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Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States

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Executive Summary

This report provides an initial assessment of shale oil resources and updates a prior assessment of shale gas resources issued in April 2011. It assesses 137 shale formations in 41 countries outside the United States, expanding on the 69 shale formations within 32 countries considered in the prior report. The earlier assessment, also prepared by Advanced Resources International (ARI), was released as part of a U.S. Energy Information Administration (EIA) report titled *World Shale Gas Resources: An Initial Assessment of 14 Regions outside the United States*.[1]

There were two reasons for pursuing an updated assessment of shale resources so soon after the prior report. First, geologic research and well drilling results not available for use in the 2011 report allow for a more informed evaluation of the shale formations covered in that report as well as other shale formations that it did not assess. Second, while the 2011 report focused exclusively on natural gas, recent developments in the United States highlight the role of shale formations and other tight plays as sources of crude oil, lease condensates, and a variety of liquids processed from wet natural gas.

As shown in Table 1, estimates in the updated report taken in conjunction with EIA's own assessment of resources within the United States indicate technically recoverable resources of 345 billion barrels of world shale oil resources and 7,299 trillion cubic feet of world shale gas resources. The new global shale gas resource estimate is 10 percent higher than the estimate in the 2011 report.

Table 1. Comparison of the 2011 and 2013 reports

ARI report coverage	2011 Report	2013 Report
Number of countries	32	41
Number of basins	48	95
Number of formations	69	137
Technically recoverable resources, including U.S.		
Shale gas (trillion cubic feet)	6,622	7,299
Shale / tight oil (billion barrels)	32	345

Note: The 2011 report did not include shale oil; however, the *Annual Energy Outlook 2011* did (for only the U.S.) and is included here for completeness

Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. The shale oil resources assessed in this report, combined with EIA's prior estimate of U.S. tight oil resources that are predominantly in shales, add approximately 11 percent to the 3,012 billion barrels of proved and unproved technically recoverable nonshale oil resources identified in recent assessments. The shale gas resources assessed in this report, combined with EIA's prior estimate of U.S. shale gas resources, add approximately 47 percent to the 15,583 trillion cubic

[1] U.S. Energy Information Administration, *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*, April 2011, Washington, DC

feet of proved and unproven nonshale technically recoverable natural gas resources. Globally, 32 percent of the total estimated natural gas resources are in shale formations, while 10 percent of estimated oil resources are in shale or tight formations.

Table 2. Technically recoverable shale oil and shale gas unproved resources in the context of total world resources (assessment dates shown in footnotes)

	Crude oil (billion barrels)	Wet natural gas (trillion cubic feet)
Outside the United States		
Shale oil and shale gas unproved resources	287	6,634
Other proved reserves[1]	1,617	6,521
Other unproved resources[2]	1,230	7,296
Total	**3,134**	**20,451**
Increase in total resources due to inclusion of shale oil and shale gas	**10%**	**48%**
Shale as a percent of total	**9%**	**32%**
United States		
EIA shale / tight oil and shale gas proved reserves[3, 4]	n/a	97
EIA shale / tight oil and shale gas unproved resources[5]	58	567
EIA other proved reserves[6]	25	220
EIA other unproved resources[5]	139	1,546
Total	**223**	**2,431**
Increase in total resources due to inclusion of shale oil and shale gas	**35%**	**38%**
Shale as a percent of total	**26%**	**27%**
Total World		
Shale / tight oil and shale gas proved reserves	n/a	97
Shale / tight oil and shale gas unproved resources	345	7,201
Other proved reserves	1,642	6,741
Other unproved resources	1,370	8,842
Total	**3,357**	**22,882**
Increase in total resources due to inclusion of shale oil and shale gas	**11%**	**47%**
Shale as a percent of total	**10%**	**32%**

[1] *Oil & Gas Journal,* Worldwide Report, December 3, 2012.

[2] Sources: U.S. Geological Survey, *An Estimate of Undiscovered Conventional Oil and Gas Resources of the World, 2012*, Fact Sheet 2012-3028, March 2012; U.S. Geological Survey, *Assessment of Potential Additions to Conventional Oil and Gas Resources of the World (Outside the United States) from Reserve Growth, 2012*, Fact Sheet 2012-3052, April 2012.

[3] U.S. Energy Information Administration, *U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves With Data for 2010*, Table 14. Shale natural gas proved reserves, reserves changes, and production, wet after lease separation, 2010; year-end reserves, August 1, 2012.

[4] Proved tight oil reserves not broken out from total year end 2010 proved reserves; will be provided in future reporting of proved reserves.

[5] Source: U.S. Energy Information Administration, *Annual Energy Outlook 2013 Assumptions report*, Tables 9.1 through 9.5.; wet natural gas volumes were determined by multiplying the *AEO2013* dry unproved natural gas resource estimate by 1.045 so as to include NGPL.

[6] Ibid. Table 5: Total natural gas proved reserves, reserves changes, and production, wet after lease separation, 2010; equals year-end figure minus the wet shale gas reserves reported for the year-end.

Box 1: Terminology: shale oil and tight oil

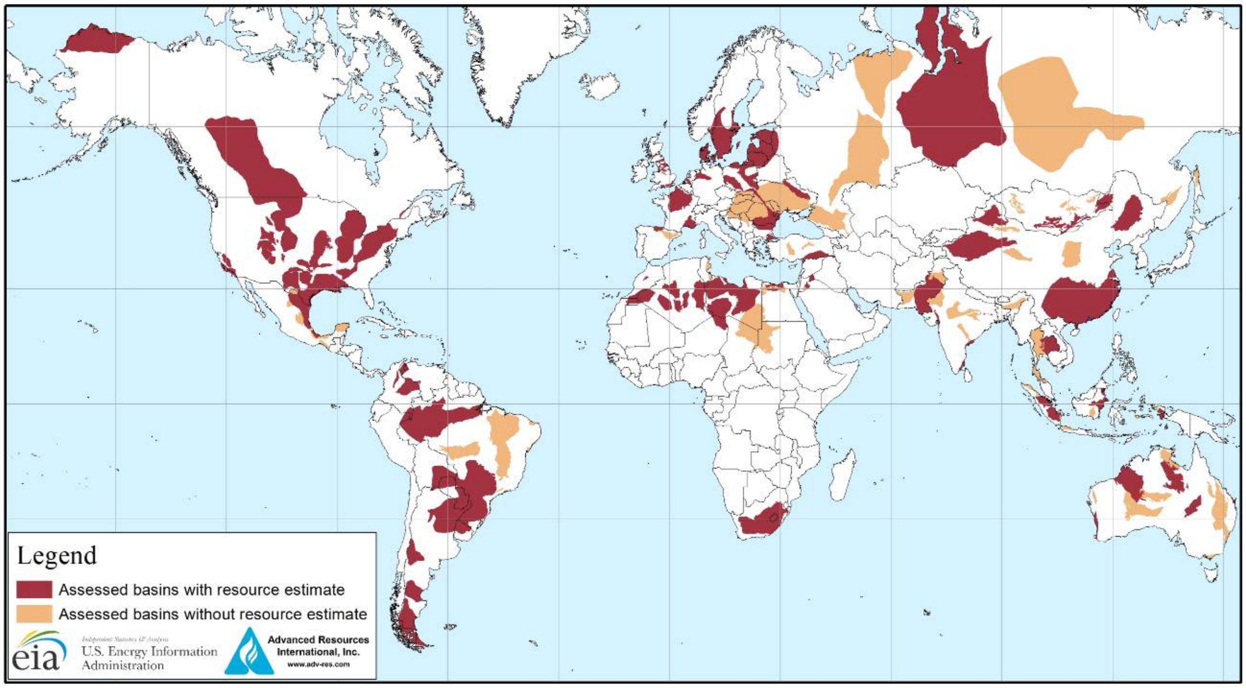
Although the terms shale oil[2] and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production. Within the United States, the oil and natural gas industry typically refers to tight oil production rather than shale oil production, because it is a more encompassing and accurate term with respect to the geologic formations producing oil at any particular well. EIA has adopted this convention, and develops estimates of tight oil production and resources in the United States that include, but are not limited to, production from shale formations. The ARI assessment of shale formations presented in this report, however, looks exclusively at shale resources and does not consider other types of tight formations.

The report covers the most prospective shale formations in a group of 41 countries that demonstrate some level of relatively near-term promise and that have a sufficient amount of geologic data for a resource assessment. Figure 1 shows the location of these basins and the regions analyzed. The map legend indicates two different colors on the world map that correspond to the geographic scope of this assessment:

- Red colored areas represent the location of basins with shale formations for which estimates of the risked oil and natural gas in-place and technically recoverable resources were provided. Prospective shale formations rarely cover an entire basin.
- Tan colored areas represent the location of basins that were reviewed, but for which shale resource estimates were not provided, mainly due to the lack of data necessary to conduct the assessment.
- White colored areas were not assessed in this report.

[2] This is not to be confused with oil shale, which is a sedimentary rock with solid organic content (kerogen) but no resident oil and natural gas fluids.

Figure 1. Map of basins with assessed shale oil and shale gas formations, as of May 2013



Source: United States basins from U.S. Energy Information Administration and United States Geological Survey; other basins from ARI based on data from various published studies.

The estimates of technically recoverable shale oil and shale gas resources summarized in Tables 1 and 2 and presented in country-level detail in Tables 3 and 4 represent risked resources for the formations reviewed. These estimates are uncertain given the relatively sparse data that currently exist. The methodology is outlined below and described in more detail in the accompanying contractor report. At the current time, there are efforts underway to develop more detailed country-specific shale gas resource assessments. A number of U.S. federal agencies are providing assistance to other countries under the auspices of the Unconventional Gas Technical Engagement Program (UGTEP) formerly known as Global Shale Gas Initiative (GSGI), which the U.S. Department of State launched in April 2010.[3]

Tables 5 and 6 provide a listing of the 10 countries holding the largest resources of shale oil and shale gas based on this assessment of shale resources in 41 countries and prior work by EIA and USGS for the United States.

[3] Other U.S. government agencies that participate in the UGTEP include: the U.S. Department of Energy's Office of Fossil Energy (DOE/FE); the U.S. Agency for International Development (USAID); the U.S. Department of Interior's U.S. Geological Survey (USGS); U.S. Department of Interior's Bureau of Ocean Energy Management (BOEM); the U.S. Department of Commerce's Commercial Law Development Program (CLDP); and the U.S. Environmental Protection Agency (EPA).

Table 3. Wet natural gas production and resources

trillion cubic feet

Region totals and selected countries[1]	2011 natural gas production[2]	January 1, 2013 estimated proved natural gas reserves[3]	2013 EIA/ARI unproved wet shale gas technically recoverable resources (TRR)	2012 USGS conventional unproved wet natural gas TRR, including reserve growth[4]	Total technically recoverable wet natural gas resources
Europe	**10**	**145**	**470**	**184**	**799**
Bulgaria	0	0	17		
Denmark	0	2	32		
France	0	0	137		
Germany	0	4	17		
Netherlands	3	43	26		
Norway	4	73	0		
Poland	0	3	148		
Romania	0	4	51		
Spain	0	0	8		
Sweden	-	-	10		
United Kingdom	2	9	26		
Former Soviet Union	**30**	**2,178**	**415**	**2,145**	**4,738**
Lithuania	-	-	0		
Russia[5]	24	1,688	287		
Ukraine	1	39	128		
North America	**32**	**403**	**1,685**	**2,223**	**4,312**
Canada	6	68	573		
Mexico	2	17	545		
United States[6]	24	318	567	1,546	2,431
Asia and Pacific	**13**	**418**	**1,607**	**858**	**2,883**
Australia	2	43	437		
China	4	124	1,115		
Indonesia	3	108	46		
Mongolia	-	-	4		
Thailand	1	10	5		
South Asia	**4**	**86**	**201**	**183**	**470**
India	2	44	96		
Pakistan	1	24	105		
Middle East and North Africa	**26**	**3,117**	**1,003**	**1,651**	**5,772**
Algeria	3	159	707		
Egypt	2	77	100		

Table 3. Wet natural gas production and resources (cont.)

trillion cubic feet

Region totals and selected countries[1]	2011 natural gas production[2]	January 1, 2013 estimated proved natural gas reserves[3]	2013 EIA/ARI unproved wet shale gas technically recoverable resources (TRR)	2012 USGS conventional unproved wet natural gas TRR, including reserve growth[4]	Total technically recoverable wet natural gas resources
Jordan	0	0	7		
Libya	0	55	122		
Morocco	0	0	12		
Tunisia	0	2	23		
Turkey	0	0	24		
Western Sahara	-	-	8		
Sub-Saharan Africa	**2**	**222**	**390**	**831**	**1,443**
Mauritania	-	1	0		
South Africa	0	-	390		
South America & Caribbean	**6**	**269**	**1,430**	**766**	**2,465**
Argentina	2	12	802		
Bolivia	1	10	36		
Brazil	1	14	245		
Chile	0	3	48		
Colombia	0	6	55		
Paraguay	-	-	75		
Uruguay	-	-	2		
Venezuela	1	195	167		
Subtotal of above countries[7]	**89**	**3,157**	**7,201**	**NA**	**NA**
Subtotal, excluding the United States[7]	**65**	**2,840**	**6,634**	**NA**	**NA**
Total World[7, 8]	**124**	**6,839**	**7,201**	**8,842**	**22,882**

[1] Regions totals include additional countries not specifically included in this table. Regions based on USGS regions http://pubs.usgs.gov/fs/2012/3042/fs2012-3042.pdf and Figure 2.

[2] Source: U.S. Energy Information Administration, International Energy Statistics, as of April 3, 2013.

[3] *Oil & Gas Journal*, Worldwide Report, December 3, 2012.

[4] Sources: U.S. Geological Survey, *An Estimate of Undiscovered Conventional Oil and Gas Resources of the World, 2012*, Fact Sheet 2012-3028, March 2012; U.S. Geological Survey, *Assessment of Potential Additions to Conventional Oil and Gas Resources of the World (Outside the United States) from Reserve Growth, 2012*, Fact Sheet 2012-3052, April 2012.

[5] Includes the Kaliningrad shale gas resource estimate of 2 trillion cubic feet.

[6] Source: U.S. Energy Information Administration, *Annual Energy Outlook 2013 Assumptions* report, Tables 9.1 through 9.5.; wet natural gas volumes were determined by multiplying the *AEO2013* dry unproved natural gas resource estimate by 1.045 so as to include NGPL.

[7] Totals might not equal the sum of the components due to independent rounding.

[8] Total of regions.

Table 4. Crude oil production and resources

million barrels

Region totals and selected countries[(1)]	2011 oil production[(2)]	January 1, 2013 estimated proved oil reserves[(3)]	2013 EIA/ARI unproved shale oil technically recoverable resources (TRR)	2012 USGS conventional unproved oil TRR, including reserve growth[(4)]	Total technically recoverable crude oil resources
Europe	**1,537**	**11,748**	**12,900**	**14,638**	**39,286**
Bulgaria	1	15	200		
Denmark	83	805	0		
France	28	85	4,700		
Germany	51	254	700		
Netherlands	21	244	2,900		
Norway	733	5,366	0		
Poland	10	157	3,300		
Romania	38	600	300		
Spain	10	150	100		
Sweden	4	-	0		
United Kingdom	426	3,122	700		
Former Soviet Union	**4,866**	**118,886**	**77,200**	**114,481**	**310,567**
Lithuania	3	12	300		
Russia[5]	3,737	80,000	75,800		
Ukraine	29	395	1,100		
North America	**6,093**	**208,550**	**80,000**	**305,546**	**594,096**
Canada	1,313	173,105	8,800		
Mexico	1,080	10,264	13,100		
United States[6]	3,699	25,181	58,100	139,311	222,592
Asia and Pacific	**2,866**	**41,422**	**61,000**	**64,362**	**166,784**
Australia	192	1,433	17,500		
China	1,587	25,585	32,200		
Indonesia	371	4,030	7,900		
Mongolia	3	-	3,400		
Thailand	152	453	0		
South Asia	**396**	**5,802**	**12,900**	**8,211**	**26,913**
India	361	5,476	3,800		
Pakistan	23	248	9,100		
Middle East and North Africa	**10,986**	**867,463**	**42,900**	**463,407**	**1,373,770**
Algeria	680	12,200	5,700		
Egypt	265	4,400	4,600		

Table 4. Crude oil production and resources (cont.)
million barrels

Region totals and selected countries(1)	2011 oil production(2)	January 1, 2013 estimated proved oil reserves(3)	2013 EIA/ARI unproved shale oil technically recoverable resources (TRR)	2012 USGS conventional unproved oil TRR, including reserve growth(4)	Total technically recoverable crude oil resources
Jordan	-	1	100		
Libya	183	48,010	26,100		
Morocco	2	1	0		
Tunisia	26	425	1,500		
Turkey	21	270	4,700		
Western Sahara	-	-	200		
Sub-Saharan Africa	**2,264**	**62,553**	**100**	**140,731**	**203,384**
Mauritania	3	20	100		
South Africa	66	15	0		
South America & Caribbean	**2,868**	**325,930**	**59,700**	**258,234**	**643,864**
Argentina	279	2,805	27,000		
Bolivia	18	210	600		
Brazil	980	13,154	5,300		
Chile	7	150	2,300		
Colombia	343	2,200	6,800		
Paraguay	1	-	3,700		
Uruguay	0	-	600		
Venezuela	909	297,570	13,400		
Subtotal of above countries[7]	**17,737**	**718,411**	**345,000**	**NA**	**NA**
Subtotal, excluding the United States[7]	**14,038**	**693,230**	**286,900**	**NA**	**NA**
Total World[7,8]	**31,875**	**1,642,354**	**345,000**	**1,369,610**	**3,356,964**

[1] Regions totals include additional countries not specifically included in this table. Regions based on USGS regions http://pubs.usgs.gov/fs/2012/3042/fs2012-3042.pdf and Figure 2.
[2] Source: U.S. Energy Information Administration, International Energy Statistics, as of April 3, 2013.
[3] *Oil & Gas Journal*, Worldwide Report, December 3, 2012.
[4] Sources: U.S. Geological Survey, An Estimate of Undiscovered Conventional Oil and Gas Resources of the World, 2012, Fact Sheet 2012-3028, March 2012; U.S. Geological Survey, Assessment of Potential Additions to Conventional Oil and Gas Resources of the World (Outside the United States) from Reserve Growth, 2012, Fact Sheet 2012-3052, April 2012.
[5] Includes the Kaliningrad shale oil resource estimate of 1.2 billion barrels.
[6] Represents unproved U.S. tight oil resources as reported in the U.S. Energy Information Administration, *Annual Energy Outlook 2013 Assumptions* report, Tables 9.1 through 9.5.
[7] Totals might not equal the sum of the components due to independent rounding.
[8] Total of regions.
"-" indicates zero, "0" indicates a nonzero value

Table 5. Top 10 countries with technically recoverable shale oil resources

Rank	Country	Shale oil (billion barrels)	
1	Russia	75	
2	U.S.[1]	58	(48)
3	China	32	
4	Argentina	27	
5	Libya	26	
6	Venezuela	13	
7	Mexico	13	
8	Pakistan	9	
9	Canada	9	
10	Indonesia	8	
	World Total	345	(335)

[1] EIA estimates used for ranking order. ARI estimates in parentheses.

Table 6. Top 10 countries with technically recoverable shale gas resources

Rank	Country	Shale gas (trillion cubic feet)	
1	China	1,115	
2	Argentina	802	
3	Algeria	707	
4	U.S.[1]	665	(1,161)
5	Canada	573	
6	Mexico	545	
7	Australia	437	
8	South Africa	390	
9	Russia	285	
10	Brazil	245	
	World Total	7,299	(7,795)

[1] EIA estimates used for ranking order. ARI estimates in parentheses.

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource, which is the focus of this report, and an economically recoverable resource. Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production. Recent experience with shale gas in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable drilling rigs and, preexisting gathering and pipeline infrastructure; and the availability of water resources for use in hydraulic fracturing.

Because they have proven to be quickly producible in large volumes at a relatively low cost, tight oil and shale gas resources have revolutionized U.S. oil and natural gas production, providing 29 percent of total U.S. crude oil production and 40 percent of total U.S. natural gas production in 2012. However, given the variation across the world's shale formations in both geology and above-the-ground conditions, the extent to which global technically recoverable shale resources will prove to be economically recoverable is not yet clear. The market effect of shale resources outside the United States will depend on their own production costs, volumes, and wellhead prices. For example, a potential shale well that costs twice as much and produces half the output of a typical U.S. well would be unlikely to back out current supply sources of oil or natural gas. In many cases, even significantly smaller differences in costs, well productivity, or both can make the difference between a resource that is a market game changer and one that is economically irrelevant at current market prices.

EIA is often asked about the implications of abundant shale resources for natural gas and oil prices. Because markets for natural gas are much less globally integrated than world oil markets, the rapid growth in shale gas production since 2006 has significantly lowered natural gas prices in the United States and Canada compared to prices elsewhere and to prices that would likely have prevailed absent the shale boom.

Turning to oil prices, it is important to distinguish between short-term and long-term effects. The increase in U.S. crude oil production in 2012 of 847,000 barrels per day over 2011 was largely attributable to increased production from shales and other tight resources. That increase is likely to have had an effect on prices in 2012. Even with that increase, global spare production capacity was low in 2012 relative to recent historical standards – without it, global spare capacity would have been considerably lower, raising the specter of significantly higher oil prices.

However, the situation is somewhat different in a longer-run setting, in which both global supply and demand forces are likely to substantially reduce the sensitivity of world oil market prices to a rise in production from any particular country or resource outside of the Organization of the Petroleum Exporting Countries (OPEC). Undoubtedly, significant volumes of oil production from shale resources that are economically recoverable at prices below those desired by OPEC decision-makers would add to the challenge facing OPEC as it seeks to manage oil prices. However, the magnitude of this challenge is probably smaller than the challenges associated with the possible success of some of its own member countries in overcoming barriers stemming from internal discord or external constraints that have kept their recent production well below levels that would be preferred by national governments and would be readily supported by their ample resources. Ultimately, the possibility of significant price impacts in response to either of these potential challenges will depend on the ability and willingness of other OPEC member countries to offset the impact of higher production on prices by reducing their output or their investment in additional production capacity. Efforts to limit the price effect of higher production could also be supported by the demand side of the market over the long term since any persistent period of lower prices would encourage a demand response that would tend to soften any long-term price-lowering effects of increased production.

The methods used for estimating shale resources in the current report are similar to those used previously. Because this report estimates shale oil resources for the first time, it distinguishes between the oil and natural gas portions of a shale formation, which has resulted in a portion of some of the area that was previously mapped as natural gas to now be designated as oil; consequently reducing the natural gas resource estimate and replacing it with an oil resource estimate. Also, the current report more rigorously applies the assessment methodology, such as the 2 percent minimum total organic content (TOC) requirement, which in this instance reduces the prospective area and resource estimates for some shales.

Future efforts

While the current report considers more shale formations than were assessed in the previous version, it still does not assess many prospective shale formations, such as those underlying the large oil fields located in the Middle East and the Caspian region. Further improvement in both the quality of the assessments and an increase the number of formations assessed should be possible over time.

The priority of such work compared to other possible projects, including efforts to determine the likely costs of production of oil and natural gas from shale resources around the world, will need to be determined in the light of available budgets.

Additional Context

Development of shale resources to date

Since the release of EIA's 2011 assessment of technically recoverable natural gas resources from selected shale formations in 32 countries, the blossoming of interest in shale resources outside the United States has resulted in the publication of more and better information on the geology of many shale formations. Wells drilled in shale formations in countries such as Argentina, China, Mexico, and Poland have also helped to clarify their geologic properties and productive potential. Therefore, the current report incorporates more complete and better quality geologic data on many of the shale formations examined in the first report, including areal extent, thickness, porosity, pressure, natural faulting, and carbon content. Based on updated geologic information, a few shale formations that were assessed in the previous report have been dropped.

It has become clear from recent developments in the United States that shale formations and other tight plays can also produce crude oil, lease condensates, and a variety of liquids processed from wet natural gas. For example, U.S. crude oil production rose by 847,000 barrels per day in 2012, compared with 2011, by far the largest growth in crude oil production in any country. Production from shales and other tight plays accounted for nearly all of this increase, reflecting both the availability of recoverable resources and favorable above-the-ground conditions for production. (For a further discussion of U.S. shale gas and tight oil production, see Box #2.)

The successful investment of capital and diffusion of shale oil and shale gas technologies has continued into Canadian shales. Canada's tight oil production averaged 291,498 barrels per day in 2012[4] and its shale gas production was 0.7 trillion cubic feet in 2012.[5] There has been interest expressed or exploration activities begun in shale formations in a number of other countries, including Algeria, Argentina, Australia, China, India, Mexico, Poland, Romania, Russia, Saudi Arabia, Turkey, Ukraine, and the United Kingdom.

It is clearly important for those interested in the evolution of global markets for liquid fuels to assess the magnitude and extent of recoverable resources from shale formations.

BOX 2: PRODUCTION FROM SHALE RESOURCES IN THE UNITED STATES

The use of horizontal drilling in conjunction with hydraulic fracturing has greatly expanded the ability of producers to profitably produce oil and natural gas from low permeability geologic formations, particularly shale formations. Application of fracturing techniques to stimulate oil and natural gas production began to grow in the 1950s, although experimentation dates back to the 19th century. The application of horizontal drilling to oil production began in the early 1980s, by which time the advent of improved downhole drilling motors and the invention of other necessary supporting equipment, materials, and technologies, particularly downhole telemetry equipment (i.e., measurement-while-drilling) brought some applications within the realm of commercial viability.

The advent of large-scale shale gas production did not occur until around 2000 when shale gas production became a commercial reality in the Barnett Shale located in north-central Texas. As commercial success of the Barnett Shale became apparent, other companies started drilling wells in this formation so that by 2005, the Barnett Shale alone was producing almost half a trillion cubic feet per year of natural gas. As natural gas producers gained confidence in their ability to profitably produce natural gas in the Barnett Shale and confirmation of this ability was provided by the results in the Fayetteville Shale in northern Arkansas, they began pursuing the development of other shale formations, including the Haynesville, Marcellus, Woodford, and Eagle Ford shales.

The proliferation of drilling activity in the Lower 48 shale formations has increased dry shale gas production in the United States from 0.3 trillion cubic feet in 2000 to 9.6 trillion cubic feet in 2012, or to 40 percent of U.S. dry natural gas production. Dry shale gas reserves increased to 94.4 trillion cubic feet by year-end 2010, when they equaled 31 percent of total natural gas reserves.[6] EIA's current estimate

[4] National Energy Board, Michael Johnson, personal correspondence on May 10, 2013.

[5] National Energy Board, *Short-term Canadian Natural Gas Deliverability 2013-2015 – Energy Market Assessment*, May 2013, Appendix C, Table C.1, pages 69-70; figure includes the Montney formation production.

[6] Reserves refer to deposits of oil, natural gas, and natural gas liquids that are proven and readily producible. Reserves are a subset of the technically recoverable resource estimate for a source of supply. Technically recoverable resource estimates encompass oil and gas reserves, the producible oil and natural gas that are inferred to exist in current oil and gas fields, as well as undiscovered, unproved oil and natural gas that can be produced using current technology. For example, EIA's estimate of all forms of technically recoverable natural gas resources in the United States for the *Annual Energy Outlook 2013* early release is 2,326.7 trillion cubic feet, of which 542.8 trillion cubic feet consists of unproved shale gas resources. Also included in the resource total are 304.6 trillion cubic feet of proved reserves that consist of all forms of readily producible natural gas, including 94.4 trillion cubic feet of shale gas.

of technically recoverable dry shale gas resources is 637 trillion cubic feet, including proved reserves of 94 trillion cubic feet.[7] Given a total estimated U.S. dry natural gas resource of 2,335 trillion cubic feet, shale gas resources constitute 27 percent of the domestic natural gas resource represented in the AEO2013 projections and 36 percent of Lower 48 onshore resources.

The growth in tight oil production shows how important shale oil production has become in the United States. U.S. tight oil production increased from an average 0.2 million barrels per day in 2000 to an average of 1.9 million barrels per day in 2012 for 10 select formations.[8] The growth in tight oil production has been so rapid that U.S. tight oil production was estimated to have reached 2.2 million barrels per day in December 2012. Although EIA has not published tight oil proved reserves, EIA's current estimate of unproved U.S. tight oil resources is 58 billion barrels.[9]

Notable changes in shale gas estimates from the 2011 report

Shale gas resource estimates for some formations were revised lower in the current report, including those for Norway's Alum Shale, Poland's Lubin Basin, Mexico's Eagle Ford Shale in the Burgos Basin, South Africa's Karoo Basin, and China's Qiongzhusi Shale in the Sichuan Basin and the Lower Cambrian shales in the Tarim Basin. As discussed below, these adjustments, based on new information in some cases, reflect a reduced estimate of total hydrocarbon resources, while in others they reflect a reclassification of resources previously identified as natural gas to the category of crude oil or condensates. This discussion is not meant to be exhaustive but rather illustrative of why some of the shale resource estimates were reduced.

Norway's shale gas assessment dropped from 83 trillion cubic feet in 2011 to zero in the current report because of the disappointing results obtained from three Alum Shale wells drilled by Shell Oil Company in 2011. The Shell wells were drilled in the less geologically complex portion of the Alum Shale that exists in Sweden, which significantly reduced the prospects for successful shale wells in the more geologically complex portion of the Alum Shale that exists in Norway.

Poland's Lubin Basin shale gas resource estimate was reduced from 44 trillion cubic feet in the 2011 report to 9 trillion cubic feet in this report. The resource reduction was due to the more rigorous application of the requirement that a shale formation have at least a 2 percent minimum total organic content (TOC). The more rigorous application of the TOC minimum requirement, along with better control on structural complexity, reduced the prospective area from 11,660 square miles to 2,390 square miles. For Poland as a whole, the shale gas resource estimate was reduced from 187 trillion cubic feet in the 2011 report to 148 trillion cubic feet in this report.

[7] Source: *AEO2013 Assumptions* report, Tables 9.1 through 9.5.
[8] The 10 select formations are the Austin Chalk, Bakken, Bone Springs, Eagle Ford, Granite Wash, Monterey, Niobrara/Codell, Spraberry, Wolfcamp, and Woodford. Some of these formations have produced oil for many decades in the higher permeability portions of the formations.
[9] Op. Cit. *AEO2013*

In Mexico, the Eagle Ford Shale gas resource estimate in Burgos Basin was reduced from 454 trillion cubic feet in the 2011 report to 343 trillion cubic feet in this report. Based on better geologic data regarding the areal extent of the formation, the prospective shale area was reduced from 18,100 square miles in the 2011 report to 17,300 square miles. A portion of the 17,300 square miles is prospective for oil, which reduced the area prospective for natural gas. Cumulatively, these changes resulted in a lower shale gas resource estimate for the Burgos Basin's Eagle Ford formation, while adding oil resources.

In South Africa, the prospective area for the three shale formations in the Karoo Basin was reduced by 15 percent from 70,800 square miles to 60,180 square miles. This reduction in the prospective area was largely responsible for the lower South African shale gas resource estimate shown in this report. The Whitehill Shale's recovery rate and resource estimate were also reduced because of the geologic complexity caused by igneous intrusions into that formation. For South Africa as a whole, the shale gas resource estimate was reduced from 485 trillion cubic feet in the 2011 report to 390 trillion cubic feet in this report.

In China, better information regarding the total organic content and geologic complexity resulted in a reduction of the shale gas resource in the Qiongzhusi formation in the Sichuan Basin and Lower Cambrian shales in the Tarim Basin. The Qiongzhusi Shale gas resource estimate was reduced from 349 trillion cubic feet in the 2011 report to 125 trillion cubic feet in this report. The lower estimate resulted from the prospective area being reduced from 56,875 square miles to 6,500 square miles. Similarly, the prospective area of the Lower Cambrian shales was reduced from 53,560 square miles in 2011 to 6,520 square miles in the current report, resulting in a reduction in the shale gas estimate from 359 trillion cubic feet in 2011 to 44 trillion cubic feet now. For China as a whole, the shale gas resource estimate was reduced from 1,275 trillion cubic feet in the 2011 report to 1,115 trillion cubic feet in this report.

Methodology

The shale formations assessed in this report were selected for a combination of factors that included the availability of data, country-level natural gas import dependence, observed large shale formations, and observations of activities by companies and governments directed at shale resource development. Shale formations were excluded from the analysis if one of the following conditions is true: (1) the geophysical characteristics of the shale formation are unknown; (2) the average total carbon content is less than 2 percent; (3) the vertical depth is less than 1,000 meters (3,300 feet) or greater than 5,000 meters (16,500 feet), or (4) relatively large undeveloped oil or natural gas resources.

The consultant relied on publicly available data from technical literature and studies on each of the selected international shale gas formations to first provide an estimate of the "risked oil and natural gas in-place," and then to estimate the unproved technically recoverable oil and natural gas resource for that shale formation. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

The risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation's success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates. The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by matching a shale formation's geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource. The specific tasks carried out to implement the assessment include:

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.
2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*[10] and *adsorbed gas*[11] that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.[12] For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources[13] represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

Based on U.S. shale production experience, the recovery factors used in this report for shale gas generally ranged from 20 percent to 30 percent, with values as low as 15 percent and as high as 35 percent being applied in exceptional cases. Because of oil's viscosity and capillary forces, oil does not flow through rock fractures as easily as natural gas. Consequently, the recovery factors for shale oil are typically lower than they are for shale gas, ranging from 3 percent to 7 percent of the oil in-place with exceptional cases being as high as 10 percent or as low as 1 percent. The consultant selected the

[10] Free gas is natural gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.
[11] Adsorbed gas is natural gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the natural gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.
[12] The recovery factor pertains to percent of the original oil or natural gas in-place that is produced over the life of a production well.
[13] Referred to as risked recoverable resources in the consultant report.

recovery factor based on U.S. shale production recovery rates, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery. The recovery rates used in this analysis are based on an extrapolation of shale well production over 30 years. Because a shale's geophysical characteristics vary significantly throughout the formation and analog matching is never exact, a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.

Key exclusions

In addition to the key distinction between technically recoverable resources and economically recoverable resources that has been already discussed at some length, there are a number of additional factors outside of the scope of this report that must be considered in using its findings as a basis for projections of future production. In addition, several other exclusions were made for this report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

Some of the key exclusions for this report include:

- **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this report.
- **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
- **Assessed formations without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional shale formations would likely increase the estimated resource.
- **Countries outside the scope of the report**, the inclusion of which would likely add to estimated resources in shale formations. It is acknowledged that potentially productive shales exist in most of the countries in the Middle East and the Caspian region, including those holding substantial nonshale oil and natural gas resources.
- **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

The U.S. shale experience and international shale development

This report treats non-U.S. shales as if they were homogeneous across the formation. If the U.S. experience in shale well productivity is replicated elsewhere in the world, then it would be expected that shale formations in other countries will demonstrate a great deal of heterogeneity, in which the geophysical characteristics vary greatly over short distances of a 1,000 feet or less. Shale heterogeneity over short distances is demonstrated in a recent article that shows that oil and natural gas production performance varies considerably across the fractured stages of a horizontal lateral and that a significant number of fractured stages do not produce either oil or natural gas; in some cases, up to 50 percent of the fractured stages are not productive.[14] The authors of that article noted that:

> "…a study including the production logs from 100 horizontal wells showed an enormous discrepancy in production between perforation clusters that is likely due to rock heterogeneity."

One reason why 3,000-to-5,000-foot horizontal laterals are employed in the United States is to increase the likelihood that a portion of the horizontal lateral will be sufficiently productive to make the well profitable.

Because of shale rock heterogeneity over short distances, neighboring well productivity varies significantly, and well productivity across the formation varies even more. Shale formation productivity also varies by depth. For example, Upper Bakken Member shale wells are less productive than Lower Bakken Member shale wells.

Shale heterogeneity also means that some areas across the shale formation can have relatively high productivity wells (also known as sweet spots), while wells in other regions have commensurately lower productivities. However, because productivity also varies significantly for wells located in the same neighborhood, a single well test cannot establish a formation's productivity or even the productivity within its immediate neighborhood. This complicates the exploration phase of a shale's development because a company has to weigh the cost of drilling a sufficient number of wells to determine the local variation in well productivity against the risk that after drilling enough wells, the formation under the company's lease still proves to be unprofitable.[15]

For those foreign shales that are expected to have both natural gas-prone and oil-prone portions, formation heterogeneity means that there could be an extended transition zone across a shale formation from being all or mostly natural gas to being mostly oil. The best example of this gradual and extended transition from natural gas to oil is found in the Eagle Ford Shale in Texas, where the distance between the natural gas-only and mostly-oil portions of the formation are separated by 20 to 30 miles, depending on the location. This transition zone is important for two reasons.

First, a well's production mix of oil, natural gas, and natural gas liquids can have a substantial impact on that well's profitability both because of the different prices associated with each component and because liquids have multiple transportation options (truck, rail, barge, pipeline), whereas large volumes of natural gas are only economic to transport by pipeline. Because many countries have large natural gas deposits that well exceed the indigenous market's ability to consume that natural gas (e.g., Qatar), the shale gas is of no value to the producer and is effectively stranded until a lengthy pipeline or LNG

[14] Society of Petroleum Engineers, *Journal of Petroleum Technology*, Utpal Ganguly and Craig Cipolla (Schlumberger), "Multidomain Data and Modeling Unlock Unconventional Reservoir Challenges," August 2012, pages 32-37; see Figure 2 for the variation in productivity along the fractured stages of four wells.

[15] Of course, there will be instances where the geophysical properties of a single well rock sample are so poor (e.g. high clay content, low porosity, low carbon content) or a well production test is so discouraging that the company abandons any further attempts in that portion of the formation.

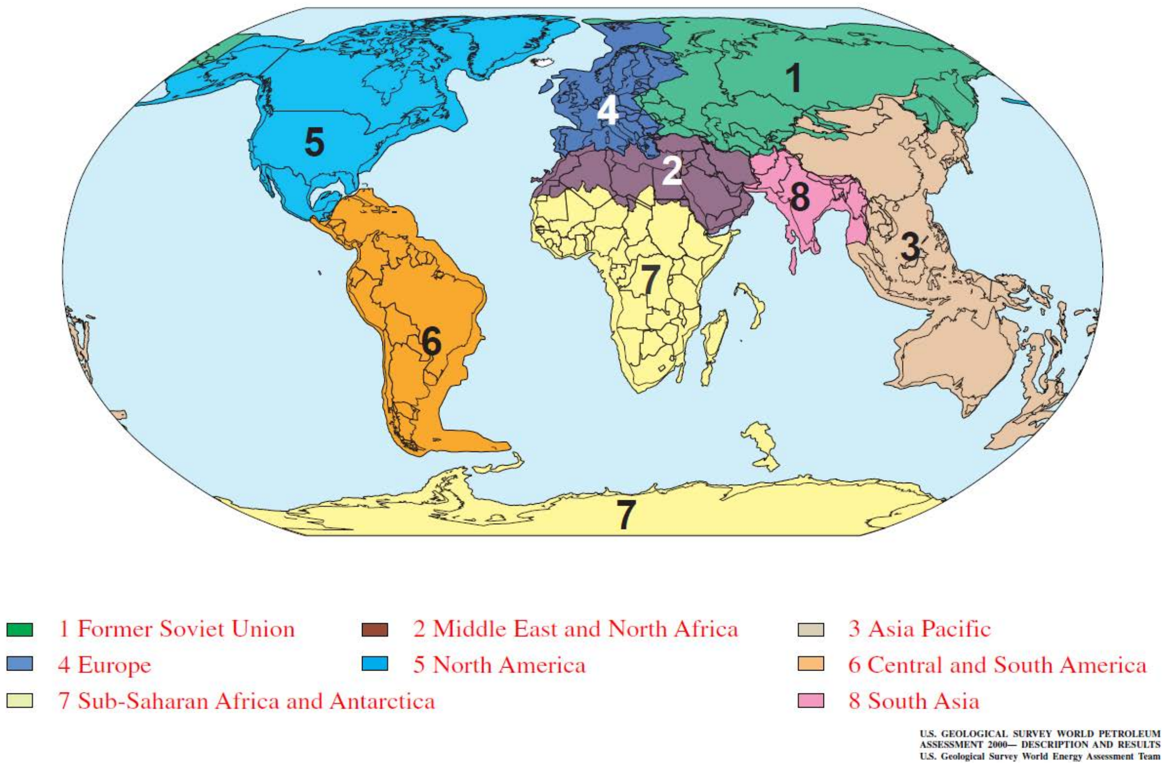
export terminal has been built to transport the natural gas to a country with a larger established consumption market.

Second, the production of shale oil requires that at least 15 percent to 25 percent of the pore fluids be in the form of natural gas so that there is sufficient gas-expansion to drive the oil to the well-bore. In the absence of natural gas to provide reservoir drive, shale oil production is problematic and potentially uneconomic at a low production rate. Consequently, producer drilling activity that currently targets oil production in the Eagle Ford shale is primarily focused on the condensate-rich portion of the formation rather than those portions that have a much greater proportion of oil and commensurately less natural gas.

Shale formation heterogeneity also somewhat confounds the process of testing alternative well completion approaches to determine which approach maximizes profits. Because of the potential variation in neighboring well productivity, it is not always clear whether a change in the completion design is responsible for the change in well productivity. Even a large well sample size might not resolve the issue conclusively as drilling activity moves through inherently higher and lower productivity areas.

Shale formation heterogeneity also bears on the issue of determining a formation's ultimate resource potential. Because companies attempt to identify and produce from the high productivity areas first, the tendency is for producers to concentrate their efforts in those portions of the formation that appear to be highly productive, to the exclusion of much of the rest of the formation. For example, only about 1 percent of the Marcellus Shale has been production tested. Therefore, large portions of a shale formation could remain untested for several decades or more, over which time the formation's resource potential could remain uncertain.

Figure 2. U.S. Geological Survey oil and gas resource assessment regions



Source: http://energy.cr.usgs.gov/WEcont/WEMap.pdf

WORLD SHALE GAS AND SHALE OIL RESOURCE ASSESSMENT

Prepared for:
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At the U.S. Department of Energy
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Advanced Resources International, Inc.

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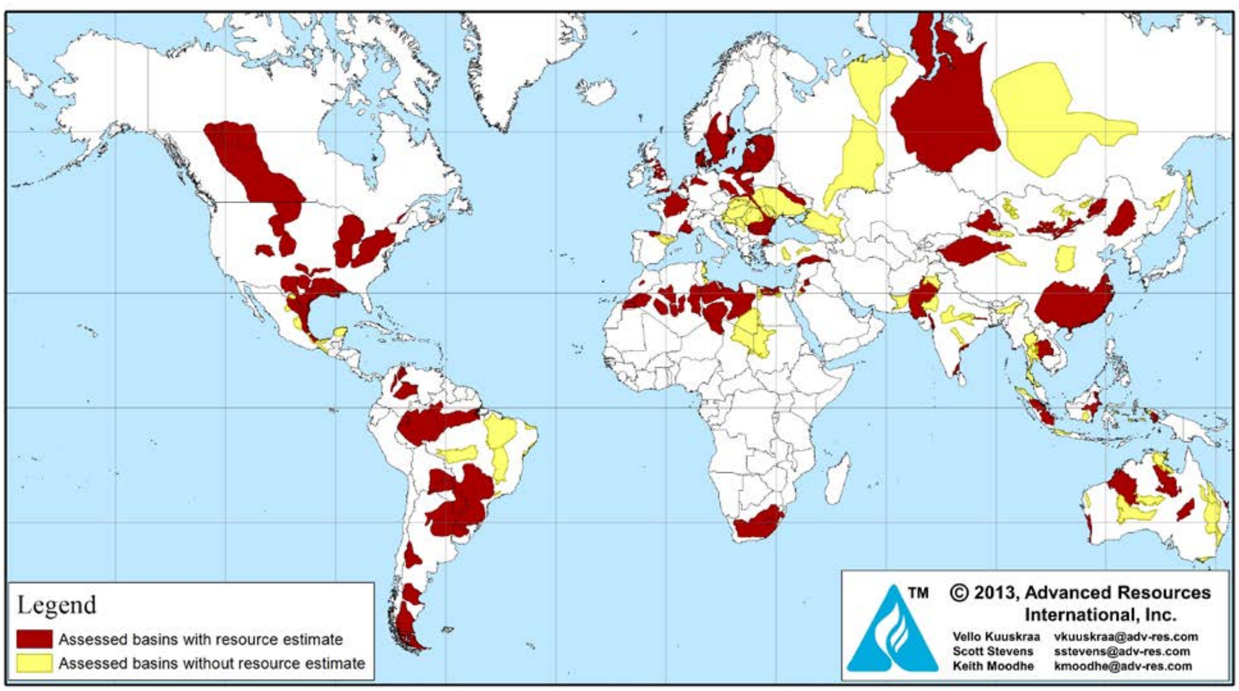
EXECUTIVE SUMMARY AND STUDY RESULTS

The "World Shale Gas and Shale Oil Resource Assessment", conducted by Advanced Resources International, Inc. (ARI) for the U.S. DOE's Energy Information Administration (EIA), evaluates the shale gas and shale oil resource in 26 regions, containing 41 individual countries, Figure 1. The assessment did not include the United States, but for completeness we have included in the Executive Summary our internal estimates of shale gas and shale oil resources for the U.S., extracted from ARI's proprietary shale resource data base.

The information provided in this report should be viewed as the second step on a continuing pathway toward a more rigorous understanding and a more comprehensive assessment of the shale gas and shale oil resources of the world. This report captures our latest view of the in-place and technically recoverable shale gas and shale oil in the 95 shale basins and 137 shale formations addressed by the study.

Figure 1. Assessed Shale Gas and Shale Oil Basins of the World



The twenty-six chapters of the report discuss our current understanding of the quantity and quality of shale gas and shale oil resources in the 41 assessed countries, Table 1. Initial shale exploration is underway in many of these countries. New geologic and reservoir data collected by these industry and research drilling programs will enable future assessments of shale gas and shale oil resources to progressively become more rigorous.

Table 1. Scope of "EIA/ARI World Shale Gas and Shale Oil Resource Assessment"

Continent	Region	Number of Countries	Number of Basins	Number of Shale Formations
North America	I. Canada	1	12	13
	II. Mexico	1	5	8
	Subtotal	**2**	**17**	**21**
Australia	III. Australia	**1**	**6**	**11**
South America	IV. N. South America	2	3	3
	V. Argentina	1	4	6
	VI. Brazil	1	3	3
	VII. Other S. South America	4	3	4
	Subtotal	**8**	**13**	**16**
Eastern Europe	VIII. Poland*	3	5	5
	IX. Russia	1	1	2
	X. Other Eastern Europe	3	3	4
	Subtotal	7	9	11
Western Europe	XI. UK	1	2	2
	XII. Spain	1	1	1
	XIII. Other Western Europe	5	5	10
	Subtotal	7	8	13
Europe	**Total**	**14**	**17**	**24**
Africa	XIV. Morocco**	3	2	2
	XV. Algeria	1	7	11
	XVI. Tunisia	1	1	2
	XVII. Libya	1	3	5
	XVIII. Egypt	1	4	4
	XIX. South Africa	1	1	3
	Subtotal	**8**	**18**	**27**
Asia	XX. China	1	7	18
	XXI. Mongolia	1	2	2
	XXII. Thailand	1	1	1
	XXIII. Indonesia	1	5	7
	XXIV. India/Pakistan	2	5	6
	XXV. Jordan	1	2	2
	XXVI. Turkey	1	2	2
	Subtotal	**8**	**24**	**38**
Total		**41**	**95**	**137**

*Includes Lithuania and Kaliningrad. **Includes Western Sahara & Mauritania

When reviewing the shale gas and shale oil resource assessments presented in this report, it is important to consider these three points:

- First, the resource assessments in the individual regional and country chapters are only for the higher quality, "prospective areas" of each shale gas and shale oil basin. The lower quality and less defined areas in these basins, which likely hold additional shale resources, are not included in the quantitatively assessed and reported values.
- Second, the in-place and technically recoverable resource values for each shale gas and shale oil basin have been risked to incorporate: (1) the probability that the shale play will (or will not) have sufficiently attractive flow rates to become developed; and (2) an expectation of how much of the prospective area set forth for each shale basin and formation will eventually be developed. (Attachment B provides a listing of the risk factors used in this shale resource assessment study.)
- We benefited greatly from the major new efforts on assessing and pursuing shale gas and shale oil resources, stimulated in part by the 2011 EIA/ARI study in countries such as Algeria, Argentina and Mexico, among many others.

No doubt, future exploration will lead to changes in our understanding and assessments of the ultimate size and recoverability of international shale gas and shale oil resources. We would encourage the U.S. Energy Information Administration, which commissioned this unique, "cutting edge" shale gas and shale oil resource assessment, to incorporate the new exploration and resource information that will become available during the coming years, helping keep this world shale resource assessment "evergreen".

SUMMARY OF STUDY FINDINGS

Although the exact in-place and technically recovered resource numbers will change with time, our work to date shows that the world shale gas and shale oil resource is vast.

- **Shale Gas Resources.** Overall, for the 41 countries assessed in the EIA/ARI study, we identified a total risked shale gas in-place of 31,138 Tcf. Of this total, approximately 6,634 Tcf is considered the risked, technically recoverable shale gas resource, not including the U.S., Table 2A. Adding the U.S. shale gas resource increases the assessed shale gas in-place and technically recoverable shale gas resources of the world to 35,782 Tcf and 7,795 Tcf, respectively.

- **Shale Oil Resources.** The previous EIA/ARI study did not assess shale oil resources, thus the 2013 report represents a major new expansion of scope. In this EIA/ARI assessment, we identified a total risked shale oil in-place of 5,799 billion barrels, with 286.9 billion barrels as the risked, technically recoverable shale oil resource, not including the U.S., Table 2B. Adding the U.S. shale oil resource increases the assessed shale oil in-place and technically recoverable shale oil resources of the world to 6,753 billion barrels and 335 billion barrels, respectively.

Two-thirds of the assessed, technically recoverable shale gas resource is concentrated in six countries - - U.S., China, Argentina, Algeria, Canada and Mexico. As shown on Figure 2, the top ten countries account for over 80% of the currently assessed, technically recoverable shale gas resources of the world.

Similarly, two-thirds of the assessed, technically recoverable shale oil resource is concentrated in six countries - - Russia, U.S., China, Argentina, Libya and Australia. The top ten countries, listed on Figure 2, account for about three-quarters of the currently assessed, technically recoverable shale oil resources of the world.

Importantly, much of this shale resource exists in countries with limited endowments of conventional oil and gas supplies such as South Africa, Jordan and Chile or resides in countries where conventional hydrocarbon resources have largely been depleted, such as Europe.

Table 2A. Risked Shale Gas In-Place and Technically Recoverable: Seven Continents

Continent	Risked Gas In-Place (Tcf)	Risked Technically Recoverable (Tcf)
North America (Ex. U.S.)	4,647	1,118
Australia	2,046	437
South America	6,390	1,431
Europe	4,895	883
Africa	6,664	1,361
Asia	6,495	1,403
Sub-Total	**31,138**	**6,634**
U.S.	4,644	1,161
TOTAL	**35,782**	**7,795**

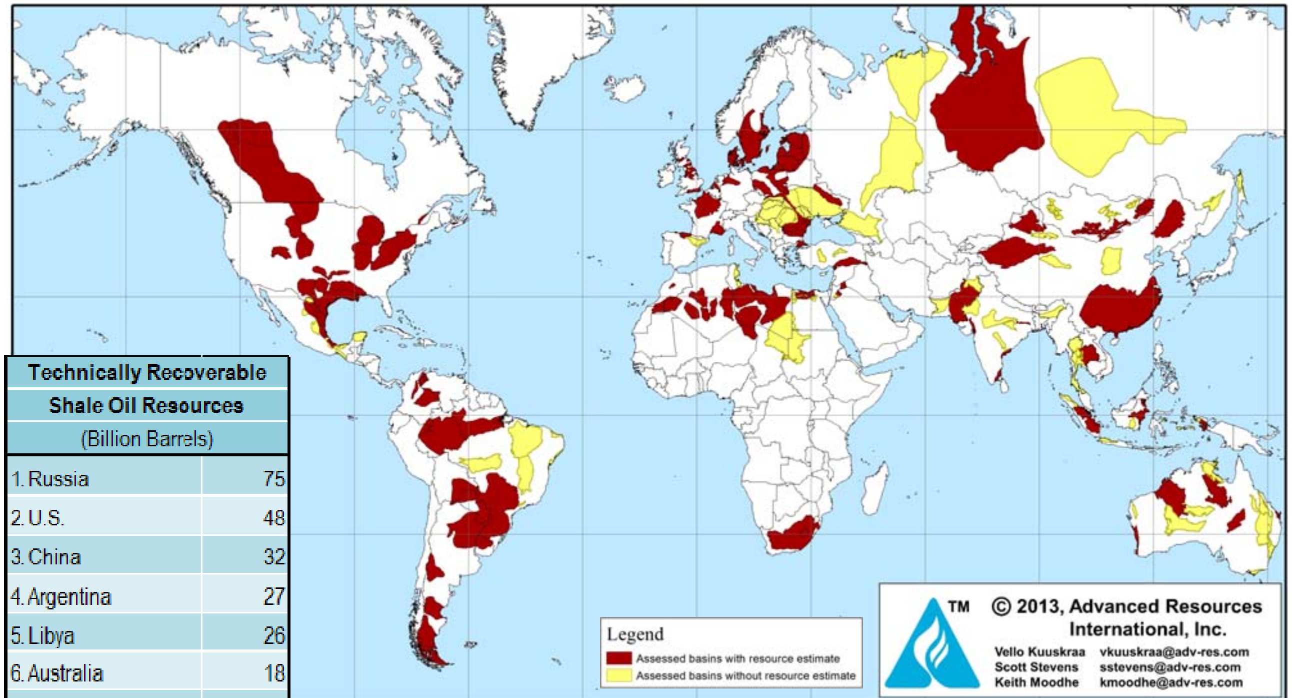
Table 2B. Risked Shale Oil In-Place and Technically Recoverable: Seven Continents

Continent	Risked Oil In-Place (B bbl)	Risked Technically Recoverable (B bbl)
North America (Ex. U.S.)	437	21.9
Australia	403	17.5
South America	1,152	59.7
Europe	1,551	88.6
Africa	882	38.1
Asia	1,375	61.1
Sub-Total	**5,799**	**286.9**
U.S.	954	47.7
TOTAL	**6,753**	**334.6**

The tabulation of shale resources at the country-level (excluding the U.S.) is provided in Table 3. More detailed information on the size of the shale gas and shale oil resource, at the basin- and formation-level, is provided in Attachment A.

Significant additional shale gas and shale oil resources exist in the Middle East, Central Africa and other countries not yet included in our study. Hopefully, future editions of this report will address these important potential shale resource areas.

Figure 2. Assessed World Shale Gas and Shale Oil Resources (42 Countries, including U.S.)



Technically Recoverable Shale Gas Resources (Tcf)	
1. U.S.	1,161
2. China	1,115
3. Argentina	802
4. Algeria	707
5. Canada	573
6. Mexico	545
7. Australia	437
8. South Africa	390
9. Russia	285
10. Brazil	245
11. Others	1,535
TOTAL	**7,795**

Technically Recoverable Shale Oil Resources (Billion Barrels)	
1. Russia	75
2. U.S.	48
3. China	32
4. Argentina	27
5. Libya	26
6. Australia	18
7. Venezuela	13
8. Mexico	13
9. Pakistan	9
10. Canada	9
11. Others	65
TOTAL	**335**

Table 3. Risked Shale Gas and Shale Oil Resources In-Place and Technically Recoverable, 41 Countries Assessed in the EIA/ARI Study

Continent	Region	Country	Risked Gas In-Place (Tcf)	Technically Recoverable (Tcf)	Risked Oil In-Place (Billion bbl)	Technically Recoverable (Billion bbl)
North America	I. Canada		2,413	573	162	8.8
	II. Mexico		2,233	545	275	13.1
	Total		**4,647**	**1,118**	**437**	**21.9**
Australia	**III. Australia**		**2,046**	**437**	**403**	**17.5**
South America	IV. N. South America	Colombia	308	55	120	6.8
		Venezuela	815	167	269	13.4
	Subtotal		1,123	222	389	20.2
	V. Argentina		3,244	802	480	27.0
	VI. Brazil		1,279	245	134	5.3
	VII. Other S. South America	Bolivia	154	36	11	0.6
		Chile	228	48	47	2.3
		Paraguay	350	75	77	3.7
		Uruguay	13	2	14	0.6
	Subtotal		744	162	150	7.2
	Total		**6,390**	**1,431**	**1,152**	**59.7**
Eastern Europe	VIII. Poland	Poland	763	148	65	3.3
		Lithuania	4	0	5	0.3
		Kaliningrad	20	2	24	1.2
	IX. Russia		1,921	285	1,243	74.6
	X. Other Eastern Europe	Bulgaria	66	17	4	0.2
		Romania	233	51	6	0.3
		Ukraine	572	128	23	1.1
	Subtotal		872	195	33	1.6
Western Europe	XI. UK		134	26	17	0.7
	XII. Spain		42	8	3	0.1
	XIII. Other Western Europe	France	727	137	118	4.7
		Germany	80	17	14	0.7
		Netherlands	151	26	59	2.9
		Denmark	159	32	0	0.0
		Sweden	49	10	0	0.0
	Subtotal		1,165	221	190	8.3
Europe	**Total**		**4,895**	**883**	**1,551**	**88.6**
Africa	XIV. Morocco*		95	20	5	0.2
	XV. Algeria		3,419	707	121	5.7
	XVI. Tunisia		114	23	29	1.5
	XVII. Libya		942	122	613	26.1
	XVIII. Egypt		535	100	114	4.6
	XIX. South Africa		1,559	390	0	0.0
	Total		**6,664**	**1,361**	**882**	**38.1**
Asia	XX. China		4,746	1,115	644	32.2
	XXI. Mongolia		55	4	85	3.4
	XXII. Thailand		22	5	0	0.0
	XXIII. Indonesia		303	46	234	7.9
	XXIV. India/Pakistan	India	584	96	87	3.8
		Pakistan	586	105	227	9.1
	XXV. Jordan		35	7	4	0.1
	XXVI. Turkey		163	24	94	4.7
	Total		**6,495**	**1,403**	**1,375**	**61.1**
Grand Total			**31,138**	**6,634**	**5,799**	**286.9**

*Includes Western Sahara & Mauritania

COMPARISON OF STUDY FINDINGS

Since the publication of the first EIA/ARI shale gas resource assessment in 2011, considerable new information has become available, helping provide a more rigorous resource assessment. New basins and countries have been added to the list. Data from more recently drilled exploration wells have helped constrain the resource size and quality - - sometimes increasing and sometimes reducing the resource estimates. With new information, some areas of prospective shale basins previously placed in the "gas window" are now classified as wet gas/condensate. In addition, associated gas from shale oil plays has been incorporated into the shale gas resource estimate.

Table 4 provides a comparison of the world shale gas resources included in the current (year 2013) EIA/ARI assessment with the initial EIA/ARI shale gas resource assessment published in 2011.

Table 5 provides a more detailed comparison and discussion of the differences between the 2011 and the current (2013) EIA/ARI estimates of risked, technically recoverable shale gas resources for 16 selected countries.

Table 4. Comparison of 2011 EIA/ARI Study and
Current EIA/ARI Study of Assessed World Shale Gas Resources

	2011	2013
Continent	**Risked Recoverable (Tcf)**	**Risked Recoverable (Tcf)**
North America (Ex. U.S.)	1,069	1,118
Australia	396	437
South America	1,225	1,431
Europe	624	883
Africa	1,042	1,361
Asia	1,404	1,403
Total	**5,760**	**6,634**

Table 5. Selected Comparison of 2011 and Current EIA/ARI Estimates of World Shale Gas Resources

	Risked, Technically Recoverable Shale Gas Resources (Tcf)		Discussion
	April 2011 Report	May 2013 Report	
1. North America			
• Canada	388	573	7 basins vs. 12 basins.
• Mexico	681	545	Better data on areal extent.
2. South America			
• Argentina	774	802	Improved dry and wet gas areal definitions.
• Brazil	226	245	New dedicated chapter.
• Venezuela	11	167	Included associated gas; better data.
3. Europe			
• Poland	187	148	Higher TOC criterion, better data on Ro.
• France	180	137	Better data on SE Basin in France.
• Norway	83	0	Eliminated speculative area for Alum Shale.
• Ukraine	42	128	Added major basin in Ukraine.
• Russia	-	285	New dedicated chapter.
4. Africa			
• Algeria	230	707	1 basin vs. 7 basins.
• Libya	290	122	Higher TOC criterion; moved area to oil.
• South Africa	485	390	Reduced area due to igneous intrusions.
• Egypt	-	100	New dedicated chapter.
5. Asia			
• China	1,225	1,115	Better data; higher TOC criterion.
• India/Pakistan	114	201	Expanded assessment for Pakistan.

Beyond the resource numbers, the current EIA/ARI "World Shale Gas and Shale Oil Resource Assessment" represents a major step-forward in terms of the depth and "hard data" of the resource information assembled for 137 distinct shale formations and 95 shale basins in 41 countries. In Table 6, we strive to more fully convey the magnitude of differences in these two shale resource assessments.

Table 6. Comparison of Scope and Coverage, EIA/ARI 2011 and 2013 World Shale Gas Resource Assessments

	EIA/ARI 2011 Report	EIA/ARI 2013 Report
No. of Regions (Chapters)	14	26
No. of Countries	32	41
No. of Basins	48	95
No. of Formations	69	137
Resource Coverage		
• Shale Gas	✓	✓
• Shale Oil	Not requested	✓
No. of Pages	355	~700
No. of Original Maps	~70	~200

Attachment A
Size of Assessed Shale Gas and Shale Oil Resources, at Basin- and Formation-Levels

Attachment A
Size of Assessed Shale Gas and Shale Oil Resources, at Basin- and Formation-Levels

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable (Tcf)	Risked Oil In-Place (Billion bbl)	Technically Recoverable (Billion bbl)
North America	Canada	Horn River	Muskwa/Otter Park	376	94	0	0.0
			Evie/Klua	154	39	0	0.0
		Cordova	Muskwa/Otter Park	81	20	0	0.0
		Liard	Lower Besa River	526	158	0	0.0
		Deep Basin	Doig Phosphate	101	25	0	0.0
		Alberta Basin	Banff/Exshaw	5	0	11	0.3
		East and West Shale Basin	Duvernay	483	113	67	4.0
		Deep Basin	North Nordegg	72	13	20	0.8
		NW Alberta Area	Muskwa	142	31	42	2.1
		Southern Alberta Basin	Colorado Group	286	43	0	0.0
		Williston Basin	Bakken	16	2	22	1.6
		Appalachian Fold Belt	Utica	155	31	0	0.0
		Windsor Basin	Horton Bluff	17	3	0	0.0
	Mexico	Burgos	Eagle Ford Shale	1,222	343	106	6.3
			Tithonian Shales	202	50	0	0.0
		Sabinas	Eagle Ford Shale	501	100	0	0.0
			Tithonian La Casita	118	24	0	0.0
		Tampico	Pimienta	151	23	138	5.5
		Tuxpan	Tamaulipas	9	1	13	0.5
			Pimienta	10	1	12	0.5
		Veracruz	Maltrata	21	3	7	0.3
Australia	Australia	Cooper	Roseneath-Epsilon-Murteree (Nappamerri)	307	89	17	1.0
			Roseneath-Epsilon-Murteree (Patchawarra)	17	4	9	0.4
			Roseneath-Epsilon-Murteree (Tenappera)	1	0	3	0.1
		Maryborough	Goodwood/Cherwell Mudstone	64	19	0	0.0
		Perth	Carynginia	124	25	0	0.0
			Kockatea	44	8	14	0.5
		Canning	Goldwyer	1,227	235	244	9.7
		Georgina	L. Arthur Shale (Dulcie Trough)	41	8	3	0.1
			L. Arthur Shale (Toko Trough)	27	5	22	0.9
		Beetaloo	M. Velkerri Shale	94	22	28	1.4
			L. Kyalla Shale	100	22	65	3.3

EIA/ARI World Shale Gas and Shale Oil Resource Assessment

Attachment A
Size of Assessed Shale Gas and Shale Oil Resources, at Basin- and Formation-Levels

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable (Tcf)	Risked Oil In-Place (Billion bbl)	Technically Recoverable (Billion bbl)
South America	Colombia	Middle Magdalena Valley	La Luna/Tablazo	135	18	79	4.8
		Llanos	Gacheta	18	2	13	0.6
	Colombia/Venezuela	Maracaibo Basin	La Luna/Capacho	970	202	297	14.8
	Argentina	Neuquen	Los Molles	982	275	61	3.7
			Vaca Muerta	1,202	308	270	16.2
		San Jorge Basin	Aguada Bandera	254	51	0	0.0
			Pozo D-129	184	35	17	0.5
		Austral-Magallanes Basin	L. Inoceramus-Magnas Verdes	605	129	131	6.6
		Parana Basin	Ponta Grossa	16	3	0	0.0
	Brazil	Parana Basin	Ponta Grossa	450	80	107	4.3
		Solimoes Basin	Jandiatuba	323	65	7	0.3
		Amazonas Basin	Barreirinha	507	100	19	0.8
	Paraguay	Parana Basin	Ponta Grossa	46	8	14	0.5
	Uruguay		Cordobes	13	2	14	0.6
	Paraguay/Bolivia	Chaco Basin	Los Monos	457	103	75	3.8
	Chile	Austral-Magallanes Basin	Estratos con Favrella	228	48	47	2.3
Eastern Europe	Poland	Baltic Basin/Warsaw Trough	Llandovery	532	105	25	1.2
		Lublin	Llandovery	46	9	0	0.0
		Podlasie	Llandovery	54	10	12	0.6
		Fore Sudetic	Carboniferous	107	21	0	0.0
	Lithuania/Kaliningrad	Baltic Basin	Llandovery	24	2	29	1.4
	Russia	West Siberian Central	Bazhenov Central	1,196	144	965	57.9
		West Siberian North	Bazhenov North	725	141	278	16.7
	Ukraine	Carpathian Foreland Basin	L. Silurian	362	72	0	0.0
		Dniepr-Donets	L. Carboniferous	312	76	23	1.1
	Ukraine/Romania	Moesian Platform	L. Silurian	48	10	2	0.1
	Romania/Bulgaria		Etropole	148	37	8	0.4
Western Europe	UK	N. UK Carboniferous Shale Region	Carboniferous Shale	126	25	0	0.0
		S. UK Jurassic Shale Region	Lias Shale	8	1	17	0.7
	Spain	Cantabrian	Jurassic	42	8	3	0.1
	France	Paris Basin	Lias Shale	24	2	38	1.5
			Permian-Carboniferous	666	127	79	3.2
		Southeast Basin	Lias Shale	37	7	0	0.0
	Germany	Lower Saxony	Posidonia	78	17	11	0.5
			Wealden	2	0	3	0.1
	Netherlands	West Netherlands Basin	Epen	94	15	47	2.4
			Geverik Member	51	10	6	0.3
			Posidonia	7	1	5	0.3
	Sweden	Scandinavia Region	Alum Shale - Sweden	49	10	0	0.0
	Denmark		Alum Shale - Denmark	159	32	0	0.0

Attachment A
Size of Assessed Shale Gas and Shale Oil Resources, at Basin- and Formation-Levels

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable (Tcf)	Risked Oil In-Place (Billion bbl)	Technically Recoverable (Billion bbl)
Africa	Morocco	Tindouf	L. Silurian	75	17	5	0.2
		Tadla	L. Silurian	20	3	0	0.0
	Algeria	Ghadames/Berkine	Frasnian	496	106	78	3.9
			Tannezuft	731	176	9	0.5
		Illizi	Tannezuft	304	56	13	0.5
		Mouydir	Tannezuft	48	10	0	0.0
		Ahnet	Frasnian	50	9	5	0.2
			Tannezuft	256	51	0	0.0
		Timimoun	Frasnian	467	93	0	0.0
			Tannezuft	295	59	0	0.0
		Reggane	Frasnian	94	16	6	0.2
			Tannezuft	542	105	8	0.3
		Tindouf	Tannezuft	135	26	2	0.1
	Tunisia	Ghadames	Tannezuft	45	11	1	0.0
			Frasnian	69	12	28	1.4
	Libya	Ghadames	Tannezuft	240	42	104	5.2
			Frasnian	36	5	26	1.3
		Sirte	Sirte/Rachmat Fms	350	28	406	16.2
			Etel Fm	298	45	51	2.0
		Murzuq	Tannezuft	19	2	27	1.3
	Egypt	Shoushan/Matruh	Khatatba	151	30	17	0.7
		Abu Gharadig	Khatatba	326	65	47	1.9
		Alamein	Khatatba	17	1	14	0.6
		Natrun	Khatatba	42	3	36	1.4
	South Africa	Karoo Basin	Prince Albert	385	96	0	0.0
			Whitehill	845	211	0	0.0
			Collingham	328	82	0	0.0

Advanced Resources International, Inc.

Attachment A
Size of Assessed Shale Gas and Shale Oil Resources, at Basin- and Formation-Levels

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable (Tcf)	Risked Oil In-Place (Billion bbl)	Technically Recoverable (Billion bbl)
Asia	China	Sichuan Basin	Qiongzhusi	500	125	0	0.0
			Longmaxi	1,146	287	0	0.0
			Permian	715	215	0	0.0
		Yangtze Platform	L. Cambrian	181	45	0	0.0
			L. Silurian	415	104	0	0.0
		Jianghan Basin	Niutitang/Shuijintuo	46	11	0	0.0
			Longmaxi	28	7	1	0.0
			Qixia/Maokou	40	10	5	0.2
		Greater Subei	Mufushan	29	7	0	0.0
			Wufeng/Gaobiajian	144	36	5	0.2
			U. Permian	8	2	1	0.1
		Tarim Basin	L. Cambrian	176	44	0	0.0
			L. Ordovician	377	94	0	0.0
			M.-U. Ordovician	265	61	31	1.6
			Ketuer	161	16	129	6.5
		Junggar Basin	Pingdiquan/Lucaogou	172	17	109	5.4
			Triassic	187	19	134	6.7
		Songliao Basin	Qingshankou	155	16	229	11.5
	Mongolia	East Gobi	Tsagaantsav	29	2	43	1.7
		Tamtsag	Tsagaantsav	26	2	43	1.7
	Thailand	Khorat Basin	Nam Duk Fm	22	5	0	0.0
	Indonesia	C. Sumatra	Brown Shale	41	3	69	2.8
		S. Sumatra	Talang Akar	68	4	136	4.1
		Tarakan	Naintupo	34	5	0	0.0
			Meliat	25	4	1	0.0
			Tabul	4	0	11	0.3
		Kutei	Balikpapan	16	1	17	0.7
		Bintuni	Aifam Group	114	29	0	0.0
	India	Cambay Basin	Cambay Shale	146	30	54	2.7
		Krishna-Godavari	Permian-Triassic	381	57	20	0.6
		Cauvery Basin	Sattapadi-Andimadam	30	5	8	0.2
		Damodar Valley	Barren Measure	27	5	5	0.2
	Pakistan	Lower Indus	Sembar	531	101	145	5.8
			Ranikot	55	4	82	3.3
	Jordan	Hamad	Batra	33	7	0	0.0
		Wadi Sirhan	Batra	2	0	4	0.1
	Turkey	SE Anatolian	Dadas	130	17	91	4.6
		Thrace	Hamitabat	34	6	2	0.1
			Total	**31,138**	**6,634**	**5,799**	**286.9**

Attachment B
Risk Factors Used for Shale Gas and Shale Oil Formations in the EIA/ARI Resource Assessment

EIA/ARI World Shale Gas and Shale Oil Resource Assessment

Attachment B

Risk Factors Used for Shale Gas and Shale Oil Formations in the EIA/ARI Resource Assessment

Continent	Region	Basin	Formation	Play Success Factor	Prospective Area Success Factor	Composite Success Factor
North America	Canada	Horn River	Muskwa/Otter Park	100%	75%	75%
			Evie/Klua	100%	75%	75%
		Cordova	Muskwa/Otter Park	100%	60%	60%
		Liard	Lower Besa River	100%	50%	50%
		Deep Basin	Doig Phosphate	100%	50%	50%
		Alberta Basin	Banff/Exshaw	100%	40%	40%
		East and West Shale Basin	Duvernay	100%	70%	70%
		Deep Basin	North Nordegg	100%	50%	50%
		NW Alberta Area	Muskwa	100%	50%	50%
		Southern Alberta Basin	Colorado Group	80%	35%	28%
		Williston Basin	Bakken	100%	60%	60%
		Appalachian Fold Belt	Utica	100%	40%	40%
		Windsor Basin	Horton Bluff	100%	40%	40%
	Mexico	Burgos	Eagle Ford Shale	100%	60%	60%
			Tithonian Shales	60%	50%	30%
		Sabinas	Eagle Ford Shale	80%	50%	40%
			Tithonian La Casita	60%	30%	18%
		Tampico	Pimienta	70%	50%	35%
		Tuxpan	Tamaulipas	70%	50%	35%
			Pimienta	70%	50%	35%
		Veracruz	Maltrata	70%	75%	53%
Australia	Australia	Cooper	Roseneath-Epsilon-Murteree (Nappamerri)	100%	75%	75%
			Roseneath-Epsilon-Murteree (Patchawarra)	100%	60%	60%
			Roseneath-Epsilon-Murteree (Tenappera)	100%	60%	60%
		Maryborough	Goodwood/Cherwell Mudstone	75%	50%	38%
		Perth	Carynginia	100%	60%	60%
			Kockatea	100%	60%	60%
		Canning	Goldwyer	75%	40%	30%
		Georgina	L. Arthur Shale (Dulcie Trough)	75%	50%	38%
			L. Arthur Shale (Toko Trough)	75%	50%	38%
		Beetaloo	M. Velkerri Shale	100%	50%	50%
			L. Kyalla Shale	100%	50%	50%

EIA/ARI World Shale Gas and Shale Oil Resource Assessment

Attachment B

Risk Factors Used for Shale Gas and Shale Oil Formations in the EIA/ARI Resource Assessment

Continent	Region	Basin	Formation	Play Success Factor	Prospective Area Success Factor	Composite Success Factor
South America	Colombia	Middle Magdalena Valley	La Luna/Tablazo	80%	70%	56%
		Llanos	Gacheta	55%	45%	25%
	Colombia/Venezuela	Maracaibo Basin	La Luna/Capacho	70%	50%	35%
	Argentina	Neuquen	Los Molles	100%	50%	50%
			Vaca Muerta	100%	60%	60%
		San Jorge Basin	Aguada Bandera	50%	40%	20%
			Pozo D-129	60%	40%	24%
		Austral-Magallanes Basin	L. Inoceramus-Magnas Verdes	75%	60%	45%
		Parana Basin	Ponta Grossa	40%	30%	12%
	Brazil	Parana Basin	Ponta Grossa	40%	30%	12%
		Solimoes Basin	Jandiatuba	50%	30%	15%
		Amazonas Basin	Barreirinha	50%	30%	15%
	Paraguay	Parana Basin	Ponta Grossa	40%	30%	12%
	Uruguay		Cordobes	40%	40%	16%
	Paraguay/Bolivia	Chaco Basin	Los Monos	50%	30%	15%
	Chile	Austral-Magallanes Basin	Estratos con Favrella	75%	60%	45%
Eastern Europe	Poland	Baltic Basin/Warsaw Trough	Llandovery	100%	40%	40%
		Lublin	Llandovery	60%	35%	21%
		Podlasie	Llandovery	60%	40%	24%
		Fore Sudetic	Carboniferous	50%	35%	18%
	Lithuania/Kaliningrad	Baltic Basin	Llandovery	80%	40%	32%
	Russia	West Siberian Central	Bazhenov Central	100%	45%	45%
		West Siberian North	Bazhenov North	75%	35%	26%
	Ukraine	Carpathian Foreland Basin	L. Silurian	50%	40%	20%
		Dniepr-Donets	L. Carboniferous	50%	40%	20%
	Ukraine/Romania	Moesian Platform	L. Silurian	55%	40%	22%
	Romania/Bulgaria		Etropole	50%	35%	18%
Western Europe	UK	N. UK Carboniferous Shale Region	Carboniferous Shale	60%	35%	21%
		S. UK Jurassic Shale Region	Lias Shale	80%	40%	32%
	Spain	Cantabrian	Jurassic	80%	50%	40%
	France	Paris Basin	Lias Shale	100%	50%	50%
			Permian-Carboniferous	80%	40%	32%
		Southeast Basin	Lias Shale	60%	30%	18%
	Germany	Lower Saxony	Posidonia	100%	60%	60%
			Wealden	75%	60%	45%
	Netherlands	West Netherlands Basin	Epen	75%	60%	45%
			Geverik Member	75%	60%	45%
			Posidonia	75%	60%	45%
	Sweden	Scandinavia Region	Alum Shale - Sweden	60%	50%	30%
	Denmark		Alum Shale - Denmark	60%	40%	24%

EIA/ARI World Shale Gas and Shale Oil Resource Assessment

Attachment B

Risk Factors Used for Shale Gas and Shale Oil Formations in the EIA/ARI Resource Assessment

Continent	Region	Basin	Formation	Play Success Factor	Prospective Area Success Factor	Composite Success Factor
Africa	Morocco	Tindouf	L. Silurian	50%	40%	20%
		Tadla	L. Silurian	50%	50%	25%
	Algeria	Ghadames/Berkine	Frasnian	100%	50%	50%
			Tannezuft	100%	50%	50%
		Illizi	Tannezuft	50%	40%	20%
		Mouydir	Tannezuft	50%	40%	20%
		Ahnet	Frasnian	50%	40%	20%
			Tannezuft	50%	40%	20%
		Timimoun	Frasnian	50%	40%	20%
			Tannezuft	50%	40%	20%
		Reggane	Frasnian	50%	40%	20%
			Tannezuft	50%	40%	20%
		Tindouf	Tannezuft	50%	40%	20%
	Tunisia	Ghadames	Tannezuft	100%	65%	65%
			Frasnian	100%	65%	65%
	Libya	Ghadames	Tannezuft	100%	50%	50%
			Frasnian	100%	50%	50%
		Sirte	Sirte/Rachmat Fms	80%	50%	40%
			Etel Fm	80%	50%	40%
		Murzuq	Tannezuft	100%	50%	50%
	Egypt	Shoushan/Matruh	Khatatba	80%	60%	48%
		Abu Gharadig	Khatatba	80%	60%	48%
		Alamein	Khatatba	70%	35%	25%
		Natrun	Khatatba	70%	35%	25%
	South Africa	Karoo Basin	Prince Albert	50%	30%	15%
			Whitehill	60%	40%	24%
			Collingham	50%	30%	15%

Attachment B

Risk Factors Used for Shale Gas and Shale Oil Formations in the EIA/ARI Resource Assessment

Continent	Region	Basin	Formation	Play Success Factor	Prospective Area Success Factor	Composite Success Factor
Asia	China	Sichuan Basin	Qiongzhusi	100%	70%	70%
			Longmaxi	100%	70%	70%
			Permian	60%	50%	30%
		Yangtze Platform	L. Cambrian	80%	70%	56%
			L. Silurian	80%	70%	56%
		Jianghan Basin	Niutitang/Shuijintuo	60%	40%	24%
			Longmaxi	60%	40%	24%
			Qixia/Maokou	50%	40%	20%
		Greater Subei	Mufushan	40%	30%	12%
			Wufeng/Gaobiajian	40%	30%	12%
			U. Permian	40%	30%	12%
		Tarim Basin	L. Cambrian	50%	70%	35%
			L. Ordovician	50%	65%	33%
			M.-U. Ordovician	50%	50%	25%
			Ketuer	50%	50%	25%
		Junggar Basin	Pingdiquan/Lucaogou	60%	60%	36%
			Triassic	60%	60%	36%
		Songliao Basin	Qingshankou	100%	50%	50%
	Mongolia	East Gobi	Tsagaantsav	40%	50%	20%
		Tamtsag	Tsagaantsav	40%	50%	20%
	Thailand	Khorat Basin	Nam Duk Fm	50%	30%	15%
	Indonesia	C. Sumatra	Brown Shale	75%	60%	45%
		S. Sumatra	Talang Akar	50%	35%	18%
		Tarakan	Naintupo	40%	50%	20%
			Meliat	40%	50%	20%
			Tabul	40%	50%	20%
		Kutei	Balikpapan	40%	40%	16%
		Bintuni	Aifam Group	40%	40%	16%
	India	Cambay Basin	Cambay Shale	100%	60%	60%
		Krishna-Godavari	Permian-Triassic	75%	60%	45%
		Cauvery Basin	Sattapadi-Andimadam	50%	50%	25%
		Damodar Valley	Barren Measure	80%	50%	40%
	Pakistan	Lower Indus	Sembar	40%	30%	12%
			Ranikot	40%	30%	12%
	Jordan	Hamad	Batra	100%	40%	40%
		Wadi Sirhan	Batra	100%	40%	40%
	Turkey	SE Anatolian	Dadas	100%	60%	60%
		Thrace	Hamitabat	60%	60%	36%

Attachment C

Estimates of U.S. Shale Gas and Shale Oil Resources Extracted from Advanced Resources International's Proprietary Shale Resource Data Base

Attachment C

Estimates of U.S. Shale Gas and Shale Oil Resources Extracted from Advanced Resources International's Proprietary Shale Resource Data Base

BACKGROUND

While not within the scope of work of the EIA/ARI study of world shale gas and shale oil resources, for purposes of completeness we have provided information from Advanced Resources International's (ARI) proprietary shale resource data base on U.S. shale gas and shale oil resources.

The overall estimate of 1,161 Tcf of risked, technically recoverable wet and dry shale gas for the U.S. represents an aggregation of information from 15 shale basins and 70 distinct and individually addressed plays, Table B-1. For example, the resource estimate for the major Marcellus Shale play in the Appalachian Basin is the sum of eight individually assessed plays, where each play has been partitioned to capture differences in geologic and reservoir conditions and in projected well performance across this vast basin. (We used an average shale gas recovery factor of 25% to estimate the U.S. shale gas resource in-place.)

The overall estimate of 47.7 billion barrels of risked, technically recoverable shale oil and condensate for the U.S. represents an aggregation of information from 8 shale basins and 35 distinct and individually assessed plays, Table A-1. (We used an average shale oil recovery factor of 5% to estimate the U.S. shale oil resource in-place.)

For completeness, the U.S. has already produced 37 Tcf of shale gas plus modest volumes of shale oil/condensate, from major shale plays such as the Barnett, Fayetteville and Bakken, among others. These volumes of past shale gas and shale oil production are not included in the above remaining reserve and undeveloped shale resource values.

Advanced Resources has plans for performing a major update of its shale gas and shale oil resource base this year, incorporating emerging shale resource plays such as the Tuscaloosa Marine Shale in Louisiana, the Eaglebrine (Woodbine/Eagle Ford) in East Texas, and the Mancos Shale in the San Juan Basin.

Table A-1. U.S. Remaining Shale Gas Reserves and Undeveloped Resources

	Shale Gas Resources		Shale Oil Resources	
	Distinct Plays (#)	Remaining Reserves and Undeveloped Resources (Tcf)	Distinct Plays (#)	Remaining Reserves and Undeveloped Resources (Billion Barrels)
1. Northeast				
▪ Marcellus	8	369	2	0.8
▪ Utica	3	111	2	2.5
▪ Other	3	29	-	-
2. Southeast				
▪ Haynesville	4	161	-	-
▪ Bossier	2	57	-	-
▪ Fayetteville	4	48	-	-
3. Mid-Continent				
▪ Woodford*	9	77	5	1.9
▪ Antrim	1	5	-	-
▪ New Albany	1	2	-	-
4. Texas				
▪ Eagle Ford	6	119	4	13.6
▪ Barnett**	5	72	2	0.4
▪ Permian***	9	34	9	9.7
5. Rockies/Great Plains				
▪ Niobrara****	8	57	6	4.1
▪ Lewis	1	1	-	-
▪ Bakken/Three Forks	6	19	5	14.7
TOTAL	**70**	**1161**	**35**	**47.7**

*Woodford includes Ardmore, Arkoma and Anadarko (Cana) basins.
**Barnett includes the Barnett Combo.
***Permian includes Avalon, Cline and Wolfcamp shales in the Delaware and Midland sub-basins.
****Niobrara Shale play includes Denver, Piceance and Powder River basins.

Attachment D
Authors of "World Shale Gas and Shale Oil Resource Assessment"

Attachment D

Authors of "World Shale Gas and Shale Oil Resource Assessment"

Study Authors

Three individuals, each a long-term member of Advanced Resources International, Inc., are the authors of this "International Shale Gas Resource Assessment", namely: Vello A. Kuuskraa, President; Scott H. Stevens, Sr. Vice President; and Keith Moodhe, Sr. Consultant. Messrs. Kuuskraa, Stevens and Moodhe (plus Tyler Van Leeuwen) were the primary authors of the previous (April, 2011) version of the world shale gas resource assessment.

In addition, numerous EIA, DOE, DOI, USGS and State Department staff provided valuable review and comments throughout the development of this study. In particular staff from EIA included Aloulou Fawzi (project manager), Philip Budzik, Margaret Coleman, Troy Cook, David Daniels, Robert King, Gary Long, James O'Sullivan, A. Michael Schaal, John Staub, and Dana Van Wagener. We are appreciative of their thoughtful input.

Vello A. Kuuskraa, President of Advanced Resources International, Inc. (ARI), has over 40 years of experience assessing unconventional oil and gas resources. Mr. Kuuskraa headed the team that prepared the 1978, three volume report entitled "Enhanced Recovery of Unconventional Gas" for the U.S. Department of Energy (DOE) that helped guide unconventional gas R&D and technology development efforts during the formative period 1978-2000. He is a member of the Potential Gas Committee and has authored over 100 technical papers on energy resources. Mr. Kuuskraa is a 2001 recipient of the Ellis Island Medal of Honor that recognizes individuals for exceptional professional contributions by America's diverse cultural ancestry. He currently serves on the Board of Directors of Southwestern Energy Company (SWN), on the Board of Directors for Research Partnership to Secure Energy for America (RPSEA) and on the National Petroleum Council. Mr. Kuuskraa holds a M.B.A., Highest Distinction from The Wharton Graduate School and a B.S., Applied Mathematics/ Economics; from North Carolina State University.

Scott H. Stevens, Sr. Vice President of Advanced Resources International, Inc. (ARI), has 30 years of experience in unconventional gas and oil resources. Mr. Stevens advises Major oil companies, governments, and financial industry clients on shale gas/oil and coalbed methane investments in North America and abroad. After starting his career with Getty and Texaco in 1983 working the liquids-rich Monterey shale deposit in California, Stevens joined ARI in 1991. He has initiated or evaluated hundreds of unconventional oil & gas drilling projects in the USA, Australia, Chile, China, Indonesia, Poland, and other countries. Mr. Stevens holds a B.A. in Geology (Distinction) from Pomona College, an M.S. in Geological Science from Scripps Institution of Oceanography, and an A.M. in Regional Studies – East Asia (Economics and Chinese) from Harvard University.

Attachment D

Authors of "World Shale Gas and Shale Oil Resource Assessment"

Keith Moodhe, Sr. Consultant with Advanced Resources International, Inc. (ARI), has eight years of experience with unconventional resources in the U.S. and globally. He is an expert in geographic information system (GIS) mapping and analysis of shale gas/oil and coalbed methane geologic and reservoir properties. During his career he has constructed a geologic data base of shale properties in China; assessed the shale and CBM resource potential of major basins in Southeast Asia, Indonesia, Australia, and South America; and conducted geologic and GIS analysis of domestic and global shale resources for the U.S. Energy Information Administration (EIA) and various industry and investment firms. Mr. Moodhe holds a B.S. in Geology with a minor in Economics from the College of William & Mary.

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

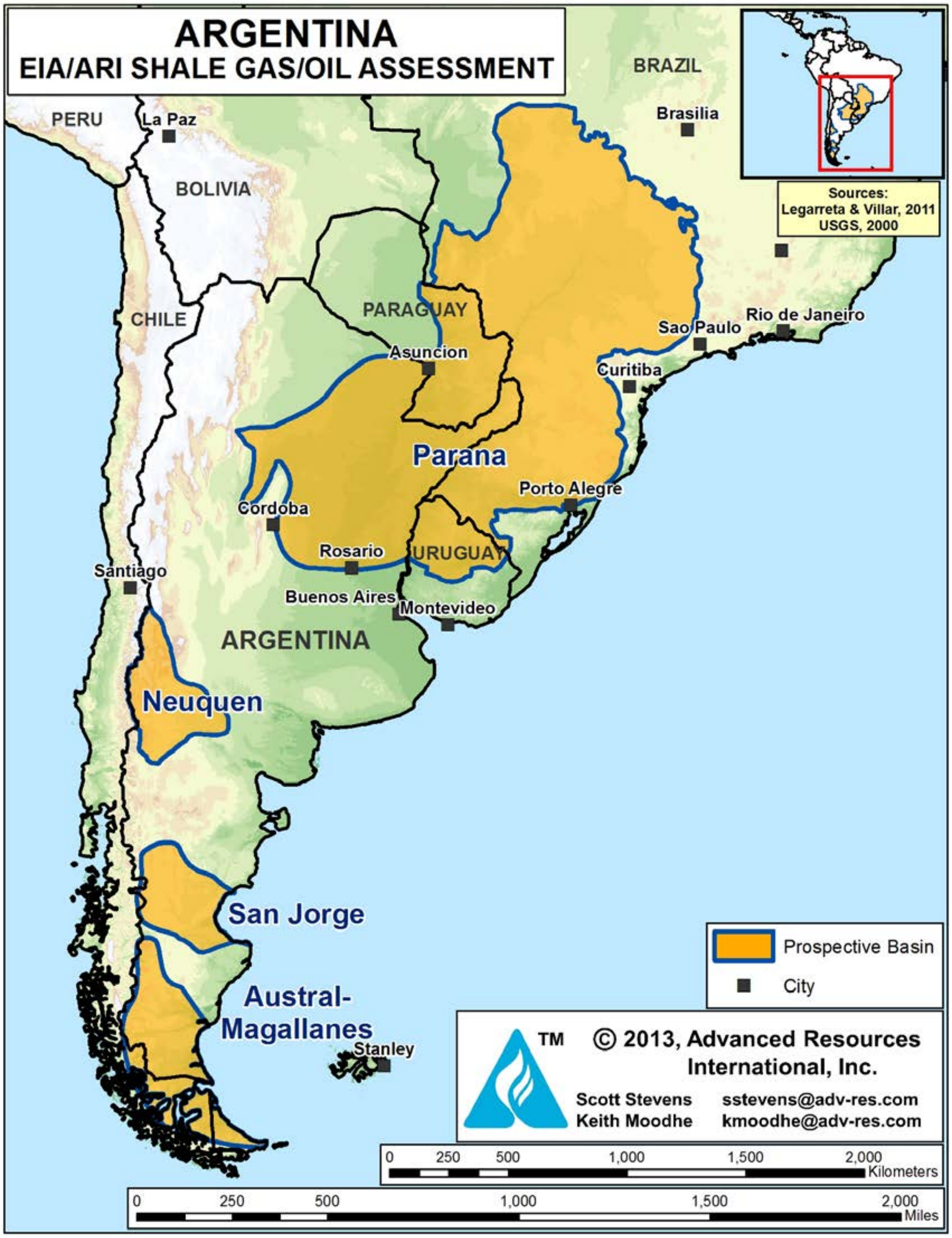
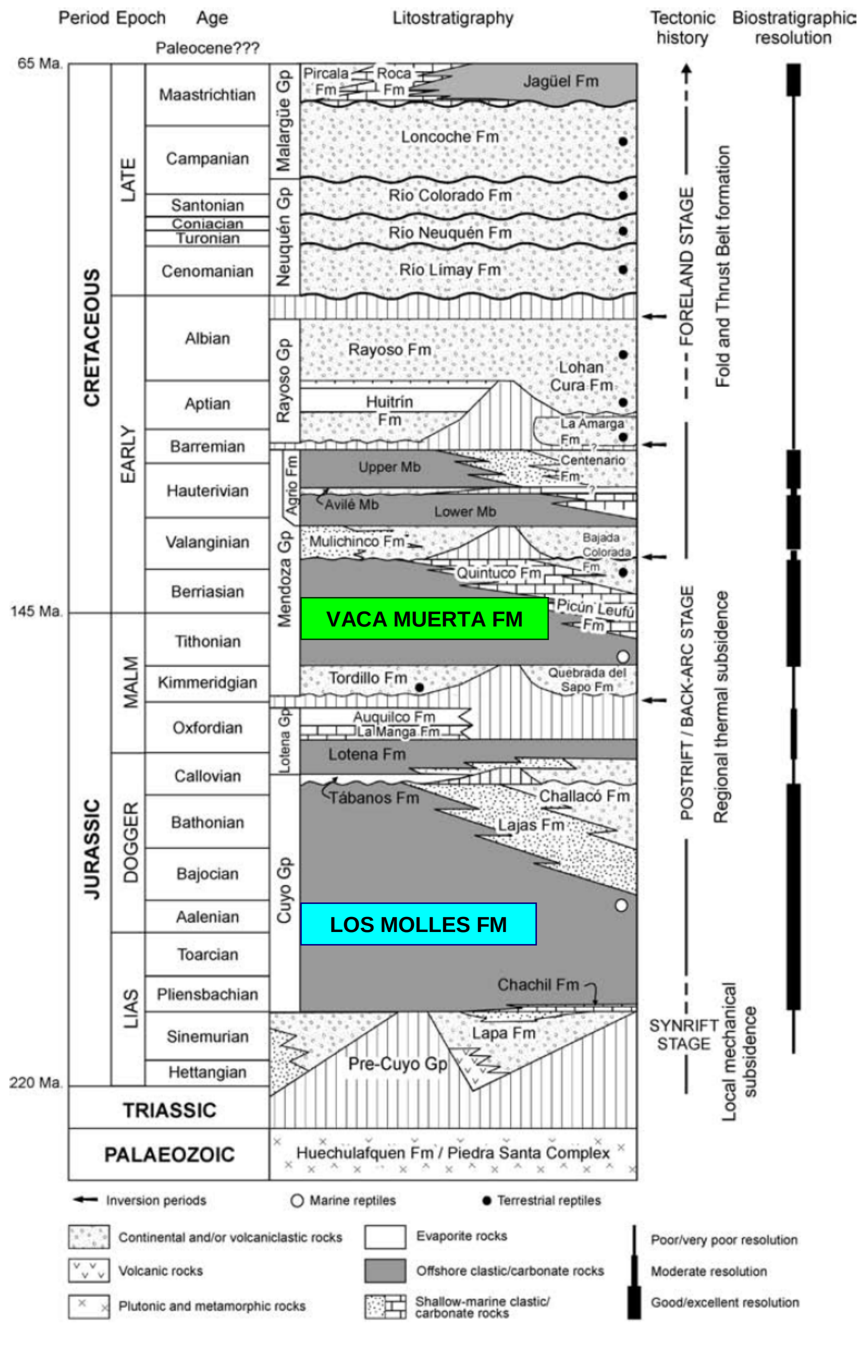


Figure 2. Neuquen Basin Stratigraphy

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



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

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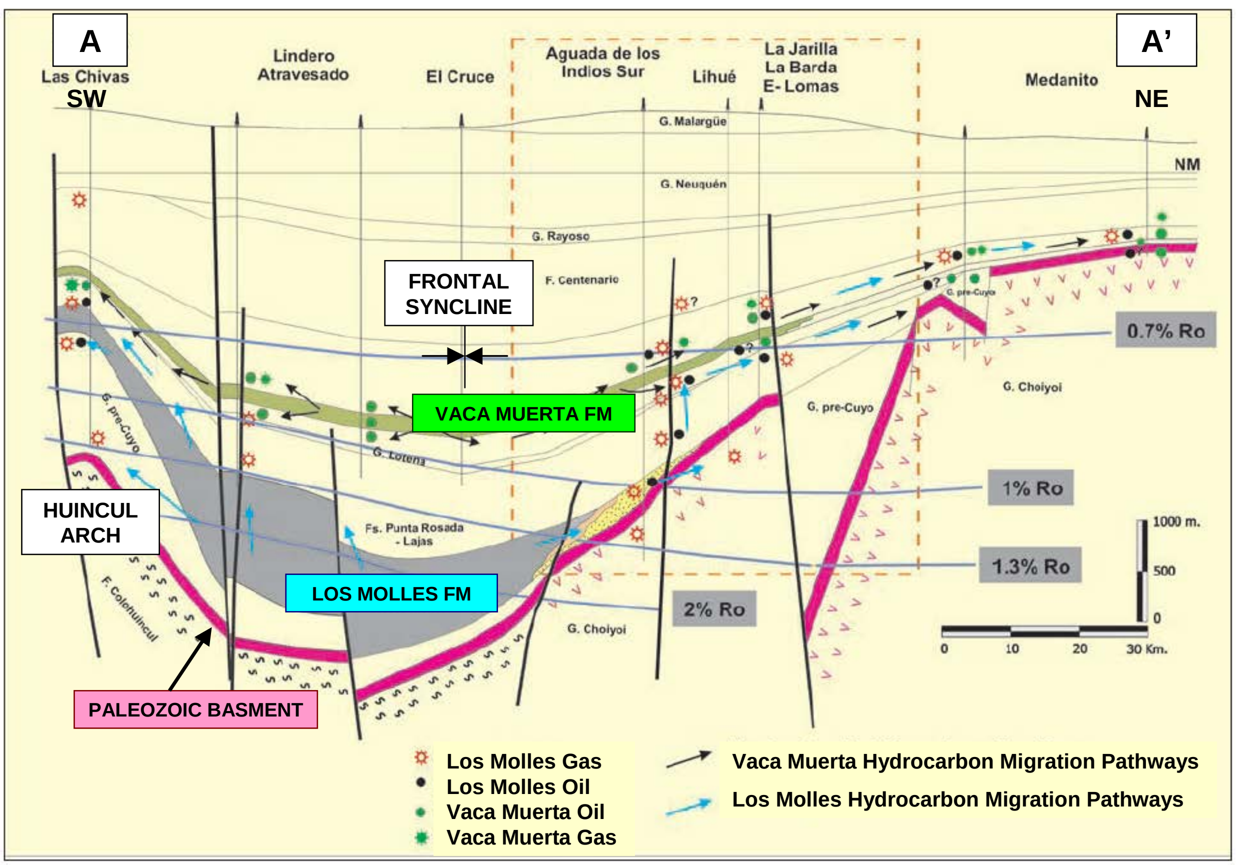
2. Establishing the Areal Extent of Major Shale Gas and Shale Oil Formations.

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

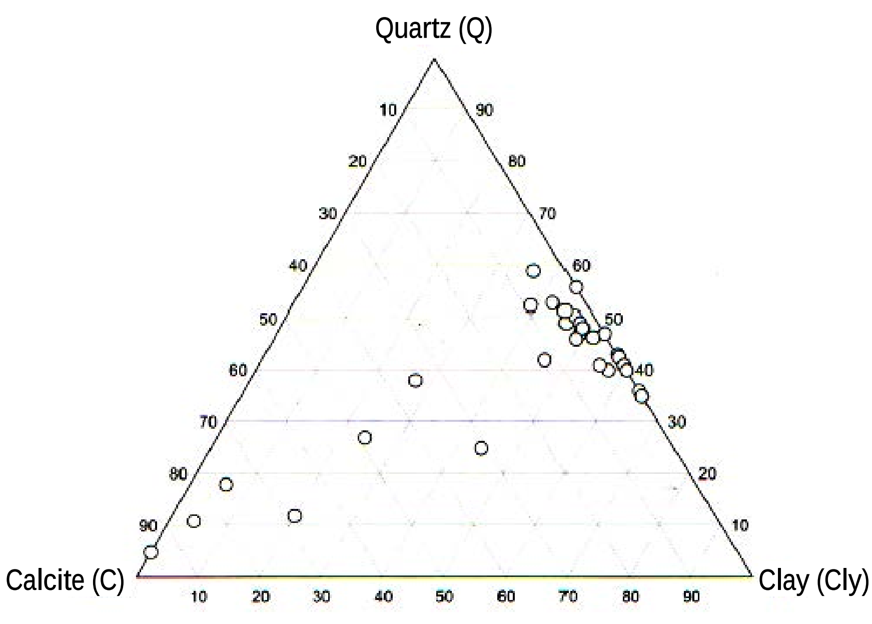
3. Defining the Prospective Area for Each Shale Gas and Shale Oil Formation.

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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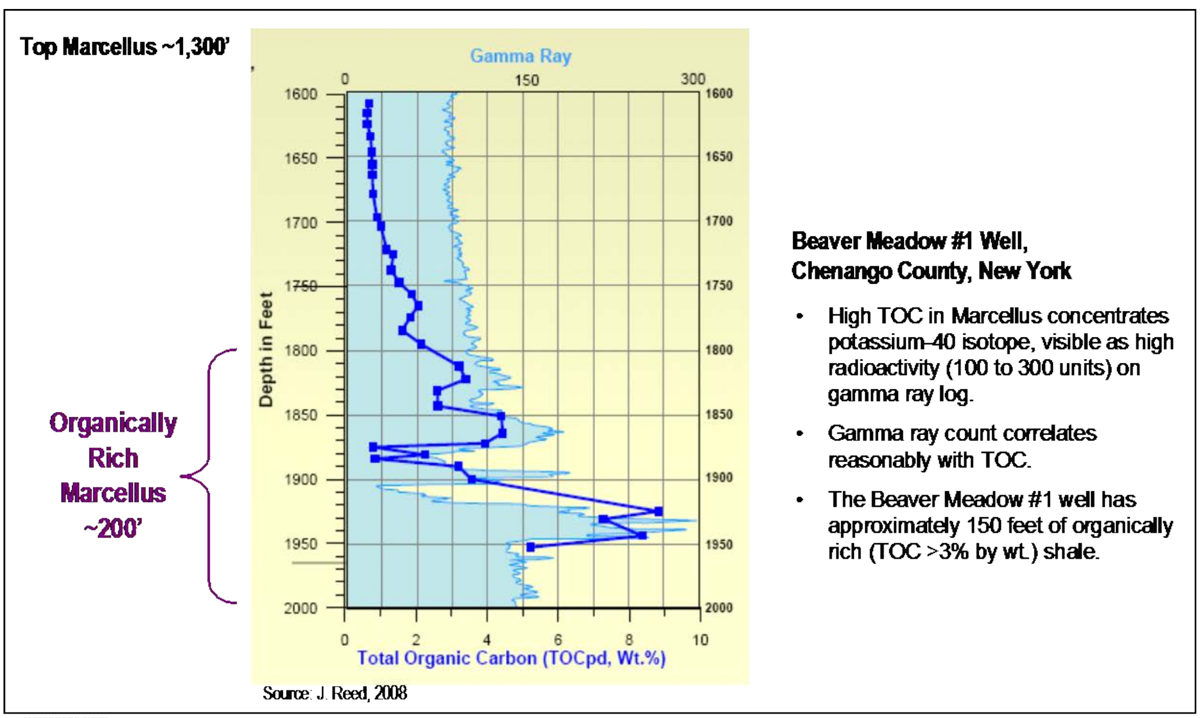
- Depth. The depth criterion for the prospective area is greater than 1,000 meters but less than 5,000 meters (3,300 feet to 16,500 feet). Areas shallower than 1,000 meters have lower reservoir pressure and thus lower driving forces for oil and gas recovery. In addition, shallow shale formations have 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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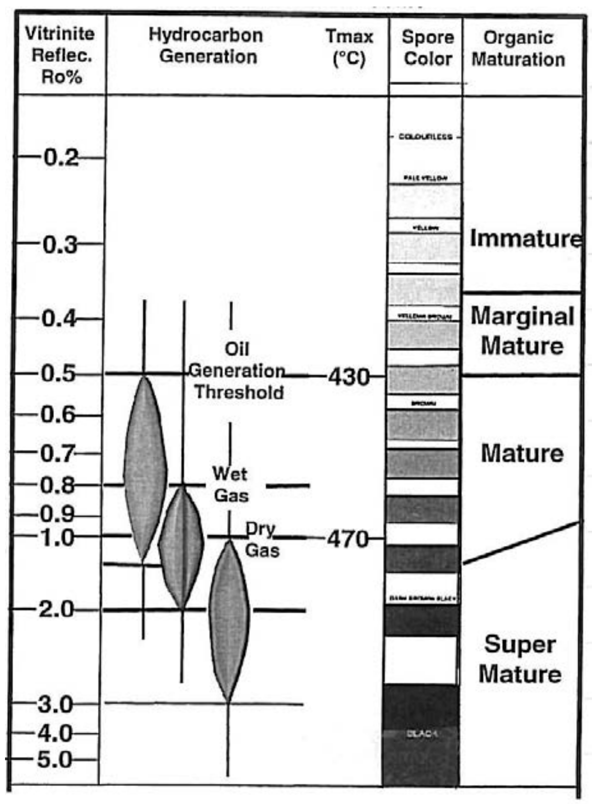
- Thermal Maturity. Thermal maturity measures the degree to which a formation has been exposed to high heat needed to break down organic matter into hydrocarbons. The reflectance of certain types of minerals (Ro%) is used as an indication of Thermal Maturity, Figure 6. The thermal maturity of the oil 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



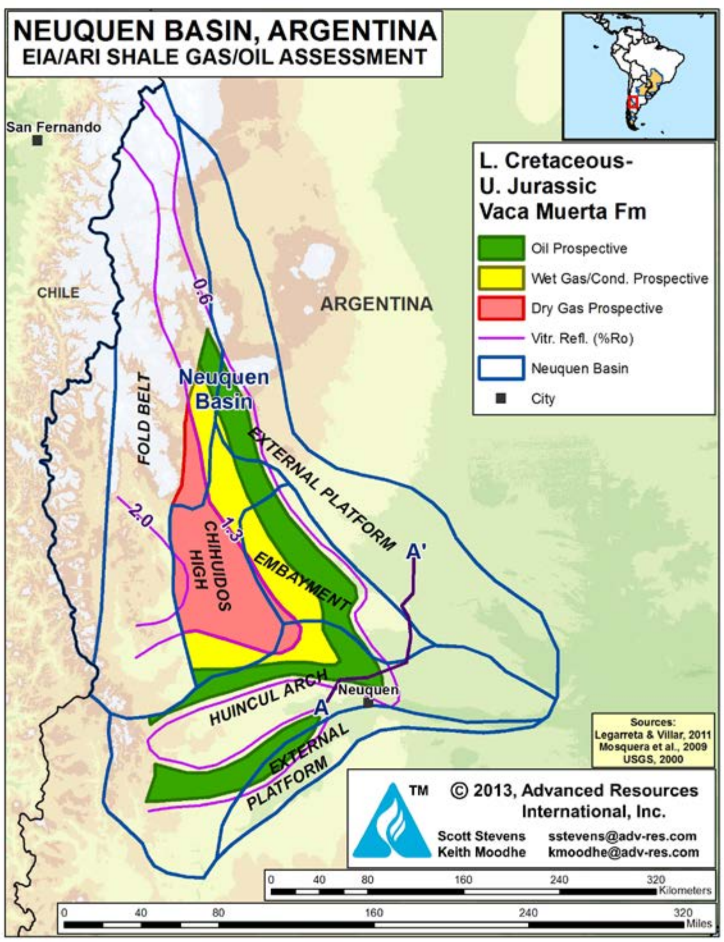
- Geographic Location. The prospective area is limited to the onshore portion of the shale gas and shale oil basin.

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^o F per 100 feet of depth and a surface temperature of 60^o 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:

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

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

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

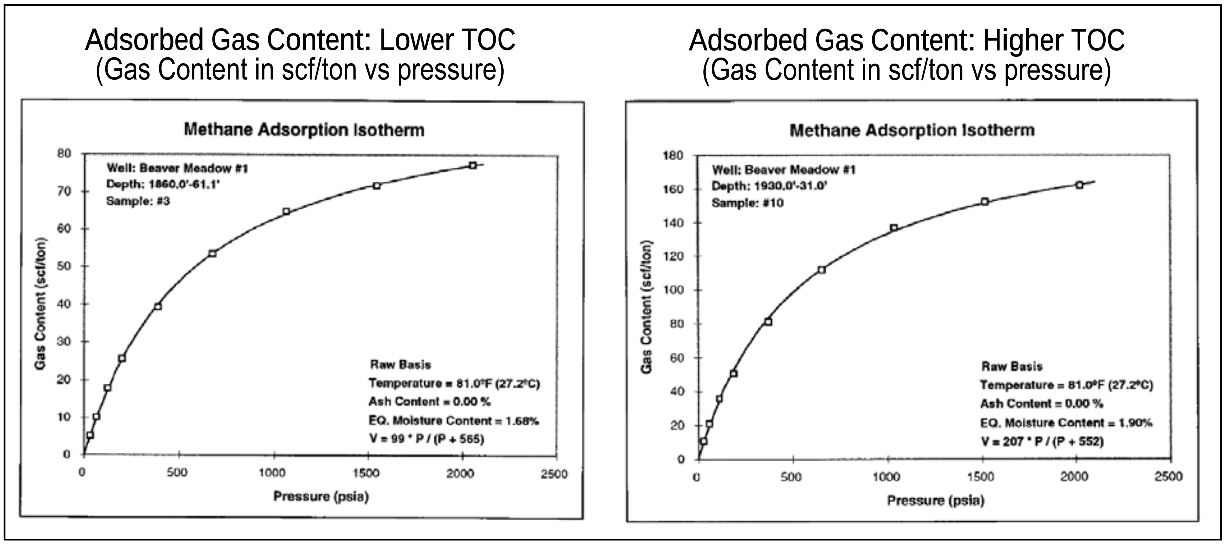


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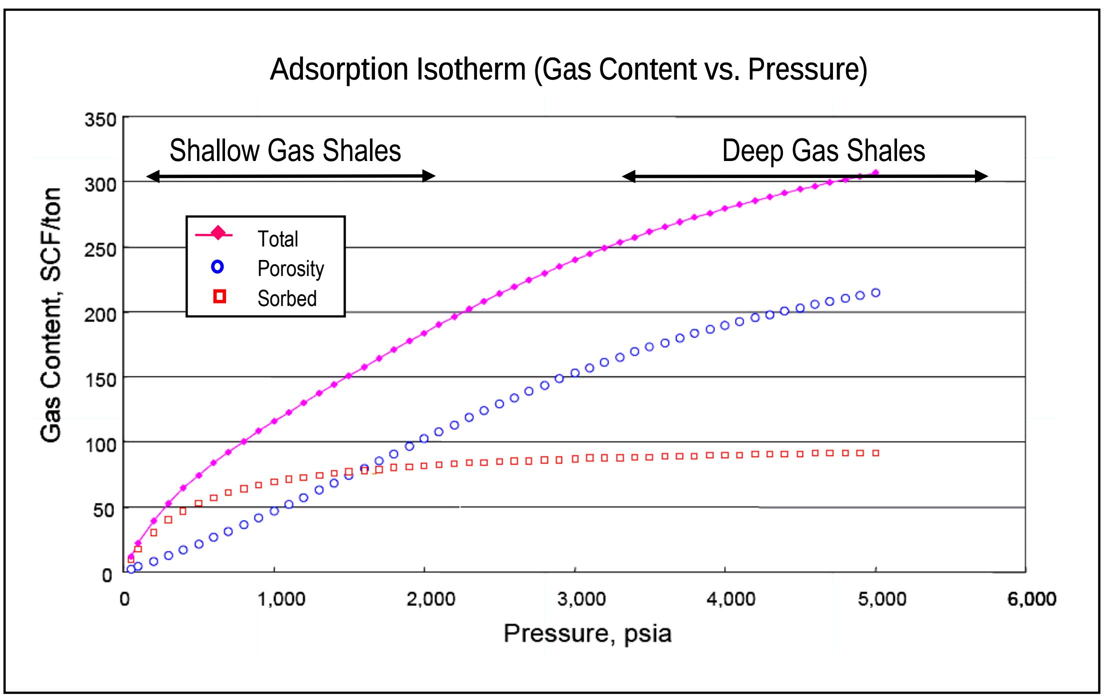
Figure 9. Combining Free and Adsorbed Gas for Total Gas In-Place



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b. 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.

- <u>Favorable Gas Recovery</u>. 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.

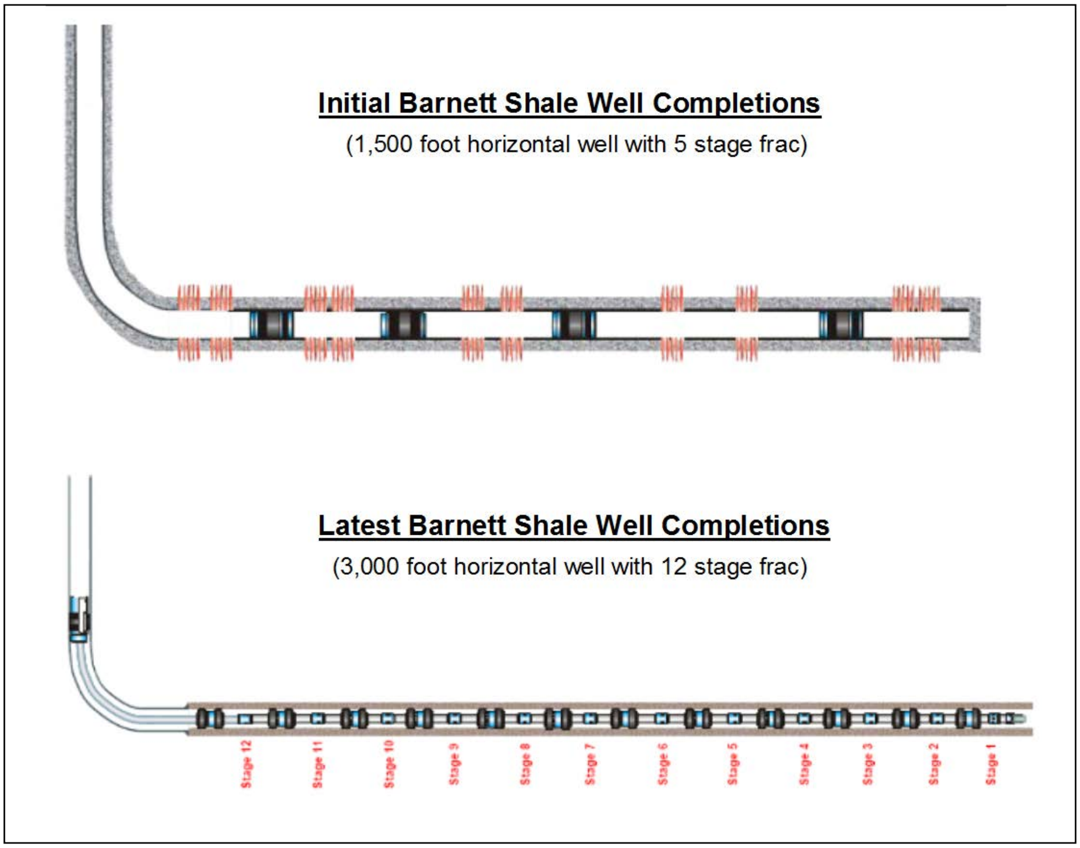
- <u>Average Gas Recovery</u>. A 20% recovery efficiency factor of the gas in-place is used for shale gas basins and formations that have a medium clay content, moderate geologic complexity and average reservoir pressure and properties.

- <u>Less Favorable Gas Recovery</u>. 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.

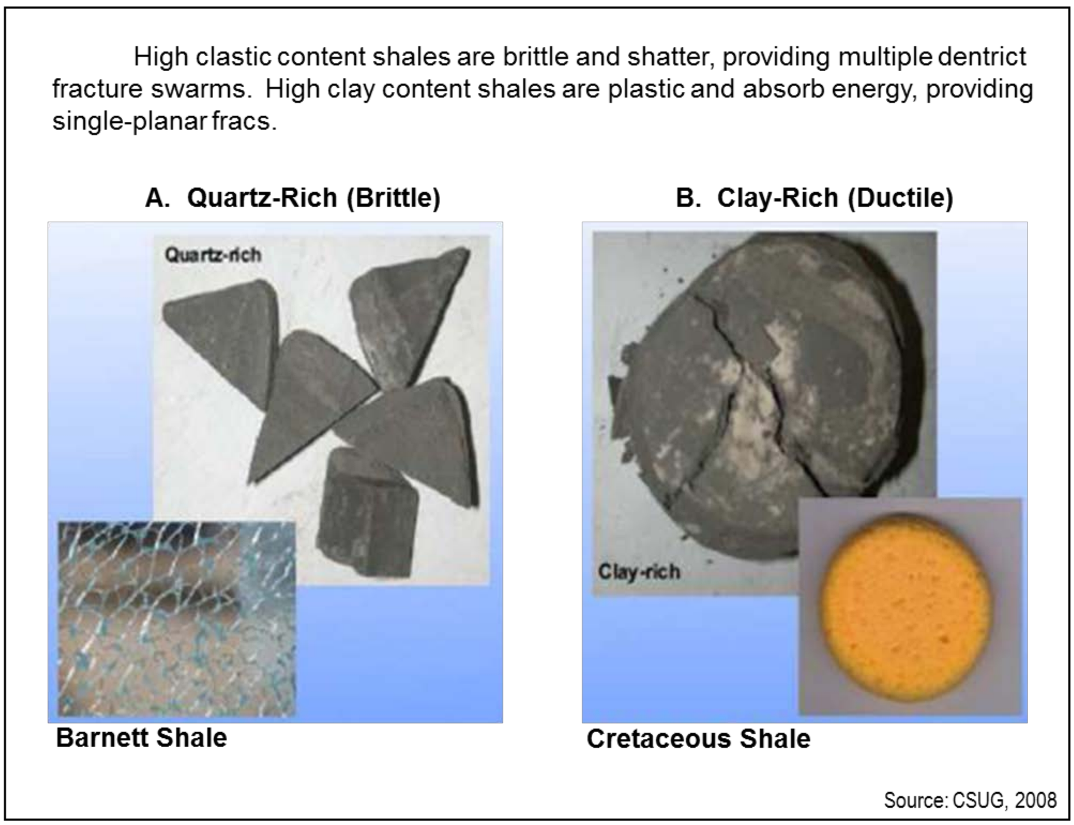
- Intensive Well Stimulation. Large volume hydraulic stimulations, conducted in multiple, closely spaced stages (up to 20), are used to "shatter" the shale matrix and create a permeable reservoir. This intensive set of induced and propped hydraulic fractures provides the critical flow paths from the 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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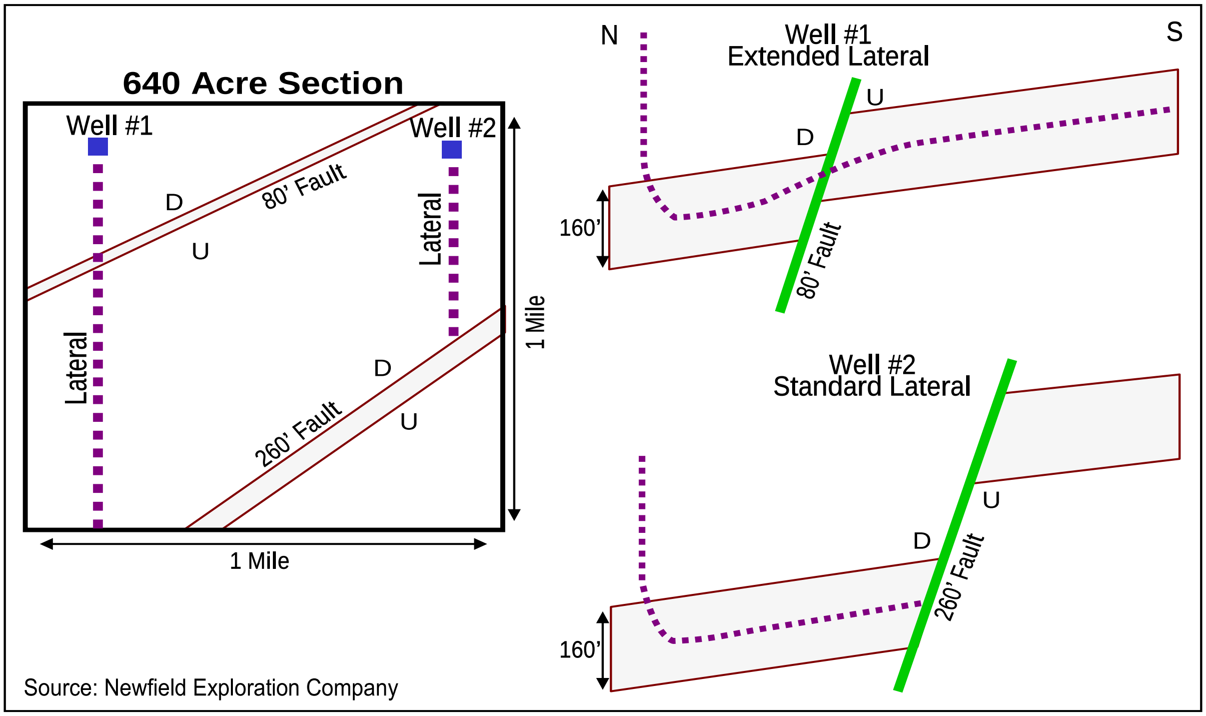
c. Significance of Geologic Complexity. A variety of complex geologic features can reduce the shale gas and shale oil recovery efficiency from a shale basin and formation:

- 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



Source: Newfield Exploration Company

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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

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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%