Shale Reservoirs: Prospect Generation To Production

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Introduction

This presentation has set an ambitious goal, that of providing an overarching, panoramic view of a substantial parts of operations that are involved in bringing an unconventional shale oil or gas reservoir to commercial production. Although "unconventional gas" has been in production in the US in the Appalachian Basin for over a century, this was on a small scale using somewhat rudimentary technology. Funding from the US DOE in the 1980- 1990s provided for research and development activity that culminated in the development of techniques and technology for the exploitation of hydrocarbons from coal, shale and tight sands and today, a substantially increasing proportion of the oil and gas production in North America is credited to unconventional reservoirs.

Unconventional gas has truly played the role of a game changer. Starting with the Barnett Shale, production started from dozens of organic shales in US and Canada. This has been followed, with some lag, in Europe, Asia and South America. A surfeit of natural gas exists in the US, something that was inconceivable a decade ago. Gas prices have crashed and have provided a stimulus for the economic recovery.This has had geopolitical impact *e.g.* the development of the super-giant Shtokhman Field in the Barents Sea with initial geological reserves estimated at 3.8 trillion cubic meters gas and 37 million tonnes of gas condensate had to be put on hold due to surplus gas in the US. On the other hand, it is expected that the US will exceed the liquid fuels production of Saudi Arabia in 2013. In this interconnected world, no state or country can be insulated from the impact of unconventional gas and oil.

How big are the world-wide reserves that we are talking about? In 2010, Cheng, *et al.* (SPE 132880) estimated worldwide unconventional gas resources at 850 Trillion m^3 equivalent (30,000 Tcfe). The biggest US oil producer, the Bakken shale could hold 24 billion bbls. of recoverable oil, while Russia's Bazhenov shale is likely to be 80 times larger. Based on the work in 25 North American basins, Cheng *et al.* (CSUG/SPE 137599) estimate that in a given basin, the ratio of unconventional gas reserves to those in conventional oil and gas reserves is about 4:1, i.e. for every Tcf of oil and gas produced from conventional reservoirs in a basin, one would expect another 4 Tcfe to be technically recoverable from unconventional gas reservoirs in the same basin.

In order to understand the intricacies of developing unconventional reservoirs, the contrast with conventional reservoirs is highlighted. Differences in pore structure, presence of Kerogen and the considerable porosity within the Kerogen, the small intergranular porosity, the extremely low permeability (in the nano-darcy range) and the importance of non-Darcy flow in the form of diffusion of gas from the matrix all together necessitate approaches different from those in conventional reservoirs.

Distinguishing Features of Unconventional Reservoirs

Organically rich shale reservoirs are distinguished by the presence of substantial content of Kerogen. Organically lean shales on an average contain Total Organic Content, TOC, of 0.8 wt. % while the TOC in organic shales can be up to 20 - 25 wt. %. The organic material when exposed to heat undergoes cracking and is first converted to oil and, if exposed to higher and higher temperatures, would undergo secondary cracking and conversion to condensate or dry gas.

Porosities in shale reservoirs are typically in the range of 2-8 % though some productive shales (Haynesville, Eagle Ford, etc.) do have porosities up to 10-14%. Permeability is, as a rule, in the nano-darcy range the pore throat may have dimension of 10 nano-meters.

Prospect Generation

Gas storage in shale reservoirs occurs in two modes: in the pore spaces and by adsorption in the Kerogen. The adsorbed gas is released as the formation pressure declines.

Due to the low porosity and extremely low permeability, commercial production of hydrocarbons from shale reservoirs is obtained by means of extensive stimulation *i.e.* hydraulic fracturing.

Generating unconventional prospects in virgin reservoirs offers its own set of challenges. The basic criteria like organic richness, maturation, porosity, permeability, gas generation, brittleness and mineralogy are all important. Evaluating Unconventional Gas Reservoirs (UGR) includes geosciences, geochemistry, reservoir engineering and economics none of which is well known at the outset. The preliminary assessment is often based on comparing the target formation to a perceived analog formation in a mature producing basin. This process is riven with uncertainty and is subjective. The basic criteria for screening potential shale reservoir are:

1. Organic richness and maturity of the organic shale
2. Reasonable porosity development
3. Thickness of the Kerogen rich interval
4. Adequate pore pressure
5. Enhanced non-clay fraction in the formation
6. Likelihood of natural and induced fracturing.
7. Presence of franc barriers above and below the interval to inhibit fracture growth into water bearing zones.

Table 1: List of common reservoir attributes used for force ranking gas-shale portfolios.

Parameter	Desired Result
Dehydration Effects (Sw)	< 40%
Depth	Shallowest Depth in Dry gas Window
Fracture Fabric and Type	Vertical vs. horizontal orientation
	Open vs. Filled with silica or calcite
Gas Composition	low CO2, N, and H2S
Gas-Filled Porosity (Bulk volume gas)	>2% Gas Filled Porosity
Gas type (biogenic, thermogenic, or mixed)	Thermogenic
Internal Vertical Heterogeneity	Less is better
Mineralogy	>40% Quartz or Carbonates
	<30% Clays
	Low expandability
	Biogenic vs. detrital silica
OGIP (free and sorbed)	> 100 BCF/section
Permeability	>100 nanoDacry
Poisson's Ratio (static)	<0.25
Pressure	>0.5 psi/ft
Reservoir Temperature	>230 F
Seals	Fracture Barriers Present Top and Base
Shows	High gas Readings-Production
Stree	<2000 psia Net Lateral Stress
Thermal Maturity	Dry gas window > 1.4 Ro
Thickness	>30 m
Total Organic Content (and Type)	>2%
Wettability	Oil prone wetting of kerogen
Young's Modulus	>3.0 MMPSIA

Table 2: List of common sources for the reservoir property list of Table 1.

Reservoir Property	Data Source
Elastic Properties	DSI (dynamic), Core-based compressiontest (static)
Fluid Properties	Mud log, PVT, PDA, pressure gradients
Fracture and Closure Stress	IFOT, Frac job, log-based (DSI)
Free & Sorbed Gas	Canister desorption & Langmuir Adsorption
Maturity	Visual Ro, maserals, Rock Eval (calc)
Permeability	SS & USS, IFOT, MICP, PDA, & NMR (calc)
Pore Pressure	IFOT, PDA, log-based, "dip-in"
Porosity	Gas expansion, MICP, NMR, & log-based
Rock Composition	XRD, TS point counts, FTIR, ICP-MS, EDAS (SEM)
Temperature	OHL & PL, frac job, & IFOT
TOC	Leco TOC & Rock Eval (Calc)
Water Saturation	Core extraction, Pc, & Log-based

Sondergeld et al., 2010

Profs. Sondergeld and Chander Shekhar Rai of the University of Oklahoma have summarized the items that govern the over-all ranking and tabulated the source from which these items may be determined. These tables are shown below.

Evaluating UGR in frontier basins includes geosciences, reservoir engineering and economics. Such data rarely available when work is initiated for UGR in frontier basins. Preliminary assessment is based on comparing the target formation to perceived analog formations in mature producing basins. This is often subjective and incomplete.

Prof. Holditch and his research fellows at Texas A&M University have developed a set of software that permits a rapid and objective evaluation of the potential of frontier basins where operators plan to develop unconventional resources. The approach is based on rapid identification and *ranking* of analogous basins and formations where unconventional resources are already well established.

A data base, ***BASIN***, has been created (Singh, K. et al: J. Energy Resources, 2008) that contains geoscience and engineering parameters for 240 formations in 25 US and Canadian basins that are mature both for conventional and unconventional reservoirs.

The ***BASIN*** module identifies those basins in the database that are deemed to be analogous to the basin under investigation for development of shale reservoirs.The other component of the software, ***FAST***, uses selected geologic and engineering parameters with weighting factors to compare a frontier "target" formation with a mature "reference" formation in the basin identified by the ***BASIN*** module. It objectively and rapidly identifies the analogous "reference" formation.

In mature formations in Unconventional Gas Reservoir basins, for "reference" formations, one may quantify the oil and gas resources and reservoir properties and track the engineering practices used to produce hydrocarbons. This knowledge in the analog formation can then be used to infer the potential unconventional hydrocarbons and guide the exploration and development of the target in the frontier basin.

This software is definitely a handy tool for operators desirous of venturing into a new basin for exploiting shale oil and gas.

Geomechanics

The nano-darcy permeabilties in shale reservoirs necessitate *(i)* increasing the exposed face of the reservoir and *(ii)* stimulation by means of hydraulic fracturing. Once the vertical pilot hole is drilled, the operator requires a quick assessment not only of the hydrocarbon bearing intervals but also those intervals that will respond to stimulation and/or the most suitable level at which to kick off the lateral(s). Geomechanical properties, derived from acoustic and density logs, are used to compute elastic properties from which an arbitrary "relative brittleness" curve is derived. Using a combination of log derived mineralogy, TOC, porosity, hydrocarbon saturation and relative brittleness, the most prospective interval in the well may be fraced or a lateral may be kicked off into the chosen interval. An example of the computed elastic properties and relative brittleness is shown below in fig. 1.

The compressional and shear travel times are used to compute Young's Modulus and Poisson's Ratio, which in turn, are employed to compute fracture closure pressure, friction angle, unconfined compressive strength, cohesive strength and relative brittleness index. These computed values are also used in design of the fracture treatment.

Identification of Sweet Spots for Stimulation

As more experience was gained in shale reservoirs, more and more horizontal wells were drilled thus exposing a larger amount of formation face and at the same time the number of frac stages has gone up from 5-6 to up to 30 stages in many instances. The common practice in the US is "geometric" placement of the frac stages, *i.e.* stages are placed at regular intervals (say every 200 m or 300 m) without regard to the variations in reservoir and geomechanical properties along the length of the lateral. This approach is less than desirable. If "sweet spots", where optimal reservoir and stimulation conditions are present, are identified, then stimulation will yield the best possible results. Some techniques to achieve this are enumerated below:

(a) Open Hole Logs in the Lateral

Of course, the best, albeit expensive, means of identifying sweet spots in the lateral is by recording a full suite of open hole logs in the lateral, which will permit us to eliminate poor reservoirs sections from the stimulation program. In the example shown in fig. 2, the last few hundred feet were not stimulated as logs confirmed poor reservoir characteristics. Savings of several hundred thousands were thus achieved that possibly exceeded the cost of logging the lateral.

There are several other simpler and less expensive techniques that may be used to identify sweet spots where frac stages may be located. Some of these are discussed below.

(b) Advanced Mud Gas Extraction

The GC TRACER, which is effectively an Advanced Mud Gas Extraction technique, can be very useful for identifying sweet spots in real time during drilling. The distinguishing features GC Tracer surveys are as follows:

- Detectors used at inlet and return point: effect of recycled gas removed

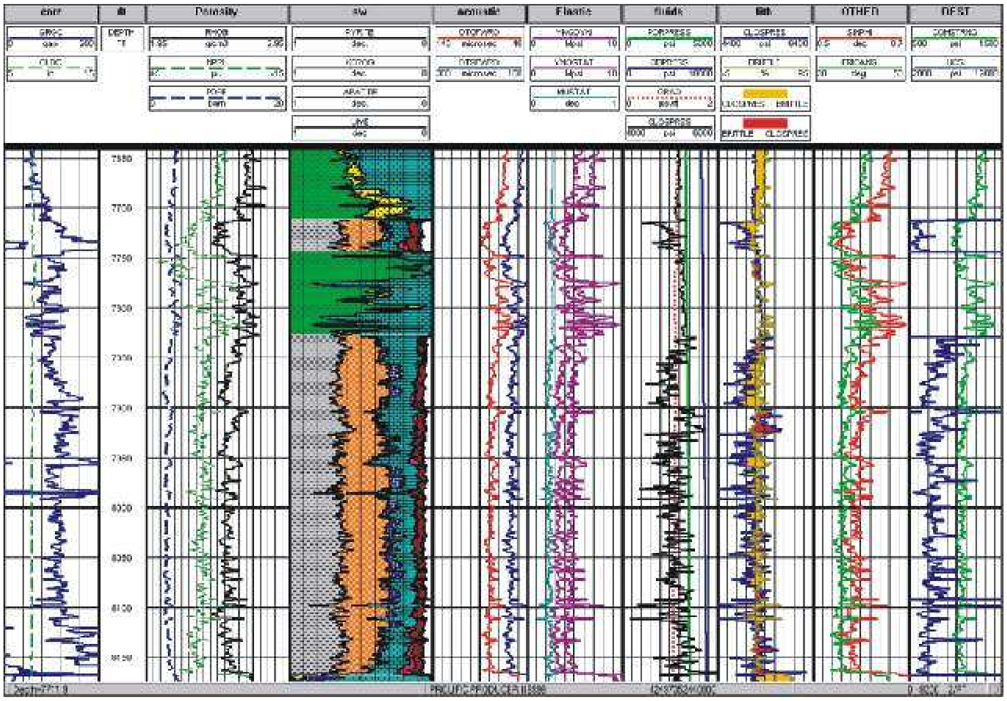


Fig. 1: Example of computed geomechanical properties and relative brittleness derived from log data being part of the criteria used in the selection of sweet spots.

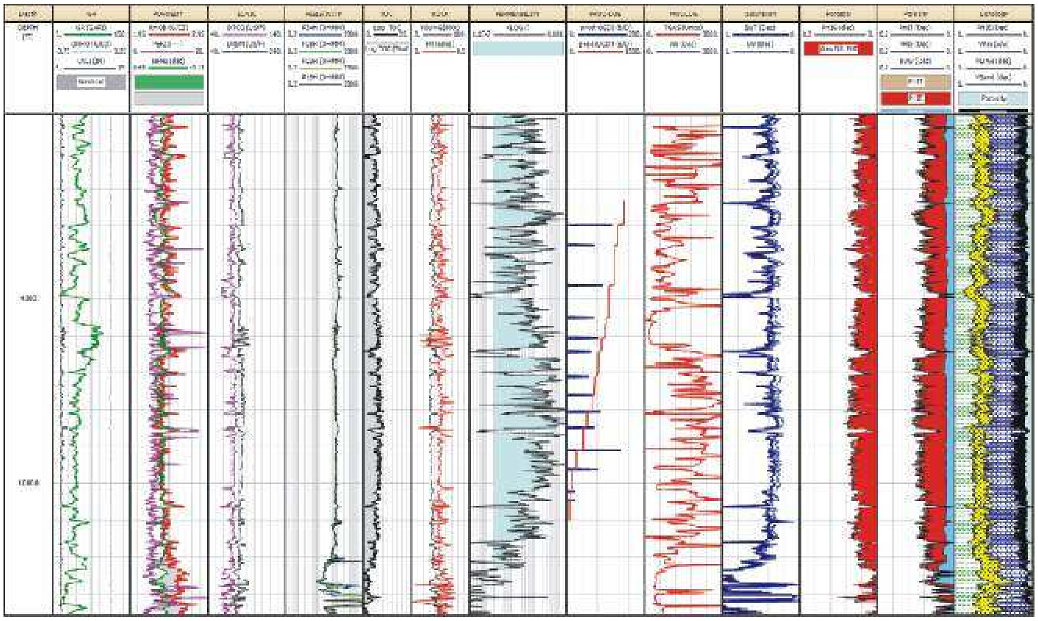


Fig. 2: Full suite of openhole logs used to eliminate non-prospective intervals and pick zones to be stimulated. Casedhole production logs confirm the efficacy of the picks.

Hashmy*et al.*, CSUG/SPE 149278-PP, 2011SPE-149278-PP

- Semi-permeable membrane in probe; probe inserted in mud; measures gas in mud - not gas in air
- Spectrum of measurements includes:
  - Methane (C_1) through Octane (C_8)
  - Aromatics, Benzene & Toluene
  - Inert gases N_2 and CO_2
- Thermocouple Detector Chromatography

Presented below in fig. 3 is a typical example of identification of a potentially productive interval using GC Tracer survey in real time.

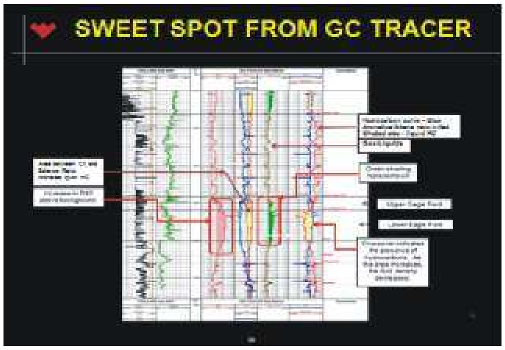


Fig. 3: Identifying a potential productive interval using data from GC Tracer, an advanced mud-gas extraction technique.

Hashmyet al., SPE-158881-PP

(c) LWD Spectral GR

A LWD Spectral Gamma Ray is now available which can also be combined with a LWD density and acoustic measurements. The Uranium, Thorium and Potassium contents are obtained from the spectral data. Many organic shale reservoirs exhibit a strong correlation between uranium content and TOC. The uranium normally dissolved in sea water becomes insoluble in the oxygen-depleted reducing environment associated with the deposition of typical organic shales, and has a particular affinity to precipitate onto organic carbon. With the aid of core data, reliable empirical relationships between uranium log values and formation TOC and gas content can often be established. It then becomes a simple question of using the U-TOC transform to compute the Total Organic Carbon, TOC, and where the density data are available, to compute the Kerogen content along the lateral section. The U curves by itself or the derived TOC or V_{ker} values offer an insight into the abundance of organic material (Kerogen). If other measurements are absent, these curve values will serve to highlight potential sweet spots since high organic content is associated with development of porosity and generation of hydrocarbons. Used singly and preferably with other measurements, the Uranium curve can be used to pick suitable spots for perforation and stimulation thus optimizing the frac efficiency by eliminating barren zones from the stimulation effort.

In this example shown in fig. 4 of an LWD azimuthal spectral gamma ray log from the Marcellus Shale, the high uranium readings (red curve in Track 2) indicate the more

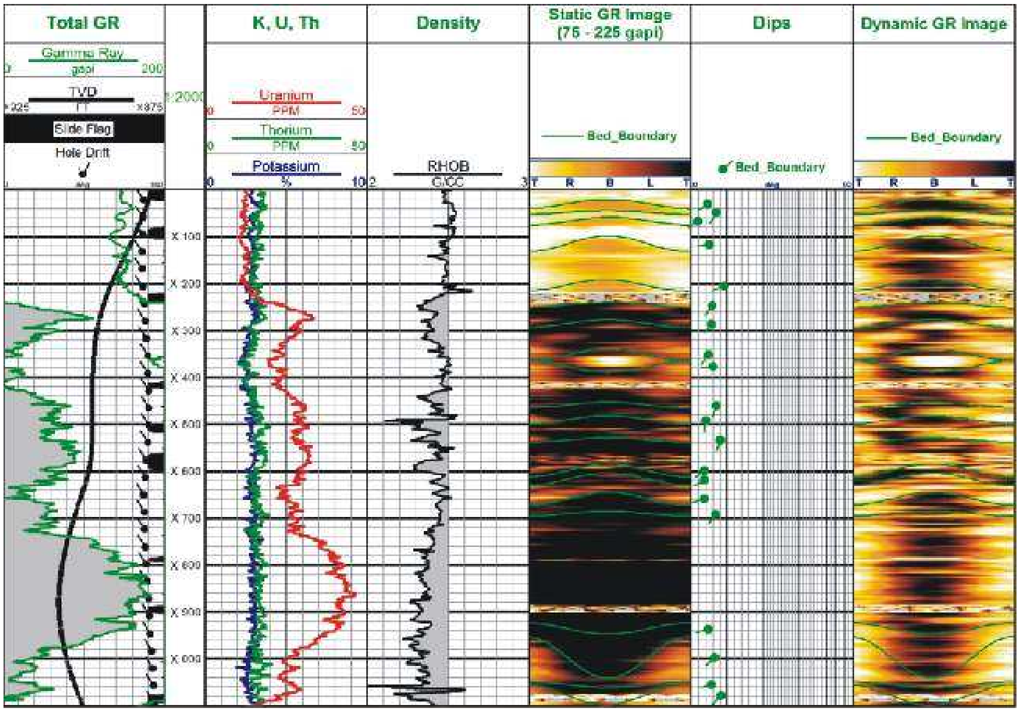


Fig. 4: Increased Uranium content observed on LWD Azimuthal Spectral Gamma measurements highlights interval with increased Kerogen and TOC contents which are likely to be productive. The LWD Bulk Density can also be used to generate an image plot which provides dip information.

organic-rich zones. The relatively constant Potassium and Thorium curves indicate that the clay volume is fairly constant, despite the wide variation in total gamma ray activity. The azimuthal gamma ray image log provides formation dip information, and indicates when the wellbore is drilling stratigraphically up or down.

(d) XRF and XRD Measurements on Drill Cuttings

X-Ray diffraction, XRD, and X-Ray Florescence, XRF, measurements are now made on drill cuttings at the well site. Element composition may be readily obtained using a hand held XRF device. Such measurements can be completed at the well site within 30 minutes of receipt of the cutting at the surface, which is why this is deemed to be a near-real time measurement.

In the example shown in fig. 5, constituent minerals in the cuttings (dots) have been derived from the element composition measured using XRF. Additionally, mineral contents obtained with XRF on cuttings have been superimposed on the corresponding minerals obtained from an Induced Neutron Capture Spectroscopy wire line survey. The correspondence between the two is very close. The difference is that the XRF data is obtained in near real time so that it may be used for navigation also, while the Induced Neutron Capture Spectroscopy survey is obtained after the well has been drilled and a separate run is made in the hole. Cost wise also, the XRF measurements on cuttings is many, many times less expensive than Induced Neutron Capture Spectroscopy survey. The XRF measurement thus can be used in near real time for delineation of mineralogy and jointly with other information, identify sweet spots.

(e) Combination of GC Tracer and XRF Measurements

When the GC Tracer and XRF measurements on cuttings are combined, they can be very diagnostic. In the example shown in fig. 6, both techniques were used in the vertical pilot hole.

Lithological packages identified from Chemostratigraphy are shown in track 2, followed by the Elemental Mineralogy in track 4, the cored interval is depicted in track 5, while the Relative Brittleness is presented in track 6, with red being more brittle and green being ductile. The next three tracks show the abundances of Vanadium, Nickel and the Vanadium to Al_2O_3 ratio. These three combined serve as a proxy for TOC the black shaded area corresponds to high TOC. The Total Hydrocarbon Content, THC, and the Gas to Liquids Ratio depicted in the last two tracks are obtained from GC Tracer measurement. The combination of high Calcite content, augmented brittleness level, indications of higher TOC from its proxies, enhanced THC magnitude combined with the light oil/condensate signature together unequivocally demarcate the sweet spot in

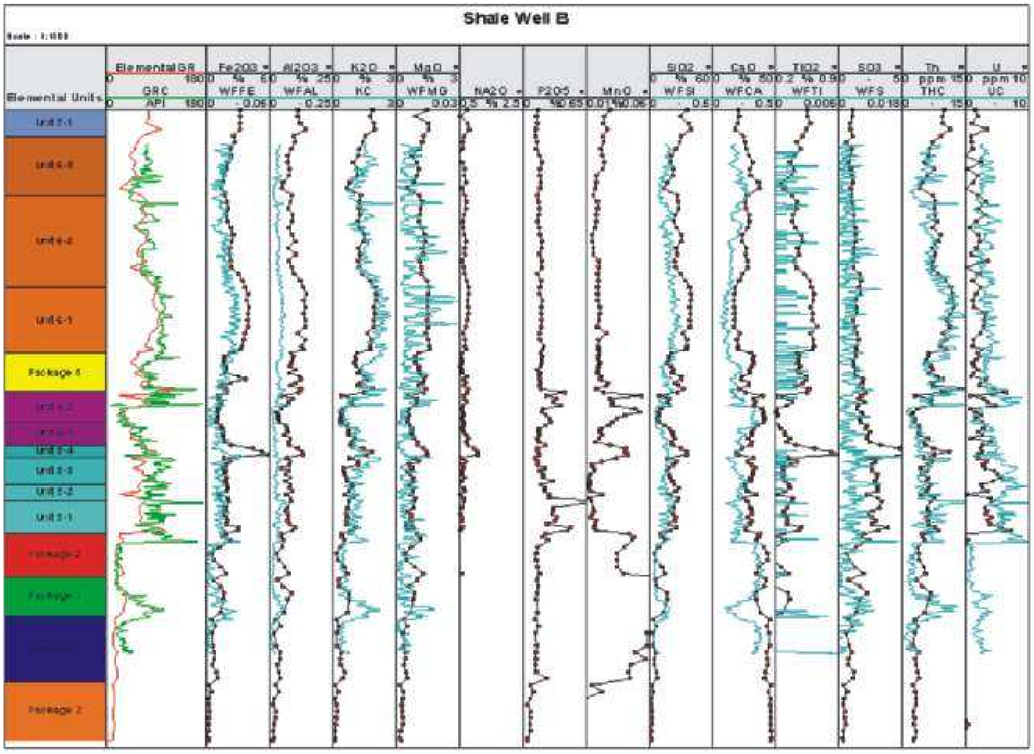
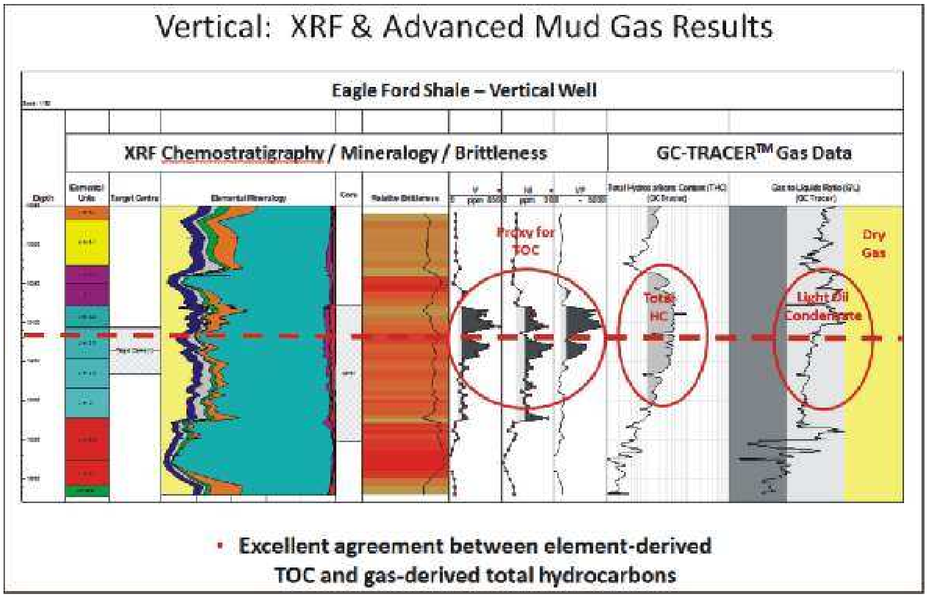


Fig. 5: Close correspondence between mineralogy derived from elemental composition obtained from XRF measurements (dots) and that yielded by wireline Induced Neutron Capture Spectroscopy logs (solid lines).

Tonner, Hashmy, *et al*., AAPG ICE Singapore 2012



Vertical: XRF & Advanced Mud Gas Results

- Excellent agreement between element-derived TOC and gas-derived total hydrocarbons

Fig. 6: Lithology and brittleness from GC Tracer combined with TOC and hydrocarbon indicators from GC Tracer survey in pilot hole pinpoints kickoff point for lateral.

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this pilot hole. Based on these findings, the operator landed the lateral at the level marked by the dashed red line. The XRF measurements made on the drill cuttings in the lateral drilled based on the results in the pilot hole are shown shown in fig. 7.

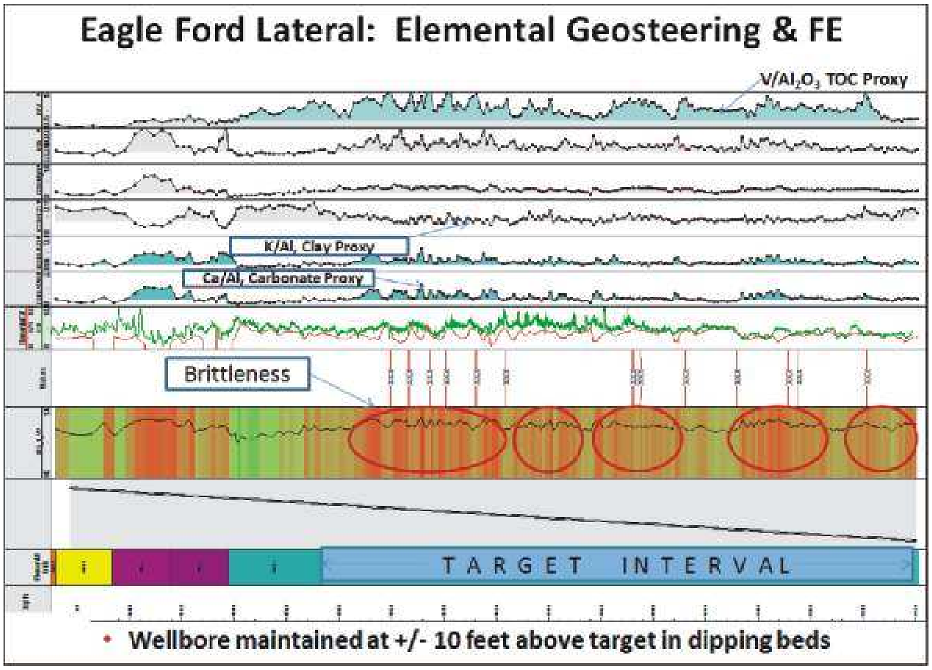

Fig. 7: XRF data in lateral clearly demarcates calcareous intervals with low clay content and increased brittleness. These are sweet spots that need to be stimulated.

Note that the lateral hole stayed well within the target zone and more important still is the fact that zones with low clay content (K/Al), increased carbonate content (Ca/Al) and the ratio of Vanadium to Al_2O_3 (proxy for TOC) together with relative brittleness obtained from mineralogy unambiguously demarcate the sweet spots in the lateral. The brittleness is displayed as a color scheme, with shades of green indicating less brittleness and greater ductility while shades of red exemplify the relatively more brittle intervals. The intervals circled on the Brittleness track are most likely to frac easily as compared to the more ductile intervals shown in shades of green. The stimulation effort in this instance ought to be concentrated on the circled zones which are likely to produce more hydrocarbons, while the greenish zones interspersed must be avoided, thus resulting in savings on stimulation expenditure.

Stimulation of Shale Reservoirs

Multiple lateral wells are now the norm for productive shale oil and gas wells. This mainly exposes a much greater length of the formation for production. Additionally, several perforation clusters ranging in number up to 30 are placed along the lateral are stimulated by hydraulic fracturing. Experience has shown that simple slick water with suitable proppants is more successful and far less expensive compared to using cross-linked gel for example. The direction in which the lateral(s) are oriented has a great effect on well productivity. The figure 8 exemplifies the various scenarios that may occur depending on the orientation of the lateral.

In all cases, the fracture will propagate in the direction of the minimum horizontal stress, $\boldsymbol{\sigma}_{h,\ min}$. The ideal situation is when the well is drilled in the minimum horizontal stress, $\boldsymbol{\sigma}_{h,\ min}$., direction. The different frac stages will each produce a single T-shaped fracture perpendicular to the well axis. These will tend to be planar and due to the simple geometry, there will be fewer impediments for the transport of proppants. The stimulated volume will be large and extend laterally and vertically at each perforation cluster.

Where the well is drilled in the direction of the maximum horizontal stress,$\boldsymbol{\sigma}_{h,\ max}$, a single vertical fracture will be produced running along the axis of the borehole no matter how many intervals are stimulated. The stimulated volume will be relatively small and the stimulation will be far less effective than in the preceding case.

A lateral oriented in an intermediate direction, between $\boldsymbol{\sigma}_{h,\ min}$and $\boldsymbol{\sigma}_{h,\ max}$ will permit multiple fractures that will start out

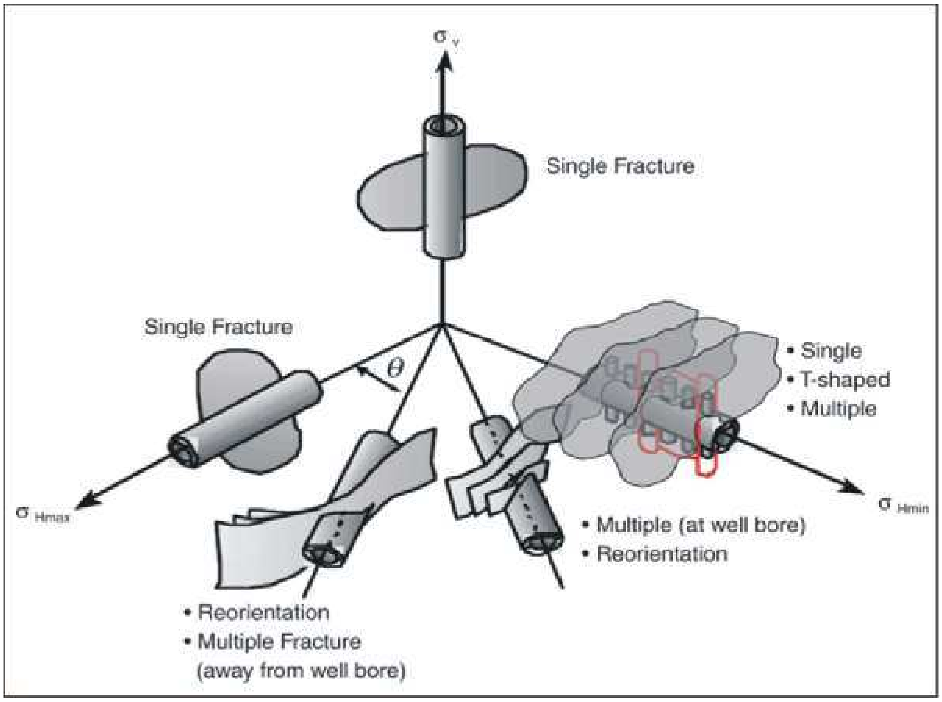

Fig. 8: Picture showing the generation of fractures in different well orientations with respect to minimum and maximum stress directions.

perpendicular to the hole axis but will rapidly veer and re-orient themselves in the direction of the minimum horizontal stress $\sigma_{h,\ min}$. The fracture plane will be curved and could impede the transport of the proppants round the curves.

Besides the proper orientation of the lateral well, other features need to be determined for the stimulation design, some of which are listed below.

1. Stage spacing (number and distance between fracs)
2. Stage Volume (fluid and proppant)
3. Stage rate and placement of perforation clusters
4. Fluid type and viscosity

Completions

Though there is a multiplicity of completions used in unconventional reservoirs, the most common are listed below:

- Plug & Perforate (PNP)
- Just in Time Perforation, JITP (cased hole or CT)
- Annular Coiled-Tubing Fracturing (ACT-Frac)
- Open Hole Multi-Stage
- Hybrid

The plug and perforate approach, PNP, has been widely used for a long time and is common so no elaboration is needed. It is schematically represented in fig. 9.

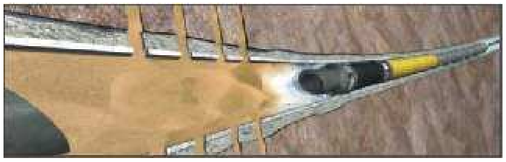

Fig. 9: Schematic representation of a Plug and Perforate (PNP) completion.

The Just in Time Perforation, JITP, a recent development, is schematically portrayed in fig. 10. In essence, it is a single-trip, multi-zone stimulation technique where simultaneous perforating and hydraulic fracturing can be achieved. Originally developed by Exxon Mobil Upstream Research Company (URC), an affiliate of Exxon Mobil Corporation, *this* technology is now available from service companies. It adds an important dimension to the extensive portfolio of completion and well stimulation technologies and services available.

The process permits more efficient tight-gas, shale-gas and coalbed-methane well development. By stimulating multiple payzones in a single operation, this process makes recovery more profitable. A dramatic increase in the number of pay zones fractured daily reduces completion costs without compromising safety or well integrity - even from unconventional reservoirs with low permeability.

Two *multi-zone stimulation technologies are now available.* Just-in-Time Perforating (JITP) and Annular

Coiled-Tubing Fracturing (ACT-Frac) are available, each delivering 40 or more zone-specific, customized treatments in a single well.

The JITP method can perform multi-zone stimulation in a single run in vertical, deviated and horizontal wells using ball sealers for diversion between frac stages.

The ACT-Frac method involves treatments being pumped at high flow rates down the annulus of coiled tubing to facilitate efficient and effective stimulation.

A schematic of the operation using JITP is shown below.

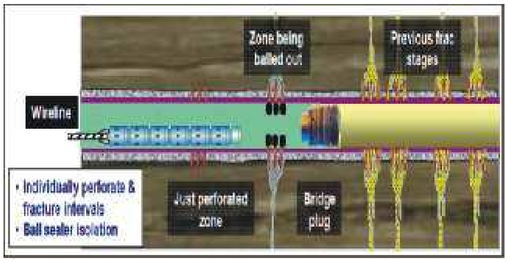

Fig. 10: The Just in Time Perforation (JITP), a single-trip, multi-zone stimulation technique, achieves simultaneous perforating and hydraulic fracturing allowing rapid multi-zone stimulations.

The open hole multi-stage completion is again a standard practice, where inflatable external packers provide zonal isolation between frac clusters. This is illustrated in the fig. 11.

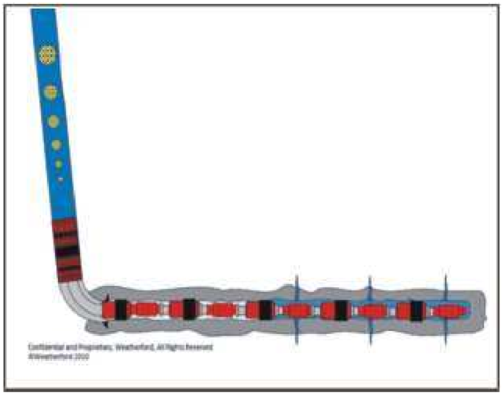

Fig. 11: Schematic of openhole multi-stage completion.

The Hybrid completion is a combination of one or more of the completions techniques described above.

Microseismic for Evaluating Fracture Dimensions

Microseismic monitoring of fracture development during and after well stimulation provides a wealth of information relating to the direction of propagation of the fracture, fracture height, half length, complexity of the fracture, estimated stimulated volume and hence the drainage volume, etc. The figure 12 shows a row of geophones located strategically in a nearby vertical hole. As the fracture propagates, the energy is released as the rock opens up. The monitoring geophones record the incoming signals and then, using the proper velocity function, each individual seismic event can be placed in a three-dimensional space specifying the hypocenter of the event. Mapping the events and viewing them in planar or cross-sectional view yields information about the fracture development.

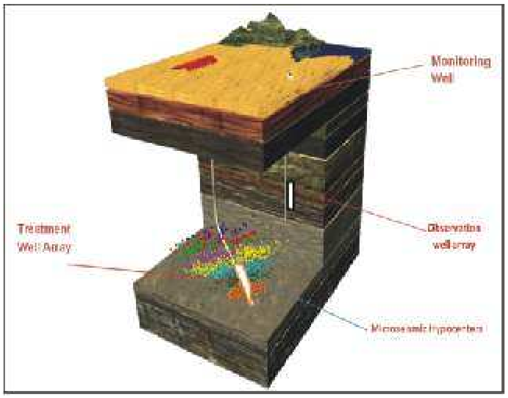

Fig. 12: Illustration of the principle of micro-seismic measurement in a horizontal well.

The process consists of the following;

- Induced microseismic activity along fractures is mapped using a velocity model and P/S wave arrival time
- Recorded from a remote well or from inside the treatment well
- Tools deployed on wireline, e-coil or permanent (tubing or behind casing)
- Measure length, height, width, azimuth and overall frac complexity
- Time component shows frac propagation in time with real time processing available
- Proven in all fraced shales Haynesville, Barnett, Marcellus, etc.
- Also used in mining, waste disposal, storage and geothermal applications

Presented below is a typical application of Microseismic monitoring (refer fig. 13).

Two adjacent horizontal wells were stimulated sequentially. As indicated in the legend on the top left corner, the third and fourth stages of fracs are displayed in Well 1 (the lateral on the left); the hypocenters are shown in black for stage 4 and light green for stage 3. For the second well, stage 1 is in bright red, stage 2 in green, stage 3 blue and stage 4 in purple. In well 2, overlapping of fracs in successive stages is observed thus the area stimulated red events is once again stimulated by the light green events, which in turn, are overlapped by the blue events and so on. Additionally, the stimulation of well 1 caused fracture

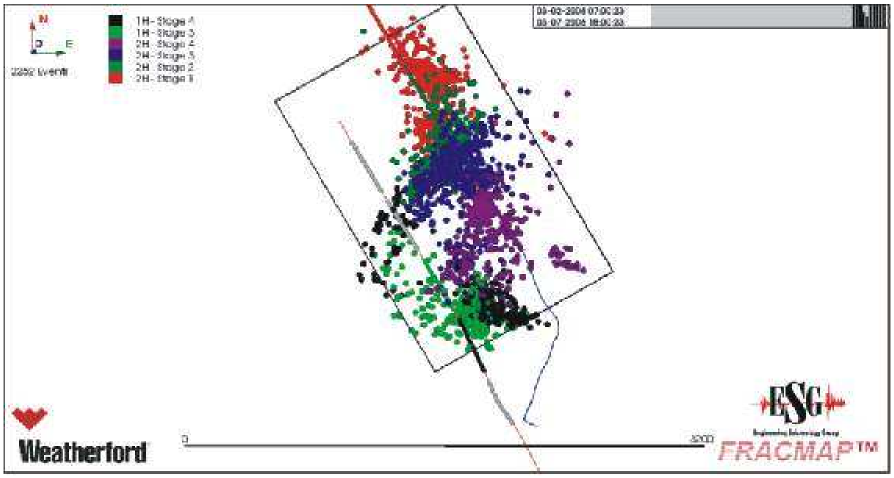

Fig. 13: Overlapping stimulated area between frac stages in individual horizontal wells and stimulated areas between adjacent horizontals indicate need for larger separation between frac stages and also wider well spacing.

growths that overlap those in well 2. Thus, the purple events of well 2 are mingling with the light green in well 1; the blue events in well 2 overlap the black events in well 1, etc.

The above observations lead us to the following conclusions:

(i) The individual frac stages in well 2 are placed too close together the same lateral length could have been effectively stimulated with fewer numbers of stages. This would result in considerable savings.

(ii) For the frac treatment designed, the two laterals are also spaced closer than is necessary. By spacing the two laterals further apart, overlapping of the stimulated zones of wells 1and 2 could have been avoided and a larger volume of the rock would have been stimulated which would result in enhanced production and increased revenues.

Microseimic data can have other important applications. Thus, in the example discussed above, the data could be presented differently, as shown in the figure 14.

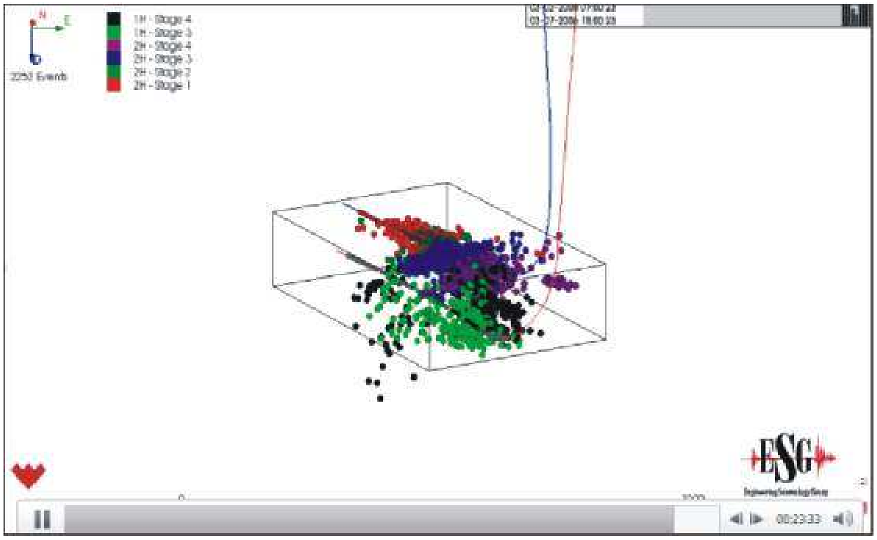

Fig. 14 : Alternate presentation of Micro-seismic data from fig. 13 canbe used to estimate the likely drainage volume for the two wells stimulated.

A cuboid parallelepiped has been drawn around the hypocenters resulting from the stimulation of the pair of horizontal wells. This covers the volume of rock that has been effectively stimulated from the pair of laterals. It thus is a measure of the volume that is likely to be drained by this pair of wells. Thus, an estimate of the drainage area may be obtained.

Remarks

Commercial production from the low permeability low porosity unconventional reservoirs is only feasible if the formation face exposed by the well is enhanced, *e.g.* bylaterals or multi-laterals which are efficiently stimulated by hydraulic fracturing. The enormous cost of fracturing 20 to 30 frac stages in each lateral necessitates certain measures to optimize the operation as whole. Some points to consider are:

- Frac Stages to be located on sweet spots, avoiding needless stimulation in ductile or poor quality reservoirs.
- Tailor the treatment to requirements of individual stage, one size fits all does not apply.
- Select proper proppants that can be transported by the frac fluid and are not subject to embedment and crushing problems.
- Evaluate efficacy of frac treatment with Microseismic to ensure that the designed fracs are providing the degree of coverage anticipated.
- Modify treatment in later wells considering information from Microseismicresults.

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