PENNSTATE

MARCELLUS CENTER
for OUTREACH & RESEARCH (MCOR)

The distribution of natural fractures above a gas shale:

Questions about whether deep fracture fluid leaks into groundwater outside the realm of faulty borehole construction

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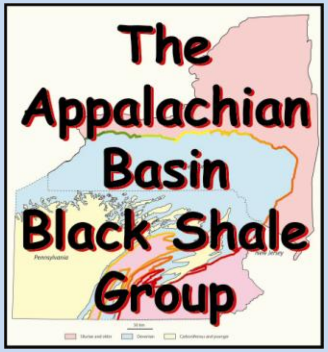
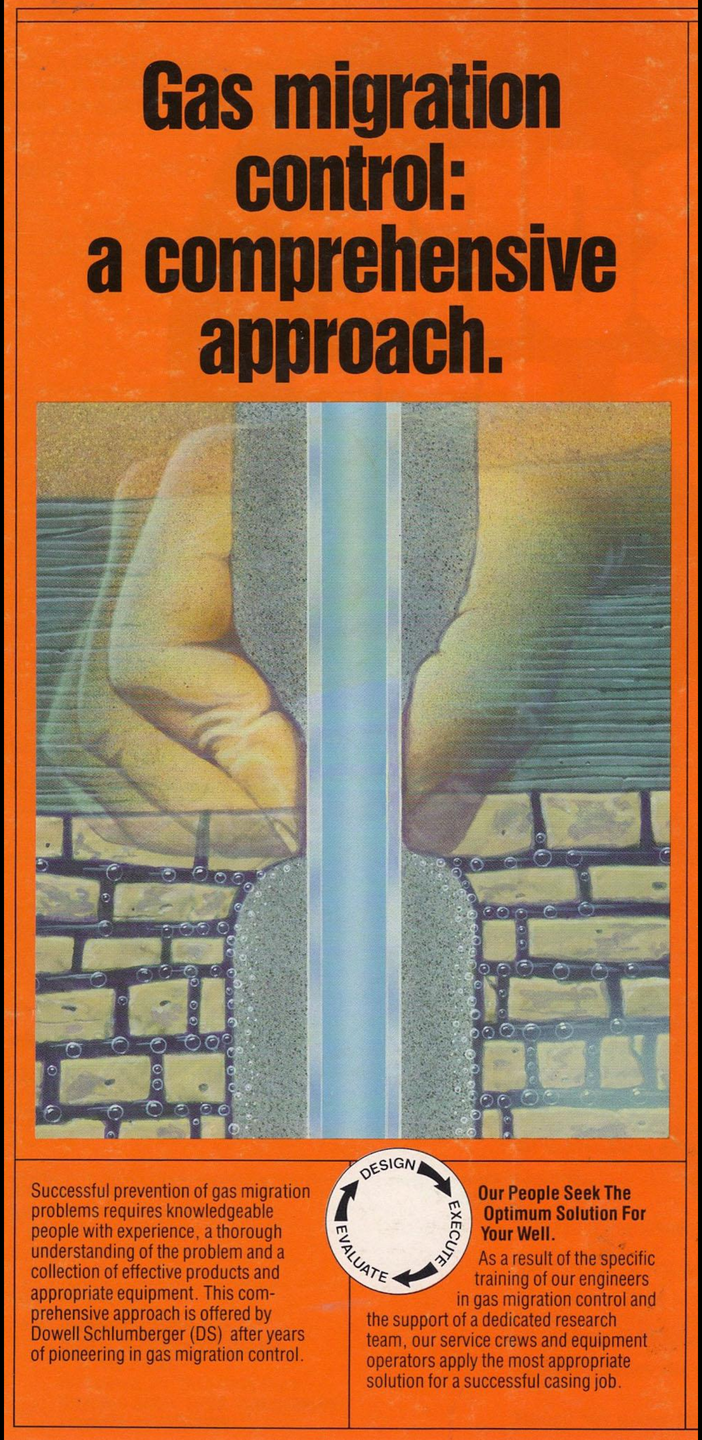




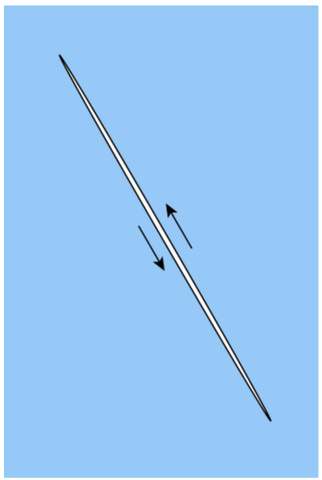
Faulty borehole construction

Successful prevention of gas migration problems requires knowledgeable people with experience, a thorough understanding of the problem and a collection of effective products and appropriate equipment. This comprehensive approach is offered by Dowell Schlumberger (DS) after years of pioneering in gas migration control.

Schlumberger Ad:
Journal of Petroleum Technology
(June 1989)

Natural pathways between Marcellus & groundwater

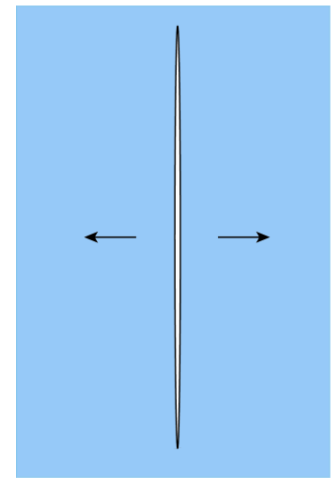
Geological Terminology



Fractures

Faults

Joints



By acting as natural pathways each might enhance bulk rock permeability!

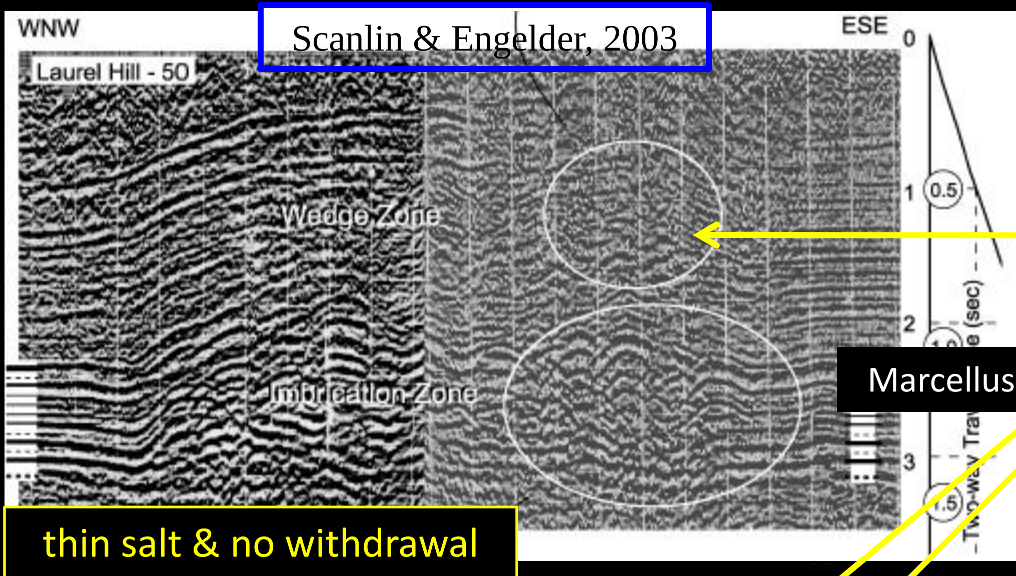
Natural pathways between Marcellus & groundwater

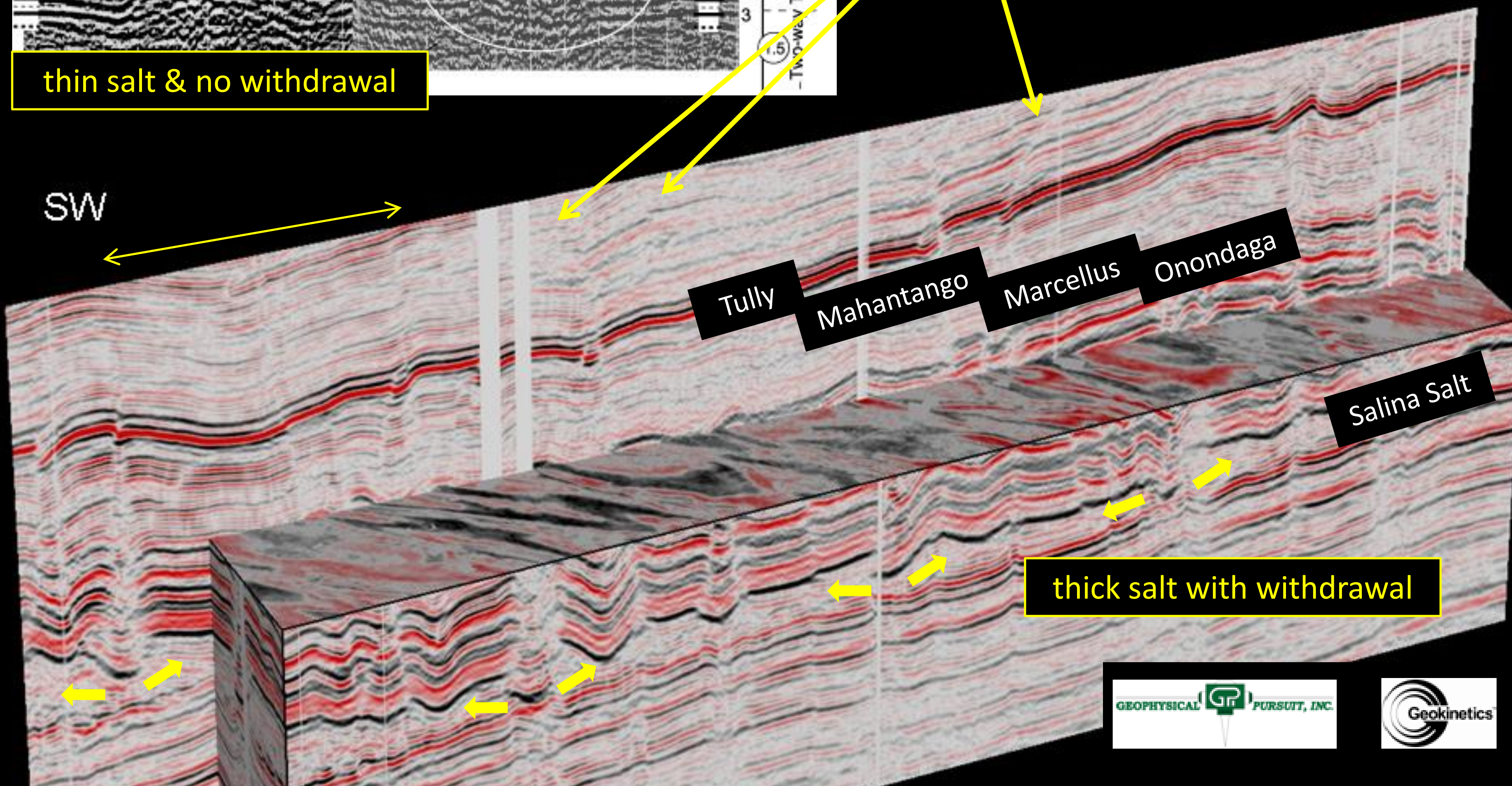
- Matrix
  - Black shale = 100 to 500 nanodarcys
- Bulk overburden
  - Fractures not interconnected = microdarcys
- Bulk overburden
  - Interconnected faults = microdarcys
    - gouge and fibers (wedge faults, flexural slip) = nanodarcys
  - Interconnected joints = millidarcys
    - open = millidarcys
    - Filled = nanodarcys

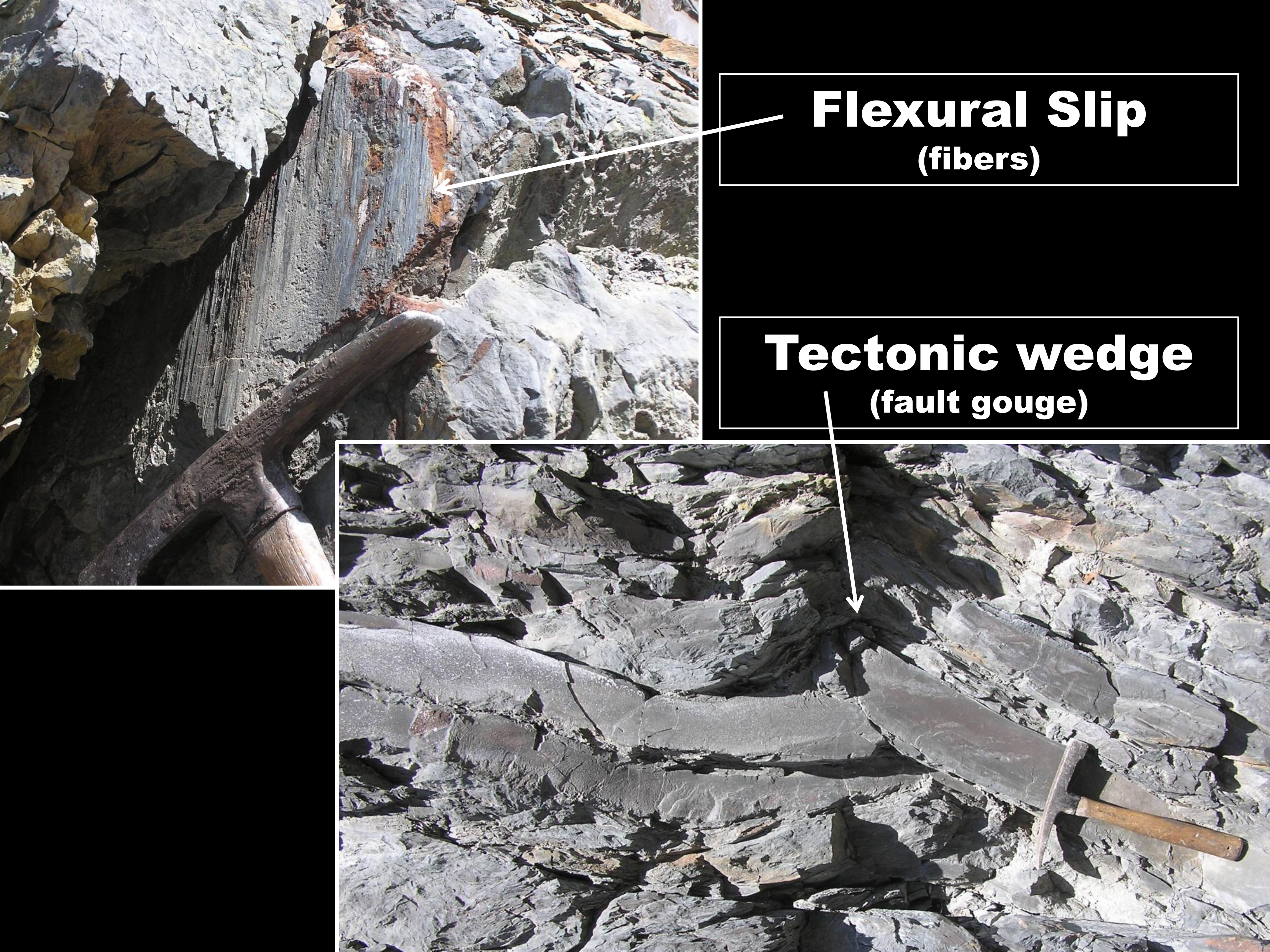
without a pressure drive (hydraulic head) there can be no leakage

Tectonic wedges:

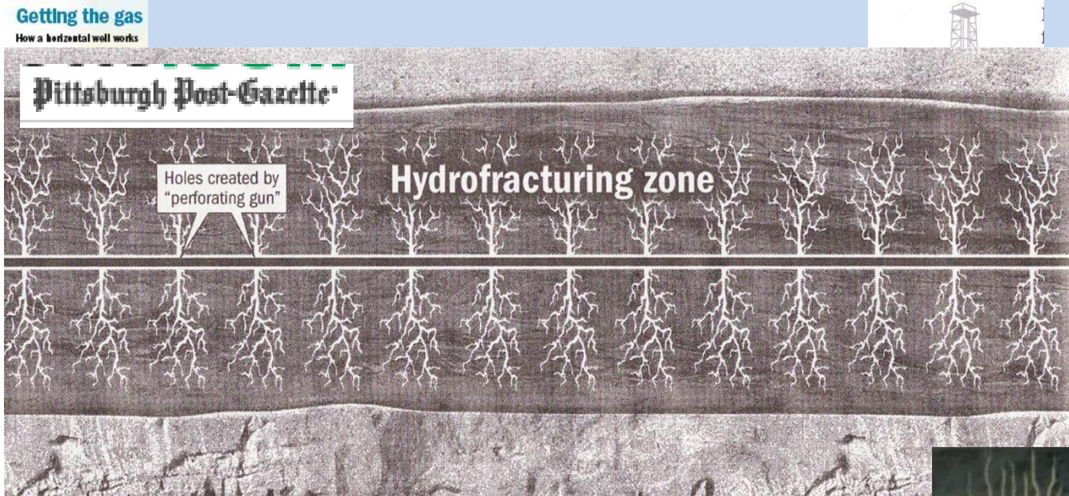
SW core: flatten on bedding
NE core: roll to horizontal

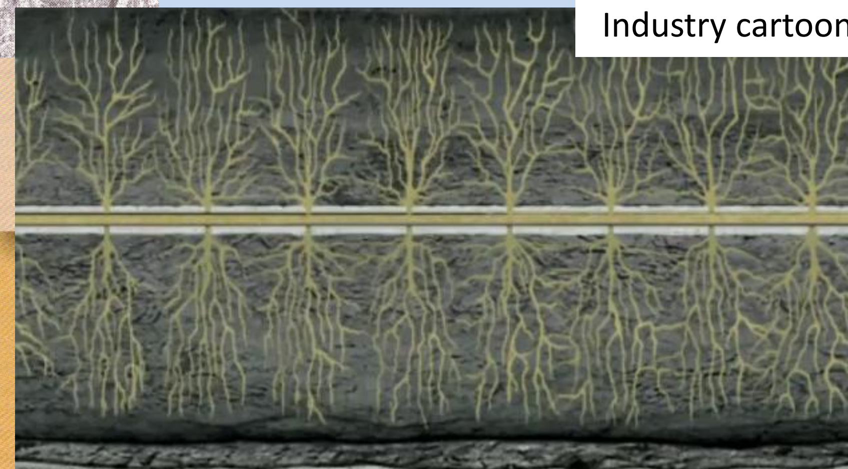


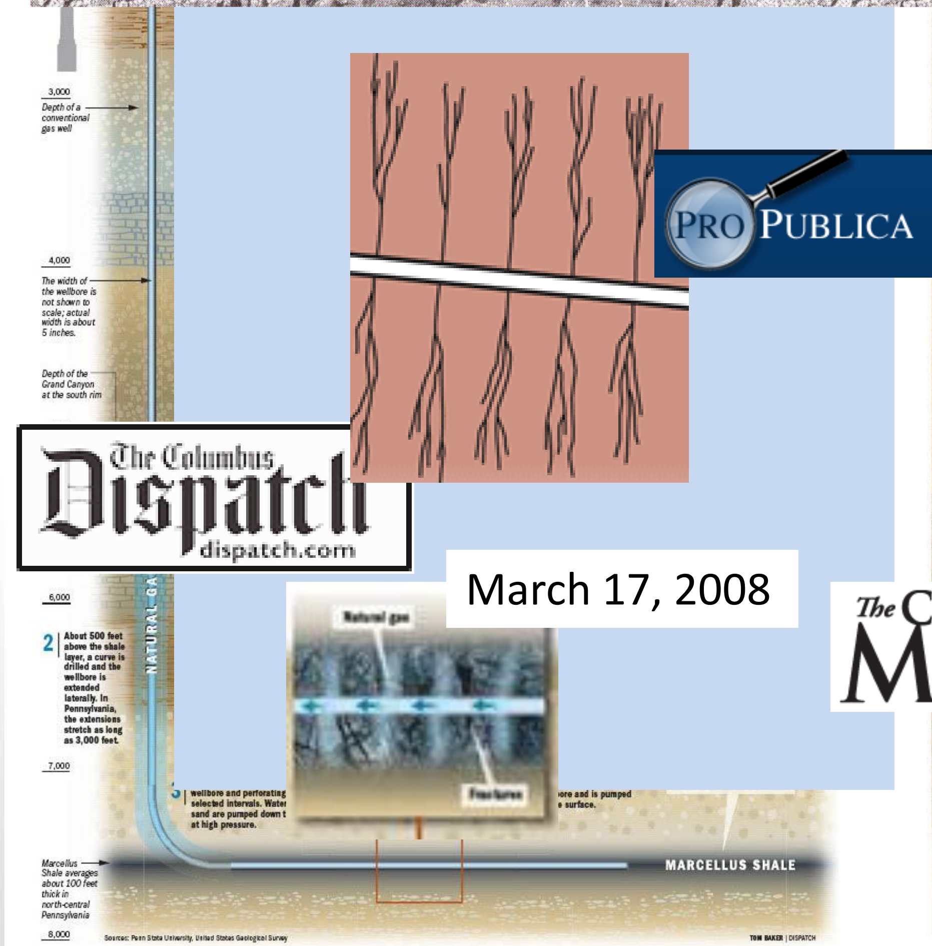



Flexural Slip
(fibers)
Tectonic wedge
(fault gouge)

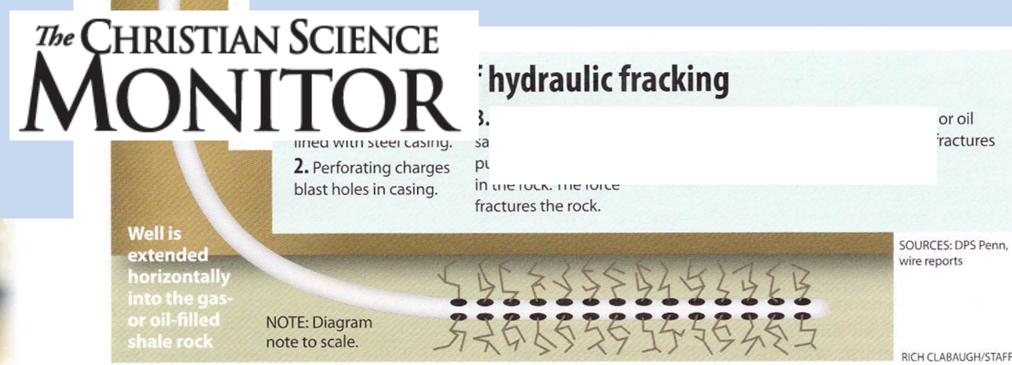
Myth: The industry cartoon! What do hydraulic fractures really look like?





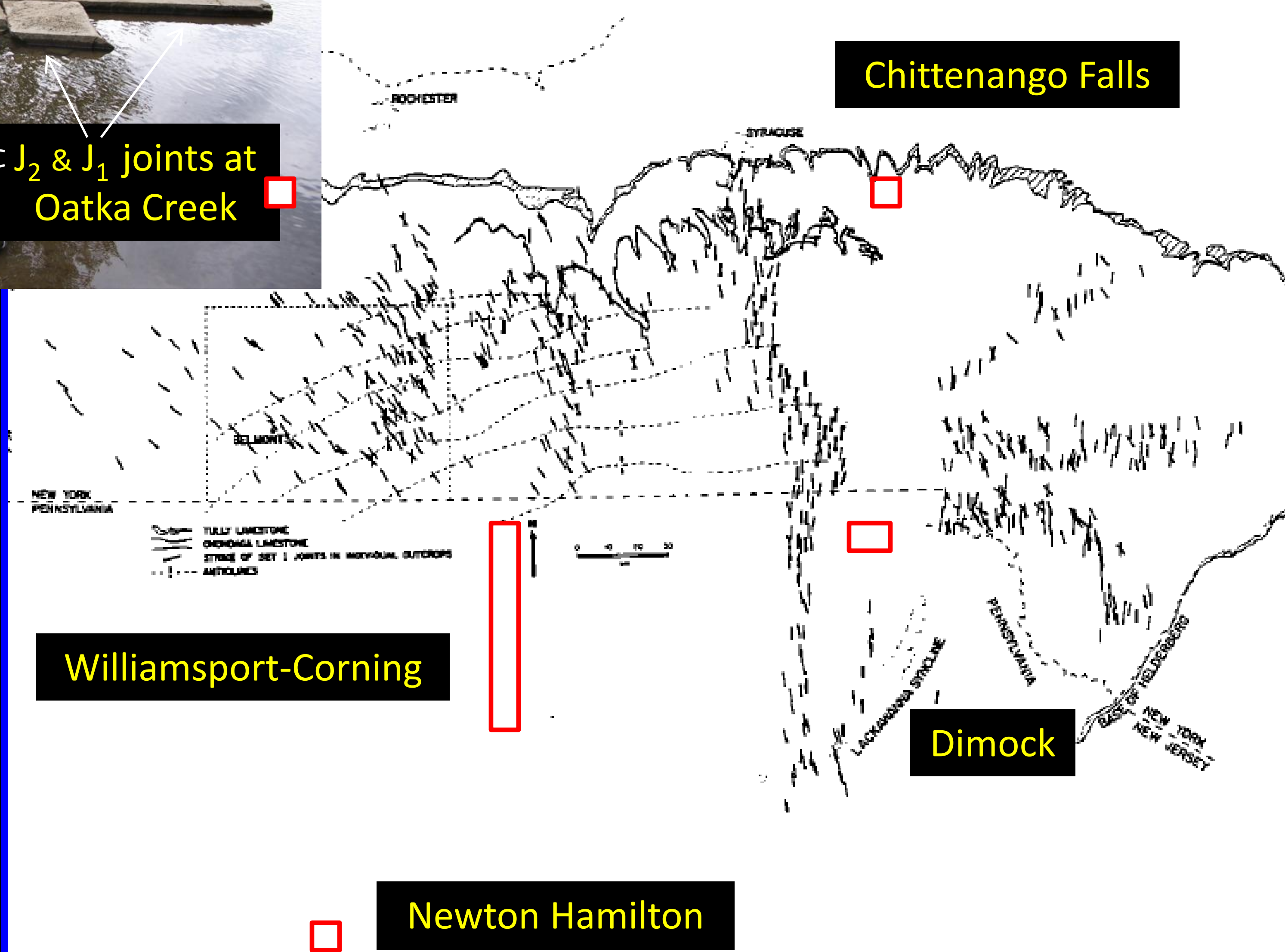


March 17, 2008



J_2 joints: Marcellus and overburden

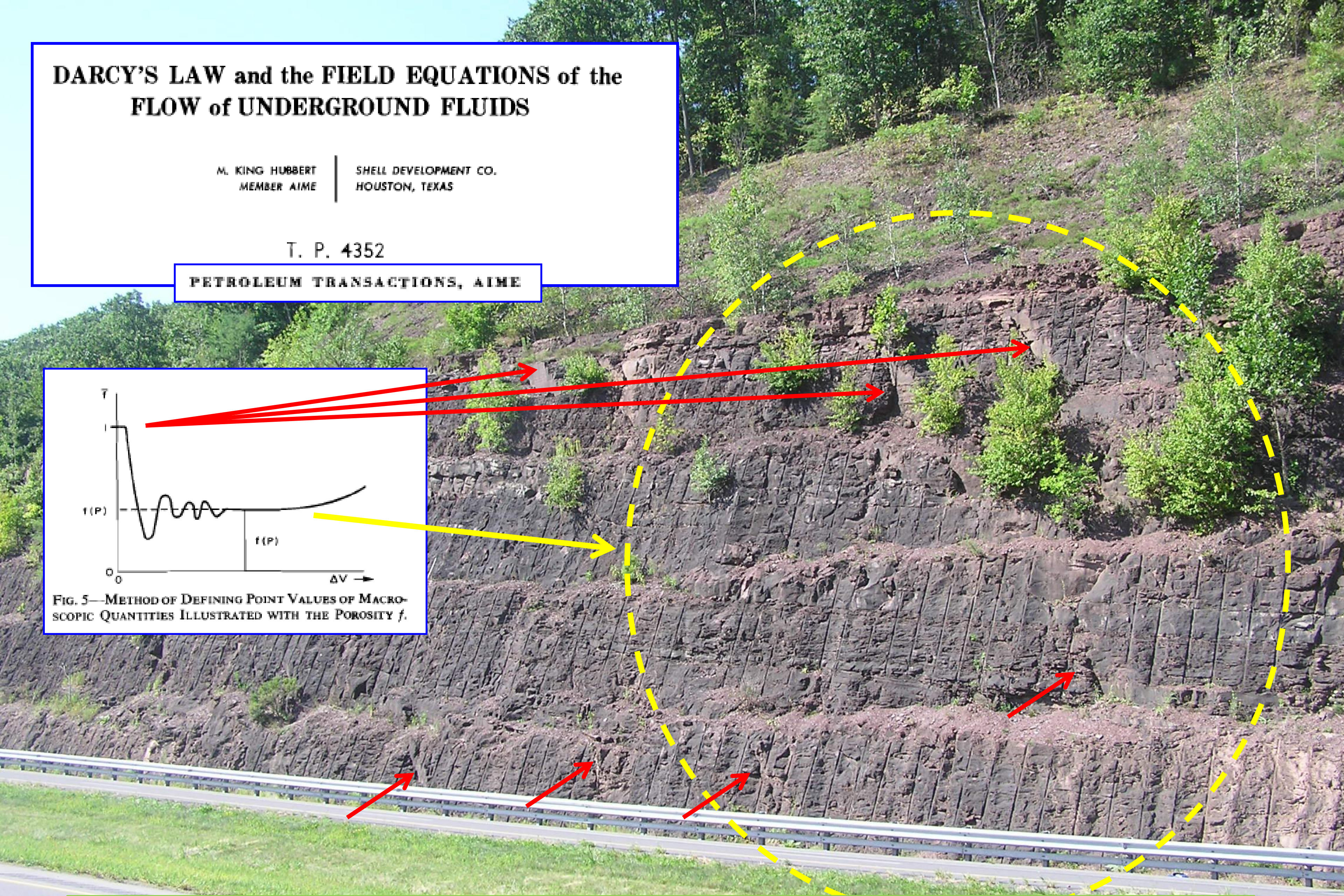
P. Geiser and T. Engelder



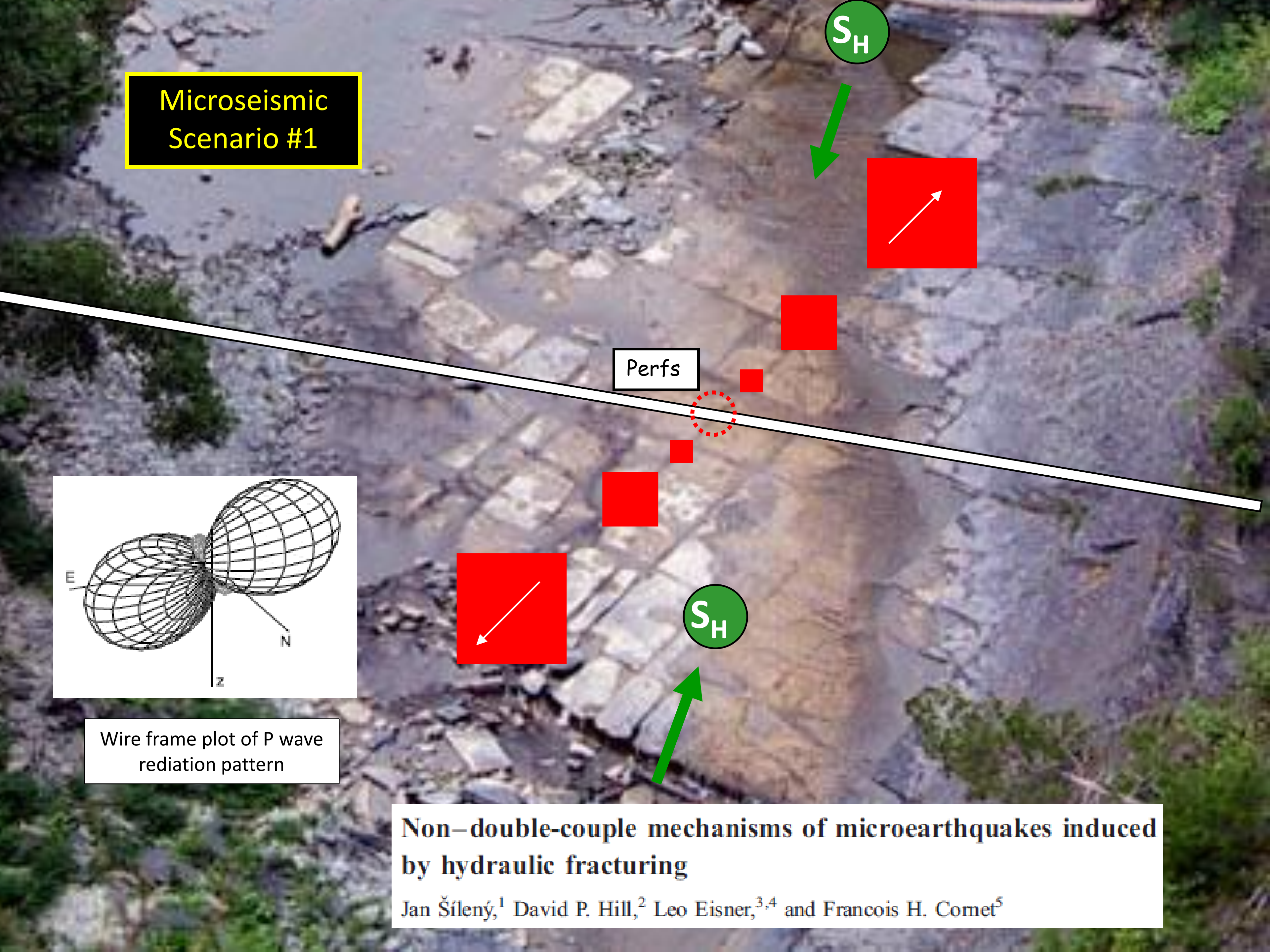
J_2 & J_1 joints: Oatka Creek equivalent at Chittenango Falls, NY

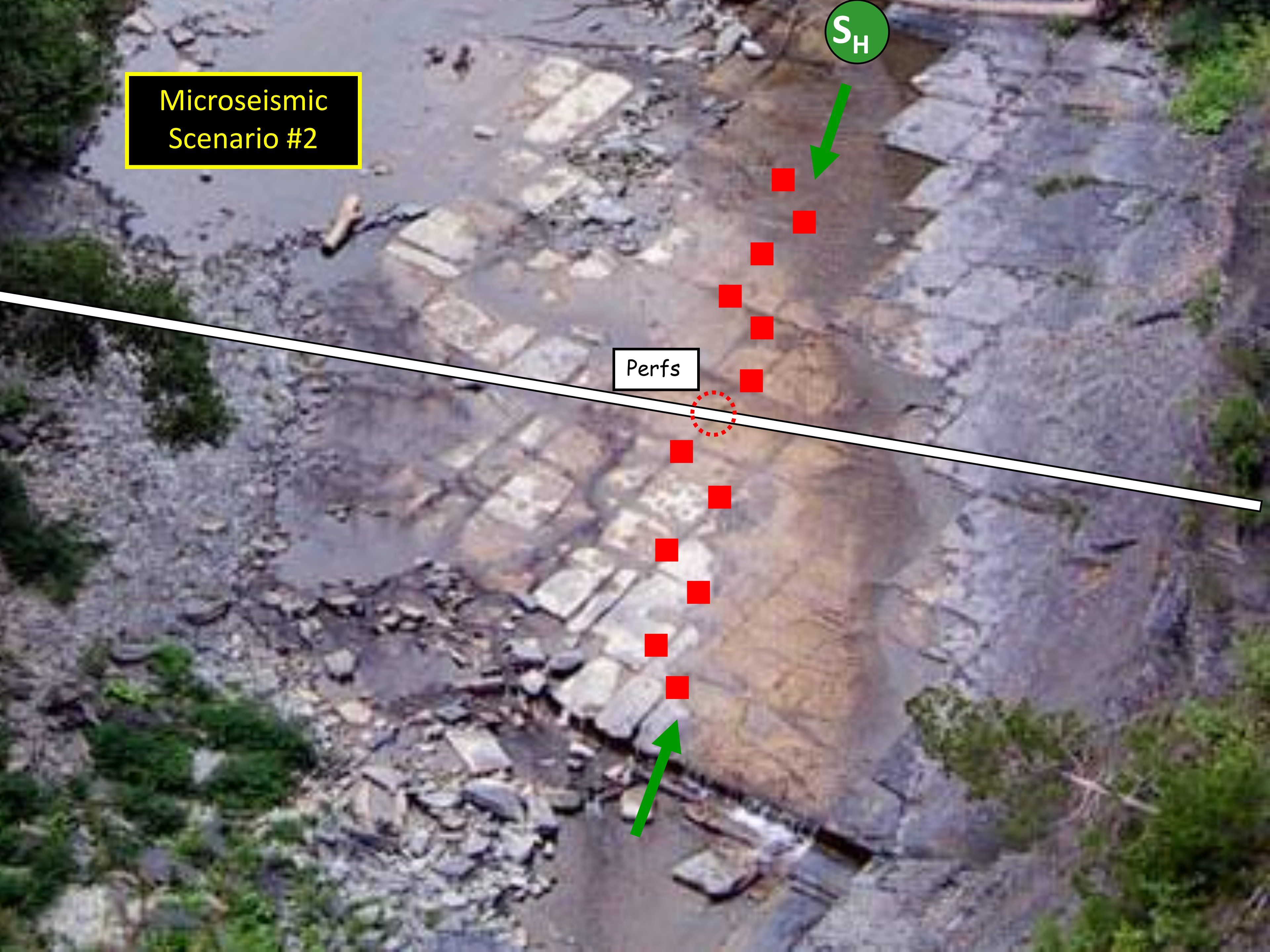
J_2 joints: Union Springs at the Newton Hamilton Railroad Cut

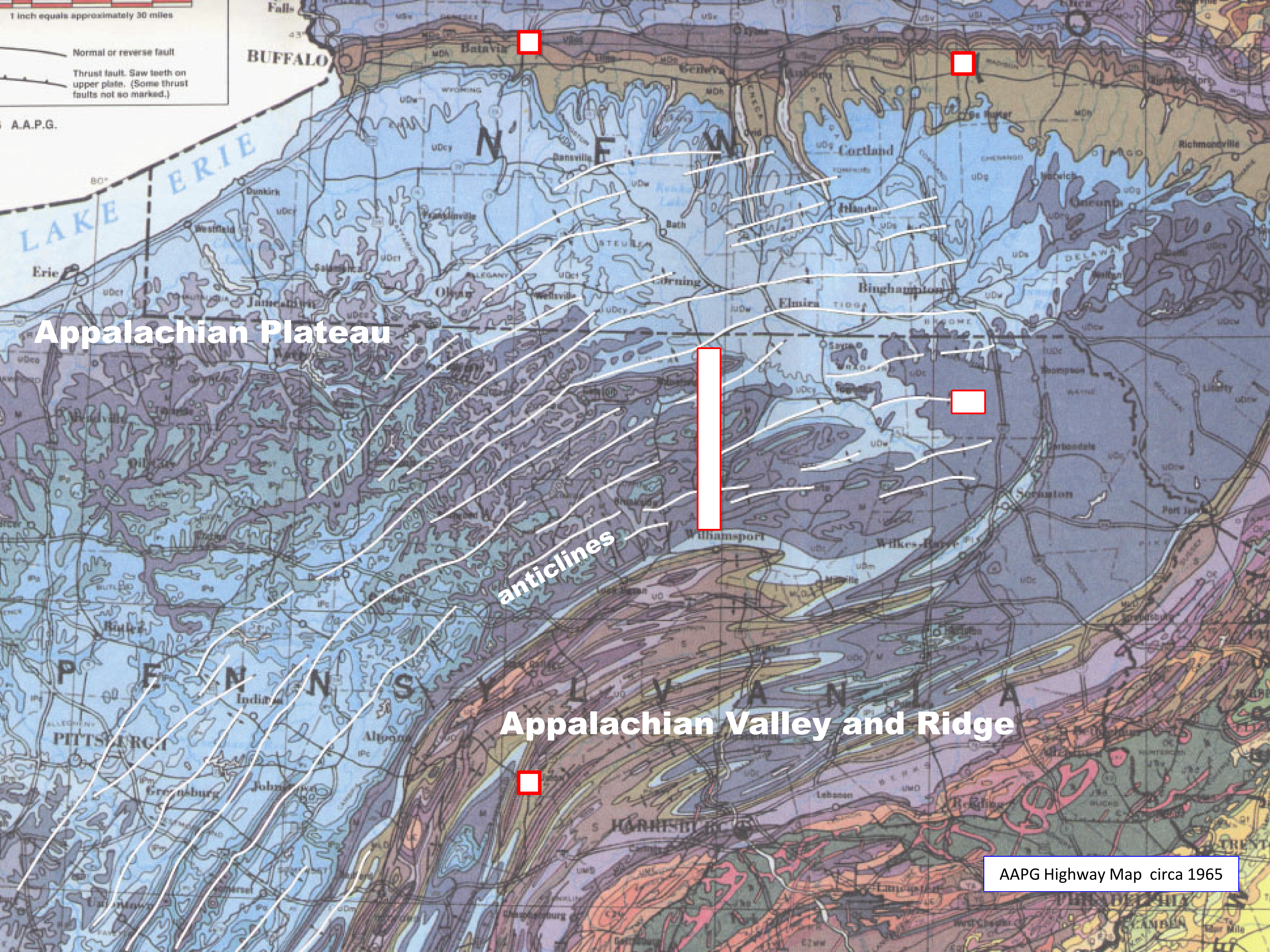
J_2 joints and exhumation-related joints: Catskill Group near Dimock, PA



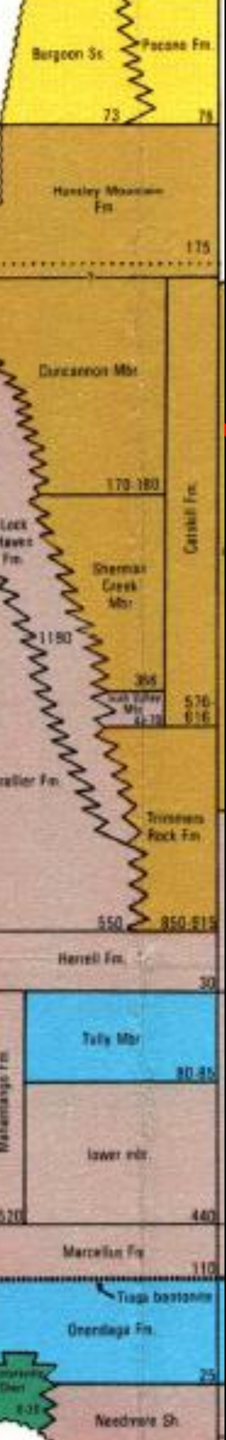
Hubbert said that small fractures & faults (red) leak a great deal but when imbedded in a larger rock, the low permeability in the larger rock controls the flow!


Microseismic Scenario #1
S_H
Perfs
E
N
z
Wire frame plot of P wave rediation pattern
S_H
Non–double-couple mechanisms of microearthquakes induced by hydraulic fracturing
Jan Šílený,[1] David P. Hill,[2] Leo Eisner,[3,4] and Francois H. Cornet[5]


Microseismic
Scenario #2
S_H
Perfs


1 inch equals approximately 30 miles
Normal or reverse fault
Thrust fault. Saw teeth on upper plate. (Some thrust faults not so marked.)
A.A.P.G.
LAKE ERIE
NEW
BUFFALO
Appalachian Plateau
anticlines
PENNSYLVANIA
Appalachian Valley and Ridge
AAPG Highway Map circa 1965

M Burgoon Fm
One joint
Burgoon Ss
Pocono Fm
73
75
Hunsley Mountain Fm
175
Duncannon Mbr
170-180
Catskill Fm
Lock Haven Fm
Sherman Creek Mbr
1190
Trimmers Rock Fm
550
850-915
Harrell Fm
30
Tully Mbr
80-85
lower mbr
Mahantango Fm
520
440
Marcellus Fm
110
Tioga bentonite
Onondaga Fm
25
Needmore Sh



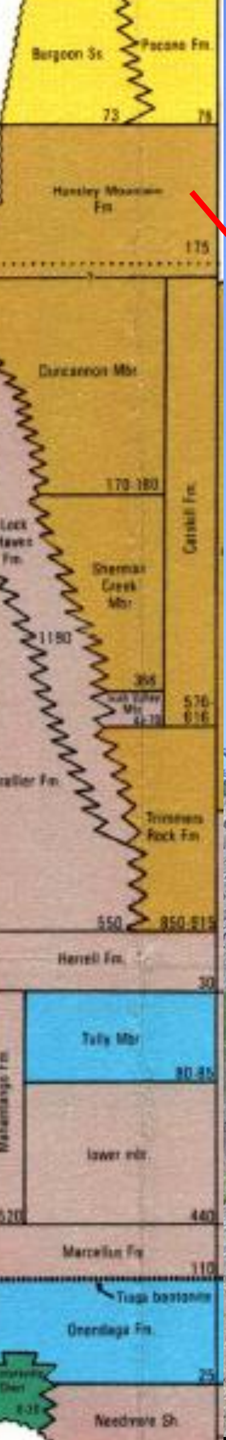
D Upper Catskill Fm

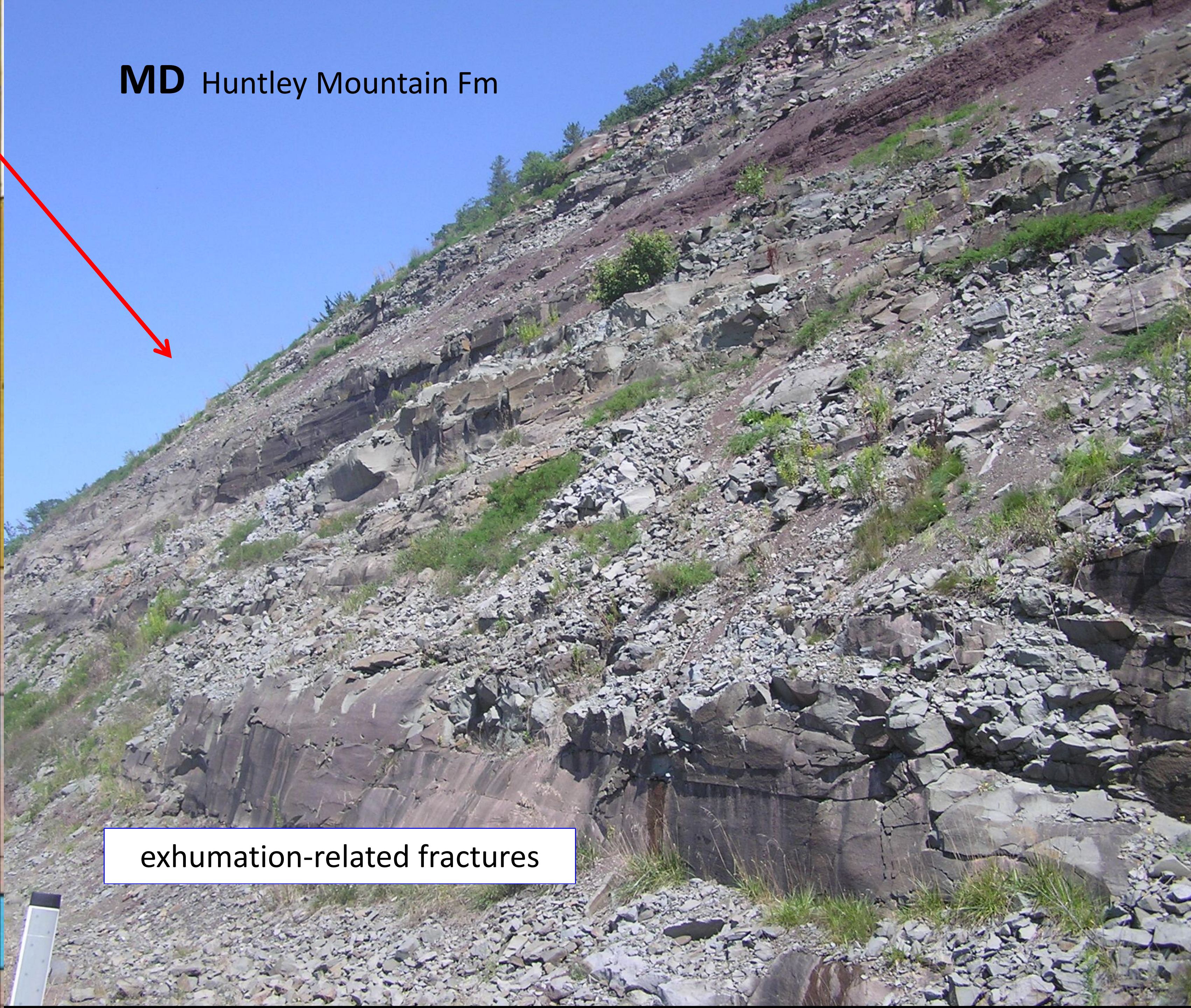
natural hydraulic fractures (joints)

v.

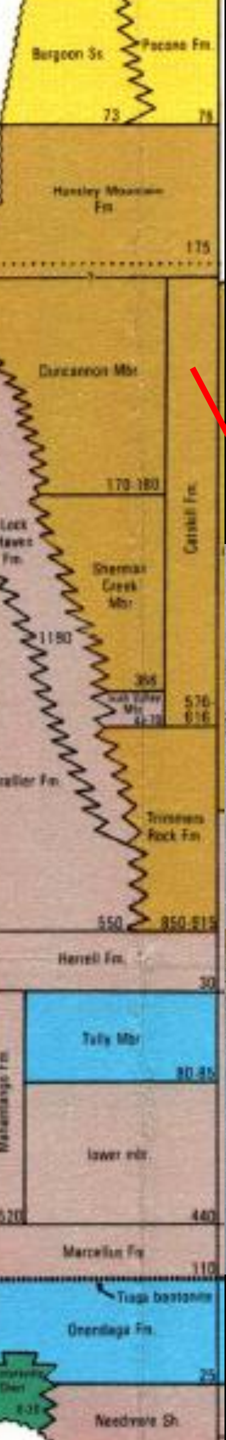
exhumation fractures

MD Huntley Mountain Fm





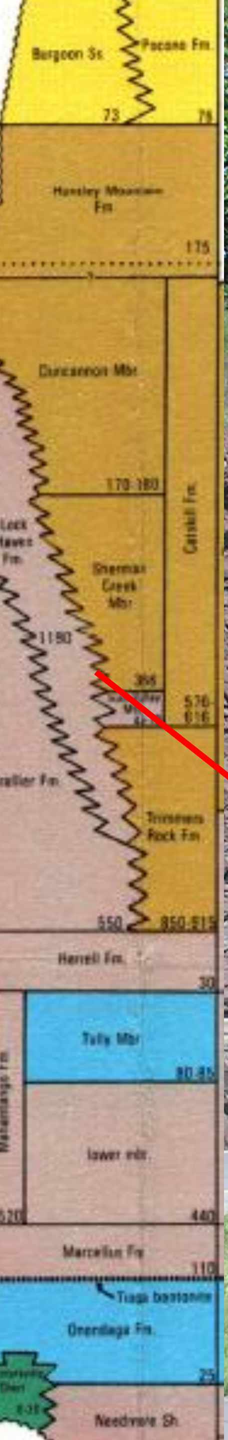
D Upper Catskill Fm



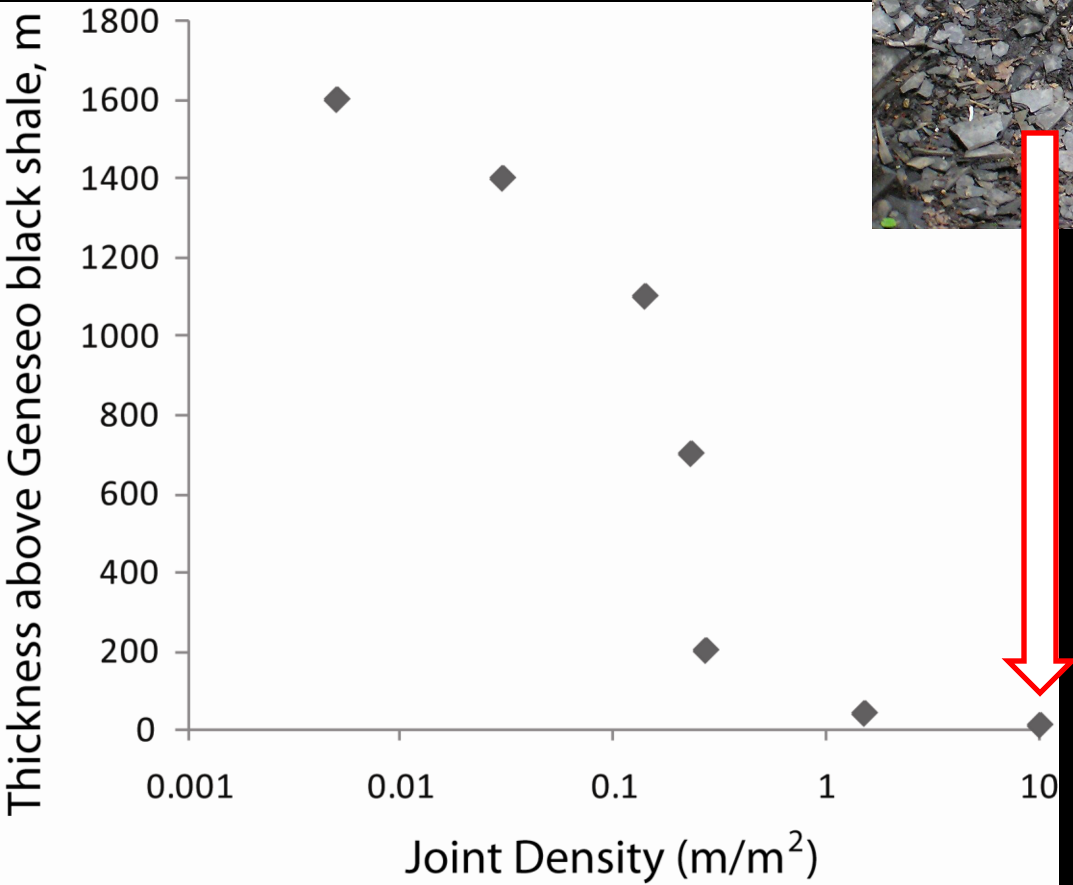
natural hydraulic fractures (joints) interconnected

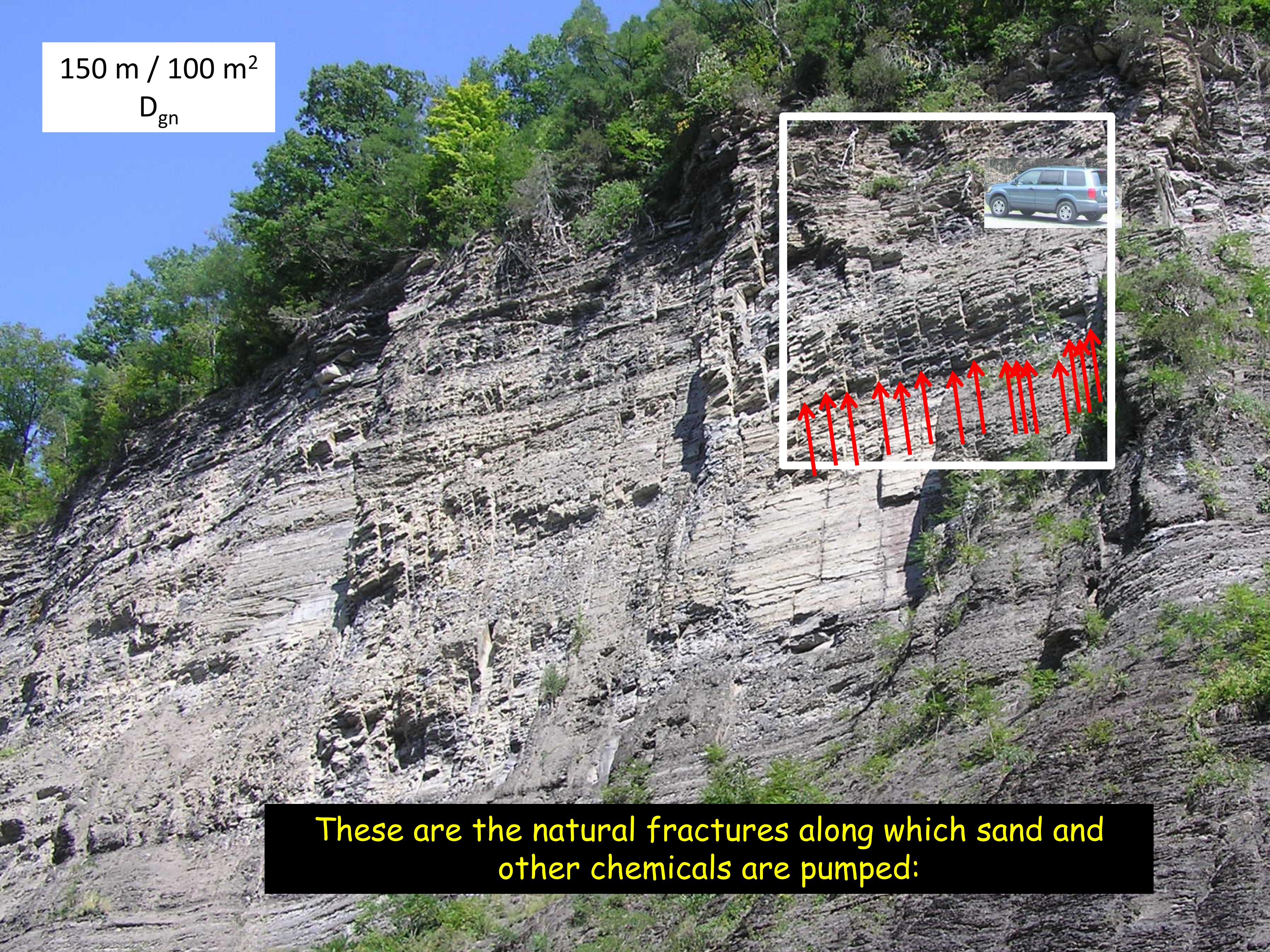
D Lower Catskill Fm
008°
Bergoon Ss.
Pocono Fm.
73
75
Hunsley Mountain Fm
175
Duncannon Mbr
170-180
Lock Haven Fm.
Sherman Creek Mbr
Catskill Fm.
1190
366
570-616
Trimmers Rock Fm
550
850-815
Harrell Fm.
30
Tully Mbr
lower mbr.
520
440
Marcellus Fm
110
Tioga bentonite
Onondaga Fm.
25
Needmore Sh.

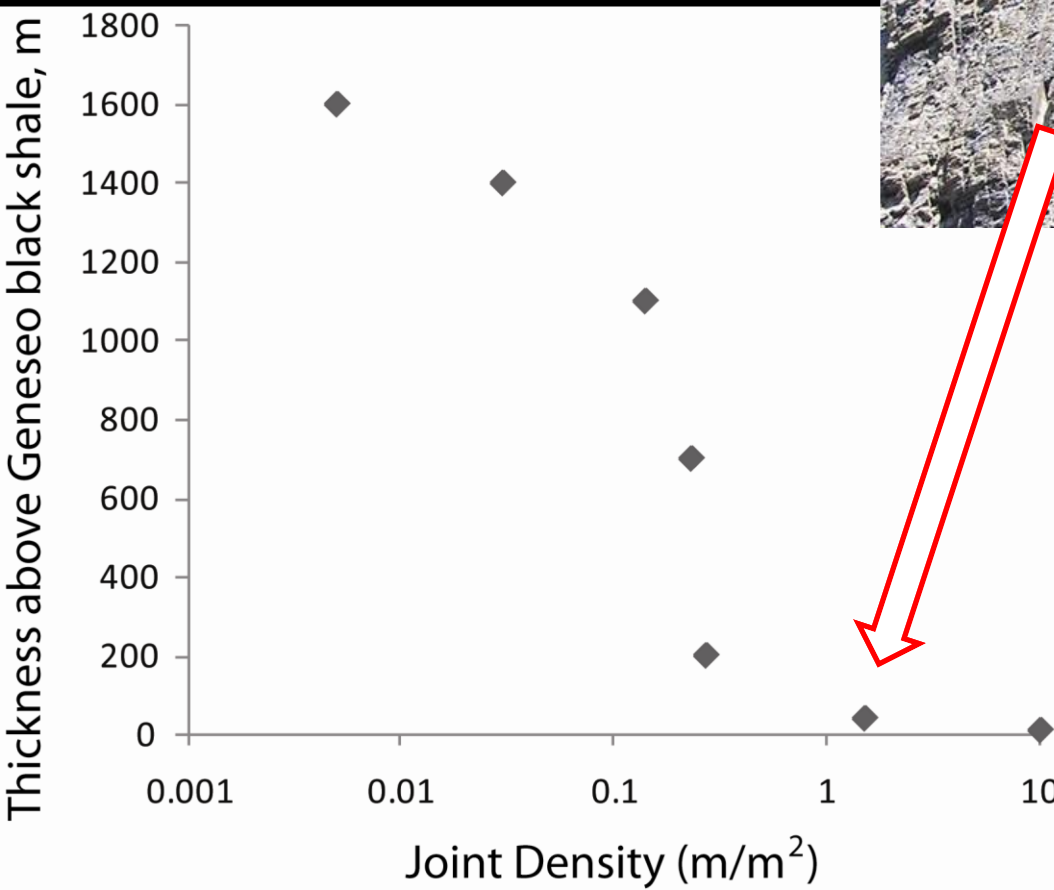
D Catskill -- Lock Haven Fms (boundary)



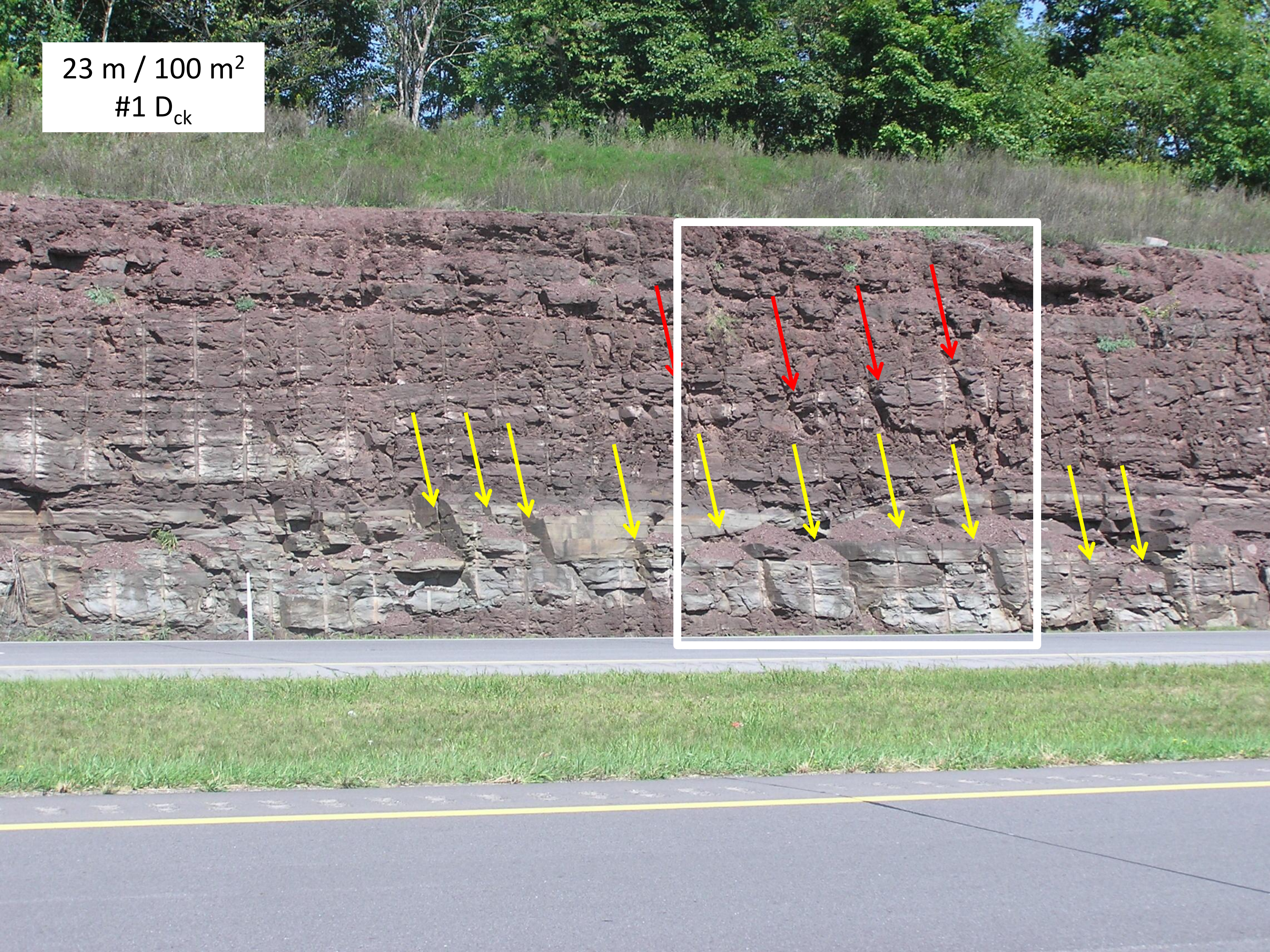

1000 m / 100 m^2
D_{gn}

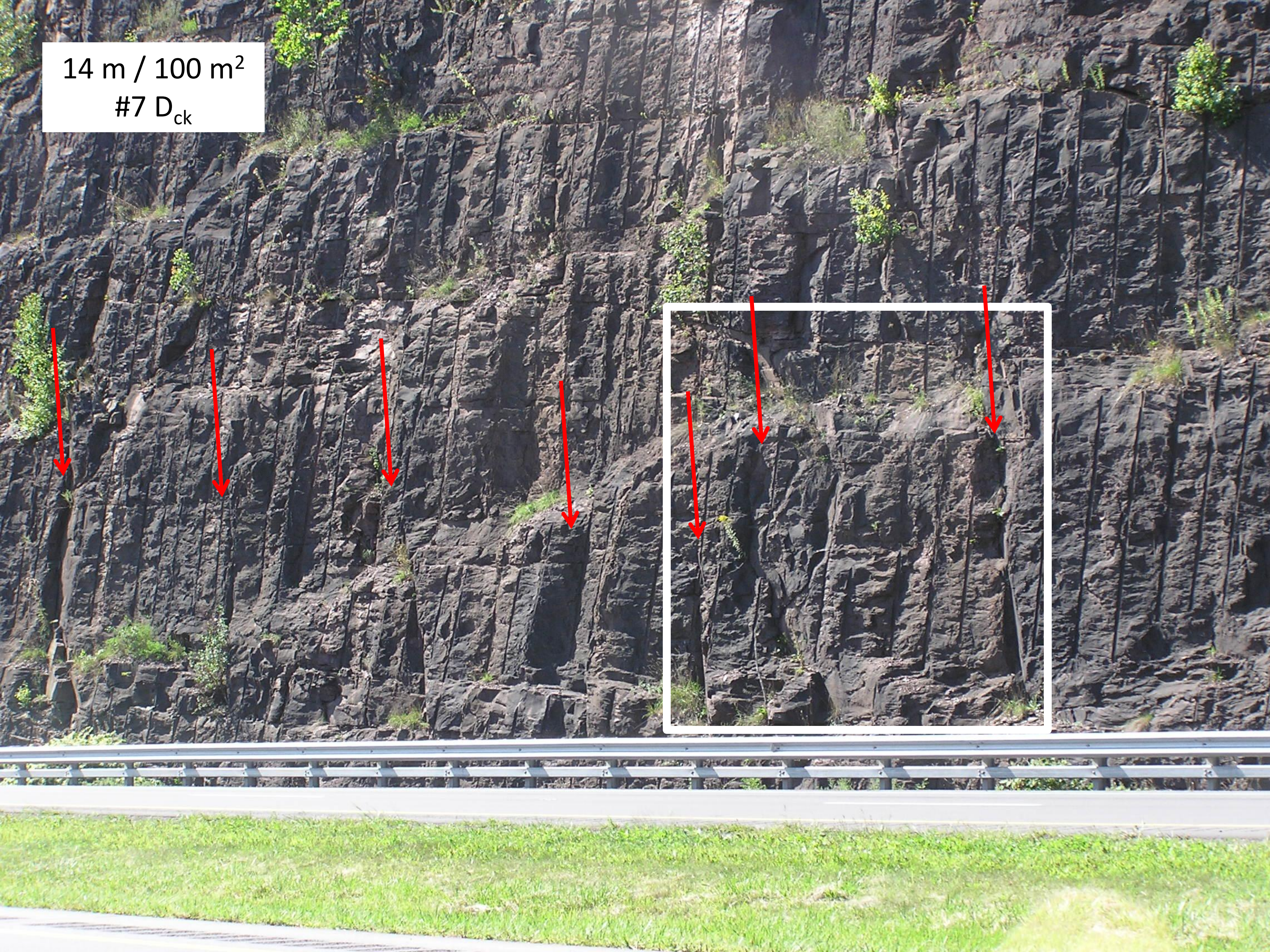

Thickness above Geneseo black shale, m
1800
1600
1400
1200
1000
800
600
400
200
0
0.001
0.01
0.1
1
10
Joint Density (m/m2)

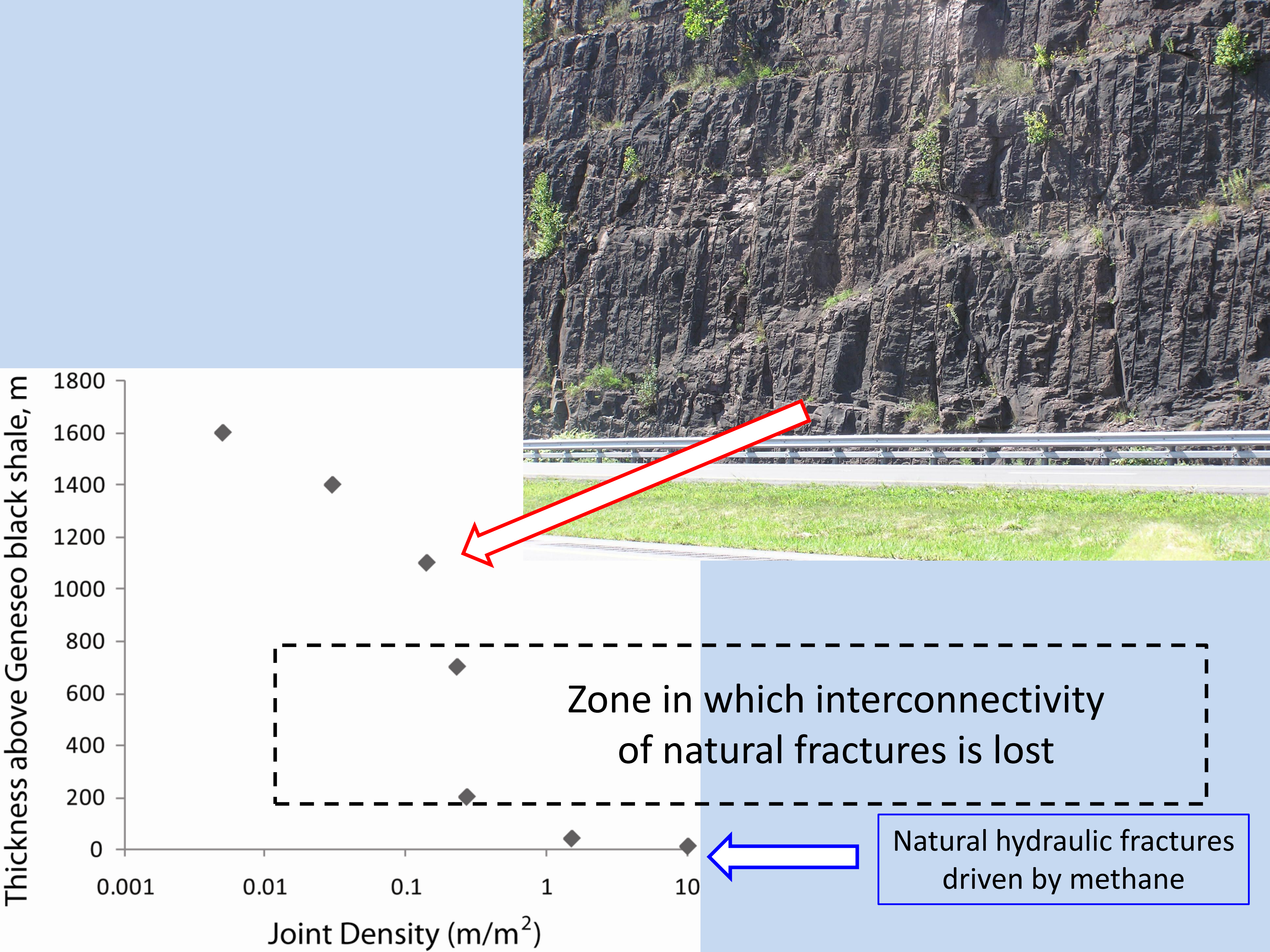

150 m / 100 m^2
D_{gn}
These are the natural fractures along which sand and other chemicals are pumped:


Thickness above Geneseo black shale, m
1800
1600
1400
1200
1000
800
600
400
200
0
0.001
0.01
0.1
1
10
Joint Density (m/m^2)

27 m / 100 m^2
#3 D_{lh}


23 m / 100 m^2
#1 D_{ck}


14 m / 100 m^2
#7 D_{ck}



Thickness above Geneseo black shale, m
1800
1600
1400
1200
1000
800
600
400
200
0
0.001
0.01
0.1
1
10
Joint Density (m/m2)
Zone in which interconnectivity
of natural fractures is lost
Natural hydraulic fractures
driven by methane

The Distribution of Natural Fractures above a Gas Shale: Questions about Whether Deep Fracture Fluid Leaks into Groundwater Outside the Realm of Faulty Borehole Construction

Terry Engelder
The Pennsylvania State University

Extended Abstract

One concern about production of shale gas is the possibility of hydraulic fracture fluid leaking upward along an interconnected network of fractures to contaminate groundwater. In the Appalachian Basin, isotopic studies of stray methane provide unambiguous evidence for leakage from gas storage fields through the Marcellus gas shale and into groundwater. The question is whether this is a case of faulty borehole construction where methane is leaking along poor cement jobs outside of casing or whether this is a case of methane traveling toward the water table along natural pathways, most likely consisting of unhealed faults or fractures. Elsewhere in the Marcellus gas fields, preliminary data isotopic studies by the Pennsylvania Department of Environmental Protection (PA DEP) indicate that thermogenic methane comes from Upper Devonian sands that are not immediately charged by gas from the Marcellus. While migration of natural gas is common, particularly at shallow depths, the migration of deep fracture fluid remains undetected in the Appalachian Basin. The question is whether the physics of fluid flow at depths of 6000' to 8000' permits leakage of fracture fluid between the Marcellus and groundwater with a probability that should concern the public. A back-of-the-envelope analysis suggests that the physics of the Earth reduces the probably of leakage to a level where the risk should be acceptable to a nation that consumes natural gas at the rate of nearly 25 trillion cubic feet (Tcf) per year.

If leakage occurs outside the realm of faulty borehole construction, unhealed fractures are the most likely pathway. The plausibility of rapid leakage along fractures depends on evidence for the pervasive development of interconnected fractures between gas shales (> 6,000 feet) and fresh groundwater (< 1,000 feet). Although continuous fracture imaging in the borehole might aid in sorting out whether fractures are interconnected from depth to the surface, borehole coverage may be insufficient for a conclusive answer. This leaves outcrop mapping as the other means of direct observation to resolve the extent of fracture interconnectivity.

For this discussion, natural fractures fall into either of two failure classes: shear failure leading to faults and tensile failure leading to macroscopic cracks called joints. Faults grow during direct shear failure under unusually high stress or grow as reactivated joints and bedding planes. Joints propagate within a spectrum failure conditions depending on their crack driving stress. If propagation takes place at depth under high fluid pressure working against crack normal

compressive stress, the joint is a natural hydraulic fracture. If propagation takes place in the near surface under relaxation stresses accompanying exhumation, the joint is an exhumation-related fracture. Natural hydraulic fractures and exhumation-related fractures are end members of a spectrum that may include fold-related jointing where both pore pressure and bed-parallel stretching lead to an effective stress state favoring propagation.

Outcrop observation is only effective to the extent that the operator has a strategy for distinguishing between deep-formed fractures and exhumation-related surface fractures. The most common fractures in a gas shale are the natural hydraulic fractures which occur in a plume emanating from the gas shale but rapidly dissipating above gas shale. Exhumation-related fractures have a much different morphology and are easily distinguished from NHF. A plume-like distribution of joints above gas shales of the Appalachian Basin is consistent with fluid-drive propagation mechanism where high pressure fluid bubbles from gas shales as a consequence of thermal maturation but rapidly looses pressure as it migrates up section. The implication is that fractures driven by fluid pressure are not uniformly distributed up to the surface but rather are concentrated near the top of gas shale.

Distribution of Natural Fractures

It is commonly assumed that if a rock contains fractures (i.e., faults, fluid-driven joints, and exhumation-related joints), they are a natural pathway for contamination of ground water. Outcrops are often densely populated with fractures and it is assumed that rocks in the subsurface look the same way throughout the 6000’ to 8000’ of overburden above a gas shale such as the Marcellus. In fact, many joints in outcrop are exhumation-related fractures that propagate in the near surface and are not found at significant depths, (> 100s of feet). Outcrops over the Marcellus of the Appalachian Plateau portion of the Appalachian Basin consist of clastic and carbonate rocks varying in age from Devonian to Permian. Faults are exceedingly rare on scales greater than the size of tectonic wedges, particularly above the Frasnian section. Tectonic wedges are most common in large-channel sandstones where bedding slip can occur on crossbeds. Fluid-driven joints are most common in gas shales but in sections overlying these gas shales, they lack the requisite interconnectivity to be effective conduits even in the presence of a pressure drive. Without an interconnected pathway of joints, the physical principle governing the rate of leakage between the Marcellus and groundwater is the equation for fluid flow in porous media, Darcy’s Law.

Darcy’s Law

The rate of fracture fluid leaking into ground water by flow through the overburden between the Marcellus and near surface rocks is understood using Darcy’s Law. Although flow along natural pathways including joints and faults may be more appropriately represented by parallel plate flow, lack of interconnectivity of these joints and faults means that Darcy’s Law is the better model for flow in the bulk rock. Fluid flow ($\boldsymbol{Q}$) in a porous media can occur only if a pressure drop ($\boldsymbol{P_a - P_b}$) (i.e., a differential hydraulic head) develops between two points with the entrance point (i.e., fracture fluid in the Marcellus) being at a higher hydraulic head than the exit point (i.e., fresh groundwater). The rate of fluid flow is governed by the magnitude of the pressure drop. The relationship between rate of flow and pressure drop is expressed in an equation with four variables including the viscosity of the fluid (***μ***), the permeability of the rock (***k***), the length of the flow path (***L***), and the cross section of the flow (***A***). Of course, the rate of flow approaches zero if the permeability, cross section, and pressure drive become very small or viscosity and flow path length become very large.

$$Q = \frac{-kA}{\mu L}\left(P_a - P_b\right)$$

Path Length (L)

The least ambiguous variable in Darcy's Law is the length of the flow path. All else being equal, the rate of leakage of fracture fluid from deep (6000' to 8000') gas shales of the Appalachian Basin is as much as four to five times less than leakage of fracture fluid from conventional gas reservoirs stimulated at a depth of 1500', for example, in the Pavilion gas field of Wyoming.

Pressure Drive (P_a – P_b)

Leakage of fracture fluid will take place only if pressure drive is present and sustained for a period long enough to drive fluid from the Marcellus to groundwater. There are three major sources for a pressure drive: pressure during wellbore stimulation, a topographic pressure drive, and maturation-related abnormal pressure. A pressure drive is the most critical part of Darcy's Law in terms of risk to groundwater.

Maturation-Related Pressure Drive (P_a – P_b)

While it might be argued that overpressure gas also creates a pressure drive from the Marcellus to groundwater, this pressure drive was incapable of draining the Marcellus gas shale over periods of as much as 260 million years ago (Ma). If fracture fluid is injected into the gas and maintained at gas pressure, the gas and water would separate with the gas making its way to the top of the pressurized column. Theoretically the top of the pressurized gas-water could drive its way to groundwater. Long before the column with gas on top got to groundwater, the column would have broken into a hydrostatically pressurized regime. Such break through would immediately relax the pressure drive and flow would stop long before fracture fluid was driven upward to place groundwater at risk. The probability of a sustained maturation-related pressure drive causing groundwater contamination is very, very low.

Regional Flow (L) and Hydrodynamic Pressure Drive (P_a – P_b)

One natural pressure drive arises from topographically-driven hydrodynamic flow. Hydrodynamic flow is driven by the pressure drop between groundwater under topographic highs and ground water under topographic lows. The depth of penetration for hydrodynamic flow is largely governed the geometry of the most permeable units but an important secondary governor is the lateral distance between source (topographic high) and sink (topographic low) and the vertical distance of flow as governed by topography. The largest volume of underground flow is short circuited by local topography where depth of penetration is less than the topography. Some groundwater is driven deeper in the section and flows further out into the basin from topographic highs. In this latter case, the volume of flow is less and the time of flow between source and sink is commensurately longer. In the Appalachian Basin, penetration to the Marcellus at 7000’ is nearly an order of magnitude greater than the local topography. Modeling suggests that penetration to 7000’ from a 300’ topography drive has a time constant of 100,000 years or longer. This means that the probability of regional flow leading to a leakage up and into groundwater is remote on time scales that really matter to the EPA debate about hydraulic fracturing. Because there is no indication from the Appalachian Basin that such long wave-length flow paths upset the density stratification of the basin, the probability of a topographic drive causing leakage between Marcellus and groundwater is again very, very low.

Density Stratification Reduces Effectiveness of Natural Pressure Drives (P_a – P_b)

Within the Appalachian Basin, groundwater is stratified by density. Freshwater is found from the top of the water table to depths of as much as 1000 feet. Below the freshwater layer, groundwater becomes progressively more saline with waters in the vicinity of the Marcellus approaching oil field brines. This high salinity may have developed by very long term (1-10 million years) groundwater circulation down section to the Silurian Salina Formation which is salt rich. In a one-dimensional flow model density stratification is stable without the possibility of a pressure drive to upset this stability. Flow between fracture fluid in the Marcellus and fresh groundwater would upset this density stratification. In the hundreds of thousands of water wells drilled in the state of Pennsylvania there is no evidence of fresh water wells gradually becoming saline, the only sign that a pressure drive associated with 50 years of hydraulic fracturing in PA has upset the regional density stratification. Density stratification indicates that rate of regional flow carrying fracture fluid to groundwater is very, very low.

Pressure Drive Reduction Upon Flowback (P_a – P_b)

Flowback immediately following well stimulation relieves any pressure drive that was momentarily developed between fracture fluid that is injected into the deep Marcellus and the layer of fresh groundwater at depths of less than 1000 feet. Without a pressure drive there can be no direct leakage between fracture fluid in the Marcellus and groundwater several thousand feet above. Any man-made pressure drive during hydraulic fracture stimulation is not held in place long enough to put groundwater at risk.

Distribution of Stimulated Fractures (k)

Recent studies indicate that stimulation may extend laterally as much as 2000 feet from the borehole (Mayerhofer – Pinnacle) and as much as 1000 feet above the borehole (Fisher - Pinnacle). In the Marcellus this leaves as much as 6000 feet between unstimulated rock and groundwater. This thickness of rock would be exceedingly difficult for fracture fluid to penetrate without large and sustained pressure drive which, of course, is lost with the onset of flowback after maximum of 1000 feet of penetration.

The Inward Pressure Drive by Gas Depletion (Pa – Pb)

Once gas production starts, reservoir pressure drops. If a pressure drive develops subsequent to the initiation of production, the pressure drive will cause flow from the rock formation and into the Marcellus reservoir. For fracture fluid at the extremes of stimulated fractures, flow is back along the fractures and into the production tubing.

Thermal Maturation (k)

The Marcellus reached maximum thermal maturation about the Middle Permian (260 Ma). At that time, generation was sufficiently rapid to cause the development of overpressure (> 0.7 psi/ft) and in some cases the high pressures drove natural hydraulic fractures. Exhumation and thermal cooling commenced with the onset of rifting in the Triassic (perhaps 220 Ma). Despite exhumation, much of the northern Appalachian Basin still holds overpressured gas. Even with a network of natural fractures, the Marcellus has not leaked a sufficient quantity of gas to reach a hydrostatic pressure. In fact, joints in shale are so planar that, when pressed together under confining stress, these joints fail to provide a sufficiently larger permeability over the matrix permeability to permit economic gas production without propping using sand of 100 mesh or less. Apparently, gas pressures in natural hydraulic fractures don’t prop these joints sufficiently to enhance bulk permeability despite the presence of overpressures.

Permeability of Black Shale (k)

Black shales including the Marcellus are seal-quality rocks with a permeability of 100 to 500 nanodarcies. A porous sandstone can have a permeability of a darcy (9.8×10^{-13} m^2). Because permeability is found in the numerator of Darcy’s law, lower permeabilities lead to reduced flow rates which means that shale matrix will not serve as a path for leakage of fracture fluid.

Permeability of Joints (k)

Laboratory experiments show that joints unfilled by any mineralization are permeable relative to rock matrix. However, in order to affect the bulk permeability of the rock, these open joints have to interconnect. Otherwise, the bulk permeability of the rock is close to the matrix permeability. In the Appalachian Basin interconnected joints are common in gas shales like the Marcellus. The population of interconnected joints trails off with distance above gas shale and groundwater. While the presence of joints allow the possibility of fracture fluid leakage as long as the joints are propped open, lack of connectivity reduces the bulk permeability of the overburden to that of the intact rock.

Permeability of Faults (k)

In oil basins, faults are some of the most effective seal rocks, much less permeable than matrix sandstone. This is particularly true for faults that cut shales where the clay smear mechanism may render a fault gouge that is less permeable than the progenitor shale. Faults leak after earthquake-related slip but in an area that is not prone to earthquakes as is the case for the Appalachian Basin, faults are rarely open conduits. Flexural slip folding causes bedding slip surfaces that are coated with fibers known as slickelites which have virtually no permeability.

Viscosity of Fluid within the Black Shale (μ)

Black shales including the Marcellus are very impermeable rocks relative to many other lithologies. Commonly, the permeability is on the order of 100 to 500 nanodarcies. This means that a low viscosity fluid such as natural gas is held in place for considerable lengths of time. Because viscosity is found in the denominator of Darcy's law, increasing the viscosity of actively moving fluid would reduce the flow rate. Injection of a high viscosity hydraulic fracture water with additives just makes a good seal all that more effective. A rock that has not leaked natural gas in geological time is unlikely to leak a more viscous fracture fluid on an anthropomorphic time scale.

Capillary Forces (k)

Capillary forces are inversely proportional to the size of pore throats in a water-wet shale. To the extent that fracture fluid converts gas shale to a water-wet rock, capillary forces may become important in reducing leakage from gas shale.

Unknown Effects

In a fully developed section, enough water is injected to cause a regional extension of 1% in the direction of the maximum horizontal stress at the depth of the Marcellus. A strain discontinuity will develop at the top of the layer of injection. The effect of this strain discontinuity of regional permeability patterns is unknown but a strain discontinuity seems unlikely to affect the nature of the section over the stimulated zone.

Conclusion

I have identified at least 16 parameters that govern potential leakage of fracture fluid between the Marcellus and groundwater. Most parameters favor the protection of groundwater. In assessing risk to each parameter, the overall risk is the product of each multiplied serially. The sixteen parameters together make a powerful case that leakage of fracture fluid from the deep Marcellus to the water table is remote. This conclusion is consistent with the 2009 Groundwater Protection Council study.