

Shale Gas Play Screening and Evaluation Criteria

Michael Burnaman, Wenwu Xia, John Shelton

Harding & Shelton Group

Abstract

The uniqueness of shale gas plays is contrasted with conventional oil and gas exploration. Based on our ten year history in shale gas exploration, a practical 17 point list of criteria to use for screening shale gas projects and ranking that encompasses geoscience, geochemistry, reservoir engineering, drilling, completions and production operations is developed and explained. Other considerations that will impact shale gas development are identified and discussed. Some key methodologies to incorporate in the evaluation process are also proposed. The outcome of this proposed screening process, if rigorously applied, should quickly identify the projects that have the most likely chance for success for recommendation to management. Examples from active shale gas plays in the United States are used to support these criteria and references to relevant recent publications and presentations are provided.

Introduction

Conventional oil and gas exploration involves locating geographic areas (prospects) where a specific set of geoscience criteria (known as an active petroleum system) are present that can provide a mechanism to focus commercial concentrations of hydrocarbons. A sophisticated risk evaluation methodology is then used to rank the prospect quality and likelihood of success of discovering commercial hydrocarbons. For almost 100 years the basic elements of these risking criteria have been set forth as 1) a trapping mechanism, whether structural or stratigraphic, that was present when hydrocarbons were generated and intact since their movement, 2) a reservoir with sufficient porosity and permeability such that commercial amounts of hydrocarbons can be stored and produced at economically viable rates, 3) a seal above the reservoir to stop the vertical migration of hydrocarbons, 4) a source rock for the hydrocarbons, usually an organic rich shale that has a burial history such that sufficient temperature and pressure has been present to transform the organic kerogen into hydrocarbons and then the expulsion of them into potential traps stratigraphically adjacent or structurally higher than the source rock, and 5) timing such that all elements of the system exist both sequentially and concurrently that the hydrocarbons are preserved. If any of the elements of the petroleum system is absent (a zero multiplier) then no hydrocarbons are present at that locale and a dry hole results. A significant amount of oil and gas literature is devoted to quantification and risk evaluation of petroleum systems to minimize drilling dry holes and thus lowering hydrocarbon finding costs.

In contrast, shale gas exploration has a much different and usually more predictable risk profile. The gas shale (or mudstone as it is more correctly described) itself contains all of the elements of petroleum risk as described above. There is no "zero" component that can preclude success once a shale gas play has been proven. In a proven shale gas exploration locale, the risk changes from "are hydrocarbons present and at what volume" to "how quickly

can the hydrocarbons be extracted and what will be the cost of extraction?" The producibility of shale gas is not limited to a single prospect but to a large geographic region. Successful shale gas development then becomes a statistically driven engineering project. Almost all wells drilled will produce gas. The challenge is to develop the proper drilling and completion techniques to optimize the gas production rate versus capital employed and operating costs. Conventional oil and gas technology development is based on over 100 years of technical literature. Shale gas exploration relies on this technical literature. New technology development focused on shale gas only is barely 10 years old but accelerating rapidly. This can only be to our advantage for the evaluation of the shale gas potential of China.

A successful shale gas project will require that certain minimal technical thresholds be satisfied. There are other considerations that are not easily quantified yet are equally important. Different authors have their own set of screening criteria. A typical set of screening parameters from another company is shown in Figure 1. The Figure 1 criteria are a first step but do not begin to address the wide range of other important issues for consideration in evaluation of any shale gas play.



Figure 1: Typical Shale Gas Screening Criteria (Curtis, 2008).

Figure 2 represents a recent comparison of data for the most active shale gas plays in the U.S. Figure 3 is another similar compilation but with more parameters contrasted. It is obviously important to compare shale gas plays to understand their science; however there is more to the comparisons than just data. We want to develop a means to rank the different shale gas plays with objective criteria and select the best for chance of exploitation success.

Gas Shale Basin	Fayetteville	Barnett	Marcellus	Haynesville	Woodford	Lewis
Estimated Basin Area, square miles	9,000	5,000	95,000	9,000	11,000	10,000
Depth, ft	1,000-7,000 ¹²	6,500-8,500 ¹²	4,000-8,500 ¹²	10,500-13,500 ¹³	6,000-11,000 ⁵	3,000-6,000 ¹²
Net Thickness, ft	20-200 ¹²	100-600 ¹²	50-200 ⁶	200-300 ^{7,14}	120-220 ¹²	200-300 ¹²
Depth to Base of Treatable Water, ft*	~500 ¹⁵	~1200	~850	~400	~400	~2000
Total Organic Carbon, %	4.0-9.8 ¹²	4.5 ¹²	3-12	0.5 - 4.0 ¹⁴	1-14	0.45-2.5 ¹²
Total Porosity, %	2-8 ¹²	4-5 ¹²	10	8-9	3-9	3.0-5.5 ¹²
Gas Content, scf/ton	60-220 ¹²	300-350 ¹²	60-100	100-330	200-300	15-45 ¹²
Water Production, Barrels water/day ¹²	0	0	0	0		0
Well spacing, Acres	40-160	40-160 ⁶	40-160 ⁶	40-560 ⁶	640 ⁶	80-320 ¹²
Gas-In-Place, Tcf	52	250	2,500	1,050	66	61.4 ³
Reserves, Tcf	17	75	516	350	20	20 ³
Est. Gas Production, mcf/day/well	2,500	2,700	2,500	6,000	3,500	100-200 ¹²

mcf = thousands of cubic feet of gas.
NOTE: Data derived from various sources and research analysis. Information from some basins was unable to be identified and confirmed at the time of this paper and has been left blank.
- for the Depth to base of treatable water data, the data was based on depth of casing information if the state's oil and gas agency did not specifically report BTW values in their data base.

Figure 2: Parameters of Various Active US Shale Gas Plays (modified after Arthur et al, 2008).

Characteristic	Barnett	Ohio and equivalents	Antrim	New Albany	Lewis
Basin	Fort Worth	Appalachian	Michigan	Illinois	San Juan
Age	Mississippian	Late Devonian	Late Devonian	Late Devonian	Late Cretaceous
Location	TX	OH, KY, NY, PA, WV, VA	MI, IN, OH	IL, IN, KY	CO, NM
Depth (ft)	6,500-8,500	2,000-5,000	800-2,000	500-2,000	3,000-6,000
Thickness (ft)	200-300	300-2,000	180	180	1,000-1,500
Net thickness (ft)	50-200	30-100	70-120	50-150	200-300
Bottom-hole temp (°F)	200	100	75	00-105	130-170
Pressure gradient (psw/ft)	0.43-0.52	0.15-0.4	0.35	0.43	0.2-0.25
Maturity (R _o , %)	1.1-1.4	1-1.3	0.4-1.6	0.6-1.3	1.6-1.88
TC wt %	1-4.5	0.5-23	0.5-20	1-20	0.5-2.5
Total porosity (%)	1-6	2-5	2-10	5-15	5-6
S _w (frac)	0.1-0.8	0.1-0.8	0.1-0.8	0.1-0.8	0.1-0.8
Gas content (scf/ton)	150-350	60-100	40-100	40-80	15-45
Adsorbed gas (% of total gas)	20	50	70	10-60	13-10
Gas prod (Mcf/day per well)	100-1,000	30-500	40-500	10-50	100-200
Water prod (bwpd)	0	0	5-1,500	5-1,000	0
Well spacing (ac)	20-160	40-160	30-160	80	80-320
Recovery factor (%)	5-20	10-20	20-60	10-20	5-15
GIP (Bcf/section)	30-40	5-10	5-35	7-10	8-50
Resources (Tcf)	26.2-252	225-250	12-20	2-20	100

Figure 3: Properties of Gas Shales (Wang, 2008).

Listed and explained below are the specific criteria and other considerations that we have developed that we believe are necessary to ensure that the best shale gas plays can be brought forward as part of a structured, technically rigorous process. These criteria consider technical, operational and

economic issues. Some of these criteria may seem obvious and probably are, others may be more subtle but still important to overall success. Still other criteria may be so important that their absence or marginal nature may condemn the shale as having little if any commercial gas potential, even though many other parameters are very favorable. The list below is not ordered in importance, although some of the most obvious components are high on the list. Other criteria farther down the list may be just as important in the final assessment of those project areas with the best chance of quickly building significant gas production and a large probable reserves base for future development.

Evaluation Criteria

1. *Shale Thickness* – It is the vertical concentration of TOC that is most important, not just the overall shale thickness. There should be at least one zone within the shale that has high TOC with at least 150 feet continuous thickness. This will be a viable target for the lateral (dependant on adjacent layered porosity zones as well) and well within the vertical extent of the hydraulic fracturing. If the TOC is vertically spread out over 500 to 1,000 feet or more, the effect of the hydraulic fracturing could be dispersed over low potential rock. The Barnett Shale optimum thickness is 300 ft; however, good wells can be present with 200 ft thickness if the organic component is a large vertically concentrated fraction of that thickness. Wells in the Haynesville shale with very high initial rates are present that have less than 150 feet of high TOC.
2. *Organic Richness, TOC, Hydrogen Index and Kerogen Type* – The TOC should be at least 2% with Type I, II or III kerogen. Higher TOC will result in higher gas-in-place volumes. Type I (oil prone kerogen) can be a good gas source if %Ro is > 1.4 to ensure that the oil has at least been cracked to wet gas or with %Ro >2.0 to ensure condensate rich gas has been cracked to dry gas. Types II and III kerogen require higher HI for comparable gas volumes. Figure 4 shows photomicrographs of Woodford shale cores with kerogen. The photo on the left is of shale with 35.5% TOC (super rich). The photo on the right is chert with 6.4% TOC, still very rich.

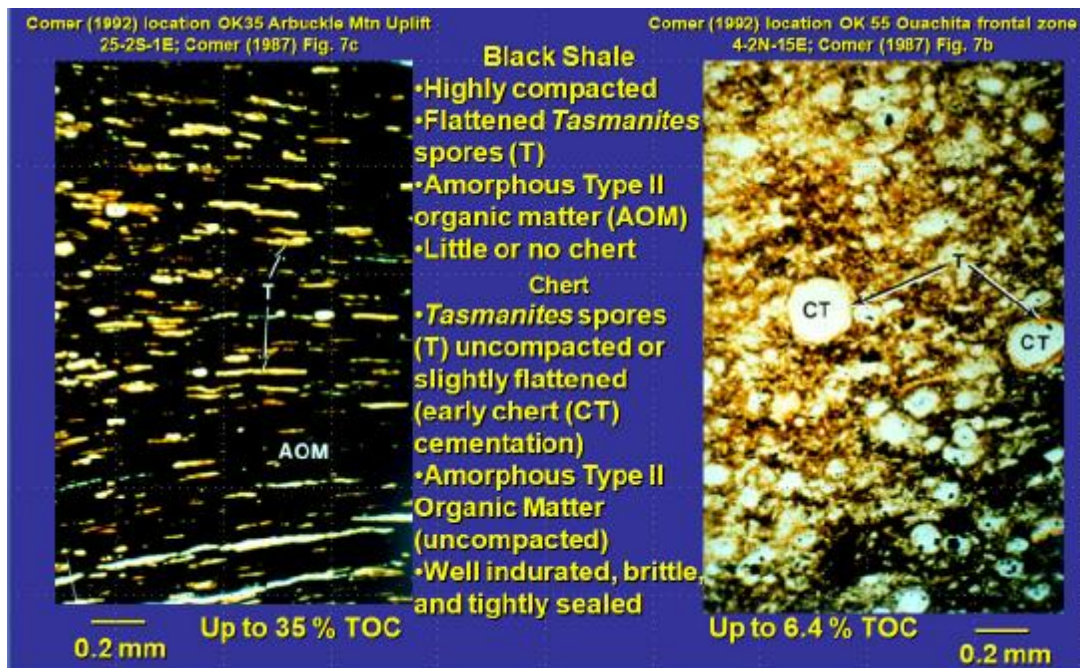


Figure 4: Photomicrographs of Woodford shale and chert organics (Comer, 2007).

3. **Thermal Maturity (%Ro, Tmax, TR, RockEval) – Vitrinite Reflectance (%Ro)** should be >1.0 and <3.0. Evaluate areas for deep burial and later inversion (uplift) as currently shallow shales may have been deeply buried with later uplift having higher %Ro than current burial depth would indicate. Beware of extremely deeply buried shales as %Ro >3.0 is onset of hydrocarbon destruction producing probable non-economic gas in place. Figure 5 illustrates the relationship between %Ro boundaries, kerogen source and hydrocarbon generation. Figure 6 shows the relationship between kerogen types, %Ro, Tmax and hydrocarbon generation. Appendix 1 is a geochemical summary of gas shale plays.

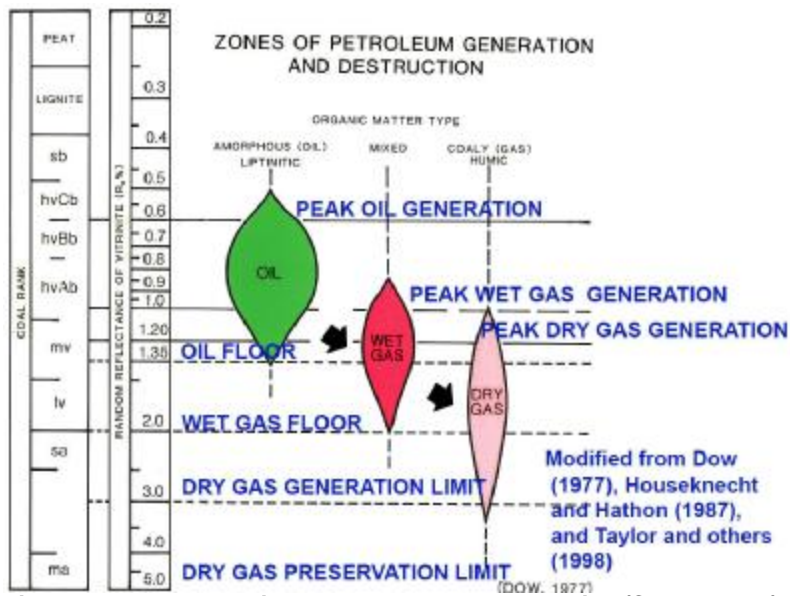


Figure 5: %Ro boundaries and hydrocarbon generation (Cardot, 2009).

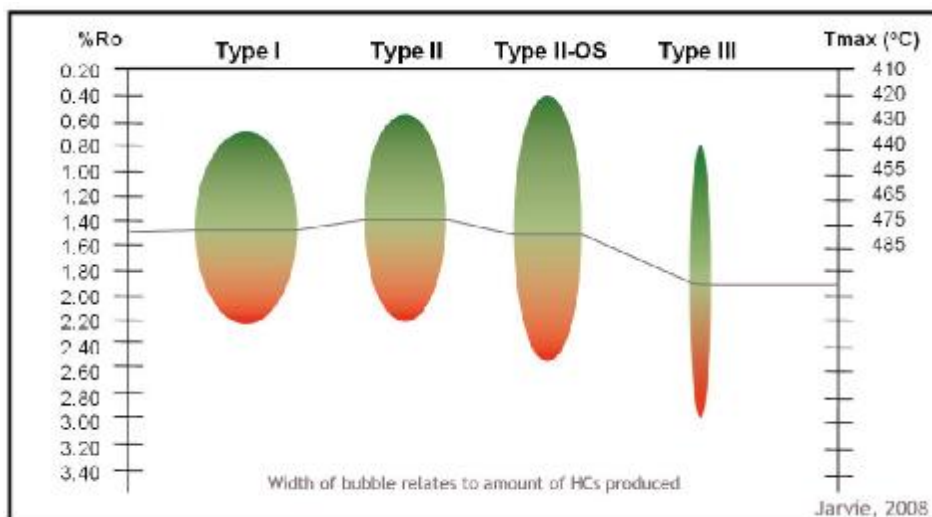


Figure 6: %Ro, Kerogen Type and Tmax Relationship (Devon et al, 2009 & Jarvie, 2008).

4. **Gas-in-Place and Reserves** – Gas-in-Place (GIP) is the total gas and is the sum of the free gas (also known as the absorbed gas) and the adsorbed gas. The free gas is present in the porosity and provides the high initial production rates. The adsorbed gas is that which is attached to the kerogen and clay plates and is released through time providing the long declining production. The free gas and adsorbed gas values are derived from core analysis and core calibrated log analysis. Total Gas should be at least 75 Bcf per sq mile. The better gas shales have over 150 Bcf per sq mile. Measured and computed gas-in-place values are presented as standard cubic feet of gas per ton of shale (scf/ton) and then converted to Bcf per square mile (Bcf/sq mi) based on area and TOC thickness. Total gas recovery factors per square mile will depend greatly on areal well density, hydraulic fracturing efficiency, gas

composition and other factors. Appendix 2 is a compilation of well gas recoveries for the major shale gas plays in the U.S.

5. *Shale Brittleness* – Extreme brittleness is absolutely necessary for hydraulic fracture efficiency and long term stability of the induced fractures. High quartz concentration adds to the shale brittleness. The shale brittleness is a function of Poisson's Ratio and Young's Modulus. These parameters can be readily determined using the Dipole Sonic log or direct conventional core measurement. The most productive gas shales have Poisson's Ratio < 0.25 and Young's Modulus > 2.0 . These shales exhibit well developed conchoidal fractures on the shale cores, like glass. The brittleness supplied by quartz can be significant. The shales often have quartz content $> 40\%$, generally siltstone but preferably with a large quartz component of organic origin (sponge spicules and radiolaria), which also increases the overall porosity to store free gas. Lack of brittleness also may cause closure of induced fractures around proppant due to plastic flow of the ductile shale and may lead to casing collapse as has happened in the Haynesville shale in North Louisiana. Appendix 3 is a photomicrograph of Barnett shale showing abundant sponge spicules.
6. *Porosity* – The best gas shales have average gas filled porosities of greater than 4.0% with the higher the better. The porosity is usually concentrated in laminated zones vertically adjacent to or within the highest TOC. The thin laminations are preserved due to a lack of bioturbation in the anoxic environment. The porosity is generally expressed as porosity-ft after wireline log analysis. Appendix 4 is a photomicrograph of Barnett shale showing laminated quartz siltstone. These concentrations of silt sized quartz make excellent porosity. Many of the high EUR Barnett Shale wells have abundant laminations of quartz with high porosity and permeability.
7. *Shale Mineral Composition* – The gas shales are actually mudstones with particle sizes ranging from clays (< 5 microns), through silts (5 to 63 microns) to sand (> 63 microns). They usually have a high concentration of quartz. Abundant pyrite is a good indicator of anoxic deep water deposition with an absence of bioturbation. Lots of organic quartz (sponge spicules and radiolarians) is often present. Appendix 5 shows compositions of shales of different geologic age. Of critical importance is what is the type and provenance of the clay minerals. Generally clays of the smectite group from mafic rock types (Ca plagioclase feldspars) and of volcanic origin have swelling problems during drilling and hydraulic fracturing. They generally produce poor gas recoveries. The kaolinite and illite groups of granitic origin (K orthoclase feldspars) have minimal negative reaction to drilling and slick water fracture fluid. X-Ray diffraction and wireline logs can easily define these constituents. Sometimes 2% to 4% KCl can be added to the fracture fluid to minimize effects of the swelling clays.
8. *Three-D Seismic Available Prior to Drilling* – While this is not an attribute of the gas shale, it is an extremely important component in evaluating drilling risk

and potentially indentifying orientations of regional and tectonic fracture swarms. Once drilling of the lateral has begun, any unsuspected fault encountered could result in the target zone not being easily accessible and could take several hundred feet of the lateral to get back in zone, possibly creating a problem later while setting casing.

9. *Tectonic Setting* – The structural complexity of the overburden and zones physically adjacent to the gas shale should be at a minimum. Complex overburden structure and faulting can significantly raise drilling costs. Similar complexity directly above and below the targeted high TOC and porosity zone can cause completion failure. This would be caused by fracture fluid diverting into faults and natural fracture zones thus losing fracture effectiveness and possibly opening highly permeable water zones that can reduce gas production to zero. The Woodford and Fayetteville shale exploration in Oklahoma and Arkansas (Figures 7 and 8) are within Ouachita fold belt thrust sheets creating drilling and completion challenges and also limiting EURs.

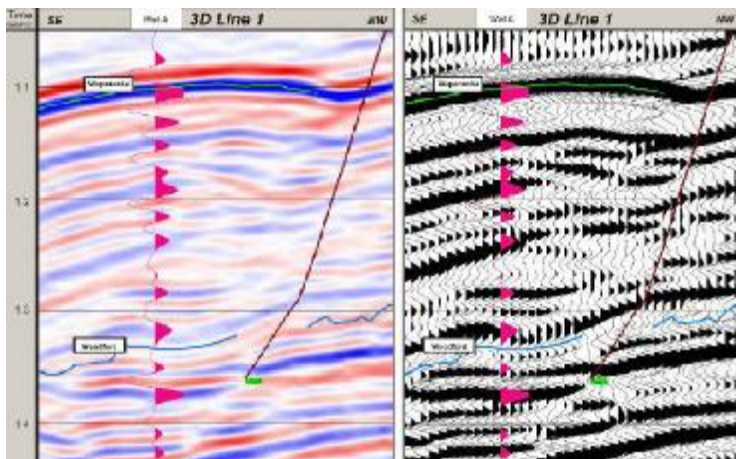


Figure 7: Woodford Shale 3D Seismic Exhibiting Reverse Faulting (Devon Energy, 2007). The dip of the Woodford, purple, is less homogeneous in cross section. Large offset normal faults, dark green, divide the Woodford's dip into the basin. The regional faults in this study area can have 1200 ft+ throws. The faults are regional enabling a structural view from 2D.

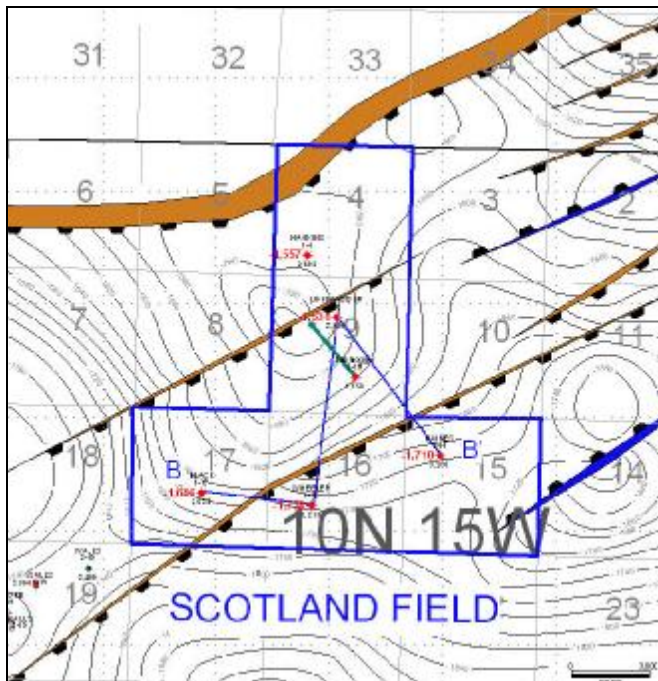


Figure 8: Fayetteville Shale Structure Showing Horizontal Well within Multiple Reverse Faults (Southwestern Energy, 2005).

10. *Lateral Continuity of Shale* – The various screening criteria must be reasonably consistent and extend over a large area to eventually produce any meaningful development and production volumes. The Barnett Shale play extends over at least 4,600 sq mi or an area about 55 miles by 85 miles. Gas-in-place is variable, but play wide ultimate recovery should exceed 50 Tcf or much more dependent on final horizontal well spacing, possibility of economic repeat fracturing of horizontal wells and improved completion techniques. This is a large resource base within a relatively small area. The reason this is possible is because of the general continuity of the Barnett reservoir geology, geochemistry, fluid properties, geological structure and relatively simple drilling condition.
11. *Permeability* – Gas shales have very low permeability (K), ranging from 0.001 mD (microDarcy) to 0.00001 mD (nanoDarcy). Contrast these K's with tight sands whose K's usually range from 0.1 mD to 0.001 mD. Figure 9 modified from Cluff, et al show permeability measurements on gas shales. Permeability is plotted versus Porosity for gas shale core data illustrating the four to six orders of magnitude permeability difference between the tight gas sands and the much tighter gas shales. The gas shales are at least 100,000 times less permeable than even the tight sand reservoirs with similar porosities. For this reason, the silts within the gas shales are in large part responsible for the high initial flow rates as their porosity is associated with some K, however small. Gas Shale recovery factors currently range from 8% to 15% and can rise significantly as well spacing is reduced and fracture design and efficiency

improves. Permeability, both vertical and lateral, will be created by the hydraulic fracturing. High TOC may also provide in-situ permeability and greatly enhance EURs (Wang, 2008).

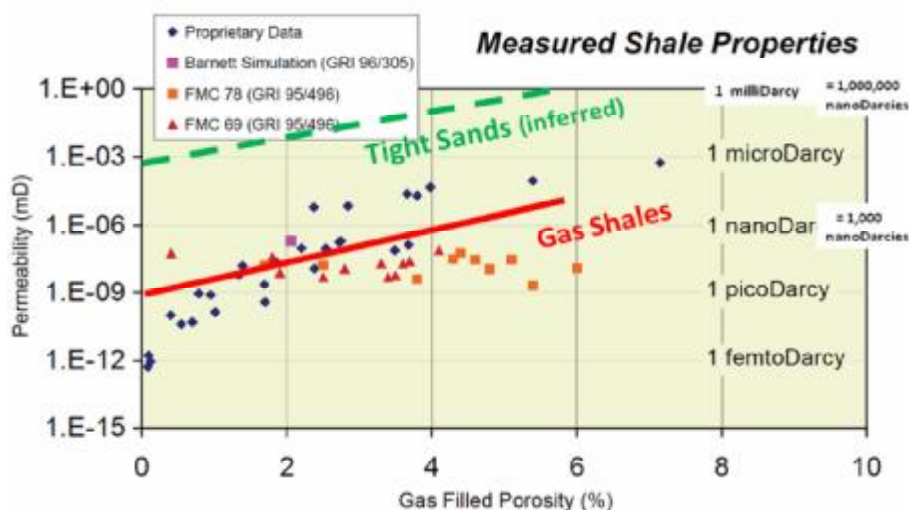


Figure 9: Permeability Differences between Tight Sands (Green) and Gas Shales (Red) (Modified after Cluff et al, 2007).

12. *Pressure Gradient* – A pressure gradient >0.465 psi/ft is optimum as it will increase gas-in-place but it should not be so high that over pressure induced drilling problems occur. High formation pressure in the Haynesville shale in North Louisiana will require use of expensive manmade proppants to overcome proppant crushing due to pressure.
13. *Absolute Age of Shale* – Paleozoic Era shales such as Barnett, Woodford, Fayetteville and Marcellus (Devonian-Mississippian) with absolute ages of 416 MM to 326 MM years appear to be the best targets at this time. This is mostly due to shale brittleness. The younger shales currently under development (Jurassic Haynesville - 160 mm years and Upper Cretaceous Eagle Ford - 100 MM years) may not have had enough time to obtain optimal brittleness. This can lead to poor EURs. Even though initial flow rates can be very high, these shales will exhibit even greater production declines than the older gas shales. This may be due to plastic movement of these younger shales over time around the proppant which may close, inducing fractures and cause casing collapse.
14. *Logistics of Water Supplies for Hydraulic Fracturing* – Each shale gas well will require 70,000 to 100,000 bbl of fresh water available at the initiation of fracture completion. The water resource can be exhausted within a week depending on the number of fracture stages employed. "Frac pits" with dimensions of two acres or larger and depths of 15 feet are normally prepared at the drill site and lined with thick plastic when the location for the drilling rigs is prepared. The pit is then filled via purchase from a local municipal water supply, water well(s) drilled especially for this purpose, or

transported using temporary pipelines from other existing water wells, adjacent rivers, lakes, ponds, streams and rainfall. In the worst (and most expensive) case water is trucked to the pit. It usually takes several months to collect a suitable water volume. In other cases portable "frac tanks", each with a volume of 400 bbl are deployed at the well site and filled. It takes 250 frac tanks to stockpile 100,000 bbls of water so fracs utilizing these tanks may have smaller total fluid volumes due to the extra expense involved. Operators in the Marcellus Shale in the Appalachian Mountains are required to obtain water well permits that require several months for approval from local governments. Figure 10 illustrates frac pits adjacent to drill pads in wooded, low relief terrain.



Figure 10: Frac Pits Adjacent to Drill Pads in Low Relief Terrain (Halliburton, 2008).

15. *Transport Infrastructure in Place* – Large diameter gas pipelines and compressor stations with access to large markets need to be in place or nearby to immediately exploit shale gas development. Some shale gas projects in the U.S. such as the Marcellus shale have been delayed due to the lack of suitable gas transport to large markets. Production from the Barnett Shale was initially constrained. The Haynesville Shale development, even though within an old producing area, has been limited in some areas.

16. *Drill Sites with Easy Access and Construction* – In the success case it will be imperative that an aggressive drilling program be instituted to bring on gas production as quickly as possible. Easy access to drill sites where multiple wells can be drilled from one drill pad is key as will be the location of the frac pits. These multi-well pads will provide the opportunity to simultaneously fracture multiple wells, share production facilities and gathering systems. Consideration of simultaneous drilling and production from the same well pad will be required for early production buildup. This would imply that surface terrain with minimum relief and a good road system would be optimum. Avoid mountainous areas where access is restricted as it will be very hard to quickly ramp up gas production. This is a central issue in West Virginia and Pennsylvania where the complex Appalachian fold belt provides beautiful scenic views but leaves little room for roads, drill sites and frac pits.
17. *Produced Water Disposal* – Environmentally safe disposal of large amounts of produced fracture fluid and salt water associated with the gas production will be required. The fracture fluid dissolves salt that is present in the shale. Gas shales usually have low water saturations but they may still produce significant amounts of salt water sourced from other formations that were invaded by the hydraulic fracturing. Disposal wells with highly permeable shallow sandstones accessible at depths below the fresh water table are required. These wells usually have higher grade casing to extend the usable life of the well. Produced water can be moved to the disposal wells by either gathering systems or truck. Salt water gathering systems laid in the same ditch as the gas gathering lines to the production pads are the most efficient long term solution. If trucks are used, time efficient unloading facilities are constructed so the trucks can unload with minimal time spent at the disposal station. This is a key issue for all shale plays in the U.S. and different resolutions are sought and required.

Other Considerations

Repeatability – Very quickly in the life of the exploration phase, the well results and EURs must become predictably repeatable. In the success case the potential exists that literally thousands of wells can be drilled within a single gas shale play. The Barnett Shale currently has over 11,000 wells with half of these wells drilled within the last four years with many more yet to drill. The initial screening criteria must be robust such that the geological, geochemical and engineering parameters can become statistically meaningful and predictable. This will be extremely important in well planning and scheduling, drilling rig requirements, completion resources, infrastructure and transport development. Any strategic planning will require this information.

Fracture Barriers May be Required – The prolific Barnett shale in some areas directly rests on the Ellenburger limestone (Ordovician age) and is always below the Marble Falls limestone (Pennsylvanian age). The Ellenburger may have zones of high permeability that will produce significant amounts of water if it is penetrated by the hydraulic fracturing. The best Barnett shale production is when the impermeable Viola limestone sits between the Barnett shale and the Ellenburger limestone with the Barnett capped by the Marble falls limestone. In

this situation a perfect set of natural fracture barriers above and below the Barnett is present and keeps the hydraulic fracturing “in zone.” This is generally the area of highest EUR. In some cases however, the Barnett sits directly on permeable Ellenburger that produces water at ½ bbl per mcf gas. In these cases gas production rate is so high that it overcomes the water production and high rate wells are present (initial rates over 10 Mmcf/gpd and EUR over 4 Bcf).

Hydrocarbon Liquids Reduce Gas EUR – Gas shales with maturation histories indicating probable dry gas production (predominantly methane with <1,025 BTU per cfg) are preferred. Oil and condensate constituents have much larger molecular size than methane and will restrict flow of the free gas and especially the absorbed gas as it moves from the kerogen and clay platelets to the pressure sinks at the perforations. Higher BTU values will work but the condensate production needs to be less than four bbl/Mmcf. The Marcellus shale has high BTU content which may restrict EURs.

Gas Composition – Dry gas with 1,025 BTU per mcf is optimal. Since we will have prepared a thorough chemical analysis of the shale prior to drilling we can also eliminate those areas where the gas will have excessive liquids, CO₂ and H₂S. This would ensure that no gas processing or treating is required. The Barnett and Fayetteville Shales have this favorable gas composition. The Marcellus Shale gas requires processing.

Economic Drill Depth – Probable optimal economics will require a drill depth less than 11,000 ft. It has been shown in the Barnett Shale that drill depths as shallow as 7,500 ft can produce shale gas wells with EURs over 5 Bcf. However, the Barnett Shale was initially at a depth of 15,500 ft where the shale became thermally mature. It was later uplifted to its present depth. The depth of optimal thermal maturity will vary dependant on the paleo-confining pressure and temperature gradient. Currently the deepest vertical depth for shale gas wells in the U.S. is 11,500 ft in the Haynesville Shale. The Mako Basin in Hungary is currently being explored for shale gas at depths deeper than 18,000 ft. The Barnett Shale in west Texas is at 18,000 feet in some places with very high gas-in-place values and operators are planning to drill it but the additional costs are significant.

Regional and Tectonic Fracture Systems Understood – The large scale regional fracture systems need to be re-examined to understand fracture density and conjugate fracture sets for initial determination of horizontal well azimuths and potential well spacing. The tectonic fracture systems can be determined by seismic interpretation. Combinations of regional and tectonic fractures and their conjugate systems will be vitally important to the drilling direction and effectiveness of the hydraulic fracturing. The Barnett shale has few open fractures but abundant carbonate filled fractures. These are often opened by hydraulic fracturing.

Low Present Day Temperature Gradient – This will increase gas-in-place due to the higher gas compressibility at lower temperature. It will also help mitigate any possibility that more expensive oil base drilling fluids will be required.

Evaluation Methods

Rapid understanding and contrasting of the petroleum systems of different areas and basins will be expedited if an abundance of deep wells with

wireline logs, well cuttings and conventional core are available. Ability to access these data using digital databases will be of utmost importance. Daily drilling reports, mud logs, core analyses, and log analyses are among the data to be analyzed.

Review of mudlogs is usually the first step in analyzing a gas shale play. Any significant gas shows that are common to the same formation over a very large area should be closely investigated. Well site analysis of the cuttings should mention that the shale is predominately jet black and greasy, obviously very carboniferous and organic with the associated high TOC. One of the best ways to judge the organic content is the old driller's technique which is to rub the shale in the palm of your hand and hope for a very jet black staining as if you had rubbed your hand with an ink marker. The shale should have obvious visual inter-bedded quartz clastics, both as grains and of biological origin. These will generally be siltstones, but in cases they can they actually grade into true sandstones. Shales that grade into a light gray, to brownish gray to brownish color have generally low TOC and the associated low gas content. Shales that are absolutely homogenous without inter-bedded clastics also tend to be low in gas content. The shape of the cuttings vary radically based on many different factors, and are not generally indicative of high or low gas content. The cuttings description should also include abundant pyrite, abundant gas shows while drilling.

In the past, few whole cores have been deliberately taken in shales. Where they are available they are precious. Whole core analysis should show conchoidal fracture, laminations of quartz material, kerogen, filled fractures or broken core that was removed directly from the core barrel signifying highly fractured rock. Shale cores that have descriptions of "bleeding gas" are significant.

Wireline log characteristics of gas shale are unique. High gamma ray count and low density indicate abundant kerogen, high resistivity indicates low water saturation, neutron-density crossover (limestone matrix) shows porosity, and low Pe (photoelectric absorption factor) is abnormal for shales and may indicate quartz siltstone. Appendix 6 is an illustration of these characteristics.

Burial history plots are important in understanding the basin thermal history. Analysis of the thermal history of a basin can best be understood by preparation of burial history plots as described by Guidish et al, 1985. Sequence Stratigraphic Source Rock Mapping helps identify prospective shale gas plays that were once oil or gas generating source rocks and that may not be located directly adjacent to current oil or gas fields. These potentially "migrated" gas shales, possibly in lower basinal areas now inverted, may be identified using Sequence Stratigraphic methodology. Such studies have probably already been made in many if not most China basins. Review of these studies focusing on source rock generation and timing coupled with burial history plots may identify basinal areas more likely to contain thermally mature and over mature oil and gas prone source rock areas. Appendix 7 (Veeken, 2007) describes recent depositional models and tectonic setting for source rock development that can be deduced from Sequence Stratigraphic interpretations.

Conclusions

The shale gas potential in China could be huge. The initial evaluation that has already begun to some extent within many business and academic institutions within China should quickly identify a region to begin the first shale gas exploration. It has been shown that this evaluation can be done through a planned, well organized, technically structured process based on proven fundamental concepts of geoscience and engineering.

References

1. Arthur, J. Daniel, Bryan Bohm, Bobbi Jo Coughlin & Mark Layne, 2008, "Hydraulic Fracturing Considerations for Natural Gas Wells of the Fayetteville Shale, ALL Consulting.
2. Cardott, Bryan, 2009, "Introduction to Vitrinite Reflectance as Thermal Maturity Indicator" in TCU Energy Institute Shale Research Workshop, January 14-15, 2009.
3. Cluff, Robert M., Keith W. Shanley & Michael A. Miller, "Three Things we Thought we understood about shale gas but were afraid to ask...", AAPG Convention, 2007.
4. Comer, John B., 2007, "Reservoir Characteristics and Gas Production Potential of Woodford Shale in the Southern Mid-Continent", Indiana Geological Survey.
5. Curtis, 2008.
6. Guidish, T. M., C. G. St. C. Kendall, I. Lerche, D. J. Toth & R.F. Yarzab, 1985, "Basin Evaluation using Burial History Calculations: An Overview", AAPG Bulletin, V. 69, No.1, pp. 92-105.
7. Halliburton Corporation, 2008, "Shale Gas, An Unconventional Resource, Unconventional Challenges - White Paper", H06377, July @008
8. Harding Company, 2004a, Dallas, Texas.
9. Harding Company, 2004b, Dallas, Texas.
10. Jarvie, Dan, 2008a, "Geochemical Comparison of Shale Resource Systems" presented at Insight Gas Shale Summit, Dallas, Texas, May 6-7, 2008.
11. Jarvie, D., 2008b, Oklahoma Gas Shales, Oklahoma City, Oklahoma, October 22, 2008.
12. Miller, Ryan and Roger Young, 2007, "Characterization of the Woodford Shale in Outcrop and Subsurface in Pontotoc and Coal Counties, Oklahoma", AAPG Annual Convention, Long Beach, California, April 1-4, 2007.
13. Ratchford, Ed, 2007, "Geologic Overview of the Fayetteville Gas Shale" presented at the Fayetteville Shale Conference, University of Arkansas, Conway, Arkansas, August 29, 2007.
14. Sigmon, James, 2008, "TXCO Resources - North American Shale Plays: The Future is Unconventional" in E&P Technology Summit, Houston, October 27-29, 2008.
15. Unknown, 2006, "Southwestern Energy: Scotland Field: Field Rules Application" presented to Arkansas Oil & Gas Commission, June 28, 2005, El Dorado, Arkansas.
16. Veeken, Paul C. H. 2007, "Seismic Stratigraphy, Basin Analysis and Reservoir Characterization", Elsevier, Amsterdam, The Netherlands, 509 pp, p. 291.
17. Walles, F., M. Cameron & D. Jarvie, 2009, "Unconventional Resources – Quantification of Thermal Maturity Indices with Relationships to Predicted

Shale Gas Producibility Gateway Visualization & Attribute Technique" in TCU Energy Institute Shale Research Workshop, January 14-15, 2009, Ft Worth, Texas.

18. Wang, Fred, 2008, "Production Fairway: Speed rails in Gas Shale?" presented at 7th Annual Gas Shales Summit, May 6-7, 2008, Dallas, Texas.

About the Principal Author

Before Harding & Shelton Group, Michael Burnaman held management, technology development and technical leadership positions within Mobil Oil Corporation and its affiliates. He also worked for Gulf Technical Services and Esso Production Research during his university period. He has nearly four decades of experience in Geoscience and Engineering within the upstream petroleum industry in North America, Southeast Asia, the North Sea, West Africa, the former Soviet Union and the Middle East. He has a proven record of finding oil and gas in clastic and carbonate environments and in reservoir characterization, both onshore and offshore. He has been involved in shale gas development for ten years in Texas, Colorado and Oklahoma, and most recently with the Harding Company in a Barnett Shale joint-venture with ExxonMobil. He earned an MS in Geophysics from the University of Houston in 1974 and BS in Geology also from the University of Houston. He is also a Principal in Harding Energy Partners and the owner of Eikonal Energy, Inc. and Virtual Geoscience Consultants, Inc., He has authored and co-authored papers in SEGs Leading Edge, AAPG Monographs and other journals, organized and chaired technical sessions for the AAPG and OTC, and held leadership posts in the Indonesian Petroleum Association, Dallas Geophysical Society and Azerbaijan Society of Petroleum Engineers. He lives in Farmers Branch, Texas.

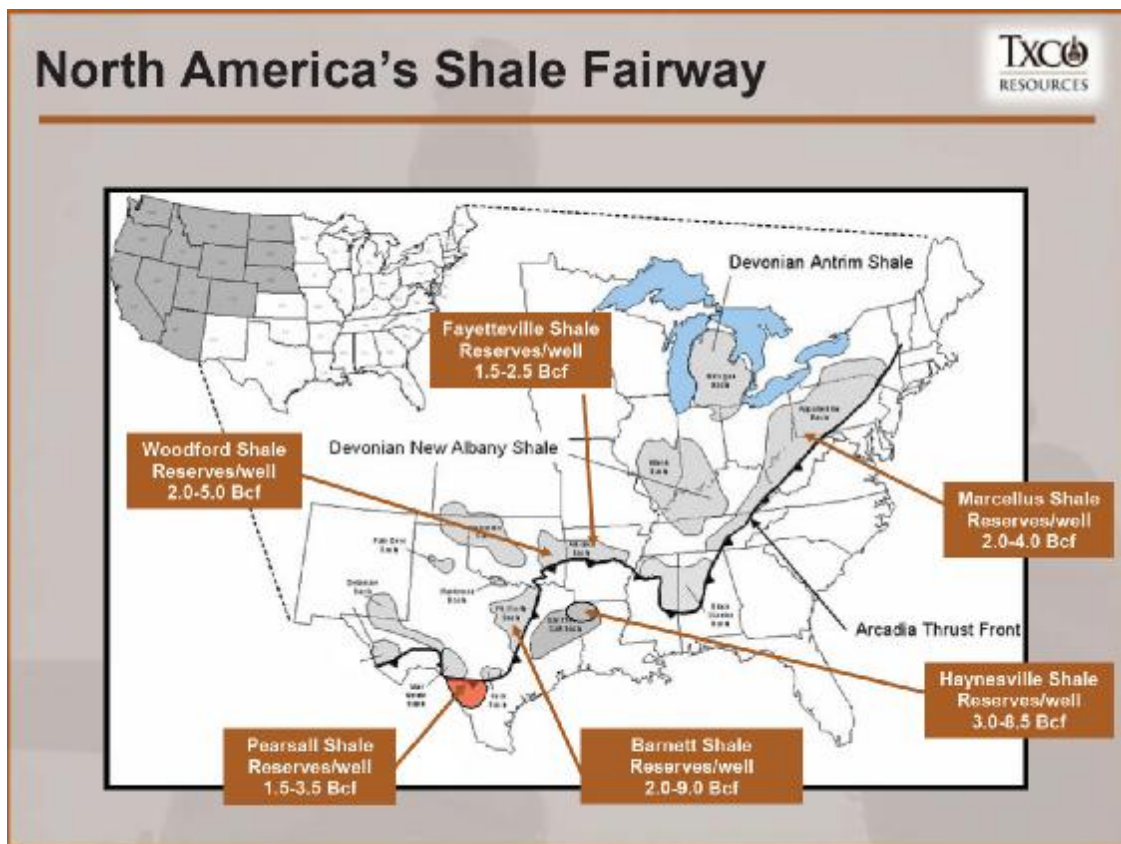
Appendix 1

Shale	Interpreted Thermal Maturity Window	TOC (wt.%)	Estimated TOC _o (wt.%)	HI (mg HC/g TOC)	Estimated TR	%R _o from Tmax	Measured %R _o	S1/TOC (mg HC/g TOC)	Count	Dry Gas Ratio (C1)/(C1+C4)	δ ¹³ C methane (ppt)	δ ¹³ C ethane (ppt)	δ ¹³ C propane (ppt)
Antrim	Immature to early oil	5.27	5.35	432	<0-20%	0.67	0.51	53	161	96%	-55	-44	-37
New Albany	Oil	7.06	7.28	428	5-40%	0.65	na	21	59	52%	-53		
Woodford	Oil	8.23	8.61	503	<0-50%	0.76	0.54	52	31				
Marcellus	Dry gas	3.37	5.27	16	>90%	2.16	na	20	33				
Utica	Dry gas	1.71	2.67	18	>90%	nr	na	33	21				
Fayetteville	Dry gas	1.86	2.91	24	>90%	nr	2.0-2.5	15	538				
Woodford	Late oil-early gas	2.04	3.19	73	>90%	0.92	na	17	40				
Barnett	Immature-early oil	5.21	5.37	380	12%	0.62	0.55	42	3				
Barnett	Early oil	4.70	5.28	299	31%	0.66	0.77	78	25				
Barnett	Gas	4.45	6.50	45	90%	1.72	1.67	19	90				
Atoka	Late oil-early gas	3.11	4.86	23	>70%	1.4	na	27	18				
Barnett	Late oil-early gas	4.04	6.31	67	>70%	0.76 - 1.48	0.69-2.15	33	656				
Woodford	Late oil-early gas	3.93	6.14	87	>70%	1.02	1.20 - 2.10	70	32				
Bossier	Dry gas	1.81	2.83	13	>90%	nr	1.40	18	78				
Lewis	Dry gas	1.48	2.28	22	>90%	NR	1.60	18	22				
Waltman	Oil	2.53	4.22	322	50%	0.75	0.69	5	43	97%	-35	-23	-22
Bakken	Oil	11.37	13.87	298	<0-70%	50 - 1.00	0.55-0.85	43	349				
Monterey	Oil	6.77	7.96	460	<0-20%	0.40	0.45	88	12				
Antelope	Oil	3.02	3.18	433	<0-30%	0.55	na	70	70				

All values are average values from Humble database and may include variable thermal maturities

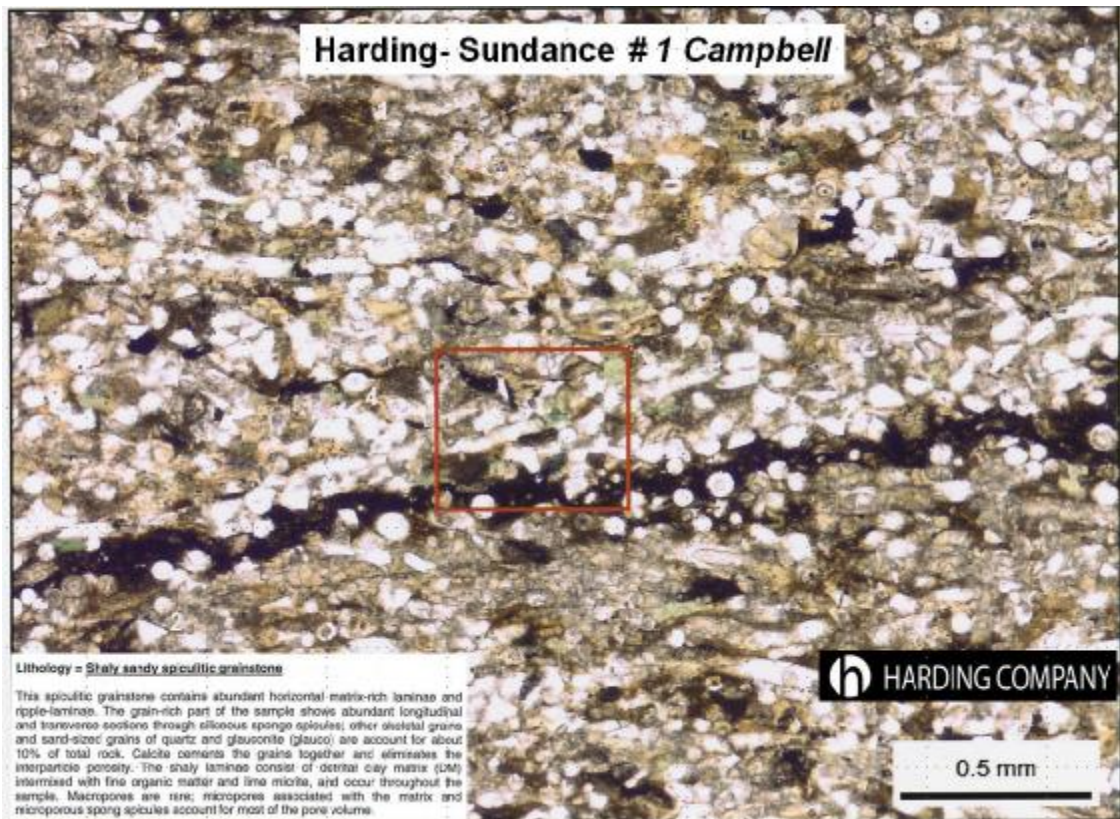
TOC_o total organic carbon, original value
HI hydrogen index (SI/TOC x 100; mg HC/g TOC)
TR transformation ratio ((HI_o - HI_{pred})/HI_o) where HI_o is original HI and HI_{pred} is present day HI value
%R_o vitrinite reflectance in oil submercion
%R_{eq} vitrinite reflectance equivalent; calculated from Rock-Eval Tmax value
ppt parts per thousand or parts per mil

Shale Gas Plays Geochemical Data Summary (Jarvie, 2008).



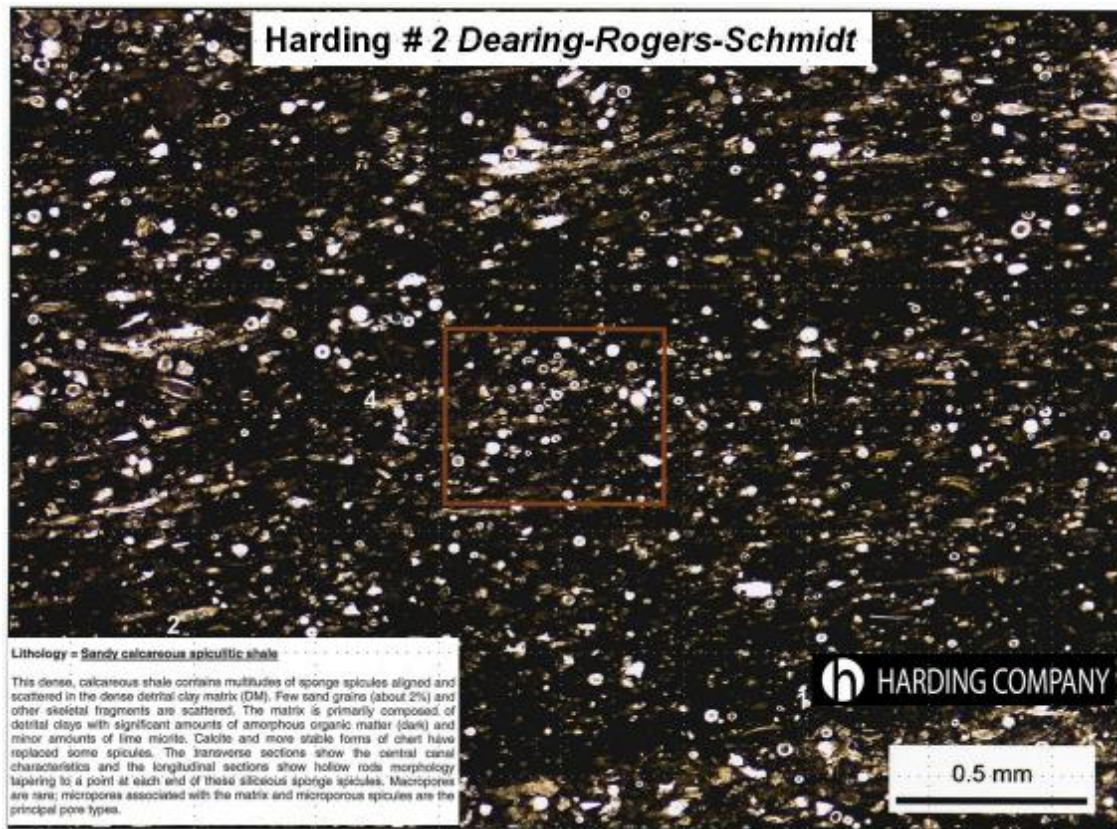
Shale Gas Well Reserves by Play Area (Sigmon, 2008).

Appendix 3



Photomicrograph of Barnett Shale laminated quartz siltstone (Harding Company, 2004).

Appendix 4



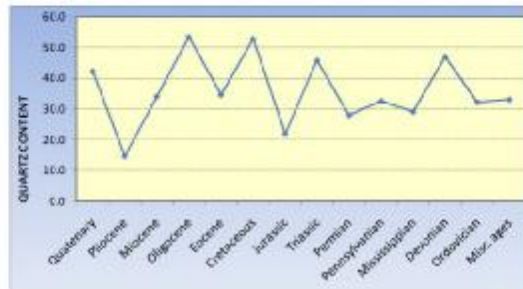
Photomicrograph of Barnett Shale quartz sponge spicules (Harding Company, 2004).

Appendix 5

Shale Composition

Age	Count	Clay Minerals	Quartz	Potassium Feldspar	Plagioclase Feldspar	Calcite	Dolomite	Siderite	Pyrite	Other
Quaternary	5	29.9	42.3	12.4	0.0	6.6	2.4	0.0	5.6	0.8
Pliocene	4	56.5	14.6	5.7	11.9	3.2	0.0	2.9	1.8	3.4
Miocene	9	25.3	34.1	7.8	11.7	14.6	1.2	0.0	1.9	3.4
Oligocene	4	33.7	53.5	3.0	0.0	5.5	0.0	0.0	0.0	4.3
Eocene	11	40.2	34.6	2.0	8.1	3.8	4.6	1.7	1.6	3.4
Cretaceous	9	27.4	52.9	3.6	1.5	2.9	7.9	0.1	1.6	2.0
Jurassic	10	34.7	21.9	0.6	4.4	14.6	1.6	0.4	10.9	10.9
Triassic	9	29.4	45.9	10.7	0.7	3.7	4.1	5.1	0.0	0.4
Permian	1	17.0	28.0	4.0	8.0	0.0	1.0	0.0	0.0	42.0
Pennsylvanian	7	48.9	32.6	0.6	6.2	1.4	2.1	3.4	3.6	1.4
Mississippian	3	57.2	29.1	0.4	2.9	0.0	0.0	0.6	5.1	4.7
Devonian	22	41.8	47.1	0.6	0.0	2.0	1.3	0.3	3.3	3.6
Ordovician	2	44.9	32.2	1.0	6.3	9.5	0.5	0.5	3.4	1.7
Misc. ages	29	47.8	33.1	1.0	6.5	5.2	2.3	0.8	3.1	1.2

Average Clay: 38%
Average Quartz: 36%



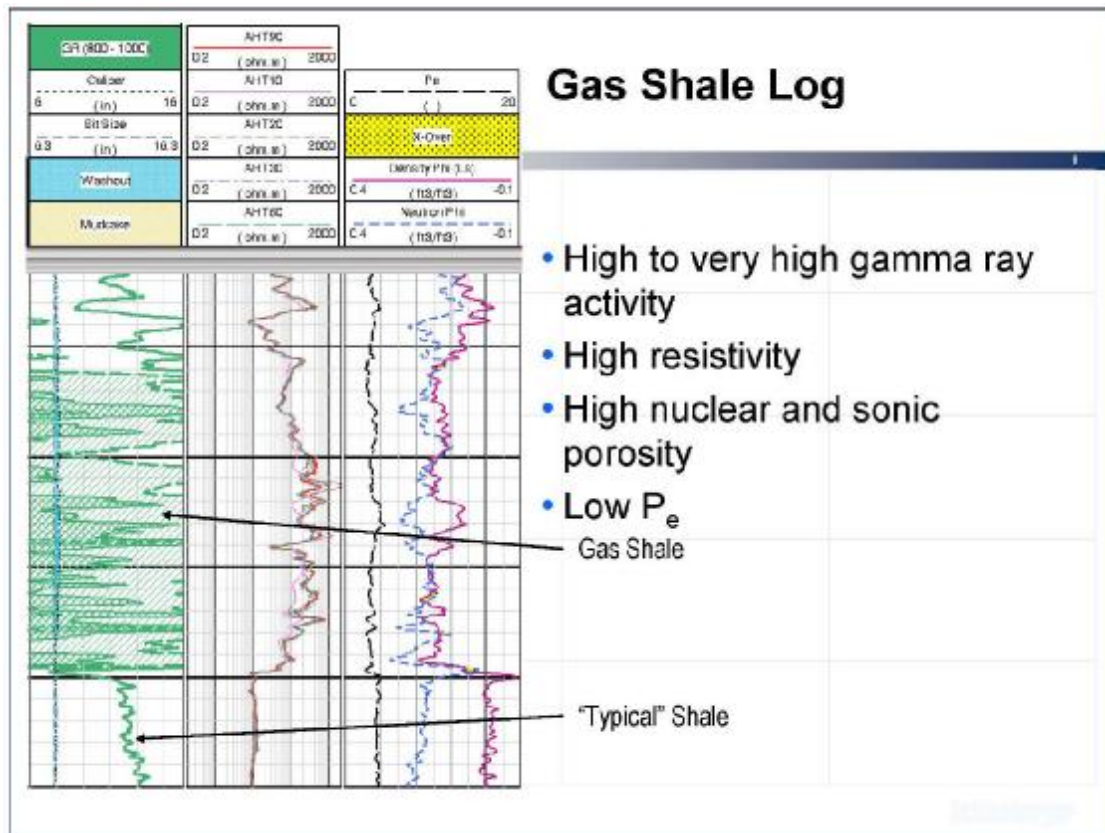
O'Brien and Slatt, 1990

 Dan Jarvie, Worldwide Geochemistry

Oklahoma Gas Shales Oct 22, 2008, OKC, OK

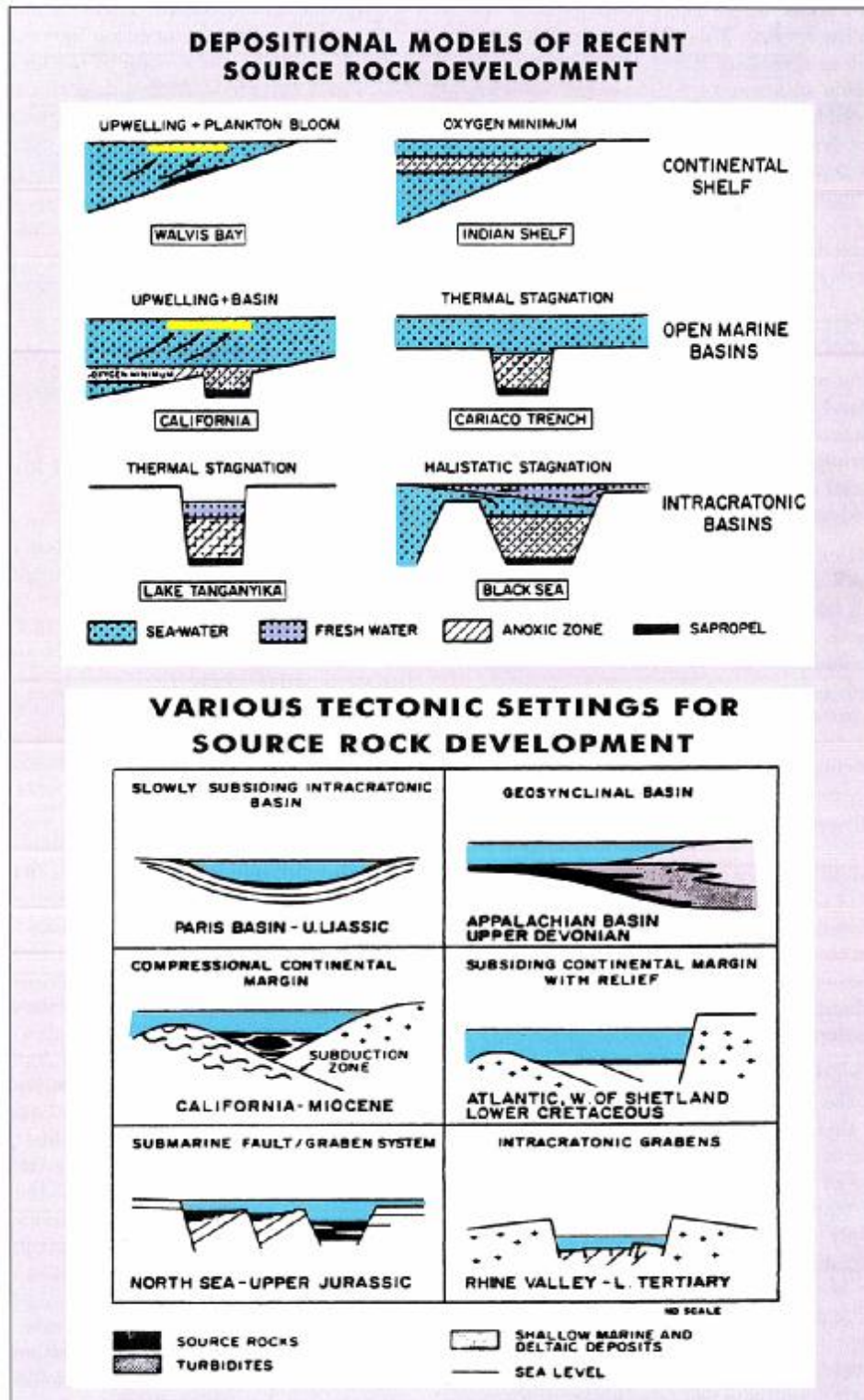
Shale Mineral Composition (Jarvie, 2008).

Appendix 6



Typical Wireline Log Curves for Gas Shale (Ratchford, 2007).

Appendix 7



Recent Depositional and Tectonic Models for Source Rock Deposition (Veeken, 2007).