SHALE GAS AND SHALE OIL RESOURCE ASSESSMENT METHODOLOGY

INTRODUCTION

This report sets forth Advanced Resources' methodology for assessing the in-place and recoverable shale gas and shale oil resources for the EIA/ARI "World Shale Gas and Shale Oil Resource Assessment." The methodology relies on geological information and reservoir properties assembled from the technical literature and data from publically available company reports and presentations. This publically available information is augmented by internal (non-confidential) proprietary prior work on U.S. and international shale gas and shale oil resources by Advanced Resources International.

The report should be viewed as an initial step toward future, more comprehensive assessments of shale gas and shale oil resources. As additional exploration data are gathered, evaluated and incorporated, the assessments of shale oil and gas resources will become more rigorous.

RESOURCE ASSESSMENT METHODOLOGY

The methodology for conducting the basin- and formation-level assessments of shale gas and shale oil resources includes the following five topics:

1. Conducting preliminary geologic and reservoir characterization of shale basins and formation(s).
2. Establishing the areal extent of the major shale gas and shale oil formations.
3. Defining the prospective area for each shale gas and shale oil formation.
4. Estimating the risked shale gas and shale oil in-place.
5. Calculating the technically recoverable shale gas and shale oil resource.

Each of these five shale gas and shale oil resource assessment steps is further discussed below. The shale gas and shale oil resource assessment for Argentina's Neuquen Basin is used to illustrate certain of these resource assessment steps.

1. Conducting Preliminary Geologic and Reservoir Characterization of Shale Basins and Formation(s).

The resource assessment begins with the compilation of data from multiple public and private proprietary sources to define the shale gas and shale oil basins and to select the major shale gas and shale oil formations to be assessed. The stratigraphic columns and well logs, showing the geologic age, the source rocks and other data, are used to select the major shale formations for further study, as illustrated in Figures 1 and 2 for the Neuquen Basin of Argentina.

Preliminary geological and reservoir data are assembled for each major shale basin and formation, including the following key items:

- Depositional environnent of shale (marine vs non-marine)
- Depth (to top and base of shale interval)
- Structure, including major faults
- Gross shale interval
- Organically-rich gross and net shale thickness
- Total organic content (TOC, by wt.)
- Thermal maturity (Ro)

These geologic and reservoir properties are used to provide a first order overview of the geologic characteristics of the major shale gas and shale oil formations and to help select the shale gas and shale oil basins and formations deemed worthy of more intensive assessment.

Figure 1: Prospective Shale Basins of Argentina

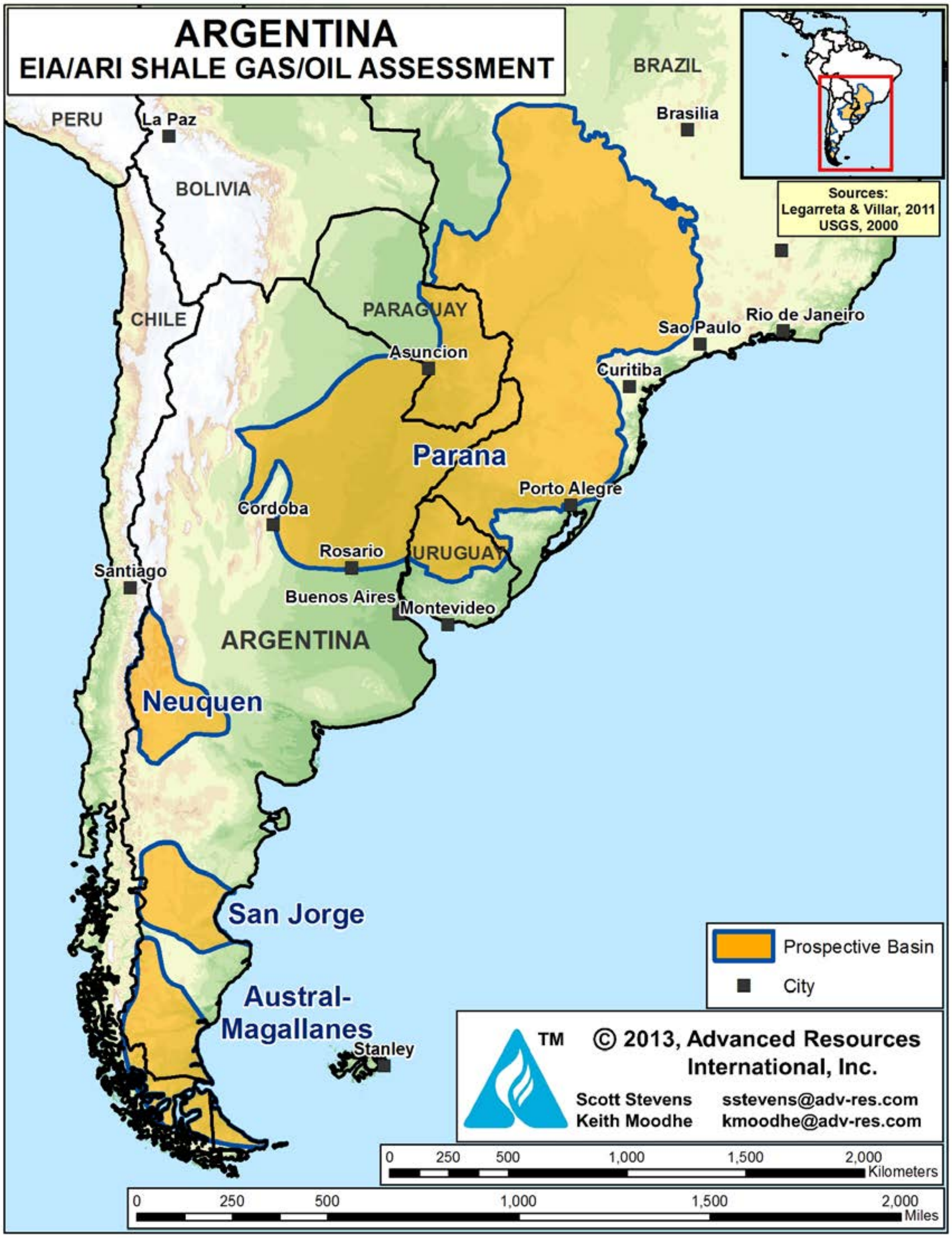
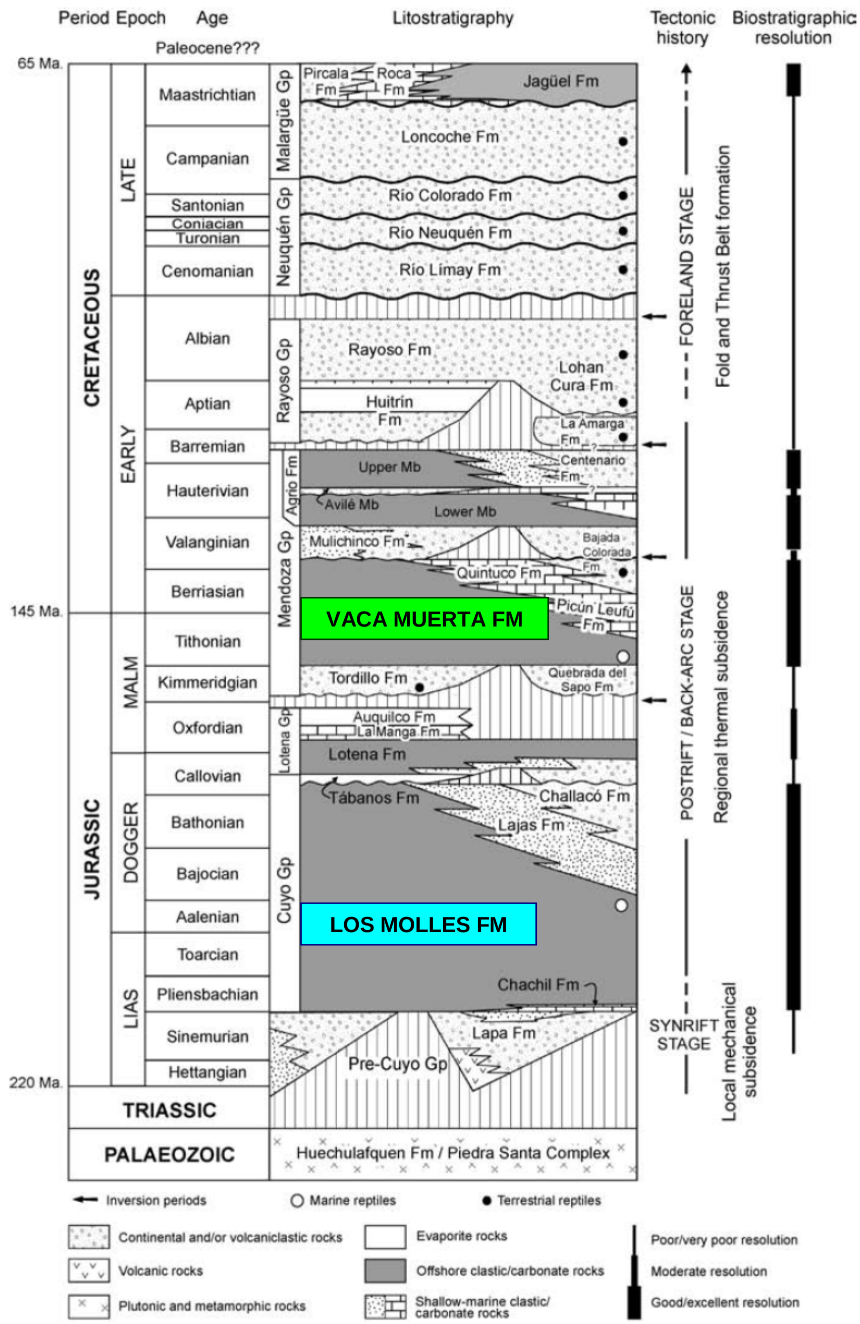


Figure 2. Neuquen Basin Stratigraphy

The Vaca Muerta and Los Molles are Jurassic-age shale formations.



Modified from Howell, J., et al., 2005

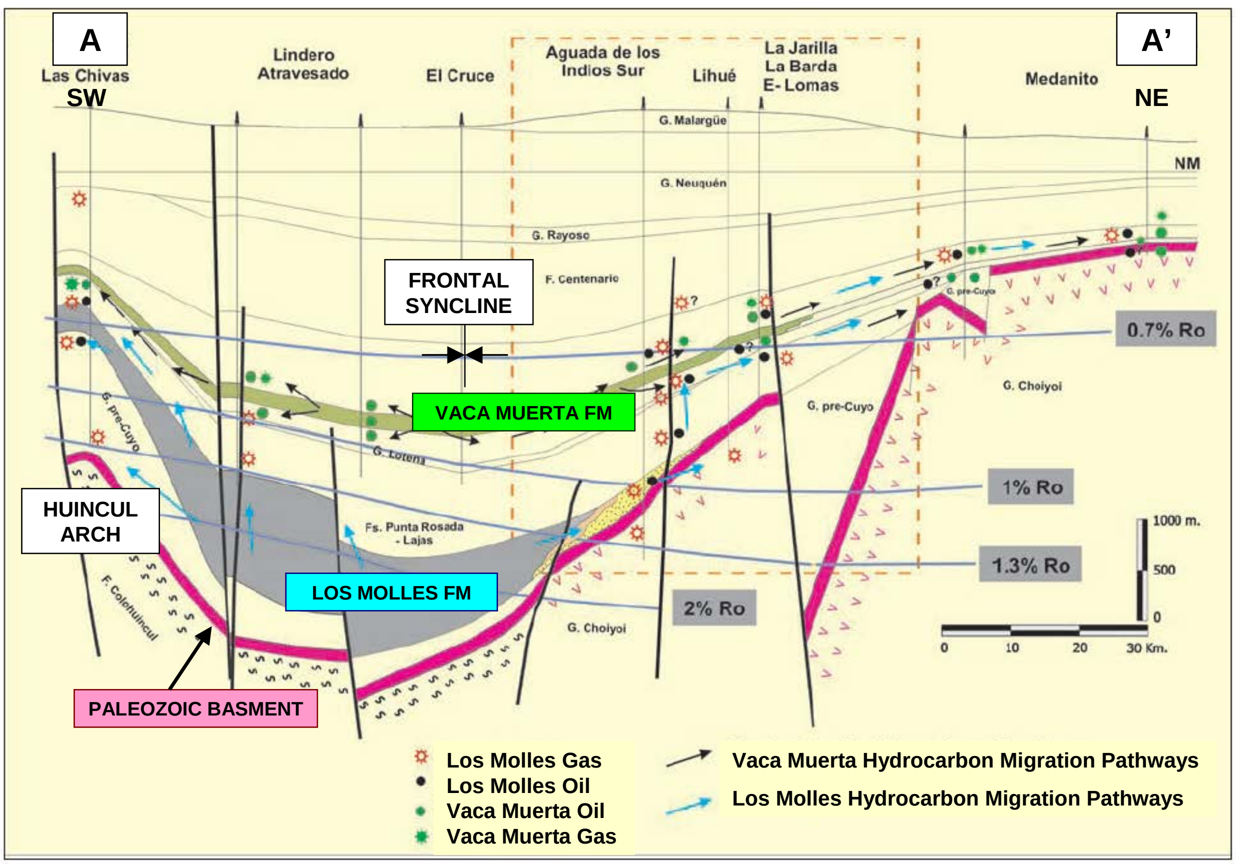
2. Establishing the Areal Extent of Major Shale Gas and Shale Oil Formations.

Having identified the major shale gas and shale oil formations, the next step is to undertake more intensive study to define the areal extent for each of these formations. For this, the study team searches the technical literature for regional as well as detailed, local cross-sections identifying the shale oil and gas formations of interest, as illustrated by Figure 3 for the Vaca Muerta and Los Molles shale gas and shale oil formations in the Neuquen Basin. In addition, the study team draws on proprietary cross-sections previously prepared by Advanced Resources and, where necessary, assembles well data to construct new cross-sections.

The regional cross-sections are used to define the lateral extent of the shale formation in the basin and/or to identify the regional depth and gross interval of the shale formation.

Figure 3: Neuquen Basin SW-NE Cross Section

(Structural settings for the two shale gas and shale oil formations, Vaca Muerta and Los Molles)



Mosquera et al., 2009

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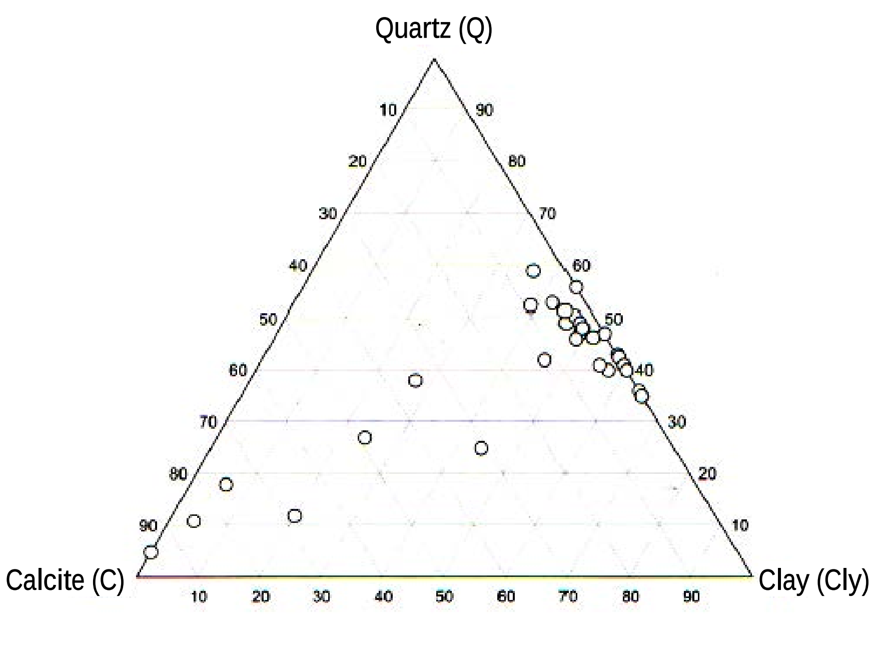
3. Defining the Prospective Area for Each Shale Gas and Shale Oil Formation.

An important and challenging resource assessment step is to establish the portions of the basin that, in our view, are deemed to be prospective for development of shale gas and shale oil. The criteria used for establishing the prospective area include:

- Depositional Environment. An important criterion is the depositional environment of the shale, particularly whether it is marine or non-marine. Marine-deposited shales tend to have lower clay content and tend to be high in brittle minerals such as quartz, feldspar and carbonates. Brittle shales respond favorably to hydraulic stimulation. Shales deposited in non-marine settings (lacustrine, fluvial) tend to be higher in clay, more ductile and less responsive to hydraulic stimulation.

  Figure 4 provides an illustrative ternary diagram useful for classifying the mineral content of the shale for the Marcellus Shale in Lincoln Co., West Virginia

Figure 4. Ternary Diagram of Shale Mineralogy (Marcellus Shale).



Source: Modified from AAPG Bull. 4/2007, p. 494 & 495

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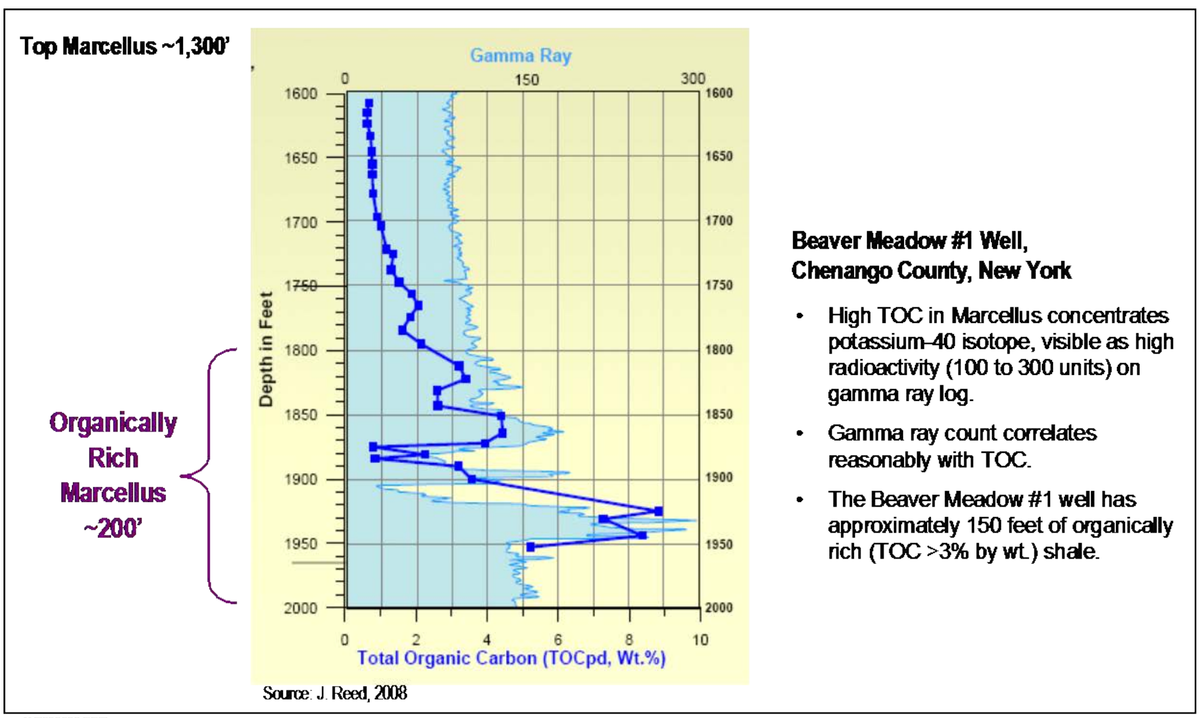
- Depth. The depth criterion for the prospective area is greater than 1,000 meters but less than 5,000 meters (3,300 feet to 16,500 feet). Areas shallower than 1,000 meters have lower reservoir pressure and thus lower driving forces for oil and gas recovery. In addition, shallow shale formations have risks of higher water content in their natural fracture systems. Areas deeper than 5,000 meters have risks of reduced permeability and much higher drilling and development costs.

- Total Organic Content (TOC). In general, the average TOC of the prospective area needs to be greater than 2%. Figure 5 provides an example of using a gamma ray log to identify the TOC content for the Marcellus Shale in the New York (Chenango Co.) portion of the Appalachian Basin.

  Organic materials such as microorganism fossils and plant matter provide the requisite carbon, oxygen and hydrogen atoms needed to create natural gas and oil. As such TOC and carbon type (Types I and II) are important measures of the oil generation potential of a shale formation.

Figure 5. Relationship of Gamma Ray and Total Organic Carbon



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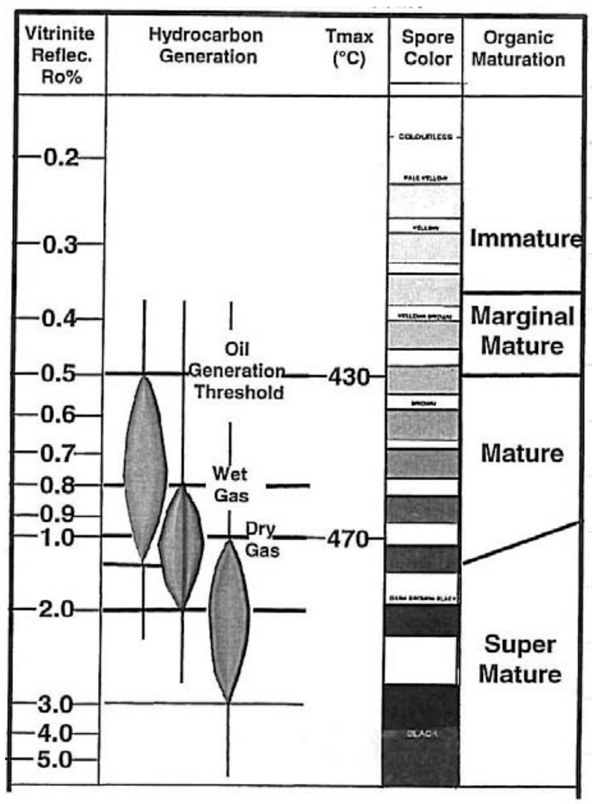
- Thermal Maturity. Thermal maturity measures the degree to which a formation has been exposed to high heat needed to break down organic matter into hydrocarbons. The reflectance of certain types of minerals (Ro%) is used as an indication of Thermal Maturity, Figure 6. The thermal maturity of the oil prone prospective area has a Ro greater than 0.7% but less than 1.0%. The wet gas and condensate prospective area has a Ro between 1.0% and 1.3%. Dry gas areas typically have an Ro greater than 1.3%. Where possible, we have identified these three hydrocarbon "windows".

Figure 6. Thermal Maturation Scale



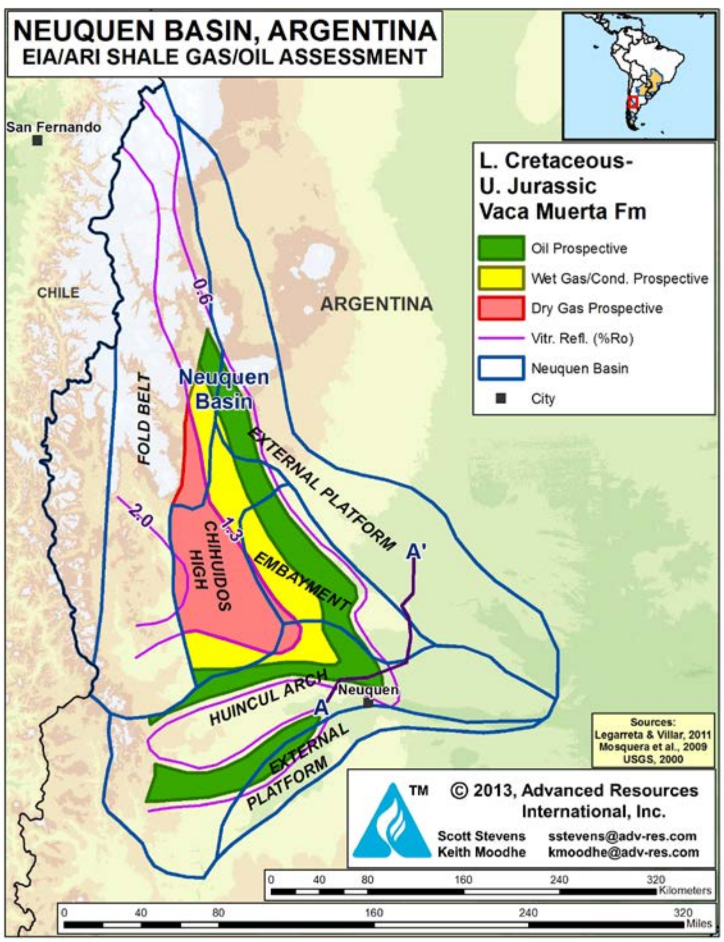
- Geographic Location. The prospective area is limited to the onshore portion of the shale gas and shale oil basin.

The prospective area, in general, covers less than half of the overall basin area. Typically, the prospective area will contain a series of higher quality shale gas and shale oil areas, including a geologically favorable, high resource concentration "core area" and a series of lower quality and lower resource concentration extension areas. However, this more detailed delineation of the prospective area is beyond the scope of this initial resource assessment.

Finally, shale gas and shale oil basins and formations that have very high clay content and/or have very high geologic complexity (e.g., thrusted and high stress) are assigned a high prospective area risk factor or are excluded from the resource assessment. Subsequent, more intensive and smaller-scale (rather than regional-scale) resource assessments may identify the more favorable areas of a basin, enabling portions of the basin currently deemed non-prospective to be added to the shale gas and shale oil resource assessment. Similarly, advances in well completion practices may enable more of the very high clay content shale formations to be efficiently stimulated, also enabling these basins and formations to be added in future years to the resource assessment.

The Neuquen Basin's Vaca Muerta Shale illustrates the presence of three prospective areas - - oil, wet gas/condensate and dry gas, Figure 7.

Figure 7. Vaca Muerta Shale Gas and Shale Oil Prospective Areas, Neuquen Basin



A more detailed resource assessment, including in-depth appraisal of newly drilled exploration wells, with modern logs and rigorous core analyses, will be required to define the next levels of resource quality and concentration for the major international shale plays.

4. Estimating the Risked Shale Gas and Shale Oil In-Place (OIP/GIP).

Detailed geologic and reservoir data are assembled to establish the oil and gas in-place (OIP/GIP) for the prospective area.

a. Oil In-Place. The calculation of oil in-place for a given areal extent (acre, square mile) is governed, to a large extent, by two key characteristics of the shale formation - - net organically-rich shale thickness and oil-filled porosity. In addition, pressure and temperature govern the volume of gas in solution with the reservoir oil, defined by the reservoir's formation volume factor.

- Net Organically-Rich Shale Thickness. The overall geologic interval that contains the organically-rich shale is obtained from prior stratigraphic studies of the formations in the basin being appraised. The gross organically-rich thickness of the shale interval is established from log data and cross-sections, where available. A net to gross ratio is used to account for the organically barren rock within the gross organically-rich shale interval and to estimate the net organically-rich thickness of the shale.

- Oil- and Gas-Filled Porosity. The study assembles porosity data from core and/or log analyses available in the public literature. When porosity data are not available, emphasis is placed on identifying the mineralogy of the shale and its maturity for estimating porosity values from analogous U.S shale basins. Unless other evidence is available, the study assumes the pores are filled with oil, including solution gas, free gas and residual water.

- Pressure. The study methodology places particular emphasis on identifying over-pressured areas. Over-pressured conditions enable a higher portion of the oil to be produced before the reservoir reaches its "bubble point" where the gas dissolved in the oil begins to be released. A conservative hydrostatic gradient of 0.433 psi per foot of depth is used when actual pressure data is unavailable because water salinity data are usually not available.

- Temperature. The study assembles data on the temperature of the shale formation. A standard temperature gradient of 1.25° F per 100 feet of depth and a surface temperature of 60° F are used when actual temperature data are unavailable.

The above data are combined using established reservoir engineering equations and conversion factors to calculate OIP per square mile.

$$\text{OIP} = \frac{7758\,(A * h) *\ \emptyset * (So)}{Boi}$$

A is area, in acres (with the conversion factors of 7,758 barrels per acre foot).

h is net organically-rich shale thickness, in feet.

ϕ is porosity, a dimensionless fraction (the values for porosity are obtained from log or core information published in the technical literature or assigned by analogy from U.S. shale oil basins; the thermal maturity of the shale and its depth of burial can influence the porosity value used for the shale).

(S_o) is the fraction of the porosity filled by oil (So) instead of water (Sw) or gas (S_g), a dimensionless fraction (the established value for porosity (ϕ) is multiplied by the term (So) to establish oil-filled porosity; the value Sw defines the fraction of the pore space that is filled with water, often the residual or irreducible reservoir water saturation in the natural fracture and matrix porosity of the shale; shales may also contain free gas (Sg) in the pore space, further reducing oil-filled porosity.

B_{oi} is the oil formation gas volume factor that is used to adjust the oil volume in the reservoirs, typically swollen with gas in solution, to oil volume in stock-tank barrels; reservoir pressure, temperature and thermal maturity (Ro) values are used to estimate the B_{oi} value. The procedures for calculating B_{oi} are provided in standard reservoir engineering text.[1,2] In addition, B_{oi} can be estimated from correlations (Copyright 1947 Chevron Oil Field Research) printed with permission in McCain, W.D., "The Properties of Petroleum Fluids, Second Edition (1990)", p. 320.

[1] Ramey, H.J., "Rapid Methods of Estimating Reservoir Compressibilities," *Journal of Petroleum Technology*, April, 1964, pp. 447-454.
[2] Vasquez, M., and Beggs, H.D., "Correlations for Fluid Physical Property Predictions," *Journal of Petroleum Technology*, June 1980, pp. 968-970.

In general, the shale oil in the reservoir contains solution or associated gas. A series of engineering calculations, involving reservoir pressure, temperature and analog data from U.S. shale oil formations are used to estimate the volume of associated gas in-place and produced along with the shale oil. As the pressure in the shale oil reservoir drops below the bubble point, a portion of the solution gas separates from the oil creating a free gas phase in the reservoir. At this point, both oil (with remaining gas in solution) and free gas are produced.

b. Free Gas In-Place. The calculation of free gas in-place for a given areal extent (acre, square mile) is governed, to a large extent, by four characteristics of the shale formation - - pressure, temperature, gas-filled porosity and net organically-rich shale thickness.

- Pressure. The study methodology places particular emphasis on identifying areas with overpressure, which enables a higher concentration of gas to be contained within a fixed reservoir volume. A conservative hydrostatic gradient of 0.433 psi per foot of depth is used when actual pressure data is unavailable.

- Temperature. The study assembles data on the temperature of the shale formation, giving particular emphasis on identifying areas with higher than average temperature gradients and surface temperatures. A temperature gradient of 1.25^{o} F per 100 feet of depth plus a surface temperature of 60^{o} F are used when actual temperature data is unavailable.

- Gas-Filled Porosity. The study assembles the porosity data from core or log analyses available in the public literature. When porosity data are not available, emphasis is placed on identifying the mineralogy of the shale and its maturity for estimating porosity values from analogous U.S shale basins. Unless other evidence is available, the study assumes the pores are filled with gas and residual water.

- Net Organically-Rich Shale Thickness. The overall geologic interval that contains the organically-rich shale is obtained from prior stratigraphic studies of the formations in the basin being appraised. The gross organically-rich thickness of the shale interval is established from log data and cross-sections, where available. A net to gross ratio is used to account for the organically barren rock within the gross organically-rich shale interval and to estimate the net organically-rich thickness of the shale.

The above data are combined using established PVT reservoir engineering equations and conversion factors to calculate free GIP per acre. The calculation of free GIP uses the following standard reservoir engineering equation:

$$\text{GIP} = \frac{43{,}560 * \text{A}\, h\Phi(S_g)}{B_g}$$

$$\text{Where: } B_g = \frac{0.02829\text{zT}}{\text{P}}$$

A is area, in acres (with the conversion factors of 43,560 square feet per acre and 640 acres per square mile).

h is net organically-rich shale thickness, in feet.

ϕ is porosity, a dimensionless fraction (the values for porosity are obtained from log or core information published in the technical literature or assigned by analogy from U.S. shale gas basins; the thermal maturity of the shale and its depth of burial can influence the porosity value used for the shale).

(S_g) is the fraction of the porosity filled by gas (S_g) instead of water (S_W) or oil (S_o), a dimensionless fraction (the established value for porosity (ϕ) is multiplied by the term (S_g) to establish gas-filled porosity; the value Sw defines the fraction of the pore space that is filled with water, often the residual or irreducible reservoir water saturation in the natural fracture and matrix porosity of the shale; liquids-rich shales may also contain condensate and/or oil (So) in the pore space, further reducing gas-filled porosity.

P is pressure, in psi (pressure data is obtained from well test information published in the literature, inferred from mud weights used to drill through the shale sequence, or assigned by analog from U.S. shale gas basins; basins with normal reservoir pressure are assigned a conservative hydrostatic gradient of 0.433 psi per foot of depth; basins with indicated overpressure are assigned pressure gradients of 0.5 to 0.6 psi per foot of depth; basins with indicated underpressure are assigned pressure gradients of 0.35 to 0.4 psi per foot of depth).

T is temperature, in degrees Rankin (temperature data is obtained from well test information published in the literature or from regional temperature versus depth gradients; the factor 460 ^{o}F is added to the reservoir temperature (in ^{o}F) to provide the input value for the gas volume factor (B_g) equation).

B_g is the gas volume factor, in cubic feet per standard cubic feet and includes the gas deviation factor (z), a dimensionless fraction. (The gas deviation factor (z) adjusts the ideal compressibility (PVT) factor to account for non-ideal PVT behavior of the gas; gas deviation factors, complex functions of pressure, temperature and gas composition, are published in standard reservoir engineering text.)

c. Adsorbed Gas In-Place. In addition to free gas, shales can hold significant quantities of gas adsorbed on the surface of the organics (and clays) in the shale formation.

A Langmuir isotherm is established for the prospective area of the basin using available data on TOC and on thermal maturity to establish the Langmuir volume (V_L) and the Langmuir pressure (P_L).

Adsorbed gas in-place is then calculated using the formula below (where P is original reservoir pressure).

$$G_C = (V_L * P) / (P_L + P)$$

The above gas content (G_C) (typically measured as cubic feet of gas per ton of net shale) is converted to gas concentration (adsorbed GIP per square mile) using actual or typical values for shale density. (Density values for shale are typically in the range of 2.65 gm/cc and depend on the mineralogy and organic content of the shale.)

The estimates of the Langmuir value (V_L) and pressure (P_L) for adsorbed gas in-place calculations are based on either publically available data in the technical literature or internal (proprietary) data developed by Advanced Resources from prior work on various U.S. and international shale basins.

In general, the Langmuir volume (V_L) is a function of the organic richness and thermal maturity of the shale, as illustrated in Figure 8. The Langmuir pressure (P_L) is a function of how readily the adsorbed gas on the organics in the shale matrix is released as a function of a finite decrease in pressure.

The free gas in-place (GIP) and adsorbed GIP are combined to estimate the resource concentration (Bcf/mi^2) for the prospective area of the shale gas basin. Figure 9 illustrates the relative contributions of free (porosity) gas and adsorbed (sorbed) gas to total gas in-place, as a function of pressure.

Figure 8. Marcellus Shale Adsorbed Gas Content

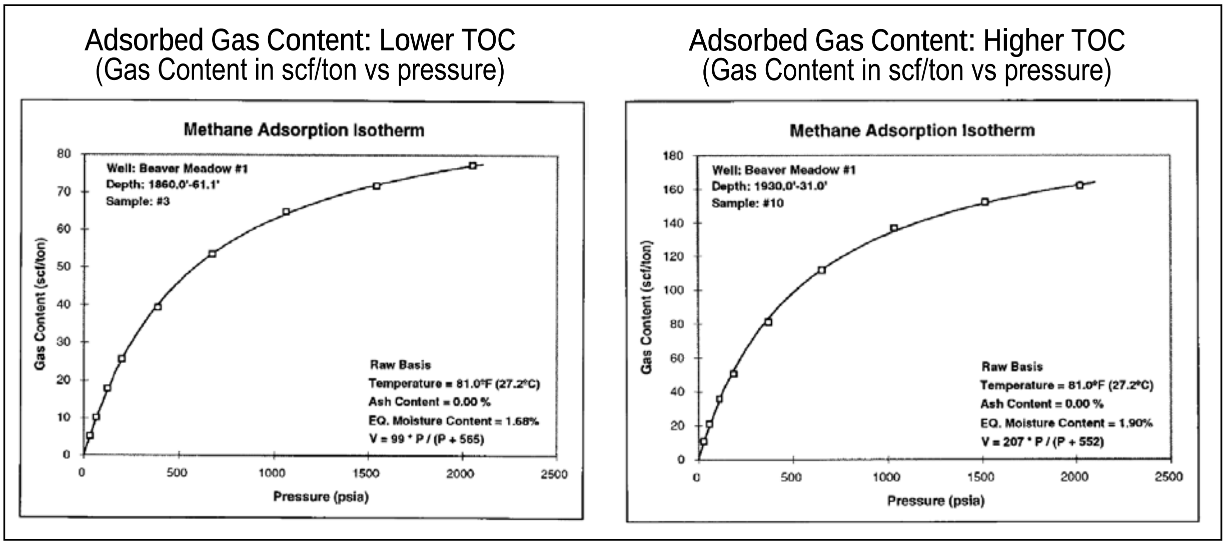


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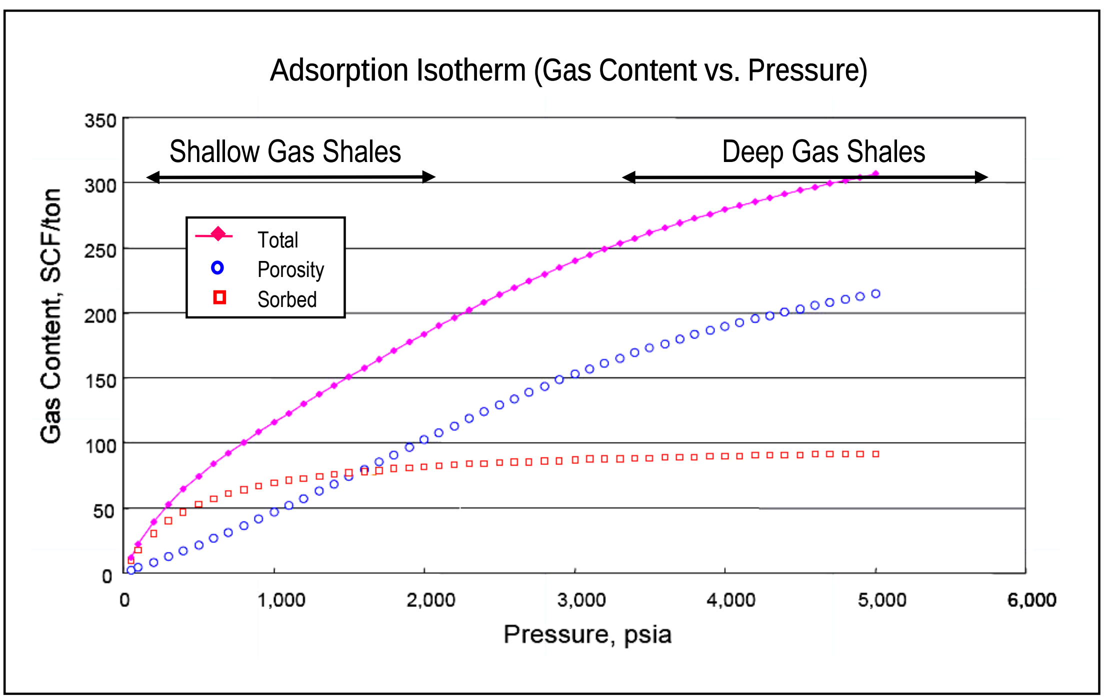
Figure 9. Combining Free and Adsorbed Gas for Total Gas In-Place



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5. Establishing the Success/Risk Factors. Two judgmentally established success/risk factors are used to estimate risked OIP and GIP within the prospective area of the shale oil and gas formation. These two factors are as follows:

- Play Success Probability Factor. The shale gas and shale oil play success probability factor captures the likelihood that at least some significant portion of the shale formation will provide oil and/or gas at attractive flow rates and become developed. Certain shale oil formations, such as the Duvernay Shale in Alberta, Canada, are already under development and thus would have a play probability factor of 100%. More speculative shale oil formations with limited geologic and reservoir data may only have a play success probability factor of 30% to 40%. As exploration wells are drilled, tested and produced and information on the viability of the shale gas and shale oil play is established, the play success probability factor will change.

- Prospective Area Success (Risk) Factor: The prospective area success (risk) factor combines a series of concerns that could relegate a portion of the prospective area to be unsuccessful or unproductive for shale gas and shale oil production. These concerns include areas with high structural complexity (e.g., deep faults, upthrust fault blocks); areas with lower thermal maturity (Ro between 0.7% to 0.8%); the outer edge areas of the prospective area with lower net organic thickness; and other information appropriate to include in the success (risk) factor.

  The prospective area success (risk) factor also captures the amount of available geologic/reservoir data and the extent of exploration that has occurred in the prospective area of the basin to determine what portion of the prospective area has been sufficiently “de-risked”. As exploration and delineation proceed, providing a more rigorous definition of the prospective area, the prospective area success (risk) factor will change.

These two success/risk factors are combined to derive a single composite success factor with which to risk the OIP and GIP for the prospective area.

The history of shale gas and shale oil exploration has shown that with time the success/risk factors improve, particularly the prospective area success factor. As exploration wells are drilled and the favorable shale oil reservoir settings and prospective areas are more fully established, it is likely that the assessments of the size of the shale gas and shale oil in-place will change.

6. Estimating the Technically Recoverable Resource.

The technically recoverable resource is established by multiplying the risked OIP and GIP by a shale oil and gas recovery efficiency factor, which incorporates a number of geological inputs and analogs appropriate to each shale gas and shale oil basin and formation. The recovery efficiency factor uses information on the mineralogy of the shale to determine its favorability for applying hydraulic fracturing to “shatter” the shale matrix and also considers other information that would impact shale well productivity, such as: presence of favorable micro-scale natural fractures; the absence of unfavorable deep cutting faults; the state of stress (compressibility) for the shale formations in the prospective area; and the extent of reservoir overpressure as well as the pressure differential between the reservoir original rock pressure and the reservoir bubble point pressure.

Three basic shale oil recovery efficiency factors, incorporating shale mineralogy, reservoir properties and geologic complexity, are used in the resource assessment.

- <u>Favorable Oil Recovery</u>. A 6% recovery efficiency factor of the oil in-place is used for shale oil basins and formations that have low clay content, low to moderate geologic complexity and favorable reservoir properties such as an over-pressured shale formation and high oil-filled porosity.

- <u>Average Oil Recovery</u>. A 4% to 5% recovery efficiency factor of the oil in-place is used for shale gas basins and formations that have a medium clay content, moderate geologic complexity and average reservoir pressure and other properties.

- <u>Less Favorable Gas Recovery</u>. A 3% recovery efficiency factor of the oil in-place is used for shale gas basins and formations that have medium to high clay content, moderate to high geologic complexity and below average reservoir pressure and other properties.

A recovery efficiency factor of up to 8% may be applied in a few exceptional cases for shale areas with reservoir properties or established high rates of well performance. A recovery efficiency factor of 2% is applied in cases of severe under-pressure and reservoir complexity.

Attachment A provides information on oil recovery efficiency factors assembled for a series of U.S. shale oil basins that provide input for the oil recovery factors presented above.

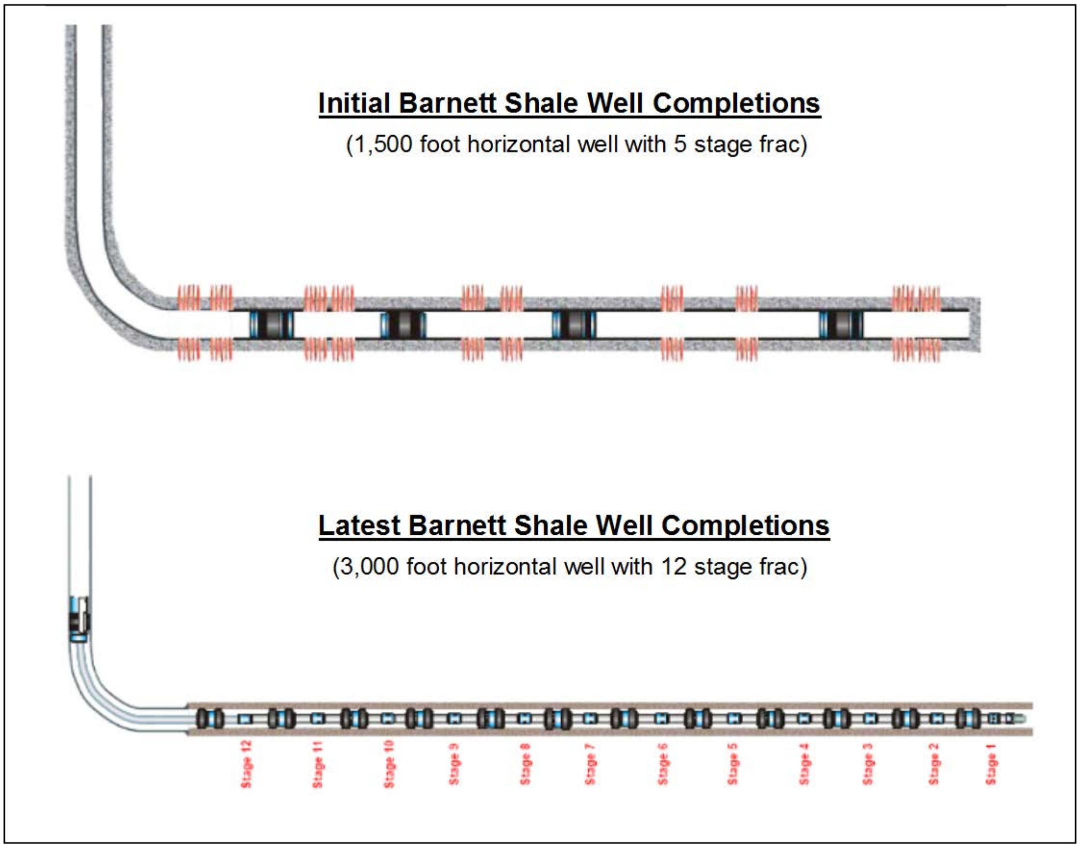
Three basic shale gas recovery efficiency factors, incorporating shale mineralogy, reservoir properties and geologic complexity, are used in the resource assessment.

- Favorable Gas Recovery. A 25% recovery efficiency factor of the gas in-place is used for shale gas basins and formations that have low clay content, low to moderate geologic complexity and favorable reservoir properties such as an overpressured shale formation and high gas-filled porosity.
- Average Gas Recovery. A 20% recovery efficiency factor of the gas in-place is used for shale gas basins and formations that have a medium clay content, moderate geologic complexity and average reservoir pressure and properties.
- Less Favorable Gas Recovery. A 15% recovery efficiency factor of the gas in-place is used for shale gas basins and formations that have medium to high clay content, moderate to high geologic complexity and below average reservoir properties.

A recovery efficiency factor of 30% may be applied in exceptional cases for shale areas with exceptional reservoir performance or established rates of well performance. A recovery efficiency factor of 10% is applied in cases of severe under-pressure and reservoir complexity. The recovery efficiency factors for associated (solution) gas are scaled to the oil recovery factors, discussed above.

a. Two Key Oil Recovery Technologies. Because the native permeability of the shale gas reservoir is extremely low, on the order of a few hundred nano-darcies (0.0001 md) to a few milli-darcies (0.001 md), efficient recovery of the oil held in the shale matrix requires two key well drilling and completion techniques, as illustrate by Figure 10:

Figure 10. Lower Damage, More Effective Horizontal Well Completions Provide Higher Reserves Per Well



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- Long Horizontal Wells. Long horizontal wells (laterals) are designed to place the oil production well in contact with as much of the shale matrix as technically and economically feasible.

- Intensive Well Stimulation. Large volume hydraulic stimulations, conducted in multiple, closely spaced stages (up to 20), are used to "shatter" the shale matrix and create a permeable reservoir. This intensive set of induced and propped hydraulic fractures provides the critical flow paths from the shale matrix to the horizontal well. Existing, small scale natural fractures (micro-fractures) will, if open, contribute additional flow paths from the shale matrix to the wellbore.

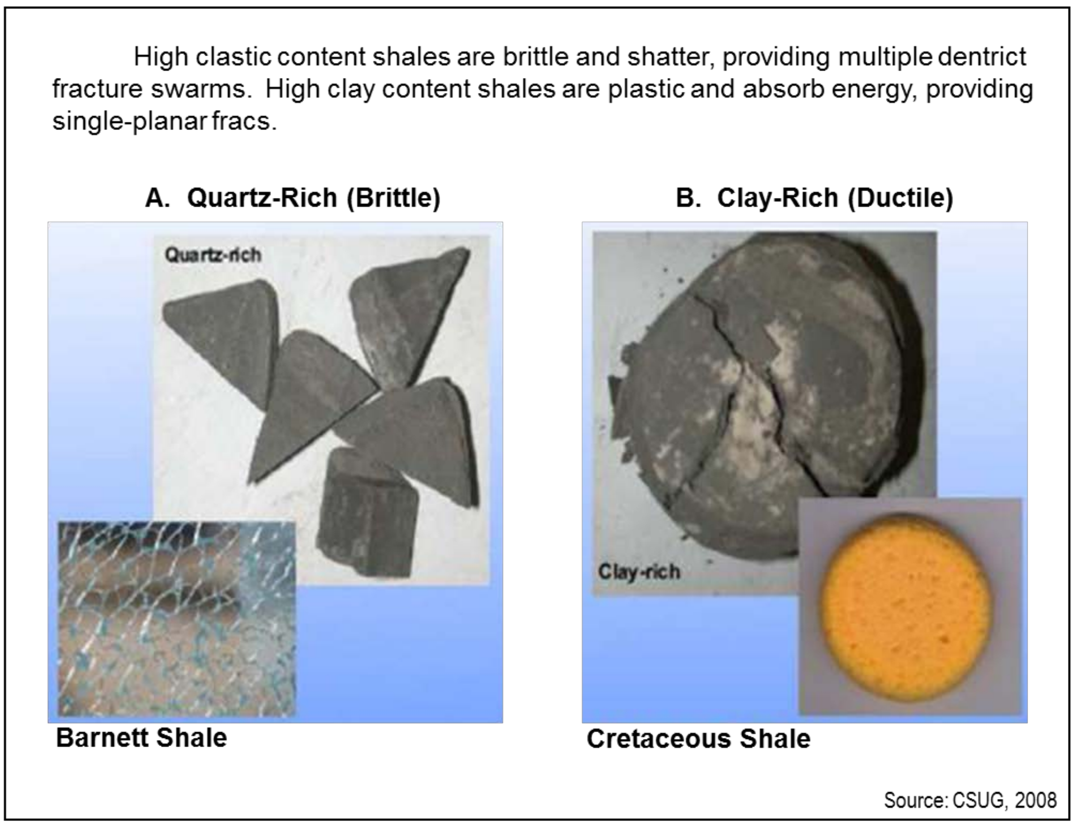
The efficiency of the hydraulic well stimulation depends greatly on the mineralogy of the shale, as further discussed below.

b. Importance of Mineralogy on Recoverable Resources. The mineralogy of the shale, particularly its relative quartz, carbonate and clay content, significantly determines how efficiently the induced hydraulic fracture will stimulate the shale, as illustrated by Figure 11:

- Shales with a high percentage of quartz and carbonate tend to be brittle and will “shatter”, leading to a vast array of small-scale induced fractures providing numerous flow paths from the matrix to the wellbore, when hydraulic pressure and energy are injected into the shale matrix, Figure 11A.

- Shales with a high clay content tend to be ductile and to deform instead of shattering, leading to relatively few induced fractures (providing only limited flow paths from the matrix to the well) when hydraulic pressure and energy are injected into the shale matrix, Figure 11B.

Figure 11. The Properties of the Reservoir Rock Greatly Influence the Effectiveness of Hydraulic Stimulations.



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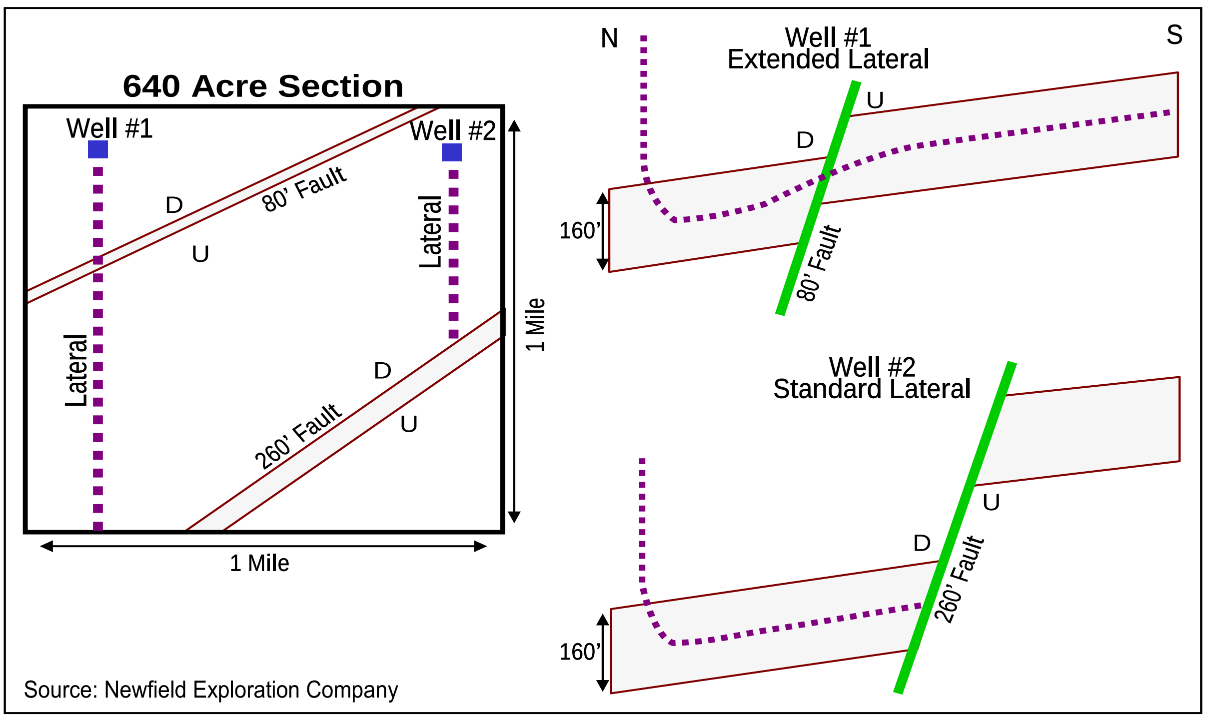
c. Significance of Geologic Complexity. A variety of complex geologic features can reduce the shale gas and shale oil recovery efficiency from a shale basin and formation:

- Extensive Fault Systems. Areas with extensive faults can hinder recovery by limiting the productive length of the horizontal well, as illustrated by Figure 12.
- Deep Seated Fault System. Vertically extensive faults that cut through organically rich shale intervals can introduce water into the shale matrix, reducing relative permeability and flow capacity.
- Thrust Faults and Other High Stress Geological Features. Compressional tectonic features, such as thrust faults and up-thrusted fault blocks, are an indication of basin areas with high lateral reservoir stress, reducing the permeability of the shale matrix and its flow capacity.

Figure 12. 3D Seismic Helps Design Extended vs. Limited Length Lateral Wells



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SUMMARY

The step-by-step application of the above shale gas and shale oil resource assessment methodology leads to three key assessment values for each major shale oil and gas formation:

- Shale Gas and Shale Oil In-place Concentration, reported in terms of billion cubic feet of shale gas per square mile or millions of barrels of shale oil per square mile. This key resource assessment value defines the richness of the shale gas and shale oil resource and its relative attractiveness compared to other gas and oil development options.
- Risked Shale Gas and Shale Oil In-Place, reported in trillion cubic feet (Tcf) of shale gas and billion barrels (Bbbl) of shale oil for each major shale formation.
- Risked Recoverable Gas and Oil, reported in trillion cubic feet (Tcf) of shale gas and billion barrels (Bbbl) of shale oil for each major shale formation.

The risked recoverable shale gas and shale oil provide the important “bottom line” value that helps the reader understand how large is the prospective shale gas and shale oil resource and what impact this resource may have on the gas and oil options available in each region and country.

Tables 1 and 2, for the Neuquen Basin and its Vaca Muerta Shale formation, provides a summary of the resource assessment conducted for one basin and one shale formation in Argentina including the risked, technically recoverable shale gas and shale oil, as follows:

- 308 Tcf of risked, technically recoverable shale gas resource, including 194 Tcf of dry gas, 91 Tcf of wet gas and 23 Tcf of associated gas, Table 1.
- 16.2 billion barrels of technically recoverable shale oil resource, including 2.6 billion barrels of condensate and 13.6 billion barrels of volatile/black oil, Table 2.

Table 1. Shale Gas Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		Neuquen ($66,900 mi^2$)		
	Shale Formation		Vaca Muerta		
	Geologic Age		U. Jurassic - L. Cretaceous		
	Depositional Environment		Marine		
Physical Extent	Prospective Area (mi^2)		4,840	3,270	3,550
	Thickness (ft)	Organically Rich	500	500	500
		Net	325	325	325
	Depth (ft)	Interval	3,000 - 9,000	4,500 - 9,000	5,500 - 10,000
		Average	5,000	6,500	8,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		5.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%
	Clay Content		Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		66.1	185.9	302.9
	Risked GIP (Tcf)		192.0	364.8	645.1
	Risked Recoverable (Tcf)		23.0	91.2	193.5

Table-2. Shale Oil Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		Neuquen ($66,900 mi^2$)	
	Shale Formation		Vaca Muerta	
	Geologic Age		U. Jurassic - L. Cretaceous	
	Depositional Environment		Marine	
Physical Extent	Prospective Area (mi^2)		4,840	3,270
	Thickness (ft)	Organically Rich	500	500
		Net	325	325
	Depth (ft)	Interval	3,000 - 9,000	4,500 - 9,000
		Average	5,000	6,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate
	OIP Concentration ($MMbbl/mi^2$)		77.9	22.5
	Risked OIP (B bbl)		226.2	44.2
	Risked Recoverable (B bbl)		13.57	2.65

ATTACHMENT A

ESTABLISHING OIL RECOVERY EFFICIENCY FACTORS FOR THE INTERNATIONAL "TIGHT OIL" STUDY

INTRODUCTION

The information assembled in Attachment A provides support for the oil recovery efficiency factors to be used by the International "Tight Oil" Resource Study being conducted for the U.S. Energy Information Administration by Advanced Resources International, Inc.

DATA BASE

The Advanced Resources proprietary data base used to establish analog values for the oil recovery efficiency factor in the International "Tight Oil" Resource Study consists of 28 "tight oil" plays in seven U.S. shale and tight sand/lime basins.

Table A-1 provides a listing of the 28 U.S. "tight oil" plays included in the analysis as well as key geological and reservoir properties that influence oil recovery efficiency, such as: (1) reservoir pressure; (2) thermal maturity; and (3) the formation volume factor.

In addition, Table A-1 provides information on the geologic age of the "tight oil" formation which influences its depositional style. In general, the 28 U.S. "tight oil" plays have deep marine depositions with low to moderate clay content.

ANALYTIC RESULTS

Table A-2 provides the oil recovery efficiency factor estimated for each of the 28 U.S. "tight oil" plays in the data base.

- The oil in-place, shown in thousand barrels per square mile, is calculated from the data on Table A-1 as well as from data in Advanced Resources proprietary unconventional gas data base.
- The oil recovery, also shown in thousand barrels per square mile, is from "type curves" based calculations of oil recovery per well times the number of wells expected to be drilled per square mile.

- The oil recovery efficiency, shown as a percent, is calculated by dividing oil recovery by oil in-place.

FINDINGS AND OBSERVATIONS

A closer look at the oil recovery efficiency data on Table A-2 leads to the following findings and observations:

- The oil recovery efficiency values range from about 1% to 9%, with an un-weighted average of about 3.5%.
- Taking out five of the extremely low oil recovery efficiency plays (which we would classify as non-productive) - - Mississippi Lime (Eastern Oklahoma Ext.), Mississippi Lime (Kansas Ext.), Delaware Wolfcamp (Texas Ext.), D-J Niobrara (North Ext. #2), and D-J Niobrara (East Ext.), raises the average oil recovery efficiency to 4.1%.
- Six of the U.S. “tight oil” plays have oil recovery factors that range from about 8% to about 9%.
- Four of the U.S. “tight oil” plays have oil recovery factors that range from about 4% to about 6%.
- Twelve of the U.S. “tight oil” plays have oil recovery factors that range from about 2% to about 3%.

A number of actions could change these initial estimates of oil recovery efficiency in future years, including: (1) use of closer well spacing; (2) continued improvements in oil recovery technology, including use of longer laterals and more frac stages; (3) completion of more of the vertical net pay encountered by the wellbore; and (4) development of the lower productivity portions of each play area.

Table A-1. Tight Oil Data Base Used for Establishing Oil Recovery Efficiency Factors

Basin	Formation/Play	Age	Reservoir Pressure	Thermal Maturity (% R_o)	Formation Volume Factor (B_{oi})
Williston	Bakken ND Core	Mississippian-Devonian	Overpressured	0.80%	1.35
	Bakken ND Ext.	Mississippian-Devonian	Overpressured	0.80%	1.58
	Bakken MT	Mississippian-Devonian	Overpressured	0.75%	1.26
	Three Forks ND	Devonian	Overpressured	0.85%	1.47
	Three Forks MT	Devonian	Overpressured	0.85%	1.27
Maverick	Eagle Ford Play #3A	Late Cretaceous	Overpressured	0.90%	1.75
	Eagle Ford Play #3B	Late Cretaceous	Overpressured	0.85%	2.01
	Eagle Ford Play #4A	Late Cretaceous	Overpressured	0.75%	1.57
	Eagle Ford Play #4B	Late Cretaceous	Overpressured	0.70%	1.33
Ft. Worth	Barnett Combo - Core	Mississippian	Slightly Overpressured	0.90%	1.53
	Barnett Combo - Ext.	Mississippian	Slightly Overpressured	0.80%	1.41
Permian	Del. Avalon/BS (NM)	Permian	Slightly Overpressured	0.90%	1.70
	Del. Avalon/BS (TX)	Permian	Slightly Overpressured	0.90%	1.74
	Del. Wolfcamp (TX Core)	Permian-Pennsylvanian	Slightly Overpressured	0.92%	1.96
	Del. Wolfcamp (TX Ext.)	Permian-Pennsylvanian	Slightly Overpressured	0.92%	1.79
	Del. Wolfcamp (NM Ext.)	Permian-Pennsylvanian	Slightly Overpressured	0.92%	1.85
	Midl. Wolfcamp Core	Permian-Pennsylvanian	Overpressured	0.90%	1.67
	Midl. Wolfcamp Ext.	Permian-Pennsylvanian	Overpressured	0.90%	1.66
	Midl. Cline Shale	Pennsylvanian	Overpressured	0.90%	1.82
Anadarko	Cana Woodford - Oil	Upper Devonian	Overpressured	0.80%	1.76
	Miss. Lime - Central OK Core	Mississippian	Normal	0.90%	1.29
	Miss. Lime - Eastern OK Ext.	Mississippian	Normal	0.90%	1.20
	Miss. Lime - KS Ext.	Mississippian	Normal	0.90%	1.29
Appalachian	Utica Shale - Oil	Ordovician	Slightly Overpressured	0.80%	1.46
D-J	D-J Niobrara Core	Late Cretaceous	Normal	1.00%	1.57
	D-J Niobrara East Ext.	Late Cretaceous	Normal	0.70%	1.26
	D-J Niobrara North Ext. #1	Late Cretaceous	Normal	0.70%	1.37
	D-J Niobrara North Ext. #2	Late Cretaceous	Normal	0.65%	1.28

Table A-2. Oil Recovery Efficiency for 28 U.S. Tight Oil Plays

(Black Oil, Volatile Oil and Condensates)

Basin	Formation/Play	Age	Oil In-Place ($MBbls/Mi^2$)	Oil Recovery ($MBbls/Mi^2$)	Oil Recovery Efficiency (%)
Williston	Bakken ND Core	Mississippian-Devonian	12,245	1,025	8.4%
	Bakken ND Ext.	Mississippian-Devonian	9,599	736	7.7%
	Bakken MT	Mississippian-Devonian	10,958	422	3.9%
	Three Forks ND	Devonian	9,859	810	8.2%
	Three Forks MT	Devonian	10,415	376	3.6%
Maverick	Eagle Ford Play #3A	Late Cretaceous	22,455	1,827	8.1%
	Eagle Ford Play #3B	Late Cretaceous	25,738	2,328	9.0%
	Eagle Ford Play #4A	Late Cretaceous	45,350	1,895	4.2%
	Eagle Ford Play #4B	Late Cretaceous	34,505	2,007	5.8%
Ft. Worth	Barnett Combo - Core	Mississippian	25,262	377	1.5%
	Barnett Combo - Ext.	Mississippian	13,750	251	1.8%
Permian	Del. Avalon/BS (NM)	Permian	34,976	648	1.9%
	Del. Avalon/BS (TX)	Permian	27,354	580	2.1%
	Del. Wolfcamp (TX Core)	Permian-Pennsylvanian	35,390	1,193	3.4%
	Del. Wolfcamp (TX Ext.)	Permian-Pennsylvanian	27,683	372	1.3%
	Del. Wolfcamp (NM Ext.)	Permian-Pennsylvanian	21,485	506	2.4%
	Midl. Wolfcamp Core	Permian-Pennsylvanian	53,304	1,012	1.9%
	Midl. Wolfcamp Ext.	Permian-Pennsylvanian	46,767	756	1.6%
	Midl. Cline Shale	Pennsylvanian	32,148	892	2.8%
Anadarko	Cana Woodford - Oil	Upper Devonian	11,413	964	8.4%
	Miss. Lime - Central OK Core	Mississippian	28,364	885	3.1%
	Miss. Lime - Eastern OK Ext.	Mississippian	30,441	189	0.6%
	Miss. Lime - KS Ext.	Mississippian	21,881	294	1.3%
Appalachian	Utica Shale - Oil	Ordovician	42,408	906	2.1%
D-J	D-J Niobrara Core	Late Cretaceous	33,061	703	2.1%
	D-J Niobrara East Ext.	Late Cretaceous	30,676	363	1.2%
	D-J Niobrara North Ext. #1	Late Cretaceous	28,722	1,326	4.6%
	D-J Niobrara North Ext. #2	Late Cretaceous	16,469	143	0.9%