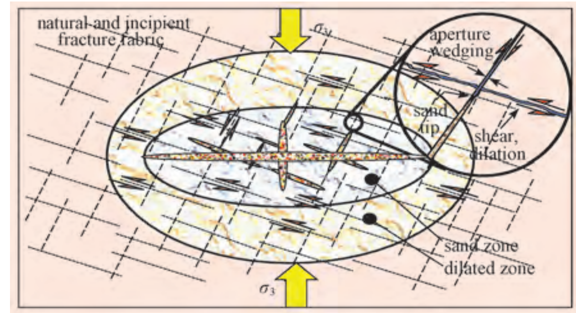

Fig. 4　Plan view of the Sand Zone (more appropriately, the Propped Zone) and the Dilated Zone around an MMHF stage

fractures," high-angle as well as bedding planes of low(er) tensile strength that will open preferentially during MMHF (Fig. 5). These incipient fractures are more clearly seen in weathered surfaces or in quarries where stress relief allows them to develop and open. In a core sample of a tight rock such as a marly shale that is carbonate-based (or a rock such as the tight dolomite mentioned in reference [11]), acid etching of a surface may help reveal incipient fractures that otherwise are not visible. The point in introducing the concept of incipient fractures is to emphasize that it is not only the fractures clearly visible in geophysical logs (borehole televiewers or FMI logs-formation micro-imaging logs) that are opened or sheared. Since significant tensile stresses are created, incipient fractures can be opened by Mode I fracturing (wedging) or extended by Mode II or Mode III fracturing (shearing). Conversely, it is also well established that not all visible fractures (borehole televiewers or FMI logs-formation micro-imaging logs) contribute to production.

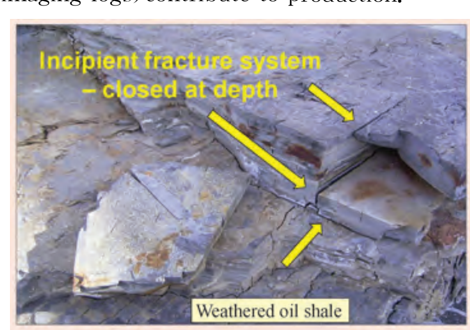

Fig. 5　Weathered Colorado oil shale in a quarry floor

Several simple "experiments" can help to clarify most of the mechanisms involved in MMHF. First, take a thick telephone book, and bend it gently to simulate bending of the strata above the proppant zone. On the flanks of that zone, bedding planes must slip to accommodate large bending distortions. Since injection pressures (p_{inj}) are high, often exceeding the total vertical stress, $p_{\text{inj}} - \sigma_{\text{v}}$, slip is facilitated and permanent flow channels are created by "self-propping" (Fig. 6). Rigid matrix blocks must also rotate, leading to fracture aperture development. Microseismicity in formations where orthogonal fracture systems align with the current princi-

① There are some soft, weak, shallow formations that contain biogenic gas; for example, the Colorado shale in Alberta, Canada.

pal stress field are representations of this behavior.

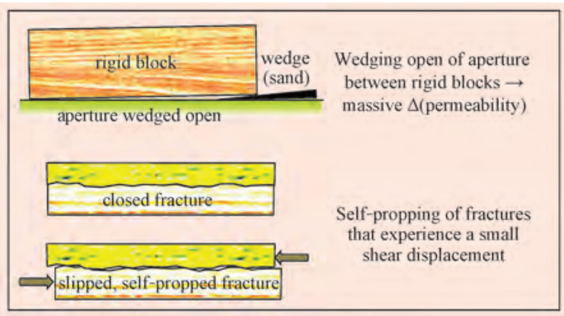

Fig. 6 Wedging (increasing aperture) and self-propping behavior of shear-displaced fracture

Second, take a thin wooden wedge (2° — 3°) and push it part way under a brick; the wedge represents the proppant in the fracture, but note that the fracture opening extends well beyond the sand tip, a process called "wedging" (Fig. 4 and Fig. 6). The effect is similar to block rotation, but the applied force is a straightforward normal extensional force (pressure leading to Mode I fracture) acting on the joint surface and forcing slurry down the opening. Block rotation also involves large changes in both the shear and normal forces at different locations along the block interfaces.

Third, make a tightly packed array of identical children's wooden blocks and then open a "sand-packed fracture" in the middle of the array. Note that the region of block rotation and fracture aperture dilation extends far from the limited sand propped zone in the center, as shown in Fig. 7. The induced fracture in the center may have some lateral extensions at different angles, and one such set of extra wings is sketched in that illustration (Fig. 7). The closest induced openings will contain some proppant, but the much larger and more important zone is the dilation region that enhances the flow capacity and contact area. The extent and integrity (resistance to closing fractures during production) of the dilated zone may be the difference between good and excellent reservoirs.

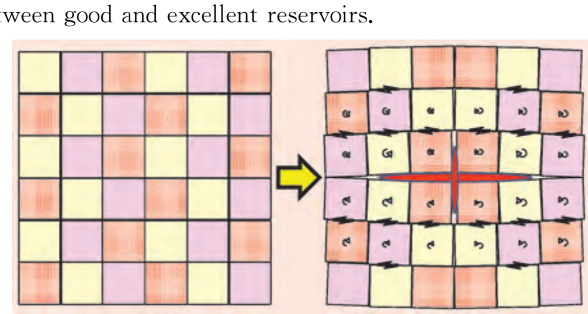

Fig. 7 Rotations of rigid blocks: propping, wedging, rotation and shear can all be seen in the distorted array of blocks as a consequence of the analog injection operations

Fourth, repeat this block experiment, but with one axis of the array placed under a mild compression; if you watch carefully, you will easily note shear displacements along block edges, especially if the boundary stress is at an angle to the orthogonal joint fabric. These shear displacements become self-propped openings, even in the absence of proppant. While doing these experiments, remember that MMHF involves pressures in excess of the minimum principal stress and often of the same order of magnitude as the overburden stress. The implication is that effective stresses are low, making slip easy. The sketch in Fig. 7 is reminiscent of the "base-friction models" of a generation ago [15-16]. Of course, these highly illustrative laboratory models or demonstrations have been replaced with numerical calculations using DEM—Discrete Element Method or similar computational protocols.

Since the rocks being subjected to MMHF have extremely low permeability, elevated pore pressures travel far beyond the propped② zone (Fig. 8). These increased pore pressures facilitate shear and promote growth of a stimulated zone that includes fractures that may be wedged open, self-propped because of slip, and opened because of rigid block rotations.

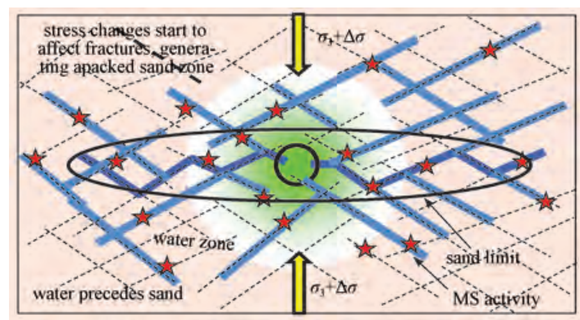

Fig. 8 Water (typical fracturing fluid) travels farther than the proppant (filtration[17], bridging, settlement, hindered motion of aggregates), the stresses change causes microseismic activity

The final element of predictable physical behavior to note is that aggressive hydraulic fracturing (large volumes, high rates, or both) leads to local stress changes that interact with local fabric. An array of induced fractures, some packed with proppant, others not, depend on factors such as leakoff rate, fluid viscosity, injection rate, and so on. The proppant bridges of f[12,17] in narrow secondary fractures, but the carrier fluid goes out much farther than the proppant. This fluid pressurizes a large volume, induces slippage on existing features (and extensional opening) and results in detectable microseismic activity. However, as noted above in Fig. 4 and 8, it is not necessary for sand (the proppant) to be everywhere to achieve a large stimulated volume; opening, wedging and shear may take care of that. It is important to get a high fluid pressure as far out as possible, and in such low permeability strata, that is likely best achieved with injecting large water③ volumes for long periods of time. The caveats to the effectiveness of shear fracturing and narrow unpropped apertures are the impeded production associated with reduced relative permeability when treatment fluid is not recovered from the fractures

② In most instances, economic considerations and in situ stress magnitudes mandate the use of sand as the proppant. Occasionally, proppant will be resin coated or hollow buoyant particles. In deeper environments, some consideration is given to intermediate strength proppant-typically ceramics; bauxite proppant is rarely used for shale gas stimulation.

③ Water, or water with friction-reducing agents, is the fluid of choice because of the cost of pumping large volumes and the potential for residual damage from incompletely broken viscosified fluids. Water requirements are a major issue in hydraulic fracturing logistics and environmental stewardship, particularly in arid regions.

created. Fluid recovery after hydraulic fracturing is commonly only on the order of 20% of the injected volume. Many remote fracture systems are orphaned during production-a significant challenge for the future.

There remain many questions as to what is the best approach to implement MMHF in specific circumstances (rock type and properties, depth, well orientation, stress field magnitudes, natural fracturing frequenc(ies) and orientation(s)...). There are also socio-economic drivers, such as the price of natural gas and environmental restrictions that warrant in-depth geomechanical evaluations of these injection programs. It is expected that improved answers to these questions will be found with a combination of better analysis, field monitoring, and compilation of post-treatment well performance histories. Consider some of the questions that are commonly posed.

- "Is it better to maximize injection rate, use proppant and pump continuously for several hours, or is it best to inject more slowly—for many days—without proppant, or is some hybrid combination desirable?"
- "Should we try for short fat fractures near the wellbore or long, extended fractures of greater volume and larger surface area—or again a combination?"
- "Can we predict when secondary fractures are induced (as in Fig. 8)?"
- "Is slick water④ (water with friction reducer) adequate for creating and sustaining a large volume, highly pressurized fracture network so as to maximize shearing in surrounding block interfaces?"
- "Does early proppant settling in slick water jeopardize stimulation?"
- "Should we inject water aggressively for many hours before introducing sand?"
- "Excluding cost, are foams or gases (nitrogen or carbon dioxide) viable alternatives?"
- "Can we reliably characterize the dilated zone and calibrate it to the volume of water and/or sand injected?"
- "Is conductivity to the outer reaches of the stimulated zone maintained after treatment and during production?"
- "Commonly only 10 to 20 percent of the injected fluid is recovered during production. Often the best producing gas wells have a smaller return of injected fluid. Why does this occur in low permeability rock?"
- "In staged fracturing, do the stress changes arising from previous stages significantly affect the success of the current hydraulic fracturing activity?"

This list is speculative and incomplete, but it would be highly desirable if we had good mathematical models so that we could query them with some of these questions, at least for "sensitivity analyses". Although the in situ processes are so complicated that a "design model" remains a distant goal, ideally, such a model could be calibrated in real cases and used to predict behavior for the next well. A comprehensive physics-based model is a great deal to hope for because of all of the non-linear and ill-defined processes involved, let alone inadequate characterization of the in situ environment. Consequently, it is clear that monitoring is and always will be needed for model calibration and verification.

4 Monitoring

Currently, there are three primary monitoring methods that can be used in practice to lead to a far better understanding of MMHF. Microseismic monitoring shows the spatial distribution and magnitude of seismicity associated with bedding plane slip as well as slip of natural and newly propagated fractures; the limits of the dilated zone are thought to be contiguous with the region of detectable microseismicity.

Fig. 9 shows microseismic data collected during a MMHF stimulation in the Barnett shale (The blue diamonds

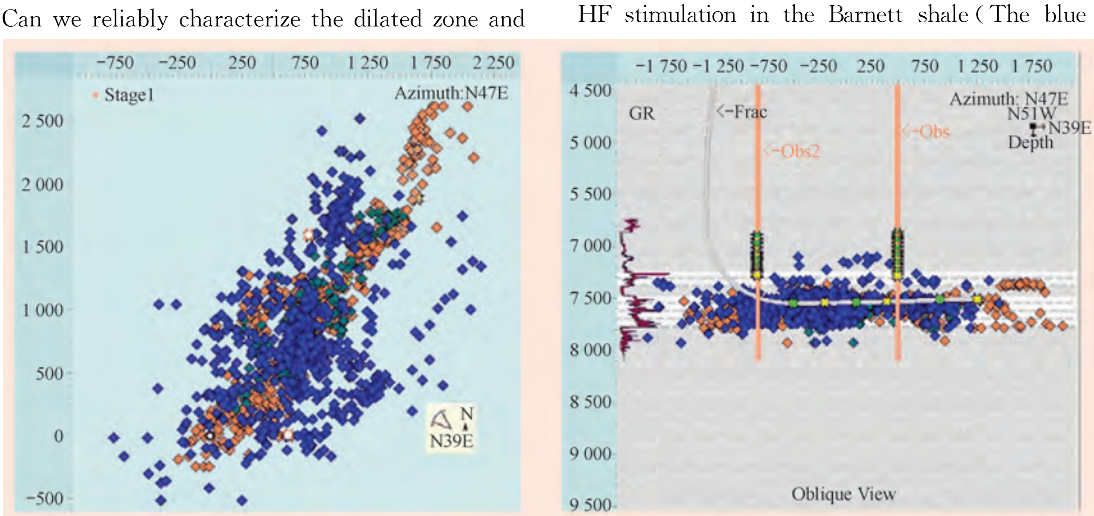

Fig. 9　Microseismic monitoring during a hydraulic fracture stimulation of Barnett Shale (modified after reference[10])

indicate location of microseismic events exceeding a threshold amplitude during the last stimulation phase involving high rate water injection only). The blue dots represent events recorded in the third of three injection phases. The figure shows that shear events are being induced far from the perforated zones in the cased well. Because bottomhole injection pressures are considerably higher than the initial value of σ_3 in these strata, the ef-

④ Slick water has become the treatment fluid of choice for several reasons including relatively low cost and indications of residual gel damage when viscosified fluids had been used in the past. The low permeability of the target formations imply that surface area rather than large conductivity is of greatest importance-as long as some modest fracture conductivity can be maintained in the presence of increasing closure stress and possibly increasing water saturation during production.

fective normal stress is so low that shearing is facilitated, leading to self-propping(Fig. 6).

Microseismic analysis is an extremely rich area for rock mechanics; it was first developed for monitoring deep mines[18-20], and is now widely used as a mine management tool. Routine use in MMHF is a more recent development, but one that has been seminal in our understanding of the processes[21]. The emissions can be analyzed in terms of spatial location, timing and sequence, amplitude, direction of motion, energy emission spectrum, and other variables. Even beyond the recent advances, this approach holds great promise for interpreting and controlling MMHF, as well as other petroleum and natural gas development processes. Uncertainty still exists in interpreting the extent of interconnected, conductive fracture paths from microseismic events.

An additional methodology that still has merit is using tiltmeters. An array of small surface deformations is measured and recorded by instrumentation with angular resolution on the order of nanoradians. Deformation monitoring using tiltmeters allows decomposition of the fracturing process into vertical and horizontal components and provides insights into the shape and magnitude of the stimulated zone.

In Fig. 10, several important aspects of deformation monitoring are shown or implied. First, because the strains are actually very small in the overburden (but not necessarily in the process zone where fracturing is concentrated), the strains from the zone being stimulated are transmitted into the surrounding strata elastically, showing up as deformations (or tilts) at the surface. This deformation field can be sampled at many points at the surface, and this can be analyzed to give information about the process at depth. Figure 10 illustrates that the complex deformation shown in the lower panel is the elastic sum of deformations arising from a locus of pure volume change (a nucleus-of-strain[22]) and a line of defined shear displacement (a displacement discontinuity). In principle, with good data, it is possible to mathematically solve for a number of these "kernels" at depth in the stimulated region, building up a picture of what is happening in real time if the deformations (or tilts) can be collected in real time. Figure 11 is an image

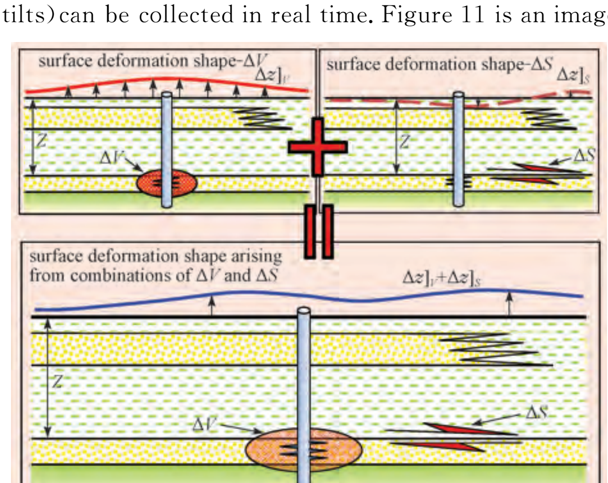

Fig. 10　Surface Deformation Decomposition

denoting vertical deformation above a steam injection operation. This scenario is different from hydraulic fracturing stimulation but the principle is the same: shear and volume changes at depth generate a surface deformation field that in principle can be analyzed mathematically to deconvolve deformations at depth[23].

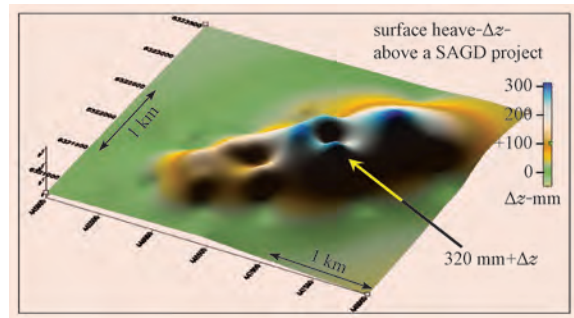

Fig. 11　Surface uplift above a steam injection project

Finally, pressure measurements during and after MMHF allow insight into the process, estimates of permeability, and estimates of the open volume generated[24]. Post-treatment pressure tests can involve pulses, buildup and decay. Sophisticated analysis methods can give insight into the extent of the stimulated zone, its deformability, and of course the flow properties. Unfortunately many publicized interpretations rely on an assumed single planar fracture system and grossly misrepresent complicated fracture networks. Whether such interpretation of an equivalent medium is tolerable is not resolved at this time.

All three of these monitoring approaches can be implemented in "real-time" and in principle can be used to track and optimize treatments. Of course, this requires rapid analysis methods, excellent graphical capability, and a robust conceptual model of the mechanisms. A combination of analysis methods applied to the data collected can lead to a far better understanding of the size of the stimulated volume and its flow properties. The success of microseismic monitoring in shale gas MMHF has been a critical learning experience. Now, if we could only use the data to calibrate models of how the reservoir and surroundings deform when they are subjected to injection or production related stress changes... in other words, can mathematical models reliably represent these complex in situ processes?

5　Mathematical Modeling

MMHF processes in fractured rock have the following physical attributes:

1) Strong coupling between fluid flow and deformations, even neglecting effects that may arise because of temperature change.

2) A strong impact from the natural fabric-lithologic variability, bedding plane discontinuities and natural fractures-including incipient natural fractures.

3) Packing of proppant into fractures, with the carrier fluid propagating far beyond the propped zone because of filtration and separation processes (sand packing, gravitational settling, hold-up at points where

flow direction changes...).

4) Wedging open of fractures by slurry (i. e., with proppant) and permanently propping open induced, reopened or reactivated fractures, at least near the wellbore. Proppant transport is inhibited by the low viscosity of water; the carrier fluid that is most commonly used.

5) Shear displacement across fractures and bedding planes, leading to self-propping or possibly fracture arrest.

6) Block displacement and elastic compression, as well as block rotations that cause fracture apertures to open and slip, leading to enhanced and preserved fracture conductivity.

7) Massive alterations in fracture permeability as the processes of wedging, shear and propping occur in a large region around the wellbore—the dilated zone.

These factors are nearly as non-linear, complex and coupled as it is possible to experience in practical geomechanics. The first requirement is to determine what simplifications and averaging methods can be realistically employed without degrading the basic principles beyond recognition; too many empirical or approximating factors and too much large-scale averaging obscures the actual physical processes. However, as we know from decades of rock mechanics experience, a simple model often tells us what we need to know, and it may even be calibrated if appropriate measurements are available. There is a long legacy of history matching of production and model calibration that can be adopted from formal reservoir engineering to assist in geomechanical MMHF model calibration.

The ability to simulate these processes will nonetheless remain severely limited, even with simplifications and volume averaging. First, the ever-present issue of rock characterization is made doubly difficult because the rocks are 1—3+km deep, closed and incipient fractures cannot be detected at depth between wellbores, and geophysical data are limited to relatively low-resolution seismic methods supplemented by borehole data. Providing realistic fracture fabric attributes for deterministic simulations in realistic cases remains beyond our current capability, although the industry is working on this with determination.

In addition, continuum mechanics simulators based on finite differences (FD), finite elements (FEM), boundary elements (BEM), displacement discontinuity methods (DD) or other formulations experience severe computational difficulties in realistically analyzing actual fractured systems experiencing opening and closing of fracture apertures, propagating fractures along their length, block rotation, and the other non-linearities involved such as slip and self-propping. For example, how would one represent the massively changing permeabilities associated with block rotation and opening of a fracture plane of changing aperture between two blocks? Can this be done using volume averaging methods with a large "unit volume"? What functions would be appropriate? These are not trivial issues; FD, FEM, BEM and DD methods, alone or iteratively coupled (e. g., a FD reservoir simulator coupled with a BEM rock mechanics simulator), cannot handle the problem size and the discrete block physics involved.

Finally, can discrete (distinct) element methods (DEM) provide an appropriate computational methodology? A discrete element code such as 3DEC™ has exceedingly long execution times if massive numbers of blocks that are free to rotate are simulated⑤. Furthermore, such codes require refinements to handle fluid flow in the fracture network with simultaneous proppant emplacement (filtration[17]) and matrix flow. How do you calculate the fluid transmission properties of a fracture that is wedged open and therefore has a varying aperture along its length? Can proppant emplacement be treated entirely separately, simply generating an input file to a DEM simulator? What are the flow properties of a self-propped shear-displacement fracture? These questions are almost unresovable. Nevertheless, despite the difficulties involved, DEM methods offer hope in generating better MMHF models, but it is unlikely that they will be used alone. Fig. 12[25] shows a model that was developed to study the effects of viscosity and treatment rate on the tendency of rocks to fail in shear along pre-defined joint planes, essentially one step toward comprehending the issues of shearing and self-propping.

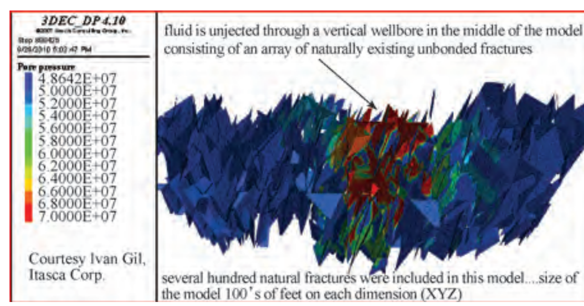

Fig. 12　Three-dimensional DEM simulation of hydraulic injection into a fractured medium (courtesy, I Gil, Itasca Houston Inc.)

Also, representing a huge volume into numerous discrete blocks is impractical because of the number of degrees of freedom involved. It may be best to imbed a DEM model within a FEM region that can handle local stress changes and fluid flow. Also, to simulate the surrounding elastic rock (the "rest of the world"), we might use BE or DD elements to give representative stress and displacement boundary conditions, as long as the distant rocks behave elastically. These methods (Fig. 13)

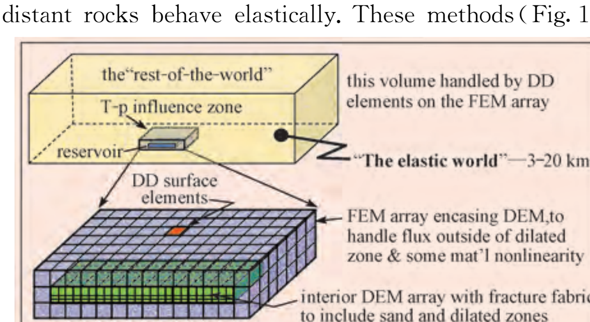

Fig. 13　Embedded DEM in a FEM array coated with DD elements to simulate a large domain

⑤ 3DECTM is a product of Itasca Consulting Group, Minneapolis, Minnesota. Code development continues with specific efforts to develop practical hydraulic fracturing simulation tools.

may reduce the degrees of freedom by a factor of 3 to 5, compared to FEM. In the local dilated zone "permeability" can be linked to the strain, but the relationship remains uncertain because of the effect of block rotations.

It may be more efficient to separate the various numerical "tasks" into different models, combining the results in a time-stepping manner (iterative coupling). For example, proppant settling in vertical and inclined fractures, sand filtration along wedged fractures, the effects of fracture widening and proppant re-mobilization during fracturing cannot be treated easily; likely, a separate module could be designed to handle this, feeding the volumetric strain distribution into the master DEM that is embedded within the FEM/DD half-space.

Superficially, treating DEM blocks as impermeable elastic blocks that do not interact with the flow regime seems to be a reasonable assumption since rocks being subjected to MMHF are low permeability and flow will be fracture-dominated. However, capillarity and imbibition are nonetheless complicating factors, recognizing particularly low velocities far away from the wellbore and acknowledging that only a small proportion of the injection fluid is recovered during flowback. An "equivalent continuum" fractured rock flow FD simulator might then be used in conjunction with the DEM in an iteratively coupled manner to introduce capillarity effects[26].

Is it feasible to handle the flow problem with a modified FD oil industry simulator based on the equivalent continuum approach, but with the permeability of each "volume" modified as a function of the amount of rotation that the DEM indicates? This coupling has been achieved with multiphase discrete fracture network simulators [26-28]. These petroleum industry simulators are sophisticated systems designed to also include temperature effects and multiphase flow.

Whatever direction turns out to be the best, there are several factors to remember: the economic impact of better MMHF simulation is huge, given the value of the resources involved; also, no progress will be made without monitoring and the use of good quality data to calibrate and verify models. There is considerable value remaining in the concept of calibrated models that are simplified, but robust enough that they can be used in subsequent analyses of a predictive nature. That is what applied petroleum geomechanics is all about: solving real problems as best we can, given the great complexity of the processes, while also recognizing technical and socio-economic-environmental issues[29].

6 The Future and Challenges for Low Permeability Reservoirs in China

6.1 Geologic considerations: tectonic complexity

Thick organic-rich Paleozoic shales in Southern China have experienced many tectonic events; e. g. Caledon (Earlier Cambrian), Indo-China (late Paleozoic-early Mesozoic), Yanshan (middle to late Mesozoic) and Himalaya movements (Cenozoic). This activity not only led to fluid expulsion and retention issues but also caused the development of faults, fold belts, and diagenesis of siliceous deposits. Compartmentalization of these reservoirs may be a significant problem. Injection of tremendously large volumes of fluid, as is common elsewhere may need to be restricted in particular cases to avoid losses through conductive faults or well-developed naturally fractured zones.

What is the nature of the natural fractures? What diagenetic activity has occurred? Will they simply be fluid loss conduits and not develop permanently open apertures? Will tectonic loading (large differences in the in situ stresses) enhance or hinder the development of an effective dilatant zone? Generalizations are inappropriate at this stage.

6.2 Geologic considerations: depth

Some of the marine shales are older than in currently productive plays; Cambrian, Ordovician and Silurian. Despite complex tectonic histories and repeated uplift and burial, some of these prospective plays are still deeply buried: e. g. shale prospects in the Sichuan basin lie between 2 000 and 4 800 m. These deeper shales have lower permeability and porosity values than equivalent shales elsewhere, e. g., several core samples from the Sichuan Basin show porosity ranging from 0.12%-2.49%[30]. Temperatures, stresses and pressures are expected to be elevated, and while higher pressures are desirable and higher temperatures may indicate reasonable maturity (possibly over-mature), the stresses and temperatures complicate well construction, increasing costs for casing and stimulation. Drilling may be more difficult in highly fractured regimes. Nevertheless, none of these issues is insurmountable with current technology.

6.3 Geologic considerations: marine vs. lacustrine shales

China is the world's leading oil producer from conventional sandstone reservoirs in lacustrine basins (e. g., Daqing). In these regions there are many potential lacustrine shale gas plays. Some prominent Mesozoic to Cenozoic lacustrine basins in China are mainly rifted basins with active faults, and the younger shales have low compositional and textural maturity, with a higher content of feldspar and rock fragments. Although the TOC in lacustrine settings is usually high, the shale gas potential of lacustrine strata is unproven and may be complicated by low maturity (Ro—Table 1). Active faulting and low potential gas contents are complications that can severely impact play quality.

Compared to marine shales, lacustrine shale facies change rapidly over small lateral distances, and most of these shales are thinner and interbedded with siltstone and sandstone. Fracturing stages will need to be strategically located and more stages with smaller volumes may be necessary to deal with the variability. Low gas content and thin zones are problematic from an OGIP perspective. However, both shale gas and shale oil wells in lacustrine shales have recently been hydraulically fractured; e. g. , shale gas from the Jurassic Ziliujing Formation in the Sichuan basin and shale oil from the Tertiary Hetaoyuan Formation in the Biyang basin.

Lacustrine shales may have mineralogies that will impact stimulation attempts. In the Sichuan Basin, detrital quartz content in characteristic lacustrine shale is characteristically high (60%－80%), clay content low (10%－20%). But the higher smectitic and mixed layer illite-smectite component in other basins may cause swelling issues with water-based, untreated stimulation fluids, e. g. , in the Dongying sub-basin within the Bohai Bay basin in eastern China, shales have relatively high clay content (40%－80%), low quartz content (10%－30%) and moderate carbonate content (7%－40%). One must not expect the same stimulation results from shales with widely differing mineralogies.

6.4 Operational considerations: optimizing treatment size and type

These issues apply worldwide, not just in China. With the tectonic complexities, the potential for compartmentalization and transmissive or active faults, it will be necessary to reconsider appropriate fracturing fluids and treatment volumes, perhaps increasing the number of stages and reducing treatment size to restrict out-of-zone growth and fault reactivation. In lacustrine environments with higher silt ratios, there may be a need for more viscous fluids and higher proppant concentrations to take advantage of overall higher equivalent permeabilities.

6.5 Operational considerations: mear wellbore complexity

It is expected that the near-wellbore environment will be more complicated in regions of high compression and tectonic deformation features, especially where a natural fracture system exists at angles to the principal stresses, leading to some induced fracture orientation changes during stimulation, a more tortuous path, and a higher proppant screen-out potential. This may require more surface horsepower and more concentrated perforating (i. e. , more widely spaced stages) so that substantial fractures can be effectively initiated.

6.6 Operational considerations: environmental considerations

Large volumes of water will be required, a significant challenge in arid parts of China. In addition, flowback water is usually highly saline and can contain NORMs (Naturally Occurring Radioactive Minerals) and heavy metals. Methods are available for processing these waters, although expenses are incurred (see for example reference [29]).

6.7 Operational considerations: induced seismicity

Injection-induced, larger-scale seismicity (i. e. , much larger than the microseismic events used in monitoring) is possible, particularly in view of the active tectonism and the proximity to faults in tectonic basins. Cladouhos et al. (2010)[31] provide an excellent review from a geothermal perspective, where the stimulation treatments and the reservoir environments are not entirely dissimilar from gas-bearing shales. To mitigate events, it may be desirable to avoid zones with significant active faults, to minimize treatment sizes and use more stages and possibly to reduce fluid loss along transmissive fractures by using higher viscosity fluids or lower injection rates. Large-scale seismic potential is not a certainty, but should be a consideration, so monitoring is essential, particularly for pilot programs.

7 Conclusions: alternatives to MMHF

While effective, MMHF as currently executed may not be a sustainable treatment protocol, but the technology should be adaptable to reservoir scenarios in China. The consequences of large, aggressive injection of water are recognized as economic, social and environmental risks and there is value in considering methods other than conventional MMHF to guide future protocols for stimulating low mobility reservoirs. Briefly, what are the opportunities? There are four generic stimulation methods with combinations-hydraulic, thermal, mechanical and chemical.

Hydraulic stimulation MMHF is a form of hydraulic stimulation, evolved by trial and error in North American settings. To fit specific geologic and economic situations, variations in treatment fluid rates and volumes must be considered. Hybrid treatments combining pumping fluids with differing viscosities might be adaptable on a more general basis, with the caveats of additional expense and potential gel damage. There is the possibility of pre-stimulation, involving low rate injection to expand elevated pore pressure distribution and to enhance the potential for shear and development of the dilated zone. Finally, cyclic or pulsed injection or Kiel fracturing concepts (although never universally adopted in the past[32]) could have value in situations where there are more natural fractures. Extreme technologies could involve injection of hydrocarbon gases (methane, propane[33]...), liquid CO_2, or nitrogen.

Mechanical stimulation Blurring the line between hydraulic and mechanical technologies are various proposed technologies such as aggressively changing treatment fluid pressure or seismically loading the formation[34]. Propellant technology may offer significant opportunities (reference 35 and many others), particularly in combination with more conventional fracturing methods. It is even possible to emplace a high-gas emission explosive slurry (ammonium nitrate and light oil) through hydraulic fracturing and detonate it in situ to generate an extremely large (albeit largely uncontrolled) gas-driven event that takes place in a very short time.

Thermal stimulation Applications of thermal stimulation by heating or cooling are also well known from produced water injection operations[36-37] and from geothermal energy considerations. It is anticipated that these can be adapted to broaden the lateral extent of hydraulic fractures, i. e. , precooling could locally adjust stresses and create secondary fractures that would be hydraulically activated by follow-on hydraulic fracturing. Liquid nitrogen or carbon dioxide injection is an approach that comes to mind in this context. A great advantage of a gas stimulant is that clean-up occurs naturally during production with no permanent rock permeability impairment.

Chemical Stimulation Areas of interest include surfactant technology for flowback and minimizing imbibition, completely different proppant types (for example, proppant that swells with time), or acidizing fractures before, during or after conventional propped fracturing in the case of carbonate-rich shales.

Acknowledgements

A shorter version of this publication, authored by the first two authors, was originally published on line by the American Rock Mechanics Association[38]. That publication has been revised to include a description of the opportunities and challenges in China and speculation on potential stimulation methods that might be introduced or re-introduced in the relatively near future. Editorial review by Elinda McKenna is gratefully acknowledged.

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