Benchmark Cases for Hydraulic Fracturing Models

ARMA Technical Committee on Hydraulic Fracturing (TCHF)

Overview

This document lists benchmark cases designed to help fracture modelers to demonstrate the model capacity of capturing recognized physics involved in hydraulic fracturing. Since different models make different assumptions and incorporate different physics, the impact and validity of these assumptions can be evaluated.

From simple to complex, these benchmark cases are:

Case 1: Single fracture in homogeneous, elastic media
Case 2: Single fracture in layered, elastic formations
Case 3: Single fracture in homogeneous, poroelastic and thermoelastic media
Case 4: Single fracture in elasto-plastic media (low cohesion, low Young's Modulus)
Case 5: Single fracture interacting with natural fractures and discontinuities (elastic and poroelastic)
Case 6: Single fracture in layered elastic media with complex fracturing fluids (non-Newtonian and compressible)
Case 7: Multiple competing fractures from perforation clusters (stress shadow effects).

The simplest Case 1 (single fracture in elastic rock with a Newtonian frac fluid with no proppant) compares the numerical results with analytical ones that are available for this problem. Cases 2 to 5 highlight the effect of rock complexity on fracture initiation and propagation. Case 6 evaluates the role of complex fluids such as CO_2 and foams. Finally, Case 7 studies the impact of stress interference between fractures.

Any fracture modeler can choose to model any benchmark case and provide their results in the required formats. Each modeler will have 15 minutes to present, starting with a list of the model assumptions and theoretical framework. The workshop committee will select the presentations based on model representativeness and slot availability.

The cases have been prepared by TCHF members including Drs. Mukul Sharma, Xiaowei Weng, Sau-Wai Wong, Joe Morris, Ahmad Ghassemi, John McLennan, Gang Han, et al. Special thanks to the suggestions from modelers such as Mike Smith, Egor Dontsov, Leonard Cruz, Pengcheng Fu, Uno Mutlu, Shawn Maxwell, Mark McClure, Guanshui Xu, Hooman Hosseinpour et al.

Test Case 1: Single fracture in homogenous elastic media

Continuous injection at a constant flow rate into a single fracture in an elastic rock with no confining layers.

(a) Newtonian frac fluid with no proppant injected at the rate of 20 bpm for 10,000 bbl under toughness dominated regime and low fluid efficiency in an isotropic elastic rock.
(b) Frac fluid with no proppant in an isotropic elastic rock under viscosity dominated regime and low efficiency in an isotropic rock.
(c) Newtonian frac fluid with no proppant injected at the rate of 20 bpm for 700 bbl under toughness dominated regime and high fluid efficiency in an isotropic elastic rock.
(d) Frac fluid with no proppant in an isotropic elastic rock under viscosity dominated regime and high fluid efficiency in an isotropic rock.
(e) Newtonian frac fluid with no proppant in an anisotropic elastic rock (vertical Young's Modulus is 3 MMpsi and vertical Poisson's Ratio is 0.25; Horizontal values are same as in the table) under toughness dominated regime and high fluid efficiency.

Mechanical Layer Properties:

	Layer Top	Layer Thickness	Min Horiz Stress	Max Horiz Stress	Vertical Stress	Young's Modulus	Poisson's Ratio	KIc
	ft	ft	psi	psi	psi	MMpsi		psi-in$^{0.5}$
Layer 1	7750	500	5000	5300	7000	4	0.3	1000

Porous Layer Properties:

	Layer Top	Layer Thickness	Permeability	Porosity	Pore Pressure
	ft	ft	mD		psi
Layer 1	7750	500	0.001	0.1	4000

Fracturing Fluid Properties:

	Density	n	K
	lb/ft^3		cp
Fluid 1	62.4	1	1
Fluid 2	62.4	1	1000

Case a: Tip Dominated, Low Efficiency (Fluid Loss such that Fluid Efficiency at End-of-Pumping is < 5%)

Injection Fluid	Pump Rate	Volume	KIc - Layer 1
	bbl/min	bbl	psi-in$^{0.5}$
Fluid 1	20	10,000	20000

Case b: Viscosity Dominated, Low Efficiency (Fluid Loss such that Fluid Efficiency at End-of-Pumping is < 5%)

Injection Fluid	Pump Rate	Volume	KIc - Layer 1
	bbl/min	bbl	psi-in$^{0.5}$
Fluid 2	20	10,000	100

Case c: Tip Dominated, High Efficiency (Fluid Loss such that Fluid Efficiency at End-of-Pumping is > 95%)

Injection Fluid	Pump Rate	Volume	KIc - Layer 1
	bbl/min	bbl	psi-in$^{0.5}$
Fluid 1	20	400	20000

Case d: Viscosity Dominated, High Efficiency (Fluid Loss such that Fluid Efficiency at End-of-Pumping is > 95%)

Injection Fluid	Pump Rate	Volume	KIc - Layer 2
	bbl/min	bbl	psi-in$^{0.5}$
Fluid 2	20	400	100

Results required to be presented in the format below:

1) Fracture geometry (half-length and height) as a function of time (X-Y plot)
2) Average and maximum fracture width as a function of time (X-Y plot)
3) Net pressure (bottom hole pressure – minimum in-situ horizontal stress in the rock) as a function of time
4) Contour plots of the minimum principal stress and the maximum shear stress surrounding the fracture as it propagates with time

Test Case 2: Single fracture in layered, elastic formations

Single fracture growth in a 3-layer rock formation with layers of different mechanical properties and stress contrasts and fracture starting from the middle layer.

(a) Newtonian fluid injected without proppant at the rate of 20bpm for 20 minutes in a three layer-reservoir. The stresses and mechanical properties of top and bottom layers are various compared to middle layer.
(b) Newtonian fluid with proppant (2ppa proppant loading) for the above scenarios

Mechanical Layer Properties:

	Layer Top	Layer Thickness	Min Horiz Stress	Max Horiz Stress	Vertical Stress	Young's Modulus	Poisson's Ratio	KIc
	ft	ft	psi	psi	psi	MMpsi		psi-in$^{0.5}$
Layer 1	7700	200	5250	5550	7000	3.5	0.35	500
Layer 2	7900	200	5000	5300	7000	4	0.3	1000
Layer 3	8100	200	5250	5550	7000	4.5	0.25	1500

Porous Layer Properties:

	Layer Top	Layer Thickness	Permeability	Porosity	Pore Pressure
	ft	ft	mD		psi
Layer 1	7700	200	0.0005	0.05	3900
Layer 2	7900	200	0.001	0.1	4000
Layer 3	8100	200	0.002	0.15	4100

Fracturing Fluid Properties:

	Density	n	K
	lb/ft^3		cp
Fluid 1	62.4	1	1

Proppant Properties:

	Density	US Mesh Size	Proppant Loading
	lb/ft^3		ppa
Proppant 1	165	40/70	2

Results required to be presented in the format below:

1) Fracture geometry (half-length and height) as a function of time (X-Y plot)
2) Average and maximum fracture width as a function of time (X-Y plot)
3) Net pressure (bottom hole pressure – minimum horizontal stress in the rock) as a function of time
4) If available, proppant distributions in terms of proppant mass per unit area at the end of injection
5) If available, the minimum principal stresses and the maximum shear stress surrounding the fracture as it propagates with time

Test Case 3: Single fracture in homogenous, poroelastic and thermoelastic media

Single fracture growth in a single-layer formation considering the stress changes around the fracture due to pressure (poroelastic) and / or temperature (thermoelastic) effects. Prior to injection, the formation contains single-phase liquid with viscosity of 1 cp. Fluid is injected at the rate of 20bpm for 20 minutes. Use Biot's constant of 0.6, reservoir temperature of 160 degF, bottom hole temperature at the perforation of 60 degF. Assume heat capacity of rock to be 1000 J/kg/K, thermal conductivity of rock to be 2.5 W/m/K and rock thermal expansion coefficient to be 11.6e-6 1/degK.

(a) Newtonian fluid without proppant in a poroelastic media
(b) Newtonian fluid without proppant in a thermoelastic media
(c) Newtonian fluid without proppant in a thermo-poro-elastic media
(d) Newtonian fluid with proppant (2ppa proppant loading) for any of the above scenarios

Mechanical Layer Properties:

	Layer Top	Layer Thickness	Min Horiz Stress	Max Horiz Stress	Vertical Stress	Young's Modulus	Poisson's Ratio	KIc
	ft	ft	psi	psi	psi	MMpsi		psi-in$^{0.5}$
Layer 1	7750	500	5000	5300	7000	4	0.3	1000

Porous Layer Properties:

	Layer Top	Layer Thickness	Permeability	Porosity	Pore Pressure
	ft	ft	mD		psi
Layer 1	7750	500	0.001	0.1	4000

Fracturing Fluid Properties:

	Density	n	K
	lb/ft^3		cp
Fluid 1	62.4	1	1

Proppant Properties:

	Density	US Mesh Size
	lb/ft^3	
Proppant 1	165	40/70

Results required to be presented in the format below:

1) Fracture geometry (half-length and height) as a function of time
2) Average and Maximum fracture width as a function of time (X-Y plot)
3) Net pressure (bottom hole pressure – minimum horizontal stress in the rock) as a function of time
4) When available, proppant distributions in terms of proppant mass per unit area at the end of injection
5) When available, plots of the minimum principal stresses, the maximum shear stress, pore pressure, and temperature, surrounding the fracture as it propagates with time

Test Case 4: Single fracture in elasto-plastic media (low cohesion, low Young's Modulus)

Single fracture growth in an elasto-plastic media (such as an unconsolidated sand). Use cohesion of 300 psi, dilation angle of 5 and internal friction angle of 30 for modeling plasticity.

(a) Newtonian fluid without proppant injected at the rate of 20 bpm for 20 minutes in a single-layer, elasto-plastic media
(b) Newtonian fluid with proppant (2ppa proppant loading) for the above scenarios

Mechanical Layer Properties:

	Layer Top	Layer Thickness	Min Horiz Stress	Max Horiz Stress	Vertical Stress	Young's Modulus	Poisson's Ratio	KIc
	ft	ft	psi	psi	psi	MMpsi		psi-in$^{0.5}$
Layer 1	7750	500	5000	5300	7000	0.5	0.3	1000

Porous Layer Properties:

	Layer Top	Layer Thickness	Permeability	Porosity	Pore Pressure
	ft	ft	mD		psi
Layer 1	7750	500	10	0.25	4000

Fracturing Fluid Properties:

	Density	n	K
	lb/ft^3		cp
Fluid 1	62.4	1	100

Proppant Properties:

	Density	US Mesh Size
	lb/ft^3	
Proppant 1	165	40/70

Results required to be presented in the format below:

1) Fracture geometry (half-length and height) as a function of time
2) Average and Maximum fracture width as a function of time (X-Y plot)
3) Net pressure (bottom hole pressure – minimum horizontal stress in the rock) as a function of time
4) When available, proppant distributions in terms of proppant mass per unit area at the end of injection
5) When available, plots of the minimum principal stresses, the maximum shear stress, and pore pressure surrounding the fracture as it propagates with time

Test Case 5: Single fracture interacting with natural fractures and discontinuities (elastic and poroelastic)

Single fracture growth in a multi-layer formation, intersecting a discontinuity (a natural fracture, bedding plane, or fault) at an angle to the hydraulic fracture. For all the scenarios, assume 300 psi horizontal stress contrast, coefficient of friction of 0.6 and an angle of intersection of 45 degrees unless specified otherwise. Below are more details of the position, orientation and size of the discontinuity.

Position: center of the discontinuity is at 150 ft from perf interval along the SH direction. A second discontinuity is at the mirror image position of this discontinuity on the opposite side of the perf but with the same azimuth
Orientation: dip is 90 deg (i.e. vertical).
Size: Assume height and length infinite (very large) as the simplest case. (However, it is optional to assume finite height or length if deemed important to explore the propagation around/beyond the edges of the discontinuity)

(a) Newtonian fluid in an elastic formation
(b) Sensitivity to coefficient of friction (0.3 and 0.6)
(c) Sensitivity to intersection angle (intersection angle as 30 degrees, 45 degrees, 60 degrees and 90 degrees)
(d) Sensitivity to stress contrast (100 psi, 300 psi, 1000 psi)
(e) Newtonian fluid with proppant for any of the above scenarios
(f) Newtonian fluid without proppant in a poroelastic formation with fluid viscosity of 1 cp for any of the above scenarios. Use Biot's constant of 0.6

Mechanical Layer Properties:

	Layer Top	Layer Thickness	Min Horiz Stress	Max Horiz Stress	Vertical Stress	Young's Modulus	Poisson's Ratio	KIc
	ft	ft	psi	psi	psi	MMpsi		psi-in$^{0.5}$
Layer 1	7700	200	5250	5550	7000	3.5	0.35	500
Layer 2	7900	200	5000	5300	7000	4	0.3	1000
Layer 3	8100	200	5250	5550	7000	4.5	0.25	1500

Porous Layer Properties:

	Layer Top	Layer Thickness	Permeability	Porosity	Pore Pressure
	ft	ft	mD		psi
Layer 1	7700	200	0.0005	0.05	3900
Layer 2	7900	200	0.001	0.1	4000
Layer 3	8100	200	0.002	0.15	4100

Fracturing Fluid Properties:

	Density	n	K
	lb/ft^3		cp
Fluid 1	62.4	1	1

Proppant Properties:

	Density	US Mesh Size	Proppant Loading
	lb/ft^3		ppa
Proppant 1	165	40/70	2

Results required to be presented in the format below:

1) Fracture trajectory as a function of time (2D or 3D)
2) Fracture geometry (half-length and width) of all fractures at the end of injection
3) Net pressure (bottom hole pressure – minimum horizontal stress in the rock) as a function of time
4) Contour plot of direction of maximum principal stress at the end of injection (and any other time that modeler wishes to show)
5) If available, plot of minimum principal stress or pore pressure as the fracture propagates
6) If available, proppant distributions in terms of proppant mass per unit area at the end of injection

Test Case 6: Single fracture in layered elastic media with complex fracturing fluids (non-Newtonian and compressible)

Single fracture growth in layered elastic media, but with non-Newtonian (crosslinked gels) and compressible (supercritical CO_2, 70% CO_2 foam) fracturing fluids. Assuming supercritical CO_2 is gelled and hence has higher viscosity. Injection rate is 20 bpm for 20 minutes.

(a) Non-Newtonian fracturing fluid with and without proppant
(b) Energized fracturing fluid (CO_2 Foam 70% quality) with and without proppant
(c) Energized fracturing fluid (supercritical CO_2) with and without proppant

Mechanical Layer Properties:

	Layer Top	Layer Thickness	Min Horiz Stress	Max Horiz Stress	Vertical Stress	Young's Modulus	Poisson's Ratio	KIc
	ft	ft	psi	psi	psi	MMpsi		psi-in$^{0.5}$
Layer 1	7700	200	5250	5550	7000	3.5	0.35	500
Layer 2	7900	200	5000	5300	7000	4	0.3	1000
Layer 3	8100	200	5250	5550	7000	4.5	0.25	1500

Porous Layer Properties:

	Layer Top	Layer Thickness	Permeability	Porosity	Pore Pressure
	ft	ft	mD		psi
Layer 1	7700	200	0.0005	0.05	3900
Layer 2	7900	200	0.001	0.1	4000
Layer 3	8100	200	0.002	0.15	4100

Fracturing Fluid Properties:

	Density	n	K
	lb/ft^3		cp
Non-Newtonian	62.4	0.7	100
CO_2 Foam	f(P,T)	0.7	100
supercritical CO_2	f(P,T)	0.7	30

Proppant Properties:

	Density	US Mesh Size	Proppant Loading
	lb/ft^3		ppa
Proppant 1	165	40/70	2

Results required to be presented in the format below:

1) Fracture half-length as a function of time (X-Y plot)
2) Fracture width as a function of time (X-Y plot)
3) Fracture height as a function of time (X-Y plot)
4) Net pressure (bottom hole pressure – minimum horizontal stress in the perforation layer) as a function of time
5) If available, proppant distributions in terms of proppant mass per unit area at the end of injection

Test Case 7: Multiple competing fractures from perforation clusters (stress interference effects)

Simultaneous growth of fractures from 3 perforation clusters, including stress interference among the fractures. For all the scenarios, assume 300 psi horizontal stress contrast, 75 ft as cluster spacing and no stress shadow from previous stage, unless specified otherwise.

(a) Newtonian fluid without proppant in an elastic single-layer formation.
(b) Newtonian fluid without proppant in an elastic multi-layer formation.
(c) Newtonian fluid without proppant in a poro-elastic single-layer formation. Use Biot's constant of 0.6
(d) Newtonian fluid without proppant in an elastic single-layer formation, but including the stress shadow from previous stage (the previous stage is identical to this stage). The elapsed time between the stages (from the end of the previous to the start of the next) is 2 hours.
(e) Newtonian fluid without proppant in an elastic single-layer formation, but with wellbore at 45 degrees from maximum horizontal stress
(f) Sensitivity of cluster spacing for a Newtonian fluid without proppant in an elastic single-layer formation (Use cluster spacing as 40 ft, 75 ft and 150 ft)
(g) Sensitivity of horizontal stress contrast for a Newtonian fluid without proppant in an elastic single-layer formation (Use horizontal stress contrast of 100 psi, 300 psi and 1000 psi)
(h) Any of the scenarios from (b) to (g) but including proppant.

Mechanical Layer Properties:

	Layer Top	Layer Thickness	Min Horiz Stress	Max Horiz Stress	Vertical Stress	Young's Modulus	Poisson's Ratio	KIc
	ft	ft	psi	psi	psi	MMpsi		psi-in$^{0.5}$
Layer 1	7750	500	5000	5300	7000	4	0.3	1000

Porous Layer Properties:

	Layer Top	Layer Thickness	Permeability	Porosity	Pore Pressure
	ft	ft	mD		psi
Layer 1	7750	500	0.001	0.1	4000

Mechanical Layer Properties:

	Layer Top	Layer Thickness	Min Horiz Stress	Max Horiz Stress	Vertical Stress	Young's Modulus	Poisson's Ratio	KIc
	ft	ft	psi	psi	psi	MMpsi		psi-in$^{0.5}$
Layer 1	7700	200	5250	5550	7000	3.5	0.35	500
Layer 2	7900	200	5000	5300	7000	4	0.3	1000
Layer 3	8100	200	5250	5550	7000	4.5	0.25	1500

Porous Layer Properties:

	Layer Top	Layer Thickness	Permeability	Porosity	Pore Pressure
	ft	ft	mD		psi
Layer 1	7700	200	0.0005	0.05	3900
Layer 2	7900	200	0.001	0.1	4000
Layer 3	8100	200	0.002	0.15	4100

Fracturing Fluid Properties:

	Density	n	K
	lb/ft^3		cp
Fluid 1	62.4	1	1

Proppant Properties:

	Density	US Mesh Size
	lb/ft^3	
Proppant 1	165	40/70

Pumping Schedule:

	Injection Time	Slurry Rate	Proppant Loading	Injection Temp	Stage Separation Time
	min	bpm	ppa	degF	hour
Stage 1	10	60	0	60	
Stage 2	20	60	1	60	2
Stage 3	20	60	2	60	2
Stage 4	20	60	3	60	2
Stage 5	10	60	0	60	2

Completion / Perforation Data:

	Diameter	Perf Start MD	Perf End MD	Shots/ft
	in	ft	ft	
Perf Cluster 1	0.45	12076	12074	5
Perf Cluster 2	0.45	12001	11999	5
Perf Cluster 3	0.45	11926	11924	5

Results required to be presented in the format below:

1) Fracture trajectory as a function of time (2D or 3D)
2) Fracture half-length of all fractures as a function of time (X-Y plot)
3) Fracture width of all fractures as a function of time (X-Y plot)
4) Fracture height of all fractures (for multi-layer case) as a function of time (X-Y plot)
5) Net pressure (bottom hole pressure – minimum horizontal in-situ stress in the perforation layer) as a function of time
6) If available, proppant distributions in all fractures in terms of proppant mass per unit area at the end of injection
7) Contour plot of direction of maximum principal stress at the end of injection (and any other time that modeler wishes to show)
8) Contour plot of minimum principal stress (and pore pressure if available) at the end of injection (and any other time that modeler wishes to show)