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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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(June 13, 2013 – corrected Executive Summary, Table 5)

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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 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

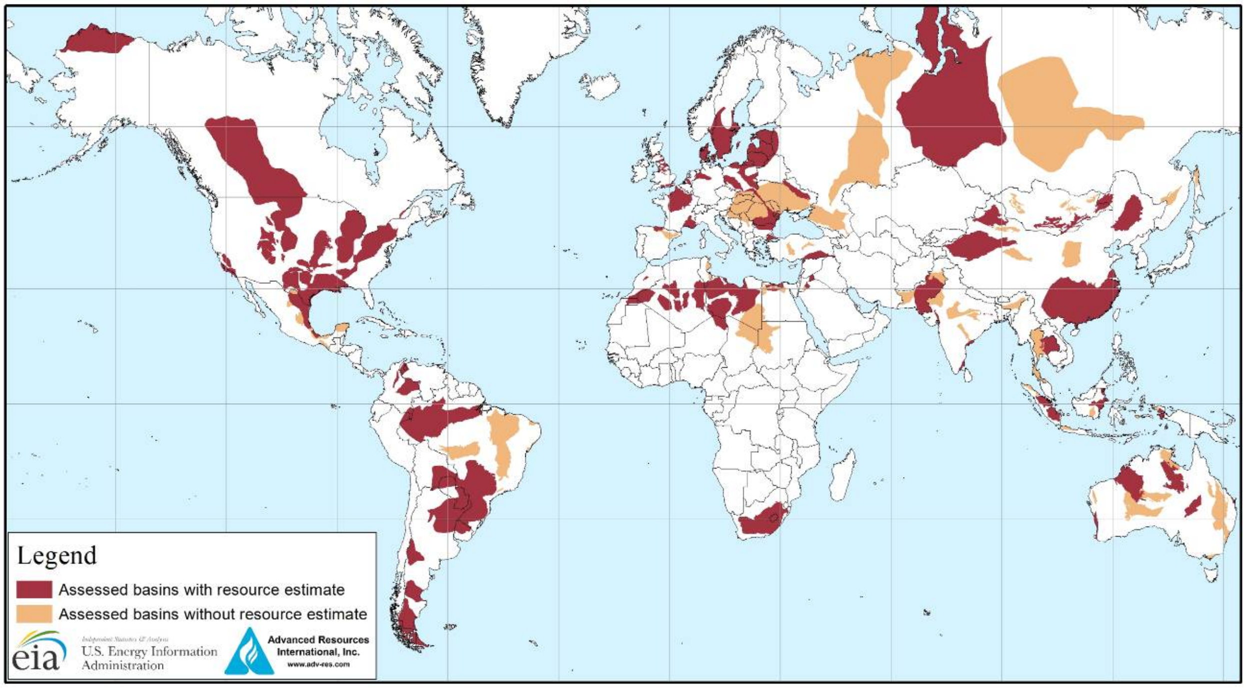
Although the terms shale oil[2] and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production. Within the United States, the 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	Australia	18	
7	Venezuela	13	
8	Mexico	13	
9	Pakistan	9	
10	Canada	9	
	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.

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[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

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[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.

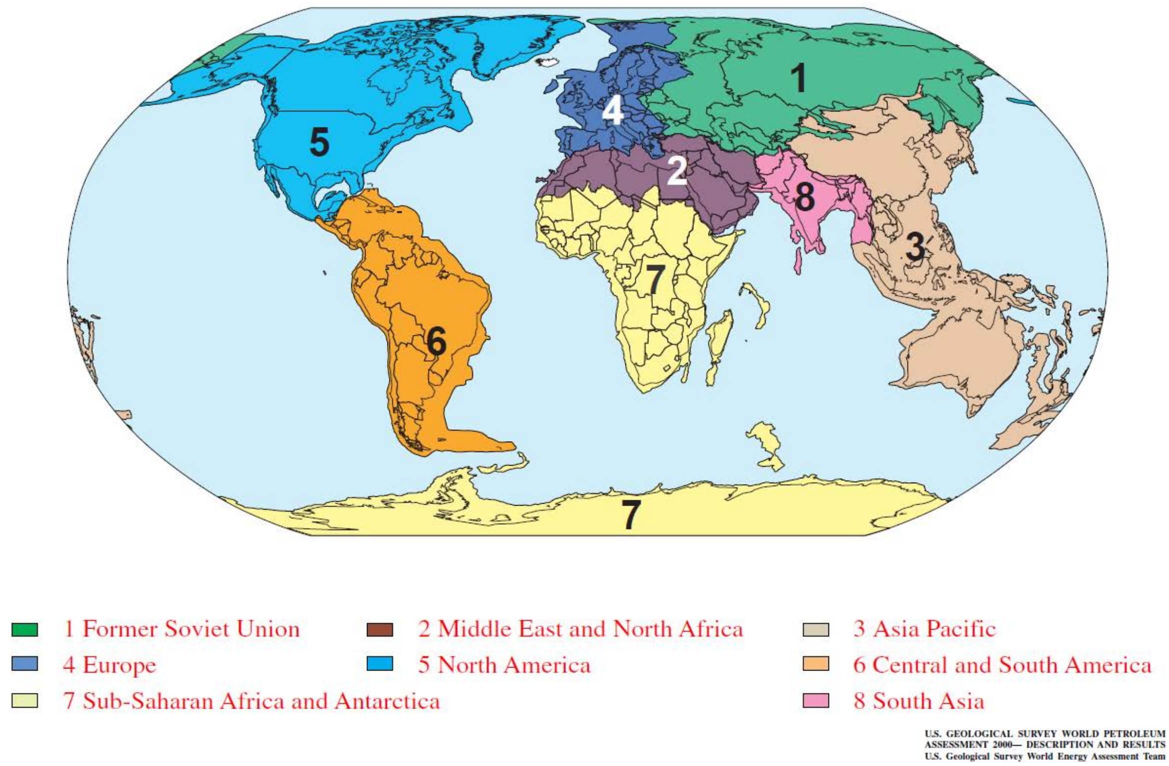
export terminal has been built to transport the natural gas to a country with a larger established consumption market.

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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May 17, 2013

Advanced Resources International, Inc.

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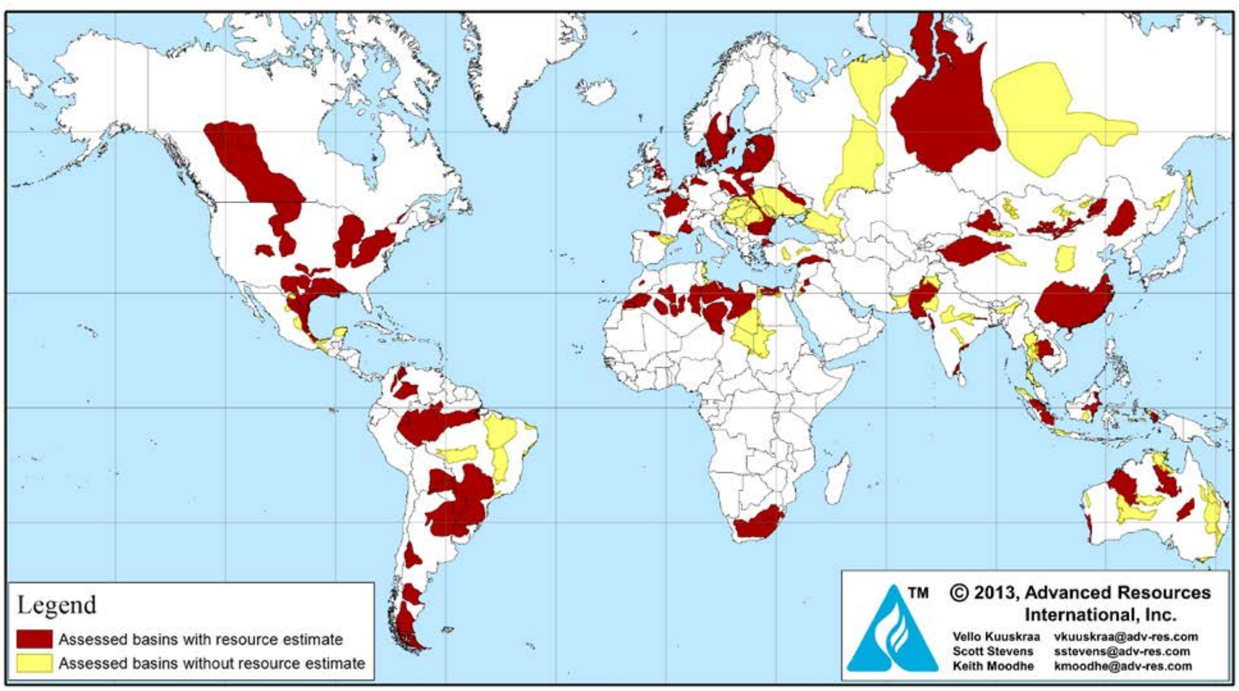
EXECUTIVE SUMMARY AND STUDY RESULTS

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**

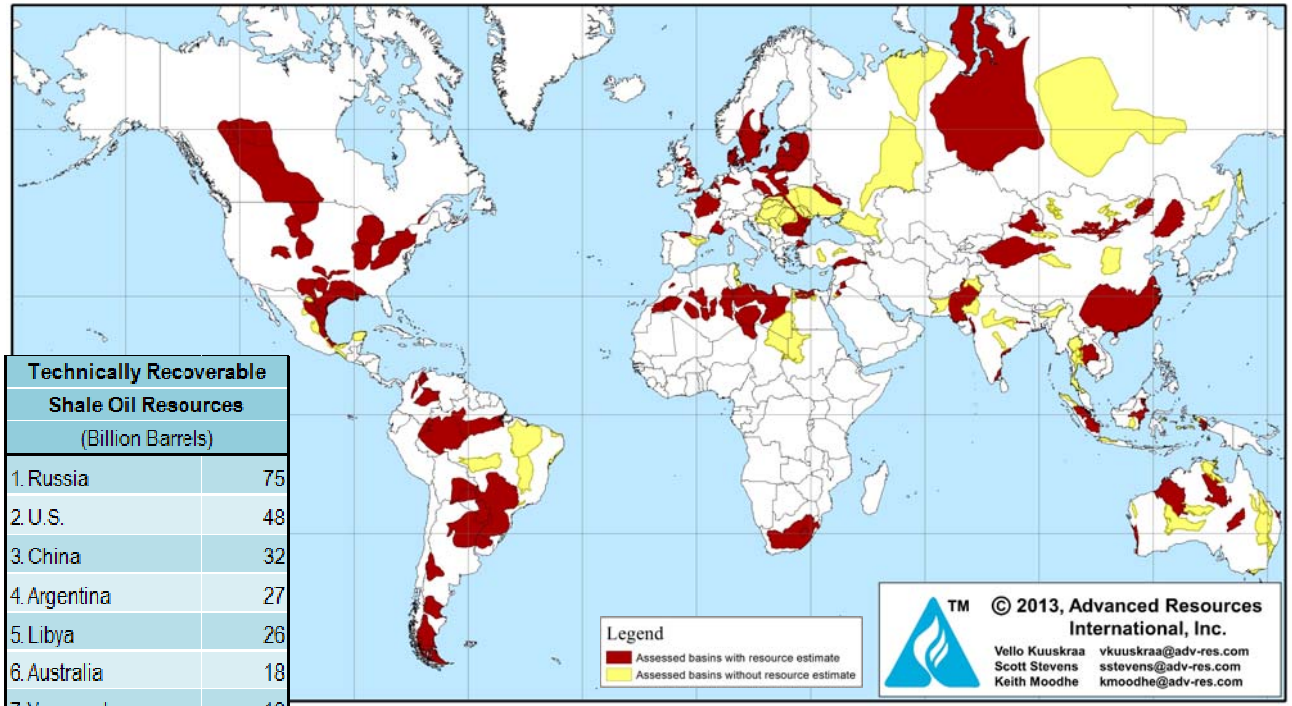
Table 2B. Risked Shale Oil In-Place and Technically Recoverable: Seven Continents

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

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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

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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

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**

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

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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%

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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.

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Figure 1: Prospective Shale Basins of Argentina

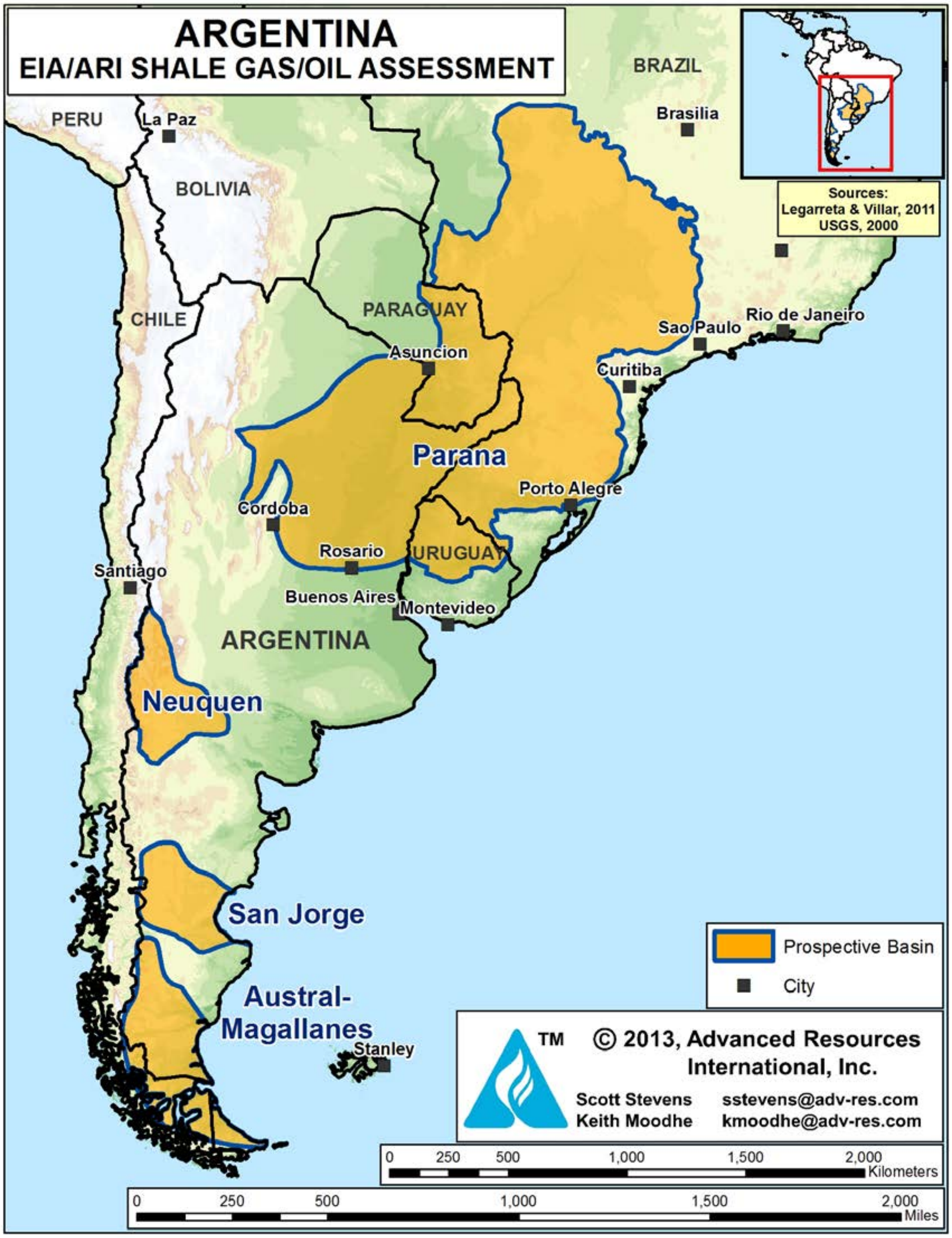
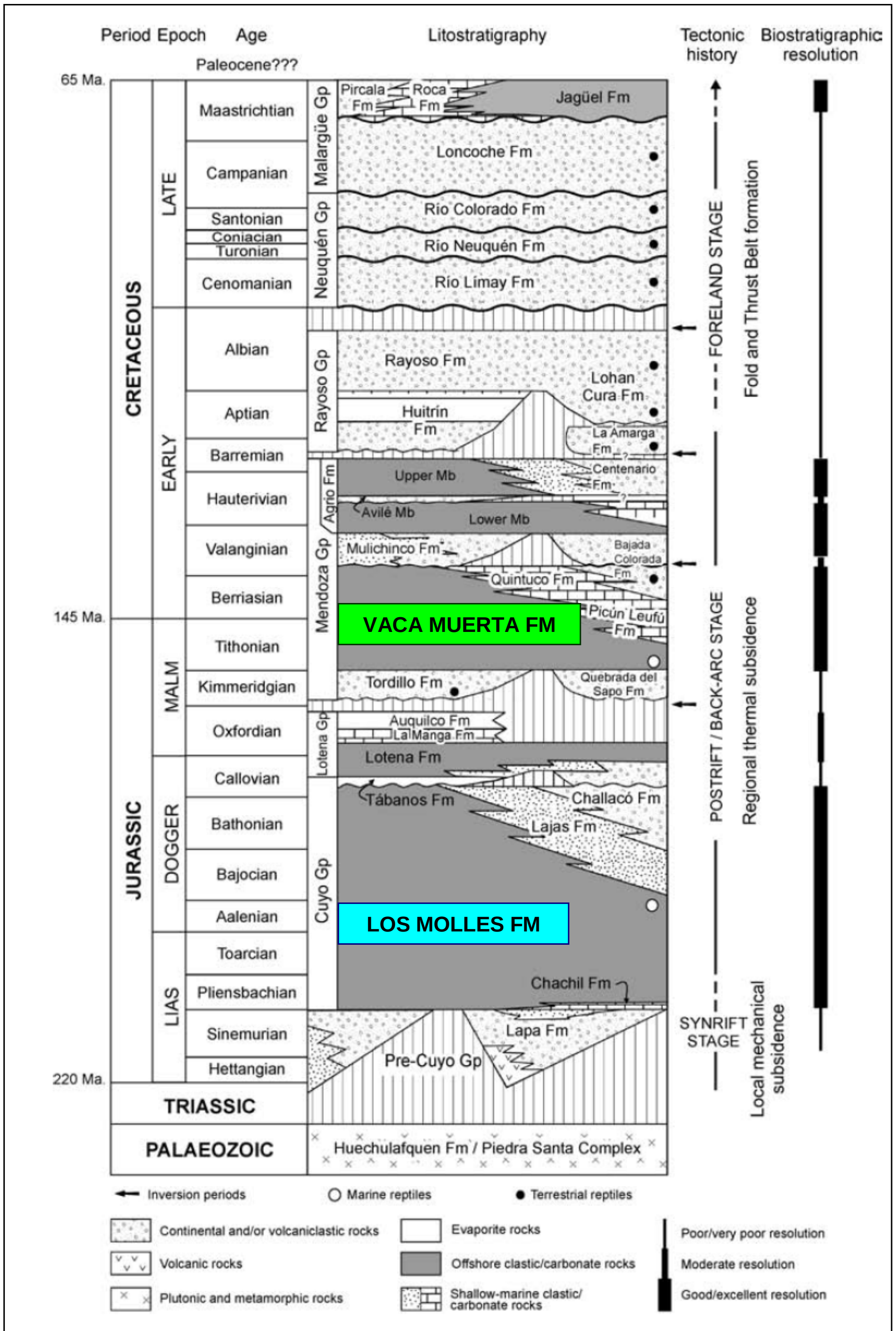


Figure 2. Neuquen Basin Stratigraphy

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



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

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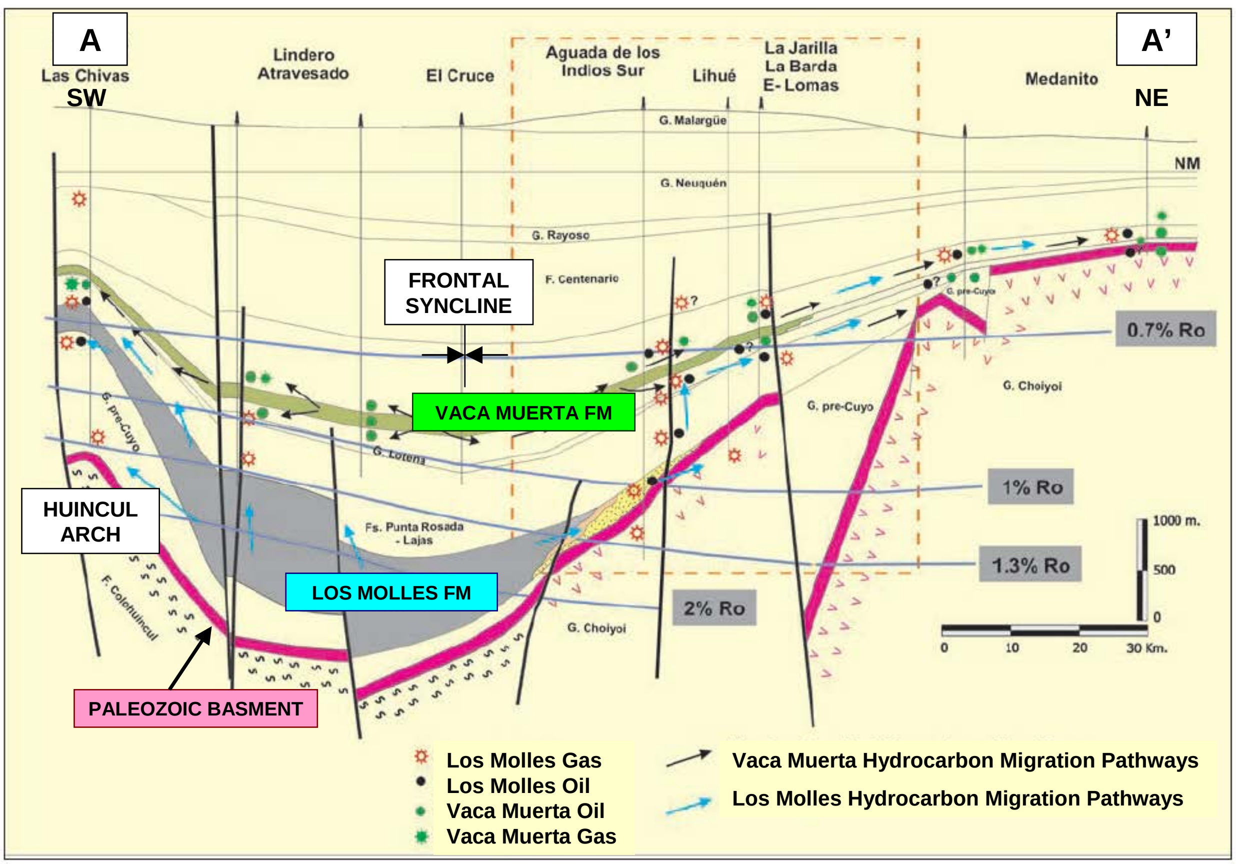
2. Establishing the Areal Extent of Major Shale Gas and Shale Oil Formations.

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

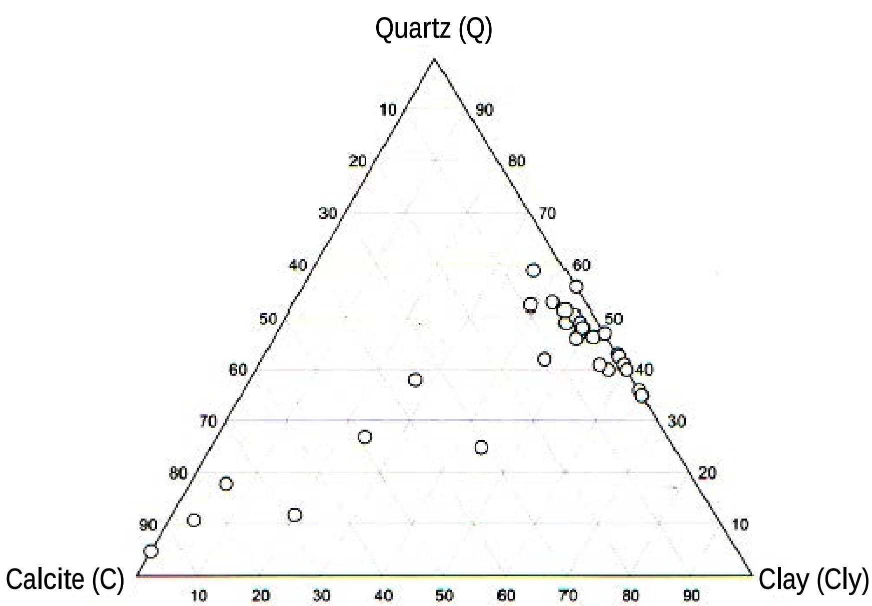
3. Defining the Prospective Area for Each Shale Gas and Shale Oil Formation.

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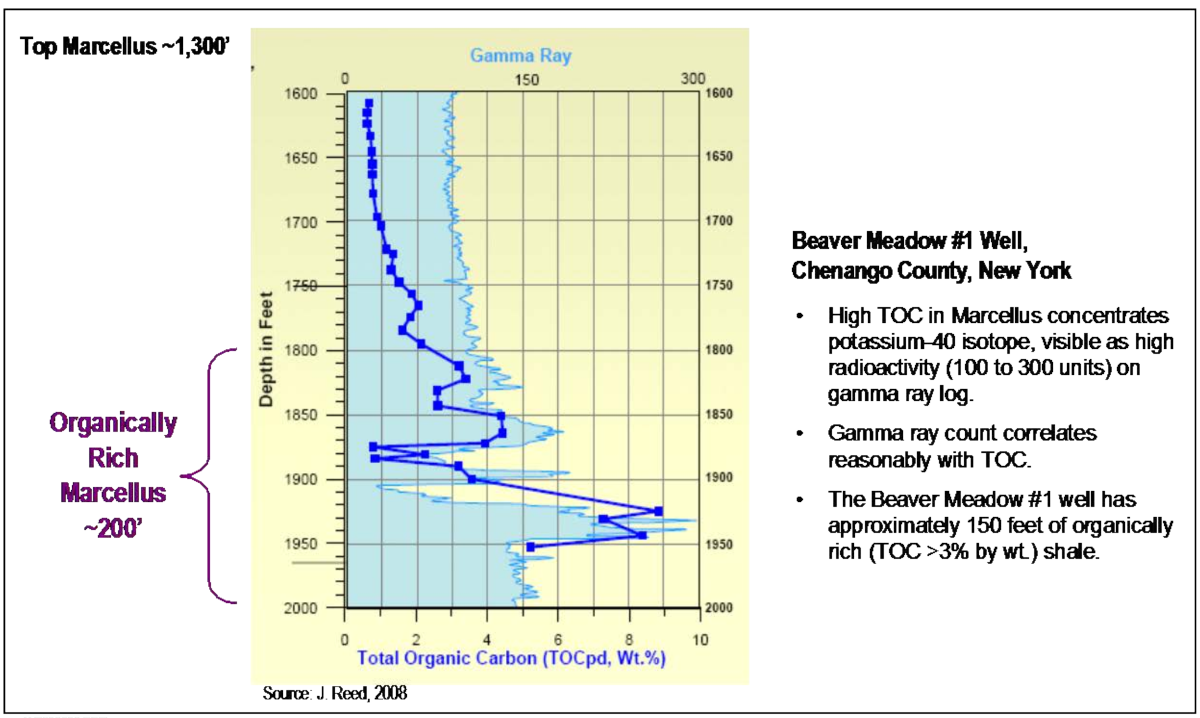
- Depth. The depth criterion for the prospective area is greater than 1,000 meters but less than 5,000 meters (3,300 feet to 16,500 feet). Areas shallower than 1,000 meters have lower reservoir pressure and thus lower driving forces for oil and gas recovery. In addition, shallow shale formations have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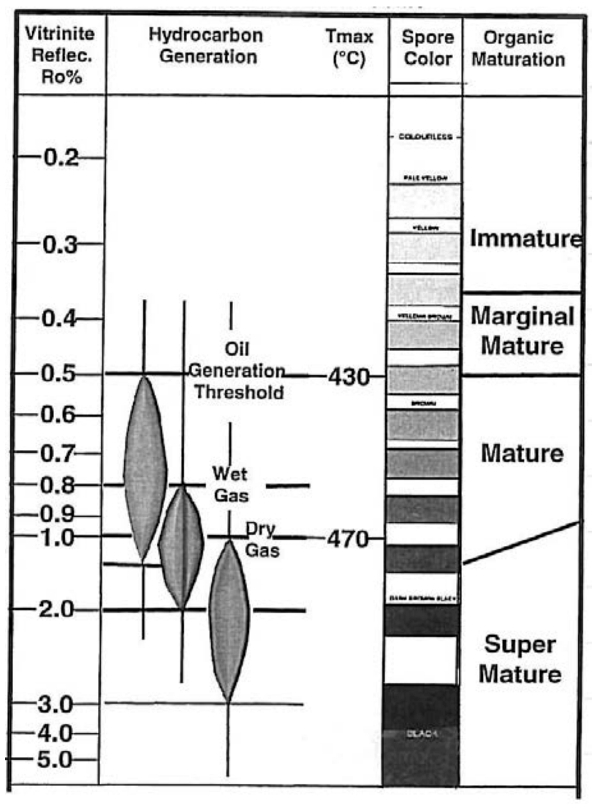
- Thermal Maturity. Thermal maturity measures the degree to which a formation has been exposed to high heat needed to break down organic matter into hydrocarbons. The reflectance of certain types of minerals (Ro%) is used as an indication of Thermal Maturity, Figure 6. The thermal maturity of the oil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



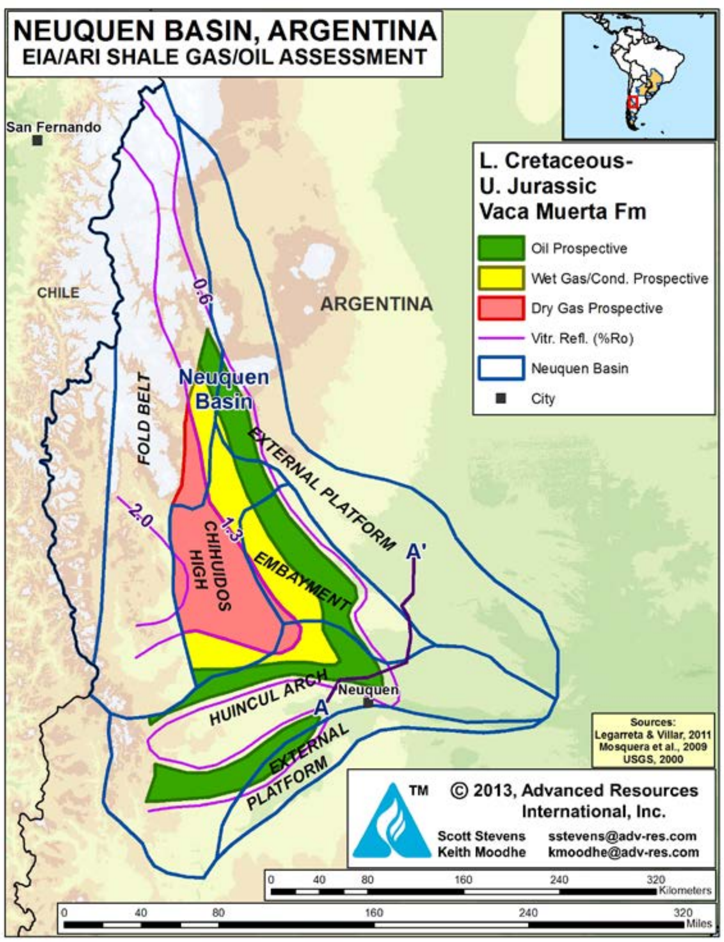
- Geographic Location. The prospective area is limited to the onshore portion of the shale gas and shale oil basin.

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.

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

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

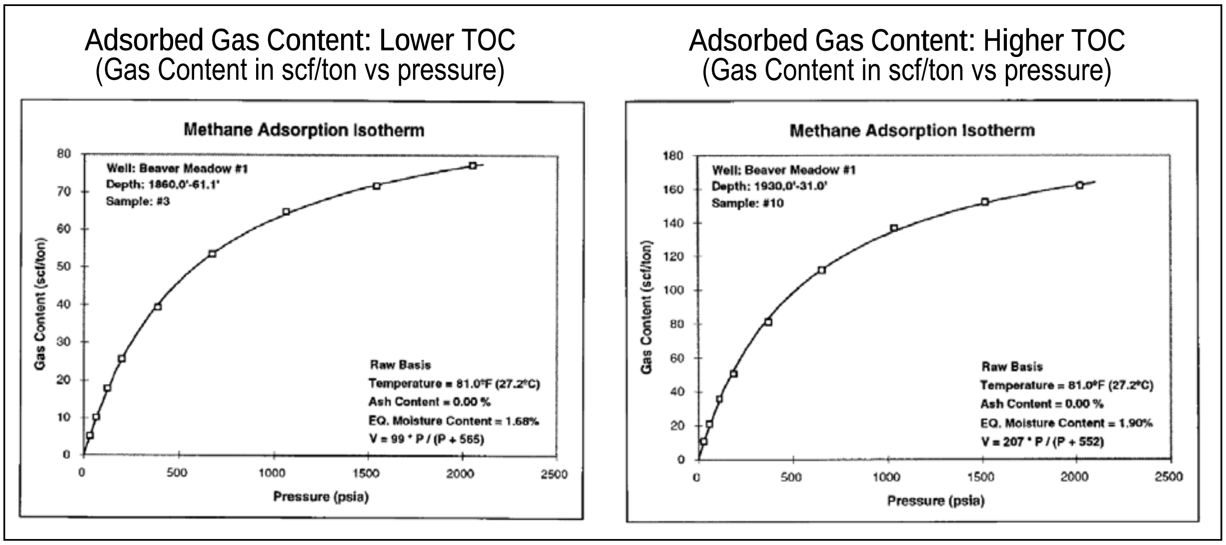

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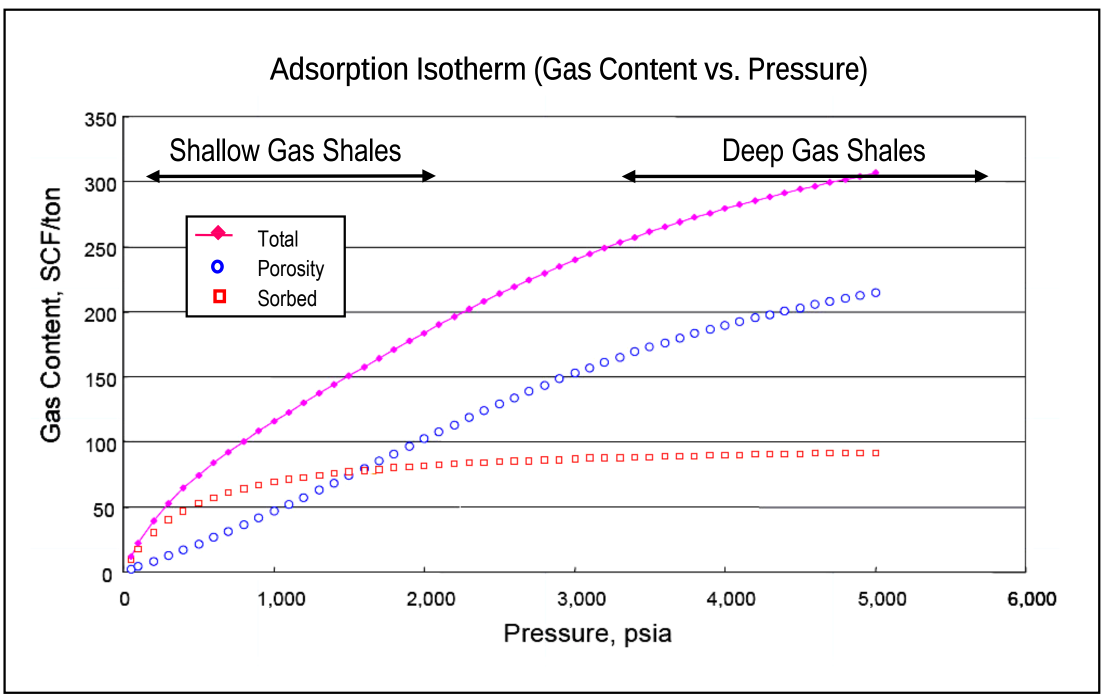
Figure 9. Combining Free and Adsorbed Gas for Total Gas In-Place



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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.

- Favorable Oil Recovery. 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.

- Average Oil Recovery. 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.

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

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

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

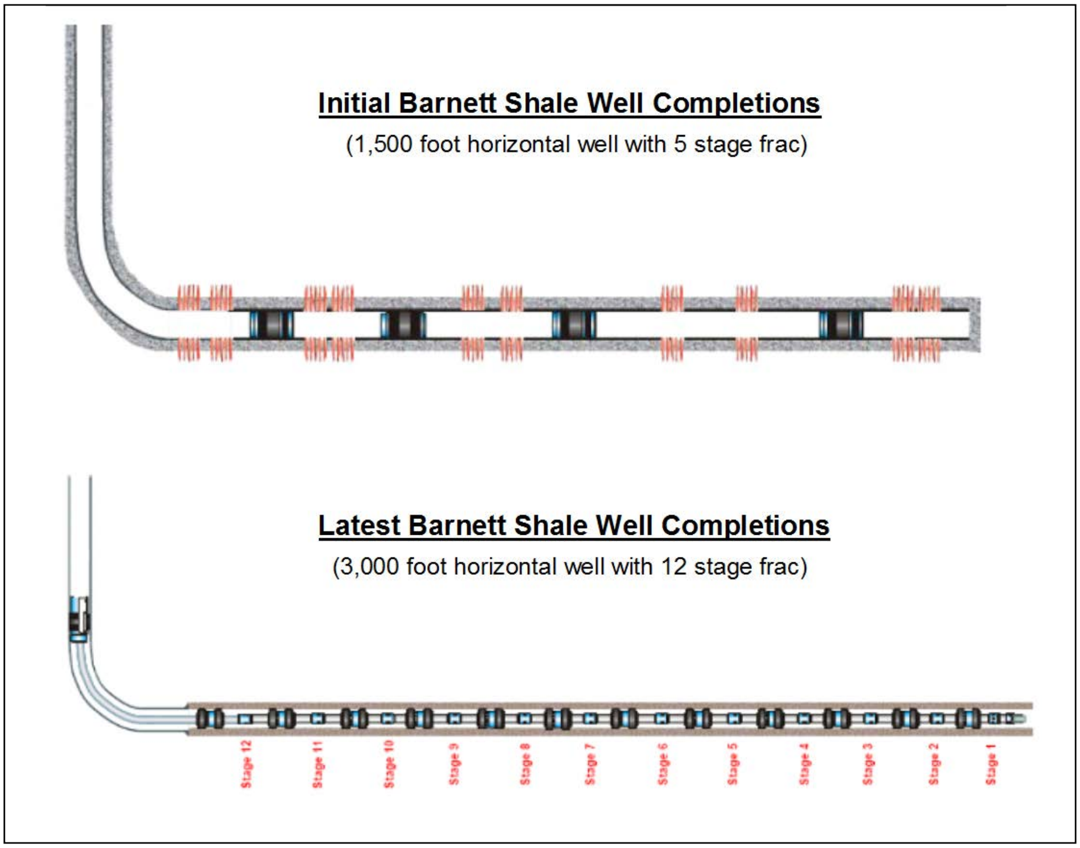
Three basic shale gas recovery efficiency factors, incorporating shale mineralogy, reservoir properties and geologic complexity, are used in the resource assessment.

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

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

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

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



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

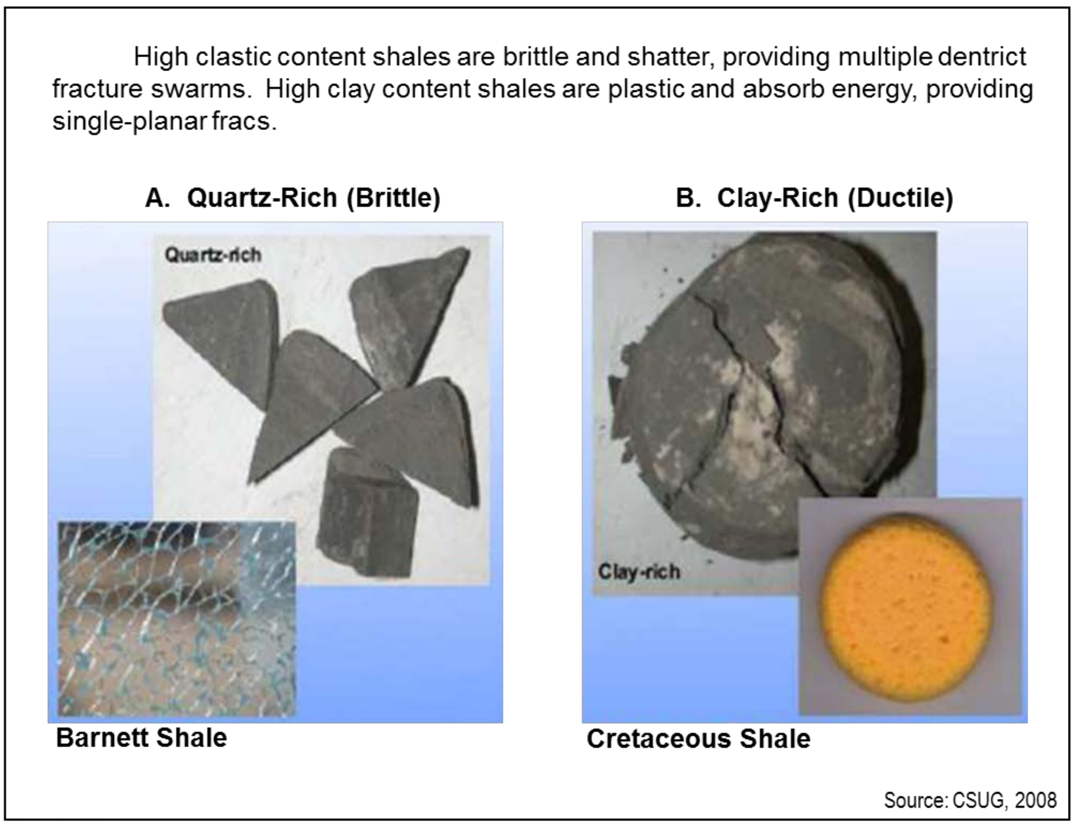
- Intensive Well Stimulation. Large volume hydraulic stimulations, conducted in multiple, closely spaced stages (up to 20), are used to “shatter” the shale matrix and create a permeable reservoir. This intensive set of induced and propped hydraulic fractures provides the critical flow paths from the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

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

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

- Shales with a high percentage of quartz and carbonate tend to be brittle and will "shatter", leading to a vast array of small-scale induced fractures providing numerous flow paths from the matrix to the wellbore, when hydraulic pressure and energy are injected into the shale matrix, Figure 11A.
- Shales with a high clay content tend to be ductile and to deform instead of shattering, leading to relatively few induced fractures (providing only limited flow paths from the matrix to the well) when hydraulic pressure and energy are injected into the shale matrix, Figure 11B.

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



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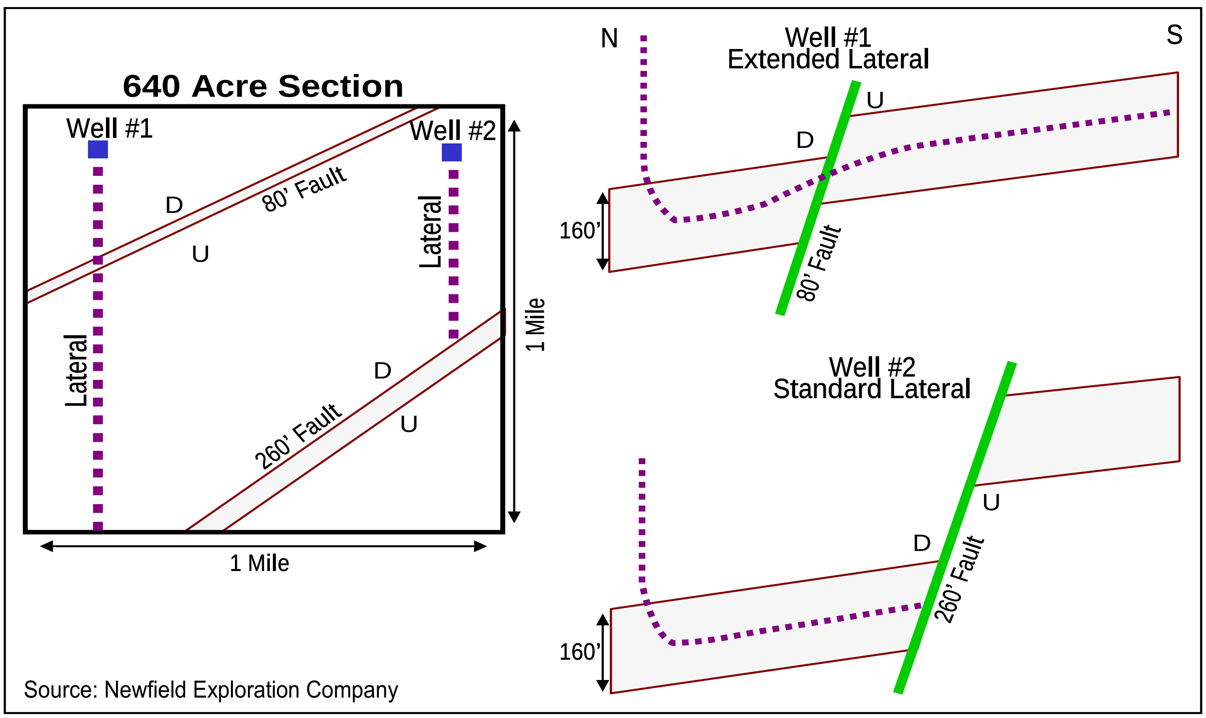
c. Significance of Geologic Complexity. A variety of complex geologic features can reduce the shale gas and shale oil recovery efficiency from a shale basin and formation:

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

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



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SUMMARY

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

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

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

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

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

Table 1. Shale Gas Reservoir Properties and Resources of Argentina

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

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

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

ATTACHMENT A

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

INTRODUCTION

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

DATA BASE

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

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

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

ANALYTIC RESULTS

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

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

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

FINDINGS AND OBSERVATIONS

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

- The oil recovery efficiency values range from about 1% to 9%, with an un-weighted average of about 3.5%.

- Taking out five of the extremely low oil recovery efficiency plays (which we would classify as non-productive) - - Mississippi Lime (Eastern Oklahoma Ext.), Mississippi Lime (Kansas Ext.), Delaware Wolfcamp (Texas Ext.), D-J Niobrara (North Ext. #2), and D-J Niobrara (East Ext.), raises the average oil recovery efficiency to 4.1%.

- Six of the U.S. “tight oil” plays have oil recovery factors that range from about 8% to about 9%.

- Four of the U.S. “tight oil” plays have oil recovery factors that range from about 4% to about 6%.

- Twelve of the U.S. “tight oil” plays have oil recovery factors that range from about 2% to about 3%.

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

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

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

Table A-2. Oil Recovery Efficiency for 28 U.S. Tight Oil Plays (Black Oil, Volatile Oil and Condensates)

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

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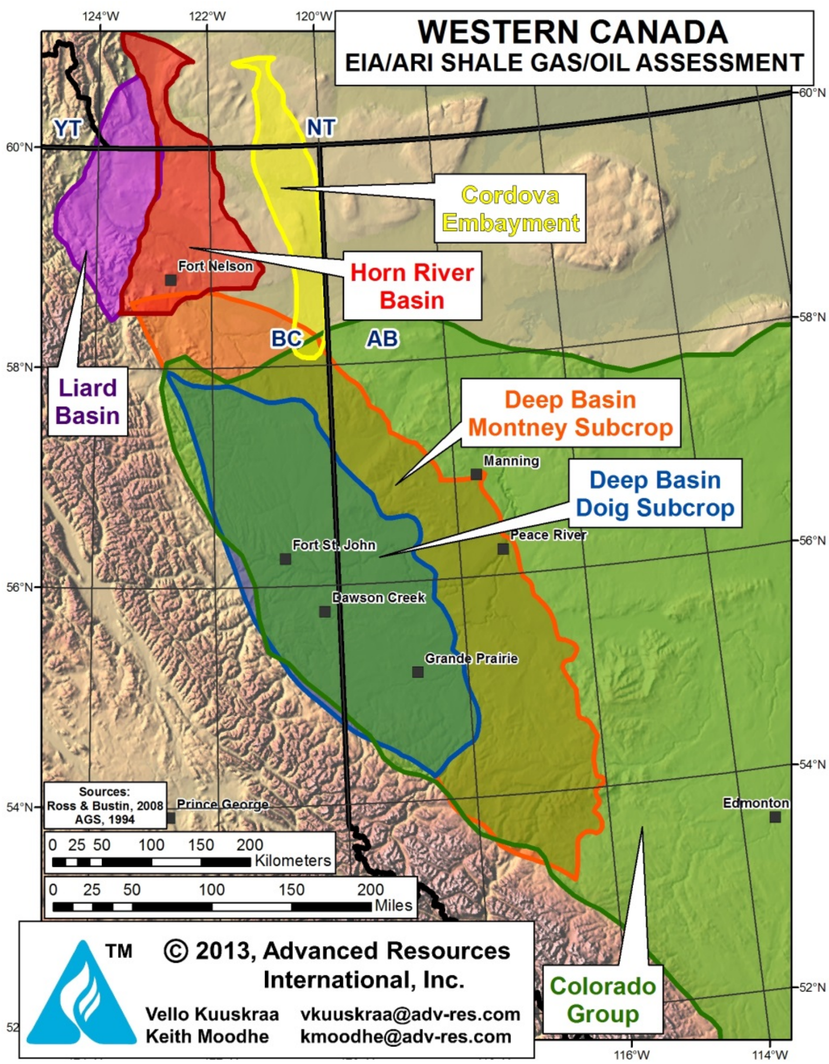
I. CANADA

SUMMARY

Canada has a series of large hydrocarbon basins with thick, organic-rich shales that are assessed by this resource study. Figure I-1 illustrates certain of the major shale gas and shale oil basins in Western Canada.

Figure I-1. Selected Shale Gas and Oil Basins of Western Canada



Source: ARI, 2012.

The full set of Canadian shale gas and shale oil basins assessed in this study include: (1) the Horn River Basin, the Cordova Embayment and the Liard Basin (located in British Columbia and the Northwest Territories) plus the Doig Phosphate Shale (located in both British Columbia and Alberta); (2) the numerous shale gas and shale oil formations and plays in Alberta, such as the Banff/Exshaw, the Duvernay, the Nordegg, the Muskwa and the Colorado Group; (3) the Williston Basin's Bakken Shale in Saskatchewan and Manitoba; and (4) the Utica Shale in Quebec and the Horton Bluff Shale in Nova Scotia.

Western Canada also contains the prolific and areally extensive Montney and Doig Resource Plays (in both British Columbia and Alberta) categorized primarily as tight sand and siltstone reservoirs. As thus, these two important unconventional gas resources are not included in this shale gas and shale oil resource assessment. In addition, Canada has a series of additional hydrocarbon-bearing siltstone and shale formations that are not included in the quantitative portion of this resource study either because of low organic content (Wilrich Shale in Alberta) or because of limited information (Frederick Brook Shale in New Brunswick).

We estimate risked shale gas in-place for Canada of 2,413 Tcf, with 573 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate risked shale oil in-place for Canada of 162 billion barrels, with 8.8 billion barrels as the risked, technically recoverable shale oil resource. Table I-1 provides a more in-depth, regional tabulation of Canada's shale gas and oil resources.

As new drilling occurs and more detailed information is obtained on these large, emerging shale plays, the estimates of the size of their in-place resources and their recoverability will undoubtedly change.

Table I-1. Shale Gas and Oil Resources of Canada

Region	Basin / Formation	Risked Resource In-Place		Risked Technically Recoverable Resource	
		Oil/Condensate (Million bbl)	Natural Gas (Tcf)	Oil/Condensate (Million bbl)	Natural Gas (Tcf)
British Columbia / Northwest Territories	Horn River (Muskwa / Otter Park)	-	375.7	-	93.9
	Horn River (Evie / Klua)	-	154.2	-	38.5
	Cordova (Muskwa / Otter Park)	-	81.0	-	20.3
	Liard (Lower Besa River)	-	526.3	-	157.9
	Deep (Doig Phosphate)	-	100.7	-	25.2
	Sub-Total	**-**	**1,237.8**	**-**	**335.8**
Alberta	Alberta (Banff / Exshaw)	10,500	5.1	320	0.3
	E/W Shale (Duvernay)	66,800	482.6	4,010	113.0
	Deep Basin (Nordegg)	19,800	72.0	790	13.3
	N.W. Alberta (Muskwa)	42,400	141.7	2,120	31.1
	S. Alberta (Colorado)	-	285.6	-	42.8
	Sub-Total	**139,500**	**987.1**	**7,240**	**200.5**
Saskatchewan / Manitoba	Williston (Bakken)	**22,500**	**16.0**	**1,600**	**2.2**
Quebec	App. Fold Belt (Utica)	**-**	**155.3**	**-**	**31.1**
Nova Scotia	Windsor (Horton Bluff)	**-**	**17.0**	**-**	**3.4**
	Total	**162,000**	**2,413.2**	**8,840**	**572.9**

*Less than 0.5 Tcf

BRITISH COLUMBIA/NORTHWEST TERRITORIES

British Columbia (BC) and the Northwest Territories (NWT) hold three “world-scale” shale basins, the Horn River Basin, the Cordova Embayment and the Liard Basin. In addition, the organic-rich Doig Phosphate Shale exists on each side of the central Alberta and BC border. In addition to these shale resources, British Columbia also has portions of the massive tight sand and siltstone Montney Resource and Doig Resource plays. These two low organic content formations, classified as tight sands by Canada’s National Energy Board, are not included in this shale gas and oil resource assessment.

This resource assessment study has benefitted greatly from the extensive geological and reservoir characterization work supported by the BC Ministry of Energy and Mines on the shale basins and formations of British Columbia.[1,2] In addition, this study has drawn on the extensive well drilling and well performance information provided by Canada’s oil and gas industry. These two information sources serve as foundations for the assessment of the shale gas and oil resources of British Columbia and the Northwest Territories. The four BC/NWT shale oil and gas basins assessed by this study contain 1,238 Tcf of risked shale gas in-place, with 336 Tcf as the risked, technically recoverable shale gas resource, Table I-2.

Table I-2. Shale Gas Reservoir Properties and Resources of British Columbia/NWT

Basic Data	Basin/Gross Area		Horn River (7,100 mi^2)		Cordova (4,290 mi^2)	Liard (4,300 mi^2)	Deep Basin (24,800 mi^2)
	Shale Formation		Muskwa/Otter Park	Evie/Klua	Muskwa/Otter Park	Lower Besa River	Doig Phosphate
	Geologic Age		Devonian	Devonian	Devonian	Devonian	Triassic
	Depositional Environment		Marine	Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		3,320	3,320	2,000	3,300	3,000
	Thickness (ft)	Organically Rich	420	160	230	500	165
		Net	380	144	207	400	150
	Depth (ft)	Interval	6,300 - 10,200	6,800 - 10,700	5,500 - 6,200	6,600 - 13,000	6,800 - 10,900
		Average	8,000	8,500	6,000	10,000	9,250
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Highly Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.5%	4.5%	2.0%	3.5%	5.0%
	Thermal Maturity (% Ro)		3.50%	3.80%	2.50%	3.80%	1.10%
	Clay Content		Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		150.9	61.9	67.5	319.0	67.1
	Risked GIP (Tcf)		375.7	154.2	81.0	526.3	100.7
	Risked Recoverable (Tcf)		93.9	38.5	20.3	157.9	25.2

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1. HORN RIVER BASIN

1.1 Geologic Setting

The Horn River Basin covers an area of 7,100 mi^2 in northern British Columbia and the Northwest Territories, Figure I-2. The basin's western border is defined by the Bovie Fault, which separates the Horn River Basin from the Liard Basin. Its northern border, in Northwest Territories, is defined by the thinning of the shale section, and its southern border is constrained by the pinch-out of the shale. Its eastern border is defined by the Slave Point/Keg River Uplift and the thinning of the shale deposit. We have defined a higher quality, 3,320-mi^2 prospective area for the Horn River Shale in the west-central portion of the basin, Figure I-3.

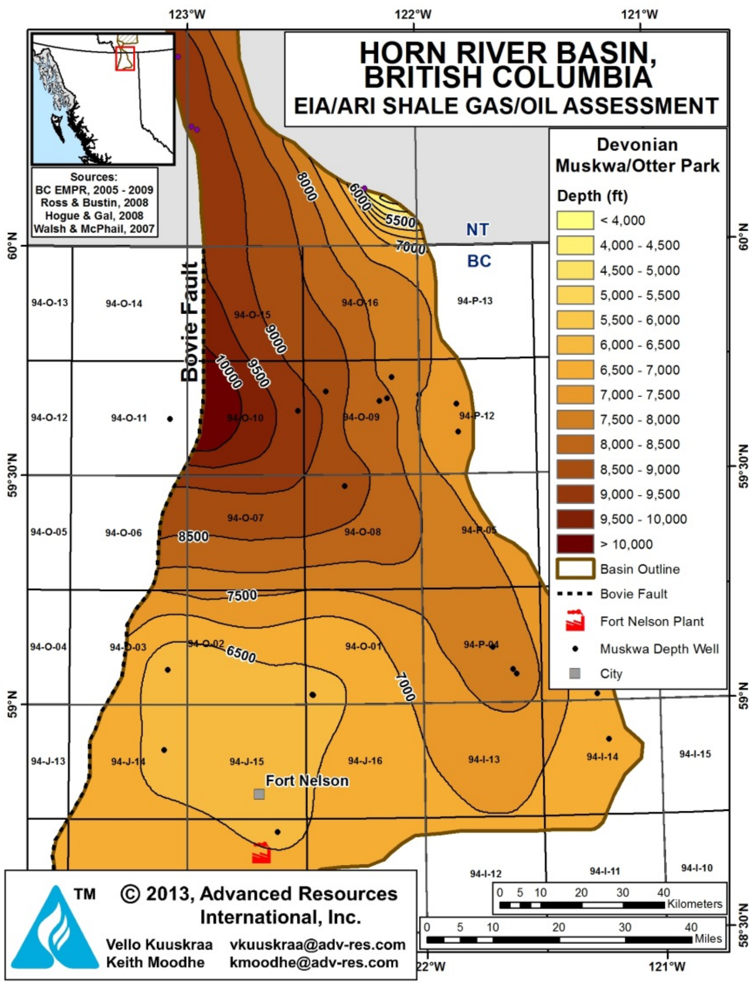
The Horn River Basin contains a series of organic-rich shales, with the Middle Devonian-age Muskwa/Otter Park and Evie/Klua most prominent, Figure I-4.[3] These two shale units were mapped in the Horn River Basin to establish a prospective area with sufficient thickness and resource concentration favorable for shale gas development. Other shales in this basin (but not included in the study) include the high organic-content, lower thermal maturity, poorly defined Mississippian Banff/Exshaw Shale and the thick, low organic-content Late Devonian Fort Simpson Shale.

1.2 Reservoir Properties (Prospective Area)

Two major shale gas formations, the Muskwa/Otter Park and the Evie/Klua, are included in the quantitative portion of our resource assessment.

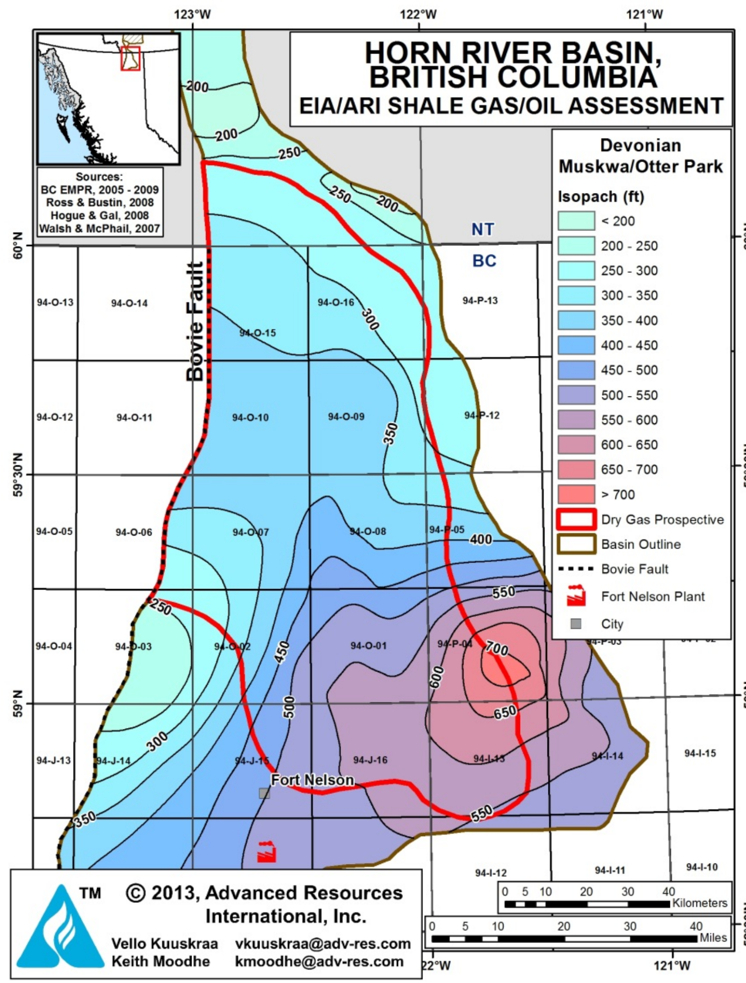
Muskwa/Otter Park. The Middle Devonian Muskwa/Otter Park Shale, the upper shale interval within the Horn River Group, is the main shale gas target in the Horn River Basin. Drilling depth to the top of the Muskwa/Otter Park Shale ranges from 6,300 to 10,200 feet, averaging 8,000 feet for the prospective area. The Muskwa/Otter Park Shale is moderately over-pressured in the center of the basin. With an organic-rich gross shale thickness of 420 feet, the Muskwa/Otter Park has a net pay of 380 feet. Total organic content (TOC) in the prospective area averages 3.5% for the net shale thickness investigated. Thermal maturity (R_o) is high, averaging about 3.5% and placing this shale gas in the dry gas window. Because of the high thermal maturity in the prospective area, the in-place shale gas has a CO_2 content of 11%. The Muskwa/Otter Park Shale has high quartz and low clay content.

Figure I-2. Horn River Basin (Muskwa/Otter Park Shale) Outline and Depth



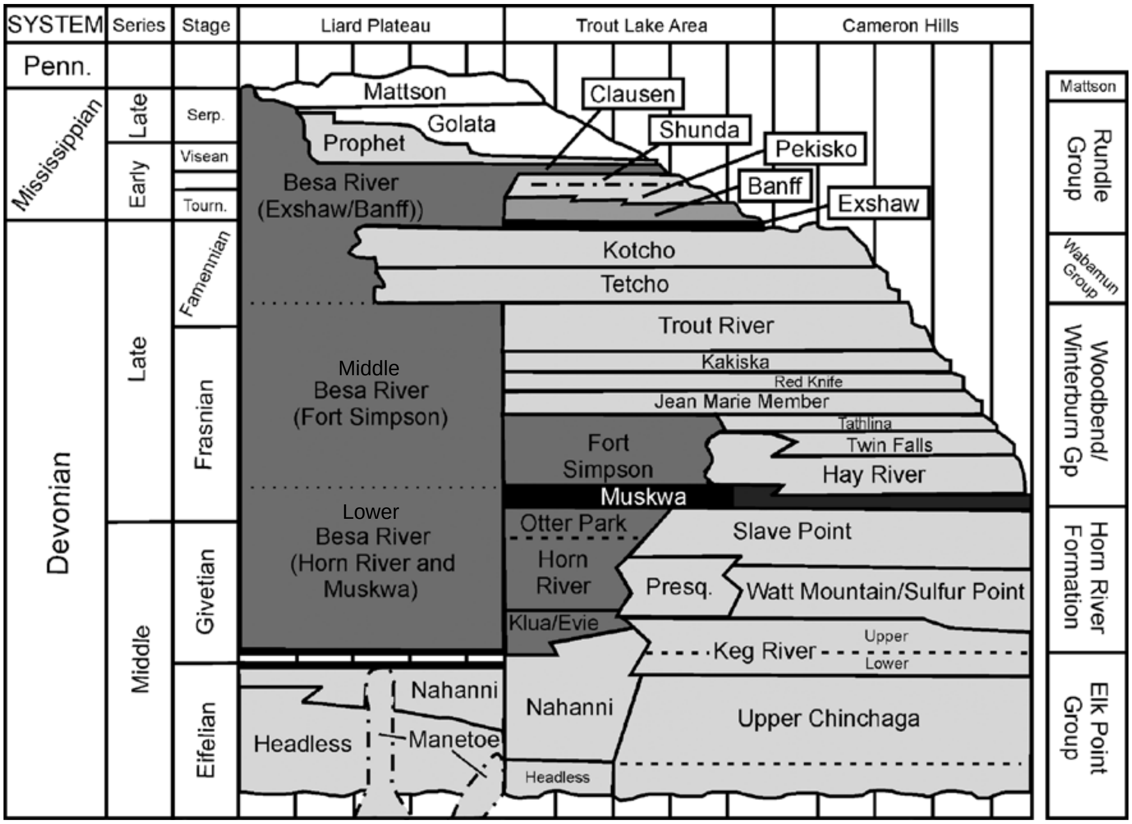
Source: ARI, 2013.

Figure I-3. Horn River Basin (Muskwa/Otter Park Shale) Isopach and Prospective Area



Source: ARI, 2013.

Figure I-4. NE British Columbia, Devonian and Mississippian Stratigraphy



Source: D. J. K. Ross and R. M. Bustin, AAPG Bulletin, v. 92, no. 1 (January 2008), pp. 87–125 JAF21300.AI

Evie/Klua. The Middle Devonian Evie/Klua Shale, the lower shale interval within the Horn River Group, provides a secondary shale gas target in the Horn River Basin. The top of the Evie/Klua Shale is approximately 500 feet below the top of the Muskwa/Otter Park Shale, separated by an organically-lean rock interval. The organic-rich Evie/Klua Shale, with an average TOC of 4.5%, has a thickness of about 160 feet (gross) and 144 feet (net). Thermal maturity (R_o) is high at about 3.8%, placing this shale gas in the dry gas window. The CO_2 content is estimated at 13%. The Evie/Klua Shale has a low clay content making the formation favorable for hydraulic stimulation.

Other Shales. The Horn River Basin also contains two shallower shales - - the Upper Devonian/Lower Mississippian Banff/Exshaw Shale and the Late Devonian Fort Simpson Shale. The Banff/Exshaw Shale, while rich in TOC (~5%) is relatively thin (10 to 30 feet). The massively thick Fort Simpson Shale, with a gross interval of 2,000 to 3,000 feet, is organically lean (TOC <1%). Because of these less favorable reservoir properties and limitations of data,

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these two shale units have not been included in the quantitative portion of the Horn River Basin shale resource assessment.

1.3 Resource Assessment

The prospective area for both the Horn River Muskwa/Otter Park Shale and the Evie/Klua Shale is approximately 3,320 mi^2.

Within this prospective area, the Horn River Muskwa/Otter Park Shale has a rich resource concentration of about 151 Bcf/mi^2 and a risked gas in-place is 376 Tcf, excluding CO_2. Based on favorable reservoir mineralogy and other properties, we estimate a risked, technically recoverable shale gas resource of 94 Tcf for the Muskwa/Otter Park Shale, Table I-2.

The thinner Evie/Klua Shale has a resource concentration of 62 Bcf/mi^2 and 154 Tcf of risked gas in-place, excluding CO_2. We estimate a risked, technically recoverable shale gas resource for the Evie/Klua Shale of 39 Tcf, Table I-2.

1.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society for Unconventional Gas estimated 75 to 170 Tcf of marketable (recoverable after extraction of CO_2 and any NGLs) shale gas for the Horn River basin.[4] Subsequently, in 2011, the BC Ministry of Energy and Mines (BC MEM) and the National Energy Board (NEB) published an assessment for the shale gas resources of the Horn River Basin that identified 448 Tcf of gas in-place, with an expected marketable shale gas resource of 78 Tcf.[5]

We estimate a larger risked, technically recoverable shale gas resource of 133 Tcf for the two shale units assessed by this study, using a recovery factor of 25% of the shale gas resource in-place. Our recovery factor is consistent with the 25% recovery factor used by the BC Oil and Gas Commission in their 2011 hydrocarbon reserves report for the Horn River Basin.[6] The BC MEM/NEB Horn River Basin assessment report, with a lower 78 Tcf of marketable (recoverable) shale gas resource, implies a lower recovery factor of 17.4% of gas in-place. (The BC MEM/NEB assessment excluded CO_2 content and produced gas used as fuel from marketable shale gas.)

Consistent with the experience of shale gas development in the U.S., this study anticipates progressively increased efficiencies for shale gas recovery as industry optimizes its well completion and production practices. One example is Nexen's testing of advanced shale well completion methods in the Horn River Basin. These advanced methods are designed to increase EURs in the Horn River Basin shales from 11 Bcf/well to 16 Bcf/well.

1.5 Recent Activity

A number of major and independent companies are active in the Horn River Shale play, including Apache Canada, EnCana, EOG Resources, Nexen, Devon Canada, Quicksilver and others.

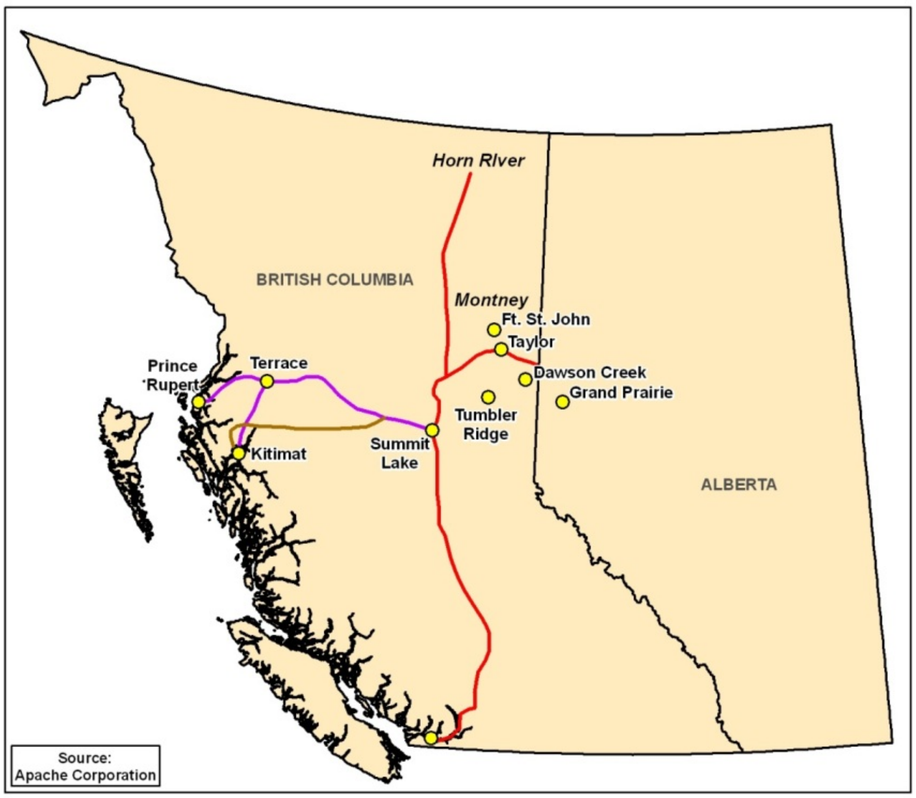
Apache Canada, the Horn River Basin's most active operator with 72 wells targeting shale gas in the basin, has full-scale development underway in the Two Island Lake area with net production of 90 million cubic feet per day (MMcfd). Apache estimates a net recoverable gas resource of 9.2 Tcf from its shale leases in the Horn River Basin.[7]

EnCana, with 68 long horizontal wells, produced a net 95 MMcfed in 2011 from its shale gas leases in the Horn River Basin. Devon, with 22 shale gas wells, is in the early stages of de-risking its 170,000 net acre lease position, which the company estimates contains nearly 10 Tcfe of net risked resource. EOG, with a 157,000 net acre lease position and 9 Tcf of potential recoverable resources, has drilled 35 shale gas wells and claims that the performance of its initial set of shale gas wells has met or exceeded expectations. Quicksilver has a 130,000 net acre lease position, 18 shale gas wells and a projected recoverable resource of over 10 Tcf. Nexen, with 90,000 acres, has drilled 42 horizontal wells and estimates 6 Tcf of recoverable resources from its lease area.[8]

Total natural gas production from the Horn River Basin was 382 MMcfd from 159 productive wells in 2011. In their 2010 report, the BC Oil and Gas Commission (BCOGC) estimated 10 Tcf of initial raw gas reserves from 40 Tcf of original gas in-place, equal to a 25% recovery factor.[8] In their 2011 report, the BCOGC increased the Horn River Shale initial recoverable raw gas reserves to 11.5 Tcf.

The gas processing and transportation capacity in the Horn River Basin is being expanded to provide improved market access for its growing shale gas production. Pipeline infrastructure is being expanded to bring the gas south to a series of proposed LNG export facilities. A 287-mile (480-km) Pacific Trail Pipeline is under construction to connect the Kitimat LNG export plant (due on line in 2017) with Spectra Energy's West Coast Pipeline System, Figure I-5. The Kitimat LNG terminal has an announced initial send-out capacity of 5 million tons of LNG per year (MTPA), expanding to 10 MTPA with a second train.

Figure I-5. Western Canada's LNG Export Pipelines and Infrastructure



TransCanada is proposing to build the 470-mile Prince Rupert Gas Transmission line with an initial capacity of 2 Bcfd (expandable to 3.6 Bcfd) to move Montney and Horn River gas to the Pacific Northwest LNG export terminal near Prince Rupert, BC. The planned in-service date is 2018. Earlier, TransCanada was selected by Shell Canada to build the 1.7 Bcfd Coastal GasLink Project, linking Horn River (and Montney) gas with Shell's planned 12 MTPA LNG export facility near Kitimat estimated to be in-service "toward the end of the decade".[9]

2. CORDOVA EMBAYMENT

2.1 Geologic Setting

The Cordova Embayment covers an area of 4,290 mi^2 in the extreme northeastern corner of British Columbia, extending into the Northwest Territories, Figure I-6. The Cordova Embayment is separated from the Horn River Basin on the west by the Slave Point Platform. The Embayment's northern and southern boundaries are defined by a thinning of the shale and its eastern boundary is the British Columbia and Alberta border. The dominant shale gas formation, the Muskwa/Otter Park Shale, was mapped to establish the 2,000-mi^2 prospective area, Figure I-7.

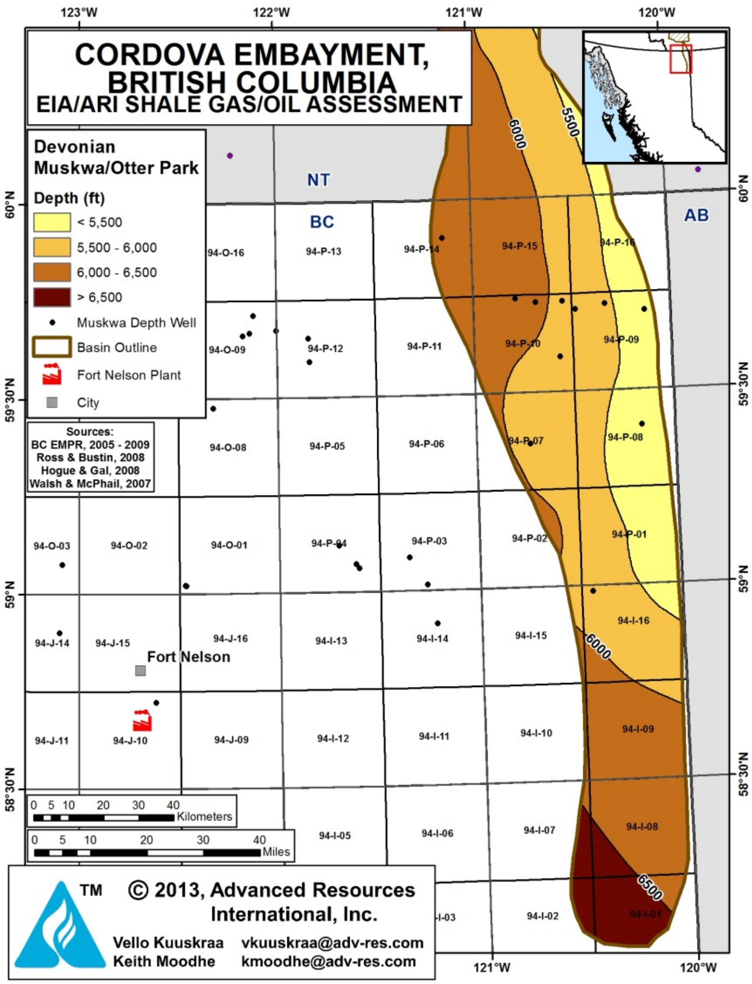
2.2 Reservoir Properties (Prospective Area)

One shale gas formation, the Muskwa/Otter Park, is included in the quantitative portion of our resource assessment.

Muskwa/Otter Park. The Middle Devonian Muskwa/Otter Park Shale is the main shale gas target in the Cordova Embayment. The drilling depth to the top of the Muskwa Shale in the prospective area ranges from 5,500 to 6,200 feet, averaging 6,000 feet. The reservoir is moderately over-pressured. The organic-rich gross thickness is 230 feet, with a net thickness of 207 feet. Total organic content (TOC) in the prospective area is 2.5% for the net shale thickness investigated. Thermal maturity averages 2.0% Ro, placing the shale in the dry gas window. The Muskwa/Otter Park Shale has a moderately high quartz content, favorable for hydraulic stimulation.

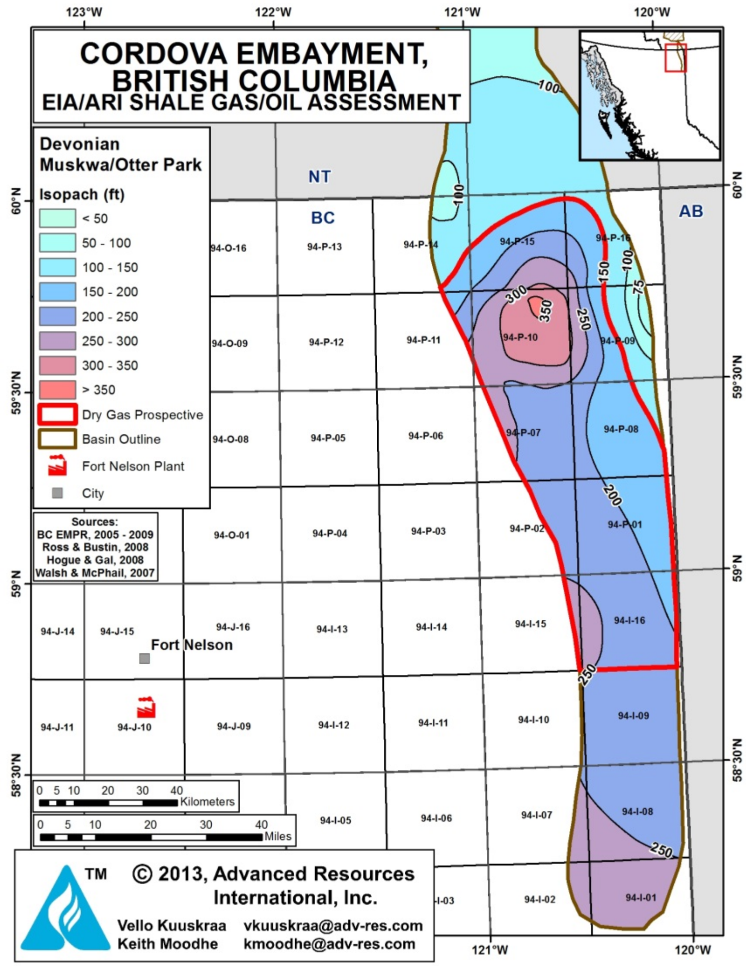
Other Shales. The deeper Evie/Klua Shale, separated from the overlying Muskwa/Otter Park by the Slave Point and Sulfur Point Formations, is thin, Figure I-8. The overlying Banff/Exshaw and Fort Simpson shales are shallower, thin and/or low in organics. These other shales have not been included in the quantitative portion of the Cordova Embayment resource assessment.

Figure I-6. Cordova Embayment (Muskwa/Otter Park Shale) Outline and Depth



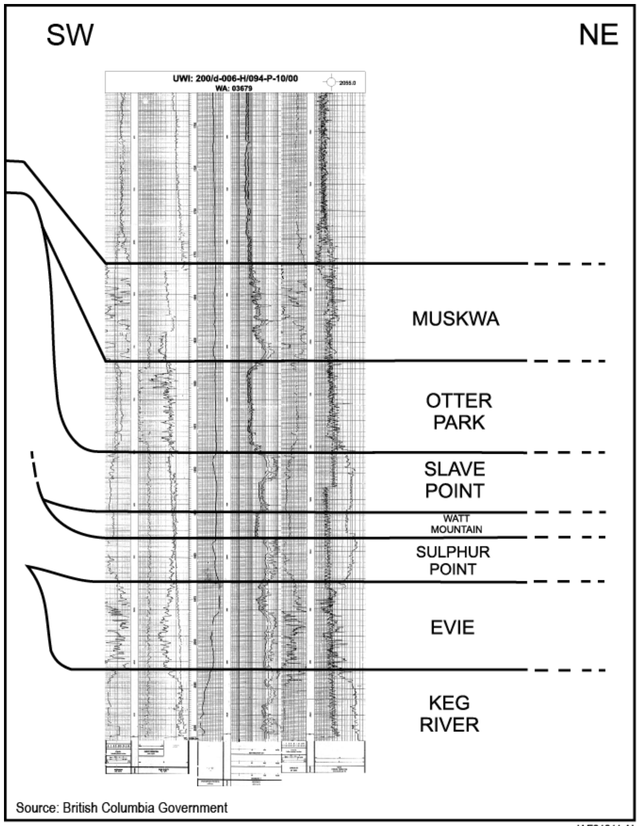
Source: ARI, 2013.

Figure I-7. Cordova Embayment - Muskwa/Otter Park Shale Isopach and Prospective Area



Source: ARI, 2013.

Figure I-8. Cordova Embayment Stratigraphic Column



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2.3 Resource Assessment

The prospective area of the Cordova Embayment's Muskwa/Otter Park Shale is approximately 2,000 mi^2. Within this prospective area, the shale has a moderate resource concentration of 68 Bcf/mi^2 and a risked gas in-place of 81 Tcf. Based on favorable reservoir mineralogy and other properties, we estimate a risked, technically recoverable shale gas resource of 20 Tcf for the Muskwa/Otter Park Shale in the Cordova Embayment, Table I-2.

2.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society of Unconventional Gas (CSUG) estimated 200 Tcf of shale gas in-place and 30 to 68 Tcf of marketable (recoverable) shale gas for the Cordova Embayment.[4] In early 2012, the BC Ministry of Energy reported 200 Tcf of gas in-place for the Cordova Embayment, a number which appears to have been based on the CSUG study.[4]

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2.5 Recent Activity

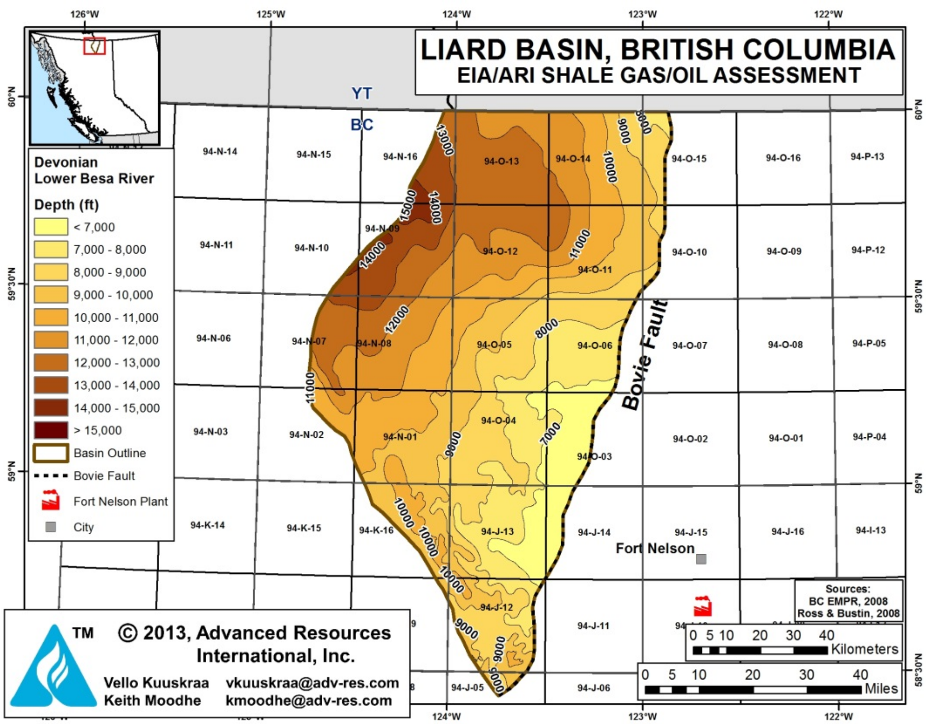
Nexen has acquired an 82,000-acre lease position in the Cordova Embayment and has drilled two vertical and two horizontal shale gas exploration wells. Nexen estimates a contingent resource of up to 5 Tcf for its lease position.[10] PennWest Exploration and Mitsubishi have formed a joint venture to develop the estimated 5 to 7 Tcf of recoverable shale gas resources on their 170,000-acre (gross) lease area.[11]

3. LIARD BASIN

3.1 Geologic Setting

The Liard Basin covers an area of 4,300 mi^2 in northwestern British Columbia, Figure I-9.[3] Its eastern border is defined by the Bovie Fault, which separates the Liard Basin from the Horn River Basin, Figure I-8. Its northern boundary is currently defined by the British Columbia and the Yukon/Northwest Territories border, and its western and southern boundaries are defined by structural folding and shale deposition.

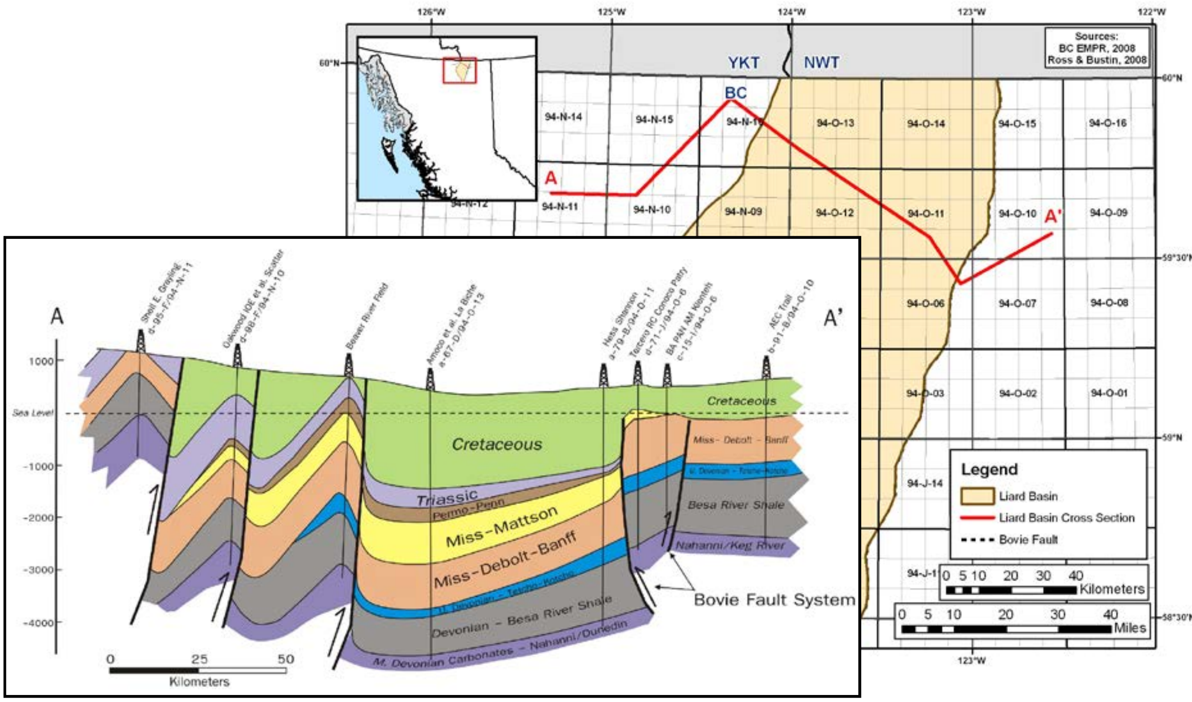
Figure I-9. Liard Basin (Lower Besa River Shale) Outline and Depth Map



Source: Modified from Ross and Bustin, 2008.

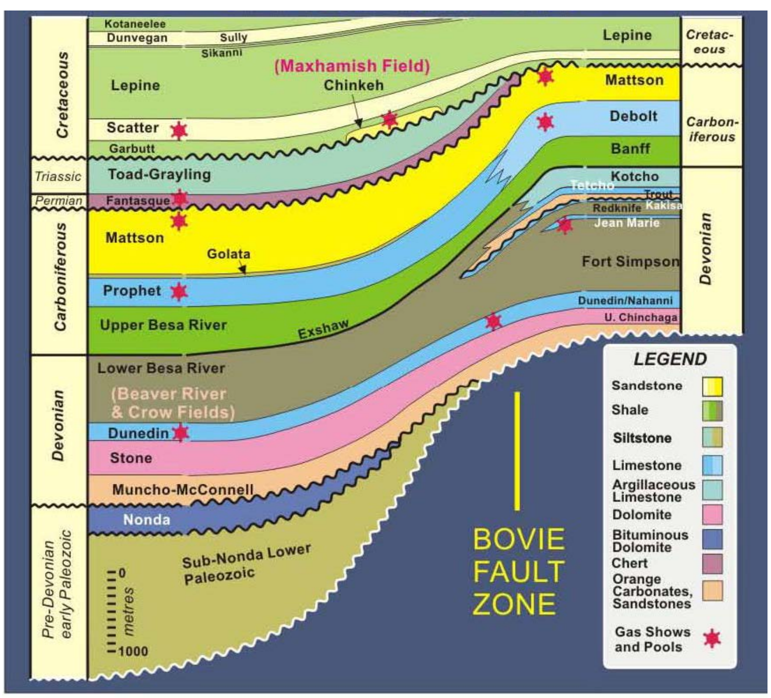
The dominant shale gas formation in the Liard Basin is the Middle Devonian-age Lower Besa River Shale, equivalent to the Muskwa/Otter Park and Evie/Klua shales in the Horn River Basin. Additional, less organically rich and less prospective shales exist in the basin's Upper Devonian- and Mississippian-age shales, such as the Middle Besa River Shale (Fort Simpson equivalent) and the Upper Besa River Shale (Exshaw/Banff equivalent), Figures I-10[12] and I-11.[13] Based on still limited data on this shale play, a prospective area of 3,300 mi^2 has been mapped for the Lower Besa River Shale in the central portion of the basin, Figure I-12.[3]

Figure I-10. Liard Basin Location, Cross-Section and Prospective Area



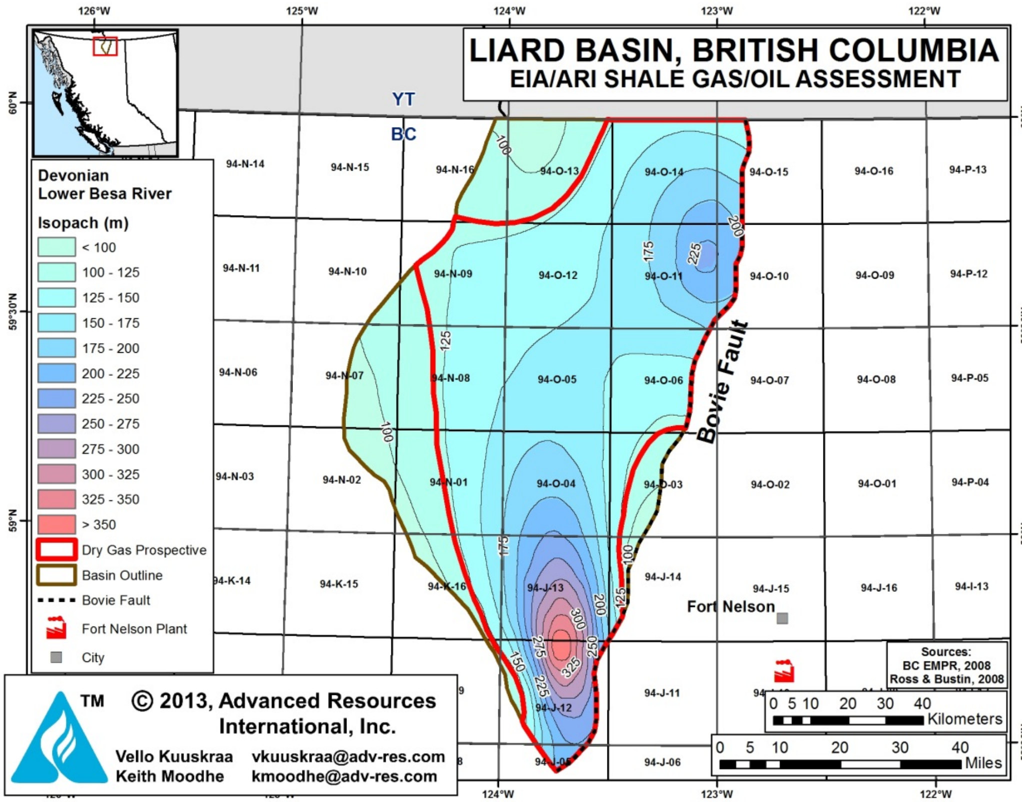
Source: Levson et al., British Columbia Ministry of Energy, Mines, and Petroleum Resources, 2009.

Figure I-11. Liard Basin Stratigraphic Cross-Section



Source: D. W. Morrow and R. Shinduke, "Liard Basin, Northeast British Columbia: An Exploration Frontier", Geological Survey of Canada (Calgary), Natural Resources Canada

Figure I-12. Liard Basin (Lower Besa River Shale) Isopach and Prospective Area



Source: Modified from Ross and Bustin, 2006.

3.2 Reservoir Properties (Prospective Area).

The Lower Besa River organic-rich shale is the main shale gas target in the Liard Basin. Drilling depths to the top of the formation in the prospective area range from 6,600 to 13,000 feet, averaging about 10,000 feet. The organic-rich Lower Besa River section has a gross thickness of 750 feet and a net thickness of 600 feet. Total organic content (TOC) in the prospective area, locally up to 5%, averages 3.5% for the net shale interval investigated. The thermal maturity of the prospective area is high, with an average Ro of 3.8%. Because of the high thermal maturity, we estimate the in-place shale gas has a CO_2 content of 13%. The geology of the Besa River Shale is complex with numerous faults and thrusts. The Lower Besa River Shale is quartz-rich, with episodic intervals of dolomite and more pervasive intervals of clay.

3.3 Resource Assessment

The Liard Basin's Lower Besa River Shale has a high resource concentration of 319 Bcf/mi^2. Within the prospective area of 3,300 mi^2, the risked shale gas in-place is approximately 526 Tcf. Based on favorable reservoir mineralogy but significant structural complexity, we estimate a risked, technically recoverable shale gas resource of 158 Tcf for the Liard Basin, Table I-2.

3.4 Recent Activity

Apache has a 430,000 acre lease position in the center of the Liard Basin's prospective area, estimating 210 Tcf of net gas in-place and 54 Tcf of recoverable raw gas (48 Tcf of marketable gas). Apache's D-34-K well, drilled to a vertical depth of 12,600 feet with a 2,900 foot lateral and 6 frac stages, had a 30-day IP of 21.3 MMcfd and a 12 month cumulative recovery of 3.1 Bcf. The well has a currently projected EUR of nearly 18 Bcf.[7]

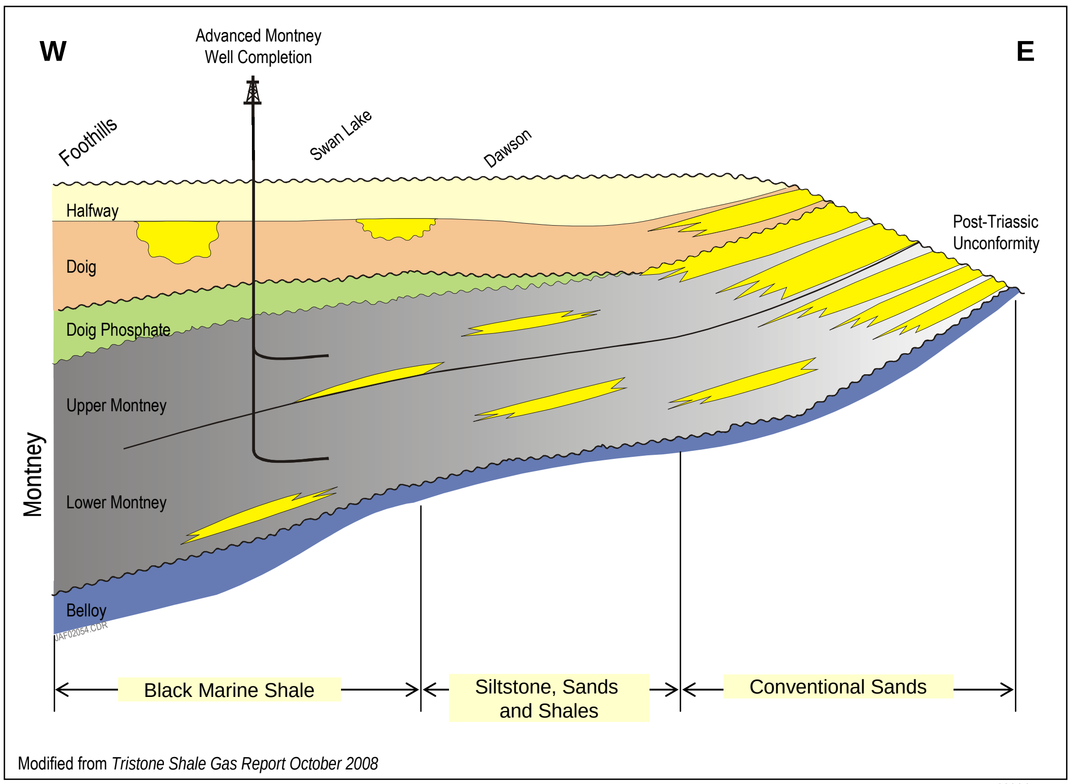
Nexen has acquired a 128,000-acre (net) land position in this basin, assigning up to 24 Tcf of prospective recoverable resource to its lease area.[10] Transeuro Energy Corp. and Questerre Energy Corp., two small Canadian operators, have completed three exploration wells in the Besa River and Mattson shale/siltstone intervals at the Beaver River Field.[14]

4. DOIG PHOSPHATE SHALE/DEEP BASIN

4.1 Geologic Setting

The Doig Phosphate Shale is located in the Deep Basin of Alberta and British Columbia. The Middle Triassic Doig Phosphate Formation serves as the base for the more extensive, predominantly siltstone and sand content Doig Resource Play, Figure I-13. The Doig Phosphate Formation, a high organic-content shale, has a prospective area of 3,000 mi^2 along the west-central portion of the Deep Basin.

Figure I-13. Deposition and Stratigraphy of Doig Phosphate and Montney/Doig Resource Plays



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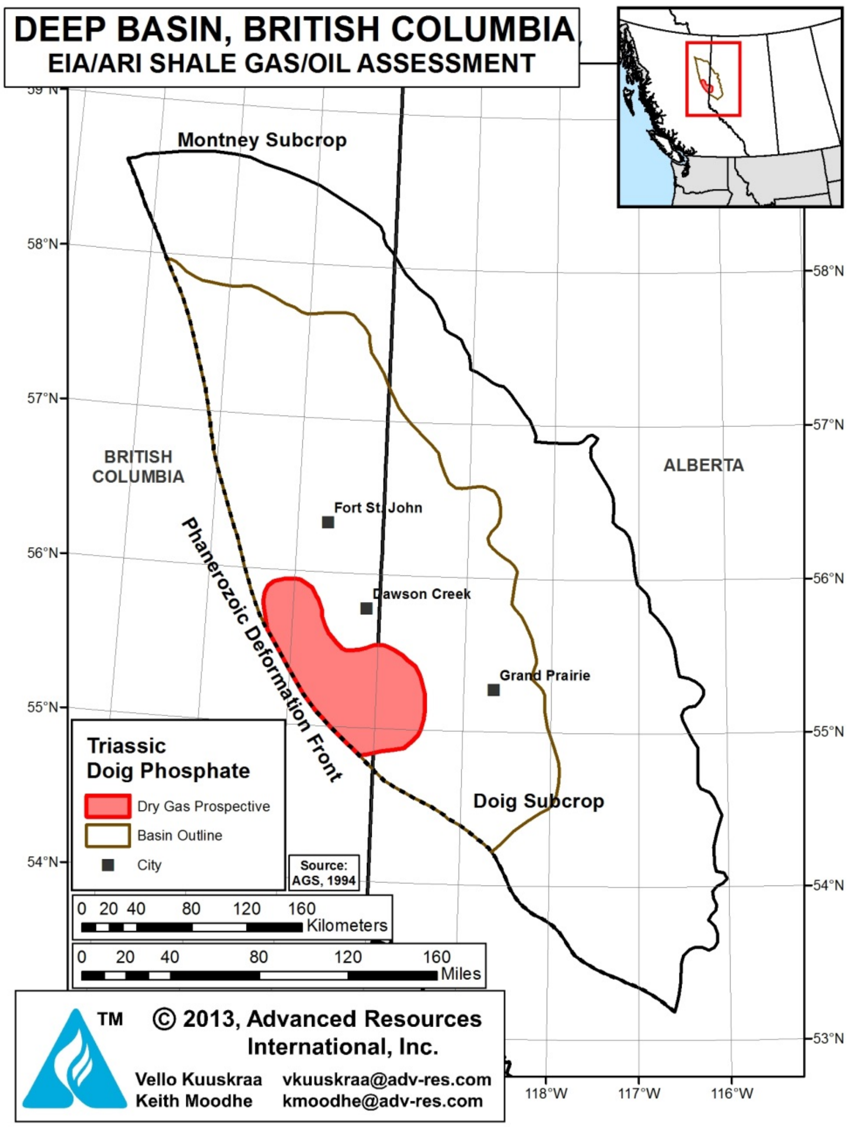
4.2 Reservoir Properties (Prospective Area)

The Middle Triassic Doig Phosphate Shale has a thick section of organic-rich shale along the western edge of the Deep Basin that forms the prospective area, Figure I-14.[15,8] Drilling depth to the top of the shale averages 9,250 feet. The organic-rich Doig Phosphate Shale's thickness ranges from 130 to 200 feet, with a net thickness of 150 feet in the prospective area. The average thermal maturity (Ro of 1.1%) places the shale in the wet gas/condensate window. The total organic content (TOC) is moderate to high, averaging 5%. X-ray diffraction of cores taken from the Doig Phosphate Formation show significant levels of quartz with minor to moderate levels of clay and trace to minor amounts of pyrite and dolomite, making the formation favorable for hydraulic fracturing.

Figure I-14. Prospective Area for the Doig Phosphate Shale (Deep Basin)



Modified from Walsh, 2006.

4.3 Resource Assessment

The prospective area of the Doig Phosphate Shale is estimated at 3,000 mi^2, limited on the west by the Phanerozoic Deformation Fault and by the pinch-out of the shales to the north, east and south. Within the prospective area, the shale has a moderate resource concentration of 67 Bcf per mi^2 of wet gas and a risked resource in-place of 101 Tcf. Based on favorable mineralogy, we estimate a risked, technically recoverable shale gas resource of 25 Tcf for the Doig Phosphate Shale.

4.4 Comparison with Other Resource Assessments

In 2006, Walsh estimated a gas in-place for the Doig Phosphate Unit of ~70 Tcf.[15]

4.5 Recent Activity

The Doig Phosphate Shale reservoir overlies the Montney Resource Play. As such, much of the activity and appraisal of the Doig Phosphate is reported as part of exploration for the Montney and Doig Resource plays. Pengrowth Energy Corp, a small Canadian producer, tested the larger Doig interval with a vertical well in 2011 with a reported test rate of 750 Mcfd. The company plans to target the Doig with a horizontal well in 2012.[8]

5. MONTNEY AND DOIG RESOURCE PLAYS (BRITISH COLUMBIA)

The Deep Basin of British Columbia contains the Montney and Doig Resource plays. These are multi-depositional, Triassic-age hydrocarbon accumulations containing large volumes of dry and wet gas in-place in conventional, tight sand and shale formations.

The Canadian National Energy Board categorizes the Montney and Doig Resource plays as tight gas sands. Work by the BC Oil and Gas Commission, in their "Montney Formation Play Area Atlas NEBC",[16] shows that only a very small portion of the Montney Resource play contains oil/condensate, Figure I-15. As such, we have excluded the Montney and Doig Resource plays from the shale resource assessment of Canada. (In our previous shale gas resource assessment, we speculated that a shale-rich Montney area with higher TOC values may exist in BC along the northwestern edge of the Deep Basin. However, because of lack of data confirming this speculation, we have excluded this area and resource volumes from our current shale oil and gas assessment.)

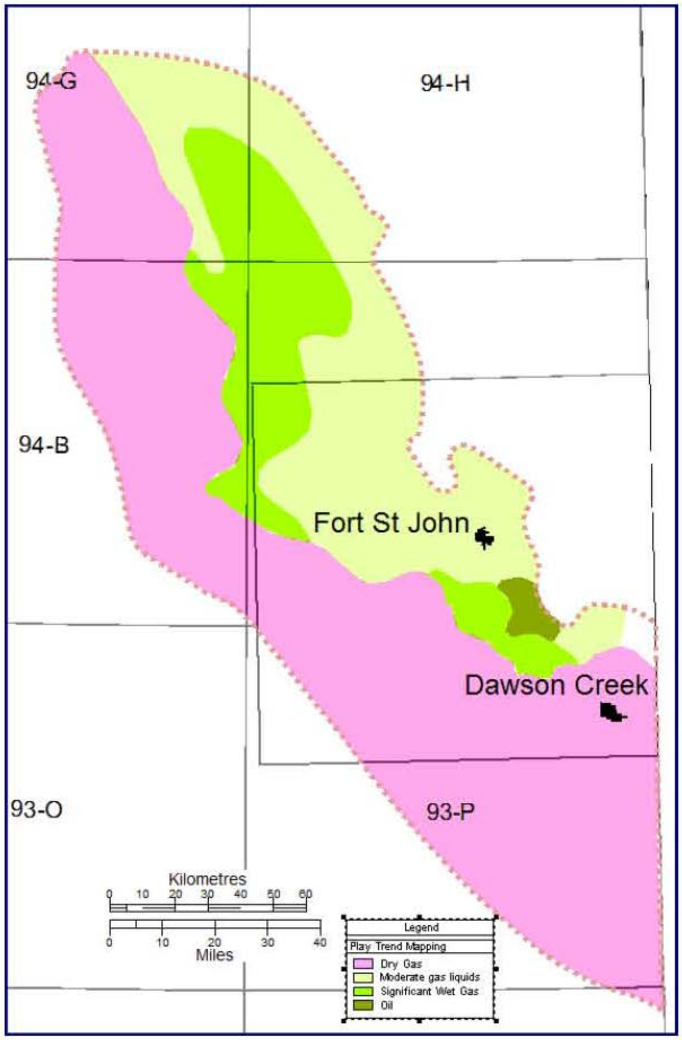
To put the potential volume of tight gas resource in the Montney and Doig Resource plays of British Columbia into perspective, the BC MEM reports a gas in-place for the BC portion of the Montney and Doig Resource plays at 450 Tcf and 200 Tcf respectively.[8]

6. CANOL SHALE

The Canol Shale is an emerging shale play located in the central Mackenzie Valley near Norman Wells, Northwest Territories. To date, only seismic and a handful of vertical wells have been drilled to explore this shale oil play. Work is underway on a multi-year study by the Northwest Territories Geoscience Office to better define this resource.

Husky Oil, having spent $376 million at the 2011 land auction, has drilled two vertical wells on its 300,000-net acre lease area and is planning on completing three wells in 2013.[17] MGM Energy Corp, with 470,000-net acres in this resource play, plans to drill one vertical well during the current winter exploration season. MGM (with Shell as its partner) withdrew plans to drill a horizontal well in 2012 to test the productivity of the Canol Shale play.[18] As information on the prospectivity of the Canol Shale is gained from the above wells, it would be timely to include this shale play in the assessment of Canada's shale gas and oil resources.

Figure I-15. Montney Trend – Identified Gas Liquids/Oil Distribution



Source: BC Oil and Gas Commission Montney Formation Play Atlas NEBC October 2012.

ALBERTA

Alberta holds a series of significant, organic-rich shale gas and shale oil formations, including: (1) the Banff and Exshaw Shale in the Alberta Basin; (2) the Duvernay Shale in the East and West Shale Basin of west-central Alberta; (3) the Nordegg Shale in the Deep Basin of west-central Alberta; (4) the Muskwa Shale in northwest Alberta; and (5) the shale gas formations of the Colorado Group in southern Alberta. (In addition, Alberta holds the eastern portion of the Doig Phosphate Shale play, discussed previously.)

The study has benefitted greatly from the in-depth and rigorous siltstone and shale data in the ERCB/AGS report entitled, "Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential".[19] This ERCB/AGS report helped define the boundaries for the oil, wet gas/condensate and dry gas play areas used by this study. This report also provided valuable data on key reservoir properties such as porosity and net pay.

To maintain consistency with the ERCB/AGS study for Alberta, our study used the same minimum criterion of 0.8% R_o for the volatile/black oil window. However, our study used the criterion of >1.3% R_o for the dry gas window, compared to the >1.35% R_o in the ERCB/AGS study. Our study also expanded on the analytical data in ERCB/AGS's report with our independently derived estimates of prospective areas as well as our assignments of pressure gradients, gas-oil ratios (as functions of reservoir pressure and temperature), and other reservoir properties to each shale play. (The ERCB/AGS assumed normal rather than over-pressured gradients in their Alberta resource assessment and linked a constant oil-gas ratio to each thermal maturity (R_o) value, independent of reservoir pressure and depth.)

The five Alberta basins assessed by this study contain 987 Tcf of risked shale gas in-place, with 200 Tcf as the risked, technically recoverable shale gas resource, Table 1-3. These five basins also contain 140 billion barrels of risked shale oil in-place, with 7.2 billion barrels as the risked, technically recoverable shale oil resource, Table I-4.

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Table I-3. Shale Gas Reservoir Properties and Resources of Alberta

Basic Data	Basin/Gross Area		Alberta Basin (28,700 mi^2)	East and West Shale Basin (50,500 mi^2)			Deep Basin (26,200 mi^2)			NW Alberta Area (33,000 mi^2)		Southern Alberta Basin (124,000 mi^2)
	Shale Formation		Banff/Exshaw	Duvernay			North Nordegg			Muskwa		Colorado Group
	Geologic Age		L. Mississippian	U. Devonian			L. Jurassic			U. Devonian		Cretaceous
	Depositional Environment		Marine	Marine			Marine			Marine		Marine
Physical Extent	Prospective Area (mi^2)		10,500	13,000	7,350	2,900	6,900	4,000	1,500	12,500	6,600	48,750
	Thickness (ft)	Organically Rich	65	45	60	70	82	72	69	70	112	523
		Net	15	41	54	63	37	31	29	25	78	105
	Depth (ft)	Interval	3,900 - 6,200	7,500 - 10,500	10,500 - 13,800	13,800 - 16,400	5,200 - 8,200	8,200 - 11,500	11,500 - 14,800	3,300 - 8,200	3,900 - 8,200	5,000 - 10,000
		Average	4,800	9,000	11,880	15,000	6,724	10,168	12,464	6,100	4,602	6,900
Reservoir Properties	Reservoir Pressure		Normal	Highly Overpress.	Highly Overpress.	Highly Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Underpress.
	Average TOC (wt. %)		3.2%	3.4%	3.4%	3.4%	11.0%	11.0%	11.0%	3.2%	3.2%	2.4%
	Thermal Maturity (% Ro)		0.90%	0.90%	1.15%	1.50%	0.90%	1.15%	1.35%	0.90%	1.10%	0.60%
	Clay Content		Medium	Low	Low	Low	Low/Med.	Low/Med.	Low/Med.	Low	Low	Low/Med.
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		1.2	12.0	47.4	63.8	4.7	19.6	22.1	4.6	34.2	20.9
	Risked GIP (Tcf)		5.1	109.1	244.1	129.5	16.2	39.2	16.6	29.0	112.7	285.6
	Risked Recoverable (Tcf)		0.3	13.1	61.0	38.8	1.3	7.8	4.1	2.9	28.2	42.8

Table I-4. Shale Oil Reservoir Properties and Resources of Alberta

Basic Data	Basin/Gross Area		Alberta Basin (28,700 mi^2)	East and West Shale Basin (50,500 mi^2)		Deep Basin (26,200 mi^2)		NW Alberta Area (33,000 mi^2)	
	Shale Formation		Banff/Exshaw	Duvernay		North Nordegg		Muskwa	
	Geologic Age		L. Mississippian	U. Devonian		L. Jurassic		U. Devonian	
	Depositional Environment		Marine	Marine		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		10,500	13,000	7,350	6,900	4,000	12,500	6,600
	Thickness (ft)	Organically Rich	65	45	60	82	72	70	112
		Net	15	41	54	37	31	25	78
	Depth (ft)	Interval	3,900 - 6,200	7,500 - 10,500	10,500 - 13,800	5,200 - 8,200	8,200 - 11,500	3,300 - 8,200	3,900 - 8,200
		Average	4,800	9,000	11,880	6,724	10,168	6,100	4,602
Reservoir Properties	Reservoir Pressure		Normal	Highly Overpress.	Highly Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.2%	3.4%	3.4%	11.0%	11.0%	3.2%	3.2%
	Thermal Maturity (% Ro)		0.90%	0.90%	1.15%	0.90%	1.15%	0.90%	1.10%
	Clay Content		Medium	Low	Low	Low/Med.	Low/Med.	Low	Low
Resource	Oil Phase		Oil	Oil	Condensate	Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		2.5	7.1	0.5	5.5	0.4	6.4	0.7
	Risked OIP (B bbl)		10.5	64.2	2.6	19.0	0.8	40.0	2.4
	Risked Recoverable (B bbl)		0.32	3.85	0.16	0.76	0.03	2.00	0.12

1. BASAL BANFF AND EXSHAW SHALE/ ALBERTA BASIN

1.1 Geologic Setting

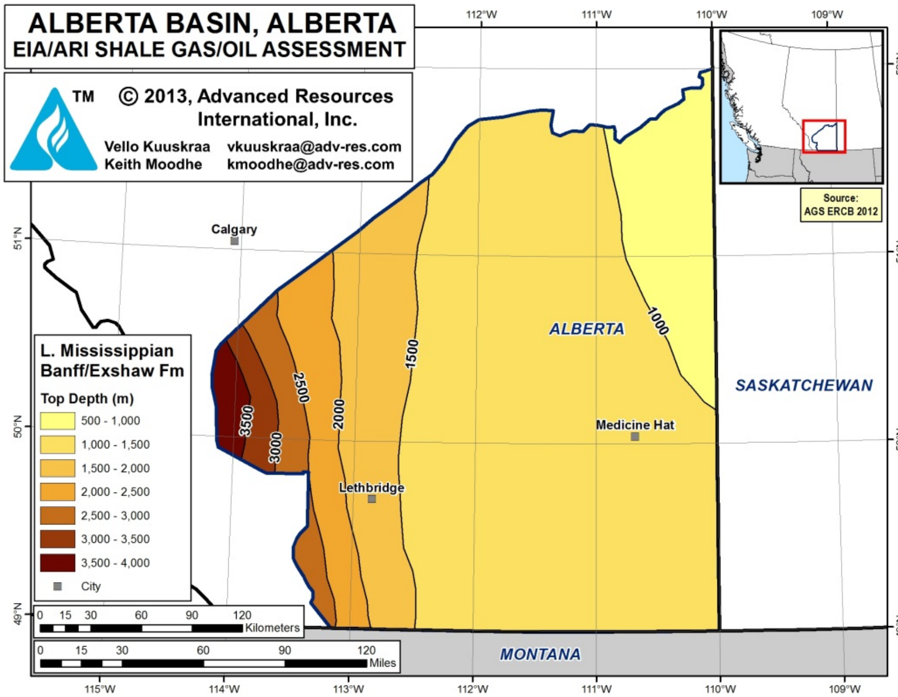
The basal Banff/Exshaw Shale assessed by this study is located in the southern Alberta portion of the Alberta Basin, Figure I-16.[19] The western boundary of this shale deposit is constrained by the Deformed Belt and its northern boundary is defined by the sub-crop erosional edge. Its eastern boundary is the Alberta and Saskatchewan border and its southern boundary is the U.S. and Canada border. Within the larger 15,360-mi^2 area of shale deposition, the Basal Banff/Exshaw Shale has a prospective area of 10,500 mi^2 for volatile/black oil, Figure I-17.[19] (The small dry gas and wet gas areas were not considered prospective.) The east to west cross-section (E-E') for the Lower Mississippian and Upper Devonian Basal Banff/Exshaw Shale shows its stratigraphic equivalence to the Bakken Formation in the Williston Basin, Figure I-18.[19]

1.2 Reservoir Properties (Prospective Area)

Similar to the Bakken Shale, the basal Banff/Exshaw Shale consists of three reservoir units. The upper and lower units are dominated by organic-rich shale. The middle unit contains a variety of lithologies including calcareous sandstone and siltstone, dolomitic siltstone and limestone. The primary reservoir is the more porous and permeable middle unit, sourced by the upper and lower organic-rich shales units. However, compared to the Bakken Shale, the prospective area of the basal Banff/Exshaw Shale is normally pressured (with higher pressures in the west) rather than over-pressured, and its middle unit appears to have considerably lower permeability and solution gas.

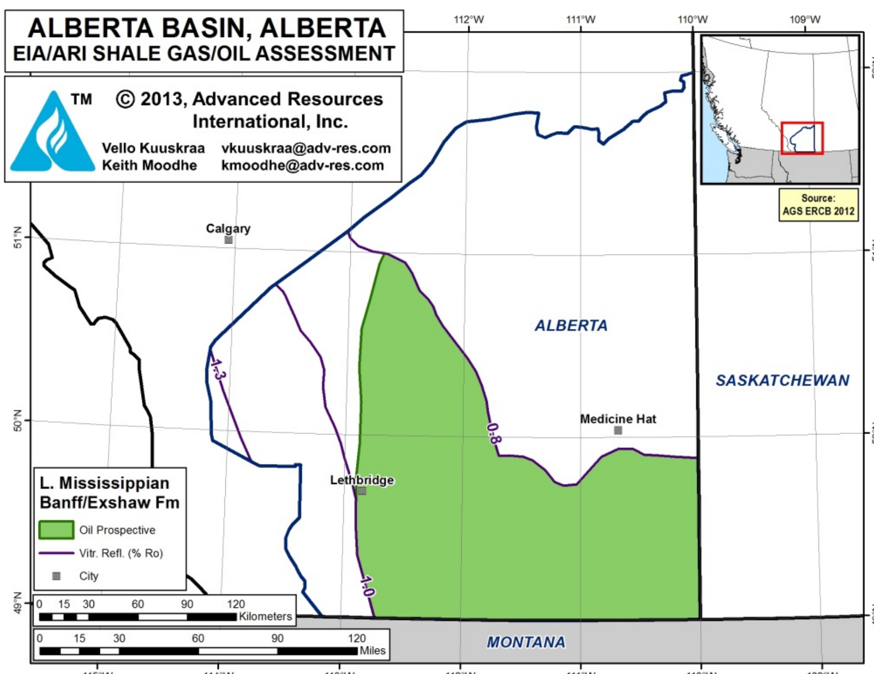
In the prospective area, the drilling depth to the top of the shale ranges from 3,300 feet on the east to about 6,600 feet on the west, averaging 4,800 feet. The upper shale unit is 3 to 5 feet thick and the lower shale unit has a gross thickness of 10 to 40 feet, providing a net, organic-rich shale pay averaging 15 feet.

Figure I-16. Outline and Depth of Basal Banff and Exshaw Shale (Alberta)



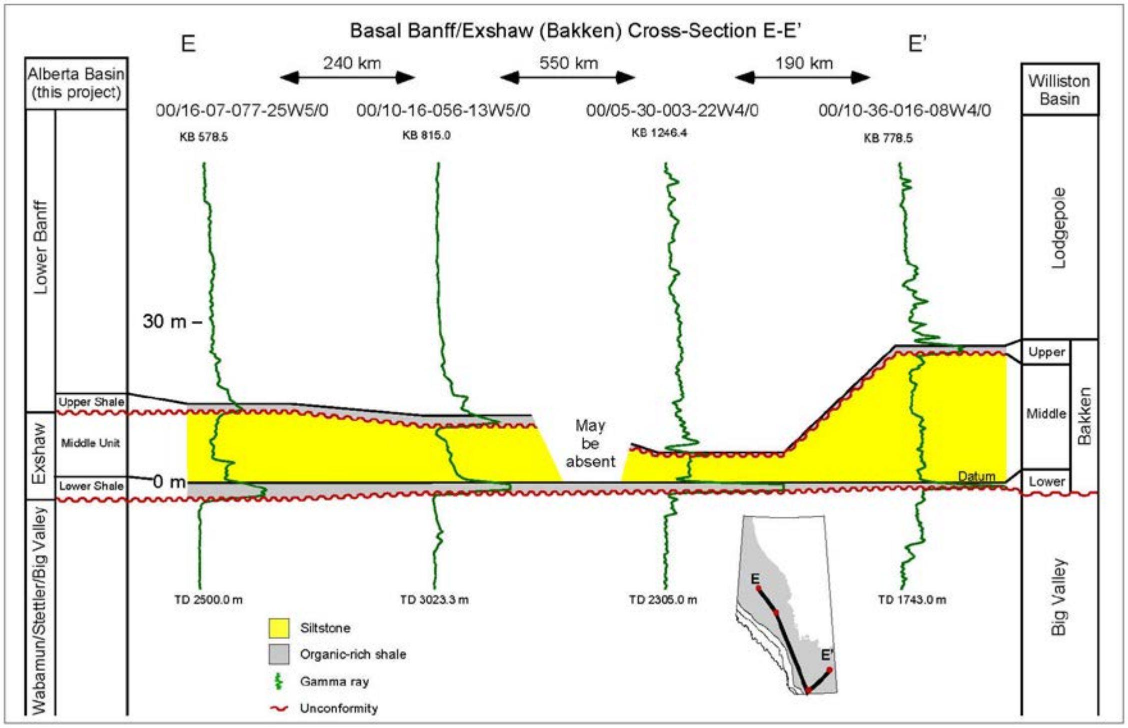
Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-17. Prospective Area for Basal Banff and Exshaw Shale (Alberta).



Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-18. Stratigraphic Cross Section E-E' of the Basal Banff and Exshaw Shale



Source: ERCB/AGS Open File Report 2012-06, October 2012.

The total organic content (TOC) in the prospective area averages 3.2% and ranges from lean to nearly 17%. The upper and lower shale units have high TOC values (3% to 17%), the middle unit has much lower TOC (lean to 3%). The thermal maturity (R_o) of the shale shows a progressive increase from immature (below 0.8% R_o) in the east to dry gas (over 1.3% R_o) in the west. However, in the western area where the thermal maturity exceeds 1.0% R_o, the shale is thin and thus has been excluded from the prospective area. As such, the basal Banff/Exshaw Shale has a prospective area for oil of 10,500 mi^2 (0.8% to 1.0% R_o) located in the center of the larger play area.

1.3 Resource Assessment

The prospective area for the Basal Banff/Exshaw Shale in the Alberta Basin is limited by depth and thermal maturity on the east and by shale thickness on the west. Within the 10,500-mi^2 prospective area for oil, the basal Banff/Exshaw Shale has a resource concentration of 2.5 million barrels of oil per mi^2 plus moderate volumes of associated gas.

The risked resource in-place for the oil prospective area is estimated at 10 billion barrels of oil plus 5 Tcf of associated natural gas. Based on recent well performance as well as reservoir properties that appear to be less favorable than for the Bakken Shale in the Williston Basin, we estimate a risked, technically recoverable resource of 0.3 billion barrels of shale oil and 0.3 Tcf of associated shale gas.

1.4 Comparison With Other Resource Assessments

The ERCB/AGS resource study, discussed above, calculated an unrisked oil in-place of 26,300 million barrels and an unrisked gas in-place of 39.8 Tcf for the basal Banff/Exshaw Shale.[19] The ERCB/AGS study did not use depth, net pay or other criteria to define a prospective area and did not estimate a risked recoverable resource.

1.5 Recent Activity

Considerable leasing occurred for the basal Banff/Exshaw Shale in 2010, sparking this southern Alberta shale play. Since then, a number of producers, such as Crescent Point and Murphy Oil, have drilled exploration wells to test the resource potential in this shale oil play. So far, of the 22 wells with reported production, only three wells have current producing rates of over 100 B/D; the remainder have rates of less than 50 B/D.

Crescent Point drilled two exploration wells into the Exshaw Shale in early 2012 with plans to drill additional wells in the area.[20] Murphy Oil has assembled a 150,000 net acre lease area. While its early exploration for this shale play has shown mixed results, Murphy's recent #15-21 well targeting the Exshaw Shale had an IP of 350 BOPD. Murphy Oil is examining the use of longer laterals, enhanced stimulation and lower costs to improve the economic viability of this shale play.[21]

2. DUVERNAY SHALE/EAST AND WEST SHALE BASIN

2.1 Geologic Setting

The East and West Shale Basin, covering an area of over 50,000 mi^2 in central Alberta, contains the organically rich Duvernay Shale, Figure I-19.[19] The western boundary of this shale deposit is defined by the Deformed Belt, the northern boundary by the Peace River Arch, the southern boundary by the Leduc Shelf, and the eastern boundary by the Grosmont Carbonate Platform. Within this larger area of shale deposition, the prospective area for the Duvernay Shale is 23,450 mi^2, primarily in the central and western portions of this basin, Figure I-20.[19]

The Upper and Middle Devonian Duvernay Shale is stratigraphic equivalent to the Muskwa Shale in northwest Alberta and northeast British Columbia. In the East Shale Basin, the Duvernay Shale is primarily an organic-rich limestone. In the West Shale Basin, the Duvernay Shale grades from a carbonate-rich mudstone in the east to an increasingly porous, organic-rich shale in the west, Figure I-21.[19]

2.2 Reservoir Properties (Prospective Area)

In the prospective area, the drilling depth to the top of the Duvernay Shale ranges from 7,500 feet in the east to 16,400 feet in the west. The gross shale thickness in the prospective area ranges from 30 feet to over 200 feet, with an average of 41 net feet in the oil prospective area, 54 net feet in the wet gas/condensate prospective area, and 63 net feet in the dry gas prospective area.

The total organic carbon (TOC) in the prospective area reaches 11%. Excluding the organically lean rock using the net to gross ratio, the average TOC is 3.4%. The thermal maturity (R_o) of the shale increases as the shales deepen, from immature (below 0.8% Ro) on the east to dry gas (1.3% to 2% R_o) in the west. As such, the Duvernay Shale has an extensive oil prospective area in the east, a wet gas/condensate prospective area in the center, and a smaller dry gas prospective area in the west.

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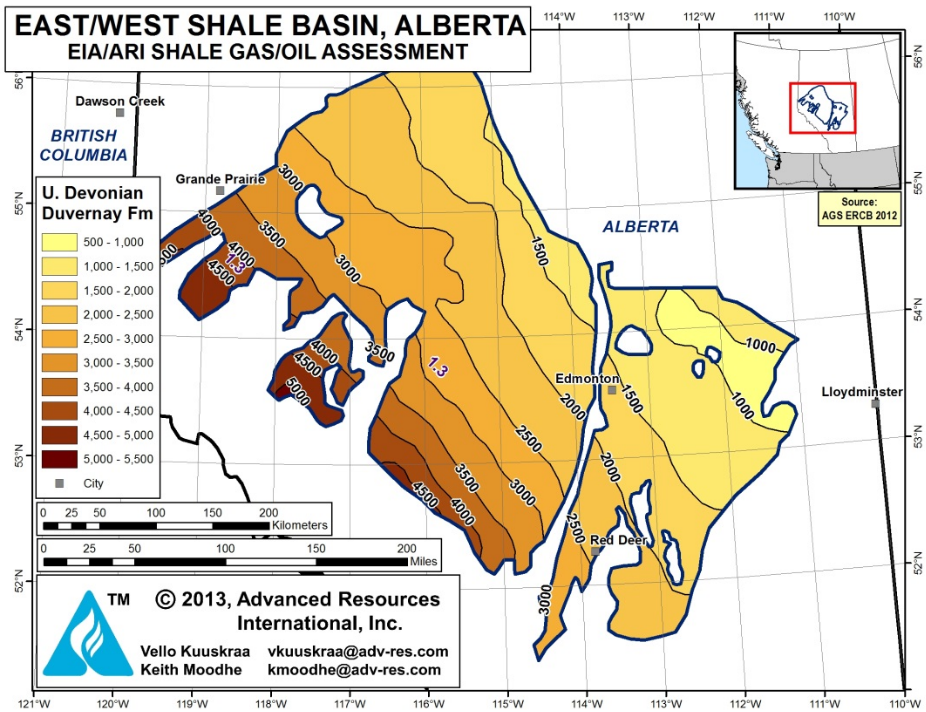
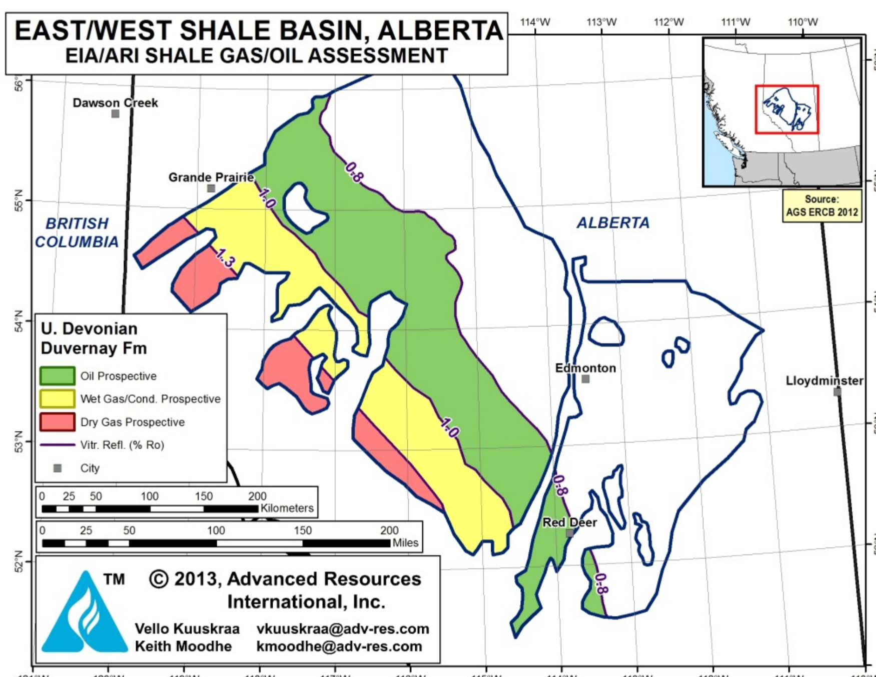
Figure I-19. Outline and Depth of Duvernay Shale (Alberta)



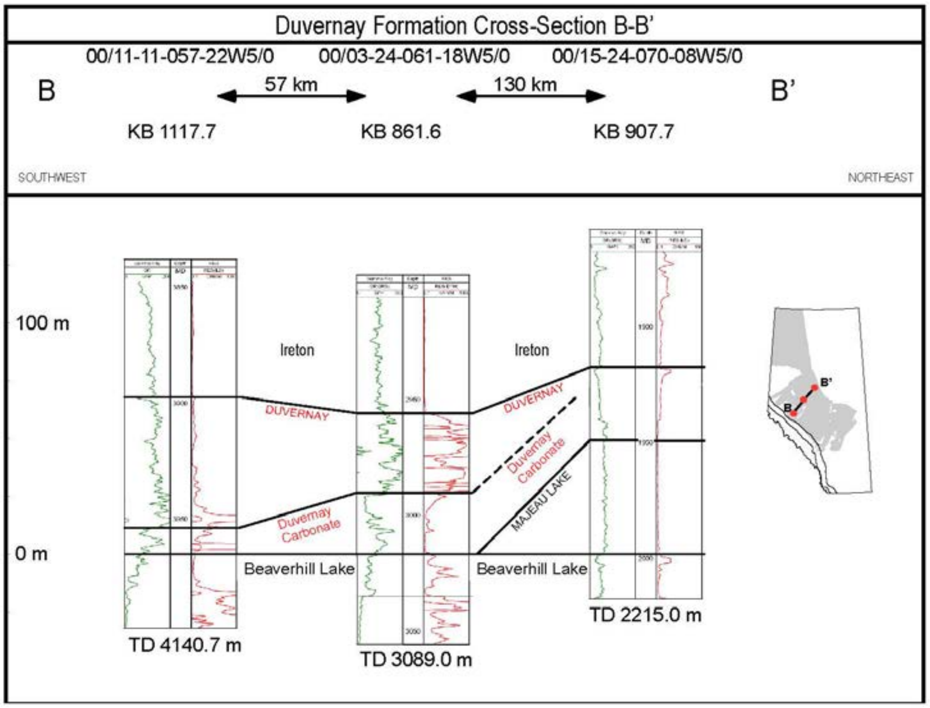
Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-20. Prospective Area for Duvernay Shale (Alberta)



Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-21. Stratigraphic Cross Section B-B' of the Duvernay Formation



Source: ERCB/AGS Open File Report 2012-06, October 2012.

2.3 Resources Assessment

The prospective area of the Duvernay Shale in the East and West Shale Basin covers 23,250 mi^2, limited on the east by low thermal maturity. Within the 13,000-mi^2 prospective area for oil, the Duvernay Shale has a resource concentration of 7.1 million barrels of oi/mi^2 plus associated gas. Within the 7,350-mi^2 wet gas/condensate prospective area, the Duvernay Shale has resource concentrations of 0.5 million barrels of condensate and 47 Bcf of wet gas per mi^2. Within the 2,900-mi^2 dry gas prospective area, the Duvernay Shale has a resource concentration of 64 Bcf/mi^2.

The risked resource in-place in the prospective areas of the Duvernay Shale is estimated at 67 billion barrels of shale oil/condensate and 483 Tcf of shale gas. Based on favorable reservoir properties and analog information from U.S. shales such as the Eagle Ford, we estimate risked, technically recoverable resources of 4.0 billion barrels of shale oil/condensate and 133 Tcf of dry and wet shale gas.

2.4 Recent Activity

The Duvernay Shale is the current “hot” shale play in Western Canada with over $2 billion spent (in 2010 and 2011) in auctions for leases. Athabasca Oil (with 1,000 mi^2) followed by Canadian Natural Resources (600+ mi^2), EnCana (580+ mi^2) and Talisman (560+ mi^2) have the dominant land positions. Twelve additional companies, ranging from Chevron to Enerplus, each hold over 100 mi^2 of leases.

Much of the current activity is in the Kaybob wet gas/condensate area. EnCana with 8 Hz wells plus one vertical well and Celtic with 7 Hz and 5 vertical wells are the most active operators. Since the first Celtic well in the Duvernay Shale in 2010, a total of 45 wells (Hz and vertical) have been drilled or are being drilled (mid-2012).

- EnCana reports that its Duvernay well tested at 2.3 MMcfd of wet gas and 1,632 barrels per day of condensate.
- Celtic’s best Duvernay well tested at 5.8 Mcfd of wet gas plus 638 barrels per day of condensate.

In the Pembina area, EnCana with four Hz wells and ConocoPhillips with three Hz wells are most active. In the Edson Area, where active leasing is still underway, Angle Energy, CNRL and Vermillion are drilling Duvernay Shale explorations wells.

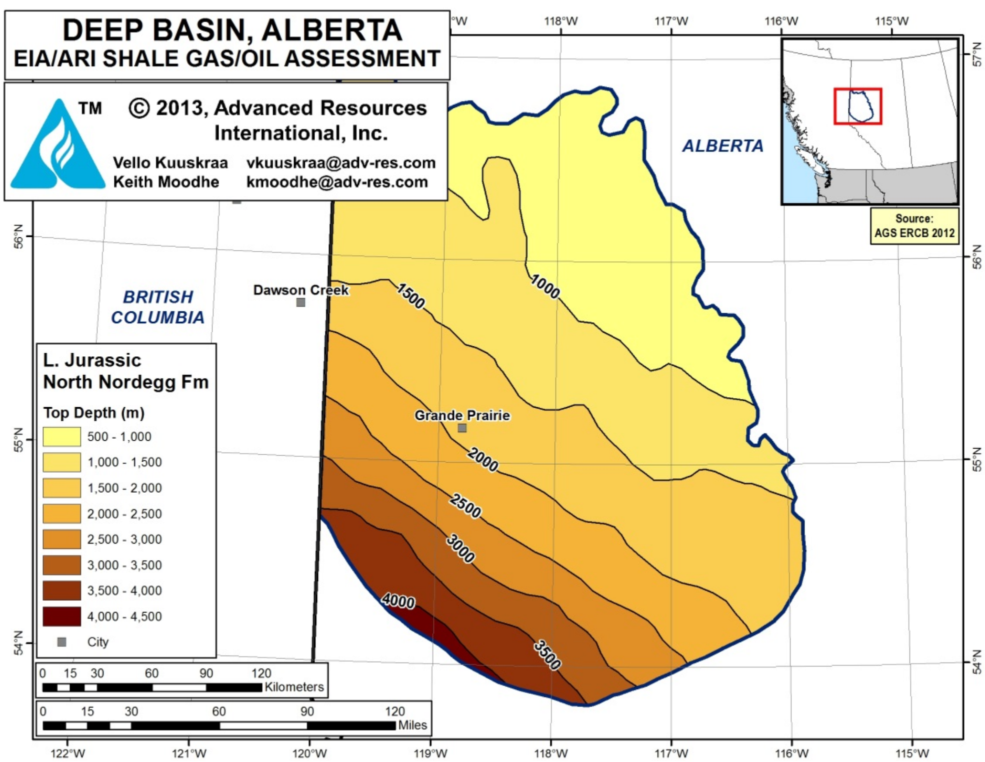
Advanced Resources International, Inc.

3. NORDEGG SHALE/DEEP BASIN.

3.1 Geologic Setting.

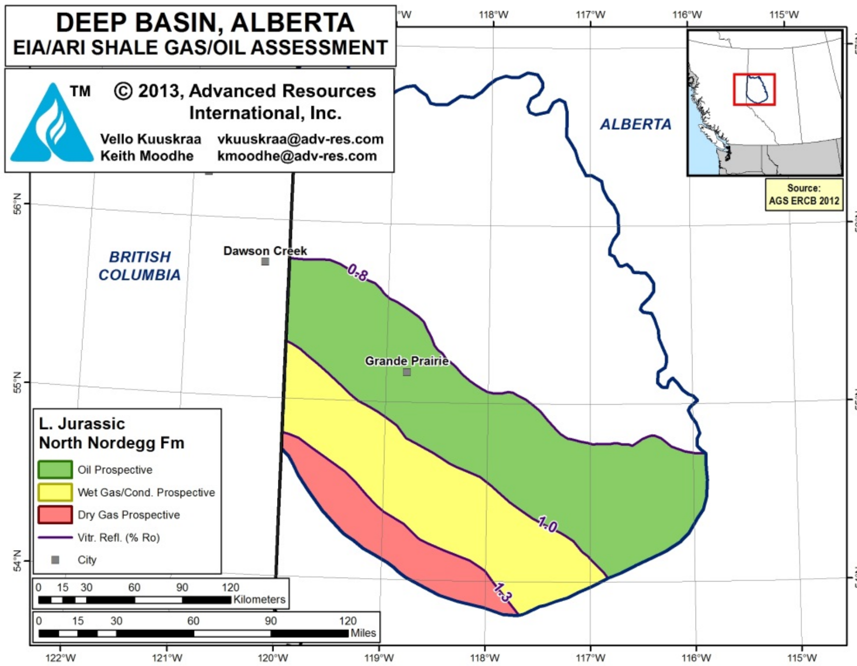
The Nordegg Shale assessed in this study is located within the Deep Basin of Alberta, Figure I-22.[19] The Lower Jurassic Nordegg Shale Member is located at the base of the Fernie Formation, shown by the cross-section on Figure I-23.[19] The Nordegg transitions from a carbonate-rich deposition on the south into a fine-grained rock on the north. In the northern area, where the shale interval is sometimes referred to as the Gordondale Member, the Nordegg Shale is an organic-rich mudstone (shale) which also includes cherty and phosphoric carbonates as well as siltstones and some sandstone, Figure 1-24.[19] The Nordegg Shale has served as a prolific source rock for shallower conventional hydrocarbon reservoirs in this portion of the Deep Basin.

Figure I-22. Outline and Depth of Nordegg Shale (Alberta).



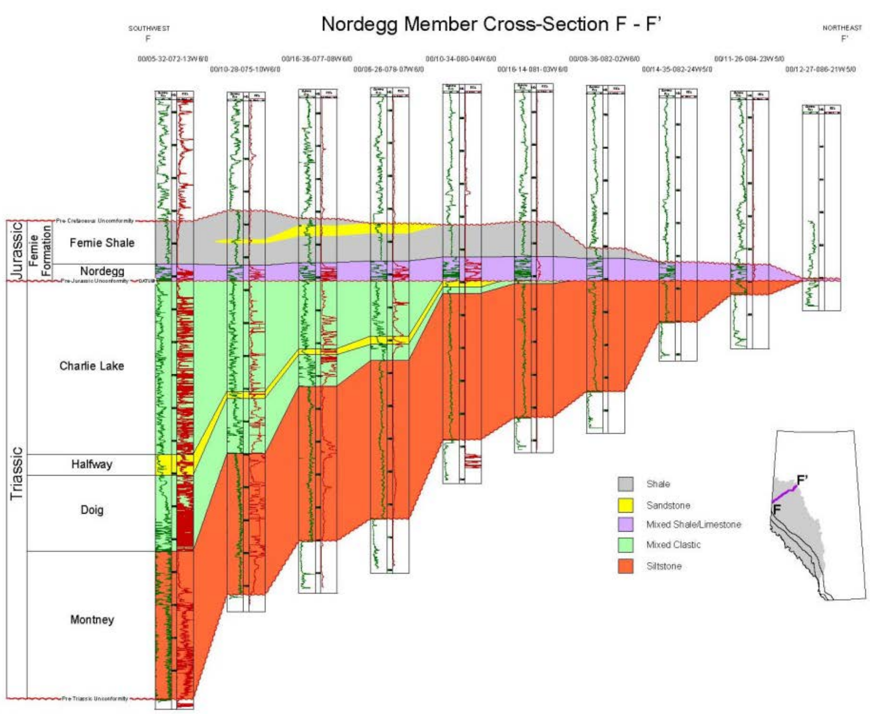
Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-23. Prospective Area for Nordegg Shale (Alberta)



Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-24. Stratigraphic Cross Section F-F' of the Nordegg Member



Source: ERCB/AGS Open File Report 2012-06, October 2012.

3.2 Reservoir Properties (Prospective Area).

In the Nordegg Shale prospective area, the drilling depth to the top of the shale ranges from 3,300 feet in the north-east to about 15,000 feet in the south. Within the overall prospective area of 12,400 mi^2, the volatile/black oil prospective area is 6,900 mi^2, the wet gas/condensate prospective area is 4,000 mi^2, and the dry gas prospective area is 1,500 mi^2. The shale thickness in the overall prospective area ranges from 50 feet to 150 feet and has a high net to gross ratio of about 0.8.

The total organic carbon (TOC) in the prospective area is high, at over 11%, based on 82 samples from 16 wells. The thermal maturity (R_o) of the shale increases to the southwest in line with increasing depth. The overall Nordegg Shale prospective area has an oil prone area (R_o of 0.8% to 1.0%) on the north, a wet gas/condensate area in the center (R_o of 1.0% to 1.3%) and a dry gas area (R_o >1.3) on the south. While the data are sparse, industry information suggests that the Nordegg Shale is over-pressured.

3.3 Resource Assessment.

Within the 6,900-mi^2 oil prospective area, the Nordegg Shale has a resource concentration of 5.6 million barrels of oil per mi^2 plus associated gas. Within the 4,000-mi^2 wet gas and condensate prospective area, the Nordegg Shale has a resource concentrations of 0.4 million barrels of oil and 20 Bcf of wet gas per mi^2. Within the 1,500-mi^2 dry gas prospective area, the Nordegg Shale has a resource concentration of 22 Bcf/mi^2.

Combined, the risked resource in-place for the prospective area of the Nordegg Shale is estimated at 20 billion barrels of oil/condensate and 72 Tcf of natural gas. Based on moderate reservoir properties and analog information from U.S. shales, we estimate risked, technically recoverable resources of 0.8 billion barrels of oil/condensate and 13 Tcf of natural gas for the Nordegg Shale.

Advanced Resources International, Inc.

3.4 Comparison with Other Resource Assessments

The ERCB/AGS resource study, discussed above, calculated an unrisked mean oil in-place of 40,645 million barrels and an unrisked mean gas in-place of 164 Tcf for the Nordegg Shale.[19] The in-place resource values in our study are different than those reported in the ERCB/AGS study due to the following: (1) given the still emerging nature of the Nordegg Shale, we judge this resource area to be only 50% de-risked; (2) we find the Nordegg Shale to be moderately over-pressured; and (3) we have a significantly lower associated gas-oil ratio for the volatile/black oil prospective resource area than used in the ERCB/AGS study.

3.5 Recent Activity

Only a modest number of exploration wells have been completed in the Nordegg Shale. Recently, Anglo Canadian drilled a horizontal test well (Shane 07-11-77-03W6) and a vertical test well (Sturgeon Lake 05-10-68-22W5) which produced non-commercial volumes of moderately heavy, 25^o API oil. Tallgrass Energy has since acquired Anglo Canadian and its large land position, with 272 mi^2 in the Nordegg Shale.[22] The literature reports that a company active in the Nordegg oil fairway has completed one Nordegg Hz well with a multi-stage frac that produced 500 BOED, with 80% oil (42^o API), during its initial flow test and completed a second well that had a 30-day initial production rate of 78 barrels of 32^o API oil.[23]

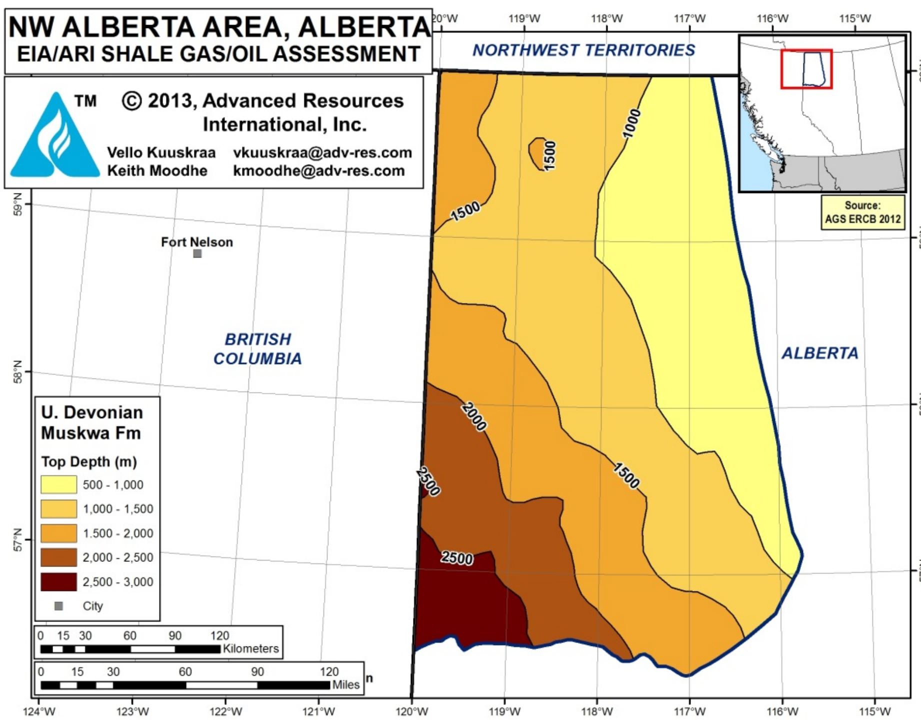
4. MUSKWA SHALE/NORTHWEST ALBERTA

4.1 Geologic Setting

The Muskwa Shale deposition in northwest Alberta is the northern continuation of the Duvernay Shale in central Alberta and the eastern continuation of Muskwa/Otter Park Shale in northeast British Columbia, Figure I-25.[19] The boundaries of the Muskwa Shale in northwest Alberta are the Alberta/British Columbia border on the west, the Alberta/NWT border on the north, the Peace River Arch on the south, and the Grosmont Carbonate Platform on the east. Within this larger depositional area, the Muskwa Shale has a prospective area of 19,100 mi^2, primarily in the western portion of the larger Muskwa Shale depositional area, Figure I-26.[19]

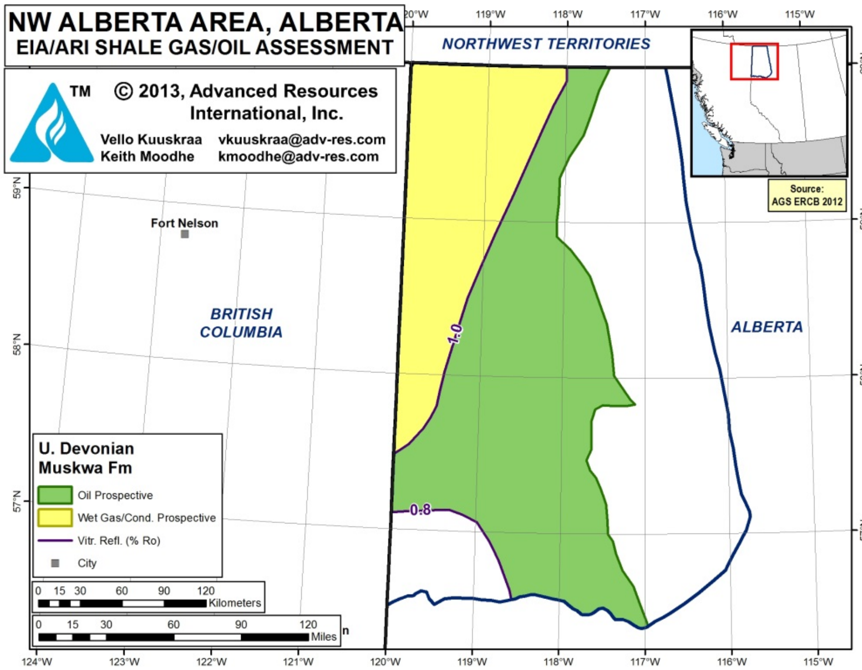
The Muskwa Shale is overlain by the Ft. Simpson Shale and is deposited on the Beaverhill Lake Formation, Figure I-27.[19] The Muskwa Shale is primarily an organic-rich limestone deposited in a deep-water marine setting.

Figure I-25. Outline and Depth of Muskwa Shale (Alberta).



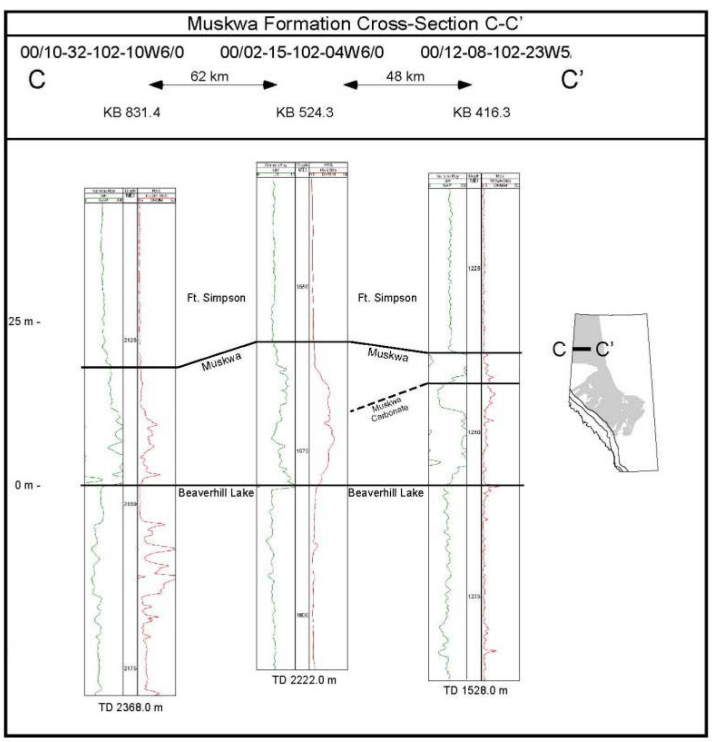
Source: ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-26. Prospective Area for Muskwa Shale (Alberta).



Source: ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-27. Stratigraphic Cross Section C-C' of the Muskwa Formation



Source: ERCB/AGS Open File Report 2012-06, October 2012.

4.2 Reservoir Properties (Prospective Area)

In the prospective area, the drilling depth to the top of the Muskwa Shale ranges from 3,300 feet in the northeast to 8,200 feet in the southwest. The gross shale thickness ranges from 33 feet to nearly 200 feet, with a high net to gross pay ratio.

The total organic content (TOC) ranges from less than 1 to over 10%, with the leaner TOC pay excluded by the net to gross pay ratio. Excluding the lean TOC segments, a sample of 47 TOC measurements from 5 wells provided an average TOC value of 3.2%. The thermal maturity (R_o) of the shale increases with depth, ranging from immature (R_o < 0.8%) in the east to thermally mature for wet gas and condensate (R_o of 1.0% to 1.2%) on the west. Based on thermal maturity, the Muskwa Shale has an oil-prone area with associated gas on the east and a wet gas/condensate area on the northwest.

4.3 Resources Assessment

The overall oil and gas prospective area of the Muskwa Shale in northwest Alberta is approximately 19,100 mi^2. Within the oil prospective area of 12,500 mi^2, the Muskwa Shale has a resource concentration of 6 million barrels of oil per mi^2 plus associated gas. Within the wet gas/condensate prospective area of 6,600 mi^2, the Muskwa Shale has a resource concentration of 1 million barrels of oil/condensate per mi^2 and 34 Bcf of wet gas per mi^2.

The risked resource in-place is estimate at 42 billion barrels of oil/condensate and 142 Tcf of shale gas. Given favorable reservoir properties and analog information from the Horn River and Cordova Embayment shales, we estimate a risked, technically recoverable resource of 2.1 billion barrels of shale oil/condensate and 31 Tcf of shale gas.

4.4 Comparison with Other Resource Assessments

The ERCB/AGS resource study, discussed above, calculated an unrisked mean oil in-place of 115,903 million barrels and an unrisked mean gas in-place of 413 Tcf for the Muskwa Shale study area in NW Alberta.[19] The in-place values in our study are different than those reported in the ERCB/AGS study due to the following: (1) given the limited exploration for the Muskwa Shale in NW Alberta, we judge this resource area to be only 50% de-risked; (2) we find the Muskwa Shale in this area to be moderately over-pressured; and (3) we have a lower associated gas-oil ratio for the shale.

4.5 Recent Activity

Husky Oil Canada, currently the most active explorer in Alberta's Muskwa Shale, has a concentrated 400,000-net acre land position in the Rainbow area. Husky drilled 14 Muskwa Shale wells in 2012, completing 4 wells, with the goal of de-risking its large land position and refining its well completion practices. Husky is currently looking for a JV partner to help finance the development of this shale oil play[17].

A smaller Canadian E&P company, Mooncor Oil and Gas, drilled a pilot test well into the Muskwa Shale in early 2009 (Well #06-34-94-12W6). The Muskwa zone was reported to be over-pressured and flowed 56^{o} API condensate plus wet gas.[24]

5. COLORADO GROUP/SOUTHERN ALBERTA

5.1 Geologic Setting

The Colorado Group Shale covers a massive, 124,000-mi^2 area in southern Alberta and southeastern Saskatchewan. The western boundary of the Colorado Group is the Canadian Rockies Overthrust. The northern and eastern boundaries are defined by shallow shale depth and loss of net pay. The southern boundary is the U.S./Canada border. The Colorado Group encompasses a thick, Cretaceous-age sequence of sands, mudstones and shales. Within this sequence are two shale formations of interest - - the Fish Scale Shale Formation in the Lower Colorado Group and the Second White Speckled Shale Formation in the Upper Colorado Group, Figure I-28.[25] We selected the 5,000 to 10,000 foot depth contours for defining the 48,750-mi^2 prospective area, Figure I-29.

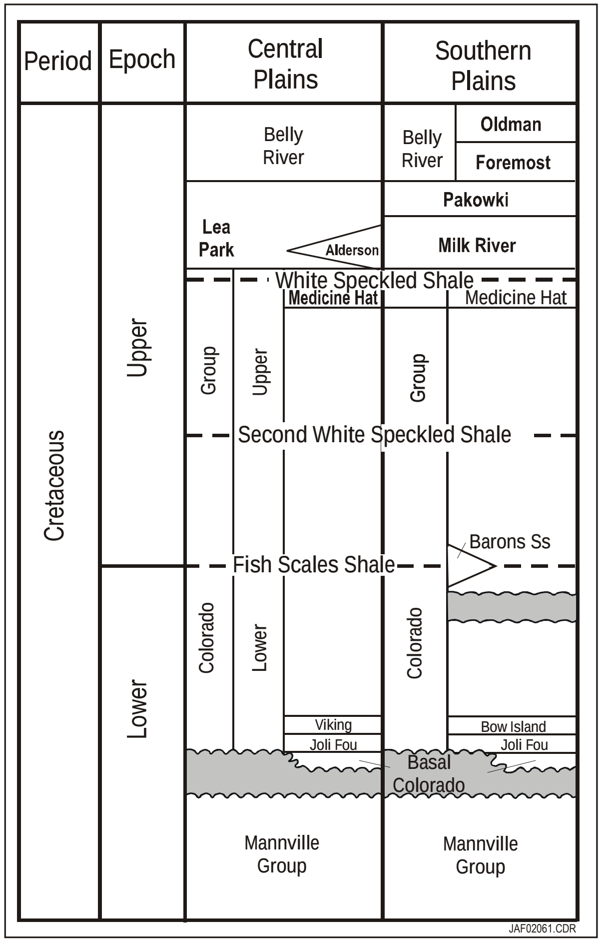
5.2 Reservoir Properties (Prospective Area)

In the prospective area, the depth to the Second White Speckled (2WS) and the Fish Scale shales ranges from 5,000 feet near Medicine Hat (on the east) to over 10,000 feet in the west. The Fish Scale Shale is generally about 200 feet deeper than the 2WS. The interval from the top of the 2WS to the base of the Fish Scales Shale ranges from 300 feet in the east to over 1,000 feet in the west, with an average gross pay of 523 feet. Assuming a conservative net to gross ratio of 20%, we estimate a net pay of 105 feet. Much of the Colorado Group Shale appears to be under-pressured, with a pressure gradient of about 0.3 psi/ft. The total organic carbon (TOC) content of the shale ranges from 2% to 3%. In the prospective area, the thermal maturity of the shale is low (R_o of 0.5% to 0.6%). However, the presence of biogenic gas appears to have provided adequate volumes of gas generation. The rock mineralogy appears to be low to moderate in clay (31%) and thus favorable for hydraulic fracturing.

5.3 Resource Assessment

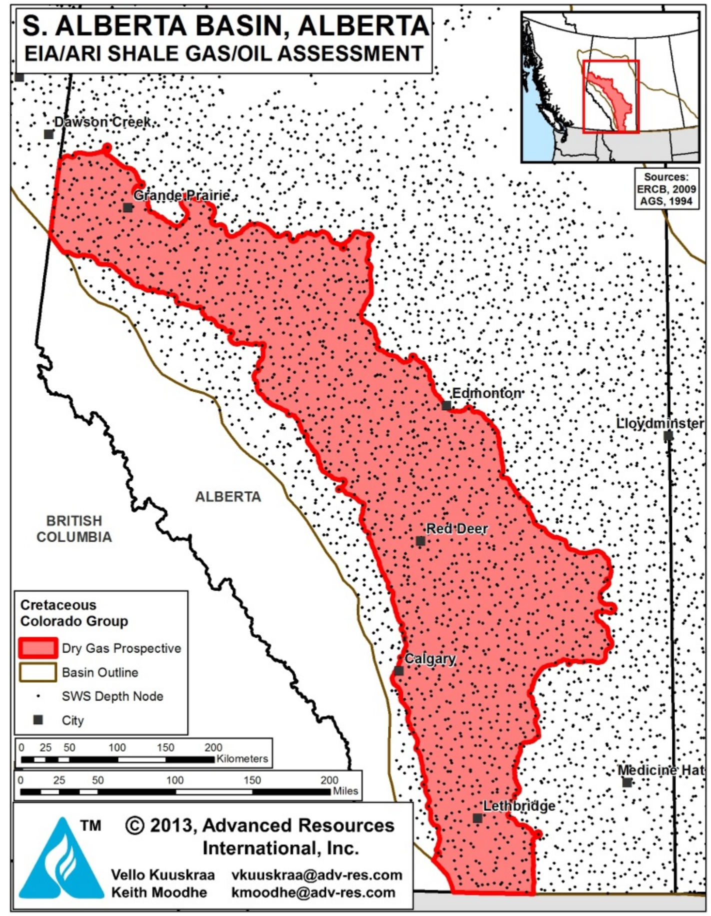
The 48,750-mi^2 prospective area of the Colorado Group Shale covers much of southwestern Alberta. Within this prospective area, the shale has a relatively low gas concentration of 21 Bcf/mi^2. The risked shale gas in-place for the Colorado Group Shale is estimated at 286 Tcf. Based on moderately favorable shale mineralogy, but other less favorable reservoir properties such as low pressure and an uncertain gas charge, we estimate a risked technically recoverable shale gas resource of 43 Tcf for the Colorado Group Shale.

Figure I-28. Colorado Group Stratigraphic Column



Source: Leckie, D.A., 1994.

Figure I-29. Colorado Group, Prospective Area



Source: ARI, 2013.

5.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society for Unconventional Gas estimated 100 Tcf of gas in-place and 4 to 14 Tcf of marketable (recoverable) shale gas for the Colorado Shale.[4]

5.5 Recent Activity

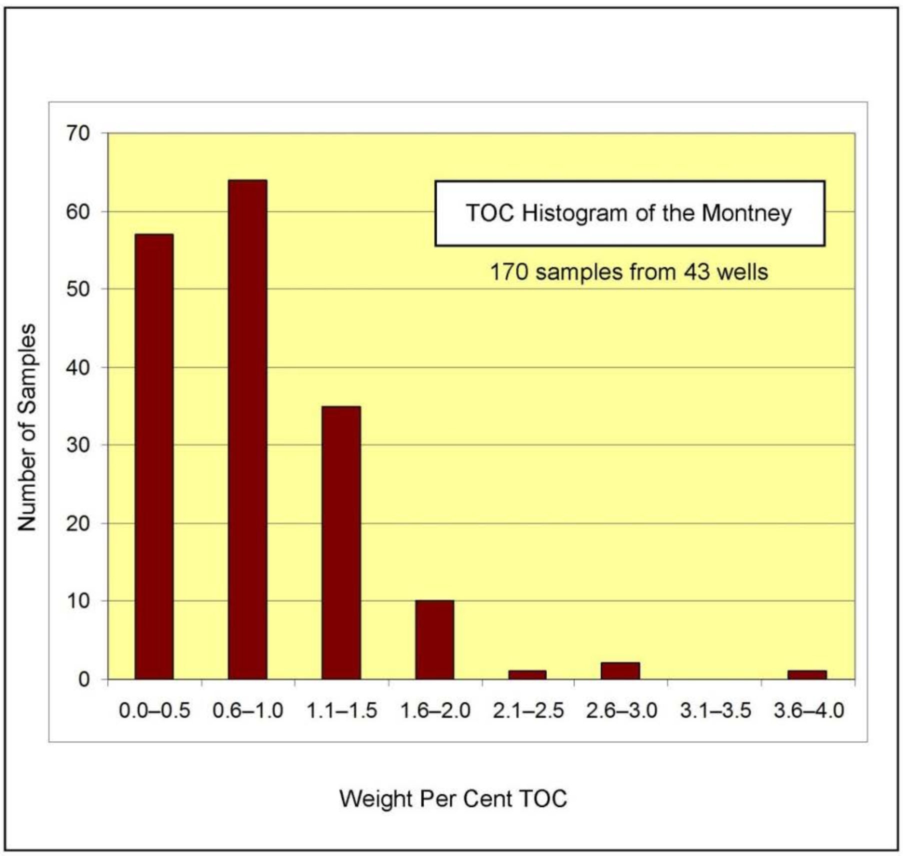
To date, the Colorado Group Shale has seen only limited exploration and development, primarily in the shallower eastern portion of the play area.

6. MONTNEY AND DOIG RESOURCE PLAYS (ALBERTA)

The Deep Basin of Canada also contains the Alberta portion of the Montney and Doig Resource plays. These multi-depositional Triassic-age hydrocarbon accumulations contain massive volumes of dry, wet and associated gas as well as oil/condensate.

We have excluded the Alberta portion of the Montney and Doig Resource Plays from our assessment because the reservoirs in the Alberta portion of the basin are generally classified as tight and conventional sands and because the organic-content (TOC) of the Montney and Doig Resource plays is low, averaging about 0.8%. Essentially all of the 170 samples taken from 43 Montney Formation wells have TOC values less than 1.5%, Figure I-30.[19] The basin average cut-off values for TOC in our study (for consistency with the USGS evaluations of shale oil and gas resources) is 2%, with individual reservoir rock intervals having to have at least 1.5% for inclusion in net, organic-rich pay.

Figure I-30. Histogram of Total Organic Carbon (TOC) of 170 Samples from the Montney Formation.



Source: ERCB/AGS Open File Report 2012-06, October 2012.

SASKATCHEWAN/MANITOBA

1. WILLISTON BASIN/BAKKEN SHALE

1.1 Geologic Setting

The Williston Basin of Canada extends northward from the U.S./Canada border into southern Saskatchewan and southwestern Manitoba and contains the Canadian portion of the Bakken Shale play, Figure I-31.[26] We estimate this basin contains 22 billion barrels of risked shale oil in-place, with 1.6 billion barrels as the risked, technically recoverable shale oil resource. The basin also contains 16 Tcf of associated shale gas in-place, with 2 Tcf as the risked, technically recoverable shale gas resource, Table I-5.

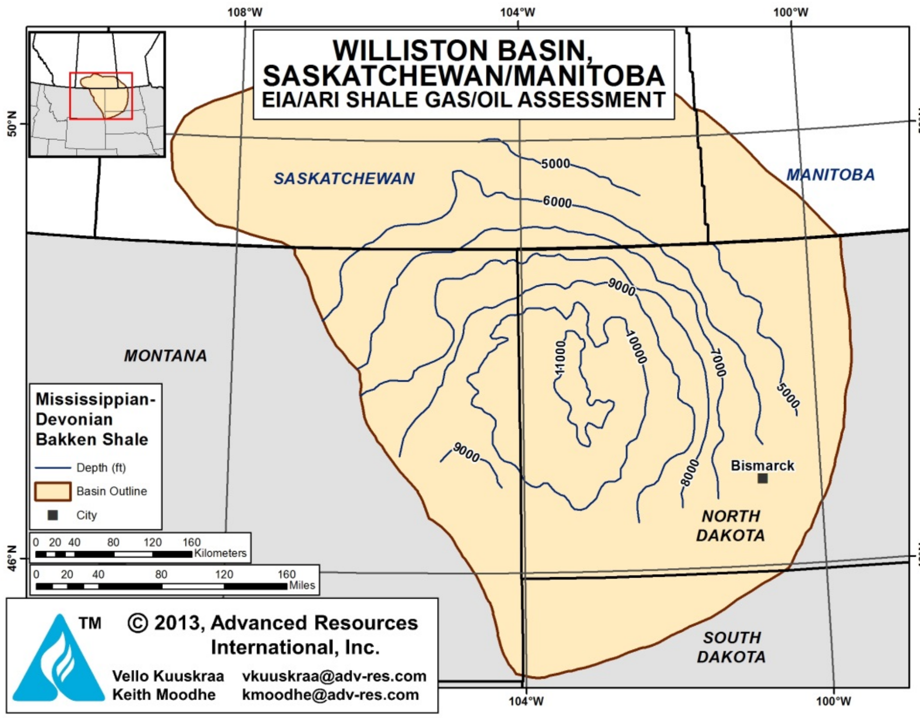
Table I-5. Shale Gas and Oil Reservoir Properties and Resources of Saskatchewan/Manitoba

Basic Data	Basin/Gross Area		Williston (110,000 mi^2)
	Shale Formation		Bakken
	Geologic Age		Devonian-Mississippian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		8,700
	Thickness (ft)	Organically Rich	50
		Net	20
	Depth (ft)	Interval	5,500 - 8,000
		Average	6,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		11.0%
	Thermal Maturity (% Ro)		0.64%
	Clay Content		Low/Medium
Resource	Gas Phase		Assoc. Gas
	GIP Concentration (Bcf/mi^2)		3.1
	Risked GIP (Tcf)		16.0
	Risked Recoverable (Tcf)		2.2

Basic Data	Basin/Gross Area		Williston (110,000 mi^2)
	Shale Formation		Bakken
	Geologic Age		Devonian-Mississippian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		8,700
	Thickness (ft)	Organically Rich	50
		Net	20
	Depth (ft)	Interval	5,500 - 8,000
		Average	6,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		11.0%
	Thermal Maturity (% Ro)		0.64%
	Clay Content		Low/Medium
Resource	Oil Phase		Oil
	OIP Concentration (MMbbl/mi^2)		4.3
	Risked OIP (B bbl)		22.5
	Risked Recoverable (B bbl)		1.57

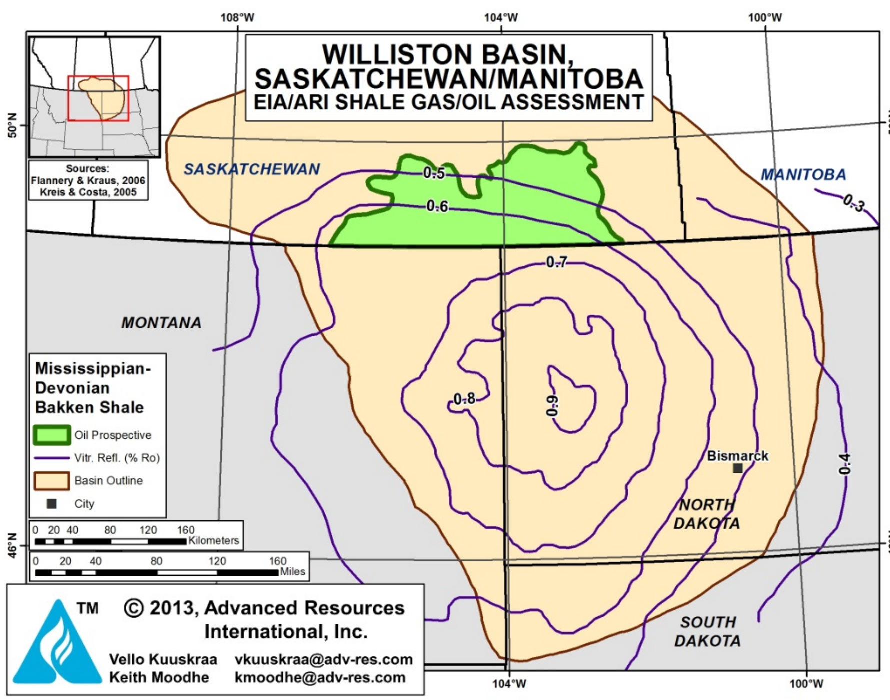
Within the larger Bakken Shale depositional area, we have defined a prospective area of 8,700 mi^2 where the shale appears to have more favorable reservoir properties and where past Bakken Shale drilling has occurred. The prospective area for the Bakken Shale in Saskatchewan and Manitoba is bounded on the north, east and west by the 30-foot shale interval contour and on the south by the U.S./Canada border, Figure I-32.[27]

Figure I-31. Outline and Depth of Williston Basin Bakken Shale (Saskatchewan/Manitoba)



Source: Modified from Saskatchewan Ministry of Energy Resources, 2010.

Figure I-32. Prospective Area for Williston Basin Bakken Shale (Saskatchewan/Manitoba)



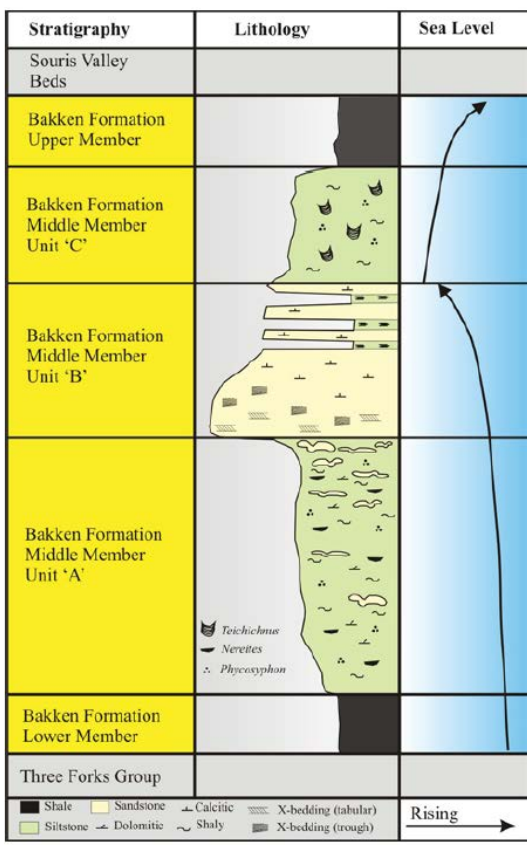
Source: AAPG Flannery & Kraus, 2006.

For this shale play, we have expanded our criteria for establishing the prospective area for oil to below our general cut-off of 0.7% thermal maturity (Ro) for two reasons. First, much of the oil in-place in this part of the Bakken Shale play is oil that has migrated from the deeper, more mature Bakken Shale in the center of the Williston Basin to the south.[28] Second, a considerable portion of the successful Bakken Shale well drilling in Canada has been in this thermally less mature area of the northern Williston Basin.

1.2 Reservoir Properties (Prospective Area).

Similar to the basal Banff/Exshaw Shale, the Late Devonian to Early Mississippian Bakken Shale consists of three reservoir units. The upper and lower units are dominated by organic-rich shale. The middle unit contains a variety of lithologies including calcareous sandstone and siltstone, dolomitic siltstone and limestone, Figure I-33.[26] The primary reservoir is the more porous and permeable middle unit, sourced by the upper and lower organic-rich shales. The Bakken Shale is over-pressured in much of its prospective area.

Figure I-33. Bakken Shale Stratigraphy (Saskatchewan)



Source: Saskatchewan Ministry of Energy Resources, 2010.

The drilling depth to the top of the Bakken Shale in the prospective area ranges from 5,500 feet on the north to about 8,800 feet on the south, averaging 6,600 feet in the prospective area. The Bakken Shale gross interval ranges from 30 to over 60 feet in the prospective area with an average net pay of about 20 feet, with favorable porosity of about 10%. The total organic content (TOC) in the prospective area averages 11% in the organic-rich upper and lower units. The Bakken Shale is prospective for oil plus associated gas.

1.3 Resource Assessment

Within the 8,700-mi^2 prospective area for oil and associated gas, the Bakken Shale has a resource concentration of 4 million barrels/mi^2 for oil plus moderate volumes of associated gas.

The risked oil resource in-place for the prospective area is estimated at 22 billion barrels plus 16 Tcf of associated natural gas. Based on recent well performance and reservoir properties, we estimate risked, technically recoverable resources of 1.6 billion barrels of oil and 2 Tcf of associated gas.

1.4 Recent Activity

The Bakken Shale in Canada is an active shale oil play with over 2,000 producing wells and about 75,000 barrels per day of oil production, as of mid-2011. The various companies active in the play have publically reported 225 million barrels of proved and probable reserves.[29]

EASTERN CANADA

Canada has four potential shale gas plays - - the Utica and Lorraine shales in the St. Lawrence Lowlands of the Appalachian Fold Belt of Quebec, the Horton Bluff Shale in the Windsor Basin of northern Nova Scotia, and the Frederick Brook Shale in the Moncton Sub-Basin of the Maritimes Basin in New Brunswick. These shale oil and gas formations and basins are in an early exploration stage. Therefore, only preliminary shale resource assessments are offered for the Utica and Horton Bluff shales. Insufficient information exists for assessing the Lorraine and Frederick Brook shales.

The two assessed Eastern Canada shale gas basins assessed by this study contain 172 Tcf of risked gas in-place, with 34 Tcf as the risked, technically recoverable shale gas resource, Table I-6.

Table I-6. Shale Gas Reservoir Properties and Resources of Eastern Canada

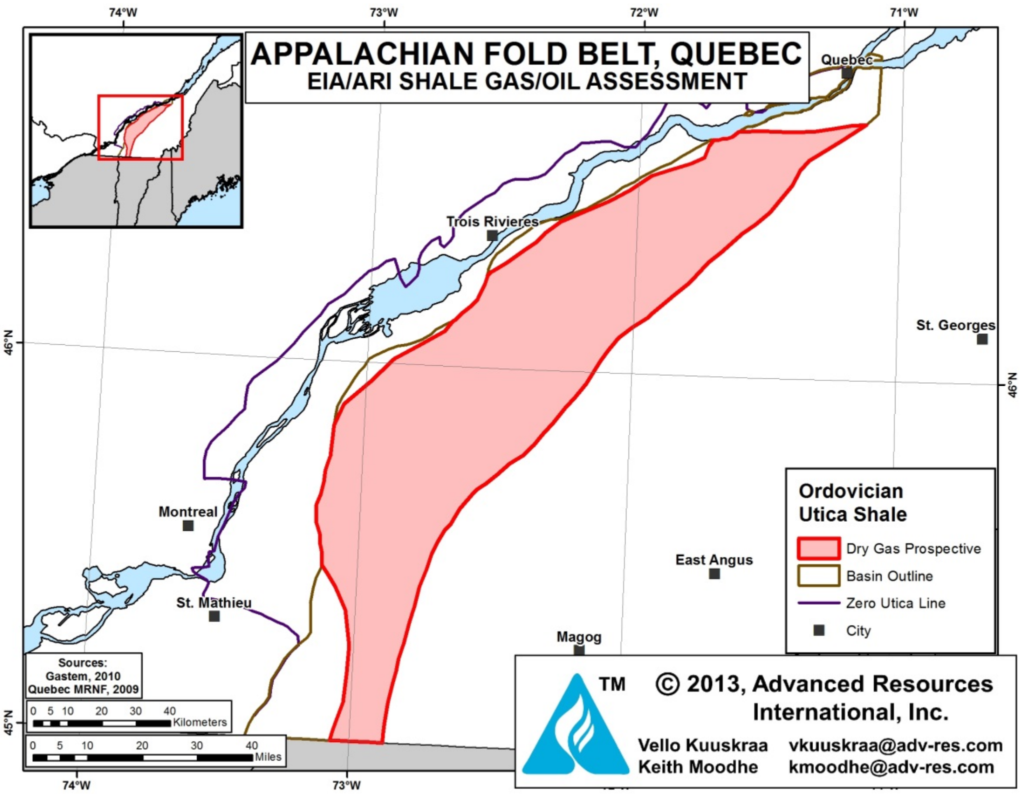
Basic Data	Basin/Gross Area		Appalachian Fold Belt ($3,500\ mi^2$)	Windsor ($650\ mi^2$)
	Shale Formation		Utica	Horton Bluff
	Geologic Age		Ordovician	Mississippian
	Depositional Environment		Marine	Marine
Physical Extent	Prospective Area (mi^2)		2,900	520
	Thickness (ft)	Organically Rich	1,000	500
		Net	400	300
	Depth (ft)	Interval	4,000 - 11,000	3,000 - 5,000
		Average	8,000	4,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Normal
	Average TOC (wt. %)		2.0%	5.0%
	Thermal Maturity (% Ro)		2.00%	2.00%
	Clay Content		Low	Unknown
Resource	Gas Phase		Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		133.9	81.7
	Risked GIP (Tcf)		155.3	17.0
	Risked Recoverable (Tcf)		31.1	3.4

1. APPALACHIAN FOLD BELT (QUEBEC)/UTICA SHALE

1.1 Introduction and Geologic Setting

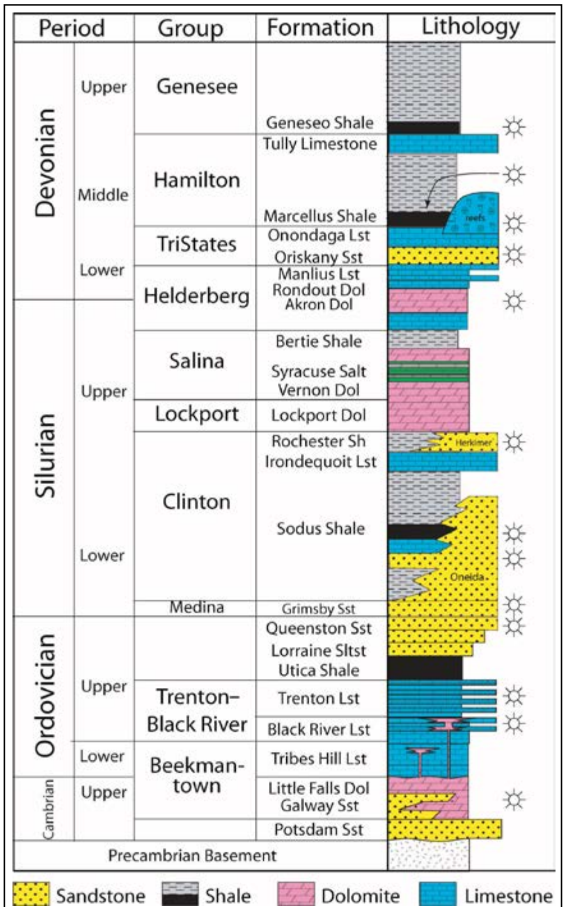
The Utica Shale is located within the St. Lawrence Lowlands of the Appalachian Fold Belt in Quebec, Canada, Figure I-34. The Utica is an Upper Ordovician-age shale, located above the conventional Trenton-Black River Formation, Figure I-35. A second, less defined, thicker but lower TOC Lorraine Shale overlies the Utica. Three major faults - - Yamaska, Tracy Brook and Logan's Line - - form structural boundaries and partitions for the Utica Shale play in Quebec.

Figure I-34. Utica Shale Outline and Prospective Area (Quebec)



Source: ARI, 2013.

Figure I-35. Utica Shale Stratigraphy (Quebec)



Source: L. Smith AAPG, AAPG Bulletin, v. 90, no. 11 (November 2006), pp. 1691–1718

JAF21299.AI

1.2 Reservoir Properties (Prospective Area)

The extensive faulting and thrusting in the Utica Shale introduces considerable exploration and completion risk. The depth to the top of the shale in the prospective area ranges from 3,000 to over 11,000 feet, shallower along the southwestern and northwestern boundaries and deeper along the eastern boundary. The Utica Shale has a gross interval of 1,000 feet. With a net to gross ratio of 40%, the net organic-rich shale is estimated at 400 feet. The total organic content (TOC) ranges from 1.5% to 3%, with the higher TOC values concentrated in the Upper Utica Shale. The thermal maturity of the prospective area ranges from an R_o of 1.1% to 4% and averages 2%, placing the shale primarily in the dry gas window. Data on quartz and clay contents are not publicly available.

1.3 Resource Assessment

The prospective area of the Utica Shale in Quebec is estimated at 2,900 mi^2. Within this prospective area, the shale has a gas in-place concentration of 134 Bcf/mi^2. As such, the risked shale gas in-place is 155 Tcf. Assuming low clay content, but considerable geologic complexity within the prospective area, we estimate a risked, technically recoverable shale gas resource of 31 Tcf for the Utica Shale.

1.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society for Unconventional Gas (CSUG) cites a gas in-place of 181 Tcf (unrisked) for the Utica Shale in Canada with 7 to 12 Tcf of marketable (recoverable) shale gas resources.[30]

1.5 Exploration Activity

Two large operators, Talisman and Forest Oil, plus numerous smaller companies such as Questerre, Junex, Gastem and Molopo, hold leases in the Utica Shales of Quebec. Approximately 25 exploration wells have been drilled with moderate results. Market access is provided by the Maritimes and Northeastern pipeline as well as the TransCanada Pipeline to markets in Quebec City and Montreal. Currently shale gas drilling in Quebec is on hold, awaiting further environmental studies.

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2. WINDSOR BASIN (NOVA SCOTIA)/HORTON BLUFF SHALE

2.1 Introduction and Geologic Setting

The Horton Bluff Shale is located in north-central Nova Scotia. It is a Carboniferous (Early Mississippian) shale within the Horton Group, Figure I-36. Because the Horton Bluff Shale rests directly on the pre-Carboniferous igneous and metamorphic basement, it has experienced high heat flow and has a high thermal maturity in northern Nova Scotia. The Horton Bluff Shale geology is complex, containing numerous faults.

2.2 Reservoir Properties (Prospective Area)

The regional extent of the Horton Shale play is only partly defined as the basin and prospective area boundaries are highly uncertain. A preliminary outline and 520-mi^2 prospective area has been estimated for the Horton Bluff Shale play, Figure I-37. The depth of the shale in the prospective area ranges from 3,000 to 5,000 feet. The shale interval is thick with 500 feet of gross pay and 300 feet of organically rich net pay. The TOC is 4% to 5% (locally higher). The thermal maturity of the prospective area ranges from a R_o of 1.2% in the south to a R_o of over 2.5% in the northeastern portion of the prospective area, placing the Horton Bluff Shale primarily in the dry gas window. Data from the Kennetcook #1, drilled to test the Horton Bluff Shale in the Windsor Basin, provided valuable data on reservoir properties.

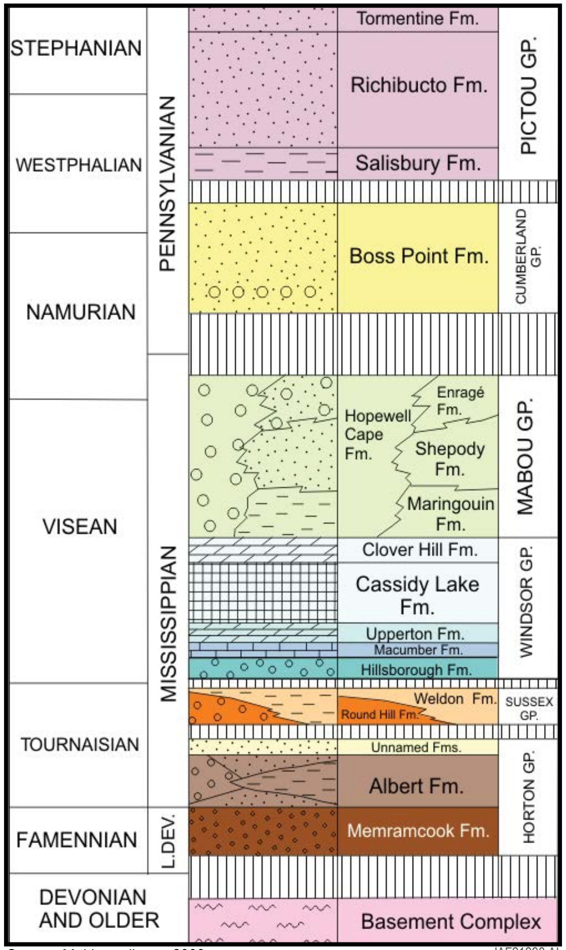
2.3 Resource Assessment

The 520-mi^2 prospective area of the Horton Bluff Shale in Nova Scotia is in the northern and eastern portions of the play area. Within this prospective area, the shale has an in-place resource concentration of 82 Bcf/mi^2. Our preliminary resource estimate is 17 Tcf of risked shale gas in-place. Given the geologic complexity in the prospective area, we estimate a risked, technically recoverable shale gas resource of 3 Tcf for the Horton Bluff Shale.

2.4 Recent Activity.

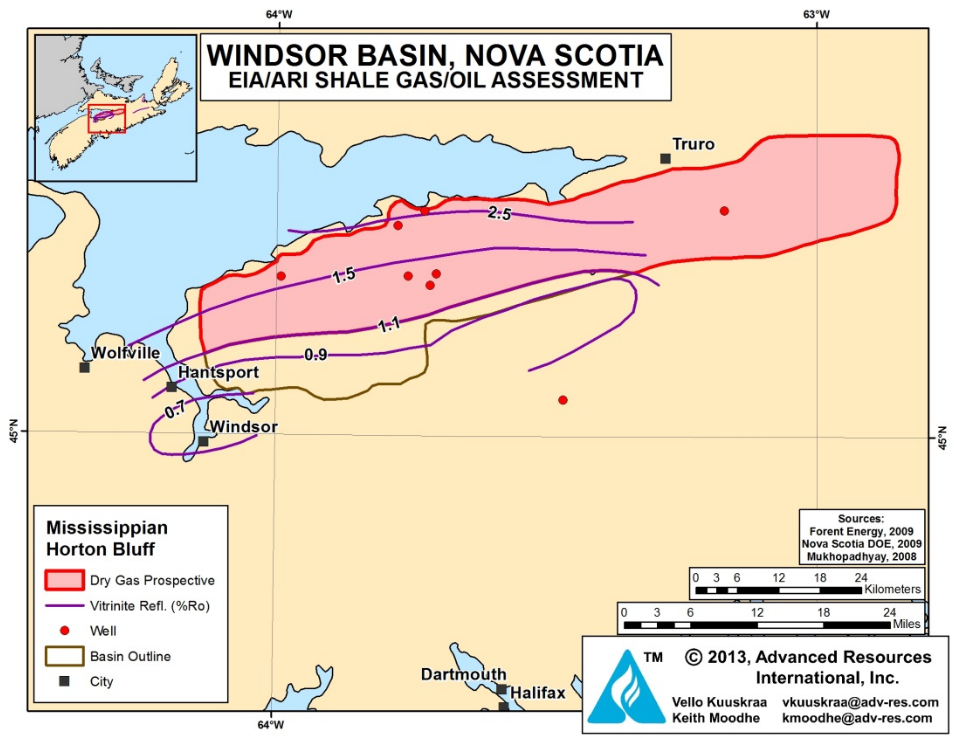
Two small operators, Triangle Petroleum and Forent Energy, have acquired leases and have begun to explore the Horton Bluff Shale.

Figure I-36. Horton and Frederick Brook Shale (Horton Group) Stratigraphy



Source: Mukhopadhyay, 2009 JAF21298.AI

Figure I-37. Outline and Prospective Area for Horton Bluff Shale (Nova Scotia)

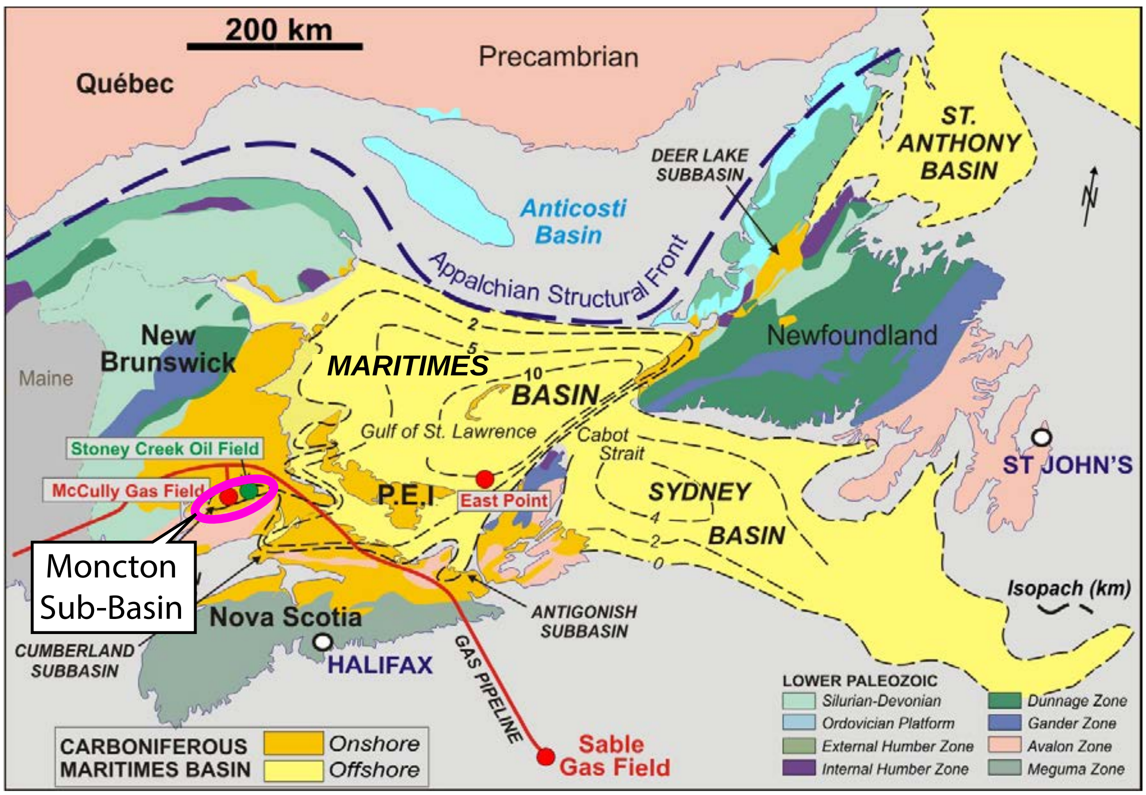


Source: ARI, 2013.

3. MONCTON SUB-BASIN (NEW BRUNSWICK)/FREDERICK BROOK SHALE

The Frederick Brook Shale is located in the Moncton Sub-Basin of the larger Maritimes Basin of New Brunswick, Figure I-38. This Mississippian-age shale is correlative with the Horton Group in Nova Scotia. The Moncton Sub-Basin is bounded on the east by the Caledonia Uplift, on the west by the Kingston Uplift, and on the north by the Westmoreland Uplift, Figure I-39. Because of limited data, the definition of the prospective area of the Frederick Brook Shale has yet to be established.

Figure I-38. Location of Moncton Sub-Basin and Maritimes Basin

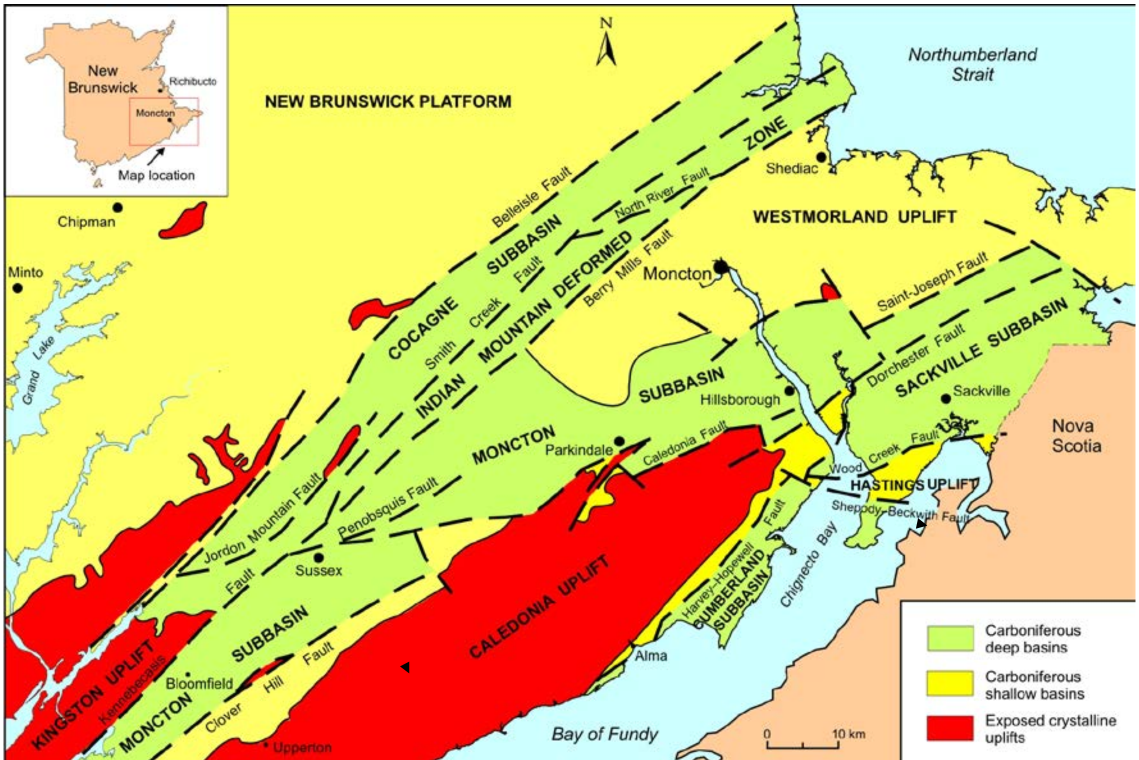


Source: Geological Survey of Canada, 2009 CSPG CSEG CWLS Convention, Canada JAF21297.AI

The Frederick Brook Shale in the Moncton Sub-Basin is structurally complex, with extensive faulting and deformation. Its depth ranges from about 3,000 feet along the basin's eastern edges to 15,000 feet in the north. The total organic content of the shale varies widely (1% to 10%), but typically ranges from 3% to 5%. No public data are available on the mineralogy of the shale. The thermal maturity ranges from immature $R_o < 1\%$ in the shallower portions of the basin to highly mature ($R_o > 2\%$) in the deeper western and southern areas of the basin.

Much of the data for this preliminary assessment of the Frederick Brook Shale is from the McCully gas field along the southwestern edge of the Moncton Sub-Basin and from a handful of vertical exploration wells. Other areas, such as the Cocagne Sub-Basin, Figure I-39, may also be prospective for the Frederick Brook Shale but have yet to be explored or assessed.

Figure I-39. Structural Controls for Moncton Sub-Basin (New Brunswick) Canada



Source: P.K. Mukhopadhyay, Search and Discovery Article #10167 (2008)

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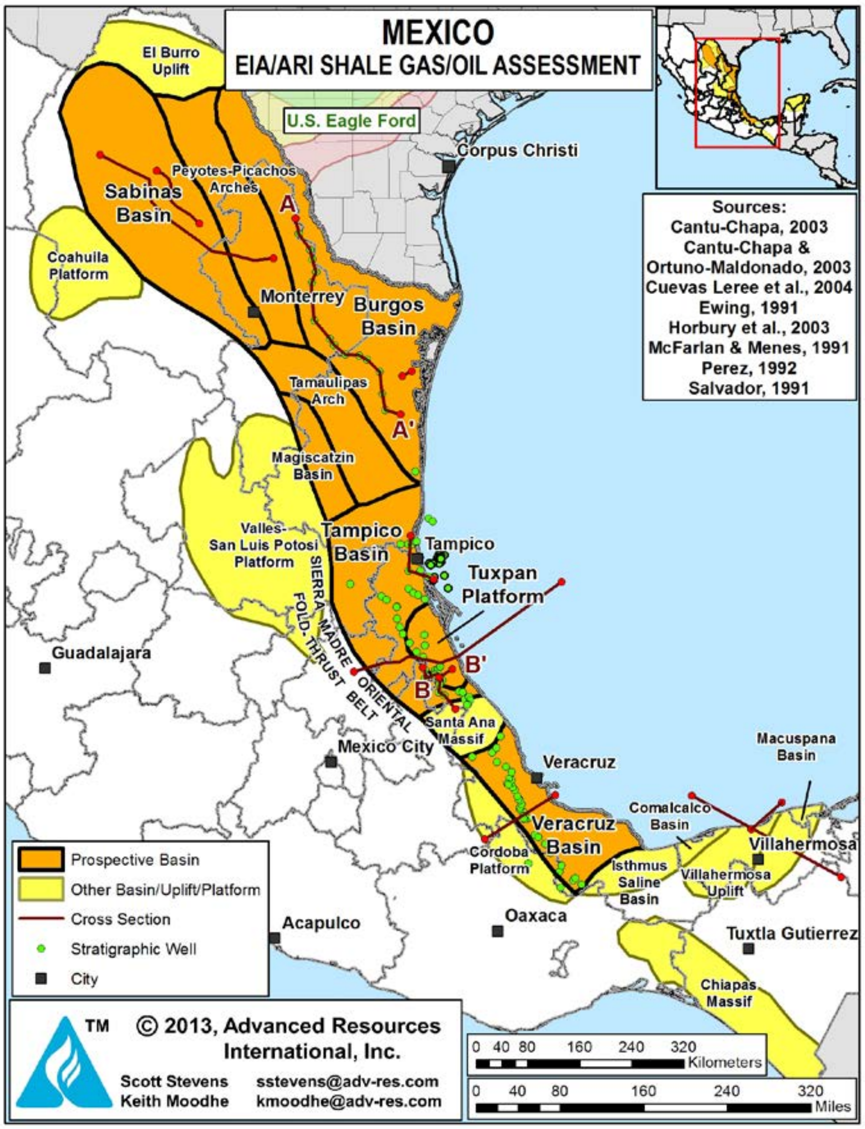
II. MEXICO

SUMMARY

Mexico has excellent potential for developing its shale gas and oil resources stored in marine-deposited, source-rock shales distributed along the onshore Gulf of Mexico region.

Figure II-1. Onshore Shale Gas and Shale Oil Basins of Eastern Mexico's Gulf of Mexico Basins.



Source: ARI, 2013.

Technically recoverable shale resources, estimated at 545 Tcf of natural gas and 13.1 billion barrels of oil and condensate, are potentially larger than the country's proven conventional reserves, Table II-1. The best documented play is the Eagle Ford Shale of the Burgos Basin, where oil- and gas-prone windows extending south from Texas into northern Mexico have an estimated 343 Tcf and 6.3 billion barrels of risked, technically recoverable shale gas and shale oil resource potential, Table II-2.

Further to the south and east within Mexico, the shale geology of the onshore Gulf of Mexico Basin becomes structurally more complex and the shale development potential is less certain. The Sabinas Basin has an estimated 124 Tcf of risked, technically recoverable shale gas resources within the Eagle Ford and La Casita shales, but the basin is faulted and folded. The structurally more favorable Tampico, Tuxpan, and Veracruz basins add another 28 Tcf and 6.8 billion barrels of risked, technically recoverable shale gas and shale oil potential from Cretaceous and Jurassic marine shales. These shales are prolific source rocks for Mexico's conventional onshore and offshore fields in this area. Shale drilling has not yet occurred in these southern basins.

PEMEX envisions commercial shale gas production being initiated in 2015 and increasing to around 2 Bcfd by 2025, with the company potentially investing $1 billion to drill 750 wells. However, PEMEX's initial shale exploration wells have been costly ($20 to $25 million per well) and have provided only modest initial gas flow rates (~3 million ft^3/d per well with steep decline). Mexico's potential development of its shale gas and shale oil resources could be constrained by several factors, including potential limits on upstream investment, the nascent capabilities of the local shale service sector, and public security concerns in many shale areas.

Table II-1. Shale Gas Reservoir Properties and Resources of Mexico

Basic Data	Basin/Gross Area		Burgos (24,200 mi^2)				Sabinas (35,700 mi^2)	
	Shale Formation		Eagle Ford Shale			Tithonian Shales	Eagle Ford Shale	Tithonian La Casita
	Geologic Age		M. - U. Cretaceous			U. Jurassic	M. - U. Cretaceous	U. Jurassic
	Depositional Environment		Marine			Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		600	10,000	6,700	6,700	9,500	9,500
	Thickness (ft)	Organically Rich	200	200	300	500	500	800
		Net	160	160	210	200	400	240
	Depth (ft)	Interval	3,300 - 4,000	4,000 - 16,400	6,500 - 16,400	7,500 - 16,400	5,000 - 12,500	9,800 - 13,100
		Average	3,500	7,500	10,500	11,500	9,000	11,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.	Underpress.	Underpress.
	Average TOC (wt. %)		5.0%	5.0%	5.0%	3.0%	4.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.60%	1.70%	1.50%	2.50%
	Clay Content		Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		21.7	74.4	190.9	100.3	131.9	69.1
	Risked GIP (Tcf)		7.8	446.4	767.5	201.6	501.0	118.1
	Risked Recoverable (Tcf)		0.9	111.6	230.2	50.4	100.2	23.6

Basic Data	Basin/Gross Area		Tampico (26,900 mi^2)			Tuxpan (2,810 mi^2)		Veracruz (9,030 mi^2)	
	Shale Formation		Pimienta			Tamaulipas	Pimienta	Maltrata	
	Geologic Age		Jurassic			L. - M. Cretaceous	Jurassic	U. Cretaceous	
	Depositional Environment		Marine			Marine	Marine	Marine	
Physical Extent	Prospective Area (mi^2)		9,000	3,050	1,550	1,000	1,000	560	400
	Thickness (ft)	Organically Rich	500	500	500	300	500	300	300
		Net	200	200	200	210	200	150	150
	Depth (ft)	Interval	3,300 - 8,500	4,000 - 8,500	7,000 - 9,000	6,000 - 9,500	6,600 - 10,000	9,800 - 12,000	10,000 - 12,500
		Average	5,500	6,200	8,000	7,900	8,500	11,000	11,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.40%	0.85%	0.90%	0.85%	1.40%
	Clay Content		Low	Low	Low	Low	Low	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Assoc. Gas	Assoc. Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		18.6	44.7	83.0	25.5	27.2	22.4	70.0
	Risked GIP (Tcf)		58.5	47.7	45.0	8.9	9.5	6.6	14.7
	Risked Recoverable (Tcf)		4.7	9.5	9.0	0.7	0.8	0.5	2.9

Table II-2. Shale Oil Reservoir Properties and Resources of Mexico

Basic Data	Basin/Gross Area		Burgos (24,200 mi^2)		Tampico (26,900 mi^2)		Tuxpan (2,810 mi^2)		Veracruz (9,030 mi^2)
	Shale Formation		Eagle Ford Shale		Pimienta		Tamaulipas	Pimienta	Maltrata
	Geologic Age		M. - U. Cretaceous		Jurassic		L. - M. Cretaceous	Jurassic	U. Cretaceous
	Depositional Environment		Marine		Marine		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		600	10,000	9,000	3,050	1,000	1,000	560
	Thickness (ft)	Organically Rich	200	200	500	500	300	500	300
		Net	160	160	200	200	210	200	150
	Depth (ft)	Interval	3,300 - 4,000	4,000 - 16,400	3,300 - 8,500	4,000 - 8,500	6,000 - 9,500	6,600 - 10,000	9,800 - 12,000
		Average	3,500	7,500	5,500	6,200	7,900	8,500	11,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		5.0%	5.0%	3.0%	3.0%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	0.85%	0.90%	0.85%
	Clay Content		Low	Low	Low	Low	Low	Low	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Oil	Oil	Oil
	OIP Concentration (MMbbl/mi^2)		43.9	15.0	37.9	17.3	36.4	33.0	23.5
	Risked OIP (B bbl)		15.8	89.8	119.4	18.5	12.7	11.5	6.9
	Risked Recoverable (B bbl)		0.95	5.39	4.78	0.74	0.51	0.46	0.28

INTRODUCTION

Mexico has large, geologically prospective shale gas and shale oil resources in the northeastern part of the country within the onshore portion of the greater Gulf of Mexico Basin, Figure II-1. These thick, organic-rich shales of marine origin correlate with productive Jurassic and Cretaceous shale deposits in the southern United States, notably the Eagle Ford and Haynesville shales, Figure II-2.[1] To date, Mexico's national oil company PEMEX has drilled at least six shale gas/oil exploration wells with modest results. The company plans to accelerate shale activity during the next few years, budgeting 6.8 billion pesos (575 million USD) in 2014.

Whereas Mexico's marine-deposited shales appear to have good rock quality, the geologic structure of its sedimentary basins often is considerably more complex than in the USA. Compared with the broad and gently dipping shale belts of Texas and Louisiana, Mexico's coastal shale zone is narrower, less continuous and structurally more disrupted. Regional compression and thrust faulting related to the formation of the Sierra Madre Ranges have squeezed Mexico's coastal plain, creating a series of discontinuous sub-basins.[2] Many of Mexico's largest conventional oil and gas fields also occur in this area, producing from conventional sandstone reservoirs of Miocene and Pliocene age that were sourced by deep, organic-rich and thermally mature Jurassic and Cretaceous-age shales. These deep source rocks are the principal targets for shale gas/oil exploration in Mexico.

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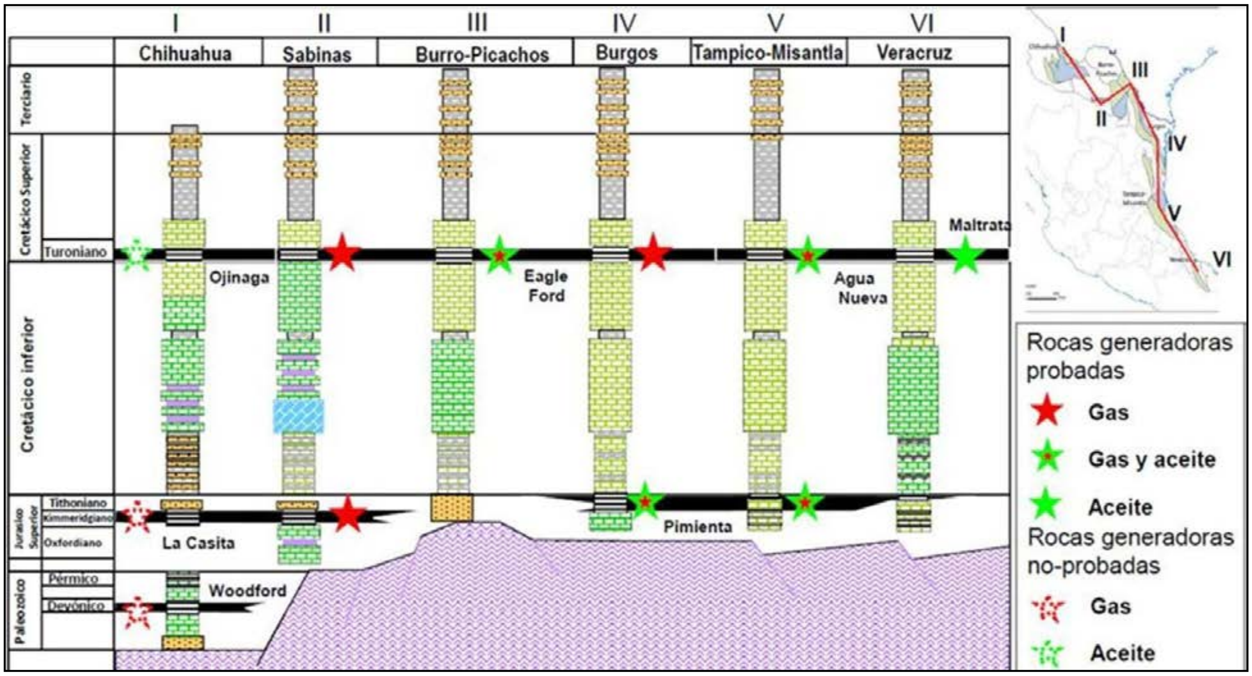
Figure II-2. Cross-Section of Shale Targets in Eastern Mexico.



Source: Escalera Alcocer, 2012.

Improved geologic data coverage collected since ARI's initial 2011 estimate indicates that Mexico's prospective areas for shale gas -- particularly in the structurally more complex basins – are slightly smaller than previously mapped. Furthermore, several of the previously mapped dry gas areas are now known to be within the wet gas to oil thermal maturity windows. On the other hand, geologic risk factors have been reduced due to the demonstration of the presence of productive hydrocarbons and improved geologic control. On an overall energy-equivalent basis, our updated estimate of Mexico's shale resources is about 10% lower than our earlier 2011 estimate (624 Tcfe in this study vs 681 Tcf previously).

PEMEX has identified some 200 shale gas resource opportunities in five geologic provinces in eastern Mexico, Figure II-3. According to the company, prospective regions include 1) Paleozoic shale gas in Chihuahua region; 2) Cretaceous shale gas in the Sabinas-Burro-Picachos region; 3) Cretaceous shale gas in the Burgos Basin; 4) Jurassic shale gas in Tampico-Misantla; and 5) unspecified shale gas potential in Veracruz.

Figure II-3. PEMEX Map Identifying Mexico's Shale Gas Potential (November 2012)

Source: PEMEX, 2012b.

PEMEX's initial internal evaluation estimated 150 Tcf (P90) to 459 Tcf (P10) of recoverable shale gas resources, with a median estimate of 297 Tcf. In 2012 PEMEX updated its shale gas and shale oil resource assessment to 141.5 Tcf of shale gas (comprising 104.7 Tcf dry and 36.8 Tcf wet) and 31.9 billion barrels of shale oil and condensate.

Initial shale gas and shale oil exploration began in Mexico in late 2011. PEMEX has drilled at least six wells in the Eagle Ford Shale play in northern Mexico to date, but the southern shale basins have not yet been tested. Despite some areas with favorable shale geology, Mexico faces significant obstacles to shale development. The country's upstream oil industry is largely closed to foreign investment. None of the shale-discovering independent E&P's, which unlocked the North American shale plays, are active in Mexico. And, well services for shale development are costlier than in the U.S. and Canada.

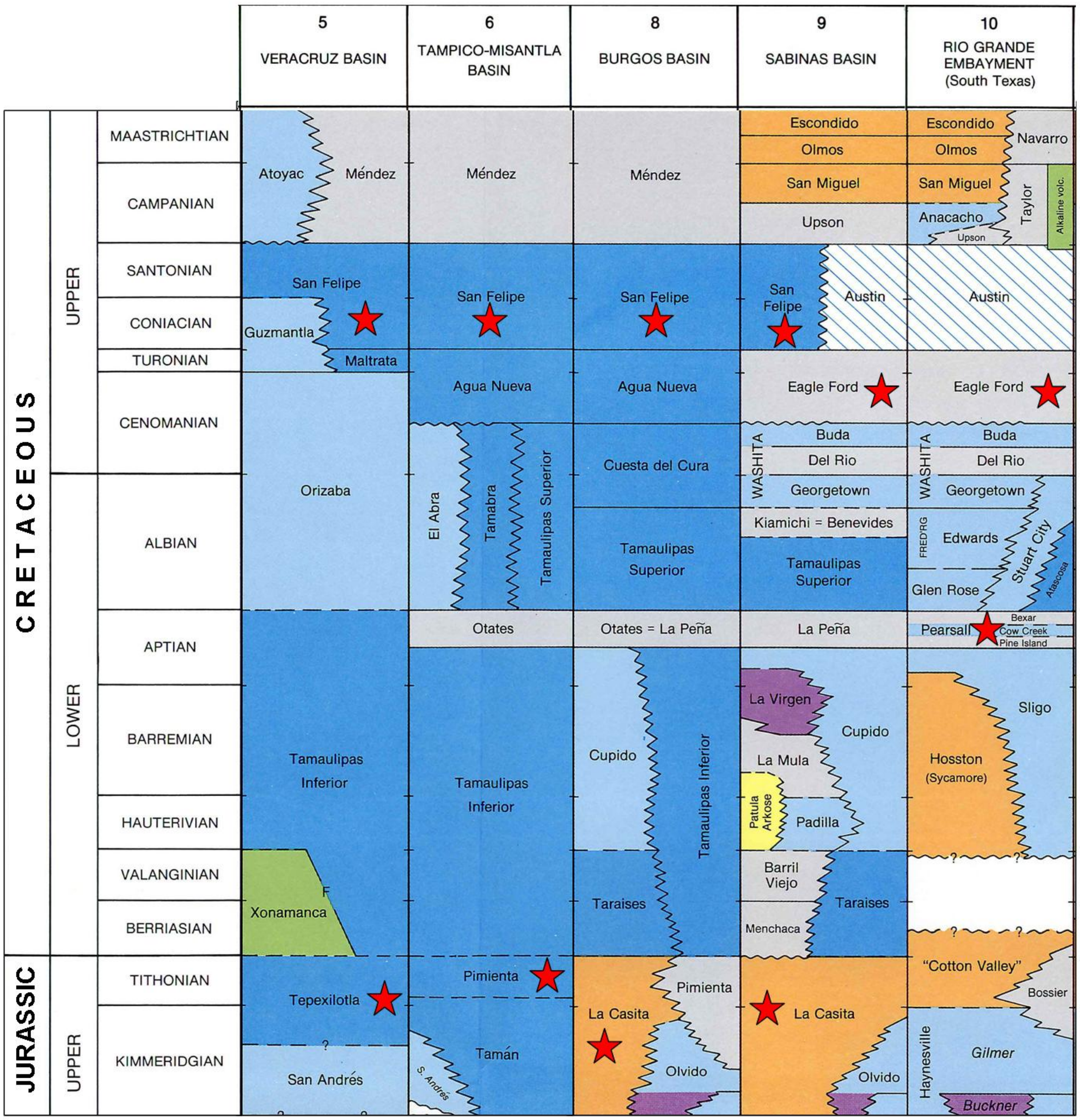
Onshore eastern Mexico contains a series of medium-sized basins and structural highs (platforms) within the larger western Gulf of Mexico Basin.[3] These structural features contain organic-rich marine shales of Jurassic and Cretaceous age that appear to be the most prospective for shale gas and oil development. The arcuate coastal shale belt includes the Burgos, Sabinas, Tampico, Tuxpan Platform, and Veracruz basins and uplifts. Because detailed geologic maps of these areas generally are not readily available, ARI constructed the general pattern of shale depth and thickness from a wide range of published local-scale maps and structural cross-sections.

Many of Mexico's shale basins are too deep in their center for shale gas and shale oil development (>5 km), while their western portions tend to be overthrusted and structurally complex. However, the less deformed eastern portions of these basins and adjacent shallower platforms are structurally more simple. Here, the most prospective areas for shale gas and shale oil development are buried at suitable depths of 1 km to 5 km over large areas.

Pyrolysis geochemistry, carbon isotope studies, and biomarker analysis of oil and gas fields identify three major Mesozoic hydrocarbon source rocks in Mexico's Gulf Coast Basin: the Upper Cretaceous (Turonian to Santorian), Lower-Mid Cretaceous (Albian-Cenomanian), and -- most importantly – Upper Jurassic (Tithonian), the latter having sourced an estimated 80% of the conventional oil and gas discovered in this region.[4] These targets, particularly the Tithonian, also appear to have the greatest potential for shale gas development, Figure II-4.

The following sections discuss the shale gas and shale oil geology of the individual sub-basins and platforms along eastern Mexico's onshore Gulf of Mexico Basin. The basins discussed start in northern Mexico near the Texas border moving to the south and southeastern regions close to the Yucatan Peninsula.

Figure II-4. Stratigraphy of Jurassic and Cretaceous rocks in the Gulf of Mexico Basin, Mexico and USA. Shale gas targets are highlighted.



Modified from Salvador and Quezada-Muneton, 1989.

1. BURGOS BASIN (Eagle Ford and Tithonian Shales)

1.1 Geologic Setting

Located in northeastern Mexico's Coahuila state, directly south of the Rio Grande River, the Burgos Basin covers an onshore area of approximately 24,200 mi^2, excluding its extension onto the continental shelf of the Gulf of Mexico, Figure II-5. The Burgos Basin is the southern extension of the Maverick Basin in Texas, the latter hosting the productive Eagle Ford and Pearsall shale plays.

The Burgos Basin expanded during the Early Jurassic and developed into a restricted carbonate platform, with thick salt accumulations that later formed a regional structural detachment as well as isolated diapirs. Structural deformation took place during the late Cretaceous Laramide Orogeny, resulting in some degree of faulting and tilting within the Burgos Basin. However, this tectonic event was focused more on the Sabinas Basin and Sierra Madre Oriental, while the Burgos remains structurally relatively simple and favorable for shale development.[5] Thick Tertiary-age clastic non-marine deposits overlie the Jurassic and Carbonate marine sequences, reflecting later alternating transgressions and regressions of sea level in northeastern Mexico.[6]

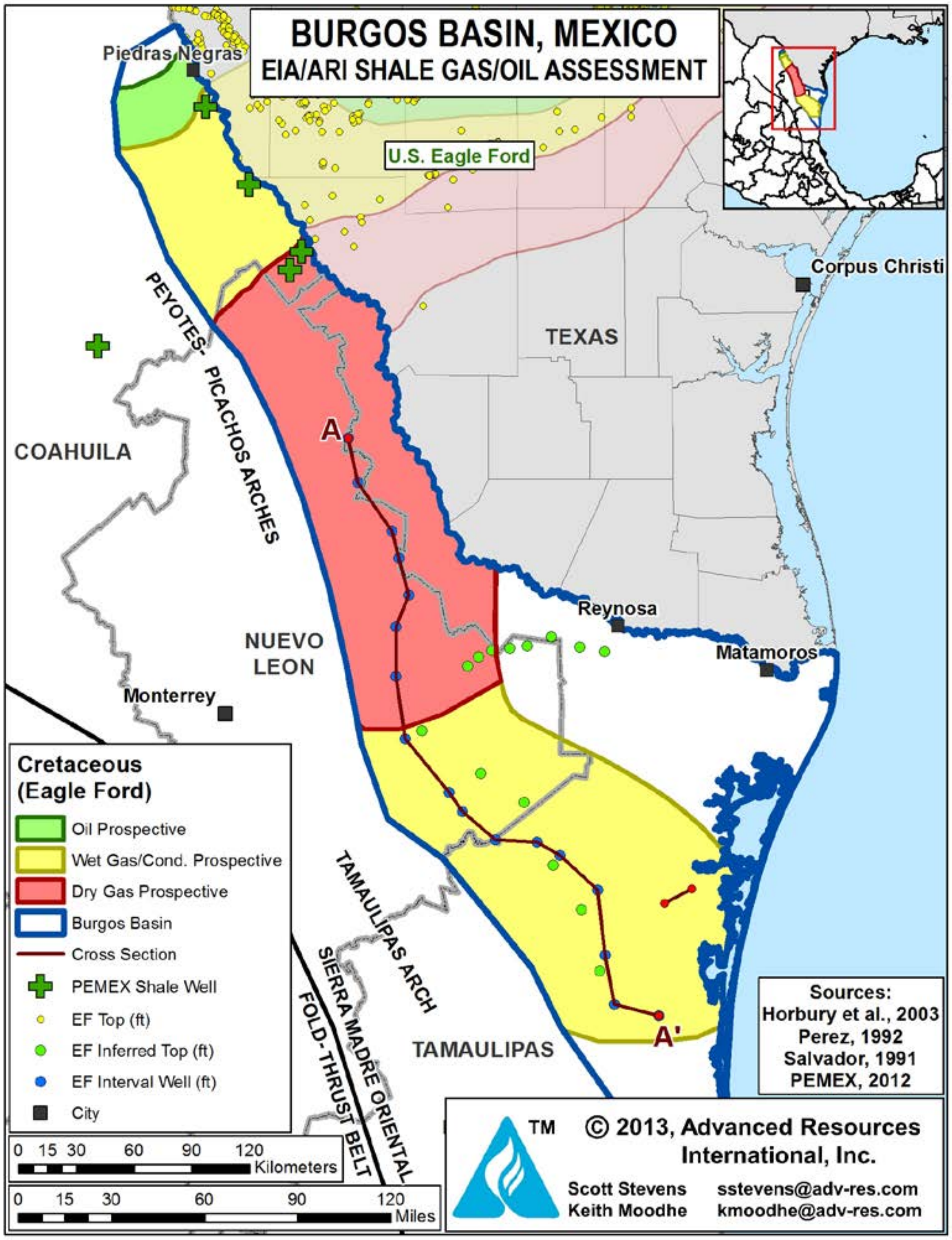
The two most prospective shale targets in Mexico are present in the Burgos Basin: the Cretaceous (mainly Turonian) Eagle Ford Shale play and the Jurassic (mainly Tithonian) La Casita and Pimienta formations, Figure II-6. The Eagle Ford Shale in Mexico is the direct extension of its commercially productive Texas equivalent, whereas the La Casita and Pimienta formations correlate with the productive Haynesville Shale of the East Texas Basin. The La Casita is believed to be the main source rock for conventional Tertiary clastic reservoirs (Oligocene Frio and Vicksburg) in the southeastern Burgos Basin, with oil transported via deep-seated normal faults.[7]

1.2 Reservoir Properties (Prospective Area)

Eagle Ford Shale. Based on analogy with the Eagle Ford Shale in Texas, industry and ARI considers the Eagle Ford Shale in the Burgos Basin to be Mexico's top-ranked shale prospect. The Eagle Ford Shale is continuous across the western margin of the Burgos Basin, where the overall formation interval ranges from 100 to 300 m thick (average 200 m).[8] Recognizing the sparse regional depth and thickness control on the Eagle Ford Shale in the

Burgos Basin,[9] we relied on a recent PEMEX shale map to estimate a prospective area of 17,300 mi², slightly less than our previous estimate of 18,100 mi², comprising three distinct areas where the shale lies within the 1 km to 5 km depth window, Figure II-5. The eastern onshore portion of the Burgos Basin is excluded as the shale is deeper than 5 km.

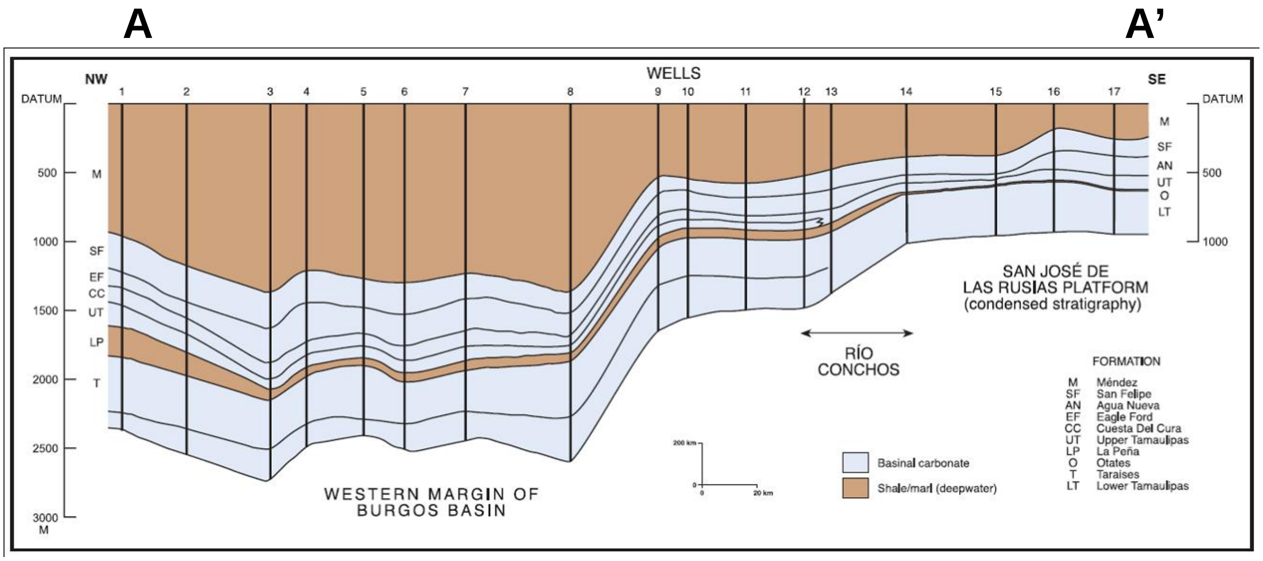
Figure II-5. Burgos Basin Outline and Shale Gas and Shale Oil Prospective Areas.



Source: ARI, 2013.

Figure II-6. Stratigraphic Cross-Section Along the Western Margin of the Burgos Basin.

Section is flattened on top Cretaceous.
The Eagle Ford Shale (EF) here ranges from about 100 to 300 m thick (average 200 m).



Modified from Horbury et al., 2003.

Net organically-rich shale thickness within the prospective area ranges from 200 to 300 ft. Total organic content (TOC) is estimated to average 5%. Vitrinite reflectance (R_o) ranges from 0.85% to 1.6% depending on depth. Over-pressured reservoir conditions are common in this basin and a pressure gradient of 0.65 psi/ft was assumed. The surface temperature in this region averages approximately 20°C, while the geothermal gradient typically is 23°C/km. Porosity is not known but assumed to be comparable to the Texas Eagle Ford Shale play at about 10%.

La Casita and Pimienta (Tithonian) Shales. Several thousand feet deeper than the Eagle Ford Shale, the La Casita and Pimienta shales (Upper Jurassic Tithonian) are considered the principal source rocks in the western Burgos Basin. Extrapolating from the structure of the younger Eagle Ford, the average depth of the Tithonian Shale is 11,500 ft, with a prospective range of 5,000 to 16,400 ft. Gross formation thicknesses can be up to 1,400 ft, with an organically rich net pay of about 200 ft. TOC of 2.6% to 4.0%, averaging 3.0%, consists mainly of Type II kerogen that appears to be entirely within the dry gas window (1.30% R_o) with little to no liquids potential.[10] Reservoir pressure and temperature conditions are similar to those in the Eagle Ford Shale play.

1.3 Resource Assessment

Eagle Ford Shale. Within its 17,300-mi^2 prospective area, the Eagle Ford Shale exhibits a high resource concentration of up to 191 Bcf/mi^2. Risked shale gas in-place (OGIP) totals 1,222 Tcf with risked shale oil in-place (OOIP) of 106 billion barrels. Risked, technically recoverable resources are estimated to be 343 Tcf of shale gas and 6.3 billion barrels of shale oil and condensate.

Tithonian Shale. Within the high-graded prospective area of 6,700 mi^2, the Tithonian La Casita and Pimienta shales are estimated to have approximately 50 Tcf of risked, technically recoverable dry gas resources from 202 Tcf of risked gas in-place. Resource concentration is about 100 Bcf/mi^2.

1.4 Recent Activity

PEMEX initiated conventional exploration in the Burgos Basin in 1942, discovering some 227 mostly natural gas fields in this basin to date. Currently, there are about 3,500 active natural gas wells producing in the Burgos Basin. These conventional reservoirs typically have low permeability with rapidly declining gas production. Due to restrictions on upstream oil and gas investment in Mexico, PEMEX is the only company that has conducted shale exploration activity in the Burgos Basin to date.

PEMEX made its first shale discovery in the Burgos Basin during late 2010 and early 2011, drilling the Emergente-1 shale gas well located a few kilometers south at the Texas/Coahuila border on a continuation of the Eagle Ford Shale trend from Texas. This initial horizontal well was drilled to a vertical depth of about 2,500 m and employed a 2,550-m lateral (although another source reported 1,364-m). Following a 17-stage fracture stimulation, the $20-25 million well tested at a modest initial rate of 2.8 million ft^3/day (time interval not reported), which would not be economic at current gas prices.[11]

As of its last report (November 2012), PEMEX had drilled four shale gas exploration wells in the Eagle Ford play of the Burgos Basin with one shale exploration well in the Sabinas basin, reporting initial production for three wells. These wells include the Nómada-1 well situated in the oil window, the Habano-1 well (IP 2.771 million ft^3/day gas with 27 bbl/day crude) and the Montañés-1 well in the wet gas window of the Burgos Basin. The dry gas window in the Burgos Basin was tested by the Emergente-1. The Percutor-1 (IP 2.17 million ft^3/day) tested the dry gas window in the Sabinas Basin. PEMEX has announced also drilled and produced gas from the Arbolero-1 well (3.2 million ft^3/day), the first test of the Jurassic shale in this basin.[12] PEMEX plans to drill up to 75 shale exploration wells in the Burgos Basin through 2015.

2. SABINAS BASIN (Eagle Ford and Tithonian Shales)

2.1 Geologic Setting

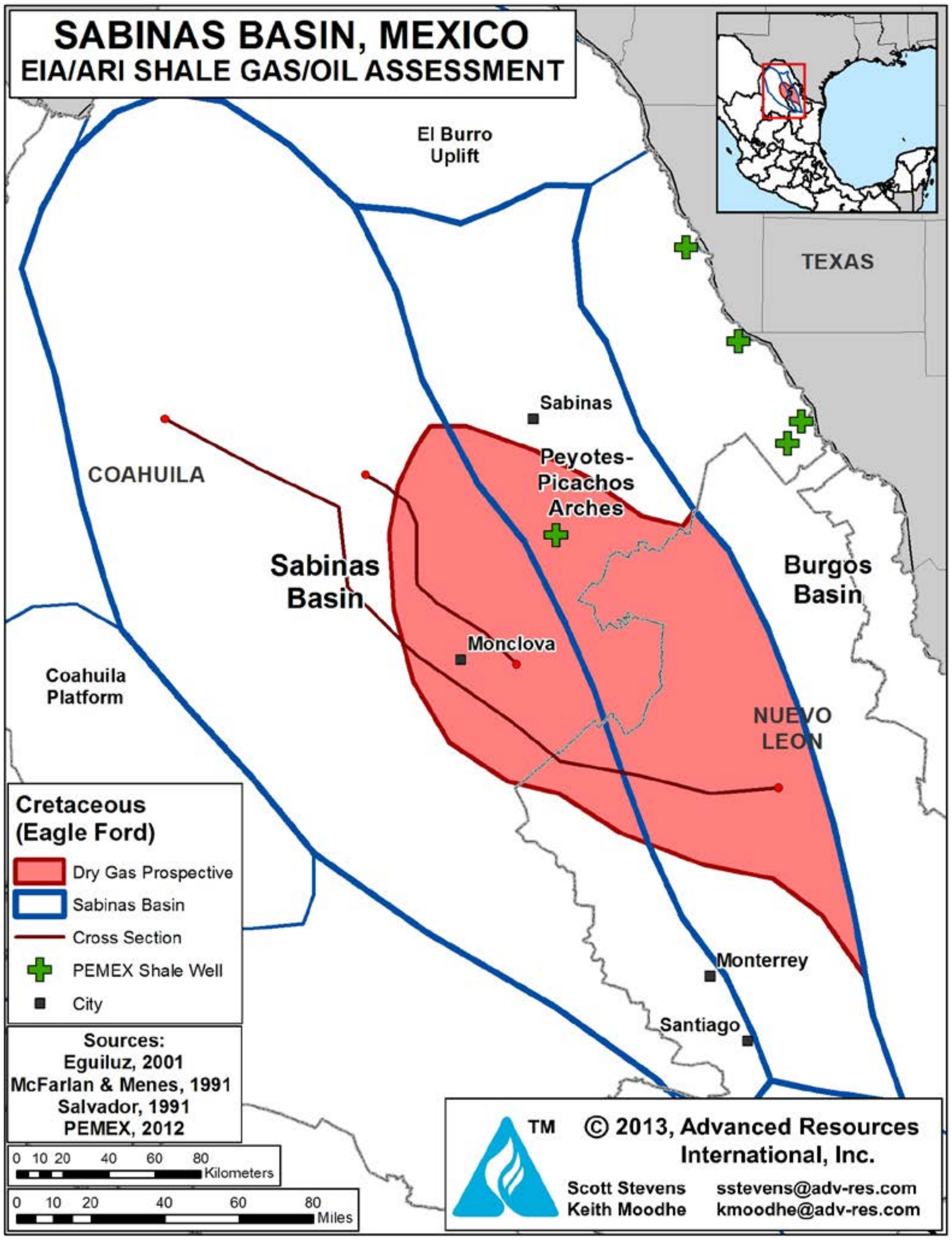
The Sabinas is one of Mexico's largest onshore marine shale basins, extending over a total area of 35,700 mi^2 in the northeast part of the country, Figure II-7. The basin initially expanded during Jurassic time with a northeast-southwest trending structural fabric and was later strongly affected by the Late Cretaceous Laramide Orogeny. Structurally complex, the Sabinas Basin has been deformed into a series of tight, NW-SE trending, evaporate-cored folds of Laramide origin called the Sabinas Foldbelt. Dissolution of Lower Jurassic salt during early Tertiary time introduced a further overprint of complex salt-withdrawal tectonics.[13] Much of the Sabinas Basin is too structurally deformed for shale gas development, but a small area on the northeast side of the basin is more gently folded and may be prospective.

Petroleum source rocks in the Sabinas Basin include the Cretaceous Olmos (Maastrichtian) and Eagle Ford Shale (Turonian) formations and the Late Jurassic (Tithonian) La Casita Formation. The latter two units contain marine shales with good petrophysical characteristics for shale development.[14] In contrast, the Olmos Formation is primarily a non-marine coaly unit that, while a good source rock for natural gas[15] as well as a coalbed methane exploration target in its own right,[16] appears to be too ductile for shale development.

2.2 Reservoir Properties (Prospective Area)

Eagle Ford Shale. The Eagle Ford Shale is distributed across the NW, NE, and central portions of the Sabinas Basin. The target is the 300-m thick sequence of black shales rhythmically interbedded with sandy limestone and carbonate-cemented sandstone. We estimated a 500-ft thick organic-rich interval with 400 feet of net pay. We considered the Eagle Ford Shale in the Maverick Basin of South Texas as the analog for reservoir properties, using a TOC of 4% and a thermal maturity of 1.50% (R_o). Our estimate of porosity was increased to 5% based on the rock fabric and correlation with the Texas Eagle Ford Shale analog. The average depth for the prospective Eagle Ford is approximately 9,000 feet. Based on reported data, mostly from coal mining areas, we use a slightly under-pressured gradient of 0.35 psi/ft for the Sabinas Basin.

Figure II-7. Sabinas Basin Outline and Shale Gas Prospective Area.



Source: ARI, 2013.

La Casita Formation. This Tithonian-age unit, regarded as the primary hydrocarbon source rock in the Sabinas Basin, consists of organic-rich shales deposited in a deepwater marine environment. The La Popa sub-basin is one of numerous sub-basins within the Sabinas Basin, Figure II-8.[17,18] The La Popa is a rifted pull-apart basin that contains thick source rock shales. Up to 370 m of black carbonaceous limestone is present overlying several km of evaporitic gypsum and halite. Total shale thickness in the La Casita ranges from 60 m to 800 m. Thick (300 m) and prospective La Casita Fm shales have been mapped at depths of 2,000 to 3,000 m in the central Sabinas Basin. Nearby, a thicker sequence (400-700 m) was mapped at greater depth (3,000 to 4,000 m).

The high-graded prospective area for the La Casita Formation averages 11,500 ft deep, about 2,500 ft deeper than the Eagle Ford Shale. The La Casita Formation averages about 240 ft of net pay thickness within an 800-ft thick organic-rich interval and has 2.0% average TOC that is gas prone (2.5% R_o). Our estimate of porosity in the La Casita was increased to 5% based on the rock fabric and correlation with the deep Texas and Louisiana Haynesville Shale analog.

2.3 Resource Assessment

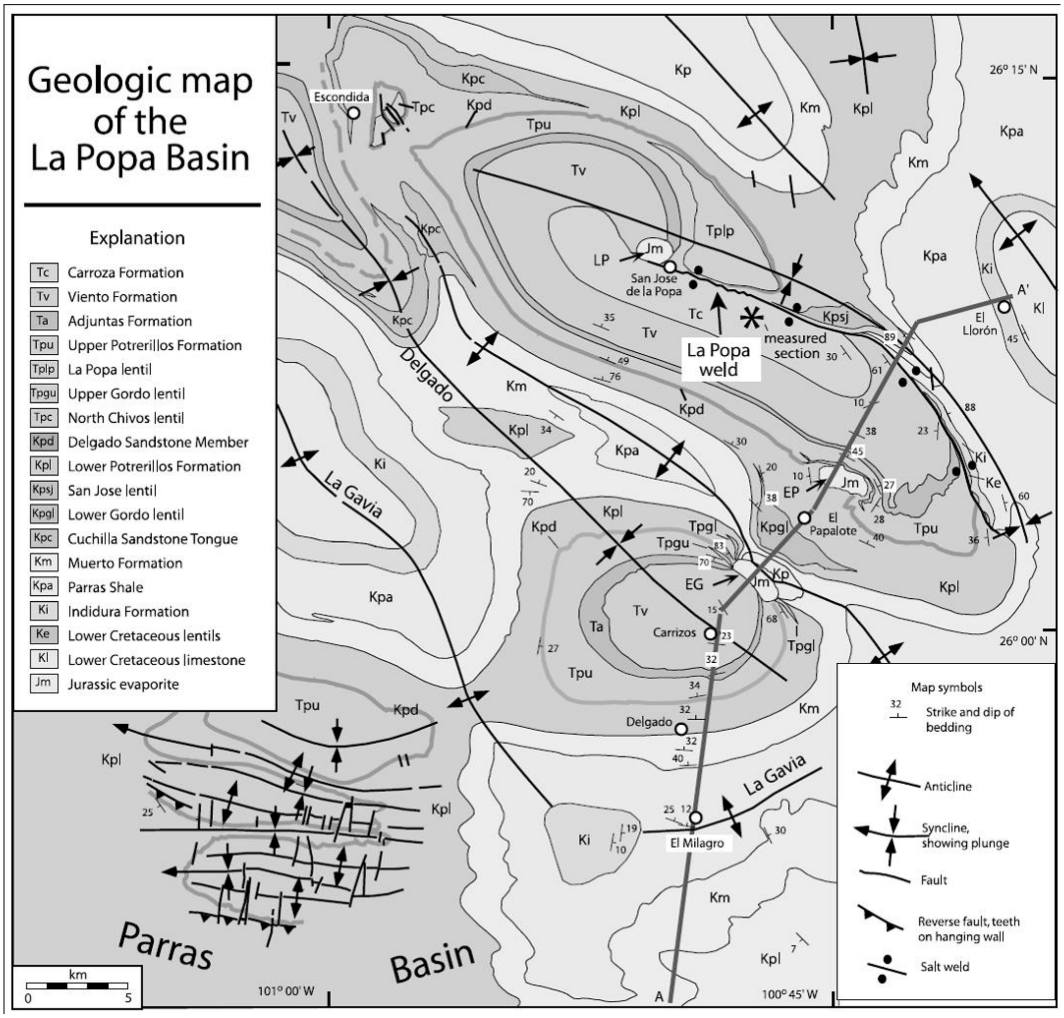
Eagle Ford Shale. The Eagle Ford Shale unit is the larger shale gas target in the Sabinas Basin, with an estimated 100 Tcf of technically recoverable shale gas resource out of 501 Tcf of risked shale gas in-place within the 9,500-mi^2 prospective area. The average resource concentration is high at 132 Bcf/mi^2.

La Casita Formation. The secondary target in the Sabinas Basin, the underlying La Casita Formation, has an estimated 24 Tcf of technically recoverable shale gas out of 118 Tcf of risked shale gas in-place. Its resource concentration is estimated at 69 Bcf/mi^2.

2.4 Recent Activity

PEMEX has drilled one shale gas exploration well in the Sabinas Basin, confirming the continuation of the Eagle Ford Shale play. The Percutor-1 horizontal well, completed in March 2012, produced dry gas from a sub-surface depth of 3,330-3,390 m. The well's initial production rate was a modest 2.17 million ft^3/day (measurement time interval not specified), with production reportedly declining rapidly.

Figure II-8. Geologic Map of the La Popa Sub-Basin, Southeastern Portion of the Sabinas Basin. Note the numerous detachment and salt-controlled folds.



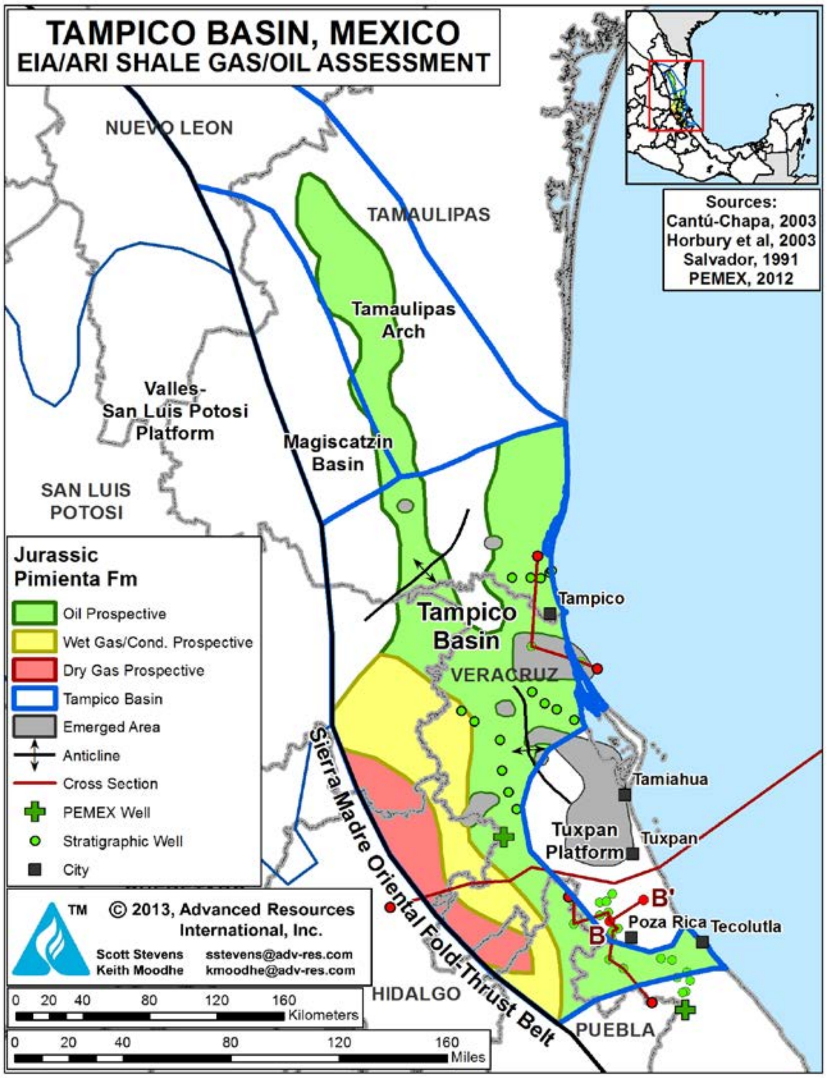
Source: Hudson and Hanson, 2010.

3. TAMPICO BASIN (Pimienta Shale)

3.1 Geologic Setting

Bounded on the west by the fold-and-thrust belt of the Sierra Madre Oriental (Laramide) and on the east by the Tuxpan platform, the Tampico-Mizatlan Basin extends north from the Santa Ana uplift to the Tamaulipas arch north of Tampico, Figure II-9. At the northern margin of the basin is an arch, limited by a series of faults extending south from the Tamaulipas arch.

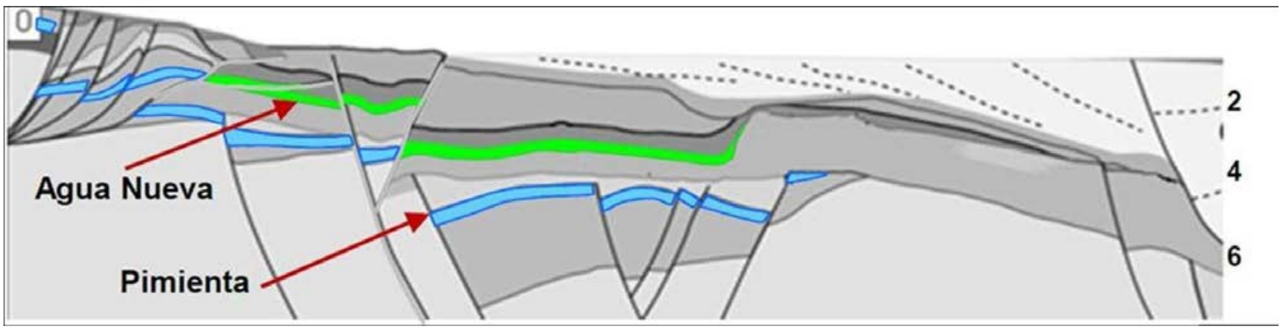
Figure II-9. Prospective Pimienta Formation (Tithonian) Shale, Tampico Basin.



Source: ARI, 2013.

The principal source rock in the Tampico Basin is the Upper Jurassic (Tithonian) Pimienta Shale, Figure II-10. Although quite deep over much of the basin, the Pimienta reaches shale-prospective depths of 1,400 to 3,000 m in the south where three uplifted structures occur. The 40-km long, NE-SW trending Piedra de Cal anticline in the southwest Bejuco area has Pimienta Shale cresting at 1,600-m depth. The 20-km long, SW-NE trending Jabonera syncline in southeast Bejuco has maximum shale depth of 3,000 m in the east and minimum depth of about 2,400 m in the west. A system of faults defines the Bejuco field in the center of the area. Two large areas (Llano de Bustos and La Aguada) lack upper Tithonian shale deposits.

Figure II-10. Structural Cross-Section of the Tampico Basin



Source: Escalera Alcocer, 2012.

3.2 Reservoir Properties

Near the city of Tampico, some 50 conventional wells have penetrated organic-rich shales of the Pimienta Formation at depths of about 1,000 to 3,000 m. Three distinct thermal maturity windows (dry gas, wet gas, and oil) occur from west to east, reflecting the gentle structural dip angle in this basin. Average shale depth ranges from 5,500 to 8,000 ft. Excluding the paleo highs, the prospective area of the Pimienta Shale totals approximately 13,600 mi^2. Detailed shale thickness data are not available, but the Pimienta Fm here generally ranges from 200 m thick to as little as 10 m thick on paleo highs. We estimate an average net shale thickness of about 200 ft, out of the total organically rich interval of 500 ft within the prospective area. Average net shale TOC is estimated at 3%, with average thermal maturity ranging from 0.85% to 1.4% R_o.

3.3 Resource Assessment

The Pimienta Shale in the Tampico Basin holds an estimated 23 Tcf and 5.5 billion barrels of risked, technically recoverable shale gas and shale oil resources, out of risked OOIP and OGIP of 151 Tcf and 138 billion barrels, respectively. The shale gas resource concentration averages 19 to 83 Bcf/mi^2 while the shale oil concentration averages 17 to 38 million bbl/mi^2.

3.4 Recent Activity

PEMEX reported that it is evaluating the shale geology of the Tampico Basin and plans to drill up to 80 shale exploration wells through 2015.[19]

4. TUXPAN PLATFORM (Pimienta and Tamaulipas Shales)

4.1 Geologic Setting

The Tuxpan Platform, located southeast of the Tampico Basin, is a subtle basement high that is capped with a well-developed Early Cretaceous carbonate platform.[20] A particularly prospective and relatively well defined shale gas deposit is located in the southern Tuxpan Platform. Approximately 50 km south of the city of Tuxpan, near Poza Rica, a dozen or so conventional petroleum development wells in the La Mesa Syncline area penetrated thick organic-rich shales of the Pimienta (Tithonian) and Tamaulipus (Lower Cretaceous) Formations.[21]

A detailed cross-section of the Tuxpan Platform shows thick Lower Cretaceous and Upper Jurassic source rocks dipping into the Gulf of Mexico Basin, Figure II-11. These source rocks reach prospective depths of 2,500 m. Thermal maturity ranges from oil- to gas-prone.

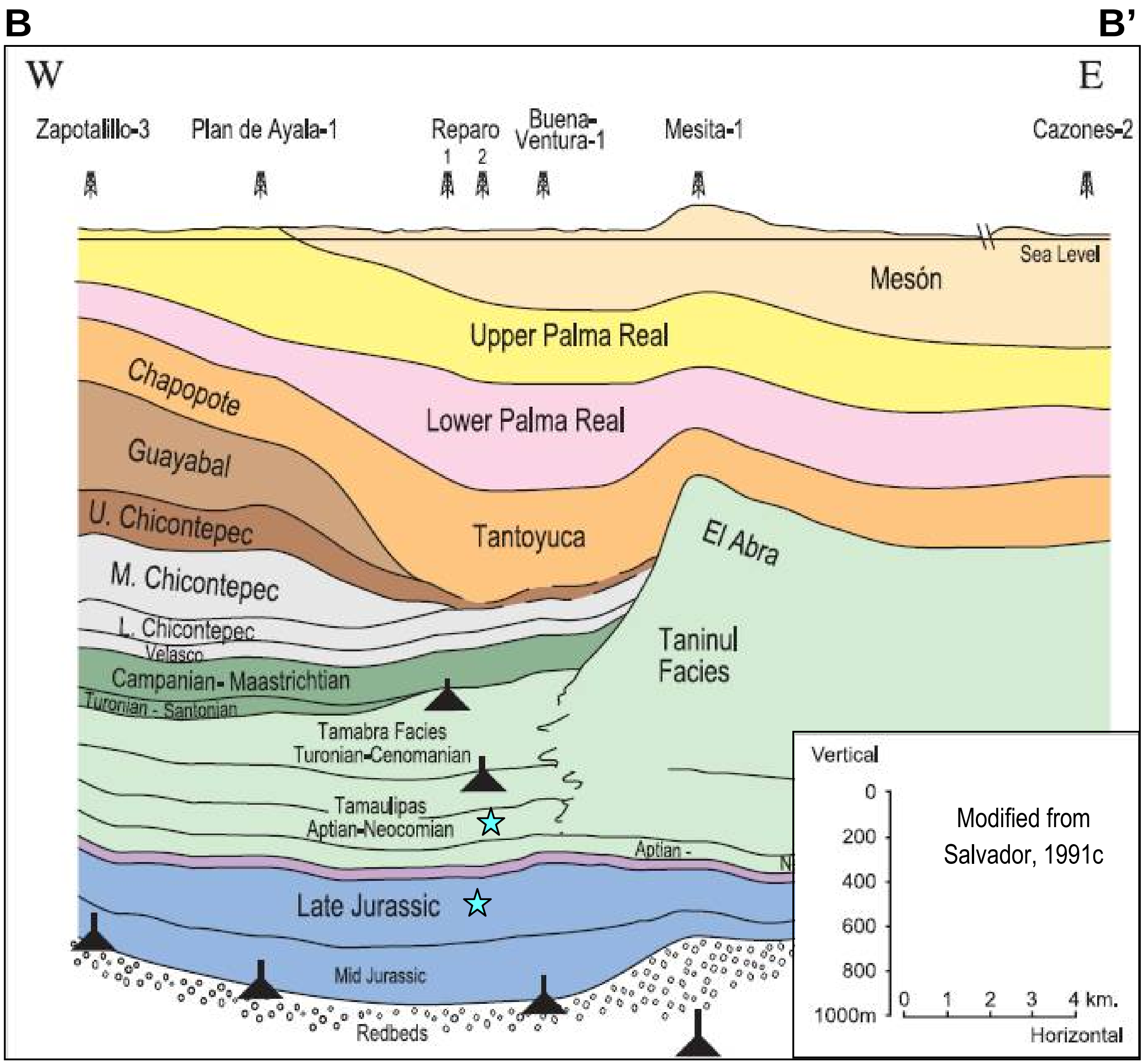
4.2 Reservoir Properties (Prospective Area)

Pimienta Fm. The organically rich portion of the Jurassic Pimienta Shale averages about 500 ft thick in the high-graded area, with net thickness estimated at 200 ft. However, southeast of Poza Rica some areas the shale is thin or absent, probably due to submarine erosion or lack of deposition, Figure 12. The gamma ray log response in the organic-rich Pimienta Shale indicates moderate TOC of 3.0%, which is in the oil to wet gas window (average R_o of 0.9%). Depth ranges from 6,600 to 10,000 ft, averaging about 8,500 ft.

Advanced Resources International, Inc.

Tamaulipas Fm. The Lower Cretaceous Tamaulipas Fm spans a depth range of 6,000 to 9,500, averaging about 7,900 ft. The organic-rich interval averages 300 ft thick, with net pay estimated at about 210 ft. TOC is estimated to be 3.0%. The average thermal maturity is slightly lower than for the deeper Pimienta, at 0.85% R_o.

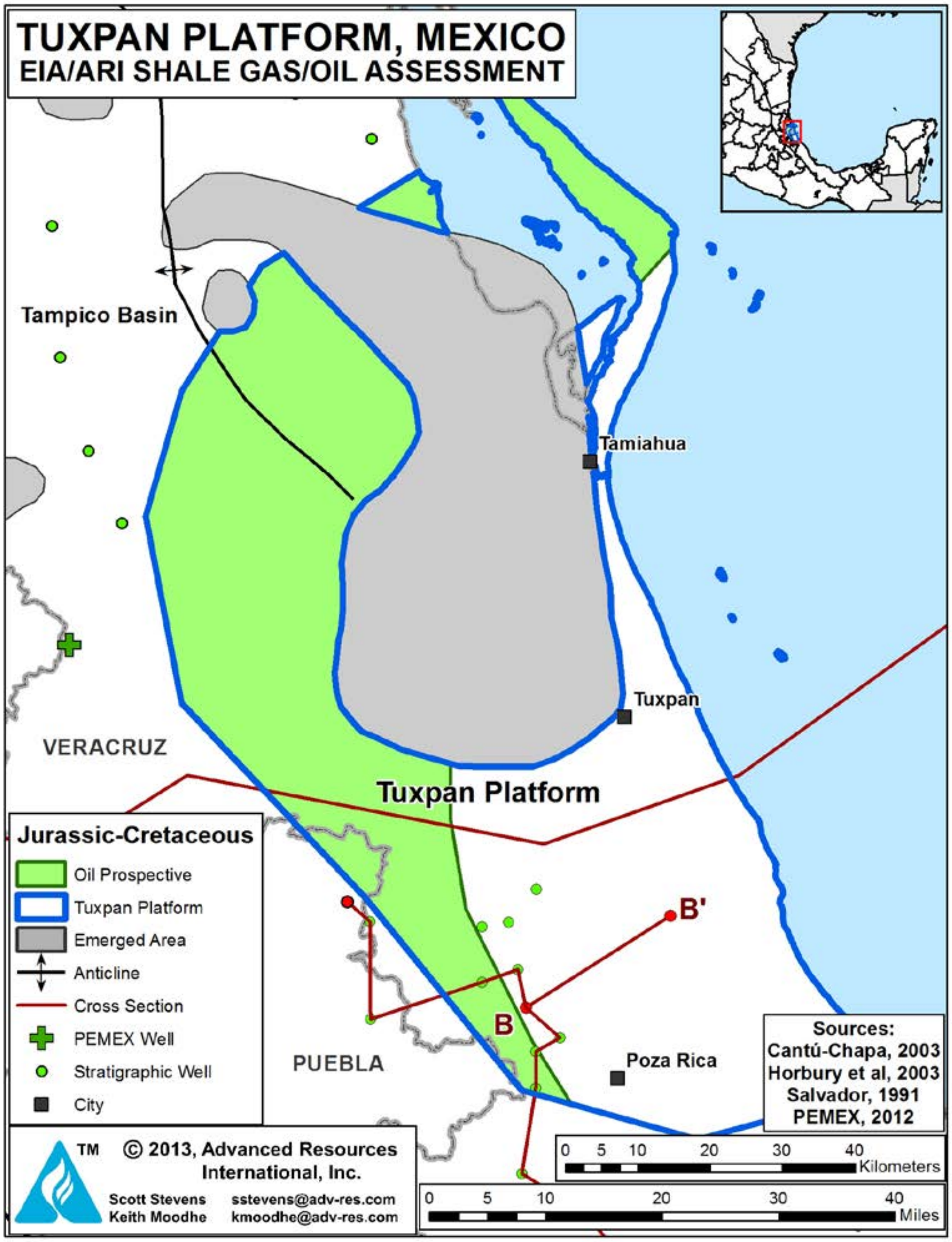
Figure II-11. Cross-Section of the Tuxpan Platform.



Modified from Salvador, 1991c.

Advanced Resources International, Inc.

Figure II-12. Potentially Prospective Shale Gas and Shale Oil Areas of the Tuxpan Platform.



Source: ARI, 2013.

4.3 Resource Assessment

Pimienta Fm. In the Tuxpan Platform, the prospective area of the Pimienta Fm shale is estimated to be approximately 1,000 mi^2. Risked, technically recoverable resources are estimated to be about 1 Tcf of shale gas and 0.5 billion barrels of shale oil and condensate. Risked shale resource in-place is estimated at 10 Tcf and 12 billion barrels.

Tamaulipas Fm. Due to limited data on the younger Tamaulipas Fm the same prospective area of the Pimienta Shale was assumed (1,000 mi^2). The Tamaulipas Shale is estimated to have risked technically recoverable resources of about 1 Tcf of shale gas and 0.5 billion barrels of shale oil and condensate, out of risked shale resources in-place of 9 Tcf and 13 billion barrels.

4.4 Recent Activity

No shale gas or oil exploration activity has been reported on the Tuxpan Platform.

5. VERACRUZ BASIN (Maltrata Shale)

5.1 Geologic Setting

The Veracruz Basin extends over an onshore area of 9,030 mi^2, near its namesake city. The basin's western margin is defined by thrusted Mesozoic carbonates (early Tertiary Laramide Orogeny) of the Cordoba Platform and Sierra Madre Oriental, Figure II-13. The basin is asymmetric in cross section, with gravity showing the deepest part along the western margin, Figure II-14.[22] The basin comprises several major structural elements, from west to east: the Buried Tectonic Front, Homoclinal Trend, Loma Bonita Anticline, Tlacotalpan Syncline, Anton Lizardo Trend, and the highly deformed Coatzacoalcos Reentrant in the south.[23]

A recent shale exploration map released by PEMEX indicates the prospective area of the Veracruz Basin is much smaller than previously assumed in the 2011 EIA/ARI study. This is because the shale is shown to be dipping at a steeper angle than previously mapped. In addition, both shale gas and oil thermal maturity windows are present.

5.2 Reservoir Properties (Prospective Area)

Maltrata Fm. The Upper Cretaceous (Turonian) Maltrata Formation is a significant source rock in the Veracruz Basin, containing an estimated 300 ft of organic-rich, shaly marine limestone. TOC ranges from 0.5% to 8%, averaging approximately 3%, and consists of Type II kerogen. Thermal maturity ranges from oil-prone (R_o averaging 0.85%) within the oil window at depths of less than 11,000 ft, to gas-prone (R_o averaging 1.4%) within the gas window at average depths below 11,500 ft.

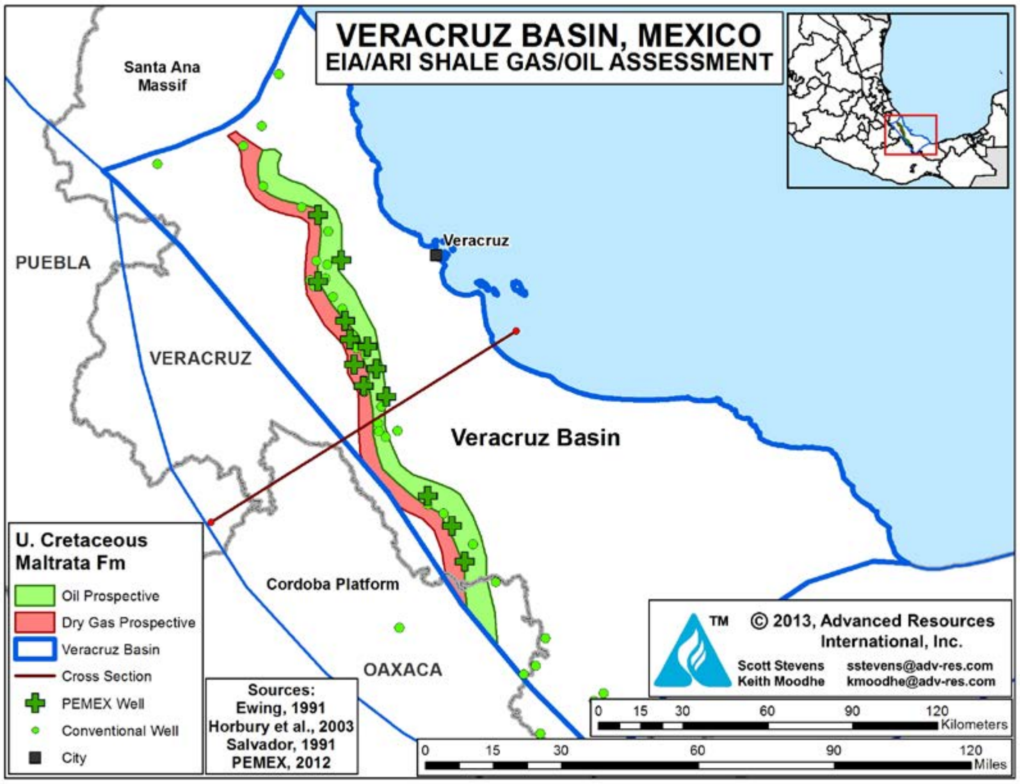
5.3 Resource Assessment

Maltrata Fm. Whereas we previously had assumed that 90% of the Veracruz Basin (8,150 mi^2) is in a favorable depth range, based on available cross-sectional data, the new PEMEX map indicates that the true prospective area in the Veracruz Basin could be much smaller, perhaps only 960 mi^2. This yields a reduced estimate of 3 Tcf and 0.3 billion barrels of risked technically recoverable shale gas and shale oil resources for the Maltrata Formation in the Veracruz Basin, out of 21 Tcf and 7 billion barrels of risked shale gas and shale oil in-place.

5.4 Recent Activity

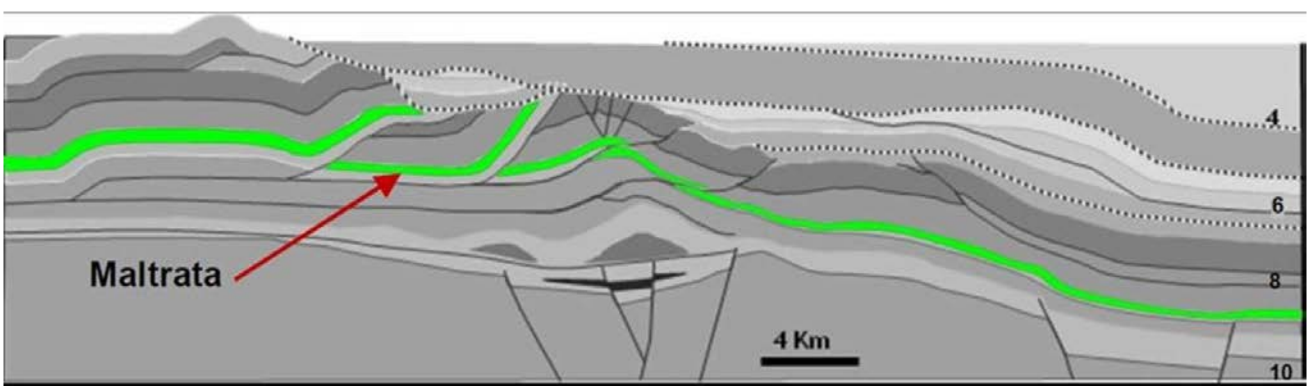
PEMEX plans to drill up to 10 shale exploration wells in the Veracruz Basin in the next three years.

Figure II-13. Veracruz Basin Outline and Shale Gas and Shale Oil Prospective Area.



Source: ARI, 2013.

Figure II-14. Veracruz Basin Cross Section Showing the Maltrata Shale



Source: Escalera Alcocer, 2012.

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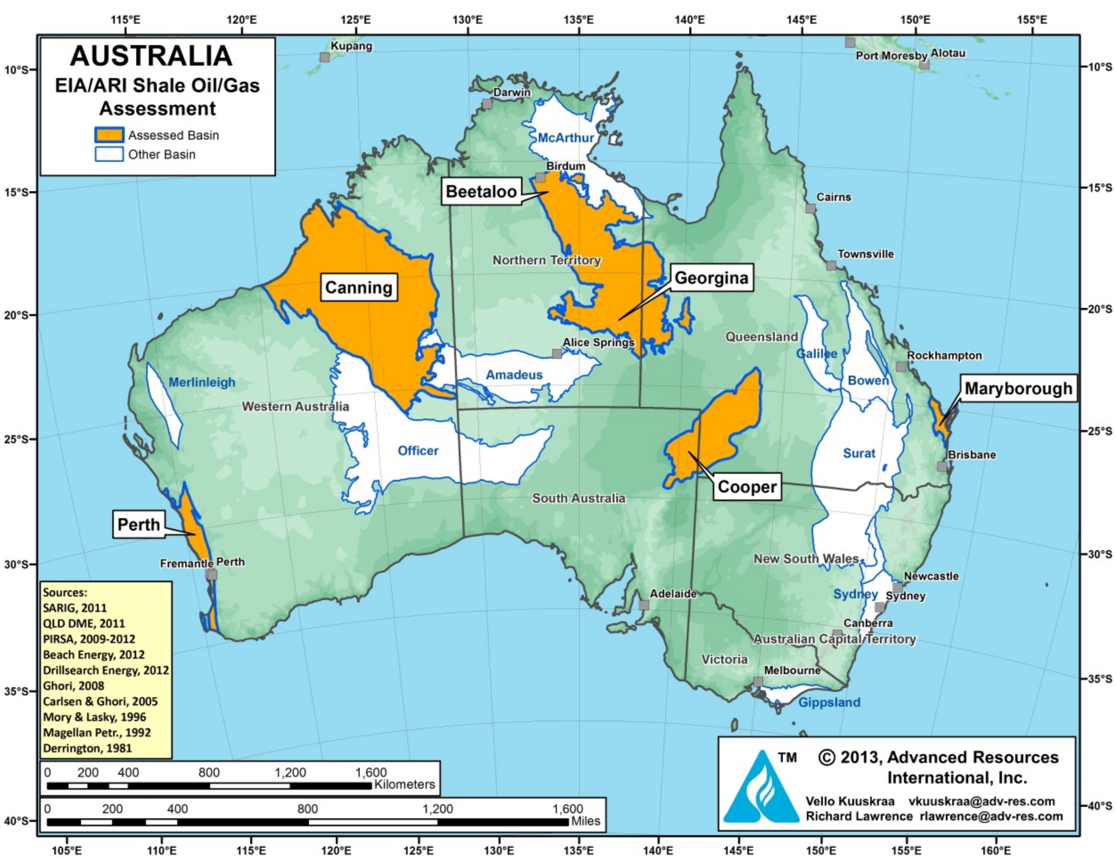
III. AUSTRALIA

SUMMARY

With geologic and industry conditions resembling those of the USA and Canada, Australia has the potential to be one of the next countries with commercially viable shale gas and shale oil production. As in the US, small independents have led the way, assembling the geological data and exploring the high potential shale basins of Australia, Figure III-1. International majors are now entering these plays by forming JV partnerships with these smaller independents, bring capital investment to the table. But, with the remoteness of many of Australia's shale gas and shale oil basins, development will likely proceed at a moderate pace.

Figure III-1. Australia's Assessed Prospective Shale Gas and Shale Oil Basins



Source: ARI, 2013

This report assesses the shale gas and shale oil potential in six major Australian sedimentary basins having sufficient geologic data for a quantitative assessment. Additional potential is likely to exist in other basins not yet assessed.

The six assessed shale gas and oil basins of Australia hold an estimated 2,046 Tcf of risked shale gas in-place, with 437 Tcf as the risked, technically recoverable shale gas resource, Tables III-1A, III-1B, and III-1C. These six basins also hold an estimated 403 billion barrels of risked shale oil in-place, with 17.5 billion barrels as risked, technically recoverable shale oil resource, Tables III-2A and III-2B.

Of the six assessed basins, the Cooper Basin, Australia's main onshore gas-producing basin, with its existing gas processing facilities and transportation infrastructure, could be the first commercial source of shale hydrocarbons. The basin's Permian-age shales have a non-marine (lacustrine) depositionals and the shale gas appears to have elevated CO_2 content, both factors adding risk to these shale gas and shale oil plays. Santos, Beach Energy and Senex Energy are testing the shale reservoirs in the Cooper Basin, with initial results from vertical production test wells providing encouragement for further delineation.

The other prospective Australian shale basins addressed in this report include the small, scarcely explored Maryborough Basin in coastal Queensland, that contains prospective Cretaceous-age marine shales thought to be over-pressured and gas saturated. The Perth Basin in Western Australia, undergoing initial testing by AWE and Norwest Energy, has prospective marine shale targets of Triassic and Permian age. The large Canning Basin in Western Australia has deep, Ordovician-age marine shales that are roughly correlative with the Bakken Shale in the Williston Basin. In Northern Territory, the Pre-Cambrian shales in the Beetaloo Basin and the Middle Cambrian shale in the Georgina Basin have reported oil and gas shows in shale exploration wells. If proved commercial, these two shale gas and shale oil basins would become some of the oldest producing hydrocarbon source rocks in the world.

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Table III-1A. Australian Shale Gas Reservoir Properties and Resources (Page 1 of 3)

Gas Resources

Basic Data	Basin/Gross Area		Cooper (46,900 mi^2)						
	Shale Formation		Roseneath-Epsilon-Murteree (Nappamerri)			Roseneath-Epsilon-Murteree (Patchawarra)			Roseneath-Epsilon-Murteree (Tenappera)
	Geologic Age		Permian			Permian			Permian
	Depositional Environment		Lacustrine			Lacustrine			Lacustrine
Physical Extent	Prospective Area (mi^2)		625	555	3,525	1,010	1,150	170	200
	Thickness (ft)	Organically Rich	250	500	500	125	100	100	225
		Net	150	300	300	75	60	60	135
	Depth (ft)	Interval	5,000 - 7,000	6,000 - 10,000	7,000 - 13,000	7,000 - 9,200	8,000 - 10,000	8,000 - 13,000	5,000 - 6,500
		Average	6,000	8,000	10,000	8,000	9,000	10,500	5,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%
	Thermal Maturity (% Ro)		0.85%	1.15%	2.00%	0.85%	1.15%	1.30%	0.85%
	Clay Content		Low	Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		13.1	87.6	100.1	7.3	15.6	18.6	10.1
	Risked GIP (Tcf)		6.1	36.5	264.7	4.4	10.8	1.9	1.2
	Risked Recoverable (Tcf)		0.7	9.1	79.4	0.4	2.7	0.5	0.1

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Table III-1B. Australian Shale Gas Reservoir Properties and Resources (Con't) (Page 2 of 3)

Gas Resources

Basic Data	Basin/Gross Area		Maryborough (4,290 mi^2)	Perth (20,000 mi^2)			Canning (181,000 mi^2)		
	Shale Formation		Goodwood/Cherwell Mudstone	Carynginia	Kockatea		Goldwyer		
	Geologic Age		Cretaceous	U. Permian	L. Triassic		M. Ordovician		
	Depositional Environment		Marine	Marine	Marine		Marine		
Physical Extent	Prospective Area (mi^2)		1,540	2,200	860	1,030	14,900	19,620	22,860
	Thickness (ft)	Organically Rich	1,250	950	300	300	1,000	1,300	1,300
		Net	250	250	160	160	250	250	250
	Depth (ft)	Interval	5,000 - 16,500	3,300 - 16,500	3,300 - 15,100	9,200 - 16,500	3,300 - 7,200	7,200 - 10,500	10,500 - 16,500
		Average	9,500	10,000	9,200	11,000	5,200	8,800	13,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	4.0%	5.6%	5.6%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		1.50%	1.40%	0.85%	1.15%	0.85%	1.15%	1.40%
	Clay Content		Low	Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Assoc. Gas	Wet Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		110.7	94.0	14.0	58.9	18.7	67.1	109.2
	Risked GIP (Tcf)		63.9	124.1	7.2	36.4	83.5	395.0	748.7
	Risked Recoverable (Tcf)		19.2	24.8	0.6	7.3	6.7	79.0	149.7

Table III-1C. Australian Shale Gas Reservoir Properties and Resources (Con't) (Page 3 of 3)

Gas Resources

Basic Data	Basin/Gross Area		Georgina (125,000 mi²)					Beetaloo (14,000 mi²)					
	Shale Formation		L. Arthur Shale (Dulcie Trough)		L. Arthur Shale (Toko Trough)			M. Velkerri Shale			L. Kyalla Shale		
	Geologic Age		M. Cambrian		M. Cambrian			Precambrian			Precambrian		
	Depositional Environment		Marine		Marine			Marine			Marine		
Physical Extent	Prospective Area (mi^2)		2,260	1,950	3,220	2,010	790	2,650	2,130	2,480	4,010	2,400	1,310
	Thickness (ft)	Organically Rich	115	115	65	65	65	450	450	450	520	520	520
		Net	85	85	50	50	50	100	100	100	130	130	130
	Depth (ft)	Interval	7,200 - 10,500	2,300 - 3,300	3,300 - 4,000	4,000 - 5,000	5,000 - 6,500	3,300 - 5,000	5,000 - 7,000	7,000 - 8,700	3,300 - 5,000	5,000 - 6,000	6,000 - 8,000
		Average	8,800	3,000	3,600	4,500	5,700	4,200	6,000	7,500	4,200	5,500	6,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.0%	5.5%	5.5%	5.5%	5.5%	4.0%	4.0%	4.0%	2.5%	2.5%	2.5%
	Thermal Maturity (% Ro)		1.15%	1.50%	0.85%	1.15%	1.50%	0.85%	1.15%	1.60%	0.85%	1.15%	1.60%
	Clay Content		Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		22.8	29.1	4.5	17.5	26.7	7.2	30.7	42.0	11.7	37.1	49.6
	Risked GIP (Tcf)		19.3	21.3	5.5	13.2	7.9	9.6	32.7	52.0	23.5	44.5	32.5
	Risked Recoverable (Tcf)		3.9	4.3	0.4	2.6	1.6	1.0	8.2	13.0	2.3	11.1	8.1

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Table III-2A. Australian Shale Oil Reservoir Properties and Resources (Con't) (Page 1 of 2)

Oil Resources

Basic Data	Basin/Gross Area		Cooper (46,900 mi²)					Perth (20,000 mi²)		Canning (181,000 mi²)	
	Shale Formation		Roseneath-Epsilon-Murteree (Nappamerri)		Roseneath-Epsilon-Murteree (Patchawarra)		Roseneath-Epsilon-Murteree (Tenappera)	Kockatea		Goldwyer	
	Geologic Age		Permian		Permian		Permian	L. Triassic		M. Ordovician	
	Depositional Environment		Lacustrine		Lacustrine		Lacustrine	Marine		Marine	
Physical Extent	Prospective Area (mi²)		625	555	1,010	1,150	200	860	1,030	14,900	19,620
	Thickness (ft)	Organically Rich	250	500	125	100	225	300	300	1,000	1,300
		Net	150	300	75	60	135	160	160	250	250
	Depth (ft)	Interval	5,000 - 7,000	6,000 - 10,000	7,000 - 9,200	8,000 - 10,000	5,000 - 6,500	3,300 - 15,100	9,200 - 16,500	3,300 - 7,200	7,200 - 10,500
		Average	6,000	8,000	8,000	9,000	5,500	9,200	11,000	5,200	8,800
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.6%	2.6%	2.6%	2.6%	2.6%	5.6%	5.6%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	0.85%	0.85%	1.15%	0.85%	1.15%
	Clay Content		Low	Low	Low	Low	Low	Low	Low	Low	Low
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Oil	Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi²)		22.5	14.5	11.1	3.0	21.9	18.9	6.1	41.1	10.2
	Risked OIP (B bbl)		10.5	6.0	6.7	2.1	2.6	9.8	3.8	183.7	60.0
	Risked Recoverable (B bbl)		0.63	0.36	0.34	0.10	0.13	0.39	0.15	7.35	2.40

Table III-2B. Australian Shale Oil Reservoir Properties and Resources (Con't) (Page 2 of 2)

Oil Resources

Basin/Gross Area		Georgina ($125,000\ mi^2$)			Beetaloo ($14,000\ mi^2$)			
Shale Formation		L. Arthur Shale (Dulcie Trough)	L. Arthur Shale (Toko Trough)		M. Velkerri Shale		L. Kyalla Shale	
Geologic Age		M. Cambrian	M. Cambrian		Precambrian		Precambrian	
Depositional Environment		Marine	Marine		Marine		Marine	
Prospective Area (mi^2)		2,260	3,220	2,010	2,650	2,130	4,010	2,400
Thickness (ft)	Organically Rich	115	65	65	450	450	520	520
	Net	85	50	50	100	100	130	130
Depth (ft)	Interval	7,200 - 10,500	3,300 - 4,000	4,000 - 5,000	3,300 - 5,000	5,000 - 7,000	3,300 - 5,000	5,000 - 6,000
	Average	8,800	3,600	4,500	4,200	6,000	4,200	5,500
Reservoir Pressure		Normal	Normal	Normal	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
Average TOC (wt. %)		3.0%	5.5%	5.5%	4.0%	4.0%	2.5%	2.5%
Thermal Maturity (% Ro)		1.15%	0.85%	1.15%	0.85%	1.15%	0.85%	1.15%
Clay Content		Low	Low	Low	Low	Low	Low	Low
Oil Phase		Condensate	Oil	Condensate	Oil	Condensate	Oil	Condensate
OIP Concentration ($MMbbl/mi^2$)		3.5	14.7	5.2	16.7	5.3	27.1	8.9
Risked OIP (B bbl)		2.9	17.7	3.9	22.1	5.7	54.4	10.7
Risked Recoverable (B bbl)		0.12	0.71	0.16	1.11	0.28	2.72	0.54

1. COOPER BASIN

1.1 Introduction

Straddling the South Australia and Queensland border, the Cooper Basin has been Australia's main onshore oil and gas supply region for the past several decades.[1] Within the basin, the Nappamerri Trough contains thick, overpressured and organic-rich shales at prospective depth. The Cooper Basin already has service industry capacity for well drilling and hydraulic fracturing that could be used to develop the prospective shale reservoirs in this basin.

However, while overall the Cooper Basin appears favorable for shale development, a key risk remains in that the shales were deposited in a lacustrine (not marine) environment. Lacustrine shales often have higher clay contents with uncertainty on how the shales will respond to hydraulic stimulation treatments, in comparison with lower clay content marine shales. In addition, high CO_2 volumes have been noted in the deeper troughs in this basin.

1.2 Geologic Setting

The Cooper Basin is a Gondwana intracratonic basin containing non-marine Late Carboniferous to Middle Triassic strata, which include prospective Permian-age shales. Following an episode of regional uplift and erosion during the late Triassic, the Cooper Basin continued to gently subside. The Paleozoic sequence was unconformably overlain by up to 1.3 km of Jurassic to Tertiary deltaic deposits of the Eromanga Basin which contain the basin's conventional sandstone reservoirs.[2]

Extending over a total area of about 130,000 km^2, the Cooper Basin contains three major deep troughs with shale gas and shale oil potential - - Nappamerri, Patchawarra (including the Arrabury Trough) and Tenappera, Figure III-2. These troughs are separated by faulted structural highs from which Permian shale-bearing strata have largely been eroded, Figure III-3.[3,4]

The prospective areas within the Cooper Basin's troughs are large, thermally mature and overpressured. Depth to the Permian horizon ranges from 5,000 feet at the southern end of the basin to 13,000 feet in the center. Nearly the entire areal extent of the Nappamerri and Patchawarra troughs, as well as the Tenappera Trough in the south, appear depth-prospective for shale development. Furthermore, relatively little faulting occurs within these troughs as structural deformation is confined largely to uplifted ridges, Figure III-3.

Figure III-2: Major Structural Elements of the Southern Cooper Basin.

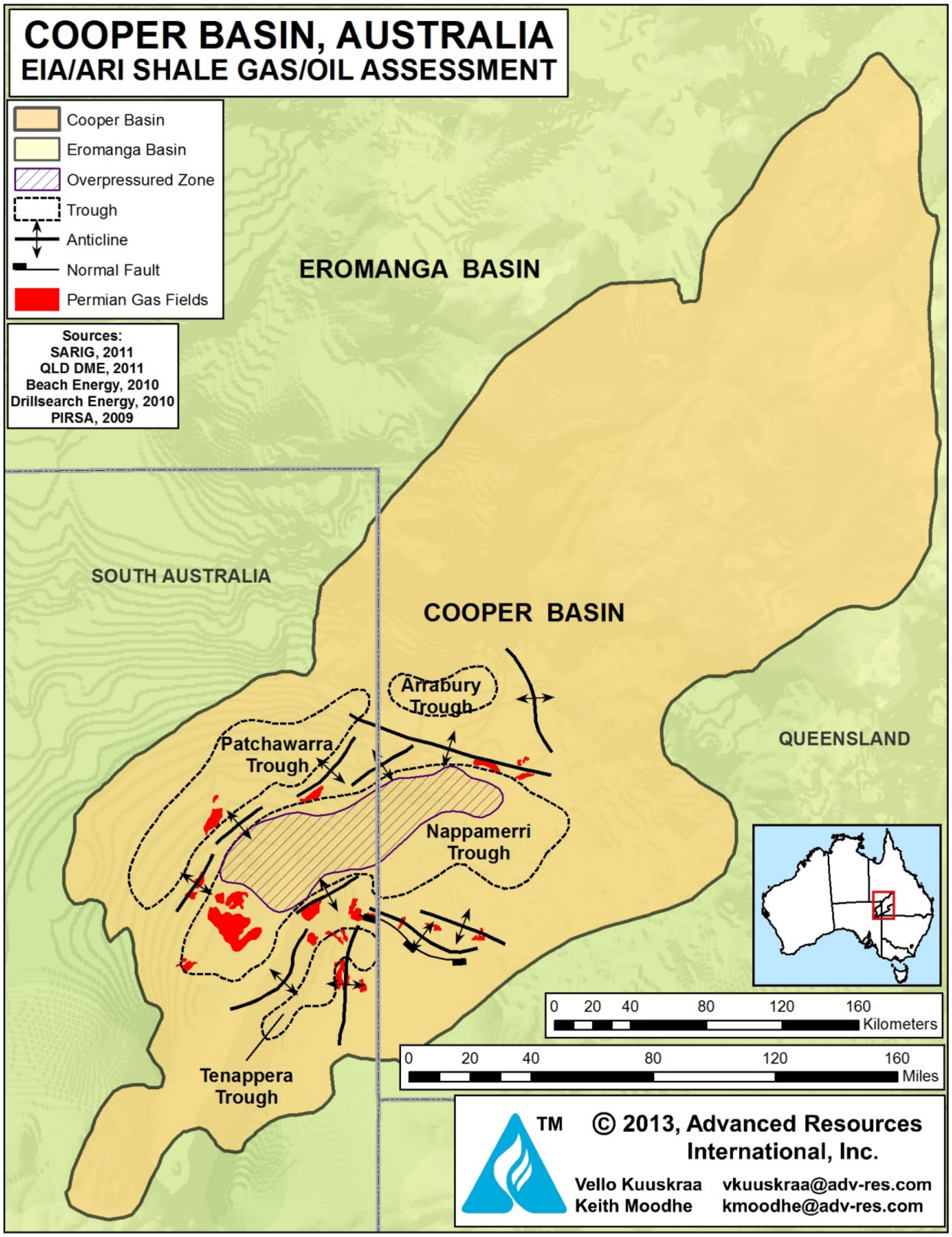
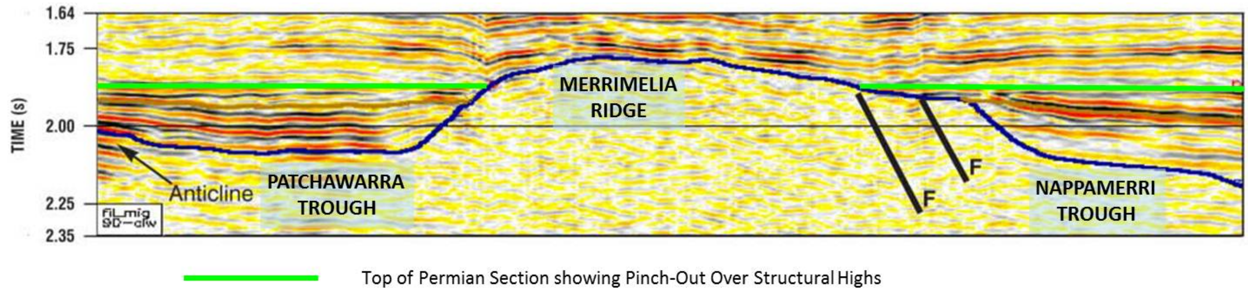


Figure III-3. Seismic Section Across the Merrimelia Ridge



(Adapted from Menpes, 2012)

The stratigraphy of the Cooper Basin is shown in Figure III-4. Conventional and tight sandstone oil and gas reservoirs are found in the Patchawarra and Toolachee formations, interbedded with coal deposits. These formations were sourced by two complexes - - the Late Carboniferous to Late Permian Gidgealpa Group and the Late Permian to Middle Triassic Nappamerri Group, both of which were deposited in non-marine settings. Of the two source rocks, the Gidgealpa Group is more prospective. Most of the gas generated by the Nappamerri Group likely came from its multiple, thin and discontinuous coal seams, since the shales in the Nappamerri Group are low in TOC.

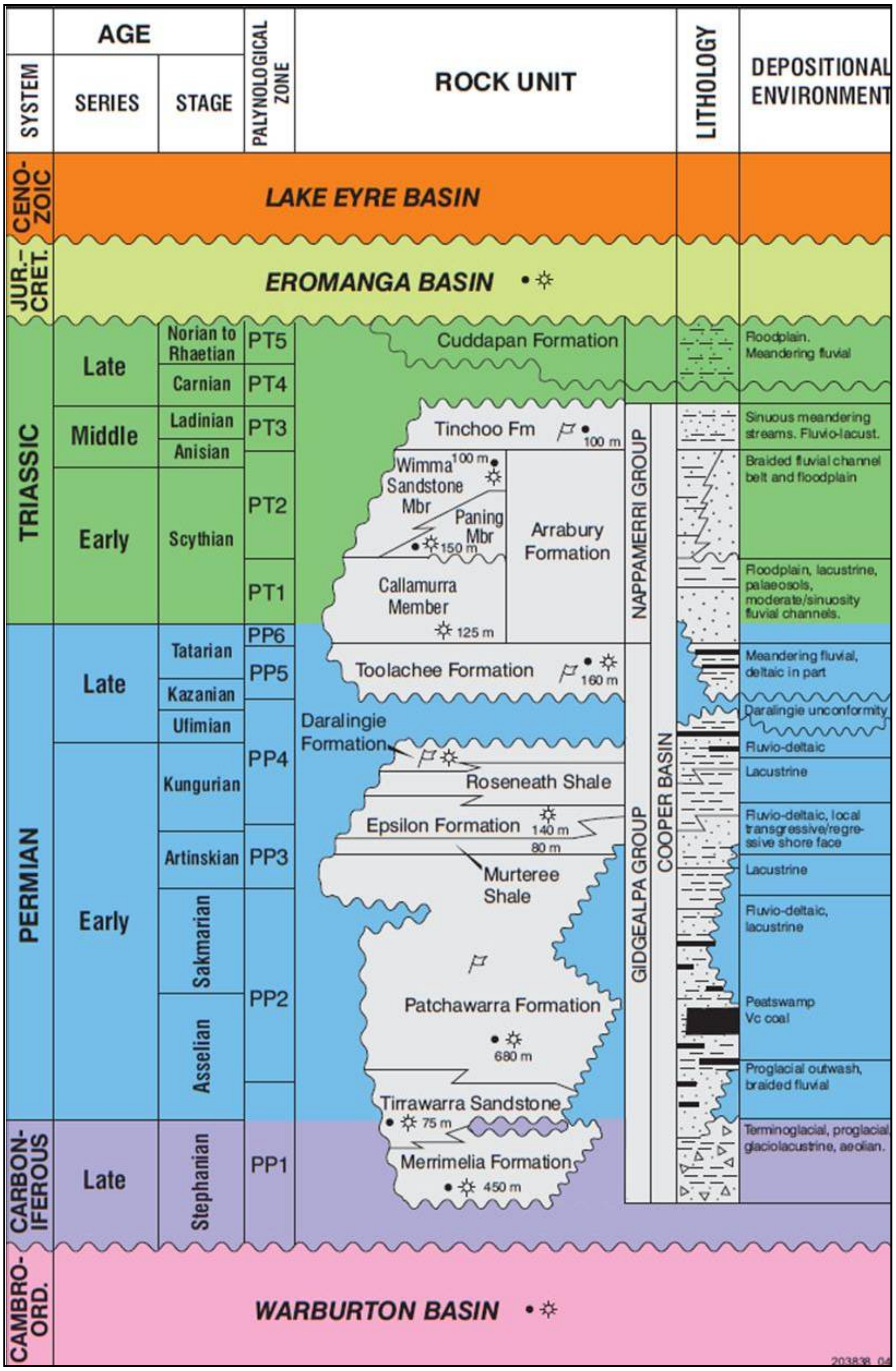
The most prospective shales in the Gidgealpa Group, with oil and gas shows during drilling and higher TOCs, are the Early Permian Roseneath and Murteree shales.[5] Figure III-5 shows a stratigraphic cross-section of the Roseneath, Epsilon, and Murteree (collectively termed REM) sequence in the Nappamerri Trough.

1.3 Reservoir Properties (Prospective Area)

The Murteree Shale is a widespread, shaley formation typically 150 feet thick across the Cooper Basin, becoming as thick as 250 feet in the Nappamerri Trough. The Murteree consists of dark organic-rich shale, siltstone and fine-grained sandstone, becoming sandier to the south. TOC of the Murteree Shale averages 2.5% based on data from seven wells.

The Roseneath Shale, less widespread than the Murteree due to erosion on uplifts, averages 120 feet thick, reaching 330 feet thick in the Nappamerri Trough. The intervening Epsilon Fm consists primarily of low-permeability (0.1 to 10 mD) quartzose sandstone with carbonaceous shale and coal. The Epsilon, averaging about 175 feet thick in drill cores, was deposited in a fluvial-deltaic environment.[6]

Figure III-4. Stratigraphy of the Cooper Basin Permian-Age Shales



Source: South Australia DMER, 2010

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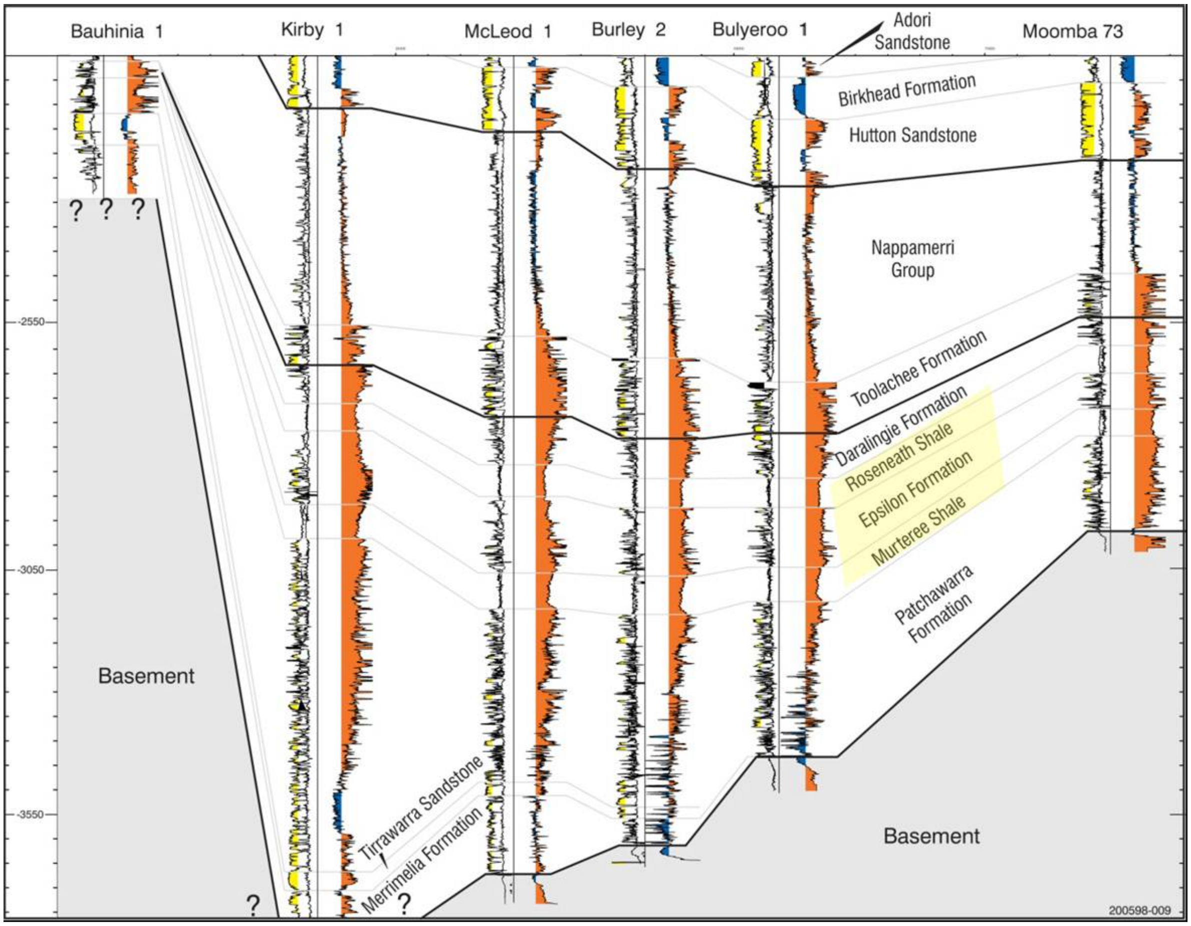
Figure III-5. Stratigraphic Cross-Section in the Cooper Basin



Source: Menpes, 2012

The organic-rich gross thickness of the REM sequence in the Nappamerri Trough averages about 500 feet, with a net pay of 300 feet in the gas prospective area and a net pay of 150 feet in the oil prospective area.[7] The gross organic-rich REM sequence is much thinner in the Patchawarra Trough, averaging 100 feet in the gas prospective area and 125 feet in the oil prospective area, with a moderate net to gross ratio. The gross organic-rich REM sequence in the Tenappera Trough averages 225 feet.

The REM source rocks are primarily Type III kerogens. They have generated medium to light gravity oil, rich in paraffin. Initial mineralogical data indicate that these shales consist mainly of quartz and feldspar (50%) and carbonate (30%; mainly iron-rich siderite). Clay content is relatively low (20%; predominately illite).[8] In spite of the lacustrine depositional origin, this lithology appears brittle and could respond well to hydraulic fracturing.

Temperature gradients in the Cooper Basin are quite high, averaging 2.55°F/100ft. Bottomhole temperature at depths of 9,000 feet average about 300º F. The Nappamerri Trough is even hotter, with a temperature gradient of up to 3.42°F/100 ft, due to its radioactive granite basement. The Patchawarra Trough, which has a sedimentary-metamorphic basement, has a lower but still elevated 2.02° F/100 ft temperature gradient.

The thermal maturity of the Permian REM section in the deeper portions of the Nappamerri and Patchawarra troughs is gas prone (R_o >1.3%). R_o values between 0.7% and 1.0% are observed at the shallower, southern ends of each trough and also in the Tenappera Trough, suggesting that the REM section is oil prone in these areas. A modest size wet gas/condensate prospective area exists between the oil prone and dry gas areas in the Nappamerri and Patchawarra troughs.

Regional hydrostatic pressure gradients are the norm in most of the Cooper Basin. However, the Nappamerri Trough becomes overpressured at depths of 9,000 to 12,000 feet, with pressure gradients of up to 0.7 psi/ft recorded in the deepest portions of the trough.[9] High levels of carbon dioxide are also common in the Cooper Basin. Gas produced from the Epsilon Formation (the central portion of the REM sequence) contains elevated CO_2, typically ranging from 8% to 24% (average 15%).[10]

1.4 Resource Assessment

The prospective areas for shale gas development in the Cooper Basin area are defined by the intersection of a minimum depth of 6,500 feet (top of the gas window, as defined by thermal maturity modeling), vitrinite reflectance greater than 1.0%, and a minimum thickness of the REM section of 50 feet. The prospective areas for shale oil are defined by R_o values between 0.7% and 1.0% and a minimum thickness of the REM section of 50 feet, Figure III-6.

Completable shale intervals in the dry and wet gas prospective areas containing the Roseneath, Epsilon, and Murteree (REM) formations have estimated shale gas resource concentrations of 88 to 100 Bcf/mi^2 in the Nappamerri Trough, benefitting from favorable thickness, moderate TOC and overpressuring, but reduced by 15% for CO_2 content. In contrast, the shale gas resource concentrations in the dry and wet gas prospective areas of the Patchawarra Trough are much less, from 16 to 19 Bcf/mi^2. The resource concentration in the oil prospective area of the Tenappara Trough is 22 million barrels/mi^2.

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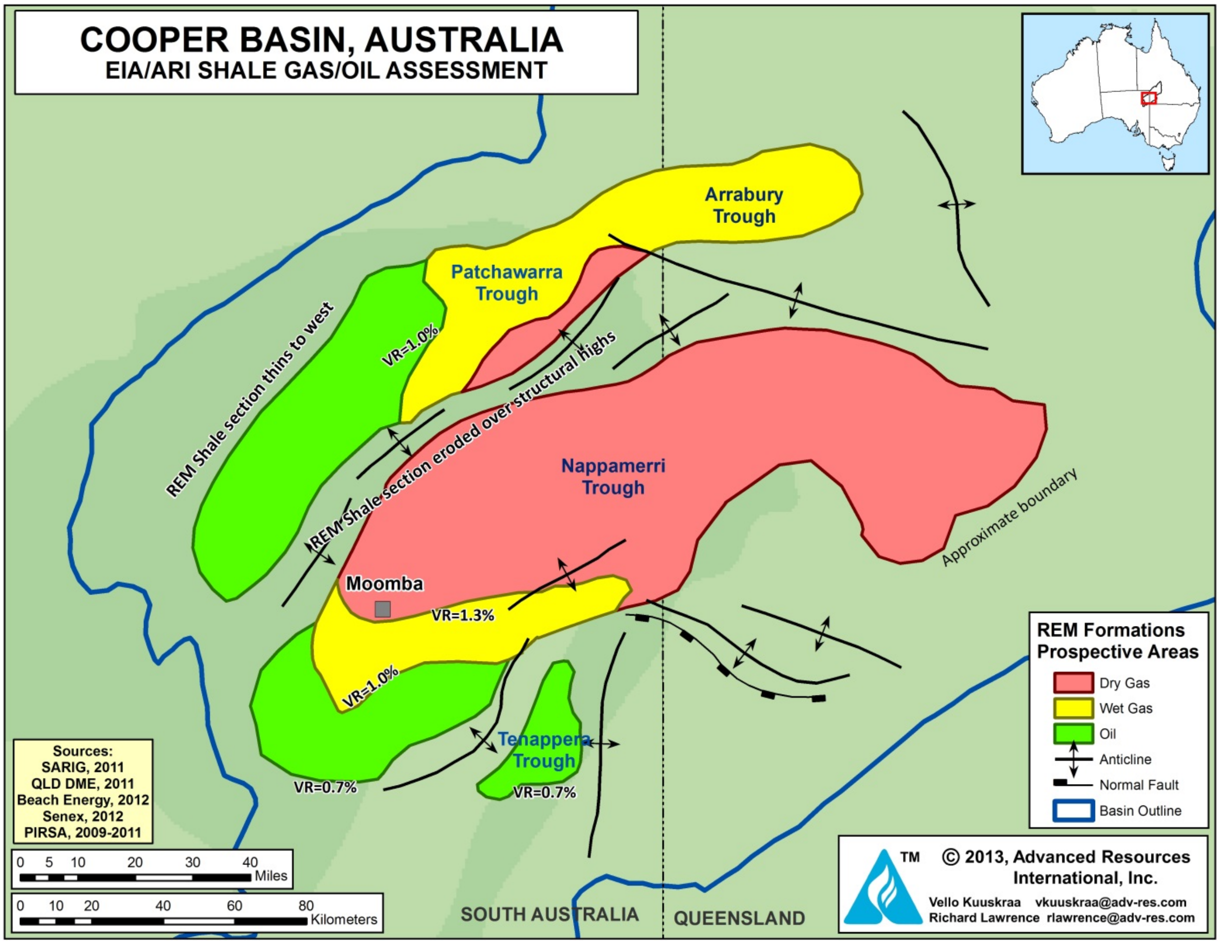
Figure III-6. Southern Cooper Basin Prospective Shale Gas and Shale Oil Areas



The total shale gas and shale oil prospective area for the Permian REM section is estimated at 7,235 mi^2, covering major portions of the Nappamerri, Patchawarra and Tenappera troughs in the Cooper Basin. Net of 15% CO_2 content, the estimated risked shale gas in-place is 325 Tcf, with a risked, technically recoverable shale gas resource of 93 Tcf, including associated gas in the shale oil prospective area, Table III-A. The risked shale oil in-place in the Cooper Basin is 29 billion barrels, with a risked, technically recoverable resource of 1.6 billion bbls, Table III-2A.

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1.5 Recent Activity

The Cooper Basin is Australia's largest onshore oil and gas production region. Beach Energy, Senex, DrillSearch Energy and Santos have active shale gas and oil exploration and evaluation programs underway.

Beach has drilled two vertical test wells in the deep, central portion of the Nappamerri Trough. These wells each tested at about 2 MMcfd gas after hydraulic stimulation. The Encounter-1, thought to be Australia's first commercially viable shale well, was drilled to a total depth of 11,850 feet and penetrated 1,290 feet of the REM sequence, reporting continuous gas shows. Beach drilled an additional three vertical test wells in the first half of 2012, with three more planned for the rest of the year. The test wells will be studied to identify the best locations for placing two horizontal wells to be drilled in late 2012.

Senex has drilled five vertical test wells in the Tenappera Trough to the south and east of the Nappamerri Trough with reports of liquid hydrocarbon production. The company is planning a 12 well drilling program for 2012/13. DrillSearch Energy, in a JV with the BG Group, has undertaken detailed shale core studies along with acquiring 425 mi^2 of 3D seismic.

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2. MARYBOROUGH BASIN

2.1 Introduction

This small basin in coastal Queensland, located about 250 km north of Brisbane, has two potential gas shale targets within the Cretaceous Maryborough Formation. The basin is highly unexplored with only five conventional oil and gas exploration wells drilled to date. Three large anticlines occur within the onshore portion of the basin, all of which have been drilled but without conventional discoveries.[11]

2.2 Geologic Setting

The Maryborough Basin is a half-graben bounded on the west by the Electra Fault. It covers an onshore area of 4,300-mi^2, Figure III-7. Major folding and faulting, along with significant erosion, occurred during the Cretaceous-Palaeogene establishing the structural setting of the basin. Two main depositional sequences were examined in the Maryborough Basin, Figure III-8.[12] The Duckinwilla Group, which contains Late Triassic to mid-Jurassic non-marine sediments, is not considered prospective for shale oil or gas. Overlying the Duckinwilla is the Grahams Creek Formation which contains Late Jurassic to Cretaceous (Neocomian) strata, including the marine-deposited Maryborough Formation.

2.3 Reservoir Properties (Prospective Area)

The Maryborough Formation (Neocomian-Aptian) appears to be the primary shale gas unit in the Maryborough Basin. Up to 8,500 feet thick, it is the only definitely marine unit in the basin. The unit consists primarily of mudstones, siltstone and sandstone with minor conglomerate, limestone and coal. Within the Maryborough Formation, the most prospective sub-units are the Goodwood Mudstone, the Woodgate Siltstone, and the Cherwell Mudstone, Figure III-9. These sub-units have been described as a monotonous series of mudstones with minor shales and siltstones. The mudstones are light to dark grey, slightly calcitic, pyritic and silty. Calcite veins are common in the lower section.[13] The Goodwood Mudstone (Shale) interval is approximately 2,000 feet thick (gross) with a depth of 5,000 feet on anticlines to 15,000 feet in the troughs. TOC averages 2.0% and the shale is within the dry gas maturity window (R_o > 1.5%). The underlying Cherwell Mudstone (Shale) interval consists mainly of black shale about 500 feet thick (gross) and ranges from 8,000 feet deep on anticlines to a projected 17,000 feet deep in the troughs. TOC averages 2.0% and the shale is thermally mature (R_o >1.5%). The net organic-rich pay in the two shale intervals is estimated at 250 feet.

Figure III-7. Maryborough Basin Prospective Shale Gas Area

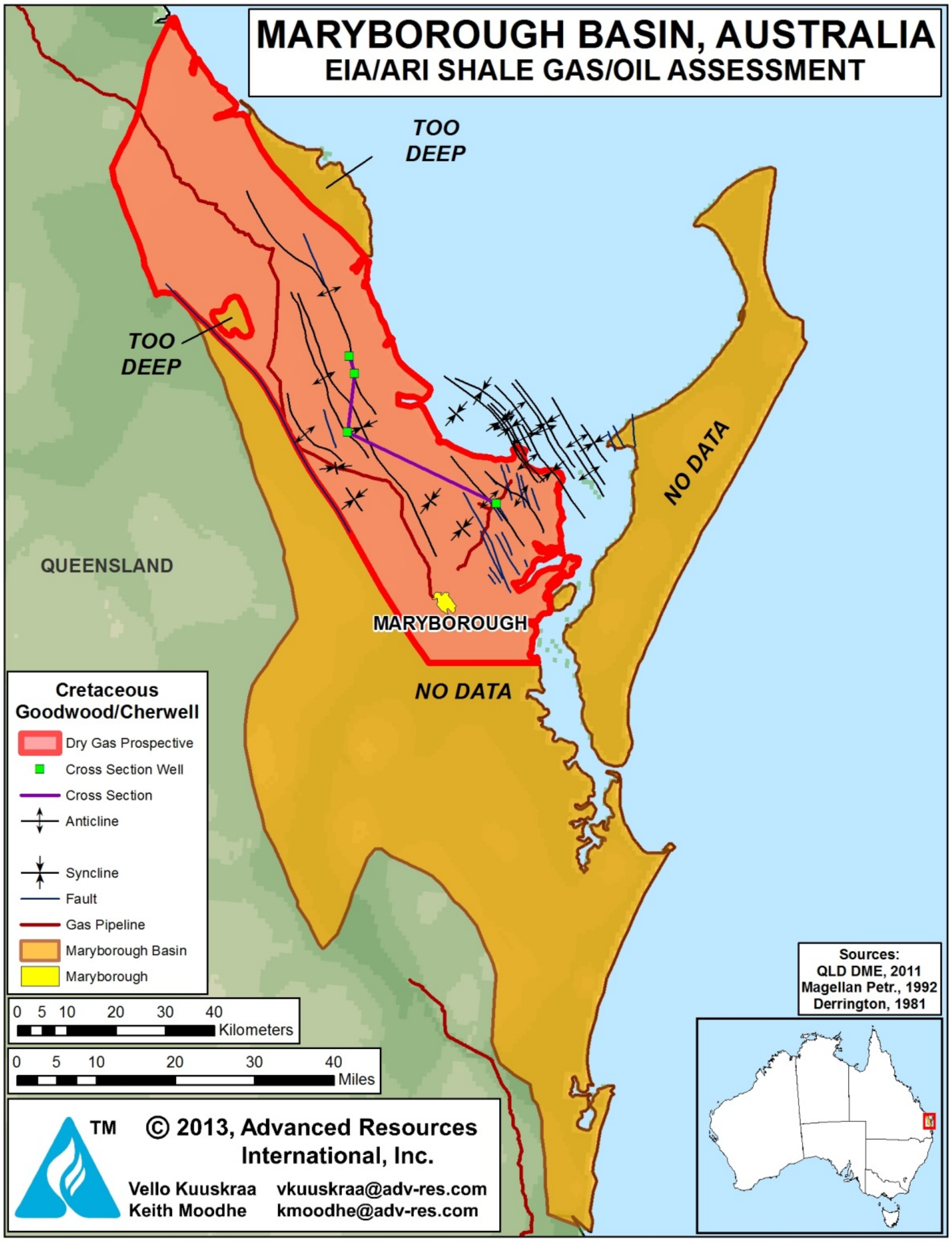
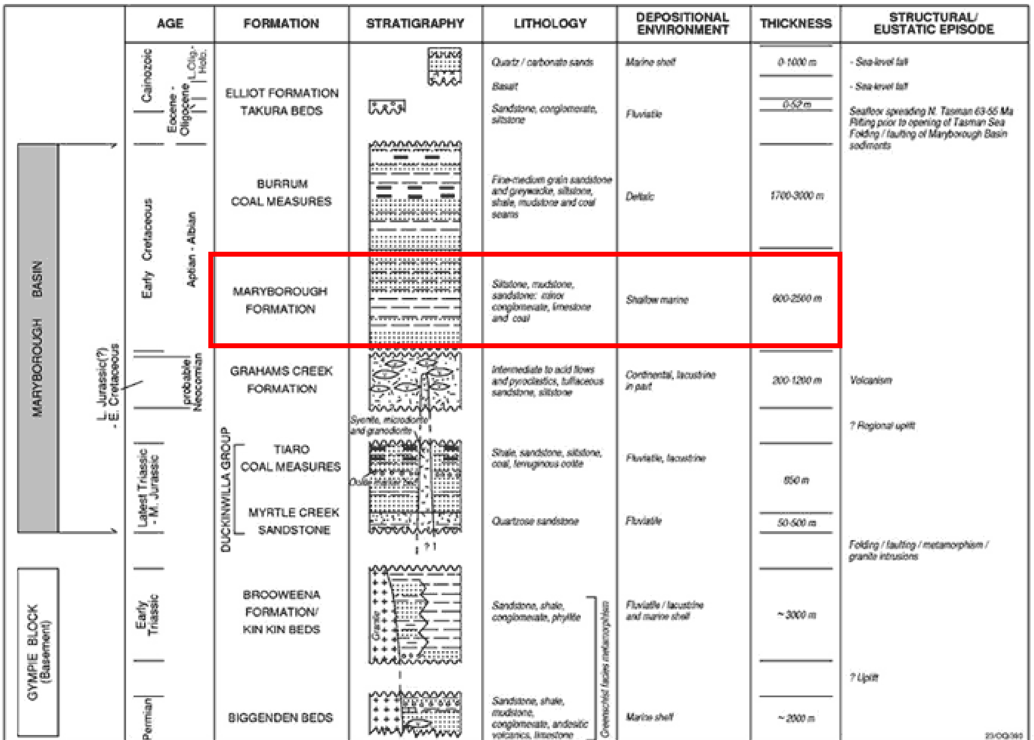
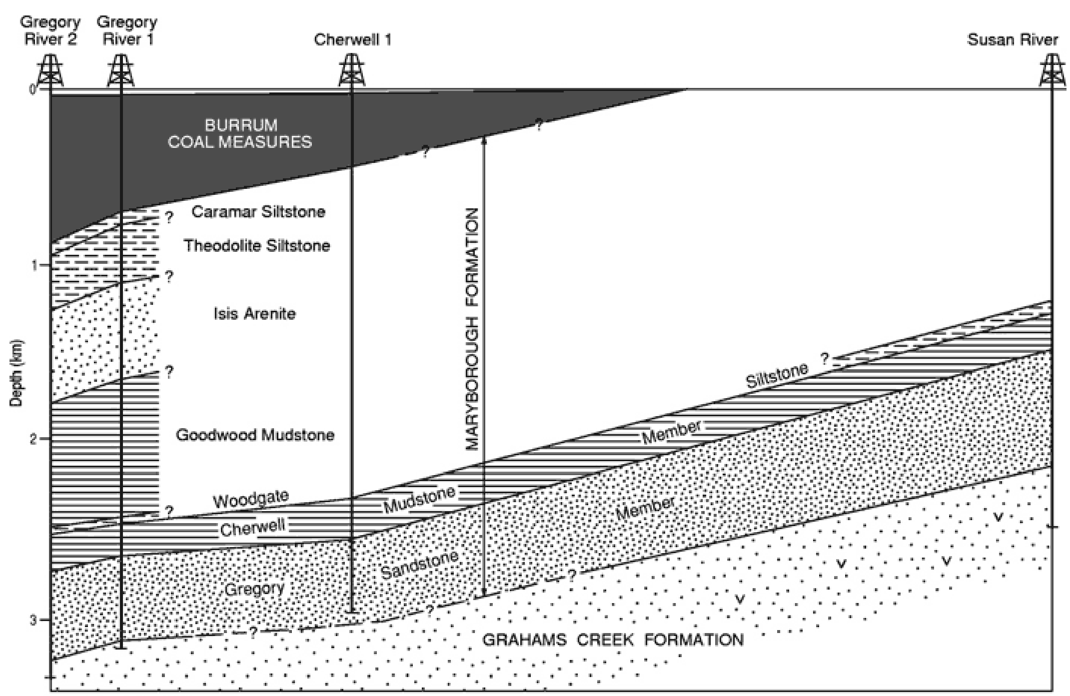


Figure III-8. Stratigraphy of the Maryborough Basin



Source: Hill 1994

Figure III-9. Cross-Section of the Maryborough Basin and the Cretaceous Maryborough Formation.



From Derrington 1981
Source: Eyles et al., 2001

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2.4 Resource Assessment

ARI evaluated only the northern portion of the Maryborough Basin where geologic data exist. We estimate that a 1,540-mi^2 area could be prospective for shale gas development. Additional areas in the poorly constrained southern half of the basin may be prospective but lack sufficient data for a rigorous resource assessment.

The basal shales of the Maryborough Formation (Cherwell and Goodwood shales) have an estimated gas in-place concentration of 111 Bcf/mi^2. The risked gas in-place for the shales in the Maryborough Basin is estimated at 64 Tcf, with a risked, technically recoverable shale gas resource of 19 Tcf, Table III-1B. With its high thermal maturity, the Maryborough Formation is dry-gas prone and thus not prospective for shale oil.

2.5 Recent Activity

Blue Energy Ltd., in a JV with Beach Energy, is awaiting award of three exploration permits in the northern portion of the Maryborough Basin. The companies are assessing the potential of shale gas in this basin target with a view toward determining a possible shale test well drilling location.[14]

3. PERTH BASIN (WESTERN AUSTRALIA)

3.1 Introduction

The Perth Basin, an active petroleum producing region, extends on- and offshore in the southwest of Western Australia. The basin contains two main organic-rich shale formations, the Permian Carynginia and the Triassic Kockatea.

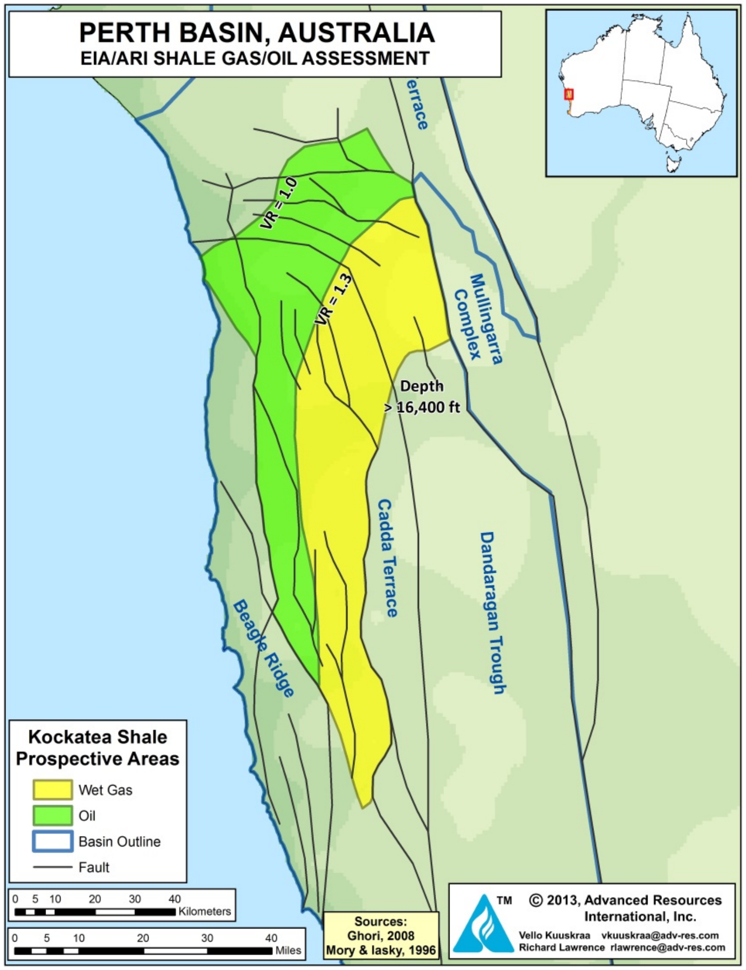
3.2 Geologic Setting

The Perth Basin is a north-northwest trending half-graben with relatively simple structure that appear favorable for shale oil and gas development. About half of the basin is onshore, covering an area of approximately 20,000 mi^2. The onshore portion of the basin contains two large, deep sedimentary sub-basins, the Dandaragan and Bunbury troughs, separated by the Harvey Ridge structural high, Figure III-10.[15]

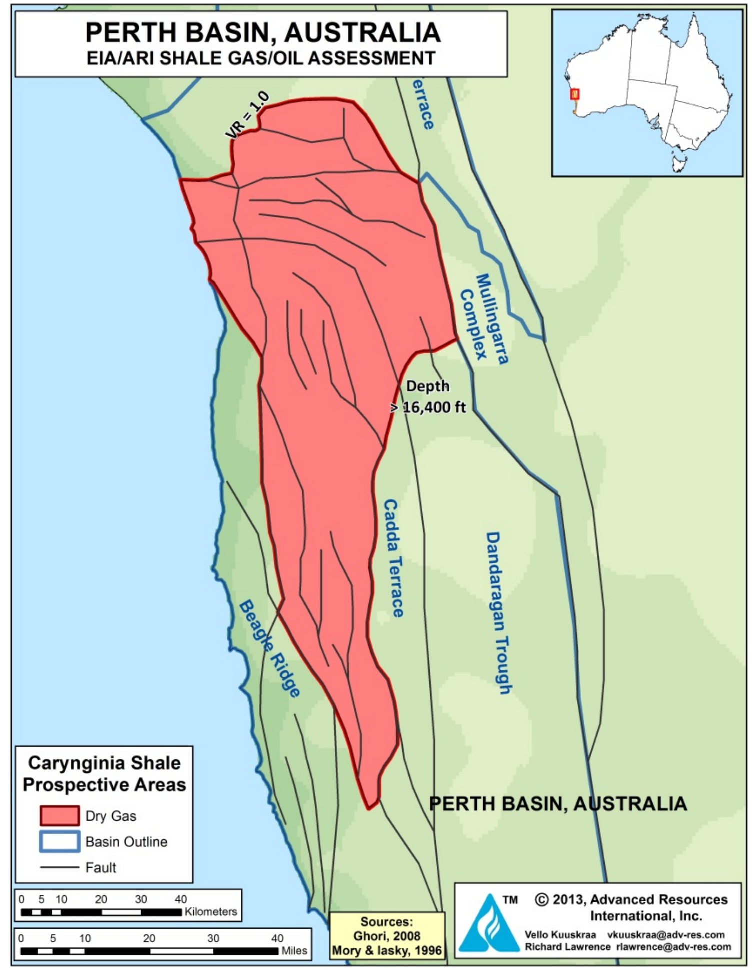
The Dandaragan Trough, a large syncline in northern Perth Basin, contains the deepest, thickest and most prospective shale gas formations. Some 300 miles long and up to 30 miles wide, the Dandaragan Trough holds as much as 9 miles of Silurian to early Cretaceous sedimentary rocks. Much of the Dandaragan Trough is too deep for shale development, but its northern area and the adjoining Beagle Ridge appear to be within the prospective shale depth window. The area is not structurally complex but does have some significant faulting, Figure III-11.[16]

Approximately 100 petroleum exploration wells have been drilled in the onshore portion of the Perth Basin, resulting in the discovery of six conventional natural gas fields, all located within the Dandaragan Trough. Proved reserves to date total about 600 Bcf with small amounts of associated oil in conventional reservoirs (Upper Permian Dongara Sandstone and Beekeeper Formation). Natural gas recovered from the deeper Permo-Triassic reservoirs (Dongara, Mondarra, Yardarino, Woodada and Whicher Range) tends to be dry, reflecting higher thermal maturity and higher proportions of gas-prone organic matter. CO_2 is generally low, apart from isolated readings of 4.1% in the Woodada-1 well and 3.9% in the Mondarra-1 well.

Figure III-10. Perth Basin Prospective Shale Gas and Shale Oil Areas

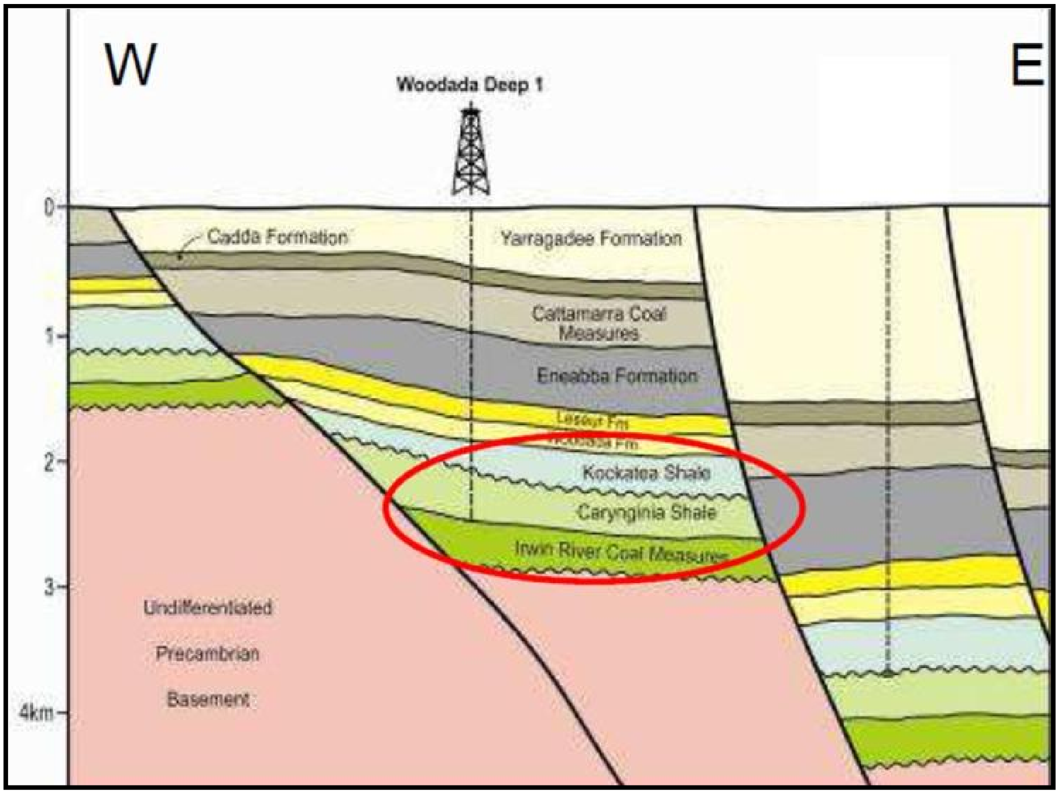


Source: ARI, 2013.



Source: ARI, 2013.

Figure III-11. The Woodada-1 Deep Well Tested the Carynginia Shale



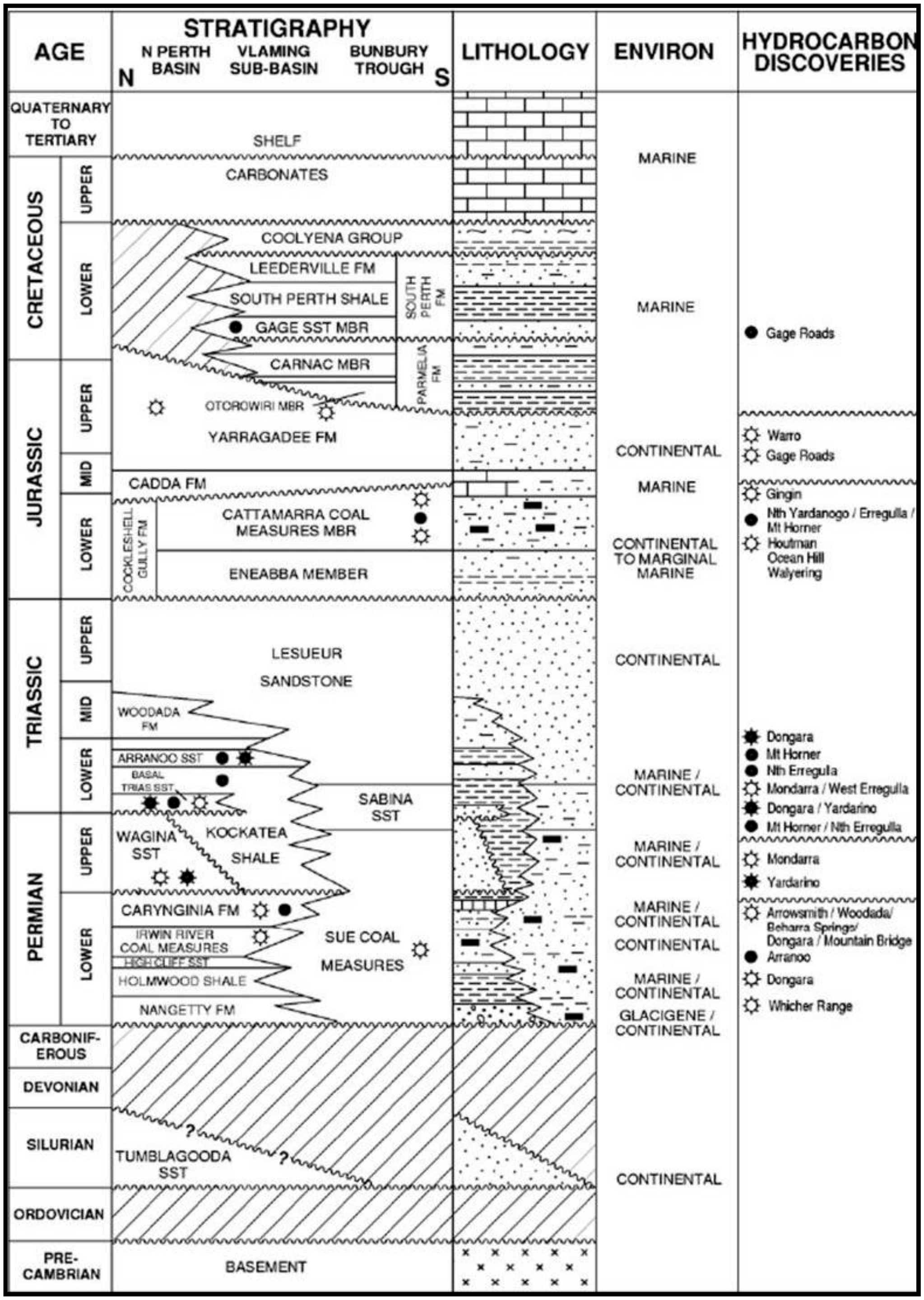
Source: AWE 2010

Tight sandstone reservoirs in the Perth Basin include the Eneabba and Yarragadee formations. These reservoirs were sourced by the Triassic and Permian source rock shales and coals, which modeling indicates are within the oil window in the far north of the Perth Basin and enter the gas window toward the southeast.

The sedimentary sequence in the Perth Basin comprises three successions: a) Lower Permian largely argillaceous glaciomarine to deltaic rocks (including the prospective Carynginia Shale); b) Upper Permian nonmarine and shoreline siliciclastics to shelf carbonates; and c) Triassic to Lower Cretaceous nonmarine to shallow marine siliciclastics (including the prospective Kockatea Shale) deposited in a predominantly regressive phase, Figure III-12.[17]

Other marine shales in the Perth Basin that were evaluated but rejected as prospects include the Triassic Woodada and Jurassic Cadda formations (too lean), the Jurassic Parmelia (Yarragadee) Formation (lacustrine origin, located only in the offshore), and the Cretaceous South Perth Formation (immature, offshore only).

Figure III-12. Stratigraphy of the Perth Basin Showing the Prospective Lower Triassic Kockatea and Permian Caryinginia Shales



Source: Cadman et al., 1994

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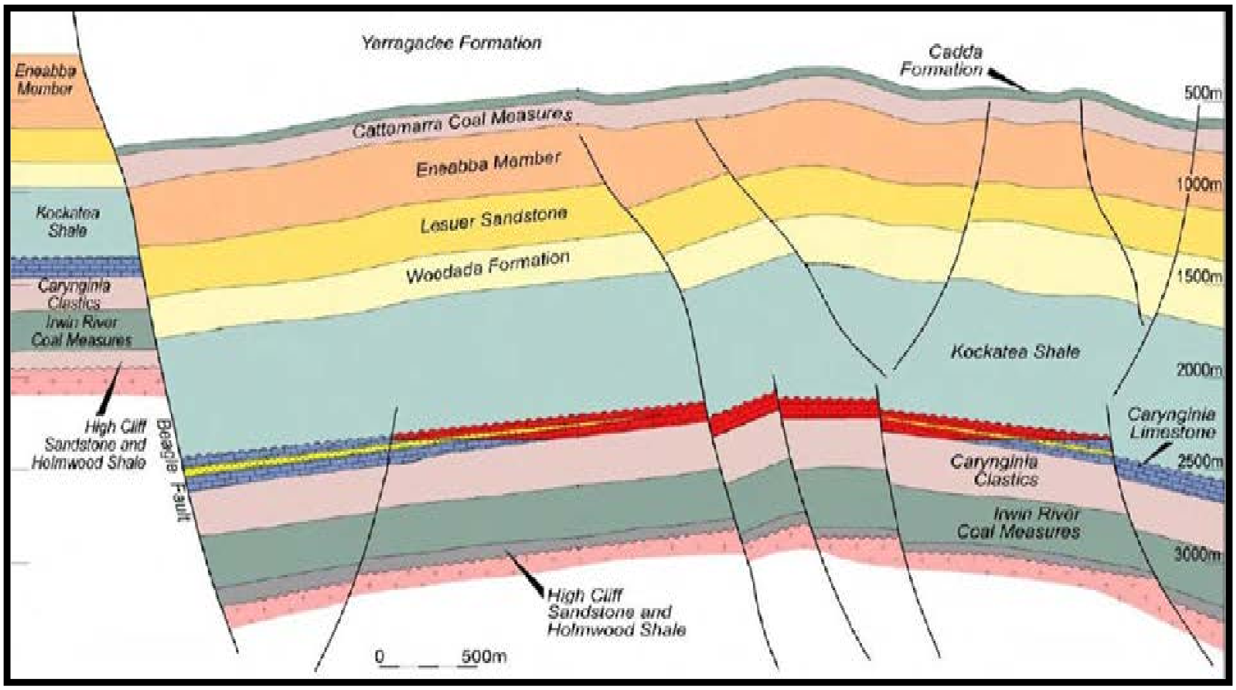
3.3 Reservoir Properties (Prospective Area)

The Lower Triassic Kockatea Shale is considered the primary oil source-rock as well as the main hydrocarbon seal in the basin. It consists of dark shale, micaceous siltstone and minor sandstone and limestone. The Kockatea Shale interval thickens to the south within the Perth Basin, reaching a maximum thickness of 3,500 ft in the Woolmulla-1 well, Figure III-13. The most organic-rich portion of this unit (Hovea Member) has recorded TOC values up to 8%.[18]

Figure III-13. Structural Cross-Section of the Perth Basin Showing 2,300 ft thick Kockatea and 820 ft Thick Carynginia Shales at Prospective 5,000 – 9,200 ft Depth



Source: Norwest Energy, 2010

Core samples of the Hovea Member of the Kockatea Shale, obtained from the Hovea-3 petroleum exploration well, provide data on reservoir quality.[19] The base of this unit contains a distinct organic-rich zone of fossiliferous dark grey mudstone, sandy siltstone and shelly storm beds. These sediments were deposited at a relatively low paleo-latitude in a shallow marine environment during the earliest stage of a marine transgression. TOC of the Kockatea Shale sampled from this well ranged from 2.31% to 7.65% (average 5.6%), consisting of inertinite-rich (Type III) kerogen.[20]

The clay content of the Hovea Member of the Kockatea Shale in the Hovea-3 well ranged from 24% to 42% (average 33%). Separately, AWE cored a high-TOC, 160 ft thick Hovea Member of the Kockatea Shale in the conventional Redback-2 exploration well in 2010, but reported discouragingly high clay content. The Kockatea is thermally mature for gas in the Dongara Trough, but less mature and possibly oil-prone on the Dongara Saddle and the flanks of the Beagle Ridge. CO_2 and N_2 contents tested low (0.5% and 0.4%, respectively) from a 4,750 ft deep Kockatea Shale zone in the Dongara-24 well.[21]

The Permian Carynginia Shale, a shallow -marine deposit present over much of the northern Perth Basin. The Carynginia Shale conformably underlies the Kockatea Shale. AWE Limited recently reported encouraging organic-shale characteristics for this 800 to 1,100 ft thick unit. A deeper-water shale member occurs near the base of the Carynginia Shale, including thin interbeds of siltstone, sandstone, and limestone.

Overlying the Carynginia Shale is a shallow-water, shelf limestone unit that contains conventional gas reservoirs. Conventional gas is produced from the Carynginia Limestone at Woodada field, sealed by the overlying Kockatea Shale. CO_2 and N_2 tested fairly low (about 2.5%) from a 8,000 ft Caryngia Fm zone in the Elegans-1 well.

While TOC values of up to 11.4% have been recorded, the TOC in the Carynginia Shale averages 4%. The kerogen is Type III, dominated by inertinite derived from land plants. Gas-prone, the Carynginia Shale is in the dry gas window over most of the Perth Basin. Source rocks are less mature on the Dongara Saddle and the flanks of the Beagle Ridge, where the shale is partly replaced by shallow-water, limestone facies.

Geothermal gradients in the Perth Basin can be elevated, ranging from 2.0°C to 5.5°C/100 m, but the thermal gradient in the Dandaragan Trough is less extreme (2°to 2.5°C/100 m). Vitrinite reflectance data show poor relationship with depth, with extreme data scatter probably caused by subertinite and bitumen suppression.

3.4 Resource Assessment

The prospective areas of the Beagle Ridge and Dandaragan Trough are located in the northern portion of the Perth Basin, where the Carynginia and Kockatea Shale source rocks are thick, deep and thermally mature, Figure III-10.

An estimated 1,030-mi^2 area is prospective for wet shale gas and condensate in the Kockatea Shale, defined using minimum and maximum depth criteria (3,300-16,500 ft) and vitrinite reflectance (R_o of 1.0% to 1.3%). A smaller 860-mi^2 area, up-dip from the wet gas prospective area, defined by R_o values between 0.7% and 1.0% and a minimum depth of 3,300 ft, appears prospective for shale oil in the Kockatea Shales. The deeper Caryngingia Shale has a dry gas prospective area of 2,200 mi^2. Additional portions of the southern half of the Perth Basin may be prospective but insufficient data were available for a quantitative assessment.

The Permian Carynginia Shale has a resource concentration of 94 Bcf/mi^2 within its 2,200-mi^2 dry gas prospective area. It holds a risked gas in-place of 124 Tcf, with a risked, technically recoverable shale gas resource of 25 Tcf, Table III-1B.

The Triassic Kockatea Shale has a resource concentration of 59 Bcf/mi^2 within its 1,030-mi^2 wet gas prospective area. Including associated gas, the Kockatea Shale has a risked gas in-place of 36 Tcf, with a risked, technically recoverable shale gas resource of 7 Tcf, Table III-1B. Shale oil resource concentrations in the Kockatea Shale are estimated at 19 million barrels/mi^2 in the oil prospective area and 6 million barrels/mi^2 in the condensate prospective area. Risked shale oil in-place in the two prospective areas is 14 billion barrels, with a risked, technically recoverable shale oil/condensate resource of 0.5 billion barrels, Table III-2A.

3.5 Recent Activity

In April 2010, AWE Limited cut five cores in the Carynginia Shale in its Woodada Deep exploration well in northern Perth Basin. The company found the upper and lower zones to have high clay content. However, the middle zone was considered more prospective, with lower clay (value not reported), 1 to 4% TOC and estimated 3 to 6% porosity at a depth between 7,780 and 7,960 ft. Zones in the Upper and Middle Carynginia were successfully hydraulically fractured in August 2012, with gas being produced during well flow-back and clean-up. AWE estimated a total 13 to 20 Tcf of gas in-place on its permit for the middle zone of the Carynginia Shale.[22]

Australian independent, Norwest Energy which produces oil and gas from conventional fields in the Perth Basin, is evaluating the shale potential on its EP413 permit area, about 20 miles north of the Woodada Deep well. Norwest is partnered with AWE and has also farmed-out an interest in EP413 to an Indian firm, Bharat PetroResources. The companies have committed up to A$15 million for shale exploration and drilling. The consortium drilled the Arrowsmith-2 well in June 2011 and fractured five stages in shale and tight sand intervals. Initial results during flowback reported gas flows from all zones including the Upper and Middle Caryngினia and both oil and gas flows from the Kockatea Shale.

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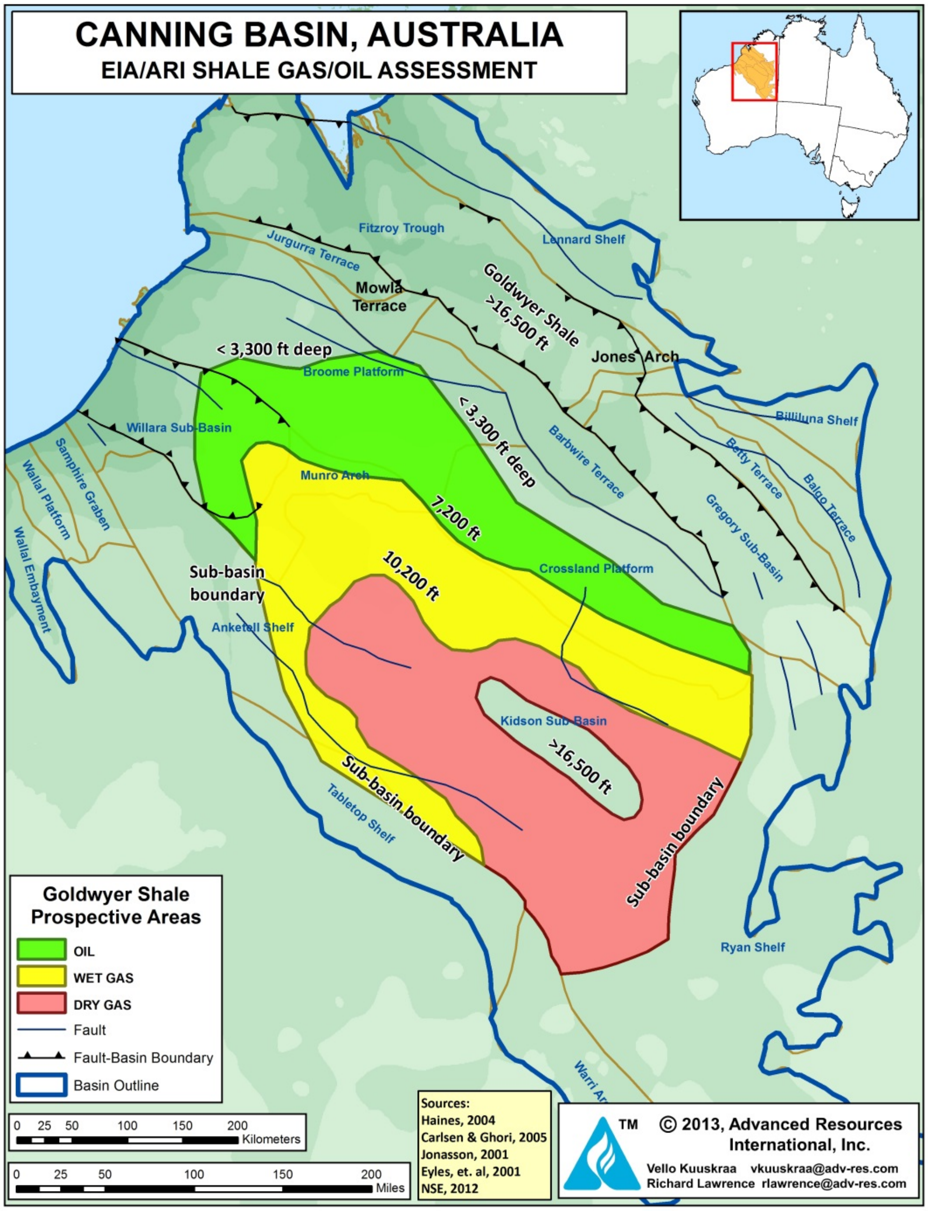
4 CANNING BASIN (WESTERN AUSTRALIA)

4.1 Introduction

The large, lightly explored Canning Basin in northwestern Australia contains several organic-rich shales, including the Laurel and Lower Anderson shales and the significant Goldwyer Shale, Figure III-14.

Figure III-14. Canning Basin Prospective Shale Gas and Shale Oil Areas



Source: ARI, 2013.

4.2 Geologic Setting

The 234,000-mi^2 Canning Basin (181,000 mi^2 onshore) is Western Australia's largest sedimentary basin. A broad intracratonic rift basin, the Canning contains up to 11 miles of Ordovician- to Cretaceous-age sedimentary rocks. The basin is separated from the Amadeus Basin to the east by a Precambrian arch. A series of northwest-trending, fault-bounded troughs within the basin, such as the Fitzroy Trough, may hold deep shale resource potential.[23]

Conventional exploration in the Canning Basin has focused on the Lennard Shelf, where petroleum occurs in the Hoya and Anderson formations. Only about 60 wells have intersected the principal source rocks in the basin, and most of the wells have been located on the uplifted terraces between the deeper troughs. Source rock data in the basin is limited, but the oil discoveries on the Lennard Shelf are sourced from Carboniferous and Devonian formations. In basin areas south of the Fitzroy Trough, the oil shows are sourced from Ordovician formations[24].

Figure III-15 shows the stratigraphy of the Canning Basin. The primary shale target in the basin is the organic-rich Ordovician Goldwyer Formation. The Carboniferous Laurel Formation could not be rigorously assessed due to insufficient data control. Other marine shales in the Canning Basin, such as the Calytrix Formation, appear to be too lean.

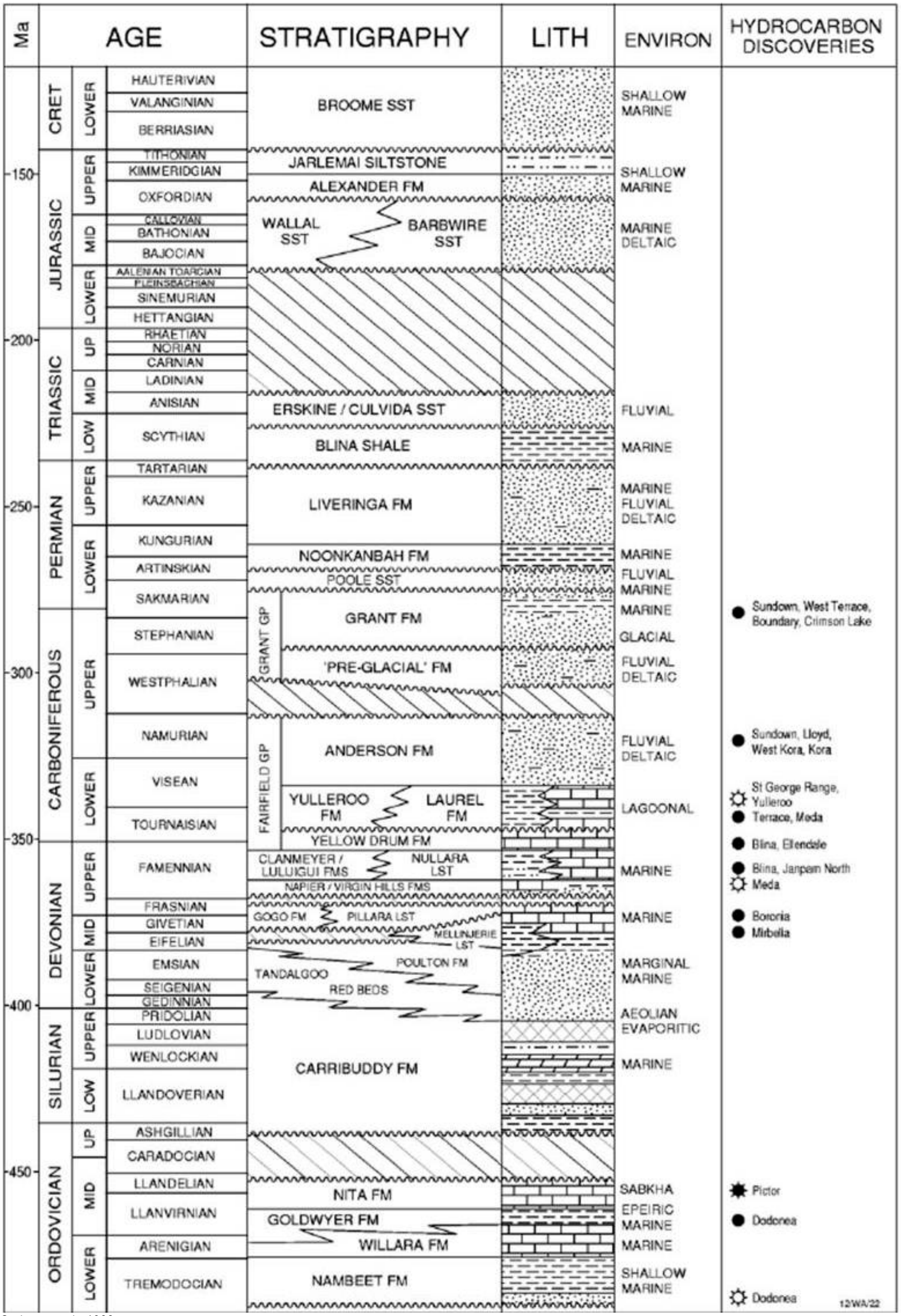
4.3 Reservoir Properties (Prospective Area)

The Middle Ordovician Goldwyer Formation was deposited mainly in open marine to intertidal conditions. Highly fossiliferous, the formation varies from mudstone-dominated in basinal areas to limestone-dominated in platform and terrace areas. The Goldwyer Formation averages about 1,300 feet thick, reaching a maximum thickness of 2,414 feet in the Willara-1 well in the Willara sub-basin.[25]

The Goldwyer Shale is dominated by mudstone and carbonate, with ratios of these components varying widely across the basin. The color of the shale ranges from grey-green to black, indicating anoxic reducing conditions.

The Goldwyer Shale contains horizons with high concentrations of the marine alga *Gloeocapsomorpha prisca*, considered to have excellent source-rock potential, similar to the Amadeus, Baltic, and Williston basins.[26] The Goldwyer Shale is oil prone on the uplifted platforms and terraces as shown by shallower exploration wells, but likely mature and gas prone in the adjacent deep troughs.

Figure III-15. Canning Basin Stratigraphic Column



Cadman et al., 1993

The depth of the Goldwyer Shale in the Canning Basin varies from greater than 16,500 feet in the southern Kidson sub-basin to less than 3,000 ft on the uplifted blocks of the Barbwire and Jurgurra Terraces, Figure III-16. In the northern, very deep Fitzroy Trough and Gregory sub-basin, the Goldwyer is at depths greater than 16,500 ft.

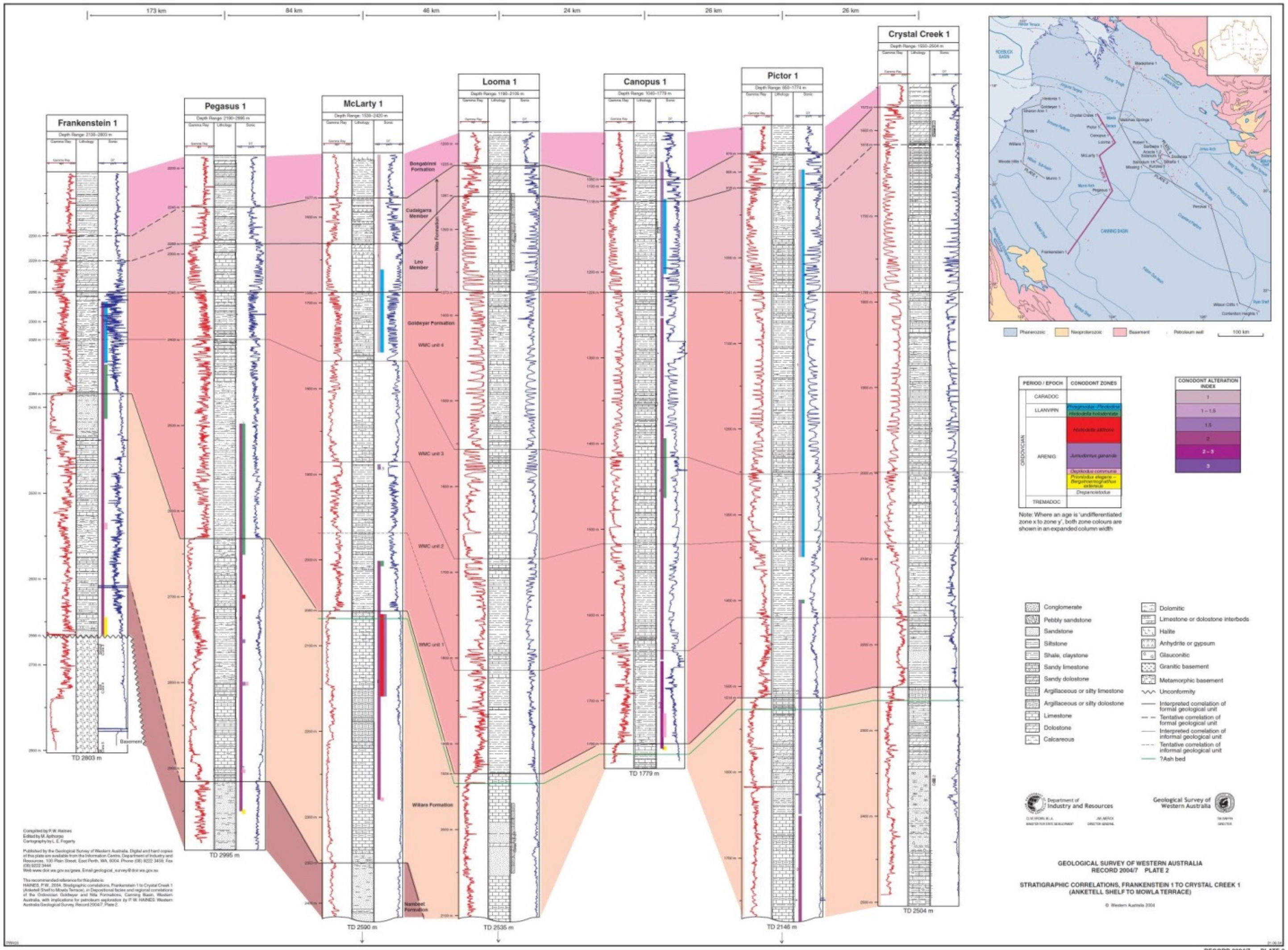
TOC in the Goldwyer Shale generally ranges from 1% to 5% (mean 3%), with some values in excess of 10%, Figure III-17.[27] The upper member of the Goldwyer Shale is particularly rich, with TOC up to 6.40%. Rock-Eval pyrolysis indicates this source rock is within the oil window over much of the southern Canning Basin and the mid-basin platform. The Kidson Sub-basin, where the Goldwyer deepens to 5,000 m, is in the dry gas window (R_o > 1.3%). In general, the Goldwyer Shale is in the oil window at depths less than 7,200 feet, in the wet gas and condensate window between 7,200 and 10,500 feet and in the dry gas window at depths over 10,500 feet.[28]

4.4 Resource Assessment

ARI identified a prospective area in the Kidson sub-basin in the southern portion of the Canning Basin. Here, the Goldwyer Shale is thick, deep (7,200-16,500 feet), and thermally mature. An estimated 22,860-mi^2 area may be prospective for dry gas development with a second 19,620-mi^2 area prospective for wet gas and condensate. A smaller 14,900-mi^2 area appears prospective for shale oil. The boundaries and depth contours for the undrilled deep trough areas were extrapolated from information at adjoining uplifts.

In the dry and wet gas prospective areas, the Goldwyer Shale has resource concentrations of 109 Bcf/mi^2 and 67 Bcf/mi^2, respectively. Including associated gas, the Goldwyer Shale in the Canning Basin has a risked shale gas in-place of 1,227 Tcf, with risked, technically recoverable shale gas of 235 Tcf. The prospective areas for oil and condensate for the Goldwyer Shale have resource concentrations of 41 million barrels/mi^2 and 10 million barrels/mi^2, respectively. Including both the oil and condensate prospective areas, the Goldwyer Shale, has risked shale oil/condensate in-place of 244 billion barrels, with risked, technically recoverable shale oil/condensate resources of 9.8 billion barrels.

Figure III-16. North-South Cross Section of the Canning Basin



Source: Haines, 2004

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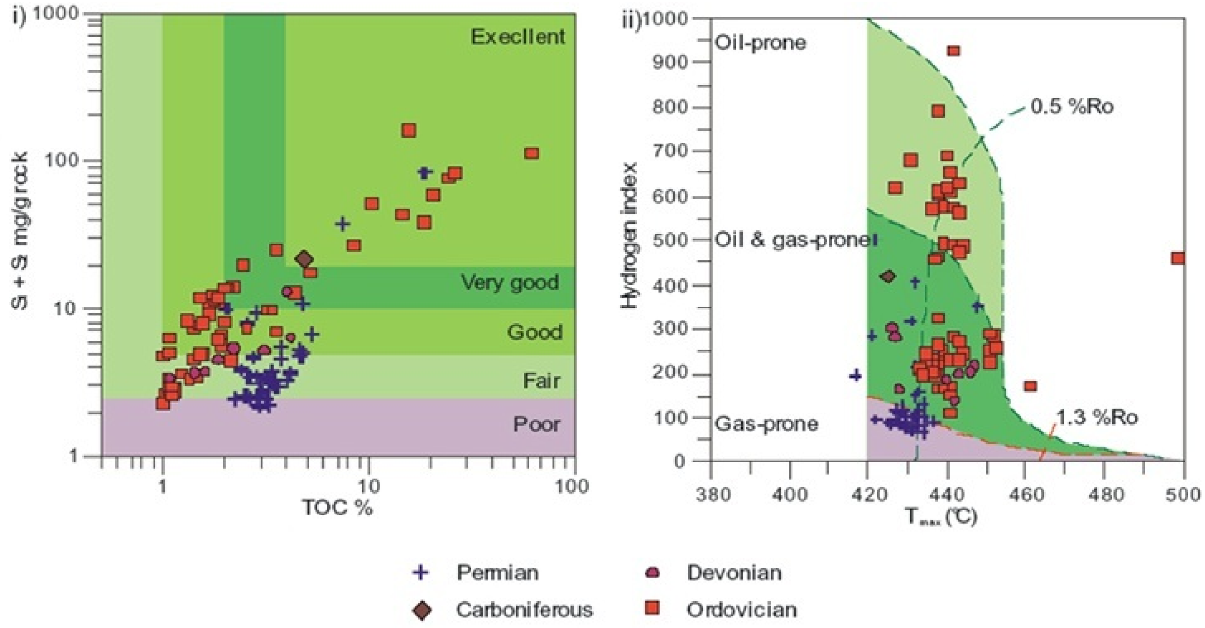
Figure III-17. TOC Values in the Ordovician Goldwyer Formation



Source: Ghori and Haines, 2007

4.5 Recent Activity

Buru Energy, an Australian E&P company, holds significant exploration permits in the Canning Basin. Buru reported gas-mature, organic-rich shale from cores in the Yulleroo-1 conventional exploration well drilled in 1967 on permit EP-391. In 2010, Mitsubishi agreed to fund an A$152.4 million exploration and development program to earn a 50% interest in Buru's permits. The two companies have plans to evaluate the Goldwyer Shale in the Kidson sub-basin.

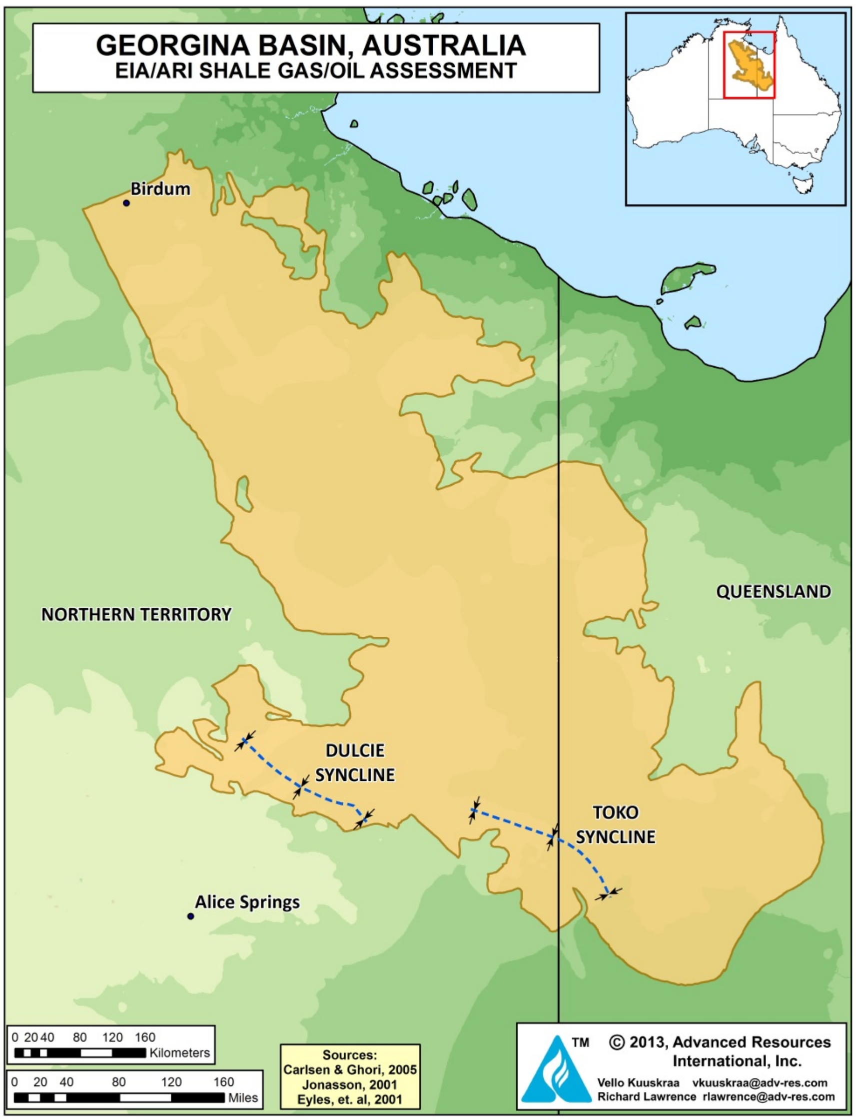
New Standard Energy (NSE), the other principal operator in the Canning Basin, holds exploration licenses covering 17,300 mi^2 in the northern edge of the Kidson sub-basin. In September 2011, NSE formed a joint venture with ConocoPhillips to accelerate exploration of the Goldwyer Shale. ConocoPhillips has announced that it will fund an exploration program over four years for up to $US119 million. Three wells will be drilled vertically and not fractured, but will have a detailed program of mud logging, full coring and wireline logs over the shale section. The first well in the program, the Nicolay #1, was spud on August 8, 2012 and is proposed to be drilled to a target depth of 11,300 feet.[29]

5. GEORGINA BASIN

5.1 Introduction

The Georgina Basin is a large, 125,000-mi^2 mainly unexplored basin in Northern Australia straddling the Northern Territory/Queensland border.[30] Twenty-nine test wells have been drilled, all in the southern third of the basin in the vicinity of the basin's two major depositional centers, the Toko and Dulcie Synclines, Figure III-18.

Figure III-18. Georgina Basin Location Map

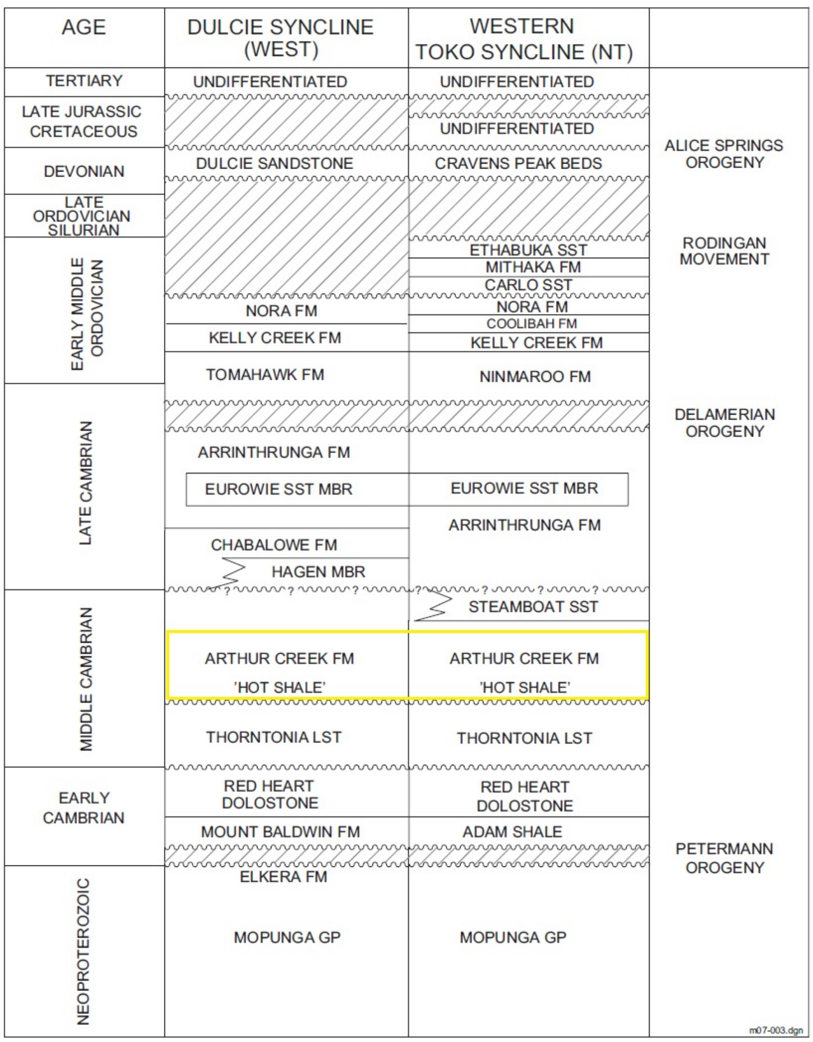


Source: ARI, 2013.

5.2 Geologic Setting

The Georgian Basin is filled with sediments deposited in a restricted anaerobic environment which supports the accumulation and preservation of organic matter. Two major depocenters consisting of downfaulted blocks and half-grabens on the southern margin of the basin contain up to 7,200 feet of Cambrian to Devonian section, Figure III-19.[31] The basin shallows northwards with the depth to top of the Cambrian Arthur Creek Shale becoming less than 3,000 feet along its northeastern border.

Figure III-19. Southern Georgina Basin Stratigraphic Column



Source: Ambrose and Putnam, 2007, modified after Ambrose et al 2001

The lower section of the Cambrian sediments in the southern synclines contains the Arthur Creek “hot” black shale, so called because of its high gamma ray response seen on electric logs. The thickness of the “hot” shale, derived from seismic interpretation and well data, thickens from west to east, Figure III-20. The shale section is interbedded with higher porosity clastic and carbonate intervals, somewhat comparable to the Bakken Shale in the U.S.

5.3 Reservoir Properties (Prospective Area)

The Arthur Creek Shale is a Middle Cambrian sequence comprised of dolomitic sands/silts, shales, dolomites and a basal black anoxic “hot shale”.[32,33] Modern electric logs run over the vertical section of the “hot shale” show log porosities up to 22% for the silt/sand stringers, averaging 10% over the whole section. The larger Arthur Creek Shale interval contains a high proportion of carbonates and has low clay content. Logs also show water saturations of less than 25% and intervals with natural fractures and small faults.

Geoscience Australia studied thirteen samples of core from four wells in the Georgina Basin, mainly from the Lower Arthur Creek Shale. The TOC of these samples ranged from 2% to 16%, with an average TOC of 5.5%.[34] The organic matter is composed of oil and wet gas prone Type I and II kerogen.

5.4 Resource Assessment

The prospective oil and gas shale areas for the Lower Arthur “Hot Shale” were confined by a minimum shale thickness of 30 feet on the southern side of the Dulcie and Toko synclines and by a vitrinite (R_o) value of 0.7% on the northern side of these two depositional center. The south-eastern boundary of the Toko Syncline prospective area is uncertain because of lack of data, Figure III-22.

Oil and gas resources were estimated for two prospective areas: an eastern region covering the Dulcie Syncline and surrounding area, and a western region covering the Toko Syncline and surrounding area. Total risked wet and dry shale gas in-place (in both synclines and including associated gas) is estimated at 67 Tcf, with a risked, technically recoverable shale gas resource of 13 Tcf, Table III-1C. Total risked shale oil and condensate in-place is estimated at 25 billion barrels, with a risked, technically recoverable shale oil and condensate resource of 1.0 billion barrels, Table III-2B.

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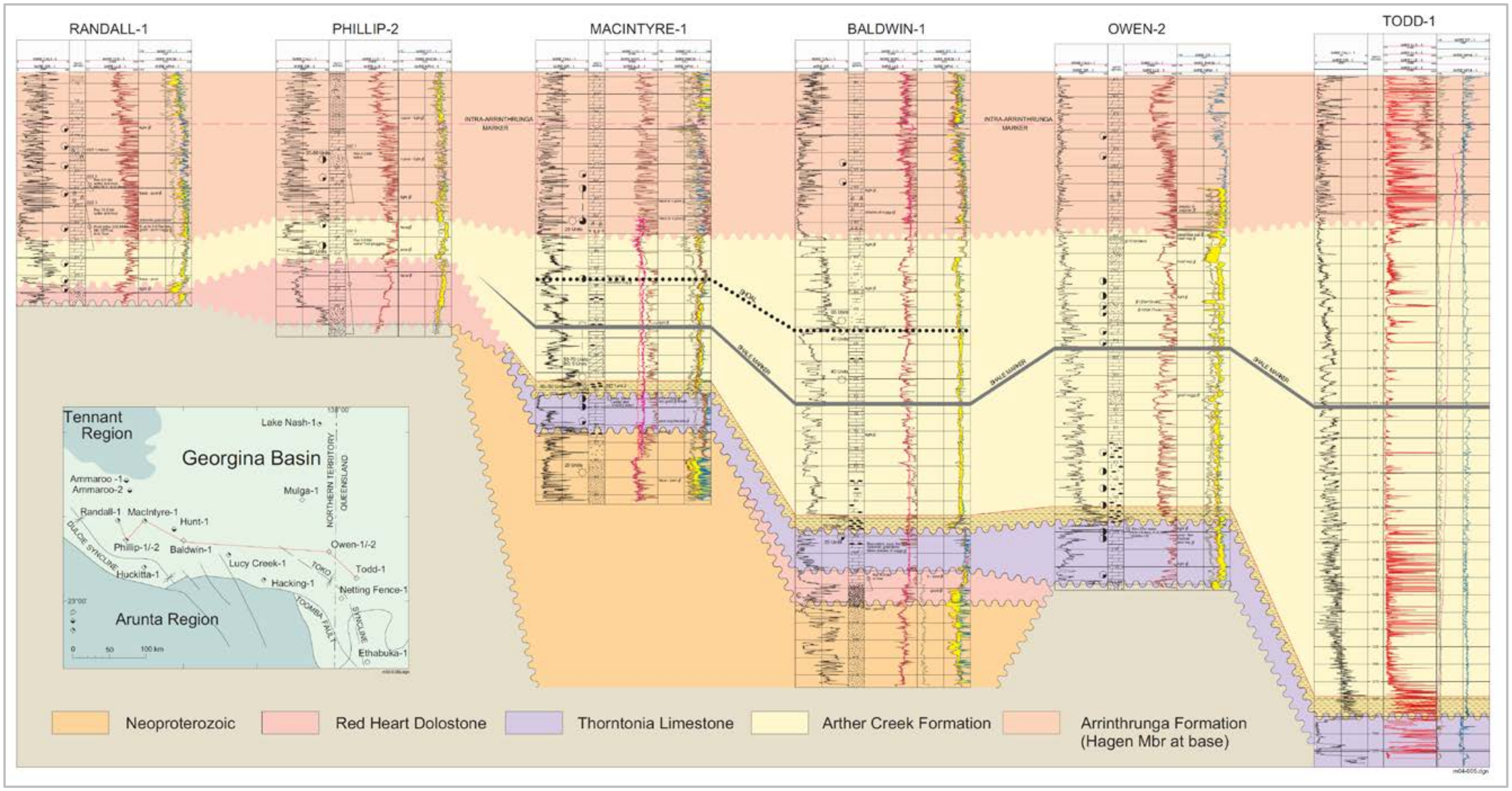
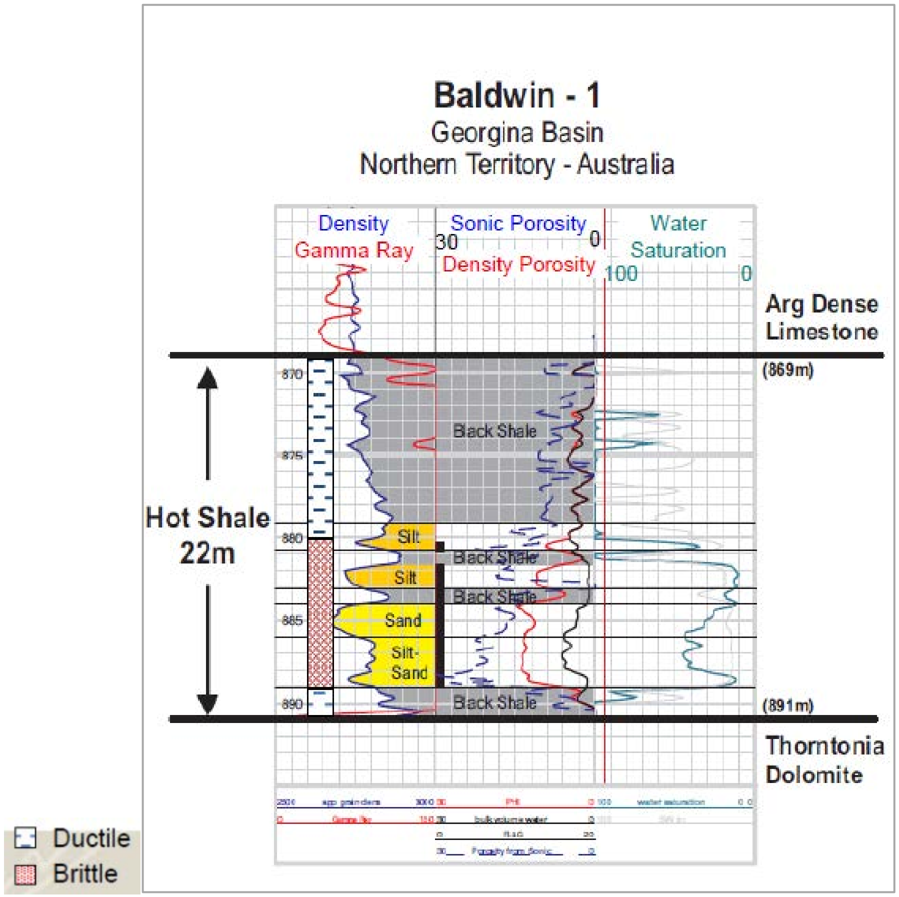
Figure III-20. East-West Cross-Section of the Southern Georgina Basin



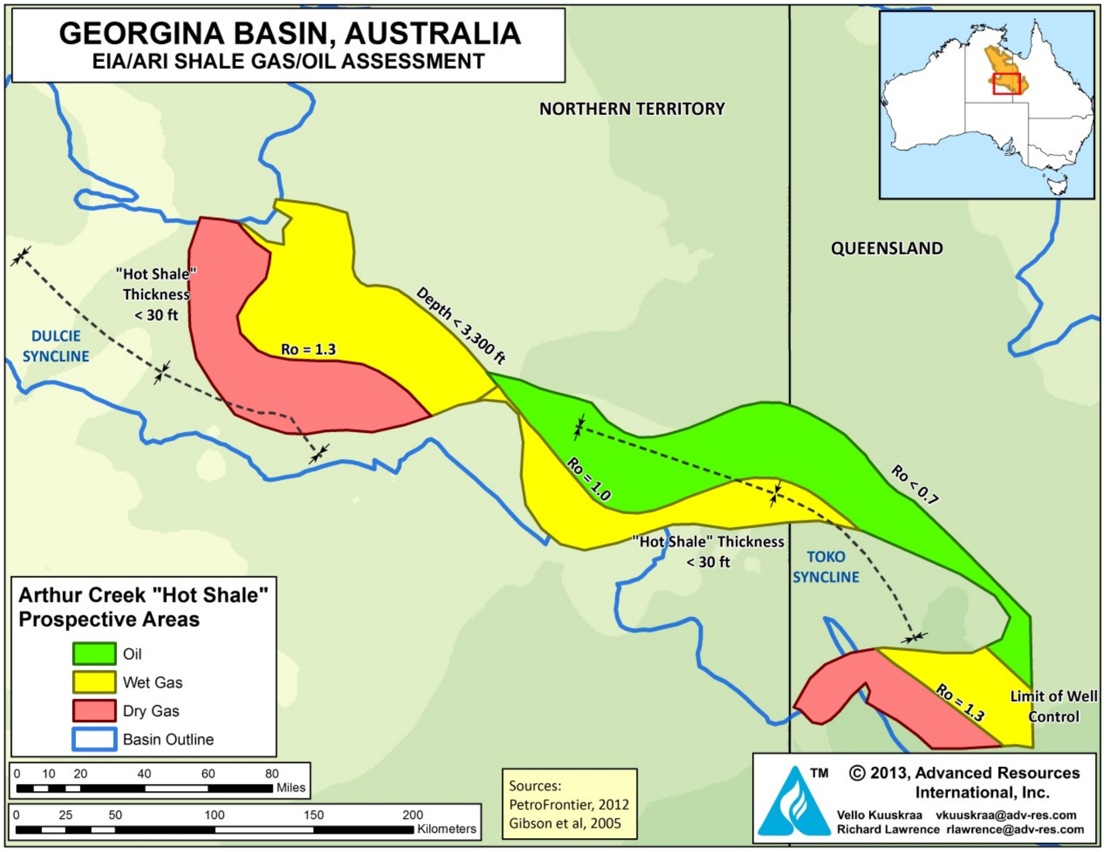
Source: Ambrose and Putnam, 2007

Figure III-21. Log Response of Lower Arthur "Hot Shale"



Source: ARI 2012

Figure III-22. Georgina Basin Prospective Shale Gas and Shale Oil Areas



Source: ARI, 2013.

5.5 Recent Activity

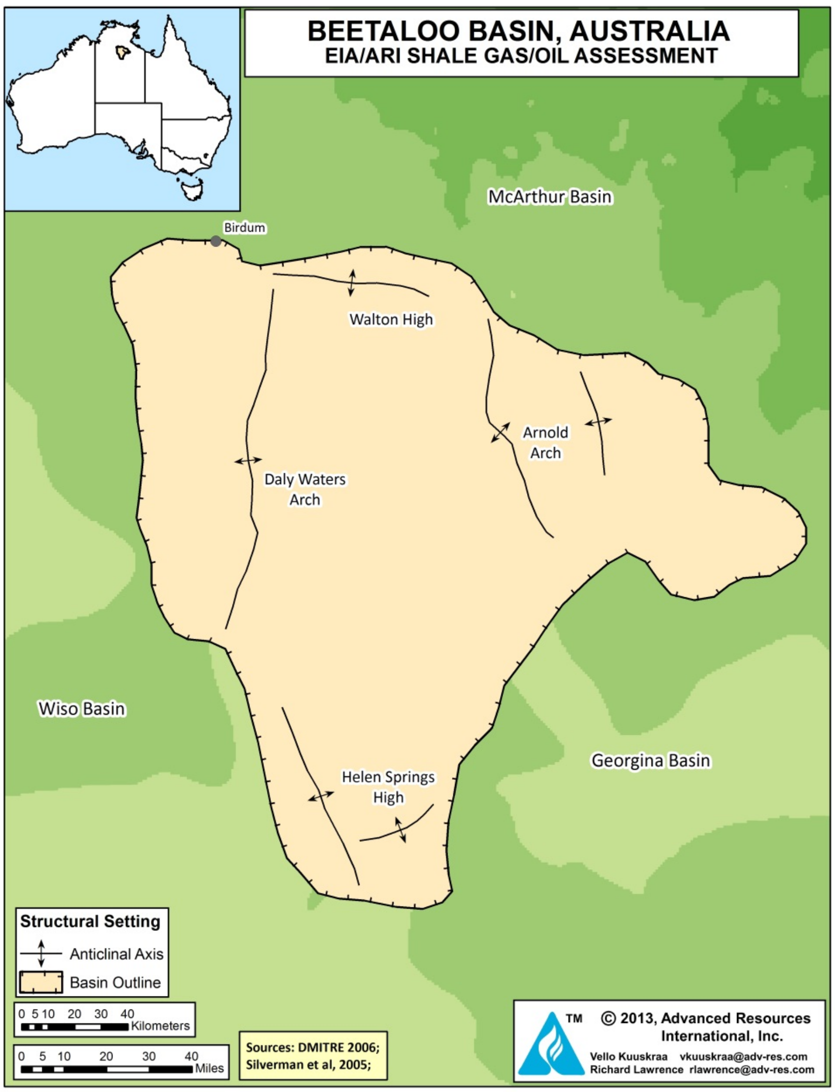
PetroFrontier Corporation, a Canadian company, holds several exploration permits in the southern portion of the Georgina Basin. A farm-in with Statoil Australia was established in 2012 with both companies committing to spending $25 million on an exploration program. Two horizontal exploration wells testing the Lower Arthur Creek “hot shale” section were drilled in the first half of 2012. The Baldwin-2Hst1 and the MacIntyre-2H were drilled in the gas-prone Dulcie Trough. A third well, the Owen-3 well is currently (August 2012) drilling its horizontal leg in the oil-prone area of the Arthur Creek “hot shale” on the flank of the Toko Trough. The vertical section of the Owen-3 was drilled to a measured depth of 3,870 feet and over 100 feet of core was cut from the “hot shale” and deeper Thorntonia Carbonate section. The core seeped oil on retrieval and had extensive florescence throughout. Wireline logging indicated over 80 feet of hydrocarbon bearing formation. [35]

6. BEETALOO BASIN (NORTHERN TERRITORY)

6.1 Introduction

The Beetaloo Basin is a 14,000-mi^2 rift basin located in the Northern Territory, approximately 400 miles southeast of Darwin, Figure III-23. The basin outline is defined by the Walton High to the north, the Helen Springs High in the south, and the Batten Trough in the east. Its western margin is projected to extend to the Daly Waters Arch.[36]

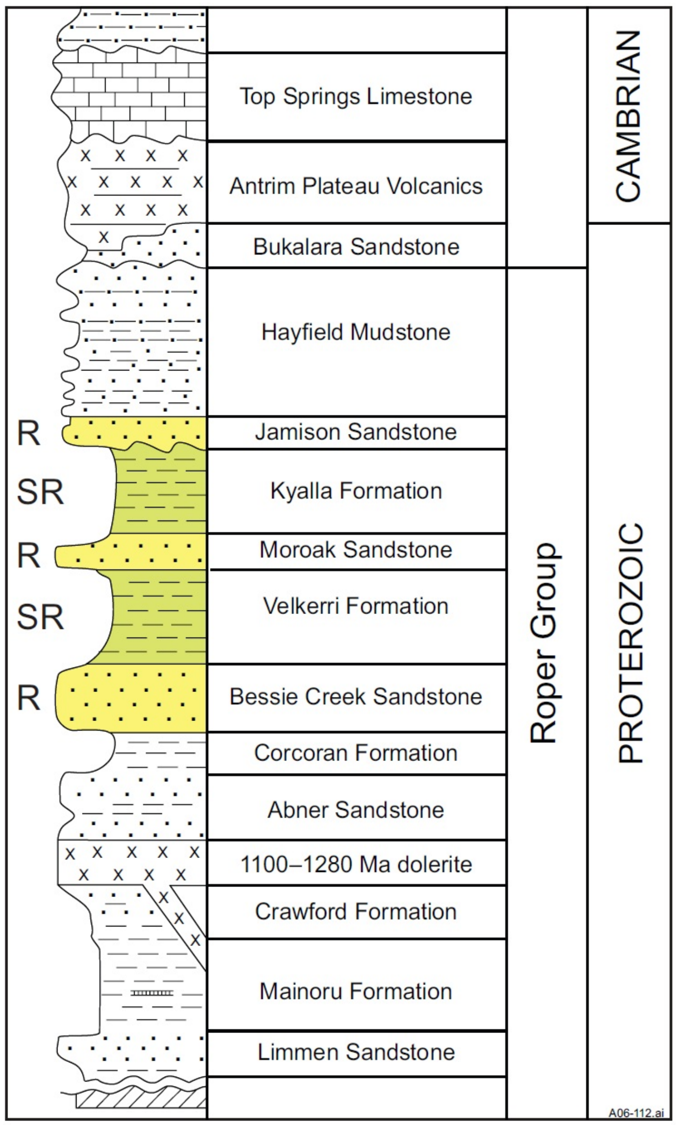
Figure III-23. Beetaloo Basin Location Map



Source: ARI, 2013

Well tests and cores from twelve exploratory wells, of late 1980s and early 1990s vintage, have identified oil and gas bearing organic-rich shales in the Pre-Cambrian Roper Group, Figure III-24. The Roper Group is up to 9,000 feet thick in the center of the Beetaloo Basin. Oil and gas shows have been observed in the Kyalla and Middle Velkerri shales, along with shows in adjoining conventional sandstone formations. These two shale formations, if prospective, would be some of the oldest producing source-rock formations in the world, on par with source rocks found in Oman and Siberia.

Figure III-24. Beetaloo Basin Stratigraphic Column

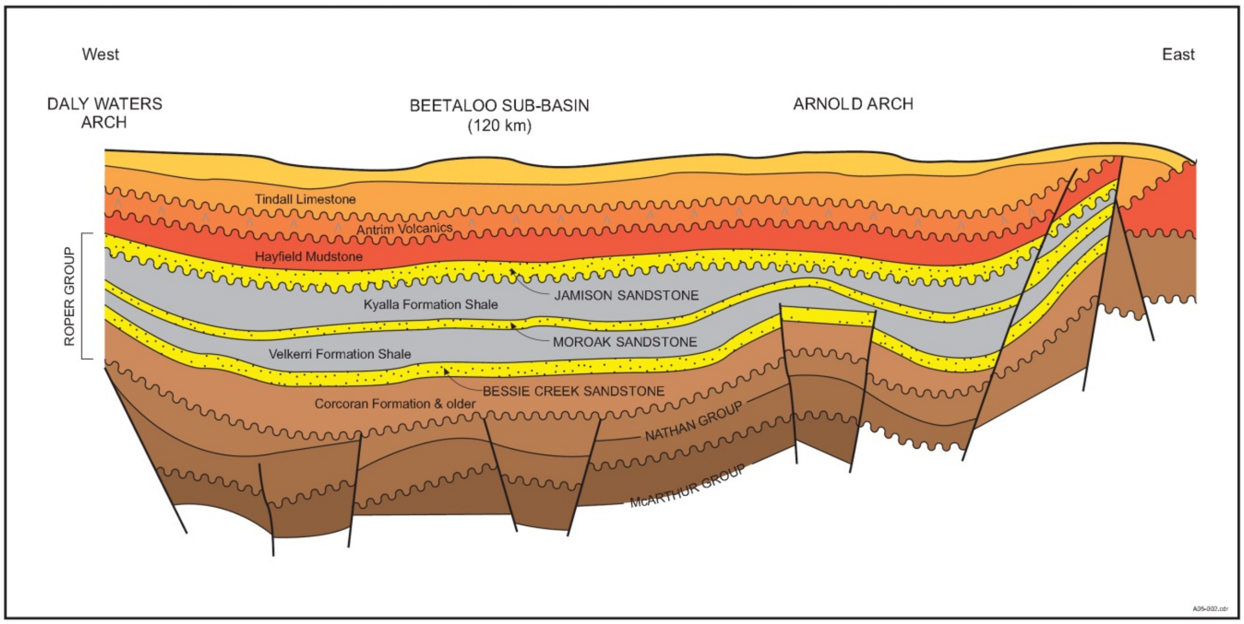


Source: Silverman et al, 2005

6.2 Geologic Setting

The structural characteristics of the Beetaloo Basin have been determined from gravity and magnetic data, along with recent reprocessing and reinterpretation of 2D seismic lines. Latest interpretations classify the basin as a rift basin[37], formed during the late Pre-Cambrian and unconformably overlying the western portion of the McArthur Basin. North-south trending faults, observed in the McArthur Basin, are thought to extend into the Beetaloo Basin Figure III-25. A 110 mile long regional gravity high bounding the west side of the basin, the Daly Waters Arch, is a thrust belt with over 3,000 feet of relief.

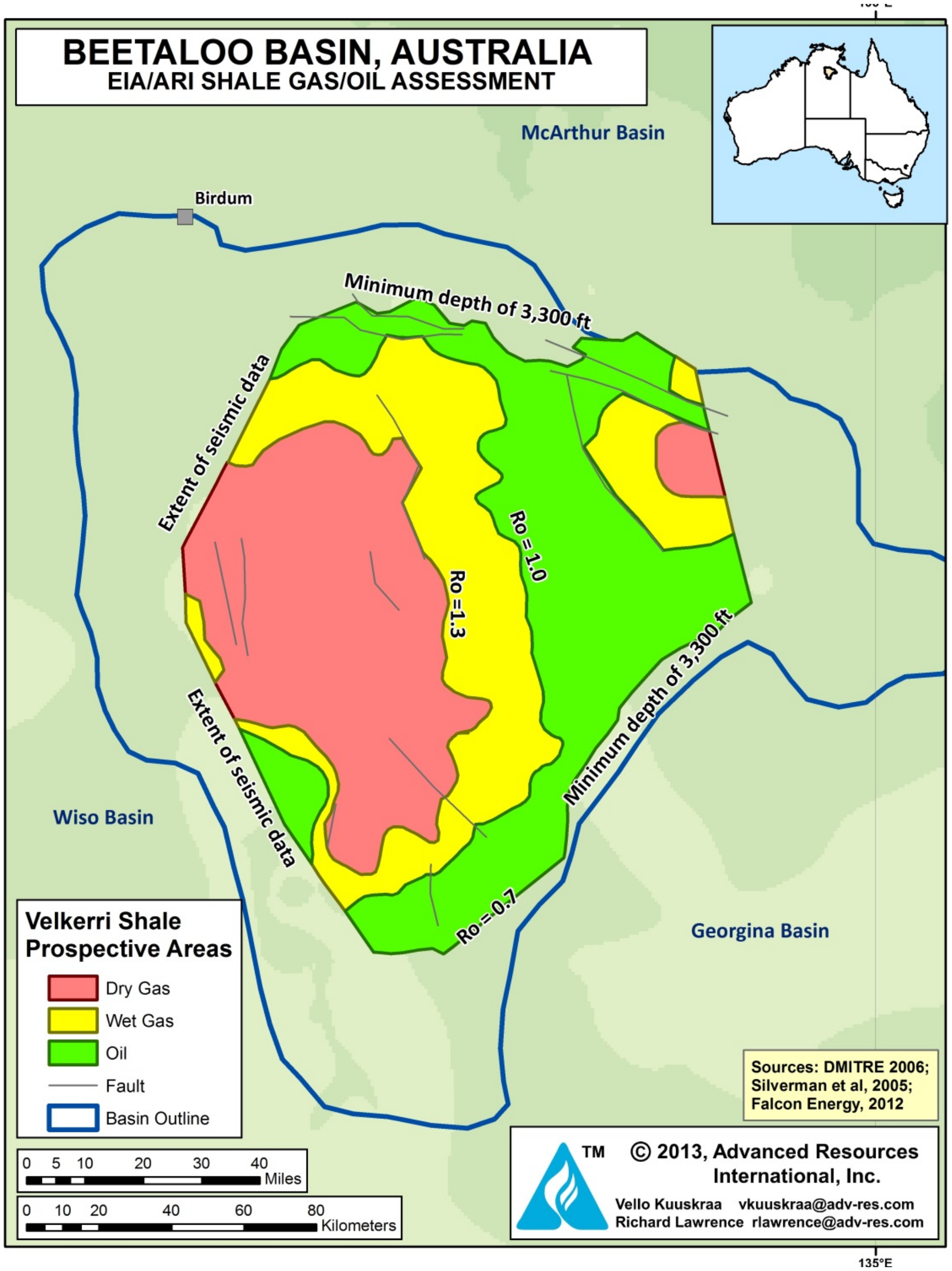
Figure III-25. East-West Cross-Section of the Beetaloo Basin



Source: Ambrose and Silverman, 2006[38]

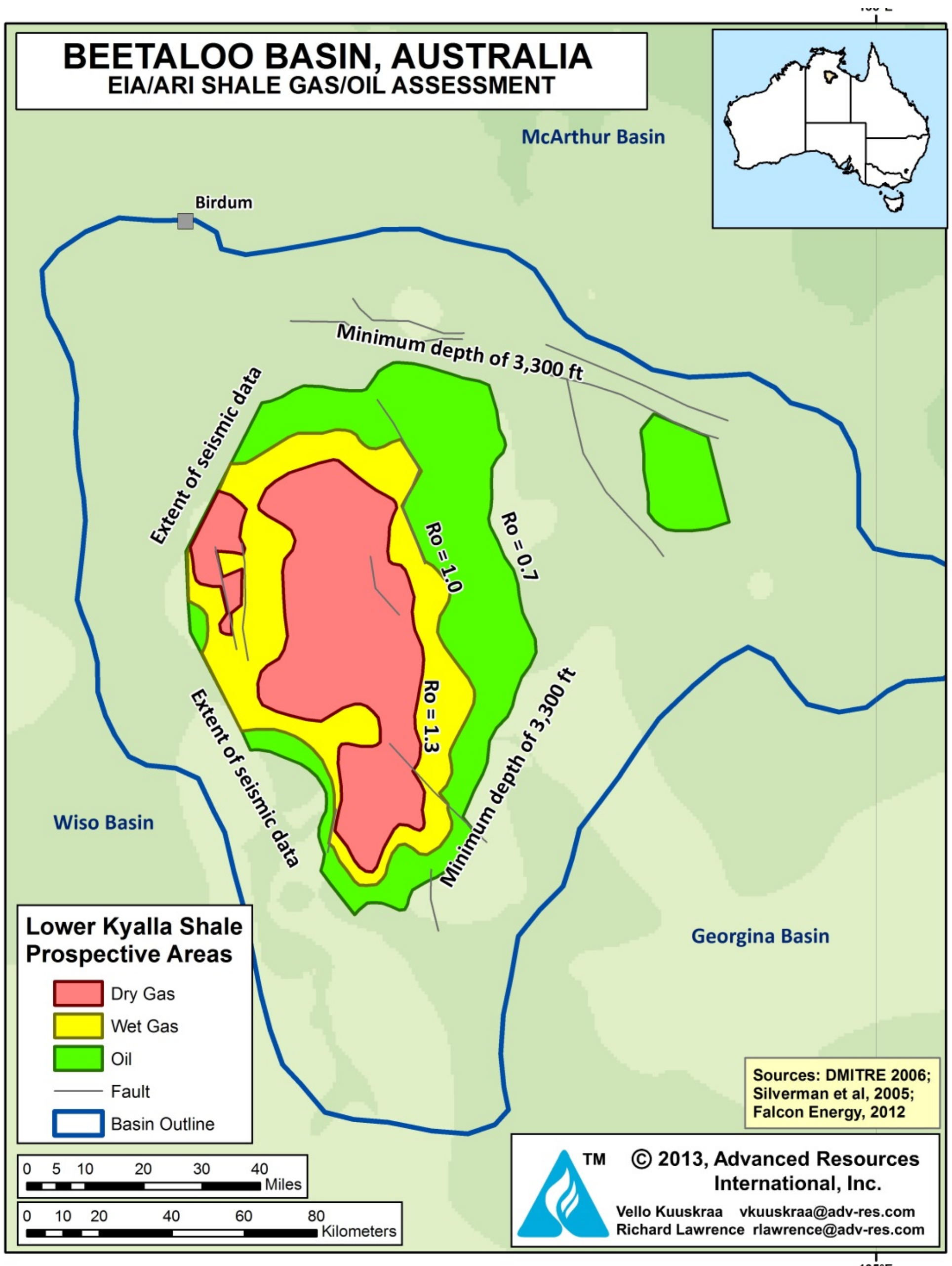
The Velkerri and the Kyalla shales have dry gas, wet gas/condensate and oil windows, based primarily on formation depth. The dry gas prospective area is 2,480 mi^2 for the Velkerri Shale and 1,310 mi^2 for the Kyalla Shale. The wet gas/condensate prospective area covers 2,130 mi^2 for the Velkerri Shale and 2,400 mi^2 Kyalla Shale. The shale oil prospective area is 2,650 mi^2 for the Velkerri Shale and 4,010 mi^2 for the Kyalla Shale, Figures III-26 and III-27.

Figure III-26. Beetaloo Basin Prospective Velkerri Shale Gas and Shale Oil Areas



Source: ARI, 2013.

Figure III-27. Beetaloo Basin Prospective Lower Kyalla Shale Gas and Shale Oil Areas



Source: ARI, 2013.

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6.3 Reservoir Properties (Prospective Area)

The Velkerri Formation is composed of black organic-rich shales layered with gray-green organic-lean shales and interbedded with thin siltstone and sandstone units. The Middle Velkerri Shale, a marine shale deposited in shallow to moderate depth environments, is considered prospective based on exploration wells drilled in the basin.[39] The depth of the prospective area of Middle Velkerri Shale ranges from 3,300 ft on the Walton High to 8,700 ft in the basin center. The organic-rich net pay of the Middle Velkerri Shale averages 100 feet across the basin.

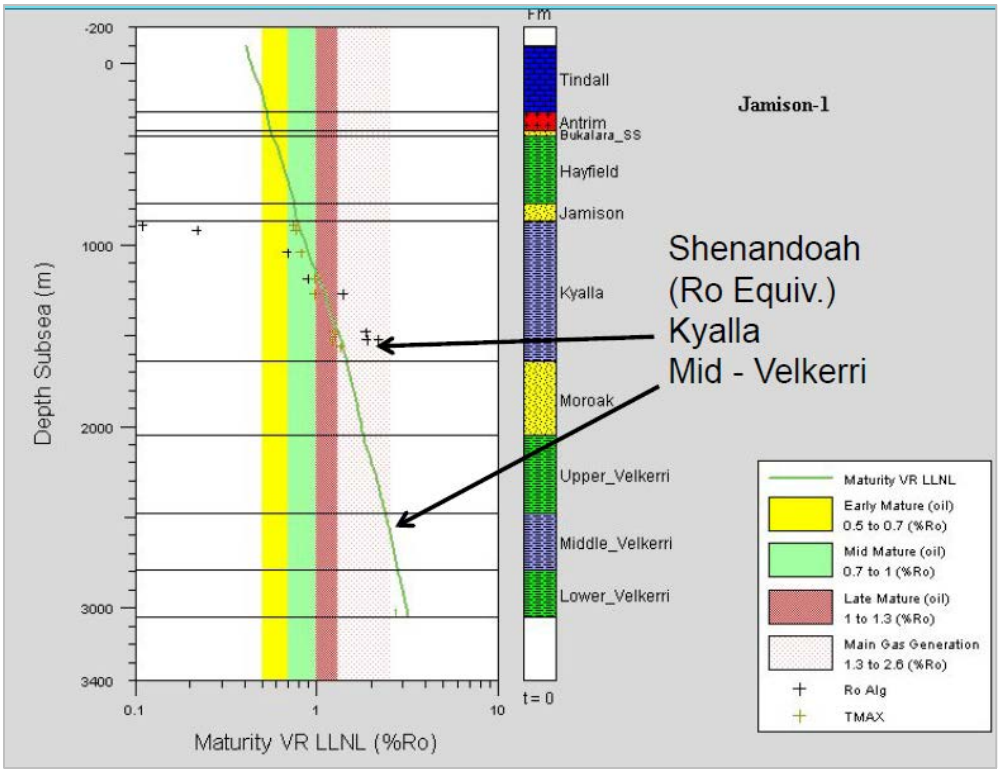
The Middle Velkerri has a maximum total organic carbon (TOC) content of 12%, averaging 4%. The organic matter is composed of oil prone Type I and II kerogens. The Upper and Lower Velkerri shales, with TOC contents of less than 2%, have not been included in the resource assessment.

The Kyalla Formation has an upper and a lower shale section, separated by the thin Kyalla Sandstone. The combined section is 600 to 2,500 ft thick, with the Upper Kyalla thinning considerably from west to east. Only the Lower Kyalla Shale has been included in the resource assessment. Shale depth in the prospective area ranges from 3,300 feet in the north and east to the 8,000 ft in the basin center. The Kyalla Shale is mature with Ro values of 0.7% to 1.6% depending on depth. While some organic-rich sections of the Lower Kyalla shale reach 9% TOC in the basin center, the TOC of the shale averages 2.5%.

The prospective areas in the Velkerri and Kyalla shales were estimated using data from well logs, thermal maturity models and seismic data, Figure III-28. The Middle Velkerri Shale is projected to be in the oil window (with R_o between 0.7% and 1.0%) from a depth of 3,300 ft to 5,000 ft. At depths greater than 5,000 ft the Middle Velkerri Shale enters the wet gas/condensate window with R_o between 1.0% and 1.3%. As the formation deepens to below 7,000 feet, the Velkerri Shale enters the dry gas window with R_o > 1.3%.

The Lower Kyalla Shale is in the oil window from 3,300-5,000 feet, enters the wet gas/condensate window below 5,000 feet, and reaches the dry gas window below 6,000 feet. The areas are constrained by the extent of the seismic data from which depths to formation were derived. Pay thickness and reservoir properties were estimated from well log data, with emphasis on the most recently drilled Shenandoah-1A well.

Figure III-28. Thermal Maturity Model for Jamison #1 Well



Source: Silverman and Ahlbrandt, 2011

6.4 Resource Assessment

The risked dry, wet and associated shale gas in-place for the Middle Velkerri Shale is 94 Tcf, with a risked, technically recoverable shale gas resource of 22 Tcf, Table III-1C. The risked shale oil/condensate in-place for the Middle Velkerri Shale is 28 billion barrels, with a risked, technically recoverable shale oil/condensate resource of 1.4 billion barrels, Table III-2B.

The Lower Kyalla Shale is calculated to have risked dry, wet and associated shale gas in-place of 100 Tcf, with a risked, technically recoverable shale gas resource of 22 Tcf, Table III-1C. The risked shale oil and condensate in-place and the risked, technically recoverable resource from the Lower Kyalla Shale are 65 billion barrels and 3.3 billion barrels respectively, Table III-2B.

6.5 Recent Activity

Falcon Oil and Gas Ltd has four exploration permits covering most of the Beetaloo Basin. In 2009, the company deepened the Shenandoah-1, a vertical test well located in the center of the basin. Drilled in 2007 by PetroHunter Energy, the original well had a total depth of 5,084 ft and intersected the Upper Kyalla Shale. Falcon deepened the well to 8,900 ft through the Lower Kyalla Shale, the Moroak Sandstone and the Velkerri Shale with gas shows noted in each formation.[40] The well was fractured and tested in November 2011, with reported gas and condensate flows from the Kyalla and Velkerri shales.

Falcon entered a Joint Venture with Hess in July 2011, covering the majority of the area in the exploration permits. Hess has committed up to $57.5 million to acquire 2,200 miles of 2D seismic. Two seismic crews are currently deployed in the basin with plans to finish surveying by the end of 2012. Hess has until June 2013 to commit to drilling five exploratory wells and earn a 62.5% interest in three of Falcon's exploration permits.[41] Falcon is seeking another partner to explore their fourth permit area which covers 700,000 acres.

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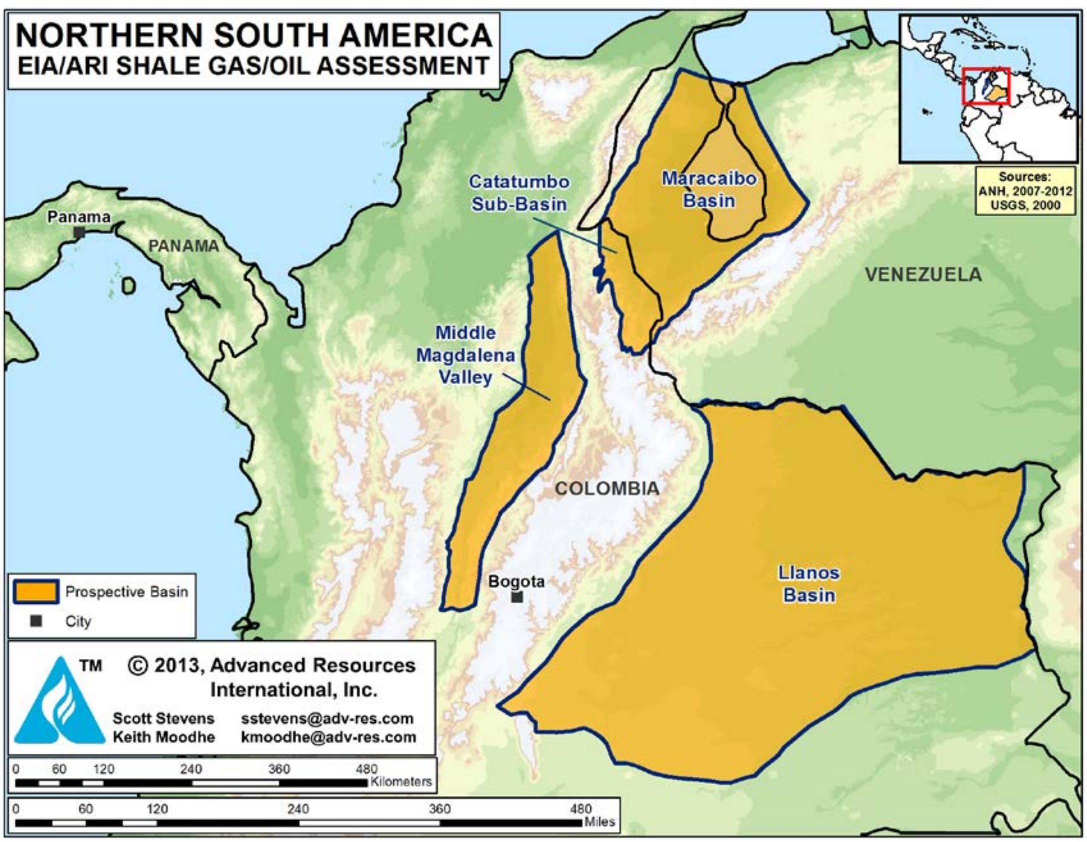
IV. NORTHERN SOUTH AMERICA

SUMMARY

Northern South America has prospective shale gas and shale oil potential within marine-deposited Cretaceous shale formations in three main basins: the Middle Magdalena Valley and Llanos basins of Colombia, and the Maracaibo/Catatumbo basins of Venezuela and Colombia, **Figure IV-1**. The organic-rich Cretaceous shales (La Luna, Capacho, and Gacheta) sourced much of the conventional gas and oil produced in Colombia and western Venezuela, and are similar in age to the Eagle Ford and Niobrara shale plays in the USA. Ecopetrol, ConocoPhillips, ExxonMobil, Shell, and others have initiated shale exploration in Colombia. Colombia's petroleum fiscal regime is considered attractive to foreign investment.

Figure IV-1: Prospective Shale Basins of Northern South America



Source: ARI 2013

For the current EIA/ARI assessment, the Maracaibo-Catatumbo Basin was re-evaluated while new shale resource assessments were undertaken on the Middle Magdalena Valley and Llanos basins. Technically recoverable resources (TRR) of shale gas and shale oil in northern South America are estimated at approximately 222 Tcf and 20.2 billion bbl, **Tables IV-1 and IV-2**. Colombia accounts for 6.8 billion barrels and 55 Tcf of risked TRR, while western Venezuela has 13.4 billion barrels and 167 Tcf. Eastern Venezuela may have additional potential but was not assessed due to lack of data.

Colombia's first publicly disclosed shale well logged 230 ft of over-pressured La Luna shale with average 14% porosity. More typically, the black shales within the La Luna and Capacho formations total about 500 ft thick, 10,000 ft deep, calcareous, and average 2-5% TOC. Thermal maturity comprises oil, wet-gas, and dry-gas windows (R_o 0.7-1.5%). Shale formations in the Llanos and Maracaibo/Catatumbo basins have not yet been tested but also have good shale oil and gas potential.

INTRODUCTION

As first highlighted in EIA/ARI's 2011 assessment, Colombia and Venezuela both have excellent potential for shale oil and gas.. In particular, Colombia's shale potential appears considerably brighter today based on the results of initial shale drilling as well as the entry of major oil companies (ConocoPhillips, ExxonMobil, and Shell) as well as several smaller companies.

Colombia's Agencia Nacional de Hidrocarburos (ANH) regulates oil and gas exploration and development. The country's model contract for unconventional gas includes 8-year exploration and 24-year production terms. Preferential terms are in place for shale gas investment, including a 40% reduction in royalties and higher oil prices. In 2011 the National University of Colombia conducted a shale gas resource evaluation for ANH, estimating a total 33 Tcf of potential in the Eastern Cordillera, Eastern Llanos and Caguan-Putumayo regions. The study and methodology have not been disclosed; apparently shale oil resources were not assessed. ANH conducted Colombia's first auction of shale gas blocks in 2012.

Table IV-1: Northern South America Shale Gas Reservoir Properties and Resources.

Basic Data	Basin/Gross Area		Middle Magdalena Valley ($13,000\ mi^2$)		Llanos ($84,000\ mi^2$)	Maracaibo/Catatumbo ($23,000\ mi^2$)		
	Shale Formation		La Luna/Tablazo		Gacheta	La Luna/Capacho		
	Geologic Age		U. Cretaceous		U. Cretaceous	U. Cretaceous		
	Depositional Environment		Marine		Marine	Marine		
Physical Extent	Prospective Area (mi^2)		2,390	200	1,820	7,280	4,290	5,840
	Thickness (ft)	Organically Rich	1,000	1,000	600	1,000	1,000	1,000
		Net	300	300	210	500	500	500
	Depth (ft)	Interval	3,300 - 16,400	3,300 - 10,000	13,000 - 16,400	5,000 - 15,000	5,500 - 15,000	6,000 - 15,000
		Average	10,000	8,000	14,500	10,000	11,000	12,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Mod. Overpress.	Normal	Normal	Normal
	Average TOC (wt. %)		5.0%	5.0%	2.0%	5.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	0.85%	1.15%	1.60%
	Clay Content		Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Assoc. Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		88.0	150.3	40.4	71.8	176.1	255.7
	Risked GIP (Tcf)		117.8	16.8	18.2	183.0	264.4	522.6
	Risked Recoverable (Tcf)		14.1	4.2	1.8	18.3	52.9	130.7

Table IV-2: Northern South America Shale Oil Reservoir Properties and Resources.

Basic Data	Basin/Gross Area		Middle Magdalena Valley ($13,000\ mi^2$)		Llanos ($84,000\ mi^2$)	Maracaibo/Catatumbo ($23,000\ mi^2$)	
	Shale Formation		La Luna/Tablazo		Gacheta	La Luna/Capacho	
	Geologic Age		U. Cretaceous		U. Cretaceous	U. Cretaceous	
	Depositional Environment		Marine		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		2,390	200	1,820	7,280	4,290
	Thickness (ft)	Organically Rich	1,000	1,000	600	1,000	1,000
		Net	300	300	210	500	500
	Depth (ft)	Interval	3,300 - 16,400	3,300 - 10,000	13,000 - 16,400	5,000 - 15,000	5,500 - 15,000
		Average	10,000	8,000	14,500	10,000	11,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Mod. Overpress.	Normal	Normal
	Average TOC (wt. %)		5.0%	5.0%	2.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	0.85%	1.15%
	Clay Content		Low	Low	Low	Low	Low
Resource	Oil Phase		Oil	Condensate	Oil	Oil	Condensate
	OIP Concentration ($MMbbl/mi^2$)		57.0	26.1	28.0	92.3	41.0
	Risked OIP (B bbl)		76.3	2.9	12.6	235.1	61.6
	Risked Recoverable (B bbl)		4.58	0.18	0.63	11.75	3.08

Venezuela's government and oil companies have not disclosed shale oil or shale gas exploration activities, although the potential in western Venezuela appears to be large and of high quality. Overall, three main basins are present in northern South America that contain prospective marine-deposited shales and were assessed in this report, Figure IV-2. These basins include:

- **Middle Magdalena Valley Basin (Colombia):** The focus of shale exploration leasing and drilling activity in the region thus far, the MMVB near Bogota also is Colombia's main conventional onshore production area. It contains thick deposits of the organic-rich Cretaceous La Luna Formation, mostly in the oil to wet gas windows.
- **Llanos Basin (Colombia):** This large basin in eastern Colombia has prospective Gacheta Formation source rock shales of Cretaceous age that are equivalent to the La Luna Fm. TOC and R_o generally appear low, but the western foothills region may be richer and more thermally mature.
- **Maracaibo/Catatumbo Basin (Venezuela and Colombia):** One of South America's richest petroleum basins, the Maracaibo (Venezuela) and Catatumbo (Colombia) basins have extensive oil and gas potential in thick, widespread Cretaceous La Luna Shale.
- A fourth basin, the **Putamayo Basin** in southern Colombia, also may contain shale potential but was not assessed due to lack of data. The Putamayo contains organic-rich Cretaceous shales in the Macarena Group.[1] While relatively shallow (3,000 ft) in this up-thrusted basin-edge location, the Macarena shales deepen towards the center of the basin where they may become less faulted. Hydraulic fracturing already is being used in the Putamayo Basin for conventional reservoirs.[2]

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Figure IV-2: Stratigraphic Chart Showing Source Rocks And Conventional Reservoirs In Northern South America.

			COLOMBIA & VENEZUELA BASINS		
	BASIN		MID MAGDALENA VALLEY	MARACAIBO-CATATUMBO	LLANOS
ERA	PERIOD	EPOCH	F O R M A T I O N		
CENOZOIC	QUATERNARY	Pleistocene	Alluvium	Alluvium	Necesidad
	TERTIARY	Pliocene	Mesa	Guayabo	Guayabo
		Miocene	Real	Leon	Leon
			Colorado	*Carbonera*	*Carbonera*
		Oligocene	*Mugrosa*		
		Eocene	*Esmeraldas*		
			La Paz	*Mirador*	*Mirador*
		Paleocene	Lisama	Los Cuervos	Los Cuervos
				Barco Catatumbo	Barco
MESOZOIC	CRETACEOUS	Upper	Umir	Mito Juan	Guadalupe
			La Luna	Colon	Gacheta
				La Luna	*Une*
			Simiti	Capacho	
		Lower		*Aguardiente*	
			Tablazo	*Apon*	
			Paja		
			Rosablanca	Rio Negro	
			Cumbre		
	JURASSIC		Arcabuco/ Giron	Giron	
	TRIASSIC				

Source Rock	*Conventional Reservoir*	Absent/Unknown

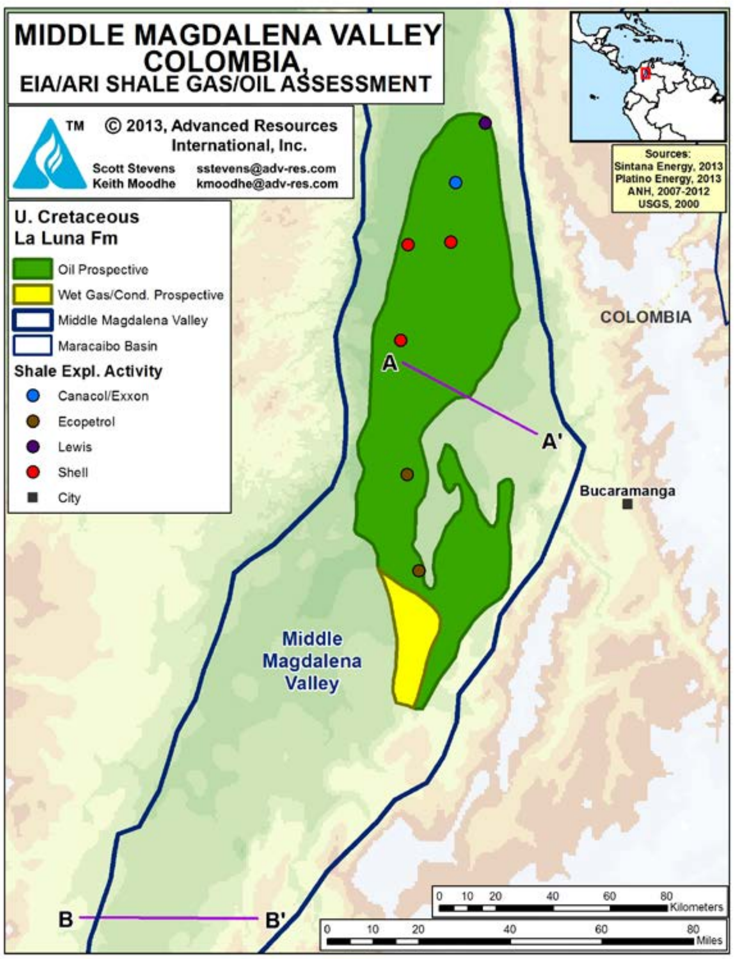
Source: ARI 2013

1. MIDDLE MAGDALENA VALLEY BASIN (COLOMBIA)

1.1 Introduction and Geologic Setting

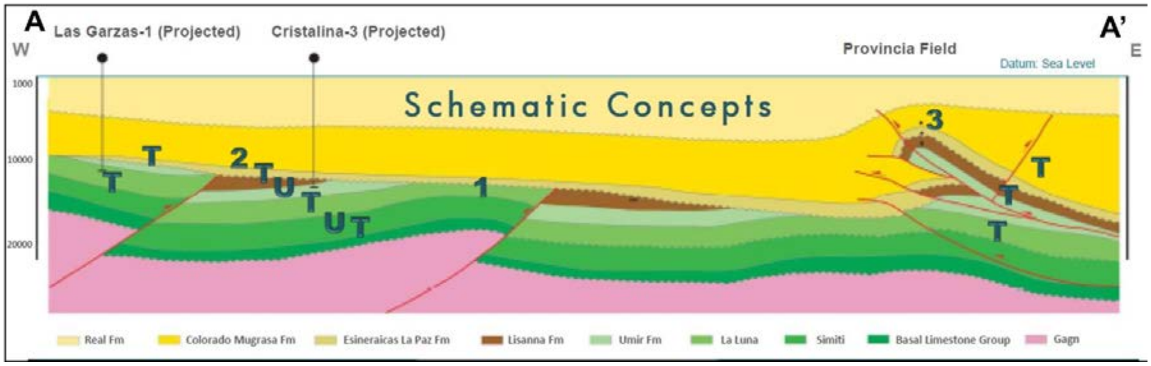
The 13,000-mi^2 Middle Magdalena Valley Basin (MMVB) is a north-south trending inter-montane basin in central Colombia, situated between the Eastern and Central cordilleras and located 150 miles north of Bogota, **Figure IV-3**. The MMVB is Colombia's most explored conventional oil and gas producing basin, with over 40 discovered oil fields that produce mainly from Tertiary sandstone reservoirs. Although within the Andes Mountains region, with its complex tectonics including numerous thrust and extensional faults, the interior of the MMVB has simpler structure with relatively flat surface topography, **Figure IV-4**.[3] The western side of the basin is structurally more complex and overthrusted, **Figure IV-5**.[4]

Figure IV-3: Middle Magdalena Valley Basin, Shale-Prospective Areas and Shale Exploration



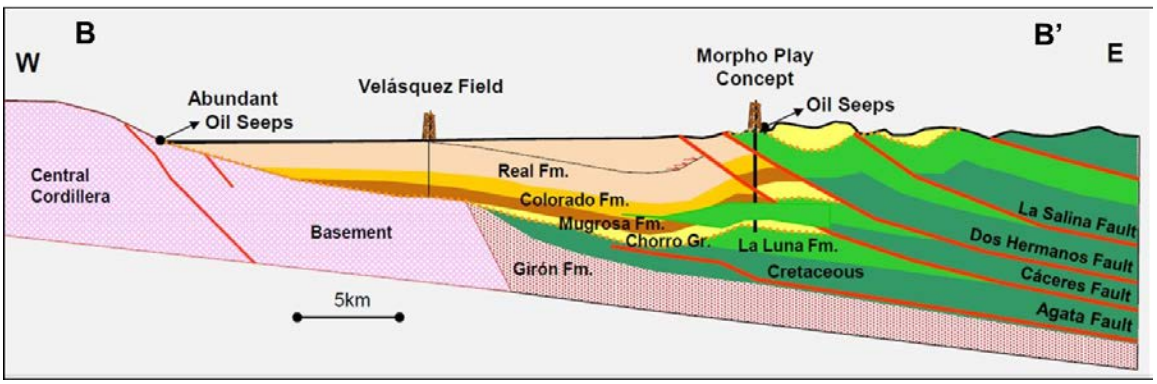
Source: ARI 2013

Figure IV-4: Schematic Cross-Section of the Middle Magdalena Valley Basin Showing U. Cretaceous Umir and La Luna And L. Cretaceous Simiti Shales Totaling 750-1,000 Ft Thick (Correlate With Eagle Ford Shale).



Source: Sintana Energy, Q3 2012

Figure IV-5: Schematic Cross-Section of Western Margin of the Middle Magdalena Valley Basin in Central Colombia, Showing Thrusted Fault Blocks with La Luna Shale.



Source: Platino Energy, 2013

The Cretaceous La Luna Formation is the principal source rock in the MMVB. A marine-deposited black shale, the organic-rich La Luna was formed in a widespread epicontinental sea and is time-equivalent (Santonian) with the Niobrara Shale in the USA.[5] However, sedimentation and facies distribution of the La Luna Fm were strongly controlled by the paleo-topography, while post-depositional tectonics caused erosional events that truncated its thickness in places. For example, much of the Campanian and lower Maastrichtian sections were eroded in the southern Upper Magdalena Valley and Putumayo Basins.[6]

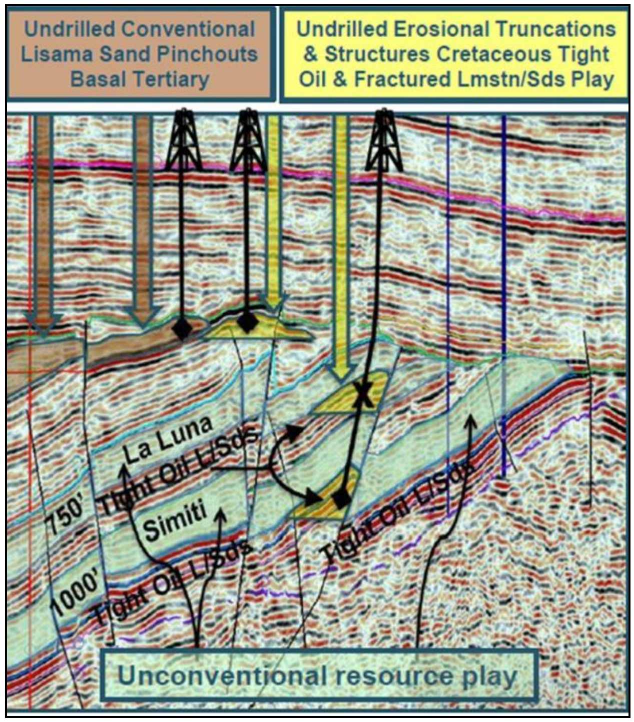
The La Luna Formation comprises three members: the Salada, Pujamana, and Galembo.[7] The most organic-rich (3-12% TOC) is the 150-m thick Salada Member, which consists of hard, black, thinly bedded and finely laminated limy shales (40% $CaCO_3$), along with thin interbeds of black fine-grained limestone. Pyrite veins and concretions are common, as are planktonic (but not benthonic) foraminifera and radiolaria. The lower-TOC Pujamana Member consists of gray to black, thinly bedded and calcareous shale (43% $CaCO_3$). The 220-m thick Galembo Member has moderate TOC (1-4%) and also consists of black, thinly bedded, calcareous shale, but with only thin argillaceous limestone interbeds. The Galembo also has abundant blue to black chert beds.[8] The underlying Cretaceous Tablazo/Rosablanca Fm, about 480-920 ft thick, also contains high TOC (2-8%) that is in the oil to wet gas windows (R_o 0.6% to 1.2%).

1.2 Reservoir Properties (Prospective Area)

The 1,000-ft thick Cretaceous La Luna Formation ranges from 3,000 ft to slightly over 15,000 ft deep across the Middle Magdalena Valley Basin. However, the La Luna is truncated in places by an erosional unconformity, which juxtaposes Paleogene La Paz Fm on top, **Figure IV-6**. The La Luna shale is organic rich (average 5%) with mainly Type II kerogen.[9] We mapped a larger (2,390-mi^2) oil-prone prospective window for the La Luna shale, with a much smaller (200 mi^2) wet gas window to the south (R_o 0.7% to 1.2%).

Calgary-based Canacol Energy Ltd. has noted that the La Luna and Tablazo/ Rosablanca shales are 4,000 to 12,000 ft deep across its blocks in the MMVB . The La Luna ranges from 1,200 to 1,800 ft thick while the underlying Tablazo/Rosablanca is 480 to 920 ft thick. TOC of the two units ranges from 2% to 8% and is mostly at oil-prone thermal maturity (R_o 0.6% to 1.2%). Shale porosity is estimated by Canacol to be 3% to 14%.[10] In 2012 Canacol drilled the Mono Arana-1 well on its VMM 2 block, where it is partnered with ExxonMobil. The well tested shallow conventional targets as well as deeper shale and carbonate potential in the La Luna and Tablazo oil source rocks. Heavy mud, up to 16.5 pounds per gallon, was required to safely drill across these over-pressured shales, indicating they are at nearly twice the normal hydrostatic pressure. The well encountered the top of the La Luna Formation at a depth of 9,180 ft and penetrated 760 ft into the formation, logging oil and gas shows across the entire shale interval. Logs run across the La Luna reportedly indicated 230 ft of potential high-quality net oil pay with 14% average porosity.

Figure IV-6: Seismic Line in the Middle Magdalena Valley Basin Showing Cretaceous La Luna and Simiti Shales Truncated by Erosional Unconformity.



Source: Sintana Energy, Q3 2012

According to Texas-based Sintana Energy the La Luna Formation averages about 1,500 ft thick (gross), has 950-1,900 ft of net pay, 5-10% TOC, 15% effective porosity, and favorably low 17% clay content (should be quite brittle) on the company's blocks in the western MMVB. The underlying Tablazo Formation averages about 600 ft thick (gross), has 150-450 ft of net pay, 5.5-7.0% TOC, 8% effective porosity, and higher 30% clay content. The La Luna in Sintana's area is in the oil window (R_o 0.7-1.0%), while the Tablazo is in the oil to wet gas windows (R_o 1.1%). The pressure gradient ranges from 0.55-0.80 psi/ft in the La Luna to 0.65 psi/ft in the Tablazo.[11]

1.3 Resource Assessment

The risked, technically recoverable shale gas and shale oil resources in the combined Cretaceous La Luna and Tablazo shales of the Middle Magdalena Valley Basin are estimated to be 18 Tcf and 4.6 billion barrels, out of risked shale gas and shale oil in-place of 135 Tcf and 79 billion barrels. By comparison Ecopetrol has estimated the MMV Basin has 29 Tcf of shale gas potential (methodology not disclosed, nor was oil potential noted).

Advanced Resources International, Inc.

1.4 Recent Activity

A number of companies -- including Ecopetrol, ConocoPhillips, ExxonMobil, Nexen, and Shell -- have initiated shale oil and gas exploration programs at existing conventional oil and gas lease positions in Colombia during the past two years. Activity has been concentrated in the Middle Magdalena Valley Basin, close to the Bogota market. More than 12 vertical and horizontal shale exploration wells were planned for 2012, including several re-entries.

State-owned Ecopetrol S.A., which controls about one-third of the oil and gas licenses in Colombia, first announced its shale exploration program in early 2011 and drilled the La Luna-1 stratigraphic test in the MMVB later that year (results not disclosed). Ecopetrol already has been drilling horizontal wells in the MMVB for non-shale targets during the past several years, providing a good foundation for future horizontal shale development in the basin.[12]

Canacol holds three conventional exploration licenses in Colombia, which the company estimates have a total 260,000 gross acres with shale oil potential. The company has disclosed a Mean Estimate of 2.9 billion barrels of recoverable resource potential within their lease position. In recent months Canacol has signed separate joint-venture agreements with ConocoPhillips, ExxonMobil, and Shell to conduct shale exploration within Canacol's acreage. These companies plan to drill a total of 19 shale exploration wells at an estimated cost of $123 million. ConocoPhillips expects to drill its first exploration well to test the La Luna Shale in the second quarter of 2013.[13] Canacol continues to review the shale potential of two of its other blocks.

Nexen was one of the first companies to report exploring for shale gas in Colombia. The company reports it holds several shale blocks in Colombia for a total 1.5 million acres with shale gas potential.[14] In late 2011 Nexen began drilling the first of four planned shale gas wells. These wells, located in Sueva and Chiquinquira blocks in the Sabana de Bogota high savannah plateau of the Eastern Cordillera mountain range, reportedly target the La Luna Formation. No further details are available.

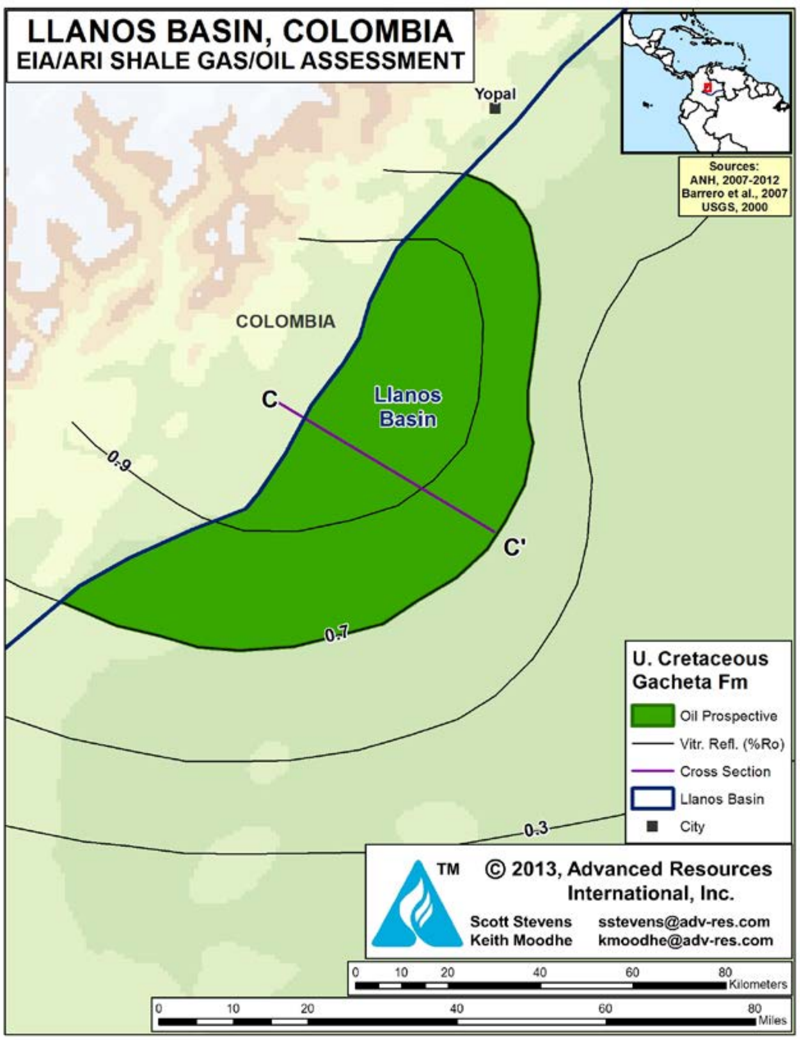
Sintana Energy has reported that its third-party consultant estimated 210 million bbl of prospective recoverable resources in shale formations at the company's VMM-37 block in the MMVB, which cover 44,000 acres (Mean Estimate). Sintana estimated initial horizontal well costs at about $13 million.

2. LLANOS BASIN (COLOMBIA)

2.1 Introduction and Geologic Setting

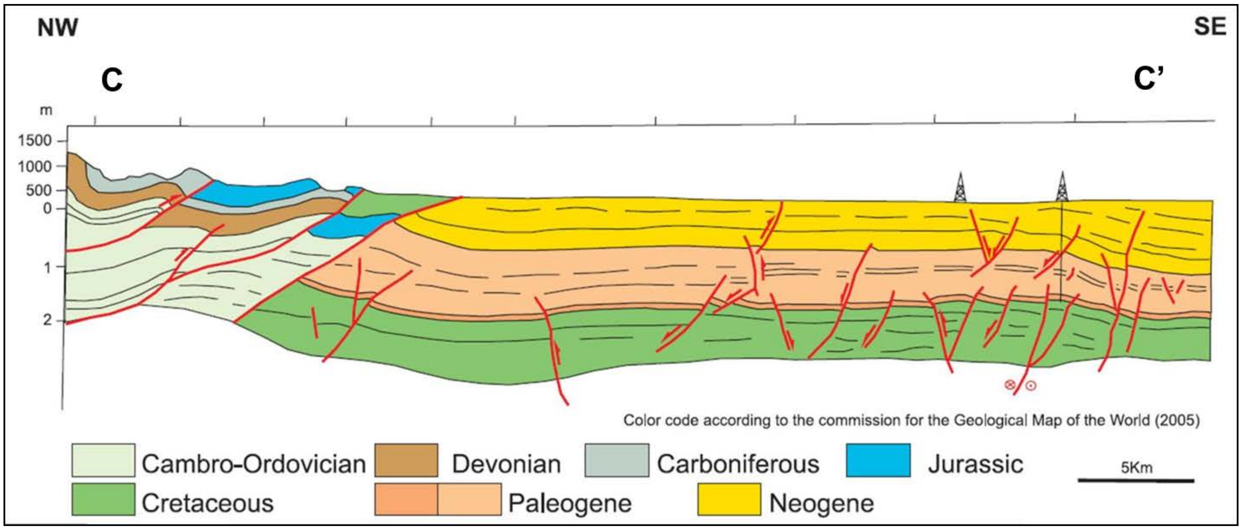
The large (84,000-mi^2) Llanos Basin, located in eastern Colombia, has only recently become a focus of shale exploration and thus is less well understood than the Middle Magdalena Valley Basin, **Figure IV-7**. The Gacheta Fm shale source rocks are equivalent to the La Luna Fm in the MMV and Maracaibo/Catatumbo basins. The northeast-trending Llanos Basin represents the northern extent of the Sub-Andean Mountain Belt. **Figure IV-8** shows the generally simple geologic structure in the interior of the Llanos Basin, as well as the overthrusting on the western margin.

Figure IV-7: Llanos Basin Showing Shale-Prospective Area.



Source: ARI 2013

Figure IV-8: Schematic Cross Section of the Llanos Basin in Colombia



Source : ANH, 2007

Up to 30,000 ft of Cambrian to Ordovician strata are unconformably overlain by thick Cretaceous marine shale deposits. These in turn were partially eroded by uplift during the early Tertiary. Other potential source rocks in the Llanos Basin include the Cretaceous Los Cuervos Fm and Tertiary shales (Carbonera and Leon formations).[15] Conventional reservoirs are found in the Paleogene Carbonera and Mirador sandstones as well as Cretaceous sandstones.

2.2 Reservoir Properties (Prospective Area)

The Cretaceous Gacheta Fm, time-equivalent to the La Luna Fm and averaging 600 ft thick, is the principal source rock in the Llanos Basin. The Gacheta reaches a depth of more than 15,000 ft along the basin's western margin, shoaling to only 2,000 feet in the east. The central axis has the Gacheta shale ranging from 4,000 to over 10,000 ft deep.

The 1,820-mi^2 depth-prospective area is entirely in the oil window. The effective source rock thickness of the Gacheta shale ranges from 150 to 300 ft (average 210 ft net), with TOC of 1% to 3% consisting of Type II and III kerogen.[16] Thermal maturity of the Gacheta ranges from the oil to wet gas windows, with R_o ranging from 0.3% in the shallow east to 1.1% in the deeper western foothills region where the shale oil potential is greatest.[17] Porosity is uncertain but assumed to be relatively high (7%) based on initial data on the correlative La Luna Shale in the MMVB. The basin is slightly over-pressured, averaging about 0.5 psi/ft gradient.

2.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources in the Llanos Basin are estimated to be 2 Tcf of associated shale gas and 0.6 billion barrels of shale oil and condensate, out of risked shale gas and shale oil in-place of about 18 Tcf and 13 billion barrels, **Tables IV-1 and IV-2**. Within the prospective area, the play has a moderate resource concentrations of about 40 Bcf/mi^2 and 28 million bbl/mi^2.

2.4 Recent Activity

No shale exploration leasing or drilling has been reported in the Llanos Basin. Sintana Energy previously mentioned the shale potential of its leases in the Llanos Basin in the company's 2011 investor presentation.

3. MARACAIBO-CATATUMBO BASIN (VENEZUELA, COLOMBIA)

3.1 Introduction and Geologic Setting

The Maracaibo Basin extends over 23,000 mi^2 in western Venezuela and eastern Colombia, the latter area known locally as the Catatumbo Sub-basin, **Figure IV-9**.[18] The Maracaibo/Catatumbo Basin contains a rich sequence of organic-rich marine-deposited Cretaceous shales that are the principal source rocks for prolific conventional fields.[19] These Cretaceous shales, especially the La Luna and Gapacho, appear to be prospective targets for shale oil and gas exploration.

Depth to the Precambrian-Jurassic basement in the Maracaibo Basin reaches over 20,000 feet in southern Lake Maracaibo and its onshore eastern edge, **Figure IV-10**. On the west side of the basin, basement and Cretaceous shale deposits become shallower again, **Figure IV-11**. Depth to the La Luna Fm ranges from less than 5,000 to over 15,000 feet, generally deepening from northeast to southwest. The eastern edge of the shale play is limited by maximum 15,000-ft depth, inferred from the structure of the Late Jurassic basement.[20]

The Catatumbo Sub-basin, located on the rugged east flank of the Andes in eastern Colombia, has similar shale targets but is structurally more complex than the rest of the Maracaibo Basin, with thrust faulting in the west and less severe wrench-faulting in the east, **Figure IV-12**.[21] Much like the northern Maracaibo Basin, the Catatumbo Sub-basin has numerous conventional oil fields.

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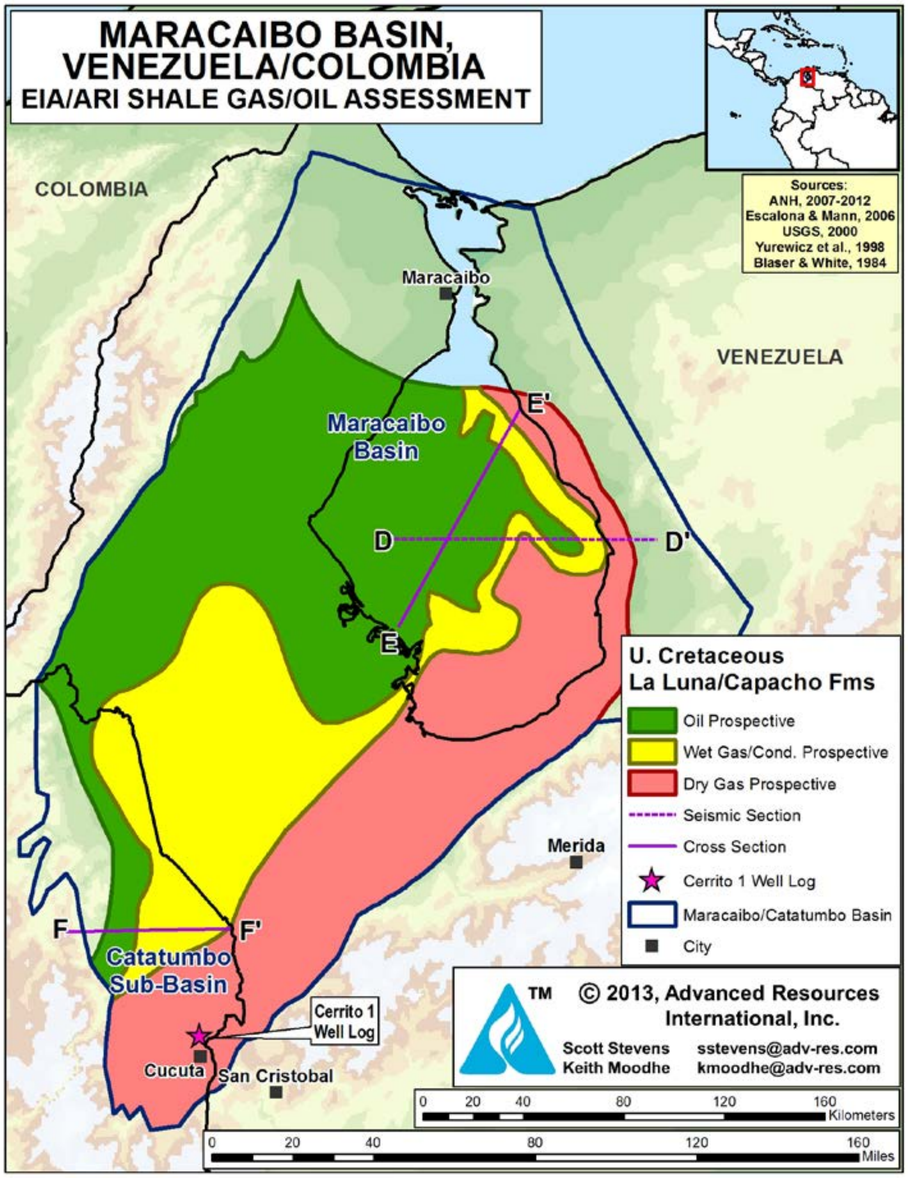
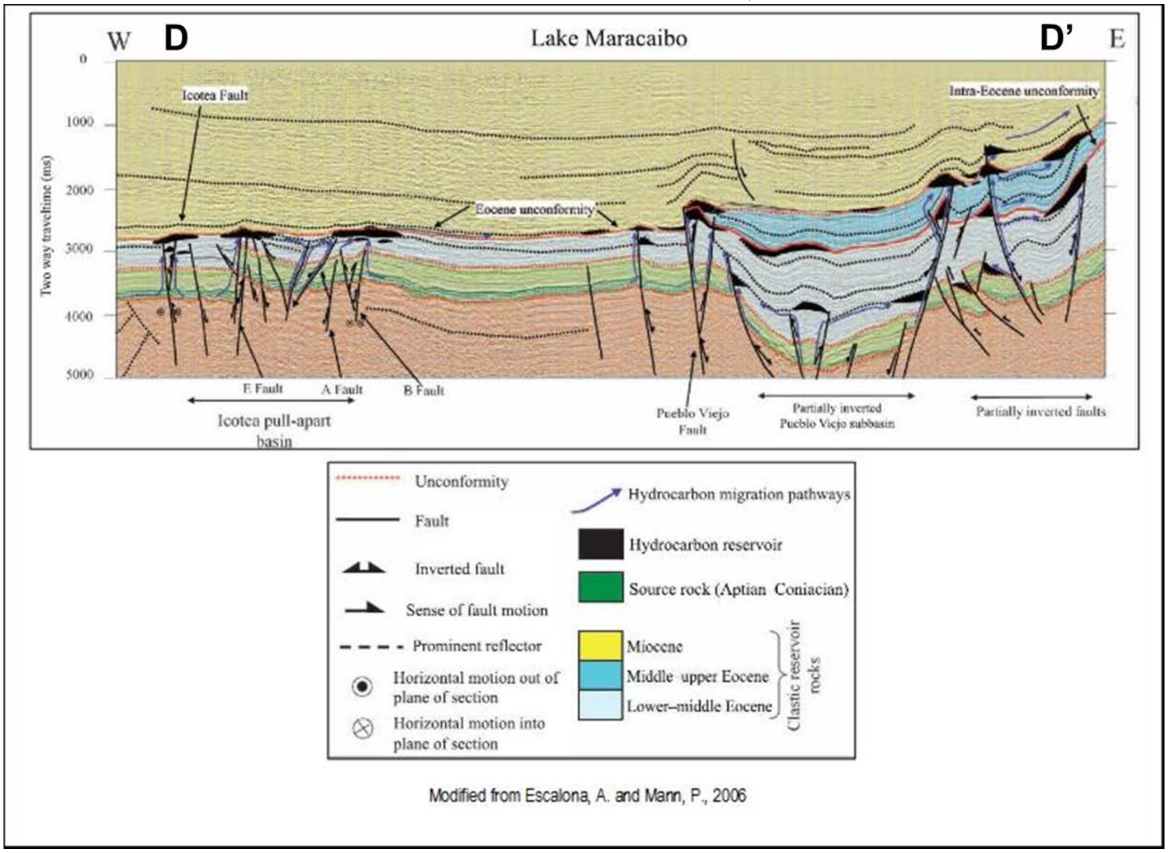
Figure IV-9: Prospective Area for Shale Exploration in the Maracaibo/Catatumbo Basin.



Source : ARI, 2013

Figure IV-10: Seismic Time Section of the Maracaibo Basin in Western Venezuela.

Modified from Escalona and Mann, 2006



Source : ARI, 2013

Advanced Resources International, Inc.

Figure IV-10: Schematic Cross-Section Showing Depth to Cretaceous Source Rocks in the Maracaibo Basin, Western Venezuela.

Modified from Escalona and Mann, 2006

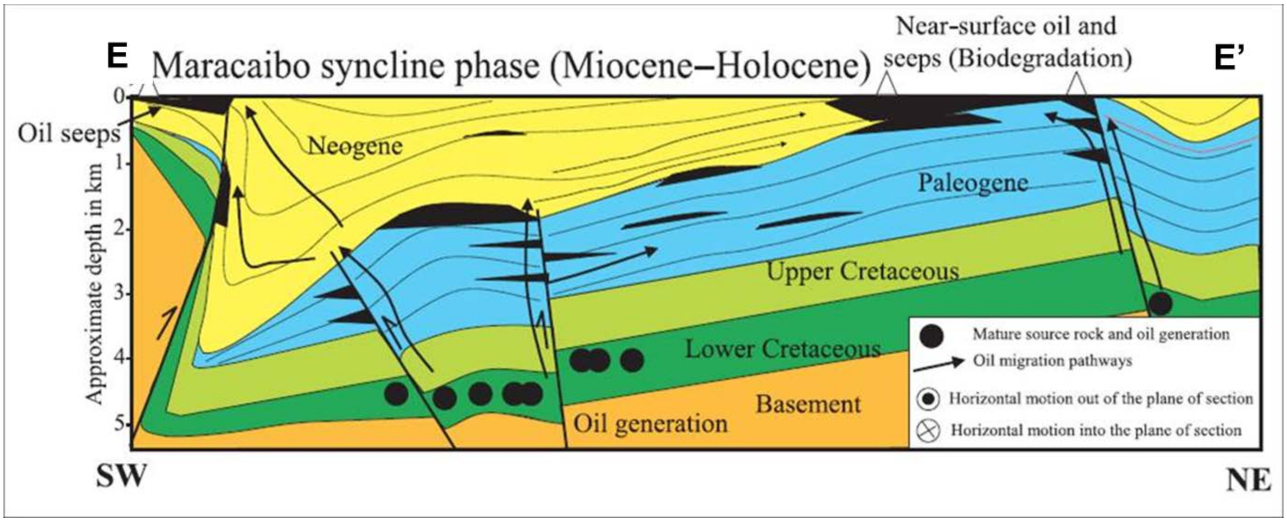
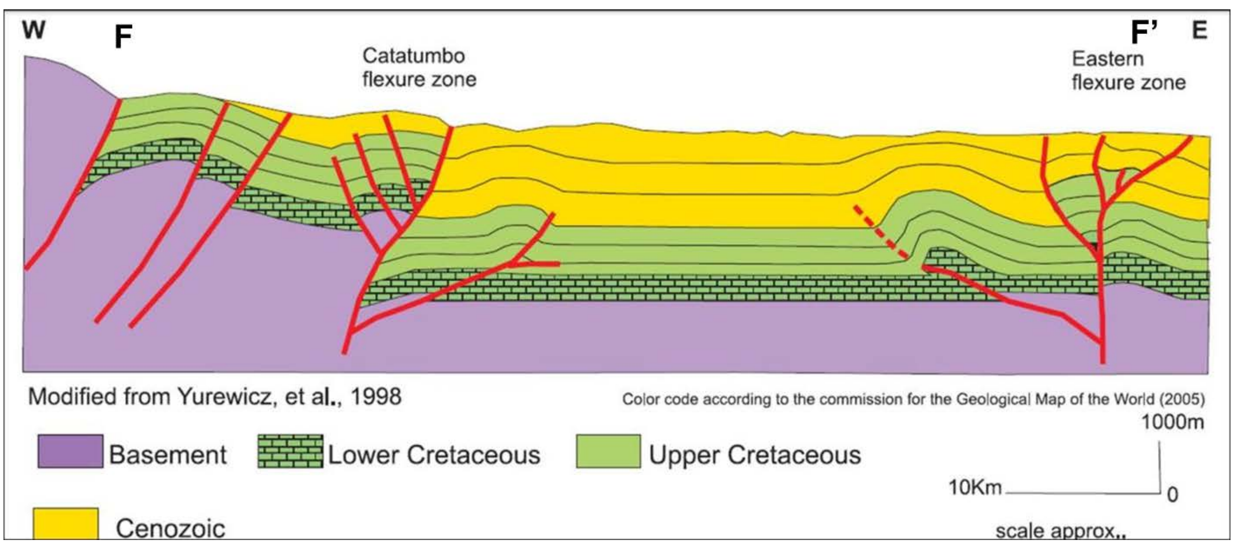


Figure IV-12: Schematic Cross-Section of the Catatumbo Sub-Basin in Eastern Colombia.

Modified from Yurewicz et al., 1998



La Luna Formation. The Maracaibo-Catatumbo Basin hosts some of the world's richest source rocks and conventional oil and gas reservoirs. The Late Cretaceous (Cenomanian-Santonian) shale of the La Luna Formation, the primary source rock in the basin[22] and time-equivalent with the Eagle Ford Shale in Texas, appears to be the most prospective target for shale oil and gas exploration. The black calcareous La Luna Shale ranges from 100 to over 400 feet thick across the basin, thinning towards the south and east. [23,24]

Total organic carbon (TOC) varies across the basin, with values ranging from 3.7% to 5.7% in the northwest to 1.7% to 2% in the south and east. Maximum TOC values can reach 16.7%. A large portion of this shale-gas-prospective area includes part of Lake Maracaibo itself. ARI chose to include this submerged area because water depths are shallow (less than 100 feet) and there are numerous conventional production platforms that could provide access to shale drilling and development.

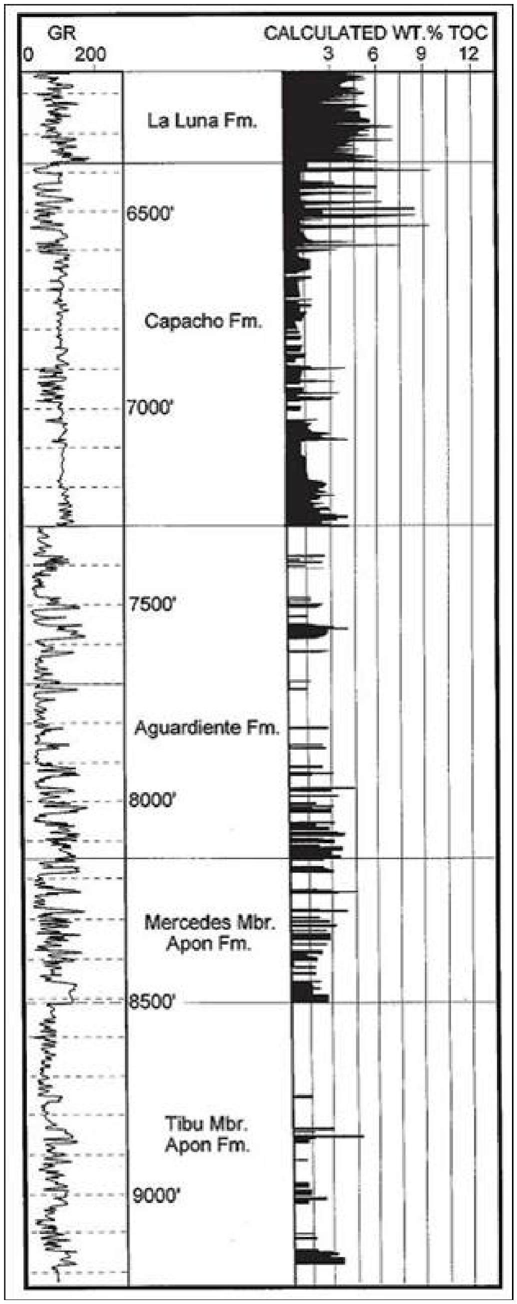
Thermal maturity of the La Luna Fm increases with burial depth from west to east across the Maracaibo Basin, from less than 0.7% R_o to over 1.7% R_o southeast of Lake Maracaibo.[25] Vitrinite reflectance data indicate the unit is mainly in the oil generation window, with a narrow sliver of dry-gas maturity in the east. Note that no significant free gas accumulations have been discovered in the Maracaibo Basin; all natural gas production has been associated gas.

In the much smaller Catatumbo Sub-Basin of Colombia, the La Luna Fm is about 200 ft thick, comprising dark-gray, laminated, limey mudstones and shales with high TOC averaging 4.5% (maximum 11%), mainly Type II with some Type III kerogen.[26] Total organic carbon in core samples reaches a maximum of 11.2% in the La Luna, but more typically averages a still rich 4 to 5% TOC. **Figure IV-13** shows a slight increase in TOC concentration towards the base of the La Luna Fm in the Cerrito 1 well, southeastern Catatumbo Sub-basin.

The La Luna is at relatively shallow depth in the Catatumbo Sub-basin, ranging from 6,000 to 7,600 feet.[27] Based on available vitrinite samples, thermal maturity ranges from 0.85 to 1.21% R_o, with generally higher reflectance in the central and northern areas of the basin. Samples from the Cerro Gordo 3 well in the southeast portion of the Catatumbo Sub-basin averaged 0.85% R_o, indicating that this area is oil prone.

Figure IV-13: Calculated TOC Profile from Well Log in the Catatumbo Sub-Basin.

Modified from Yurewicz et al., 1998



Capacho Formation. The Capacho Formation (Cenomanian-Coniacian) is a distinct unit from the overlying La Luna, although its upper portion is fairly similar. In the Maracaibo basin the Capacho Fm consists of dark-gray to black shales and limestones and is much thicker than the La Luna, ranging from 590 to nearly 1,400 feet in total thickness. However, less data are available on the Capacho. Thus, for this assessment we combined the 200-ft thick, TOC-rich upper portion of the Capacho with the stratigraphically adjacent La Luna for analysis.

Depth to the Capacho ranges from 6,500 feet to 8,500 feet in the Catatumbo Sub-basin, with greater measured depth in the north and east at 8,275 feet in the Socuavo 1 well. TOC reaches 5% in the Socuavo 1 well, northeastern Catatumbo Sub-basin, but more typically is about 1.5%. Kerogen is Type II and III. Vitrinite reflectance ranges from 0.96% R_o in the northern Rio de Oro 14 well to 1.22-1.24% R_o in southeastern well samples.

3.2 Reservoir Properties (Prospective Area)

Three thermal maturity windows were mapped in the Maracaibo/ Catatumbo Basin: dry-gas, wet-gas, and oil. Geologic modeling shows that the present-day temperature gradient in the area ranges from 1.7 and 2.0° F per 100 feet of depth.

Dry Gas Window. Within the 5,840-mi^2 depth-screened, dry-gas thermal maturity window (average 1.6% R_o) of the Maracaibo/Catatumbo Basin, the Cretaceous La Luna Fm and the adjoining upper portion of the Capacho Fm averages about 500 ft thick net, about 12,000 ft deep, and is estimated to have average 5% TOC. Reservoir pressure is uncertain thus assumed to be normal (hydrostatic).

Wet Gas Window. Within the 4,290-mi^2 depth-screened, wet-gas thermal maturity window (average 1.15% R_o), the La Luna and upper Capacho formations average about 11,000 ft deep. Other parameters are similar to the dry gas window.

Oil Window. The La Luna and upper Capacho shales in the thermally less mature portion of the Maracaibo/Catatumbo basin are oil-prone, with average 0.85% R_o. The oil window extends over an area of about 7,280 mi^2 and averages about 10,000 ft deep.

3.3 Resource Assessment

Total risked, technically recoverable shale gas and shale oil resources in the La Luna and Capacho formations of the Maracaibo and Catatumbo basins are estimated to be 202 Tcf and 14.8 billion barrels, out of risked shale gas and shale oil in-place of 970 Tcf and 297 billion barrels, **Tables IV-1 and IV-2**. The play has high a resource concentration of up to 256 Bcf/mi^2 within the dry gas prospective area.

Dry Gas Window. Risked, technically recoverable shale gas resources in the dry-gas window of the Maracaibo/Catatumbo Basin are estimated at 131 Tcf, from a risked shale gas in-place of 523 Tcf. Resource concentration is high (average 256 Bcf/mi^2) due in part to favorable shale thickness and porosity.

Wet Gas Window. The slightly shallower and less thermally mature wet gas window of the Maracaibo/Catatumbo Basin has risked, technically recoverable resources of approximately 53 Tcf of shale gas and 3.1 billion barrels of shale condensate. Risked in-place resources are estimated at 264 Tcf of wet shale gas and 62 billion barrels of shale condensate.

Oil Window. The still shallower and oil-prone window of the La Luna formation and upper Capacho formation in the Maracaibo/Catatumbo basins has an estimated risked, technically recoverable resource of 11.8 billion barrels of shale oil and 18 Tcf of associated shale gas. Risked in-place shale resources are about 235 billion barrels of shale oil and 183 Tcf of shale gas.

3.4 Recent Activity

Junior Canadian E&P Alange Energy Corporation is evaluating the prospectivity of the eastern area of the Catatumbo Sub-basin. However, this exploration activity appears to be focused on conventional reservoirs within the La Luna Shale interval. No shale exploration leasing or drilling has been reported in the Maracaibo Basin.

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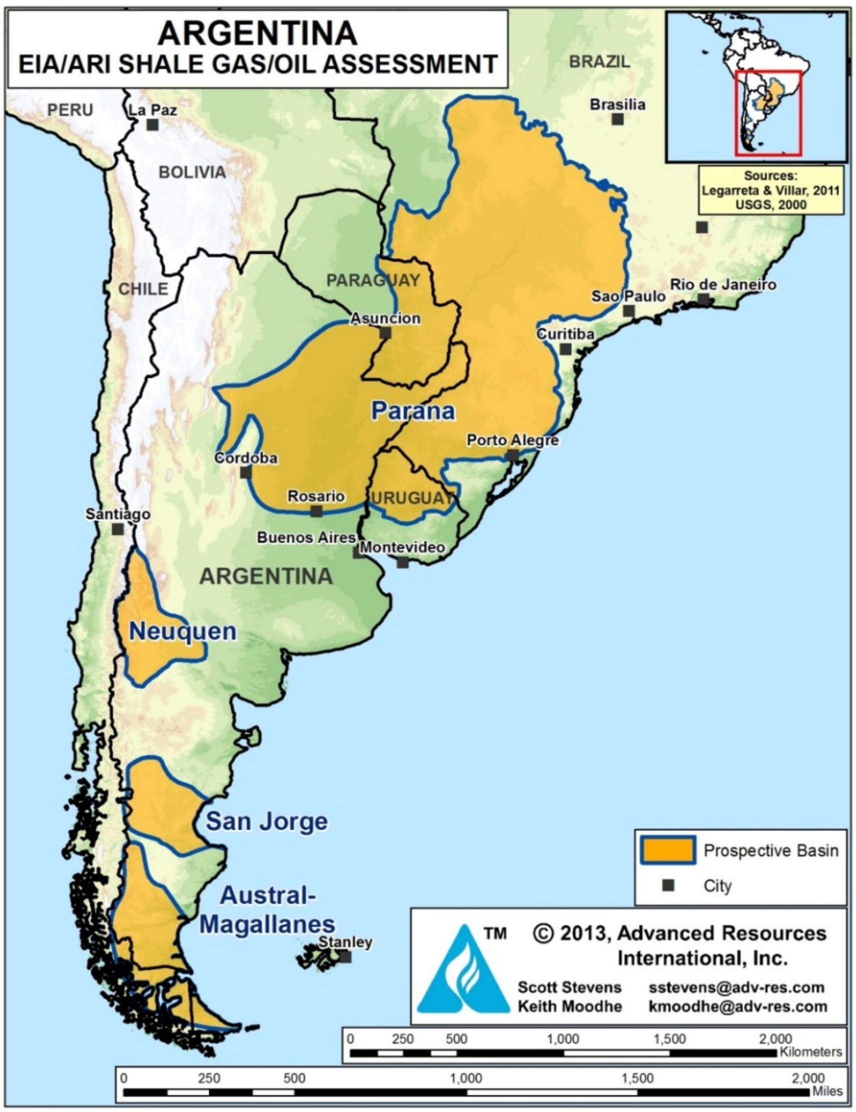
V. ARGENTINA

SUMMARY

Argentina has world-class shale gas and shale oil potential – possibly the most prospective outside of North America – primarily within the Neuquen Basin. Additional shale resource potential exists in three other untested sedimentary basins, Figure V-1.

Figure V-1. Prospective Shale Basins of Argentina



Source: ARI, 2013.

Significant exploration programs and early-stage commercial production are underway in the Neuquen Basin by Apache, EOG, ExxonMobil, TOTAL, YPF, and smaller companies. Thick, organic-rich, marine-deposited black shales in the Los Molles and Vaca Muerta formations have been tested by approximately 50 wells to date, with mostly good results. Vertical shale wells are producing at initial rates of 180 to 600 bbl/day following typically 5-stage fracture stimulation. Horizontal wells also are being tested although initial results have not been uniformly encouraging.

Cretaceous shales in the Golfo San Jorge and Austral basins in southern Argentina also have good potential, although higher clay content may pose a risk in these lake-formed deposits. Marine-deposited Devonian shales in the Parana Basin are prospective over a limited area of northeast Argentina. Argentina has an estimated 802 Tcf of risked, shale gas in-place out of 3,244 Tcf of risked, technically recoverable shale gas resources, Table V-1. In-place risked shale oil resources are estimated at 480 billion barrels, of which about 27 billion barrels of shale oil may be technically recoverable, Table V-2.

Table V-1A. Shale Gas Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		Neuquen ($66,900 mi^2$)					
	Shale Formation		Los Molles			Vaca Muerta		
	Geologic Age		M. Jurassic			U. Jurassic - L. Cretaceous		
	Depositional Environment		Marine			Marine		
Physical Extent	Prospective Area (mi^2)		2,750	2,380	8,140	4,840	3,270	3,550
	Thickness (ft)	Organically Rich	800	800	800	500	500	500
		Net	300	300	300	325	325	325
	Depth (ft)	Interval	6,500 - 9,500	9,500 - 13,000	13,000 - 16,400	3,000 - 9,000	4,500 - 9,000	5,500 - 10,000
		Average	8,000	11,500	14,500	5,000	6,500	8,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		2.0%	2.0%	2.0%	5.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	2.20%	0.85%	1.15%	1.50%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		49.3	118.0	190.1	66.1	185.9	302.9
	Risked GIP (Tcf)		67.8	140.4	773.8	192.0	364.8	645.1
	Risked Recoverable (Tcf)		8.1	35.1	232.1	23.0	91.2	193.5

Table V-2B. Shale Gas Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		San Jorge ($46,000 mi^2$)			
	Shale Formation		Aguada Bandera	Pozo D-129		
	Geologic Age		U. Jurassic - L. Cretaceous	L. Cretaceous		
	Depositional Environment		Lacustrine	Lacustrine		
Physical Extent	Prospective Area (mi^2)		8,380	920	540	4,120
	Thickness (ft)	Organically Rich	1,600	1,200	1,200	1,200
		Net	400	420	420	420
	Depth (ft)	Interval	6,500 - 16,000	6,600 - 8,000	8,000 - 10,000	10,000 - 16,400
		Average	13,000	7,300	9,000	12,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.2%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		3.00%	0.85%	1.15%	2.00%
	Clay Content		Med./High	Med./High	Med./High	Med./High
Resource	Gas Phase		Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		151.7	41.2	103.4	163.3
	Risked GIP (Tcf)		254.2	9.1	13.4	161.5
	Risked Recoverable (Tcf)		50.8	0.5	2.0	32.3

Table V-3C. Shale Gas Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		Austral-Magallanes ($65,000 mi^2$)			Parana ($747,000 mi^2$)	
	Shale Formation		L. Inoceramus-Magnas Verdes			Ponta Grossa	
	Geologic Age		L. Cretaceous			Devonian	
	Depositional Environment		Marine			Marine	
Physical Extent	Prospective Area (mi^2)		4,620	4,600	4,310	270	2,230
	Thickness (ft)	Organically Rich	800	800	800	400	400
		Net	400	400	400	200	200
	Depth (ft)	Interval	6,600 - 11,000	9,000 - 14,500	11,500 - 16,400	9,000 - 10,000	10,000 - 11,500
		Average	8,000	11,500	13,500	9,500	10,500
Reservoir Properties	Reservoir Pressure		Slightly Overpress.	Slightly Overpress.	Slightly Overpress.	Normal	Normal
	Average TOC (wt. %)		3.5%	3.5%	3.5%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.60%	1.15%	1.40%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		32.5	113.8	155.9	34.9	56.9
	Risked GIP (Tcf)		67.5	235.6	302.4	1.1	15.2
	Risked Recoverable (Tcf)		6.8	47.1	75.6	0.2	3.0

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

Basic Data	Basin/Gross Area		Neuquen (66,900 mi²)			
	Shale Formation		Los Molles		Vaca Muerta	
	Geologic Age		M. Jurassic		U. Jurassic - L. Cretaceous	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi²)		2,750	2,380	4,840	3,270
	Thickness (ft)	Organically Rich	800	800	500	500
		Net	300	300	325	325
	Depth (ft)	Interval	6,500 - 9,500	9,500 - 13,000	3,000 - 9,000	4,500 - 9,000
		Average	8,000	11,500	5,000	6,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		2.0%	2.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi²)		36.4	9.2	77.9	22.5
	Risked OIP (B bbl)		50.0	11.0	226.2	44.2
	Risked Recoverable (B bbl)		3.00	0.66	13.57	2.65

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

Basic Data	Basin/Gross Area		San Jorge (46,000 mi²)		Austral-Magallanes (65,000 mi²)		Parana (747,000 mi²)
	Shale Formation		Pozo D-129		L. Inoceramus-Magnas Verdes		Ponta Grossa
	Geologic Age		L. Cretaceous		L. Cretaceous		Devonian
	Depositional Environment		Lacustrine		Marine		Marine
Physical Extent	Prospective Area (mi²)		920	540	4,620	4,600	270
	Thickness (ft)	Organically Rich	1,200	1,200	800	800	400
		Net	420	420	400	400	200
	Depth (ft)	Interval	6,600 - 8,000	8,000 - 10,000	6,600 - 11,000	9,000 - 14,500	9,000 - 10,000
		Average	7,300	9,000	8,000	11,500	9,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Slightly Overpress.	Slightly Overpress.	Normal
	Average TOC (wt. %)		2.0%	2.0%	3.5%	3.5%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	1.20%
	Clay Content		Med./High	Med./High	Low/Medium	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Condensate
	OIP Concentration (MMbbl/mi²)		63.7	20.3	48.4	14.8	8.1
	Risked OIP (B bbl)		14.1	2.6	100.6	30.6	0.3
	Risked Recoverable (B bbl)		0.42	0.08	5.03	1.53	0.01

INTRODUCTION

Argentina has large and potentially high-quality shale gas and oil resources in four main sedimentary basins, **Figure V-1**. Basins assessed in this chapter include:

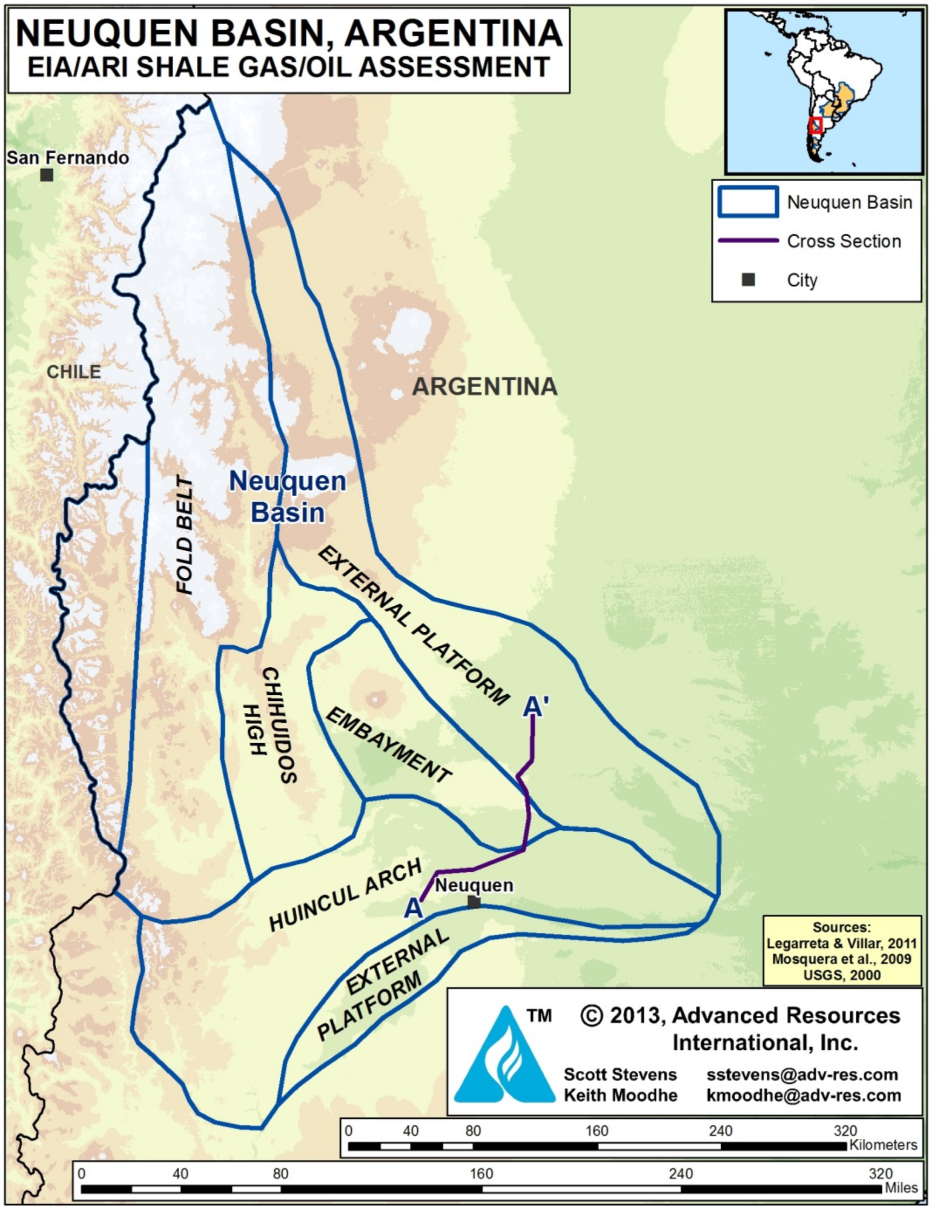
- **Neuquen Basin:** The main focus of shale exploration in Argentina, some 50 mostly vertical wells drilled since 2010 indicate good production potential in the marine-deposited Los Molles and especially Vaca Muerta shales of Jurassic age.
- **Golfo San Jorge Basin:** Containing mostly non-marine lacustrine shale source rocks of Jurassic to Cretaceous age, this basin has untested but prospective, primarily shale gas resources in a structurally simple setting.
- **Austral Basin**: Known as the Magallanes Basin in Chile, the Austral Basin of southern Argentina contains marine-deposited black shale in the Lower Cretaceous, considered a major source rock in the basin.
- **Paraná Basin**: Although more extensive in Brazil and Paraguay, Argentina has a small area of the Paraná Basin with Devonian black shale potential. The structural setting is simple but the basin is partly obscured on surface by flood basalts, although they are less prevalent in Argentina than in Brazil.

1 NEUQUEN BASIN

1.1 Introduction and Geologic Setting

Located in west-central Argentina, the Neuquen Basin contains Late Triassic to Early Cenozoic strata that were deposited in a back-arc tectonic setting.[1] Extending over a total area of 66,900 mi^2, the basin is bordered on the west by the Andes Mountains and on the east and southeast by the Colorado Basin and North Patagonian Massif, **Figure V-2**. The sedimentary sequence exceeds 22,000 ft in thickness, comprising carbonate, evaporite, and marine siliclastic rocks.[2] Compared with the thrusted western part of the basin, the central Neuquen is deep and structurally less deformed. Already a major oil and gas production area from conventional and tight sandstones, the Neuquen Basin is emerging as the premier shale gas and shale oil development area of South America.

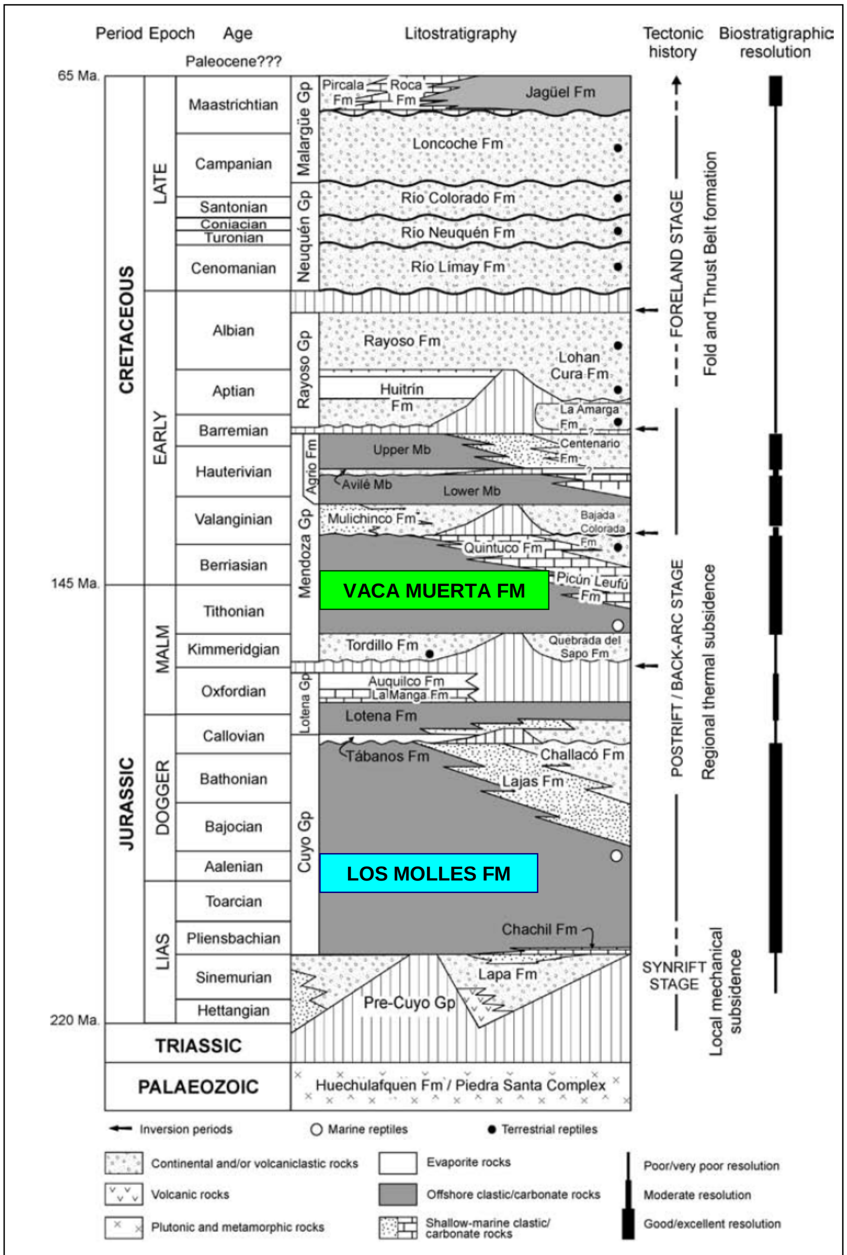
Figure V-2. Neuquen Basin Structure Map



Source: ARI, 2013.

The stratigraphy of the Neuquen Basin is shown in **Figure V-3**. Of particular exploration interest are the shales of the Middle Jurassic Los Molles and Late Jurassic-Early Cretaceous Vaca Muerta formations. These two thick deepwater marine sequences sourced most of the oil and gas fields in the basin and are considered the primary targets for shale gas development.

Figure V-3: Neuquen Basin Stratigraphy.



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

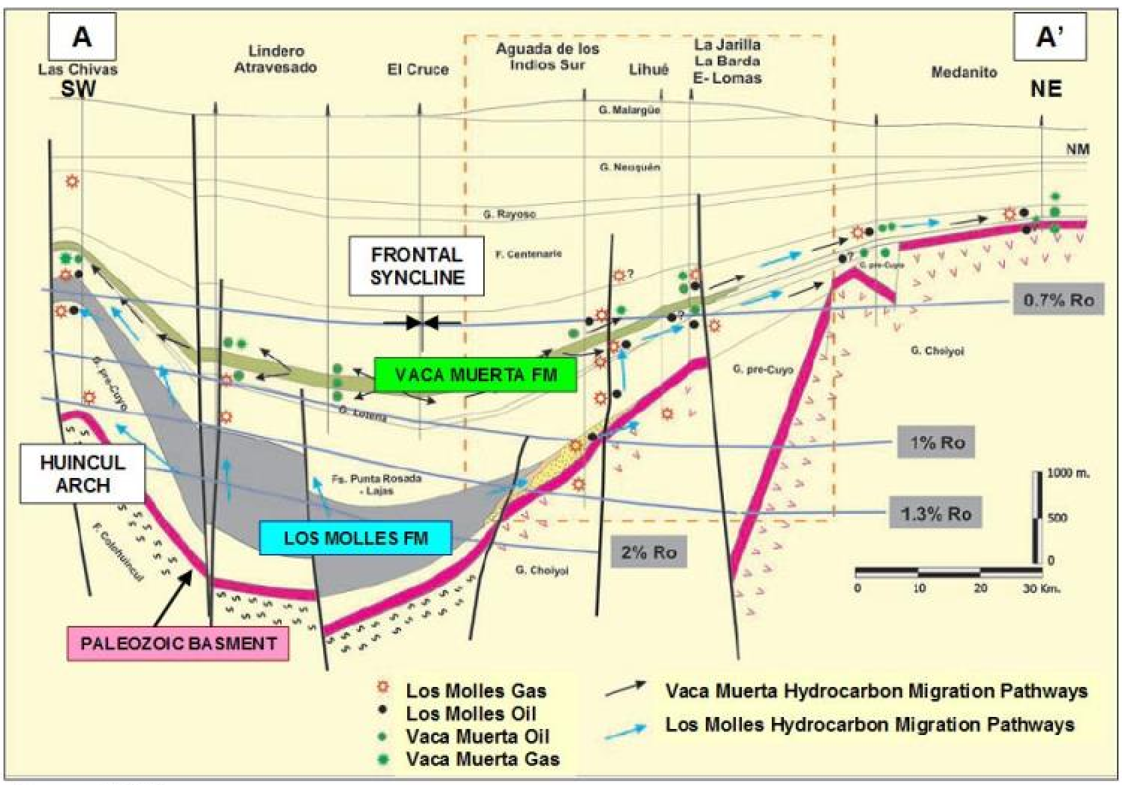
Source: Howell et al., 2005.

1.2 Reservoir Properties (Prospective Area)

Los Molles Shale. The Middle Jurassic (Toarcian-Aalenian) Los Molles Formation is considered an important source rock for conventional oil and gas deposits in the Neuquen Basin. Thermal maturity modeling indicates that hydrocarbon generation took place in the Los Molles at 50 to 150 Ma, with the shallower Lajas Formation tight sands serving as reservoirs.[3] The overlying Late Jurassic Aquilco Formation evaporites effectively seal this hydrocarbon system, resulting in overpressuring (0.60 psi/ft) in parts of the basin.

The Los Molles shale is distributed across much of the Neuquen Basin, reaching more than 3,300 ft thick in the central depocenter. Available data shows the shale thinning towards the east.[4] A southeast-northwest regional cross-section, **Figure V-4**, shows the Los Molles deposit particularly thick in the basin troughs. Well logs reveal a basal Los Molles shale about 500 feet thick.[5]

Figure V-4: Neuquen Basin SW-NE Regional Cross Section



Source: Mosquera et al., 2009.

On average, the prospective Los Molles shale occurs at depths of 8,000 to 14,500 ft, with maximum depth surpassing 16,000 ft in the basin center. In the south, the shale occurs at depths of 7,000 feet or shallower within the uplifted Huincul Arch. The Los Molles shale is at shale-prospective depth across much of the Neuquen Basin.

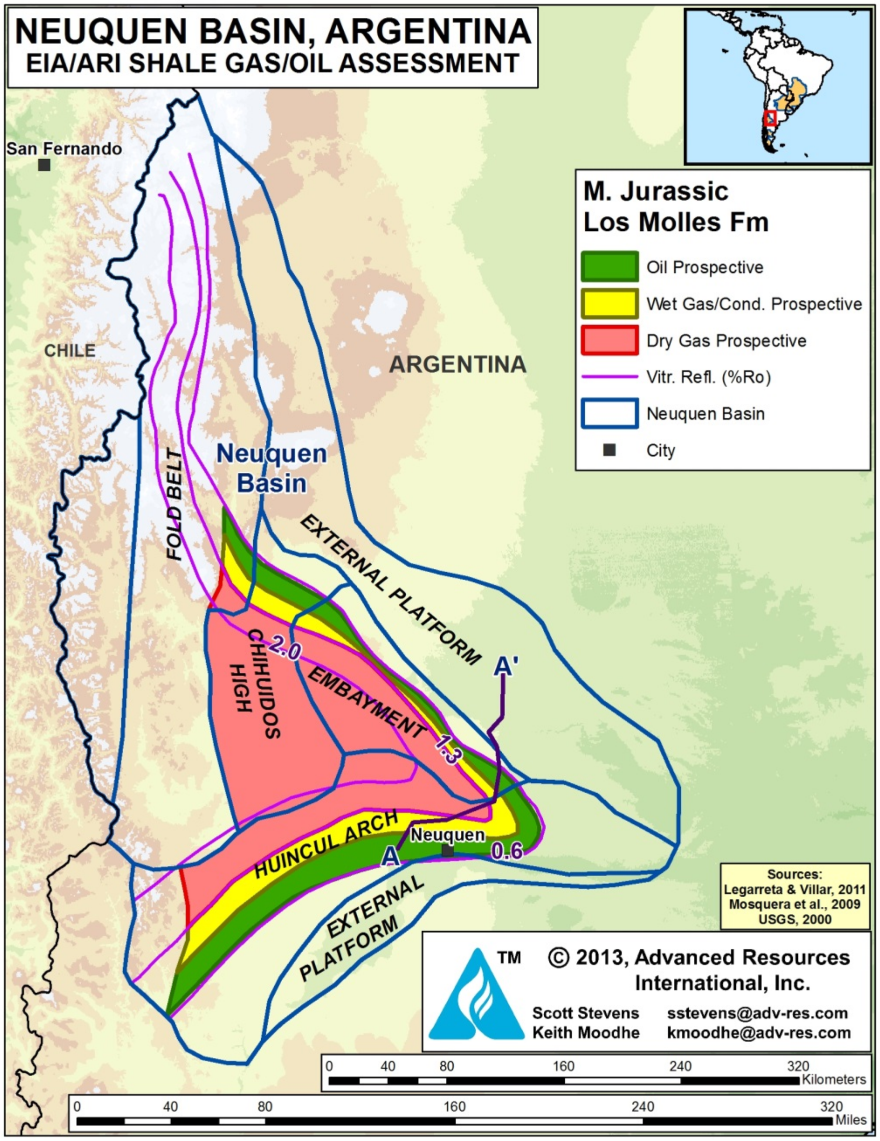
Total organic carbon for the Los Molles shale was determined from various locations across the Neuquen Basin. Samples from five outcrops in the southwestern part of the basin showed average TOC ranging from 0.55 to 5.01%.[6] In the southeast, TOC averaged 1.25% at shallower depths of 7,000 feet at one location. Further east, another interval of the Los Molles Formation, sampled from depths of 10,500 to 13,700 feet, yielded TOC's in the range of 0.5% to nearly 4.0%. The lowermost 800-ft section here recorded a mean TOC of about 2%. Limited data were available for the central and northern regions, where shale is deeper and gas potential appears highest. One well in the basin's center penetrated two several-hundred-foot thick intervals of Los Molles shale, with average 2% and 3% TOC, respectively.[7]

The thermal maturity of the Los Molles shale varies across the Neuguen Basin, from highly immature (R_o = 0.3%) in the shallow Huincul Arch region, to oil-prone (R_o = 0.7%) in the eastern and southern parts of the basin, to fully dry-gas mature (R_o > 2.0%) in the basin center.[8,9] The lower portion of the Los Molles is in the wet gas window (R_o > 1.0%) in a well located north of the Huincul Arch. Gas shows are prevalent throughout the Los Molles Formation.

The prospective area of the Los Molles, **Figure V-5**, is defined by low vitrinite reflectance cutoff in the north, thinning in the east, and complex faulting and shallow depth at the Huincul Arch in the south. The oil-prone thermal maturity window within the prospective area covers an area of 2,750 mi^2; the wet gas window 2,380 mi^2; and the dry gas window 8,140 mi^2.

ARI extended the western play edge beyond the main productive Neuquen area, where most of the conventional oil and gas fields are located, into the Agrio Fold and Thrust Belt along the foothills of the Andes Mountains. While there is some geologic risk associated with this region, the thermal maturity is favorable.

Figure V-5: Prospective Shale Gas and Shale Oil Areas, Los Molles Formation, Neuquen Basin.



Source: ARI, 2013.

Vaca Muerta Shale. The Late Jurassic to Early Cretaceous (Tithonian-Berriasian) shale of the Vaca Muerta Formation is considered the primary source rocks for conventional oil production in the Neuquen Basin. The Vaca Muerta shale consists of finely-stratified black and dark grey shale and lithographic lime-mudstone that totals 200 to 1,700 feet thick.[10] The organic-rich marine shale was deposited in reduced oxygen environment and contains Type II kerogen. Although somewhat thinner than the Los Molles Fm, the Vaca Muerta shale has higher TOC and is more widespread across the basin.

The Vaca Muerta Formation thickens from the south and east towards the north and west, ranging from absent to over 700 feet thick in the basin center.[11] Depth ranges from outcrop near the basin edges to over 9,000 feet deep in the central syncline.[12]

The Vaca Muerta Formation generally is richer in TOC than the Los Molles Formation. Sparse available TOC data were derived from wells and bitumen veins sampled from mines in the north.[13] These asphaltites are very rich in organic carbon, increasing northward to a maximum of 14.2%. In the south, mapped TOC data ranges from 2.9 to 4.0%. TOC of up to 6.5% is reported in the lower bituminous shale units of the Vaca Muerta.

While the Vaca Muerta Formation is present across much of the Neuquen Basin, its thermal maturity changes, increasing from east to west. **Figure V-4** is a cross-section for the Vaca Muerta illustrating the oil and gas regions of this formation. Thermal maturity increases from less than 0.7% R_o along the eastern border of the basin to over 1.5% R_o in the deep northwest trough.[14] Northeast of the Huincul Arch, R_o of 0.8% was measured, placing this area in the oil window.

The Vaca Muerta Formation has three distinct prospective areas of hydrocarbons in the Neuquen Basin, as shown on the thermal maturity and prospective area map, Figure V-6. The oil-prone thermal maturity window within the prospective area covers an area of approximately 4,840 mi^2; the wet gas window covers 3,270 mi^2; and the dry gas window covers 3,550 mi^2.

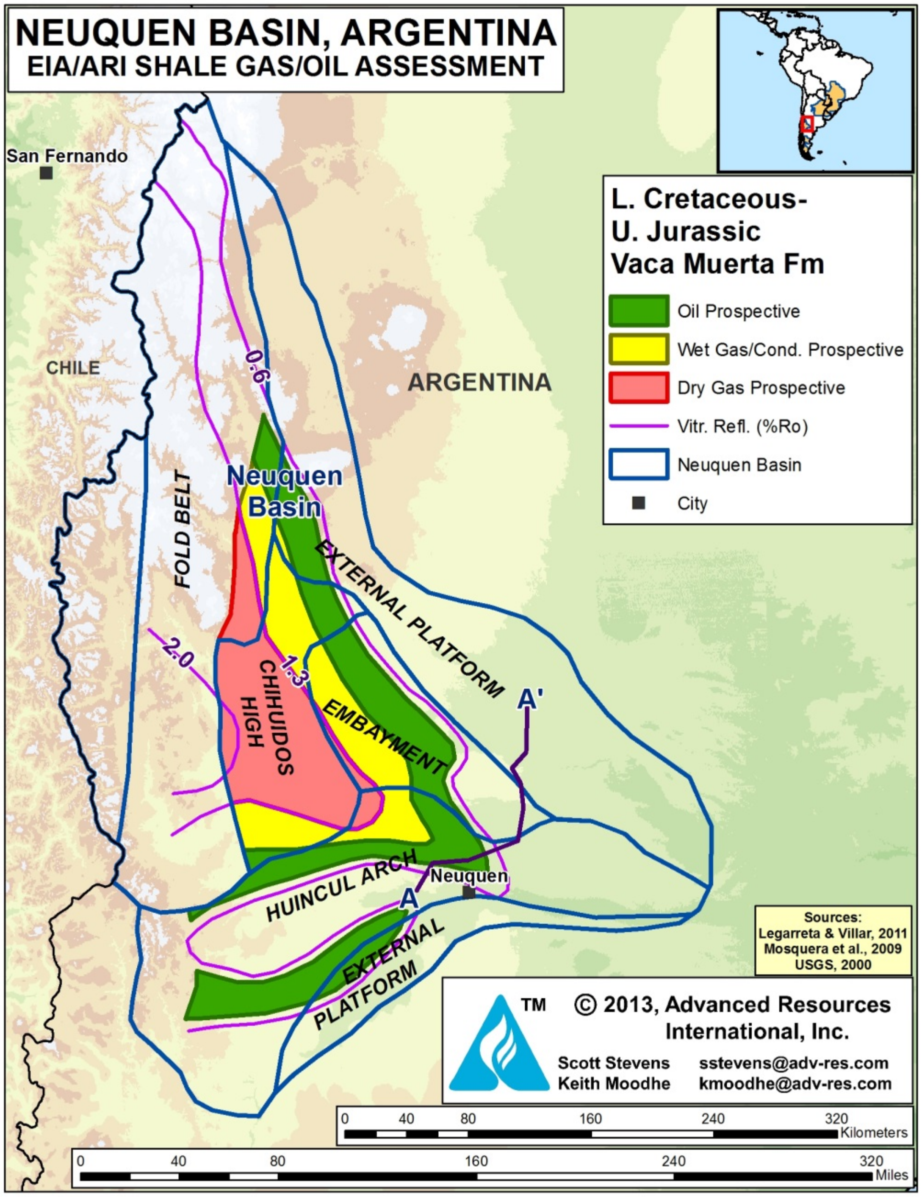
1.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from black shale within the Los Molles Formation of the Neuquen Basin are estimated at 275 Tcf of shale gas and 3.7 billion barrels of shale oil and condensate, from 982 Tcf and 61 billion barrels of risked, in-place shale gas and shale oil resources, Tables 1 and 2. The Los Molles Formation has moderate to high resource concentrations of 49 to 190 Bcf/mi^2 for shale gas and 9 to 36 million bbl/mi^2 for shale oil, depending on the thermal maturity window.

The Vaca Muerta Formation has risked, technically recoverable shale gas and shale oil resources of 308 Tcf of gas and 16 billion barrels of oil and condensate, from 1,202 Tcf and 270 billion barrels of risked, in-place shale gas and shale oil resources. The Vaca Muerta has high to very high resource concentrations of 66 to 303 Bcf/mi^2 for shale gas and 23 to 78 million bbl/mi^2 for shale oil, depending on thermal maturity window.

Advanced Resources International, Inc.

Figure V-6. Prospective Shale Gas and Shale Oil Areas, Vaca Muerta Formation, Neuquen Basin.



Source: ARI, 2013.

1.4 Recent Activity

Early drilling and production testing are underway in the Neuquen Basin, evaluating the Vaca Muerta Formation mostly at depths of 6,000 to 11,000 ft. YPF reported it holds about 3 million net acres in the basin and is negotiating with Chevron, TOTAL, Statoil, Dow Chemical, and other companies to jointly develop its shale resources. Including earlier Repsol operated wells, YPF has drilled 37 Vaca Muerta wells through 2012.[15] Chevron has reportedly agreed to invest up to $1 billion to drill 100 wells with YPF in the Neuquen Basin, although the deal awaits final approval. CNOOC signed a joint venture deal with YPF to invest up to $1.5 billion to drill 130 wells in the basin.

Repsol, which previously operated YPF's position in the Neuquen Basin, drilled some 20 vertical wells targeting the Vaca Muerta Shale that produced at encouraging initial rates of 180 to 600 bbl/day on restricted 4-mm choke. In 2012, Repsol estimated that its leases held a total of 92 Tcf and 7.0 billion barrels of contingent and prospective shale gas and oil resources.[16]

Apache has 1.3 million net acres in the Neuquen Basin with Vaca Muerta Shale potential, of which the company estimates 586,000 net acres is liquids-rich. Apache estimates its net recoverable potential at 0.8 billion barrels. The company completed its first Vaca Muerta horizontal well during 2012, a relatively short 1,900-ft lateral treated with a 7-stage hydraulic stimulation, described by Apache as "very encouraging."[17] The company's earlier Los Molles horizontal, drilled into the dry gas thermal maturity window at a depth of 4,400 m, IP'd at 4.5 MMcfd from a 2100' lateral that was stimulated by a 9-stage fracture treatment. Apache plans to invest $200 MM during 2013 to drill 16 net wells focusing on the Vaca Muerte within the TDF and Rio Negro blocks.[18]

EOG Resources estimates it holds about 100,000 net acres with shale potential in the Neuquen Basin. The company reported lower-than-expected results from its first horizontal oil well in the Vaca Muerta Formation, with production similar to its nearby vertical well. EOG is evaluating the results of the two wells and plans to proceed cautiously during 2013.[19]

Calgary-based Americas Petrogas operates 15 blocks covering nearly 1.4 million net acres in the Neuquen Basin. To date the company has drilled four shale exploration wells to test the Vaca Muerta Formation. Its LTE.x1 vertical well on the Los Toldos II block, drilled with partner ExxonMobil, IP'd at 309 boe/day (30-day average rate; 82% oil) from the 343-m thick Vaca Muerta Formation following a 5-stage hydraulic stimulation. The company's second vertical shale well, drilled on the Los Toldos I block, intersected 562 m of Vaca Muerta Formation at depths of 2,570-2,929 m. This well produced up to 3.2 million ft^3/day of natural gas with 9 to 18 bbl/day of condensate following a 4-stage fracture stimulation.[20]

2 GOLFO SAN JORGE BASIN

2.1 Introduction and Geologic Setting

Located in central Patagonia, the 67,000-mi^2 Golfo San Jorge Basin accounts for about one-quarter of Argentina's conventional oil and gas production.[21] An intra-cratonic extensional basin, the San Jorge extends across the width of southern Argentina, from the Andean foothills on the west to the offshore Atlantic continental shelf in the east. Excluding its small offshore extent, the onshore Golfo San Jorge Basin covers approximately 46,000 mi^2.

The basin is bordered by the Deseado Graben and Massif to the south, by the Somuncura Massif to the north, and the Andes Mountains in the west. Compressional structures of the San Bernardo Fold Belt transect the west-central region.[22] Extensional faults are widespread in the northeastern and southern flanks, while the northwestern edge of the basin is less faulted.[23]

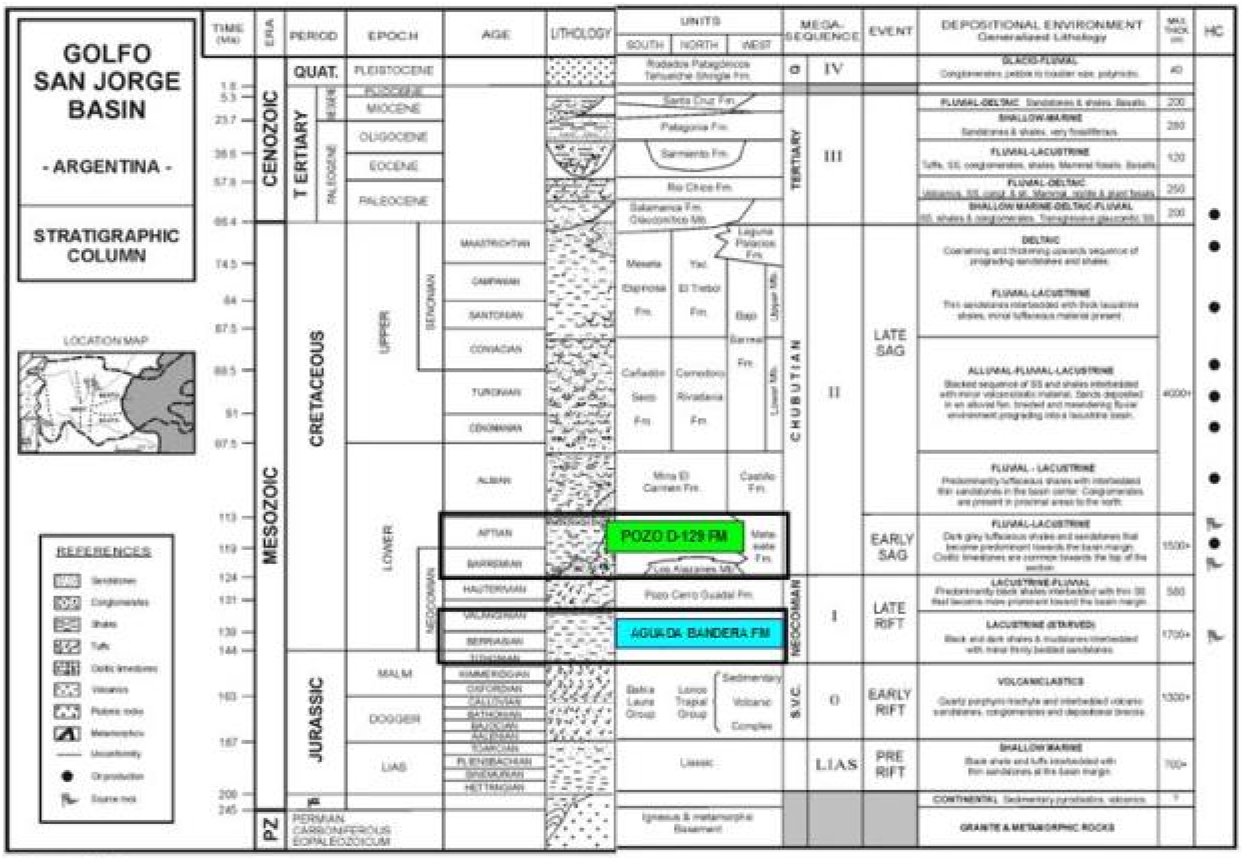
Extensional events marked by the formation of grabens and half-grabens in the present-day location of the Golfo San Jorge Basin began in the Triassic to Early Jurassic as the Gondwana supercontinent began to break up.[24] A separate period of extension followed in the Middle Jurassic, as the Lonco Trapial Volcanics were deposited via northwest-striking faults. The region subsided by the end of the Jurassic and extensive, mainly lacustrine deposits formed, including the thick black shale and mudstone source rocks of the Neocomian Aguada Bandera Formation.

2.2 Reservoir Properties (Prospective Area)

Aguada Bandera Shale. The Late Jurassic-Early Cretaceous Aguada Bandera Formation comprises fine gray sandstones that grade upward into a tuffaceous matrix, with black shales and mudstones increasing towards its base, **Figure V-7**.[25] Much of the formation is lacustrine in origin, although foraminifera found in western areas suggest possible marine sources in particular beds.[26] Towards the north, other biota indicative of an outer marine platform depositional environment were observed in well samples near Lago Colhue Huapi.[27]

Advanced Resources International, Inc.

Figure V-7: Golfo San Jorge Basin Stratigraphy



Sylwan, 2001

Source: Sylwan, 2001.

The Aguada Bandera Formation is a heterogeneous unit comprising shale, sandstone, and occasional limestone. Total formation thickness varies widely, from more than 15,000 ft thick in the southwest to 0-2,000 ft thick about 60 miles offshore in the east. A similar thickness variation also is seen in the west. Limited data is present south of Lago Colhue Huapi to the north. The Aguada Bandara Formation generally is 1,000 to 5,000 ft thick in the central basin, probably only a fraction of which is high-quality organic shale.

Depth to the top of the Aguada Bandera Formation was mapped based on the top of the underlying Middle Jurassic Loncol Trapial volcanics. Burial depth reaches a maximum 20,000 ft along the onshore coast in the center of the basin. Depocenters in the western portion of the basin typically average a more prospective 10,000 to 12,000 ft deep. The Aguada Bandera is much shallower, 2,000 to 8,000 ft deep, along the northern and western flanks. In the eastern coastal onshore portion of the basin, the Aguada Bandera Shale is about 1,500 to 2,500 ft thick and 20,000 ft deep.

Limited geochemical data were available for analyzing the Aguada Bandera, which is considerably deeper than the conventional reservoirs and thus rarely sampled. Only two available wells have TOC and R_o data, both located in the basin's western area. Average TOC ranged from 1.44% to 3.01% at depths of 12,160 ft and 11,440 ft, respectively.[28] Organic-rich intervals reached 4.19% TOC. Vitrinite reflectance indicated a dry-gas thermal maturity of 2.4% R_o.

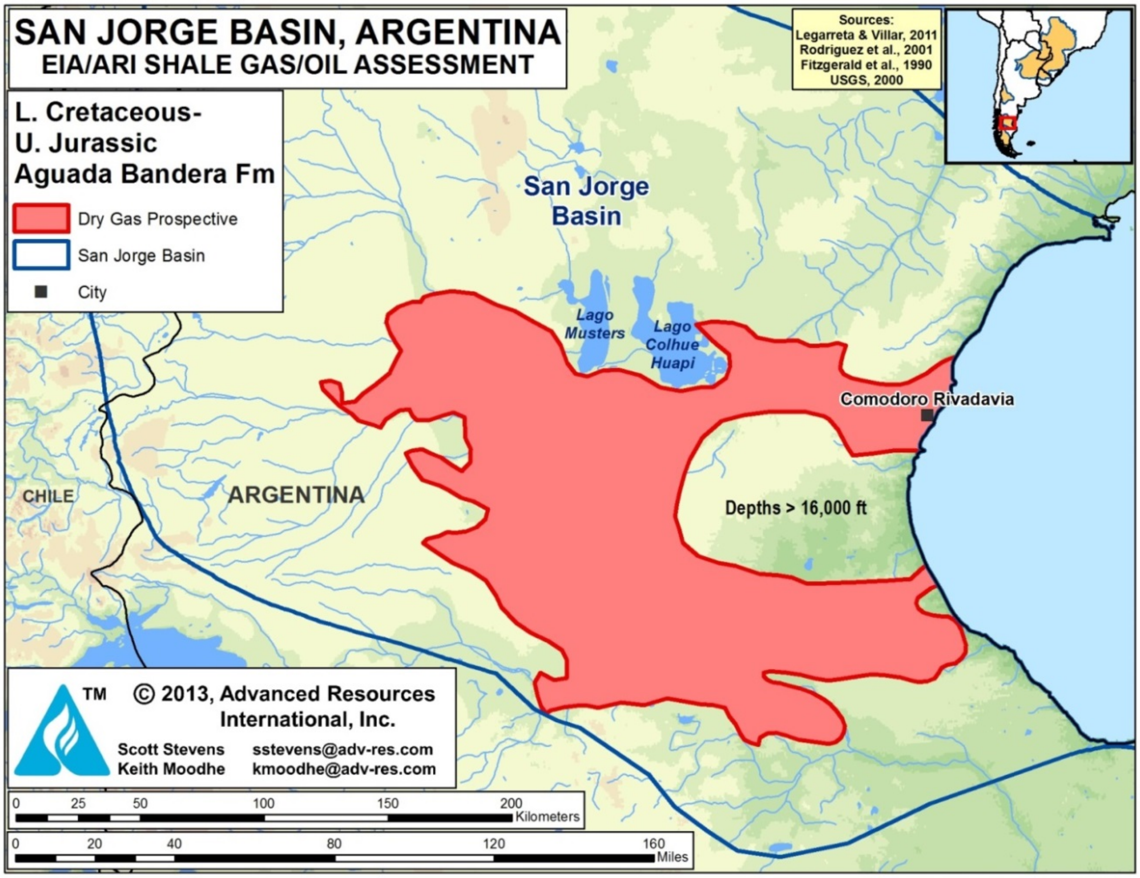
Petroleum basin modeling indicates that the minimum gas generation threshold (R_o = 1.0 to 1.3%) is typically achieved across the basin at depths below about 6,600 ft. Thus, the Aguada Bandera Formation appears to be mature for gas generation across most of the basin, **Figure V-8**. The unit is likely to be over mature in the deep basin center, where R_o is modeled to exceed 4%.

Using depth distribution and appropriate minimum and maximum R_o cutoffs, ARI's prospective area for the Aguada Bandera Shale covers approximately 8,380 mi^2 of the onshore Golfo San Jorge Basin. The central coastal basin (>16,000 ft deep) and the northern Lake region (<6,000 ft deep) were excluded as not prospective.

Pozo D-129 Shale. The Early Cretaceous Pozo D-129 Formation comprises a wide range of lithologies, with the deep lacustrine sediments -- organic black shales and mudstones – considered most prospective for hydrocarbon generation.[29] The presence of pyrite, dark laminations, and the absence of fossil burrows in the marine shale portions of this unit all point to favorably anoxic depositional conditions.[30] Siltstones, sandstones, and oolitic limestones also were deposited in the shallower water environments of the Pozo D-129.

The Pozo D-129 Shale is consistently thicker than 3,000 ft in the central basin, with local maxima exceeding 4,500 ft thick. Along the northern flank the interval is typically 1,000 to 2,000 ft thick. A locally thick deposit occurs in the western part of the basin, but thins rapidly from about 1,000 ft thick to absent.

Figure V-8: Aguada Bandera Fm Prospective Area, Golfo San Jorge Basin



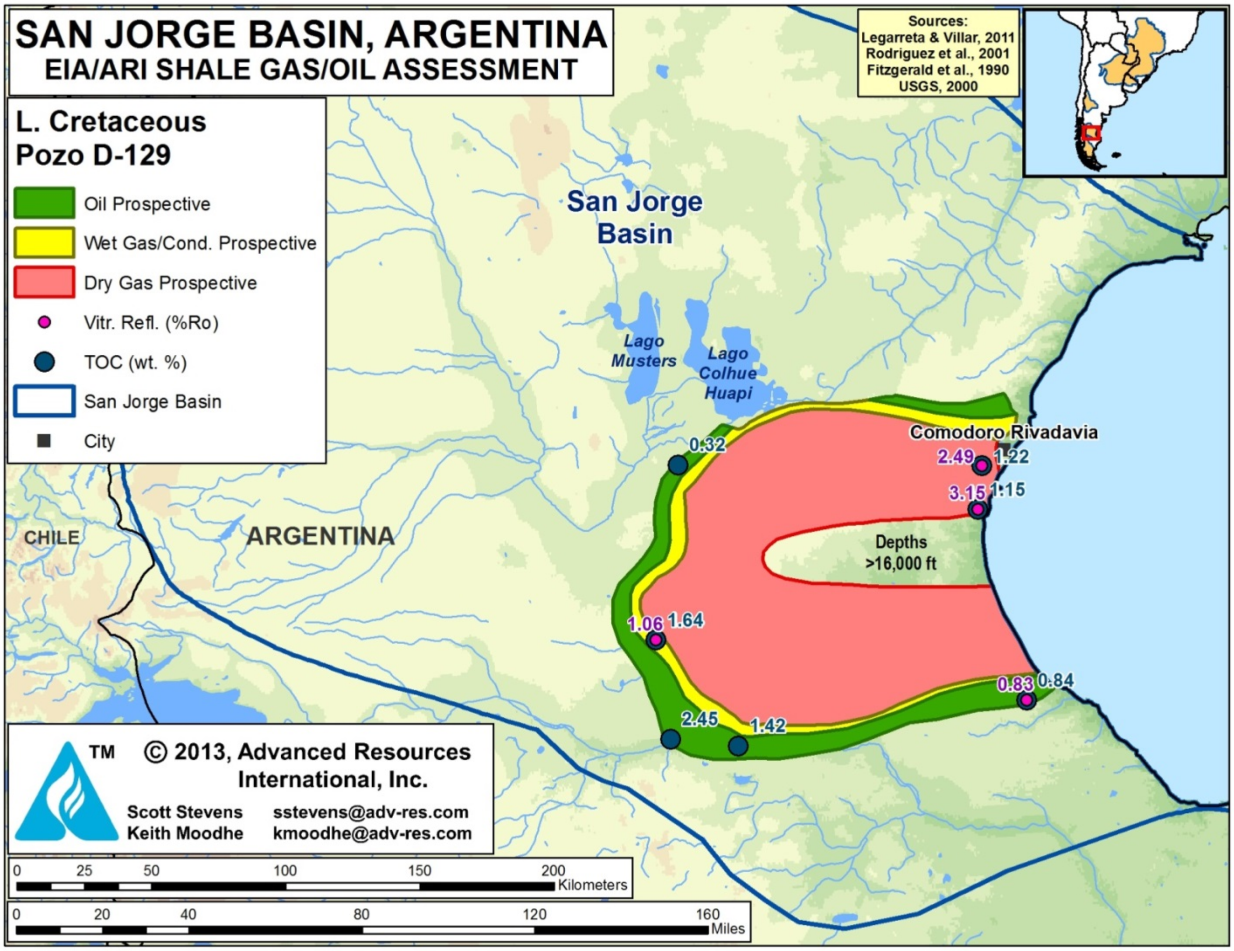
Source: ARI, 2013.

Northeast of Lago Colhue Huapi, the Pozo D-129 shoals rapidly from 6,000 ft to about 2,800 ft deep. Just southwest of the lake, depth increases from about 5,000 ft to nearly 9,500 ft. To the south, depths range from 5,000 to 6,400 ft, with similar depths in the west. The Pozo D-129 deepens along the eastern coastal flank of the basin to nearly 15,900 ft near the city of Comodoro Rivadavia.

Available data indicates organic richness in the southwest, 1.42% to 2.45% TOC, with a corresponding early gas maturity of 1.06% R_o. In the north-central region a low 0.32% TOC was recorded, with slightly higher 0.5% R_o near Lago Colhue Huapi.[31] Towards the basin center in the east, organic carbon (TOC) rises to around 1.22%. The thermal maturity in this deep setting is correspondingly high, 2.49 to 3.15% R_o. In the south, thermal maturity drops to oil-prone levels, 0.83% R_o with a measured TOC here of about 0.84%, excluding this area from the resource assessment.

ARI defined the shale prospective areas for the Pozo D-129 Formation based primarily on depth and available (but incomplete) vitrinite reflectance data, **Figure V-9**. The total prospective area for the Pozo D-129 Shale is estimated at approximately 5,580 mi^2, mainly in the dry gas window (4,120 mi^2), with much smaller wet gas (540 mi^2) and oil-prone (920 mi^2) areas.

Figure V-9: Pozo D-129 Fm, TOC, Thermal Maturity, and Prospective Area, Golfo San Jorge Basin



Source: ARI, 2013.

2.3 Resource Assessment

Aguada Bandera Formation. Risked, technically recoverable shale gas resources for the Aguada Bandera Formation in the Golfo San Jorge Basin are estimated at 51 Tcf of natural gas, from risked shale gas in-place of 254 Tcf, Table 1. The play has a high net average resource concentration of 152 Bcf/mi^2.

Pozo D-129 Formation. The Pozo D-129 Formation has risked, technically recoverable shale resources estimated at 35 Tcf of shale gas and 0.5 billion barrels of shale oil and condensate, from 184 Tcf and 17 billion barrels of risked, in-place shale gas and shale oil resources, Tables 1 and 2. The Pozo D-129 has moderate to high net resource concentrations of 41 to 163 Bcf/mi^2 of shale gas and 20 to 64 million bbl/mi^2 of shale oil and condensate, depending on the thermal maturity window.

2.4 Recent Activity

No shale activity has been reported in the Golfo San Jorge Basin.

3 AUSTRAL BASIN

3.1 Introduction and Geologic Setting

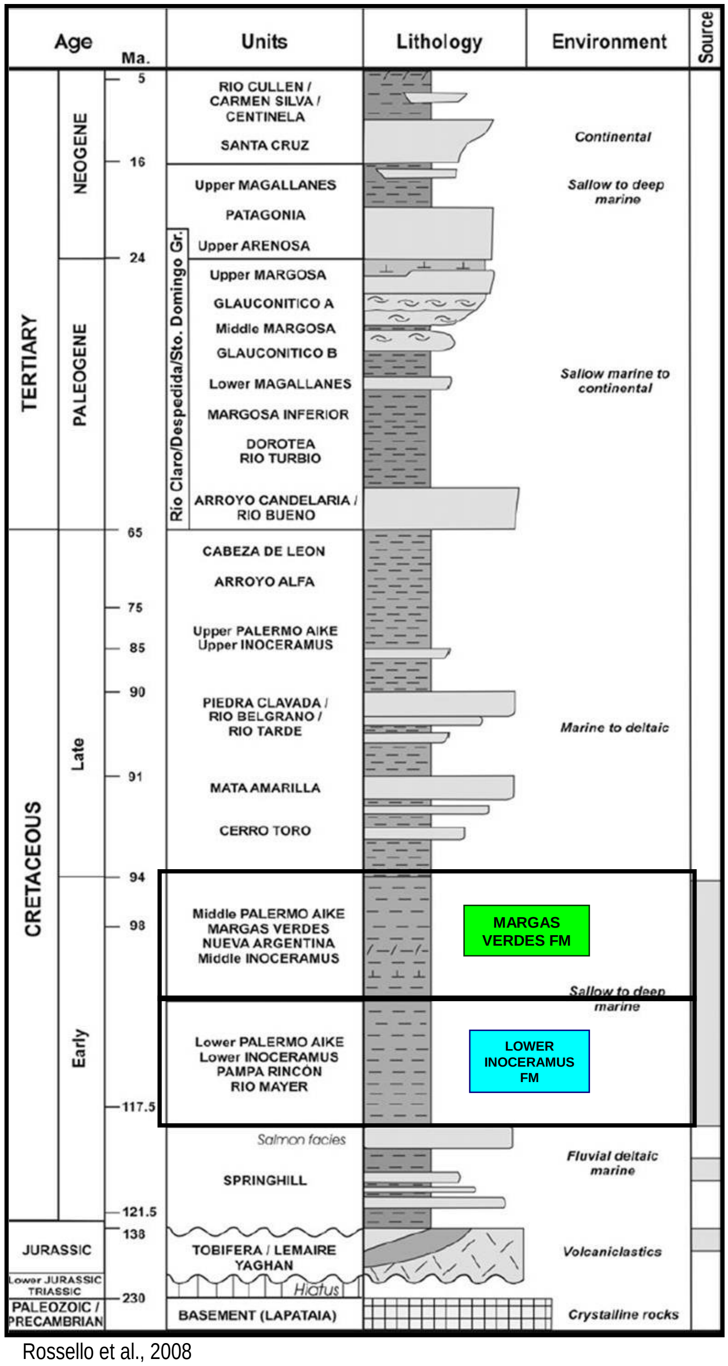
Located in southern Patagonia, the 65,000-mi^2 Austral-Magallanes Basin has promising but untested shale gas potential, **Figure V-10**. Most of the basin is in Argentina, where it is usually called the Austral Basin. A small southernmost portion of the basin is located in Chile's Tierra del Fuego region, where it is referred to as the Magallanes Basin. Oil and gas has been produced in the basin for decades from deltaic to fluvial sandstones in the Early Cretaceous Springhill Formation at depths of about 6,000 ft.

The Austral Basin comprises two main structural regions: a normal faulted eastern region and a thrust faulted western area. The basin contains a thick sequence of Upper Cretaceous and Tertiary sedimentary and volcaniclastic rocks which unconformably overlie the deformed metamorphic basement of Paleozoic age. Total sediment thickness ranges from 3,000 to 6,000 ft along the eastern coast to a maximum 25,000 ft along the basin axis. Jurassic and Lower Cretaceous petroleum source rocks are present at moderate depths of 6,000 to 10,000 ft across large areas, **Figure V-11**.[32] The overlying Cretaceous section comprises mainly deepwater turbidite clastic deposits up to 4 km thick which appear to lack shale gas and oil potential.[33]

The organic-rich shales of Jurassic and Early Cretaceous age formed under anoxic marine conditions within a Neocomian sag on the edge of the Andes margin. The basal sequence consists of Jurassic source rocks that accumulated under restricted lacustrine conditions within small half-grabens. Interbedded shale and sandstone of the Zapata and Punta Barrosa formations were deposited in a shallow-water marine environment.[34] The mid-lower

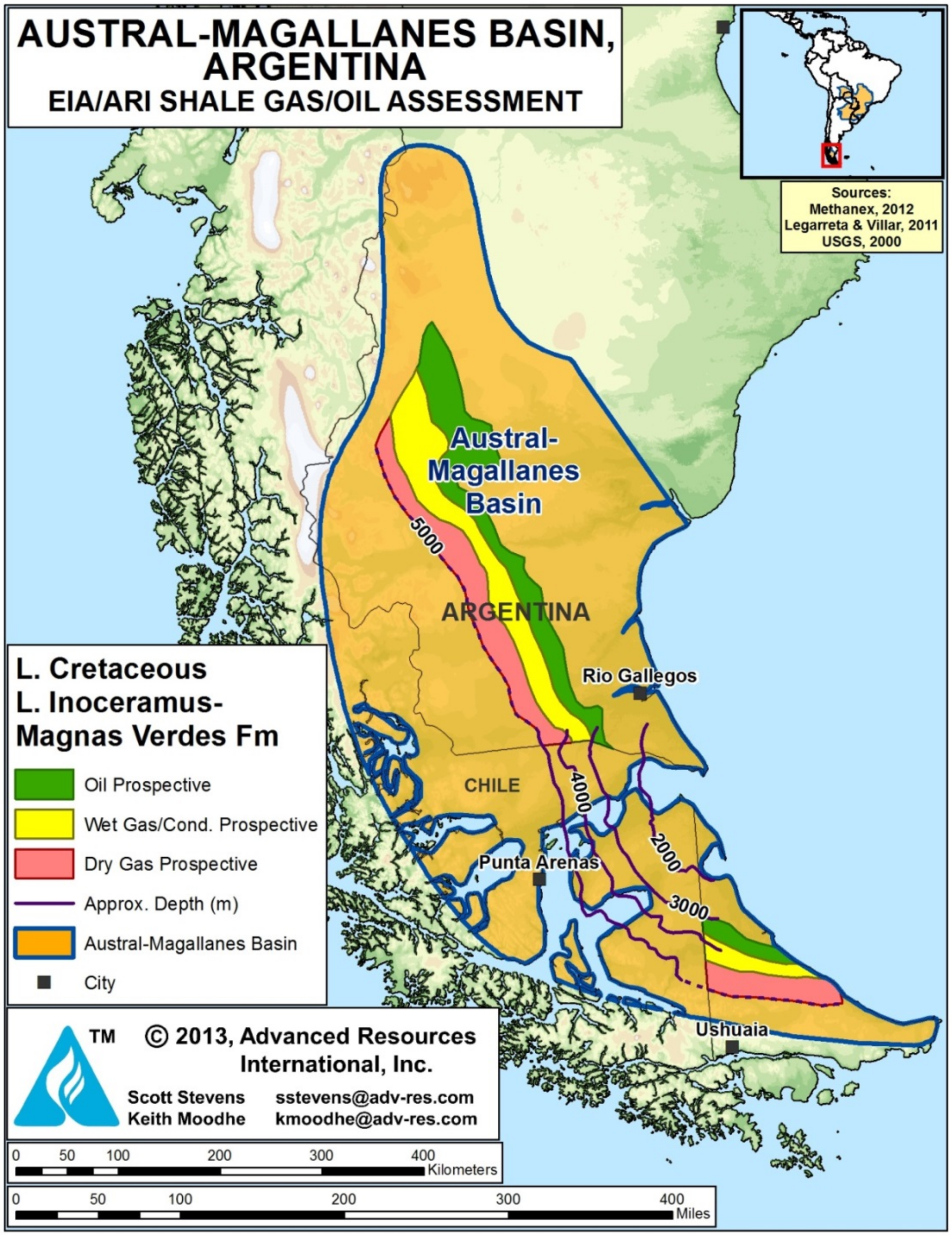
Jurassic Tobifera Formation contains 1% to 3% TOC (maximum 10% in coaly shales), consisting of Types I to III kerogen. However, carbon in this unit is mainly coaly and probably insufficiently brittle for shale exploration.

Figure V-10: Stratigraphy of the Austral-Magallanes Basin, Argentina and Chile



Source: Rossello et al., 2008

Figure V-11: Inoceramus Shale, Depth, TOC, and Thermal Maturity, Austral / Magallanes Basin

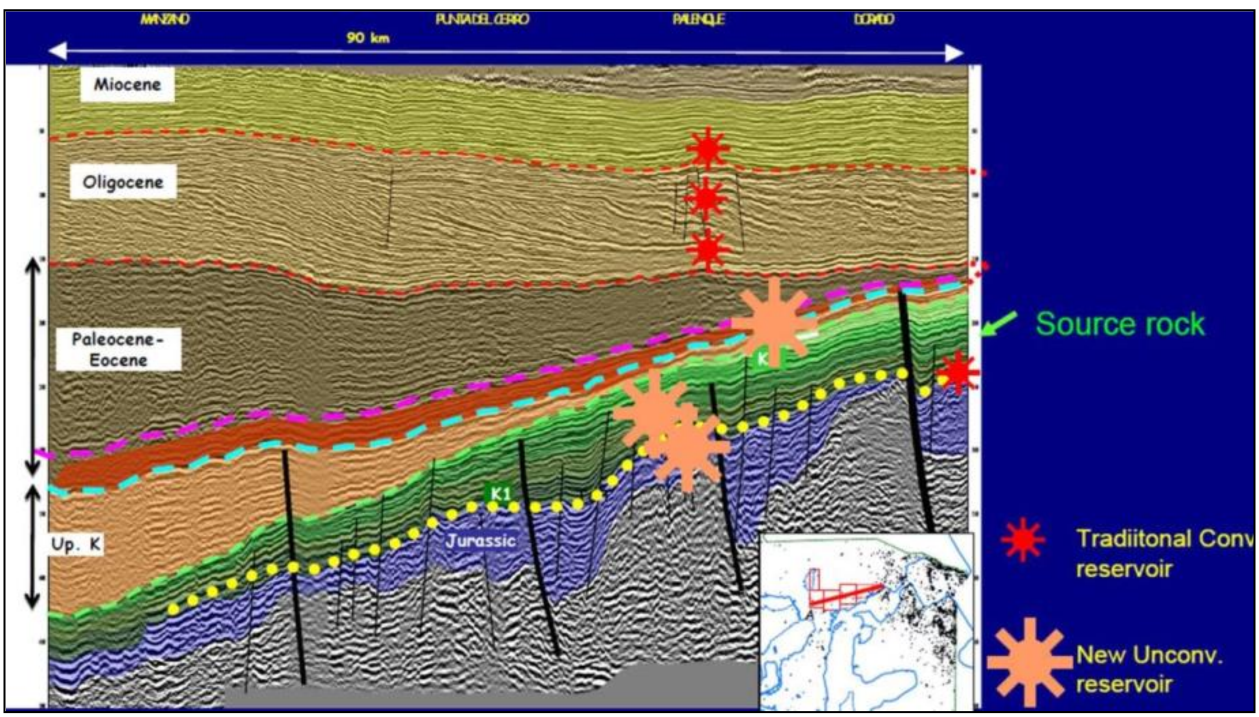


Source: ARI, 2013.

Overlying the Tobifera Formation are more prospective shales within the Early Cretaceous Lower Inoceramus or Palermo Aike formations (Estratos con Favrella Formation in Chile). The Tobifera was deposited under shallow water marine conditions. The Lower Inoceramus Formation is 50 to 400 m thick. In the Argentina portion of the basin, the total shale thickness (including the Magnas Verdes Formation) ranges from 800 ft thick in the north to 4,000 ft thick in the south, representing neritic facies deposited in a low-energy and anoxic environment.[35] Total organic content of these two main source rocks generally ranges from 1.0% to 2.0%, with hydrogen index of 150 to 550 mg/g.[36] Based on analysis in Chile reportedly conducted by Chesapeake Energy, the Lower Cretaceous Estratos con Favrella Formation contains marine-deposited shale with consistently good to excellent (up to 6%) TOC, particularly near its base.[37]

Figure V-12, a seismic time section across the basin, shows the 180-m thick Estratos con Favrella Formation dipping gently west in a relatively simple structural setting. ENAP has estimated porosity of 6% to 12%, but we assumed a more conservative estimate of 6%. Thermal maturity increases gradually with depth in a half-moon pattern, ranging from oil-prone (R_o 0.8%) to dry gas prone (R_o 2.0%). The transition from wet to dry gas (R_o 1.3%) occurs at a depth of about 3,600 m in this basin.[38]

Figure V-12: Seismic Time Section in the Magallanes Basin, Chile



Source: Methanex, September 27, 2012.

3.2 Reservoir Properties (Prospective Area)

Argentina's portion of the Austral Basin has an estimated 13,530-mi^2 prospective area with organic-rich shale in Lower Cretaceous formations. Of this total prospective area, approximately 4,620 mi^2 is in the oil window; 4,600 mi^2 is in the wet gas/condensate thermal maturity window; and 4,310 mi^2 is in the dry gas window. These shales average about 800 ft thick (organic-rich), 8,000 to 13,500 ft deep, and have estimated 3.5% average TOC. Thermal maturity (R_o) ranges from 0.7% to 2.0% depending mainly on depth. Porosity is estimated at about 5%. The Estancia Los Lagunas gas condensate field in southeast Argentina measured a 0.46 psi/ft pressure gradient with elevated temperature gradients in the Serie Tobifera Formation, immediately underlying the Lower Inoceramus equivalent.[39]

3.3 Resource Assessment

Risked, technically recoverable shale gas and oil resources from the Lower Cretaceous formations in the Argentina portion of the Austral Basin are estimated at 130 Tcf of shale gas and 6.6 billion barrels of shale oil and condensate, Tables V-1 and V-2. Risked shale gas and oil in-place is estimated at 606 Tcf and 131 billion barrels. The play has moderate to high resource concentrations of 33 to 156 Bcf/mi^2 of shale gas and 15 to 48 million bbl/mi^2 of shale oil and condensate, depending on the thermal maturity window.

3.4 Recent Activity

No shale leasing or exploration activity has been reported in the Austral Basin. In Chile, Methanex had partnered with ENAP in conventional oil and gas exploration in the Magallanes basin and also had expressed interest in shale gas exploration during 2011-12. However, recently the company decided to relocate about half of its methanol capacity in Chile to Louisiana, USA.[40]

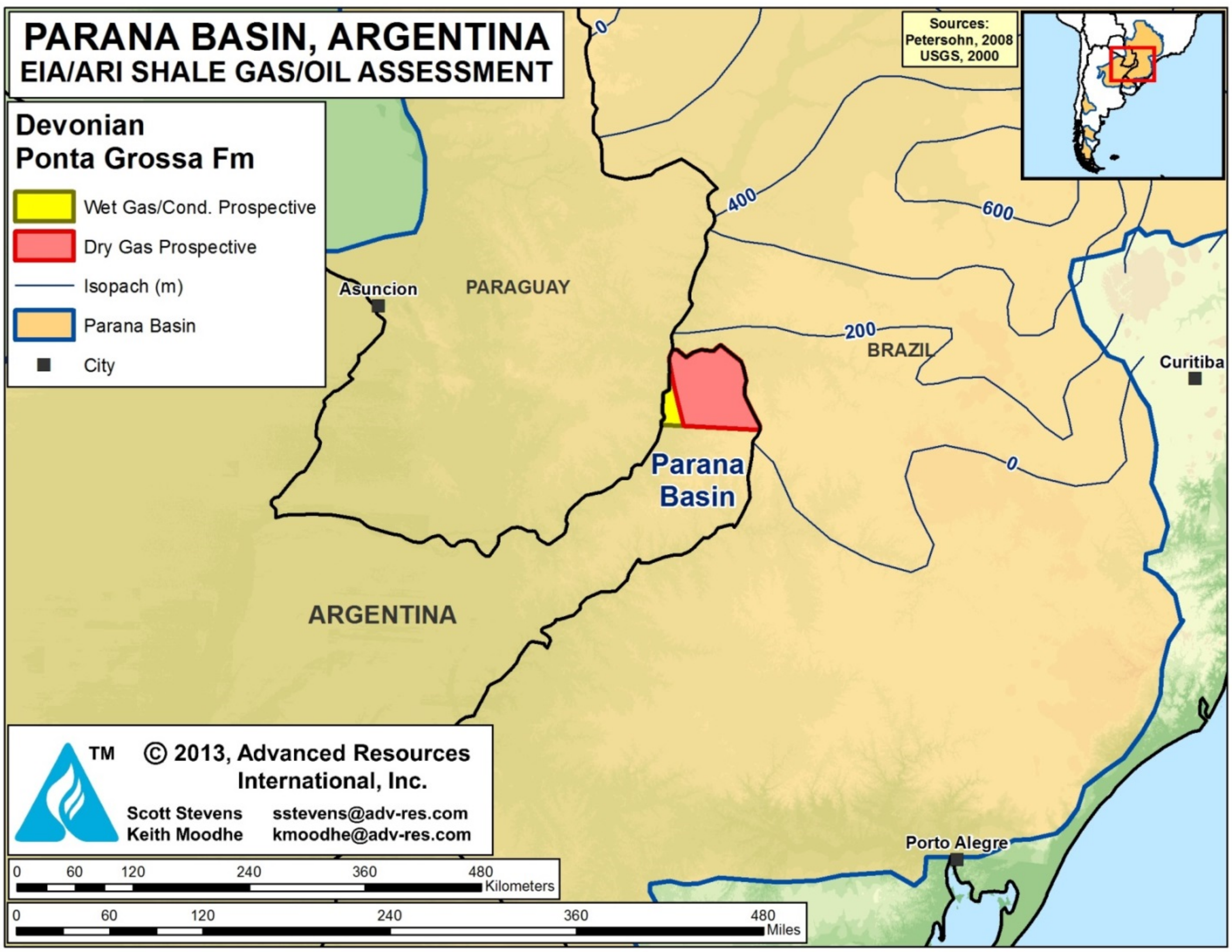
UK-based GeoPark holds conventional petroleum leases in the Magallanes Basin of Chile, which the company notes contains shales in the Estratos con Favrella Formation which previously have produced oil. In 2012, GeoPark conducted diagnostic fracture injection tests on eight wells on the Fell Block to determine reservoir properties of the shale.[41]

4 PARANÁ BASIN

4.1 Introduction and Geologic Setting

The Paraná Basin is a large (747,000 mi^2) depositional feature that covers areas of Brazil, Paraguay, and Uruguay, as well as a small area of northeastern Argentina, **Figure V-13**. The basin contains up to 5 km (locally 7 km) of Paleozoic and Mesozoic sedimentary rocks that range from Late Ordovician to Cretaceous. The basin's western border is defined by the Asuncion Arch, related to Andean thrusting, while the east is truncated by the South Atlantic tectonic margin.[42] Much of the Brazilian portion of the basin is covered by flood basalts, partly obscuring the underlying geology from seismic and increasing the cost of drilling, but the Argentina portion is largely free of basalt.

Figure V-13: Prospective Shale Area in the Parana Basin, Argentina



Source: ARI, 2013.

The main petroleum source rock in the Paraná Basin is the Devonian (Emsian/Frasnian) black shale of the Ponta Grossa Formation. The entire formation ranges up to 600 m thick in the center of the basin, averaging about 300 m thick. TOC of the Ponta Grossa Fm reaches up to 4.6% but more typically is 1.5% to 2.5%. The mostly Type II kerogen sourced natural gas that migrated into conventional sandstone reservoirs.[43]

Figure V-14, a cross-section of the Paraná Basin, illustrates the thick and gently dipping Devonian source rocks that pass through the oil window into the gas window.[44] A conventional well log in the Paraguay portion of the basin penetrated Devonian source rocks and interbedded sandstones with oil and gas shows.[45] In outcrop, the Devonian Cordobes Formation ranges up to 160 m thick, including up to 60 m of organic-rich shale. TOC ranges from 0.7 to 3.6%, consisting mainly of Type II marine kerogen. Based on the low thermal maturity at outcrop (R_o 0.6%), ANCAP has estimated the boundary between dry and wet gas to occur at a depth of about 3,200 m.[46]

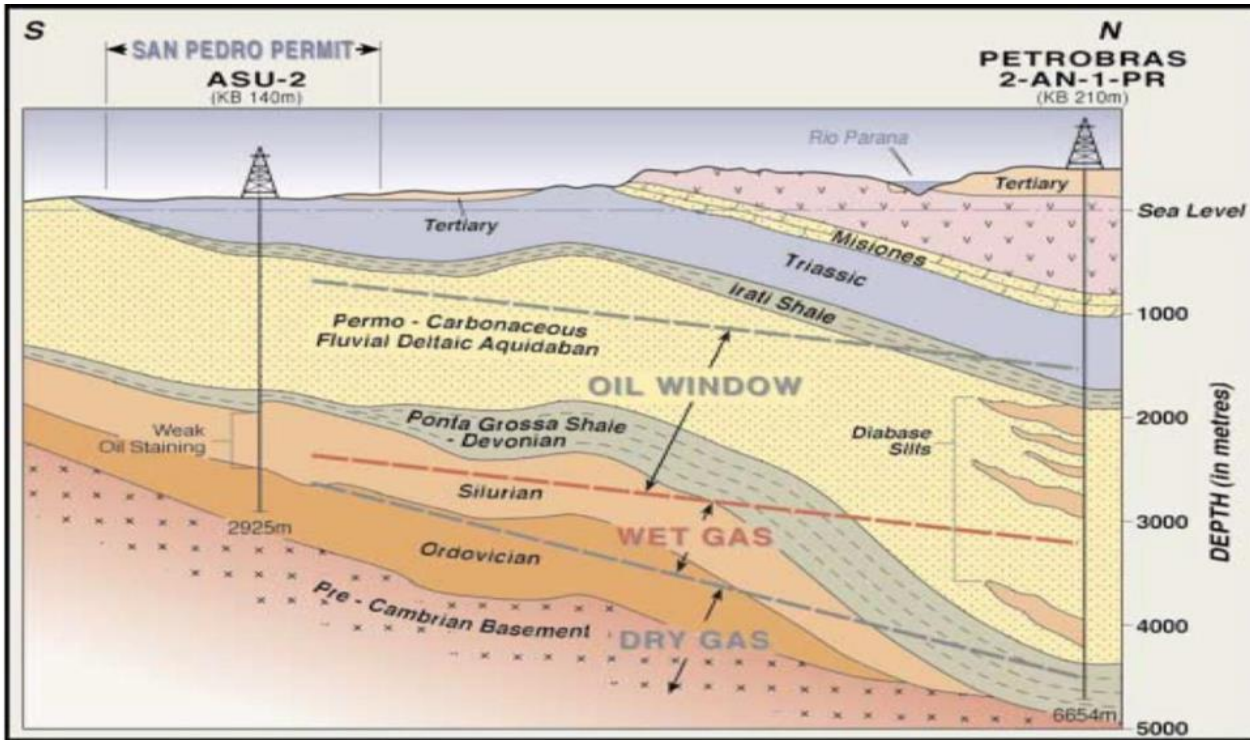
The Paraná Basin has remained at moderate burial depth throughout its history. Consequently, the bulk of thermal maturation took place during the late Jurassic to early Cretaceous igneous episode. Most of the basin remains thermally immature (R_o <0.5%), but there are sizeable concentric windows of oil-, wet-gas-, and dry-gas maturity in the central deep portion of the basin.

4.2 Reservoir Properties (Prospective Area)

Depth and thermal maturity of the Devonian Ponta Grossa Formation are moderately constrained by data in the Argentina portion of the Paraná Basin. The total prospective area in Argentina is estimated at 2,500 mi^2, of which 270 mi^2 is in the wet gas/condensate thermal maturity window, and 2,230 mi^2 is in the dry gas window (the oil window is negligible in this basin). Devonian Ponta Grossa shale averages about 300 m thick (net), 11,000 to 14,000 ft deep, and has estimated 2.0% average TOC. Thermal maturity (R_o) ranges from 0.85% to 1.5% depending mainly on depth.

For example, Amerisur reported that the Devonian Lima Formation has good (2-3%) TOC and is oil-prone (R_o 0.87%) at their conventional exploration block in Paraguay. Porosity is estimated at about 4% and the pressure gradient is assumed to be hydrostatic.

Figure V-14: Cross-Section of the Paraná Basin of Paraguay, Showing Thick and Gently Dipping Devonian Source Rocks Passing Through the Oil and Gas Windows.



Source: Chaco Resources PLC, 2004.

4.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from black shale in the Devonian Ponta Grossa Formation in the Argentina portion of the Paraná Basin are estimated at 3.2 Tcf of natural gas and minimal (0.01 billion barrels) shale oil and condensate, Tables V-1 and V-2. Risked shale gas and shale oil in-place is estimated at 16 Tcf and 0.3 billion barrels. The play has low to moderate net resource concentrations of 35 to 57 Bcf/mi^2 of shale gas and 8 million bbl/mi^2 of shale oil and condensate, depending on the thermal maturity window.

4.4 Recent Activity

No shale leasing or exploration activity has been reported in the Argentina portion of the Paraná Basin. In Uruguay TOTAL, YPF, and small Australia-based Petrel Energy hold large exploration licenses with Devonian shale potential but have not drilled.

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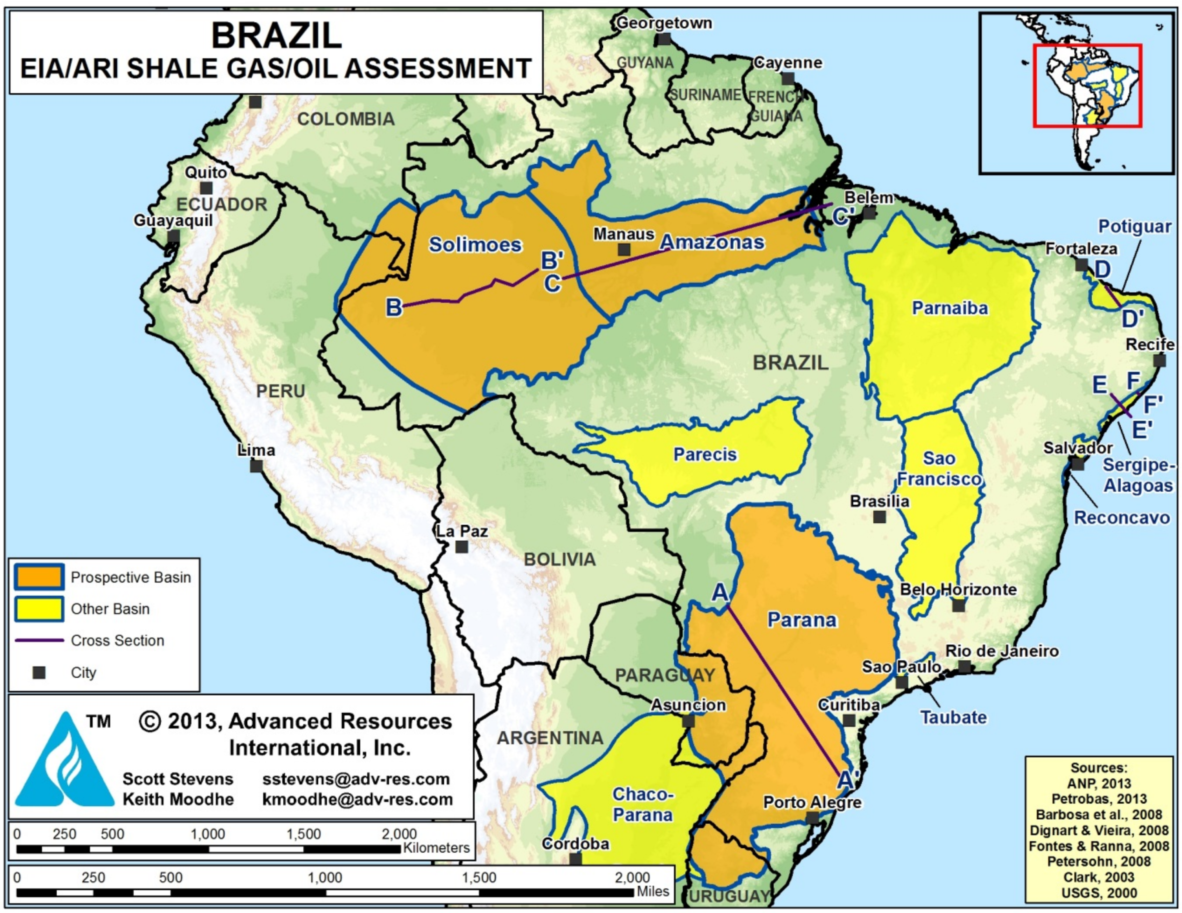
VI. BRAZIL

SUMMARY

While Brazil's most prolific petroleum basins lie offshore, the country has 18 mostly undeveloped and lightly explored sedimentary basins onshore, **Figure VI-1**. Three of these basins -- the Paraná in the south and the Solimões and Amazonas in the north – produce significant conventional oil and gas from demonstrated source rock systems. These three basins also have sufficient geologic data to be assessed for shale gas and shale oil potential.

Figure VI-1: Prospective Shale Basins of Brazil



Source: ARI, 2013

The main shale target is the Devonian (Frasnian) marine black shale, which is extensively developed in the three structurally simple basins but has relatively modest TOC (2-2.5%). Several other basins in Brazil may have shale gas and oil potential but lack proven source rock systems, are thermally immature, and/or lack sufficient public data for assessment.

Brazil's risked, technically recoverable shale gas and shale oil resources in the Paraná, Solimões and Amazonas basins are estimated at 245 Tcf and 5.4 billion barrels, Tables VI-1 and VI-2. Risked, in-place shale resources are estimated to be 1,279 Tcf of shale gas and 134 billion barrels of shale oil. No shale-focused exploration leasing or drilling has been announced to date in Brazil.

Table VI-1. Shale Gas Reservoir Properties and Resources of Brazil

Basic Data	Basin/Gross Area		Parana (747,000 mi^2)			Solimoes (350,000 mi^2)		Amazonas (230,000 mi^2)		
	Shale Formation		Ponta Grossa			Jandiatuba		Barreirinha		
	Geologic Age		Devonian			Devonian		Devonian		
	Depositional Environment		Marine			Marine		Marine		
Physical Extent	Prospective Area (mi^2)		25,600	18,050	22,840	8,560	54,750	5,520	3,260	44,890
	Thickness (ft)	Organically Rich	1,000	1,000	1,000	160	160	260	300	300
		Net	300	300	300	120	120	195	225	225
	Depth (ft)	Interval	9,500 - 13,000	10,000 - 14,000	12,000 - 16,400	3,300 - 10,000	10,000 - 16,400	6,500 - 13,000	8,000 - 14,000	3,300 - 16,400
		Average	11,000	12,000	14,000	7,500	12,000	9,500	11,500	12,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	2.2%	2.2%	2.5%	2.5%	2.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	1.15%	1.60%	0.85%	1.15%	1.60%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		25.5	55.7	91.3	20.1	36.1	15.2	45.4	70.2
	Risked GIP (Tcf)		78.5	120.7	250.4	25.8	296.8	12.6	22.2	472.4
	Risked Recoverable (Tcf)		6.3	24.1	50.1	5.2	59.4	1.0	4.4	94.5

Table VI-2. Shale Oil Reservoir Properties and Resources of Brazil

Basic Data	Basin/Gross Area		Parana (747,000 mi^2)		Solimoes (350,000 mi^2)	Amazonas (230,000 mi^2)	
	Shale Formation		Ponta Grossa		Jandiatuba	Barreirinha	
	Geologic Age		Devonian		Devonian	Devonian	
	Depositional Environment		Marine		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		25,600	18,050	8,560	5,520	3,260
	Thickness (ft)	Organically Rich	1,000	1,000	160	260	300
		Net	300	300	120	195	225
	Depth (ft)	Interval	9,500 - 13,000	10,000 - 14,000	3,300 - 10,000	6,500 - 13,000	8,000 - 14,000
		Average	11,000	12,000	7,500	9,500	11,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.2%	2.5%	2.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.15%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		26.8	11.4	5.5	18.3	8.7
	Risked OIP (B bbl)		82.4	24.7	7.1	15.1	4.3
	Risked Recoverable (B bbl)		3.30	0.99	0.28	0.61	0.17

Advanced Resources International, Inc.

INTRODUCTION AND GEOLOGIC OVERVIEW

Brazil has 18 onshore sedimentary basins, of which 14 basins may have petroleum source rocks. However, since the 1980s Brazil has focused mainly on its offshore oil and gas resources, while the onshore basins have seen less activity. Only two onshore basins have significant oil and gas output (Amazonas and Paraná). Relatively few conventional oil and gas wells have been drilled to the deep source rock intervals in these basins. Shale exploration drilling has not yet occurred. As a result, geologic data on the shale source rocks in Brazil are relatively scant.

Brazil's National Oil and Gas Agency (ANP) has conducted exploration surveys, mostly gravity and magnetics with minimal drilling, on four onshore basins: the Amazonas, Parana, Parnaiba, and part of the Sao Francisco.[1] Recently ANP estimated that Brazil may have 208 Tcf of shale gas resources, based on a rough analogy of three onshore Brazilian basins (Parnaiba, Parecis, Recôncavo) with the Barnett Shale in the Fort Worth Basin of Texas.[2] Petrobras, the national oil company, recently drilled its first shale oil well in Argentina but has not announced plans for shale drilling in Brazil.

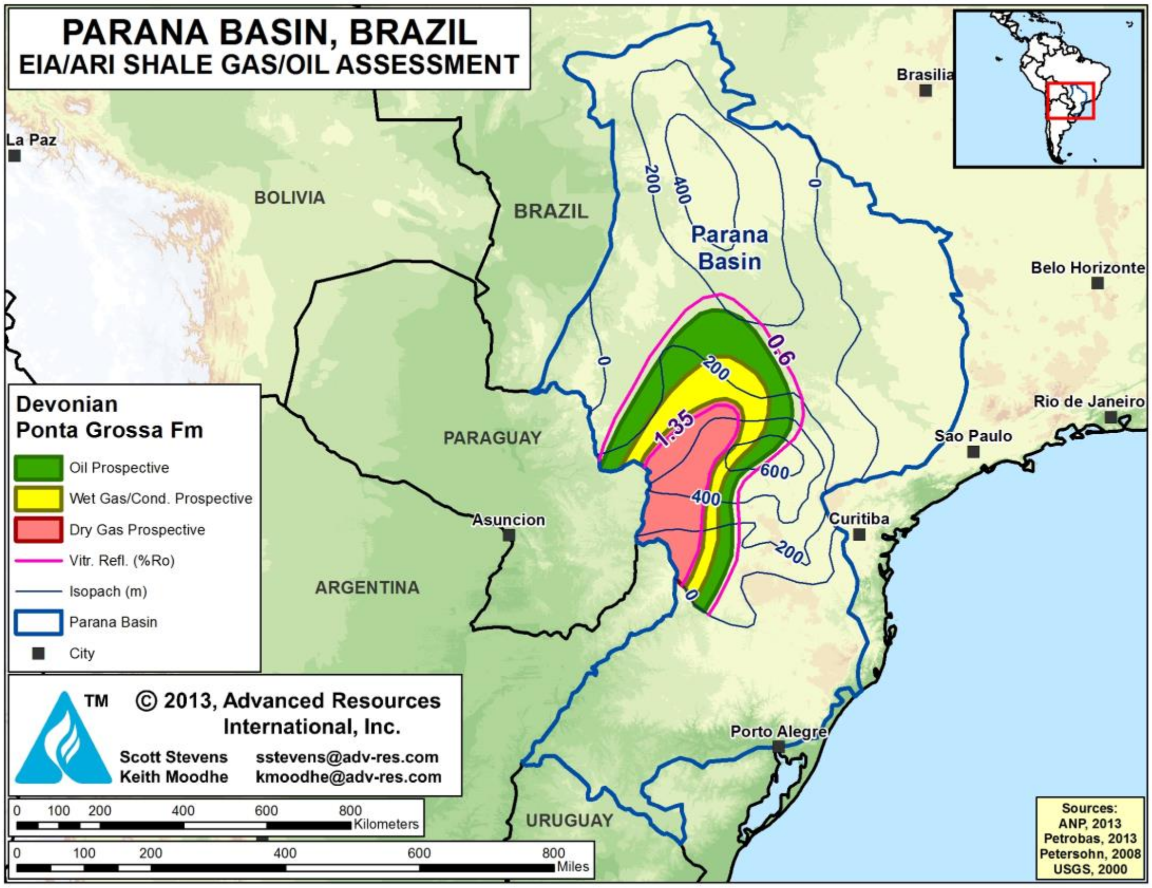
EIA/ARI has assessed the shale resource potential of three of Brazil's onshore basins (Paraná, Solimões, and Amazonas). These basins have prospective shales that sourced commercially productive conventional oil and gas fields as well as sufficient available geologic data for resource analysis. In addition, Brazil has a half-dozen other basins which may have shale potential, but their source rock systems are less proven and/or they lack sufficient available geologic data. These six other basins -- which were reviewed but not formally assessed in this study -- include the Potiguar, Parnaiba, Parecis, Recôncavo, Sergipe-Alagoas, Sao Francisco, Taubaté, and Chaco- Paraná.

1. PARANÁ BASIN

1.1 Introduction and Geologic Setting

Located in Brazil's economically most developed southern region, the Paraná Basin is a large (1.5 million km^2) depositional feature that covers 747,000 mi^2 within Brazil, with additional area in Paraguay, Uruguay, and northern Argentina, **Figure VI-2**. Major infrastructure in the region includes the Brazil-Bolivia and Uruguaiana-Porto Alegre pipelines.

Figure VI-2: Prospective Shale Gas and Shale Oil Areas in the Paraná Basin



Source: ARI, 2013

Conventional petroleum exploration began in the Paraná Basin during the 1890's, but the first (and thus far only) commercial discovery came in 1996, with the low-permeability Barra Bonita gas field of limited output (36 Bcf total through 2009).[3] Approximately 124 petroleum wells have been drilled in the Brazil portion of the Paraná Basin, a low drilling density of 1 well per 10,000 km^2. In addition, some 30,000 km of 2D seismic have been acquired.[4] Only a fraction of this data set has been published and made available for our study.

The Paraná Basin contains up to 5 km (locally 7 km) of Paleozoic and Mesozoic sedimentary rocks that range from Late Ordovician to Cretaceous. Its western border is defined by the Asuncion Arch, related to Andean thrusting, while the east is truncated by the South Atlantic tectonic margin.[5] On the north the basin onlaps Precambrian basement. Some two-thirds of the basin is covered by flood basalts, partly obscuring the underlying geology from seismic and increasing the cost of drilling.

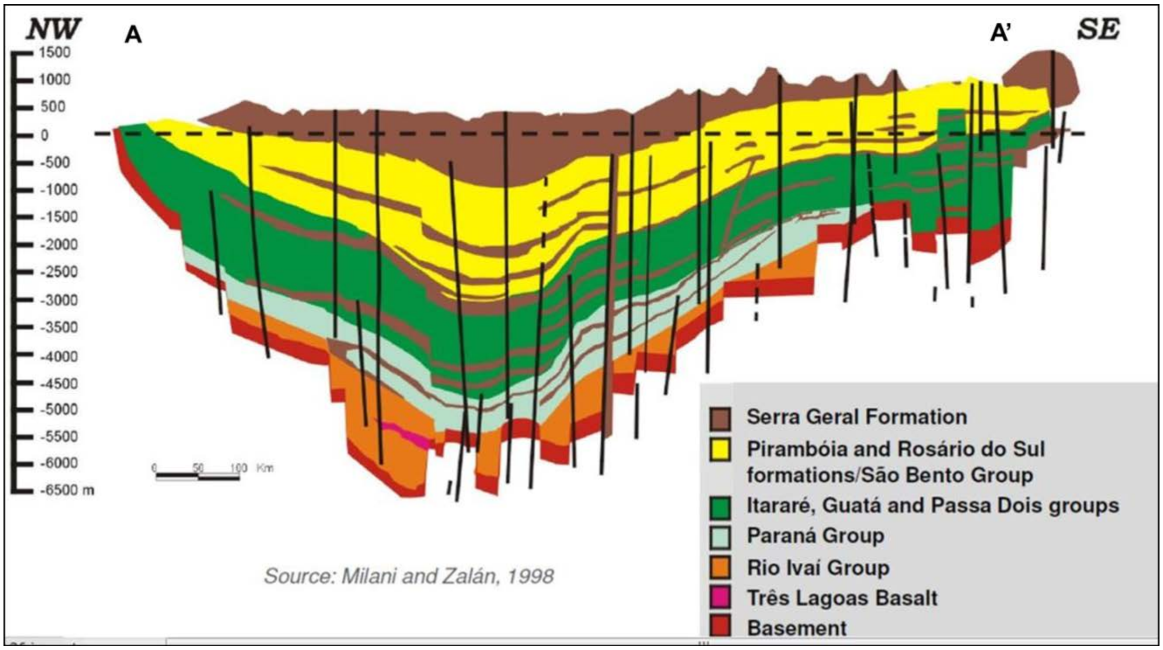
The structure of the Paraná Basin appears to be moderately simple, at least based on available data, consisting of a gentle syncline with minor faulting and secondary folding, **Figure VI-3**. Faults, predominately normal in orientation, are controlled by older basement faults (aulocogens) which separate large undeformed tracts of the basin interior. However, numerous igneous sills and dikes, related to emplacement of the flood basalts during the Early Cretaceous, intrude the sedimentary sequence. More detailed seismic reveals the presence of numerous smaller faults, **Figures VI-4 and VI-5**.

The main petroleum source rock in the Paraná Basin is the Devonian black shale of the Ponta Grossa Formation (Emsian/Frasnian), **Figure VI-6**. This formation ranges up to 600 m thick in the center of the basin, averaging about 300 m thick. TOC of the Ponta Grossa Fm reaches up to 4.6% but more typically is 1.5% to 2.5%. The mostly Type II kerogen sourced natural gas that migrated into conventional sandstone reservoirs of the Late Carboniferous to Early Permian Itararé Group.[6]

The Paraná Basin has remained at moderate burial depth throughout its history. Consequently, the bulk of thermal maturation took place during the late Jurassic to early Cretaceous igneous episode. Most of the basin remains thermally immature (R_o <0.5%), but there are sizeable concentric windows of oil-, wet-gas-, and dry-gas maturity in the deep central basin area.

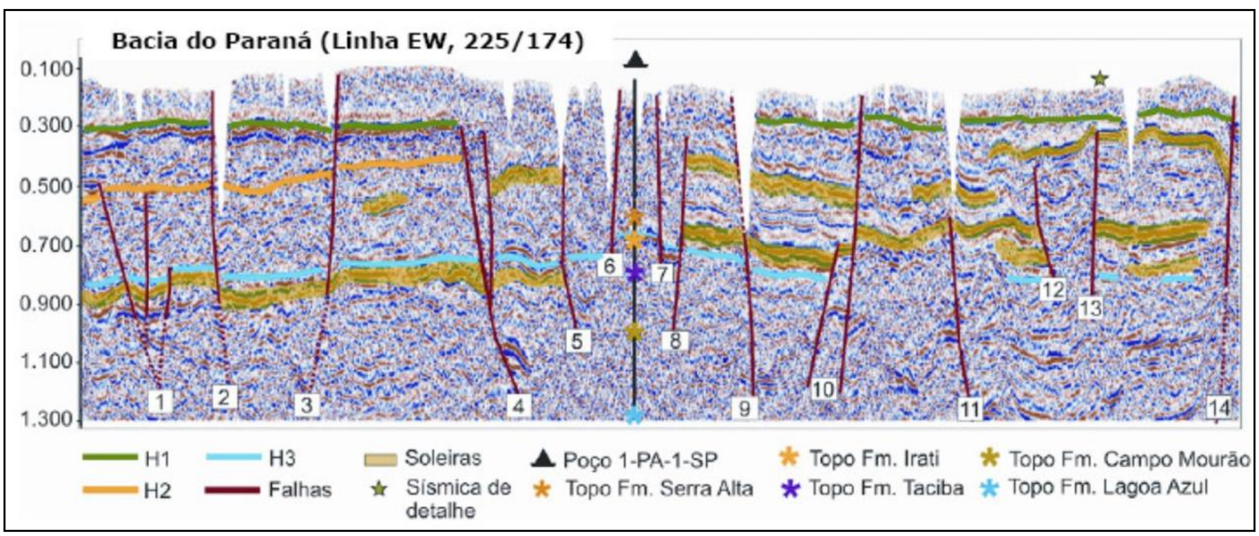
A second less prolific source rock in the Paraná Basin is the Permo-Triassic Irati Formation. This non-marine bituminous unit sourced oil trapped in biodegraded conventional sandstones (tar sands) of the Permian and Triassic Rio Bonito and Pirambóia formations.[7] The Irati Formation is widespread and can be organic-rich, averaging 8-13% TOC of Type I kerogen with peaks to 24%, but the shales are quite thin and thermally immature (R_o <0.5%). Petrobras is mining Irati oil shale from the surface at São Mateus do Sul and processing it using rock pyrolysis. Although the Irati Fm may be thermally mature in the deep Paraguay portion of the Paraná Basin,[8] its Brazil extension was not assessed due to low thermal maturity.

Figure VI-3. Cross-Section of the Paraná Basin, Brazil



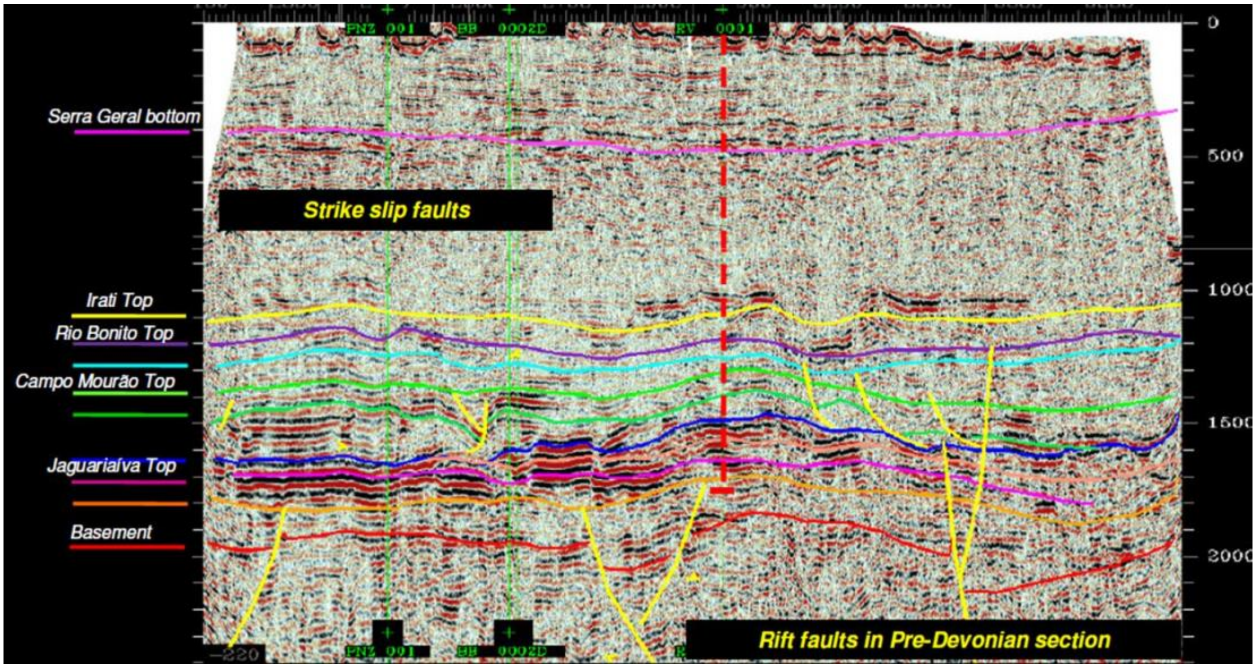
Source: ANP, 2012

Figure VI-4: Seismic Time Section Showing Regional Moderate Block Faulting of the Paraná Basin, Brazil



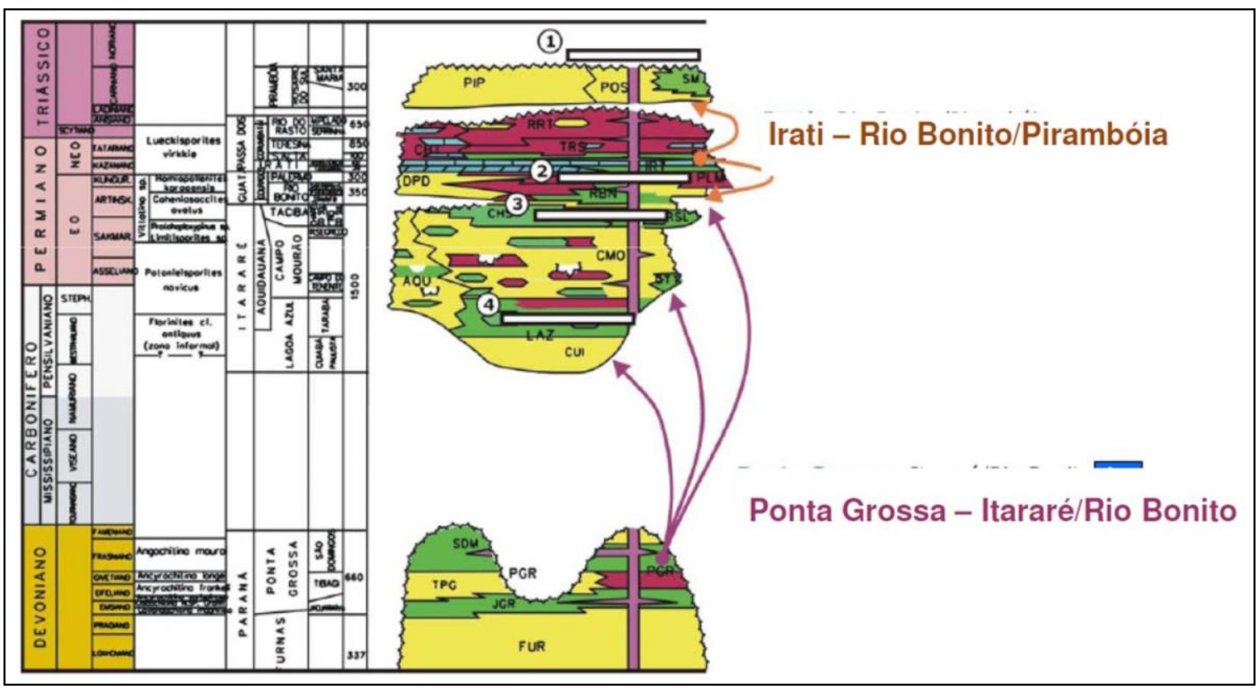
Source: Petersohn, 2003

Figure VI-5: Seismic Time Section of the Paraná Basin Showing Small Faults.



Source: Petersohn, 2003

Figure VI-6: Stratigraphy of Paraná Basin Showing Source Rock Shales, Devonian Ponta Grossa Formation



Source: Petersohn, 2003

1.2 Reservoir Properties (Prospective Area)

The prospective area of organic-rich shale in the Devonian Ponta Grossa Formation of the Paraná Basin is estimated at approximately 66,500 mi^2, of which 25,600 mi^2 is in the oil window; 18,050 mi^2 is in the wet gas/condensate thermal maturity window; and 22,840 mi^2 is in the dry gas window. The Devonian shale averages about 300 m thick (net), 11,000 to 14,000 ft deep, and has estimated 2.0% average TOC. Thermal maturity (R_o) ranges from 0.85% to 1.5% depending mainly on depth. Porosity is estimated at about 4% and the pressure gradient is assumed to be hydrostatic.

1.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from Devonian Ponta Grossa (Frasnian) black shale in the Paraná Basin are estimated at 81 Tcf of shale gas and 4.3 billion barrels of shale oil and condensate, Tables VI-1 and VI-2. Risked shale gas and shale oil in-place is estimated at 450 Tcf and 107 billion barrels. The play has moderate net resource concentrations of 26 to 91 Bcf/mi^2 for shale gas and 11 to 27 million bbl/mi^2 for shale oil depending on thermal maturity window.

1.4 Recent Activity

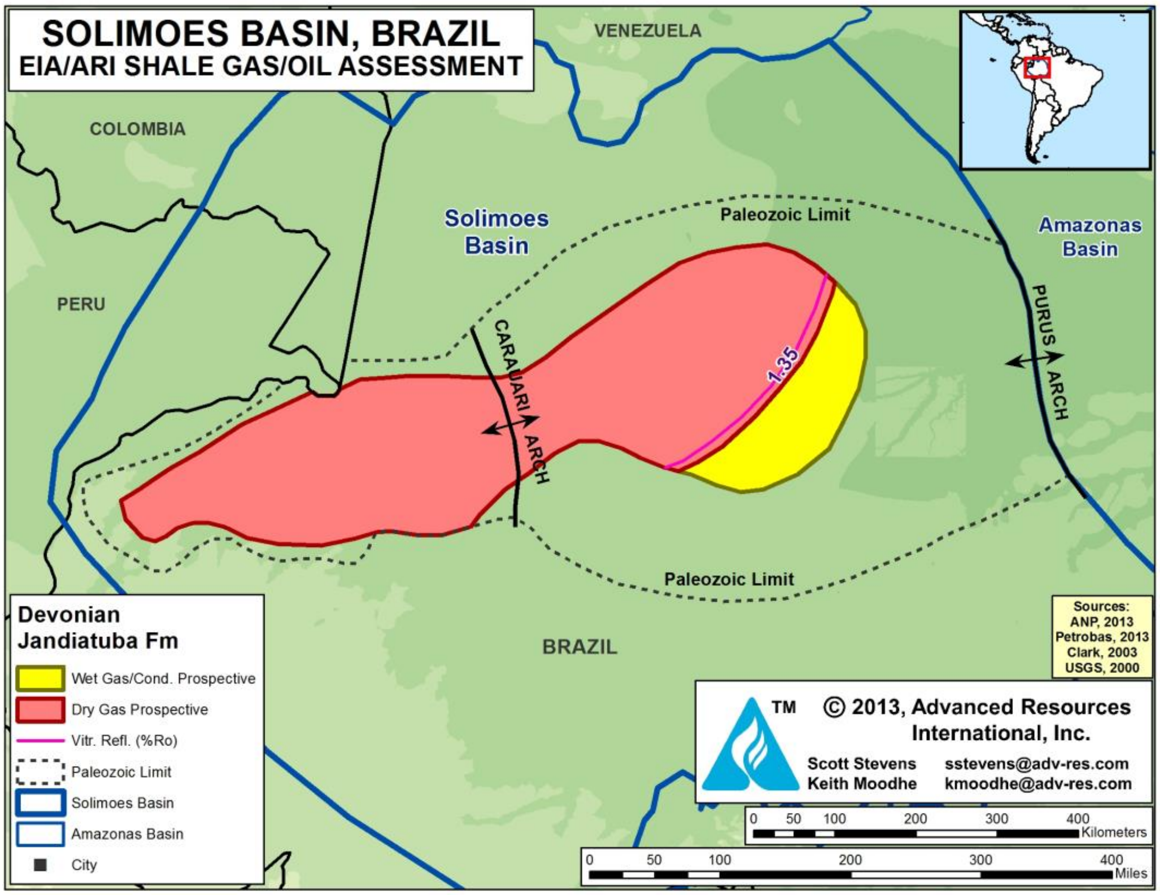
No shale gas/oil exploration activity has been reported in the Brazil portion of the Paraná Basin, although Amerisur Energy has discussed the shale potential of the Cretaceous Irati Fm in the Paraguay portion of the basin.

2. SOLIMÕES BASIN

2.1 Introduction and Geologic Setting

Located in northern Brazil, the Solimões Basin extends over 350,000 mi^2 of Amazon jungle, **Figure VI-7**. While less prolific than Brazil's offshore fields, the Solimões is the country's most productive onshore basin, with output of about 50,000 bbl/d of oil and 12 million m^3/d of natural gas from the Carboniferous Juruá Formation sandstone.[9]

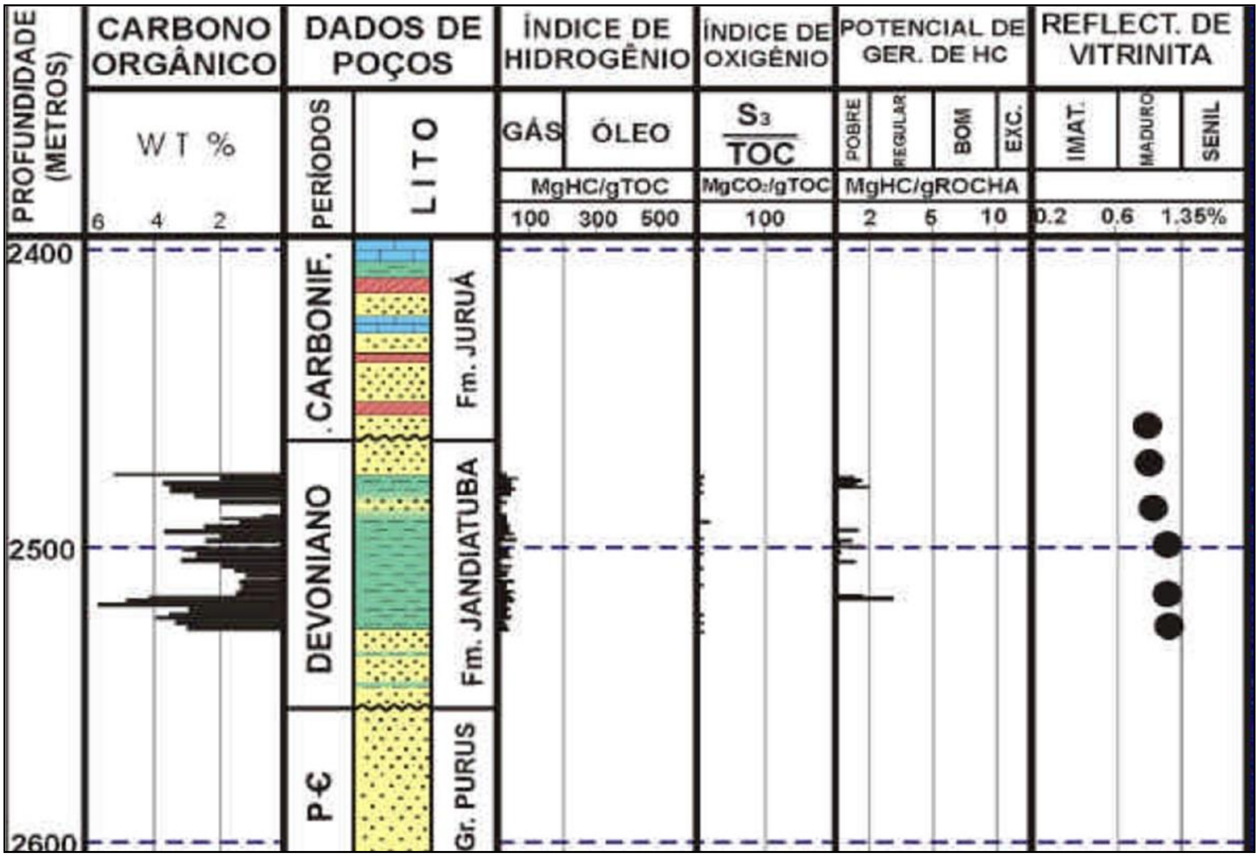
Figure VI-7: Prospective Shale Gas and Shale Oil Areas in the Solimões Basin



Source: ARI, 2013

These conventional reservoirs directly overlie and were sourced by marine-deposited source rocks within the Devonian Jandiatuba (mostly), Jaraqui and Ueré formations. The Jandiatuba Fm (Frasnian) contains a 50-m thick section of radioactive ("hot") black shale, with TOC ranging from 1% to 4% (average 2.2%; maximum 8.25%), **Figure VI-8**. Thermal maturity is mostly in the dry gas window (R_o >1.35%), apart from a small area in the east that is wet-gas prone (R_o 1.0% to 1.3%).[10]

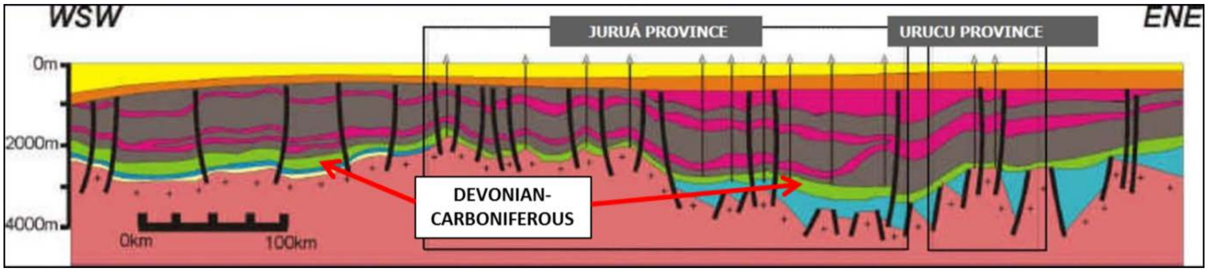
Figure VI-8: Black Shale in the Devonian Jandiatuba Formation of the Solimões Basin is about 40 m Thick with 1% to 4% TOC at this Location



Source: Clark, 2003

Figure VI-9, a regional cross-section oriented in the basin's strike direction, shows the mostly flat-lying but still moderately faulted Devonian shale at depths of 2 to 3 km. Note that a dip-oriented cross-section would reveal the steeper dips. Structural uplifts define several sub-basins. The easternmost Juruá Sub-basin, with up to 3.8 km of sedimentary rocks, accounts for most of the conventional oil and gas found in the Solimões Basin, indeed in the entire Paleozoic sequence of South America. The shale's thermal history is controlled more by proximity to igneous intrusions rather than simple burial depth.

Figure VI-9: Cross-Section (Strike Direction) of the Solimões Basin, Showing Flat-lying but Moderately Faulted Devonian Shale (Green) at Depths of 2 to 3 km.



Source: Clark, 2003

2.2 Reservoir Properties (Prospective Area)

The total estimated prospective area of organic-rich shale in the Devonian Jandiatuba Formation of the Solimões Basin is estimated at 63,000 mi^2, of which 8,560 mi^2 is in the wet gas thermal maturity window and 54,750 mi^2 is in the dry gas window. The Jandiatuba shale averages about 120 ft thick (net), 7,500 to 12,000 ft deep, and has estimated 2.2% average TOC. Porosity is estimated at 4% and the pressure gradient is assumed to be hydrostatic.

2.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from Devonian Jandiatuba black shale in the Solimões Basin are estimated at 65 Tcf of shale gas and 0.3 billion barrels of shale oil, out of risked shale gas and shale oil in-place of 323 Tcf and 7.1 billion barrels, Tables VI-1 and VI-2. The play has a moderate net resource concentration of 20 to 36 Bcf/mi^2 for shale gas and 5.5 million bbl/mi^2 for shale oil.

2.4 Recent Activity

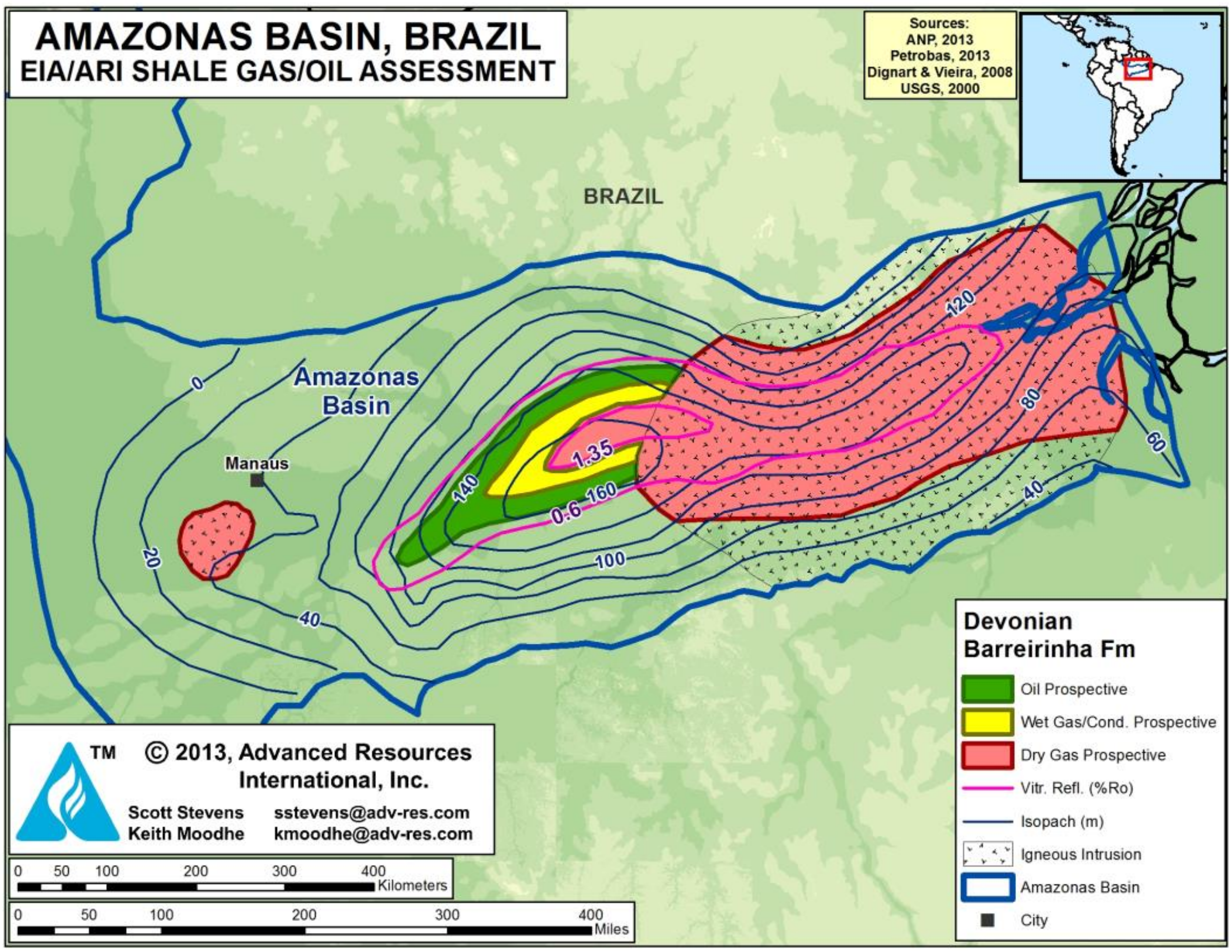
No shale gas/oil exploration activity has been reported in the Solimões Basin.

3. AMAZONAS BASIN

3.1 Introduction and Geologic Setting

Extending over more than 230,000 mi^2 of Amazon forest in remote northern Brazil, the Amazonas Basin is an ENE-WSW trending structural trough bounded by the Purus and Garupa arches, **Figure VI-10**. The first conventional petroleum fields were discovered in 1999 and commercialized starting in 2009, when the Urucu-Coari-Manaus gas and LPG pipeline system was commissioned. By late 2010, this pipeline was transporting about 0.2 Bcfd, mainly from the nearby Solimões Basin, along with smaller volumes from the Amazonas Basin.

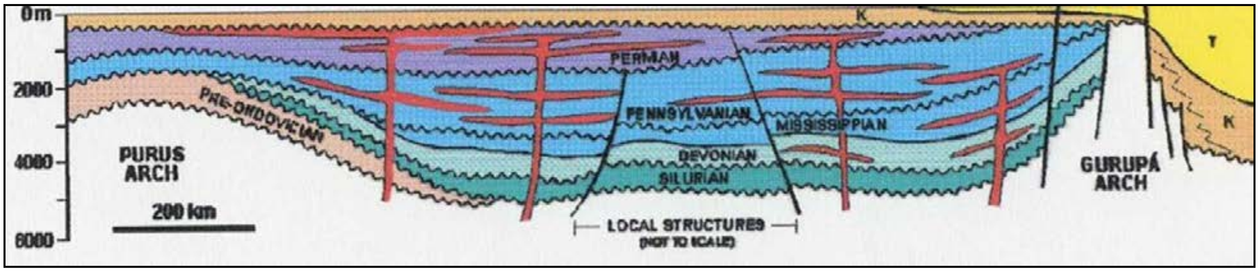
Figure VI-10: Prospective Shale Gas and Shale Oil Areas in the Amazonas Basin



Source: ARI, 2013

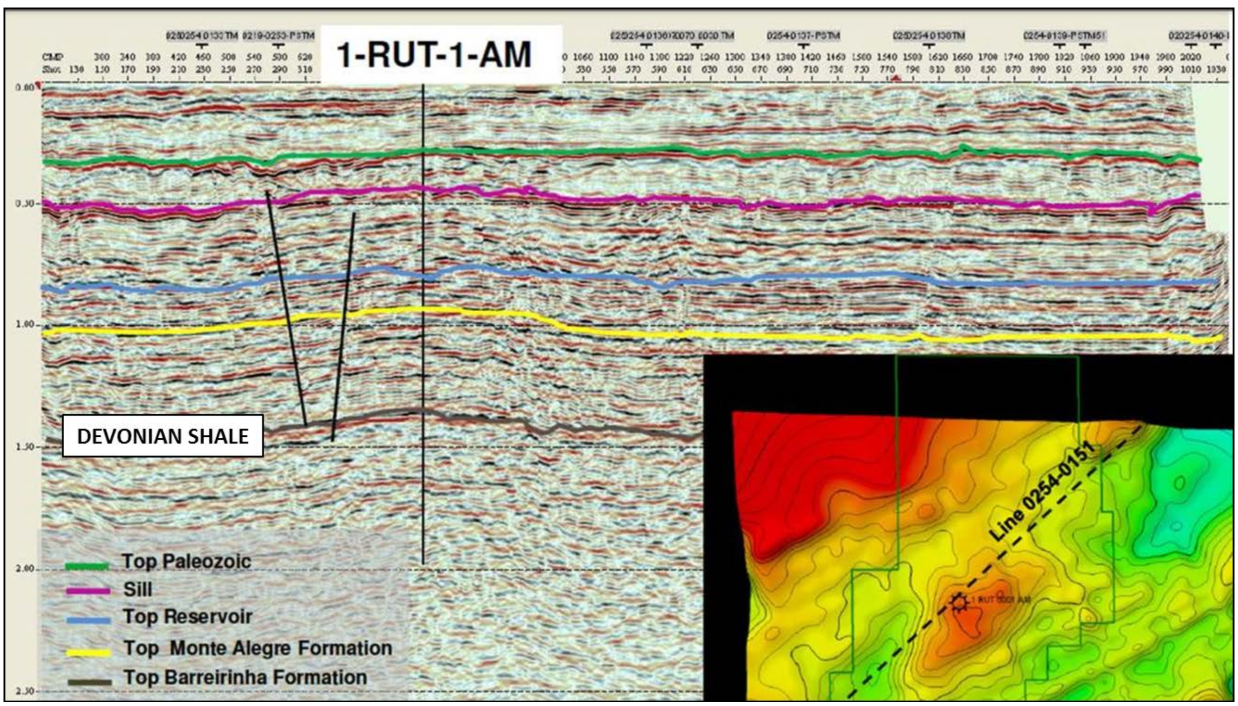
The Amazonas Basin contains up to 5 km of mostly Paleozoic sedimentary rock that are covered by Mesozoic and Cenozoic strata, **Figure VI-11**. While not structurally complex, the Amazonas Basin was extensively intruded by igneous activity during the Early Jurassic, particularly in the eastern half of the basin. This was followed by Cenozoic structural deformation that included extensional block and strike-slip faulting and salt tectonics. **Figure VI-12** illustrates the relatively simple local structure in one portion of the basin.

Figure VI-11: Devonian (Frasnian) Marine Black Shale Ranges from 2 to 4 Km Deep in the Amazonas Basin. Faults Appear to be Widely Spaced but Igneous Intrusions are Common.



Source: Dignart and Vieira, 2007

Figure VI-12: Seismic Time Section in the Amazonas Basin Showing Simple Structure of the Devonian Marine Black Shale.



Source: Dignart and Vieira, 2007

The petroleum system in the Amazonas Basin is broadly similar to that in the Solimões Basin. Up to 160 m (average 80 m) of laminated marine-deposited black shales are present in the Devonian Barreirinha Formation (Frasnian), which was the source rock for conventional sandstones of the overlying Nova Olinda Formation.[11] Ranging from 2 to 4 km deep, the Devonian shale has 2% to 5% TOC that consists of Type II kerogen. The Devonian is thermally immature (R_o < 0.5%) in the shallow and western portions of the basin, increasing to wet gas prone in the deeper center and dry gas prone in the more heavily intruded east. Additional marine black shales occur in the Silurian Pitinga Formation, but these contain less than 2% TOC and thus were not assessed.

3.2 Reservoir Properties (Prospective Area)

Based on the limited geologic control available for the Amazonas Basin, the total estimated prospective area of organic-rich shale in the Devonian Barreirinha Formation is estimated at about 54,000 mi^2, of which 5,520 mi^2 is in the oil window; 3,260 mi^2 is in the wet gas and condensate window; and 44,890 mi^2 is in the dry gas window. The Devonian shale averages 195-225 ft thick (net), 9,500-12,000 ft deep, and has estimated 2.5% average TOC. Porosity is estimated at 4% and the pressure gradient is assumed to be hydrostatic.

3.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from the Devonian Barreirinha Formation (Frasnian) black shale in the Amazonas Basin are estimated at 100 Tcf of shale gas and 0.8 billion barrels of shale oil and condensate, out of risked shale gas and shale oil in-place of 507 Tcf and 19 billion barrels, Tables VI-1 and VI-2. The play has a moderate net resource concentrations of approximately 15 to 70 Bcf/mi^2 for shale gas and 9 to 18 million bbl/mi^2 for shale oil.

3.4 Recent Activity

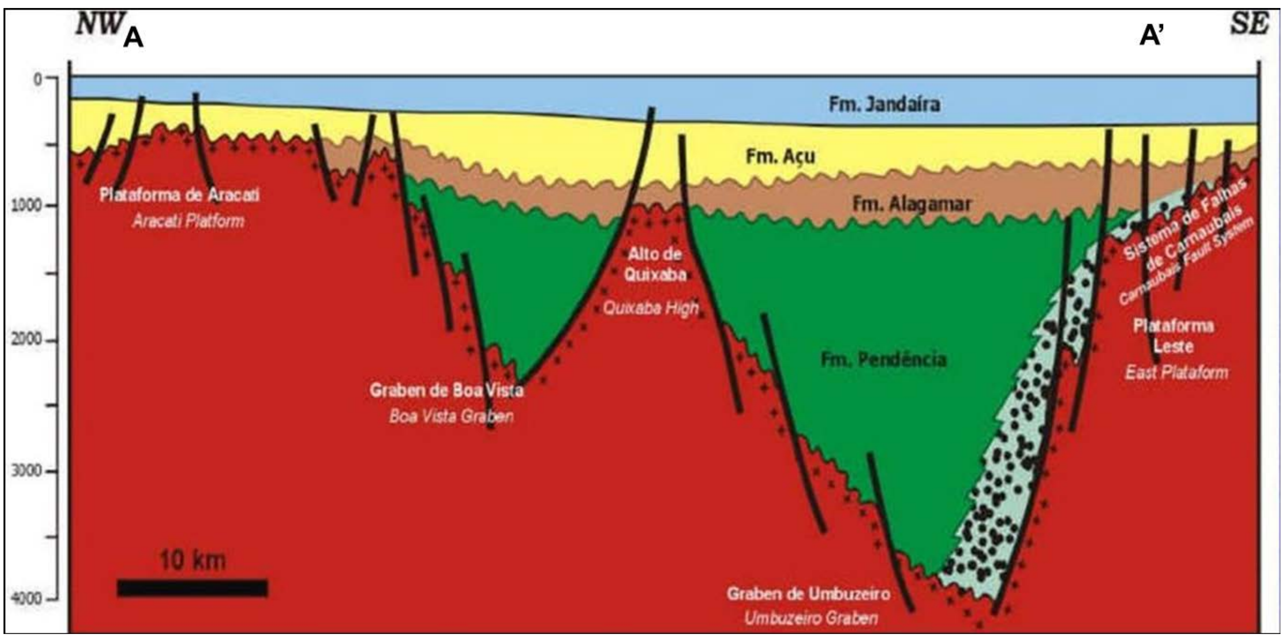
No shale gas/oil exploration leasing or drilling activity has been reported in the Amazonas Basin.

4. OTHER BASINS

More than a dozen other sedimentary basins occur in onshore Brazil. Most have no commercial oil and gas production and some lack identified petroleum generation and maturation systems. Some of these basins may have shale potential but public data are not currently sufficient for detailed characterization and assessment by EIA/ARI. However, these basins could be prospective for shale exploration and should be assessed once additional geologic data become available. Six of the more promising basins include:

- **Potiguar Basin.** This Neocomian rift basin in northeastern Brazil extends over an onshore area of about 33,000 km^2 plus a much larger area offshore. The onshore portion of the basin contains up to 4 km of mostly Cretaceous deposits. The basin comprises a number of smaller fault blocks, with major structures trending northeast-southwest, **Figure VI-13**. Oil production currently averages 125,000 bbl/day, making the Potiguar Basin Brazil's second largest production area after the offshore Campos Basin. The 5,000 mostly onshore wells have recovered a total of 0.5 billion barrels of oil and 0.5 Tcf of natural gas.[12]

Figure VI-13: Cross-Section of the Potiguar Basin, Showing the Pendência and Alagamar Formations.



Source: ANP, 2003

The Upper Cretaceous (Barremenian) to Paleocene Pendência Formation, a rift sequence, is considered the main petroleum source rock in the Potiguar Basin, containing about 4% TOC of Type I kerogen. The Alagamar Formation contains up to 6% TOC of Types I and II kerogen, but is shallow (<1 km) in the onshore.[13] However, shale resources were not assessed in the Potiguar Basin due to its apparent structural complexity and the lack of available data control on source rock depth, thickness, and thermal maturity.

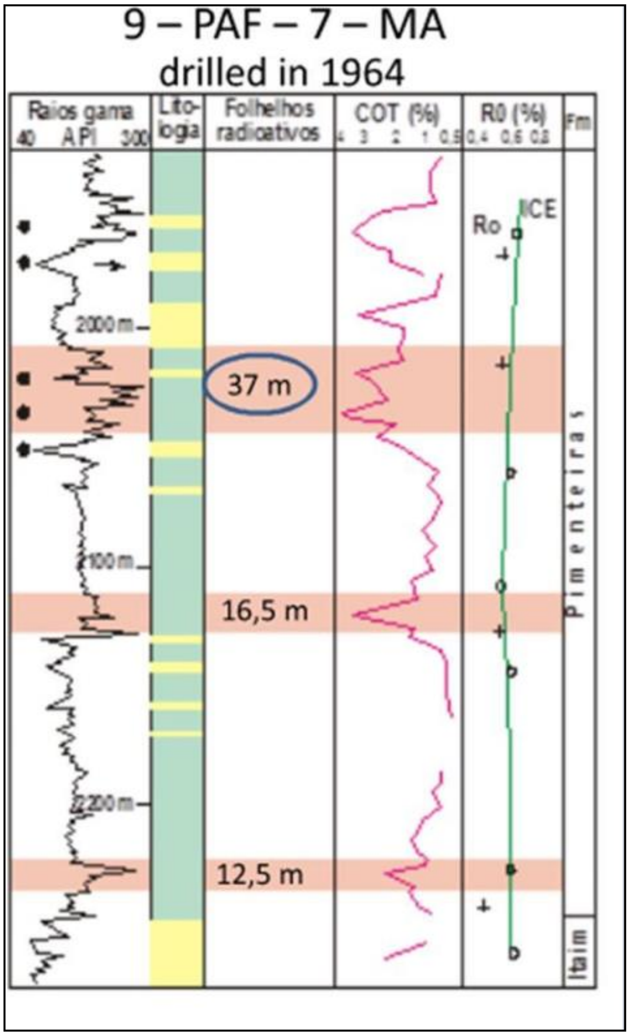
- **Parnaiba Basin.** Also located in northeastern Brazil, this large (600,000-km^2) circular basin contains up to 3.5 km of sedimentary rocks within a relatively simple -- albeit heavily intruded -- structural setting. The Devonian Pimenteiras Formation contains marine black shale up to 300 m thick with 2.0-2.5% TOC. Local independent operator MPX Energia S.A. has reported the company logged gas shows while drilling through a 23-m thick "naturally fractured" Devonian shale interval.[14]

  Figure VI-14 shows the distribution of thickness, depth, TOC, and thermal maturity of the Pimenteiras at a conventional exploration well in an undisclosed portion of the basin. Organic-rich shale in this well totals about 50 m thick at a depth of 2,000 to 2,200 m. The TOC ranges up to 4%, averaging 2.5%, but is thermally immature (R_o ~0.5%) at this location. ANP has projected that thermal maturity reaches oil- and eventually gas-prone levels in the deeper parts of the basin (1,600 to 2,500 m), and estimated 64 Tcf of recoverable shale gas resources, based on analogy with the Barnett Shale play in the Fort Worth Basin.[15]

  However, as just noted available data suggests the Pimenteiras Fm is thermally immature (R_o 0.5%) at a depth of 2,200 m and may only just be entering the oil window at 2,500 m. Other researchers have reported this unit to be thermally immature, apart from local contact zones near the abundant igneous intrusions. Note also that the basin lacks commercial oil and gas production. Given the sparse data available for this study, EIA/ARI did not assess the shale potential of the Parnaiba Basin.

- **Parecis Basin.** A frontier non-productive sedimentary basin in northern Brazil. ANP has noted that radioactive dark shale averages some 50 m thick in the deep basin grabens. As much as 106 m was logged at a depth of 4 km in one conventional petroleum well. ANP recently estimated that 124 Tcf of shale gas may be recoverable based on the Barnett Shale comparison. However, data available to EIA/ARI were not sufficient for assessing the shale potential of the Parecis Basin, which does not produce oil and gas.

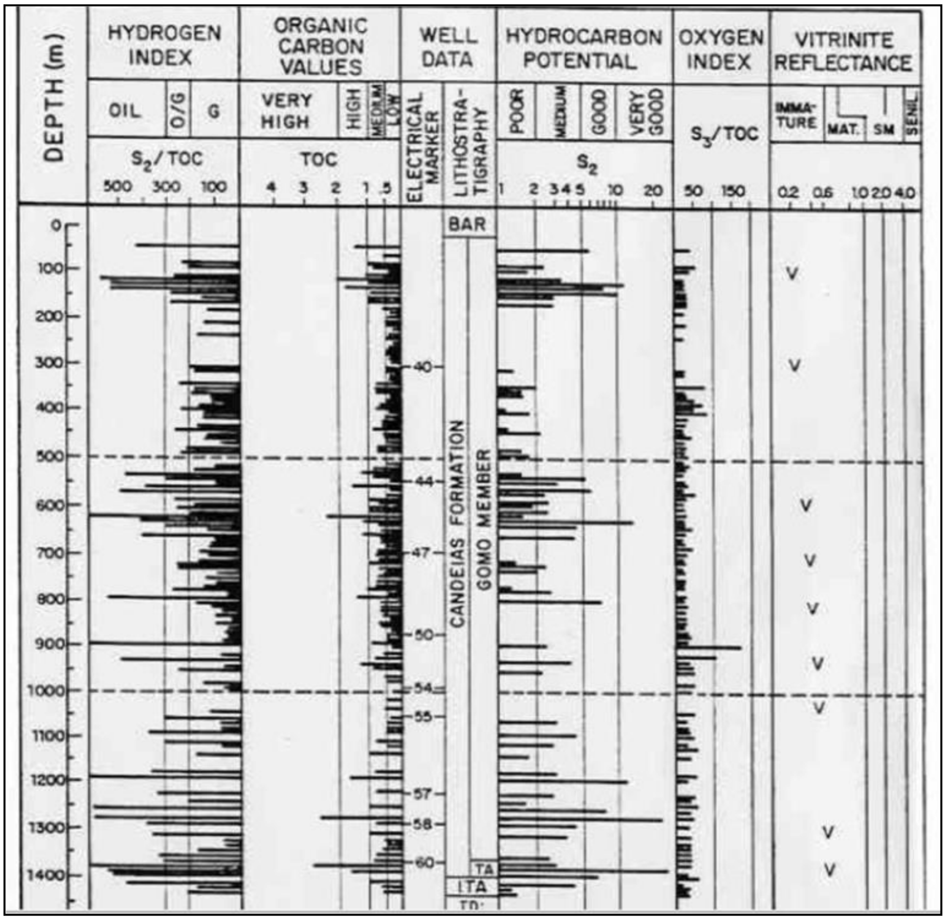
Figure VI-14: Source Rock Thickness, Depth, TOC, and Thermal Maturity of the Pimienta Shale in the Parnaiba Basin



Source: ANP, 2003

- **Recôncavo Basin.** One of many failed rift basins in eastern Brazil, the Recôncavo Basin was the country's first productive petroleum basin. Over 6,000 wells have drilled, of which some 1,800 extent producing wells make 50,000 bbl/day of oil. The Gomo Member of the Lower Cretaceous Candeias Formation, deposited in a lacustrine environment during early rifting, is considered the main source rock.[16] Although quite thick (200-1,000 m), the Gomo Member has relatively low TOC, mostly ranging from 1% to 2%, **Figure VI-15**. ANP recently estimated recoverable shale gas resources in the Recôncavo Basin to be 20 Tcf. However, based on EIA/ARI's screening criteria, the Gomo Member appears to be below the 2% average TOC cutoff and its shale potential was not assessed.

Figure VI-15: The Gomo Member of the Lower Cretaceous Candeias Formation in the Recôncavo Basin can be Thick (>1 km) but is Low in TOC (<2%) and Mostly Thermally Immature (R_o < 0.6%)



Source: ANP, 2003

- **Sergipe-Alagoas Basin.** Another Neocomian rift basin in northeastern Brazil, the Sergipe-Alagoas Basin extends over an onshore area of 12,600 km^2 as well as a considerably larger area offshore. The basin comprises a number of relatively small, isolated and tilted fault blocks, with major structures trending northeast-southwest, **Figure VI-16**.[17] To date some 57 conventional oil and gas fields have been discovered in the basin, with nearly 5,000 wells drilled, primarily in the onshore portion of the basin. **Figure VI-17** shows a detailed cross-section of the Campo de Pilar Field, showing the numerous closely spaced faults.

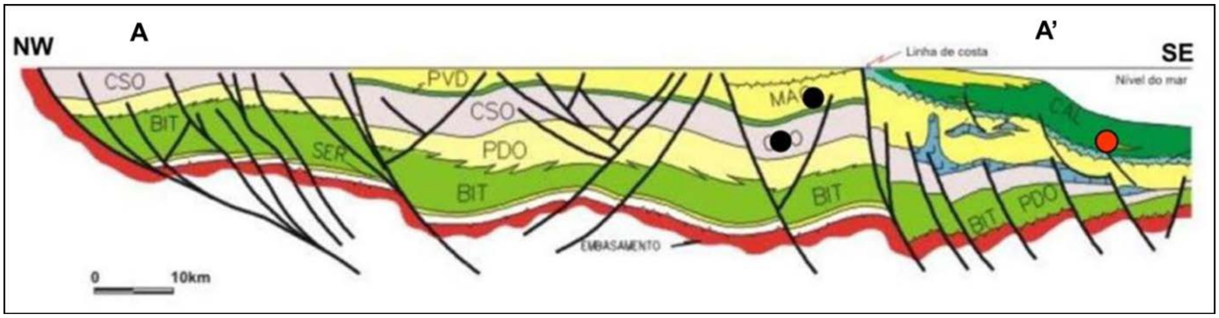
The Cretaceous Maceió Formation (Neoaptian) is the main source rock in the Sergipe-Alagoas Basin. The Maceió Fm contains organic-rich black shales, marls and calcilutites that were deposited in a lacustrine, non-marine setting which may exhibit ductile behavior during hydraulic stimulation. The higher-quality source rock shales within the Maceió Fm average about 200 m thick (maximum 700 m) and average 3.5% TOC (maximum 12%; Type II kerogen).[18] However, this basin was not assessed due to its structural complexity and lack of available geologic data.

- **São Francisco Basin.** Very little conventional exploration has occurred in this frontier basin in Minas Gerais and there is no significant commercial oil and gas production.[19] Potential source rocks are of Proterozoic age, much older than the productive shales of North America, which are about 400 m thick within a moderately faulted structural setting at depths of 2 to 5 km. Shell reportedly plans to drill its first Brazilian exploration well for unconventional gas in the São Francisco Basin, although this effort appears to be targeting tight sandstone and carbonate formations rather than shale.[20] The São Francisco basin was not assessed by EIA/ARI due to the lack of an established hydrocarbon generation system and the paucity of available geologic data.

- **Taubaté Basin.** Located in southeast Brazil, the Taubaté Basin is a northeast-southwest trending trough related to the Atlantic Ocean continental breakup. The Oligocene Tremembé Formation contains up to 500 m of organic-rich deposits that were deposited within a non-marine lacustrine environment. Within this interval there is a 50-m thick section of laminated black shale with average 10% TOC.[21] However, this deposit is thermally immature oil shale[22] and is not considered prospective for shale gas and oil exploration.

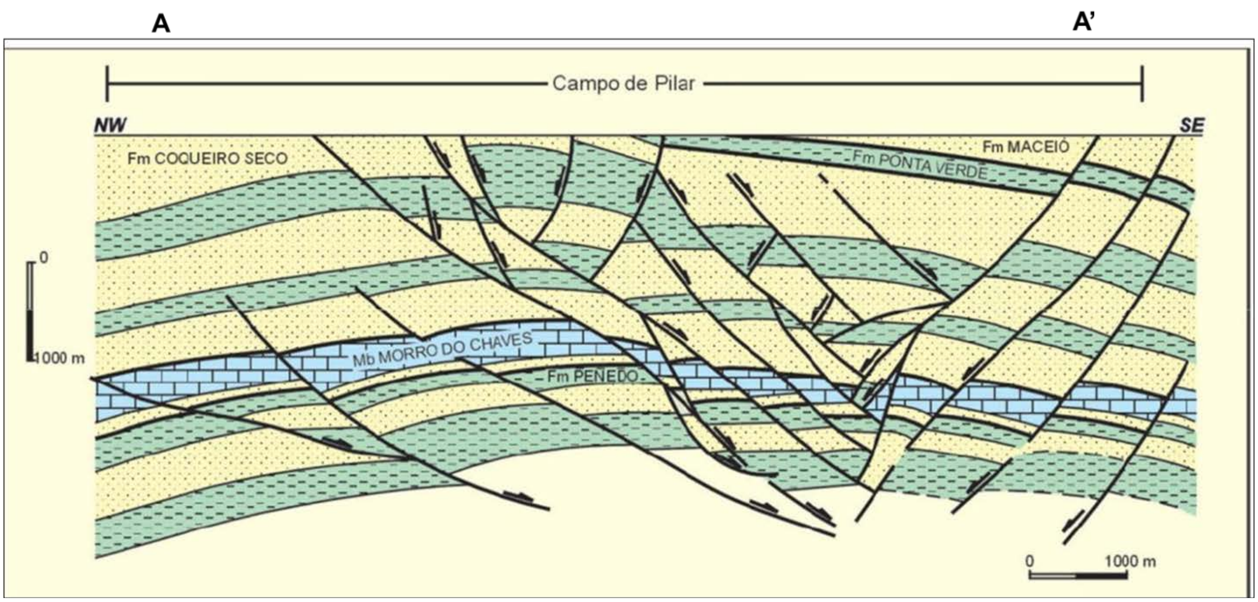
- **Chaco-Paraná Basin.** Not to be confused with the Paraná Basin, the Chaco-Paraná Basin is a large (500,000-km^2) elliptical-shaped depositional feature mainly in northern Argentina, Paraguay and Uruguay. However, only a very small area lies within southern Brazil. The basin contains up to 5 km of early Paleozoic (Ordovician to Devonian) sedimentary and igneous rocks, overlain in the northeast particularly by Cretaceous basalt flows. About 1.2 km of Devonian marine-deposited sandstones (Cabure Formation) and black shales (Rincon Fm) is present. These are overlain by up to 2.3 km of Perm-Carboniferous sandstones and black shales (Sachayoj Fm). The Chaco-Paraná Basin was not assessed due to its small extent and lack of data control within Brazil.

Figure VI-16: Cross-section of the Alagoas Sub-basin, Showing Faulted Pendência and Alagamar Source Rock Shales.



Source: ANP, 2007 (no vertical scale)

Figure VI-17: Detailed Cross-section of the Campo de Pilar Field in the Sergipe-Alagoas Basin, Showing Numerous Closely Spaced Faults.



Source: ANP, 2007

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VII. OTHER SOUTH AMERICA

SUMMARY

Four other countries in South America (Bolivia, Chile, Paraguay, and Uruguay) have prospective shale gas and shale oil potential within marine-deposited Cretaceous and Devonian shale formations in three large basins: the Paraná Basin of Paraguay and Uruguay; the Chaco Basin of Bolivia and Paraguay; and the Magallanes Basin of Chile, Figure VII-1. (Extensions of these basins within neighboring Argentina and Brazil were assessed in separate chapters.)

Figure VII-1: Prospective Shale Gas and Shale Oil Resources in Bolivia, Chile, Paraguay, and Uruguay.

Source: ARI, 2013

Risked, technically recoverable shale gas and shale oil resources in these four other South American countries are estimated at 162 Tcf and 7.2 billion barrels, Tables VII-1 and VII-2. The geologic setting of this region generally is favorably simple, with mostly gentle structural dip and relatively few faults or igneous intrusions (apart from surface basalt flows). Technically recoverable shale resources by country are: Bolivia (36 Tcf; 0.6 billion barrels); Chile (49 Tcf; 2.4 billion barrels); Paraguay (75 Tcf; 3.7 billion barrels); and Uruguay (2 Tcf; 0.6 billion barrels). Initial shale-related leasing and evaluation has been reported in Paraguay and Uruguay within existing conventional petroleum license areas.

Table VII-1A. Shale Gas Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Parana (747,000 mi^2)				
	Shale Formation		Ponta Grossa			Cordobes	
	Geologic Age		Devonian			Devonian	
	Depositional Environment		Marine			Marine	
Physical Extent	Prospective Area (mi^2)		3,830	3,260	2,350	2,690	1,230
	Thickness (ft)	Organically Rich	800	800	800	800	800
		Net	240	240	240	240	240
	Depth (ft)	Interval	10,000 - 11,000	11,000 - 12,000	12,000 - 13,000	3,300 - 5,000	5,000 - 7,000
		Average	10,500	11,500	12,500	4,000	6,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	3.6%	3.6%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas
	GIP Concentration (Bcf/mi^2)		19.9	44.1	71.2	9.7	46.3
	Risked GIP (Tcf)		9.1	17.3	20.1	4.2	9.1
	Risked Recoverable (Tcf)		0.7	3.5	4.0	0.3	1.8

Table VII-1B. Shale Gas Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Chaco (157,000 mi^2)			Austral-Magallanes (65,000 mi^2)		
	Shale Formation		Los Monos			Estratos con Favrella		
	Geologic Age		Devonian			L. Cretaceous		
	Depositional Environment		Marine			Marine		
Physical Extent	Prospective Area (mi^2)		6,870	9,890	14,210	1,580	1,920	1,500
	Thickness (ft)	Organically Rich	1,500	1,500	1,500	800	800	800
		Net	450	450	450	400	400	400
	Depth (ft)	Interval	3,300 - 9,000	7,000 - 12,000	10,000 - 16,400	6,600 - 10,000	10,000 - 14,500	11,500 - 16,400
		Average	7,000	10,000	13,000	8,000	12,000	13,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		2.5%	2.5%	2.5%	3.5%	3.5%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	0.85%	1.15%	1.60%
	Clay Content		Low	Low	Low	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		27.8	86.8	140.5	32.5	114.8	155.9
	Risked GIP (Tcf)		28.7	128.7	299.5	23.1	99.2	105.2
	Risked Recoverable (Tcf)		2.9	25.7	74.9	2.3	19.8	26.3

Table VII-2A. Shale Oil Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Parana (747,000 mi^2)			
	Shale Formation		Ponta Grossa		Cordobes	
	Geologic Age		Devonian		Devonian	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		3,830	3,260	2,690	1,230
	Thickness (ft)	Organically Rich	800	800	800	800
		Net	240	240	240	240
	Depth (ft)	Interval	10,000 - 11,000	11,000 - 12,000	3,300 - 5,000	5,000 - 7,000
		Average	10,500	11,500	4,000	6,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	3.6%	3.6%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		21.8	9.3	27.7	12.0
	Risked OIP (B bbl)		10.0	3.6	11.9	2.4
	Risked Recoverable (B bbl)		0.40	0.15	0.48	0.09

Table VII-2B. Shale Oil Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Chaco (157,000 mi^2)		Austral-Magallanes (65,000 mi^2)	
	Shale Formation		Los Monos		Estratos con Favrella	
	Geologic Age		Devonian		L. Cretaceous	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		6,870	9,890	1,580	1,920
	Thickness (ft)	Organically Rich	1,500	1,500	800	800
		Net	450	450	400	400
	Depth (ft)	Interval	3,300 - 9,000	7,000 - 12,000	6,600 - 10,000	10,000 - 14,500
		Average	7,000	10,000	8,000	12,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		2.5%	2.5%	3.5%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Low	Low	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		46.0	18.7	48.4	14.5
	Risked OIP (B bbl)		47.4	27.7	34.4	12.6
	Risked Recoverable (B bbl)		2.37	1.39	1.72	0.63

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INTRODUCTION

This chapter discusses the shale potential of the other countries in South America (Argentina, Brazil, and Colombia-Venezuela are assessed in separate chapters). As first highlighted in EIA/ARI's 2011 assessment, these other South American countries (Bolivia, Chile, Paraguay, and Uruguay) have significant shale gas and oil resource potential in favorable structural settings. Exploration shale drilling has not yet begun in the region although initial shale leasing and evaluation are underway.

Bolivia. A significant natural gas exporter to Argentina and Brazil, Bolivia produces natural gas from conventional reservoirs, mainly in the Chaco Basin in the southeast part of the country. Following 2006 nationalization, YPFB administers investment and production in Bolivia's oil and gas sector, while the Ministry of Hydrocarbons and Energy (MHE) and the National Hydrocarbons Agency establish overall policy. Shale exploration or leasing have not been reported in Bolivia.

Chile. ENAP, the national oil company of Chile, produces about 5,000 bbl/day mainly from conventional reservoirs in the Magallanes basin.[1] In March 2011 ENAP announced that it will require companies bidding for conventional oil and gas exploration blocks to also explore for shale gas. While exploration is underway for tight gas sandstone reservoirs in the basin, no shale-specific exploration has been reported in Chile.

Paraguay. Paraguay does not produce oil and gas, although extensions of its sedimentary basins are productive in both Argentina and Bolivia. Only two conventional petroleum wells have been drilled in Paraguay during the past 25 years. Shale drilling has not occurred in the country but President Energy is investigating the shale potential at its conventional petroleum licenses in the Chaco Basin.

Uruguay. Uruguay also does not produce oil and gas, although extensions of its sedimentary basins are productive in neighboring Brazil and Argentina. ANCAP (Administración Nacional de Combustibles, Alcoholes y Portland), the state-owned oil company in Uruguay, administers the country's petroleum licensing. TOTAL, YPF, and others hold leases in the onshore Paraná Basin and are evaluating the shale potential.

Three major sedimentary basins with prospective organic-rich and marine-deposited black shales are present in Bolivia, Chile, Paraguay, and Uruguay, Figure VII-1. These basins, which were assessed in this chapter, are:

- **Paraná Basin** (Paraguay, Uruguay): The Paraná Basin contains black shale within the Devonian Ponta Grossa Formation. The structural setting is simple but the basin is partly obscured at surface by flood basalts, although this igneous cap is less prevalent here than in the Brazil portion of the basin.
- **Chaco Basin** (Paraguay, Bolivia): Black shale in the Devonian Los Monos Formation is present within a relatively simple structural setting in northwest Paraguay. The shale becomes increasingly deep and thrust faulted in southeast Bolivia, where they source that country's prolific conventional reservoirs.
- **Magallanes Basin** (Chile): Known as the Austral Basin in Argentina, the Magallanes Basin of southern Chile contains marine-deposited black shale in the Lower Cretaceous Estratos con Favrella Formation, considered a major source rock in the basin.

1 PARANÁ BASIN (PARAGUAY, URUGUAY)

1.1 Introduction and Geologic Setting

The Paraná Basin is a large depositional feature in south-central South America. Most of the basin is located in southern Brazil, but there are significant extensions into Paraguay, Uruguay, and northern Argentina, **Figure VII-2**. This section focuses on the Paraguay and Uruguay portions of the basin. The Paraná Basin contains up to 5 km (locally 7 km) of Paleozoic and Mesozoic sedimentary rocks that range from Late Ordovician to Cretaceous. Its western border is defined by the Asuncion Arch, related to Andean thrusting, while the east is truncated by the South Atlantic tectonic margin.[2] Much of the Brazilian portion of the basin is covered by flood basalts, partly obscuring the underlying geology from seismic and increasing the cost of drilling, but the Paraguay portion is largely free of basalt.

The main petroleum source rock in the Paraná Basin is the Devonian (Emsian/Frasnian) black shale of the Ponta Grossa Formation. The entire formation ranges up to 600 m thick in the center of the basin, averaging about 300 m thick. TOC of the Ponta Grossa Fm reaches up to 4.6% but more typically is 1.5% to 2.5%. The mostly Type II kerogen sourced natural gas that migrated into conventional sandstone reservoirs.[3]

Figure VII-2: Prospective Shale Gas and Shale Oil Areas in the Paraná Basin of Paraguay and Uruguay

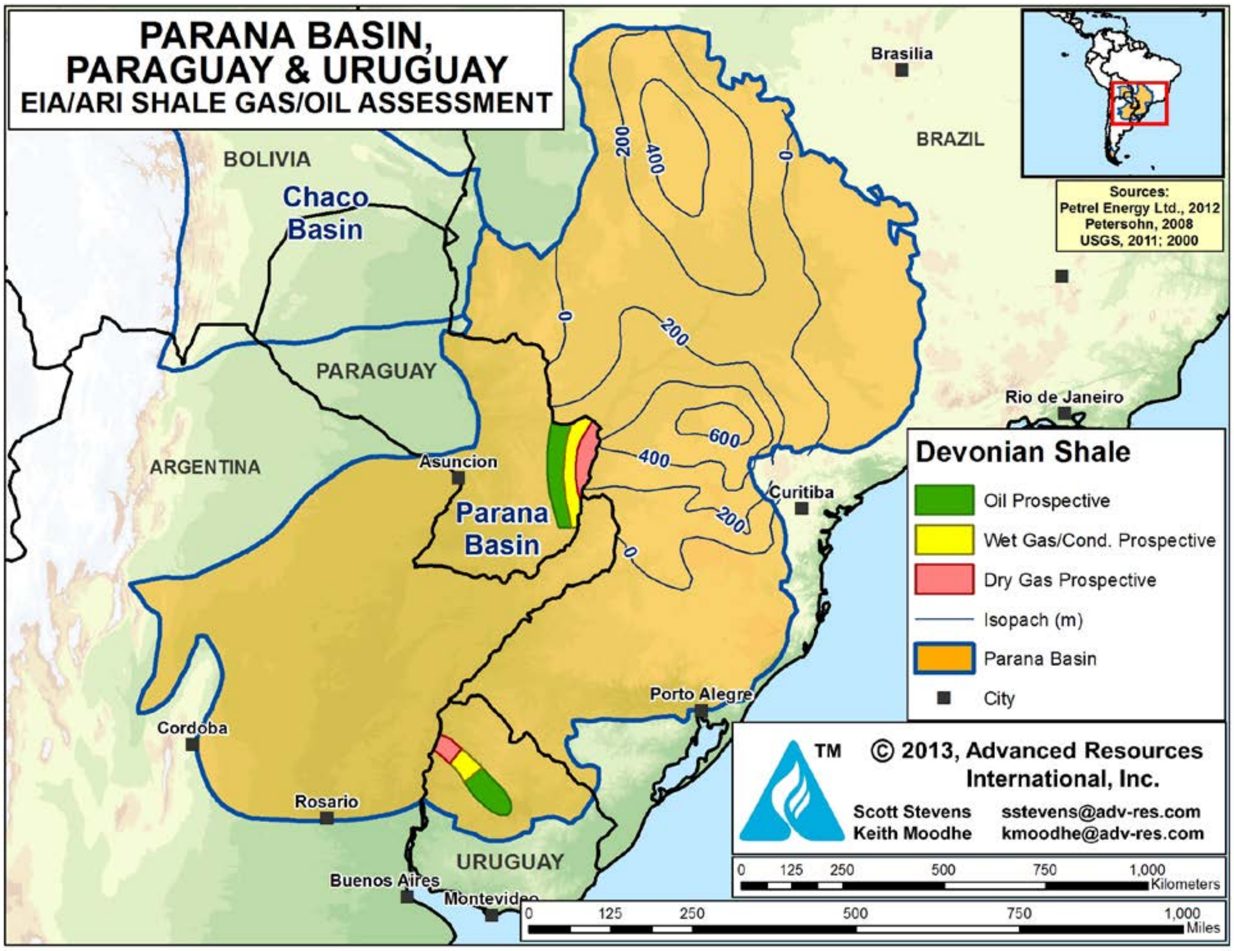
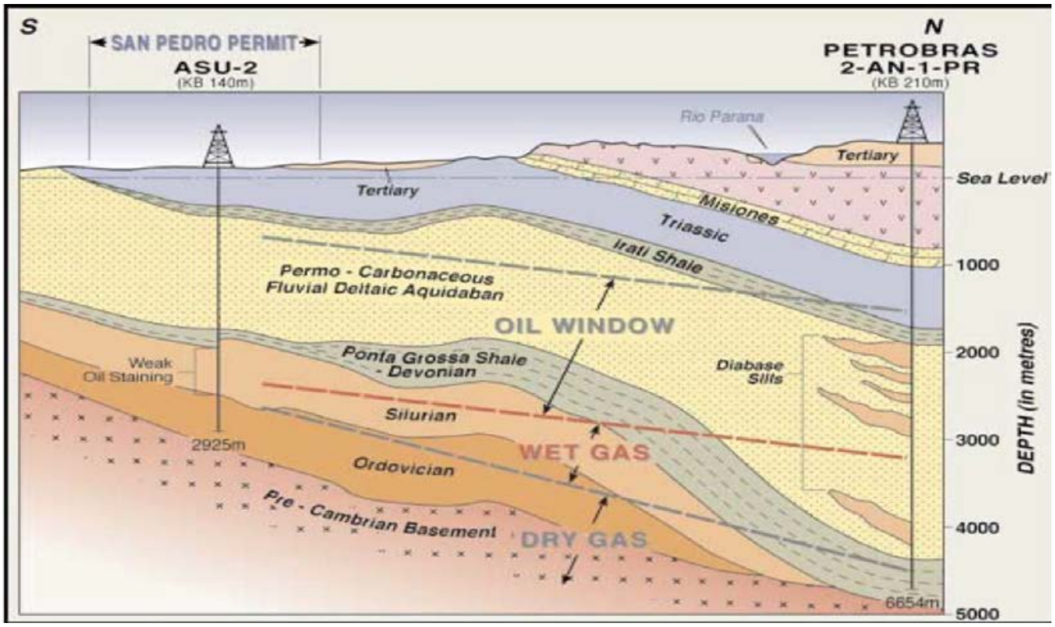


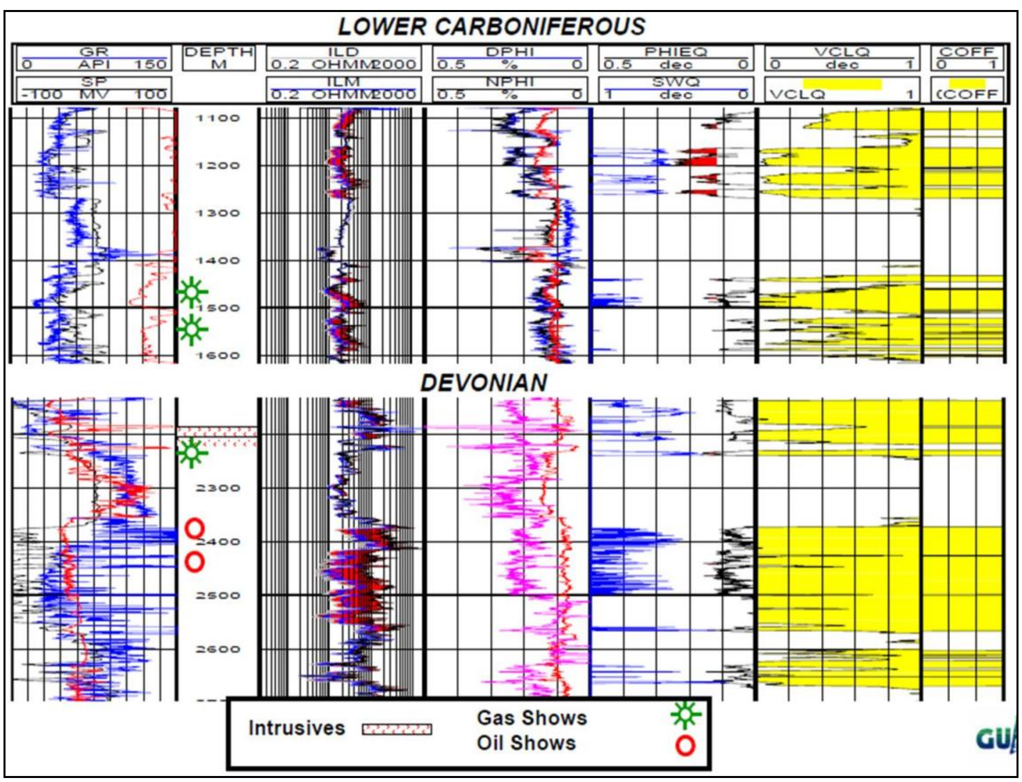
Figure VII-3, a cross-section of the Paraná Basin, illustrates the thick and gently dipping Devonian source rocks that pass through the oil window into the gas window.[4] **Figure VII-4**, a conventional well log in the Paraguay portion of the basin, shows Devonian source rocks and interbedded sandstones with oil and gas shows.[5] In outcrop, the Devonian Cordobes Formation ranges up to 160 m thick, including up to 60 m of organic-rich shale. TOC ranges from 0.7 to 3.6%, consisting mainly of Type II marine kerogen. Based on the low thermal maturity at outcrop (R_o 0.6%), ANCAP has estimated the boundary between dry and wet gas to occur at a depth of about 3,200 m.[6]

Figure VII-3: Cross-Section of the Paraná Basin of Paraguay, Showing Thick and Gently Dipping Devonian Source Rocks Passing Through the Oil and Gas Windows.



Source: Chaco Resources PLC, 2004

Figure VII-4: Asuncion-1 Well Log from the Paraná Basin of Paraguay, Showing Devonian Source Rocks and Interbedded Sandstones with Oil and Gas Shows.



Source: Guapex S.A., 2012

The Paraná Basin has remained at moderate burial depth throughout its history. Consequently, the bulk of thermal maturation took place during the late Jurassic to early Cretaceous igneous episode. Most of the basin remains thermally immature (R_o <0.5%), but there are sizeable concentric windows of oil-, wet-gas-, and dry-gas maturity in the deep central portion of the basin.

1.2 Reservoir Properties (Prospective Area)

Depth and thermal maturity of the Devonian Ponta Grossa Formation are relatively well constrained in the Paraguay portion of the Paraná Basin. The prospective area in Paraguay is estimated at 9,440 mi^2, of which 3,830 mi^2 is in the oil window; 3,260 mi^2 is in the wet gas/condensate thermal maturity window; and 2,350 mi^2 is in the dry gas window.

However, Devonian depth and thermal maturity are much less certain in Uruguay. Uruguay's shale-prospective area is estimated at 3,920 mi^2, of which 2,690 mi^2 is in the oil window and 1,230 mi^2 is in the wet gas/condensate thermal maturity window (no evidence the Devonian attains dry-gas thermal maturity in Uruguay). The Ponta Grossa shale averages about 240 m thick (net), 10,500 to 12,500 ft deep in Paraguay but only 4,000 to 6,000 ft deep in Uruguay, and averages 2.0% to 3.6% TOC.

Thermal maturity (R_o) ranges from 0.85% to 1.5% depending mainly on depth. For example, Amerisur reported that the Devonian Lima Fm has good (2-3%) TOC and is oil-prone (R_o 0.87%) at their conventional exploration block. Porosity is estimated at about 4% and the pressure gradient is assumed to be hydrostatic.

1.3 Resource Assessment

Risked, technically recoverable shale gas and oil resources from the Devonian Ponta Grossa Shale in the Paraguay portion of the Paraná Basin are estimated at 8 Tcf of shale gas and 0.6 billion barrels of shale oil and condensate, Tables VII-1 and VII-2. Uruguay has further estimated resources of 2 Tcf of shale gas and 0.6 billion barrels of shale oil and condensate in this play. Risked shale gas and shale oil in-place in Paraguay and Uruguay are estimated at 60 Tcf and 28 billion barrels. The play has low-moderate net resource concentrations of 10 to 71 Bcf/mi^2 for shale gas and 9 to 28 million bbl/mi^2 for shale oil, depending on thermal maturity window.

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The USGS recently estimated that Uruguay's portion of the Paraná Basin (Norte Basin) has 13.4 Tcf of shale gas and 0.5 billion barrels of shale oil resources in the Devonian Cordobes Formation. They noted that the sub-basalt extent of inferred deep grabens for their study was imaged by ANCAP using geophysical methods, with no well control.[7] Petrel Energy recently noted that new data indicates the Devonian is less thermally mature than mapped by the USGS.[8] The EIA/ARI thermal windows were adjusted accordingly.

1.4 Recent Activity

TOTAL, YPF, and small Australia-based Petrel Energy hold large exploration licenses with Devonian shale potential in the Uruguay portion of the Paraná Basin (Norte Basin). No shale-focused drilling has occurred in Uruguay, nor has shale leasing or drilling activity been reported in the Paraguay portion of the Paraná Basin.

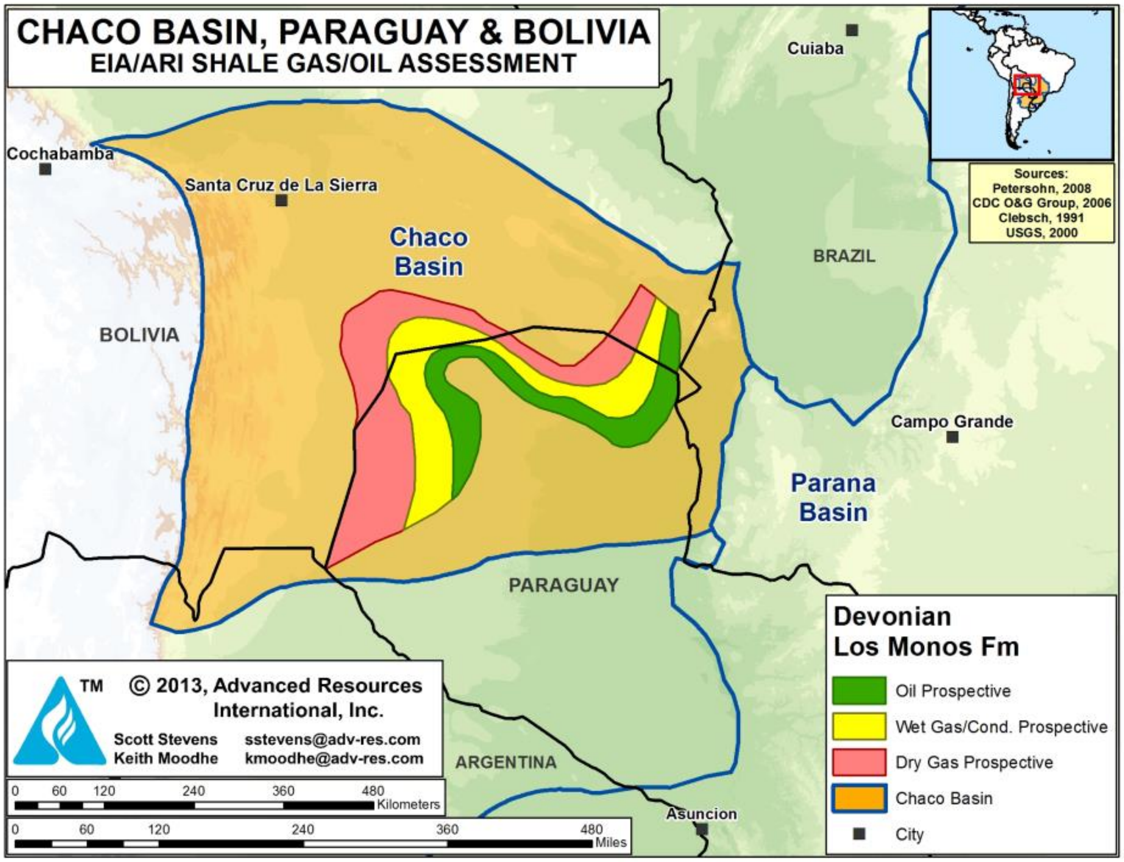
2 CHACO BASIN (BOLIVIA, PARAGUAY)

2.1 Introduction and Geologic Setting

The large (157,000-mi^2) Chaco Basin is an intra-cratonic foreland basin broadly similar in origin to the Neuquen and other South American basins east of the Andes Mountains, **Figure VII-5**. The Chaco Basin extends across southeast Bolivia and northwest Paraguay, as well as southern Brazil and northern Argentina (please see separate chapters for these countries). Structural highs (Ascuncion Arch) separate the Chaco Basin from the Parana Basin to the southeast. Structure is relatively simple, with scattered mainly vertical normal faults and none of the thrusting typical of Andean tectonics further to the west.

Sub-basins include the Pirity, Carandayty, and Curupayty troughs. Oil and gas production occurs in Bolivia and Argentina but not in Paraguay, which has experienced much less drilling. Fewer than 10 petroleum wells have been drilled in the Pirity Sub-basin of Paraguay, all pre-1987, where no commercial production has occurred. However, the Argentina portion of the Basin (Olmedo Sub-basin) has produced over 110 million bbls of oil from the Upper Cretaceous Yacoraite and Palmer Largo formations and that basin continues to be productive.[9] Apart from the international border, no geologic discontinuity separates the two sub-basins.

Figure VII-5: Prospective Area of the Devonian Los Monos Formation, Chaco Basin, Paraguay and Bolivia



The main source rocks include the Silurian Kirusillas Formation and the Devonian Los Monos and Icla formations.[10] The Devonian, considered the main source rock for the world-class conventional gas fields in the Tarija Basin foothills of southeast Bolivia, appears to have shale gas potential in northwest Paraguay where structure is considerably simpler, **Figure VII-6**. The gas window in this basin reportedly is at about 2 km depth.

Significant shale gas potential exists within the 8,000- to 12,000-foot thick Devonian Los Monos Formation in the Carandaity and Curupaity sub-basins of Paraguay. The Devonian is exceptionally thick in southern Bolivia but consists mainly of coarse-grained sandstones there. The Devonian is also deeper and structurally more complex in much of Bolivia, **Figure VII-7**. Within the Los Monos, the San Alfredo Shales appear to be most prospective, comprising a lower sandy unit and an upper thick, monotonous black shale that formed under shallow marine conditions.[11] The thickest Devonian section (8,339 feet) penetrated in the Chaco Basin was in the Pure Oil Co. Mendoza-1 well. The Los Monos marine shale accounted for about 8,200 feet of this section.[12]

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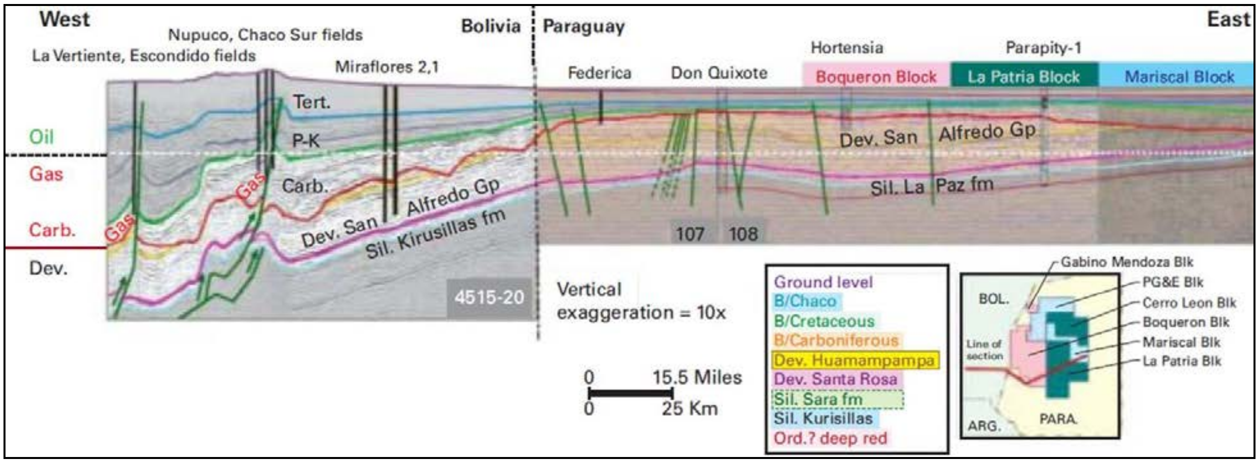
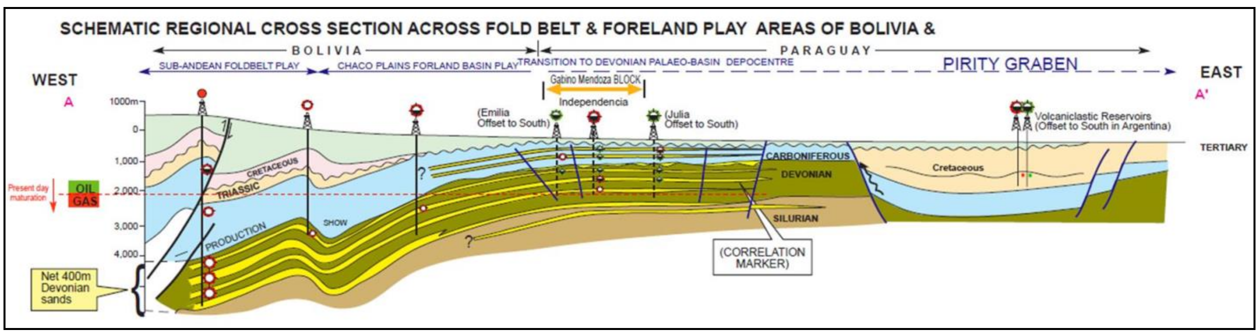
Figure VII-6: Regional Seismic Time Section Across the Chaco Basin of Bolivia and Paraguay, Showing Thick and Mostly Flat-Lying Silurian and Devonian Source Rocks.



Source: Wade, 2009

Figure VII-7: Regional Cross-Section Across the Chaco Basin of Bolivia and Paraguay, Showing Thick and Mostly Flat-Lying Silurian and Devonian Source Rocks.



Source: CDS Oil and Gas Group, PLC, 2006

Scarce geochemical data suggest 2.5% overall average TOC for the entire Los Monos, but richer zones are likely to be present within this thick and poorly documented unit. An exploration well in the Curupaity sub-basin measured up to 2.1% TOC in the Los Monos. Independent E&P Amerisur reports TOC of 1.44% to 1.86% in the Devonian Los Monos Fm in the Curupaity sub-basin.[13] Depth to the Los Monos Shale can exceed 10,000 feet (3,000 m) in deep synclines such as the San Pedro Trough.[14,15] Structural uplifts within the Chaco Basin have high geothermal gradients and are gas-prone.

Another potential source rock is the Puesto Guardian Member in the lower portion of the U. Cretaceous Yacoraite Formation. The Puesto Guardian reportedly contains about 78 m of black shale within a 6,000-km^2 area of the Pirity Sub-basin of the Cretaceous Basin.[16] TOC is up to 12%, consisting of Type II / III amorphous and algal kerogen that was deposited in lacustrine to restricted marine environments. Peak hydrocarbon maturation and charge is estimated to have occurred 34-40 million years ago, with current maturity in the oil window. However, the potential of the Cretaceous shale was not assessed due to insufficient geologic control.

2.2 Reservoir Properties (Prospective Area)

The Devonian Los Monos Formation is exceptionally thick (as much as 12,000 feet) in the Chaco Basin, of which 2,000 feet (San Alfredo Shales) was conservatively assumed to be organic-rich. Faulting is not extensive, thus relatively little area is sterilized due to structural complexity.

The shale matrix reportedly consists primarily of brittle minerals such as calcite, dolomite, albite feldspar, ankerite, quartz as well as significant rutile and pyrite. Some clay is present -- mainly illite, kaolinite and chlorite – but is considered “less common.”[17] Temperature gradients range from elevated 1.9°F/100 feet on structural highs to 1.0°F/100 feet in the Carandaity sub-basin.

Depth and thermal maturity of the Devonian Los Monos Formation are relatively well constrained in the Paraguay portion of the Chaco Basin. The prospective area in Paraguay is estimated at 22,210 mi^2, of which 6,200 mi^2 is in the oil window; 7,450 mi^2 is in the wet gas/condensate thermal maturity window; and 8,560 mi^2 is in the dry gas window. An additional 8,760 mi^2 is prospective in Bolivia, of which 670 mi^2 is in the oil window; 2,440 mi^2 is in the wet gas/condensate thermal maturity window; and 5,650 mi^2 is in the dry gas window.

2.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from the Devonian Los Monos black shale in the Paraguay portion of the Chaco Basin are estimated at 67 Tcf of shale gas and 3.2 billion barrels of shale oil and condensate, Tables VII-1 and VII-2. Bolivia has further estimated resources of 37 Tcf of shale gas and 0.6 billion barrels of shale oil and condensate. Risked shale gas and shale oil in-place are estimated at 457 Tcf of shale gas and 75 billion barrels of shale oil for the two countries. The play has moderate to high net resource concentrations of 28 to 141 Bcf/mi^2 for shale gas and 19 to 46 million bbl/mi^2 for shale oil, depending on thermal maturity window.

2.4 Recent Activity

Initial shale evaluation is occurring on existing conventional petroleum exploration leases in the Chaco Basin, but no shale-specific drilling or testing has occurred yet. President Energy PLC (UK) holds eight conventional petroleum exploration licenses which it considers to have shale gas/oil potential.

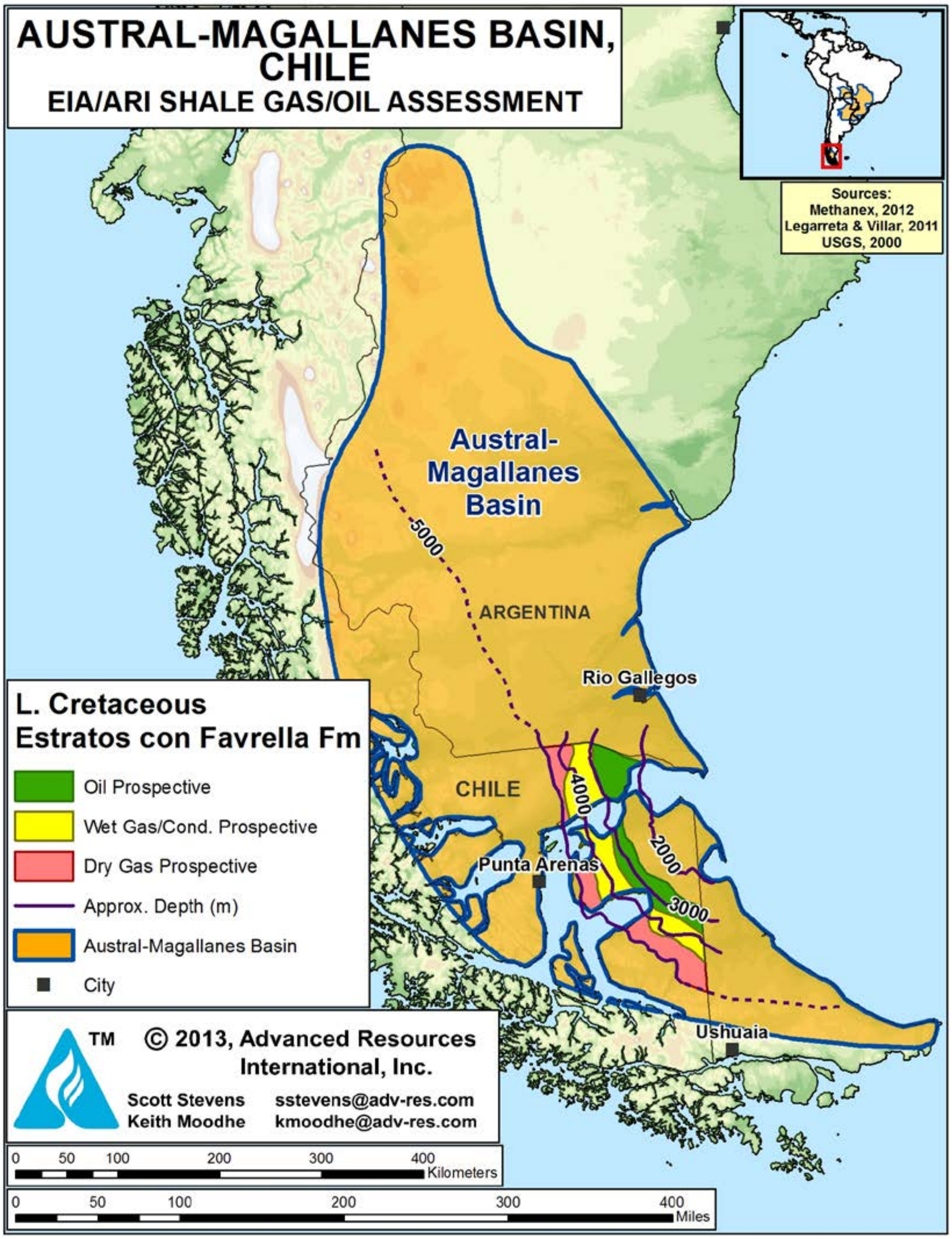
3 MAGALLANES BASIN (CHILE)

3.1 Introduction and Geologic Setting

Located in southern Patagonia, the 65,000-mi^2 Austral-Magallanes Basin has promising but untested shale gas potential, **Figure VII-8**. While most of the basin is in Argentina, where it is called the Austral Basin, a portion of the basin is located in Chile's Tierra del Fuego region, where it is referred to as the Magallanes Basin. The Chile portion of the basin, which started producing conventional natural gas over 60 years ago, currently accounts for most of that country's oil and gas output, produced primarily from deltaic to fluvial sandstones in the Early Cretaceous Springhill Formation at depths of about 6,000 feet.

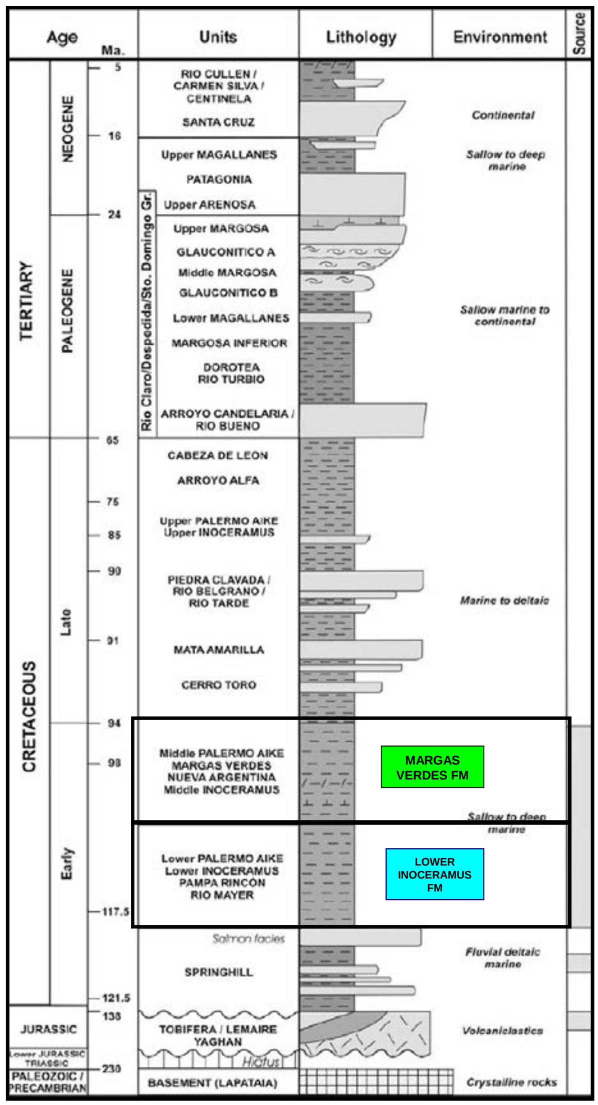
The Magallanes Basin comprises two main structural regions: a normal faulted eastern region and a thrust faulted western area. The basin contains a thick sequence of Upper Cretaceous and Tertiary sedimentary and volcaniclastic rocks which unconformably overlie deformed metamorphic basement of Paleozoic age. Total sediment thickness ranges from 3,000 to 6,000 feet along the eastern coast to a maximum 25,000 feet along the basin axis. Jurassic and Lower Cretaceous petroleum source rocks are present at moderate depths of 6,000 to 10,000 feet across large areas.[18] The overlying Cretaceous section comprises mainly deepwater turbidite clastic deposits up to 4 km thick, which appear to lack shale gas and oil potential.[19]

Figure VII-8: Prospective Area of the L. Cretaceous Estratos con Favrella Formation, Magallanes Basin, Chile



The organic-rich shales of Jurassic and Early Cretaceous age formed under anoxic marine conditions within a Neocomian sag on the edge of the Andes margin, Figure VII-9. The basal sequence consists of Jurassic source rocks that accumulated under restricted lacustrine conditions within small half-grabens. Interbedded shale and sandstone of the Zapata and Punta Barrosa formations were deposited in a shallow-water marine environment.[20] The mid-lower Jurassic Tobifera Formation contains 1% to 3% TOC (maximum 10% in coaly shales), consisting of Types I to III kerogen. However, this unit is mainly coaly and probably insufficiently brittle for shale exploration.

Figure VII-9: Stratigraphy of the Austral-Magallanes Basin, Argentina and Chile



Source: Rossello et al., 2008

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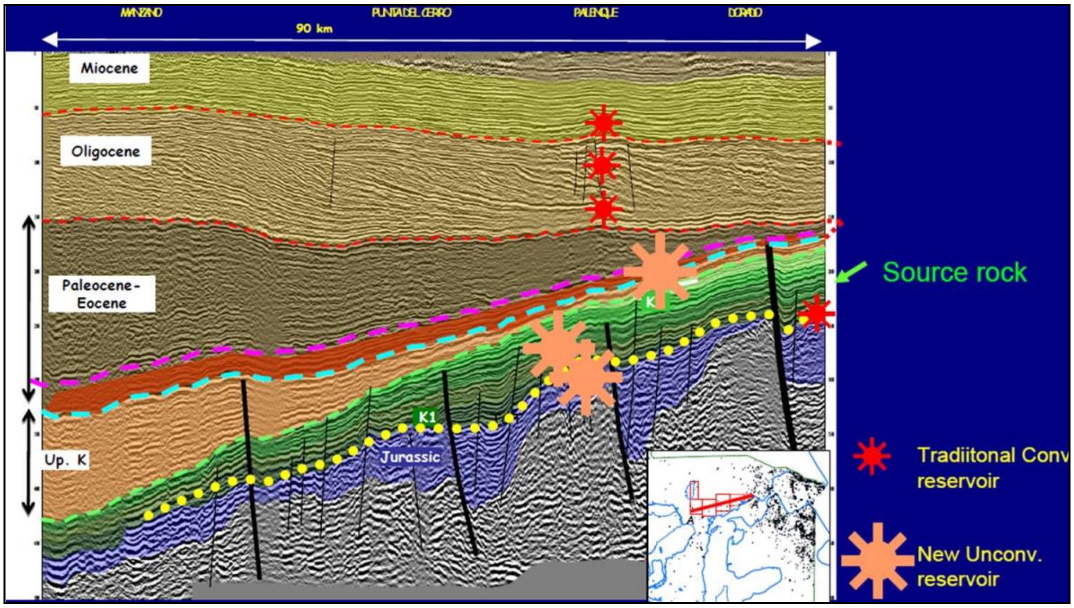
Overlying the Tobifera Fm are more prospective shales within the Early Cretaceous Estratos con Favrella Formation (or Lower Inoceramus or Palermo Aike in Argentina), deposited under shallow water marine conditions. The Lower Inoceramus Formation is 50 to 400 m thick. In the Argentina portion of the basin, the total shale thickness (including the Magnas Verdes Formation) ranges from 800 feet thick in the north to 4,000 feet thick in the south, representing neritic facies deposited in a low-energy and anoxic environment.[21] Total organic content of these two main source rocks have been reported to range from 1.0% to 2.0%, with hydrogen index of 150 to 550 mg/g.[22] More recent analysis conducted by Chesapeake Energy of the Lower Cretaceous Estratos con Favrella Formation in Chile indicates this unit contains marine-deposited shale with consistently good to excellent (up to 6%) TOC, particularly near its base.[23]

Figure VII-10, a seismic time section across the basin, shows the 180-m thick Estratos con Favrella Formation dipping gently west in a relatively simple structural setting. Net organic-rich shale thickness was estimated by ENAP to be only 40 to 120 ft, although this appears conservative and we assumed 280 net ft. ENAP also estimated porosity of 6% to 12%, but we assumed a more conservative estimate of 6%. Thermal maturity increases gradually with depth in a half-moon pattern, ranging from oil-prone (R_o 0.8%) to dry gas prone (R_o 2.0%). The transition from wet to dry gas (R_o 1.3%) occurs at a depth of about 3,600 m in this basin.[24]

3.2 Reservoir Properties (Prospective Area)

Chile's portion of the Magallanes Basin has an estimated 5,000-mi^2 prospective area with organic-rich shale in the Estratos con Favrella and adjoining Lower Cretaceous formations. Of this total prospective area, about 1,580 mi^2 is in the oil window; 1,920 mi^2 is in the wet gas/condensate thermal maturity window; and 1,500 mi^2 is in the dry gas window. The Estratos con Favrella and adjoining shales average about 800 ft thick (organic-rich), 8,000 to 13,500 ft deep, and have estimated 3.5% average TOC. Thermal maturity (R_o) ranges from 0.7% to 2.0% depending mainly on depth. Porosity is estimated at about 5%. The Estancia Los Lagunas gas condensate field in southeast Argentina measured a 0.46 psi/ft pressure gradient with elevated temperature gradients in the Serie Tobifera Fm, immediately underlying the Lower Inoceramus equivalent.[25]

Figure VII- 10: Seismic Time Section Across the Magallanes Basin, Showing Marine Source Rock Shales in the 180-m Thick L. Cretaceous Estratos con Favrella Formation within a Relatively Simple Structural Setting.



Source: Methanex, September 27, 2012

3.3 Resource Assessment

Risked, technically recoverable shale gas and oil resources from the Estratos con Favrella and adjoining Lower Cretaceous formations in the Chile portion of the Magallanes Basin are estimated at 48 Tcf of shale gas and 2.4 billion barrels of shale oil and condensate, Tables VII-1 and VII-2. Risked shale gas and shale oil in-place are estimated at 228 Tcf and 47 billion barrels, respectively. The play has moderate to high net resource concentrations of 33 to 156 Bcf/mi^2 for shale gas and 15 to 48 million bbl/mi^2 for shale oil, depending on thermal maturity window.

3.4 Recent Activity

No shale leasing or exploration activity has been reported in the Magallanes Basin. Methanex operates a methanol manufacturing plant in the basin which is running at about 10% of its 2 million t/year capacity due to local shortages of natural gas supply.[26] During 2011-2, Methanex had partnered with ENAP on conventional oil and gas exploration in the Magallanes Basin and also had expressed interest in shale gas exploration. However, recently the company decided to relocate about half of its methanol production capacity in Chile to Louisiana, USA.[27]

UK-based GeoPark holds conventional petroleum leases in the Magallanes Basin of Chile, which the company notes contains shales in the Estratos con Favrella Formation which previously have produced oil. In 2012 GeoPark conducted diagnostic fracture injection tests on eight wells on the Fell Block to determine reservoir properties of the shale.[28]

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VIII. POLAND (INCLUDING LITHUANIA AND KALININGRAD)

SUMMARY

Poland has some of Europe's most favorable infrastructure and public support for shale development. The Baltic Basin in northern Poland remains the most prospective region with a relatively simple structural setting. The Podlasie and Lublin basins also have potential but are structurally complex, with closely spaced faults which may limit horizontal shale drilling. A fourth area, the Fore-Sudetic Monocline in southwest Poland, is less recognized but has non-marine coaly shale potential similar to Australia's Cooper Basin.

Figure VIII-1: Location of Assessed Shale Basins in Poland.

Source: Modified from San Leon Energy, 2012

Poland's risked, technically recoverable shale resources are estimated at 146 Tcf of shale gas and 1.8 billion barrels of shale oil in four assessed basins, Tables VIII-1 and VIII-2. Lithuania adds 0.4 Tcf and 0.3 billion barrels of risked, technically recoverable shale gas and shale oil resources, Table VIII-3. Kaliningrad adds 2.0 Tcf and 1.2 billion barrels of risked, technically recoverable shale gas and shale oil resources, Table VIII-3. Initial exploration has confirmed the shale resource potential but suggests that reservoir conditions are more challenging than originally anticipated by industry. New data collected since our 2011 resource assessment resulted in a 20% reduction in EIA/ARI's estimate of Poland's shale resources, on an energy-equivalent basis.

Table VIII-1: Shale Gas Reservoir Properties and Resources of Poland.

Basic Data	Basin/Gross Area		Baltic/Warsaw Trough ($16,200\ mi^2$)			Lublin ($4,980\ mi^2$)	Podlasie ($6,600\ mi^2$)			Fore Sudetic ($19,700\ mi^2$)
	Shale Formation		Llandovery			Llandovery	Llandovery			Carboniferous
	Geologic Age		L. Sil - Ord. - U. Cambrian			L.Sil-Ord-U.Cambrian	L. Sil - Ord. - U. Cambrian			Carboniferous
	Depositional Environment		Marine			Marine	Marine			Lacustrine
Physical Extent	Prospective Area (mi^2)		830	2,070	5,680	2,390	1,000	1,100	860	9,070
	Thickness (ft)	Organically Rich	820	820	820	415	540	540	540	330
		Net	451	451	451	228	297	297	297	182
	Depth (ft)	Interval	6,500 - 9,800	7 - 13,000	9 - 16,000	7,000 - 16,000	6 - 9,000	6,500 - 11,500	10- 16,000	8 - 16,000
		Average	8,200	10,000	12,500	11,000	7,500	9,500	12,500	12,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress	Mod. Overpress.	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.	Slightly Overpress	Slightly Overpress.
	Average TOC (wt. %)		3.9%	3.9%	3.9%	3.0%	3.0%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.80%	1.35%	0.85%	1.15%	1.80%	1.60%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		36.6	131.0	181.1	91.2	27.4	82.3	122.4	67.2
	Risked GIP (Tcf)		12.1	108.5	411.5	45.8	6.6	21.7	25.3	106.7
	Risked Recoverable (Tcf)		1.2	21.7	82.3	9.2	0.7	4.3	5.1	21.3

Source: ARI, 2013

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Table VIII-2: Shale Oil Reservoir Properties and Resources of Poland.

Basic Data	Basin/Gross Area		Baltic/Warsaw Trough (16,200 mi^2)		Podlasie (6,600 mi^2)	
	Shale Formation		Llandovery		Llandovery	
	Geologic Age		L. Sil - Ord. - U. Cambrian		L. Sil - Ord. - U. Cambrian	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		830	2,070	1,000	1,100
	Thickness (ft)	Organically Rich	820	820	540	540
		Net	451	451	297	297
	Depth (ft)	Interval	6,500 - 9,800	7,000 - 13,000	6,000 - 9,000	6,500 - 11,500
		Average	8,200	10,000	7,500	9,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		3.9%	3.9%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		42.2	12.8	36.2	11.1
	Risked OIP (B bbl)		14.0	10.6	8.7	2.9
	Risked Recoverable (B bbl)		0.70	0.53	0.43	0.15

Source: ARI, 2013.

Table VIII-3: Shale Gas and Shale Oil Reservoir Properties and Resources of Lithuania/Kaliningrad

Basic Data	Basin/Gross Area		Baltic (90,000 mi^2)
	Shale Formation		Llandovery
	Geologic Age		L. Sil - Ord. - U. Cambrian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		3,030
	Thickness (ft)	Organically Rich	575
		Net	316
	Depth (ft)	Interval	6,500 - 9,800
		Average	8,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		3.9%
	Thermal Maturity (% Ro)		0.85%
	Clay Content		Medium
Resource	Gas Phase		Assoc. Gas
	GIP Concentration (Bcf/mi^2)		25.2
	Risked GIP (Tcf)		24.5
	Risked Recoverable (Tcf)		2.4

Basic Data	Basin/Gross Area		Baltic (90,000 mi^2)
	Shale Formation		Llandovery
	Geologic Age		L. Sil - Ord. - U. Cambrian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		3,030
	Thickness (ft)	Organically Rich	575
		Net	316
	Depth (ft)	Interval	6,500 - 9,800
		Average	8,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		3.9%
	Thermal Maturity (% Ro)		0.85%
	Clay Content		Medium
Resource	Oil Phase		Oil
	OIP Concentration (MMbbl/mi^2)		29.8
	Risked OIP (B bbl)		28.9
	Risked Recoverable (B bbl)		1.45

Poland's shale industry is still at an early exploratory, pre-commercial phase. About 30 vertical exploration wells and a half-dozen vertical and two horizontal production test wells have been drilled to date. However, early results have not met industry's high initial expectations. Last year, ExxonMobil abandoned the fault-prone Lublin and Podlasie basins after drilling two vertical test wells. ConocoPhillips and Chevron are moving cautiously towards drilling their initial test wells in the Baltic and Lublin basins, respectively. And even in the geologically favorable Baltic Basin, Marathon and Talisman recently exited after expressing “disappointment” with reservoir quality and being “not particularly enthused by results we've had to date.” Meanwhile, the government debates rolling back some favorable shale investment terms, by introducing higher taxes and mandating government back-in rights.

Yet, it is too soon to dismiss Poland’s extensive shale potential. Derisking shale plays in North America typically requires drilling about 100 wells, while achieving economies of scale requires many hundreds more. E&P companies continue to explore Poland’s shale potential in over 100 geologically diverse licenses. State oil company PGNiG, which controls the country’s largest shale lease position, reported test gas production from its first stimulated vertical shale well and recently drilled a horizontal offset well. Determining best-practices operations remains a key challenge, including locating the best completion zones within the thick shale sequence, achieving better execution of hydraulic fracture stimulations, and reducing the current several-fold higher well cost differential compared with North America.

INTRODUCTION

With an established onshore conventional oil and gas production industry as well as recent experience with coalbed methane exploration, Poland offers Europe’s best prospects for developing a viable shale gas/oil industry. Shale leasing and development in Poland began in 2007 when the Ministry of Environment implemented highly favorable policies for shale gas development, including a simple tax and royalty fiscal system.

The current investment terms for shale gas development include a 1,200-km^2 maximum block size, minimal signature fees of 50 Euros/block, freedom from mandatory government back-in rights, and reduced production royalties of \$0.06/Mcf and \$1.60/bbl. The typical shale contract comprises an initial 5-year exploration period, which can be extended, followed by a 30-year production period. Industry’s response has been strong: over 100 shale gas exploration licenses have been awarded, covering more than 35,000 km^2, no less than one-third of the country’s area.

However, more recently the government is discussing modifications to the shale fiscal terms which may increase profit taxes on shale gas production to 40% or more, while establishing a government-owned entity to gain a minority equity stake in shale gas development projects. These changes, if implemented, could significantly reduce industry investment in shale exploration at a time of disillusionment with early well results.

The initial results from some 30 vertical and two horizontal shale wells have been less successful than hoped. Production rates and reservoir quality have been lower than expected, with one operator testing ~4% porosity and ~40% clay content in several wells. Hydraulic fracturing operations to stimulate production from the shale also have been sub-par. However, as exploration continues, operators may successfully identify the geologic sweet spots, while service companies are likely to improve their implementation of North American drilling and stimulation technology.

GEOLOGIC OVERVIEW

Poland has four main basins where Paleozoic shales are prospective and exploration activity is taking place, Figure VIII-1. Discussed separately in Sections 1-4, these include the Baltic Basin and Warsaw Trough in northern Poland, the Podlasie Depression and the Lublin Basin in east Poland, and the Fore-Sudetic Monocline in the southwest.[1] A fifth region, the Carpathian Foreland belt of southeastern Poland, could be prospective for oil-prone Jurassic shales, but this area is structurally complex and has not yet been targeted for shale leasing.

The Paleozoic sedimentary sequence in Poland contains several marine-deposited shale deposits which in places are thick, organic-rich and buried at prospective depths of 1,000 to 5,000 m. Most areas are in the gas-prone thermal maturity window, with smaller liquids-rich areas occurring in the north and east. Organic matter generally is dominated by Type II kerogen. Abundant geologic data exists on these Paleozoic shales. They have been subjected to extensive study as they are considered the main source rocks for Poland's conventional oil and gas fields. Basic shale exploration maps can be accurately constructed in most regions.

However, the distribution of favorable shale rock properties -- particularly the combination of high porosity and brittle mineralogy with low clay content -- is still poorly understood. Several of the early shale exploration wells have tested lower-than-expected porosity. And whereas quartz content in selected areas can be favorably high (40-80%), some recent shale drilling has tested high clay content (30-40%), which is less conducive to effective fracture stimulation. In addition, the local structural geology often is poorly known, in particular the extent and precise location of problematic faults which may interfere with shale drilling and completion. Consequently, considerable exploration drilling and seismic surveys are still needed to define potential sweet spots.

The main stratigraphic targets for shale gas/oil exploration in Poland are the Lower Silurian and Ordovician marine-deposited shales. The thinner but thermally more mature Cambrian shale is emerging as a secondary objective, while non-marine Carboniferous shales also have potential.

- **Lower Silurian** (Llandovery-Wenlock) graptolitic black shale is the primary shale exploration target in Poland. The Silurian section comprises several hundred to several thousand meters of shale and siltstone, with TOC generally increasing towards the bottom of the section. The most prospective portion is approximately 500 m of high-resistivity, high-TOC section in the Llandovery, Wenlock and lowest Ludlow, consisting of dark gray to black, dense siltstones and shales. Natural fractures are common and usually filled with calcite, although the matrix is non-calcareous. The Llandovery generally averages 1.5% to 2.5% TOC but is richer in the central Baltic Basin, while the Podlasie Basin averages 6% TOC and TOC can be high in the northwest Lublin Basin as well. The Wenlock is richest in the eastern Baltic and southeastern Lublin basins.

- **Ordovician.** Marine-deposited graptolitic black shales in Poland are part of a regional deposit extending from Scandinavia to Russia.[2] These include Early Ordovician Dictyonema Shale, which comprises fine-grained, non-metamorphosed, organic-rich deposits.

- **Cambrian.** Although not evaluated in the previous 2011 EIA/ARI assessment, the Cambrian also contains organic-rich shale that increasingly is being targeted for exploration. PGNiG and Lane Energy have reported test gas production from the Cambrian. Up to 700 m of Cambrian section is present, mostly tight sandstone but with thin shales near the top. Cambrian units include the Zarnowiec and Upper Vendians, which represent the transition from continental alluvial fan deposits to shallow marine terrigenous sedimentary environments.

  The Lower Cambrian is dominated by quartz sandstones interbedded with shales, while the relatively thin Mid-Cambrian Alum Shale is a transgressive, sediment-starved sequence containing high TOC.[3] The Upper Cambrian to Tremadocian shale, present only in the northern part of the Baltic Basin, contains high average TOC of 3-12% but is quite thin (several to 50 m).

- **Carboniferous Coaly Shales.** Non-marine, lacustrine-deposited carbonaceous shale sequences of Carboniferous age are widely present in Poland.[4] These organic-rich units, such as the Anthracosia Shales, are associated with economically important coal deposits. Although considered good source rocks for natural gas, as well as coalbed methane exploration targets in their own right, these coal-shale packages may not be brittle enough for effective shale development. However, comparable deposits in the Cooper Basin of Australia recently have produced shale gas. San Leon Energy is testing the Carboniferous shales in southwest Poland's Fore-Sudetic Monocline.

In addition to these four main stratigraphic targets that were assessed, additional organic-rich shale candidates exist in Poland but were excluded from this study. These apparently less prospective shales include:

- **Upper Permian Kupferschiefer Shale.** Stratigraphically positioned between the L. Permian Rotliegendes tight sandstone and the U. Permian Zechstein evaporite sequence, the Kupfershiefer Shale is present in the Fore-Sudetic Monocline and Lublin basins as well as in other areas of Poland. The Kupferschiefer is a black shale that was deposited under anoxic marine conditions, typically containing 7% to 16% TOC.[5] However, the economically important metal sulfides (pyrite, spalerite, galena) that also occur in high concentrations in this shale may interfere with fracture stimulation and gas production. None of the Poland shale operators have reported targeting the Kupferschiefer.

- **Mesozoic and Tertiary Shales.** Numerous younger, organically rich black shales also occur in the Carpathian Foredeep Basin of southeast Poland, but these generally are non-marine and mostly thermally immature.[6] For example, the Oligocene to early Miocene Menilite black shale, with 4-8% TOC (mainly Type II kerogen), is considered a high-quality source rock for conventional oil and gas fields in the Carpathian fold belt. In addition, up to 200 m of organic-rich sandy mudstone and claystone with average 4% TOC is present in the Jurassic (Bathonian-Aalenia) foreland platform. Finally, the Upper Jurassic organic-rich Mikulov marls, about 1400-m thick with 0.2% to 10% TOC, are considered world-class source rocks in the nearby Vienna Basin.[7] The Mikulov may be present in the subthrust of the Polish Carpathians but appears too deep and structurally complex to be prospective for shale development.

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PGI AND USGS ASSESSMENTS OF POLAND SHALE GAS RESOURCES

In 2012 the Polish Geological Institute (PGI) and the U.S. Geological Survey (USGS) collaborated on a preliminary shale gas and shale oil assessment of Poland. PGI and USGS released separate independent assessments of the technically recoverable shale gas and shale oil resources within Lower Paleozoic formations in the Baltic, Podlasie, and Lublin basins. The PGI study drew heavily on earlier detailed shale mapping and analysis conducted by Poprawa and colleagues at PGI.[8] Both the PGI and USGS studies were based on conventional oil and gas logs, core, and seismic data collected during the 1970-80's. Neither study cited recent data measured from shale industry exploration programs in Poland.

PGI estimated technically recoverable shale gas resources in the onshore Baltic-Podlasie-Lublin region to be 230.5 to 619.4 billion m^3 (8 to 22 Tcf), with an additional 1.569 to 1.956 billion barrels of oil (their "higher probability range" estimate).[9] The corresponding USGS estimate was about 1.345 Tcf and 0.168 billion barrels (mean estimate), or roughly 10% of PGI's estimate.[10]

The PGI and USGS resource estimates both are considerably less than EIA/ARI's current estimate of 146 Tcf and 1.8 billion barrels for Paleozoic shale gas and oil in Poland, Tables VIII-1 and VIII-2. Part of the difference arises because PGI excluded the Lublin Basin, while PGI and USGS both excluded the Fore-Sudetic Monocline, two large regions where shale gas drilling and gas production are underway. But most of the difference is because these researchers followed a different methodology and used different assumptions. The key differences among the PGI, USGS, and EIA/ARI studies are as follows:

- **Methodology.** PGI and the USGS followed the methodology used by the USGS for assessing shale gas and shale oil resources in the United States, wherein empirical shale production data are analyzed to estimate per-well recoveries.[11] In Poland's case there are no empirical shale production data. PGI considered but rejected individual US shale plays as analogs for Poland, instead selecting for its mean estimate a range of EURs "on the lower end" of 26 shale gas plays evaluated by the USGS. The USGS methodology for its Poland assessment has not been published but appears similar.

  EIA/ARI followed a different (volumetric) approach: calculating the prospective gas in-place and then estimating likely recovery factors based on multiple analogous North American shale plays.

- **Per-Well Recovery.** PGI and USGS estimated that per-well recoveries in Poland would be lower than those calculated by the USGS for many shale plays in the USA. For Poland, the USGS estimated average shale gas and oil EUR's of 0.245 Bcf/well and 34,000 bbl/well on 160-acre spacing. PGI estimated an average 0.4 Bcf/well recovery for Poland on implied 150-acre well spacing, with maximum of 1.0 Bcf/well and minimum of 0.04 Bcf/well.

  However, improved technology has significantly increased per-well recovery in most US shale plays in recent years. For example, recent Marcellus Shale wells are performing much better than the wells initially drilled in this play during 2007-10. In addition, vertical wells have not been employed for Marcellus development since about 2009, after which new development has been entirely based on horizontal wells.

  Using production data available at the time, which included many early vertical wells, the 2011 USGS Marcellus study estimated a mean 1.15 Bcf gas recovery per 149-acre cell within their main Interior Marcellus play.[12] This equates to approximately 0.82 Bcf/well recovery on the tighter 107-acre well spacing (6 wells per mi^2) that is commonly used in the Marcellus today.

  However, Marcellus operators recently are reporting that improved drilling and completion technology has steadily boosted their average horizontal well recoveries to between 5 and 11 Bcf/well at present. Indeed, the average per-well recovery reported by 10 large Marcellus operators, which account for most of the gas production in this play, has risen to 7.1 Bcf/well, Table VIII-4.[13] Other US shale plays have seen increases in per-well recovery in recent years due to improved technology, underscoring the need for continuous appraisal of even proven shale plays.

  The EIA/ARI study does not explicitly estimate per-well recovery for Poland, but we do estimate recovery efficiency. Assuming 80-acre spacing and relatively low gas recoveries of 10% to 20%, our equivalent per-well recoveries in Poland range from 1 to 4 Bcf/well. This has not yet been confirmed by well testing in Poland but the industry there is still in the early exploration phase. Our assumption of higher per-well recovery potential, based in part on more current US data, is a major reason why the EIA/ARI shale resource estimate is so much larger than the PGI and USGS estimates.

- **Basins Assessed.** The PGI assessment is limited to the Baltic and Podlasie basins; the Lublin Basin was excluded due to low TOC. However, PGNiG, Chevron, Marathon and other companies are continuing to explore for shale gas in the Lublin Basin. PKN Orlen recently drilled the first horizontal well there and is preparing to fracture stimulate. The USGS Poland map indicates they assessed the Baltic, Podlasie, and Lublin basins. The current EIA/ARI assessment covers the Baltic, Podlasie, and Lublin basins but also includes the Fore-Sudetic Monocline, where shale gas leasing and drilling are underway.

Table VIII-4 : Comparison of Marcellus and Poland Shale Gas Per-Well Recovery Estimates

Source	Mean Estimated Ultimate Recovery Bcf/107-acre Well		Current Net Production	Proved Reserves + Risked Resources		Report	Location
	Bcf/well	Source	Million ft^3/d	Tcf	Source	Date	in play
Chesapeake	5.2	Chesapeake	800	39.0	Chesapeake	2/21/2013	PA & WV
Range Resources	8.5	Range	600	30.0	Range	3/4/2013	NE PA
Shell	-	-	295	24.1	ARI est	5/28/2010	PA & WV
Statoil	-	-	451	18.9	Statoil	2/28/2013	PA & WV
ExxonMobil	-	-	-	17.6	ARI est	8/23/2012	PA & WV
EQT Corp.	7.3	EQT	800	15.0	EQT	2/5/2013	PA & WV
Consol/Noble Energy	5.9	Consol	280	14.8	Noble	2/7/2013	PA & WV
Chevron Atlas Reliance	-	-	158	13.0	Atlas	5/6/2010	SW PA
Talisman Energy	5.0	Talisman	450	8.0	Talisman	2/13/2013	NE PA
Ultra Petroleum	6.0	Ultra	194	7.4	Ultra	3/4/2013	NE PA
Anadarko Corp.	8.0	Anadarko	330	6.0	Anadarko	2/20/2013	NE PA
Cabot Oil & Gas	11.0	Cabot	930	5.3	ARI est	2/28/2013	NE PA
Chevron Chief Oil	-	-	140	5.0	Chevron	5/4/2011	SW PA
BG Exco JV	-	-	-	4.8	Exco	5/10/2010	Central PA
Southwestern Energy	8.0	Southwestern	300	4.7	ARI est	3/1/2013	NE PA
National Fuel Gas	6.0	NFG	194	4.1	ARI est	2/7/2013	Central PA
Operator Marcellus Mean or Total	**7.1**	**Operators**	**5,922**	**218**			PA & WV
USGS Interior Marcellus Equiv 107-Ac Mean Est	**0.82**	**USGS**	**-**	**81.4**		11/23/2011	PA & WV
PGI Poland Mean Shale Gas 150-Ac Est	**0.40**	**PGI**	**0**	**8 to 22**		3/1/2012	Baltic-Podlasie
USGS Poland Mean Shale Gas 160-Ac Est	**0.25**	**USGS**	**0**	**1.3**		7/1/2012	Baltic-Podlasie

- **TOC.** PGI screened out the Lublin Basin because their log analysis did not identify significant shale layers thicker than 15 m with TOC above 2%. However, they noted the evaluation process was “not easy and straightforward” due to the poor quality of the 40- to 50-year-old core and log data. EIA/ARI, relying on more recent shale exploration data and published source rock studies, developed a more optimistic view that shallower portions of the deep Lublin Basin still may have prospective shale targets.

In summary, the EIA/ARI shale gas/oil resource estimate for Poland is larger because it includes two additional shale plays (Podlasie and Fore-Sudetic Monocline), incorporates more recent shale industry data, and assumes higher recovery factors more consistent with (but still considerably less than) actual Marcellus Shale well performance.

Advanced Resources International, Inc.

1. BALTIC BASIN

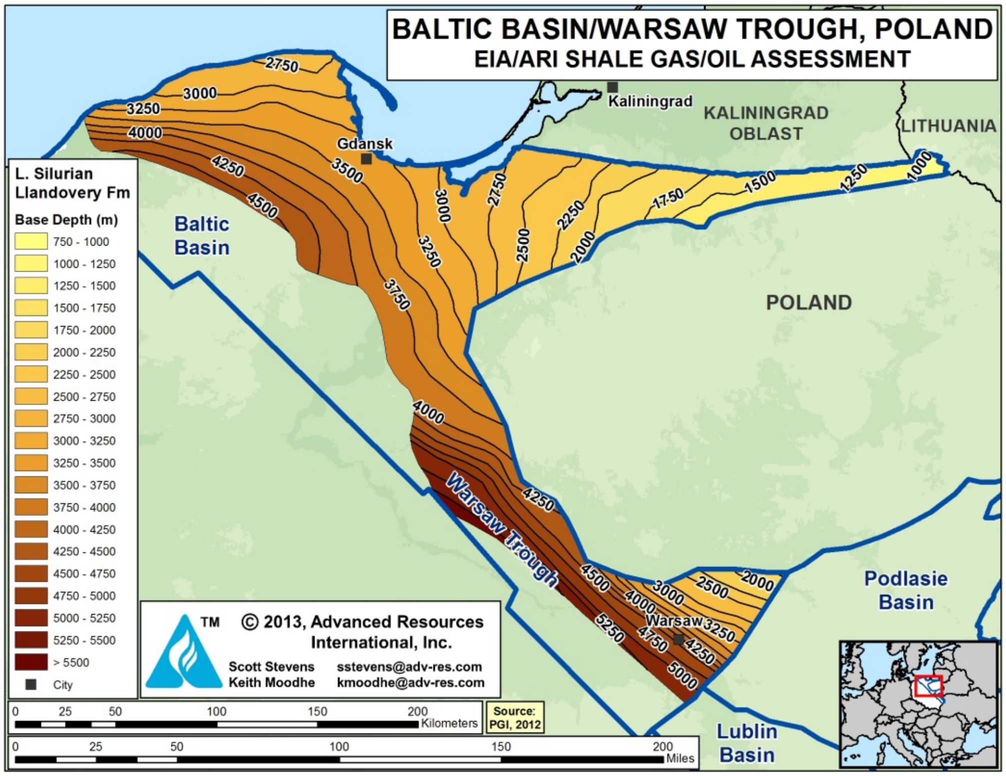
1.1 Introduction and Geologic Setting

The 16,200-mi^2 Baltic Basin in northern Poland, Lithuania and Kaliningrad is a rare (for Europe), relatively tectonically quiescent area that contains a sequence of Paleozoic to Mesozoic deposits, including Lower Paleozoic organic-rich shales that are prospective for shale gas and oil development.[14] These mostly marine-deposited shales are separated by regional unconformities related to Caledonian, Variscan, and Alpine tectonics. A small portion of the basin extends into Lithuania and the Kaliningrad Oblast.

Figure VIII-2 illustrates the depth to the Lower Silurian Llandovery Shale, one of the principal targets for exploration in the Baltic Basin, highlighting the 1 to 5 km prospective depth window. The basin's structure is much simpler than most other areas in Poland and Europe. Faulting does occur but it is more widely spaced and less severe. In addition, the shale strata dip gently in this basin**,** Figure VIII-3. Detailed seismic sections identify fairly broad areas which appear to be intact and free of faulting in places, Figure VIII-4. Faulting in the Baltic Basin is most likely related to uplift during the Devonian (Caledonian Orogeny), coupled with relatively rapid deposition during the late Paleozoic and Mesozoic.

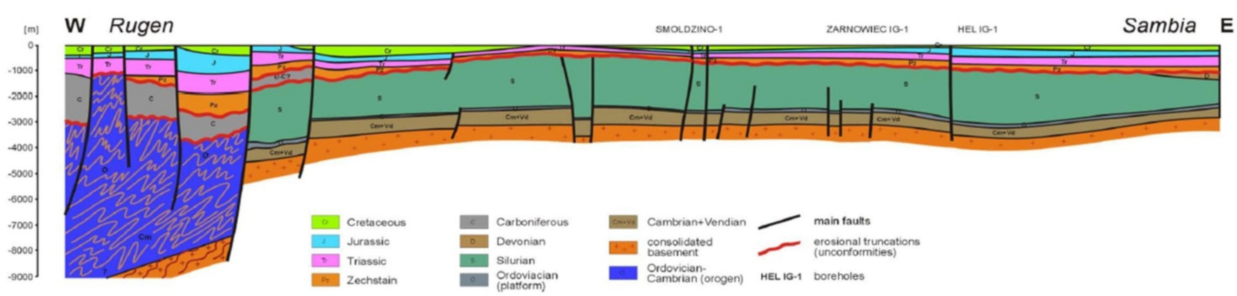
The Baltic Basin formed as a result of late Precambrian rifting followed by early Paleozoic post-rift downwarping of the East European Platform. The basin's southwest boundary is defined by the northwest-southeast trending Trans-European Suture Zone (TESZ), a deformed fault zone, while the Mazury-Belarus High defines the eastern boundary. The basin extends to the north into the Baltic Sea.

Figure VIII-2: Baltic Basin Map Showing Depth To Lower Silurian Llandovery Shale.



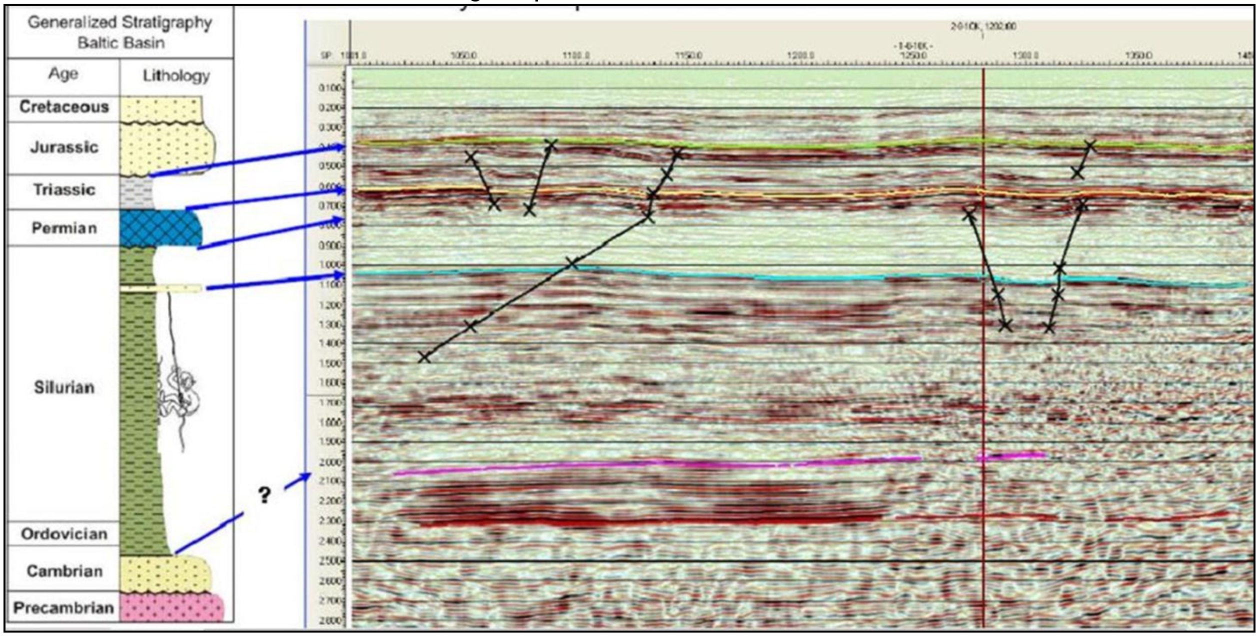
Source: Modified from Polish Geological Institute, 2012

Figure VIII-3: Structural Cross-Section in North Poland Baltic Basin Showing Relatively Simple Structure and Widely Spaced Faults.



Source: Modified from San Leon Energy, 2012

Figure VIII-4: Detailed Seismic Section in North Poland Baltic Basin
Showing Simple Structure and Few Faults.



Source: LNG Energy Ltd.

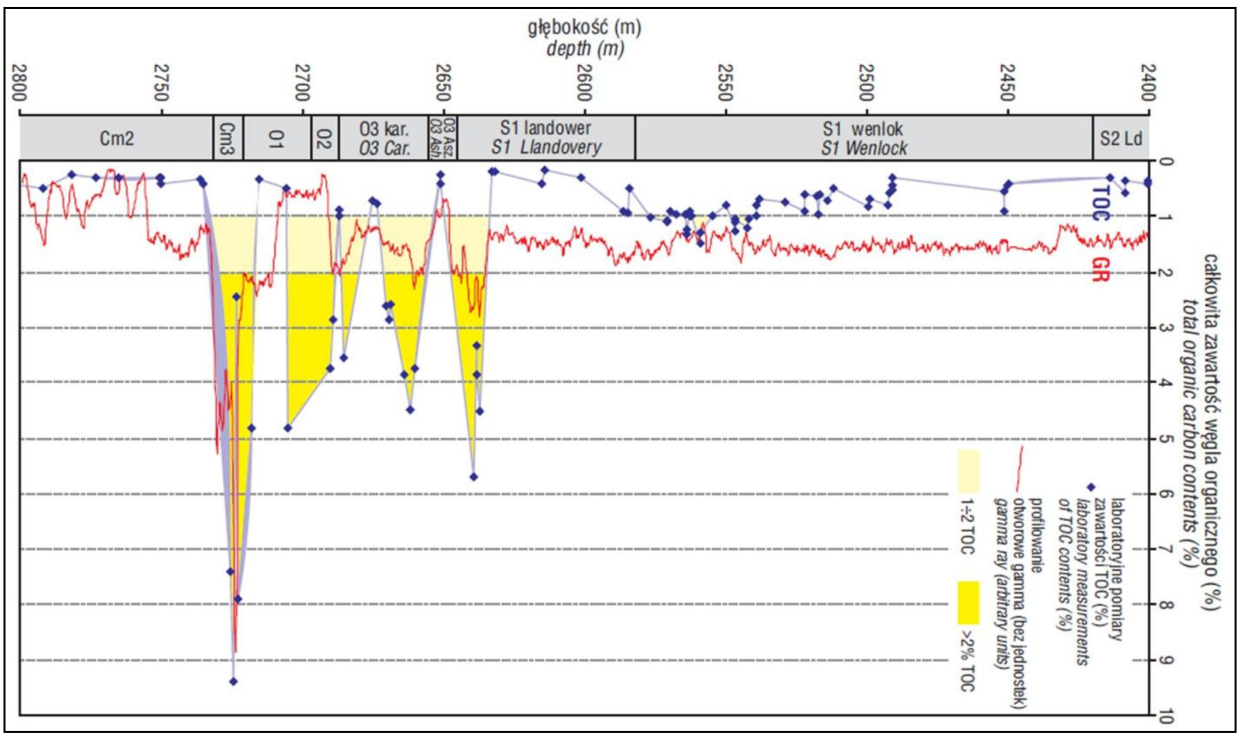
Organic-rich shales of Paleozoic age within the Baltic Basin are relatively flat lying, high in TOC, thermally mature in the gas to oil windows, and among the most prospective in Europe for shale development. Figure VIII-5 exhibits organic-rich shales that are typically present within the Lower Silurian, Ordovician, and Cambrian strata. TOC distribution in the Zarnowiec IG-1 conventional well, northern Baltic Basin, shows several high TOC zones totaling about 75 m thick, with good correlation of gamma ray log and core data. These Lower Paleozoic deposits form a package of quite thick, laterally extensive, dark grey to black organic-rich rocks that contain marine (type II/III) kerogen. The main shale targets in the Baltic Basin include:

- **Cambrian.** Up to 700 m of Cambrian sandstone and shale is present, including the Zarnowiec and other Upper Vendian units. These represent a transition from continental alluvial fan deposits to shallow marine terrigenous sedimentary environments.
- **Ordovician.** Deposited under deep water marine conditions, the Ordovician is thinner, ranging from 80 to 200 m. The Lower Ordovician Arenig and Lower Caradoc formations are predominately marly limestone interbedded with claystone and siltstone. The overlying Upper and Middle Caradoc Formation consists of graptolite-rich black shale.
- **Silurian.** The overlying Silurian sequence is extremely thick at up to 3 km in the southwest near the TESZ, but more typically 1 km thick in the shale exploration areas.

The Silurian shale is locally interbedded with dolomitic limestone. The thick middle Silurian Wenlock and thin Lower Silurian Llandovery formations contain dark grey to black organic shale that commonly exhibits strong gas shows in exploration wells.

The Ordovician and Silurian shales are overlain by more than 200 m of anhydrite and halite (salt) of the Permian Zechstein Formation, a weak zone that frequently decouples the younger overlying section from the Paleozoic strata. Finally a 1,200-m thick sequence of overlying Mesozoic sandstones and claystone is capped by a thin veneer of Tertiary sand and gravel. Additional potential source rock shales are present in the Upper Jurassic and Lower Cretaceous in the Baltic Basin but were not assessed due to low thermal maturity. These Mesozoic shales locally have TOC >1.5% but are thermally immature (R_o 0.5% to 0.7%) at well depths of 1.5 to 3.2 km.[15]

Figure VIII-5: TOC Distribution in L. Paleozoic, Zarnowiec IG-1 Conventional Well, Northern Baltic Basin, Shows Several High TOC Zones Totaling About 75 m Thick. Note Good Correlation of Gamma Ray Log and Core Data.



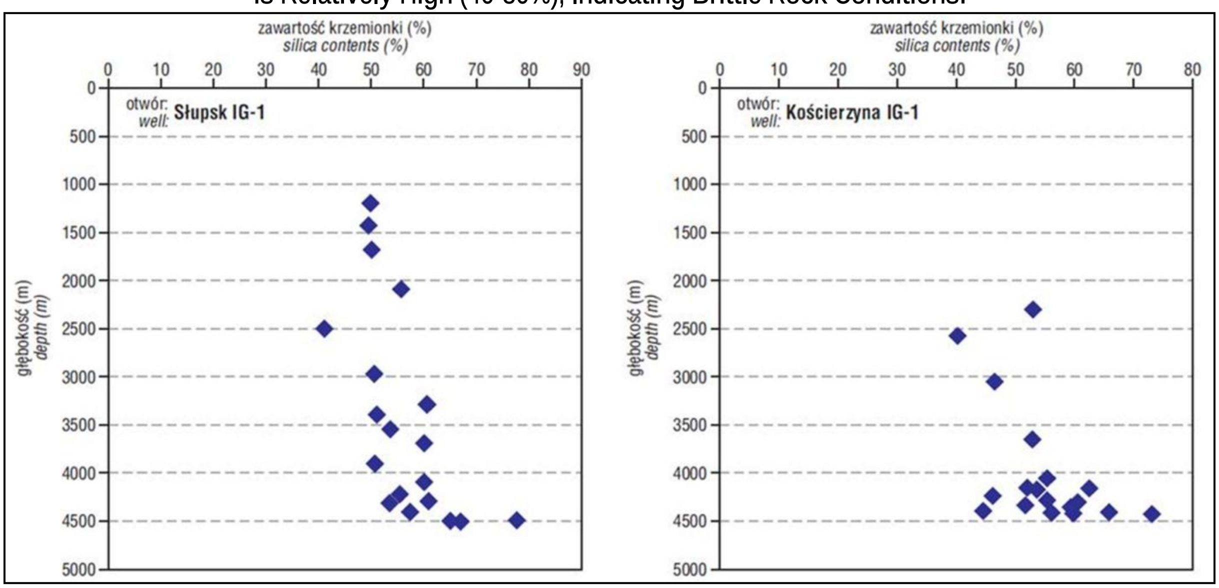
Source: Poprawy, 2010

1.2 Reservoir Properties (Prospective Area)

The combined Lower Silurian, Ordovician, and Cambrian section in the Baltic Basin totals from 1,000 to 3,500 feet thick. The organic-rich shale interval for the Lower Paleozoic is estimated to average 820 ft thick, of which approximately 55% is considered net thickness. TOC averages about 3.9%. Silica content from two older western Baltic Basin wells measured relatively high (40-80%), Figure VIII-6, indicating brittle rock conditions. However, high clay content (33-44%) has been reported from two of BNK's recent shale exploration wells.

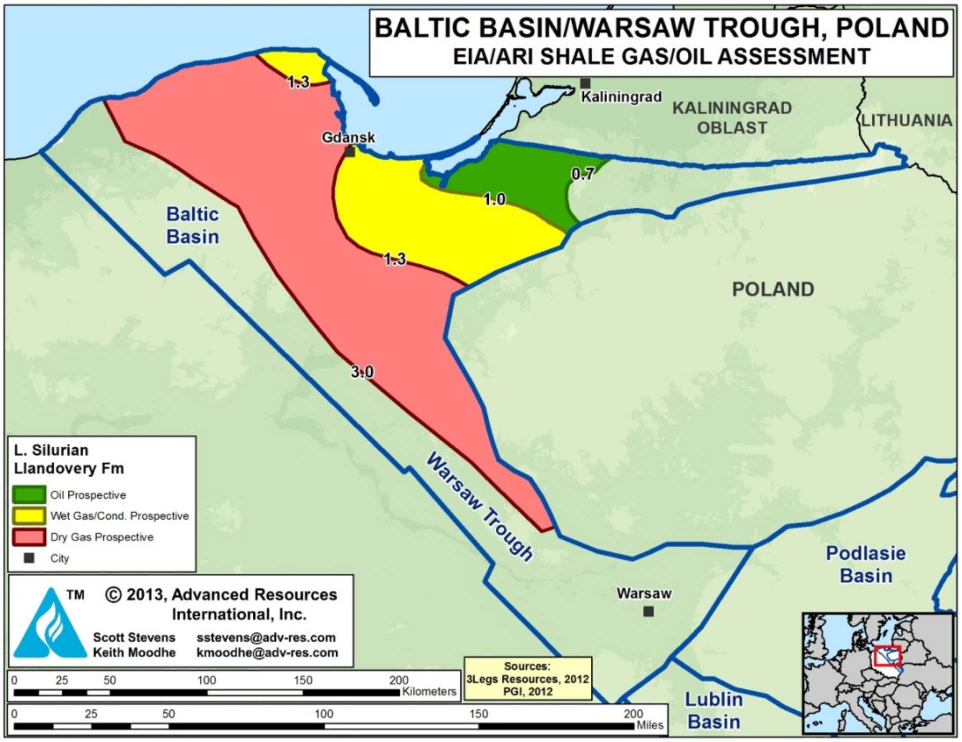
Thermal maturity ranges from oil- to gas-prone, Figure VIII-7, increasing steadily with depth in the basin as illustrated in the Gdansk IG-1 well, Figure VIII-8. The average depth ranges from 8,200 ft in the oil window, to 10,000 ft in the wet gas window area, to 12,500 ft in the oil window. Porosity is estimated at 4% based on recent exploration results. The basin is slightly over-pressured with an estimated 0.50 psi/ft gradient. Gas impurities such as CO_2 or N_2 appear low in most of the basin.

Figure VIII-6: Silica Content in the Lower Paleozoic From Two Western Baltic Basin Wells is Relatively High (40-80%), Indicating Brittle Rock Conditions.



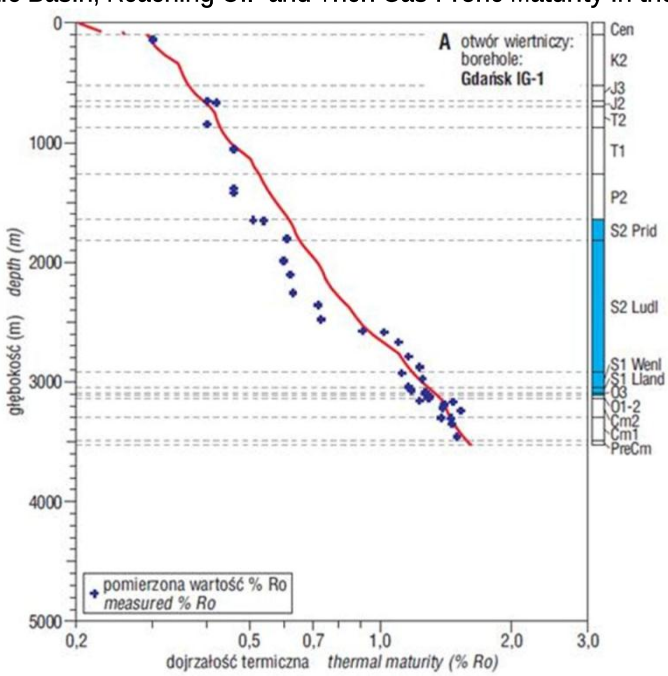
Source: Krzemiñskiego & Poprawy, 2006 in Poprawy, 2010

Figure VIII-7: Baltic Basin Map Showing Thermal Maturity Windows and Prospective Area for Lower Silurian Llandovery Shale, Poland



Source: Contours modified from San Leon Energy, 2012 and Polish Geological Institute, 2012

Figure VIII-8: Thermal Maturity Increases Steadily with Depth in the Gdansk IG-1 Well Central Baltic Basin, Reaching Oil- and Then Gas-Prone Maturity in the Paleozoic.



Source: Poprawa, 2010

1.3 Resource Assessment

Total risked, technically recoverable shale resources in the Poland portion of the Baltic Basin and Warsaw Trough are estimated at 105 Tcf of shale gas and 1.2 billion barrels of shale oil and condensate.

Dry Gas Window. The mapped prospective area for Poland's dry gas window in the Baltic Basin is estimated at 5,680 mi^2. Lower Paleozoic shale (comprising the L. Silurian, Ordovician, and Cambrian) has a favorable resource concentration of approximately 181 Bcf/mi^2. Risked, technically recoverable shale gas resources are estimated at 82 Tcf, out of a risked shale gas in-place of 412 Tcf.

Wet Gas Window. The wet gas prospective area covers about 2,070 mi^2. Risked, technically recoverable resources are estimated at 22 Tcf of shale gas and 0.5 billion barrels of shale condensate from 109 Tcf and 14 billion barrels of risked, in-place shale gas and shale oil resources.

Oil Window. The much smaller oil window within the northern Baltic Basin prospective area covers about 830 mi^2. Risked technically recoverable resources are estimated to be about 0.7 billion barrels of shale oil and condensate and 1.2 Tcf of associated shale gas, out of a risked in-place shale oil and condensate resource of 14 billion barrels.

1.4 Exploration Activity

Poland, and in particular the Baltic Basin, has a large existing data set of well logs and seismic to guide shale exploration. Over 200 petroleum exploration wells have been drilled targeting conventional oil and gas plays in Poland, penetrating shale formations and providing general information on thickness, depth, TOC and thermal maturity. Seismically, the Lower Paleozoic shales can be difficult to image due to acoustic interference caused by the 200-m thick overlying Zechstein salt. Regional modern 2D and localized 3D seismic data are being acquired by shale operators over their licenses to aid in siting well locations, particularly to avoid problematic faults.

Since 2010 the smaller independent E&P companies have pioneering shale exploration in the Baltic Basin, including Lane Energy, BNK Petroleum, San Leon Energy, and others. More recently large oil companies (ConocoPhillips, Marathon, Talisman) have farmed into some of these positions or acquired their own blocks. PGNiG is active but has focused mainly outside of the Baltic Basin. Thus far the Poland shale test programs have had limited success with modest gas flow rates. Key challenges seem to be locating the best stratigraphic zones in which to position the lateral, as well as successfully implementing hydraulic stimulation programs.

A brief summary of operator activities in the Baltic Basin is provided below, including the limited public geologic and reservoir results released to date:

- **PGNiG**, the national oil and gas company of Poland, holds 15 shale gas exploration licenses. Last year the company reported plans to invest $0.5 billion in shale gas development with several Polish state-owned partners. PGNiG has drilled at least four shale gas exploration wells to date in the Baltic Basin, producing shale gas from the Cambrian in two vertical wells from depths of about 3,000 m, while logging gas shows in the Ordovician and L. Silurian. The company recently drilled its first horizontal well nearby (Lubocino-2H) and targets commercial production in the Baltic Basin starting 2016.[16]

- **ConocoPhillips** has farmed into three of **Lane Energy**'s (subsidiary of 3Legs Resources PLC) shale blocks in the western Baltic Basin. Lane Energy has tested low gas rates (90 and 500 Mcfd) from two stimulated horizontal shale wells. ConocoPhillips recently became the operator of these blocks, shifting focus to the liquids-rich window in the north. The company recently spud its first Poland shale well, the vertical Strzeszewo LE-1, in an area with 3D seismic coverage.[17]

  Lane's Lebien LE-2H well, a vertical well stimulated with a single-stage fracture treatment, produced an average 27 Mcf from the Upper Ordovician during a 5-day test. The well was re-entered in 2011 and a 1-km lateral was drilled into the Ordovician and stimulated with a large 13-stage frac treatment. This horizontal well produced at an initial 2.2 MMcfd, stabilizing at about 500 Mcfd on nitrogen lift during a 17-day test, making it the highest production for a shale well in Poland to date.

  Lane's Warblino LE-1H well encountered hole instability while drilling into the U. Cambrian shale. The well was re-drilled with a 500-m lateral and stimulated with a 7-stage gel frac, testing 18 to 90 Mcfd on lift assist.

- **Marathon** and partner **Nexen** have acquired new seismic and drilled at least one shale well in the Baltic Basin.[18] Marathon's most recent remarks (May 2012) on Poland noted "disappointment" with the reservoir quality. Currently, Marathon is conducting injectivity tests to determine whether to proceed with hydraulic stimulation.

- **Talisman** and **San Leon Energy** have drilled three vertical shale wells in the Baltic Basin, logging gas and some liquids shows throughout the Cambrian, Ordovician, and Silurian section. San Leon reported that it may drill its first horizontal shale well during 2Q-2013, with a planned 1,000+ m lateral completed with a multi-stage frac. However, Talisman's most recent remarks (October 2012) noted "we're not particularly enthused by results we've had to date. It's a difficult thing."[19]

- **BNK Petroleum** has drilled five vertical shale wells in the Baltic Basin ($12 million/well). Porosity (3-4%) was lower than expected in over-pressured L. Paleozoic shale; clay content was fairly high (30-40%). The company estimated total GIP concentration of up to 135 Bcf/mi^2, including 86 Bcf/mi^2 in the target Ordovician and L. Silurian shale zones (total 110 m thick). The Lebork S-1 well flared gas from several intervals, but a fracture stimulation was unsuccessful due to high stress and inadequate pump capacity.

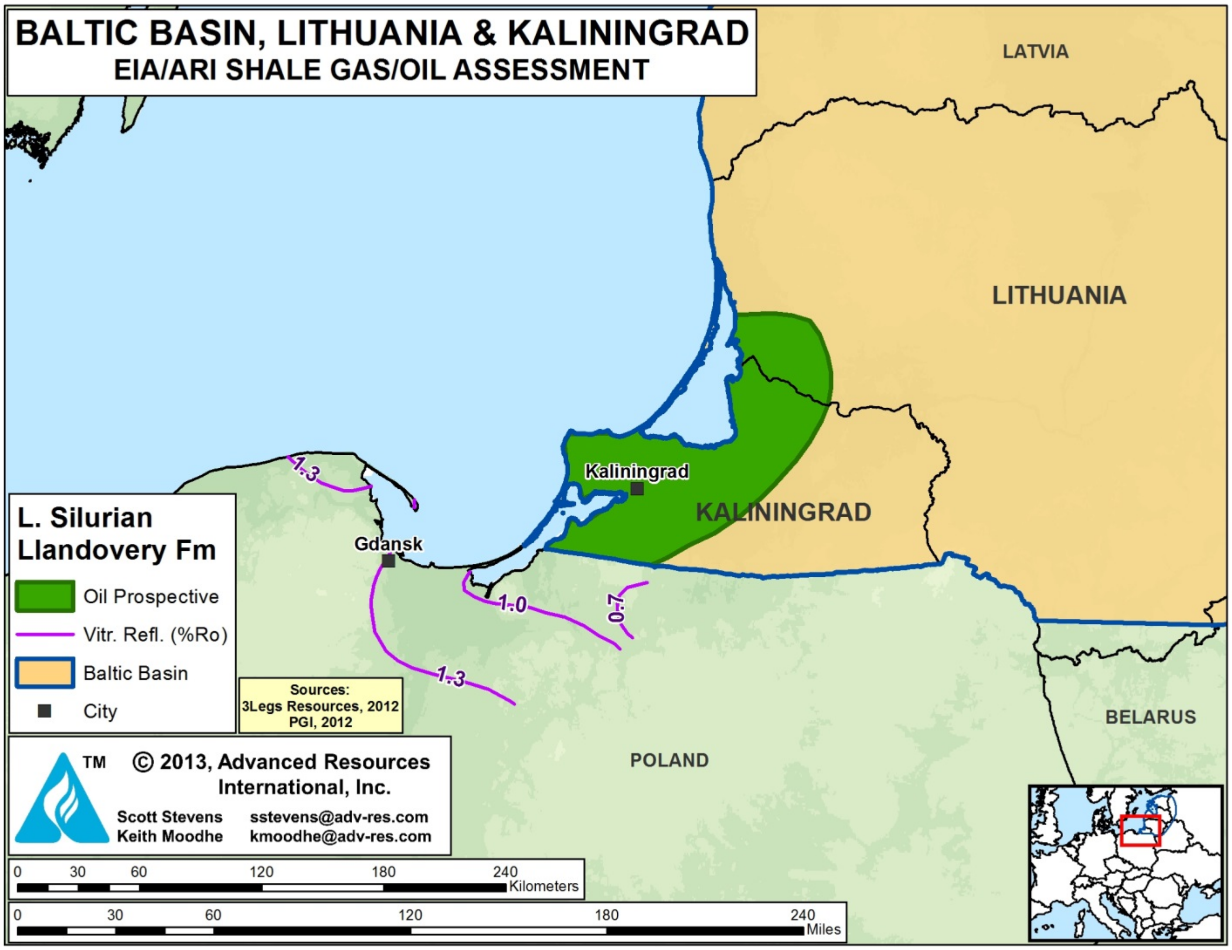
1.5 Lithuania

For the northeastern extension of the Baltic Basin into Lithuania, we estimate a risked 6 billion barrels of shale oil and 4 Tcf of associated shale gas in-place in the prospective area (Figure VIII-9), with 0.3 billion barrels of shale oil and 0.4 Tcf of associated shale gas as the risked, technically recoverable shale resources.

1.6 Russia (Kaliningrad Oblast)

For the northeastern extension of the Baltic Basin into Russia's Kaliningrad Oblast, we estimate a risked 23 billion barrels of shale oil and 20 Tcf of associated shale gas in-place in the prospective area (Figure VIII-9), with 1.2 billion barrels of shale oil and 2 Tcf of associated shale gas as the risked, technically recoverable shale resources.

Figure VIII-9. Baltic Basin Map Showing Thermal Maturity Windows and Prospective Area for Llandovery Shale, Lithuania and Kaliningrad



2. LUBLIN BASIN

2.1 Introduction and Geologic Setting

The 5,000-mi^2 Lublin Basin may be considered the southeastern extension of the Baltic Basin, with which it shares generally similar shale stratigraphy and lithology, Figure VIII-10. However, the Lublin Basin's structural geology is significantly more complex, with seismic sections showing numerous closely spaced faults. In addition, the basin is mostly too deep while shale TOC appears to be relatively low.

Although the Lublin Basin is experiencing early-stage shale gas exploration, it appears somewhat less prospective and was assessed separately from the Baltic Basin. Several vertical shale wells have been drilled, while the first horizontal well was drilled in late 2012 and is planned to be stimulated soon. PGNiG, Chevron, Marathon, and other companies are active.

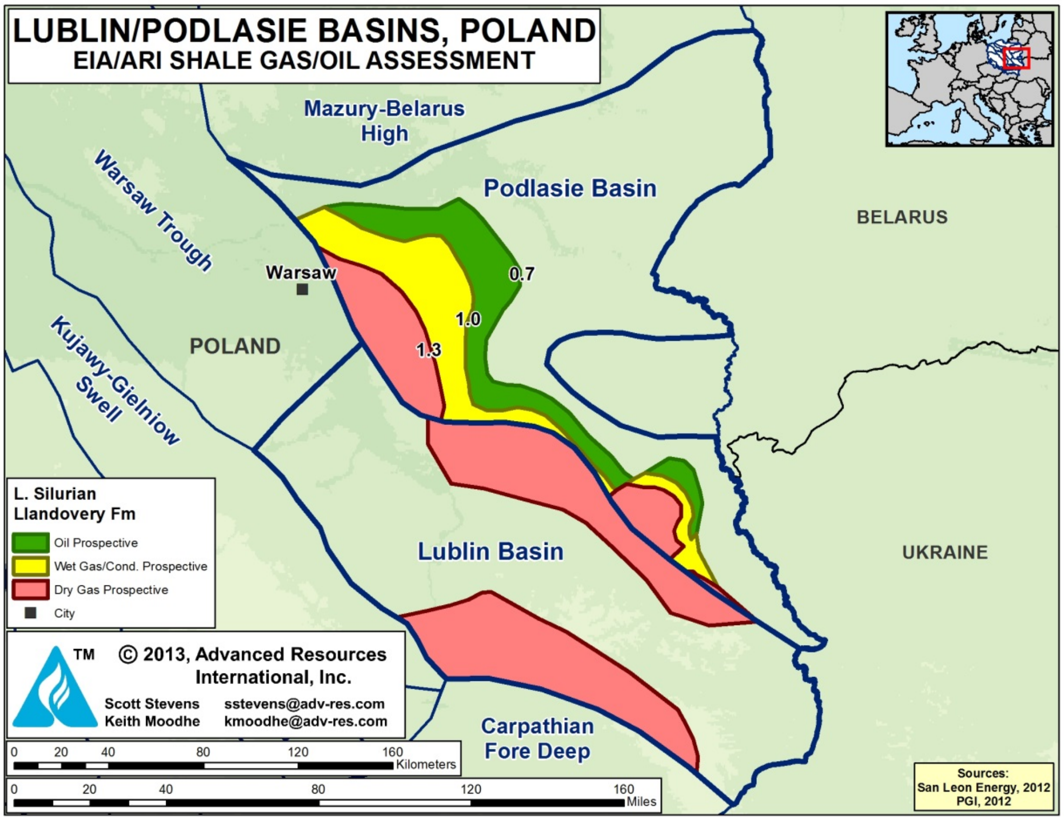
Figure VIII-11 illustrates the extent of faulting and sub-salt tectonic decoupling of the Lower Paleozoic in the Lublin Basin.[20] Figure VIII-12 shows hydrological flow within the Devonian strata, including closely spaced faults and steep dips.[21] Major fault systems in the basin include the northwest-southeast trending Kock, Izbeca-Zamosc, Ursynow-Kazimierz, and Holy Cross faults. Clearly, the Lublin Basin is structurally more complex than the Baltic Basin.

Several small conventional natural gas fields have been discovered in the Lublin Basin, such as the Ciecierzyn-Mełgiew Field which produces from Devonian carbonate reservoirs. Source rocks include Silurian and Ordovician shales, but marine limestones and claystones of the Devonian Bychawa Formation are considered more significant.[22] The Lublin Basin also contains significant coal and coalbed methane deposits in Carboniferous strata, which continue to the southeast into the Lvov-Volhynia Basin of Ukraine.[23]

2.2 Reservoir Properties (Prospective Area)

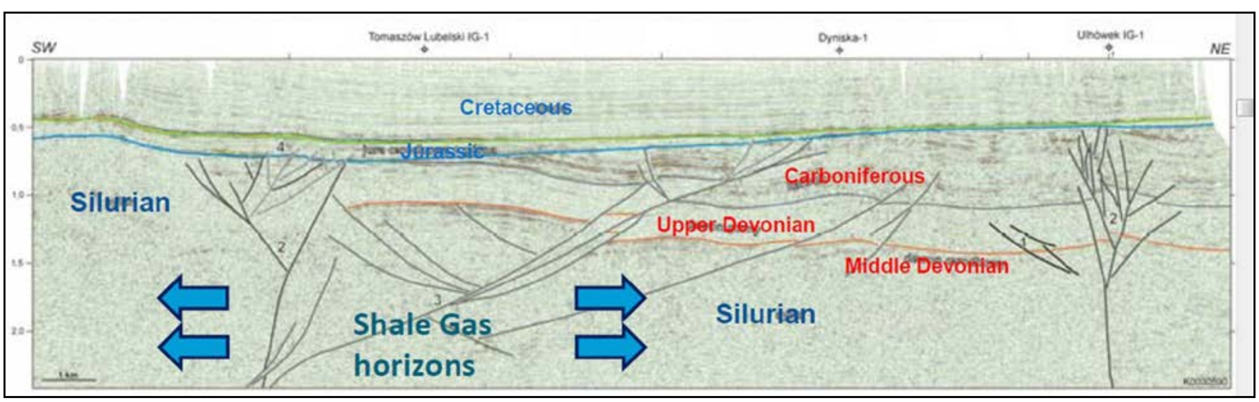
The combined Lower Silurian, Ordovician, and Cambrian section in the Lublin Basin totals from 330 to 1,100 feet thick. The organic-rich shale interval for the Lower Paleozoic is estimated to average 415 ft thick, of which about 55% is considered net pay. A good example is the Lopiennik IG-1 well, Figure VIII-13, showing about 150 m of gas-bearing Paleozoic shale with TOC of 0.2% to 1.4%.[24]

Figure VIII-10: Lublin and Podlasie Basin Map Showing Depth to Lower Silurian Llandovery Shale.



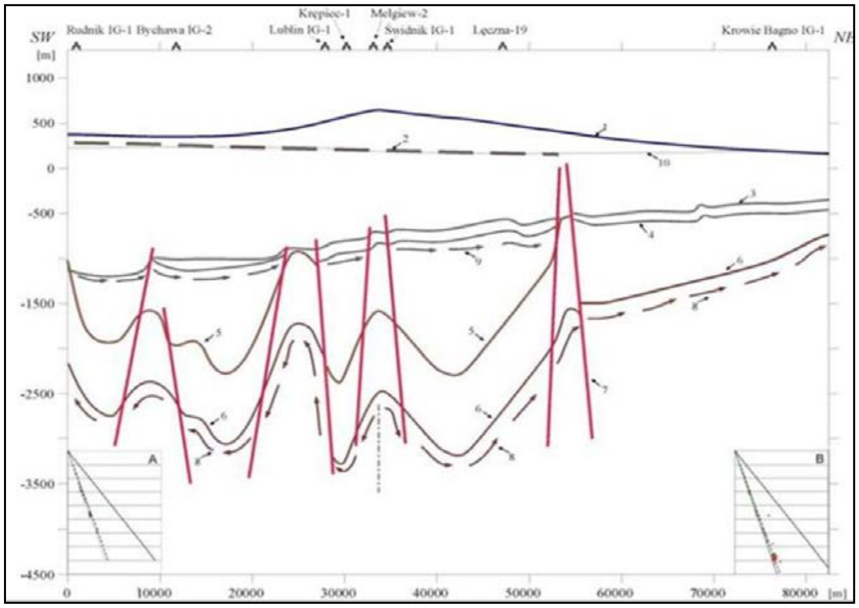
Source: Modified from Polish Geological Institute, 2012

Figure VIII-11: Seismic Section in Lublin Basin Showing Relatively Complex Structure and Numerous Faults, as Well as Poor Image Quality in Deep Lower Paleozoic.



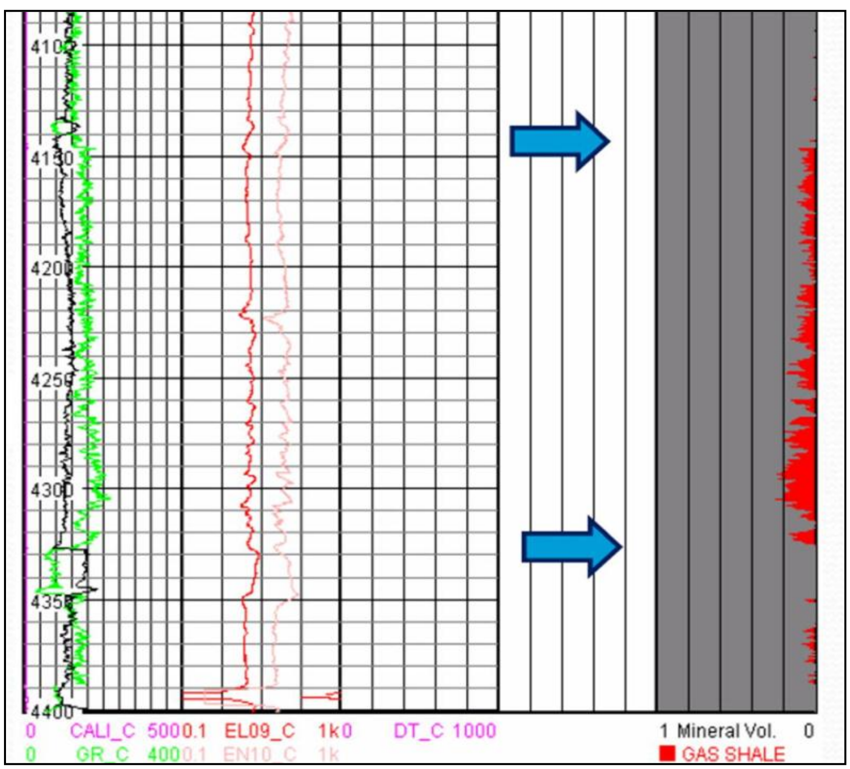
Source: Zywiecki and Lewis, 2011

Figure VIII-12: Hydrological Cross-Section in the Lublin Basin, Poland.



Source: Zawisza, 2006

Figure VIII-13: Well Log Showing Approximately 150 m of Gas-Bearing Shale with TOC of 0.2 to 1.4% in the Lopiennik IG-1 Well, Lublin Basin



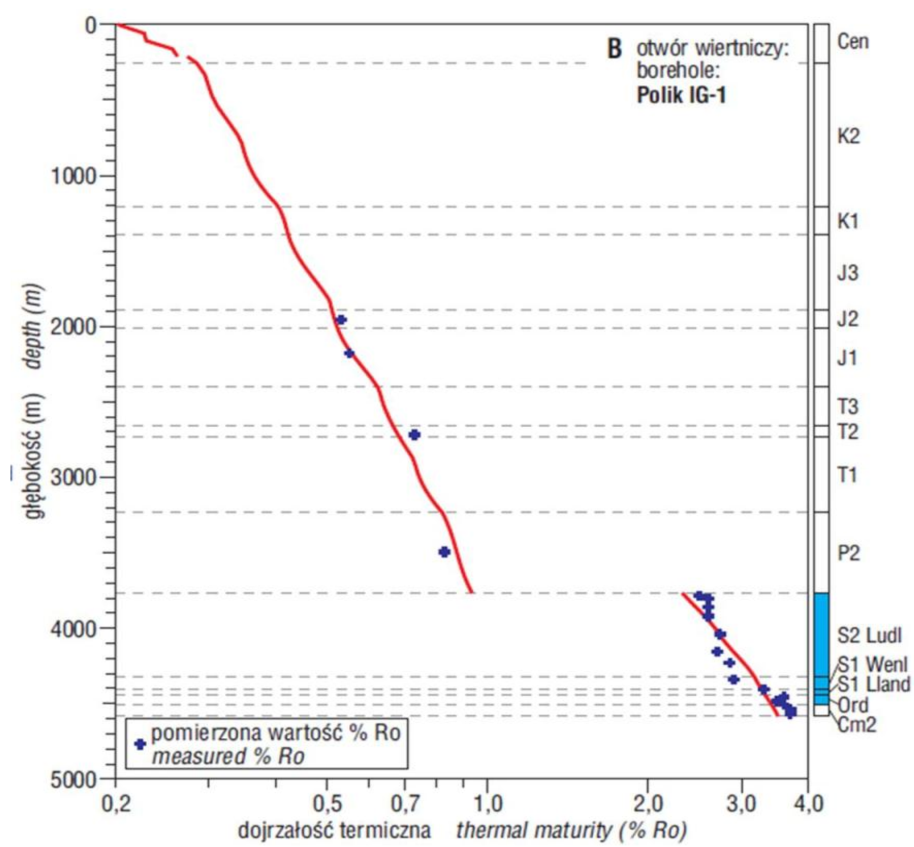
Source: Zywiecki and Lewis, 2011

However, TOC often is higher in core analyses than calculated from older logs, averaging about 3% in the Lublin Basin. The thermal maturity of the Paleozoic is in the dry gas window to overmature, increasing steadily with depth as illustrated in the Polik IG-1 well, Figure VIII-14. Depth to the shale averages approximately 11,000 ft. Porosity is estimated at about 5%. The pressure gradient in the Devonian section is slightly over-pressured, about 2-10% above the hydrostatic gradient.[25] Gas impurities such as CO_2 or N_2 appear to be negligible.

2.3 Resource Assessment

The 2,390-mi^2 prospective area mapped in the Lublin Basin is entirely within the dry gas thermal maturity window. The Lower Paleozoic shale (L. Silurian, Ordovician, and Cambrian) has a moderate resource concentration of approximately 91 Bcf/mi^2. Risked, technically recoverable shale gas is estimated at 9 Tcf, out of risked, shale gas in-place of 46 Tcf.

Figure VIII-14: Thermal Maturity In The Paleozoic Increases Abruptly Below the Unconformity in the Polik IG-1 Well, Lublin Basin, Reaching Gas-Prone and Then Over-Maturity.



Source: Poprawy, 2010

2.4 Exploration Activity

PGNiG, ExxonMobil, Chevron, Marathon and other companies have been pursuing shale gas exploration in the Lublin basin. In March 2012 **PGNiG** began drilling the **Lubycza Królewska** well in the Tomaszów Lubelski license. The vertical well is planned for 4,300-m TD using a 2000-HP Drillmec 2000 Walking Rig, currently Poland’s most advanced drilling rig, and targets Lower Paleozoic shales at depths of 2,300 to 4,300 m.[26]

In 2009 **ExxonMobil** leased six licenses in the Lublin and Podlasie basins of eastern Poland. The company drilled two vertical shale gas test wells (Krupe 1 and Siennica 1), locating one well in each basin. However, ExxonMobil terminated its Poland shale gas exploration efforts in mid-2012 after failing to demonstrate “sustained commercial hydrocarbon flow rates.”[27]

In late 2012 ExxonMobil sold two of the licenses (Wodynie-Lukow and Wolomin in the Podlasie Basin) to **PKN Orlen**. PKN Orlen holds 10 shale gas licenses totaling nearly 9,000 km^2 (including the two former ExxonMobil blocks). In late October 2012, PKN reported drilling the first horizontal well in the Lublin Basin, which it plans to hydraulically stimulate.

In 2009 **Chevron** acquired and currently operates four shale gas exploration blocks totaling 4,433 km^2 in the Lublin Basin of southeast Poland. In October 2011 Chevron completed a 12-month 2-D seismic acquisition program across the four licenses to help plan a multi-well exploration drilling campaign. The company completed its first wells in the Grabowiec and Frampol licenses during Q1 2012; results have not been disclosed.

Marathon Oil also holds shale exploration blocks in the Lublin Basin. The company has acquired seismic data but has not reported testing results. PGNiG also holds licenses in the Lublin Basin and drilled the vertical **Markowola-1** shale well in the in the Pionki-Kazimierz license during 2010. The well was fracture stimulated by Halliburton and reportedly achieved “mixed” results.

3. PODLASIE BASIN

3.1 Introduction and Geologic Setting

Like the Lublin Basin, the 6,600-mi^2 Podlasie Depression (Basin) may be considered a southeastern extension of the Baltic Basin, with which it shares generally similar shale stratigraphy and lithology. However, whereas the Podlasie is structurally more complex than the Baltic Basin, it is less complex than the Lublin Basin and thus is separately assessed. Eight key older conventional exploration wells have been drilled in the basin, including the Wyszków IG 1 borehole (TD 2388 m) which penetrated organic-rich Silurian, Ordovician, and Cambrian shale deposits.[28] Organic matter measurements in older core were low, but some operators have noted that fresh shale core samples yield higher values.

3.2 Reservoir Properties (Prospective Area)

The combined organic-rich shale interval within the Lower Paleozoic is estimated to average 540 ft thick, of which about 55% is considered net. TOC averages about 3%. The thermal maturity of the Lower Paleozoic shale ranges from dry gas in the deeper portion of the basin, to wet gas and eventually oil at shallower levels. Depth to shale averages about 7,500 ft to 12,500 ft. Porosity is estimated at about 5%. The basin is slightly over-pressured with an estimated 0.50 psi/ft gradient. Gas impurities such as CO_2 or N_2 appear to be minimal in most of the basin.

3.3 Resource Assessment

Dry Gas Window. The mapped prospective area within the dry gas window of the Podlasie Basin is estimated at 860 mi^2. Lower Paleozoic shale (L. Silurian, Ordovician, and Cambrian) has a moderate resource concentration of 122 Bcf/mi^2. Risked, technically recoverable shale gas is estimated at 5 Tcf, out of risked shale gas in-place of about 25 Tcf.

Wet Gas Window. The wet gas window is prospective within an area of 1,100 mi^2. Risked technically recoverable shale resources are estimated at 4 Tcf of shale gas and 0.2 billion barrels of shale condensate from risked, in-place resources of 22 Tcf and nearly 3 billion barrels, respectively.

Oil Window. The oil window, mapped in the eastern Podlasie Basin, is prospective within an area of approximately 1,000 mi^2. Risked, technically recoverable shale resources are estimated at 0.4 billion barrels of shale oil and condensate along with 0.7 Tcf of associated shale gas, from an in-place risked shale oil resource of nearly 9 billion barrels.

3.4 Exploration Activity

Several operators hold shale gas exploration licenses in the Podlasie Depression. Marathon drilled one vertical shale exploration well in the basin but has not released results.

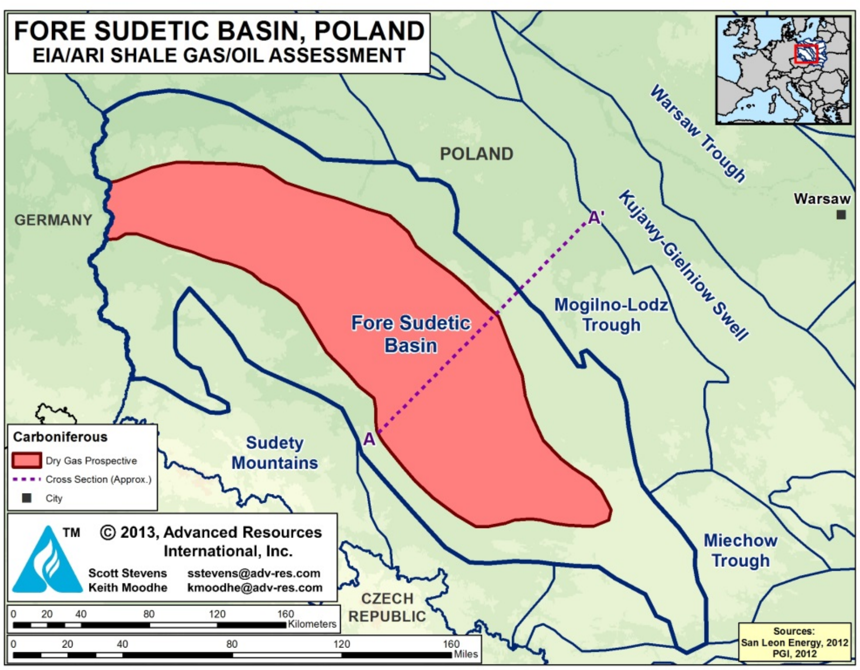
4. FORE-SUDETIC MONOCLINE

4.1 Introduction and Geologic Setting

Unconventional gas plays, mainly tight sandstone but potentially including shale gas, are being pursued in the Fore-Sudetic Monocline of southwestern Poland, Figure VIII-15. While the marine-deposited Lower Paleozoic shales are too deep to be prospective in this region, the overlying Carboniferous non-marine shales may be present at depths of 2 to 5 km. Shale exploration is less active here than in the Baltic Basin, but at least two companies (San Leon, PGNiG) have reported leasing and drilling.

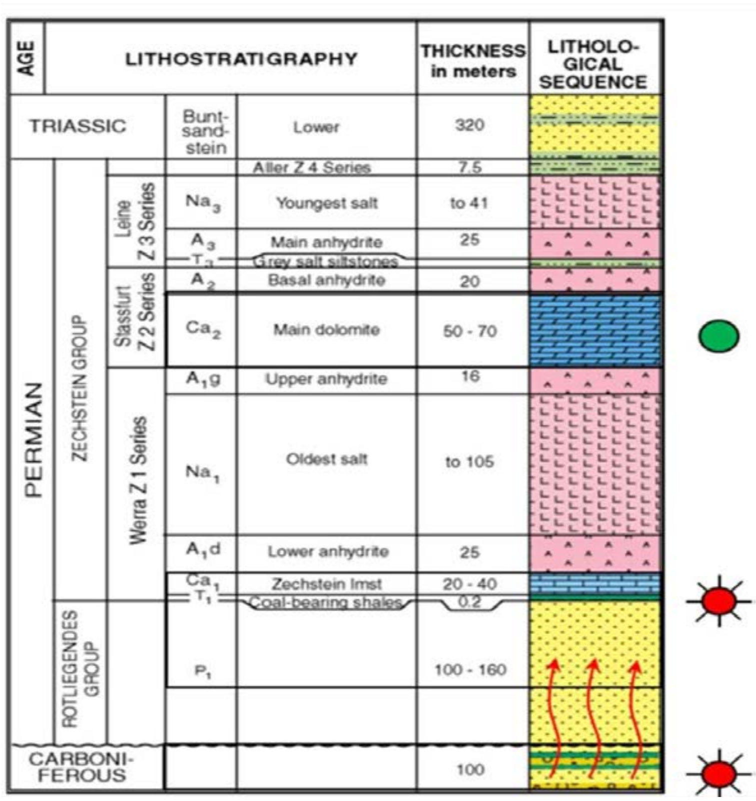
The nearly 20,000-mi^2 Fore-Sudetic Monocline is considered a southern continuation of the Mid-Polish Trough, where Paleozoic and younger strata shoal to shale-prospective depths of about 2 to 5 km.[29] The Lower Permian Rotliegend sandstone has been developed for tight gas production in this province for several decades, Figure VIII-16. Figure VIII-17, a regional southwest-northeast cross-section, indicates that the structural geology is relatively simple, although additional faults are likely to be present. Indeed, San Leon Energy has noted that the poor quality seismic available in this region masks the true geologic structure, thus the company recently acquired four 3D seismic surveys totaling 650 km^2 and over 1,000 km of 2D seismic.

Figure VIII-15: Fore-Sudetic Monocline of Southwestern Poland, Showing Shale Prospective Area.



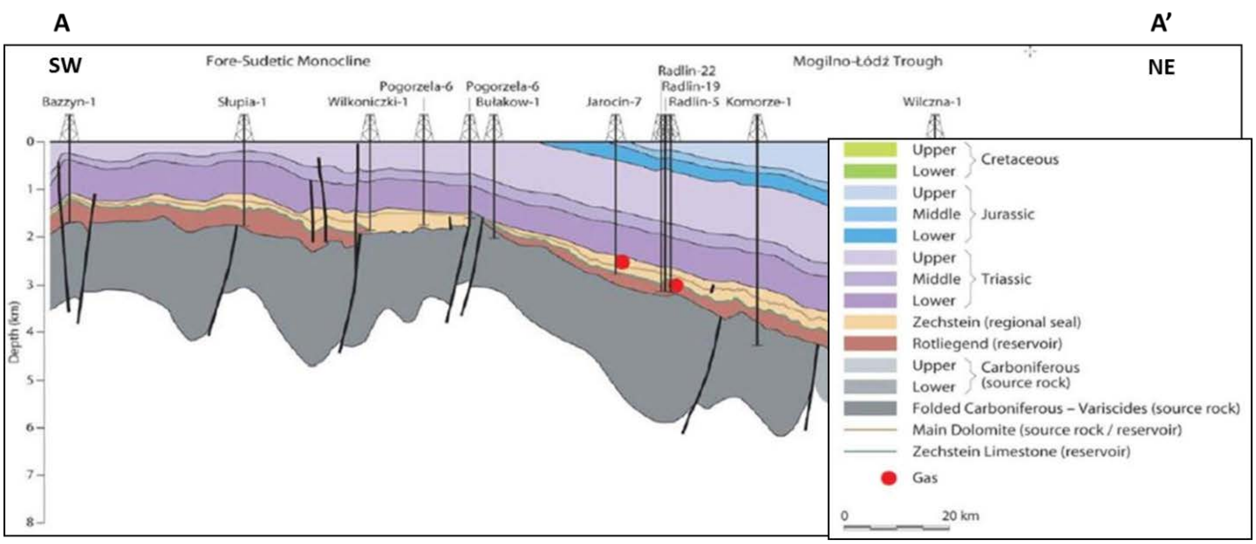
Source: ARI, 2013.

Figure VIII-16: Stratigraphy of the Carboniferous and Younger Formations in the Fore-Sudetic Monocline.



Source: San Leon Energy, 2012

Figure VIII-17: Structural Cross-Section In The Fore-Sudetic Monocline Of Southwest Poland Baltic Basin Showing Relatively Simple Structure And Widely Spaced Faults (vertical exaggeration = 10x).



Source: San Leon Energy, November 2012

A thick non-marine, coal-bearing Carboniferous sequence is present, with multiple targets of tight sandstone, deep coal seams, and carbonaceous shales. The Carboniferous underlies the Rotliegend sandstone and sourced it with natural gas, which FX Energy reported averages about 80% methane and 20% carbon dioxide.[30] The overall stratigraphic sequence in the Carboniferous appears broadly similar to that of the REM shale-sandstone-coal sequence in the Cooper Basin of Australia, where initial shale gas production has been reported. San Leon Energy, FX Energy, PGNiG and other companies are actively exploring for shale gas here but scant data have been released.

San Leon Energy disclosed that it is evaluating the Carboniferous shale gas potential of the Pre-Sudetic Monocline, which reportedly is structurally simple and over-pressured.[31] Note that the organic-rich shales in the Pre-Sudetic Monocline were deposited in a non-marine setting and are associated with coal deposits, thus may be clay-rich and ductile. Lower Paleozoic marine-deposited rocks, similar to those present in the Baltic Basin, underlie the Carboniferous in this region, but are likely too deep to be prospective and thus were not assessed.

4.2 Reservoir Properties (Prospective Area)

San Leon Energy estimates the Carboniferous shale in the Fore-Sudetic Monocline contains 1% to 5% TOC, is in the dry gas thermal maturity window (R_o of 1.3% to 2.0%), and contains 20% to 60% silica with 2% to 8% total porosity. ARI estimated the organic-rich shale interval to be 330 ft thick, with about half considered as net pay (165 ft). Depth averages 12,000 ft, ranging from 8,000 to 16,000 ft. The basin is reported to be slightly over-pressured. Significant levels of nitrogen contamination (20%) are expected, based on the typical composition of produced gas from the overlying Rotliegend sandstone.

4.3 Resource Assessment

The large but poorly constrained 9,070-mi^2 prospective area mapped in the Fore-Sudetic Monocline based on depth appears to be entirely within the dry gas thermal maturity window. The Carboniferous shale is estimated to have moderate resource concentration of approximately 67 Bcf/mi^2. Risked technically recoverable resources are estimated at 21 Tcf, out of risked shale gas in-place of 107 Tcf.

4.4 Exploration Activity

The only shale gas exploration well announced to date in the region is San Leon's vertical well, which tested the Carboniferous shales. The 3,520-m deep **Siciniy-2** well logged continuous gas shows across the 1-km thick Carboniferous section. Two tight sandstone intervals totaling 185 m thick and three shale zones were identified, both highly fractured in core. The quartz content of the shale was described as high. San Leon estimated total gas in place at 450 Bcf/mi^2, of which 280 Bcf/mi^2 is in sandstone and 170 Bcf/mi^2 in shale. At last report, the company planned to frac the well.

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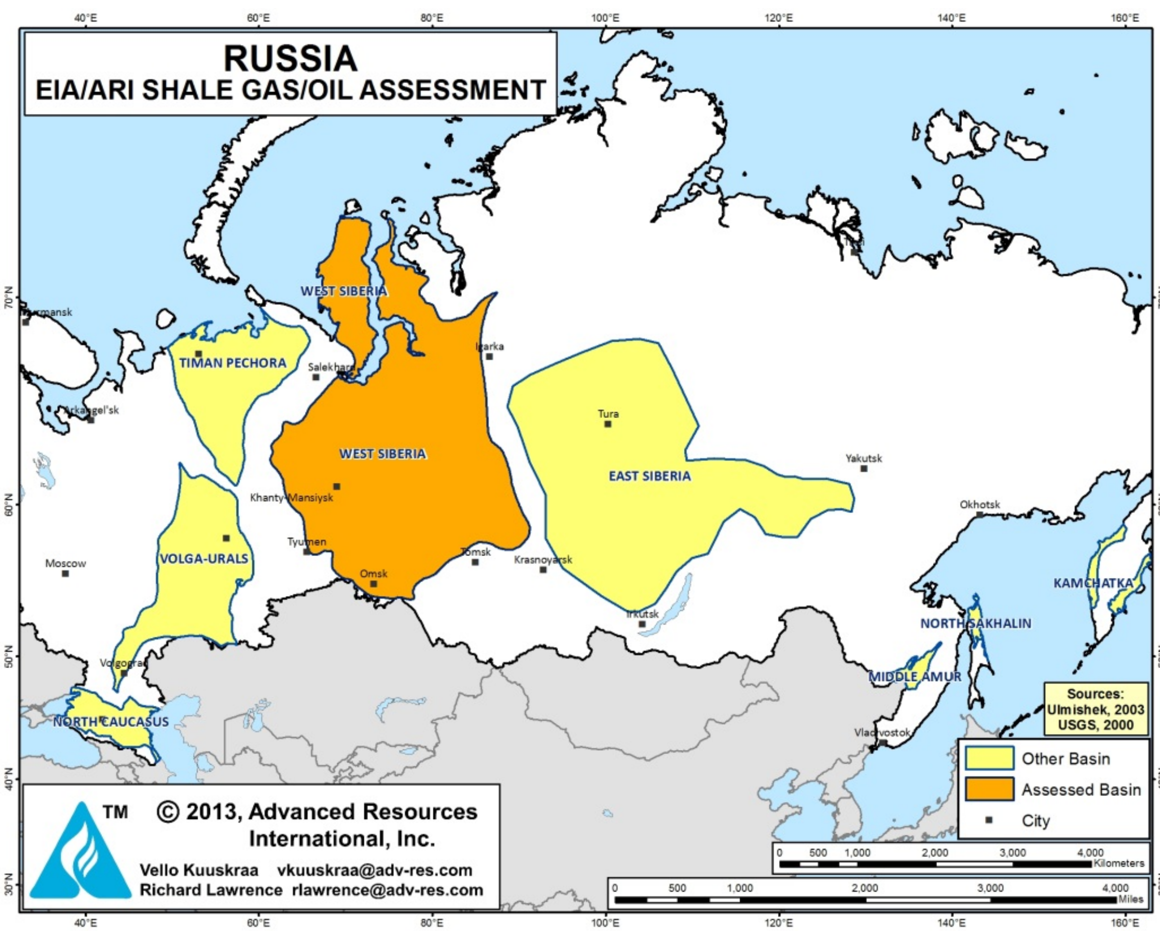
IX. RUSSIA

SUMMARY

Our shale gas and shale oil resources assessment for Russia addresses the Upper Jurassic Bazhenov Shale in the West Siberian Basin, Figure IX-1. This organically rich, siliceous shale is the principle source rock for the conventional gas and oil produced from the West Siberian Basin. We also examined other shale basins (e.g., Timan-Pechora) but were not able to assemble sufficient, publicly available data for a quantitative resource assessment.

Figure IX-1. Prospective Shale Gas and Shale Oil Basins of Russia



Source: ARI, 2013

For the Bazhenov Shale, we estimate 1,243 billion barrels of risked shale oil in-place, with 74.6 billion barrels as the risked, technically recoverable shale oil resource, Table IX-1. In addition, we estimate 1,920 Tcf of risked shale gas in-place, with 285 Tcf as the risked, technically recoverable shale gas resource, Table IX-2.

Table IX-1. Shale Oil Reservoir Properties and Resources of Russia

Basic Data	Basin/Gross Area		West Siberian (1,350,000 mi^2)			
	Shale Formation		Bazhenov Central	Bazhenov North		
	Geologic Age		U. Jurassic - L. Cretaceous	U. Jurassic - L. Cretaceous		
	Depositional Environment		Marine	Marine		
Physical Extent	Prospective Area (mi^2)		116,200	74,400	14,800	10,540
	Thickness (ft)	Organically Rich	100	100	100	100
		Net	85	85	85	85
	Depth (ft)	Interval	6,500 - 12,000	6,500 - 13,000	8,500 - 15,000	10,000 - 16,000
		Average	8,200	9,800	12,000	13,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		10.0%	5.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	0.85%	1.15%	1.45%
	Clay Content		Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		22.9	19.4	42.0	66.0
	Risked GIP (Tcf)		1,196.0	378.9	163.0	182.5
	Risked Recoverable (Tcf)		143.5	45.5	40.8	54.8

Source: ARI, 2013

Table IX-2. Shale Gas Reservoir Properties and Resources of Russia

Basic Data	Basin/Gross Area		West Siberian (1,350,000 mi^2)		
	Shale Formation		Bazhenov Central	Bazhenov North	
	Geologic Age		U. Jurassic - L. Cretaceous	U. Jurassic - L. Cretaceous	
	Depositional Environment		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		116,200	74,400	14,800
	Thickness (ft)	Organically Rich	100	100	100
		Net	85	85	85
	Depth (ft)	Interval	6,500 - 12,000	6,500 - 13,000	6,500 - 13,000
		Average	8,200	9,800	12,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		10.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	0.85%	1.15%
	Clay Content		Low	Low	Low
Resource	Oil Phase		Oil	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		18.5	13.4	4.3
	Risked OIP (B bbl)		964.8	261.5	16.8
	Risked Recoverable (B bbl)		57.89	15.69	1.01

Source: ARI, 2013

1. WEST SIBERIAN BASIN

1.1 Introduction and Geologic Setting

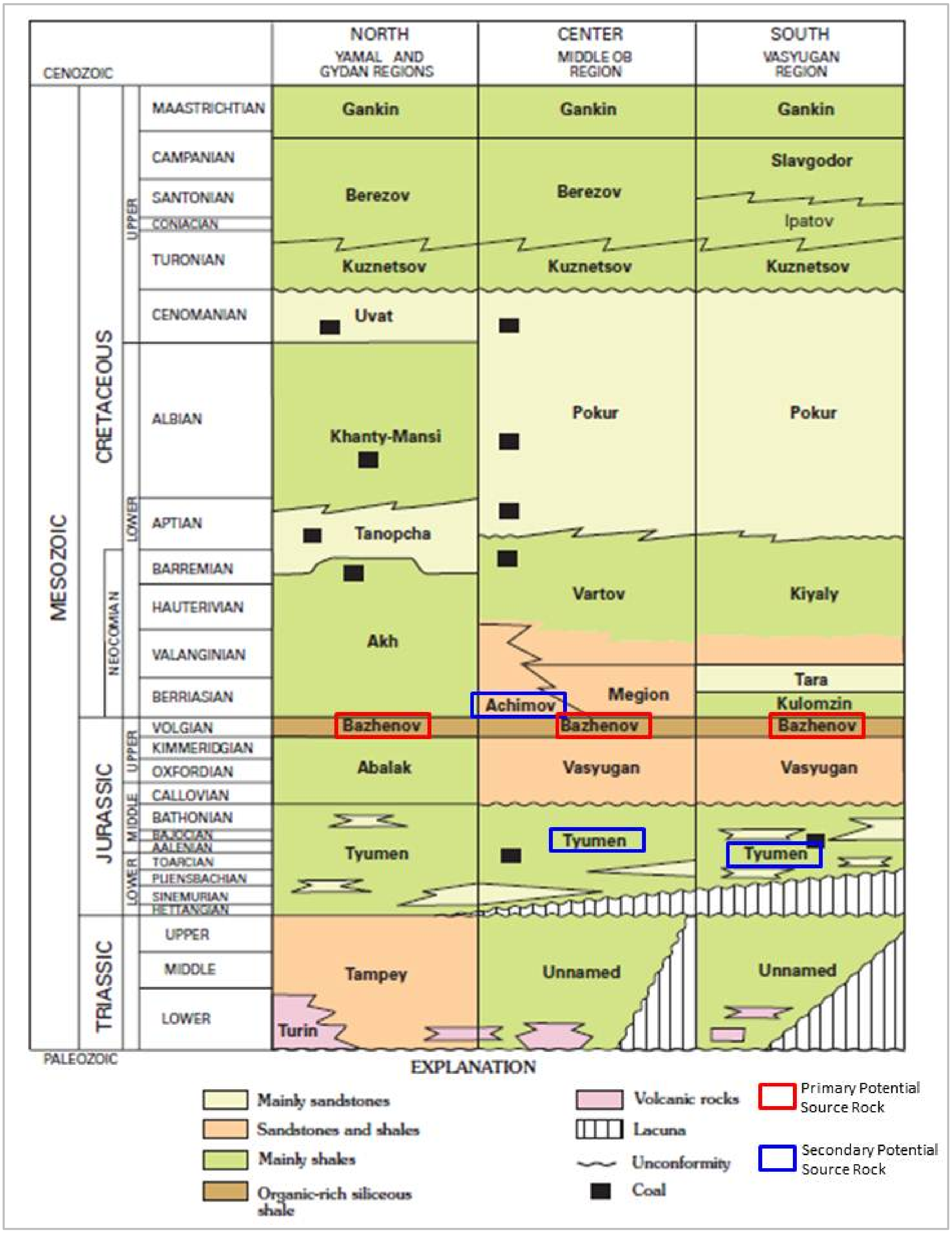
The 850,000-mi^2 West Siberian Basin is the largest petroleum basin in the world[1]. The basin lies between the Ural Mountains to the west and the Yenisey River to the east, while extending north offshore under the Kara Sea and reaching south to the border with Kazakhstan, Figure IX-1.

Conventional oil and gas production has taken place in the basin since the 1960's, with reservoirs found predominately in Cretaceous sandstone formations. Oil production occurs mainly in the southern and central regions of the basin, with gas fields more prevalent in the north. The West Siberian Basin contains tens of giant and super-giant fields such as the Samotlor oil field (28 billion barrels of original oil reserves) in the central Middle Ob petroleum region and the 350-Tcf Urengoy gas field north of the Arctic Circle. Although the West Siberian Basin still delivers over 60% of Russia's annual oil production, its output peaked in the late 1980's. Declining conventional production is stimulating interest in finding new oil and gas production from unconventional resources.

The Upper Jurassic Bazhenov Shale, a marine shale rich in TOC, is considered the main source rock for the Western Siberian Basin's conventional oil reservoirs. The Bazhenov Shale, the primary shale addressed in this resource assessment, has been selectively drilled, providing shows and variable quantities of oil production.

Other formations that may contain shales with gas and oil potential are the Lower Jurassic Tyumen and Lower Cretaceous Achimov formations, Figure IX-2. The Tyumen Formation is not considered prospective in the northern areas of the basin where it is projected to be at depths greater than 16,400 ft (5,000 m). The publicly available data for the Achimov Formation is not sufficient for a quantitative resource assessment. As such, these two formations were excluded from our shale gas and shale oil assessment.

Figure IX-2: Stratigraphic Column of the West Siberian Basin



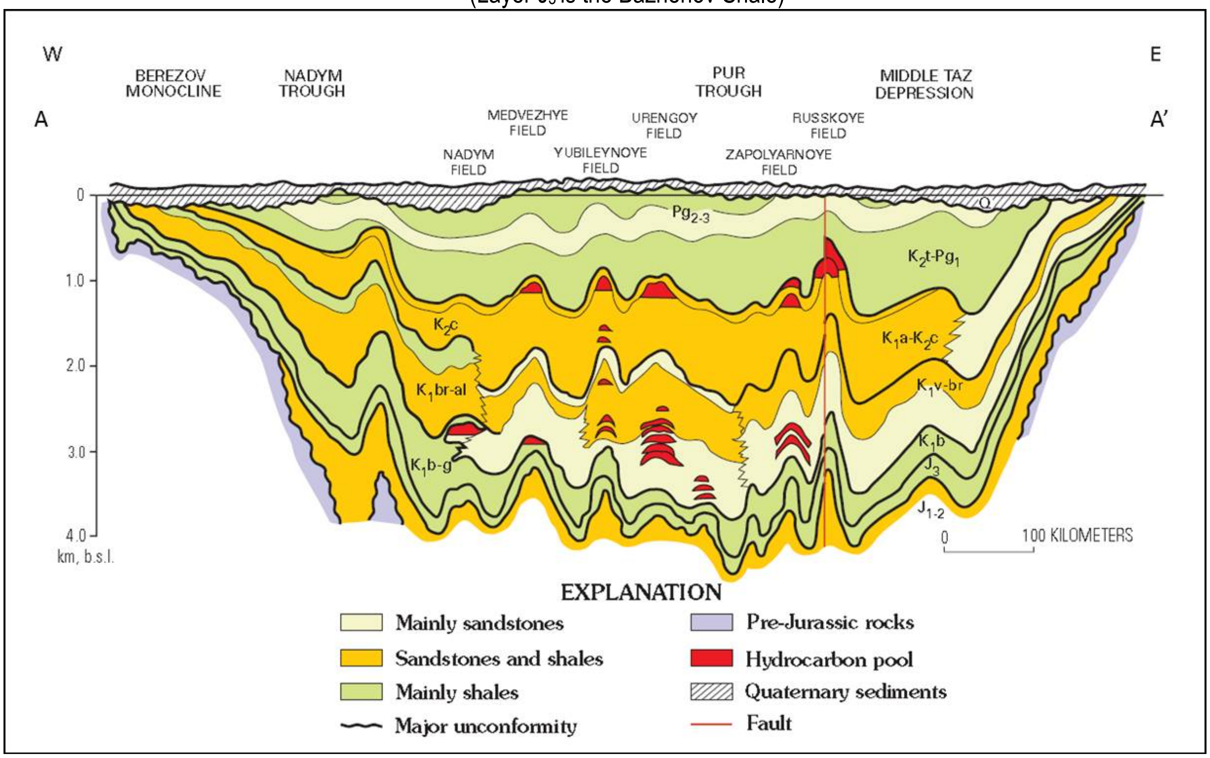
Source: Modified from Ulmishek, 2003

The West Siberian Basin is an intra-cratonic sag basin containing over 4,000 m (13,000 ft) of Mesozoic and Cenozoic sediments. Basement rocks of Paleozoic age were deeply eroded prior to the Triassic period, with subsequent early Triassic continental rifting primarily responsible for the formation of the basin. Major Triassic rifts and faults are oriented in a predominantly north-south alignment, influencing the structural alignment of large anticlines and synclines that formed in the late Mesozoic. The central tectonic element of the basin is the Triassic Koltogor-Urengoy graben, which extends 1800 km north-to-south and is 10 to 80 km wide.[2]

The majority of discovered conventional oil and gas reserves are found in gentle anticlinal uplifted structural traps, located on regional arches, Figure IX-3. Faults, where present, have a displacement of only a few tens of meters and seldom penetrate above the Lower-Middle Jurassic Tyumen Formation.

Figure IX-3. Cross-Section Across Central West Siberian Basin.
(See Figure 4 for location; vertical exaggeration 100x)

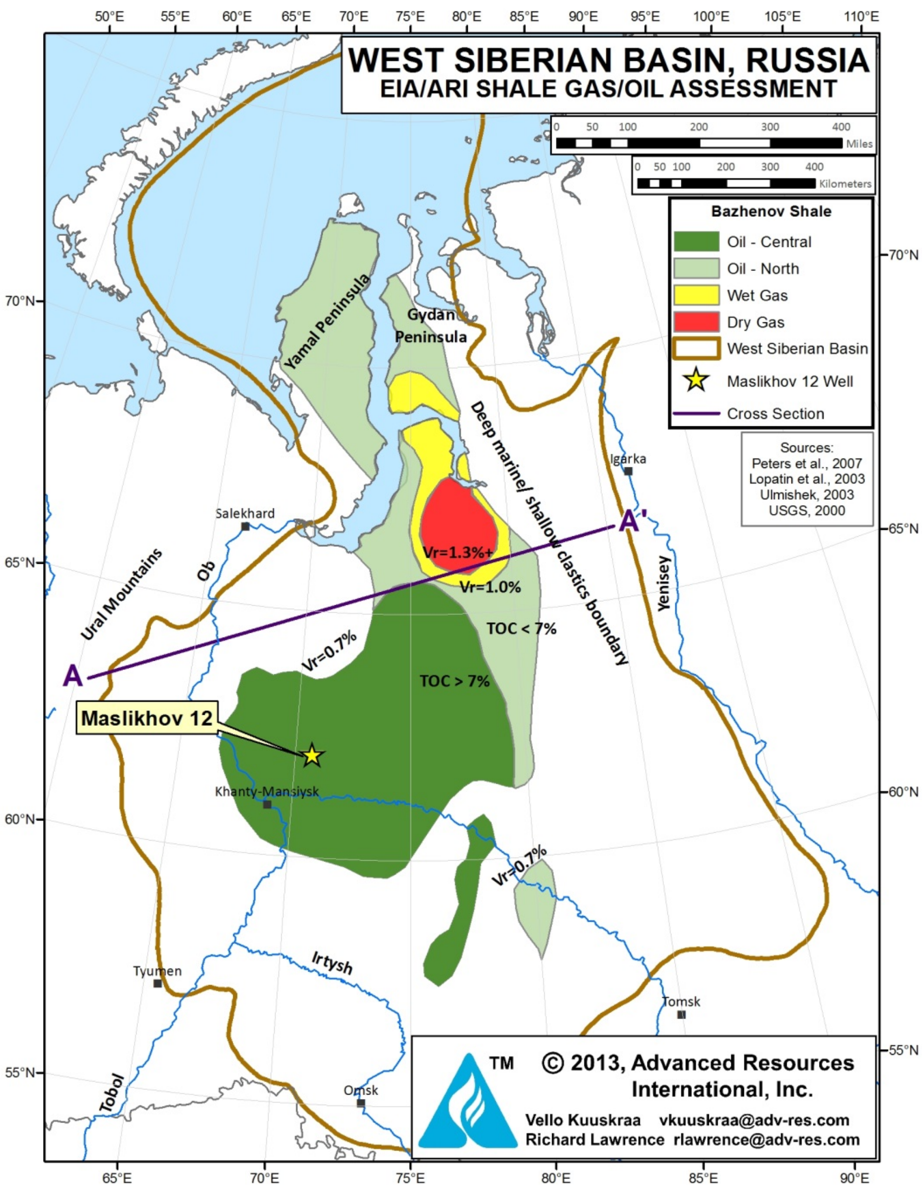
(Layer J_3 is the Bazhenov Shale)



Source: Ulmishek, USGS 2003.

We have partitioned the Bazhenov Shale in the Western Siberian Basin into two areas based on TOC and thermal maturity: Bazhenov North and Bazhenov Central.,. Bazhenov North, with a prospective area of 99,740 mi^2 and an average TOC of 5%, contains oil, wet gas/condensate and dry gas. Bazhenov Central, with a prospective area of 116,200 mi^2 and a high average TOC of 10%, is thermally mature for shale oil, Figure IX-4.[3,4]

Figure IX-4. West Siberian Basin, Prospective Areas for Shale Gas and Shale Oil



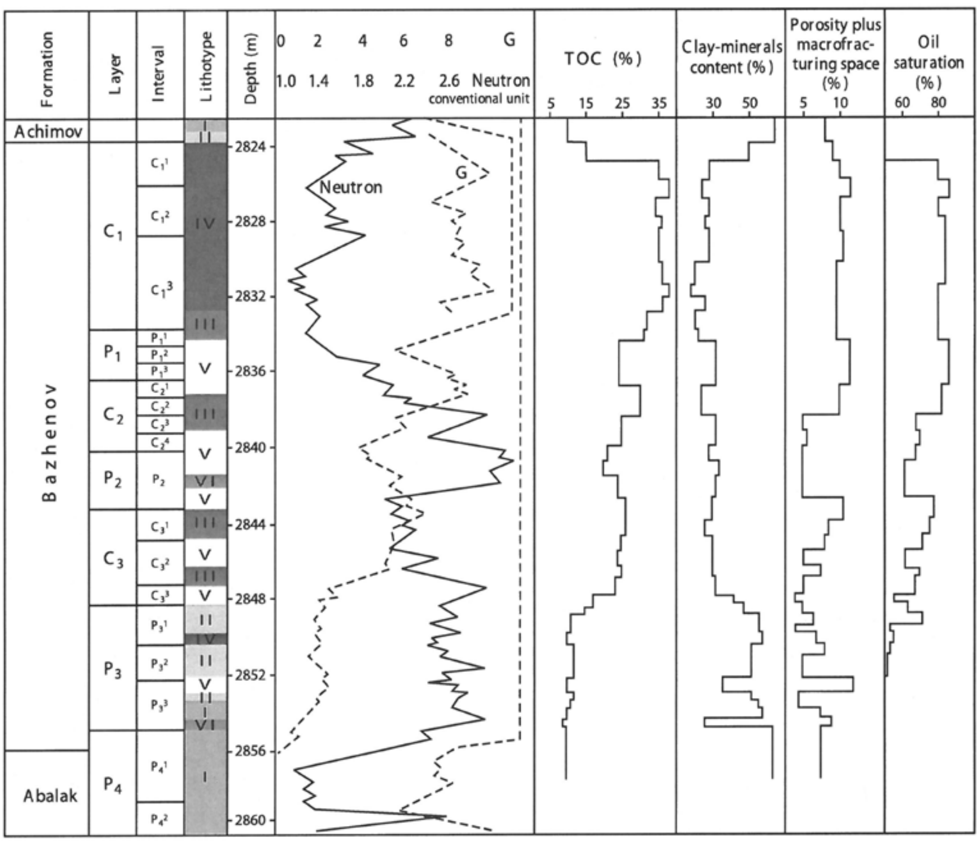
Source: ARI, 2013.

1.2 Reservoir Properties (Prospective Area)

The Upper Jurassic Bazhenov Shale is present across much of the West Siberian Basin, outcropping at the basin edges and reaching depths of over 16,400 ft (5,000 m) in the central northern region. The shale's gross thickness typically ranges from 65 to 160 ft (20 to 50 m), but can reach up to 200 ft (60 m) in localized areas.

The Bazhenov Shale was deposited in a deep marine, anoxic environment and is composed primarily of siliceous argillites, rich in planktonic Type II organic matter.[5] TOC contents are generally highest in the central region of the Basin, typically exceeding 15%, Figure IX-5.[6] TOC values decrease towards the periphery of the basin and to the north where the TOC typically ranges from 2 to 7%. TOC averages 5% in Bazhenov North and 10% in Bazhenov Central.[5]

Figure IX-5. Reservoir Properties of the Bazhenov Shale from Maslikhov Well.



Source: Lopatin et al., 2003.

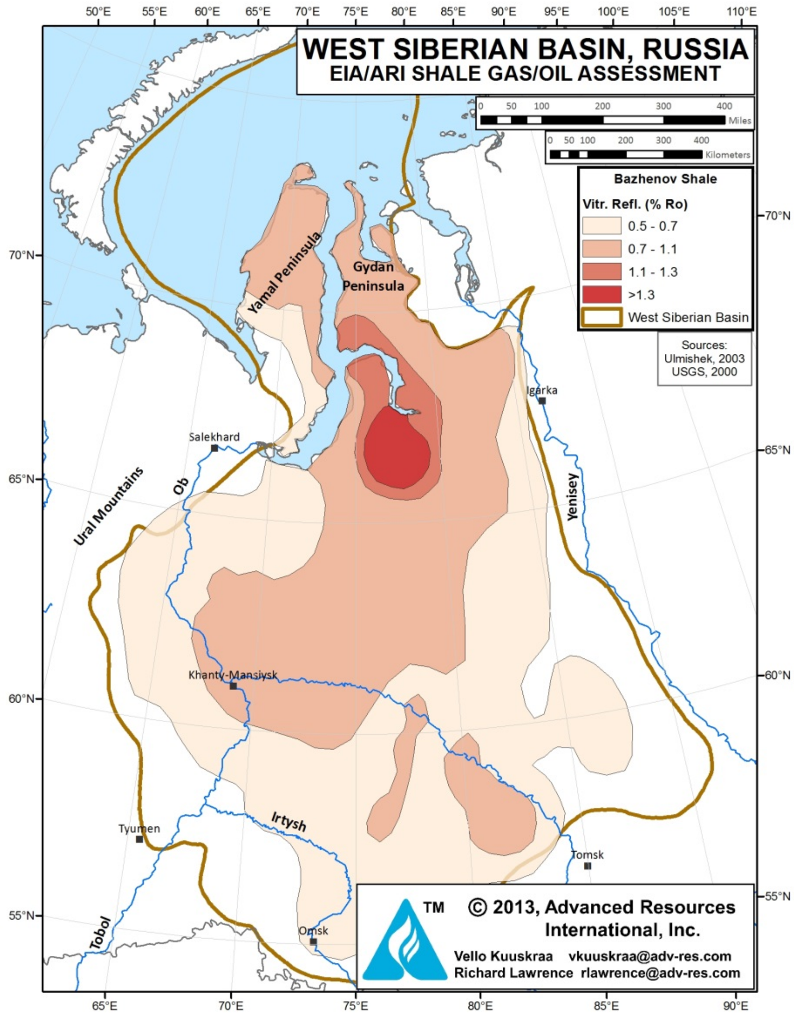
The literature describes the Bazhenov as being over-pressured, caused by oil generation and expulsion as the shales passed through the “oil window”. Measured shut-in bottom-hole pressures in the Salym oil field region are reported in some wells to be abnormally high, up to 70% above normal hydrostatic pressure.[7] Temperature gradients are also high. Clay content is usually reported as less than 20%.

The Bazhenov reservoir structure consists of layers of high-TOC shale interbedded with carbonate/dolomite layers.[8] The shales are the source of the oil, with the fractured carbonate layers providing additional reservoir capacity. This is somewhat analogous to the Bakken Shale play of North Dakota, which comprises a carbonate reservoir “sandwiched” between two oil rich/saturated shales.

Bazhenov North is prospective for oil, wet gas/condensate and dry gas. The 74,400-mi^2 area prospective for shale oil in Bazhenov North is defined by vitrinite reflectance (R_o) values between 0.7% and 1.0%, TOC content greater than 2%, and reservoir depth greater than 3,300 ft. The 14,800-mi^2 area prospective for wet gas and condensate in Bazhenov North is defined by R_o values between 1.0% and 1.3%. The 10,540-mi^2 area prospective for dry gas is defined by R_o values greater than 1.3%, Figure IX-6A. The Bazhenov North prospective area is further constrained on the east side of the basin, where the Bazhenov Shale changes from a deep marine shale to shallow clastic deposit, Figure IX-6B.

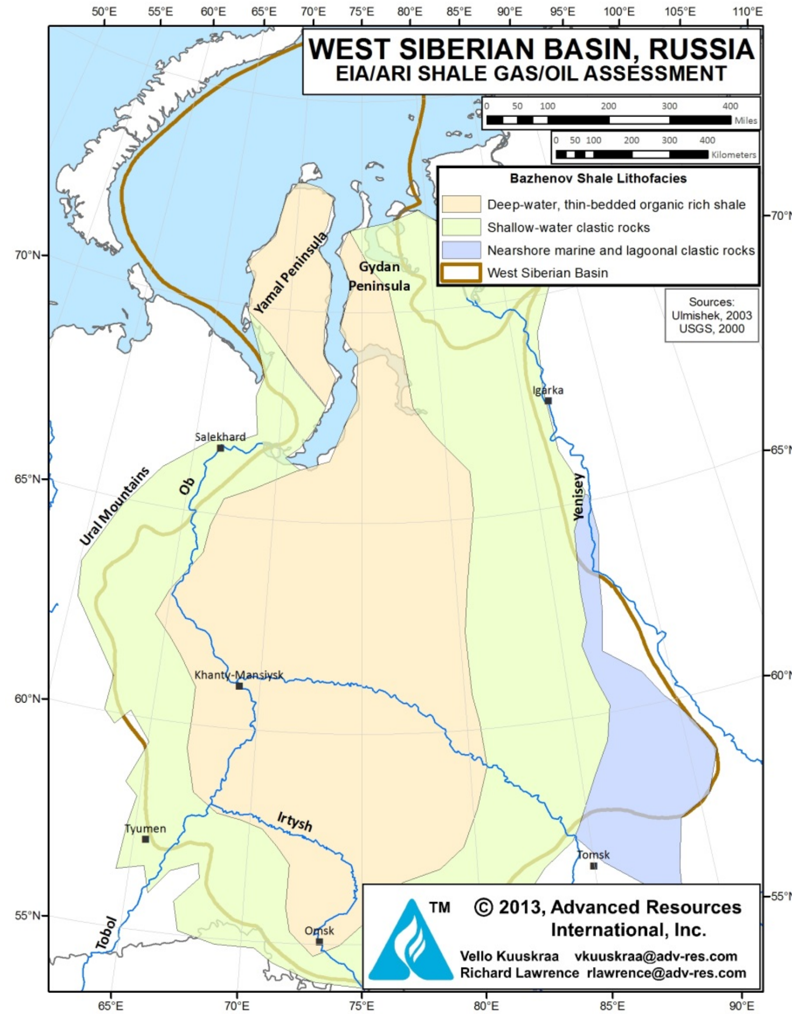
Bazhenov Central contains a 116,200-mi^2 prospective area for oil, with a thermal maturity (R_o) of 0.7 to 1.0%. The TOC content of the shale is high in Bazhenov Central, averaging 10%. Similarly, the Bazhenov Central prospective area is limited on the east by the marine shale to clastic sediments facies change.

Figure IX-6A. West Siberian Basin - Vitrinite Reflectance



Source: ARI, 2013.

Figure IX-6B. West Siberian Basin - Lithofacies Map



Source: ARI, 2013.

1.3 Resource Assessment

The shale oil in the Bazhenov North prospective area has an estimated resource concentration of 13 million barrels/mi^2 plus associated gas in the oil window; resource concentrations of 4 million barrels/mi^2 and 42 Bcf/mi^2 in the wet gas/condensate window; and a resource concentration of 66 Bcf/mi^2 in the dry gas window. The shale in the Bazhenov Central prospective area has an estimated resource concentration of 18 million barrels/mi^2 plus associated gas in the oil window.

For the total Bazhenov shale prospective area in the West Siberian Basin, we estimate a risked shale oil in-place of 1,243 billion barrels, with 74.6 billion barrels as the risked, technically recoverable shale oil resource, Table IX-1. In addition, for this prospective area, we estimate a risked shale gas in-place of 1,920 Tcf, with 285 Tcf as the risked, technically recoverable shale gas resource, Table IX-2.

In its 2011 Annual Report, Rosneft estimated the company had 4.4 billion barrels of recoverable oil resources from the Bazhenov "suite" on its license areas in Western Siberia.[9]

1.4 Recent Activity

The majority of Russia's current oil production (nearly two thirds) comes from large fields in the West Siberian Basin, located between the Ural Mountains and the Central Siberian Plateau, with the remaining oil production coming mainly from the Volga-Urals region, the Timan-Pechora Basin, the north Caucasus Region, and the Sakhelin Basin.

The oldest fields have produced since the 1940s and production rates are declining, even with the new technical focus on secondary recovery and hydro-fracturing. Exploration for conventional oil and gas is in the more remote East Siberian Basin and in the higher cost Arctic region. As such, Russian oil companies are becoming interested in the drilling and production techniques used in the U.S. to develop their unconventional oil and gas resources. Rosneft, Russia's national oil company, has signed agreements with ExxonMobil and Statoil with the aim of using horizontal drilling and large scale stimulation techniques to unlock the vast shale gas and shale oil resources of Russia.

To date, Rosneft and Exxon Mobil have announced plans to begin drilling the Bazhenov Shale in 2013, after completion of their geologic study. Gazprom Neft and Shell, as part of their West Siberia JV, proposed to start drilling the Bazhenov Shale in early 2014 near the Salym oil field, which has a history of Bazhenov Shale oil production. Lukoil has announced plans to test the Bazhenov reservoir in two area of West Siberia.[10]

Development of the Bazhenov Shale is complicated by Russia's current tax regime, which is geared towards conventional reservoirs. The Russian government is currently working on a proposal to change the mineral extraction tax (MET) for "tight oil" reservoirs with a permeability of less than 2 millidarcies (mD).[11] It is possible that shale gas and shale oil reservoirs would be incorporated into the proposed change in the MET.

2. TIMAN-PECHORA BASIN

The Timan-Pechora Basin covers an onshore area of about 122,000 mi^2 on the Arctic Circle of northern Russia, Figure IX-1. The principle source rock in this basin is the Upper Devonian (Frasnian) organic-rich shale in the Domanik Formation.[12]

These source rocks, composed of thin-bedded, dark siliceous shales, limestones and marls, were deposited in a deep water marine setting. The source rocks contain Type I and II kerogen with total organic content (TOC) ranging from 1% to 15%, typically averaging 5%[13]. These source rocks are present, with adequate thickness and maturity, over much of the Timan-Pechora Basin except for the southwestern margin. With thermal maturity of 0.6% to 1.0%, these source rocks are primarily in the oil window. The mineralogy of the shale appears to be favorable, with low (<10%) clay.[14]

While the gross thickness of the Domanik interval can range from 100 m to 300 m (330 to 1,000 ft), publicly available information is lacking on its net organic-rich interval, its porosity and pressure. The Domanik Formation has been correlated with the Duvernay Formation/Shale in Western Canada Sedimentary Basin.[13]

At current time, the publicly available geologic and reservoir data are insufficient to prepare a quantitative shale oil and gas resource assessment for the Domanik Shale in the Timan-Pechora Basin. Other source rocks and shales also exist in this basin, but have been excluded from the assessment. The Late Jurassic to Early Cretaceous (Kimmeridgian) shales in this basin have high TOC but are reported to be thermally immature. The Silurian-Ordovician shales in this basin appear to have low TOC of 0.5% to 1.5%.[12]

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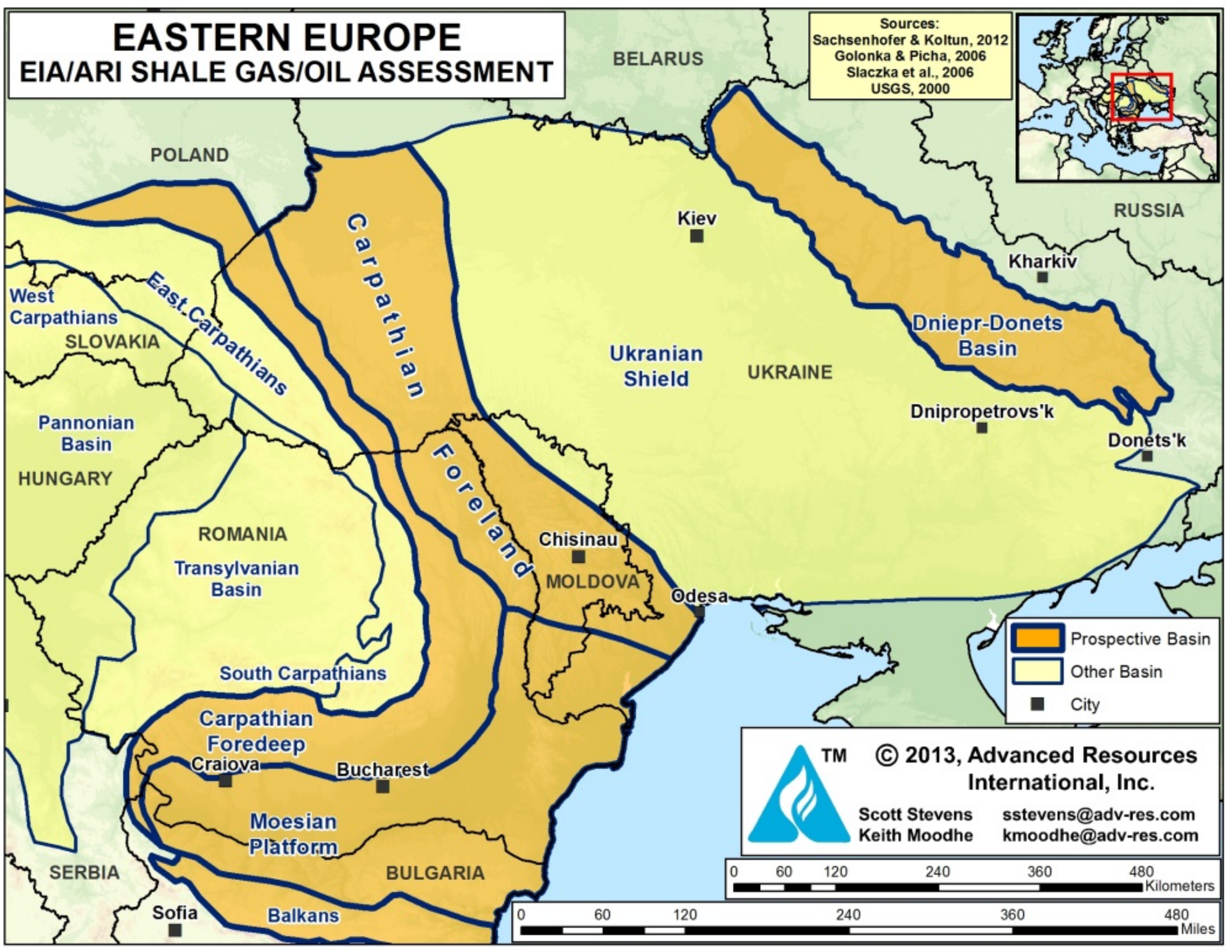
X. EASTERN EUROPE (BULGARIA, ROMANIA, UKRAINE)

SUMMARY

Eastern Europe (ex. Poland, assessed separately) has significant prospective shale gas and oil resources in three sedimentary basins: the Dniepr-Donets Basin, the Carpathian Foreland Basin, and the Moesian Platform, Figure X-1. Shale exploration is underway in Ukraine and Romania, while Bulgaria currently has a moratorium on shale development.

Figure X-1: Prospective Shale Basins of Eastern Europe



Source: ARI, 2013.

The total risked, technically recoverable shale resource potential for the three basins is estimated at 195 Tcf of shale gas and 1.6 billion barrels of shale oil and condensate, Tables X-1 and X-2. Our new, larger interpretation of the shale resource is based on recent shale leasing, drilling, and seismic activities that were stimulated in part by the 2011 EIA/ARI study.

Table X-1: Shale Gas Reservoir Properties and Resources, Eastern Europe.

Basic Data	Basin/Gross Area		Carpathian Foreland ($70,000\ mi^2$)	Dniepr-Donets ($23,200\ mi^2$)			Moesian Platform ($45,000\ mi^2$)		
	Shale Formation		L. Silurian	L. Carboniferous			L. Silurian		Etropole
	Geologic Age		L. Silurian	L. Carboniferous			L. Silurian		L. Jurassic
	Depositional Environment		Marine	Marine			Marine		Marine
Physical Extent	Prospective Area (mi^2)		16,080	1,460	2,680	6,010	840	760	7,940
	Thickness (ft)	Organically Rich	1,000	700	700	700	600	600	650
		Net	400	350	350	350	450	450	260
	Depth (ft)	Interval	3,300 - 16,400	3,300 - 16,400	3,300 - 16,400	3,300 - 16,400	6,600 - 16,400	13,000 - 16,400	5,000 - 16,400
		Average	10,000	11,000	12,000	13,000	11,000	14,000	10,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Mod. Overpress.	Mod. Overpress.	Normal	Normal	Highly Overpress.
	Average TOC (wt. %)		2.0%	4.5%	4.5%	4.5%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		2.50%	0.90%	1.15%	2.00%	1.15%	2.00%	1.15%
	Clay Content		Medium	Low	Low	Low	Medium	Medium	Medium
Resource	Gas Phase		Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas	Wet Gas
	GIP Concentration (Bcf/mi^2)		112.7	49.2	118.5	195.2	121.9	154.4	106.7
	Risked GIP (Tcf)		362.5	14.4	63.5	234.6	22.5	25.8	148.2
	Risked Recoverable (Tcf)		72.5	1.4	15.9	58.6	4.5	5.2	37.1

Source: ARI 2013.

Table X-2: Shale Oil Reservoir Properties and Resources, Eastern Europe.

Basic Data	Basin/Gross Area		Dniepr-Donets ($23,200\ mi^2$)		Moesian Platform ($45,000\ mi^2$)	
	Shale Formation		L. Carboniferous		L. Silurian	Etropole
	Geologic Age		L. Carboniferous		L. Silurian	L. Jurassic
	Depositional Environment		Marine		Marine	Marine
Physical Extent	Prospective Area (mi^2)		1,460	2,680	840	7,940
	Thickness (ft)	Organically Rich	700	700	600	650
		Net	350	350	450	260
	Depth (ft)	Interval	3,300 - 16,400	3,300 - 16,400	6,600 - 16,400	5,000 - 16,400
		Average	11,000	12,000	11,000	10,000
Reservoir Properties	Reservoir Pressure		Normal	Mod. Overpress.	Normal	Highly Overpress.
	Average TOC (wt. %)		4.5%	4.5%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.90%	1.15%	1.15%	1.15%
	Clay Content		Low	Low	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Condensate	Condensate
	OIP Concentration ($MMbbl/mi^2$)		45.3	18.1	8.9	5.0
	Risked OIP (B bbl)		13.2	9.7	1.6	7.9
	Risked Recoverable (B bbl)		0.66	0.48	0.08	0.40

Source: ARI 2013.

Advanced Resources International, Inc.

The main shale targets in Eastern Europe are marine-deposited black shales within the Lower Carboniferous of the Dniepr-Donets Basin (TRR of 76 Tcf and 1.2 billion barrels); the Silurian of the Carpathian Foreland Basin (73 Tcf); and the Silurian and Jurassic Etropole shale deposits of the Moesian Platform (47 Tcf and 0.5 billion barrels). By country, the estimates are Ukraine (128 Tcf and 1.2 billion barrels); Romania (51 Tcf and 0.3 billion barrels); and Bulgaria (17 Tcf and 0.2 billion barrels). Compared with North America, the shale geology of Eastern Europe is more complex, although faulting appears less prevalent than in other parts of Europe.

Shale resource assessments are reported to be underway in Ukraine, Romania, and Bulgaria but no official assessments have been published yet. To date only one shale-focused exploration core well has been drilled in the region (Bulgaria); no production testing has occurred. In Ukraine, Shell recently signed a Production Sharing Agreement in the Dniepr-Donets Basin, committing at least $200 million for exploration, while Chevron reportedly has been negotiating for a block in the Ukraine portion of the Carpathian Foreland Basin. Chevron's previously awarded shale blocks in Romania and Bulgaria have been put on hold.

INTRODUCTION

Since EIA/ARI's initial shale assessment first defined the potential in 2011, several Eastern European countries have begun to investigate their shale gas/ and shale oil resource potential. International oil and gas companies, including Chevron and Shell, have negotiated shale exploration licenses in Bulgaria, Romania, and Poland. The countries of Eastern Europe are taking various approaches to shale exploration. Ukraine currently welcomes shale investment. On the other hand, Bulgaria and Romania have placed shale exploration on hold, after initially proceeding with shale leasing.

Ukraine. The Ukraine State Service of Geology and Mineral Resources (Gosgeonedra) has announced shale gas resources in the country of 7 trillion m^3 (Tm^3) or 247 Tcf.[1] However, the basis for this estimate has not been released and the figure includes some tight gas resources. The newly created Geological Research and Production Center in Poltava plans to coordinate shale gas studies in Ukraine, while monitoring water quality in drilling areas. Ukraine's current Production Sharing Agreement (PSA) involves a 5-year exploration period and up to 45 years for development. Tender fees are modest: $60,000 for the tender and $10,000 for the geologic information package.

On February 23, 2012 the Ukraine government announced a tender for shale exploration and development in the Oleska and Yuzovska blocks of western and eastern Ukraine, respectively. Shell, ExxonMobil, Chevron, ENI, and TNK-BP initially responded to the tender. In January 2013, Ukraine awarded the first shale gas PSA, signing with Shell at the World Economic Forum in Davos, Switzerland. Shell's 50-year PSA permit at Yuzovska in the eastern Dniepr-Donets Basin covers an area of 7,886 km^2 and assigns oil and gas rights to all strata to a depth of 10 km, including tight and basin-centered gas. The contract allows for 70% investor recovery and a 16.5% government revenue share.

Chevron has been in negotiations with the government for a PSA at the Oleska field in western Ukraine. This block is along strike with Poland's Lublin basin, where Chevron already holds shale licenses. Duration and terms likely would be similar to those granted to Shell.

Bulgaria. While the country lacks a shale-specific investment regime, Bulgaria's conventional oil and gas production terms are attractive. Production licenses extend for 35 years, with royalties ranging from 2.5% to 30% on a sliding scale, with a 10% corporate income tax. The Economy and Energy Minister has suggested that Bulgaria's shale gas resources could be in the range of 0.3 to 1.0 Tm^3 (11 to 35 Tcf), but no supporting study has been released. The Shale Gas Research Group, a newly formed consortium of Sofia University and Bulgaria's Institutes of Geology and Organic Chemistry, is conducting long-term studies of organic-rich shale deposits in Bulgaria.[2]

However, during the past year public opposition to shale gas development has increased dramatically in Bulgaria. This opposition has been led by environmental organizers, with no effective counter-balancing information campaign offered by the petroleum industry or the government, such as exists in Poland. In January 2012 the government banned all shale gas exploration and production, whether or not it involves hydraulic fracturing. The performance of the shale industry in Poland and the UK is expected to influence the future political acceptance and government policies in Romania and Bulgaria.[3]

Romania. Romania also recently banned shale gas exploration and production, although some local observers believe its ban would be easier to reverse than Bulgaria's. In May 2012 the newly elected Romanian government began an informal (i.e., not legislated) ban on shale gas exploration activities, pending the outcome of European-level studies on the health, safety, and environmental aspects of shale gas development.

Romania lacks specific regulations for shale gas development, thus shale applications fall under the country's conventional petroleum terms. In 2011 the National Agency for Mineral Resources, which regulates petroleum operations in Romania, initiated a study of the country's shale gas deposits, in cooperation with the national research institute GeoEcoMar and three universities (Bucharest, Iasi and Cluj). No further details are available.

More than a dozen companies have expressed interest in shale gas exploration in Romania. Beginning in March 2012 Chevron was awarded four shale gas exploration licenses totaling 9,000 km^2, three blocks located in Dobruja and one in the Moldova region. Hungary's MOL was awarded three shale gas permits in northwestern Romania (Voivozi, Adea, and Curtici). Sterling Resources and partner TransAtlantic Petroleum jointly hold the 5,800-km^2 Sud Craiova license of southwest Romania. Finally, state-owned energy firm Romgaz reported that it discovered shale gas resources in 5 out of 20 of its exploration wells in Transylvania, noting that it had applied hydraulic fracturing technology in Romania as early as the mid-1990's. All of these projects are on hold due to Romania's shale ban.

GEOLOGIC OVERVIEW

Eastern Europe has three distinct shale-prospective areas with shale gas and oil potential in Paleozoic and Mesozoice marine-deposited black shales. Within the Paleozoic, the Carboniferous and Silurian black shales are most prospective, while the mid-Jurassic shales are most prospective for oil and gas within the Mesozoic. Other organic-rich shales exist locally but these tend to be less widespread and/or are thermally less mature, and thus were not assessed.

- **Carpathian Foreland Basin.** The moderately complex Lviv-Volyn Basin of western Ukraine is similar to the Lublin Basin in southeast Poland. However, the Silurian black shale belt becomes structurally simpler as it trends towards the southeast across southwestern Ukraine and northern Romania until it reaches the Black Sea. This deep Paleozoic belt north of the Carpathian Foldbelt is called the Carpathian Foreland Basin.
- **Dniepr-Donets Basin.** This well-defined Late Paleozoic basin in eastern Ukraine and southern Belarus contains prospective organic-rich L. Carboniferous black shales.
- **Moesian Platform.** Silurian and Jurassic black shales are present across Romania and Bulgaria. Note that the Moesian Platform shale plays are less well defined than the previous two plays and may be considerably larger than assessed here.

Other basins in Eastern Europe contain organic-rich source rock shales but these were deemed to be less prospective. The large Pannonian-Transylvanian basin of Hungary, Romania, Serbia and Montenegro, Slovenia, and Bosnia and Herzogovina has Paleozoic shale which appears too deep for shale development. The Carpathian, Balkan, and related fold belts appear much too structurally complex to be prospective.

1. CARPATHIAN FORELAND BASIN (UKRAINE-ROMANIA-MOLDOVA)

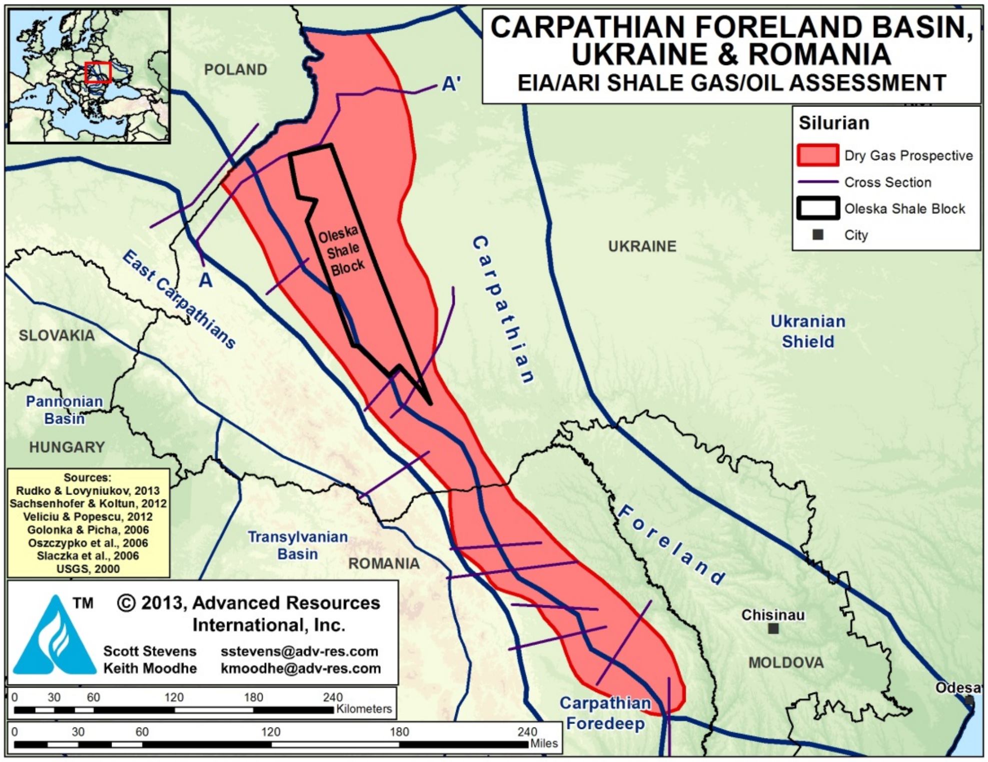
1.1 Introduction and Geologic Setting

Prospective marine black shales of Silurian age extend continuously within a 50- to 200- km wide Paleozoic belt, from Poland all the way to the Black Sea. In western Ukraine, Silurian deposits of southeast Poland's Lublin Basin continue into the adjoining Lviv-Volyn Basin, where 62 conventional oil and gas fields have been developed. Much of the Lviv-Volyn Basin appears to be too deep and faulted for shale development.

However, the Silurian belt becomes wider and structurally simpler as it continues further to the southeast across western Ukraine and northern Romania, Figure X-2. After some tectonic disturbance, the Silurian belt re-enters southern Ukraine and eastern Romania in the Scythian Platform before heading out into the Black Sea. It then briefly re-emerges onto land on the Crimean Peninsula near Odessa before continuing offshore. The North Dobrogea Orogen separates this belt from the Silurian of the Moesian Platform to the south[4], which was separately assessed. We refer to the Silurian belt as the Carpathian Foreland Basin, but other researchers have named it the Lviv-Moldava Slope.[5]

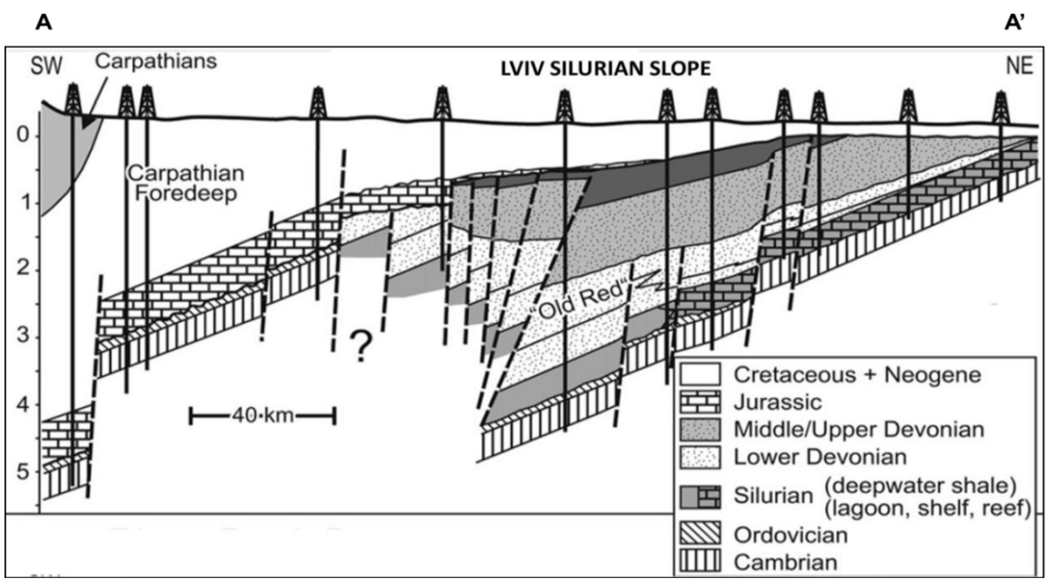
The Carpathian Foreland Basin has good shale gas development potential in Silurian black shales. As the foreland basin to the Carpathian thrust belt, this shale belt dips gently to the southwest and is characterized by mostly simple structure with few faults, Figure X-3. Further to the south, the structurally complex Carpathian region also contains multiple rich marine source rocks. These include the 500-m thick Jurassic Kokhanivka Formation with up to 12% TOC, the 200-m thick L. Cretaceous Spas and Shypot formations with 2-7% TOC, and the Oligo-Miocene Lower Menilite Formation with up to 20% TOC. However, the Carpathian region is intensely faulted with complex nappe tectonics, Figure X-4,[6,7] and was not assessed.

Figure X-2: Carpathian Foreland Basin Showing Shale-Prospective Areas.



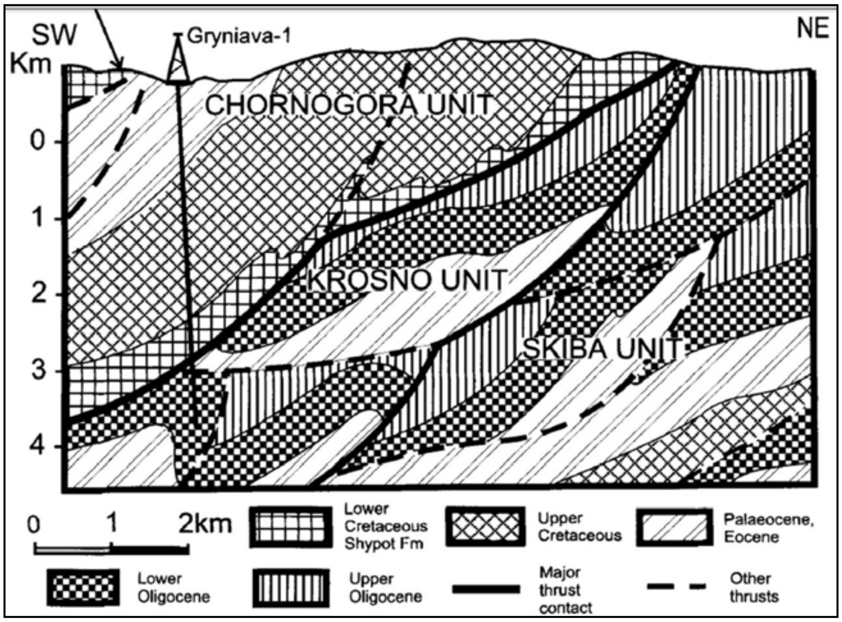
Source: ARI 2013

Figure X-3: Cross-Section of Lviv Slope Portion of the Carpathian Foreland Basin in Western Ukraine



Source: Sachsenhofer et al., 2012

Figure X-4: Cross-Section of a Nappe Structure in the Carpathian Thrust Belt

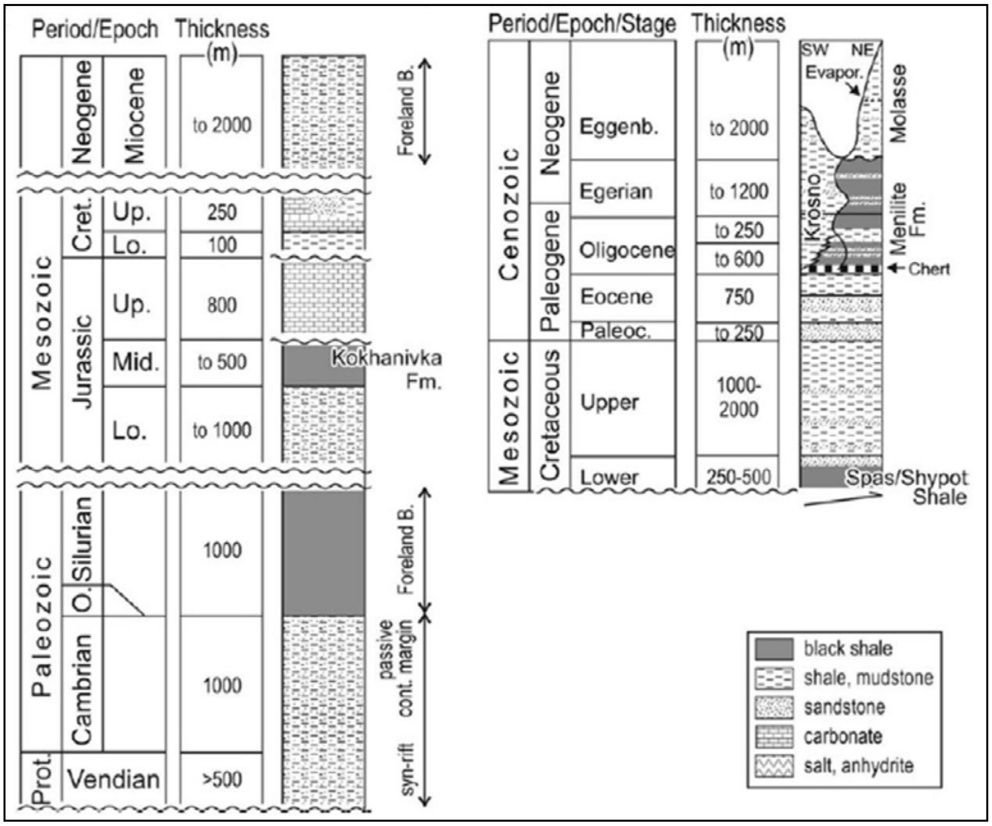


Source: Koltun et al., 1998

The Silurian is the main petroleum source rock and shale gas exploration targets in the Carpathian Foreland Basin, Figure X-5. Compared with Poland, the reservoir characteristics of the Silurian shale in western Ukraine are less certain. About 400 to 1,000 m of deep-water Silurian shale is present, transitioning eastward into thinner, shallow-water carbonates. The Ludlow member of the Silurian is considered the most prospective interval. The Ludlow ranges from 400 to 600 m thick and occurs at depths of 2 to 3 km in western Ukraine.

Silurian shale TOC may be lower in Ukraine than in Poland, at least based on the single well data point available (IS-1). Most TOC measurements at a depth range of 1,400 to 1,592 m in this well were less than 1%. However, the original TOC is estimated at 3% prior to thermal alteration. Given the depositional environmental of the Silurian, it is likely that higher TOC exists in places. Thermal maturity mapping, calculated from conodant alternation index, indicates the Silurian is entirely in the dry gas window (R_o of 1.3% to 3.5%). Several (possibly spurious) over-mature values of 5% R_o also were measured. Maturation is believed to have occurred prior to the Mesozoic. As Sachsenhofer and Koltun (2012) noted: “additional investigations are needed to investigate lateral and vertical variations of TOC contents and refine the maturity patterns in Lower Paleozoic rocks.”

Figure X-5: Stratigraphy of Carpathian Foreland Basin Showing Thick Black Shales of Silurian and Mid-Jurassic-Age (left). L. Cretaceous and Paleogene Source Rocks Occur in the Carpathians (right).



Source: Sachsenhofer et al., 2012

The Kovel-1 petroleum well is a key stratigraphic test drilled during the late 1980s in western Volynia, northwestern Ukraine. The well is located along the transition between the structurally complex Lublin-Lviv basins on the west and the less deformed Volynia region of the Slope. The Kovel-1 well cored Ordovician at a depth of about 250 m; Silurian apparently had been eroded in this uplifted location.[8]

1.2 Reservoir Properties (Prospective Area)

Based on geologic control from regional cross-sections, the total estimated shale gas prospective area in the Carpathian Foreland Basin is estimated to be approximately 16,080 mi^2, of which 11,520 mi^2 is in Ukraine and 4,560 mi^2 in Romania. The target organic-rich portion of the 500-m thick Ludlow Member of the Silurian is estimated to average 1,000 ft thick gross and 10,000 ft deep within the prospective region, and have 4% porosity. TOC averages a relatively low 2.0% and is in the dry gas window (R_o average 2.5%). The pressure gradient is assumed to be hydrostatic (0.43 psi/ft).

1.3 Resource Assessment

Risked, technically recoverable resources from Silurian black shale in the Carpathian Foreland Basin are estimated to be 73 Tcf (52 Tcf in Ukraine and 21 Tcf in Romania), out of a risked shale gas in-place of 363 Tcf, Table X-1. The play has a moderately high resource concentration of about 113 Bcf/mi^2, reflecting the significant thickness of the organic-rich shale that is present.

Ukraine's State Commission on Mineral Resources has estimated that the Oleska shale gas license area in the Lviv-Volyn Basin has about 0.8 to 1.5 trillion m^3 (28 to 53 Tcf) of shale gas resources. Whether this estimate reflects in-place or recoverable resources was not specified.

An independent assessment of Silurian shale gas resources in the Romanian portion of the Carpathian Foreland Basin arrived at a Mean Estimate of 5.6 Tcf technically recoverable out of 279 Tcf of gas in-place. This estimate utilized EIA/ARI's 2011 methodology, but key assumptions (thickness, porosity, risk) were not specified, nor was Ukraine evaluated.[9]

1.4 Recent Activity

Chevron reportedly is in negotiations with the government to develop a shale gas project in the Oleska block of western Ukraine. The government recently removed its self-imposed deadline of May 2013 for completing this deal. Chevron also initially acquired the 6,257-km^2 Barlad shale gas permit in northeastern Romania close to Moldova, but the status of this block is unclear following the shale ban in Romania.

In 2012 ENI acquired half of LLC WestGasInvest, which controls nine unconventional gas licenses totaling 3,800-km^2 in the Lviv Basin of western Ukraine, which may include shale gas potential. The company and its partners, including UK-based Cadogan Petroleum, plan to spend about $55 million exploring for shale gas in the Lviv basin from 2012 through 2015.

2. DNIEPR-DONETS BASIN (EAST UKRAINE)

2.1 Introduction and Geologic Setting

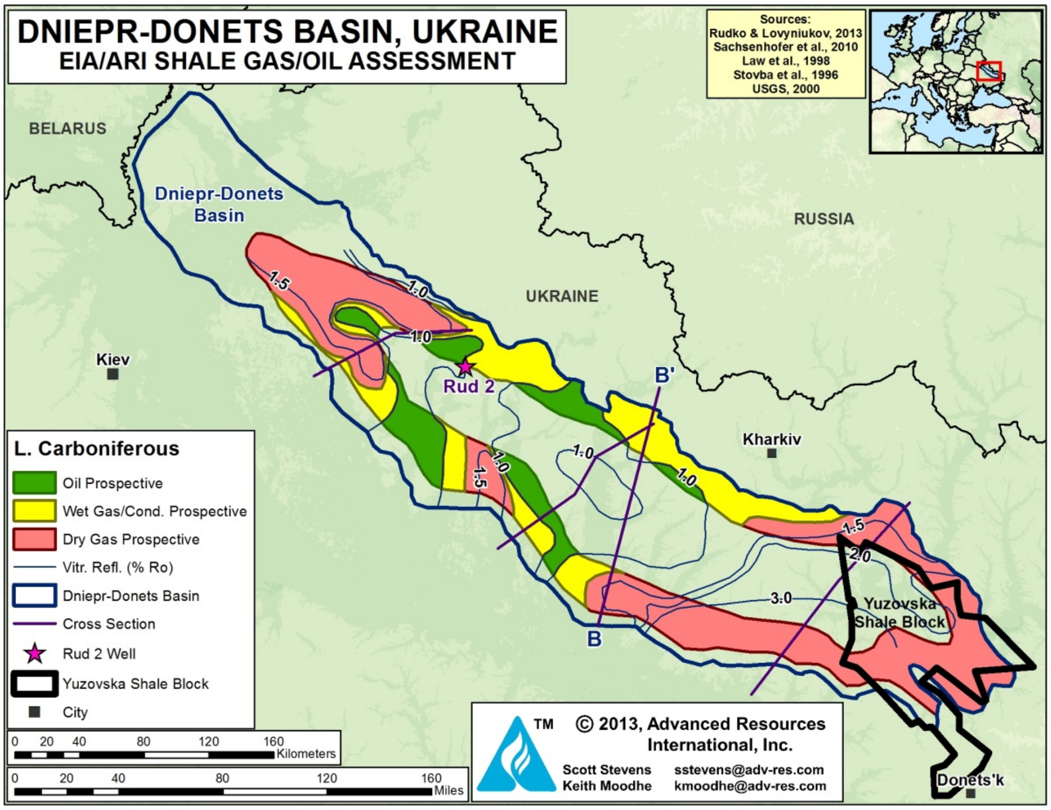
The Dniepr-Donets Basin (DDB) in eastern Ukraine is a Mid-to Late-Devonian failed rift basin on the Eastern European Craton, Figure X-6. The basin contains a thick sequence of Lower Carboniferous black shale which may be prospective for oil and gas development. Economically important Carboniferous coal deposits and tight sands of the Moscovian overlie these shales,[10] but this coaly sequence does not appear to be a prospective shale target.

The DDB accounts for most of Ukraine's onshore petroleum reserves and is comparatively well understood, with several thousand oil and gas wells, some of which reached depths of over 5 km. Lower Carboniferous black shales and coal seams are the main source rocks, while overlying clastic Carboniferous sandstones provide conventional reservoirs within mainly structural traps. To the northwest the DDB continues into the Pripyat Trough of southern Belarus, which appears to be too shallow and low in TOC for shale development. To the southeast the basin continues into the Donbas Foldbelt of southwestern Russia.

Roughly symmetrical, the DDB is about 700 km long, 40 to 70 km wide, and trends northwest-southeast.[11] It comprises a series of half grabens bounded by large-displacement faults (h= 100 m to 2 km). The individual blocks are quite sizeable (50-100 km by 20-40 km), although numerous smaller faults are locally present. The basin contains as much as 15 km of Devonian and younger sedimentary rocks, which includes 1 to 2 km of mostly Devonian (Frasnian) salt deposited under restricted rift conditions. Figure X-7 is a structural cross-section showing depth to the L. Carboniferous (L. Visian) black shale as well as salt flows in the basin.[12]

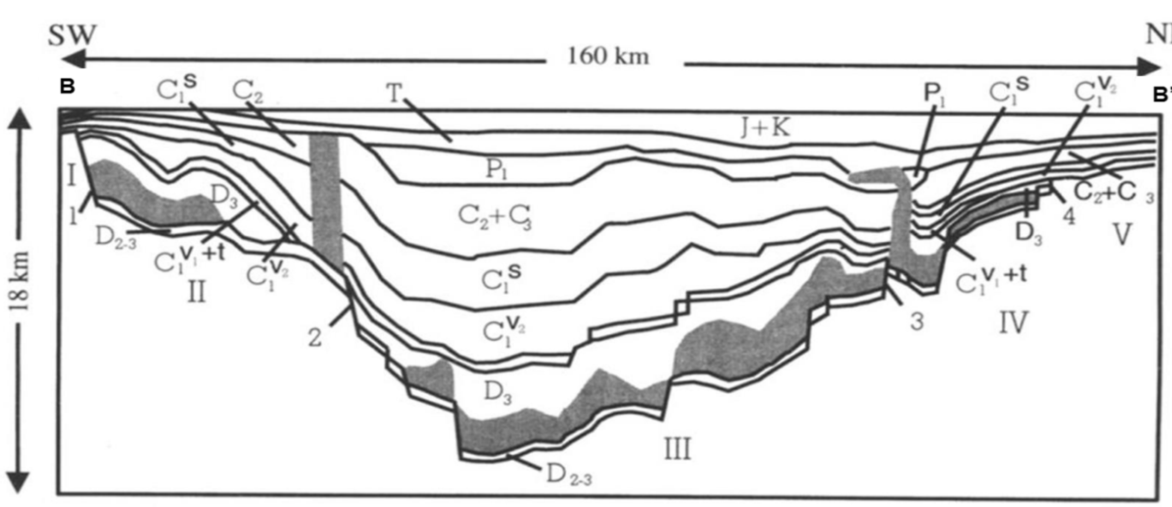
L. Carboniferous black shale overlies the Devonian salt interval. This black shale and the overlying coal seams sourced most of the conventional oil and gas fields in the basin. The entire Carboniferous section ranges up to 11 km thick in the DDB and is up to 15 km deep near its base along the basin axis. In the northwest portion of the DDB the Carboniferous is continental in origin, but transitions into partly shallow marine depositional cycles, each of which is typically 50 m thick and contains an organic-rich shallow marine shale layer.

Figure X-6: Dniepr-Donets Basin Showing Shale-Prospective Areas



Source: ARI, 2013

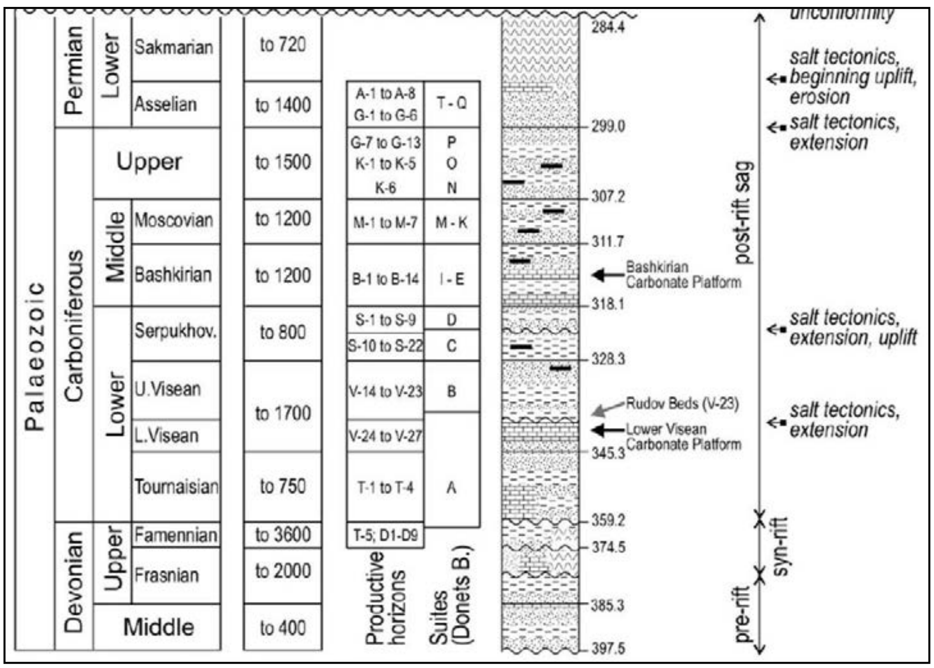
Figure X-7: Cross-Section of Dneipr-Donets Basin Showing Depth to the L. Carboniferous (L. Visian) Black Shale



Source: Stovba et al., 1996

Several black shale targets occur within the L. Carboniferous sequence, Figure 8.[13] The Upper Visean Rudov Beds are considered the best quality source rock and shale gas target. These black shales are up to 70 m thick, but more typically 30-40 m, and particularly well developed in the Srebnen and Zhdanivske depressions where they are quite deep and dry gas prone. The Rudov Beds are rich in siliceous radiolaria, making them potentially brittle, while the lower part of the formation is high in calcite as well as clay. The organic-rich middle section of the Rudov Beds has 3.0% to 10.7% TOC (average 5%), mostly Type III with some Type II kerogen. Additional slightly leaner (TOC of 3.0% to 3.5%) but still quite prospective source rocks occur in the Upper Visean above the Rudov Beds, while the lower Serpukhovian contains black shales with up to 5% TOC.

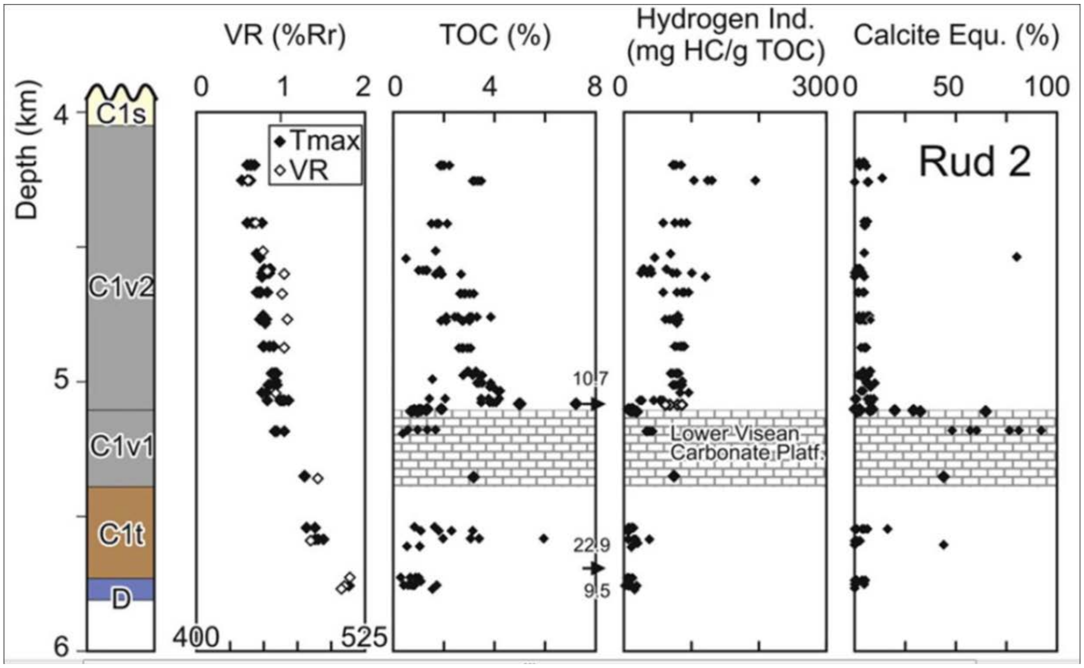
Figure X-8: Stratigraphy of Dniepr-Donets Basin. Black shales Occur in L. Carboniferous Rudov and U. Visean.



Source: modified from Sachsenhofer et al., 2010

Thermal maturity of the Rudov Beds and the overlying Upper Visean is mainly in the oil window (R_o 0.8-1.0%) in the central and northwestern DDB, increasing to dry gas maturity (R_o 1.3-3.0%) in the southeast. For example, the Rud-2 petroleum well in the Dniepr-Donets Basin penetrated a nearly 1-km thick Carboniferous Upper Visean shale interval at a depth of 4 to 5 km, **Figure X-9**. TOC of up to 4% in this interval is within the oil thermal maturity window (R_o 0.8-1.0%). The oil window in this basin appears to be normally to under-pressured, while the dry gas window is likely to be over-pressured due to ongoing gas generation, although pressure data control is poor.[14]

Figure X-9: Rud-2 Well in the Dniepr-Donets Basin, Showing the Carboniferous Upper Visean Shale (C1v2) with TOC up to 4% in the Oil Window (Ro 0.8 to 1.0%).



Source: Sachsenhofer et al., 2012

The southwest flank of the Dneipr-Donets Basin is characterized by a structurally simple dip slope, where thick L. Carboniferous black shale tilts gently to the NNE towards the basin axis. The L. Carboniferous is at ideal depth for shale development (1-5 km) over a broad belt. The northeast flank of the DDB has thinner L. Carboniferous that is structurally more complex. Lacking a detailed depth map on the Carboniferous, we constrained the depth-prospective area using basement contours and multiple published cross-sections, yielding good control on the prospective area. Note that salt intrusions up to 15 km thick may negatively impact shale potential along various parts of the slope.

2.2 Reservoir Properties (Prospective Area)

Lower Carboniferous black shales (Rudov Beds, Lower Visean, and Lower Serpukhovian) are prospective within a 10,150-mi^2 depth-controlled belt that surrounds the axis of the Dneipr-Donets Basin. These shales are estimated to total about 1 km in thickness but are relatively deep (3-5 km). They largely consist of siliceous or calcareous lithologies rich in radiolarian and thus are expected to be brittle with high porosity (6%). Gas recovery rates also should be favorable (30%) due to the inferred frackability of the shale. TOC appears favorable, averaging about 4.5%. Thermal maturity ranges from oil to dry gas. On the negative side, salt intrusions may sterilize some of the mapped prospective area (10%).

2.3 Resource Assessment

Dry Gas Window. The mapped prospective area for the dry shale gas window in southeastern Dniepr-Donets Basin is estimated at 6,010 mi^2. Lower Carboniferous shale (comprising the Rudov Beds and portions of the overlying Upper Visean) has a highly favorable resource concentration of approximately 195 Bcf/mi^2. Risked, technically recoverable shale gas resources are estimated to be 59 Tcf, out of a risked shale gas in-place of 235 Tcf.

Wet Gas Window. The wet gas prospective area of the DDB extends over about 2,680 mi^2. Risked, technically recoverable resources are estimated at 16 Tcf of shale gas and 0.5 billion barrels of condensate from in-place shale gas and shale oil resources of 63 Tcf and 10 billion barrels.

Oil Window. The smaller oil window in the northwestern Dniepr-Donets Basin covers a prospective area of about 1,460 mi^2. Risked technically recoverable resources are estimated to be about 0.7 billion barrels of shale oil and condensate and 1 Tcf of associated shale gas, out of risked in-place shale oil resources of 13 billion barrels.

Ukraine's State Commission on Mineral Resources has estimated that the Yuzovska shale gas license in the eastern Dniepr-Donets Basin has 2-3 Tm^3 (71-107 Tcf) of shale gas and tight gas resources. Whether this estimate reflects in-place or recoverable resources was not specified.

2.4 Recent Activity

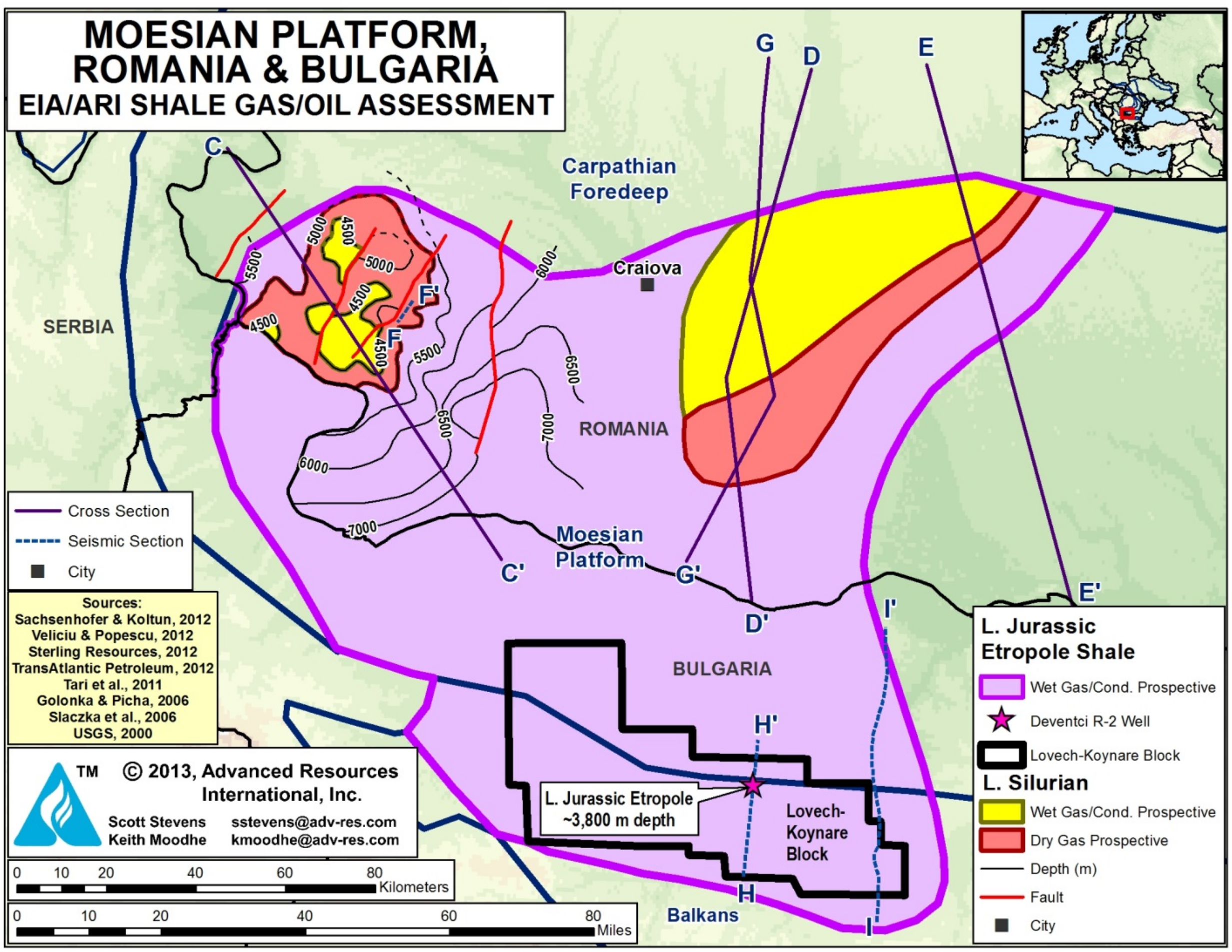
In early 2013 Shell was awarded Ukraine's first formal shale gas exploration license, the 7,800-km^2 Yuzovska PSA located on the south flank of the Dniepr-Donets Basin. Shell's first-stage investment commitment is $200 million. Previously in 2011, ENI acquired from Cadogan Petroleum portions of the Zagoryanska and Pokroskoe conventional licenses in the DDB, which may include shale potential.

3. MOESIAN PLATFORM (ROMANIA, BULGARIA)

3.1 Introduction and Geologic Setting

The Moesian Platform is a comparatively simple (for Europe) foreland basin that stretches across southern Romania and north-central Bulgaria, Figure X-10. The Platform is overthrusted by the Balkan thrust system to the south, while the Carpathian thrust system forms the northern boundary; both are Cenozoic features related to Alpine tectonics. To the east, the Moesian Platform is separated from the Carpathian Foreland Basin and on the north by the North Dobrogea Orogen. The adjacent Getic Basin of Romania, the foreland of the South Carpathians, contains similar source rocks but is more deformed by Tertiary tectonic events and considered less prospective.

Figure X-10: Moesian Platform Region Showing Shale-Prospective Areas.



Source: ARI 2013

Up to 12 km of mostly flat-lying, carbonate-rich Paleozoic and Mesozoic sedimentary rocks are present on the Moesian Platform, Figure X-11. The relatively few conventional oil and gas fields that have been discovered in this region produce mainly from mid-Triassic dolomite and occasionally from basal Jurassic sandstone. [15,16]

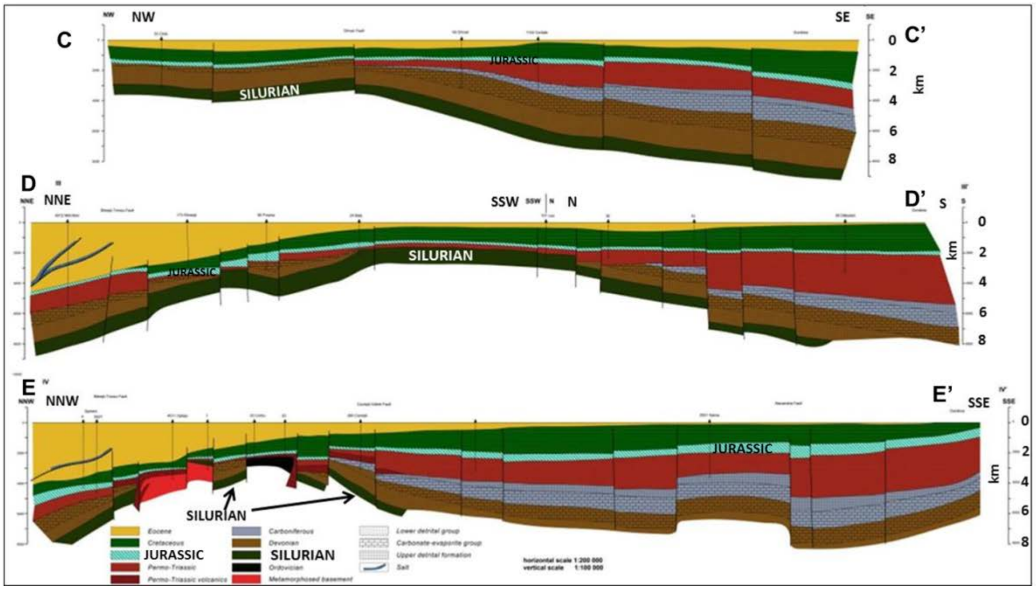
The Moesian Platform contains multiple organic-rich source rock shales that are prospective for shale gas development, Figure X-12. These include the Ordovician to Upper Carboniferous Tandarei, Vlasin, and Calarasi formations, including Silurian shales; the Jurassic Etropole Shale; the Bathonian (Dogger) shales (Bals Formation); and Mid-Miocene marls and shales (Badenian to Sarmatian). The main targets for shale gas exploration are the Silurian shale and Jurassic Etropole Shale.

The Silurian shale in the Moesian Platform is broadly similar to that targeted in Poland and the Carpathian Foreland Basin further to the north. Regional cross-sections show the Silurian ranges from 2 to over 5 km deep across the Moesian Platform. At the South Craiova Block in southwest Romania, the Silurian Llandovery Shale is at least 160 m thick, 4,050 to 4,200 m deep, and has about 3% TOC, Figures X-13 and X-14.[17] At the Bulgarian Arch in eastern Bulgaria, thick (650-m), organic-rich Silurian shales reportedly are at prospective depths of 1 to 5 km, but data were not sufficient to map this portion of the play.

The other main target in the Moesian Platform is the Jurassic Etropole Shale, considered the main petroleum source rock in northwest Bulgaria, Figure X-15. In particular its organic-rich lower portion, the Stefanetz Member, contains thick, carbonate-rich (40-50%) black shale with interbeds of marl and limestone that was deposited in a marine environment, not dissimilar to the Upper Jurassic Haynesville Shale.[18] TOC ranges from 1.0% to 4.6%,[19] with Type II kerogen predominating.[20] The Etropole Shale generally ranges from 2.5 to >5 km deep[21] and is over-pressured in much of the region, with an elevated pressure gradient of 0.78 psi/ft. Thermal maturity falls in the oil window in the north, increasing to wet and dry gas in the south near the Balkan thrust belt (R_o 1.0% to 1.5%).[22]

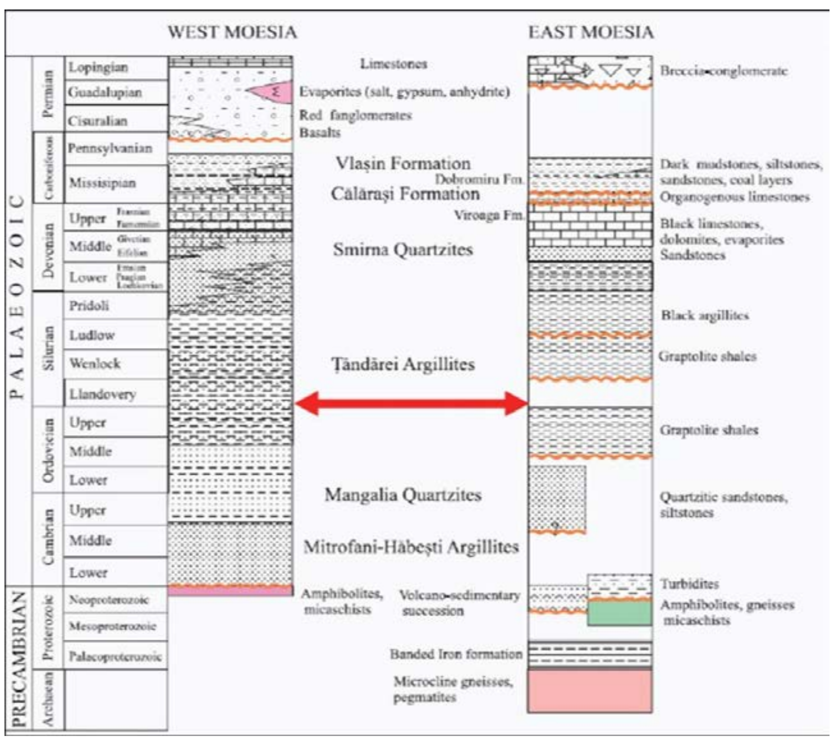
Oil and gas has been produced from conventional silty, sandy, and carbonate intervals within the Etropole Formation, such as the Peshtene R-5 well which reportedly flowed gas at an unstimulated rate of 530,000 ft^3/d. In addition, oil produced from the Jurassic Dolni Lukovit and Mid-Triassic Dolni Dabnik fields has been chemically linked back to the Etropole Shale.

Figure X-11: Regional Cross-Sections in of the Moesian Platform In Romania Showing Jurassic and Paleozoic Shale at Mostly Moderate Depth with Relatively Simple Structure.



Source: Veliciu and Popescu, 2012

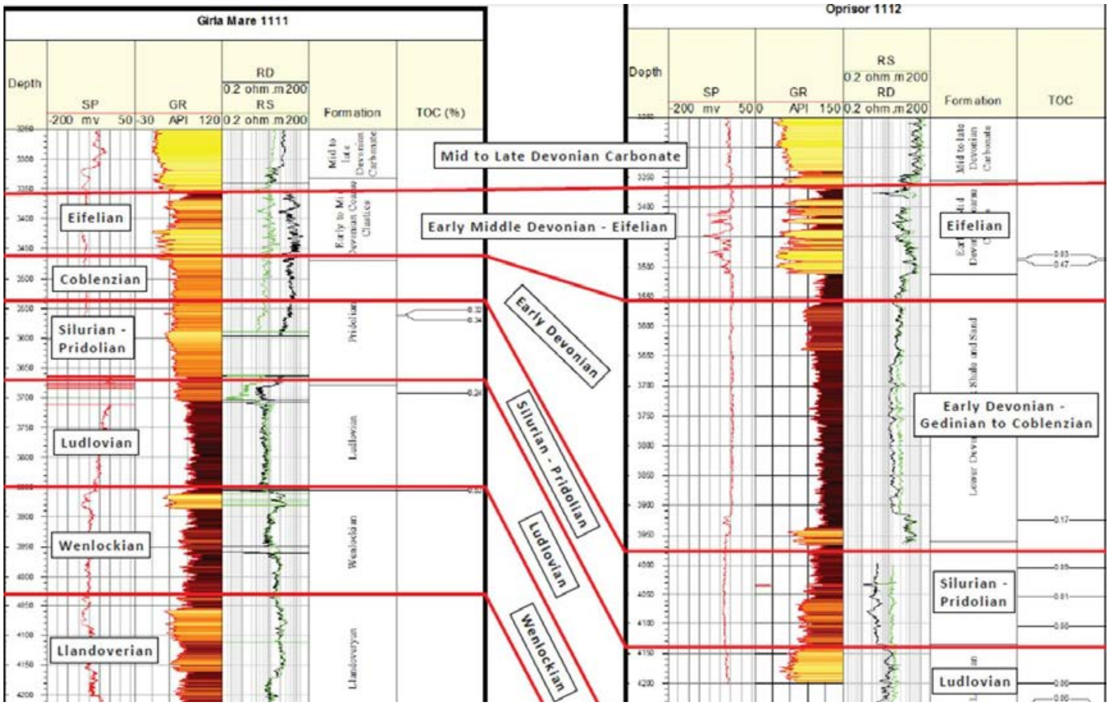
Figure X-12: Stratigraphic Column Showing L. Silurian Llandovery Shales in Southwest Romania.



Source: Sterling Resources, 2013

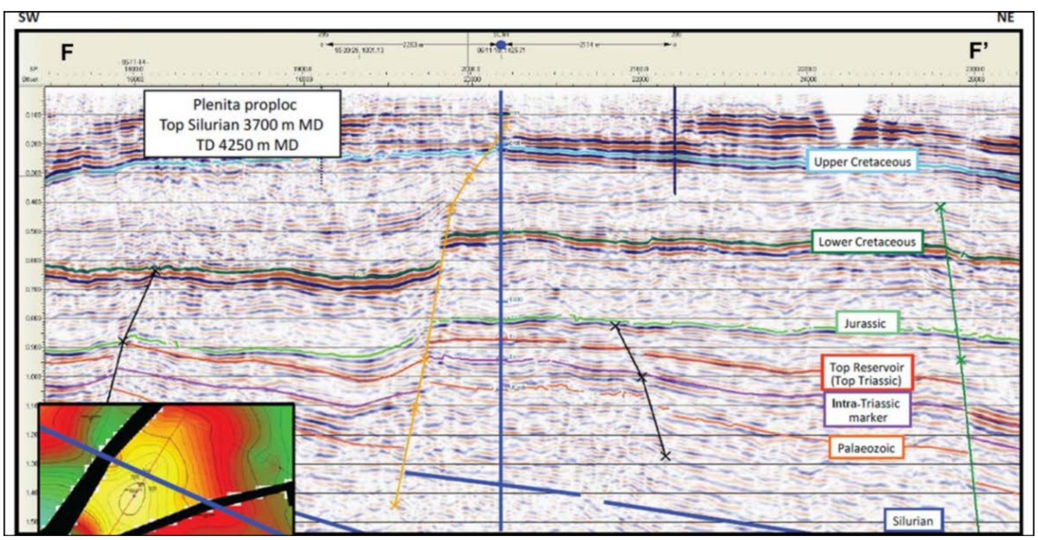
Advanced Resources International, Inc.

Figure X-13: Well Logs Showing Paleozoic Section Including L. Silurian Llandovery Shales at the South Craiova Block (EIII-7) in Southwest Romania.



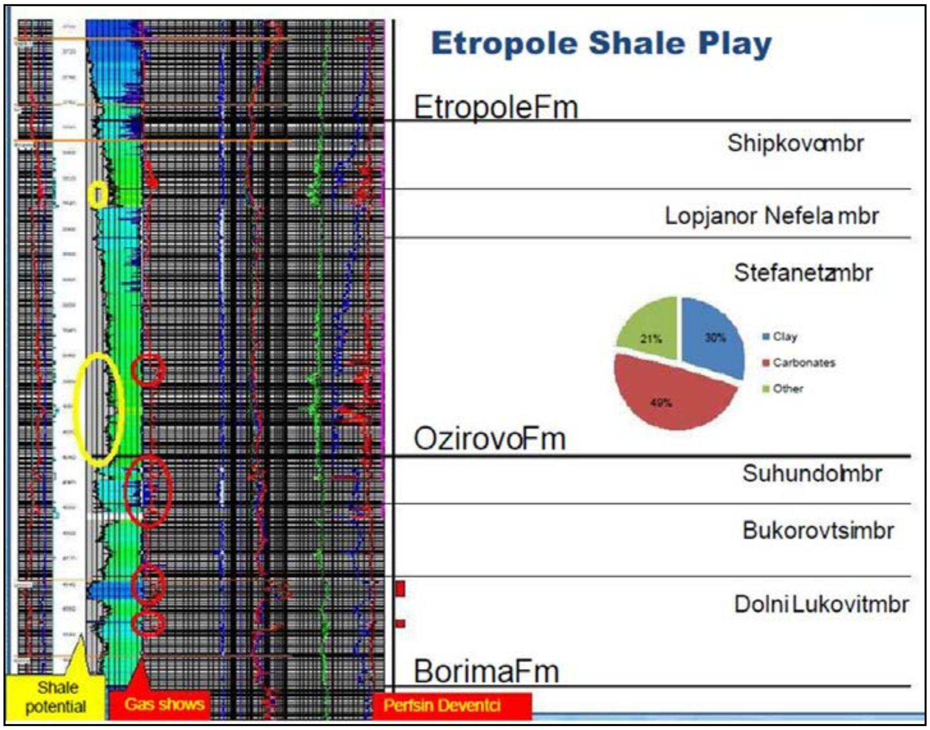
Source: Sterling Resources, 2013

Figure X-14: SW-NE Trending Seismic Line Showing Paleozoic Section Including L. Silurian Llandovery Shales at the South Craiova Block in Southwest Romania. Structure is Relatively Simple But Faults are Present.



Source: Sterling Resources, 2013

Figure X-15: Well log across the Jurassic Etropole Shale in Bulgaria

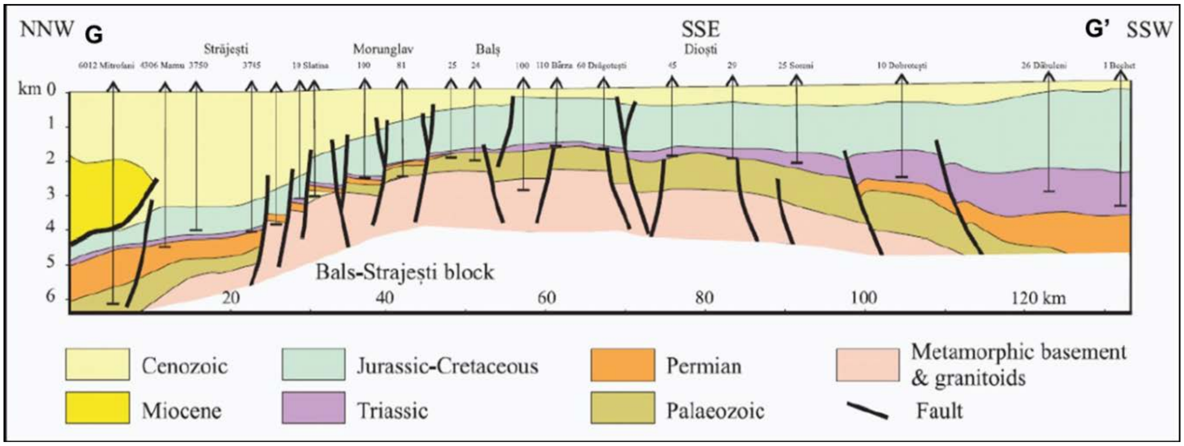


Source: TransAtlantic Petroleum Ltd, February 2011

At the Sud Craiova license in southwest Romania, operated by Sterling and TransAtlantic, the Etropole Shale ranges from 115 to over 700 m thick and 3,700 to 4,500 m deep across the block, Figure X-16. At the Lovech block in northwest Bulgaria the Etropole Shale is about 3,800 m deep, Figure X-17. Structure is fairly simple in this region, with flat lying dips cut by several faults. Other portions of the Moesian Platform lacking data control also were assumed to have relatively similar structure.

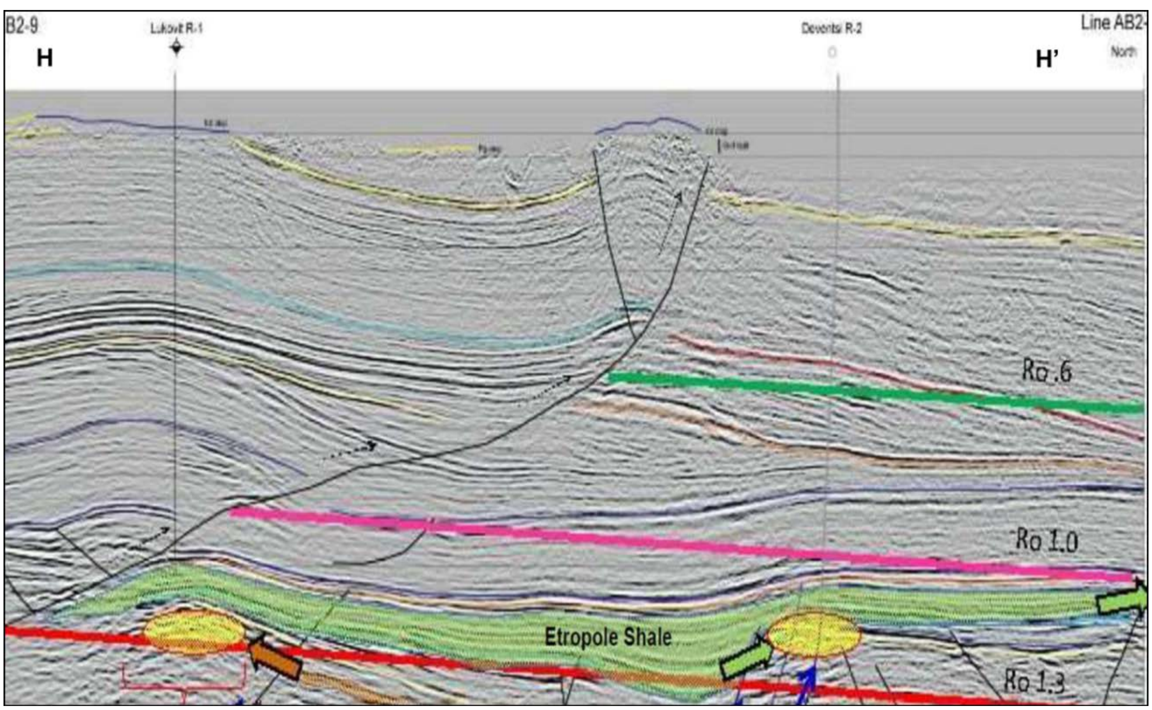
The eastern continuation of the Jurassic Etropole Shale is unclear and could not be rigorously mapped. Two time-structure transects suggest the Etropole may be present in eastern onshore Bulgaria at two-way seismic times of 0.5 to 3.0 seconds, deepening to the east into the Black Sea, Figure X-18. The Central Dobrogea Green Schist Zone, comprising uplifted blocks of Proterozoic basement blocks north of the Palazu Fault, has only a thin or no Jurassic sequence. On the other hand, the North Bulgarian Arch -- where Chevron initially was awarded a shale gas license – holds preserved Jurassic to Tertiary sedimentary sequences.[23]

Figure X-16: Regional Seismic Section Showing Jurassic and L. Silurian Llandovery Shales at the South Craiova Block in Southwest Romania. The Structural Dip is Relatively Gentle but Numerous Faults are Present.



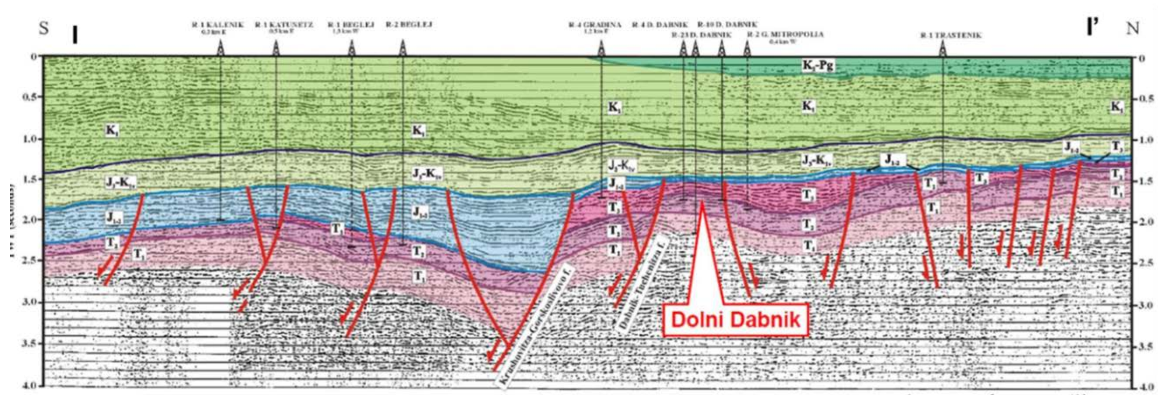
Source: Sterling Resources, 2013

Figure X-17: Jurassic Etropole Shale is about 3,800 m Deep with 1.0% to 1.3% Ro at TransAtlantic Petroleum's Lovech Block in Northwest Bulgaria.



Source: TransAtlantic Petroleum, 2011

Figure X-18: Regional Cross-Section Showing Thick Jurassic Lias and Dogger Shale Deposits in Northern Bulgaria Which Thin Markedly to the North into Romania.



Source: Tari et al., 2011

3.2 Reservoir Properties (Prospective Area)

L. Silurian Shale. The mapped prospective area for black shales in the L. Silurian totals 1,600 mi^2, all of which is located in Romania. No prospective area was identified in Bulgaria due to data limitations, although there could be prospective Silurian areas in northeast Bulgaria. Depth ranges from 2 to 5 km. Organic-rich thickness averages about 600 ft (gross). Thermal maturity ranges from wet to dry gas. TOC is estimated at 3%, porosity at about 4%.

Jurassic Etropole Shale. Black shales in the Mid-Jurassic Etropole Shale are prospective within an estimated 7,940-mi^2 area of the Moesian Platform, in northwest Bulgaria and southwest Romania. The most organic-rich shales are estimated to total about 250 m thick (gross) at moderate depth of about 10,000 ft. Porosity is assumed to be moderately high (5%). Gas recovery rates also could be favorable based on the inferred brittle lithology. TOC appears moderate, averaging about 3% in the more prospective intervals. Thermal maturity is wet gas (R_o 1.0% to 1.3%). The pressure gradient is estimated at 0.7 psi/ft.

3.3 Resource Assessment

Risked, technically recoverable shale resources in the Moesian Platform region of Romania and Bulgaria are estimated to be 47 Tcf of shale gas and 0.5 billion barrels of shale condensate, out of a risked shale gas and shale oil in-place of 196 Tcf and 10 billion barrels, respectively. Romania's share is approximately 30 Tcf and 0.3 billion barrels while Bulgaria's share is estimated at 16 Tcf and 0.2 billion barrels.

Silurian Llandovery Shale. Risked, technically recoverable shale gas resources in the Silurian shale of the Moesian Platform of Romania and Bulgaria are estimated to be 10 Tcf, out of a risked shale gas in-place of 48 Tcf.

Jurassic Etropole Shale. Risked, technically recoverable shale resource in the Jurassic Etropole Shale within the Moesian Platform of Romania and Bulgaria are estimated to be 37 Tcf out of a risked shale gas in-place of 148 Tcf, while shale oil/condensate resources are estimated at 0.4 billion barrels of condensate out of 7.9 billion barrels of risked oil in-place.

Separately, in northeastern Bulgaria, the government has estimated the 4,400-mi^2 Novi Pazar block has 0.3 to 1.0 Tm^3 (11 to 35 Tcf) of shale gas resource potential in the Devonian-Silurian silty shale. The Devonian-Silurian was reported in the study to be up to 2 km thick, 800 to 2,800 m deep, and have 3.5% sapropelic organic matter with TAI from 2 to 5.[24] However, it was not possible to map this play due to lack of data.

At the 1,500-mi^2 Sud Craiova license in southwest Romania, Sterling and TransAtlantic have estimated that the Silurian shale has gross recoverable prospective resources of approximately 3 Tcf (Best Estimate). Including the Jurassic Etropole, TransAtlantic has estimated its blocks hold a total of 0.3 Tm^3 (11 Tcf) of unrisked, recoverable shale gas prospective resources (gross; Best Estimate).[25]

Independent researchers in Romania recently estimated the technically recoverable resources in the Silurian shale of the southern Romanian portion of the Moesian Platform to be 26 Tcf, out of 1,295 Tcf of OGIP (Mean Estimate). The Jurassic was not assessed, nor was the Silurian potential in Bulgaria.[26]

3.4 Recent Activity

Several companies have pursued shale gas leasing in Bulgaria but only one shale test well has been drilled. In June 2011, Chevron received a 5-year shale gas exploration permit for the 4,400-km^2 Novi Pazar block of northeastern Bulgaria. However, since the shale ban of January 2012 Chevron can only pursue conventional targets in the block without hydraulic fracturing.

US-based TransAtlantic Petroleum, through its subsidiary Direct Petroleum Bulgaria, holds a shale gas exploration license at the 2,300-km^2 Lovech block, located in the southern Moesian Platform north of the Balkan forelands in northwest Bulgaria. TransAtlantic recently was also awarded the adjacent 648-km^2 Koynare block.

In November 2011 TransAtlantic and Canada-based partner LNG Energy drilled the 3,190-m deep Goljamo Peshtene R-11 exploration well at Lovech to core and test the Mid-Jurassic Etropole Shale. The R-11 well was drilled in 56 days and cost $7.5 million. It was located near the Peshtene R-5 well, which had flowed 530,000 ft^3/d from a conventional interval in the Jurassic Etropole. The R-11 well penetrated 354 m of Etropole argillite with numerous gas shows (C1-C3) and cored 289 m of the Jurassic Etropole and Ozirovo formations. LNG described rock properties as similar to those of productive US shale plays. The well was not fracture stimulated as Bulgaria has a ban in place. TransAtlantic plans to test the Etropole Shale elsewhere on the Lovech block where it is about 3,800-m deep.[27]

Canada's Park Place Energy received an exploration permit in northwest Bulgaria's Dobruja province (blocks Vranino 1 to 11). In June 2011 Chevron won a tender to explore for shale gas at the Novi Pazar field, also located in Dobruja, but the permit was cancelled in January 2012 when the shale gas ban came into effect. Bulgaria's state gas company Bulgargaz has not disclosed any shale-related activity.

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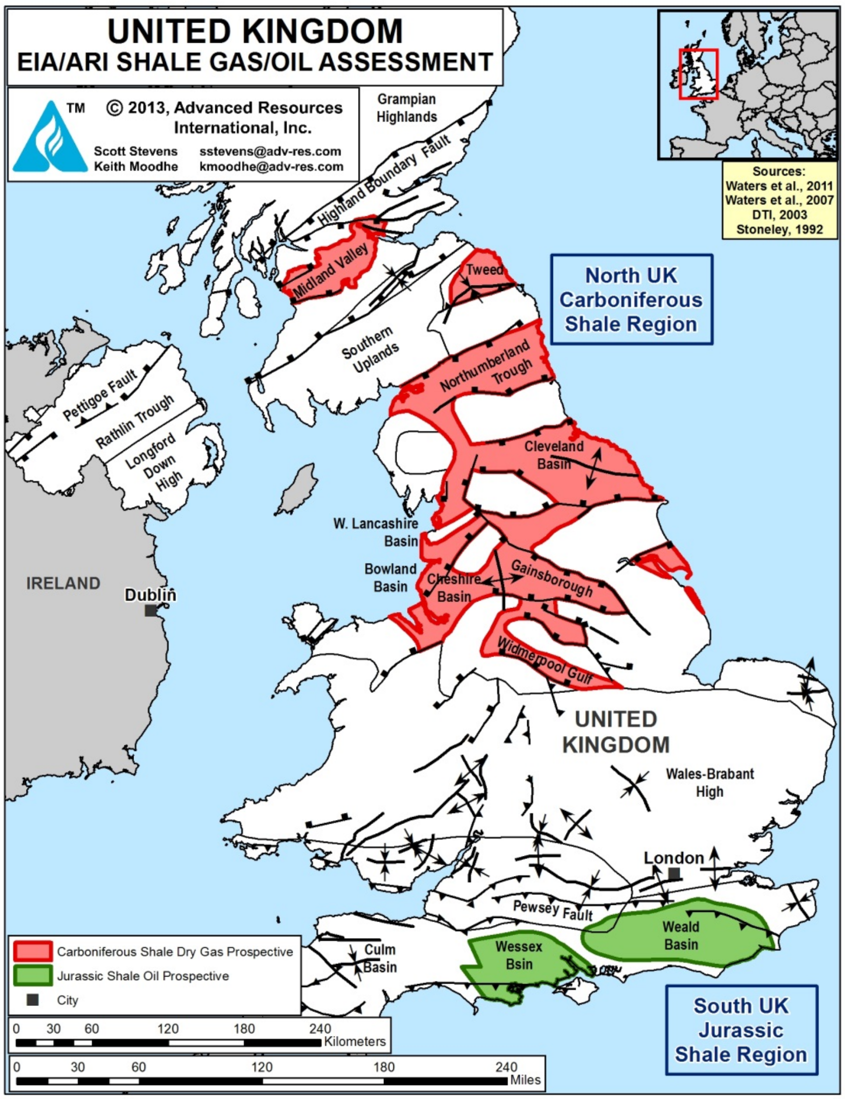
XI. UNITED KINGDOM

SUMMARY

The United Kingdom has substantial volumes of prospective shale gas and shale oil resources within Carboniferous- and Jurassic-age shale formations distributed broadly in the northern, central and southern portions of the country.

Figure XI-1 : Shale Basins in the United Kingdom



Source: ARI 2013.

The risked, technically recoverable shale resources of the U.K. are estimated at 26 Tcf of shale gas and 0.7 billion barrels of shale oil and condensate in two assessed regions, Tables XI-1 and XI-2. This is based on the much larger unrisked estimates of 623 Tcf of shale gas in-place (134 Tcf, risked) and 54 Bbbl of shale oil in-place (17 billion barrels, risked). These estimates reflect only the higher-TOC portions of the Carboniferous and Jurassic shale intervals.

Table XI-1. Shale Gas Reservoir Properties and Resources of the United Kingdom

			North UK Carboniferous Shale Region (10,200 mi^2)	South UK Jurassic Shale Region (3,470 mi^2)
Basic Data	Basin/Gross Area		North UK Carboniferous Shale Region (10,200 mi^2)	South UK Jurassic Shale Region (3,470 mi^2)
	Shale Formation		Carboniferous Shale	Lias Shale
	Geologic Age		Carboniferous	L. Jurassic
	Depositional Environment		Marine	Marine
Physical Extent	Prospective Area (mi^2)		5,100	1,735
	Thickness (ft)	Organically Rich	820	165
		Net	410	149
	Depth (ft)	Interval	5,000 - 13,000	4,000 - 6,000
		Average	8,500	5,000
Reservoir Properties	Reservoir Pressure		Normal	Normal
	Average TOC (wt. %)		3.0%	3.0%
	Thermal Maturity (% Ro)		1.30%	0.85%
	Clay Content		Medium	Medium
Resource	Gas Phase		Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		117.3	14.5
	Risked GIP (Tcf)		125.6	8.0
	Risked Recoverable (Tcf)		25.1	0.6

Source: ARI, 2013

Table XI-2. Shale Oil Reservoir Properties and Resources of the United Kingdom

			South UK Jurassic Shale Region (3,470 mi^2)
Basic Data	Basin/Gross Area		South UK Jurassic Shale Region (3,470 mi^2)
	Shale Formation		Lias Shale
	Geologic Age		L. Jurassic
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		1,735
	Thickness (ft)	Organically Rich	165
		Net	149
	Depth (ft)	Interval	4,000 - 6,000
		Average	5,000
Reservoir Properties	Reservoir Pressure		Normal
	Average TOC (wt. %)		3.0%
	Thermal Maturity (% Ro)		0.85%
	Clay Content		Medium
Resource	Oil Phase		Oil
	OIP Concentration (MMbbl/mi^2)		30.9
	Risked OIP (B bbl)		17.1
	Risked Recoverable (B bbl)		0.69

Source: ARI, 2013

Advanced Resources International, Inc.

Initial exploration drilling has confirmed the presence of thick, gas-bearing shale deposits in the Bowland Sub-basin in the west portion of the Pennine Basin of northwest England. However, production testing has not yet occurred and the other shale regions remain undrilled. EIA/ARI's current estimate of the UK's shale gas resources is about 10% higher than our initial 2011 assessment, while new shale oil potential has been added.

Compared with North America, the shale geology of the UK is considerably more complex, while drilling and completion costs for shale wells are substantially higher. The Pennine Basin, one of the country's most prospective areas, has been tested with five vertical wells which cored the Carboniferous Bowland Shale. Other prospective areas include the rest of the North UK Carboniferous Shale region and the liquids-rich Jurassic Shale region of southern England in the Wessex and Weald basins, Figure XI-1.

Shale testing is still at an early phase in the UK – flow testing and horizontal shale drilling have not even been attempted. In a temporary setback, the first shale well to be hydraulically stimulated triggered a series of minor earthquakes related to a nearby fault. Following an 18-month moratorium, the government concluded that the environmental risks of shale exploration are small and manageable. Shale drilling was allowed to resume in December 2012, albeit with stricter monitoring controls. Current shale operators include Cuadrilla Resources, IGAS, Dart Energy, and others.

INTRODUCTION

Within Europe, the United Kingdom stands next after Poland in pursuing its shale gas and shale oil potential. However, with a small existing onshore conventional oil and gas industry, the UK has limited domestic service sector capability for shale exploration. Natural gas prices are high (~$9/MMBtu) in the UK compared with North America, but geologic conditions are much more complex. Faults are numerous, geologic data control is weak, and shale wells are more costly to drill. While the UK's shale resource base appears substantial, commercial levels of shale production are yet to be established.

Political opposition to shale development is greater in the UK than in Poland but less than in France or Germany. Hydraulic fracturing got off to an abysmal start. The UK's first shale production test well triggered small local earthquakes during fracture stimulation and the vertical wellbore was deformed. This is perhaps unsurprising given the highly faulted nature of shale deposits in the UK (and generally in Europe). The government banned onshore hydraulic fracturing for a period of eighteen months to better evaluate the risks.

In January 2012 the British Geological Survey noted that the risks of shale development to groundwater and earthquakes had been exaggerated. Minor earthquakes caused by the Preese Hall-1 well were "comparable in size to the frequent minor quakes caused by coal mining. What's more, they originate much deeper in the crust so have all but dissipated by the time they reach the surface."[1] In December 2012 the UK government finally granted conditional approval for shale exploration, albeit with strict monitoring conditions. Cuadrilla recently delayed its plan to resume fracture stimulation until 2014 at the earliest.

Companies which have been granted a Petroleum Exploration and Development license (PEDL) by the UK government are permitted to explore and develop shale gas, as well as other types of petroleum resources (conventional, coalbed methane, tight gas, etc.). Field development is subject to necessary national and local consent and planning permission. Currently there are about 334 onshore PEDLs, of which several dozen have recognized shale potential. Proprietary shale data typically are kept confidential for a four-year period from the date of well completion.

At least six oil and gas companies are targeting shale gas exploration in the UK but only two have actually drilled shale wells. All wells have been vertical. UK-based Cuadrilla Resources, partly (43%) owned by Australian drilling company AJ Lucas, is the most active, drilling and coring four shale exploration wells in the West Bowland Sub-basin that confirmed the presence of up to 2-km of gas-bearing organic-rich shale. However, at least one well encountered active faults and high-stress conditions. IGAS Energy has drilled a shale well nearby, coring the 1,600-ft thick Bowland Shale. Horizontal shale wells have not yet been attempted in the UK, nor have flow tests been reported. Coastal Oil and Gas Ltd., Celtique Energie, Dart Energy, and Eden Energy also are evaluating their UK shale resource potential but haven't yet drilled.

GEOLOGIC OVERVIEW

As early as the late 1980s researchers at Imperial College, London had identified the main stratigraphic targets for shale gas exploration in the UK, the marine-deposited black shales of Carboniferous and Jurassic age.[2,3] More recently in 2003, a study conducted by the British Geological Survey (BGS) and published by the UK Department of Trade and Industry (DTI) presented an integrated review of the geology of Britain's onshore conventional oil and gas fields and source rock shales, although it was not asked to consider shale as a productive reservoir.[4] In 2010 BGS published a compilation of shale-specific geologic data collected from outcrops and conventional petroleum wells.[5]

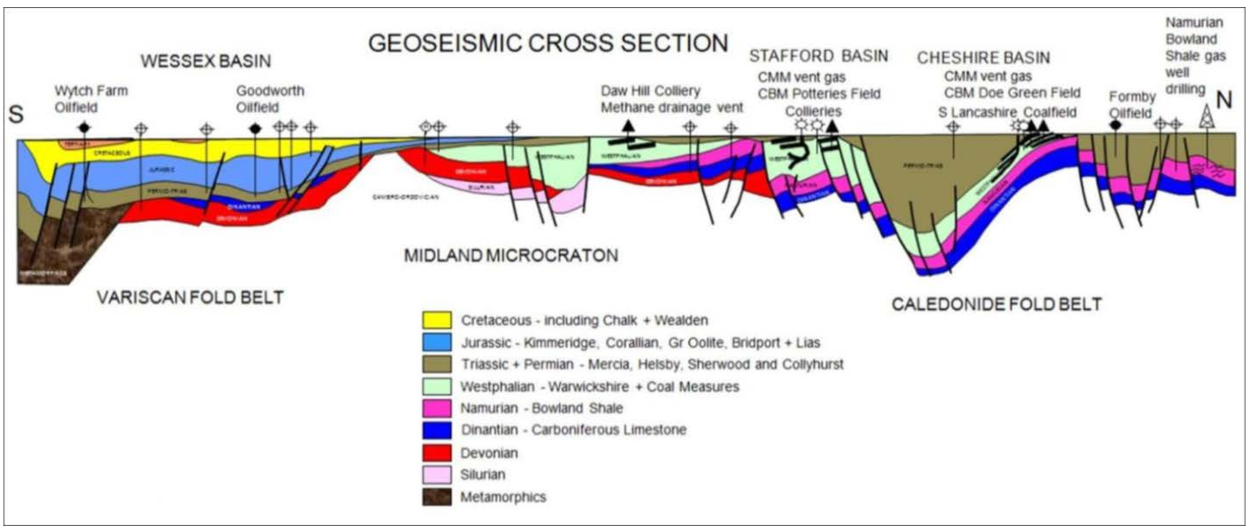
BGS published its preliminary evaluation of UK shale gas resources later in 2010, conducted on behalf of the Department of Energy and Climate Change (DECC).[6] BGS' initial estimate was 5.3 Tcf (150 Bcm) of recoverable shale gas resources. BGS, in association with DECC, plans to release an updated evaluation of shale gas potential of northwest England later in 2013, followed eventually by a more complete national estimate.[7]

The main onshore sedimentary basins in the UK that produce oil and gas or have conventional or shale exploration potential are shown in Figure XI-1. The current EIA/ARI resource assessment groups these numerous, typically fault-bounded basins into two main shale exploration regions:

- **North UK Carboniferous Shale Region.** A complex assemblage of isolated structural basins and troughs is present across northern England and southern Scotland. These contain prospective organic-rich shales of Carboniferous age, including notably the Bowland Shale. Within the greater Pennine Basin, individual sub-basins include the Bowland, Cleveland, Cheshire, West Lancashire, Northumberland, East Midlands, Gainsborough, Midland Valley, as well as others. The Bowland Sub-basin is the only area to undergo shale exploration drilling to date.
- **South UK Jurassic Shale Region.** In southern England the Wessex and Weald basins extend offshore into the English Channel. They contain Jurassic-age shales that are oil-prone. While no shale drilling has occurred here yet, the region includes Britain's largest onshore oil field and appears highly prospective for shale oil development.

It is important to note that the UK shale basins generally are not simple continuous structures, such as found in many North America shale regions, but rather typically comprise a series of small fault-bounded sub-basins. Figure XI-2 shows a regional cross-section from the Wessex Basin in the south to the Bowland Sub-basin in the north, highlighting the Carboniferous-Namurian and Jurassic shale targets. Even the interior of the sub-basins may be significantly faulted, to an extent generally not displayed on schematic cross-sections. The structural complexity, coupled with the relatively small data base of onshore petroleum wells in the UK (particularly in the troughs), makes resource assessment more difficult. It also could slow the pace of shale exploration, de-risking, and commercial development in the UK.

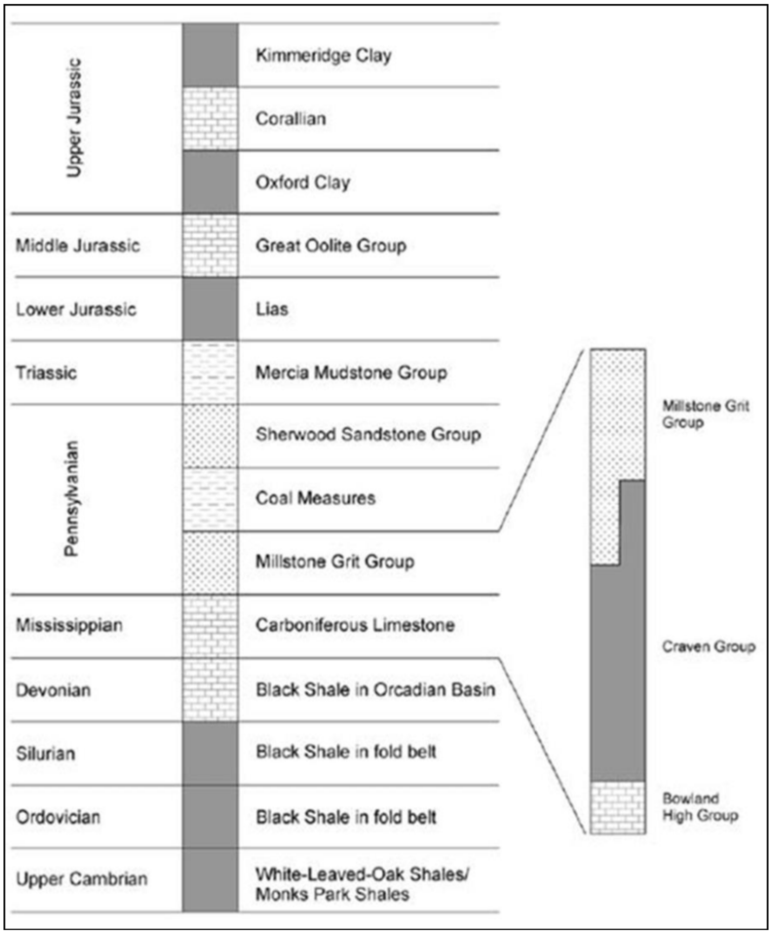
Figure XI-2 : Regional Cross-Section from Wessex Basin Through Bowland Sub-basin Highlighting Carboniferous-Namurian and Jurassic Shale Targets



Source: British Geological Survey, 2012

The main stratigraphic targets for shale exploration in the UK are the Carboniferous Mississippian (Lower Namurian)[8] and the Lower Jurassic Lias formations, both of which contain organic-rich, marine-deposited shales, Figure XI-3. Other potential shale targets include the U. Cambrian and the U. Jurassic Oxford and Kimmeridge Clays, but these were excluded from our study due to their low thermal maturity, lower organic content, and/or extreme structural complexity. In particular, organic-rich shales found within the Carboniferous Coal Measures were excluded because these non-marine shales are coaly, high in clay, and unlikely to be sufficiently brittle. However, further data collection and mapping may reveal these or other shale formations to be prospective in places.

Figure XI-3: Stratigraphic Column Showing UK Formations That Contain Organic-Rich Shales. The Lower Jurassic Lias And Carboniferous Shales Appear Most Prospective.



Source: Smith et al., 2010

The BGS has cited the Middle Cambrian Conasauga Shale in Alabama as the closest North American geologic analog for Cambrian shale deposits in the UK, given their similar age and degree of structural complexity. However, shale gas development in the Conasauga Shale has not been successful to date. The Cambrian-age shale deposits in the UK were not assessed in the EIA/ARI study due to their structural complexity and lack of geologic data.

SEISMIC HAZARDS

The UK shale industry experienced a serious setback in 2011, when the first hydraulic fracturing operation of a shale well unexpectedly generated a series of very small earthquakes. However, it is noteworthy that none of the approximately 50,000 horizontal shale wells drilled in North America during the past decade have generated significant earthquakes, although a few suspected seismic events are under review.

In August 2010 Cuadrilla drilled the UK's first shale gas exploration well, spudding the **Preese Hall-1** vertical well in the Bowland Sub-basin near Blackpool, Lancashire. The well was fracture stimulated during early 2011, inducing several dozen small earthquakes close to the downhole injection zone. The timing of the earthquakes corresponded with fluid injection and continued for several hours after injection ceased. Fortunately, the largest earthquakes were relatively small, measuring magnitudes of 2.3 and 1.5 on the Richter scale. No surface damage was reported. However, the UK government shut down shale testing in the country for 18 months to determine the cause of the seismic events and to develop mitigation rules.

An evaluation of seismicity from these earthquakes generated by the Preese Hall-1 well and the fault geometry of the basin indicated that movement was strike-slip along a sub-vertical fault plane. The suspected fault was located on the well's image log as well as on detailed seismic, Figure XI-4.[9] Separately, bedding plane slip -- already noted in core cut prior to running casing in the well -- induced wellbore damage, with oval deformation noted across several hundred feet of the 5.5-inch casing.

The maximum horizontal stress gradient, based on mini-frac and borehole breakout data, was determined to be relatively high at 1.25 psi/ft. The stress differential within the Bowland Shale -- about 4,000 psi -- was found to be an order of magnitude higher than in North American shale plays, which typically have stress differentials of only several hundred psi. It is unclear whether the high stress differential is local or widely prevalent across the UK.

Cuadrilla's consultants concluded that excess fluid pressure exerted on the fault during the hydraulic stimulation overcame the rock friction containing this stress, which enabled the fault to slip and generate small earthquakes. Simultaneously, bedding plane slip up the hole caused the well's casing string to deform. Based on fault size and geometry, the maximum earthquake in the Bowland Sub-basin was estimated to be approximately magnitude 3.0, still considered too small to cause significant damage to surface structures in this region.

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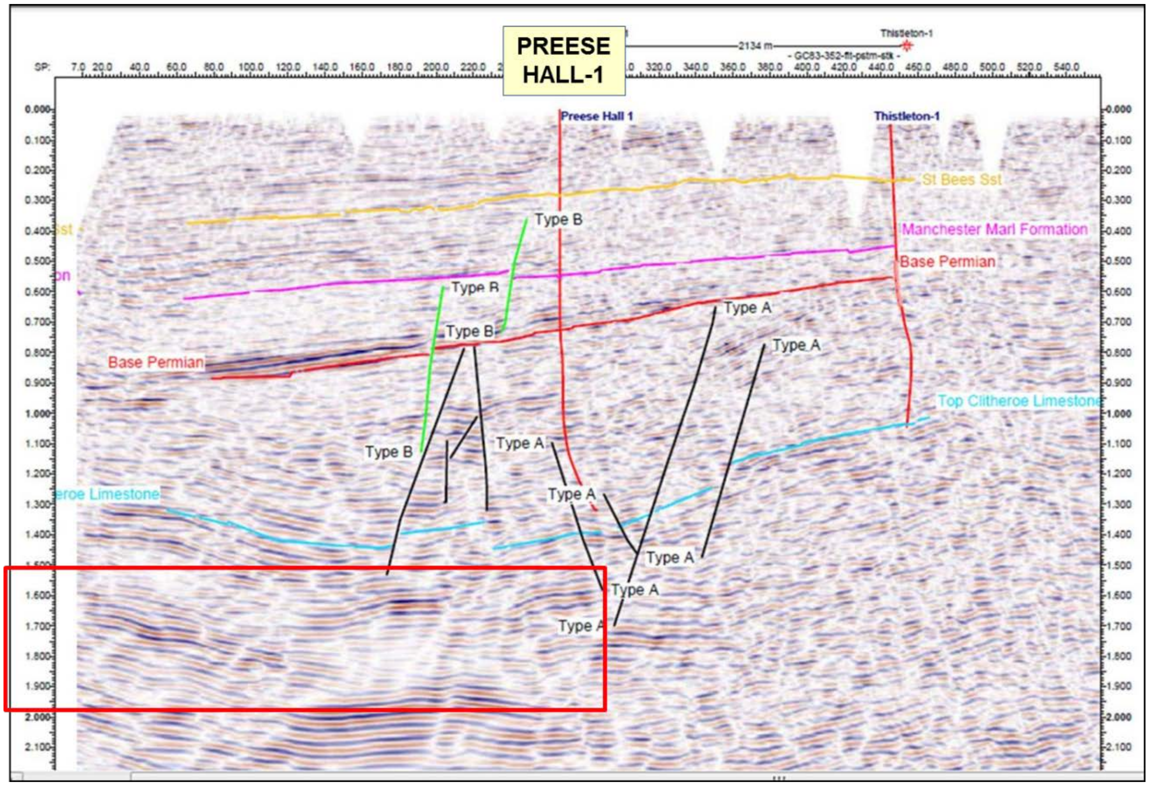
Figure XI-4: Seismic Reflection Line Showing Suspected Active Faults
Near The Preese Hall-1 Well In The Bowland Sub-basin



Source: de Pater and Baisch, 2011

The consultants also inferred that the injected frac fluid remained contained within the induced fracture system and did not leak into the shallow freshwater aquifer system, because of the thick and impermeable Bowland Shale and overlying Permian anhydrites. A subsequent report recommended monitoring during hydraulic fracturing operations to help mitigate induced seismicity.[10]

As a result of the earthquakes the government halted shale operations in the UK from May 2011 until December 2012. The Royal Society and Royal Academy of Engineering conducted a review of the risks, recommending the following three primary steps for ensuring health and safety during shale development:[11]

- ***Groundwater Monitoring***. The BGS should conduct regional baseline surveys of groundwater ahead of shale development, while operators conduct site-specific surveys to identify possible natural methane concentrations in groundwater. Abandoned wells should be monitored and remediated to prevent fracture fluids from entering freshwater aquifers.

- ***Well Integrity***. Well design, construction, and integrity testing should ensure that multiple layers of steel and cement are present to preclude leakage of fluids into freshwater aquifers.
- ***Mitigating Seismicity.*** The BGS should survey the regional distribution of faults, stresses, and seismic hazards ahead of shale development, while operators conduct site-specific surveys. Seismicity should be monitored before, during, and after hydraulic stimulation, which should be shut down if seismic risks become unacceptable.

After considering these and other views, DECC put in place a new regulatory regime for shale development starting December 2012. The regime requires operators to evaluate potential seismic hazards posed by hydraulic fracturing, implement seismic monitoring of each individual well site area, and propose mitigation steps to minimize the chance of future earthquakes due to hydraulic fracturing. A real-time trigger is to be installed to cut off injection should significant earthquake risks arise. These rules are expected to add significant cost and time to drill shale wells in the UK. Cuadrilla's Anna's Road-1 well is the first to be spud under the new shale rules. Hydraulic stimulation of this well -- which Cuadrilla recently announced would be delayed until 2014 at the soonest -- would require further specific approvals.

1. NORTH UK CARBONIFEROUS SHALE REGION

1.1 Introduction and Geologic Setting

Northern England and southern Scotland are characterized by a complex assemblage of isolated basins and troughs which contain thick, organic-rich Carboniferous shales, Figure XI-1. These shale-prospective lows are separated by structural highs where Carboniferous was not deposited or has been eroded. Based on mapping of Carboniferous basins conducted by the BGS, these troughs cover a total area of approximately 10,000 mi^2.

The Bowland Sub-basin of Lancashire, where shale drilling has been concentrated thus far, is one such trough, representing the onshore margin of the petroliferous East Irish Sea Basin. Further to the east the Cleveland Basin is considered the onshore extension of the Southern North Sea gas basin. In between lay the Cheshire, West Lancashire, Northumberland, East Midlands, Pennine, Gainsborough, Midland Valley, and other basins and troughs containing Carboniferous-age shales. Our study grouped these isolated basins into a single region for shale resource assessment.

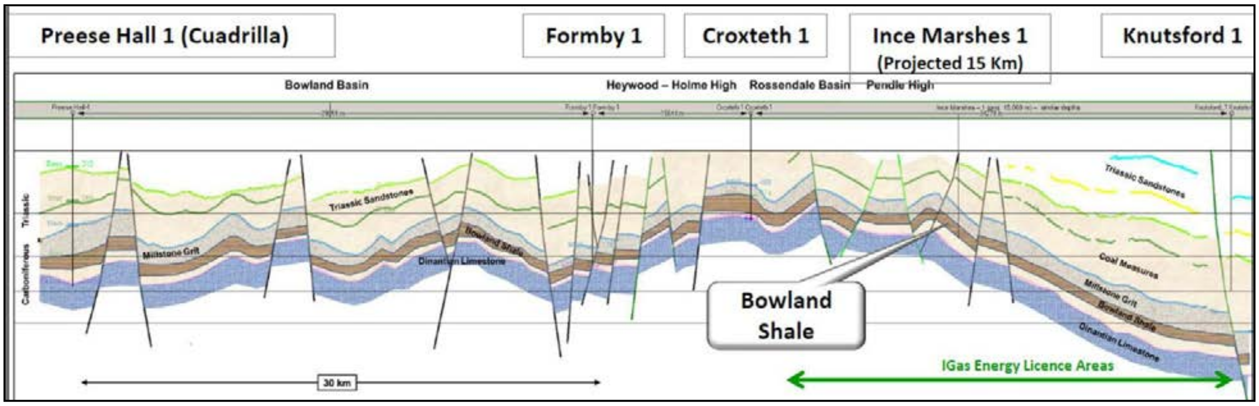
The western portion of the Bowland Sub-basin has been the site of all UK shale exploration drilling to date. The Carboniferous Bowland Shale is the main target, ranging from about 2.0 to 2.5 km deep across the moderately faulted Bowland Sub-basin, Figures XI-5 and XI-6. Cuadrilla's Preese Hall-1 well encountered the top of the target Lower Carboniferous Bowland Shale at a measured depth of 6,854 ft and penetrated a total 2,411 ft of organic-rich shale, Figure XI-**7**. The BGS has mapped the thickness of the Upper Bowland Shale Formation, as well as its organic-rich (high-gamma) section, across northern England, Figure XI-8. The organic-rich shale ranges up to 120 m thick but more typically is recorded as 20 to 40 m thick. Note, however, that petroleum wells are preferentially drilled on structural highs, where shale tends to be thinner than in the troughs.

The eastern Bowland Shale play extension in the Gainsborough Basin has less geologic control than the west. Here the shale ranges up to 300 m thick in the Dinantian half-graben basins, Figure XI-9. Dart Energy reported that the most organic-rich portion defined by high-gamma shales ranges up to 110 m thick. In the Cheshire Basin the Carboniferous (Namurian) Bowland and Holywell shales with TOC up to 5% occur at depths of 1 to 5 km, Figure XI-10.

Elsewhere in the region, the Namurian Holywell Shale, source rock for conventional oil fields in the southern East Irish Sea as well as the Formby oil field, is reported to have an overall average TOC of 2.1% (range 0.7% to 5%) and averages 3.0% TOC in its lower, more organic-rich portion. Clay content is uncertain, although public data indicate that Carboniferous mudstones in the UK generally average around 25% Al_2O_3 (range 12-38%), mostly from clay.

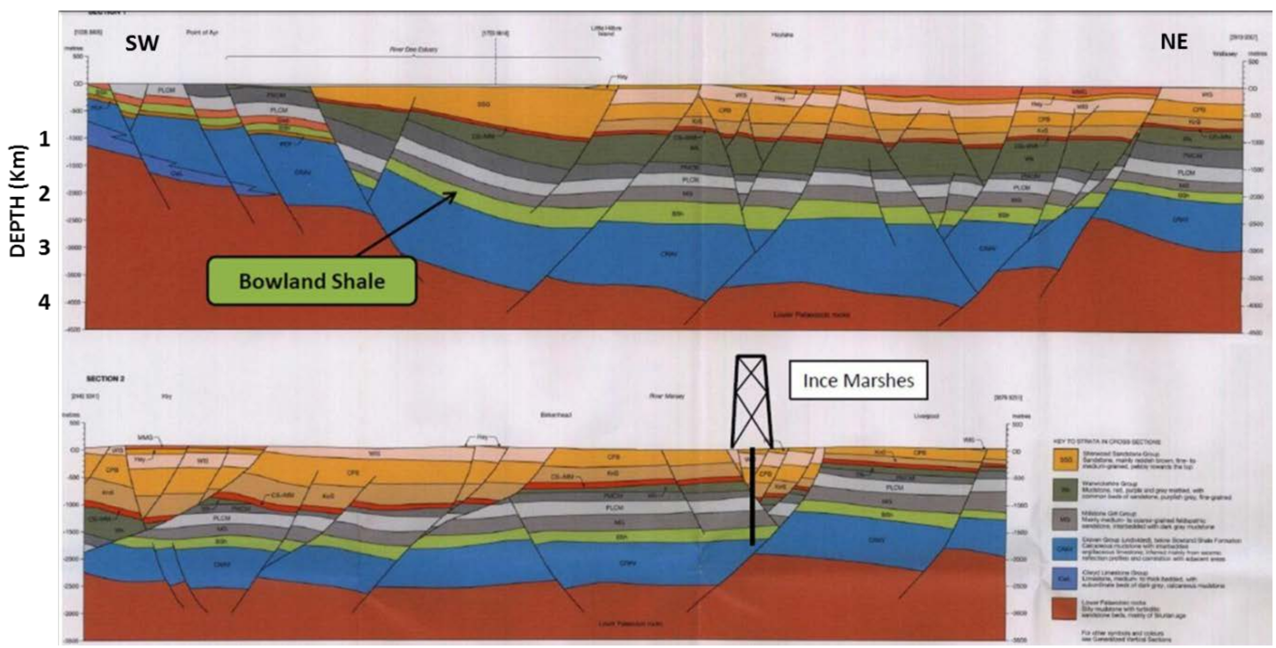
The Pennine Basin has relatively good geologic control from past petroleum exploration. The Craven Group (Mississippian) ranges from about 1.5 km thick in the Craven sub-basin to over 5 km thick in the Widmerpool Gulf. These mudstones were deposited in distal slope turbidite and hemipelagic environments in relatively narrow, deep depocenters. The early Namurian shale units (local names Bowland, Edale, Holywell shales, top part of Craven Group) of the Pennine Basin have high TOC and are known to have sourced hydrocarbons. These Namurian marine shales generally have rich TOC in excess of 4%.

Figure XI-5: Structural Cross-Section in the Bowland Sub-basin Region, Northwest UK Showing Numerous Faults Across the Cuadrilla and IGas Energy Licenses.



Source: Source: IGAS Energy, 2012

Figure XI-6: Structural Cross-Section In The Bowland Sub-basin Region Showing The Highly Faulted Bowland Shale At 2 To 3 Km Depth. Additional Faults Penetrated By The Ince Marshes Well Suggest That Many Additional Faults Are Present But Unrecognized.



Source: IGAS Energy, 2012; modified from BGS Map 96_Liverpool

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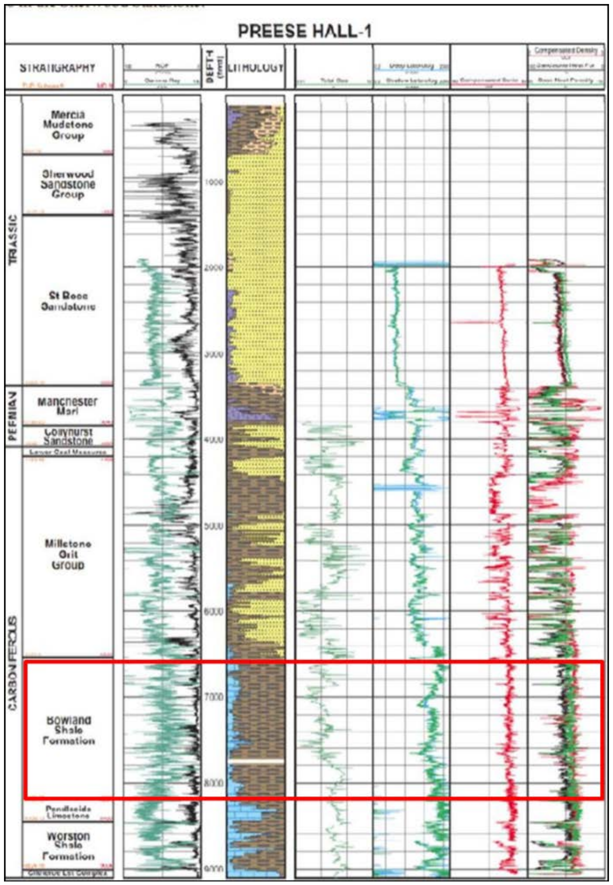
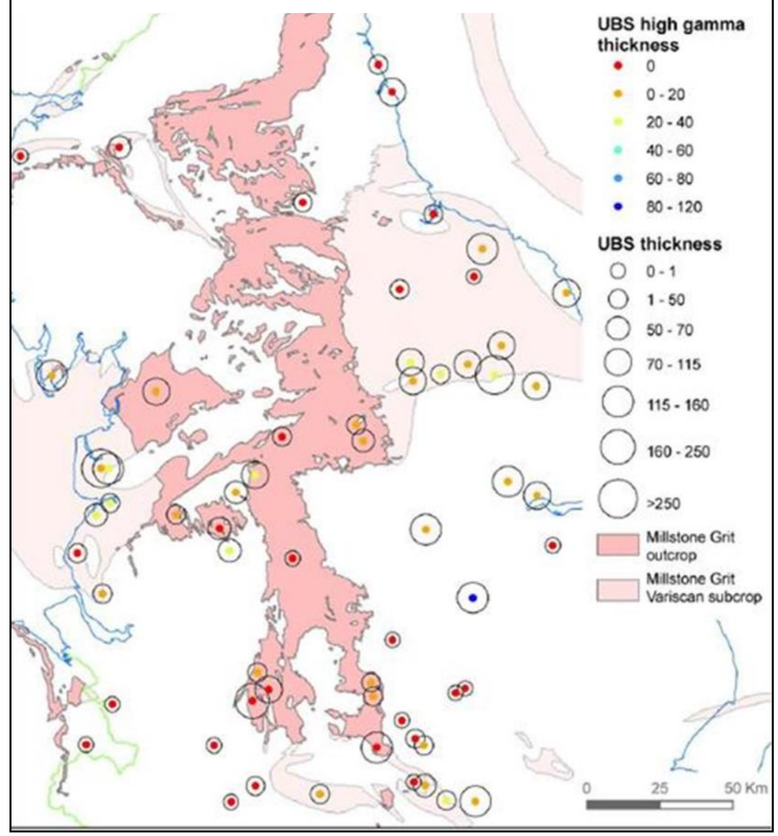
Figure XI-7: Stratigraphic Column and Composite Log for the Cuadrilla Preese Hall-1 well in the Bowland Sub-Basin



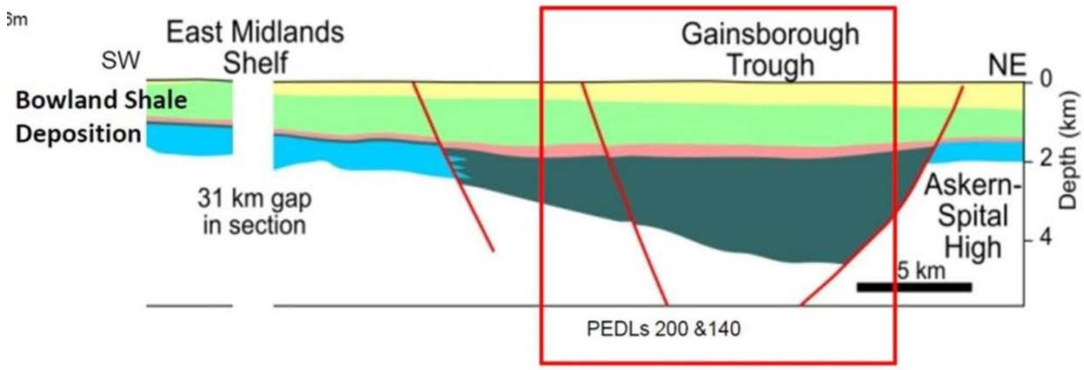
Source: de Pater and Baisch, 2011

Figure XI-8: Thickness of the Upper Bowland Shale Formation in Northern England, as Well as the High-Gamma Thickness. Note That Petroleum Wells Tend to be Drilled on Structural Highs Where the Shale May be Thinner Than in the Troughs.



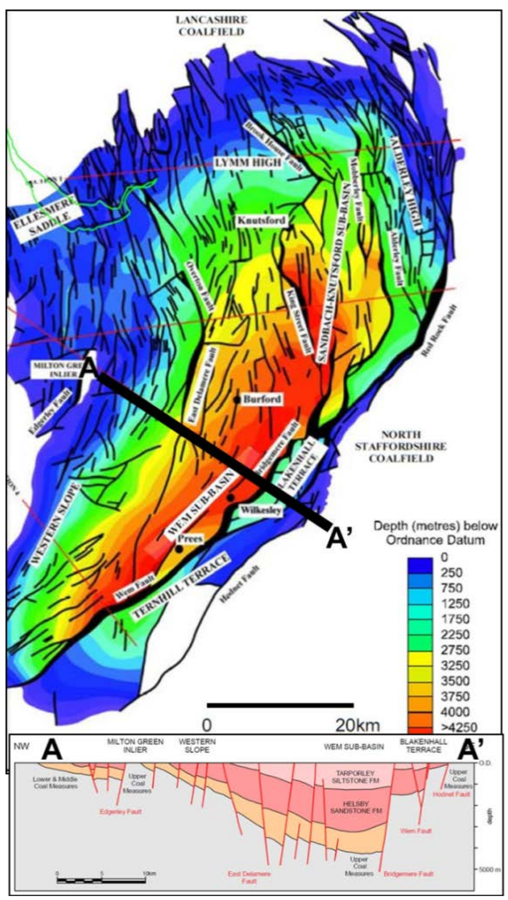
Source: Smith et al., 2010

Figure XI-9: Schematic Cross-Section Across The Gainsborough Trough Showing Thick Bowland Shale. Additional Faults Are Likely To Be Present But Not Shown.



Source: Dart Energy, 2013

Figure XI-10: Geologic Map and Generalized Structural Cross-Section of the Cheshire Basin. Carboniferous (Namurian) Bowland and Holywell Shales with TOC Up to 5% Occur at Depths of 1 to 5 km.



Source: DECC, 2012

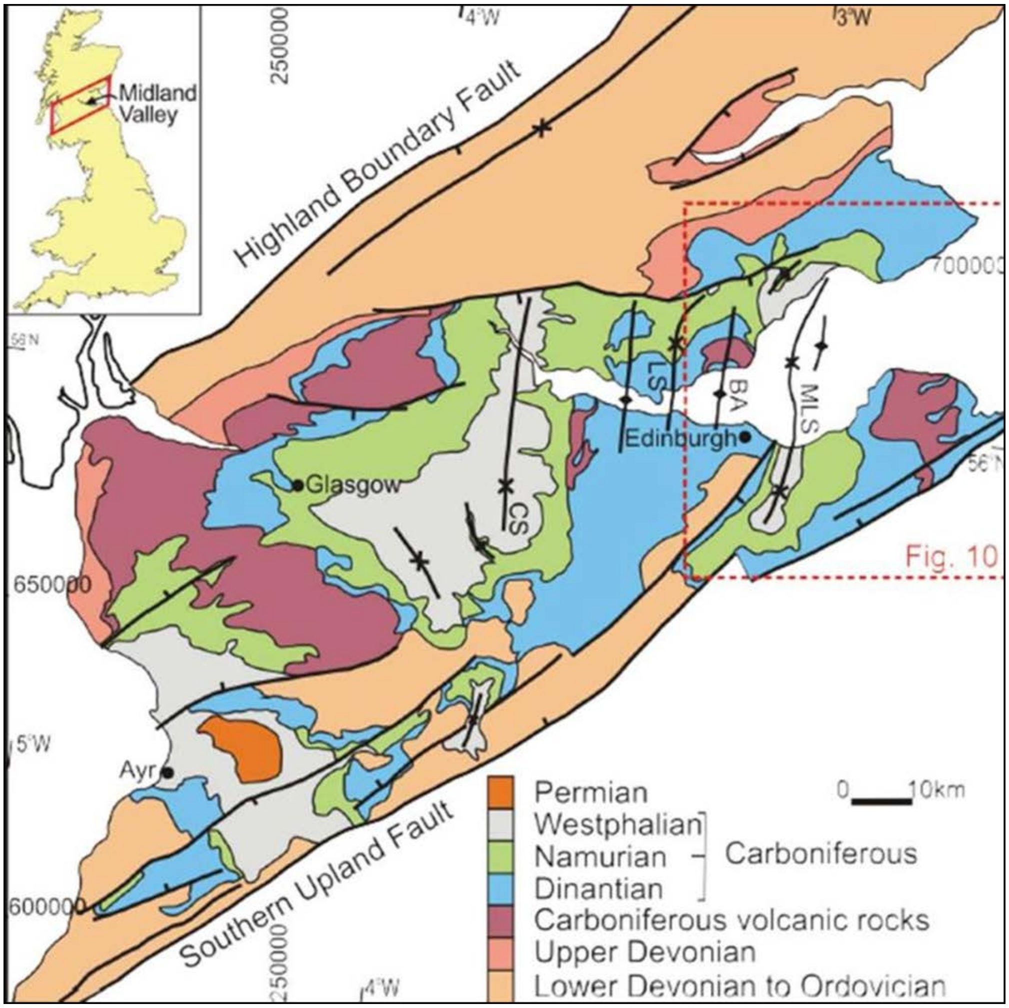
The North UK Carboniferous Shale region is mainly in the dry gas window. For example, the Normanby-1 and Grove-3 conventional petroleum wells reportedly recorded high-gamma sections within the Bowland Shale, while the Scaftworth-B2 well measured 2.07% to 3.63% TOC with 1.26% R_o at a depth of 2,246 m.[12] In addition, most of the Cleveland Basin is known to be within the dry gas window. Oil and wet gas thermal maturity windows may be present locally but could not be defined with the limited data available.

No porosity data are available for Namurian shales in the Pennine Basin. Based on boreholes drilled by the BGS in the southern Midlands, relatively shallow (900 m deep) Upper Paleozoic shales retained high porosities (5-10%). However, porosity is likely to be considerably lower (perhaps 3-5%) at typical target shale depth of 2-4 km.

The Midland Valley Basin (MVB), a large east-northeast trending graben complex that stretches across southern Scotland, is bounded by the Highland Boundary Fault to the northwest and the Southern Upland Fault to the southeast. The MVB comprises a complex series of small faulted sub-basins, such as the Kinkardine Basin where Dart Energy is evaluating shale gas resources. This structural complexity was over-printed by extensive igneous intrusion during late Carboniferous to early Permian time.

The MVB contains a relatively complete sequence of Carboniferous deposits up to 6 km thick, Figure XI-11.[13] Namurian strata range from 450 m to 1,400 m thick at outcrop. The depositional sequence reflects mixed marine shelf carbonate and deltaic successions, comprising upward-coarsening cycles of marine limestone, mudstone, siltstone and sandstone.[14] Lower Carboniferous (Dinantian) oil-shale source rocks, such as the Mid-Lothian Oil shale, buried deeply in the Midlothian-Leven Syncline generated waxy crude oil that sourced clastic reservoirs of similar age in the adjacent anticlines.

Figure XI-11: Geologic Map of the Midland Valley Basin. Carboniferous (Namurian) Shales Crop Out at the Surface but May Reach Prospective Depth.



Source: Underhill et al., 2009

1.2 Reservoir Properties (Prospective Area)

The total mapped deep Carboniferous area in the North UK Carboniferous Shale region is approximately 10,200 mi^2. Because of structural complexity and poor depth control was poor, only half of the total area was assumed to be in the prospective depth window and relatively unfaulted (4,635 mi^2). The target lower organic-rich portion of the Bowland and Holywell shales (and local equivalents) averages about 300 ft thick and 8,000 ft deep in the Bowland Sub-basin region, with 3.0% average TOC. Porosity is estimated to be about 4% at target depths of 3 km, much lower than the 5-10% measured at shallow <1 km depth. Thermal maturity is mainly in the dry gas window (R_o 1.3%), although less mature pockets in the wet gas window may exist.

1.3 Resource Assessment

Risked, technically recoverable shale gas resources in the North UK Carboniferous Shale region are estimated to be 25 Tcf, out of a risked shale gas in-place of 126 Tcf, Table XI-1. The play has a favorable net resource concentration of about 117 Bcf/mi^2, reflecting the significant thickness of organic-rich shale.

For comparison, in September 2011 Cuadrilla Resources estimated the total shale gas in-place within its Bowland Sub-basin licenses to be approximately 200 Tcf, based on logs and core from two shale and three conventional petroleum wells.[15] The company has estimated the total shale gas resource-in-place concentration at its Preese Hall-1 well to be 539 Bcf/mi^2. Cuadrilla's estimate is that 10% or about 20 Tcf may be recoverable. It appears that Cuadrilla's estimate is based on the entire shale section, whereas EIA/ARI considers only the lower, most organic-rich section as the prospective interval.

Separately, IGAS Energy's independent consultant identified a 1,195-km^2 prospective area within an average 250-m thick organic-rich interval, constrained by geophysical logs from eight conventional petroleum wells that penetrated the Bowland Shale. After drilling its first shale appraisal well last year, IGAS estimated the shale gas in-place (GIP) resources within its licenses to be about 9.2 Tcf.

Dart Energy's third-party consultant NSAI has estimated that Dart's licenses have some 32.46 Tcf of GIP in unspecified shale formations in the Gainsborough Trough of East Midlands, as well as 30.55 Tcf of shale gas GIP in the Cheshire Basin (gross, Best Estimate). No recovery estimate was reported.[16] Finally, in Scotland's Midland Valley Basin, Dart Energy reported that the company's PEDL 133 license has an estimated 2.5 Tcf of shale gas GIP based on a third-party consultant report. Recoverable prospective shale gas resources were estimated at 115 Bcf in the Carboniferous Black Metal Shale and 255 Bcf in the Lothian-Broxburn Shale (Best Estimates; net to Dart).

1.4 Recent Activity

The Bowland Sub-basin, the only active shale drilling region in the UK, has had five shale exploration wells drilled to date. The main operators are Cuadrilla Resources (4 licenses totaling 1185 km^2; 4 wells), IGAS Resources (14 licenses; 1363 km^2; 1 well), and Dart Energy (11 licenses; 1041 km^2).

In August 2010 Cuadrilla drilled the first shale gas exploration well in the UK, spudding the **Preese Hall-1** vertical well in the Bowland Sub-basin near Blackpool, Lancashire. The top of the target Lower Carboniferous Bowland Shale was encountered at a measured depth of 6,854 ft. The well penetrated a total 2,411 ft of organic-rich shale. Naturally fractured, the Bowland is within the dry gas thermal maturity window.

After drilling was completed on the Preese Hall-1, Cuadrilla completed and fracture stimulated the well in early 2011. This operation represented the UK's first and only concerted attempt to produce shale gas. As previously discussed, small earthquakes were induced near the well by the hydraulic fracture stimulation. Operations at the well were halted in May 2011 with no gas production reported.

In completing the well, Cuadrilla perforated shale formations within the Bowland Shale, Worston Shale, and Hodder Mudstone at depths ranging from 7,670 to 8,949 ft. Five shale zones, out of 12 originally planned, were individually stimulated with a sand/water slurry, separated by bridge plugs. The total stimulation size, over 50,000 bbl of water and 400 t of sand proppant, was relatively large for a vertical shale well but still considerably smaller than the typical stimulation of a horizontal shale well in North America (about half the water volume and 10% of the sand volume).

Cuadrilla drilled and cored two other vertical wells in the Bowland Basin. During 2H 2010 the nearby **Grange Hill-1** vertical well logged over 2 km of Carboniferous shale across the depth interval of 1,200 m to 3,300 m, the total depth of the well. In 2011 the **Becconshall-1** well logged shale from depths of 2,450 m to 3,100 m, the total depth of the well.

Cuadrilla's most recent shale well in the Bowland Sub-basin, the **Anna's Road-1**, was abandoned at a depth of 2,000 ft due to drilling problems. The well was expected to be re-spud in January 2013 and completed in about four weeks, with the top Bowland Shale predicted at a depth of about 3100 m.

IGAS Energy Plc, 24.5% owned by Nexen and the UK's largest onshore operator of oil and gas fields, is evaluating the shale gas potential of its blocks. IGAS had acquired Nexen's portfolio of UK coalbed methane licenses in March 2011. The company reported that at its Point of Ayr acreage has shale extending over the entire block with an expected average thickness of more than 800 ft. IGAS Energy noted that a significant proportion of its acreage in the northwest England—from Ellesmere Port in the west in PEDL 190 to the Trafford Centre in the east within PEDL 193—is considered to have shale potential.

In 2011-12 IGAS drilled the **Ince Marshes-1** well to a total depth of 5,714 ft in the Bowland Sub-basin. Originally intended as a shallow coalbed methane test, the well was deepened and encountered the upper two-thirds of the Bowland Shale at depths of 4,200 to 5,200 ft. The Bowland Shale, estimated at 1,600-ft total thickness, had gas shows and TOC ranging from 1.2% to 6.9% (average 2.7%). Thermal maturity appeared to be in the wet gas window (R_o 1.0-1.1%).[17]

Dart Energy, based in Australia and Singapore, holds a significant shale position in the UK, including the western Pennine Basin, but has not yet drilled for shale there or elsewhere in the country. Dart's 14 PEDL's with shale potential, part of its acquisitions of coalbed methane operators Composite and Greenpark Energy, total about 3,700 km^2 in gross area. Third-party consultant NSAI has estimated these blocks hold approximately 65 Tcf of total shale GIP, of which approximately 30.5 Tcf is located in the western Pennine Basin (gross, Best Estimate).

No shale drilling has occurred yet on the eastern side of the Bowland Shale Region. Dart Energy holds the largest land position, a total of 13 licenses covering about 1,235 km^2. NSAI has estimated that Dart's blocks hold about 47.6 Tcf of shale GIP (gross, Best Estimate). Houston-based eCORP International, LLC has committed to drilling and coring a horizontal well by 2014 to farm into one of Dart's blocks. Separately, IGAS estimates it holds 388 km^2 of shale-prospective area in 9 licenses in this region.

Dart Energy, the only active shale operator in the Midland Valley Basin, has not announced firm plans for shale drilling. BG Group remains a joint-venture partner on Dart's Lothian Shale interval in this region.

Much further to the south, Australia-based **Eden Energy** and UK-based **Coastal Oil and Gas Ltd.** jointly control 2100 km^2 of shale gas and coalbed methane potential in South Wales, Bristol, and Kent. Prospective recoverable shale gas resources were estimated by Eden's third-party consultant to be 18.3 Tcf out of a total 49.8 Tcf of GIP (gross; Best Estimate). This includes 806 km^2 within 7 PEDLs in South Wales with potential in the Namurian Measures. However, this region was not assessed by EIA/ARI because of limited publicly available data.

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2. SOUTH UK JURASSIC SHALE REGION

2.1 Introduction and Geologic Setting

The Wessex and Weald basins region of southern England is the UK's principal onshore oil-producing area. Both basins produce oil and some natural gas from conventional Jurassic and Triassic clastic and carbonate reservoirs which were sourced by Jurassic marine shales. The Wessex Basin hosts the 500 million bbl Wytch Farm oil field, by far the country's largest onshore field, whereas the Weald Basin has several much smaller oil fields.

The Wessex Basin comprises a series of post-Variscan extensional sedimentary troughs and intra-basinal highs, located mainly in Hampshire and Dorset and extending into adjacent offshore areas. The Weald Basin is a better defined and structurally simpler syncline located in Sussex, Surrey, and Kent. The basins are separated by the Hampshire-Dieppe High, but the boundary is indistinct and the two basins were intermittently connected during Mesozoic deposition. They contain repeating cycles of Jurassic shallow-water marine mudrocks, sandstones, and limestones which are overlain by largely non-marine sediments of the Lower Cretaceous Wealden Group.

For the purpose of this study, the Wessex and Weald basins are considered a single Jurassic oil-prone shale resource region. Additional Jurassic shale areas with affinity to the Wessex Basin may exist further to the west (e.g., Bristol Channel Basin), but these were not assessed.[18]

The structural geology of the Wessex and Weald basins is somewhat simpler than most other UK shale regions, although still more complex and faulted than North American shale plays. While not intensively deformed, these basins comprise a series of individual sub-basins separated by normal faults. For example, the Wessex Basin comprises four smaller half-grabens (Pewsey, Mere-Portsdown, Dorset and Channel).

Figure XI-12 shows that roughly 10,000-ft thick of Lower Carboniferous to Tertiary sedimentary rocks is present in the Weald Basin. Lower Jurassic organic-rich shales reach depths of about 7,000 ft or more along the basin axis. Interior faults appear to be relatively few, spaced about 5 to 10 km apart, and seemingly allow ample room for shale development. The strata dip quite gently, only a few degrees.

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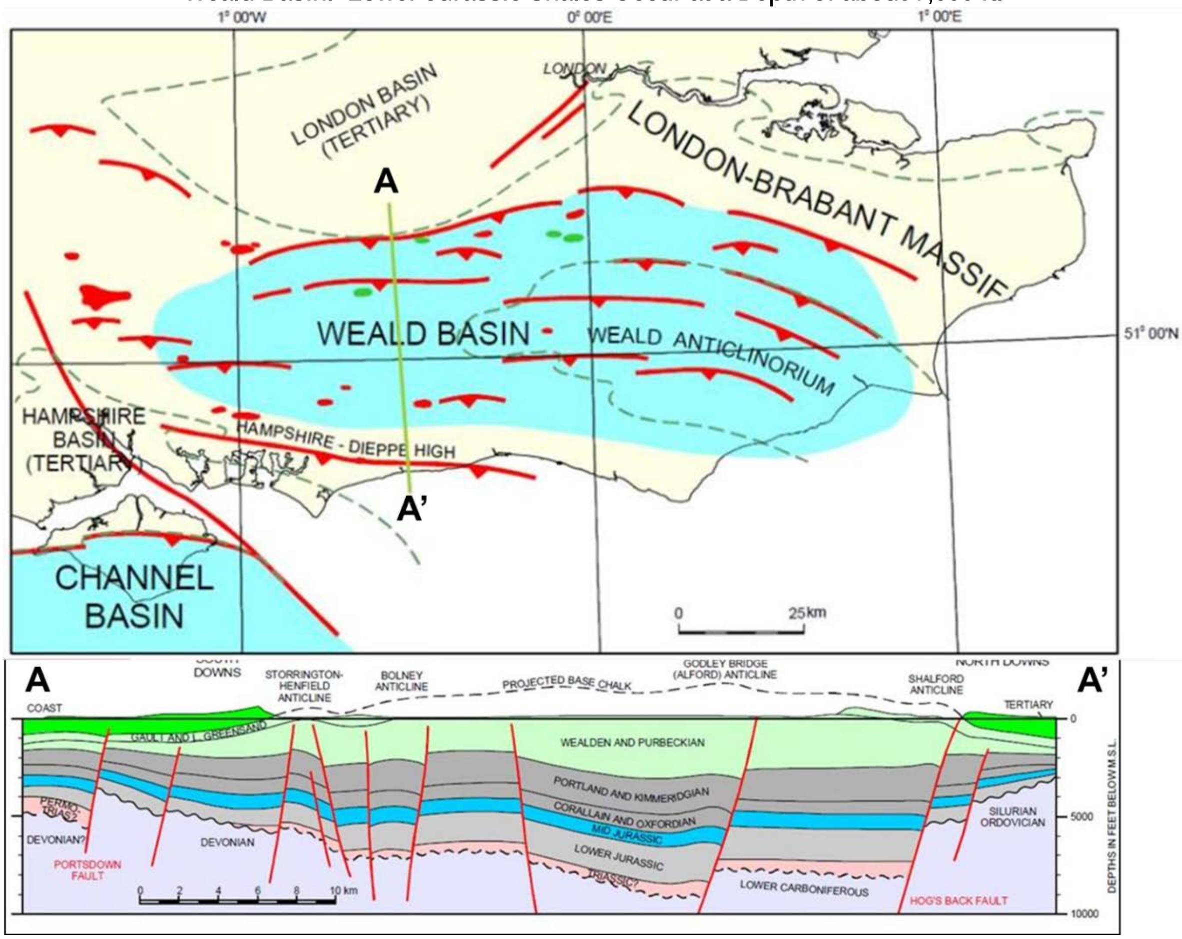
Figure XI-12: Geologic Map and Generalized Structural Cross-Section of the Weald Basin. Lower Jurassic Shales Occur at a Depth of about 7,000 ft.

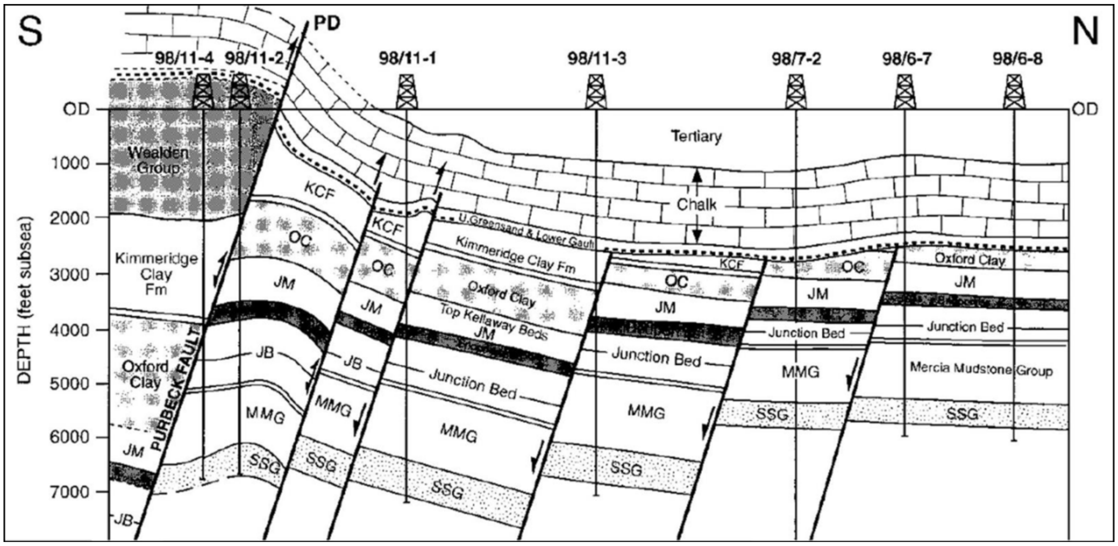


Source: DTI, 2003

However, close-spaced drilling often reveals the presence of additional faults. Indeed, a detailed cross-section of the southern portion of the Wessex Basin, constrained by multiple wells, shows a series of closely spaced faults, Figure XI-13. The depth to the Lias (JB) in this offshore setting south of Wytch oil field ranges from 4,000 to 5,000 ft. Note how each well is located in a separate fault block. Further drilling is likely to discover additional faults.

The Jurassic section comprises an alternating sequence of organic-rich mudstones and carbonates with subordinate sandstones. The main source rocks and potential shale targets in this region are several Jurassic-age shale formations, which are mainly oil-prone in deeper settings (immature elsewhere), in contrast with the mostly dry-gas prone Carboniferous shales of northern England and Scotland.

Figure XI-13: Structural Cross-Section of a 9-Mile Long Portion of the Wessex Basin, Located Offshore Just South of Wytch Oil Field, Showing Depth to the Lias (JB) Ranging from 4,000 to 5,000 ft. Note How Each Well is Located in a Separate Fault Block and Further Drilling is Likely to Discover Additional Faults.



Source: Underhill and Paterson, 1998

The Lias, Kimmeridge, and Oxford clays contain Types II (algal sapropelic), III (terrestrial plant), and II/III (mixed or degraded) kerogen sources. Thermal maturity is highly variable, dependent upon the complex structural evolution of the basins. In general, thermal maturity increases towards the centers of the Wessex and Weald basins, where it reaches adequate rank for shale oil exploration.

The Lower Lias Clays (L. Jurassic), the most important source rock in the region as well as the main shale target, consists of interbedded shales, mudstones, marls and micritic limestones. Lower Lias shales contain 0.5% to 2.1% TOC, reaching as high as 7%. The isotopic character of conventional oils in the Weald Basin (35-42° API gravity) matches with that of the Lower Liassic, indicating close source rock genesis. Organic matter is predominantly sapropelic oil-prone kerogen derived from marine plankton.[19] While vertical TOC variation is considerable, the eastern Weald Basin appears to have lower TOC.

The Arreton 2 well, a key data point located south of the Isle of Wight monocline, recorded oil-prone thermal maturity of 0.8% to 0.9% R_o in the Lias. Similar oil-prone maturity was noted at Penshurst in the central Weald Basin. Thermal maturity modeling indicates that the Lias is within the oil window across much of the Wessex-Channel Basin, perhaps becoming marginally gas-prone in the Pewsey Sub-Basin.

Secondary potential exists in the Oxford (up to 12% TOC) and Kimmeridge clays (up to 20% TOC) in the Upper Jurassic. The Upper Jurassic Kimmeridge Clay consists of alternating shales (including oil shales), calcareous mudstones, interbedded micritic limestones, and thin sandstones and siltstones. The TOC of some thin black shales frequently reaches 10%, occasionally even 20%. Britain's first natural gas well, drilled in 1895 at Heathfield in Sussex, produced 1,000 ft^3/d from an unstimulated Kimmeridge Clay section. However, the Kimmeridge Clay is considered thermally immature in the Wessex-Weald region, apart possibly from the northernmost axial part of the Wessex-Channel Basin. The Upper Jurassic Oxford Clay is organic-rich, reaching 10% TOC, but likewise is thermally immature. Consequently, the Kimmeridge and Oxford clays were excluded from our evaluation.

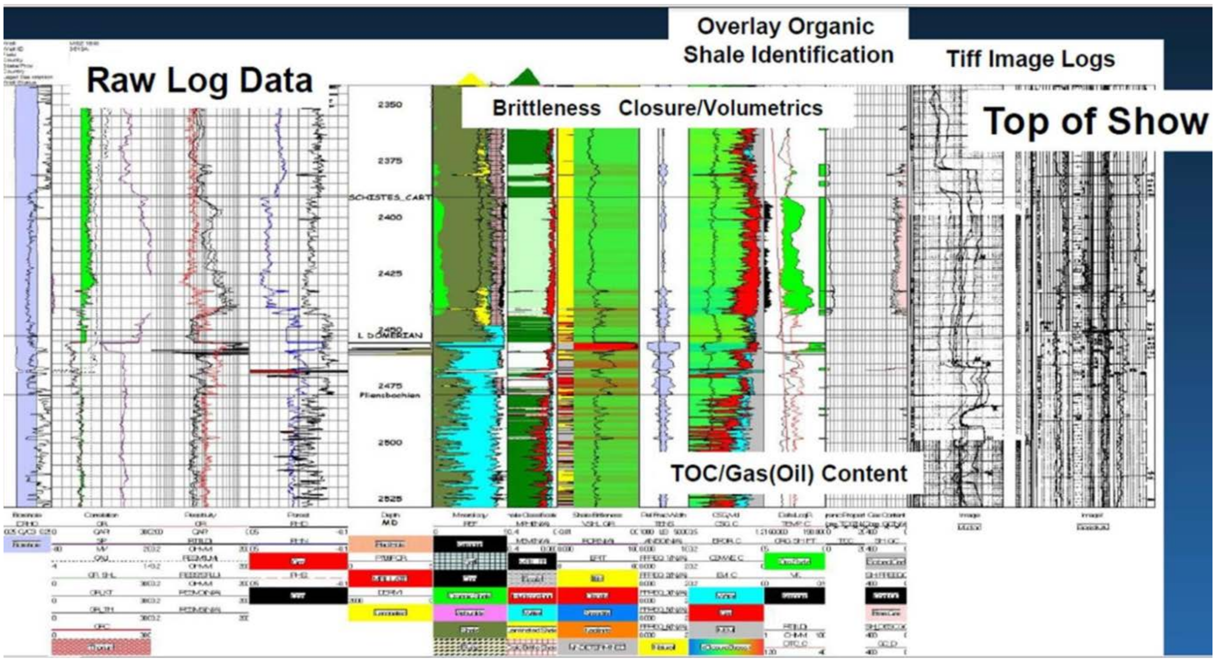
Porosity and permeability of the Jurassic shales are likely to be higher than in the Carboniferous because they have not been subject to as much compaction. Jurassic mudstones encountered in shallow (<30 m) engineering boreholes have porosities in the range 30-40%. However, Jurassic shales buried at depths of 1-5 km are likely to have much lower porosity, perhaps 7%.

2.2 Reservoir Properties (Prospective Area)

The Lias shales average about 600 thick (gross) in the Wessex and Weald basins. Organic-rich thickness of the most oil-saturated and brittle zones, based on analysis of the Lias in the Paris Basin,[20] is estimated at approximately 165 ft, Figure XI-14. Depth to the Lias reaches 6,000 ft in the Weald Basin, averaging about 5,000 ft deep. TOC of the prospective zone is estimated to average 3% but could be considerably higher. Porosity, estimated at 7%, is likely to be higher than older Carboniferous shales, but lower than the 30-40% porosity measured at shallow locations near outcrop.[21] The current average geothermal gradient is 33°C/km.

Although not assessed, the Jurassic Kimmeridge Clay, another potential source rock in the Wessex and Weald basins, is notable for containing thin limestone stringers. These include coccolithic carbonates which are somewhat similar to the lithology of the carbonate-rich Mid-Bakken Shale in North Dakota.

Figure XI-14: Log Suite Showing the Jurassic Lias In the Paris Basin, as a Proxy for the Wessex-Weald Shale Region in the UK



Source: M. Mullen, Realm Energy, 2011

2.3 Resource Assessment

The Wessex and Weald basins extend over an onshore area of approximately 3,500 mi^2. The prospective area was estimated to be half of total area (1,740 mi^2), with the remaining area excluded due to potential faulting, shallow depth, erosion of the Lias, and surface access issues. Out of a risked shale oil in-place of 17 Bbbl and risked shale gas in-place of 8 Tcf, the risked, technically recoverable resources are estimated to be 0.7 billion barrels of shale oil and 0.6 Tcf of associated shale gas, Tables XI-1 and XI-2.

Celtique Energie has reported that the Liassic Shale at their Weald Basin licenses ranges from 9,000 to 13,000 ft deep within a 467-km^2 prospective area. The company estimated that the Liassic could have mean recoverable shale oil and shale gas resources of 125 million barrels of oil and 10 Tcf of shale gas.

2.4 Recent Activity

Privately held **Celtique Energie** holds licenses in three areas of the UK: the Cheshire Basin, East Midlands, and the Weald Basin. In the Weald Basin, Celtique has a 50% share in licenses covering 1,000 sq km. The company claims to have unconventional oil and gas potential in the Jurassic Liassic shales, as well as conventional potential in the Triassic. No shale drilling has been reported.

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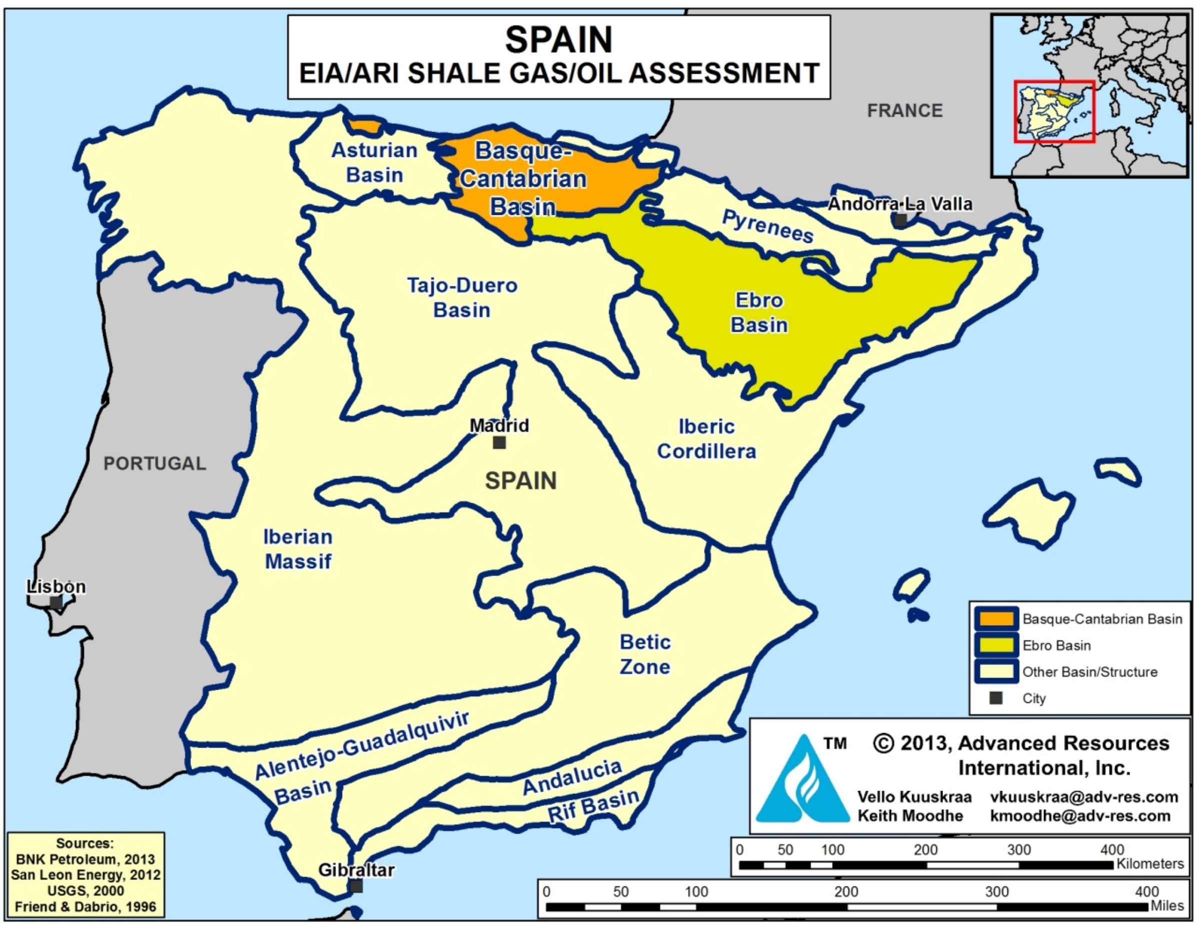
XII. SPAIN

SUMMARY

The Basque-Cantabrian Basin, located in northern Spain, contains a series of organic-rich Jurassic-age shales with potential for wet gas and condensate, Figure XII-1. In addition, the Ebro (Solsona) Basin, located to the south and east of the Basque-Cantabrian Basin, may also have local potential for shale gas and oil. However, the shale in the Ebro Basin has TOC below the 2% cut-off used in this study and thus was not quantitatively assessed.

Figure XII-1. Selected Shale Gas and Oil Basins of Spain



Source: ARI, 2013

The Jurassic-age (Liassic) marine shale in the Basque-Cantabrian Basin contains an estimated 42 Tcf of risked shale gas resource in-place, with about 8 Tcf as the risked, technically recoverable shale gas resource, Table XII-1. In addition, the Jurassic Lias Shale contains nearly 3 billion barrels of risked oil/condensate in-place, with about 0.1 billion barrels as the risked, technically recoverable shale oil resource, Table XII-2.

Table XII-1. Shale Gas Reservoir Properties and Resources of Spain

Basic Data	Basin/Gross Area		Basque-Cantabrian (6,620 mi^2)
	Shale Formation		Jurassic
	Geologic Age		L. - M. Jurassic
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		2,100
	Thickness (ft)	Organically Rich	600
		Net	150
	Depth (ft)	Interval	8,000 - 14,500
		Average	11,000
Reservoir Properties	Reservoir Pressure		Slightly Overpress.
	Average TOC (wt. %)		3.0%
	Thermal Maturity (% Ro)		1.15%
	Clay Content		Medium
Resource	Gas Phase		Wet Gas
	GIP Concentration (Bcf/mi^2)		49.8
	Risked GIP (Tcf)		41.8
	Risked Recoverable (Tcf)		8.4

Source: ARI, 2013

Table XII-2. Shale Oil Reservoir Properties and Resources of Spain

Basic Data	Basin/Gross Area		Basque-Cantabrian (6,620 mi^2)
	Shale Formation		Jurassic
	Geologic Age		L. - M. Jurassic
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		2,100
	Thickness (ft)	Organically Rich	600
		Net	150
	Depth (ft)	Interval	8,000 - 14,500
		Average	11,000
Reservoir Properties	Reservoir Pressure		Slightly Overpress.
	Average TOC (wt. %)		3.0%
	Thermal Maturity (% Ro)		1.15%
	Clay Content		Medium
Resource	Oil Phase		Condensate
	OIP Concentration (MMbbl/mi^2)		3.4
	Risked OIP (B bbl)		2.9
	Risked Recoverable (B bbl)		0.14

Source: ARI, 2013

INTRODUCTION

The Jurassic-age rocks of the Basque-Cantabrian Basin crop out in the eastern and western portion of the basin, providing access to valuable information on the geologic setting and reservoir properties of these shales. Analysis of rock samples indicates Type I/II organic matter with TOC values (in immature samples) of up to 25%.[1]

The shales in the Lower Jurassic Comino and Castillo Pedroso formations (Toarcian- and Pliensbachian-age) were deposited under deep marine conditions following tectonic extension. The shales are interbedded within limestones and marls which, much like in the Bakken Shale of the Williston Basin (USA), may provide additional flow and storage capacity for oil and gas expulsed from the maturing shales.[1,2]

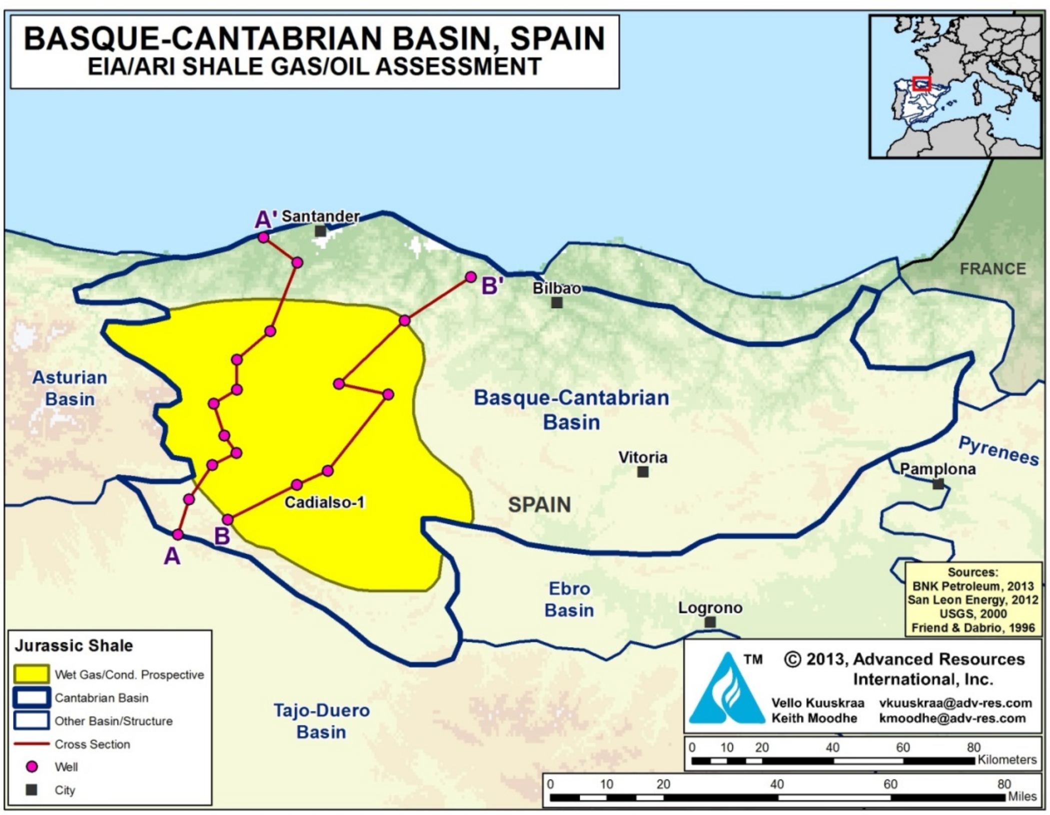
1. BASQUE-CANTABRIAN BASIN

The Basque-Cantabrian Basin covers a large 6,620-mi^2 area along the northern border of Spain. The basin is bounded by faults and thrusts on the east, west and south and by the Cantabrian Sea on the north. The Basque-Cantabrian Basin contains a sequence of formations that hold organic-rich shales of Silurian-Ordovician, Jurassic and Cretaceous age. Of these, the Jurassic (Liassic) shales appear to offer the most potential.

1.1 Geologic Setting

Jurassic Shales. The Basque-Cantabrian Basin contains a series of regionally significant, thick black shales of Jurassic-age, including the Lias Shale at the base of the Lower Jurassic. We have mapped a 2,100-mi^2 higher quality prospective area for the Lias Shale in the western portion of this geologically complex basin. We used information on the erosion of the Lias Shale on the north and south and the 400-m gross Jurassic interval to establish our prospective area, Figure XII-2.[3]

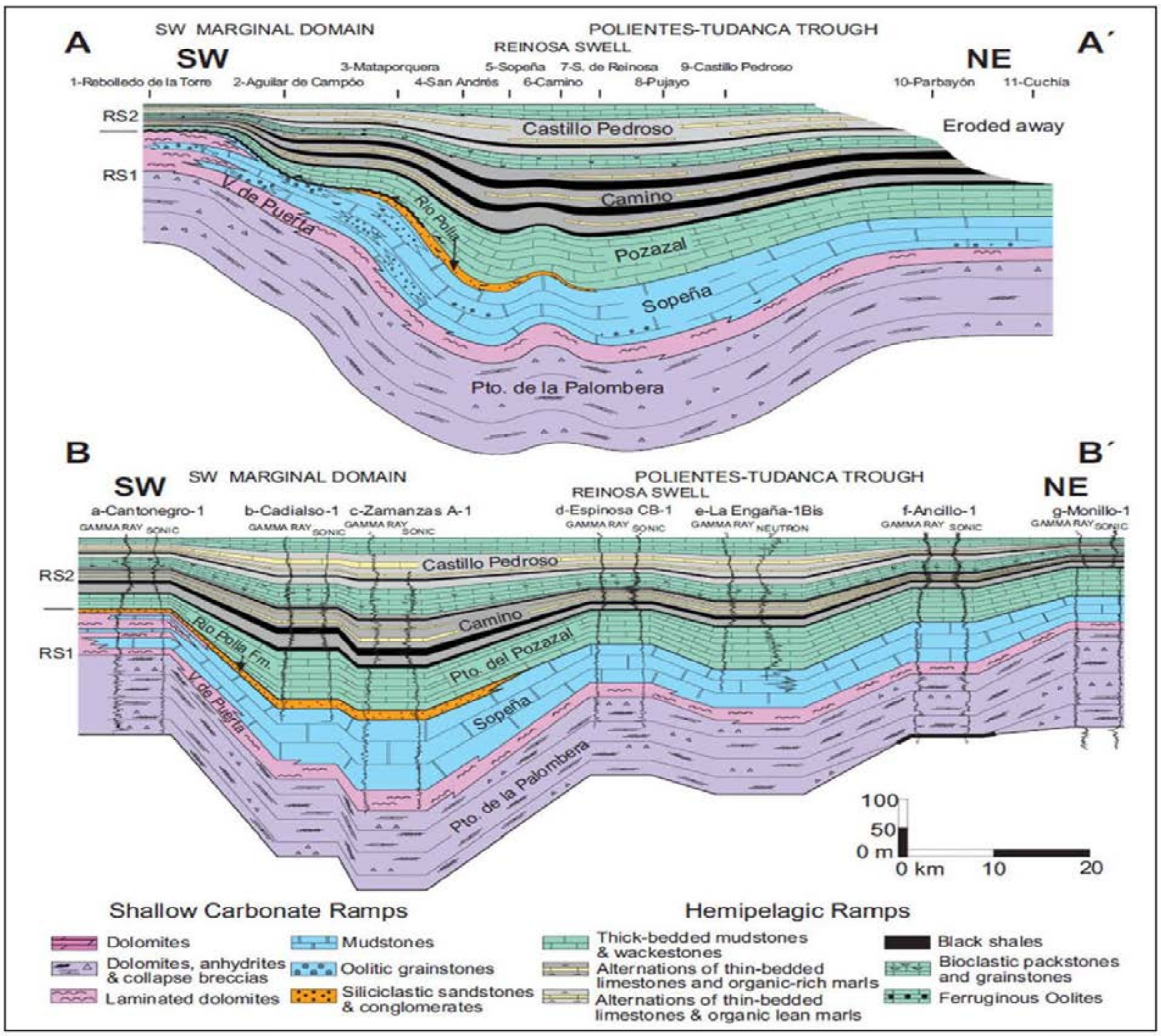
Figure XII-2. Prospective Area of Jurassic Shale, Basque-Cantabrian Basin



Source: ARI, 2013

A series of interbedded black shales and carbonates exists within the Jurassic interval. Figure XII-3 provides two regional cross-sections, A to A' and B to B', identifying the sequence of Jurassic black shales in the prospective area of the basin. Figure XII-2, shown previously, provides the location of these two cross-sections and identifies the key Cadialso-1 well near the south-western end of cross-section B to B'.

Figure XII-3. Cross-Sections Through Prospective Area of Basque-Cantabrian Basin



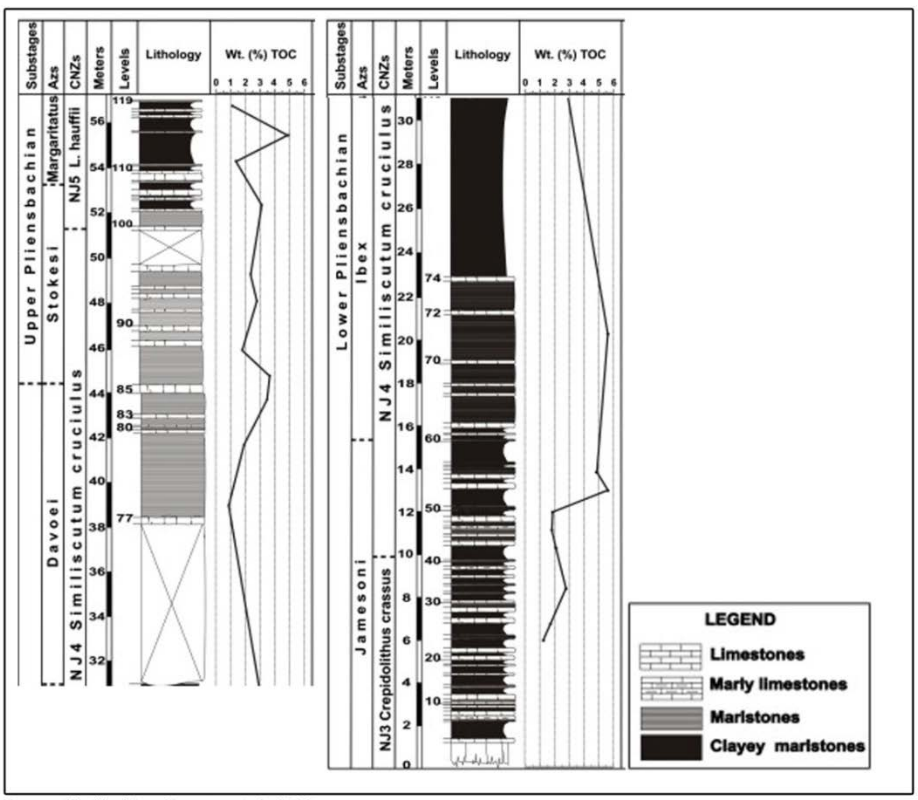
Source: Quesada, S., 2005.

1.2 Reservoir Properties (Prospective Area)

Jurassic (Liassic) Shales. The Cadialos-1 well (shown on Cross-Section B-B'), drilled to 12,000 ft, provided valuable information on the organic-rich Lias Shale. The shale has a gross thickness of 280 ft with a net thickness of 30 to 50 ft, TOC values of 2% to 4% and a thermal maturity (R_o) of 1.2%. The well also intersected a shallower Jurassic Shale at about 9,500 ft with a gross thickness of 400 ft and a net thickness of about 100 ft. This shallower Jurassic Shale has a TOC of about 2% and a thermal maturity (R_o) of 1.1%.

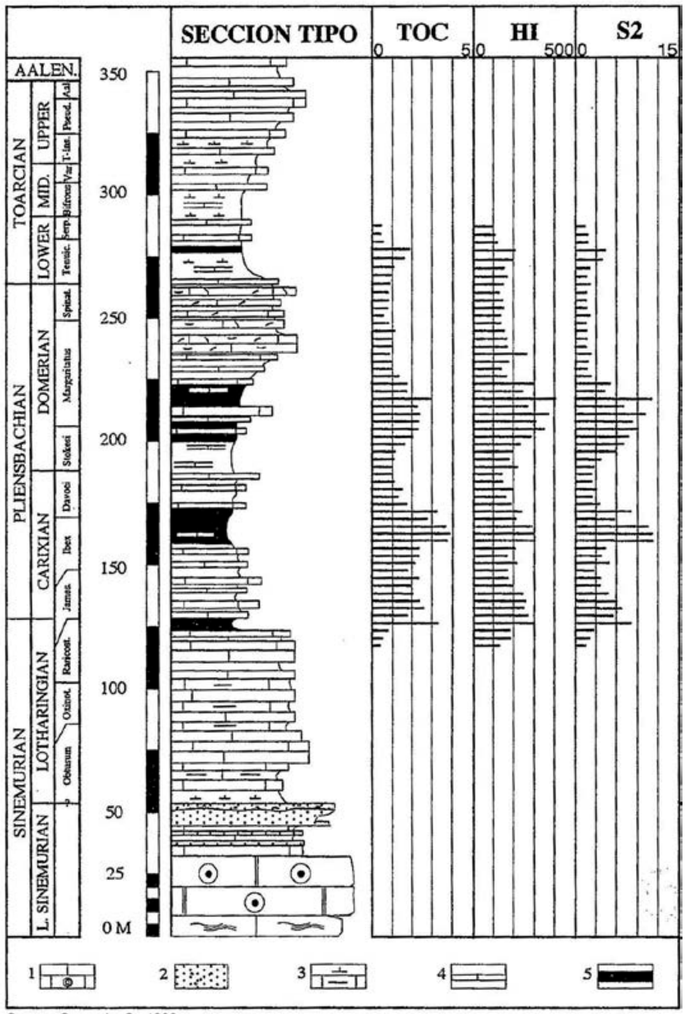
Figures XII-4 and XII-5 provide additional information on the TOC and thermal maturity values for the Jurassic (Pliensbachian) Lias Shale in the northern portion of the prospective area near the Poliente-Tudanca Trough.[4,5,6]

Figure XII-4. TOC Values in the Pliensbachian Interval of the Jurassic



Source: Modified from Fraguas at al., 2008

Figure XII-5. TOC Values in the Pliensbachian Interval of the Jurassic



Source: Quesada, S., 1996.

1.3 Resource Assessment

The entire package of Jurassic shales, including the Lias Shale, within the 2,100-mi^2 prospective area of the Basque-Cantabrian Basin has a resource concentration of about 50 Bcf/mi^2 of wet shale gas and 3 million barrels/mi^2 of shale condensate.

The risked resource in-place within the prospective area is estimated at 42 Tcf of wet shale gas and 3 billion barrels of shale condensate. Based on moderate reservoir properties, we estimate risked, technically recoverable resources from these Jurassic shales of 8 Tcf of wet shale gas and 0.1 billion barrels of shale condensate.

1.4 Recent Activity

Several companies hold leases and are actively exploring the Jurassic Shales in the Basque-Cantabrian Basin. For example, San Leon Energy (who acquired Realm Energy and its oil and gas concessions in Spain) has two concession areas, totaling over 210,000 acres in the basin. In addition, BNK Petroleum has a 380,000-acre Jurassic Shale concession in Castillo y Leon and hopes to spud an exploration well in this area during 1Q 2013, pending approval.[7]

HEYCO Energy and Cambria Europe, along with the Basque Energy Board, announced a USD $138 million exploration program in 2011.[8] No further information is available on the activities or results of this exploration program.

2. OTHER SHALES OF THE BASQUE-CANTABRIAN BASIN

Ordovician and Silurian Shales. The presence of the Ordovician and Silurian shale interval, a major source rock in the Middle East and North Africa, has been well established in Spain in outcrops and boreholes. To further assess the resource potential of these shales, a total of 24 new samples of the Lower Silurian Formigoso Formation and Middle Ordovician Sueve Formation was gathered from twelve different outcrop locations in the provinces of Asturias and Leon during May 2010. [9]

Nineteen of the twenty-four samples had TOC values less than 1% and no sample recorded a TOC above 2%. In addition, the remaining kerogen type was mostly inertinite.[9] Based on the results of this geochemical work, the investigators concluded that the Lower Paleozoic (Ordovician and Silurian) shales in this part of the basin have poor potential for shale gas and oil. As such, these shales were excluded from further assessment.[9]

Cretaceous Shales. The thick Cretaceous-age (Albian-Cenomanian) Valmaseda Formation contains the Enara Shale, which hold an estimated 185 Bm^3 (6.5 Tcf) of shale gas based on a study of 13 wells in the Gran Enara field in northern Spain. A shale gas exploration program has been proposed.[10] However, no details in the TOC or other properties accompanied this initial shale gas assessment. San Leon Energy's separate characterization of the Valmaseda Formation and the Enara Shale indicates that the TOC, while up to 3.6% locally, averages only about 1%. As such, these shales were excluded from further assessment.

3. EBRO BASIN

The Ebro (Solson) Basin is located to the south and east of the Basque-Cantabrian Basin in the northeast portion of Spain. The shale potential in this basin has been evaluated based on 30 older petroleum wells, twelve of which penetrated the Paleozoic section. The wells identified a shale sequence at 1,650 to 4,000 m depth, with a thickness of 50 to 100 m and a thermal maturity ranging from 1% to 2% R_o, placing these shales in the wet to dry gas window. However, because the TOC of these shales averages only about 1%, the Paleozoic shales in the Ebro Basin were excluded from further assessment.[4]

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A series of younger Eocene-age reservoir intervals also contain thermally mature shales. These mostly Middle Eocene shales are deposited as thin layers of shale interbedded within low-porosity sandstones. Again, however, the TOC values in these Eocene shales averaged less than 1%, therefore these shales were excluded from further assessment.[4]

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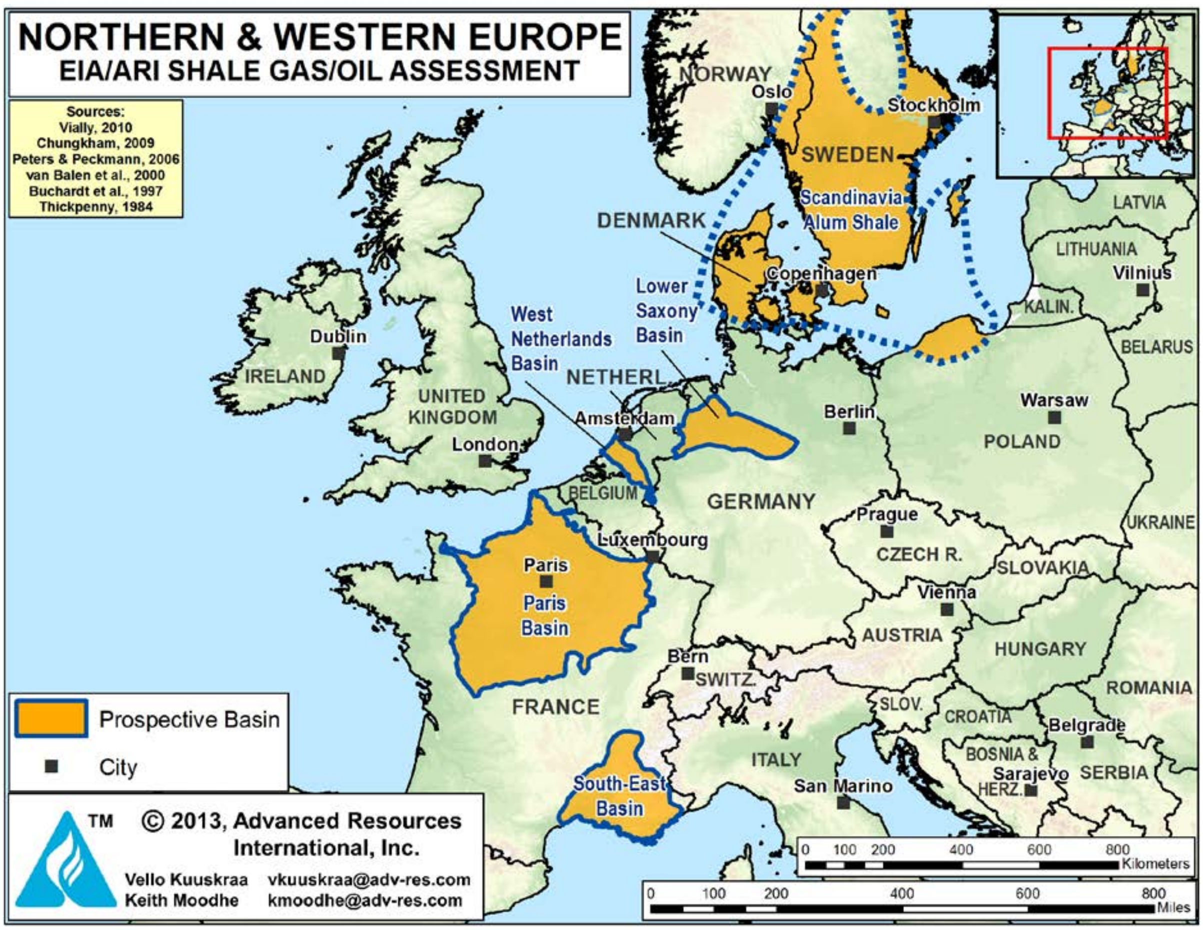
XIII. NORTHERN AND WESTERN EUROPE

SUMMARY

Numerous shale gas basins and formations exist in Northern and Western Europe. This Chapter discusses five of the more prominent of these shale basins and formations, namely: the Paris and South-East basins of France, the Lower Saxony Basin of Germany, the West Netherland Basin of the Netherlands, and the Alum Shales underlying Scandinavia, Figure XIII-1. Please see individual Chapters for United Kingdom (Chapter XI) and Spain (Chapter VII) for discussion of the other shale basins of Northern and Western Europe.

Figure XIII-1. Prospective Shale Basins of Northern and Western Europe



Source: ARI, 2013.

We estimate risked shale gas in-place for the five Northern and Western European shale basins addressed by this study of 1,165 Tcf, with 221 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate that these five shale basins contain 190 billion barrels of risked shale oil in-place, with 8.3 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-1.

Table XIII-1. Shale Gas and Shale Oil Resources of Northern and Western Europe

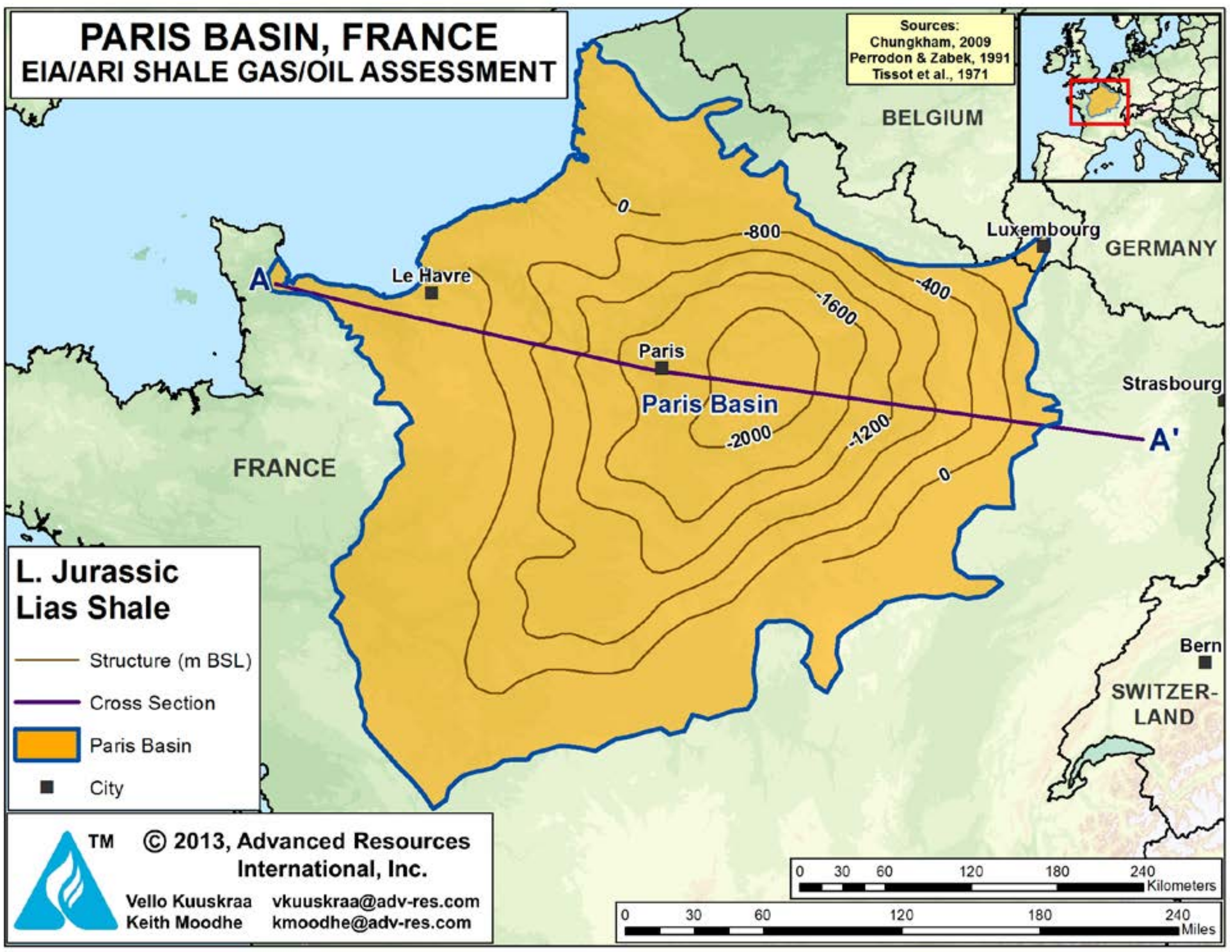
Basin/Formation	Risked Shale Gas Resources: In-Place (Tcf)	Risked Shale Gas Resources: Technically Recoverable (Tcf)	Risked Shale Oil Resources: In-Place (B bbl)	Risked Shale Oil Resources: Technically Recoverable (B bbl)
1. Paris Basin (France)				
·L. Jurassic Lias	23.8	1.9	38.0	1.52
·Permian-Carboniferous	666.1	127.3	79.5	3.18
Total	689.9	129.3	117.5	4.70
2. South-East Basin (France)				
·L. Jurassic Lias	37.0	7.4	0.0	0.00
Total	37.0	7.4	0.0	0.00
3. Lower Saxony Basin (Germany)				
·Toarcian Posidonia	77.7	16.9	10.6	0.53
·Wealden	1.8	0.1	3.2	0.13
Total	79.5	17.0	13.8	0.66
4. West Netherlands Basin (Netherlands)				
·Namurian Epen	93.7	14.8	47.1	2.35
·Namurian Geverik	50.6	10.1	6.3	0.32
·Toarcian Posidonia	6.8	1.0	5.4	0.27
Total	151.1	25.9	58.8	2.94
5. Alum Shale				
·Denmark	158.6	31.7	0.0	0.00
·Sweden	48.9	9.8	0.0	0.00
Total	207.5	41.5	0.0	0.00
Total	**1,165.1**	**221.0**	**190.0**	**8.29**

1. PARIS BASIN

1.1 Introduction

The Paris Basin of France is a large 65,000-mi^2 intra-cratonic basin that encompasses most of the northern half of the country, Figure XIII-2. The basin is bounded on the east by the Vosges Mountains, on the south by the Central Massif, on the west by the Armorican Massif and, for the purposes of this study, by the English Channel on the north. The Paris Basin is filled mostly with Mesozoic and Paleozoic rocks which reach 10,000 feet of thickness in the center of the basin but are exposed along its margins.

Figure XIII-2. Outline and Structure of Paris Basin



Source: ARI, 2013

The Paris Basin and its two distinct shale gas and oil formations - - the Lias Shale and the Permian-Carboniferous Shale - - hold 690 Tcf of risked shale gas in-place, with 129 Tcf as the risked, technically recoverable shale gas resource, Table XIII-2. In addition, the Paris Basin and its two shale formations hold 118 billion barrels of risked shale oil in-place, with 4.7 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-3.

Table XIII-2. Shale Gas Reservoir Properties and Resources of the Paris Basin

Basic Data	Basin/Gross Area		Paris ($61,000\ mi^2$)			
	Shale Formation		Lias Shale	Permian-Carboniferous		
	Geologic Age		L. Jurassic	Permian-Carboniferous		
	Depositional Environment		Marine	Lacustrine		
Physical Extent	Prospective Area (mi^2)		5,670	11,960	17,940	17,940
	Thickness (ft)	Organically Rich	350	400	250	500
		Net	105	160	83	100
	Depth (ft)	Interval	4,000 - 10,000	6,000 - 8,000	9,000 - 11,000	12,000 - 16,400
		Average	7,000	7,000	10,000	14,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		4.5%	9.0%	9.0%	9.0%
	Thermal Maturity (% Ro)		0.85%	0.85%	1.15%	1.60%
	Clay Content		Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		8.4	12.8	46.2	61.3
	Risked GIP (Tcf)		23.8	48.9	265.1	352.0
	Risked Recoverable (Tcf)		1.9	3.9	53.0	70.4

Table XIII-3. Shale Oil Reservoir Properties and Resources of the Paris Basin

Basic Data	Basin/Gross Area		Paris ($61,000\ mi^2$)		
	Shale Formation		Lias Shale	Permian-Carboniferous	
	Geologic Age		L. Jurassic	Permian-Carboniferous	
	Depositional Environment		Marine	Lacustrine	
Physical Extent	Prospective Area (mi^2)		5,670	11,960	17,940
	Thickness (ft)	Organically Rich	350	400	250
		Net	105	160	83
	Depth (ft)	Interval	4,000 - 10,000	6,000 - 8,000	9,000 - 11,000
		Average	7,000	7,000	10,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal
	Average TOC (wt. %)		4.5%	9.0%	9.0%
	Thermal Maturity (% Ro)		0.85%	0.85%	1.15%
	Clay Content		Medium	Medium	Medium
Resource	Oil Phase		Oil	Oil	Condensate
	OIP Concentration ($MMbbl/mi^2$)		13.4	20.4	0.2
	Risked OIP (B bbl)		38.0	78.3	1.2
	Risked Recoverable (B bbl)		1.52	3.13	0.05

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1.2 Geologic Setting

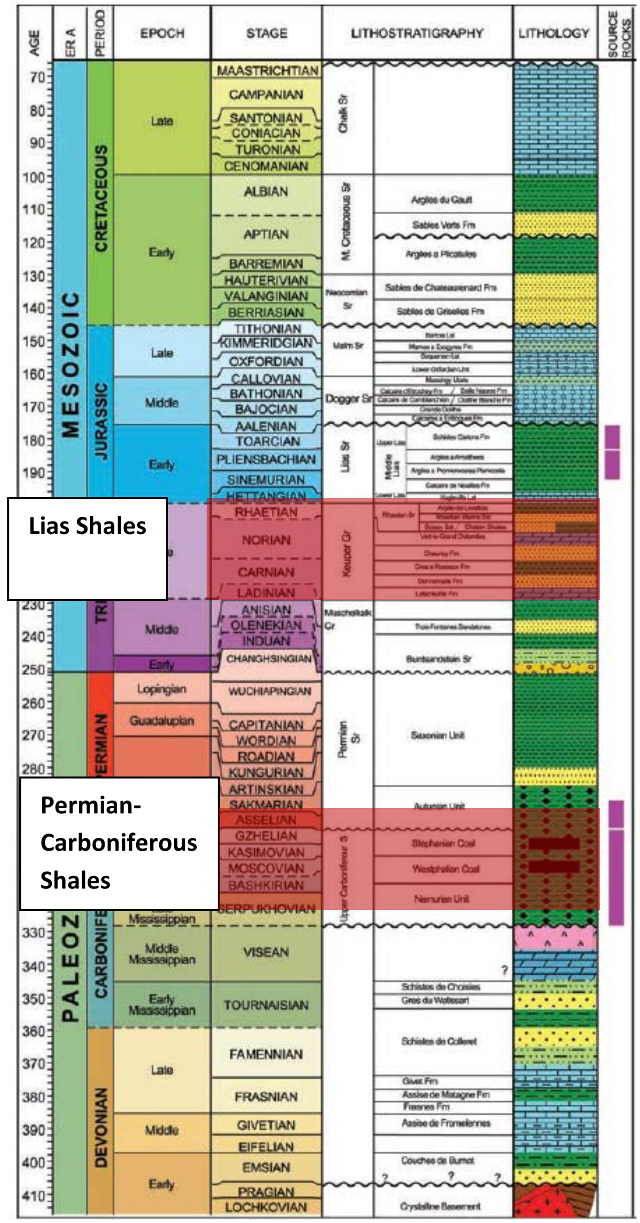
The Paris Basin contains two shale plays addressed by this resource study - - the Lower Jurassic Lias Shale and the Permian-Carboniferous Shale, Figure XIII-3[1]. The Jurassic Lias Shale is composed of three distinct organic-rich black shales - - the Hettangian-Sinemurian (Lower Lias) Shale, the Pliensbachian (Middle Lias) Shale, and the younger Toarcian ("Schistes Carton") Shale which is equivalent to the Posidonia Shale in Germany and the Netherlands. Together these three shales are as much as 650 feet thick in the central part of the Paris Basin.[2] For the purpose of this shale resource assessment, we have grouped these three shales into a single shale assessment interval called the Lias (Liassic) Shale.

Figure XIII-4 provides an east to west cross-section for the Lias Shale across the Paris Basin.[2] (The location of the cross-section is provided on Figure XIII-2). Basin modeling of the Lias Shale, in a smaller 3,640-mi^2 study area of the Paris Basin, indicated that this composite shale interval, primarily the Toarcian ("Schistes Carton") Shale, has generated 81 billion barrels of hydrocarbons.[3] Extrapolating the smaller basin modeling study area to the full Lias Shale prospective area in the Paris Basin of 5,670 mi^2 and assuming that 30% of the generated hydrocarbon still remains in the source rock, we estimate that 38 billion barrels of hydrocarbons remain in the Lias Shale.

The deeper Permian-Carboniferous unconventional gas play is located in the eastern and southern portions of the Paris Basin, particularly in the Lorraine Sub-basin. This area contains a thick package of tight sands, shales and methane-charged coals. This resource assessment will address the organic-rich shales of the Permian-Carboniferous interval, including the Lower Permian Autunian Unit, the Upper Carboniferous (Late Mississippian and Early Pennsylvanian) Namurian Unit, as well as the Upper Carboniferous (Middle and Pennsylvanian) inter-bedded bituminous shales in the Stephanian and Westphalian sections.

Figure XIII-5 provides an east to west cross-section across the Paris Basin, identifying the Permian-Carboniferous Shale in the eastern portion of the basin.[1] The shales have fluvial and lacustrine deposition raising concern with respect to higher clay content and less brittle reservoir rock. The kerogen in the shales is a mixed Type II/III.

Figure XIII-3. East Paris Basin Stratigraphic Column



Source: Chungkham, 2009

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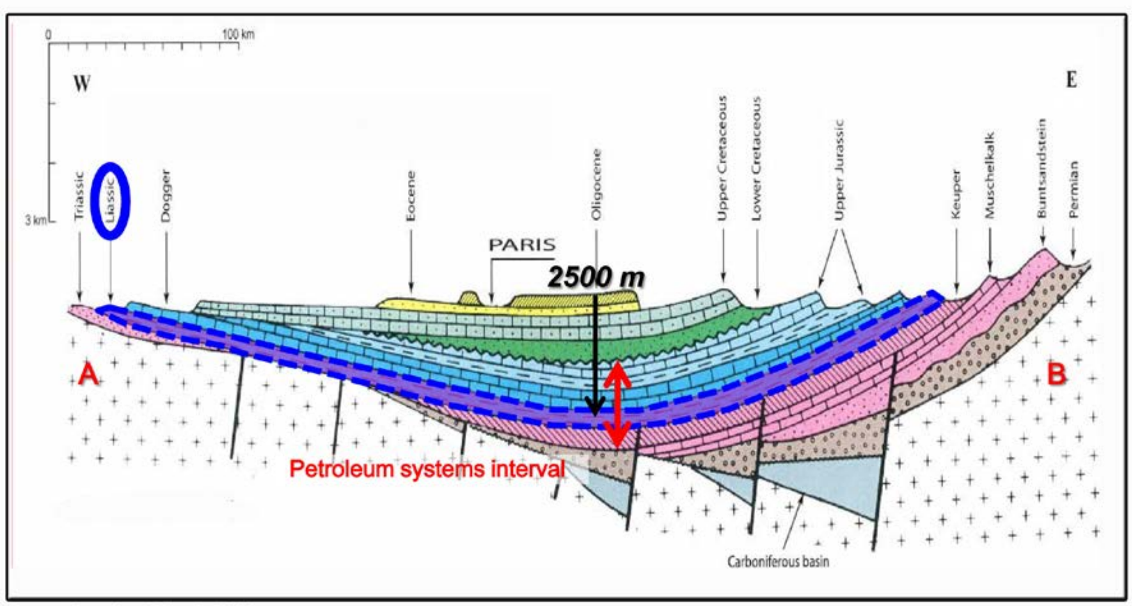
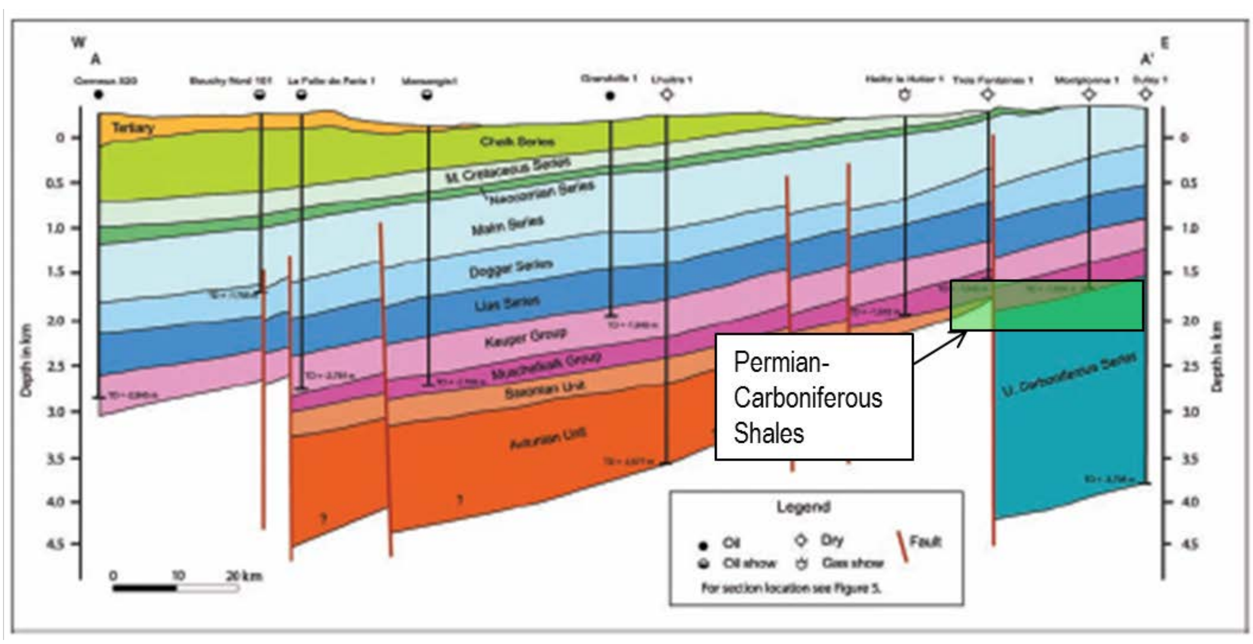
Figure XIII-4. East-West Cross-Section of Paris Basin Highlighting Lias (Liassic) Shales



Source: Perrodon, Zabeck, 1990

Figure XIII-5. East-West Cross-Section of Paris Basin Highlighting Permian-Carboniferous Shales

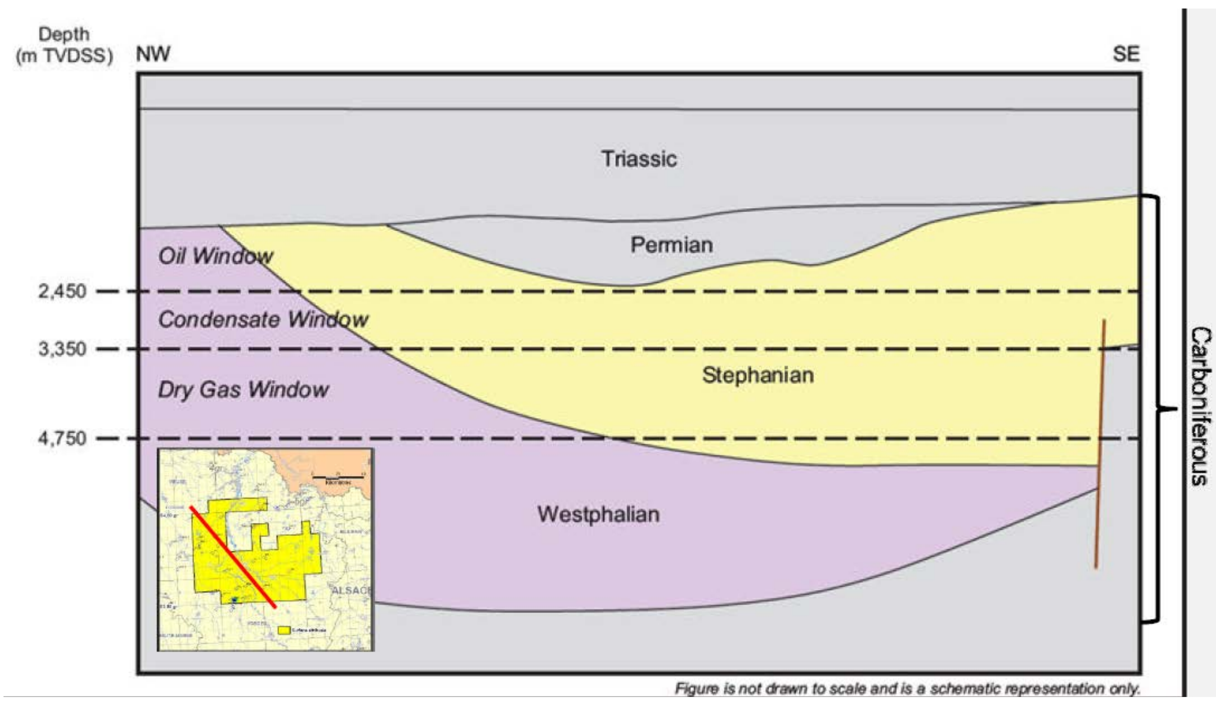


Source: Chungkham, 2009

We have concentrated our assessment on the Lower Permian Autunian and Upper Carboniferous Namurian shales. The substantial presence of less brittle coals in the Upper Carboniferous Westphalian and Stephanian may hinder successful application of hydraulic stimulation in these shales. In addition, the organic content (TOC) of the inter-bedded shales in the Westphalian and Stephanian is reported to range from 0.5 to 1.4%, below the minimum TOC criterion used in this study.[4]

Based on information in the technical literature, we have used depth as a proxy for thermal maturity (R_o) for establishing the dry, wet gas/condensate and oil windows for this shale play. The dry gas window is represented by burial depth between 3,350 m and 4,750 m; the wet gas/condensate window is represented by burial depth between 2,450 m and 3,350 m, and the oil window is represented by burial depth between 1,200 m and 2,450 m, Figure XIII-6.[5]

Figure XIII-6. Relationship of Thermal Maturity and Burial Depth, Paris Basin



Source: Elixir, 2011

1.3 Reservoir Properties (Prospective Area)

Lias Shale. We have mapped a 5,670-mi^2 oil prospective area for the Lias Shale based on the 435^o C Tmax contour area for the higher organic content Toarcian ("Schistes Carton") Shale. The 435^o C Tmax contour (oil window) for the deeper Hettangian-Sinemurian Shale underlies the 435^{o}C Tmax contour of the Toarcian ("Schistes Carton") Shale, Figure XIII-7.

The depth of the Lias Shale ranges from 4,000 feet to 10,000 feet in the basin center, averaging 7,000 feet. The gross thickness of the shale ranges from 300 to 400 feet, with 105 feet of net organic-rich shale over the prospective area. The thermal maturity of the shale in the prospective area (bounded by the 435^o C Tmax contour) ranges from 0.7% to 1.0%, placing the Lias Shale in the oil window.[1] The TOC of the shale, while highest in the Toarcian and lowest in the Sinemurian, averages 4.5%.

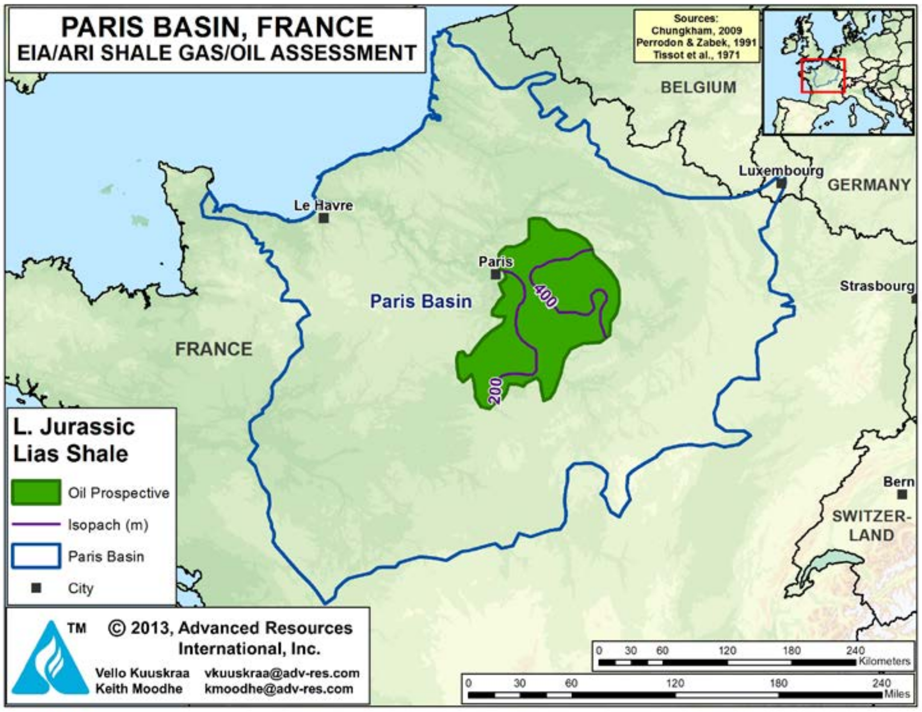
The shales are assumed to be normally pressured, given the presence of vertical fractures (and higher vertical permeability). The shale appears to be medium in clay content, lower in calcite (10% to 30%) and quartz (5% to 20%).

Permian-Carboniferous Shale. We have mapped a 17,940-mi^2 prospective area for dry gas and wet gas/condensate for the Permian-Carboniferous Shale and a more limited 11,960-mi^2 prospective area for oil. For this, we used the 200 m gross isopach on the north and west and the boundaries of the Paris Basin on the south and east, Figure XIII-8.[1] Approximately 50 wells provide control for this gross isopach. We assumed that the shallower oil interval extended across two-thirds of the larger prospective area.

Until recently, information on the Permian Carboniferous Shale was limited. Fortunately, Elixir Petroleum has undertaken an exploration program on their Moselle Permit in the Paris Basin and has provided information on their program. We have combined this data with information from the technical literature for the reservoir properties of the Permian-Carboniferous Shales.

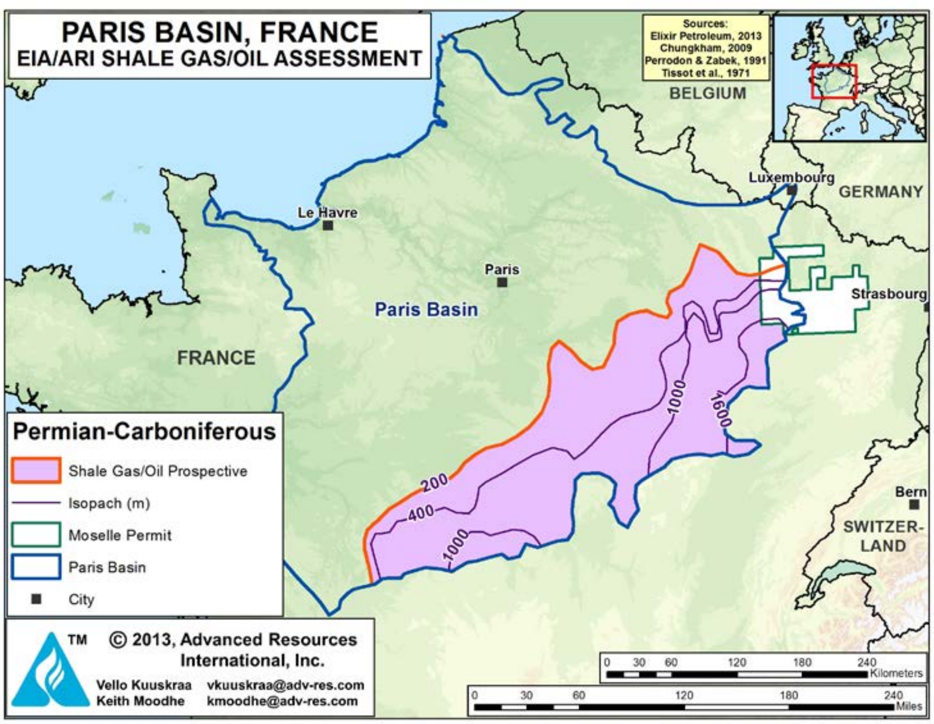
The depth of the Permian Carboniferous Shale ranges from 6,000 feet to 16,400 feet, averaging 7,000 feet in the oil window, 10,000 feet in the wet gas/condensate window, and 14,200 feet in the dry gas window. A significant portion of the Upper Carboniferous Namurian section is at depths below 5,000 m and thus excluded from this resource assessment.

Figure XIII-7. Prospective Area for Lower Jurassic Lias Shale, Paris Basin



Source: ARI, 2013

Figure XIII-8. Prospective Area for Permian-Carboniferous Shale, Paris Basin



Source: ARI, 2013

While the gross interval in the prospective area is quite thick, much of this interval contains lower TOC rocks. We estimate an average organic-rich net shale pay for the Permian Carboniferous Shale of 83 to 160 feet, using low to moderate net to gross ratios. The TOC of the shales ranges from 2% to 15%, averaging 9%. The reservoir is normally pressured.

1.4 Resource Assessment

Lias Shale. The Lias Shale of the Paris Basin contains a resource concentration of 13 million barrels/mi^2 of oil plus associated gas. We estimate risked oil in-place for the Lias Shale of 38 billion barrels, with 1.9 billion barrels as the risked, technically recoverable shale oil resource. In addition, we estimate risked associated shale gas in-place of 24 Tcf, with 2 Tcf as the risked, technically recoverable shale gas resource, Tables XIII-2 and XIII-3.

Permian-Carboniferous Shale. Given the limited data on the extent and distribution of the individual shale units within the prospective area, we view the resource assessment of the Permian-Carboniferous Shale as preliminary. The Permian-Carboniferous Shale of the Paris Basin contains resource concentrations of 61 Bcf/mi^2 in the dry gas window, 46 Bcf/mi^2 in the wet gas/condensate window, and 20 million barrels/mi^2 in the oil window. We estimate risked gas in-place for the Permian-Carboniferous Shale of 666 Tcf, with a risked, technically recoverable shale gas resource of 127 Tcf (including associated gas). In addition, we estimate risked shale oil/condensate in-place of 80 billion barrels, with 3.2 billion barrels as the risked, technically recoverable shale oil resource, Tables XIII-2 and XIII-3.

1.5 Recent Activity

Most of the past exploration in the Paris Basin has targeted the Jurassic-age Lias Shale oil play. However, some firms are beginning to acquire acreage in the eastern portions of the Paris Basin where the Permian-Carboniferous Shale formation is the target. The 2,070 mi^2 Moselle Permit and its Permian-Carboniferous resource interval, first granted to East Paris Petroleum Development Corp, has been acquired by Elixir Petroleum. While the terms of the lease do not require the company to drill any wells, Elixir has publically stated that it intends to investigate the unconventional gas potential (tight gas, CBM and shale gas) on its lease.[5]

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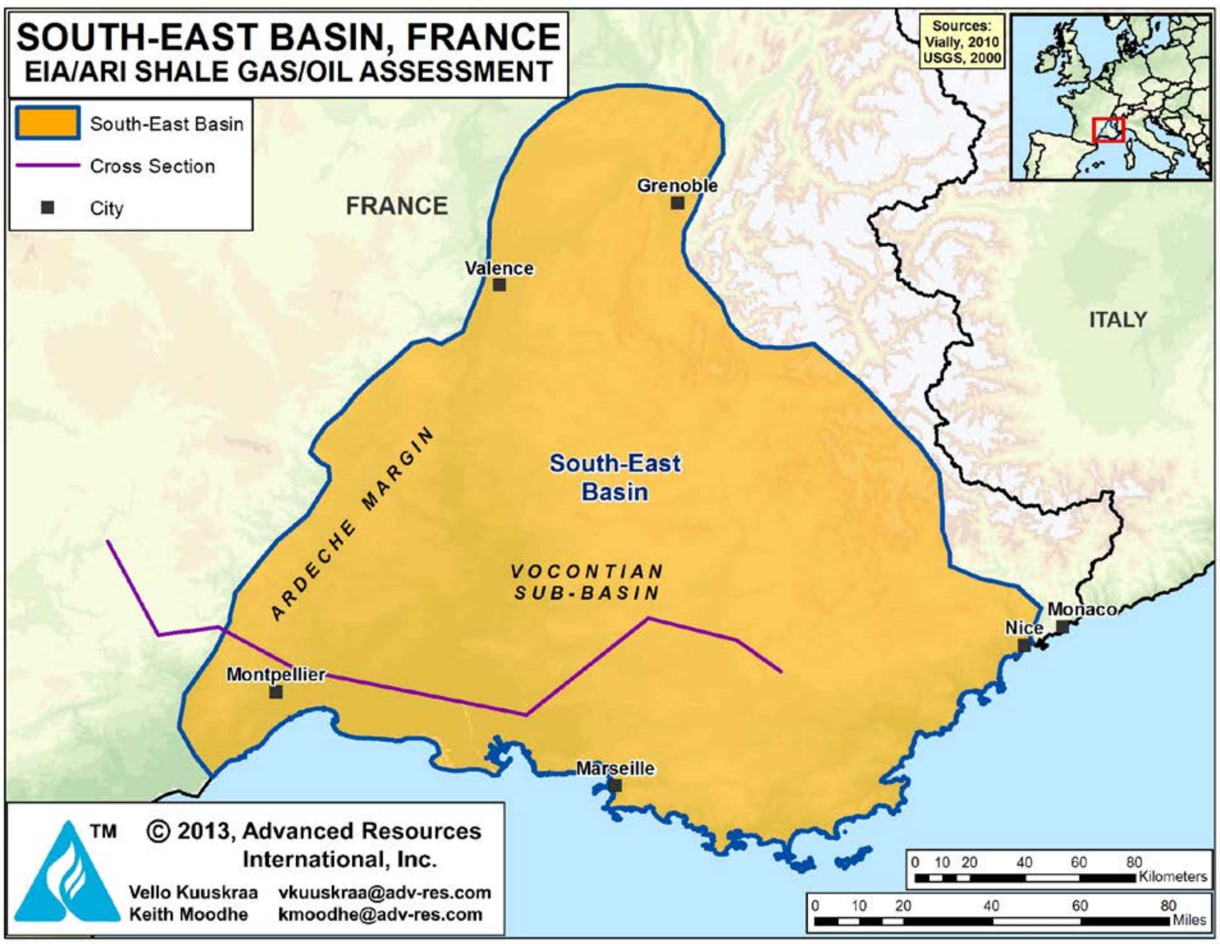
2. SOUTH-EAST BASIN

2.1 Introduction

The South-East Basin is the thickest sedimentary basin in France, containing up to 10 km of Mesozoic to Cenozoic sediments. The basin is bounded on the east and south by the Alpine thrust belt and on the west by the Massif Central, an uplifted section of the Paleozoic basement, Figure XIII-9. Local oil and gas seeps discovered in the 1940's encouraged hydrocarbon exploration in the South-East Basin. However, despite the drilling of 150 wells in the onshore and offshore portions of the basin, no significant oil and gas deposits have been found. Recent re-evaluations of the basin's potential have stimulated a further look at this complex basin and its shale formations.

Figure XIII-9. Outline of South-East Basin of France



Source: ARI, 2013

We estimate that the South-East Basin contains 37 Tcf of risked shale gas in-place, with 7 Tcf as the risked, technically recoverable shale gas resource, Table XIII-4. We have limited our shale resource assessment to the western portion of the basin and its deep dry gas potential area. In addition, given considerable uncertainty as to the location of the higher TOC (>2%) portions of the basin, we have assumed that only 30% of the overall dry gas prospective area will meet the 2% TOC criterion used by the study.

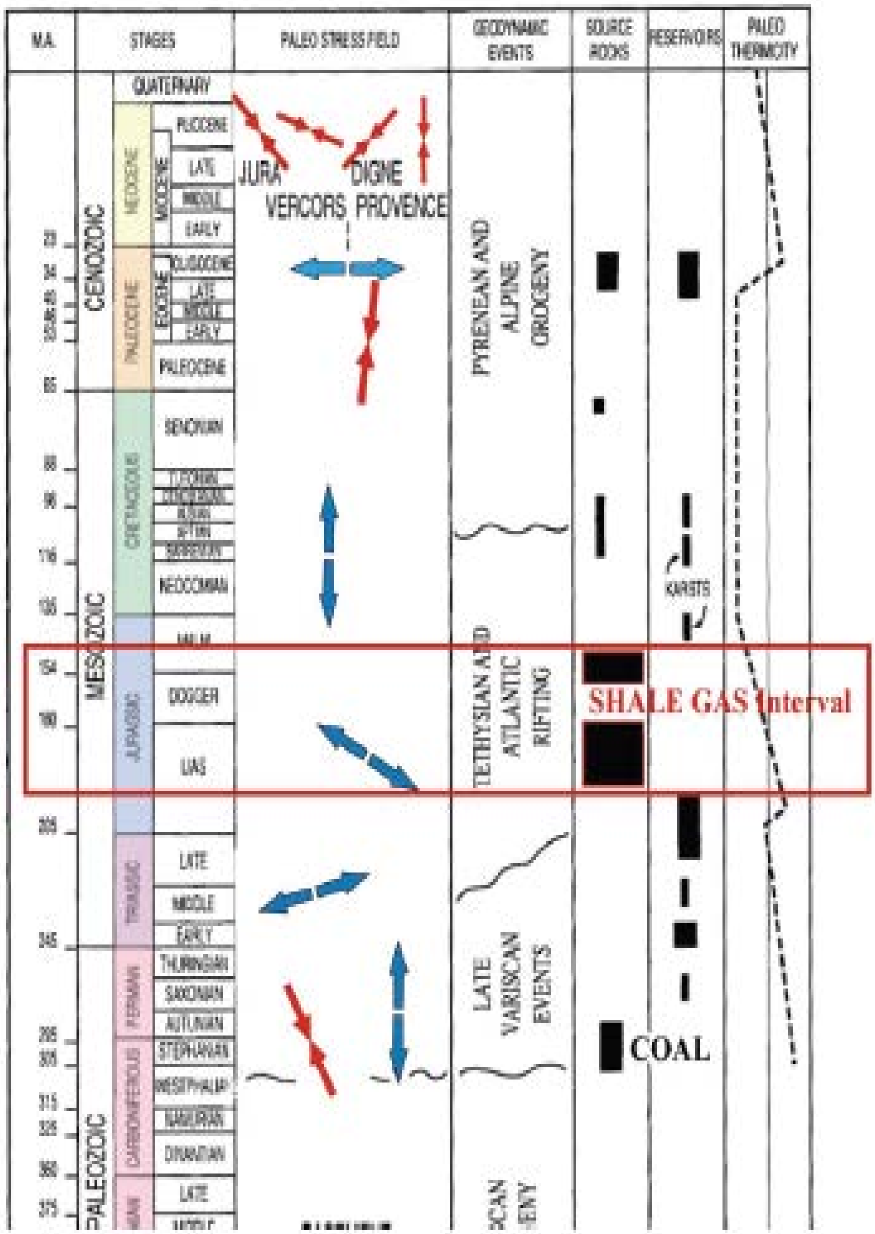
Table XIII-4. Shale Gas Reservoir Properties and Resources for the South-East Basin

Basic Data	Basin/Gross Area		South-East (17,800 mi²)
	Shale Formation		Lias Shale
	Geologic Age		L. Jurassic
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi²)		3,780
	Thickness (ft)	Organically Rich	525
		Net	158
	Depth (ft)	Interval	8,200 - 16,400
		Average	12,300
Reservoir Properties	Reservoir Pressure		Normal
	Average TOC (wt. %)		2.0%
	Thermal Maturity (% Ro)		1.50%
	Clay Content		Medium
Resource	Gas Phase		Dry Gas
	GIP Concentration (Bcf/mi²)		54.4
	Risked GIP (Tcf)		37.0
	Risked Recoverable (Tcf)		7.4

2.2 Geologic Setting

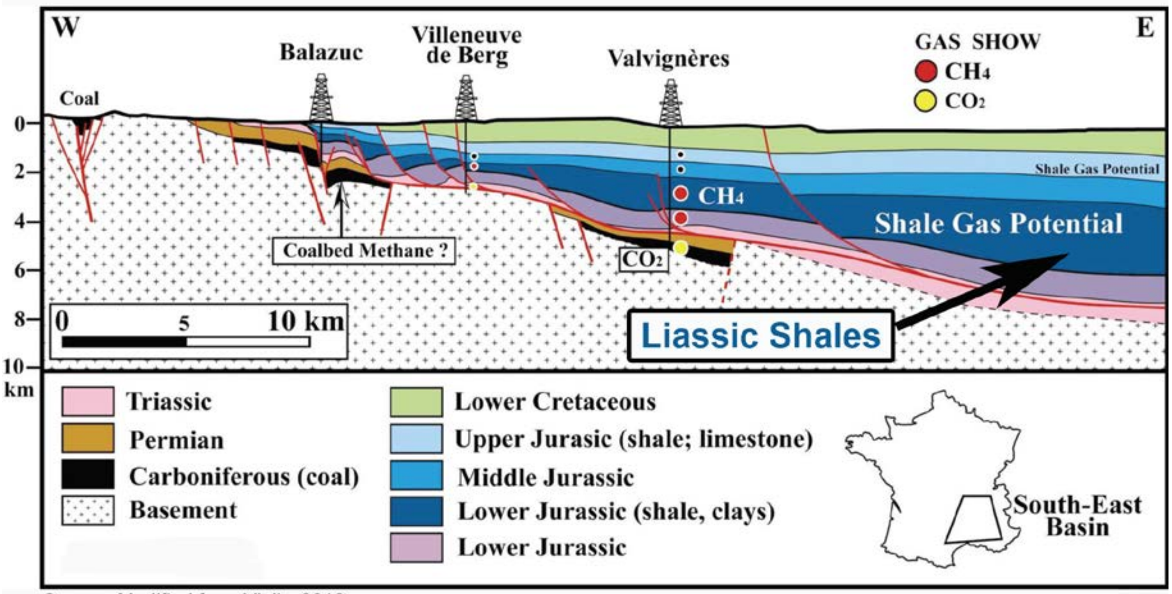
This study examined the shale gas potential of two formations in the South-East Basin, the Upper Jurassic “Terres Niores” black shale, and the Lower Jurassic Liassic black shale, Figure XIII-10. These shales are composed of Type II marine organic matter and were deposited during a time of subsidence and rifting, when the “Liguro-Piemontais” ocean covered portions of what is now southern France[6]. However, the Upper Jurassic “Terres Niores” black shale has low TOC, not exceeding 1%.[6] As such, this shale was excluded from further assessment. The Lower Jurassic Lias Shale, while thermally mature and present in much of the South-East Basin contains a wide spectrum of TOC values, ranging from 0.4% to 4.1%, Figure XIII-11.[7] Because of the presence of some higher TOC values, we have included the Lias Shale in our resource assessment but have highly risked this shale play.

Figure XIII-10. South-East Basin Stratigraphic Column



Source: Vially, R., 2010.

Figure XIII-11. Generalized South-East Basin Cross Section



Source: Modified from Vially, 2010

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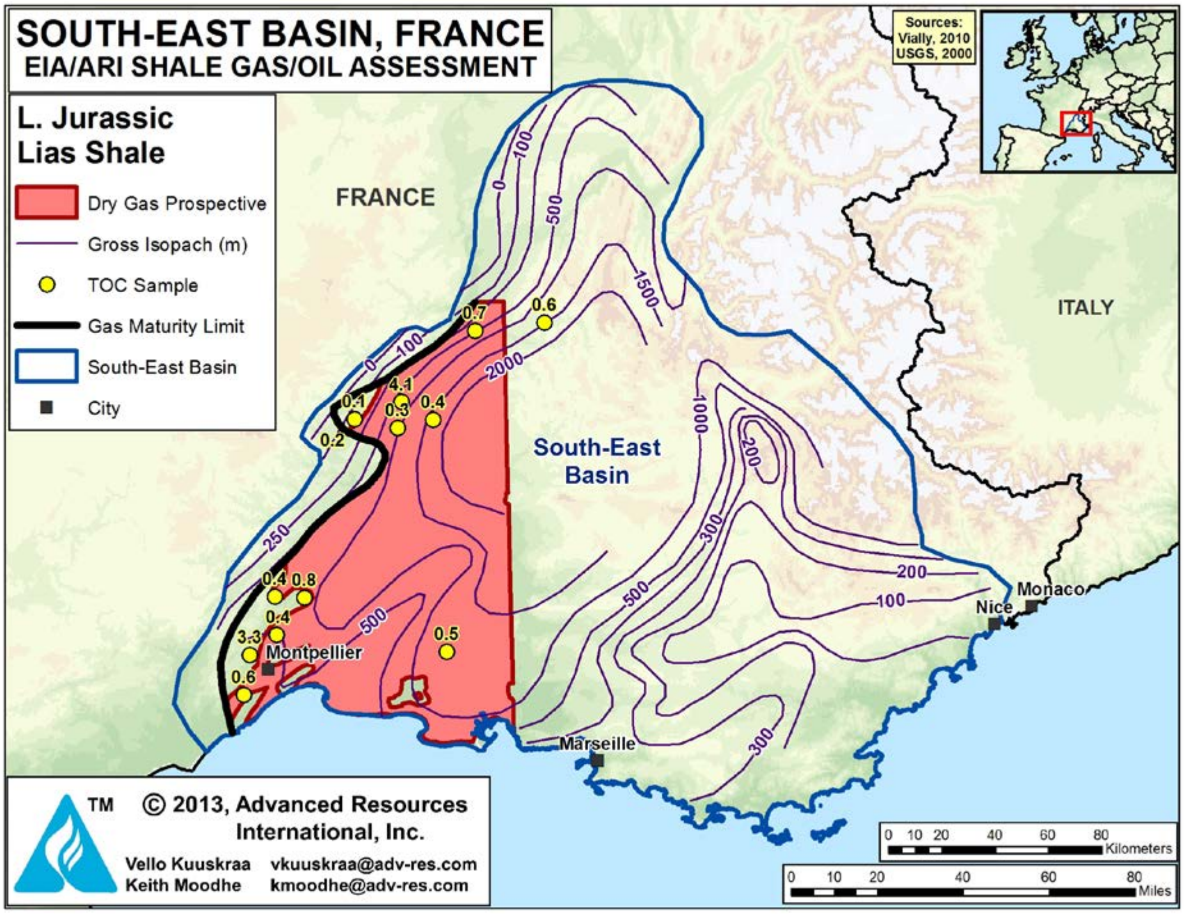
We have mapped an unrisked, 4,000-mi^2 area prospective for shale gas in the eastern portion of the South-East Basin, Figure XIII-12. The prospective area is bounded on the west by the dry gas maturity limit, on the south by the onshore portion of basin, and on the east by the available data on the TOC of the Lias Shale.

2.3 Reservoir Properties (Prospective Area)

Uplifting along the western margin of the South-East Basin has brought the Lias Shale to a more favorable depth for exploration. Depth to the Lias Shale ranges from 3,300 feet to 16,300 feet deep over the basin, with most of the shale in the prospective area at an average depth of 12,300 feet, Figure XIII-12. The organic-rich gross interval of the shale is estimated at 525 feet with 158 feet of net shale. Total organic content (TOC) in the risked prospective area averages 2%. Thermal maturity in the Lias Shale increases with depth, ranging from 1.3% R_o in the shallower western areas to over 1.7% R_o in the deeper central area. Average vitrinite reflectance (R_o) over the prospective area is 1.5%.

Figure XIII-12. Prospective Area for the Lias Shale, South-East Basin of France



Source: ARI, 2013

2.4 Resource Assessment

We estimate a moderate resource concentration in the dry gas prospective area of the Lias Shale, South-East Basin of 54 Bcf/mi^2. The risked shale gas in-place is estimated at 37 Tcf, with 7 Tcf as the risked, technically recoverable shale gas resource.

2.5 Recent Activity

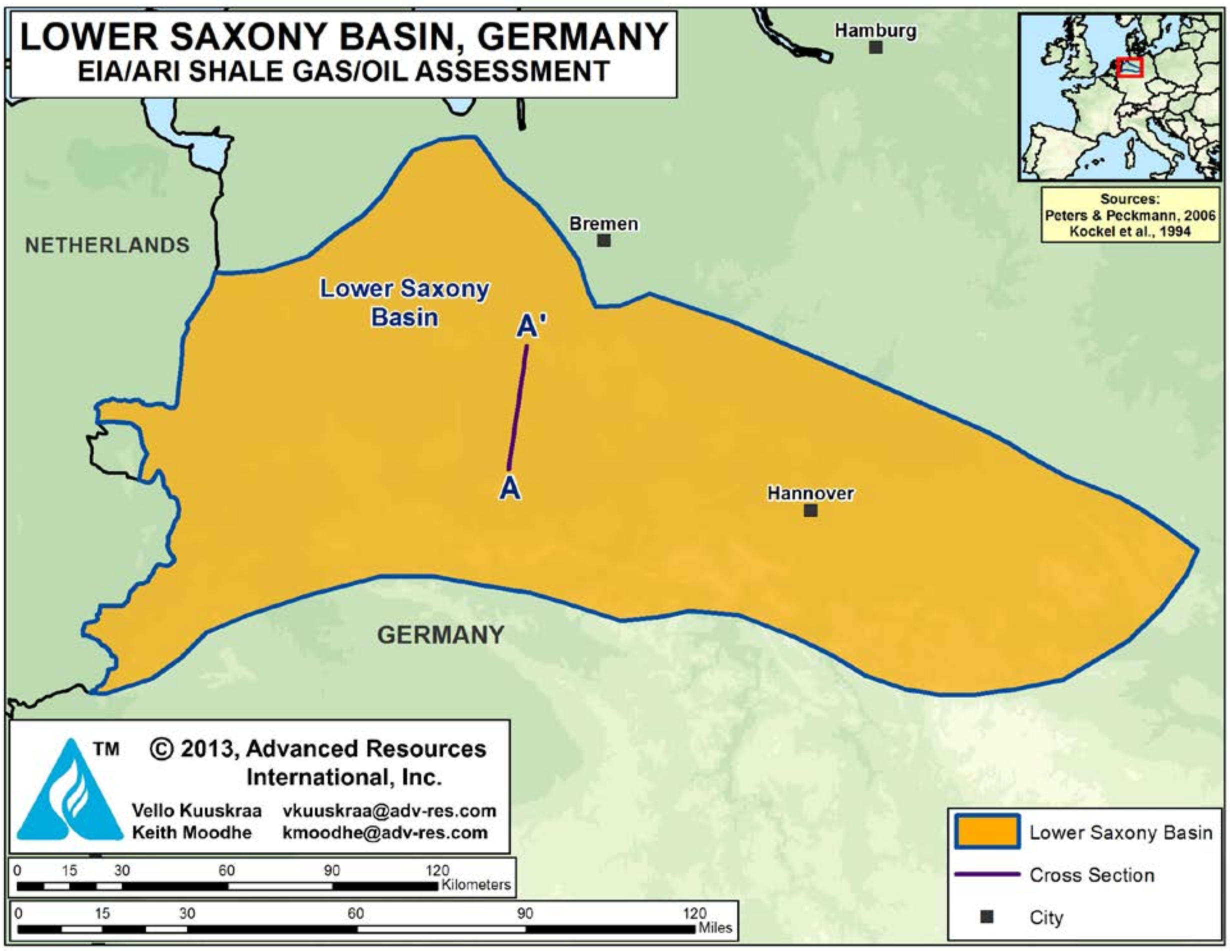
A number of firms are beginning to examine the shale gas potential of the South-East Basin; the initial permit award deadline was delayed due to the large numbers of applications. The French Ministry of Energy and the Environment awarded several exploration permits, covering over 4,000 mi^2, to companies interested in investing in the drilling and exploration of shale formations in the South-East Basin of France.

3. LOWER SAXONY BASIN: GERMANY

3.1 Introduction

The Lower Saxony Basin, covering an area of 10,000 mi^2 and located in northwestern Germany, is filled with Jurassic- to Cretaceous-age marine and lacustrine rocks, Figure XIII-13. The basin contains two petroleum systems, the Jurassic and its Posidonia (Toarcian) Shale source rock and the Lower Cretaceous and its Wealden (Berriasian) Shale source rock. The Posidonia Shale is present throughout the Lower Saxony Basin while the Wealden Shale exists primarily in its western portion of the basin.

Figure XIII-13. Outline Map for Lower Saxony Basin, Germany.



Source: ARI, 2013

For the Lower Saxony Basin of Germany, we estimate risked in-place shale gas of 80 Tcf, with 17 Tcf as the risked, technically recoverable shale gas resource, Table XIII-5. In addition, we estimate risked in-place shale oil of 14 billion barrels, with 0.7 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-6.

Table XIII-5. Shale Gas Reservoir Properties and Resources of the Saxony Basin, Germany

Basic Data	Basin/Gross Area		Lower Saxony ($10,000\ mi^2$)			
	Shale Formation		Posidonia			Wealden
	Geologic Age		L. Jurassic			L. Cretaceous
	Depositional Environment		Marine			Lacustrine
Physical Extent	Prospective Area (mi^2)		1,590	770	1,390	720
	Thickness (ft)	Organically Rich	100	100	100	112
		Net	90	90	90	75
	Depth (ft)	Interval	6,000 - 10,000	10,000 - 13,000	13,000 - 16,400	3,300 - 10,000
		Average	8,000	11,500	14,500	6,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Slightly Overpress.
	Average TOC (wt. %)		8.0%	8.0%	8.0%	4.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	2.00%	0.85%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		10.8	44.0	56.5	5.5
	Risked GIP (Tcf)		10.3	20.3	47.1	1.8
	Risked Recoverable (Tcf)		1.0	4.1	11.8	0.1

Table XIII-6. Shale Oil Reservoir Properties and Resources of the Saxony Basin, Germany

Basic Data	Basin/Gross Area		Lower Saxony ($10,000\ mi^2$)		
	Shale Formation		Posidonia		Wealden
	Geologic Age		L. Jurassic		L. Cretaceous
	Depositional Environment		Marine		Lacustrine
Physical Extent	Prospective Area (mi^2)		1,590	770	720
	Thickness (ft)	Organically Rich	100	100	112
		Net	90	90	75
	Depth (ft)	Interval	6,000 - 10,000	10,000 - 13,000	3,300 - 10,000
		Average	8,000	11,500	6,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Slightly Overpress.
	Average TOC (wt. %)		8.0%	8.0%	4.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%
	Clay Content		Low/Medium	Low/Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil
	OIP Concentration ($MMbbl/mi^2$)		12.7	4.2	9.9
	Risked OIP (B bbl)		9.1	1.5	3.2
	Risked Recoverable (B bbl)		0.46	0.07	0.13

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3.2 Geologic Setting

The Lower Saxony Basin is a distinct sub-basin within the greater North Sea-German Basin. The Lower Saxony Basin is a graben that subsided and filled during Late Jurassic and Early Cretaceous. The graben is bounded on the south by the Hanz Mountains, on the north by the Pompecky Block, on the west by the Central Netherland High and on the east by Hercynian Uplifts. During the Late Cretaceous, the Lower Saxony Basin was subject to complex tectonics that transformed the basin's normal boundary faults into reverse or overthrust faults. These events facilitated volcanic intrusions causing intense metamorphism of the organics.

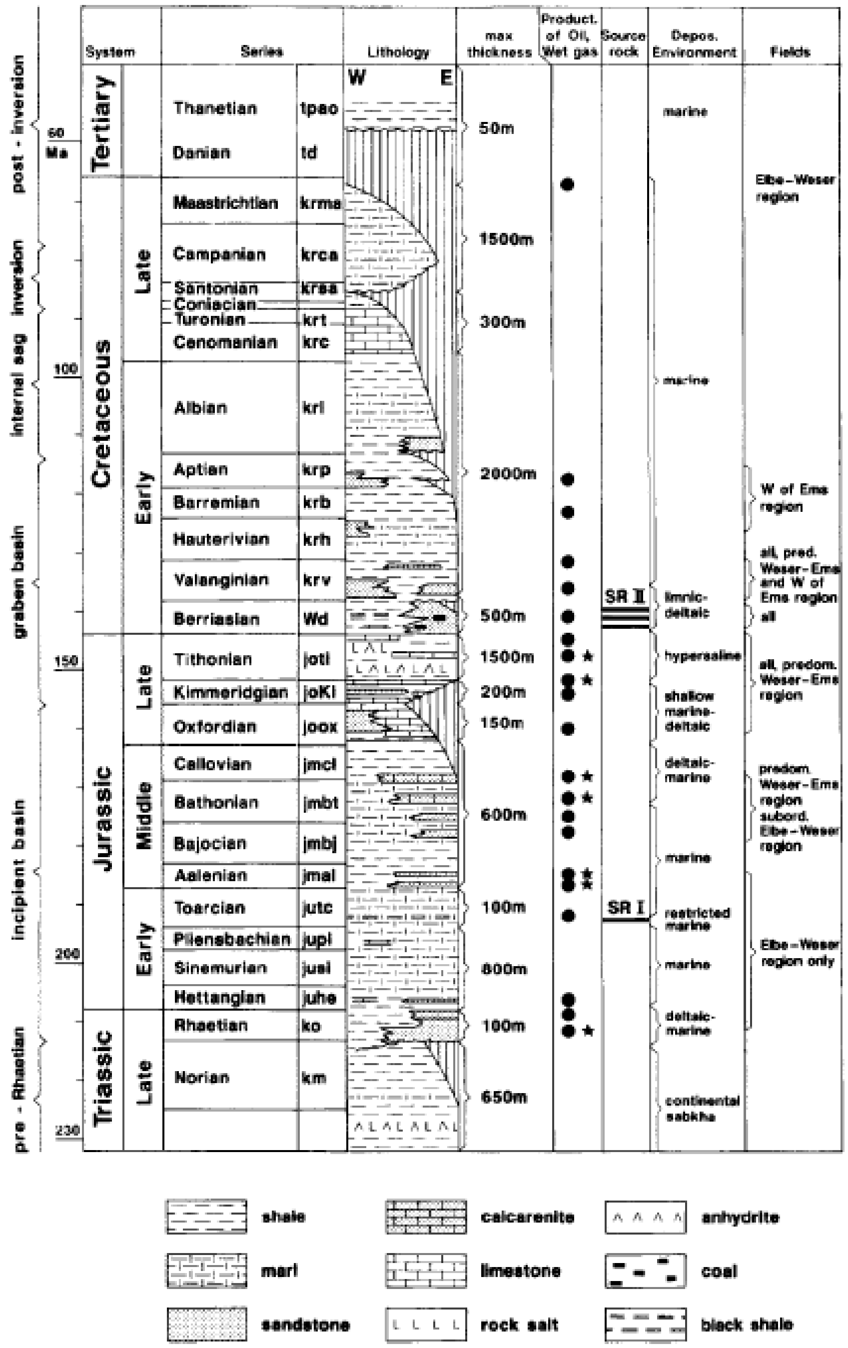
The Lower Saxony Basin contains two organic-rich shale source rocks - - the restricted marine Lower Toarcian (Jurassic) Posidonia Shale that underlies most of the basin, and the Early Cretaceous (Berriasian) lacustrine-deltaic Wealden Shale that underlies the western part of the basin (west of the Weser River). The generalized stratigraphic column for the Triassic to Tertiary interval in the Lower Saxony Basin is provided on Figure XIII-14.[8]

We mapped a 3,750-mi^2 prospective area for the Posidonia Shale in the Lower Saxony Basin, containing: (1) a 1,590-mi^2 oil prospective area (R_o of 0.7% to 1%) along the north eastern border of the basin; (2) an adjoining 770-mi^2 wet gas/condensate prospective area (R_o 1% to 1.3%); and (3) a 1,390-mi^2 dry gas prospective area (R_o >1.3%) in the deeper southwestern portion of the basin, Figure XIII-15. We also mapped a smaller 720-mi^2 oil prospective area for the shallower Wealden Shale in the Lower Saxony Basin, Figure XIII-16.

In addition to the two shale formations addressed in this resource assessment, a series of other shale gas formations exist in Germany, particularly the Lower Carboniferous Visean and Westphalian coaly shales. However, these shales, while thick, thermally mature for gas and buried at acceptable depths of 1,000 to 5,000 m, have TOC values of less than 2%.[9] Thus, these shale formations have not been included in our resource assessment.

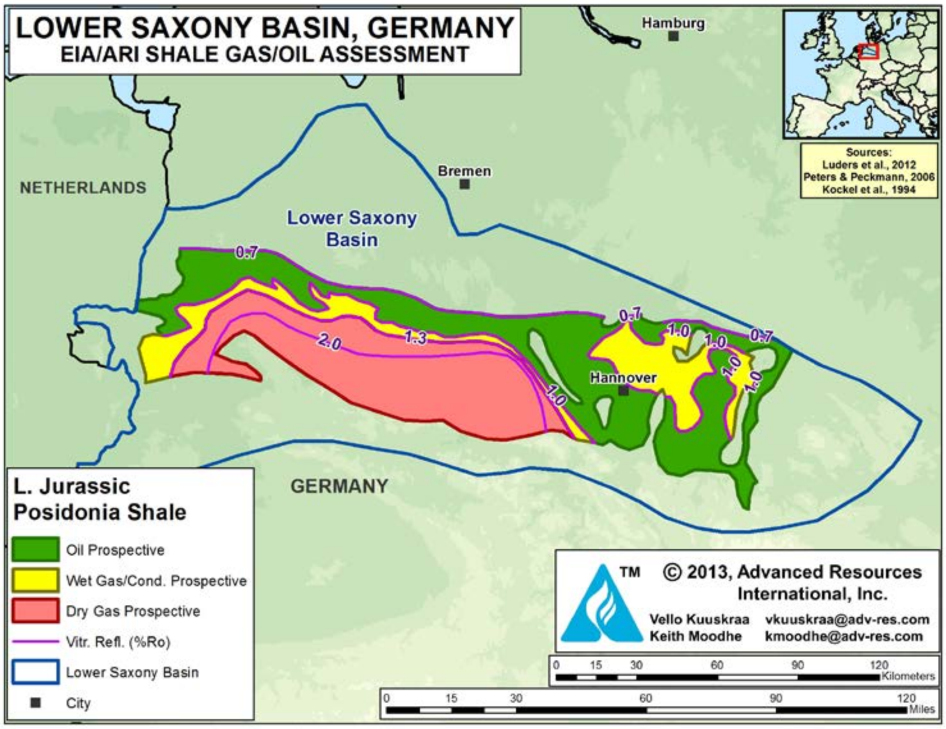
In addition, organic-rich mudstones occur in the Upper Permian Stassfurth Carbonate Formation in the eastern part of the North Sea-German Basin in southern Brandenburg. The Ca2 shale interval in this formation occurs at a depth of 3,800 to 4,000 m, has a thermal maturity of over 2% R_o, and contains a mixed Type II/III kerogen. However the shale formation is thin (6m) and has a low TOC content of 0.2% to 0.8%.[9] As such, this shale has also not been included in our resource assessment.

Figure XIII-14. Generalized Stratigraphic Column for the Lower Saxony Basin.



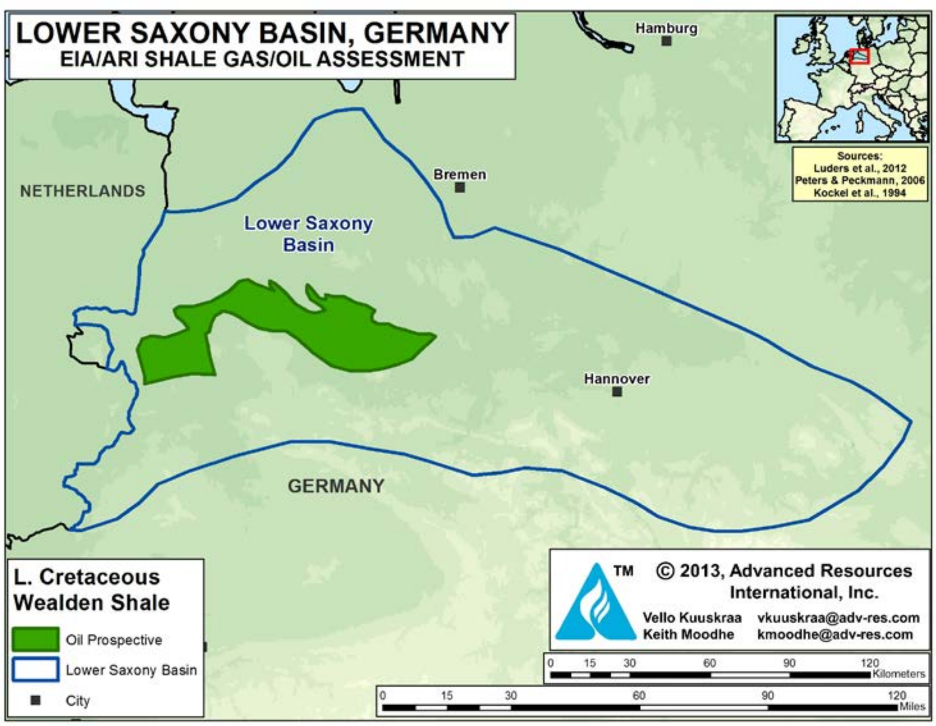
Source: Kockel, 1994.

Figure XIII-15. Prospective Area of the Posidonia Shale, Lower Saxony Basin, Germany.



Source: ARI, 2013.

Figure XIII-16. Prospective Area of the Wealden Shale, Lower Saxony Basin, Germany.

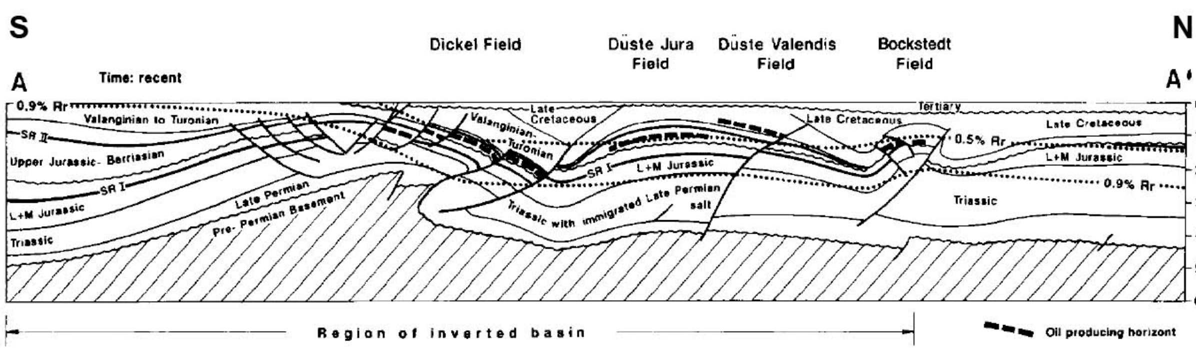


Source: ARI, 2013.

3.3 Reservoir Properties (Prospective Area)

Jurassic (Toarcian) Posidonia Shale. The depth to the Posidonia Shale ranges from 3,300 feet to 16,400 feet, with an average depth in the oil prospective area of 8,000 feet, an average depth in the wet gas/condensate prospective area of 11,500 feet, and an average depth in the dry gas prospective area of 14,500 feet. Figure XIII-17 provides a north to south cross-section through the center of the Lower Saxony Basin, illustrating the sequence of complex faults and the thrust features common to the Posidonia Shale. (The location of the north to south cross-section, A to A', is provided in Figure XIII-10.) The shale interval in the prospective area is moderate in thickness, with an organic-rich gross thickness of 100 feet and a net shale thickness of 90 feet. Organic matter in the Posidonia Shale is Type II marine kerogen with a TOC that averages 8%, Figure XIII-18. The outer portion of the basin area is in the oil window, with the central, deeper areas of the Posidonia Shale in the wet gas/ condensate and dry gas windows, Figure XIII-15.

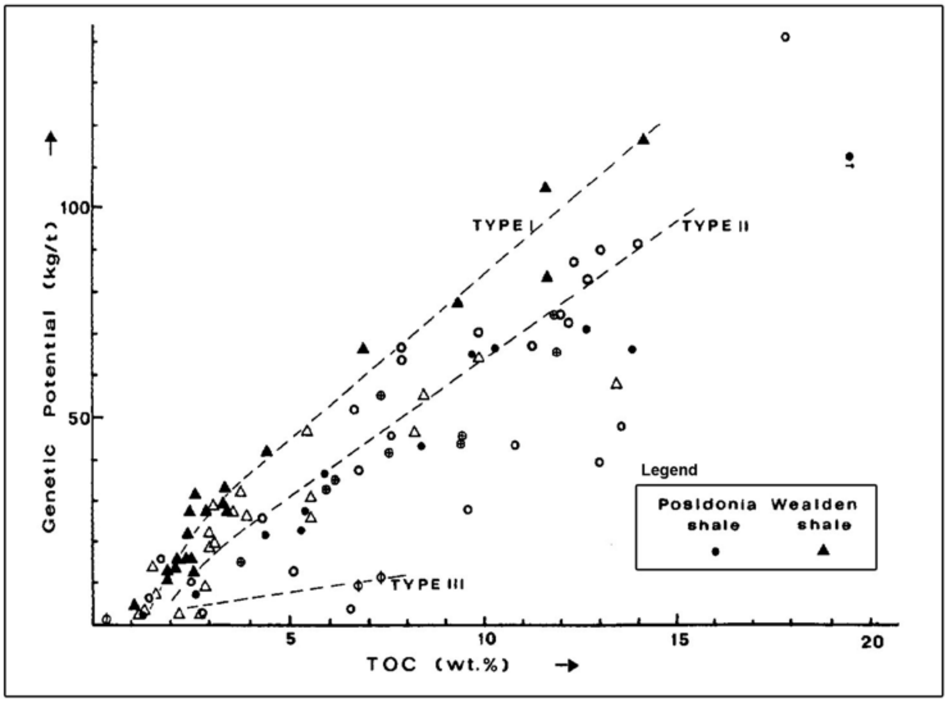
Figure XIII-17. Lower Saxony Basin North to South Cross Section, A to A'



Source: Kockel, 1994.

Cretaceous (Berriasian) Wealden Shale. The prospective area for the Wealden Shale is thermally mature for oil generation. The prospective area was defined by the depositional and depth limits of the Wealden Shale within the Lower Saxony Basin. In the prospective area, the depth of the Wealden Shale ranges from 3,300 feet to 10,000 feet, averaging 6,000 feet. The Wealden Shale has a gross organic-rich shale interval of 112 feet and 75 feet of net shale thickness[8]. The TOC in the Wealden Shale is highly variable, ranging from 1% to 14%, averaging 4.5% in the prospective area, Figure XIII-18. Thermal maturity ranges from 0.7% to 1.0% Ro, placing the Wealden Shale in the oil window.[8]

Figure XIII-18. Total Organic Content, Posidonia and Wealden Shales, Lower Saxony Basin



Source: Kockel, F., 1994.

3.4 Resource Assessment

Jurassic Posidonia Shale. We calculate that the prospective area of the Posidonia Shale in the Lower Saxony Basin has resource concentrations of 56 Bcf/mi^2 in the dry gas window, 44 Bcf/mi^2 of wet gas and 4 million barrels/mi^2 of condensate in the wet gas and condensate window, and 13 million barrels/mi^2 of oil in the oil window. Within the prospective area, the Posidonia Shale contains 78 Tcf of risked gas in-place, with 17 Tcf as the risked, technically recoverable shale gas resource (including associated gas), Table XIII-5. In addition, the Posidonia Shale contains 11 billion barrels of risked shale oil in-place, with 0.5 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-6.

Cretaceous Wealden Shale. The 720-mi^2 prospective area of the Wealden Shale in the Lower Saxony Basin has an oil resource concentration of 10 million barrels/mi^2. The risked oil in-place is 3 billion barrels, with 0.1 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-6. The oil prospective area of the Wealden Shale also contains in-place and risked, technically recoverable associated shale gas of 2 Tcf and 0.1 Tcf respectively.

3.5 Recent Activity

ExxonMobil has been the lead company active in the Lower Saxony Basin of Germany. The company has drilled a series of test wells on its exploration leases, at least three of which are reported to be testing shale gas potential. Starting in 2008, the company drilled the Damme 2/2A and Damme 3 test wells on its Munsterland concession and the Oppenwehe 1 exploration well on its Minden concession. In late 2010, the company spudded the Niederzwehren test well on its Schaumberg permit. After drilling these test wells, ExxonMobil halted operations in the province following the passage of a moratorium on hydraulic fracturing.

Realm Energy obtained a small, 25-square mile shale gas exploration permit in West Germany. The company plans to explore the oil and gas potential in the Posidonia and Wealden shales underneath its acreage. Realm's concession is valid for three years and does not require well drilling, but does provide the company with data from the 21 wells drilled on its acreage in past years.

BNK Petroleum has leased approximately 3,745 square miles for shale, CBM and tight gas sand exploration in West and Central Germany. The company has yet to drill on any of its properties, but reports "targeting shale formations," most likely the Posidonia and Wealden shales. Most of its concessions are not near areas with previously defined shale gas potential, suggesting the company is pursuing a wildcatting approach in Germany. To date, the company has not provided details of its drilling plans.

After a lengthy period of study, the German government issued, in late February 2013, draft legislation what would allow the development of shale and the use of hydraulic stimulation (fracturing) under environmental safeguards.

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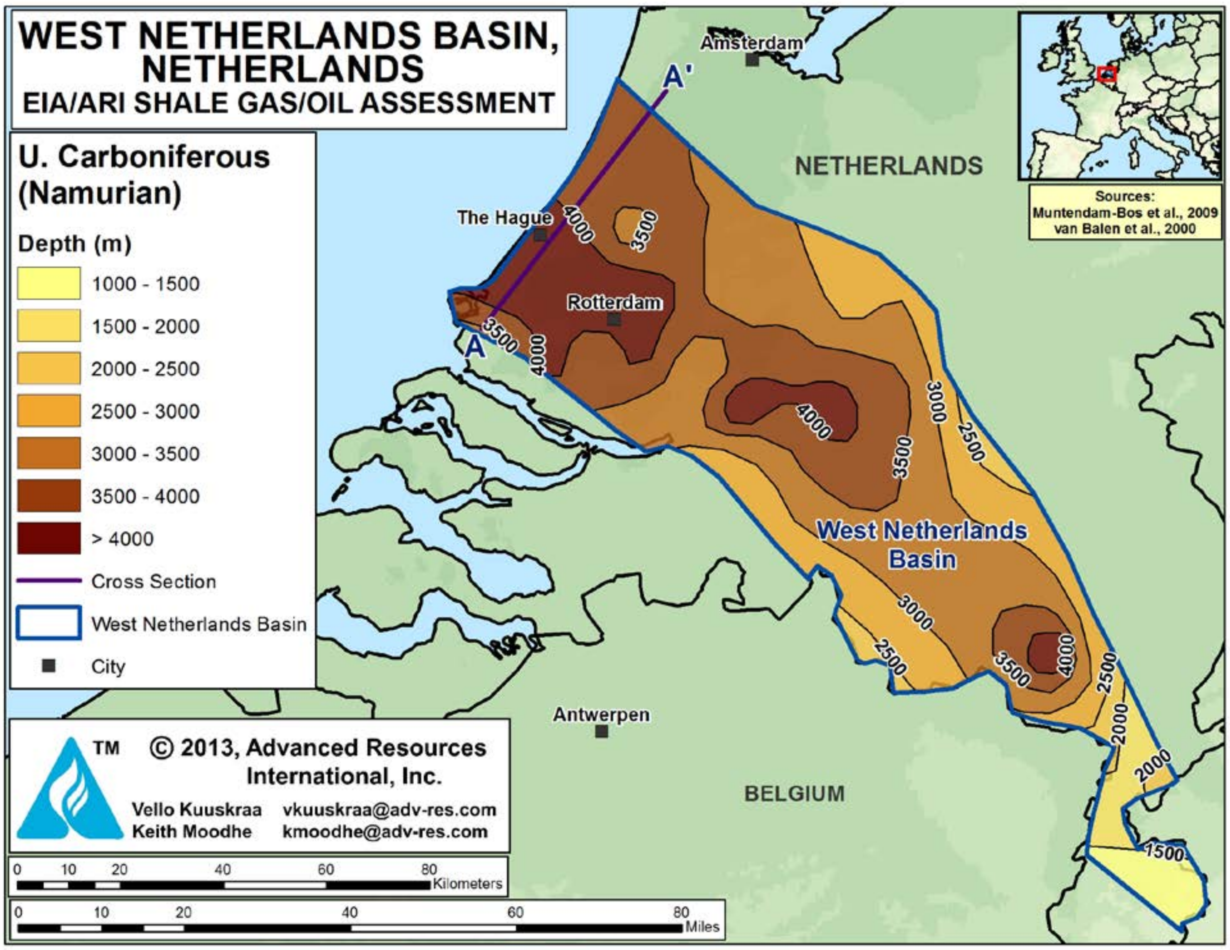
4. WEST NETHERLAND BASIN: NETHERLANDS

4.1 Introduction

The West Netherland Basin (WNB) is located in the southwestern portion of the Netherlands, extending into the offshore, Figure XIII-19. The basin is bounded in the south by the London-Brabant Massif and on the north by the Zandvoort Ridge. In the south-east, the WNB merges with the Ruhr Valley Graben. The West Netherlands Basin is part of a series of Late Jurassic to Early Cretaceous trans-tensional basins of Western Europe.

Figure XIII-19. Outline and Depth Map for West Netherland Basin, Netherlands



Source: ARI, 2013

For the West Netherland Basin, we estimate risked in-place shale gas of 151 Tcf, with 26 Tcf as the risked, technically recoverable shale gas resource, Table XIII-7. In addition, we estimate risked in-place shale oil of 59 billion barrels, with 2.9 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-8.

Table XIII-7. Shale Gas Reservoir Properties and Resources of West Netherland Basin, Netherlands

Basic Data	Basin/Gross Area		West Netherlands (2,750 mi^2)				
	Shale Formation		Epen		Geverik Member	Posidonia	
	Geologic Age		U. Carboniferous		U. Carboniferous	L. Jurassic	
	Depositional Environment		Lacustrine		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		1,460	860	2,320	850	170
	Thickness (ft)	Organically Rich	1,500	1,500	225	100	100
		Net	450	450	135	90	90
	Depth (ft)	Interval	3,300 - 10,000	10,000 - 15,500	5,000 - 16,400	3,300 - 9,000	9,000 - 12,500
		Average	8,500	12,500	11,000	6,500	10,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		2.4%	2.4%	4.0%	6.0%	6.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.15%	0.85%	1.15%
	Clay Content		Medium	Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Wet Gas	Assoc. Gas	Wet Gas
	GIP Concentration (Bcf/mi^2)		60.6	139.2	48.5	10.2	38.5
	Risked GIP (Tcf)		39.8	53.9	50.6	3.9	2.9
	Risked Recoverable (Tcf)		4.0	10.8	10.1	0.4	0.6

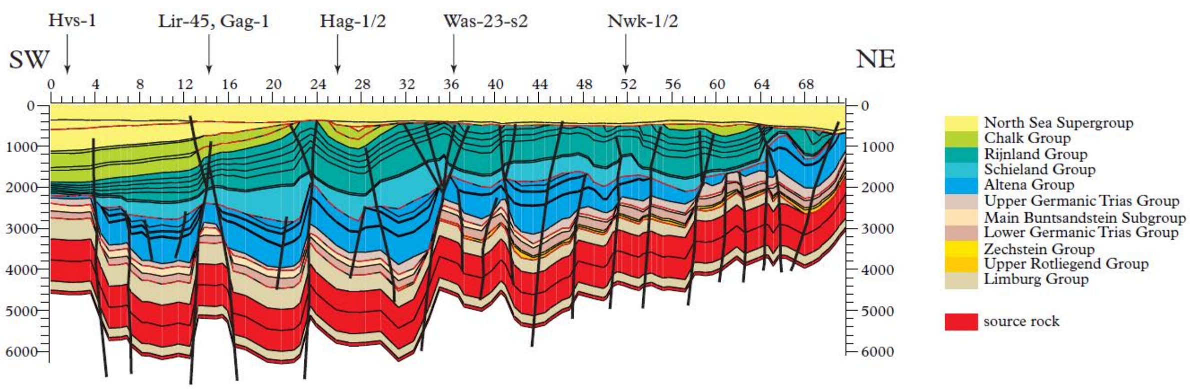
Table XIII-8. Shale Oil Reservoir Properties and Resources of West Netherland Basin, Netherlands

Basic Data	Basin/Gross Area		West Netherlands (2,750 mi^2)				
	Shale Formation		Epen		Geverik Member	Posidonia	
	Geologic Age		U. Carboniferous		U. Carboniferous	L. Jurassic	
	Depositional Environment		Lacustrine		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		1,460	860	2,320	850	170
	Thickness (ft)	Organically Rich	1,500	1,500	225	100	100
		Net	450	450	135	90	90
	Depth (ft)	Interval	3,300 - 10,000	10,000 - 15,500	5,000 - 16,400	3,300 - 9,000	9,000 - 12,500
		Average	8,500	12,500	11,000	6,500	10,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		2.4%	2.4%	4.0%	6.0%	6.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.15%	0.85%	1.15%
	Clay Content		Medium	Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		60.4	19.0	6.1	13.2	4.1
	Risked OIP (B bbl)		39.7	7.4	6.3	5.0	0.3
	Risked Recoverable (B bbl)		1.98	0.37	0.32	0.25	0.02

4.2 Geologic Setting

The West Netherland Basin (WNB), while commonly described as a single structural entity, contains a series of smaller structural elements bounded by long, northwest-trending faults. The complex tectonic features present in this basin are illustrated by the northeast to southwest cross-section (A-A') located on the far western portion of the basin, Figure XIII-20.[10] (The location of the cross-section is shown on Figure XIII-19.)

Figure XIII-20. Cross-Section A to A', Western Portion of West Netherland Basin.



Source: van Balen, R.T. et al., 2000.

The WNB contains a series of prospective shale formations, including two Carboniferous (Namurian) shale formations, the Epen Formation and the Geverik Member, plus the Lower Jurassic (Toarcian) Posidonia Shale, Figure XIII-21.[10] Based on analysis of core and cutting samples from the deep Geverik-1 exploration well, located in the southeastern part of the basin, the Epen Shale contains Type III kerogen, with lacustrine-deltaic deposition, while the Geverik Shale contains Type II kerogen, with open-marine deposition. The Posidonia Shale contains Type II marine kerogen.

Additional shale source rocks exist in the WNB, particularly in Late Jurassic and Late Carboniferous intervals. However, these shales are considered of minor importance or contain significant inter-beds of coal.[10] Thus, these shales have been excluded from the quantitative resource assessment. An excellent, comprehensive review of the shale formations of the Netherlands is provided in the TNO report entitled, "Inventory Non-Conventional Gas" by A.G. Muntendam-Bos et al., 2009.[11]

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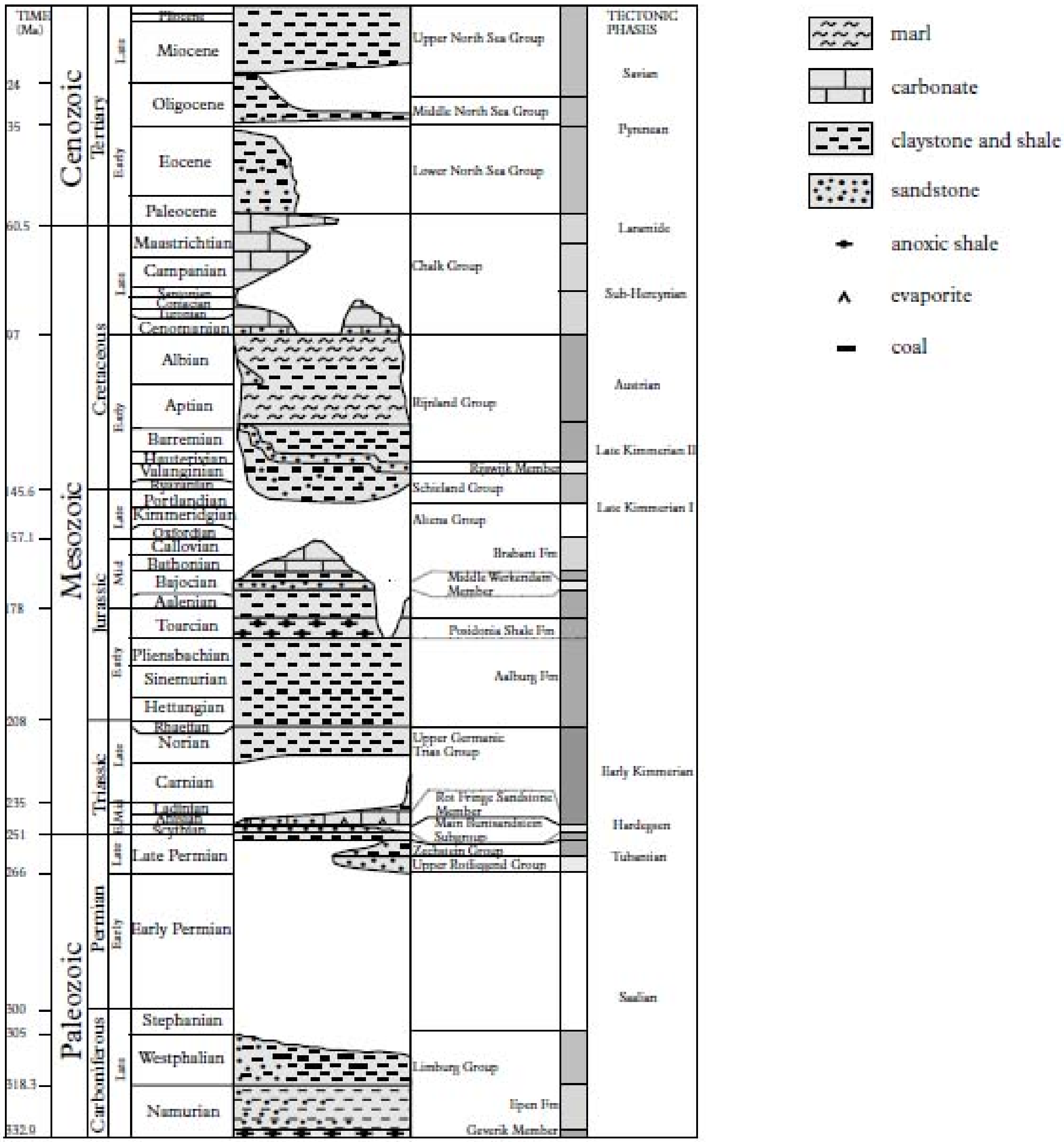
Figure XIII-21. Stratigraphic Section for West Netherland Basin.



Numerical ages in the Namurian and Jurassic to Tertiary are after Harland et al. (1990), in the Triassic and Permian after Menning (1995), and in the Westphalian and Stephanian after Lippolt et al. (1984).
Source: van Balen, R.T. et al., 2000.

For the Epen Shale, we have mapped a 1,460-mi^2 area prospective for oil and associated gas and a smaller 860-mi^2 area prospective for wet gas and condensate, Figure XIII-22. For the Geverik Shale, we have mapped a 2,320-mi^2 area prospective for wet gas and condensate, Figure XIII-23. For the Posidonia Shale, we have mapped a 850-mi^2 area prospective for oil and a smaller 170-mi^2 area prospective for wet gas and condensate, Figure XIII-24.

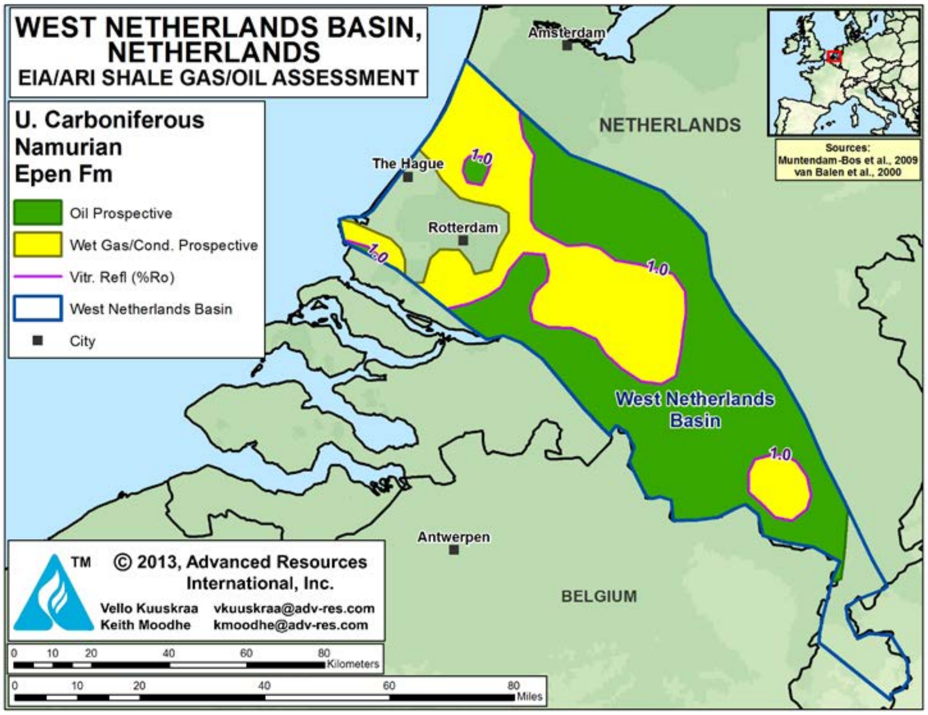
4.3 Reservoir Properties (Prospective Area)

Carboniferous (Namurian) Epen and Geverik Shales. As discussed above, the Carboniferous (Namurian) sequence in the Netherlands contains two prospective shale formations, the Epen and Geverik. The key technical paper by R. T. van Balen, et al. (2000)[10] and data provided in the more recent TNO report (Muntendam-Bos, A.G., et al., 2009)[11] were used to establish prospective areas including information on depth, thermal maturity and thickness for these two shale gas formations.

Depth to the Epen Shale ranges from 3,300 feet to 16,400 feet, averaging 8,500 feet in the oil prospective area and averaging 12,500 feet in the wet gas/condensate prospective area. In the west-central portion of the WNB, the depth of the Epen Shale is below 5,000 m. As such, this portion of the basin has been excluded from the prospective area. The Epen Shale's oil prospective area has a thermal maturity of 0.7% to 1.0% R_o in the southern portion of the basin and along the shallower basin edges. In the center of the basin, the thermal maturity of the shale ranges from 1.0% to 1.3% Ro, placing the shale in the wet gas/condensate window. The Epen Shale is very thick, with a gross organic-rich thickness of 1,500 feet and a net thickness of 450 feet, based on an estimated 30% net to gross ratio. Total organic content ranges from 1% to 15%, averaging 2.4%. The shale is over-pressured and because of its lacustrine deposition has medium assumed clay content.

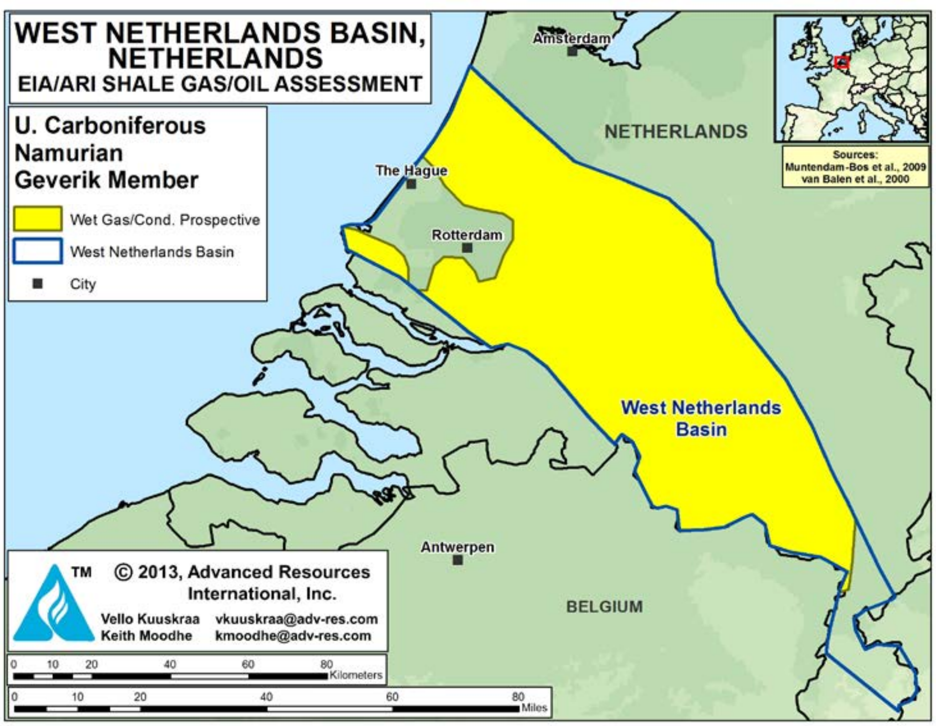
Depth to the underlying Geverik Shale ranges from 5,000 feet to 16,400 feet, averaging 11,000 feet in the wet gas/condensate prospective area. As for the Epen Shale, the deep west-central portion of the basin below 5,000 m has been excluded. The Geverik Shale has an organic-rich gross interval of 225 feet, with an estimated 135 feet of net pay, based on an estimated 60% net to gross ratio. The thermal maturity of this deeper shale ranges from 1.0% to 1.3%, placing the Geverik Shale in the wet gas and condensate window. Total organic content of the shale ranges from 2% to 7%, averaging 4%. The shale is over-pressured and due to its marine deposition has low to medium assumed clay content.

Figure XIII-22. Prospective Areas for Epen Shale, West Netherland Basin.



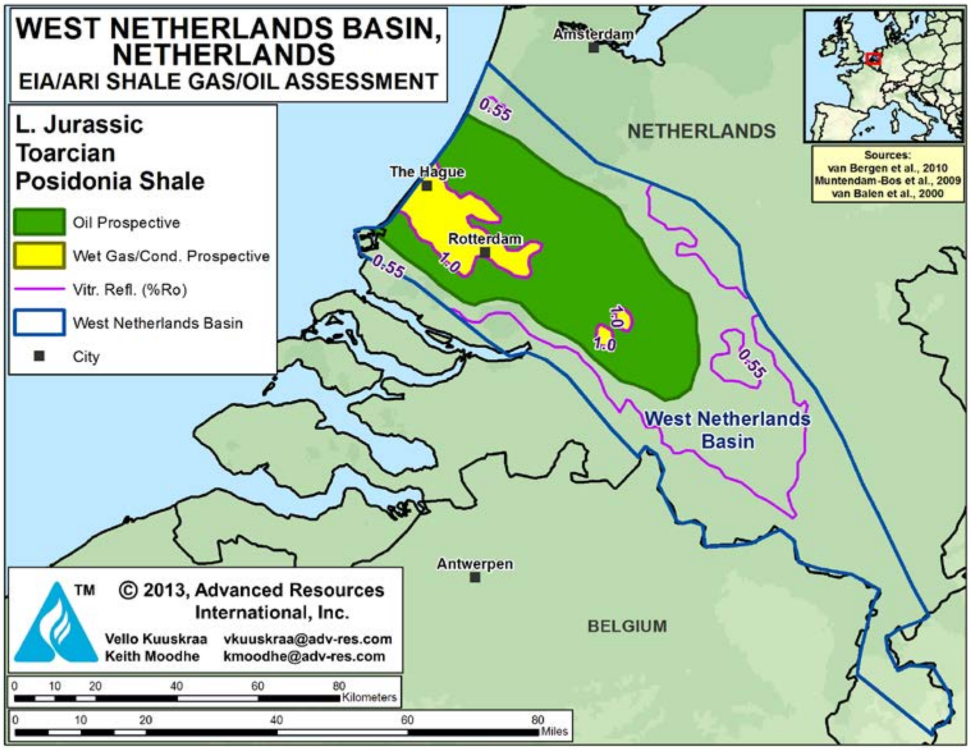
Source: ARI, 2013

Figure XIII-23. Prospective Areas for Geverik Shale, West Netherland Basin.



Source: ARI, 2013

Figure XIII-24. Prospective Area for Posidonia Shale, West Netherland Basin.



Source: ARI, 2013

Jurassic (Toarcian) Posidonia Shale. The shallower Posidonia Shale overlies the Carboniferous Epen and Geverik shales in the West Netherland Basin. The shale has reservoir properties similar to the Posidonia Shale in the Lower Saxony Basin of Germany, discussed previously. A total of 140 wells have been drilled through the Posidonia Shale, providing valuable data and control for this resource assessment.

The depth of the Posidonia Shale ranges from 3,300 feet on the margins of the prospective area to 12,500 feet in the basin center, averaging 6,500 feet in the oil prospective area and 10,500 feet in the wet gas/condensate prospective area. In the shallower portions of the prospective area, the Posidonia Shale has a thermal maturity of 0.7% to 1.0% R_o (oil window). In the deeper basin center, Posidonia Shale has a thermal maturity of 1.0% to 1.3% R_o (wet gas/condensate window). The gross organic-rich shale interval is 100 feet, with 90 feet of net pay. The shale contains Type II marine kerogen with a TOC that ranges from less than 1% to a maximum of 16%, averaging 6%. The formation is slightly over-pressured with low to medium clay content.

4.4 Resource Assessment

Carboniferous (Namurian) Epen Shale. We estimate that the prospective area of the Epen Shale in the West Netherland Basin contains risked shale gas in-place of 94 Tcf, with 15 Tcf as the risked, technically recoverable shale gas resource (including both wet shale gas and associated shale gas). In addition, we estimate that the Epen Shale in this basin has risked in-place shale oil/condensate of 47 billion barrels, with 2.4 billion barrels as the risked, technically recoverable shale oil resource.

Carboniferous (Namurian) Geverik Shale. We estimate that the prospective area of the Geverik Shale in the West Netherland Basin contains risked shale gas in-place of 51 Tcf, with 10 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate that the Geverik Shale in this basin has risked in-place shale oil/condensate of 6 billion barrels, with 0.3 billion barrels as the risked, technically recoverable shale oil resource.

Jurassic (Toarcian) Posidonia Shale. We estimate that the prospective area of the Posidonia Shale in the West Netherland Basin contains risked shale gas in-place of 7 Tcf, with 1 Tcf as the risked, technically recoverable shale gas resource (including both wet shale gas and associated shale gas). In addition, we estimate that the Posidonia Shale in this basin has risked in-place shale oil/condensate of 5 billion barrels, with 0.3 billion barrels as the risked, technically recoverable shale oil resource.

4.5 Recent Activity

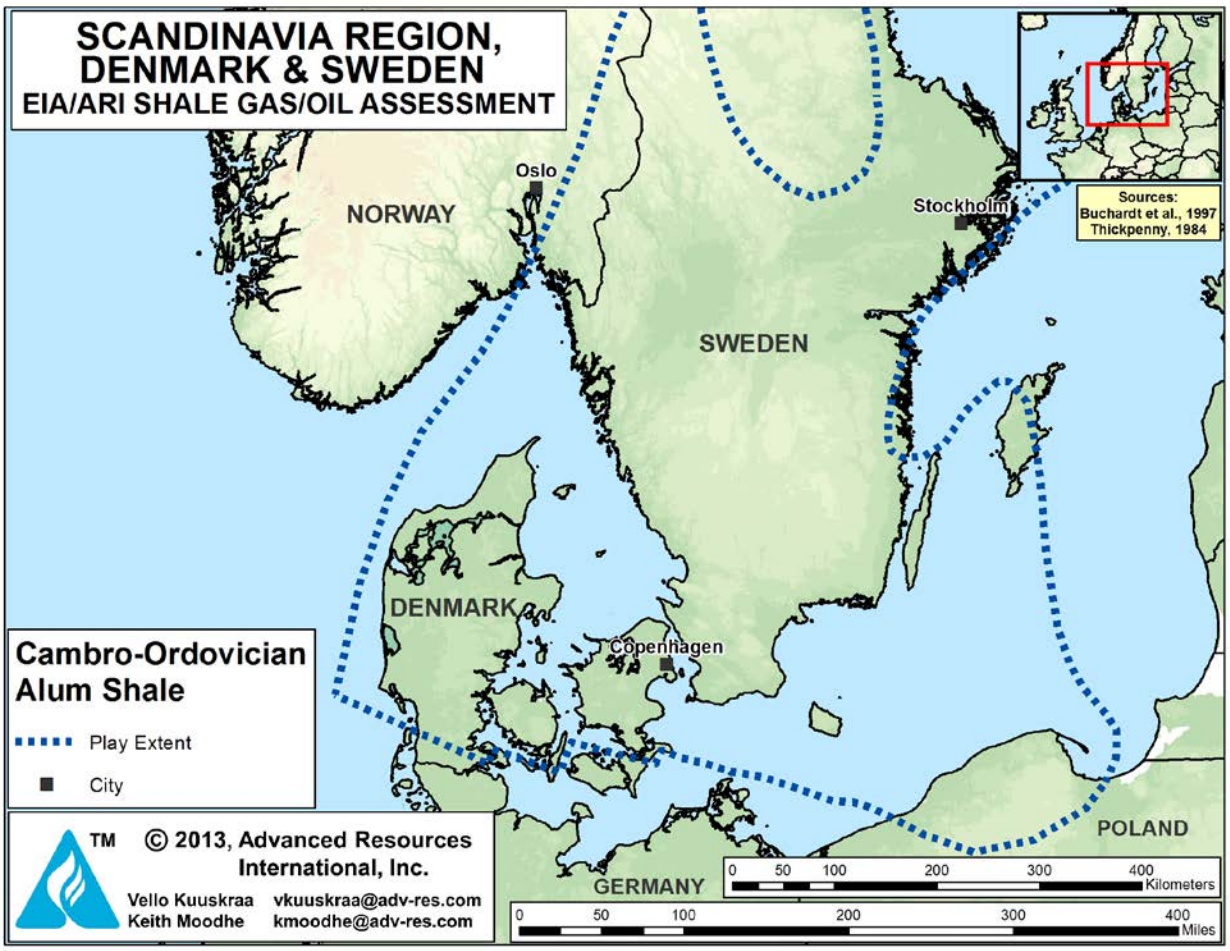
Three companies have acquired shale gas and oil leases in the Netherlands. Cuadrilla Resources and DSM Energie have leases in the West Netherland Basin while Queensland Gas Company (now part of BG Group) has leases in north-central Netherlands. Beyond the earlier exploratory wells that helped define the shale resources in the West Netherland Basin, we are not aware of any recent shale gas or oil development in the Netherlands.

5. SCANDINAVIA

5.1 Introduction

The Cambrian-Ordovician (Lower Paleozoic) Alum Shale underlies significant portions of Scandinavia, including Sweden, Denmark and potentially Norway, Figure XIII-25. However, in much of this area the Alum Shale is shallow, thin and immature. The outline of the Alum Shale depositional area examined by this shale resource assessment is bounded on the west by the Caledonia Deformation Front and outcrops of the Alum Shale. The basin is bounded on the east by the inferred depositional limits of the Lower Paleozoic and on the south by the 2.7% (R_o) thermal maturity contour.

Figure XIII-25. Outline Map for Alum Shale of Scandinavia



Source: ARI, 2013

For the Alum Shale in Sweden, we estimate risked in-place shale gas of 49 Tcf, with 10 Tcf as the risked, technically recoverable shale gas resource. For the Alum Shale in Denmark, we estimate risked in-place shale gas of 159 Tcf, with 32 Tcf as the risked, technically recoverable shale gas resource, Table XIII-9. A modest volume of shale gas may exist in the Oslo Graben of Norway. However, there is not sufficient data to reliably estimate the size of Norway's shale resource. Our shale gas resource estimates are preliminary and have been highly risked, awaiting more definite information from industry's planned exploration efforts, particularly in Denmark.

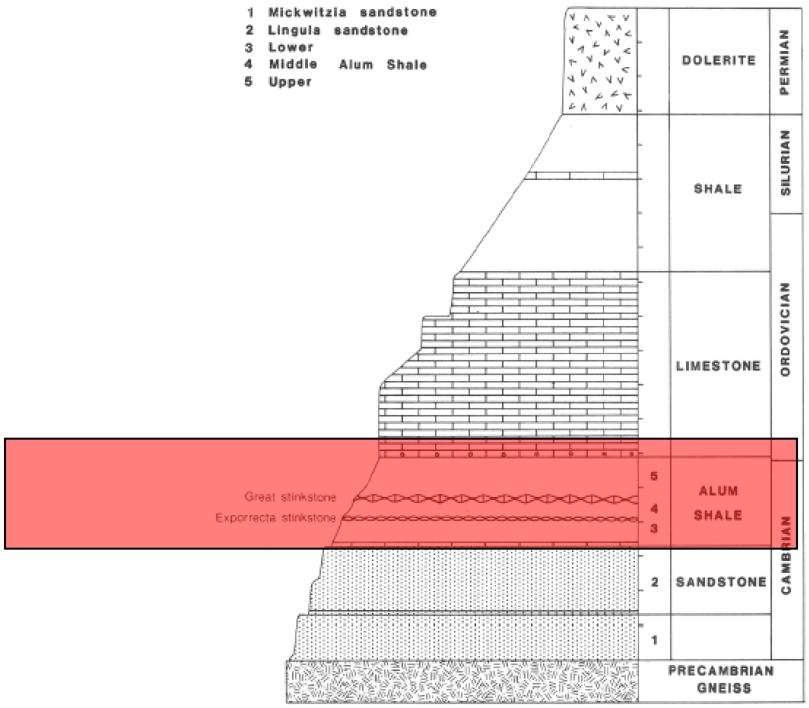
Table XIII-9. Shale Gas Reservoir Properties and Resources of Scandinavia

Basic Data	Basin/Gross Area		Scandinavia Region ($90,000\ mi^2$)	
	Shale Formation		Alum Shale - Sweden	Alum Shale - Denmark
	Geologic Age		Cambro-Ordovician	Cambro-Ordovician
	Depositional Environment		Marine	Marine
Physical Extent	Prospective Area (mi^2)		2,120	5,980
	Thickness (ft)	Organically Rich	250	250
		Net	200	200
	Depth (ft)	Interval	3,300 - 7,000	11,000 - 15,000
		Average	5,000	13,500
Reservoir Properties	Reservoir Pressure		Normal	Normal
	Average TOC (wt. %)		7.5%	7.5%
	Thermal Maturity (% Ro)		2.00%	2.00%
	Clay Content		Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		76.8	110.5
	Risked GIP (Tcf)		48.9	158.6
	Risked Recoverable (Tcf)		9.8	31.7

5.2 Geologic Setting

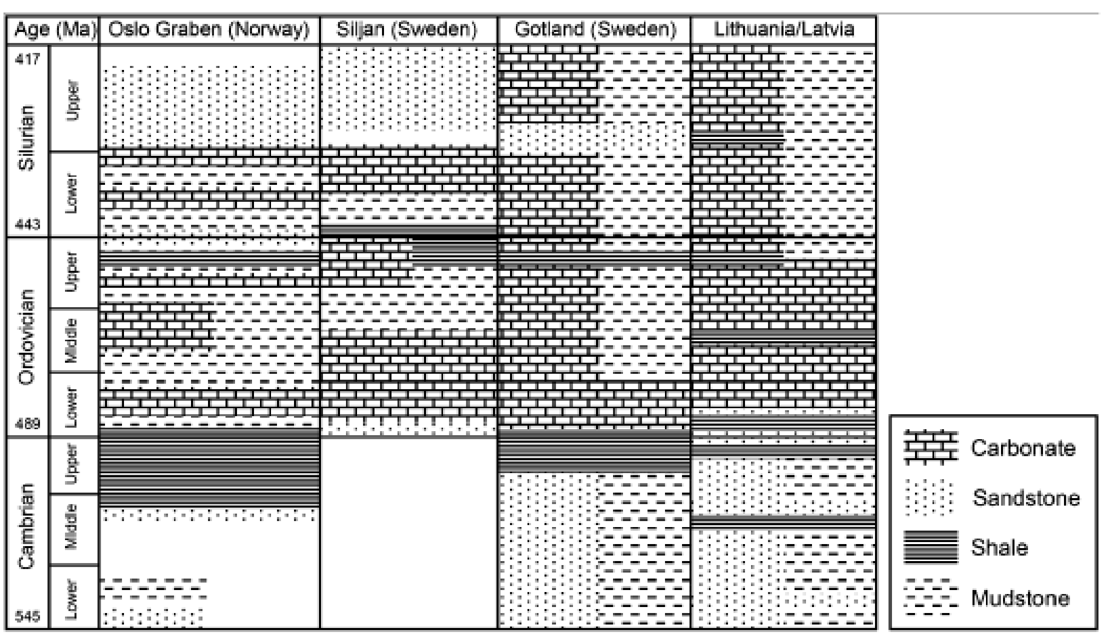
The depositional setting of the Cambrian-Ordovician Alum Shale in southern Sweden and northern Denmark has been mapped in the technical literature. Outcrops of the Alum Shale exist along the Caledonian Mountain belt along the Sweden-Norway border and in southern Sweden. Figure XIII-26 provides the stratigraphic position of the Alum Shale in Sweden. Figure XIII-27, compiled from a variety of sources, indicates the presence of the Alum Shale in the Oslo Graben of Norway and on Gotland in Sweden. While the stratigraphy of the Alum Shale has only moderate variation in central Sweden, the structural setting becomes complex along the Caledonian Front in Norway, western Sweden and northern Denmark.

Figure XIII-26. Stratigraphic Column for Cambrian Through Permian, Sweden



Source: Thickpenny, A, 1984.

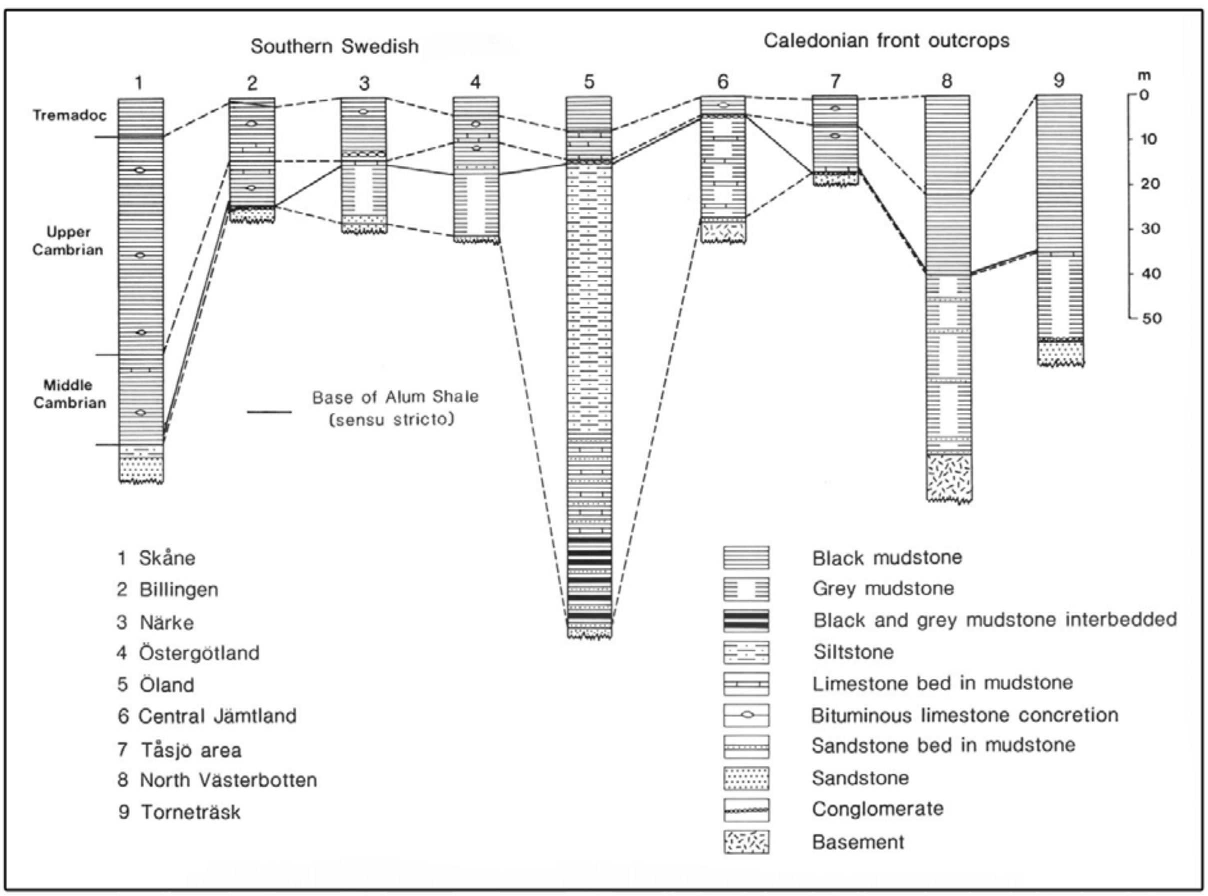
Figure XIII-27. Generalized Lower Paleozoic Stratigraphy for the Scandinavia-Baltic Region.



Modified from Bjørlykke (1974), Vlierboom et al. (1986), Thickpenny and Leggett (1987), Brangulis et al. (1993), Zdanaviciute and Bojesen-Kofoed (1997), Bondar et al. (1998), Sivhed et al. (2004).
Source: Pedersen, J.H., 2007

The Alum Shale contains a series of distinct lithotypes, as shown by the cross-section of data from selected outcrop areas in southern Sweden and the Caledonian Front, Figure XIII-28. Two of these lithotypes are important shale source rocks. The first is the black organic-rich mudstone with TOC of 5% to 7% in the Middle Cambrian, reaching up to 20% in the Upper Cambrian.[12] This interval contains 30% to 40% illite clay, and ±25% quartz, plus pyrite and K-feldspar. The second is the black and gray (dark brown) inter-bedded mudstone, with TOC of about 5%. Grey mudstone, bituminous limestone and thin sandstone, siltstone lamina constitute the remaining lithotypes. The Alum Shale was deposited in a relatively shallow, anoxic marine environment.

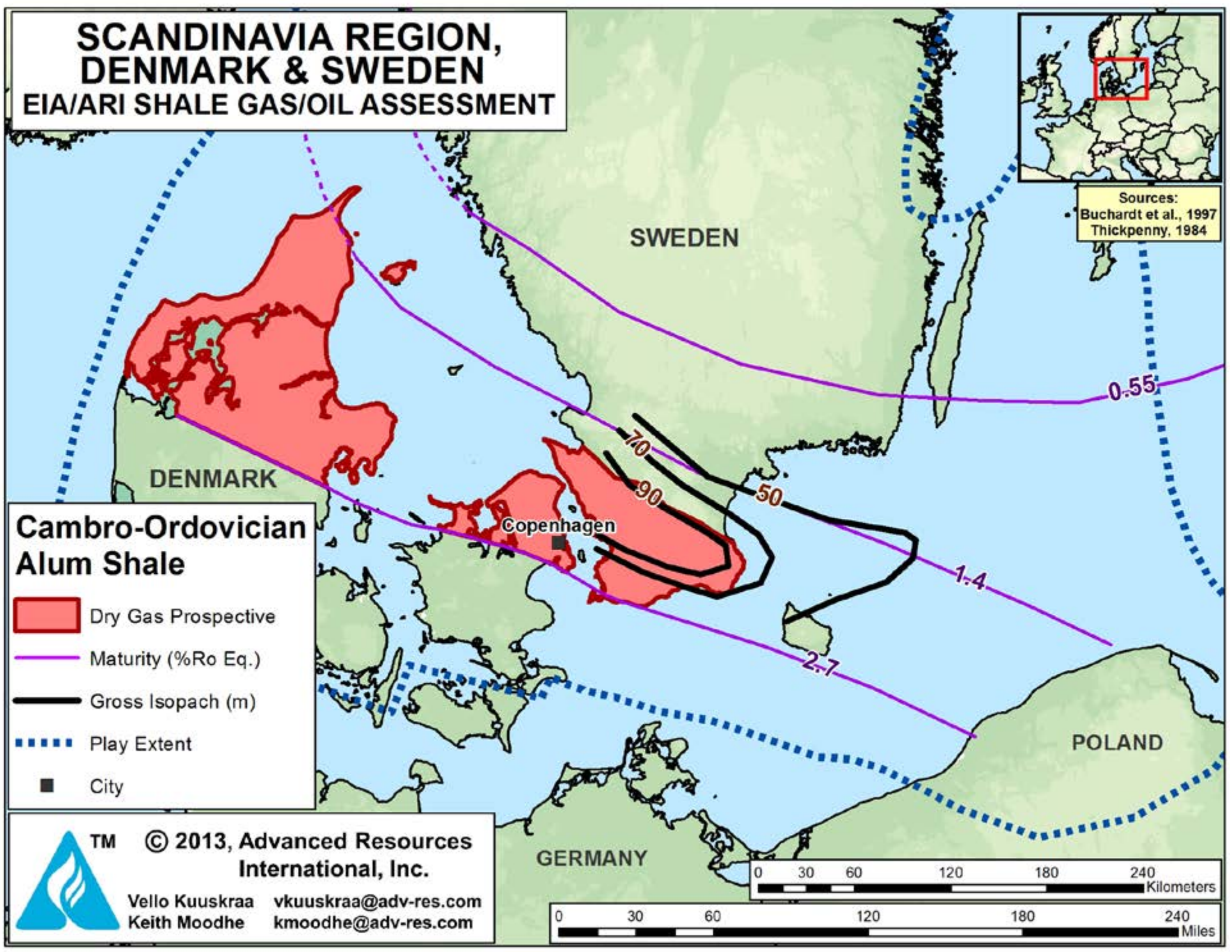
Figure XIII-28. Comparative Middle and Upper Cambrian Stratigraphic Columns for Selected Outcrop Areas in Scandinavia



Source: Thickpenny, 1984

Except for outcroppings and data from shallower wells, rigorous data on the properties of the Alum Shale are scarce. ARI has identified an 8,100-mi^2 prospective area where the shale is deposited below 3,300 feet at depth and where the thermal maturity data indicate the shale is inside the gas window, Figure XIII-29. The bulk of the Alum Shale prospective area is in northern Denmark, encompassing 5,680 mi^2. The remaining 2,120-mi^2 prospective area for the Alum Shale is in southern Sweden.

Figure XIII-29. Prospective Areas for Alum Shale in Denmark and Sweden.



Source: ARI, 2013.

The outlines of the Alum Shale prospective area are based on thermal maturity of 2.7% R_o on the south and the 3,300-foot depth limit (plus outcrops of the shale in the Skane area) on the north. Data from well drilling by Shell provided information on the depth of the Alum Shale in southern Sweden.

5.3 Reservoir Properties (Prospective Area)

The depth of the Alum Shale ranges from 3,300 feet in southern Sweden to 15,000 feet in northern Denmark. We have assumed a depth of 5,000 feet for the dry gas prospective area in Sweden and a depth of 13,500 feet for the two dry gas prospective areas in Denmark.

The thickness of the Alum Shale generally ranges from 20 to 60 m, but can reach 80 to 100 m in the Skane area and 200 m or more in repeated sequences due to multiple thrust faults along the Caledonian Front.[13,14] The Alum Shale gross thickness is relatively constant, ranging from 250 to 300 feet in the prospective area, Figure XIII-29. We have assumed a relatively high net to gross ratio of 80%, giving a net shale thickness of 200 feet. Since we include both the high TOC black shale and the lower TOC dark brown shale in our net pay, we use an average TOC of 7.5%. The Alum Shale formation is normally pressured, has moderately high clay content and is structurally complex, making the shale a high risk play.

5.4 Resource Assessment

For the Alum Shale in Sweden, we calculate a resource concentration of 77 Bcf/mi^2. Based on this and a 2,120-mi^2 prospective area, we estimate risked shale gas in-place of 49 Tcf, with 10 Tcf as the risked, technically recoverable shale gas resource, Table XIII-9.

For the Alum Shale in Denmark, we calculate a resource concentration of 110 Bcf/mi^2. Based on this and a 5,980-mi^2 prospective area, we estimate risked shale gas in-place of 159 Tcf, with 32 Tcf as the risked, technically recoverable shale gas resource, Table XIII-9.

Additional investigation and data are required to establish the shale resources of Norway, particularly in the deeper Oslo Graben.

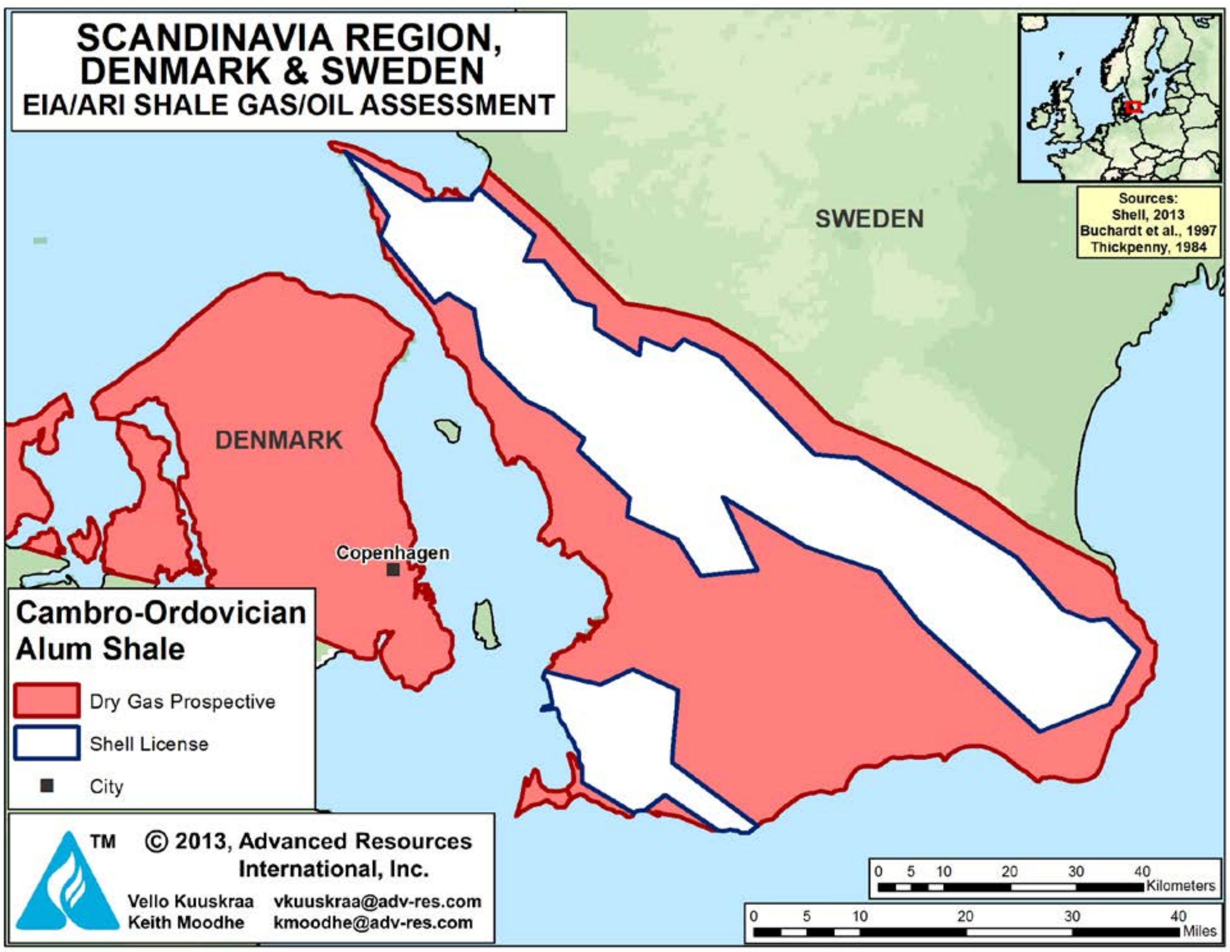
5.5 Recent Activity

The Alum Shale has a rich exploration history that dates back to the 1600s with the extraction of alum salt. Subsequently, the Alum Shale was mined for oil shale in 1930 to 1950 and later as a source for uranium. [15]

Of the numerous companies that have applied for exploration licenses in Sweden, Shell Oil has been the most active. Shell drilled three wells on their 400-mi^2 lease area in the Skane Region of Southern Sweden between 2008 to 2011, Figure XIII-30. However, according to information from the Geologic Survey of Denmark and Greenland, “They drilled three wells, but found it uneconomic."[15] Other companies with Alum Shale exploration licenses in Sweden are Gripen Gas and Energigas, with twelve licenses in south-central Sweden. However, Gripen Gas is pursuing biogenic source gas with a series of exploration wells in the shallow portion of the Alum Shale.

In Denmark, Total E&P Denmark B.V. is exploring for deep shale gas in two license areas in northern Denmark. Total submitted the work program for the first exploration well, Vendsyssel-1, in late 2012 and plans a six year exploration program to determine whether their lease areas contain sufficient shale gas resources to warrant further development.

Figure XIII-30. Shell Oil License Areas, Alum Shale, Sweden



Source: ARI, 2013.

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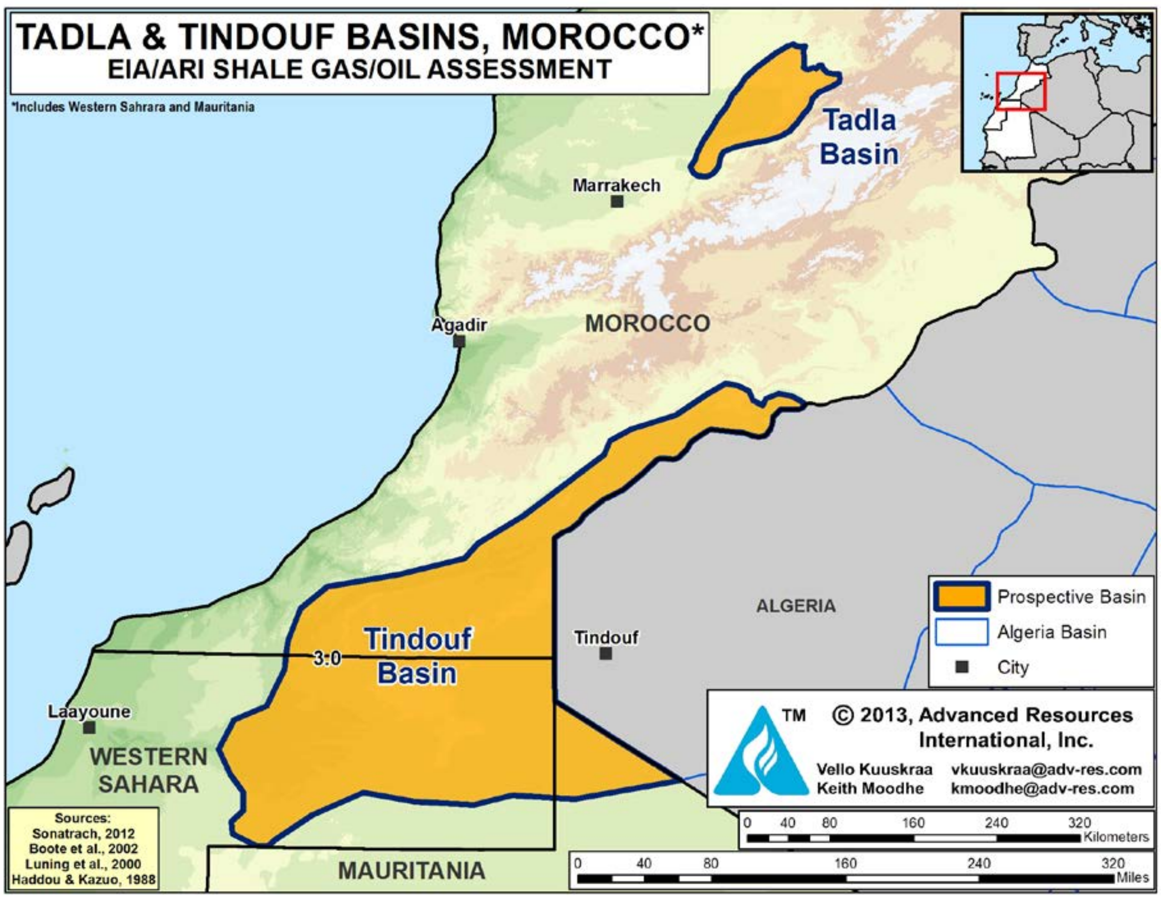
XIV. MOROCCO (INCLUDING WESTERN SAHARA AND MAURITANIA)

SUMMARY

In addition to large accumulations of Late-Cretaceous immature oil shale (kerogen) at depths suitable for surface mining[1], Morocco and its two neighboring countries, Mauritania and Western Sahara, also possess organic-rich Silurian- and Devonian-age shale gas and shale oil potential in the Tindouf and Tadla basins, Figure XIV-1. Mapping and resource characterization of these shales is challenging because regional deformation, erosion and subsidence of the shale deposits have led to their discontinuous and complex present day distribution.

Figure XIV-1. Shale Gas Basins of Morocco, Western Sahara and Mauritania



Source: ARI, 2013.

ARI estimates that the Tindouf and Tadla basins contain risked shale gas in-place of 95 Tcf, with 20 Tcf of risked, technically recoverable shale gas resources, Table XIV-1. In addition, these two basins contain risked shale oil/condensate in-place of 5 billion barrels, with 0.2 billion barrels of risked, technically recoverable shale oil/condensate resources, Table XIV-2.

Table XIV-1. Reservoir Properties and Shale Gas Resources of Morocco, Sahara Desert and Mauritania

Basic Data	Basin/Gross Area		Tindouf (77,000 mi^2)			Tadla (2,800 mi^2)
	Shale Formation		L. Silurian			L. Silurian
	Geologic Age		L. Silurian			L. Silurian
	Depositional Environment		Marine			Marine
Physical Extent	Prospective Area (mi^2)		2,020	4,670	12,380	1,670
	Thickness (ft)	Organically Rich	60	60	60	328
		Net	54	54	54	197
	Depth (ft)	Interval	6,600 - 11,000	6,600 - 13,000	6,600 - 14,000	3,280 - 9,840
		Average	9,000	10,000	11,000	6,560
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Underpress.
	Average TOC (wt. %)		4.0%	4.0%	4.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	2.80%	2.25%
	Clay Content		Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		6.8	18.9	22.0	49.0
	Risked GIP (Tcf)		2.7	17.7	54.5	20.5
	Risked Recoverable (Tcf)		0.3	3.5	13.6	3.1

Table XIV-2. Reservoir Properties and Shale Oil Resources of Morocco, Sahara Desert and Mauritania

Basic Data	Basin/Gross Area		Tindouf (77,000 mi^2)	
	Shale Formation		L. Silurian	
	Geologic Age		L. Silurian	
	Depositional Environment		Marine	
Physical Extent	Prospective Area (mi^2)		2,020	4,670
	Thickness (ft)	Organically Rich	60	60
		Net	54	54
	Depth (ft)	Interval	6,600 - 11,000	6,600 - 13,000
		Average	9,000	10,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		4.0%	4.0%
	Thermal Maturity (% Ro)		0.85%	1.15%
	Clay Content		Medium	Medium
Resource	Oil Phase		Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		7.9	1.7
	Risked OIP (B bbl)		3.2	1.6
	Risked Recoverable (B bbl)		0.16	0.08

INTRODUCTION

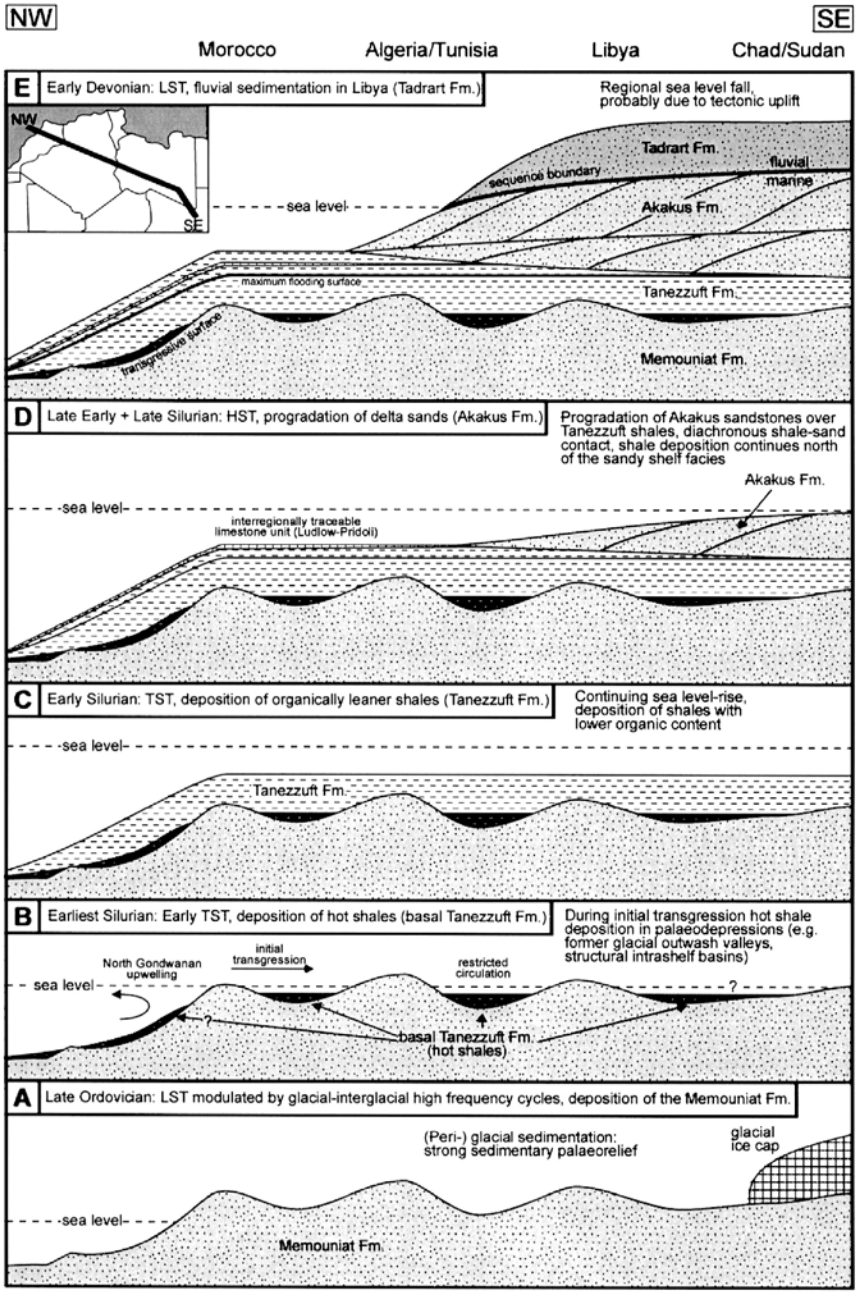
The primary shale resource on Morocco, Mauritania and Western Sahara is the lower Silurian "Hot Shale," which consists of thin but very organic-rich layers of marine organic matter deposited during a regional anoxic event. Data from wells drilled across the country confirm the presence of organic-rich Silurian shales, although not always within the current formally established boundaries of hydrocarbon basins.

The presence of a thick Silurian section, observed in many Moroccan hydrocarbon basins, does not guarantee the presence of organic-rich shale, as areas that were regional highs during the early Silurian may not have received organic-rich sediments, Figure XIV-2.[2]

Accurately identifying promising shale basins and estimating their resource potential in such geologically complex areas requires significant amounts of data, which are not widely available in Morocco and its neighboring countries because of limited well drilling and data confidentiality. As this data becomes more publically available, a more rigorous shale gas and oil resource assessment of Morocco may be possible.

This report assesses the two basins which appear to have the highest potential for shale gas and oil resources based on publically available data: the Tindouf (Zag) Basin in the south of Morocco (extending into Algeria, Western Sahara, and Mauritania), and the central Moroccan Tadla Basin.

Figure XIV-2. Sedimentary Depositional Environment in Morocco, Ordovician-Devonian[2]



1. TINDOUF BASIN

1.1 Geologic Setting

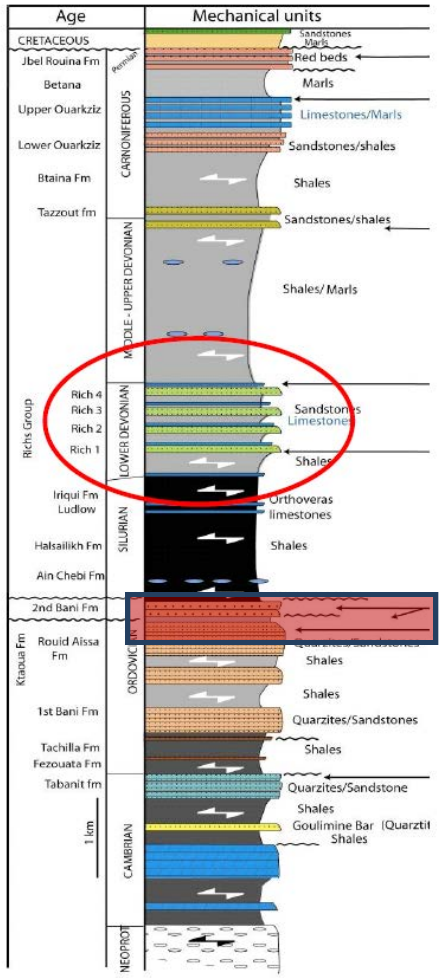
The Tindouf Basin is the westernmost of the major North African Paleozoic basins, covering a 31,660-mi^2 area in Morocco, Western Sahara and Mauritania. The basin is bounded by the Atlas Mountains and Ougarta Arch to the north and the Reguibate Massif in the south. Although once covered unconformably by a blanket of Mesozoic to early Tertiary sediments, the Paleozoic now crops out over much of the region. The Tindouf Basin is an asymmetric depression with a broad gentle southern flank and a steeply dipping, more structurally complex northern margin.

The Tindouf Basin was a large sediment depocenter from late Ordovician to Carboniferous time, accumulating multiple layers of organic-rich Silurian, Devonian (Frasnian) and Carboniferous (Visean) shales, Figure XIV-3.[3] However, these deposits were affected by the Hercynian deformation and the prospectivity of these shale formations is uncertain. High heat flow through the basin caused the Tindouf Basin shales to reach high maturity during the Carboniferous. Uplift and erosion of these shales may have caused significant underpressuring, as the shales were not buried deep enough to replenish hydrocarbons dissipated during the Hercynian orogeny.

This report focuses on the Lower Silurian "Hot Shale," which has greater data availability and higher confidence of remaining gas saturation in this shale interval. Through mapping of depth and thermal maturity, we have identified a 19,070-mi^2 prospective area in the Morocco, Mauritania and Western Sahara portion of the Tindouf Basin. The northern boundary of the prospective area is the 1,000-meter depth contour on the upthrusted northern portion of the basin, Figure XIV-4.[4] The southern boundary is the 0.7% R_o thermal maturity contour. The eastern boundary is the Algeria Border.

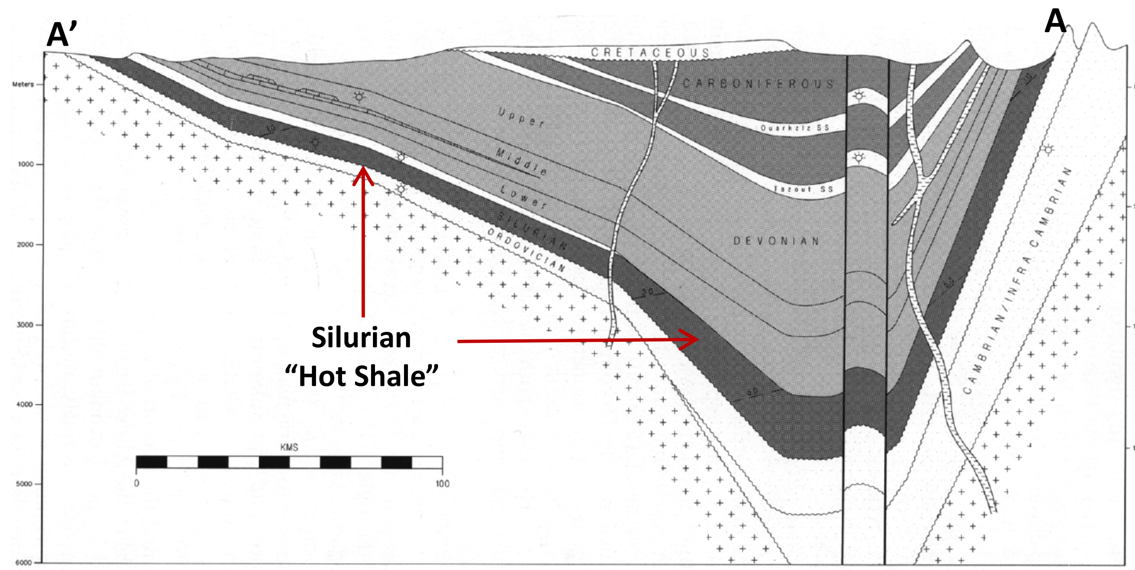
While the drilling density in the basin is extremely low, with an average of only one well per 5,000 mi^2, the data suggest that organic-rich, basal Silurian shales were deposited throughout the basin.[2] Additional well and seismic data have been collected by various international companies in partnership with Moroccan oil company, ONHYM, but these data are not yet in the public domain.

Figure XIV-3. Tindouf Basin Stratigraphic Column



Source: Longreach Petroleum Corporate Presentation, 2010

Figure XIV-4. Tindouf Basin Cross Section

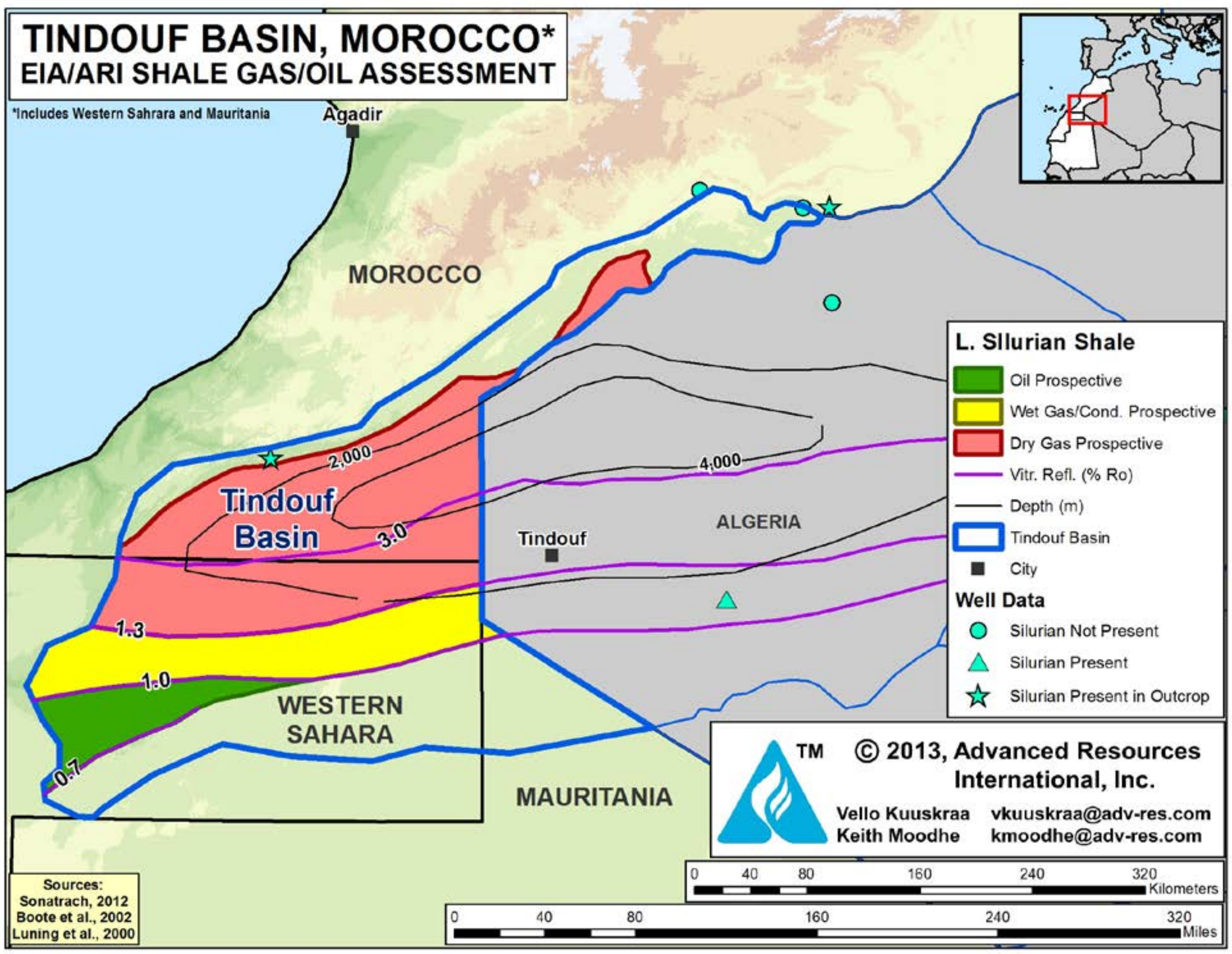


Source: Boote, 2002.

1.2 Reservoir Properties (Prospective Area)

Within the Tindouf Basin's prospective area, the depth to the Silurian "Hot Shale" ranges from 6,600 to 14,000 ft, Figure XIV-5. Present day TOC content ranges from 1% to 7%, averaging 4%. It is likely that the TOC content was higher during the time of hydrocarbon generation, due to the basin's very high thermal maturity.[5] Thermal maturity increases to the north across the basin, ranging from 0.7% to over 3% R_o.[4] Organic-rich net shale thickness is estimated at 54 ft, based on data from a well drilled in the southern flank of the basin.[6]

Figure XIV-5. Tindouf Basin Prospective Area, Morocco, Western Sahara and Mauritania



Source: ARI, 2013

1.3 Resource Assessment

We estimate that the wet and dry gas prospective area of the Silurian "Hot Shale" in the Morocco, Mauritania and Western Sahara portions of the Tindouf Basin has a resource concentration of 19 to 22 Bcf/mi^2. The oil prospective area of the Silurian "Hot Shale" has a resource concentration of 8 million barrels/mi^2 plus associated gas. While the shale formation is organic-rich, it is thin, limiting its resource concentration.

Within the overall 19,020-mi^2 prospective area, the Lower Silurian "Hot Shale" in the Tindouf Basin contains a 12,380-mi^2 area prospective for dry gas, a 4,670-mi^2 area prospective for wet shale gas and shale condensate, and a 2,020-mi^2 area prospective for shale oil. The risked shale gas in-place for the Tindouf Basin is estimated at 75 Tcf, with 17 Tcf as the risked, technically recoverable shale gas resource. In addition, the Tindouf Basin has an estimated 5 billion barrels of shale oil/condensate in-place, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

1.4 Recent Activity

The Moroccan national oil and gas company, ONHYM, has been evaluating the country's shale gas potential since mid-2010. It has plans to collect seismic data followed by the drilling of a shale gas exploration well. The well is proposed to be drilled in partnership with San Leon Energy (Ireland) and Longreach Oil and Gas (Canada) on the Zag exploration license.[7]

2. TADLA BASIN

2.1 Geologic Setting

The Talda Basin is a 2,800-mi^2 intra-cratonic basin located in central Morocco within the Moroccan Mesta. The basin contains nearly 16,500 feet of Paleozoic through Cenozoic sedimentary strata, Figure XIV-6. Paleozoic rocks dominate the sediments in this basin, except in areas where uplift has caused their erosion, Figure XIV-7. The Talda Basin is bounded by the Central Massif in the north, the Atlas Mountains in the east, the Jebiliet Massif in the south, and the Rehamna Massif in the west. The Fkih Ben Salah Fault divides the basin into a southeast section, characterized by complex tectonics including heavy folding and faulting, and a northwest section, with thick carboniferous strata and minor, infrequent faulting.[8]

As in the Tindouf Basin, regional uplifting during the Hercynian and Alpine events exposed the Silurian, Devonian and Ordovician shales after they had matured and begun to generate hydrocarbons. While these shales were subsequently buried on the western edge of the basin by approximately 6,500 ft of Cretaceous and Tertiary sediments, it is unlikely that the shales generated additional hydrocarbons after reburial.[8] As such, this basin is at high risk for underpressuring, although data are not available to confirm this assumption.

The 1,670-mi^2 prospective area of the Tadla Basin is bounded by the 1,000-m depth contour, various faults and the Atlas Mountain range to the east, Figure XIV-8. Little data are available in the southern portion of the basin where the prospective area is bounded by the apparent lack of organic-rich Silurian strata.

2.2 Reservoir Properties (Prospective Area)

The Lower Silurian "Hot Shale" in the Tadla Basin reaches maximum depth west of the Fkih Ben Salah Fault, ranging from 3,280 to 9,840 ft.[8] To the east, the shale becomes shallower. Average depth in the prospective area is estimated at 6,560 ft. Where it has not been eroded, the Silurian section can reach up to 800 feet thick, with over 300 feet of organic-rich shale, of which 200 ft is net shale.[9] TOC data from outcrops suggest that the organic content reaches 10-12%,[10] but deep well data from inside the prospective area indicates TOC values closer to 2%. The Silurian shale is thermally highly mature over the prospective area; R_o values of 1.5% to 3% place the shale in the dry gas window.[8]

Figure XIV-6. Tadla Basin Stratigraphic Column[8]

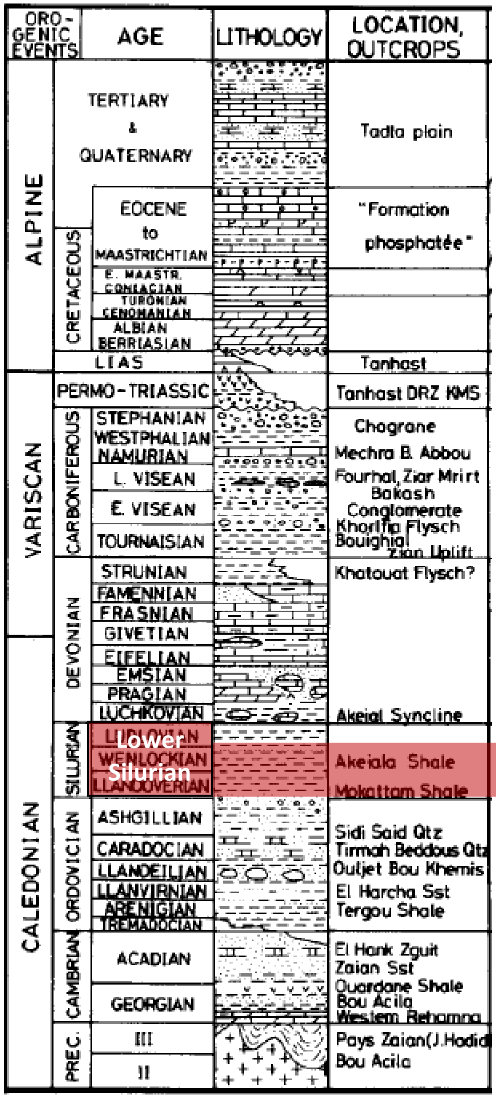


Figure XIV-7. Tadla Basin Cross Sections[8]

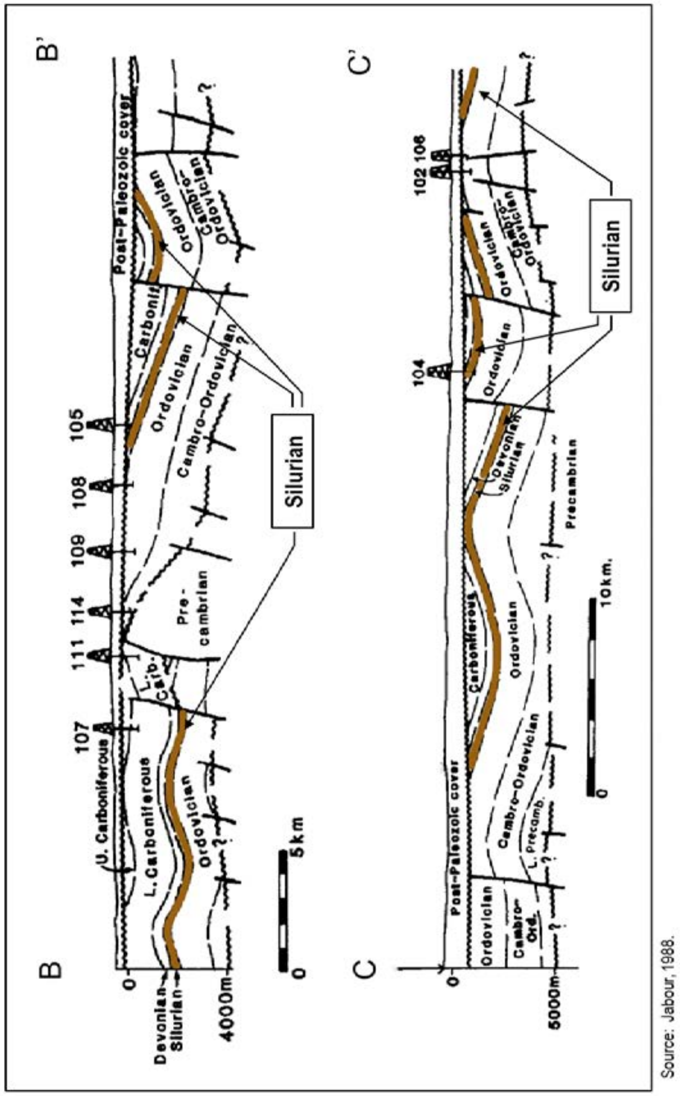
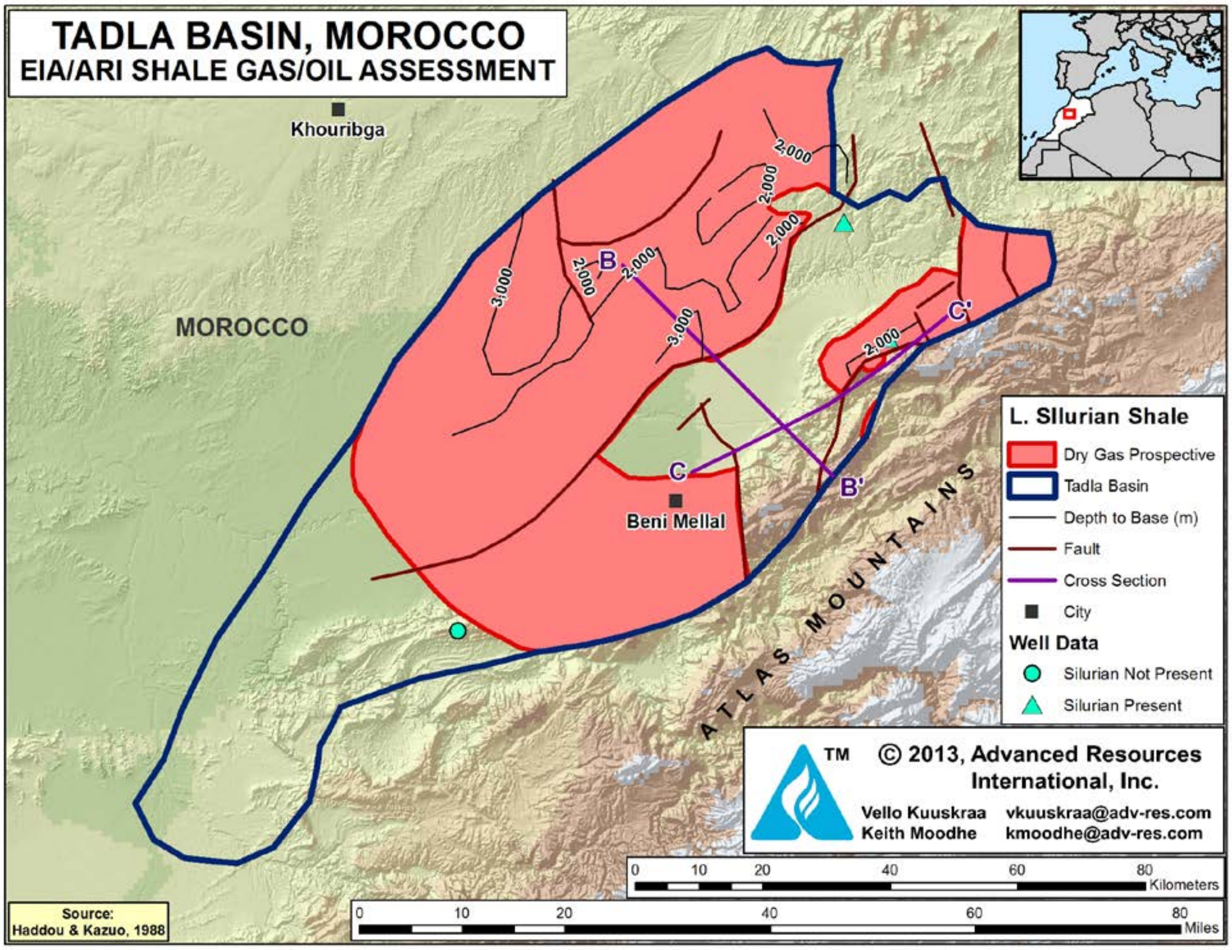


Figure XIV-8. Tadla Basin Prospective Area, Morocco



Source: ARI, 2013

2.3 Resource Assessment

The Silurian "Hot Shale" in the Tadla Basin's 1,670-mi^2 prospective area has a moderate 49-Bcf/mi^2 dry gas resource concentration. The basin contains an estimated 20 Tcf of risked shale gas in-place, with 3 Tcf as the risked, technically recoverable shale gas resource.

2.4 Recent Activity

No shale gas exploration activity has been reported in the Tadla Basin of Morocco.

3. SHALE RESOURCES BY COUNTRY

3.1 Morocco

Morocco has a 1,670-mi^2 dry gas prospective area in the Tadla Basin and an 8,000-mi^2 dry gas prospective area in the Tindouf Basin. Within these two prospective areas, Morocco has 56 Tcf of risked shale gas in-place, with 12 Tcf as the risked, technically recoverable shale gas resource.

3.2 Western Sahara

The Western Sahara portion of the Tindouf Basin has a 4,380-mi^2 dry gas prospective area, a 4,670-mi^2 wet shale gas/condensate prospective area, and a 2,020-mi^2 shale oil prospective area. Within these prospective areas, Western Sahara has an estimated 39 Tcf of risked dry, wet and associated shale gas in-place, with 8 Tcf as the risked, technically recoverable shale gas resource. In addition, Western Sahara has 5 billion barrels of risked shale oil/condensate in-place, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

3.3 Mauritania

Mauritania has a small 50-mi^2 wet shale gas/condensate prospective area in the Tindouf Basin containing only minor shale gas and oil resources.

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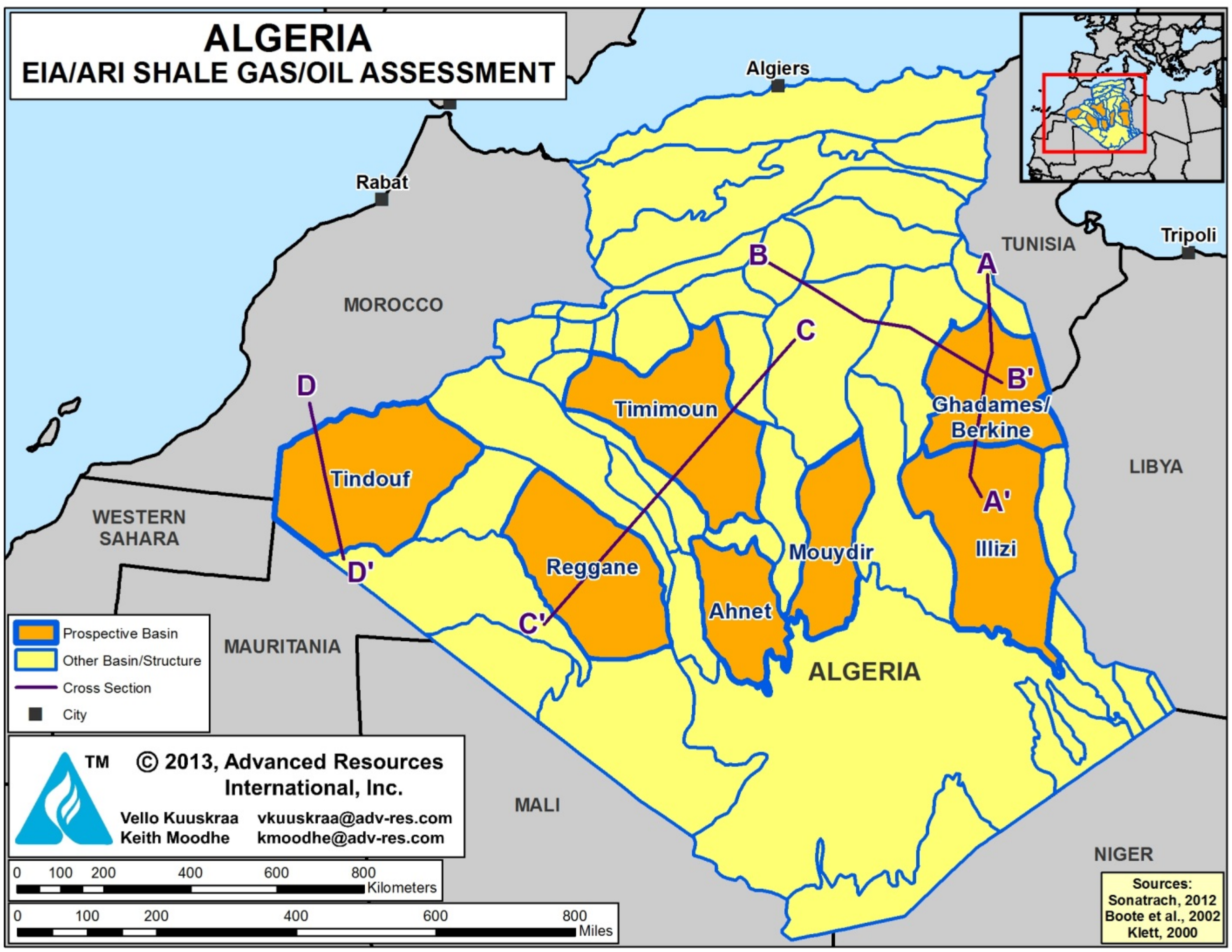
XV. ALGERIA

SUMMARY

Algeria's hydrocarbon basins hold two significant shale gas and shale oil formations, the Silurian Tannezuft Shale and the Devonian Frasnian Shale. This study examines seven of these shale gas and shale oil basins: the Ghadames (Berkine) and Illizi basins in eastern Algeria; the Timimoun, Ahnet and Mouydir basins in central Algeria; and the Reggane and Tindouf basins in southwestern Algeria, Figure XV-1.

Figure XV-1. Shale Gas and Shale Oil Basins of Algeria



Source: ARI, 2013.

Our assessment is that these seven basins contain approximately 3,419 Tcf of risked shale gas in-place, with 707 Tcf as the risked, technically recoverable shale gas resource, Table XV-1A, 1B and 1C. In addition, six of these basins hold 121 billion barrels of risked shale oil and condensate in-place, with 5.7 billion barrels as the risked, technically recoverable shale oil resource, Table XV-2.

Table XV-1A. Shale Gas Reservoir Properties and Resources of Algeria.

Basic Data	Basin/Gross Area		Ghadames/Berkine (117,000 mi^2)					Illizi (44,900 mi^2)	
	Shale Formation		Frasnian			Tannezuft		Tannezuft	
	Geologic Age		U. Devonian			Silurian		Silurian	
	Depositional Environment		Marine			Marine		Marine	
Physical Extent	Prospective Area (mi^2)		2,720	3,840	3,490	6,050	22,080	9,840	16,760
	Thickness (ft)	Organically Rich	275	275	275	115	115	180	180
		Net	248	248	248	104	104	162	162
	Depth (ft)	Interval	8,000 - 10,500	9,000 - 10,000	10,000 - 16,000	10,000 - 14,500	11,000 - 16,000	3,300 - 8,000	3,300 - 8,000
		Average	8,500	9,500	13,000	10,500	13,000	5,000	5,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		6.0%	6.0%	6.0%	5.7%	5.7%	5.7%	5.7%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.70%	1.15%	1.90%	1.15%	1.70%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		35.4	111.4	133.9	42.9	54.5	50.9	60.7
	Risked GIP (Tcf)		48.2	213.8	233.7	129.9	601.3	100.1	203.6
	Risked Recoverable (Tcf)		4.8	42.8	58.4	26.0	150.3	15.0	40.7

Table XV-1B. Shale Gas Reservoir Properties and Resources of Algeria.

Basic Data	Basin/Gross Area		Timimoun (43,700 mi^2)		Ahnet (20,200 mi^2)			Mouydir (22,300 mi^2)
	Shale Formation		Frasnian	Tannezuft	Frasnian		Tannezuft	Tannezuft
	Geologic Age		U. Devonian	Silurian	U. Devonian		Silurian	Silurian
	Depositional Environment		Marine	Marine	Marine		Marine	Marine
Physical Extent	Prospective Area (mi^2)		32,040	41,670	1,650	5,740	11,730	12,840
	Thickness (ft)	Organically Rich	200	100	275	60	330	60
		Net	180	90	248	54	297	54
	Depth (ft)	Interval	3,300 - 9,000	5,000 - 15,000	3,300 - 6,600	5,000 - 9,500	6,000 - 10,500	5,000 - 10,000
		Average	6,000	10,000	5,000	7,000	8,000	6,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		4.0%	2.8%	4.0%	3.0%	2.8%	3.0%
	Thermal Maturity (% Ro)		1.70%	2.00%	1.15%	1.70%	2.00%	2.20%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Dry Gas	Dry Gas	Wet Gas	Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		72.9	35.5	77.6	21.6	109.0	18.5
	Risked GIP (Tcf)		467.1	295.5	25.6	24.8	255.7	47.6
	Risked Recoverable (Tcf)		93.4	59.1	3.8	5.0	51.1	9.5

Table XV-1C. Shale Gas Reservoir Properties and Resources of Algeria.

			Reggane				Tindouf	
Basic Data	Basin/Gross Area		(40,000 mi^2)				(77,000 mi^2)	
	Shale Formation		Frasnian		Tannezuft		Tannezuft	
	Geologic Age		U. Devonian		Silurian		Silurian	
	Depositional Environment		Marine		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		2,570	2,110	10,150	24,600	5,340	23,800
	Thickness (ft)	Organically Rich	330	260	130	230	60	60
		Net	297	234	117	207	54	54
	Depth (ft)	Interval	5,500 - 14,500	6,600 - 16,000	5,000 - 9,500	7,500 - 16,000	6,600 - 13,000	6,600 - 14,000
		Average	10,000	11,000	8,000	12,000	10,000	11,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.0%	3.0%	4.0%	4.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		1.15%	1.70%	1.15%	1.80%	1.15%	2.50%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Wet Gas	Dry Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		103.9	97.3	38.3	94.4	18.9	24.2
	Risked GIP (Tcf)		53.4	41.0	77.8	464.5	20.2	115.2
	Risked Recoverable (Tcf)		8.0	8.2	11.7	92.9	3.0	23.0

Table XV-2. Shale Oil Reservoir Properties and Resources of Algeria.

			Ghadames/Berkine			Illizi	Ahnet	Reggane		Tindouf
Basic Data	Basin/Gross Area		(117,000 mi^2)			(44,900 mi^2)	(20,200 mi^2)	(40,000 mi^2)		(77,000 mi^2)
	Shale Formation		Frasnian		Tannezuft	Tannezuft	Frasnian	Frasnian	Tannezuft	Tannezuft
	Geologic Age		U. Devonian		Silurian	Silurian	U. Devonian	U. Devonian	Silurian	Silurian
	Depositional Environment		Marine		Marine	Marine	Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		2,720	3,840	6,050	9,840	1,650	2,570	10,150	5,340
	Thickness (ft)	Organically Rich	275	275	115	180	275	330	130	60
		Net	248	248	104	162	248	297	117	54
	Depth (ft)	Interval	8,000 - 10,500	9,000 - 10,000	10,000 - 14,500	3,300 - 8,000	3,300 - 6,600	5,500 - 14,500	5,000 - 9,500	6,600 - 13,000
		Average	8,500	9,500	10,500	5,000	5,000	10,000	8,000	10,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		6.0%	6.0%	5.7%	5.7%	4.0%	3.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate
	OIP Concentration (MMbbl/mi^2)		43.7	9.7	3.1	6.5	14.4	11.4	3.9	1.7
	Risked OIP (B bbl)		59.4	18.7	9.5	12.8	4.8	5.9	8.0	1.8
	Risked Recoverable (B bbl)		2.97	0.93	0.47	0.51	0.19	0.24	0.32	0.07

INTRODUCTION

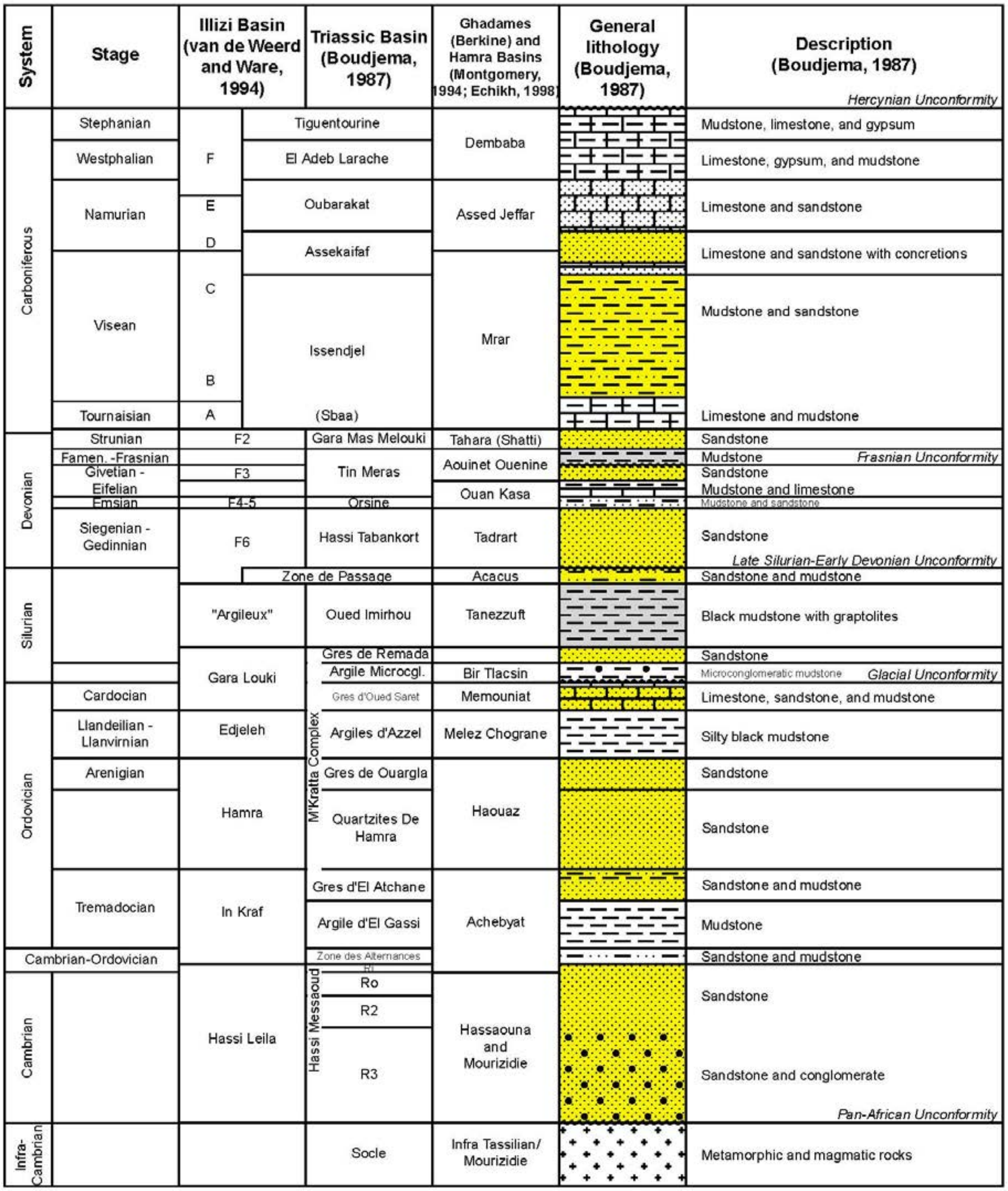
For most of Paleozoic time, North Africa (including Algeria) was a single massive depositional basin.[1] The separation and subsequent collision of Laurasia and Gondwana (the Hercynian event) established the seven individual basin outlines and uplift structures of present day Algeria.[2] Two major transgressions, first in the Silurian and the second in the Late Devonian, provided the deposition of the organically rich marine (generally Type I and II) source rocks in these basins. Subsequent transpressional movements reactivated the older structures. These events, plus additional compression and movement, caused the local uplifts and erosion that today define and characterize these basins.[3]

The stratigraphic column for the shale basins of Algeria is provided in Figure XV-2,[4] identifying the Silurian Tannezuft black mudstone interval and the Upper Devonian Frasnian mudstone that are the principal shale source rocks for the conventional oil and gas discovered to date in Algeria. The stratigraphy of the Silurian section is generally more continuous than of the Devonian section, which has been influenced by more localized deposition[5].

Geochemical modeling indicates that these shales may have generated over 26,000 Tcf of gas (including secondary cracking of generated oil), with some portion of this gas still retained in the shales. The present day total organic content (TOC) of the Silurian Tannezuft Shale ranges from 2% to 4%. However, the TOC of the shale has been reduced by as much as one-half due to the thermal maturation process.[6] The present day TOC of the Upper Devonian Frasnian Shale ranges more widely, from 1% to 8%, decreasing westward across the region.

The following series of three regional cross-sections provides a useful perspective of the depositional and structural setting for six of these basins, Figures XV-3,[4] XV-4[4] and XV-5.[1] Figure XV-1(provided previously) shows the location of these three cross-sections.

Figure XV-2. Stratigraphic Column and Nomenclature for Illizi and Ghadames (Berkine) Basins.
(Major reservoir rocks are shown in yellow and source rocks in gray.)



Source: Klett, 2000A.

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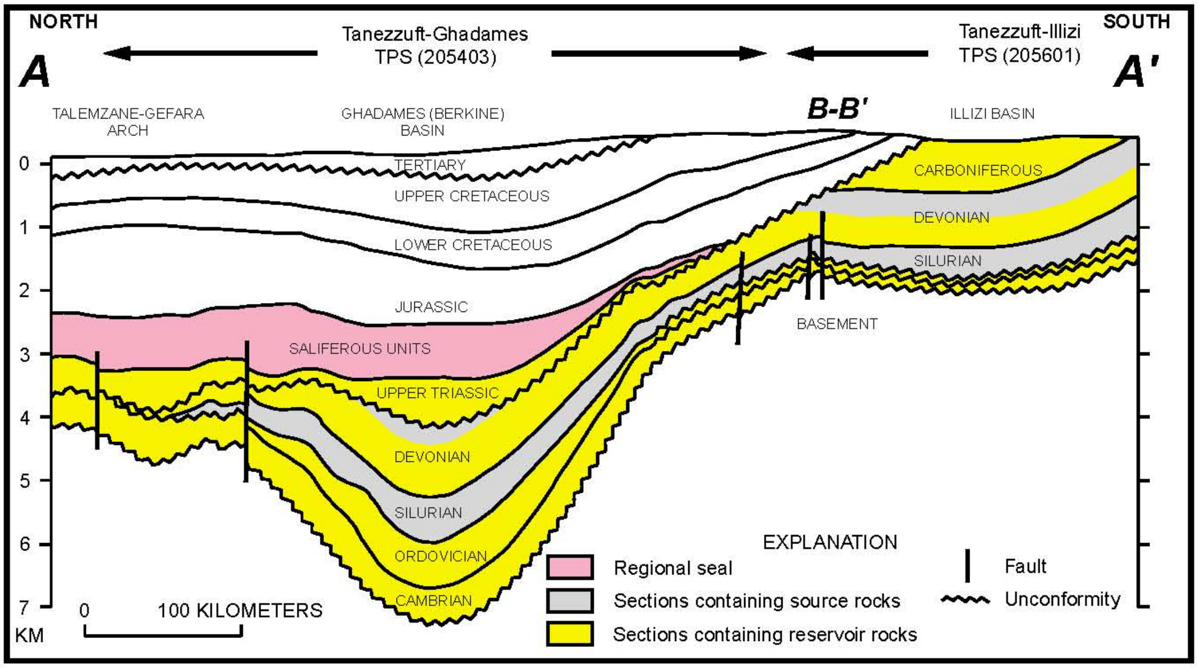
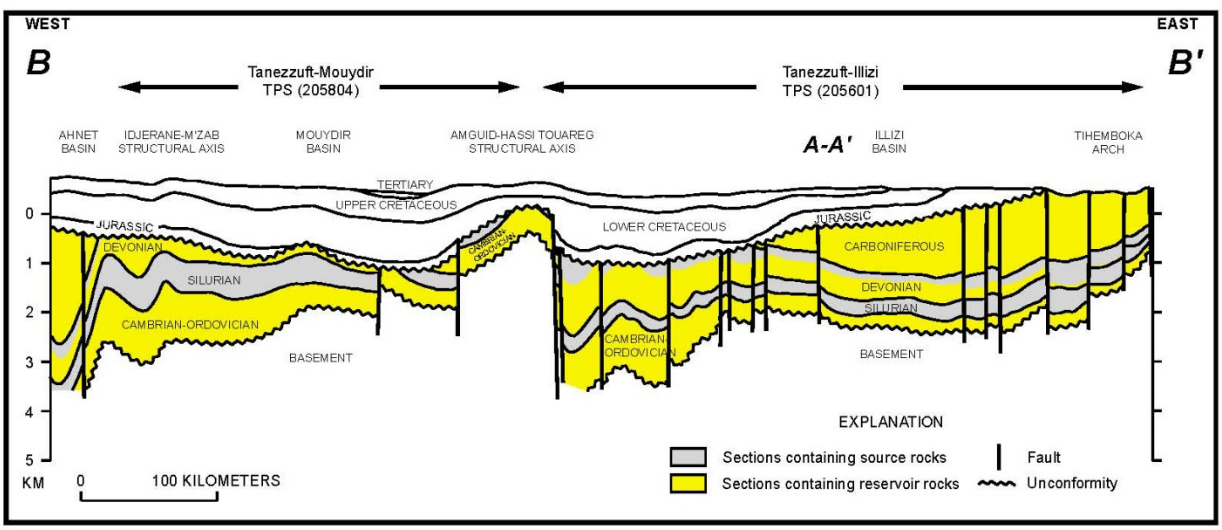
Figure XV-3. Cross Section A-A': Ghadames (Berkline) and Illizi Basins



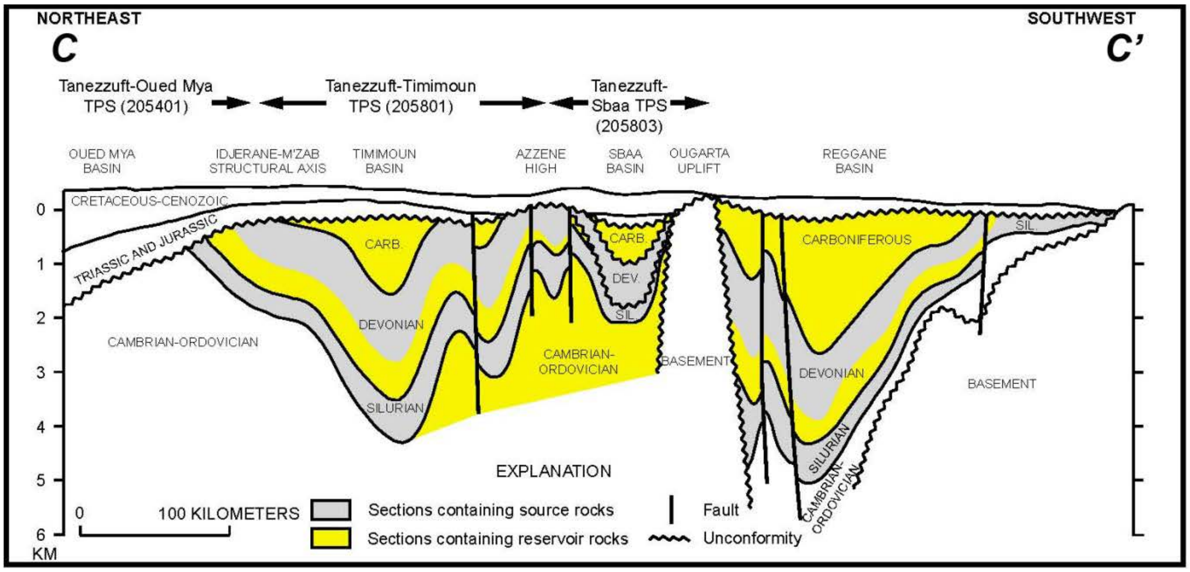
Source: Klett, 2000A.

Figure XV-4. Cross Section B-B': Ahnet, Mouydir and Illizi Basins



Source: Klett, 2000A.

Figure XV-5. Cross-Section C-C': Timimoun and Reggane Basins



Source: Klett, 2000B.

1. GHADAMES (BERKINE) BASIN

1.1 Geologic Setting

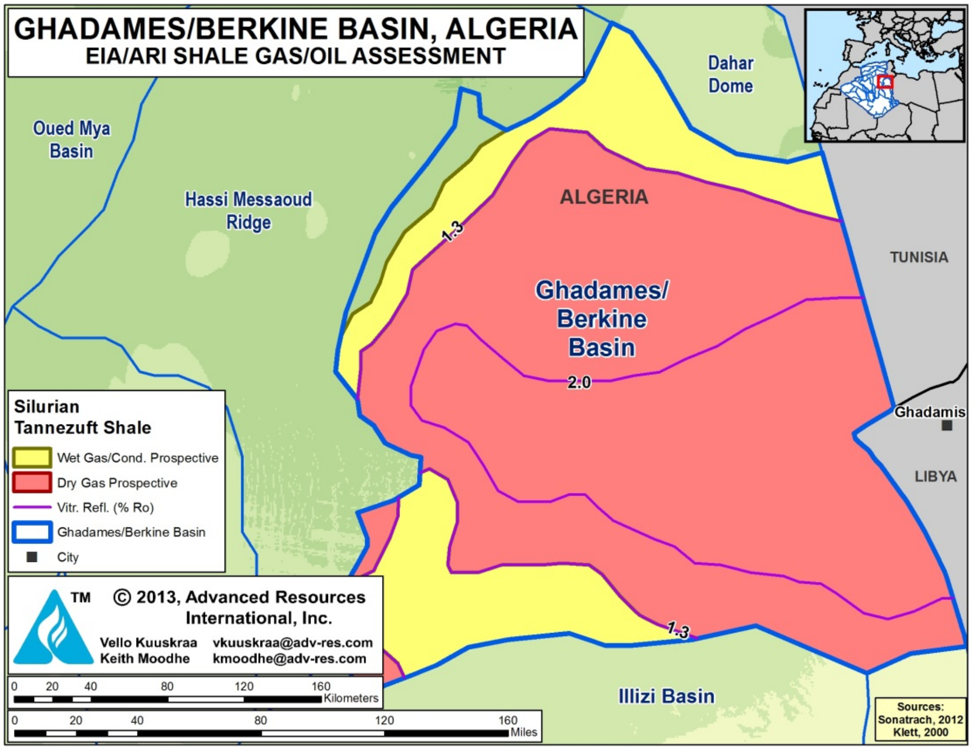
The Ghadames (Berkine) Basin is a large intra-cratonic basin underlying eastern Algeria, southern Tunisia and western Libya. The basin contains a series of reverse faults, providing structural traps for conventional oil and gas sourced from Devonian- and Silurian-age shales. The central, deep portion of the basin contains uplifted fault blocks formed during the Cambrian-Ordovician.[7] The Ghadames Basin and its two significant shale formations, the Silurian Tannezuft and the Upper Devonian Frasnian, are located in the eastern portion of Algeria. Figures XV-6 and XV-7 provide the basin outline and shale thermal maturity contours for these two shale formations.

In Algeria's portion of the Ghadames Basin, the Silurian Tannezuft Formation contains an organic-rich marine shale that increases in maturity toward the basin center. We have mapped a 28,130-mi^2 higher quality prospective area for the Tannezuft Shale in this basin. The western and northern boundaries of the Tannezuft Shale prospective area are defined by the erosional limits of the Silurian and by minimum thermal maturity. The eastern border of the prospective area is defined by the Tunisia and Algerian border.

The central, dry gas portion of the Tannezuft Shale prospective area in the Ghadames Basin, covering 21,420 mi^2, has thermal maturity (R_o) of 1.3% to over 2%. The remaining portion of the prospective area of 6,710 mi^2 has an R_o between 1.0% and 1.3%, placing this area in the wet gas and condensate window.

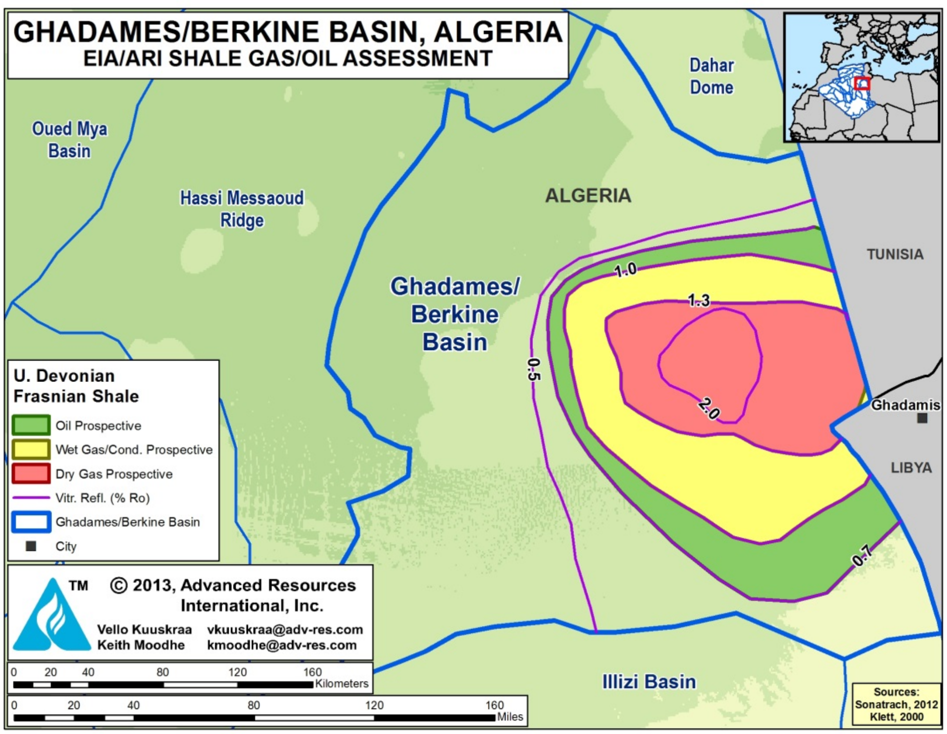
Deposited above the Tannezuft is the areally more limited and thermally less mature Upper Devonian Frasnian Shale. We have mapped a 10,040-mi^2 higher quality prospective area for the Frasnian Shale in the Ghadames Basin of Algeria. The western, northern and southern boundaries of the Frasnian Shale prospective area are set by the minimum thermal maturity criterion of 0.7% R_o. The eastern boundary of the prospective area is the Tunisia and Algeria border. The northern, eastern and southern outer ring of the Frasnian Shale prospective area in the Ghadames Basin, encompassing an area of 2,720 mi^2, is in the oil window with R_o between 0.7% and 1.0%. The central 5,010-mi^2 portion of the Frasnian Shale prospective area is in the dry gas window, with R_o of 1.3% to over 2%. In between is the 2,310-mi^2 wet gas and condensate window for the Frasnian Shale, with R_o between 1.0% and 1.3%.

Figure XV-6. Ghadames Basin Silurian Tannezuft Shale Outline and Thermal Maturity



Source: ARI, 2013.

Figure XV-7. Ghadames Basin Upper Devonian Frasnian Shale Outline and Thermal Maturity



Source: ARI, 2013.

1.2 Reservoir Properties (Prospective Area)

Silurian Tannezuft Formation. The depth of the gas prospective area of the Silurian Tannezuft Shale in the Ghadames (Berkine) Basin of Algeria ranges from 10,000 ft along the northern and eastern edge of the basin to 16,000 ft in the basin center, averaging 10,500 ft in the wet gas prospective area and 13,000 ft in the dry gas prospective area. The gross thickness of the Tannezuft Shale ranges from 30 to 200 ft, with an organic-rich average net thickness of 104 ft. The TOC of the Tannezuft Shale averages 5.7%. The lower portion of the formation is particularly organic-rich, with TOC values of up to 15%.[8]

Upper Devonian Frasnian Formation. The depth of the prospective area of the overlying Upper Devonian Frasnian Shale ranges from 8,000 ft to 16,000 ft, averaging 8,500 ft in the oil-prone area, 9,500 ft in the wet gas/condensate area, and 13,000 ft in the dry gas area. The Frasnian Shale has a gross thickness of 50 to 500 ft, with an average organic-rich net thickness of 248 ft. The Frasnian Shale has TOC values ranging from 3% to 10%, with an average of 6%.[10]

1.3 Resource Assessments

Silurian Tannezuft Shale. The Tannezuft Shale, within its 6,050-mi^2 wet gas and condensate prospective area, has resource concentrations of 43 Bcf/mi^2 of wet gas and 3 million barrels/mi^2 of condensate. Within its larger 22,080-mi^2 dry gas prospective area, the Tannezuft Shale has a resource concentration of 55 Bcf/mi^2. The risked resource in-place for the 28,130-mi^2 wet gas/condensate and dry gas prospective areas of the Tannezuft Shale is 731 Tcf of wet and dry gas and 10 billion barrels of condensate. Based on presence of clays but otherwise favorable reservoir properties, we estimate a risked, technically recoverable resource of 176 Tcf of wet/dry shale gas and 0.5 billion barrels of shale condensate.

Upper Devonian Frasnian Shale. The Frasnian Shale has resource concentrations of 44 million barrels/mi^2 for oil in the 2,720-mi^2 oil window; 10 million barrels/mi^2 of condensate and 111 Bcf/mi^2 of wet gas in the 3,840-mi^2 wet gas/condensate window; and 134 Bcf/mi^2 of dry gas in the 3,490-mi^2 dry gas window. The risked resource in-place within the overall 10,050-mi^2 prospective area is 496 Tcf of shale gas and 78 billion barrels of shale oil/condensate, with risked, recoverable of 106 Tcf for shale gas and 3.9 billion barrels for shale oil.

2. ILLIZI BASIN

2.1 Geologic Setting

The Illizi Basin is located south of the Ghadames (Berkine) Basin, separated by a hinge line in the slope of the basement rocks. This hinge line controls much of the differing petroleum generation, migration and accumulation histories of these two basins.[4] The Illizi Basin is bounded on the east by the Tihemboka (Garoaf) Arch, on the south by the Hoggar Massif, and on the west by the Amguid-Hassi Touareg structural axis which separates the Illizi Basin from the Mouydir Basin, Figure XV-8.[4] The Illizi Basin is located on a basement high and thus its shale formations are shallower than in the Ghadames (Berkline) Basin. We have mapped an overall shale gas and oil prospective area of 26,600 mi^2 for the Illizi Basin.

2.2 Reservoir Properties (Prospective Area)

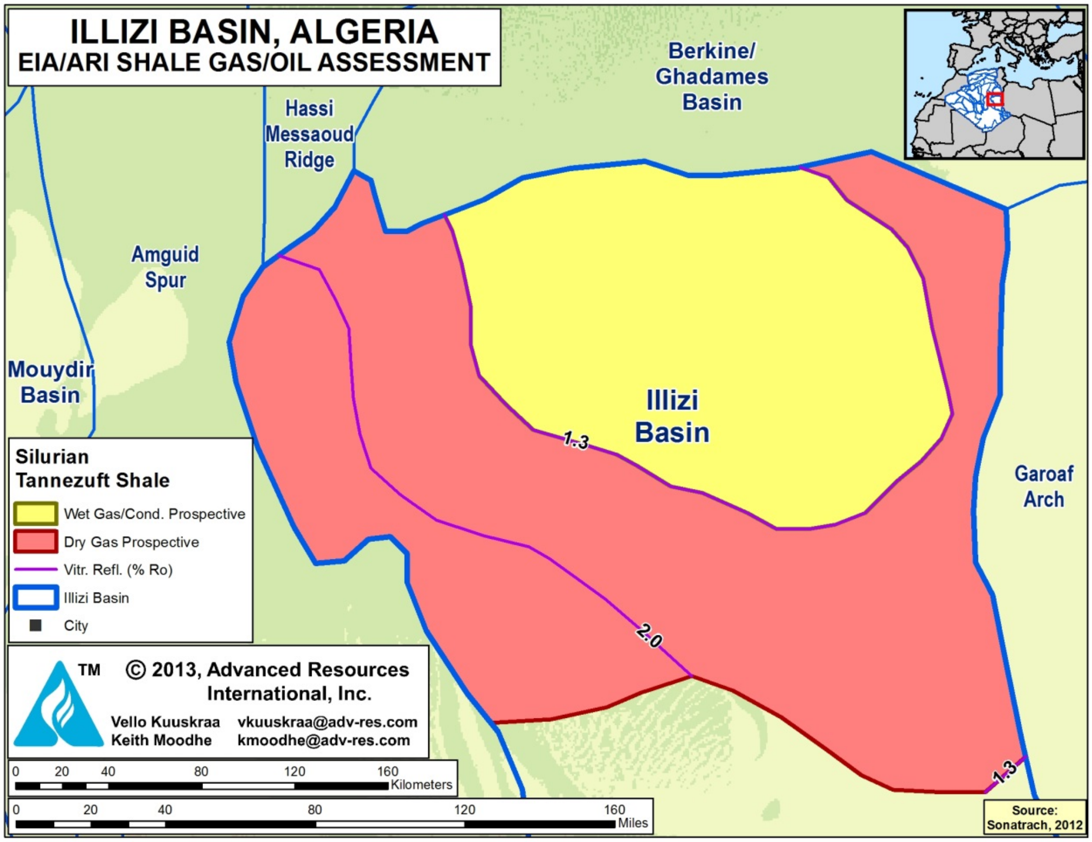
Only the Silurian Tannezuft Shale is assessed as prospective in the Illizi Basin. (The Upper Devonian Frasnian Shale in the Illizi Basin has been excluded because of insufficient thickness and low thermal maturity.) The depth of the Tannezuft Shale ranges from 3,000 to 8,000 ft, averaging 5,000 ft in the northern prospective area of the basin. The gross thickness of the Tannezuft Shale ranges from 30 to 330 ft, with an average net pay of 162 ft. The TOC of this Type II kerogen marine shale ranges from 2% to 10%, with an average of 5.7%. The basin has a thermal maturity (R_o) of 1% to over 2%. This places the Tannezuft Shale in the wet gas and condensate window (R_o of 1% to 1.3%) in the north-central portion of the basin and places the shale in the deeper surrounding area of the Illizi Basin in the dry gas window.

2.3 Resource Assessment

Within its 9,840-mi^2 prospective area for wet gas and condensate, the Silurian Tannezuft Shale of the Illizi Basin has resource concentrations of 51 Bcf/mi^2 of wet shale gas and 6 million barrels/mi^2 of shale oil and condensate. Within its 16,760-mi^2 prospective area for dry gas, the shale has a resource concentration of 61 Bcf/mi^2.

The risked resource in-place in the total prospective area is estimated at 304 Tcf of wet/dry shale gas plus 13 billion barrels of shale oil/condensate. Of this, 56 Tcf of wet/dry shale gas and 0.5 billion barrels of shale oil/condensate are estimated as the risked, technically recoverable resource.

Figure XV-8. Illizi Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



Source: ARI, 2013.

3. TIMIMOUN BASIN

3.1 Geologic Setting

The Timimoun Basin, located in central Algeria, is bounded on the north and east by structural uplifts, on the west by the Beni Abbes Saddle, and on the south by the Djoua Saddle that separates the Timimoun Basin from the Ahnet Basin. The depth and deposition of the Timimoun Basin varies greatly due to erosion along the structural highs during the Hercynian. The Paleozoic section is thickest in the center of the Timimoun Basin, thinning to the north and east. The major shale source rocks in this basin are the Silurian Tannezuft Shale and the Upper Devonian Frasnian Shale.

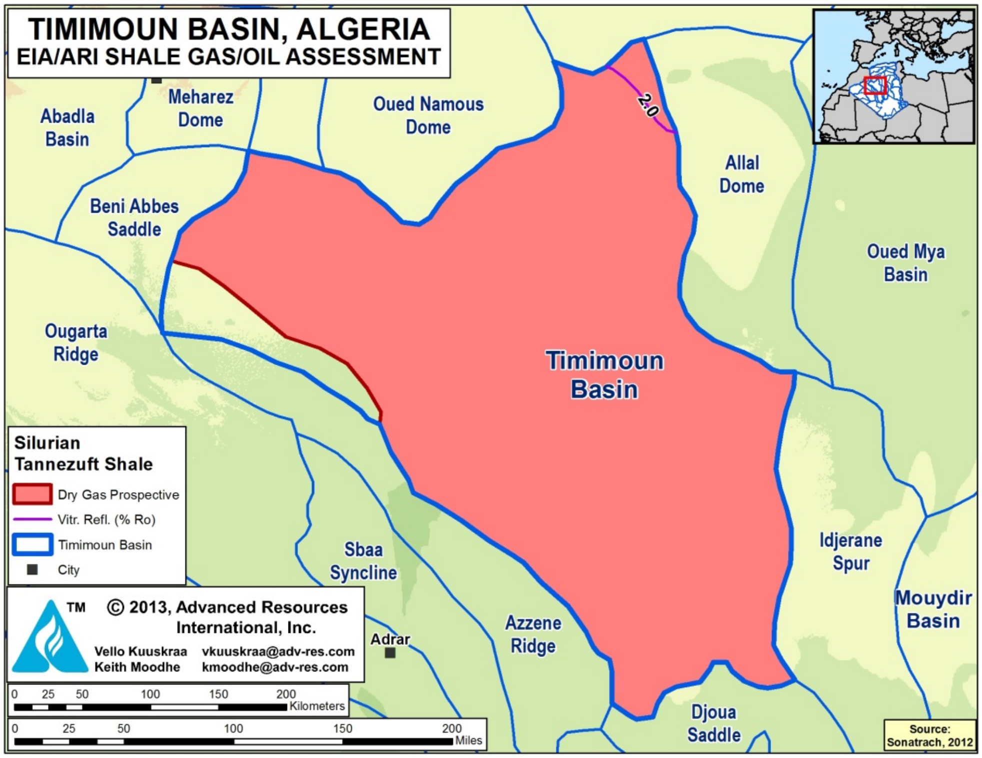
We mapped a 41,670-mi^2 dry gas prospective area for the Tannezuft Shale that covers essentially all of the Timimoun Basin, excluding a small area along the north-western portion of the basin where the Silurian is absent, Figure XV-9. In addition, we mapped a 32,040-mi^2 Frasnian Shale dry gas prospective area that covers the eastern two-thirds of the basin, excluding the low (<2%) TOC area along the western portion of the basin, Figure XV-10.

3.2 Reservoir Properties (Prospective Area).

Silurian Tannezuft Formation. The depth of the dry gas prospective area of the Tannezuft Shale in the Timimoun Basin ranges from 5,000 ft on the edges of the basin to nearly 15,000 ft in the basin center, averaging 10,000 ft. The thickness of the gross shale interval is 100 ft, with a net organic-rich pay of 90 ft. The TOC of the Tannezuft Shale averages 2.8% in the prospective area.

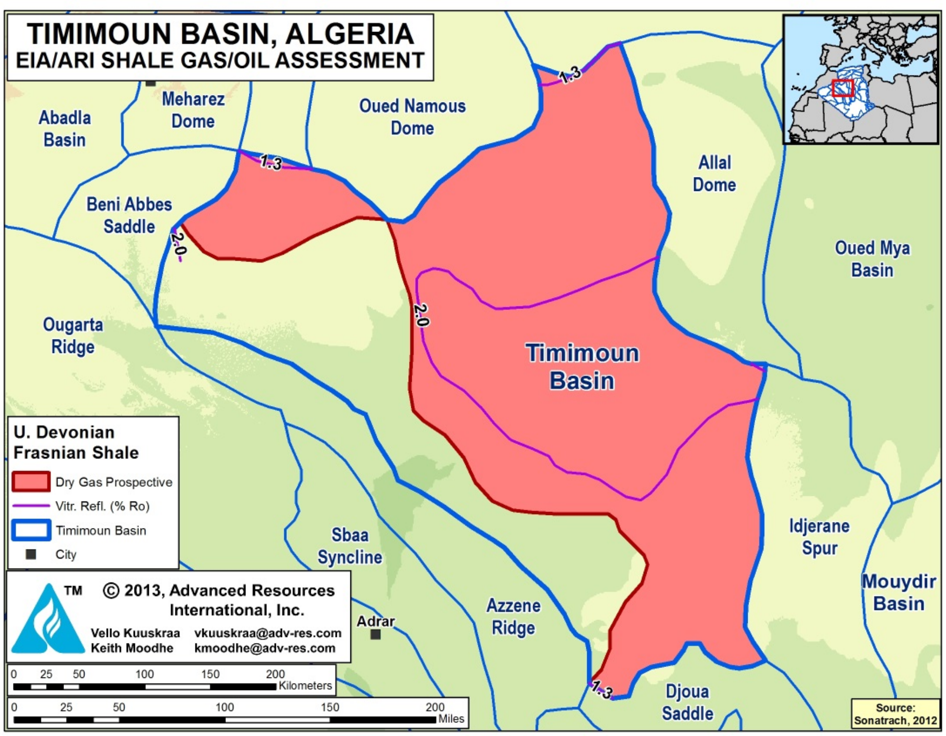
Upper Devonian Frasnian Formation. The depth of the dry gas prospective area of the Upper Devonian Frasnian Shale in the Timimoun Basin ranges from about 3,300 ft along the basin edge to about 9,000 ft in the basin center, averaging 6,000 ft. The thickness of the gross shale interval is 200 ft, with a net organic-rich pay of 180 ft. The TOC of the Frasnian Shale averages 4% in the prospective area.

Figure XV-9. Timimoun Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



Source: ARI, 2013.

Figure XV-10. Timimoun Basin Upper Devonian Frasnian Shale, Outline and Thermal Maturity



Source: ARI, 2013.

3.3 Resource Assessment

Silurian Tannezuft Shale. The Tannezuft Shale, within the 41,670-mi^2 dry gas prospective area of the Timimoun Basin, has a resource concentration of 36 Bcf/mi^2. The risked shale gas resource in-place in the prospective area is 296 Tcf, with 59 Tcf as the risked, technically recoverable shale gas resource.

Upper Devonian Frasnian Shale. The Frasnian Shale, within the 32,040-mi^2 dry gas prospective area of the Timimoun Basin, has a resource concentration of 73 Bcf/mi^2. The risked shale gas resource in-place in the prospective area is 467 Tcf, with 93 Tcf as the risked, technically recoverable shale gas resource.

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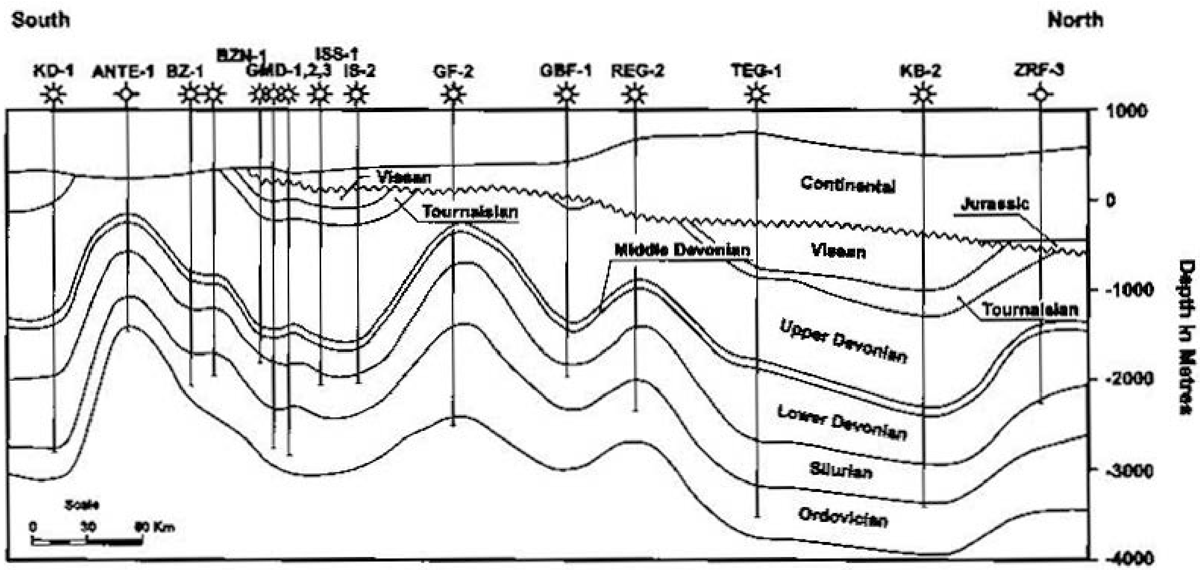
4. AHNET BASIN

4.1 Geologic Setting

The Ahnet Basin is located in the Sahara Desert Platform, south of the large Timimoun Basin, west of the Mouydir Basin, and north of the Hoggar Shield. The Ahnet Basin is a north-south trending basin that contains thick (over 3,000 ft) of Paleozoic sediments including organic-rich Silurian and Devonian shales. The structures in the basin take the form of large, elongate anticlines and domes formed as a result of tectonic compression, as shown on the north to south cross-section, Figure XV-11.[9]

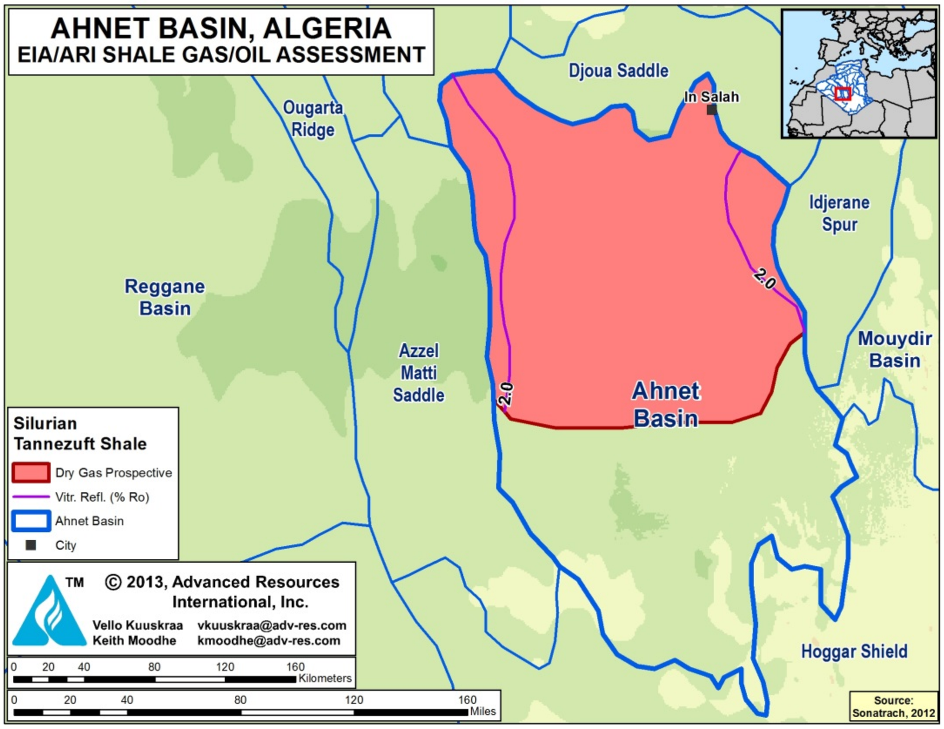
Figure XV-11. Schematic Cross Section of the Ahnet Basin, Algeria



Source: Logan, P. and Duddy, I., 1998.

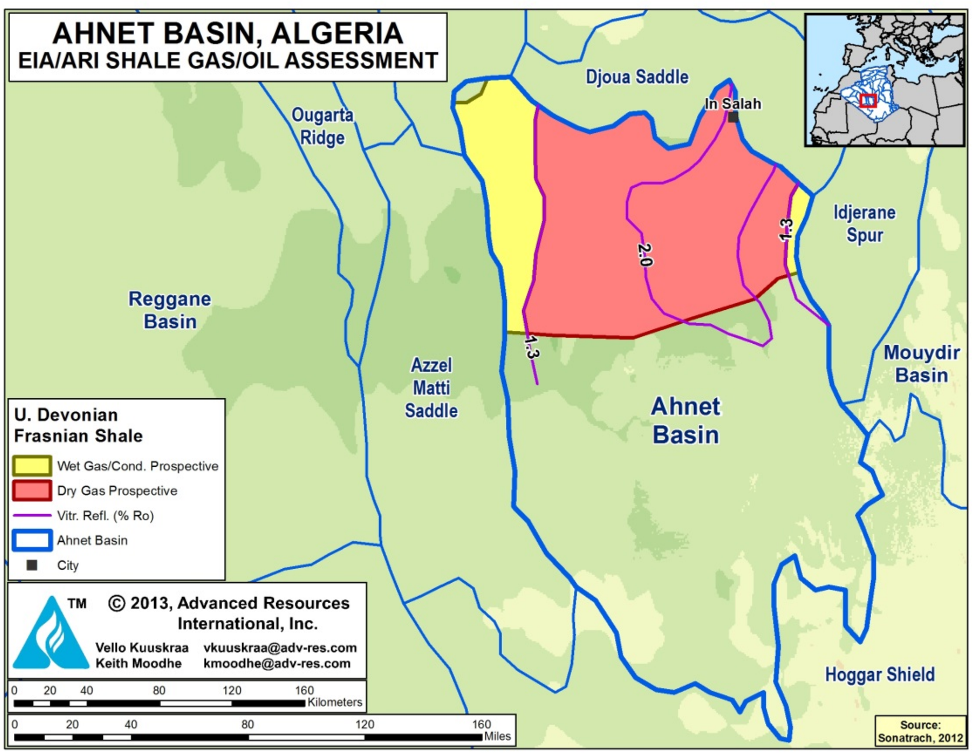
The Ahnet Basin contains the Silurian Tannezuft and Upper Devonian Frasnian formations and their organic-rich shale intervals. In some portions of the basin, the Paleozoic section was eroded during Hercynian deformation. However, up to 4 km of Paleozoic deposits remain intact in the center of the basin.[9] We have defined prospective areas of 11,730 mi^2 for the Silurian Tannezuft Shale and 7,390 mi^2 for the Devonian Frasnian Shale in the northern portion of the Ahnet Basin, Figures XV-12 and XV-13.

Figure XV-12. Ahnet Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



Source: ARI, 2013.

Figure XV-13. Ahnet Basin Upper Devonian Frasnian Shale, Outline and Thermal Maturity



Source: ARI, 2013.

4.2 Reservoir Properties (Prospective Area).

Silurian Tannezuft Formation. The depth of the Tannezuft Shale in the prospective area of the Ahnet Basin ranges from 6,000 to 10,500 ft, averaging 8,000 ft. The thickness of the shale ranges from 150 to 500 ft, averaging 330 ft with a high net to gross ratio. The TOC of the shale ranges from 1.5% to 4% and contains Type III gas-prone kerogen. The thermal maturity places the prospective area of the Tannezuft Shale of the Ahnet Basin in the dry gas window (R_o > 1.3%).

Devonian Frasnian Formation. The depth of the Frasnian Shale in the prospective area of the Ahnet Basin ranges from about 3,300 to 9,500 ft, averaging 6,000 ft, with the wet gas/condensate area shallower and the dry gas area deeper. The gross thickness of the shale ranges from 60 to 275 ft, with a net pay of approximately 54 ft in the dry gas area and 248 ft in the wet gas/condensate area. The TOC ranges from 3% to 4% and is mostly Type III gas-prone kerogen. The thermal maturity of the prospective area of the Frasnian Shale is in the wet gas/condensate and dry gas windows (R_o > 1.0%). Petrophysical evaluations of the Frasnian Shale indicate porosity of 6% and low water saturation in the deeper, prospective area of the Ahnet Basin.

4.3 Resource Assessments (Prospective Area).

Silurian Tannezuft Shale. Within its 11,730-mi^2 dry gas prospective area, the Tannezuft Shale in the Ahnet Basin has a resource concentration of 109 Bcf/mi^2. The risked shale gas resource in-place in the dry gas prospective area is 256 Tcf, with 51 Tcf estimated as the risked, technically recoverable shale gas resource.

Devonian Frasnian Shale. Within its 5,740-mi^2 dry gas prospective area, the Frasnian Shale in the Ahnet Basin has a resource concentration of 22 Bcf/mi^2. Within its 1,650-mi^2 wet gas/condensate prospective area, the Frasnian Shale has resource concentrations of 15 million barrels/mi^2 of shale oil/condensate and 78 Bcf/mi^2 of wet shale gas.

The risked shale gas resource in-place in the overall 7,390-mi^2 wet/dry gas prospective area is 50 Tcf, with 9 Tcf as the risked technically recoverable shale gas resource. The risked shale oil resource in-place in the 1,650-mi^2 oil/condensate prospective area is 5 billion barrels, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

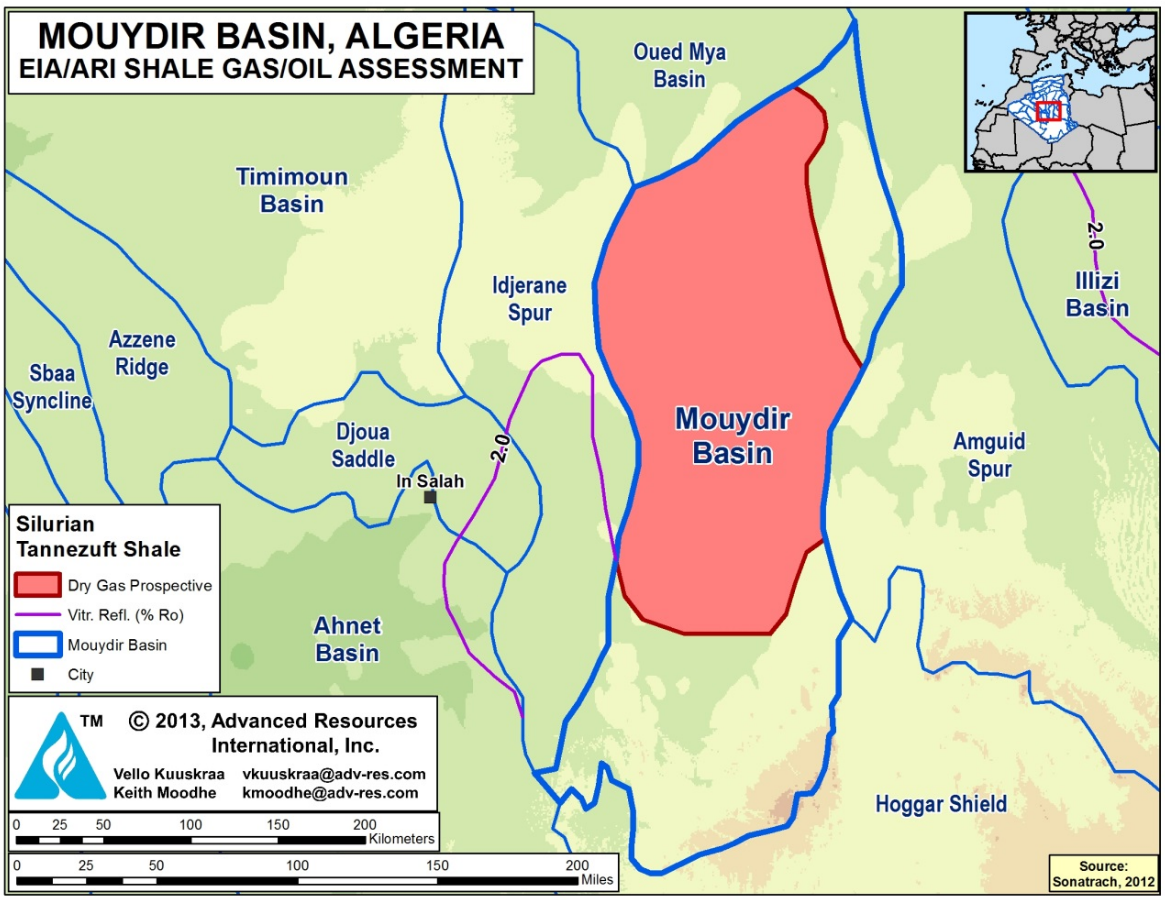
5. MOUYDIR BASIN

5.1 Geologic Setting.

The Mouydir Basin is located in central Algeria, west of the Illizi Basin and east of the Timimoun and Ahnet basins. A variety of upthrusted structural ridges separate these basins. The Paleozoic Silurian and Devonian sediments, which include the important Silurian Tannezuft Shale and the Upper Devonian Frasnian Shale, are deepest in the northern portion of the basin and crop out in the southern portion of the basin.

We have mapped a prospective area of 12,840 mi^2 in the northern portion of the basin, limited on the south by the depth of the shale, Figure XV-14.

Figure XV-14. Mouydir Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



Source: ARI, 2013.

5.2 Reservoir Properties (Prospective Area).

Only the Silurian Tannezuft Shale is assessed as prospective in the Mouydir Basin. (The Devonian Frasnian Shale, although thick and organically rich, is mostly too shallow, less than 3,300 ft, excluding the shale from further assessment.) The depth of the Tannezuft Shale ranges from 5,000 to 10,000 ft, averaging 6,500 ft in the prospective area. The gross thickness of the shale ranges from 20 to 120 ft, averaging 60 ft with a high net to gross ratio. The Tannezuft Shale in the Mouydir Basin has TOC ranging from 2% to 4%, with a thermal maturity above 1.3% R_o, placing the shale in the dry gas window.

5.3 Resource Assessment.

Within its 12,840-mi^2 dry gas prospective area, the Silurian Tannezuft Shale of the Mouydir Basin has a resource concentration of 19 Bcf/mi^2. The risked resource in-place in the dry gas prospective area is estimated at 48 Tcf, with 10 Tcf as the risked, technically recoverable shale gas resource.

6. REGGANE BASIN

6.1 Geologic Setting.

The Reggane Basin, located in the Sahara Desert portion of central Algeria, is separated from the Timimoun Basin by the Ougarta Ridge. The basin is an asymmetric syncline, bounded on the north by a series of reserve faults and on the south by shallowing outcrops, Figure XV-15.[9] This basin may contain over 800 m of Silurian section, although well control in the deep northern portion of the basin is limited. The basin also contains the Upper Devonian Frasnian Formation which is reported to reach a maximum thickness of 400 m.

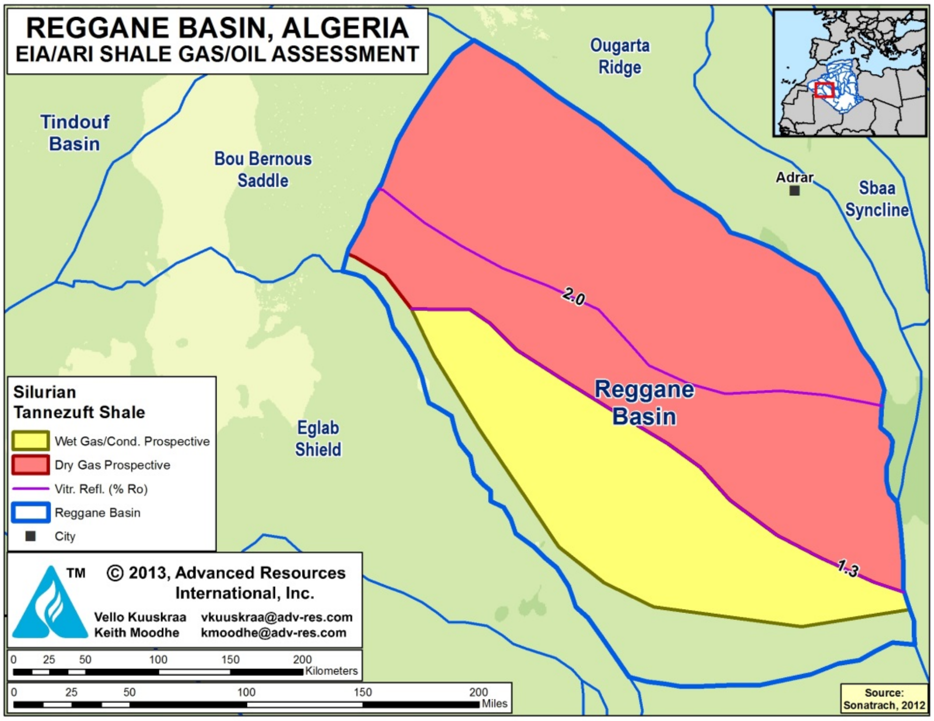
We have mapped prospective areas of 34,750 mi^2 for the Silurian Tannezuft Shale and 4,680 mi^2 for the Upper Devonian Frasnian Shale in the eastern portions of the Reggane Basin, Figures XV-16 and XV-17.

6.2 Reservoir Properties (Prospective Areas).

Silurian Tannezuft Formation. The depth of the prospective area for the Silurian Tannezuft Shale ranges from 16,000 ft on the north to 5,000 ft on the south, averaging 10,000 ft. The wet gas/condensate prospective area is slightly shallower than this average, while the dry gas prospective area is deeper.[9] The gross thickness of the organic-rich section in the prospective area ranges from about 130 to 230 ft, with a high net to gross ratio.[9] TOC is favorable, ranging from 3% to 5%. The thermal maturity places the prospective area of the Tannezuft Shale into the wet gas and condensate window (R_o of 1.0 to 1.3%) in the shallower south and into the dry gas window (R_o > 1.3%) in the deeper north, as illustrated by the north to south cross-section on Figure XV-17.[10]

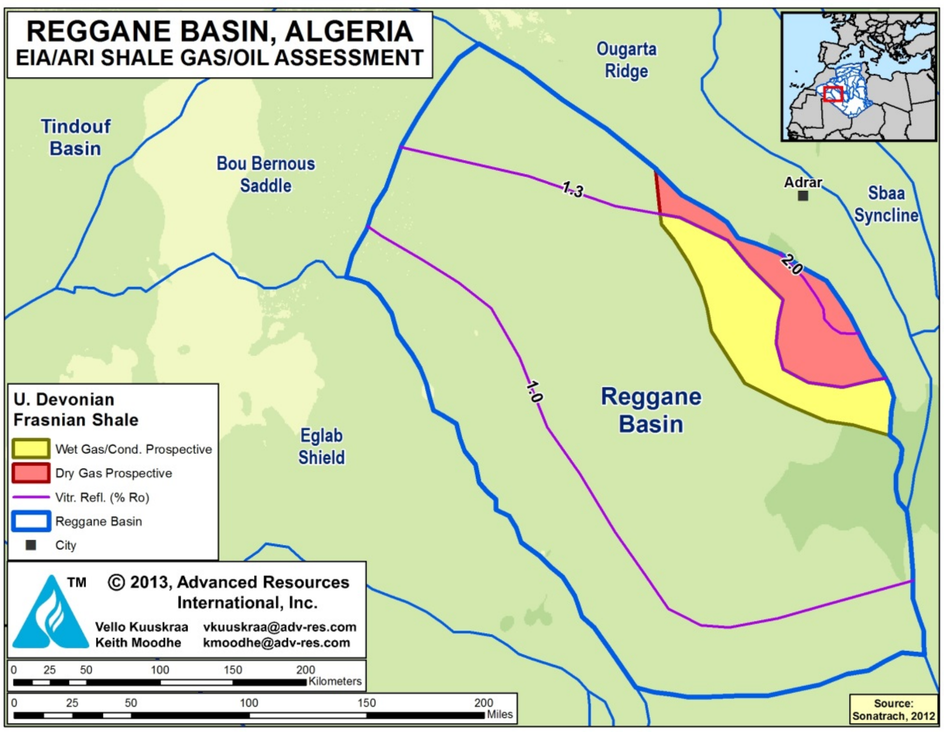
Upper Devonian Frasnian Formation. The depth of the shallower Upper Devonian Frasnian Shale in the Reggane Basin ranges from 5,500 ft to 16,000 ft, averaging about 10,500 ft in the prospective area, with the wet gas/condensate area shallower and the dry gas area somewhat deeper.[9] The thickness of the organic-rich portion of the shale ranges from 260 to 330 ft, with a high net to gross ratio.[9] The TOC of the shale ranges from 2% to 4%.[10] The thermal maturity places the prospective area of the Frasnian Shale in the wet/condensate and dry gas windows (R_o > 1%). The Frasnian Shale is judged to have good porosity of about 6% with low water saturation, based on petrophysical evaluations of the Frasnian Shale in the adjoining Ahnet Basin.[10,11]

Figure XV-15. Reggane Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



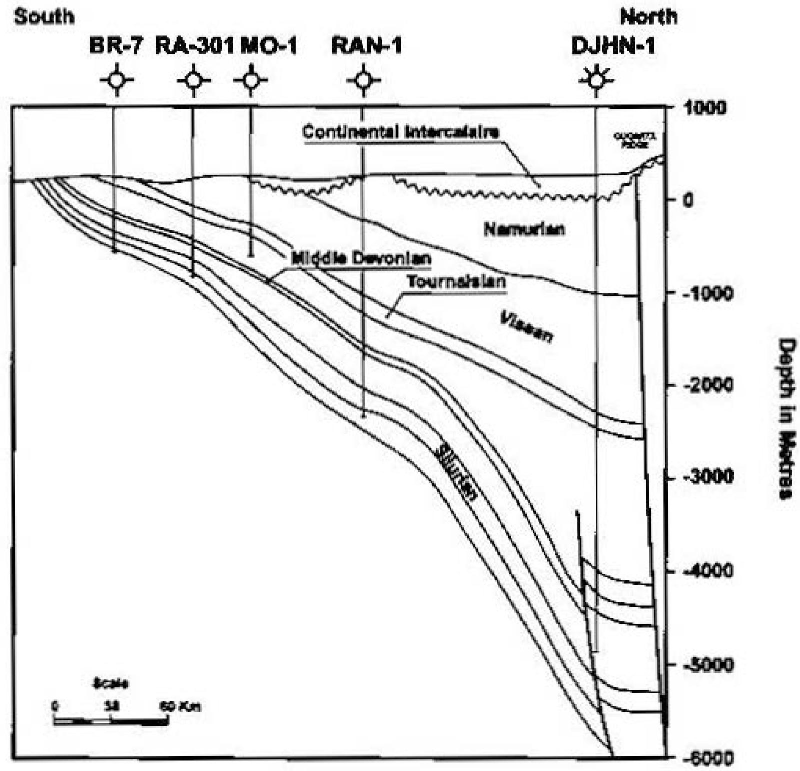
Source: ARI, 2013.

Figure XV-16. Reggane Basin Upper Devonian Frasnian Shale, Outline and Thermal Maturity



Source: ARI, 2013.

Figure XV-17. Schematic Cross Section of the Reggane Basin, Algeria



Source: Logan, P. and Duddy, I., 1998.

6.3 Resource Assessment

***Silurian Tannezuft Shale*.** Within its 24,600-mi^2 dry gas prospective area, the Tannezuft Shale in the Reggane Basin has a resource concentration of 94 Bcf/mi^2. Within its 10,150-mi^2 wet gas and condensate prospective area, the shale has resource concentrations of 38 Bcf/mi^2 of wet gas and 4 million barrels/mi^2 of oil/condensate.

The risked resource in-place for the overall 34,750-mi^2 Silurian Tannezuft Shale prospective area in the Reggane Basin is 542 Tcf of wet/dry shale gas plus 8 billion barrels of shale oil/condensate. Of this, 105 Tcf of wet/dry shale gas plus 0.3 billion barrels of shale oil/condensate are estimated as the risked, technically recoverable resource.

Devonian Frasnian Shale. Within its 2,110-mi^2 dry gas prospective area, the Frasnian Shale in the Reggane Basin has a resource concentration of 97 Bcf/mi^2. Within its 2,570-mi^2 wet gas and condensate prospective area, the shale has resource concentrations of 104 Bcf/mi^2 of wet gas and 11 million barrels/mi^2 of oil and condensate.

The risked resource in-place for the overall 4,680-mi^2 Devonian Frasnian Shale prospective area in the Reggane Basin is estimated at 94 Tcf of wet/dry shale gas plus 6 billion barrels of shale oil/condensate. Of this, 16 Tcf of wet/dry shale gas plus 0.2 billion barrels of shale oil/condensate are estimated as the risked, technically recoverable resource.

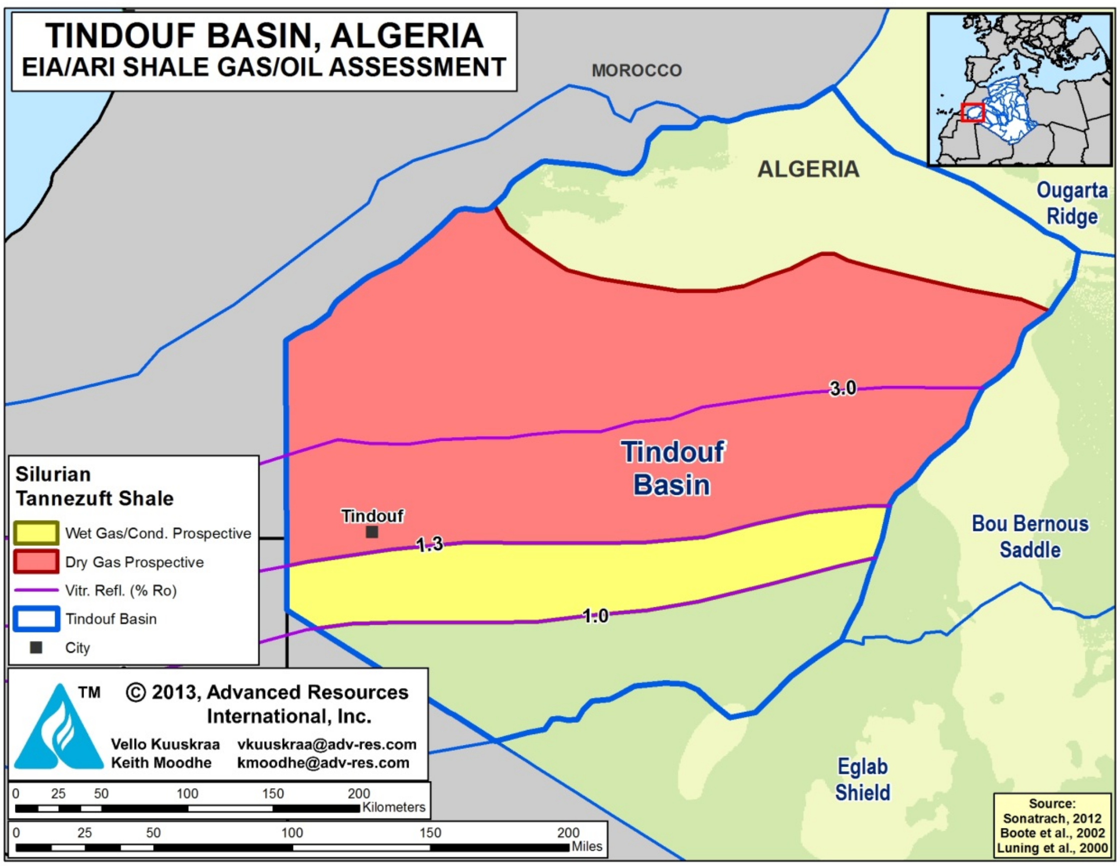
7. TINDOUF BASIN

7.1 Geological Setting.

The Tindouf Basin is located in the far southwestern portion of Algeria, bordered on the west by Morocco and on the south by Mauritania. This large basin, the least explored basin in the Sahara Desert Platform, covers an area of over 45,000 mi^2 just within the Algeria.

Because of limited well penetrations, considerable uncertainty surrounds the shale gas and oil potential of the Tindouf Basin. Based on recent data from Sonatrach, the Devonian Frasnian Shale is relatively thin (average of 10 m) with a TOC of only about 1%.[10] As such, this shale unit has been excluded from further quantitative assessment. However, the Silurian Tannezuft Shale appears to be more promising. We have established a dry and wet gas prospective area of 29,140 mi^2 for the Silurian Tannezuft Shale in the northern portion of the Tindouf Basin where the TOC is 2% or higher, Figure XV-18.

Figure XV-18. Tindouf Basin Silurian Tannezuft Shale Outline and Thermal Maturity

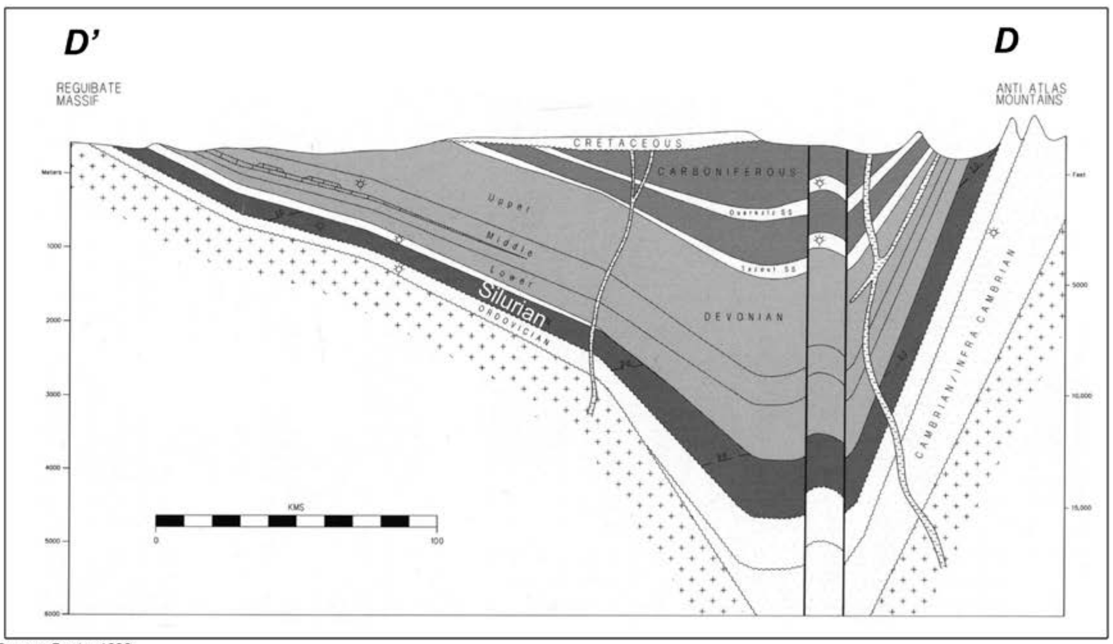


Source: ARI, 2013.

7.2 Reservoir Properties (Prospective Area).

The depth of the Silurian Tannezuft Shale in the prospective area ranges from 6,600 to 14,000 ft, averaging about 10,500 ft. While the total Upper Silurian section can be several thousand feet thick, the organic-rich portion of the Silurian Tannezuft Shale has a net thickness of only 54 ft where the TOC exceeds 2%. In the prospective area, the Tannezuft Shale is in both the wet gas/condensate and the dry gas windows (R_o > 1.0%) and has gas-prone Type III kerogen.[10,12] Figure XV-19 provides a cross-section for this frontier hydrocarbon basin.[13]

Figure XV-19. Tindouf Basin Cross Section



Source: Boote, 1998

Source: Boote, 1998.

7.3 Resource Assessment.

Within its 23,800-mi^2 dry gas prospective area, the Silurian Tannezuft Shale in the Tindouf Basin has a resource concentration of 24 Bcf/mi^2. Within its 5,340-mi^2 wet gas and condensate area, the shale has resource concentrations of 19 Bcf/mi^2 for wet gas and 1.7 million barrels/mi^2 for oil/condensate.

Within its overall 29,140-mi^2 prospective area, the risked resource in-place for the Tannezuft Shale in the Tindouf Basin is estimated at 135 Tcf of wet/dry shale gas and 2 billion barrels of shale oil/condensate. Of this, 26 Tcf of wet/dry shale gas and 0.1 billion barrels of shale oil/condensate are estimated as the risked, technically recoverable resource.

ACTIVITY

Algeria's natural gas and gas company, Sonatrach, has undertaken a comprehensive effort to define the size and quality of its shale gas (and oil) resources. To date, the company has established a data base of older cores, logs and other data and complemented this with information from new shale well logs in the main shale basins of Algeria. Next in the plan is to drill a series of pilot wells to test the productivity of the high priority basins, targeting shale formations with high TOC (>2%) and thick pay (>20m) at moderate depths (<3,000 m). The first pilot well within this comprehensive shale resource assessment program is scheduled for the Berkine (Ghadames) Basin, followed by test wells in the Illizi, Timimoun, Ahnet and Mouydir basins.[10] International energy companies, Statoil and Repsol, have also undertaken geological and reservoir characterization studies of Algeria's shales.[11]

Over the past year, Algeria has passed amendments to its federal legislation covering the hydrocarbon sector improving investment climate in anticipation of an expanded hydrocarbon licensing round due in 2013. However, the position of its stated-owned company Sonatrach is expected to remain dominant in this sector.

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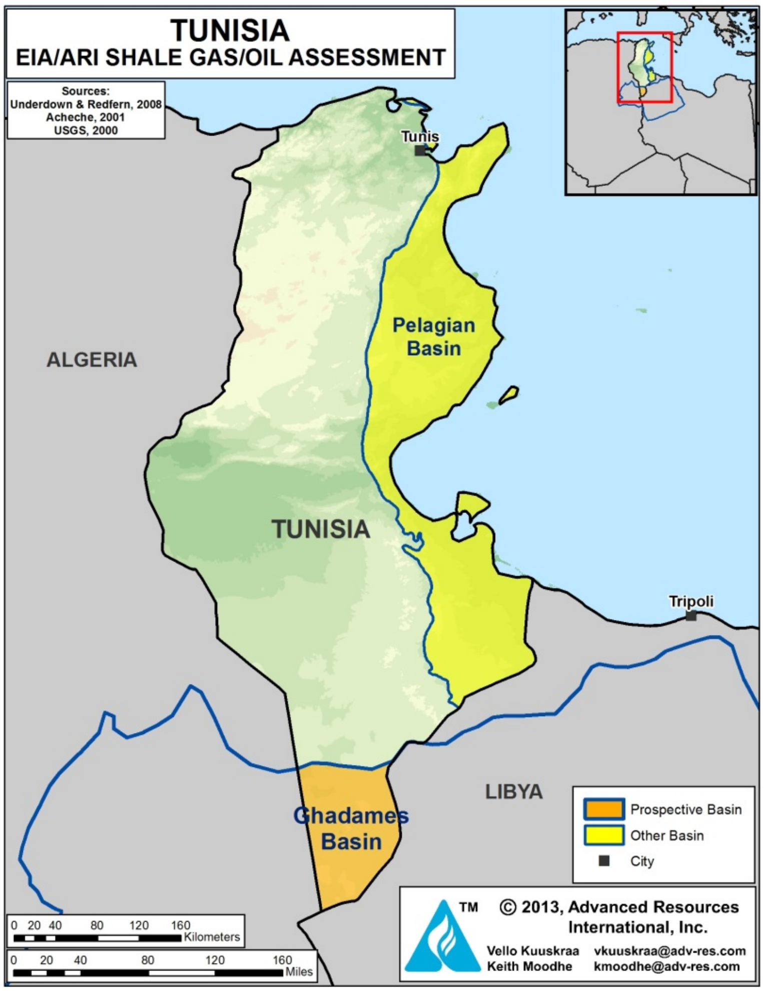
XVI. TUNISIA

SUMMARY

Tunisia has two significant formations with potential for shale gas and shale oil - - the Silurian Tannezuft "Hot Shale" and the Upper Devonian Frasnian Shale. These shale formations are in the Ghadames Basin, located in southern Tunisia. Additional shale gas and oil potential may exist in the Jurassic-Cretaceous and Tertiary petroleum systems in the Pelagian Basin of eastern Tunisia, as discussed further in this Chapter, Figure XVI-1.

Figure XVI-1. Tunisia's Shale Gas and Shale Oil Basins



Source: ARI, 2013.

Our assessment is that the Tannezuft and Frasnian shale formations in the Ghadames Basin contain 114 Tcf of risked shale gas in-place, with 23 Tcf as the risked, technically recoverable shale gas resource, Table XVI-1. In addition, these two shale formations contain 29 billion barrels of risked shale oil in-place, with 1.5 billion barrels as the risked, technically recoverable shale oil resource, Table XVI-2.

Table XVI-1. Shale Gas Reservoir Properties and Resources of Tunisia.

Basic Data	Basin/Gross Area		Ghadames ($117,000\ mi^2$)				
	Shale Formation		Tannezuft		Frasnian		
	Geologic Age		Silurian		U. Devonian		
	Depositional Environment		Marine		Marine		
Physical Extent	Prospective Area (mi^2)		410	940	1,210	850	80
	Thickness (ft)	Organically Rich	115	115	197	197	197
		Net	104	104	177	177	177
	Depth (ft)	Interval	10,000 - 11,000	11,000 - 14,500	8,000 - 10,000	9,000 - 10,000	10,000 - 11,000
		Average	10,500	13,000	8,500	9,500	10,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.7%	5.7%	6.0%	6.0%	6.0%
	Thermal Maturity (% Ro)		1.15%	1.60%	0.85%	1.15%	1.35%
	Clay Content		Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		42.9	54.5	25.4	79.8	100.7
	Risked GIP (Tcf)		11.4	33.3	20.0	44.1	5.2
	Risked Recoverable (Tcf)		2.3	8.3	2.0	8.8	1.3

Table XVI-2. Shale Oil Reservoir Properties and Resources of Tunisia.

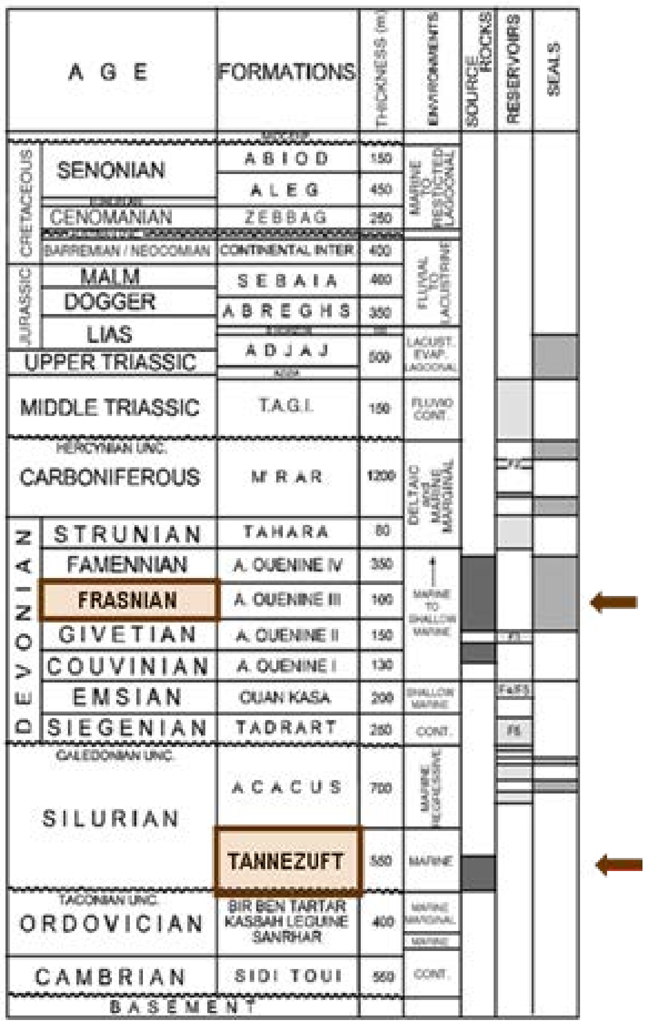
Basic Data	Basin/Gross Area		Ghadames ($117,000\ mi^2$)		
	Shale Formation		Tannezuft	Frasnian	
	Geologic Age		Silurian	U. Devonian	
	Depositional Environment		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		410	1,210	850
	Thickness (ft)	Organically Rich	115	197	197
		Net	104	177	177
	Depth (ft)	Interval	10,000 - 11,000	8,000 - 10,000	9,000 - 10,000
		Average	10,500	8,500	9,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.7%	6.0%	6.0%
	Thermal Maturity (% Ro)		1.15%	0.85%	1.15%
	Clay Content		Medium	Medium	Medium
Resource	Oil Phase		Condensate	Oil	Condensate
	OIP Concentration ($MMbbl/mi^2$)		3.1	31.3	7.0
	Risked OIP (B bbl)		0.8	24.6	3.9
	Risked Recoverable (B bbl)		0.04	1.23	0.19

1. GHADAMES BASIN

1.1 Introduction and Geologic Setting

The Silurian-age Tannezuft "Hot Shale" (called "hot" because of its high uranium content; gamma-ray values >150 API units) is present in much of North Africa and the Middle East. This organic-rich shale has served as a major source rock for many of the conventional oil and gas fields in the region. The Upper Devonian-age Frasnian Shale is deposited above the deeper Tannezuft Shale. It has also served as an important source rock for the Devonian and Triassic conventional reservoirs in the region, Figure XVI-2.[1]

Figure XVI-2. Ghadames Basin Stratigraphic Column



Source: Acheche, M.H, 2001.

Prior geological and source rock studies by Acheche (2001),[1] Yahi (2001),[2] and Klett (2000),[3] as well as more recent information from oil and gas production companies operating in Tunisia[4,5,6,7] have provided valuable information on the geologic setting and reservoir properties of the shale formations of Tunisia.

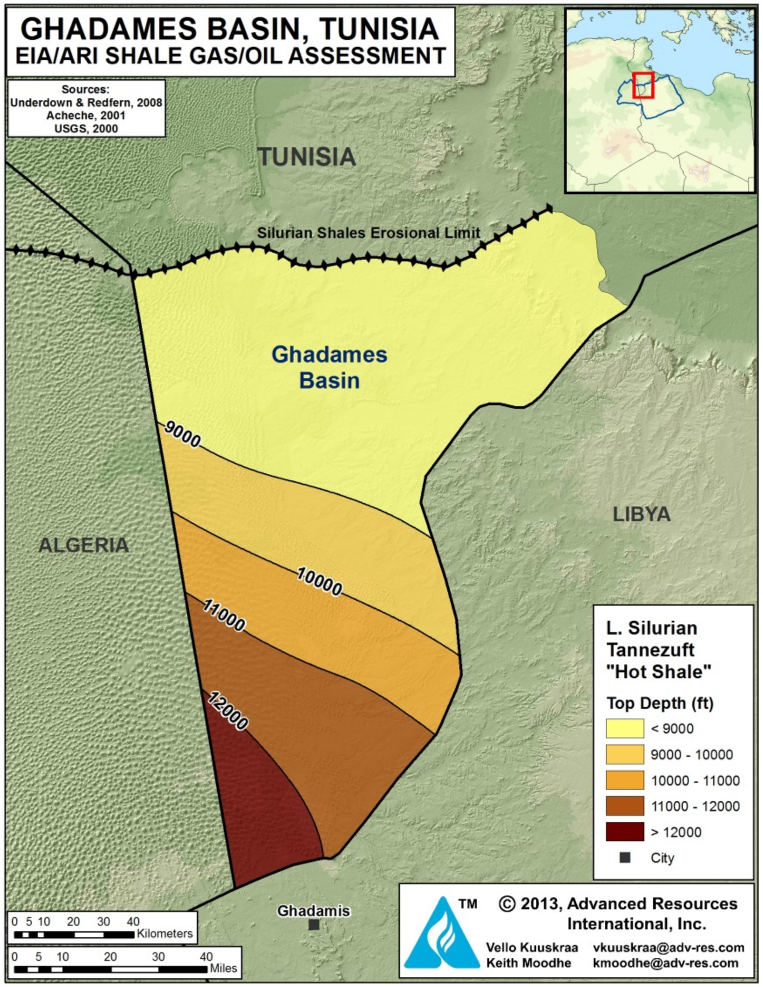
The Ghadames Basin and its two significant shale formations are located in the southern portion of Tunisia. Figures XVI-3 and XVI-4 provide the Ghadames Basin's shale outline and depth contours for the Silurian Tannezuft "Hot Shale"[1] and the Upper Devonian Frasnian Shale.

In Tunisia's portion of the Ghadames Basin, the Tannezuft Formation contains a organic-rich marine shale that grades from immature on the north to post-mature on the south. We have mapped a 1,350-mi^2 higher quality prospective area for the Tannezuft "Hot Shale" in the Ghadames Basin giving considerable emphasis to the recently assembled data on the mineralogy of the shale. The western and northern boundaries of the prospective area are defined by a change in shale deposition from higher quartz, lower clay to lower quartz, higher clay mineralogy. The eastern and southern borders of the prospective area are defined by the Tunisia and Libya border.

The northern portion of the Tannezuft "Hot Shale" prospective area covers 410 mi^2 and has thermal maturity of 1.0% to 1.3% R_o, placing this area in the wet gas and condensate window. The remaining prospective area of 940 mi^2 for the Tannezuft "Hot Shale", with R_o greater than 1.3%, is in the dry gas window, Figure XVI-5.

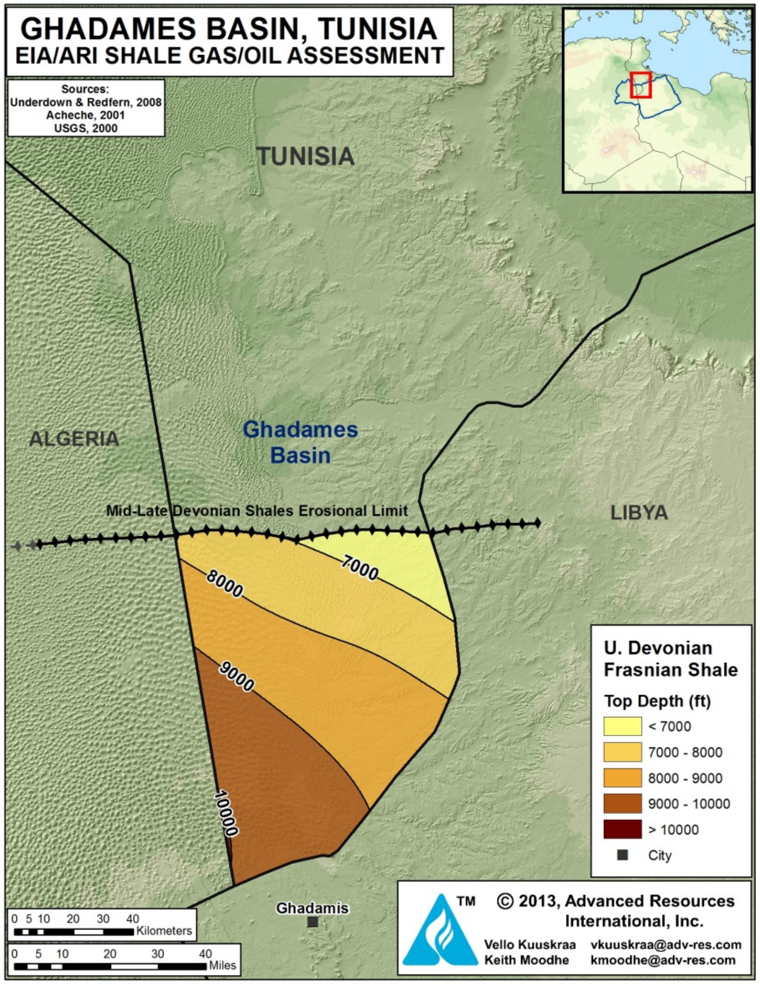
Deposited above the Tannezuft "Hot Shale" is the thermally less mature Frasnian Shale. We have mapped a 2,140-mi^2 prospective area for the Frasnian Shale in Tunisia's portion of the Ghadames Basin. The northern boundary of the Frasnian Shale prospective area is the minimum oil maturity criterion of 0.7% R_o. The western boundary of the prospective area is the Tunisia and Algeria border. The eastern and southern boundary of the Frasnian Shale prospective area is the Tunisia and Libya border.

Figure XVI-3. Ghadames Basin Silurian Tannezuft Shale Outline and Depth Contours



Source: ARI, 2013.

Figure XVI-4. Ghadames Basin Upper Devonian Frasnian Shale Outline and Depth Contours



Source: ARI, 2013.

The 1,210-mi^2 northern and eastern portion of the Frasnian Shale prospective area is in the oil window, with R_o between 0.7% and 1.0%. The 850-mi^2 central portion of the prospective area is in the wet gas and condensate window, with R_o between 1.0% and 1.3%. A relatively small 80-mi^2 area in the southwestern portion of the Frasnian Shale prospective area is in the dry gas window, with R_o above 1.3%, Figure XVI-6.

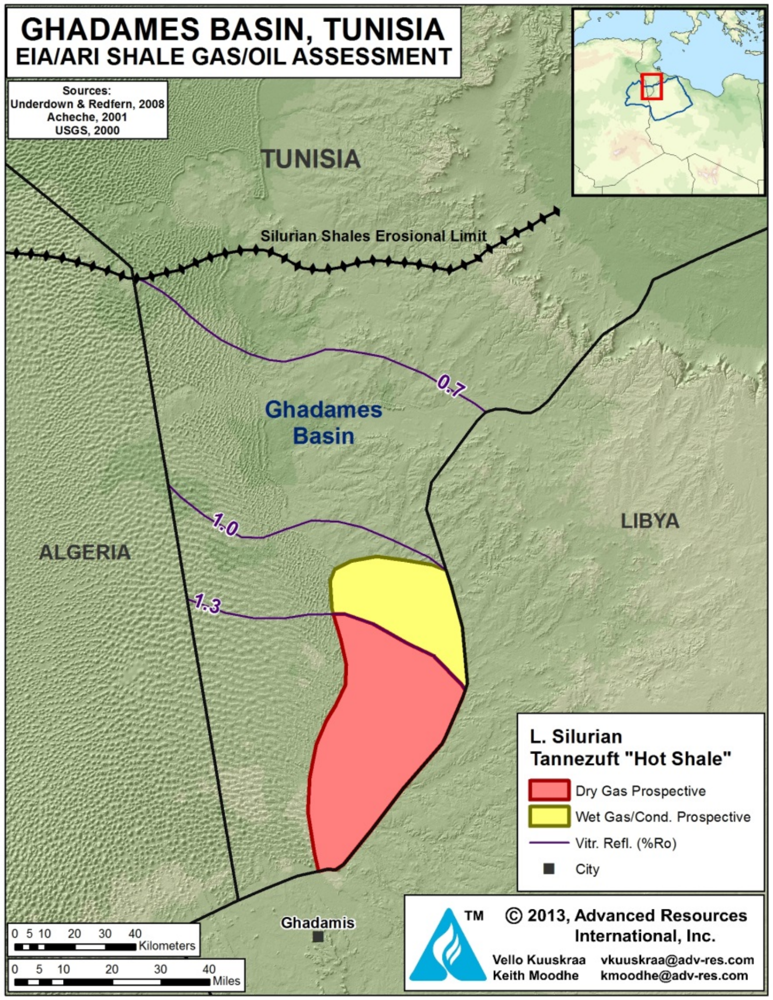
1.2 Reservoir Properties (Prospective Area)

Silurian Tannezuft Shale. The depth of the Silurian Tannezuft "Hot Shale" in the prospective area ranges from 10,000 ft along the northern and eastern basin edge to 14,500 ft in the basin center, averaging 10,500 ft in the wet gas area and 13,000 ft in the dry gas area, Figure XVI-3. The gross thickness of the Tannezuft "Hot Shale" is 115 ft, with an organic-rich average net thickness of 104 ft. (A thick package of Wenlockian silty sands overlies the Llandoverian "Hot Shales" within the Silurian Tannezuft Formation. These high porosity, potentially gas-charged silty sands are not included in our shale gas resource assessment.)

The TOC of the Tannezuft "Hot Shale" averages 5.7%. The lower portion of the formation is particularly organic-rich, with TOC values of up to 15%.[4] The thermal maturity of the Tannezuft "Hot Shale" ranges from wet gas (R_o of 1.0% to 1.3%) in the northern portion of the prospective area to dry gas (R_o >1.3%) in the southern portion of the prospective area in the Ghadames Basin, Figure XVI-5.

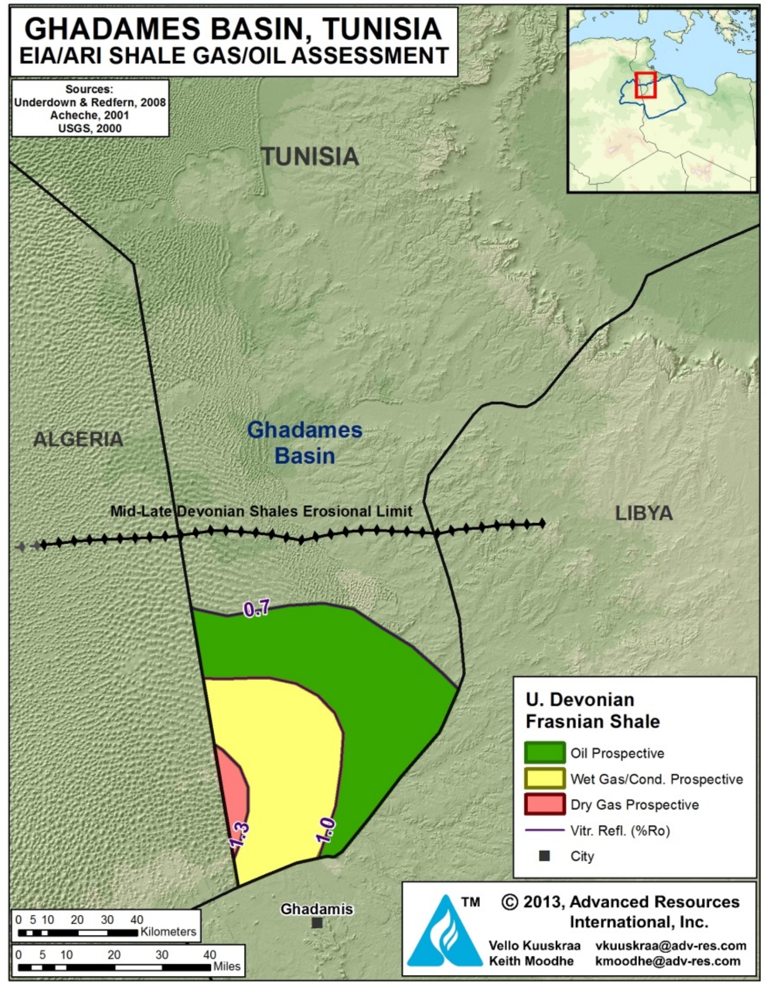
Upper Devonian Frasnian Shale. The depth of the overlying Upper Devonian Frasnian Shale in the prospective area ranges from 8,000 ft to 11,000 ft, averaging 8,500 ft in the oil-prone area, 9,500 ft in the wet gas/condensate area, and 10,500 ft in the dry gas area, Figure XVI-3. The Frasnian Shale has a gross thickness of 197 ft with an organic-rich net thickness of 177 ft. The Frasnian Shale has TOC values that range from 1% to 10% with an average of 6%.[3] The thermal maturity in the Frasnian Shale in the prospective area ranges from 0.7% in the north to over 1.3% R_o in the southwest, placing the shale in the oil, wet gas/condensate and dry gas windows, Figure XVI-5.

Figure XVI-5. Ghadames Basin Silurian Tannezuft "Hot Shale" Prospective Area



Source: ARI, 2013.

Figure XVI-6. Ghadames Basin Upper Devonian Frasnian Shale Prospective Area



Source: ARI, 2013.

1.3 Resource Assessment

Silurian Tannezuft Shale. The Tannezuft "Hot Shale", within its 410-mi^2 wet gas and condensate prospective area, has resource concentrations of 43 Bcf/mi^2 of wet gas and 3.1 million barrels/mi^2 of condensate. Within its 940-mi^2 dry gas prospective area, the Tannezuft "Hot Shale" has a resource concentration of 54 Bcf/mi^2.

The risked resource in-place for the overall 1,350-mi^2 wet gas/condensate and dry gas prospective area is 45 Tcf of shale gas and 0.8 billion barrels of shale oil. Based on moderate reservoir properties, particularly the medium level of clay content, we estimate risked, technically recoverable resources from the Tannezuft "Hot Shale" of 11 Tcf of shale gas and less than 0.1 billion barrels of shale oil, Tables XVI-1 and XVI-2.

Upper Devonian Frasnian Shale. The Frasnian Shale, within its overall 2,140-mi^2 prospective area has resource concentrations of 31 million barrels/mi^2 of oil (plus associated gas) in the 1,210-mi^2 oil window, 7 million barrels/mi^2 of condensate and 80 Bcf/mi^2 of wet gas in the 850-mi^2 wet gas/condensate window, and 101 Bcf/mi^2 of dry gas in the 80-mi^2 dry gas window.

The risked resource in-place within the overall 2,140-mi^2 prospective area is 69 Tcf of shale gas and 28.5 billion barrels of shale oil. Based on moderate reservoir properties, we estimate risked, technically recoverable resources from the Frasnian Shale of 12 Tcf of shale gas and 1.4 billion barrels of shale oil, Tables XVI-1 and XVI-2.

1.4 Recent Activity

Considerable exploration activity is underway in the Ghadames Basin, with much of the activity still devoted to conventional oil and gas resources. Cygam Energy has acquired four permits in the Ghadames Basin totaling 1.6 million net acres.[4] Cygam's exploration program involves 200 km of 3D seismic and two deep exploration wells. The company reportedly conducted a hydraulic stimulation in March 2010 on Well No. 1, completed in the Tannezuft Shale at a depth of 13,000 ft in their Sud Tozeur permit area. No information has been provided on test results. Cygam is seeking a JV partner to further develop its four Tunisia permit areas.

Chinook Energy Inc. has acquired a series of lease blocks in the Ghadames Basin, totaling 1.3 million net acres. The large Sud Remada block totals 1.2 million acres and targets the Tannezuft Shale as well as conventional formations.[5] The company plans to drill a deep exploration well in the Sud Remada lease block during 2013, targeting conventional Ordovician and Silurian resources. Previous drilling into the deeper, oil bearing "TT" Ordovician reservoir showed hydrocarbon potential in the Silurian Tannezuft Formation.

In early 2010, Perenco Tunisia reportedly drilled and hydraulically stimulated a deep Silurian well (Well #5) to test the shale gas potential in their El Franig Field. The company has not released data on the well's performance. In late 2012, Perenco reported that their gas production in Tunisia was all from conventional reservoirs and the company was not producing any shale gas. Winstar Resources, a small Canadian E&P company active in Tunisia, has sponsored an evaluation of the Silurian Tannezuft Shale in the Ghadames Basin of southern Tunisia. Winstar has acquired a series of concession areas in the basin and, with participation of ETAP (the state company), has committed to drilling a deep, test well (Sabria 12) in 2013.

2. OTHER BASINS

In addition to the shale gas and oil potential in the Ghadames Basin, Tunisia may also have shale resource potential in the less defined Pelagian Basin, located in the eastern portion of the country and extending into the offshore.

The Pelagian Basin contains two hydrocarbon systems with established shale source rocks. The first is the Jurassic-Cretaceous Petroleum System and its shale source rocks, particularly the Jurassic Nara Formation and the Early Cretaceous (Albian) Fahdene Formation contains Type II and III kerogen. The third potential shale source rock is the Late Cretaceous (Cenomanian to Turonian) Bahloul Formation containing Type II kerogen that underlies a limited portion of the basin. The thermal maturity of these source rocks ranges from early mature to late mature with TOCs that range from 0.5% to 14%, generally 1% to 3%. The oil generated from these Jurassic-Cretaceous source rocks is generally light, averaging 33^{o} API.

The second hydrocarbon system in the Pelagian Basin is the Tertiary Petroleum Systems and its Early Eocene Bou Dabbous Formation shale. The Bou Dabbous Shale contains Type I and II kerogen with TOC that ranges from 0.4% to 4%. The thermal maturities of the shale ranges from early mature to mature, providing a variety of oil gravities, ranging from 18^{o} to 53^{o} API.

A number of companies have begun exploration efforts in the Pelagian Basin, including a small Canadian-listed company, African Hydrocarbons and super-major Shell Oil. African Hydrocarbons has a minority interest in the 130,000-acre Bouhajla and Ktititir carbonate-chalk reservoir. While the company acknowledges that its lease acreage many also hold an unconventional shale play, it plans to target the "low hanging fruit" first.[8]

Shell Oil acquired a large lease position in the Pelagian Basin and has announced a $150 million exploration program to target conventional reservoirs as well as shale gas and shale oil potential on its lease acreage.

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[4] Cygam Energy, Incorporated, 2012.

[5] Chinook Energy, Incorporated, 2012.

[6] Perenco Tunisia, 2012.

[7] Winstar Resources, 2012

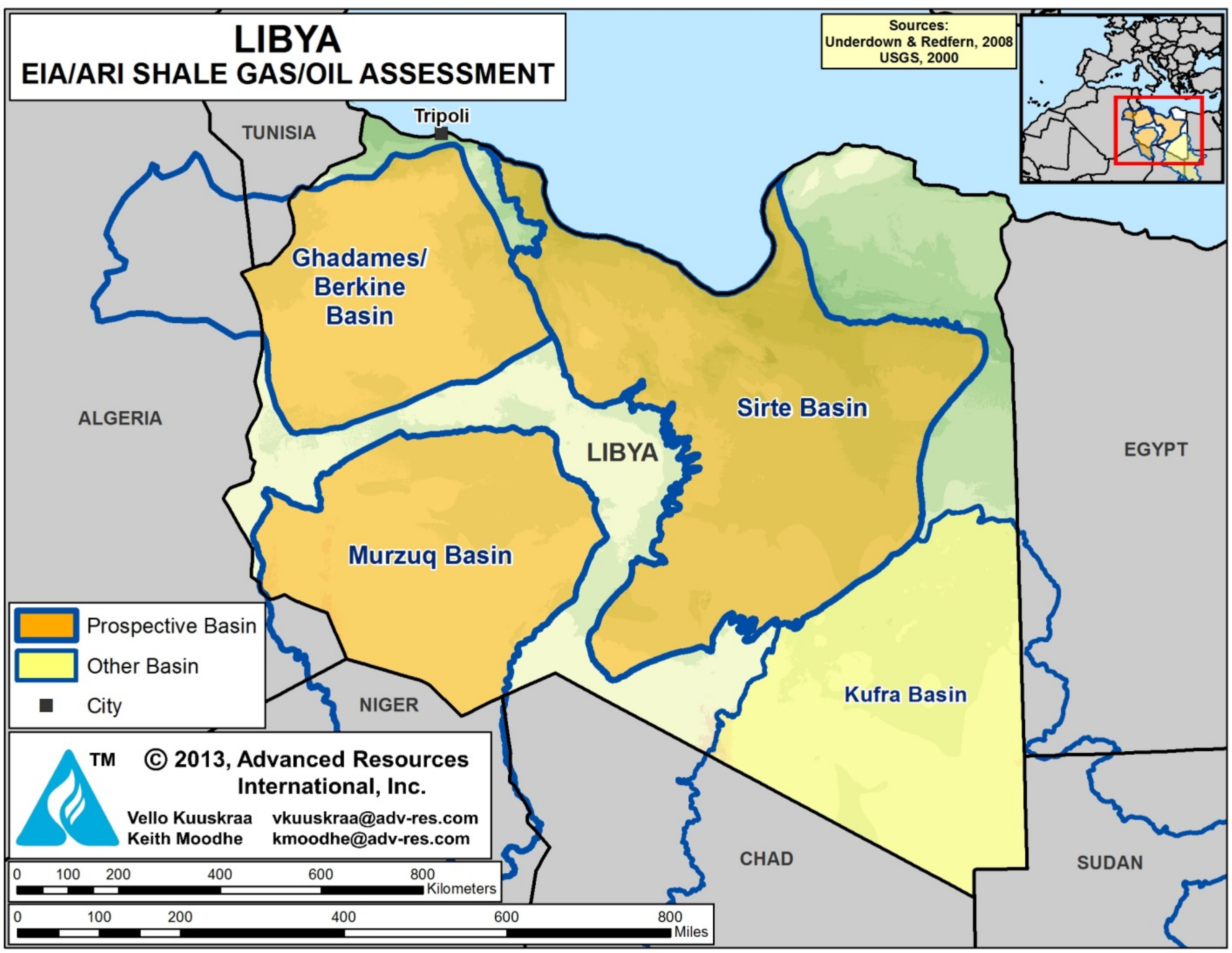
[8] Stafford, J., 2013. "Is Tunisia the New Hot Spot for Energy Investors?" www.rigzone.com accessed April 10, 2013.

XVII. LIBYA

SUMMARY

This shale gas and shale oil resource assessment addresses three of Libya's major hydrocarbon basins: the Ghadames (Berkine) Basin in the west, the Sirte Basin in the center, and the Murzuq Basin in the southwest of the country, Figure XVII-1. One additional basin, the Kufra Basin in the southeast, is discussed but is not quantitatively assessed due to the speculative and limited nature of the available data.

Figure XVII-1. Shale Gas and Shale Oil Basins of Libya



Source: ARI, 2013.

We estimate that these three basins in Libya contain 942 Tcf of risked shale gas in-place, with 122 Tcf as the risked, technically recoverable shale gas resource, Tables XVII-1A and 1B. In addition, the shale formations in these three basins also contain 613 billion barrels of risked shale oil and condensate in-place, with 26.1 billion barrels as the risked, technically recoverable shale oil resource, Tables XVII-2A and 2B.

Table XVII-1A. Shale Gas Reservoir Properties and Resources of Libya.

Basic Data	Basin/Gross Area		Ghadames (117,000 mi^2)					
	Shale Formation		Tannezuft			Frasnian		
	Geologic Age		L. Silurian			U. Devonian		
	Depositional Environment		Marine			Marine		
Physical Extent	Prospective Area (mi^2)		16,440	3,350	2,580	1,570	370	30
	Thickness (ft)	Organically Rich	115	115	115	197	197	197
		Net	104	104	104	177	177	177
	Depth (ft)	Interval	10,000 - 11,000	10,500 - 11,500	11,000 - 14,500	8,000 - 10,000	9,000 - 10,000	11,000 - 12,000
		Average	10,500	11,000	13,000	8,500	9,500	11,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.7%	5.7%	5.7%	6.0%	6.0%	6.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.60%	0.85%	1.15%	1.35%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		11.8	43.4	54.5	25.4	79.8	93.1
	Risked GIP (Tcf)		96.9	72.7	70.3	19.9	14.8	1.4
	Risked Recoverable (Tcf)		9.7	14.5	17.6	2.0	3.0	0.3

Table XVII-1B. Shale Gas Reservoir Properties and Resources of Libya.

Basic Data	Basin/Gross Area		Sirte (172,000 mi^2)		Murzuq (97,000 mi^2)
	Shale Formation		Sirte/Rachmat	Etel Fm	Tannezuft
	Geologic Age		U. Cretaceous	U. Cretaceous	L. Silurian
	Depositional Environment		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		35,240	19,920	5,670
	Thickness (ft)	Organically Rich	2,000	600	67
		Net	200	120	60
	Depth (ft)	Interval	10,000 - 12,000	11,000 - 16,400	3,300 - 10,000
		Average	11,000	13,500	6,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Mod. Overpress.
	Average TOC (wt. %)		2.8%	3.6%	7.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.90%
	Clay Content		Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		24.8	37.4	6.5
	Risked GIP (Tcf)		349.8	297.9	18.6
	Risked Recoverable (Tcf)		28.0	44.7	1.9

Table XVII-2A. Shale Oil Reservoir Properties and Resources of Libya.

			Ghadames ($117,000\ mi^2$)			
Basic Data	Basin/Gross Area		Ghadames ($117,000\ mi^2$)			
	Shale Formation		Tannezuft		Frasnian	
	Geologic Age		L. Silurian		U. Devonian	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		16,440	3,350	1,570	370
	Thickness (ft)	Organically Rich	115	115	197	197
		Net	104	104	177	177
	Depth (ft)	Interval	10,000 - 11,000	10,500 - 11,500	8,000 - 10,000	9,000 - 10,000
		Average	10,500	11,000	8,500	9,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.7%	5.7%	6.0%	6.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration ($MMbbl/mi^2$)		12.0	3.1	31.3	7.0
	Risked OIP (B bbl)		98.8	5.1	24.6	1.3
	Risked Recoverable (B bbl)		4.94	0.26	1.23	0.06

Table XVII-2B. Shale Oil Reservoir Properties and Resources of Libya.

Basic Data	Basin/Gross Area		Sirte ($172,000\ mi^2$)		Murzuq ($97,000\ mi^2$)
	Shale Formation		Sirte/Rachmat	Etel Fm	Tannezuft
	Geologic Age		U. Cretaceous	U. Cretaceous	L. Silurian
	Depositional Environment		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		35,240	19,920	5,670
	Thickness (ft)	Organically Rich	2,000	600	67
		Net	200	120	60
	Depth (ft)	Interval	10,000 - 12,000	11,000 - 16,400	3,300 - 10,000
		Average	11,000	13,500	6,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Mod. Overpress.
	Average TOC (wt. %)		2.8%	3.6%	7.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.90%
	Clay Content		Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil
	OIP Concentration ($MMbbl/mi^2$)		28.8	6.3	9.5
	Risked OIP (B bbl)		405.9	50.5	26.9
	Risked Recoverable (B bbl)		16.24	2.02	1.34

INTRODUCTION

Libya is one of the important hydrocarbon producing countries of North Africa, with a successful history of oil and gas exploration, particularly in the Sirte Basin. The geologic setting of Libya's sedimentary basins is complex, having been formed by a series of tectonic events, the Hercynian that separated the area into a series of horsts and grabens (uplifts and troughs) filled with Cambrian though Oligocene sediments. This tectonic overprint is a key factor in defining and limiting the shale gas and oil prospective areas, as discussed for each of these assessed basins of Libya.

The regionally dominant Lower Silurian Tannezuft basal or "hot shale" and the Upper Devonian Frasnian Shale are assessed in the Ghadames (Berkine) Basin. Two distinct Late Cretaceous shales -- Sirte/Rachmat and Etel -- are the subject of our shale resource assessment in the Sirte Basin. The basal "hot shale" within the Silurian Tannezuft Formation is the main shale formation assessed in the Murzuq Basin.

While our shale resource assessment has targeted three of Libya's most prospective basins and their shale source rocks, it is likely that future exploration will identify additional shale resources in other basins and formations.

1. GHADAMES (BERKINE) BASIN

1.1 Introduction and Geologic Setting

The Ghadames (Berkine) Basin is a large intra-cratonic basin underlying eastern Algeria and southern Tunisia. It encompasses an 84,000-mi^2 area in northwestern Libya and hosts two significant shale formations, the Lower Silurian Tannezuft and the Upper Devonian Frasnian, Figure XVII-2.[1]

In Libya's portion of the Ghadames Basin, the Silurian Tannezuft Formation contains a basal organic-rich marine shale ("hot shale") that increases in maturity toward the basin center. We have mapped a 22,370-mi^2 higher quality area for the Tannezuft "hot shale" in this basin, comprising separate dry gas, wet gas/condensate, and oil-prone windows. The southern, northern and eastern boundaries of the Tannezuft Shale prospective area are defined by uplifts, the erosional limits of the Silurian, and by thermal maturity. (Due to limited thermal maturity data for the eastern portion of the prospective area, we relied on the ring of discovered oil fields as the eastern boundary.) The western boundaries of the prospective area is defined by the Libya, Tunisia and Algerian border.

The central, dry-gas portion of the 2,580-mi^2 Tannezuft Shale prospective area in the Ghadames Basin has a thermal maturity (R_o) ranging from 1.3% to over 2%. The wet gas/condensate prospective area covers 3,350 mi^2 and has a R_o between 1.0% and 1.3%. The remainder of the prospective area of 16,440 mi^2 is in the oil window, with a R_o of 0.7% to 1.3%, Figure XVII-3.

The Upper Devonian Frasnian Shale is deposited above the Tannezuft Formation. The Frasnian Shale is more limited in area and is thermally less mature. We have mapped a 1,970-mi^2 higher quality prospective area for the Frasnian Shale in the Ghadames Basin of Libya. The eastern, northern and southern boundaries of the Frasnian Shale prospective area in this basin are set by the minimum thermal maturity criterion of 0.7% R_o. The western boundary of the prospective area is the Tunisia, Algeria, and Libyan border.

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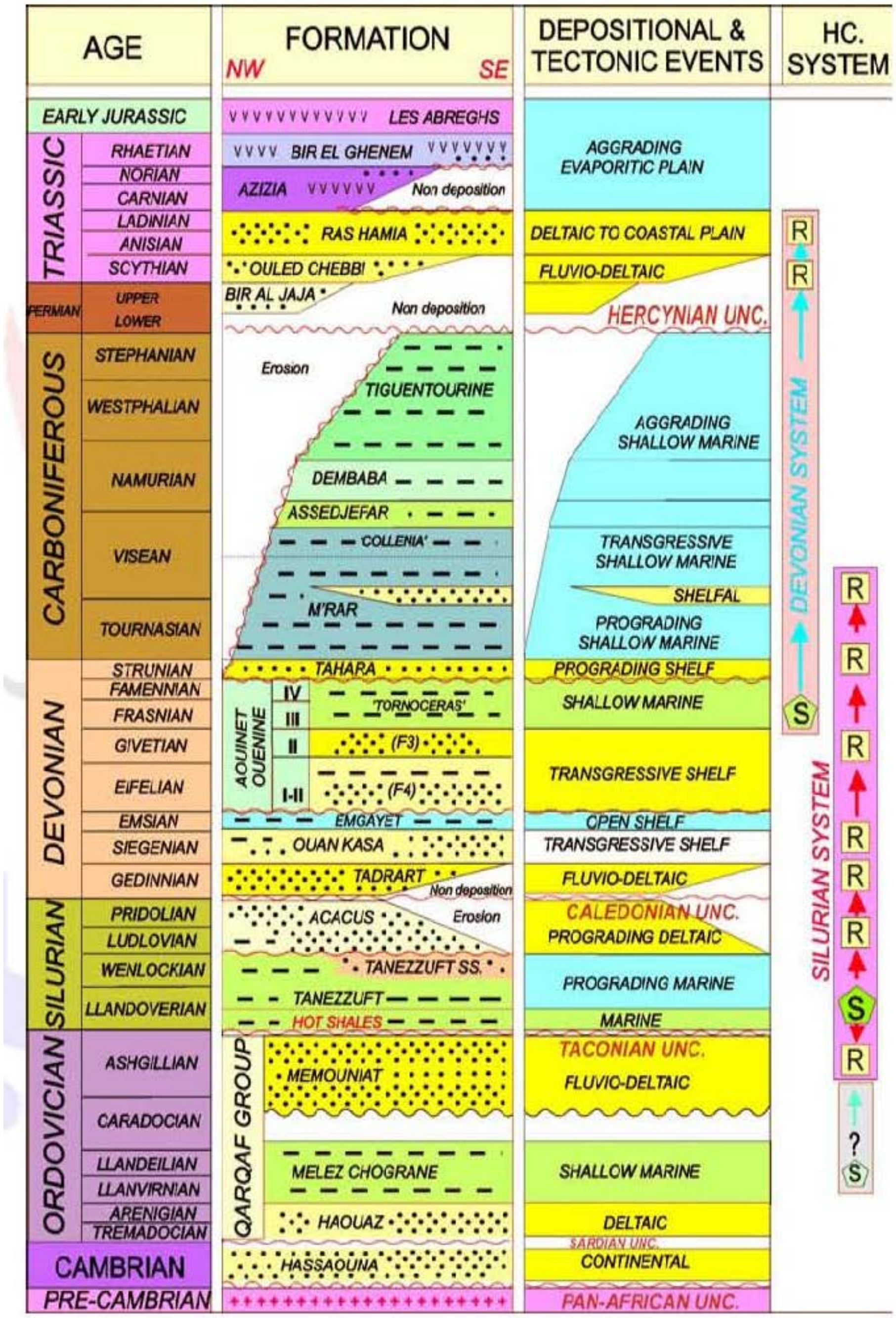
Figure XVII-2. Ghadames Basin Stratigraphic Column



Source: Seddiq Hussein, 2004.

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The northern, eastern and southern outer ring of the Frasnian Shale prospective area in the Ghadames Basin, encompassing an area of 1,570 mi^2, is in the oil window with R_o between 0.7% and 1.0%. The central, quite small 30-mi^2 portion of the Frasnian Shale prospective area is in the dry gas window, with R_o of 1.3% to over 2%. In between is the 370-mi^2 wet gas and condensate area for the Frasnian Shale, with R_o between 1.0% and 1.3%, Figure XVII-4.

1.2 Reservoir Properties (Prospective Area)

Silurian Tannezuft Formation. The depth of the gas prospective area of the Silurian Tannezuft Shale in the Ghadames (Berkine) Basin of Libya ranges from 10,000 ft along the northern and eastern edge of the basin to 14,500 ft toward the basin center, averaging about 13,000 ft in the dry gas area, 11,000 ft in the wet gas area, and 10,500 ft in the oil area. The lower organic-rich basal shale unit has a net thickness of 104 ft. The TOC of the basal Tannezuft Shale averages 5.7%.[2]

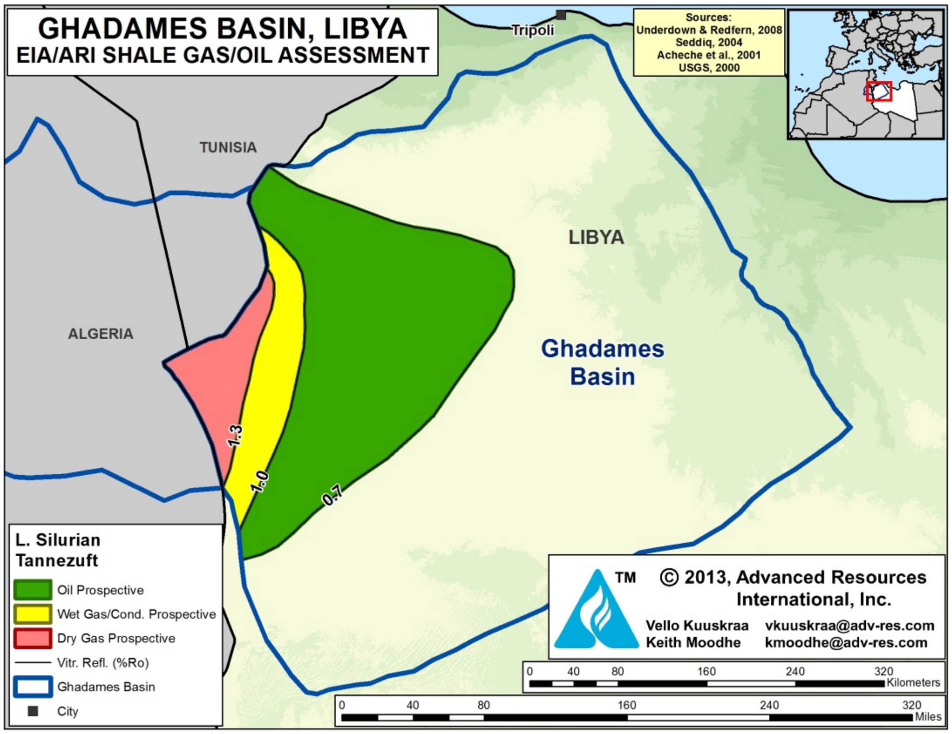
Upper Devonian Frasnian Formation. The depth of the prospective area of the overlying Upper Devonian Frasnian Shale in the Ghadames (Berkine) Basin of Libya ranges from 8,000 to 12,000 ft, averaging 8,500 ft in the oil-prone area; 9,500 ft in the wet gas/condensate area; and 11,500 ft in the dry gas area. The organic-rich portion of the Frasnian Shale has an average net thickness of 177 ft. The Frasnian Shale has TOC values ranging from 3% to 10%, with an average of 6%.[3]

1.3 Resource Assessments

Silurian Tannezuft Shale. The Tannezuft Shale, within its 2,580-mi^2 dry gas prospective area, has a resource concentration of 54 Bcf/mi^2. Within its larger 3,350-mi^2 wet gas and condensate prospective area, the Tannezuft Shale of the Ghadames (Berkine) Basin has resource concentrations of 43 Bcf/mi^2 of wet gas and 3 million barrels/mi^2 of condensate. The resource concentration in the 16,440 mi^2 oil prospective area is 12 million barrels/mi^2.

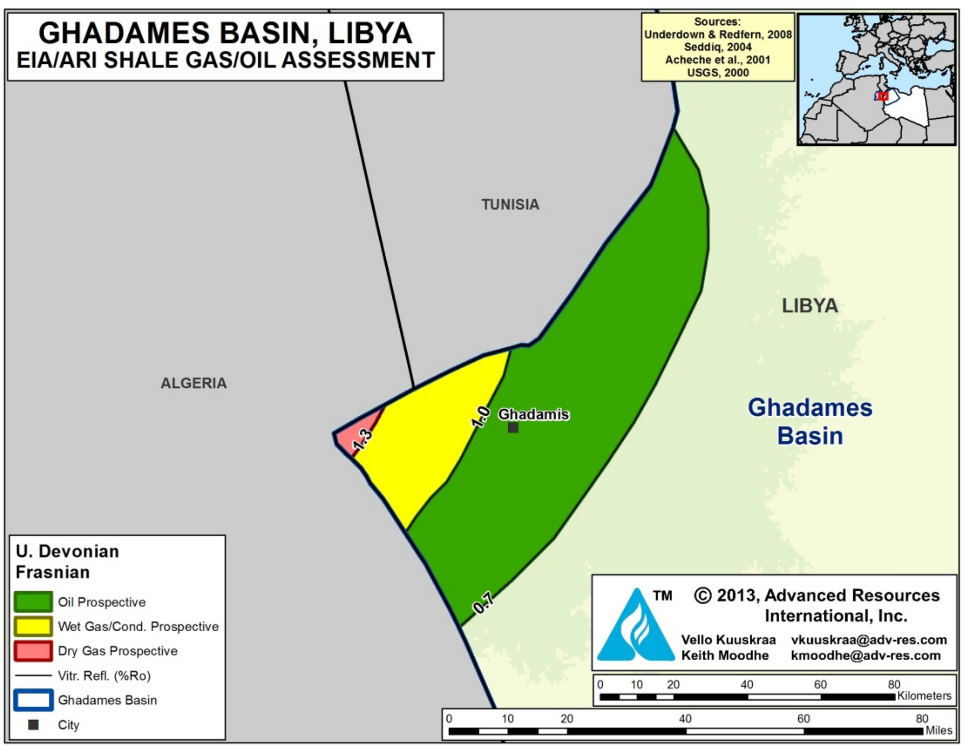
The risked resource in-place for the prospective areas of the Tannezuft Shale is 104 billion barrels of shale oil/condensate and 240 Tcf of wet and dry shale gas. Given concerns with presence of clays but otherwise favorable reservoir properties, we estimate a risked, technically recoverable shale oil/condensate resource of 5.2 billion barrels and 42 Tcf of wet and dry shale gas.

Figure XVII-3. Ghadames Basin Silurian Tannezuft Shale Outline and Thermal Maturity



Source: ARI, 2013

Figure XVII-4. Ghadames Basin Upper Devonian Frasnian Shale Outline and Thermal Maturity



Source: ARI, 2013

Upper Devonian Frasnian Shale. The Frasnian Shale has resource concentrations of 31 million barrels/mi^2 for oil (plus associated gas) in the 1,570-mi^2 oil window, 7 million barrels/mi^2 of condensate and 8 Bcf/mi^2 of wet gas in the 370-mi^2 wet gas/condensate window, and 93 Bcf/mi^2 of dry gas in the 30-mi^2 dry gas window.

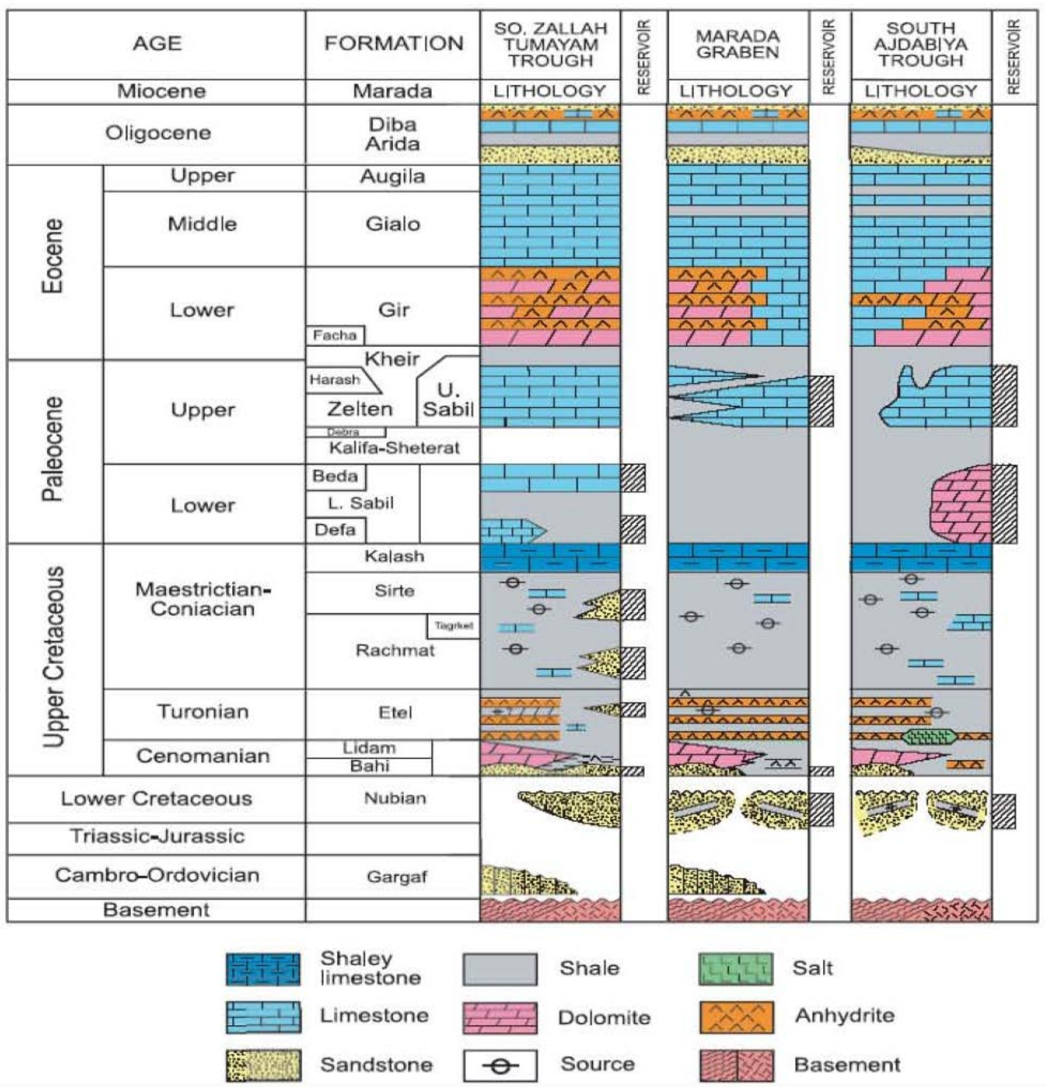
The risked resource in-place for the prospective areas is 23 billion barrels of oil/condensate and 33 Tcf of wet/dry shale gas, with risked, recoverable shale oil of 1.2 billion barrels and 4 Tcf of wet/dry shale gas.

2. SIRTE BASIN

Introduction and Geologic Setting

The Sirte Basin, covering an area of 172,000 mi^2 in central Libya, is the most prolific hydrocarbon basin in North Africa. The Sirte Basin contains sixteen giant oil and gas fields (defined as fields containing more than 500 million barrels of oil equivalent. To date, the Sirte Basin has yielded 45 billion barrels of oil and 33 Tcf of natural gas discoveries (SEPM Strata, 2013). The Upper Cretaceous Sirte/Rachmat and Etel shales are the principal source rocks for these hydrocarbon discoveries and are the two organic-rich shale formations addressed by this resource study, Figure XVII-5.[1]

Figure XVII-5. Sirte Basin Stratigraphic Column

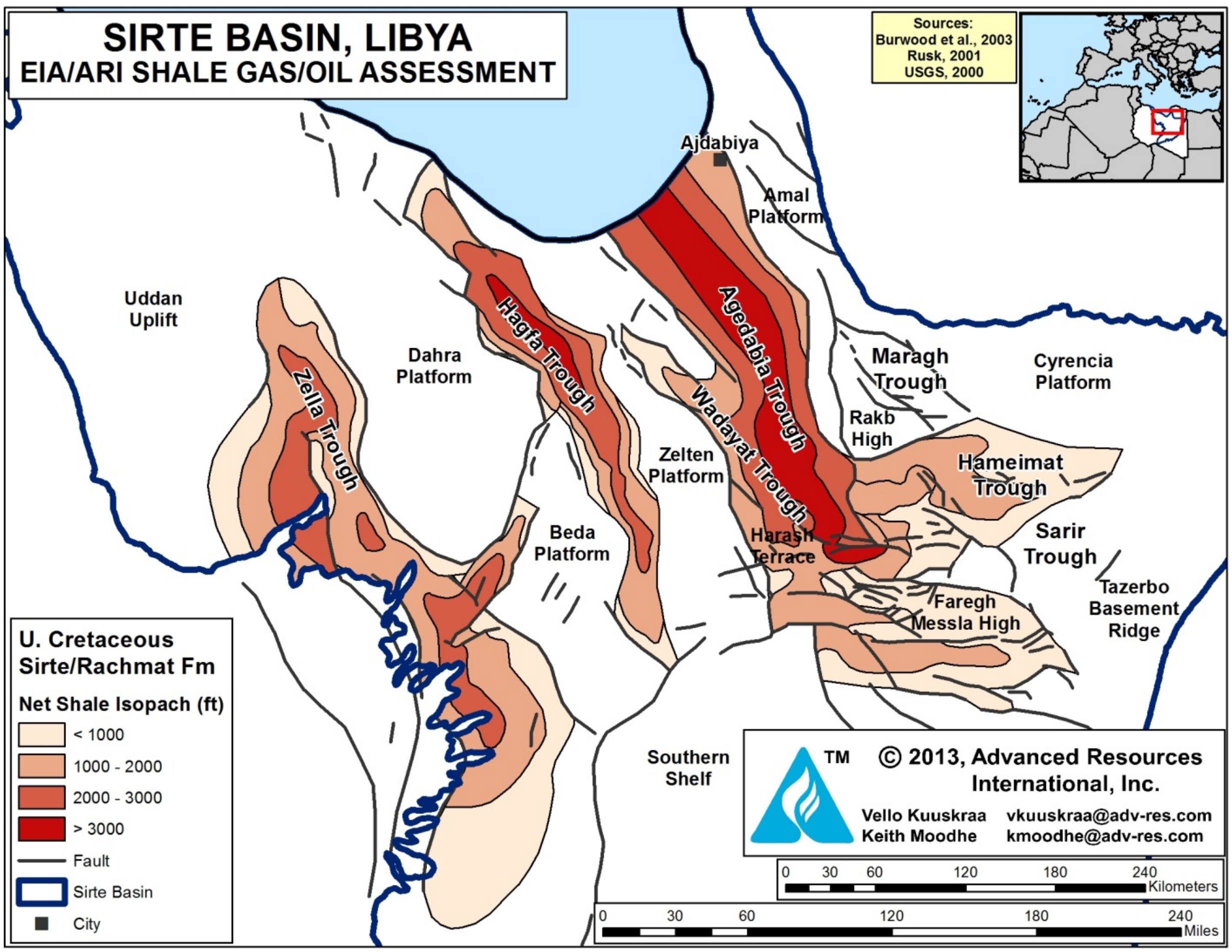


Source: Seddiq Hussein, 2004

2.1 Geologic Setting

The Sirte Basin consists of a series of horst and graben structures trending northwest to southeast including the Hameimat, Agedabia, Wadayat, Hagfa and Zella, as shown in Figure XVII-6. These troughs contain the two main shale formations evaluated by this study - - the Upper Cretaceous Sirte/Rachmat Shale and the underlying Upper Cretaceous Etel Shale. We have mapped an oil-prospective area totaling 35,240 mi^2 for the Sirte/Rachmat Shale in these five troughs, similarly, we have mapped a 19,920-mi^2 wet gas/condensate area for the areally more limited Etel Shale in these five troughs.

Figure XVII-6. Sirte Basin Net Shale Isopach for the Sirte/Rachmat Shale

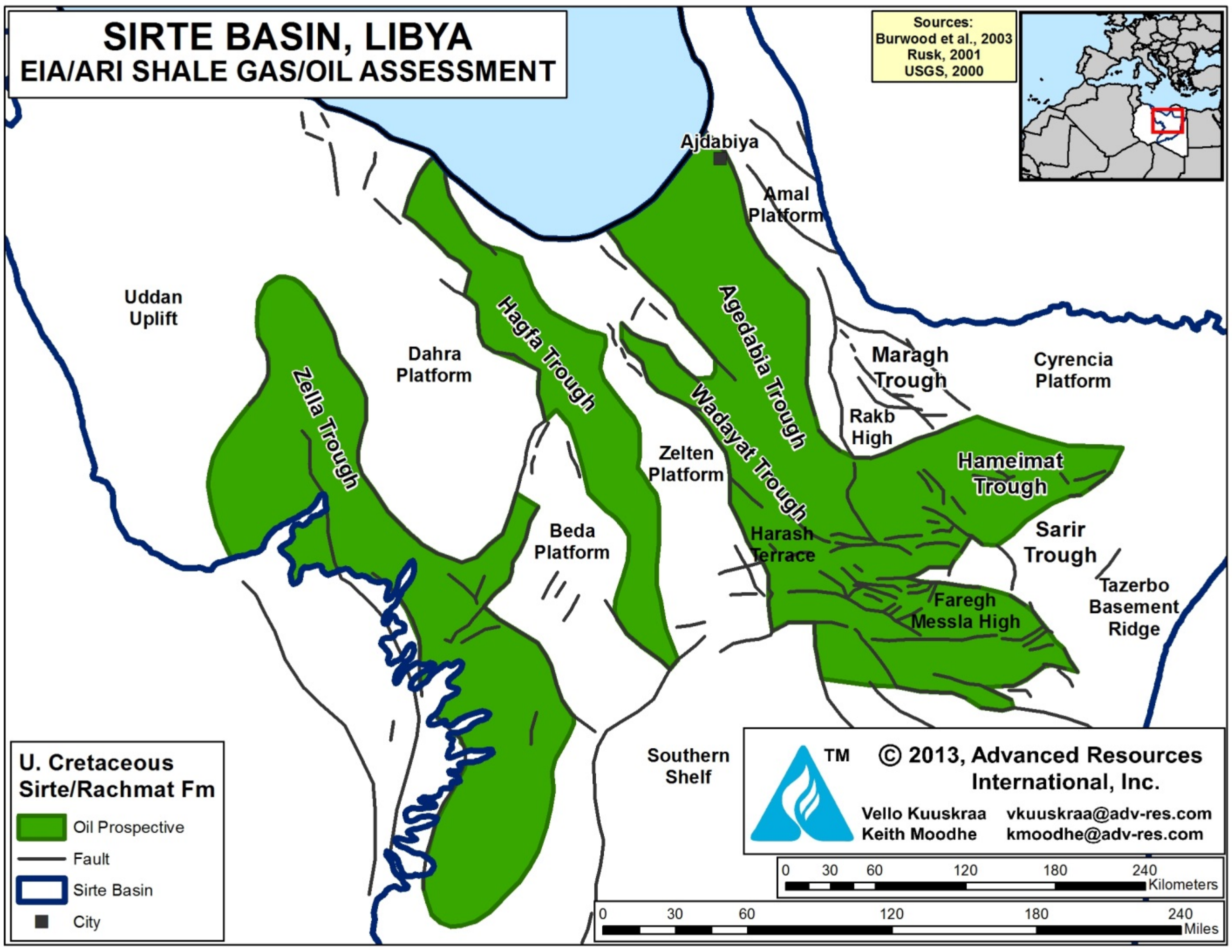


Source: ARI, 2013

2.2 Reservoir Properties (Prospective Area)

Sirte/Rachmat Shale. Within the oil-prospective area of the Sirte Basin, the Sirte/Rachmat Shale is present in a series of troughs at depths of 10,000 to 12,000 ft, averaging 11,000 ft, Figure VXII-7. The total Sirte/Rachmat Formation has a gross thickness of 2,000 ft with a net organic-rich shale section of 200 ft. The TOC of the organic–rich shale interval averages 2.8% and the shale is in the oil window (R_o of 0.7% to 1.0%).

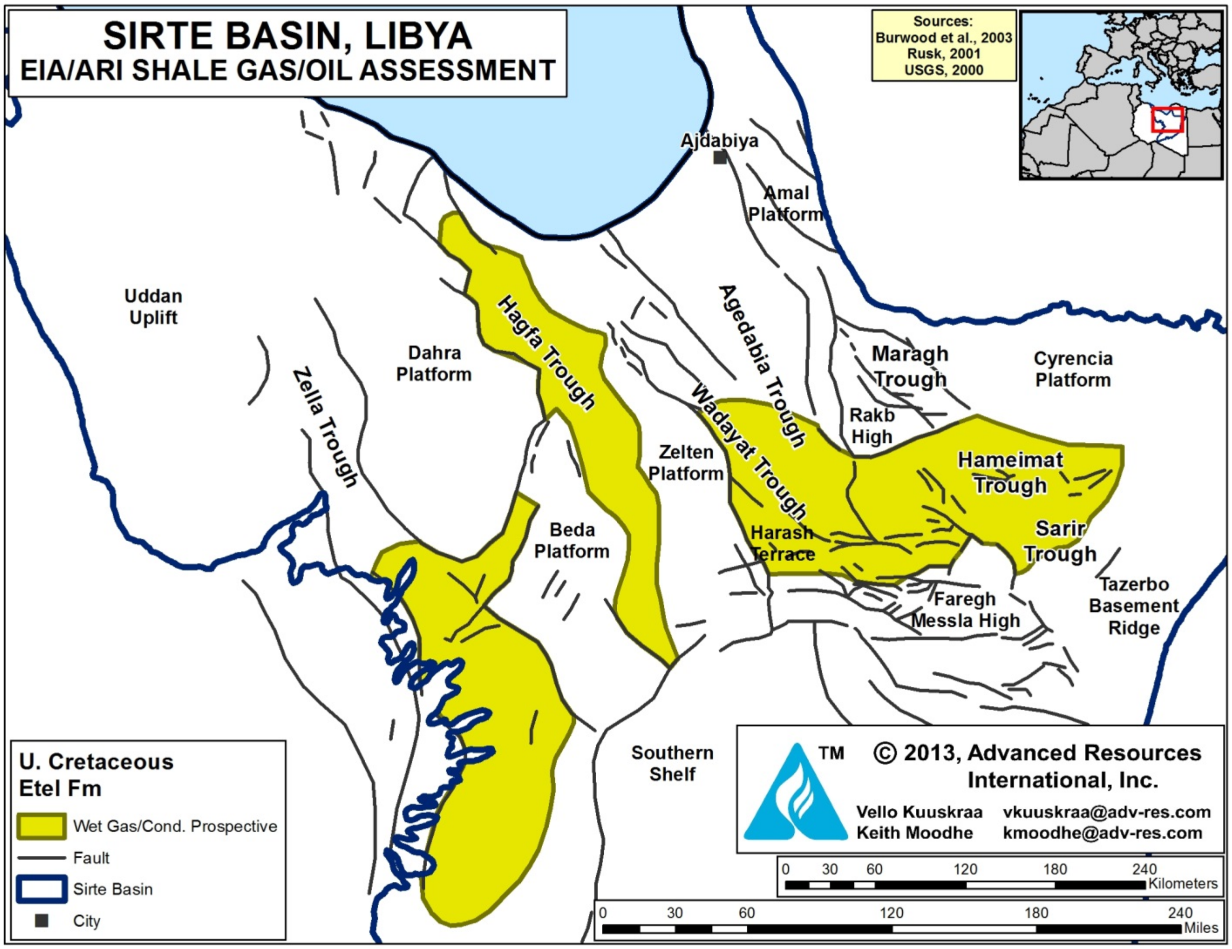
Figure XVII-7. Sirte Basin, Sirte/Rachmat Shale Prospective Area



Source: ARI, 2013

Etel Shale. The Etel Shale's 19,920-mi^2 prospective area underlies the Sirte/Rachmat Shale at depths of 11,000 to 16,400 ft, averaging 13,500 ft, Figure XVIII-8. The Etel Formation is about 600 ft thick, of which 120 net ft is organic-rich shale. The TOC of the organic-rich shale is high at 3.6%. The thermal maturity (R_o) of 1.0% to 1.3% places the Etel Shale in the wet gas/condensate window.

Figure XVII-8. Sirte Basin, Etel Shale Prospective Area



Source: ARI, 2013

2.3 Resource Assessment

Sirte/Rachmat Shale. The Upper Cretaceous Sirte/Rachmat Shale, within its 35,240-mi^2 prospective area for oil, has an oil concentration of 29 million barrels/mi^2, plus associated gas. The risked shale oil in-place is estimated at 406 billion barrels, with 16.2 billion barrels as risked, technically recoverable. In addition, we estimate a risked associated shale gas in-place of 350 Tcf, with 28 Tcf as the risked, technically recoverable shale gas resource.

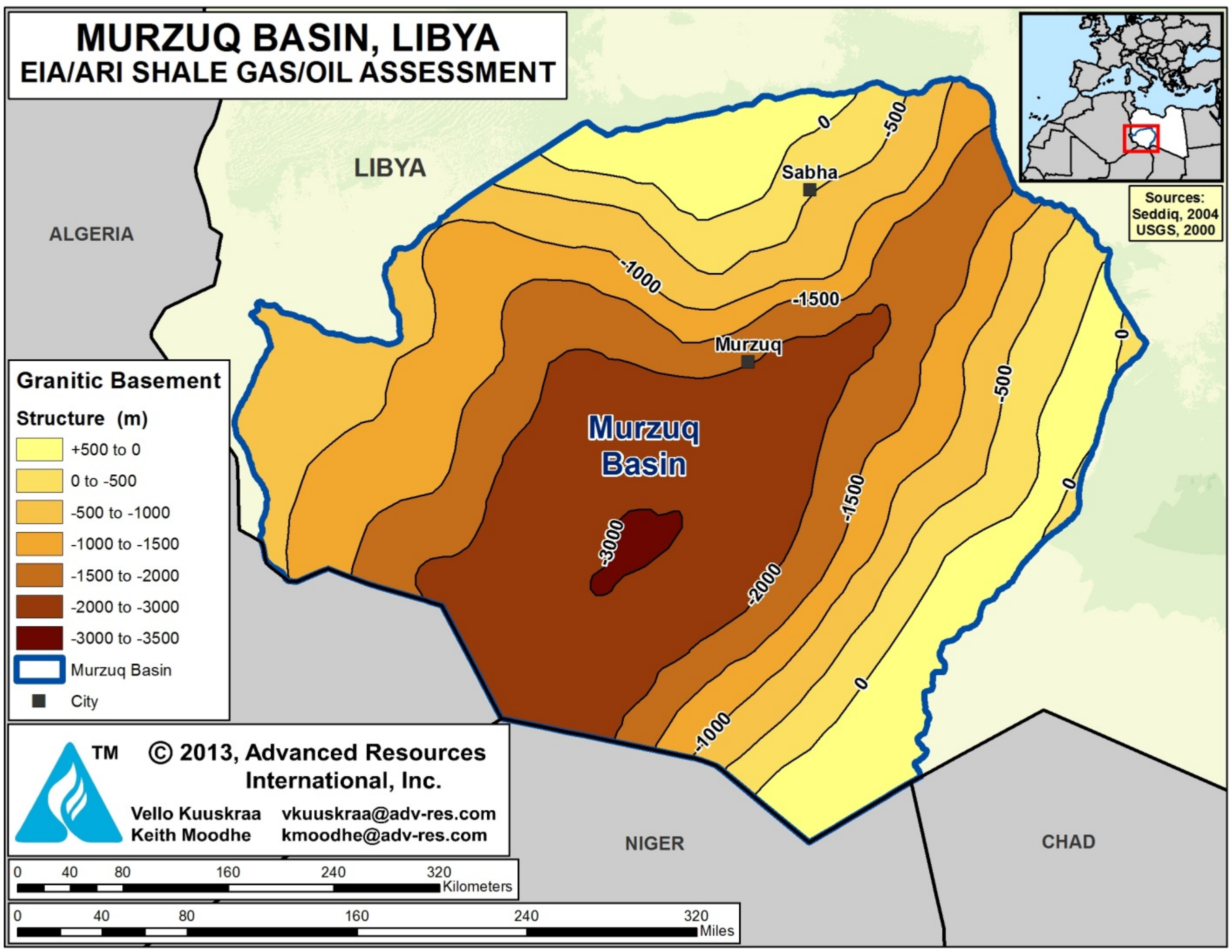
Etel Shale. The Upper Cretaceous Etel Shale has a prospective area of 19,920 mi^2 for wet gas and condensate. The Etel Shale has resource concentrations of 6 million barrels of oil and 37 Bcf of wet gas per square mile. With risked resources in-place of 51 billion barrels of oil/condensate and 298 Tcf of wet gas, the risked, technically recoverable shale oil and gas resources are estimated at 2.0 billion barrels of shale oil/condensate and 45 Tcf of shale gas.

3. MURZUQ BASIN

Introduction

The Murzuq Basin extends over a large 97,000-mi^2 area in the southwestern portion of Libya (extending southward into the Republic of Chad), Figure XVII-9. With its remote location, the Murzuq Basin remained undiscovered and unproven for hydrocarbons until the 1980s. Since then, four large discoveries, including the giant Elephant field plus numerous smaller fields, account for 5.4 billion barrels of discovered oil in-place, with 1.75 billion barrels estimated as recoverable.

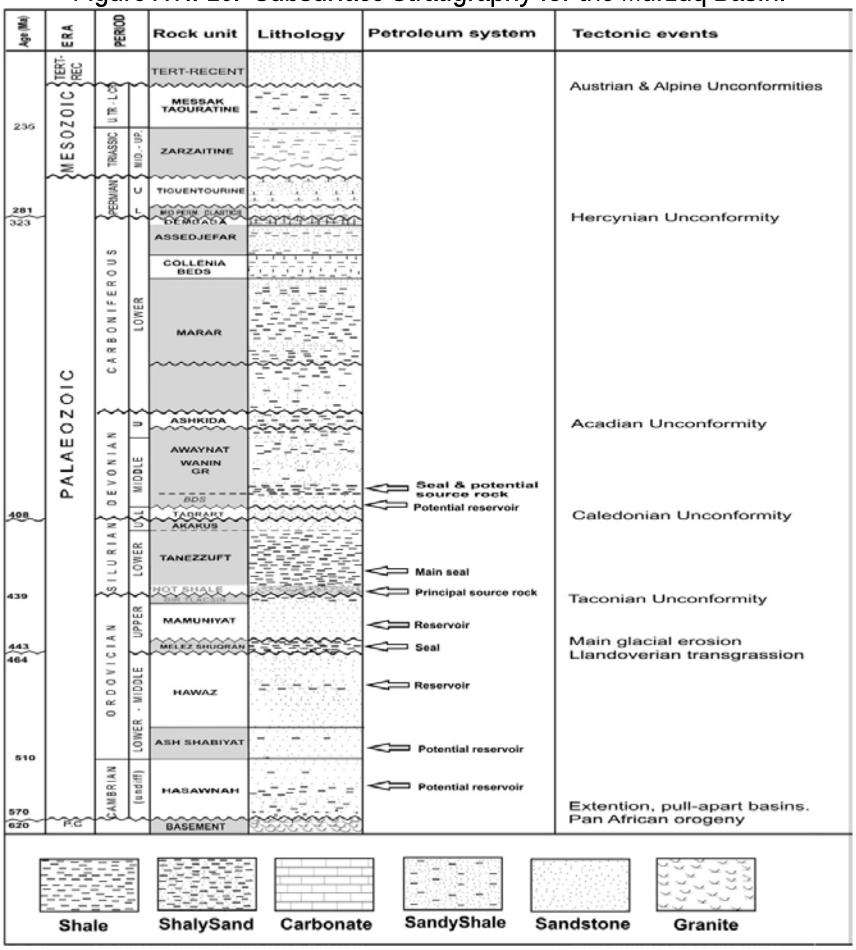
Figure XVII-9. Basin Outline and Structural Contour Map (Granitic Basement) for the Murzuq Basin



Source: ARI, 2013

The primary shale source rock addressed in the Murzuq Basin resource study is the Lower Silurian Tannezuft Formation, notably the “hot shale” interval at the base of the formation, Figure XVII-10.[4] Another potential source rock in this basin, not further assessed due to lack of data and concern with respect to thermal maturity, is the Middle Devonian Awaynat Formation in the deep center of the basin.

Figure XVII-10. Subsurface Stratigraphy for the Murzuq Basin.

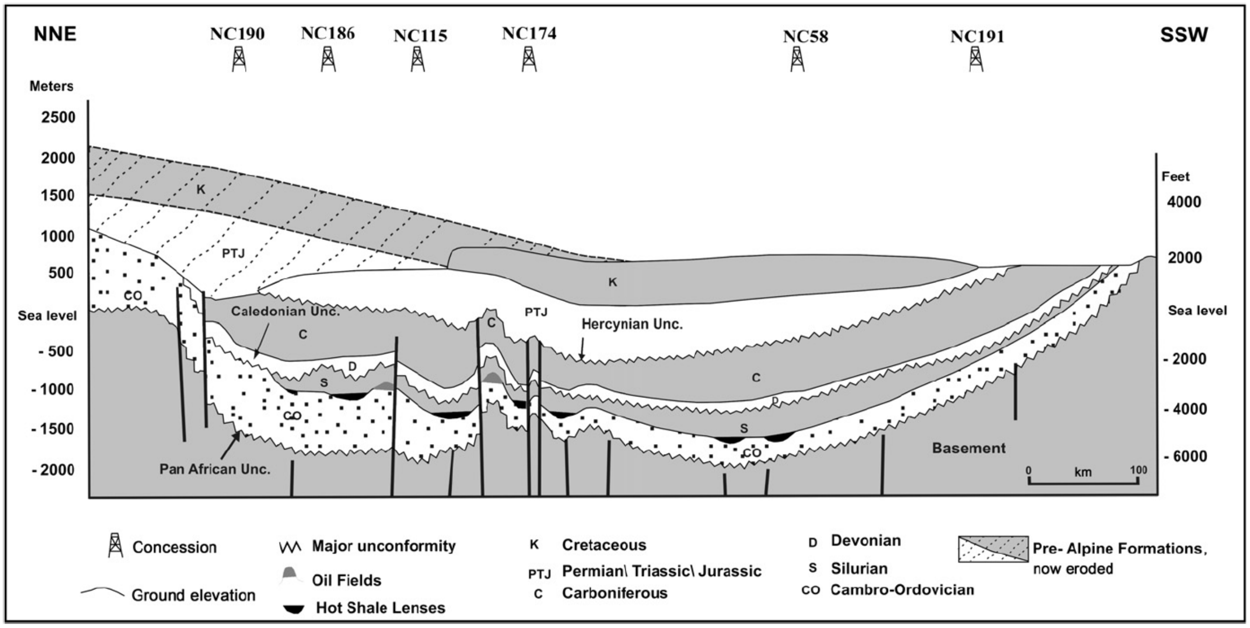


Source: Belaid at al., 2010

3.1 Geologic Setting

The Murzuq Basin is bounded on the east by the Tibisti Arch, on the west by the Tihembada Arch (which separates it from the Illizi Basin in Algeria), on the north by the Qurcal Arch (which separates it from the Ghadames Basin), and on the south by the Libya and Chad borders. Figure XVII-11[4] provides a generalized cross-section across the northern portion of the Murzuq Basin.

Figure XVII-11. Cross-Section for Murzuq Basin



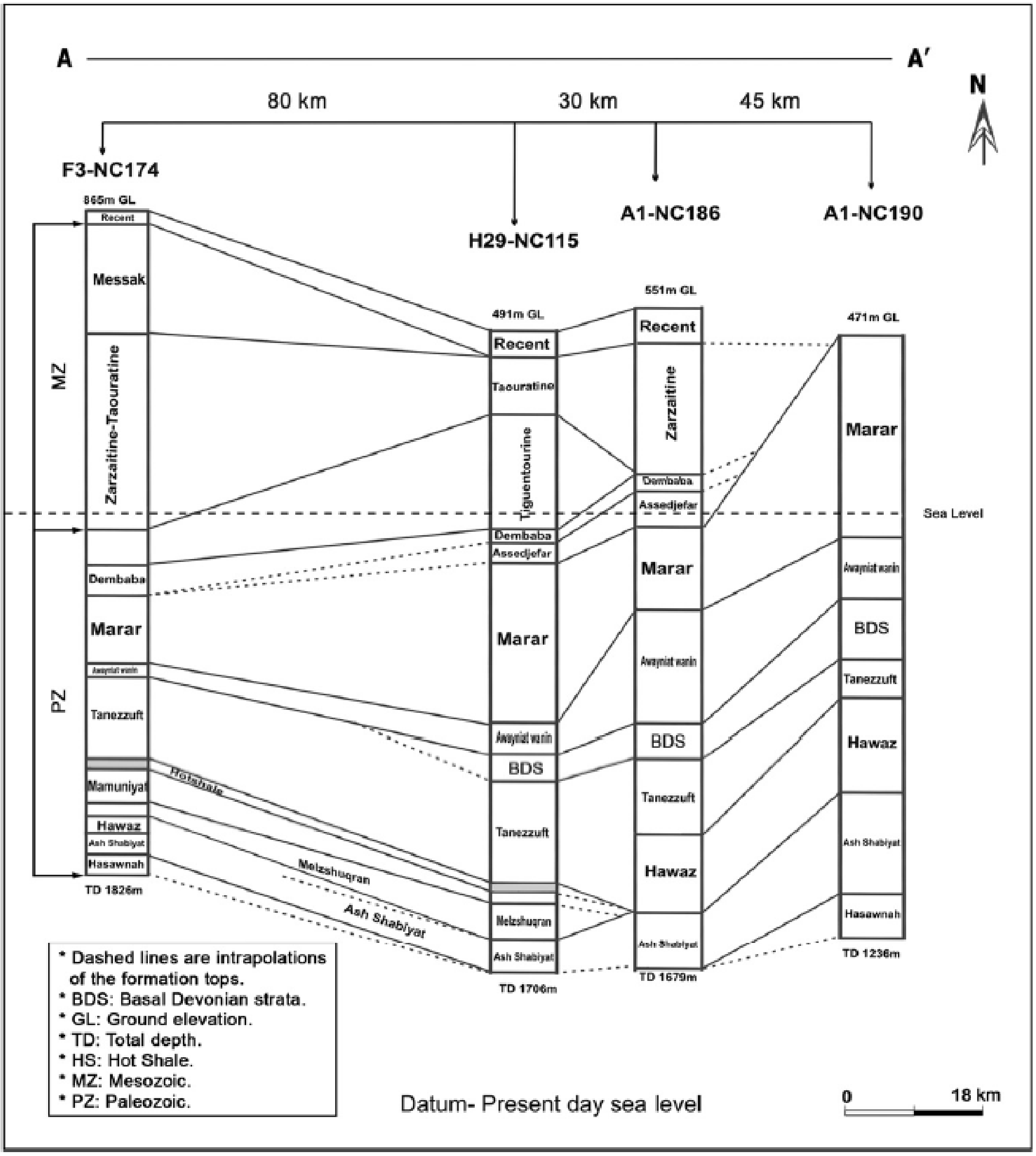
Source: Belaid at al., 2010

The intra-cratonic Murzuq Basin contains a series of troughs and uplifts that dominate the basin's deposition and hydrocarbon potential. Of particular significance is the Awabari Trough in the center of the basin where a series of cored wells (F3-NC174 and H29-NC115) have been drilled that provide a most valuable data set for this resource assessment. Within this trough, the Silurian Tannezuft Formation, particularly its lower "hot shale" interval, is the primary hydrocarbon source rock for the oil discoveries in the Murzuq Basin. The presence of this shale interval is illustrated by the cross-section on Figure XVII-12,[4] with the cross-section location provided on Figure XVII-13.[4]

3.2 Reservoir Properties (Prospective Area).

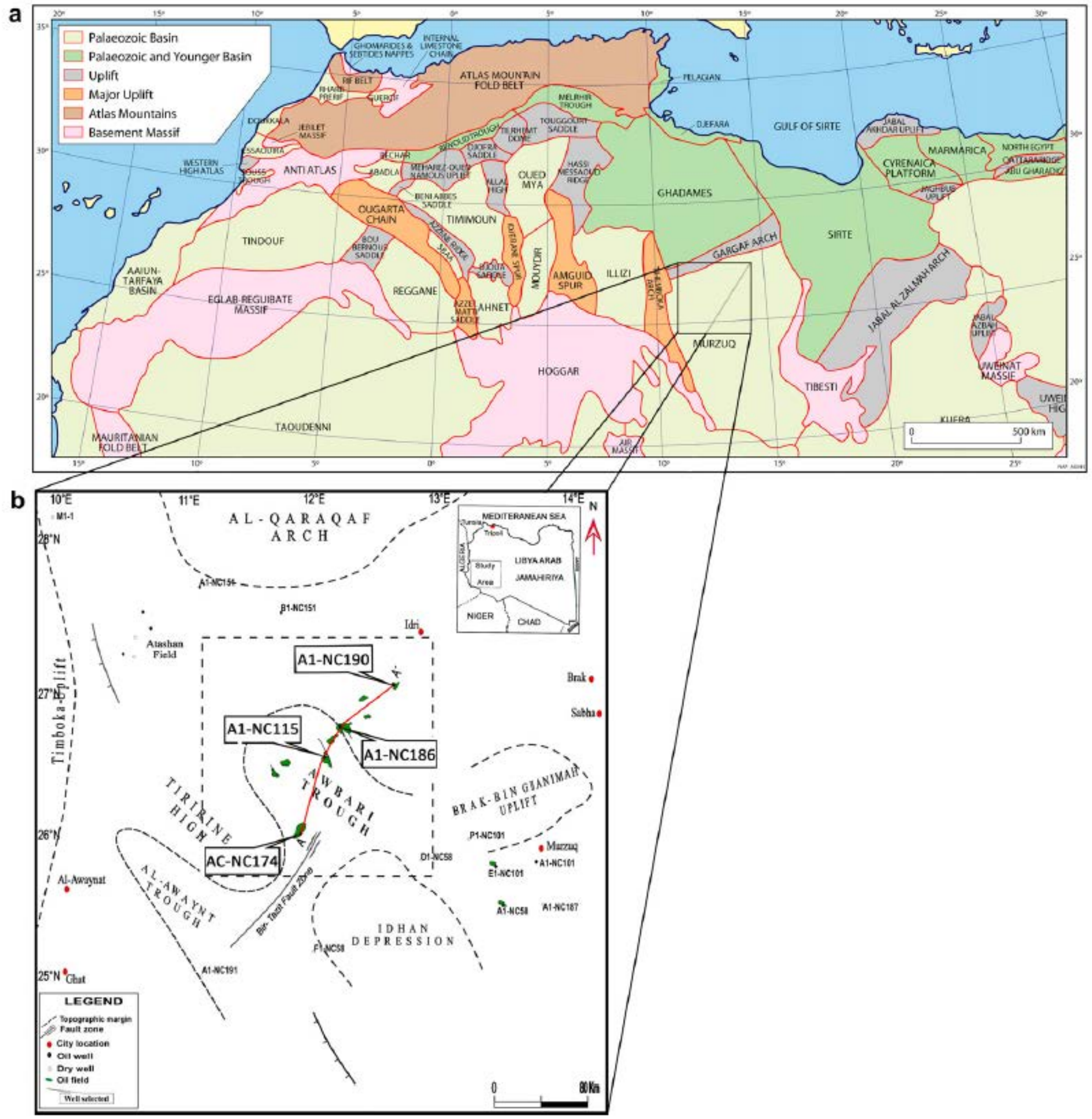
Lower Silurian Tannezuft Shale. The Silurian Tannezuft Formation (early Llandoverian) consists of dark gray to black graptolitic shales with intervals of siltstone and fine-grained sandstone deposited in a marine environment.[5]

Figure XVII-12. General Stratigraphy and Cross Section (A-A') for Four Murzuq Basin Study Wells
(See Figure XVIII-13 for Cross-Section Locations)



Source: Belaid et al., 2010

Figure XVII-13. Awabari Trough of the Murzuq Basin



Source: Belaid at al., 2010

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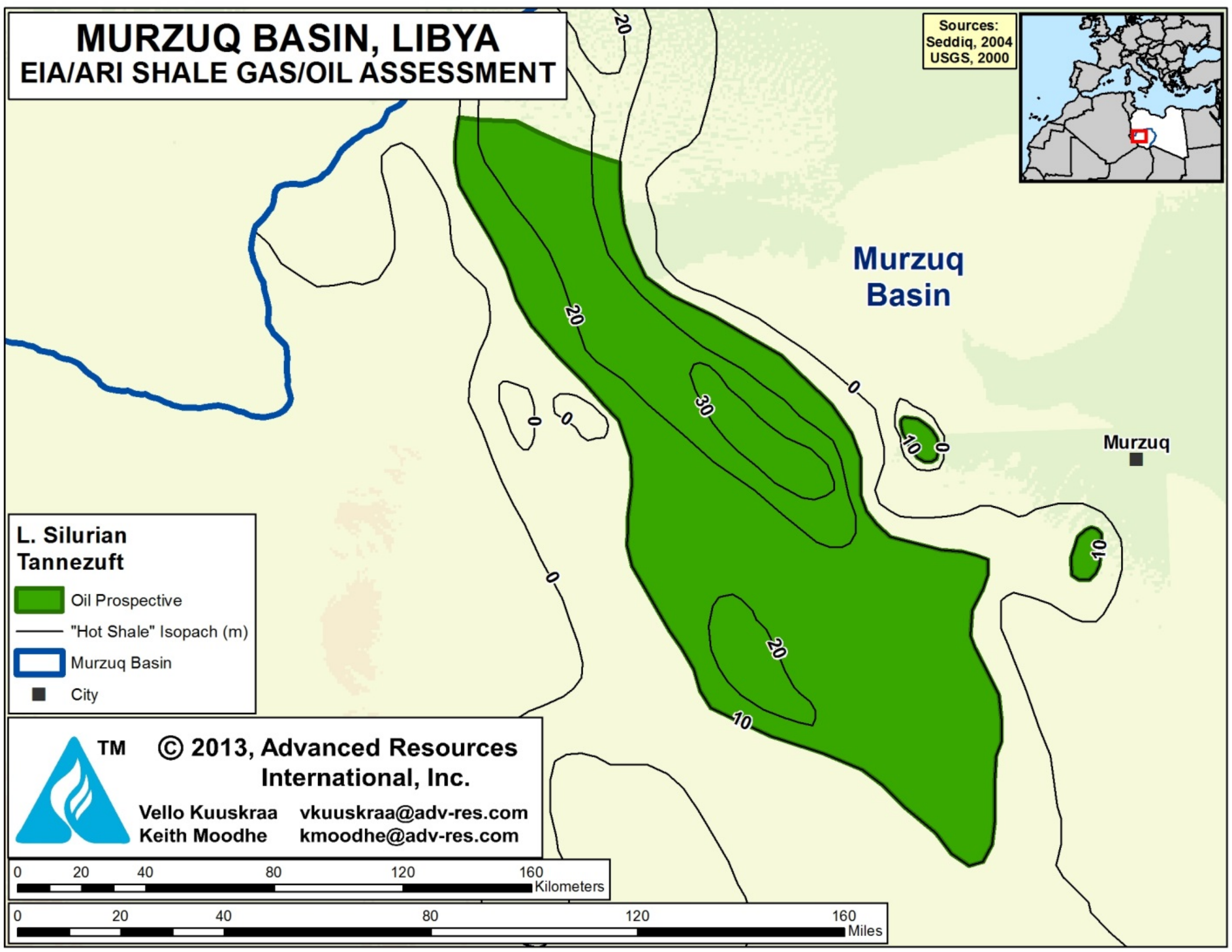
We have mapped a 5,670-mi^2 oil-prospective area in the center of the Murzuq Basin, Figure XVII-14. The depth of the Tannezuft "hot shale" in the prospective area of the Murzuq Basin ranges from 3,300 ft on the flanks to 10,000 ft in the central part of the basin.[6] The outcrops of the Tannezuft Formation in the uplifts surrounding the basin provide useful information on formation thickness and other properties. While the overall Tannezuft Formation can be up to 1,000 ft thick, only the basal "hot shale" unit, with thickness ranging from 30 to 100 ft has been included in our resource assessment.

Figure XVII-14. Shale Prospective Area of the Murzuq Basin.



Source: ARI, 2013

- In the NC-115 license area, 146 m of core was taken from 22 wells, all of which penetrated the Tannezuft Formation. Here the basal Tannezuft shale serves as both a seal as well as the source rock for the productive Mamuniyat sandstone formation in the license area. In this area, the "hot shale" exists as a north to south belt with limited width, ranging in thickness up to 35 m, with the thickest development in the southeastern portion of the prospective area. The TOC of the "hot shale" ranges from 3.2% to 23.1% (average 9.9%) and the shale has a thermal maturity of R_o 0.83% to 0.95% in well A1-NC115, placing the shale in the late oil maturity window. The maturity of the shale is believed to increase toward the southern portion of the prospective area.[4]

- Core analysis from a second well, F3-NC174, recorded TOC values that ranged from 3.7% to 4.7% (average 4.0%), with thermal maturity of 0.7 R_o.[4]
- A detailed analysis of the E1-NC174 well, drilled in 1997, provides further information on the properties of Tannezuft "hot shale" in the Awabari Trough. The core data shows the presence of Type II (oil prone) kerogen with TOC values of up to 13%. The "hot shale" existed over an interval from 7,244 to 7,267 ft, with leaner but still organic-rich intervals above and below the "hot shale" interval, Figure XVII-15.[7]

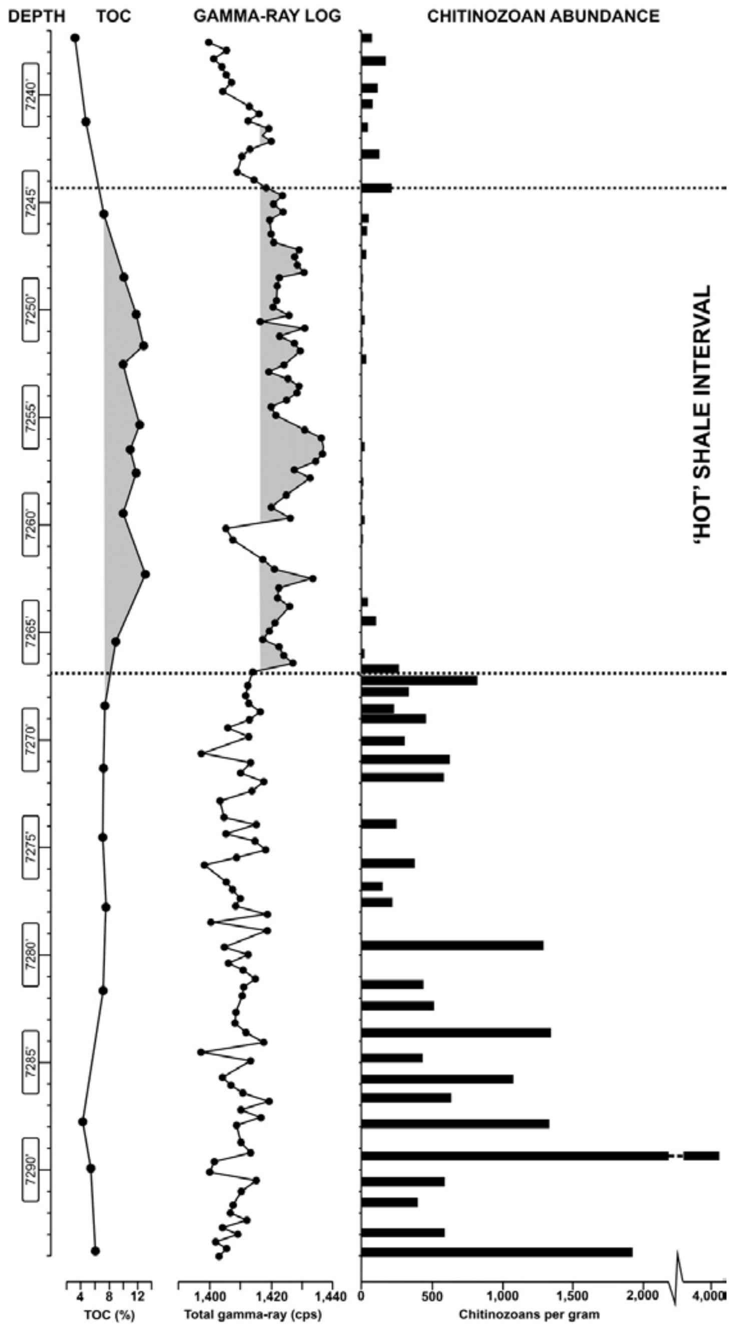
Upper Silurian Tannezuft Shale. An in-depth geochemical investigation was performed recently on a series of representative shale samples from the Upper Silurian Tannezuft Formation of the Murzuq Basin.[5] The purpose of this study was to establish the source rock quality of the extensive Silurian Tannezuft "cool shales" at the top of the Silurian section. (Geochemical analysis of the Upper Silurian Shale in Jordan, as reported in our separate Jordan chapter, indicated the potential for prospective organic-rich shale within the Upper Silurian in addition to the organic-rich shale in the Lower Silurian.)

The rock samples from this upper interval were mainly Type III kerogen (gas prone) with some contribution of mixed Type II and III kerogen (gas/oil prone) from marine/terrigenous sources, Figure XVIII-16.[5] The rock samples showed an early to intermediate stage of thermal maturity with Tmax values of 435° to 445°C, indicating the source rock was in the early to middle oil window (R_o of 0.6% to 0.9%) The organic content of the samples was characterized as poor to fair, with TOC values ranging from 0.4% to 1.28%, indicating a mixed oxic to sub-oxic depositional environment.

While the overall Tannezuft Shale Formation in the Murzuq Basin is on the order of 300 m thick, it appears that only the basal ("hot shale") unit of the Silurian Tannezuft Formation is sufficiently organic-rich to be included in our shale resource assessment.

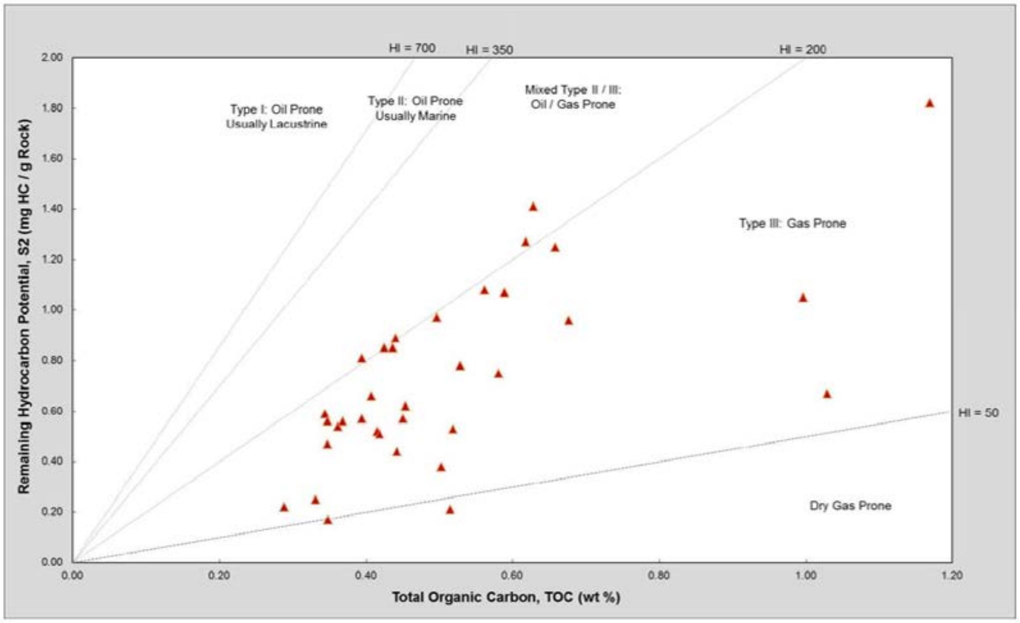
Devonian Awaynat Wanin Formation. The Middle-Late Devonian Awaynat Wanin Formation is also considered a potential shale source rock in the Murzuq Basin. However, only limited information exists for this unit. To date, only the Silurian Tannezuft-Mamuniyat has been established as an effective petroleum system.[8]

Figure XVII-15. TOC Values within the E1-NC174 Core.
Modified from Luning et al. 2003.



Source: Butcher, 2013.

Figure XVII-16. Cross Plot Between S2 mg HC/g Rock and %TOC for Tannezuft Formation, Field A, NC-115, Murzuq Basin.
Modified from GeoMark Research, LTD (2009).



Source: Hodairi, T. and Philp, P., 2011.

3.3 Resource Assessment

The Tannezuft "hot shale", within the 5,670-mi^2 prospective area of the Murzuq Basin, has a resource concentration of 10 million barrels/mi^2 of oil plus associated gas. The risked shale oil resource in-place is estimated at 27 billion barrels of shale oil plus 19 Tcf of associated shale gas, with 1.3 billion barrels of shale oil and 2 Tcf of associated shale gas as the risked, technically recoverable resource.

4. KUFRA BASIN

Introduction

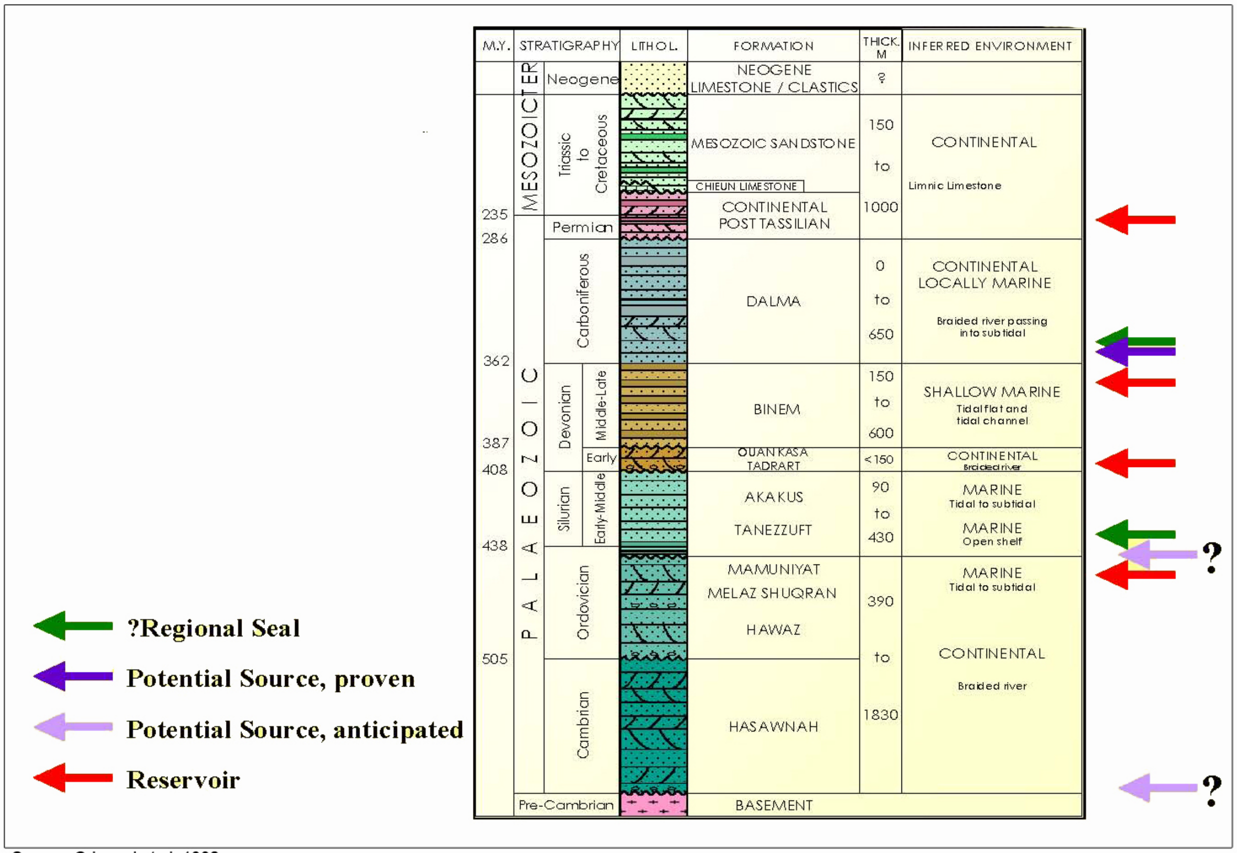
The Kufra Basin is a large 400,000-km^2, remote intra-cratonic sag basin located in southeastern Libya. The Paleozoic structural and deposition history of the Kufra Basin is similar to that of the Murzuq Basin, discussed earlier in this chapter. However, there is considerable uncertainty as to the presence of sufficiently organic-rich source rocks in this basin.

The Lower Silurian Tannezuft Formation is described as up to 130 m thick in outcrops at the basin margins, Figure XVII-17.[9] However, the basal section of the Tannezuft Formation containing the Silurian "hot shale" in the Murzuq Basin appears to be missing in outcrops along the northern and eastern margins of the basin.[10]

In addition, the "hot shale" unit was absent in three exploration wells drilled to date, having been replaced by siltstones and sandstones in two dry exploration wells drilled in the northern part of the basin by AGIP in the late 1970s and early 1980s (Bellini, 1991). The absence of lower Silurian shales in these two Kufra Basin exploration wells - - A1-NC-43 and B1-NC43 - - suggests that this area may have been deposited as a sandy delta during the early Silurian, representing the westward continuation of the sandy lower Silurian in western Egypt where the Tannezuft basal "hot shale" is also absent, Figure XVII-18.[10] Since then, one additional exploration well drilled in 1997 has noted the absence of the lower Silurian "hot shale" in the Kufra Basin.

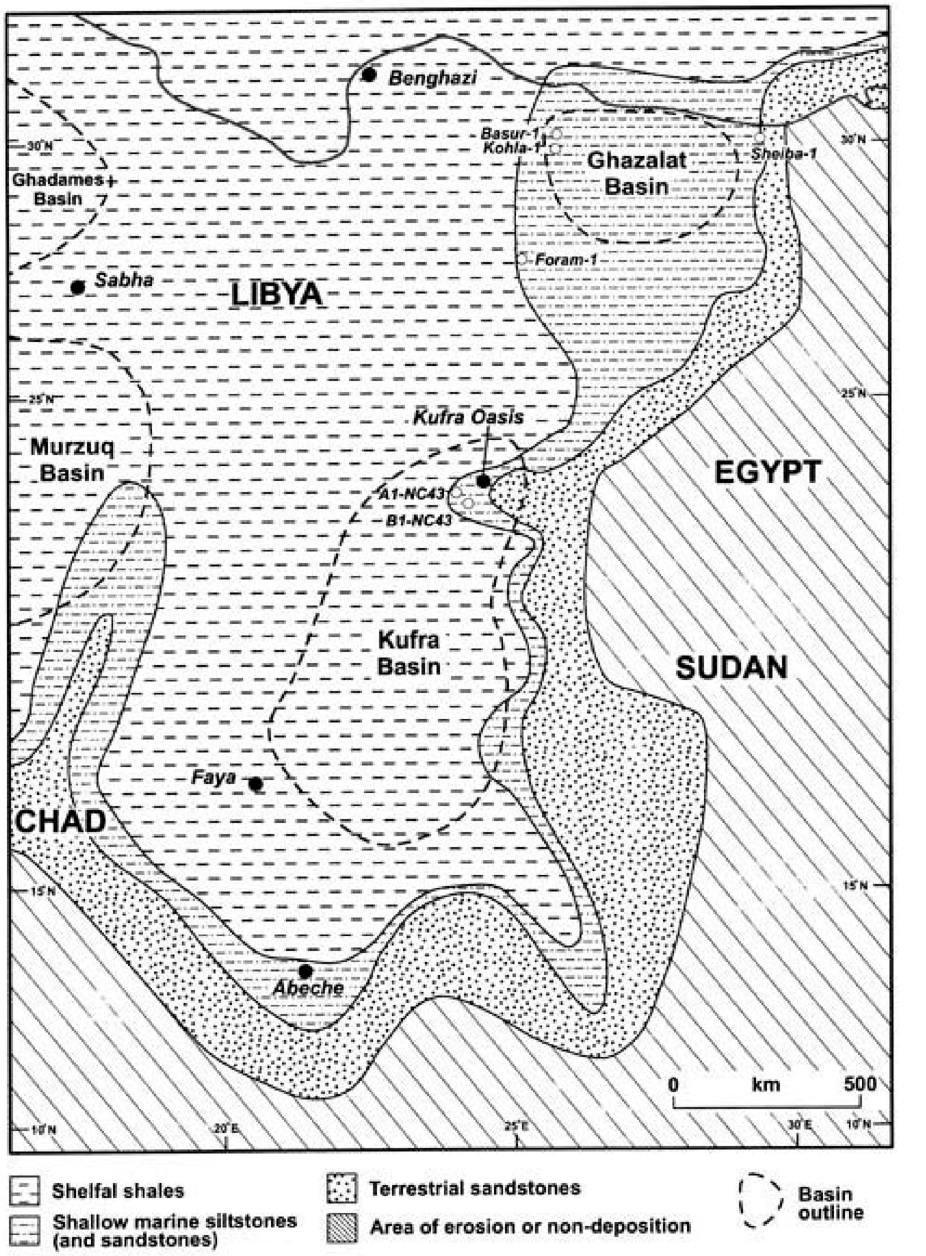
Lower Silurian, organic-rich shales may be present in the western part of the Kufra Basin.[11] However, the areal distribution of this shale unit is laterally highly variable with Silurian basal "hot shale" occurrences deposited as linear features and patches, surrounded by areas in which the basal "hot shale" is absent.[10]

Figure XVII-17. Stratigraphic Column of the Kufra Basin



Source: Grignani et al. 1992

Figure XVII-18. Early Silurian Paleogeography of the Kufra Basin
Based on Keeley, 1989; Semtner et al., 1997; Selley, 1997b; Keeley & Masoud, 1998 and Luning, 1999.



Source: Luning et al. 1999

RECENT ACTIVITY

Libya's oil and gas exploration, including the assessment of its shale oil and gas resources came to a halt during the uprising that overthrew the government of Muammar Gaddafi. However, in late 2012, the Chairman of Libya's National Oil Company, Mr. Nuri Berruien, announced that the company is examining options for exploring its unconventional oil and gas resources. One option discussed by Chairman Berruien is to internally evaluate the unconventional resources and then bring in international companies with expertise in unconventional resource exploration and development.[12]

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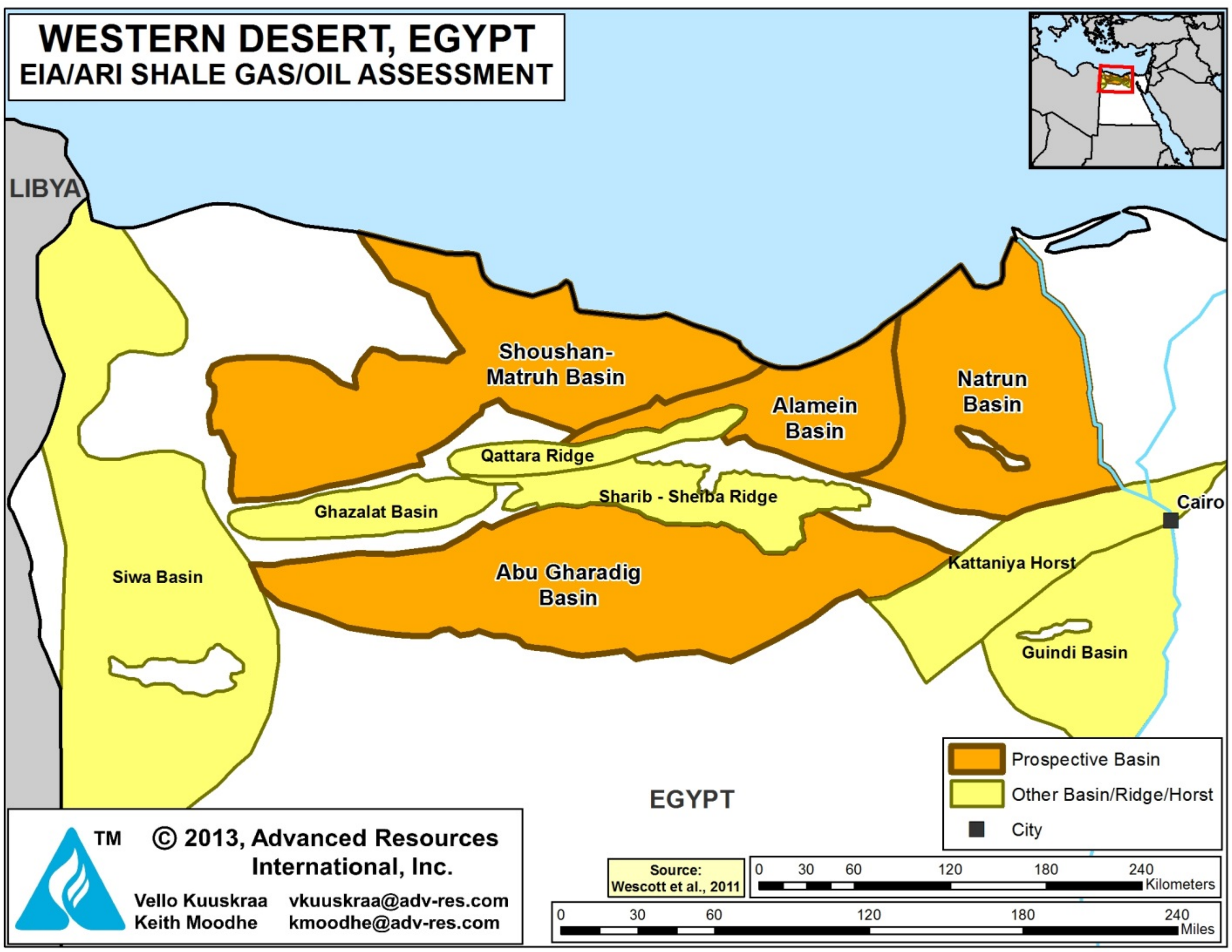
XVIII. EGYPT

SUMMARY

Egypt has four basins in the Western Desert with potential for shale gas and shale oil - - Abu Gharadig, Alamein, Natrun and Shoushan-Matruh, Figure XVIII-1.[1] The target horizon is the organic-rich Khatatba Shale, sometimes referred to as the Kabrit Shale or Safa Shale, within the larger Middle Jurassic Khatatba Formation.

Figure XVIII-1. Hydrocarbon Basins of the Western Desert, Egypt



Source: ARI, 2013.

Our assessment is that the Khatatba Shale contains approximately 535 Tcf of risked shale gas in-place, with 100 Tcf of risked, technically recoverable shale gas resources, Table XVIII-1. In addition, we estimate that the Khatatba Shale contains about 114 billion barrels of risked shale oil in-place, with 4.6 billion barrels of risked, technically recoverable shale oil resources, Table XVIII-2.

Table XVIII-1. Shale Gas Reservoir Properties and Resources of Egypt

			Abu Gharadig	Alamein	Natrun	Shoushan-Matruh
Basic Data	Basin/Gross Area		(7,670 mi^2)	(2,340 mi^2)	(4,860 mi^2)	(7,080 mi^2)
	Shale Formation		Khatatba	Khatatba	Khatatba	Khatatba
	Geologic Age		M. Jurassic	M. Jurassic	M. Jurassic	M. Jurassic
	Depositional Environment		Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		6,840	2,340	4,860	4,420
	Thickness (ft)	Organically Rich	1,500	1,000	1,200	1,000
		Net	300	200	240	200
	Depth (ft)	Interval	11,000 - 13,000	13,000 - 15,000	13,000 - 15,000	10,000 - 15,000
		Average	12,000	14,000	14,000	13,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		4.0%	4.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		1.15%	0.85%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Wet Gas	Assoc. Gas	Assoc. Gas	Wet Gas
	GIP Concentration (Bcf/mi^2)		99.2	29.1	35.0	71.3
	Risked GIP (Tcf)		325.7	16.7	41.6	151.2
	Risked Recoverable (Tcf)		65.1	1.3	3.3	30.2

Table XVIII-2. Shale Oil Reservoir Properties and Resources of Egypt

			Abu Gharadig	Alamein	Natrun	Shoushan-Matruh
Basic Data	Basin/Gross Area		(7,670 mi^2)	(2,340 mi^2)	(4,860 mi^2)	(7,080 mi^2)
	Shale Formation		Khatatba	Khatatba	Khatatba	Khatatba
	Geologic Age		M. Jurassic	M. Jurassic	M. Jurassic	M. Jurassic
	Depositional Environment		Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		6,840	2,340	4,860	4,420
	Thickness (ft)	Organically Rich	1,500	1,000	1,200	1,000
		Net	300	200	240	200
	Depth (ft)	Interval	11,000 - 13,000	13,000 - 15,000	13,000 - 15,000	10,000 - 15,000
		Average	12,000	14,000	14,000	13,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		4.0%	4.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		1.15%	0.85%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Oil Phase		Condensate	Oil	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		14.3	25.1	30.1	7.9
	Risked OIP (B bbl)		47.1	14.4	35.9	16.8
	Risked Recoverable (B bbl)		1.88	0.58	1.43	0.67

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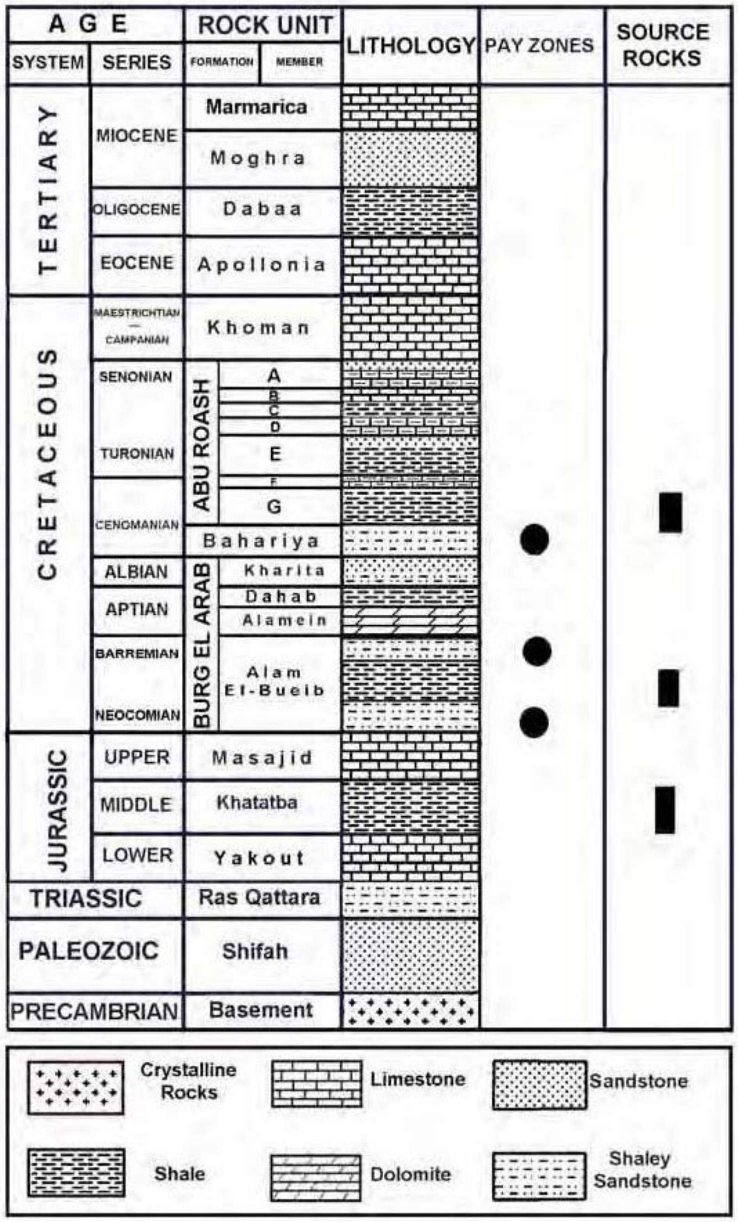
INTRODUCTION

The northern portion of the Western Desert of Egypt contains a series of basins underlain by organic-rich shales that have provided the source for the conventional hydrocarbons production from these basins. The primary hydrocarbon basins in the Western Desert include Abu Gharadig, Alamein, Natrun and Shoushan-Matruh. The Western Desert is the location of many of the major oil and gas fields of Egypt, including the more recently discovered, large Jurassic fields of Kanayes (discovered in 1992), Obayeid (discovered in 1993) and Shams (discovered in 1997).[2]

The basins have a thick sedimentary sequence comprising Paleozoic through Tertiary strata that exceed 15,000 feet, Figure XVIII-2.[3] Despite many years of successful discovery of conventional oil and gas deposits, the large Western Desert hydrocarbon basins of Egypt are still only lightly explored, particularly for their deeper formations.

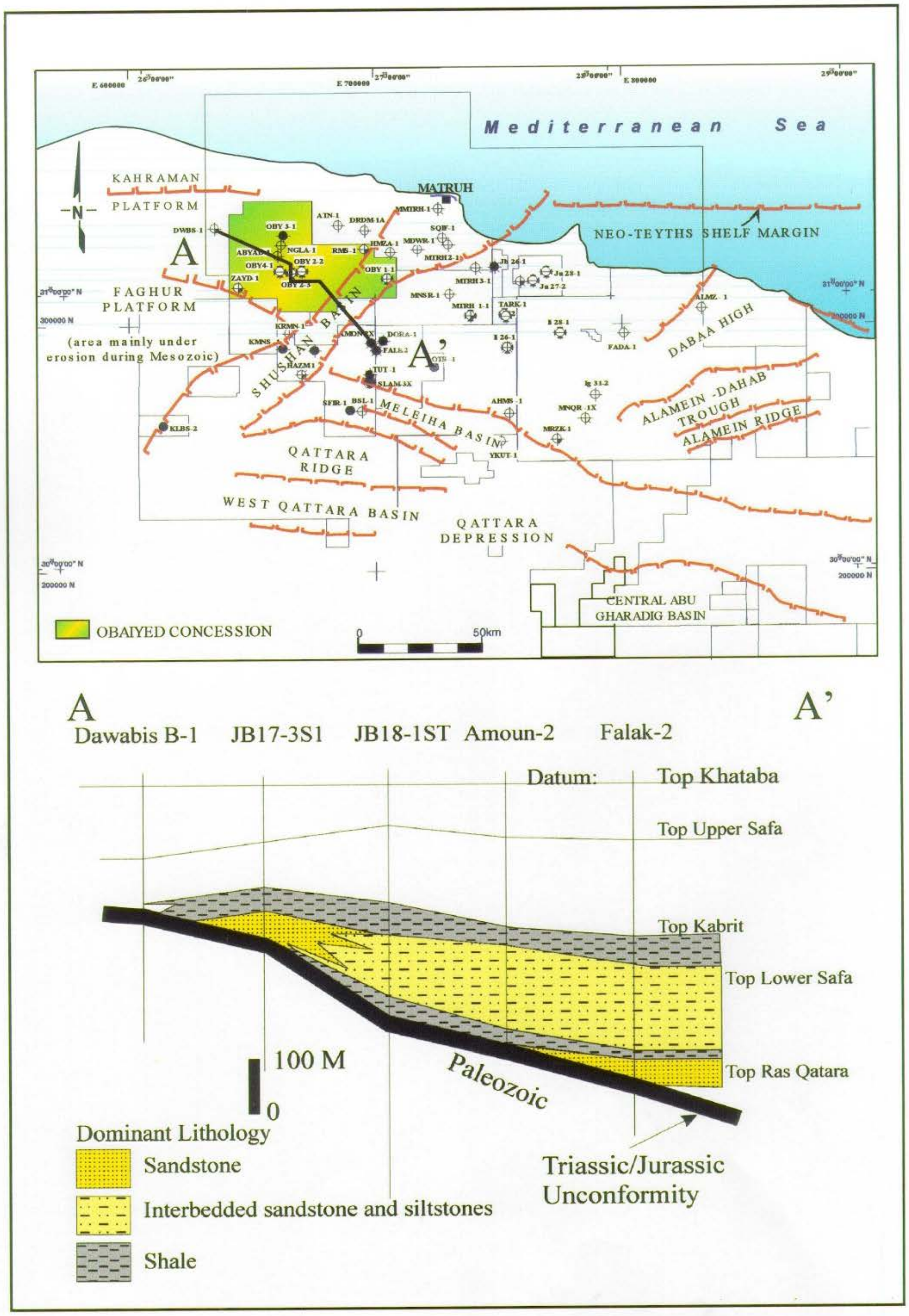
The focus of our shale resource study is the Khatatba Shale within the Middle Jurassic Khatatba Formation, also called the Kabrit Shale and the Safa Shale, Figure XVIII-3.[4]

Figure XVIII-2. Generalized Lithostratigraphic Column of the Western Desert of Egypt.



Source: Younes, 2012 (Modified after Abdou,1998).

Figure XVIII-3. Khatatba Formation and Kabrit (Safa) Shale, Shoushan-Matruh Basin, Western Desert.



Source: Dolson, 2000.

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Egypt's geologic history is complex and a full discussion of its geology and tectonics is beyond the scope of this resource assessment. However, this chapter provides an overview that is intended to help place the shale oil and gas resources of the Western Desert into context. As such, the study examined three major shale source rocks in the Western Desert of Egypt before establishing the Middle Jurassic Khatatba Shale as the primary target.

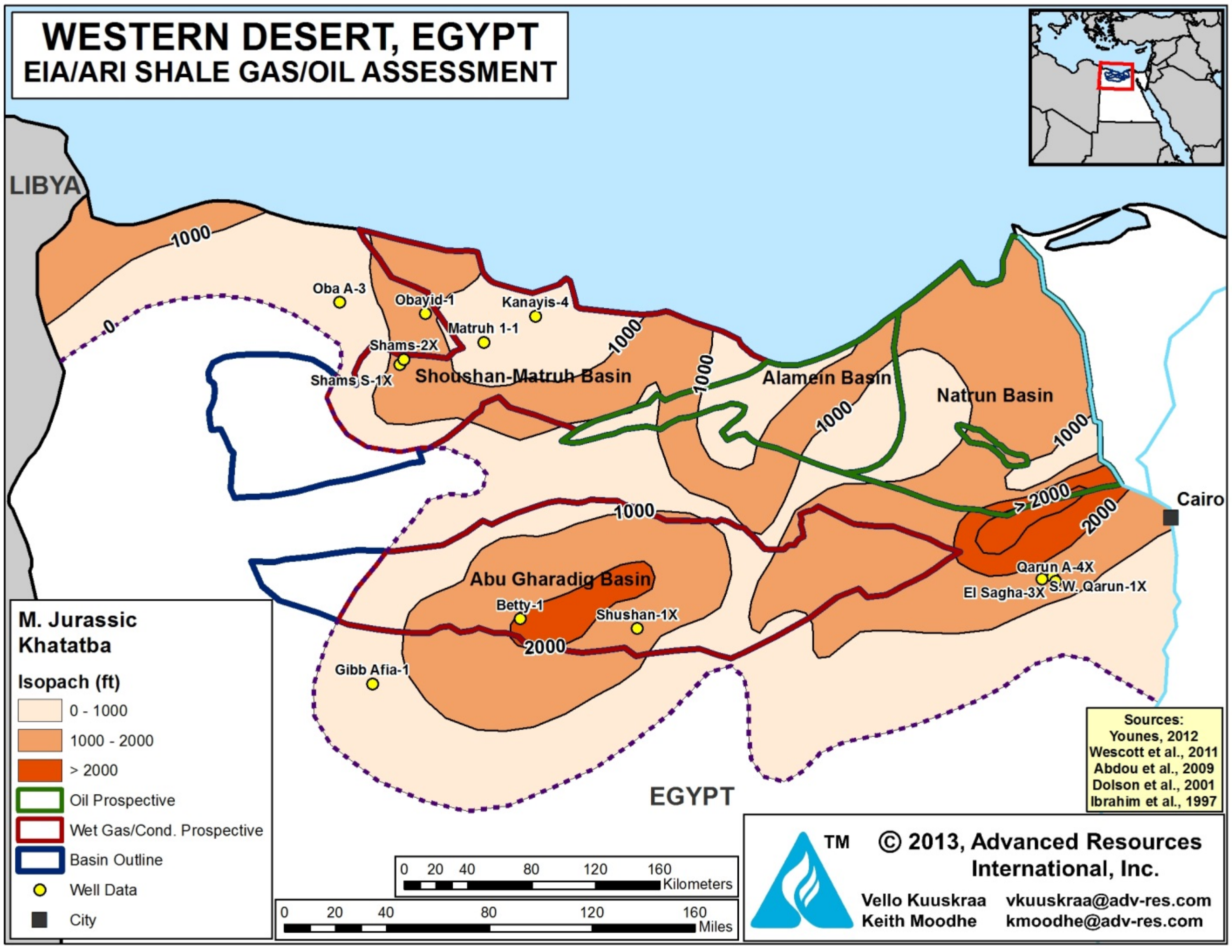
Silurian. A thick sequence of Silurian siltstone, estimated at about 200 to 300 m in the Basur-1 and Kohka-1 wells, exists in the northwestern portion of the Western Desert.[5] These sandstones and siltstones thin to the south and east as shown by the Foram-1 and Sheiba-1 wells.[6] The sandstone and siltstone units appear to rest directly on Upper Ordovician glacial deposits without any evidence of Silurian organic-rich shales.[8] The Western Desert of Egypt lacks a Silurian Tannezuft ("Hot Shale") source rock equivalent due to a paleo-basement high and erosion of Silurian sediments.[7]

Cretaceous. Cretaceous-age shale source rocks within the Alam El-Bueib and Abu Roash formations exist across much of the Western Desert. However, these shales have been classified as marginal to moderate source rock quality for oil and gas generation, with TOC values generally reported at less than 2%. In addition, the Cretaceous-age source rocks are thermally immature in significant portions of the Western Basin study area.[8] Due to these less favorable reservoir properties and limited data, we have not included these Cretaceous-age source rocks in our shale oil and gas resource assessment.

Jurassic. During the late Triassic and Jurassic, a series of rift basins formed in the Western Desert. These rift basins and their subsequent extension during the Cretaceous provided the setting for the important Khatatba Formation and its thick, black shale deposition. The Khatatba Shale (also called the Safa Shale) has served as the source rock for much of the oil and gas found in the Western Desert.[2,3]

The larger Khatatba Formation ranges from 1,000 feet to over 2,000 feet thick in the Western Desert. The type section of the Kabrit (Safa) Shale Member within the Khatatba Formation ranges in thickness from 0 to over 600 feet in the Western Desert, with an estimated net pay of 200 to 300 feet, XVIII-Figure 4.[3,9,2,10]

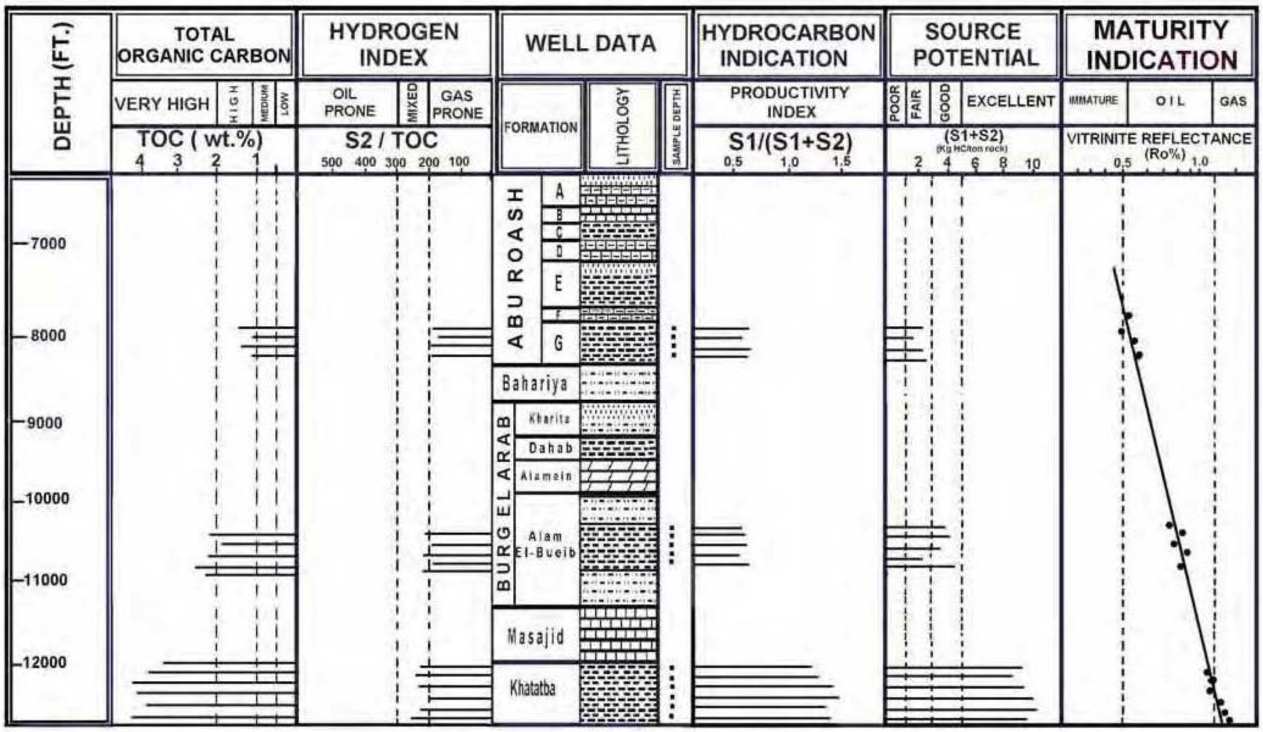
Figure XVIII-4. Middle Jurassic Khatatba Formation Gross Isopach



Source: ARI, 2013.

Detailed source rock evaluations of core samples from the Shushan-1X well in the southern portion of the Abu Gharadig Basin provided important data on the reservoir properties of the Khatatba Shale. The TOC of the shale varied from 3.6% to 4.2% with a vitrinite reflectance (R_o) of 1.0% to 1.3%, placing the shale primarily in the wet gas and condensate window, Figure XVIII-5.[3] The shale contains mixed vitrinite-inertinite kerogen derived from land plants and algae, implying a mixture of marginal marine and continental organic matter.[11] The combination of maximum temperature and kerogen type places the Khatatba Shale primarily in the wet gas/condensate and volatile oil windows with significant associated plus free gas in the pore space.

Figure XVIII-5. TOC and Maturity Data, Jurassic- and Cretaceous-Age Source Rocks, Western Desert, Egypt



Source: Younes, 2012

ABU GHARADIG BASIN

Geologic Setting. The 7,670-mi^2 Abu Gharadig Basin is an east-west trending half graben with a depth to basement that exceeds 30,000 feet. The basin is bounded on the north by the Qattara Ridge and on the south by the Sitra Platform. The Jurassic-age Khatatba Shale is considered the major hydrocarbon source rock in this basin.[2] We have identified a 6,840-mi^2 prospective area in this basin after excluding the western portion of the basin which lacks Middle Jurassic deposits, Figure XVIII-4.

Reservoir Properties (Prospective Area). Within the 6,840-mi^2 prospective area, the depth of the Khatatba Shale in the Abu Gharadig Basin ranges from 11,000 to 13,000 feet, averaging 12,000 feet. The gross interval of the Khatatba Formation ranges from near 0 to over 2,000 feet, averaging about 1,500 feet thick. The net shale, using a net to gross ratio of 0.2, is estimated at 300 feet. Based on grain and bulk density data from the Betty-1 well, drilled in the south central portion of the basin, the porosity ranges from 2.4% to 8.4%, averaging 5.7% for six core samples. The TOC of the shale, using data from the Shushan-1X well, ranges from 3.6% to 4.2%, averaging 4%, with thermal maturity (Ro) values of 1.0% to 1.3%.

Resource Assessment. Within the 6,840-mi^2 prospective area of the Abu Gharadig Basin, the Khatatba Shale has a resource concentration of 99 Bcf of wet gas and 14 million barrels of oil/condensate per mi^2. The risked resource in-place for wet gas in the prospective area is estimated at 326 Tcf, with 65 Tcf as the risked, technically recoverable shale gas resource, Table XVIII-1. The risked resource in-place for oil/condensate in the prospective area is estimated at 47 billion barrels with 1.9 billion barrels of the risked, technically recoverable shale oil resource, Table XVIII-2.

ALAMEIN BASIN

Geologic Setting. The Alamein Basin is a large Jurassic rift basin in the northwestern portion of the Western Desert which was further extended during the Cretaceous. The onshore portion of the basin is bounded on the north by the Mediterranean Sea and on the south by the Qattara Ridge. The Jurassic-age Khatatba Shale, which contains mixed Type II and III kerogen, appears to be the main shale oil and gas target in this basin. Remarkably, the entire basin appears to be prospective for the Khatatba Shale.

Reservoir Properties (Prospective Area). Within the 2,340-mi^2 prospective area, the depth of the Khatatba Shale in the Alamein Basin ranges from 13,000 to 15,000 feet, averaging 14,000 feet. The gross interval of the Khatatba Formation averages 1,000 feet with a porosity of 5.7%. Organic content ranges up to 10%, with an average of 4%, and the shale is in the oil thermal maturity window (R_o of 0.8% to 1.0%).[12]

Resource Assessment. Within the 2,340-mi^2 prospective area of the Alamein Basin, the Khatatba Shale has a resource concentration of 25.1 million barrels of oil/condensate per mi^2 plus associated gas. The risked resource in-place for oil/condensate in the prospective area is estimated at 14 billion barrels, with 0.6 billion barrels as the risked, technically recoverable resource, Table XVIII-2. The basin also has associated gas estimated at 17 Tcf of risked in-place, with about 1 Tcf as risked technically recoverable, Table XVIII-1.

NATRUN BASIN

Geologic Setting. The Natrun Basin, covering an area of 4,860 mi^2, is a poorly defined basin located between the major oil and gas fields of the Nile Delta and the Western Desert.[13] The basin is bounded on the north by the Mediterranean Sea and on the south by the Kattaniya Horst. The Natrun Basin appears to hold a favorable conventional petroleum system of source rock, reservoir-seal, and timing of thermal maturity. The Jurassic-age Khatatba Shale is considered the major hydrocarbon source rock in this basin.[2] The entire basin appears to be prospective for the Middle Jurassic Khatatba Shale, Figure XVIII-4.

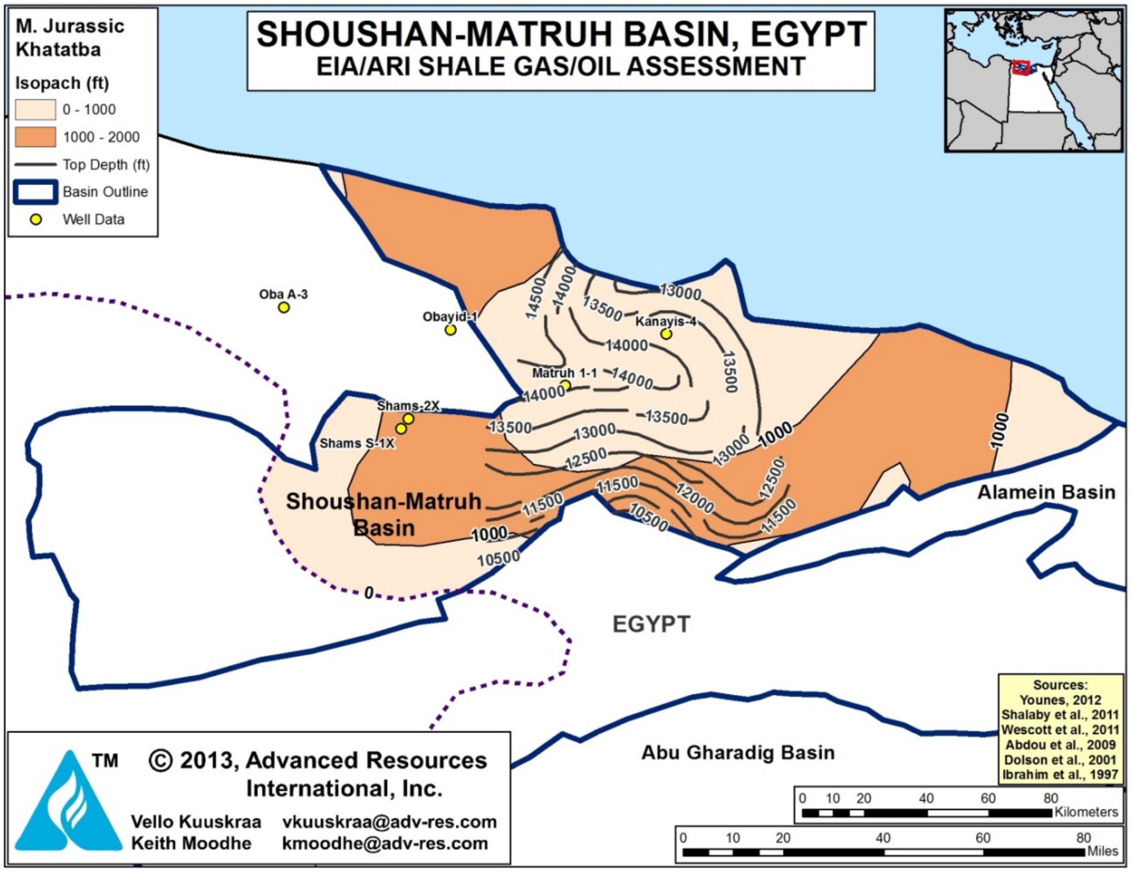
Reservoir Properties (Prospective Area). Within the 4,860-mi^2 prospective area, the depth of the Khatatba Shale in the Natrun Basin ranges from 13,000 to 15,000 ft, averaging 14,000 ft. The gross interval of the Khatatba Formation ranges from near 0 to over 2,000 ft, averaging about 1,200 ft thick. The net shale, using a net to gross ratio of 0.2, is estimated at 240 ft, with a porosity averaging 5.7%. The TOC averages 4% with thermal maturity (R_o) values of 0.7% to 1.0%, placing the shale in the oil window. (Although thermal modeled vitrinite reflectance values indicated over-mature Jurassic source rocks, borehole data from intra-basinal sediments showed a thermal maturity in the oil window).**Error! Bookmark not defined.**

Resource Assessment. Within the 4,860-mi^2 prospective area of the Natrun Basin, the Khatatba Shale has a resource concentration of 30.1 million barrels of oil/condensate per mi^2. The risked resource in-place for oil/condensate in the prospective area is estimated at 36 billion barrels, with 1.4 billion barrels as the risked, technically recoverable resource, Table XVIII-2. The basin also has associated gas estimated at 42 Tcf of risked in-place, with 3 Tcf of risked technically recoverable resources, Table XVIII-1.

SHOUSHAN-MATRUH BASIN

Geologic Setting. The Shoushan-Matruh Basin is a large Jurassic rift basin in the northwestern portion of the Western Desert which also was further extended during the Cretaceous. The basin is bounded on the north by the Mediterranean Sea and on the south by the Qattara Ridge. The Jurassic-age Khatatba Shale is the focus of our shale oil and gas resource assessment in this basin. We have identified a prospective area of 4,420 mi^2 in this basin after deleting the western portion of the basin beyond the limits of Middle Jurassic deposition, Figure XVIII-6.[3,14,1,9,2,10]

Figure XVIII-6. Shoushan-Matruh Basin, Khatatba Shales Depth and Gross Isopach



Source: ARI, 2013.

Reservoir Properties (Prospective Area). Within the 4,420-mi^2 prospective area, the depth of the Khatatba Shale in the Shoushan-Matruh Basin ranges from 10,000 to 15,000 ft, averaging 13,000 ft. The gross interval of the Khatatba Formation ranges from near zero to over 1,500 ft averaging 1,000 ft. The Khatatba Shale has an organic content averaging 4% and a thermal maturity of R_o 1.0% to 1.3%, placing the shale in the wet gas/condensate window. Core analysis indicates a porosity of about 5.7%.

Resource Assessment. Within the 4,420-mi^2 prospective area of the Shoushan-Matruh Basin, the Khatatba Shale has a resource concentration of 71 Bcf of wet gas and 7.9 million barrels of oil/condensate per mi^2. The risked resource in-place for wet gas in the prospective area is estimated at 151 Tcf, with 30 Tcf as the risked technically recoverable resource, Table XVIII-1. The risked resource in-place for oil/condensate in the prospective area is estimated at 17 billion barrels, with 0.7 billion barrels as the risked, technically recoverable resource, Table XVIII-2.

RECENT ACTIVITY

Much of the past exploration drilling in the Western Desert has targeted the Cretaceous and shallower sediments. Recently, however, Apache has begun to successfully explore the deeper Jurassic sediments, such as the Safa Sandstone in the Faghur Basin of the Western Desert. In 2010, Apache announced that an unidentified shale formation below the East Bahariya Field holds "between 700 million and 2.2 billion barrels of oil". The company stated that, "We have two wells planned to test the idea here later this year."[15] However, no further information is publically available as to activity or results involving the exploration for oil from these shales.

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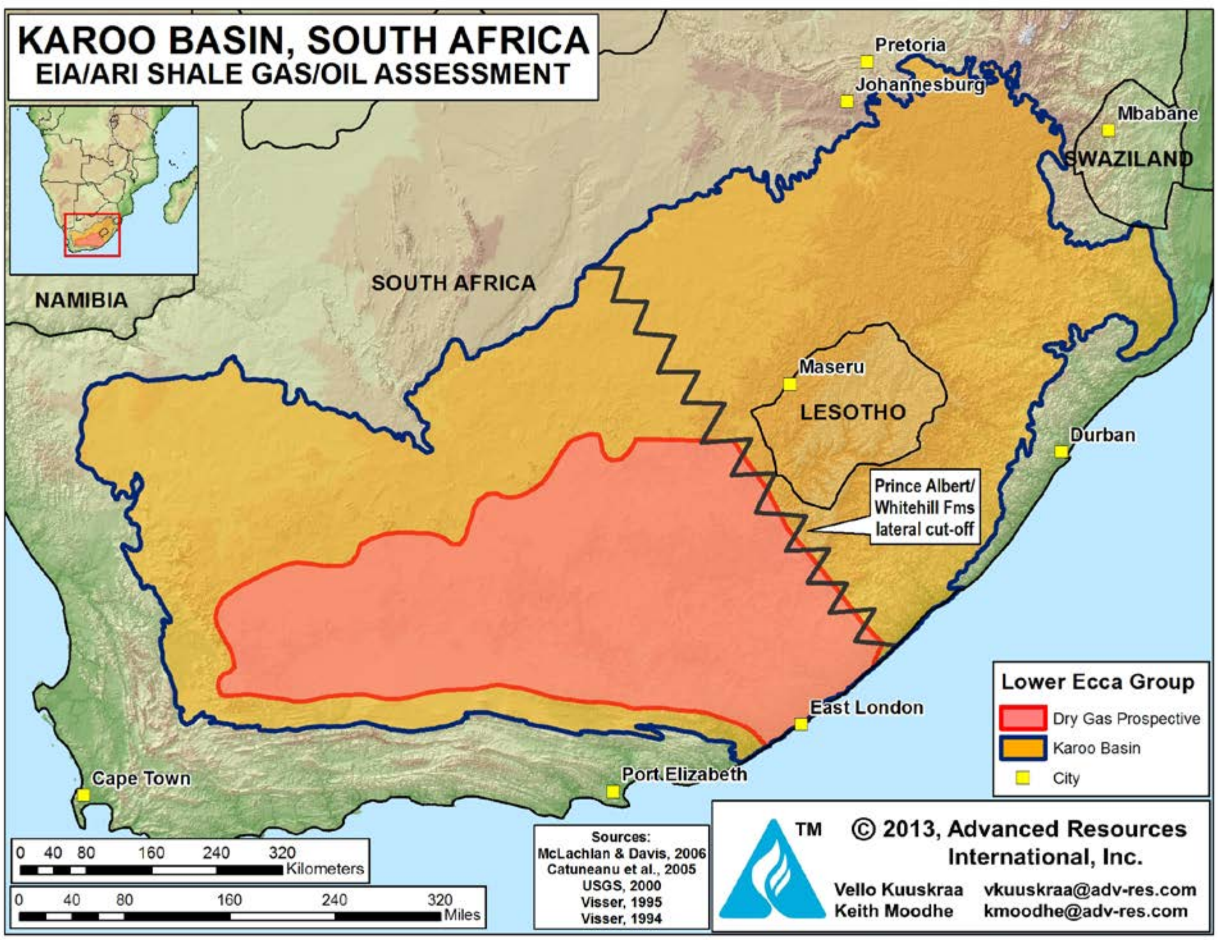
XIX. SOUTH AFRICA

SUMMARY

South Africa has one major sedimentary basin that contains thick, organic-rich shales - - the Karoo Basin in central and southern South Africa, Figure XIX-1.[1,2,3] The Karoo Basin is large (236,400 mi^2), extending across nearly two-thirds of the country, with the southern portion of the basin potentially favorable for shale gas. However, the basin contains significant areas of igneous (sill) intrusions that may impact the quality of the shale resources, limit the use of seismic imaging, and increase the risks of shale exploration.

Figure XIX -1: Outline of Karoo Basin and Prospective Shale Gas Area of South Africa



Source: ARI, 2013.

The Permian-age Ecca Group, with its organic-rich source rocks in the Lower Ecca Formation, is the primary shale formation addressed by this assessment. Of particular interest is the organic-rich, thermally mature black shale unit in the Whitehill Formation of the Lower Ecca. This shale unit is regionally persistent in composition and thickness and can be traced across most of the southern portion of the Karoo Basin.[4]

We estimate that the Lower Permian Ecca Group shales in this basin contain 1,559 Tcf of risked shale gas in-place, with 370 Tcf as the risked, technically recoverable shale gas resource, Table XIX-1. We have excluded the Upper Ecca shales in this basin from quantitative assessment because their TOC content is reported to be below the 2% TOC standard used by this resource assessment study.

Table XIX-1: Shale Gas Reservoir Properties and Resources of the Karoo Basin

Basic Data	Basin/Gross Area		Karoo (236,400 mi^2)		
	Shale Formation		Prince Albert	Whitehill	Collingham
	Geologic Age		L. Permian	L. Permian	L. Permian
	Depositional Environment		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		60,180	60,180	60,180
	Thickness (ft)	Organically Rich	400	200	200
		Net	120	100	80
	Depth (ft)	Interval	6,000 - 10,500	5,500 - 10,000	5,200 - 9,700
		Average	8,500	8,000	7,800
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		2.5%	6.0%	4.0%
	Thermal Maturity (% Ro)		3.00%	3.00%	3.00%
	Clay Content		Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		42.7	58.5	36.3
	Risked GIP (Tcf)		385.3	845.4	327.9
	Risked Recoverable (Tcf)		96.3	211.3	82.0

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INTRODUCTION

South Africa is a net natural gas importer, primarily from neighboring Mozambique and Namibia. As such, South Africa has given priority to exploration for domestic gas and oil. Shale exploration is initiated via a Technical Cooperation Permit (TCP), which may lead to an Exploration Permit (EP) and eventually to a production contract. The country has a corporation tax of 28% and royalty of 7%, terms that are favorable for gas and oil development.

A number of major and independent companies have signed Technical Cooperation Permits (TCPs) to pursue shale gas in the Karoo Basin, including Royal Dutch Shell, the Falcon Oil & Gas/Chevron joint venture, the Sasol/Chesapeake/Statoil joint venture, Sunset Energy Ltd. of Australia and Anglo Coal of South Africa.

1. KAROO BASIN

1.1 Introduction

The Karoo foreland basin is filled with over 5 km of Carboniferous to Early Jurassic sedimentary strata. The Early Permian-age Ecca Group underlies much of the Karoo Basin, cropping out along the southern and western basin margins, Figure XIX-1. The Ecca Group contains a sequence of organic-rich mudstone, siltstone, sandstone and minor conglomerates.[5]

1.2 Geologic Setting

The larger Ecca Group, encompassing an interval up to 10,000 ft thick in the southern portion of the basin, is further divided into the Upper Ecca (containing the Fort Brown and Waterford Formations) and the Lower Ecca (containing the Prince Albert, Whitehill and Collingham Formations), Figure XIX-2. The three Lower Ecca formations are the subject of this shale resource assessment.

The regional southwest to northeast cross-section illustrates the structure of the Cape Fold Belt of the Ecca Group on the south and the thermal maturity for the Ecca Group on the north, Figure XIX-3.[6]

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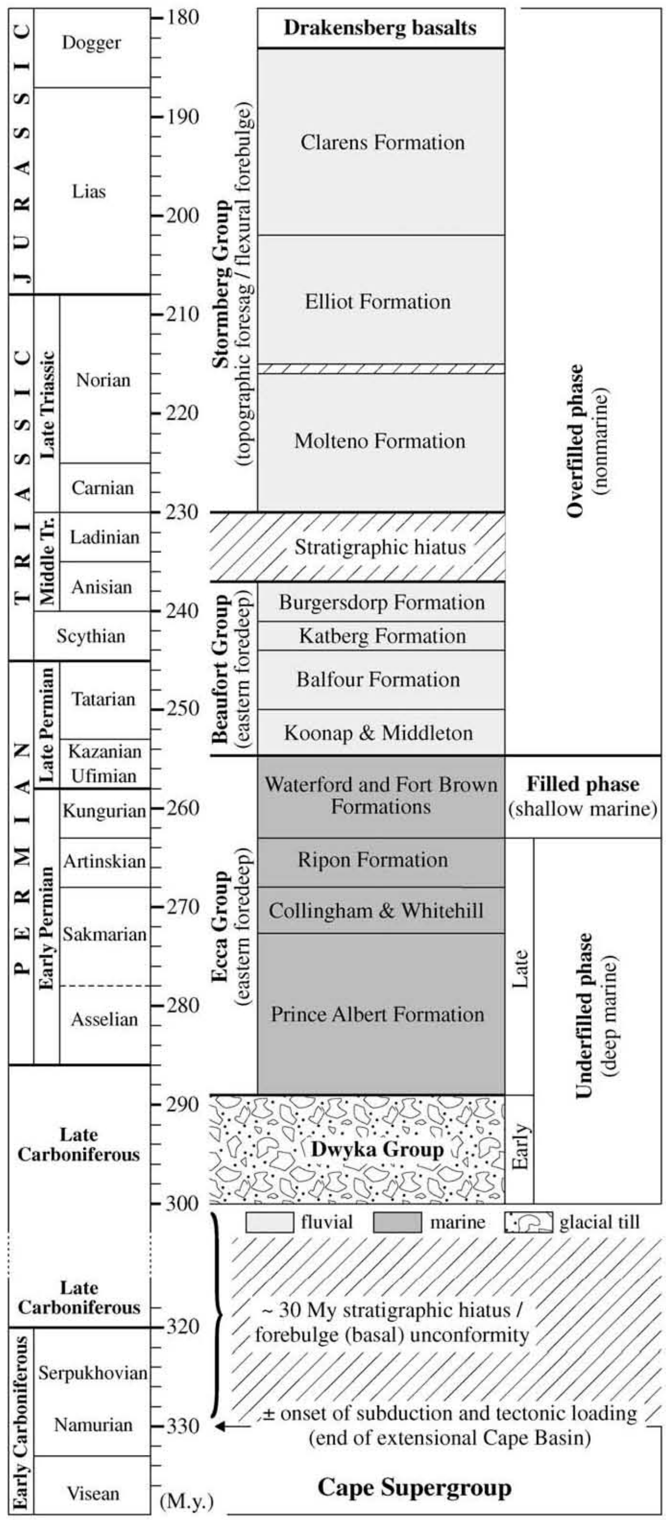
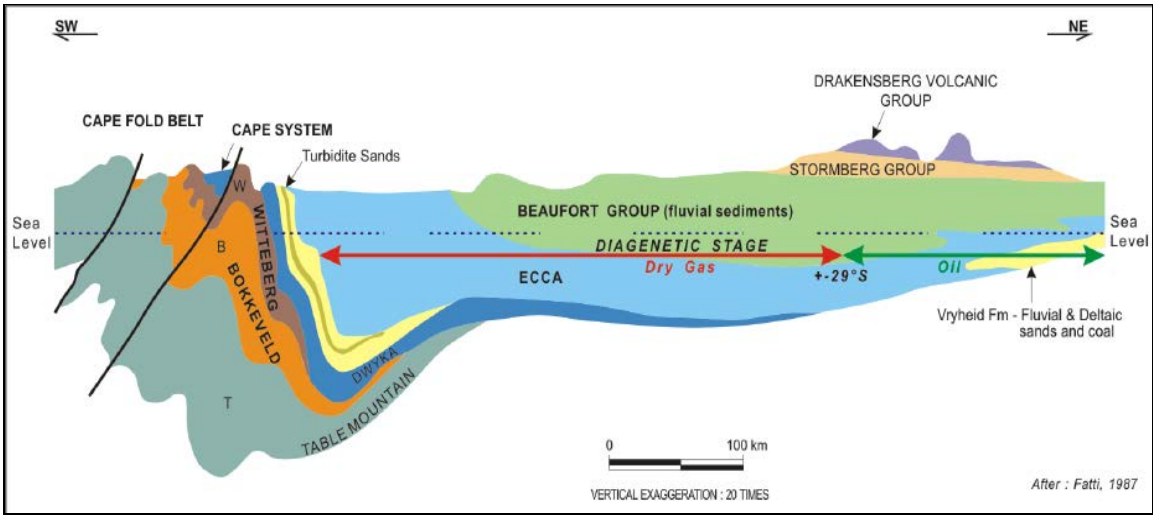
Figure XIX-2. Stratigraphic Column of the Karoo Basin of South Africa



Source: Catuneanu, O. et al., 2005.

Figure XIX-3. Schematic Cross-Section of Southern Karoo Basin and Ecca Group Shales

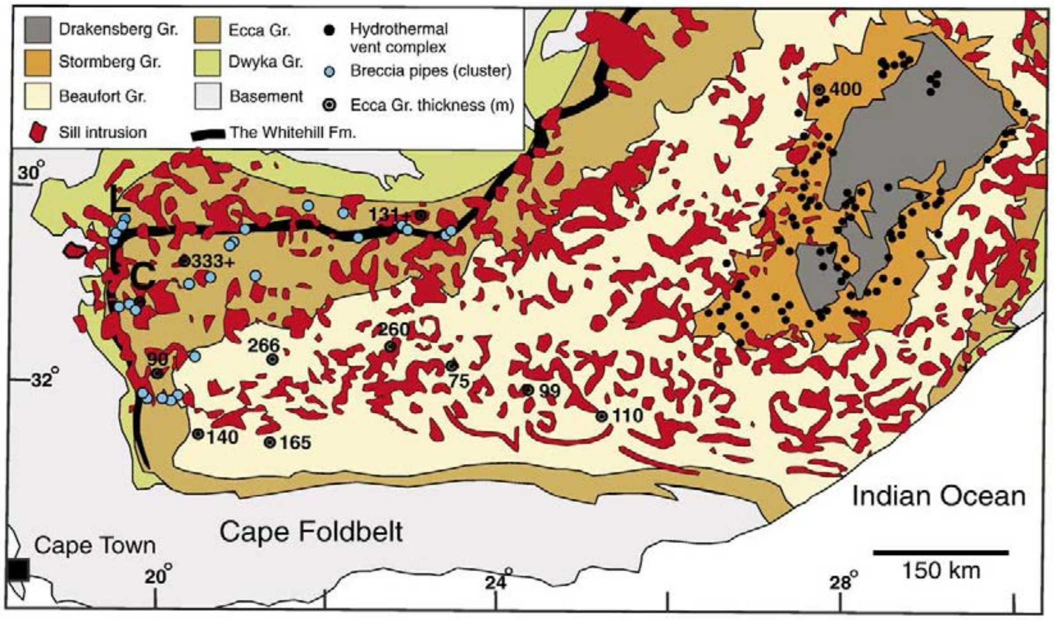


Source: McLachlan, I. and Davis, A., 2006.

Major portions of the Karoo Basin have igneous (sill) intrusions and complex geology, with the most extensive and thickest sills concentrated within the Upper Ecca and Balfour formations.[7] This unusual condition creates significant exploration risk in pursuing the shale resources in the Karoo Basin, Figure XIX-4.[8] (Note that this map reflects the maximum extent of intrusions, which are expected to be less within the target shale formations.) Local mapping indicates that contact metamorphism is restricted to quite close to the intrusions. As such, we removed 15% of the prospective area to account for the potential impact of igneous intrusions and significantly risked the remaining resource.

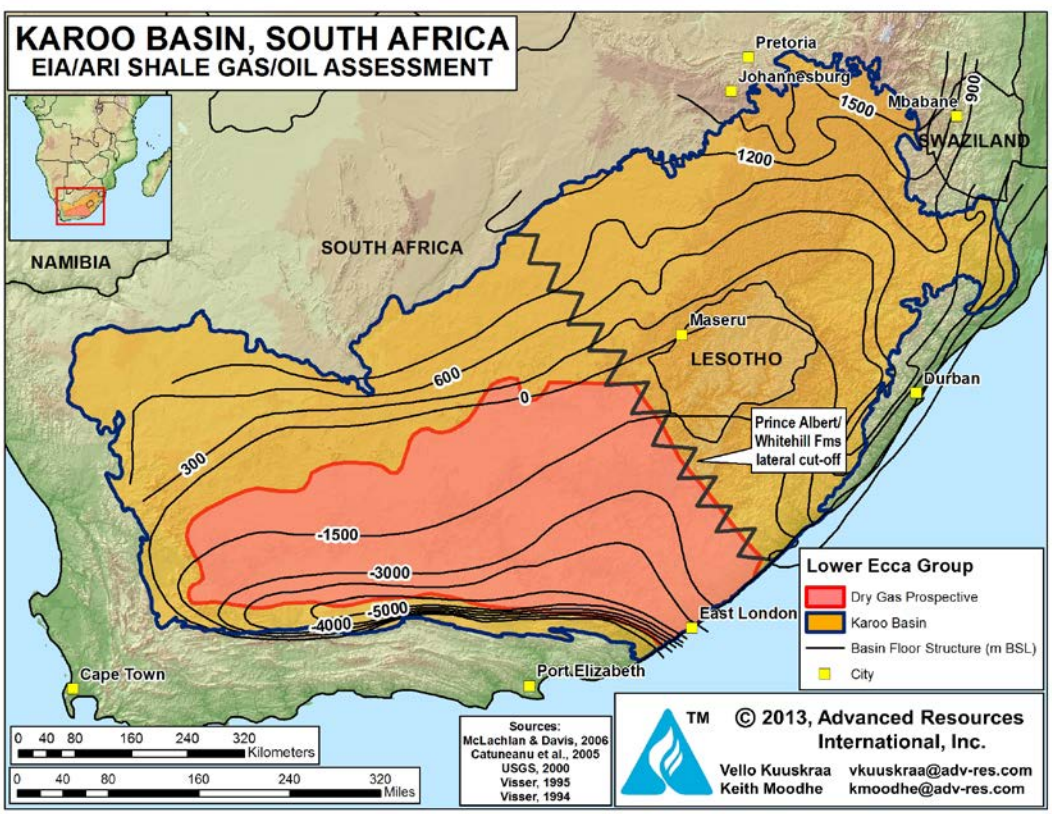
The prospective area for the Lower Ecca Group shales is estimated at 60,180 mi^2, Figure XIX-5. The boundaries of the prospective area are defined by the outcrop of the Upper Ecca Group on the east, south and west/northwest and the pinch-out of the Lower Ecca Group shales on the northeast, Figure XIX-1. The dry gas window is south of the approximately 29^o latitude line. Given the thermal maturity information and the depositional limits of the Lower Ecca shales, the prospective area of the Lower Ecca shales is primarily in the dry gas window.

Figure XIX-4. Igneous Intrusions in the Karoo Basin, South Africa



Source: Svensen, H. et al., 2007.

Figure XIX-5. Lower Ecca Group Structure Map, Karoo Basin, South Africa



Source: ARI, 2013.

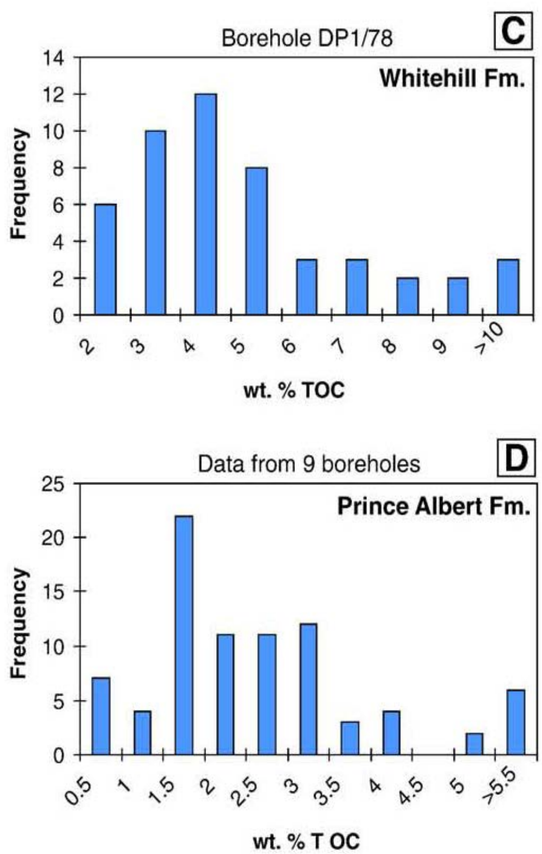
1.2 Reservoir Properties (Prospective Area)

Lower Ecca Shales. The Lower Ecca shales include the thick basal Prince Albert Formation, overlain by the thinner Whitehill and Collingham Formations. Each of these sedimentary units has been individually assessed and is discussed below.

Prince Albert Shale. The Lower Permian Prince Albert Formation has a thick, thermally mature area for shale gas in the Karoo Basin. Depth to the Prince Albert Shale ranges from 6,000 to over 10,000 ft, averaging about 8,500 ft in the deeper prospective area in the south. The Prince Albert Shale has a gross thickness that ranges from 200 to 800 ft, averaging 400 ft, with a net organic-rich thickness of about 120 ft.

The total organic content (TOC) of the Prince Albert Shale within its organic-rich net pay interval ranges from 1.5 to 5.5%, averaging 2.5%, Figure XIX-6.[8] Local TOC values of up to 12% have been recorded.[9] However, in areas near igneous intrusions much of the organic content may have been lost or converted to graphite.

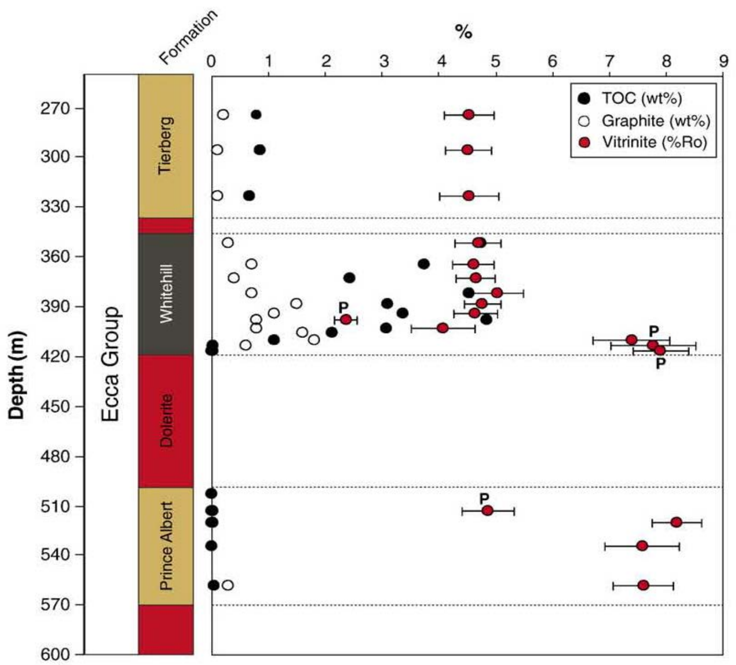
Figure XIX-6. Total Organic Content of Prince Albert and Whitehill Formations



Source: Svensen, H. et al., 2007.

Because of the presence of igneous intrusions, the thermal maturity of the Prince Albert Shale is high, estimated at 2% to 4% R_o, placing the shale well into the dry gas window. In areas near igneous intrusions, the formation is over-mature, with vitrinite reflectance (R_o) values reaching 8%, indicating that the organic content has been transformed into graphite and CO_2, Figure XIX-7. The Prince Albert Shale was deposited as a deep marine sediment and is inferred to have mineralogy favorable for shale formation stimulation.

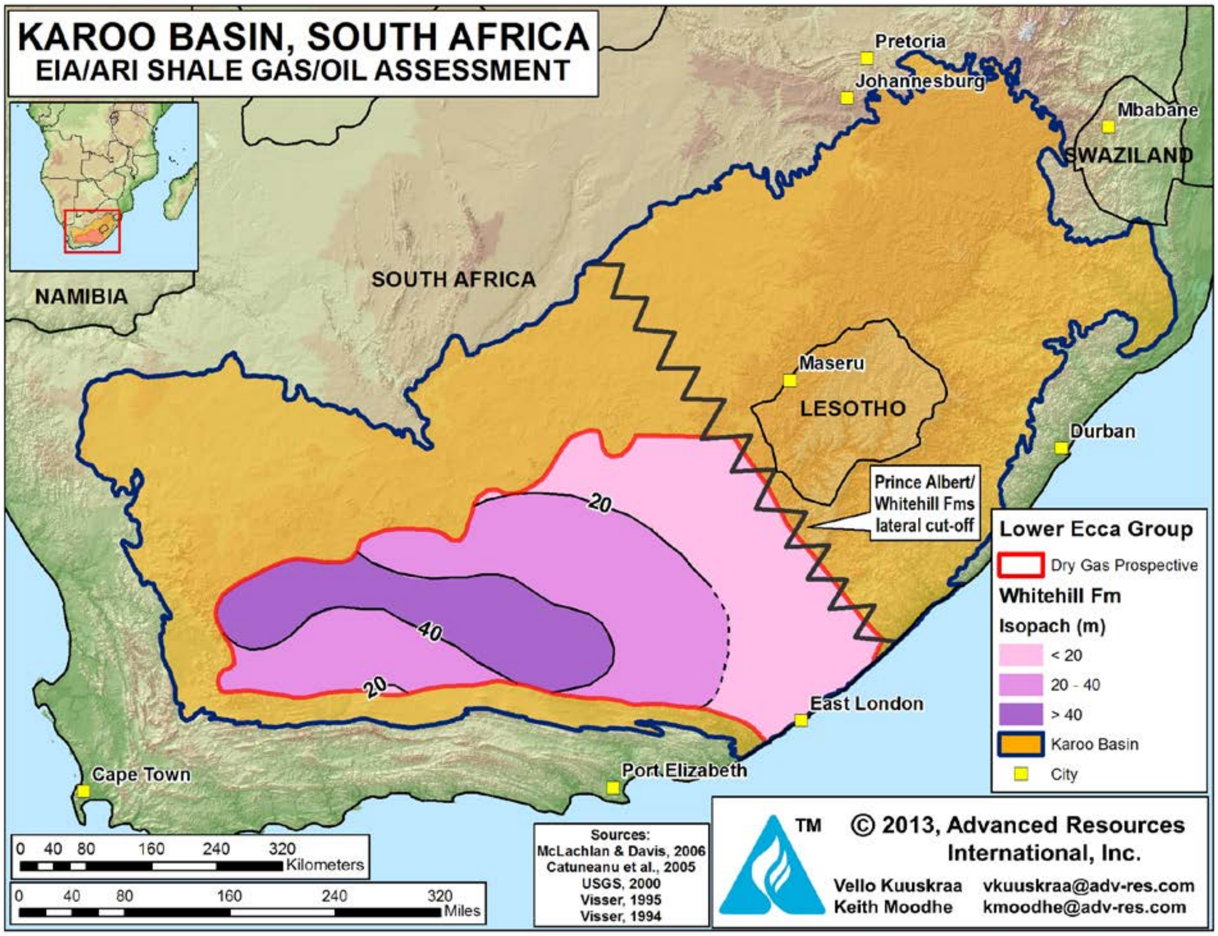
Figure XIX-7. Carbon Loss in Lower Ecca Group Metamorphic Shale



Based on limited well data, primarily from the Cranemere CR 1/68 well completed in the Upper Ecca interval, the Prince Albert Shale appears to be overpressured and has a high thermal gradient.

Whitehill Shale. The organic-rich Lower Permian Whitehill Formation contains one of the main shale gas targets in the Karoo Basin of South Africa. The depth to the Whitehill Shale ranges from 5,500 to 10,000 ft, averaging 8,000 ft in the prospective area. The Whitehill Shale has an estimated gross organic thickness of 100 to 300 ft,[10] with an average net thickness of 100 ft within the prospective area, as shown by the isopach map on Figure XIX-8.[11]

Figure XIX-8. Isopach Map of the Whitehill Formation



Source: ARI, 2013.

The total organic content (TOC) for the Whitehill Shale in the prospective area ranges from 3% to 14%, averaging 6%. Local areas have TOC contents up to 15%.[4] In areas near igneous intrusions, portions of the organic content may have been converted to graphite. The main minerals in the Whitehill Formation are quartz, pyrite, calcite and chlorite, making the shale favorable for hydraulic stimulation. The Whitehill Shale is assumed to be overpressured. The thermal maturity (R_o) of the Whitehill Shale in the prospective area ranges from 2% to 4%, placing the shale into the dry gas window.

The hydrogen and oxygen indexes of the Whitehill Formation indicate a mixture of Type I and Type II kerogen.[9] The Whitehill Shales was deposited in deep marine, anoxic setting and contains minor sandy interbeds from distal turbidites and storm deposits.[12,13]

Collingham Shale. The Lower Permian Collingham Formation (often grouped with the Whitehill Formation) contains the third shale formation addressed by this resource study. The Collingham Formation has an upward transition from deep-water submarine to shallow-water deltaic deposits.[9] The depth to the Collingham Shale averages 7,800 ft within the prospective area. Except for total organic content, the shale has reservoir properties similar to the Whitehill Shale. It has an estimated gross organic thickness of 200 ft, a net thickness of 80 ft, and TOC of 2% to 8%, averaging 4%. Thermal maturity is high, estimated at 3% R_o, influenced by igneous intrusions. The shale is assumed to be overpressured based on data from the Upper Ecca Group.

Upper Ecca Shales. The Upper Ecca Formation extends over a particularly thick, 1,500 m (~5,000 ft) vertical interval in the central and northern Karoo Basin. The Upper Ecca contains two shale sequences of interest - - the Waterford and the Fort Brown. The Fort Brown Formation accounts for the great bulk of the vertical interval of the Upper Ecca. These shales are interpreted by some investigators to have been deposited in a shallow marine environment,[2] although others categorize them as lacustrine.[14]

The organic content and thermal maturity of the Upper Ecca shales are considerably less than for the Lower Ecca shales. The total organic content (TOC) is reported to range from about 1% to 2%. With a thermal maturity ranging from 0.9% to 1.1% R_o, the Upper Ecca shales area is in the oil to wet gas window.[15]

In the materials below, we provide a qualitative description for the Upper Ecca shales. However, because their average TOC is below the 2% criterion set for the study, these shales have been excluded from our quantitative assessment.

The boundaries of the prospective area for the Upper Ecca shales are defined by the outcrop of the Upper Ecca on the east, south and west and the shallowing of the Lower Ecca shales on the northeast. The shale oil window is north of the approximately 29^o latitude line. A significant basalt intrusion area of about 10,000 mi^2 in the center of the prospective area has been excluded. Major portions of the prospective area have igneous intrusions that have locally destroyed portions of the organics, creating significant exploration risk.

Fort Brown Shale. The Fort Brown Shale, as described in the Cranemere CR 1/68 well, is a dark gray to black shale with occasional siltstone stringers. In this well, the Fort Brown Shale exists over a gross interval of nearly 5,000 ft (1,500 m) from 7,012-11,997 ft. Sunset

Energy, the current permit holder in the area surrounding the Cranemere CR 1/68 well, reports that 24-hour DST testing in one interval of the Fort Brown shale, from 8,154-8,312 ft, had a flow rate of 1.84 MMcfd. The well is reported to have blown out at a depth of about 8,300 ft (2,500 m), requiring 10.5 pound per gallon mud to bring the well under control.

The prospective area for the Upper Ecca Fort Brown Shale is estimated at 31,700 mi^2. The Fort Brown Shale in the prospective area has an average depth of 6,000 ft and ranges from 3,000 to 9,000 ft. The shale has an estimated 600 ft of net organic rich thickness, based on using a net to gross ratio of 20% and an average gross thickness of 3,000 ft. The shale has a total organic content (TOC) that ranges from 1 to 2% and an estimated average thermal maturity of 1.1% R_o (based on limited data).

Waterford Shale. The prospective area for the Upper Ecca Waterford Shale is estimated at 20,800 mi^2. The Waterford Shale in the prospective area has an average depth of 4,500 ft, ranging from 3,000 to 6,000 ft. The shale has an estimated 100 ft of net organic rich thickness within an average gross thickness of 500 ft. Total organic content ranges from 1 to 2%, with average thermal maturity, based on very limited data, of 0.9% R_o.

1.3 Resource Assessment

Prince Albert Shale. Within its 60,180-mi^2 dry gas prospective area, the Prince Albert Shale has a resource concentration of about 43 Bcf/mi^2. Given limited exploration data, the risked shale gas in-place is estimated at 385 Tcf. Based on favorable TOC and reservoir mineralogy, balanced by complex geology and volcanic intrusions in the prospective area, ARI estimates a risked, technically recoverable shale gas resource of 77 Tcf for the Prince Albert Shale in the Karoo Basin.

Whitehill Shale. Within its 60,180-mi^2 dry gas prospective area, the Whitehill Shale has a resource concentration of about 59 Bcf/mi^2. While somewhat more defined than the Prince Albert Shale, the exploration risk for the Whitehill Shale is still substantial, leading to a risked shale gas in-place of 845 Tcf. Based on favorable reservoir mineralogy but complex geology, ARI estimates a risked, technically recoverable shale gas resource of 211 Tcf for the Whitehill Shale in the Karoo Basin.

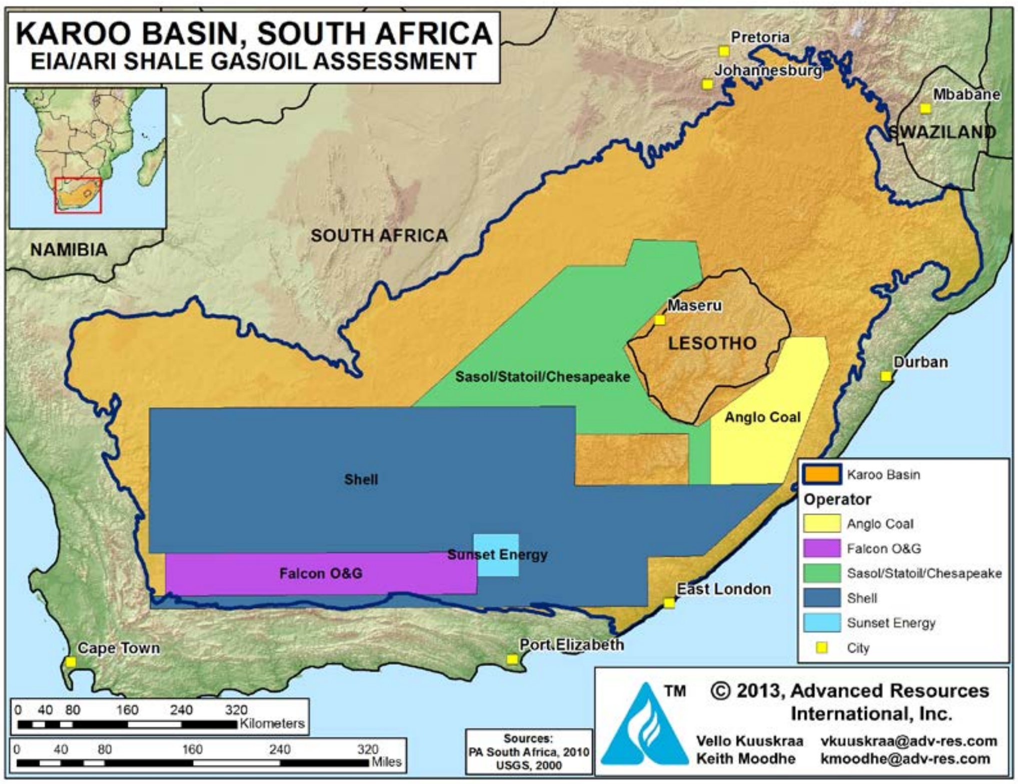
Collingham Shale. With a prospective area of 60,180 mi^2 and with a resource concentration of 36 Bcf/mi^2, the risked gas in-place for the Collingham Shale is estimated at 328 Tcf, with a risked, technically recoverable shale gas resource of 82 Tcf.

Considerable uncertainty surrounds the characterization and assessment of the shale oil resources of South Africa, particularly for the net organic-rich thickness and the vertical and areal distribution of thermal maturity. Shale exploration is just starting in the Karoo Basin and few data points exist, particularly for the Upper Ecca group of formations.

1.4 Recent Activity

Falcon Oil & Gas Ltd., an early entrant into the shale gas play of South Africa, obtained an 11,600-mi^2 TCP along the southern edge of the Karoo Basin. Shell obtained a larger 71,400-mi^2 TCP surrounding the Falcon area. Sunset Energy holds a 1,780-mi^2 TCP to the west of Falcon. The Sasol/Chesapeake/Statoil JV TCP area of 34,000 mi^2 and the Anglo Coal TCP application area of 19,300 mi^2 are to the north and east of Shell's TPC, Figure XIX-9. [16]

Figure XIX-9. Map Showing Operator Permits in the Karoo Basin, South Africa



Source: ARI, 2013.

Recently, Chevron announced that it would partner with Falcon Oil & Gas to pursue the shale resources of the Karoo Basin, starting with seismic studies.[17]

Five older (pre-1970) wells have penetrated the Ecca Shale interval. Each of the wells had gas shows, while one of the wells - - the Cranemere CR 1/68 well - - flowed 1.84 MMcfd from a test zone at 8,154 to 8,312 ft. The gas production, considered to be from fractured shale, depleted relatively rapidly during the 24-hour test. The CR 1/68 well was drilled to 15,282 ft into the underlying Table Mountain quartzite and had gas shows from six intervals, starting at 6,700 ft and ending at 14,650 ft, indicating that the shales in this area are gas saturated.

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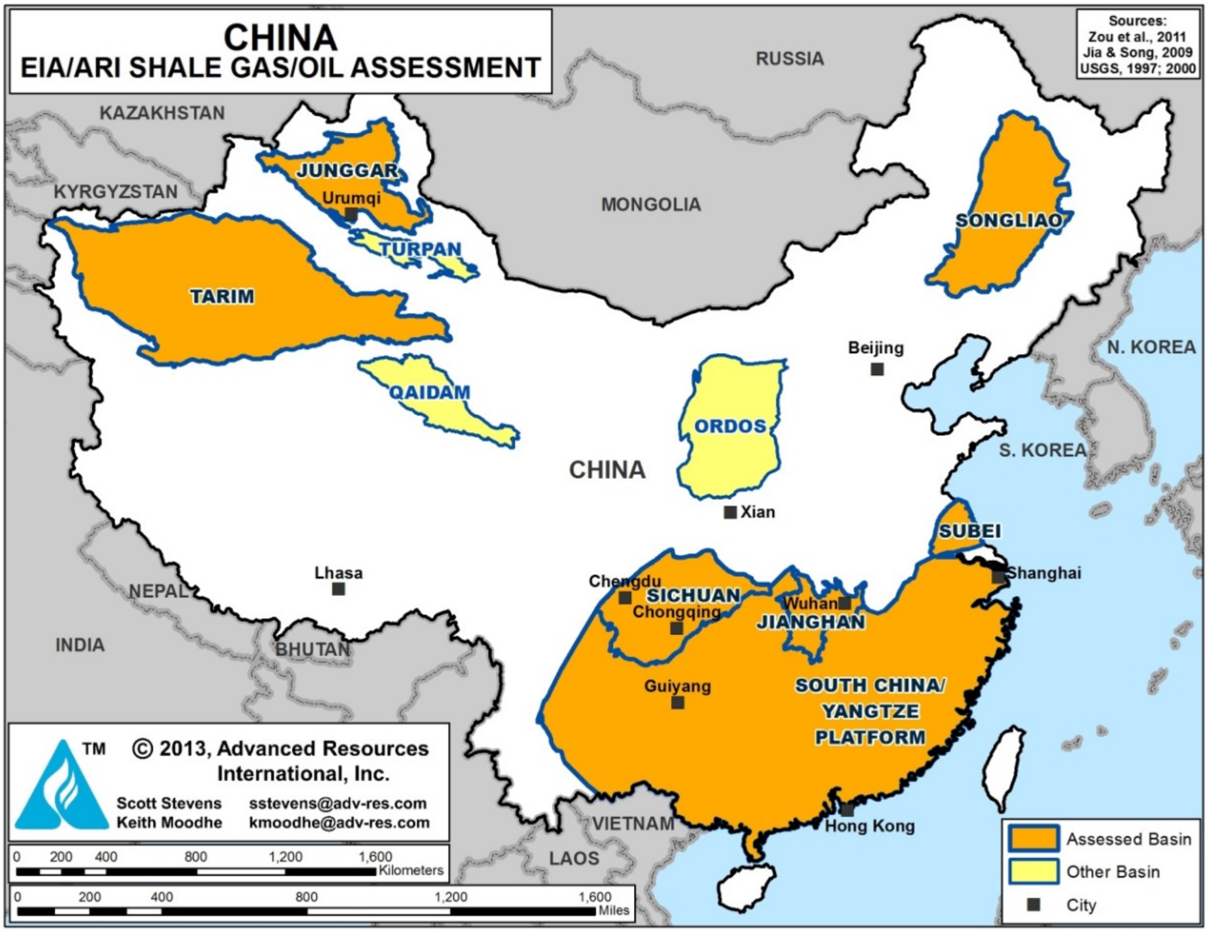
XX. CHINA

SUMMARY

China has abundant shale gas and shale oil potential in seven prospective basins: Sichuan, Tarim, Junggar, Songliao, the Yangtze Platform, Jianghan and Subei, Figure XX-1.

Figure XX-1. China's Seven Most Prospective Shale Gas and Shale Oil Basins are the Jianghan, Junggar, Sichuan, Songliao, Subei, Tarim, and Yangtze Platform.



Source: ARI, 2013.

China has an estimated 1,115 Tcf of risked, technically recoverable shale gas, mainly in marine- and lacustrine-deposited source rock shales of the Sichuan (626 Tcf), Tarim (216 Tcf), Junggar (36 Tcf), and Songliao (16 Tcf) basins. Additional risked, technically recoverable shale gas resources totaling 222 Tcf exist in the smaller, structurally more complex Yangtze Platform, Jianghan and Subei basins. The risked shale gas in-place for China is estimated at 4,746 Tcf, tables XX-1A through XX-1E.

China's also has considerable shale oil potential which is geologically less defined. Risked, technically recoverable shale oil resources in the Junggar, Tarim, and Songliao basins are estimated at 32.2 billion barrels, out of 643 billion barrels of risked, prospective shale oil in place), Table XX-2A through XX-2C. However, China's shale oil resources tend to be waxy and are stored mostly in lacustrine-deposited shales, which may be clay-rich and less favorable for hydraulic stimulation.

The shale gas and shale oil resource assessment for China represents a major upgrade from our prior year 2011 EIA/ARI shale gas assessment. Importantly, this update assessment incorporates a significant new information from ARI's proprietary data base of geologic data extracted from about 600 published technical articles (mostly Chinese language) as well as recent drilling data.

Shale gas leasing and exploration drilling already are underway in China, focused in the Sichuan Basin and Yangtze Platform areas and led by PetroChina, Sinopec, and Shell and the government has set an ambitious but probably unachievable target for shale gas production of 5.8 to 9.7 Bcfd by 2020.

Table XX-1A. China Shale Gas Resources and Geologic Properties.

			Sichuan (74,500 mi²)			Yangtze Platform (611,000 mi²)	
Basic Data	Basin/Gross Area		Sichuan (74,500 mi²)			Yangtze Platform (611,000 mi²)	
	Shale Formation		Qiongzhusi	Longmaxi	Permian	L. Cambrian	L. Silurian
	Geologic Age		L. Cambrian	L. Silurian	Permian	L. Cambrian	L. Silurian
	Depositional Environment		Marine	Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		6,500	10,070	20,900	3,250	5,035
	Thickness (ft)	Organically Rich	500	1,000	314	500	1,000
		Net	275	400	251	275	400
	Depth (ft)	Interval	10,000 - 16,400	9,000 - 15,500	3,280 - 16,400	10,000 - 16,400	9,000 - 15,500
		Average	13,200	11,500	9,700	13,200	11,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Normal	Normal
	Average TOC (wt. %)		3.0%	3.2%	4.0%	3.0%	3.2%
	Thermal Maturity (% Ro)		3.20%	2.90%	2.50%	3.20%	2.90%
	Clay Content		Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		109.8	162.6	114.1	99.4	147.1
	Risked GIP (Tcf)		499.6	1,146.1	715.2	181.0	414.7
	Risked Recoverable (Tcf)		124.9	286.5	214.5	45.2	103.7

Table XX-1B. China Shale Gas Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Jianghan (14,440 mi²)					
	Shale Formation		Niutitang/Shuijintuo	Longmaxi		Qixia/Maokou		
	Geologic Age		L. Cambrian	L. Silurian		Permian		
	Depositional Environment		Marine	Marine		Marine		
Physical Extent	Prospective Area (mi^2)		1,280	670	1,230	650	1,100	2,080
	Thickness (ft)	Organically Rich	533	394	394	700	700	700
		Net	267	197	197	175	175	175
	Depth (ft)	Interval	9,840 - 16,400	8,200 - 12,000	10,000 - 14,760	3,300 - 7,000	7,000 - 10,000	10,000 - 13,120
		Average	13,120	10,000	12,380	5,500	8,500	11,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		6.6%	2.0%	2.0%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		2.25%	1.15%	2.00%	0.85%	1.15%	1.80%
	Clay Content		Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		148.9	51.0	67.1	14.1	48.3	66.6
	Risked GIP (Tcf)		45.7	8.2	19.8	1.8	10.6	27.7
	Risked Recoverable (Tcf)		11.4	1.6	4.9	0.2	2.7	6.9

Table XX-1C. China Shale Gas Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Greater Subei (55,000 mi^2)				
	Shale Formation		Mufushan	Wufeng/Gaobiajian		U. Permian	
	Geologic Age		L. Cambrian	U. Ordovician-L. Silurian		U. Permian	
	Depositional Environment		Marine	Marine		Marine	
Physical Extent	Prospective Area (mi^2)		2,040	5,370	9,620	1,350	290
	Thickness (ft)	Organically Rich	400	820	820	500	500
		Net	300	246	246	150	150
	Depth (ft)	Interval	13,000 - 16,400	11,500 - 13,500	13,500 - 16,400	3,300 - 8,200	8,000 - 1,000
		Average	14,700	12,500	14,500	5,800	9,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.1%	1.1%	1.1%	2.0%	2.0%
	Thermal Maturity (% Ro)		1.20%	1.15%	1.45%	1.15%	1.35%
	Clay Content		Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		118.6	66.0	87.8	35.8	55.4
	Risked GIP (Tcf)		29.0	42.5	101.4	5.8	1.9
	Risked Recoverable (Tcf)		7.3	10.6	25.4	1.5	0.5

Table XX-1D. China Shale Gas Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Tarim (234,200 mi^2)				
	Shale Formation		L. Cambrian	L. Ordovician	M.-U. Ordovician		Ketuer
	Geologic Age		L. Cambrian	L. Ordovician	M.-U. Ordovician		L. Triassic
	Depositional Environment		Marine	Marine	Marine		Lacustrine
Physical Extent	Prospective Area (mi^2)		6,520	19,420	10,450	10,930	15,920
	Thickness (ft)	Organically Rich	380	300	300	390	400
		Net	240	170	160	240	200
	Depth (ft)	Interval	11,000 - 16,400	10,000 - 16,400	8,610 - 12,670	9,840 - 16,400	9,500 - 16,400
		Average	14,620	13,690	10,790	12,180	13,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.4%	2.1%	2.5%	3.0%
	Thermal Maturity (% Ro)		2.0%	1.80%	0.90%	2.00%	0.90%
	Clay Content		Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Assoc. Gas	Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		77.1	59.8	12.6	85.0	40.5
	Risked GIP (Tcf)		175.9	377.5	32.8	232.3	161.2
	Risked Recoverable (Tcf)		44.0	94.4	3.3	58.1	16.1

Table XX-1E. China Shale Gas Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Junggar (62,100 mi²)		Songliao (108,000 mi²)
	Shale Formation		Pingdiquan/Lucaogou	Triassic	Qingshankou
	Geologic Age		Permian	Triassic	Cretaceous
	Depositional Environment		Lacustrine	Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi²)		7,400	8,600	6,900
	Thickness (ft)	Organically Rich	820	820	1,000
		Net	410	410	500
	Depth (ft)	Interval	6,600 - 16,400	5,000 - 16,400	3,300 - 8,200
		Average	11,500	10,000	5,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		0.85%	0.85%	0.90%
	Clay Content		Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Assoc. Gas
	GIP Concentration (Bcf/mi²)		64.7	60.5	45.0
	Risked GIP (Tcf)		172.4	187.5	155.4
	Risked Recoverable (Tcf)		17.2	18.7	15.5

Table XX-2A. China Shale Oil Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Jianghan (14,440 mi²)			Greater Subei (55,000 mi²)	
	Shale Formation		Longmaxi	Qixia/Maokou		Wufeng/Gaobiajian	U. Permian
	Geologic Age		L. Silurian	Permian		U. Ordovician-L. Silurian	U. Permian
	Depositional Environment		Marine	Marine		Marine	Marine
Physical Extent	Prospective Area (mi²)		670	650	1,100	5,370	1,350
	Thickness (ft)	Organically Rich	394	700	700	820	500
		Net	197	175	175	246	150
	Depth (ft)	Interval	8,200 - 12,000	3,300 - 7,000	7,000 - 10,000	11,500 - 13,500	3,300 - 8,200
		Average	10,000	5,500	8,500	12,500	5,800
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	1.1%	2.0%
	Thermal Maturity (% Ro)		1.15%	0.85%	1.15%	1.15%	1.15%
	Clay Content		Low	Low	Low	Low	Low
Resource	Oil Phase		Condensate	Oil	Condensate	Condensate	Condensate
	OIP Concentration (MMbbl/mi²)		5.0	28.5	5.7	7.0	6.2
	Risked OIP (B bbl)		0.8	3.7	1.3	4.5	1.0
	Risked Recoverable (B bbl)		0.04	0.18	0.06	0.23	0.05

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Table XX-2B. China Shale Oil Resources and Geologic Properties.

			Tarim (234,200 mi^2)		Junggar (62,100 mi^2)		Songliao (108,000 mi^2)
Basic Data	Basin/Gross Area		Tarim (234,200 mi^2)		Junggar (62,100 mi^2)		Songliao (108,000 mi^2)
	Shale Formation		M.-U. Ordovician	Ketuer	Pingdiquan/Lucaogou	Triassic	Qingshankou
	Geologic Age		M.-U. Ordovician	L. Triassic	Permian	Triassic	Cretaceous
	Depositional Environment		Marine	Lacustrine	Lacustrine	Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		10,450	15,920	7,400	8,600	6,900
	Thickness (ft)	Organically Rich	300	400	820	820	1,000
		Net	160	200	410	410	500
	Depth (ft)	Interval	8,610 - 12,670	9,500 - 16,400	6,600 - 16,400	5,000 - 16,400	3,300 - 8,200
		Average	10,790	13,000	11,500	10,000	5,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Highly Overpress.	Highly Overpress.	Mod. Overpress.
	Average TOC (wt. %)		2.1%	3.0%	5.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		0.90%	0.90%	0.85%	0.85%	0.90%
	Clay Content		Low	Low	Medium	Medium	Medium
Resource	Oil Phase		Oil	Oil	Oil	Oil	Oil
	OIP Concentration (MMbbl/mi^2)		11.9	32.5	40.9	43.3	66.4
	Risked OIP (B bbl)		31.1	129.5	108.9	134.1	229.2
	Risked Recoverable (B bbl)		1.55	6.47	5.44	6.70	11.46

Initial drilling confirms China's shale gas and oil resource potential, but rapid commercialization may be challenging due to the typically complex geologic structure (faulting, high tectonic stress), restricted access to geologic data, and the high cost and rudimentary state of in-country horizontal drilling and fracturing services.

1. **South China "Shale Corridor": Sichuan, Jianghan, Subei Basins** and **Yangtze Platform**. These areas have classic marine-deposited, quartz-rich, black shales of Cambrian and Silurian age that are roughly comparable to North American analogs. The Sichuan Basin -- China's premier shale gas area -- has existing gas pipelines, abundant surface water supplies, and close proximity to major cities. Current exploration is focusing on the southwest quadrant of the basin, which is relatively less faulted and low in H_2S. The adjacent Yangtze Platform and the Jianghan and Subei basins are structurally complex with poor data control, but also located close to major cities centers and still considered prospective.

   Shale targets in the southwestern portion of the Sichuan Basin are brittle and dry-gas mature, but lower in TOC (~2%) than North American shales and furthermore still quite faulted. PetroChina's first horizontal shale well required 11 months to drill (vs 2 weeks in North America). The induced fractures grew planar due to high stress and this well produced a disappointing initial rate of 560 Mcfd. Shell tested 2.1 million ft^3/day from a vertical well, but noted hole instability and out-of-zone deviation while drilling horizontally nearby. Sinopec, BP, Chevron, ConocoPhillips, Statoil, TOTAL and others also have expressed interest in the region. Assuming its significant geologic and operational issues can be solved, the Sichuan may become China's premier shale gas basin, capable of providing several Bcfd of supply within 20 years.

2. The **Tarim Basin** has relatively deep shale gas potential in marine-deposited black shales of Cambrian and Ordovician age that are rich in carbonate and often graptolitic. No shale leasing or drilling have been reported, probably because of this basin's remoteness and extreme depth of the shale. Structure is relatively simple but the shales are mostly too deep, reaching prospective depth only on uplifts where TOC unfortunately tends to be low (1-2%). Nitrogen contamination (~20%) and karstic collapse structures also are issues. Shallower, lower-rank Ordovician shale and Triassic lacustrine mudstone have potential. Horizontal wells already account for half of conventional oil production in the Tarim Basin, providing a good foundation for application in future shale development.

3. **Junggar Basin**, while not the largest shale resource in China, may have its best shale geology. Permian source rocks are extremely thick (average 1,000 ft), rich (4% average TOC; 20% maximum) and over-pressured. Triassic source rocks are leaner but also appear prospective. The structural geology of the basin is favorably simple, while thermal maturity ranges from oil to wet gas within the prospective area. Large, continuous shale oil and wet gas leads were identified. The main risk in the Junggar Basin is the lacustrine rather than marine depositional origin of the shale and the concomitant issues of brittleness and "frack-ability". Shell and Hess are evaluating shale oil prospects in the similar, smaller Santanghu Basin just east of the Junggar Basin.

4. **Songliao Basin**, China's largest oil-producing region, the Songliao has thick Lower Cretaceous source rock shales in the oil to wet gas windows. While these organic-rich shales are lacustrine in origin and unfavorably rich in clay minerals, they have the advantages of being over-pressured and naturally fractured. Prospective shales occur in isolated half-grabens at depths of 300 to 2,500 m but faulting is intense. PetroChina considers the Songliao Basin to be prospective for shale exploration and has already

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noted commercial shale oil production here. Hess and PetroChina have jointly conducted a study of shale/tight oil potential at giant Daqing oil field. Jilin Oilfield has drilled and hydraulically fractured deep horizontal wells into a tight sandstone gas reservoir. Their 1,200-m lateral, 11-stage frac technology could be applied to shale oil reservoirs in the Songliao Basin.

5. **Other Basins.** Several other sedimentary basins in China have shale potential but could not be quantified due to low geologic quality or insufficient data control. The Turpan-Hami Basin, east of the larger Junggar, has equivalent Permian organic-rich shales that are lacustrine in origin, oil- to wet gas-prone, and appear prospective. The Qaidam Basin, southeast of the Tarim, comprises isolated fault-bounded depressions containing Upper Triassic mudstone source rocks with high TOC; these appear oil prone but are very deep. The Ordos Basin has simple structure but its Triassic shales have low TOC and high clay content (80%), while Carboniferous and Permian mudstones are coaly and ductile. No shale drilling has been reported in these less prospective areas.

INTRODUCTION

China has abundant shale gas and shale oil resource potential that is at the early stage of delineation, evaluation, and testing. China's government is prioritizing shale development on legal, technological, and commercial fronts. In December 2011 the State Council approved a petition from the Ministry of Land and Resources' (MLR) to separate the ownership of shale gas from conventional resources, although the ownership of shale oil resources remains unclear. In March 2012 the Twelfth Five-Year Plan for Shale Gas Development envisioned large-scale commercial development of China's shale resources, while fiscal incentives and subsidies to support shale investment are under consideration.

However, the prevailing industry view, which is shared by ARI, is that geologic and industry conditions are considerably less favorable in China than in North America. Numerous challenges seem certain to complicate and slow commercial development compared with North America. In particular, most Chinese shale basins are tectonically complex with numerous faults -- some seismically active -- which is not conducive to shale development. Similar issues have slowed China's production of coalbed methane, a distantly related unconventional gas resource. CBM output is still under 0.5 Bcfd following 20 years of commercial development.

Furthermore, China's service sector is just beginning to acquire the necessary capability for large-scale horizontal drilling combined with massive multi-stage hydraulic stimulation. Only a small number of horizontal shale gas and oil wells have been tested thus far, with generally low but at least meaningful production rates. Significant commercial production appears some years in the future. Considerable work is needed to define the geologic sweet spots, develop the service sector's capacity to effectively and economically drill and stimulate modern horizontal shale wells, and install the extensive surface infrastructure needed to transport product to market.

Industry is cautious regarding China's likely pace of shale gas development. Even in its best area, PetroChina engineers observed: "the Sichuan Basin's considerable structural complexity, with extensive folding and faulting, appears to be a significant risk for shale development."[1] And a BP official recently noted: "It will be a long time before China could commercialize its shale resources in a large way."[2] The National Energy Administration's mean shale gas output target of 7.7 Bcfd by 2020 appears ambitious in this context.

Another issue is data availability. Much of the basic geologic and well data that commonly is publicly available in other countries – and essential for resource and prospect evaluation -- is considered by China to be state secrets. To overcome these data limitations, ARI has drawn on its extensive proprietary China shale geology data base, compiled from approximately 400 technical papers published in Chinese language. Data locations plotted on our China maps provide an indication of geologic control (or lack thereof).

Four main onshore regions assessed by this study have shale gas and oil potential, Figure XX-1. These include:

- South China Shale Corridor (Sichuan, Jianghan, Subei basins and Yangtze Platform).
- The Tarim, Junggar, and Songliao basins in northern China.

Additional basins exist but may lack data control or do not appear to have large shale gas/oil potential (e.g., Ordos, Qaidam, Turpan-Hami).

1. SOUTH CHINA SHALE CORRIDOR : SICHUAN, JIANGHAN, SUBEI BASINS, YANGTZE PLATFORM

1.1 Introduction and Geologic Setting

Organic-rich marine shales, mostly gas-prone to thermally over-mature, underlie a vast area of south-central and eastern China. This “Shale Corridor” comprises the Sichuan Basin and adjoining Yangtze Platform in Sichuan, Yunnan, Guizhou, Hubei, and western Hunan provinces, as well as the smaller Jianghan and Subei basins in southeastern China. Within this broad region, Paleozoic shales in the Sichuan Basin and Yangtze Platform offer some of China’s most prospective shale gas potential. However, while the essential rock quality in this region appears favorable and not dissimilar with certain North American shales (e.g., Marcellus, Barnett), significant exploration challenges still exist. These include locally excessive depth and high thermal maturity and -- most concerning – intense faulting and structural complexity.

The overall sedimentary sequence in the South China Shale Corridor is 6 to 12 km thick and includes multiple organic-rich shales of marine and non-marine origin within Pre-Cambrian, Cambrian, Ordovician, Silurian, Devonian, Permian, Triassic, and Eocene formations. Figure XX-2 illustrates the stratigraphy of the Sichuan Basin and Yangtze Platform, highlighting potentially prospective L. Cambrian, L. Silurian, and U. Permian source rocks.

Paleozoic shales in the South China Shale Corridor -- the most prospective of this sequence and the closest in character to productive North American shales -- typically are thick, carbon- and quartz-rich, of marine depositional origin, and mostly thermally mature within the dry-gas to over-mature windows. In contrast, the Triassic and Eocene shales were deposited primarily within freshwater lacustrine (rather than marine) environments and tend to be clay-rich, probably more ductile, and thus less prospective. Our work -- consistent with published information by PetroChina, Shell, and others -- indicates that the Lower Cambrian, Lower Silurian, and Upper Permian marine shales in the Sichuan Basin, Yangtze Platform, and adjoining regions offer some of China’s best promise for shale gas development.

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Figure XX-2. Stratigraphy of the Sichuan Basin and Yangtze Platform, Highlighting Potentially Prospective L. Cambrian, L. Silurian, and U. Permian Source Rocks.

SICHUAN BASIN

ERA	PERIOD	EPOCH	FORMATION	AGE (Ma)	THICKNESS (m)
CENOZOIC	QUATERNARY			0 - 3	0 - 380
	TERTIARY	Upper		3 - 25	0 - 300
		Lower		25 - 80	0 - 800
MESOZOIC	CRETACEOUS			80 - 140	0 - 2000
	JURASSIC	Upper	Penglaizhen	140 - 195	650 - 1400
		Middle	Suining		340 - 500
			Shaximiao		600 - 2800
		Middle-Lower	**Ziliujing**		200 - 900
	TRIASSIC	Upper	***Xujiahe***	195 - 205	250 - 3000
		Middle	Leikoupo	205 - 230	900 - 1700
		Lower	Jialingjiang		
			Feixianguan		
PALEOZOIC	PERMIAN	Upper	**Changxing**	230 - 270	200 - 500
			Longtan		
		Lower	Maokou		200 - 500
			Qixia-Liangshan		
	CARBONIFEROUS	Mississippian	Huanglong	270 - 320	0 - 500
	SILURIAN	Upper		320 - 570	0 - 1500
		Lower	**Longmaxi**		
	ORDOVICIAN				0 - 600
	CAMBRIAN	Upper	Xixiangchi		0 - 2500
		Middle	Yuxiansi		
		Lower	**Qiongzhusi**		
PROTEROZOIC	SINIAN	Upper	Dengying	570 - 850	200 - 1100
			Doushantuo		
		Lower			0 - 400
	PRE-SINIAN			850	

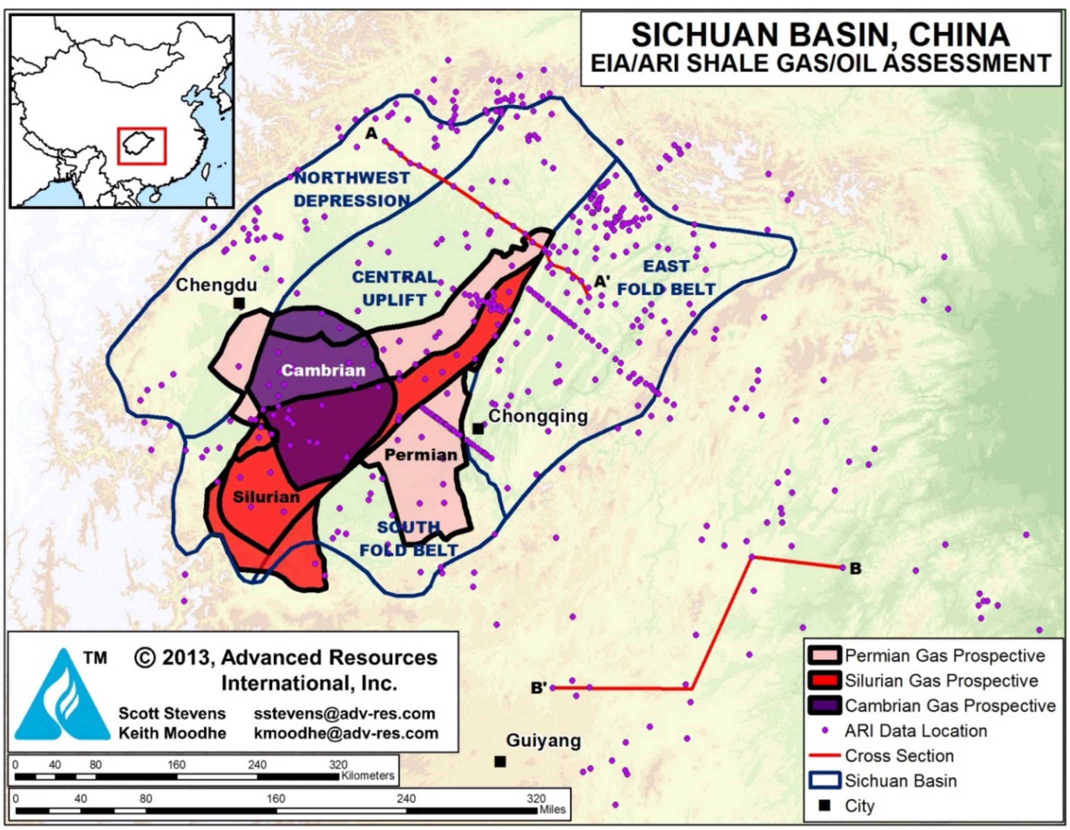
Source Rock ***Conventional Reservoir***

Source: ARI, 2013.

The **Sichuan Basin** covers a large 74,500-mi^2 area in south-central China, while the structurally more complex and sparsely drilled Yangtze Platform covers a larger but discontinuous area to the south and east. The Sichuan Basin currently produces about 1.5 Bcfd of natural gas from conventional and low-permeability sandstones and carbonates. These reservoirs occur mainly in the Triassic Xujiahe and Feixianguan formations, stored in complex structural-stratigraphic traps (mainly faulted anticlines) that are distributed across the basin. A limited volume of oil also is produced from overlying Jurassic sandstones. The conventional oil and gas fields are underlain and were sourced by deeper organic-rich Paleozoic marine shales, the main target of current shale gas exploration. Proterozoic to L. Paleozoic gas fields also have been discovered more recently. Extremely high H_2S concentrations (up to 50%) and CO_2 (up to 18%) occur in sour gas fields such as Puguang in the northeast part of the basin. Levels of these contaminants are much lower in the south but can still be locally significant.[3]

A number of technical journal articles have been published on the Sichuan Basin in both Chinese and English, with the volume and quality of public reports increasing in recent years. ARI extracted a substantial data base on Sichuan Basin source rock shale geology from 47 Chinese and 20 English language technical articles, comprising 23 cross-sections, 714 well/outcrop locations, and 1,462 total samples, Figure XX-3. This data set provides good control of shale thickness, depth, structural geology, thermal maturity, and organic content. We provide selected examples of specific geologic data to illustrate our conclusions. We then mapped and characterized the three distinct Paleozoic shale leads discussed below.

Figure XX-3. Structural Elements of Sichuan Basin and Adjoining Yangtze Platform Showing ARI-Proprietary Shale Data Locations and High-Graded Areas for Cambrian, Silurian, Permian Shales.

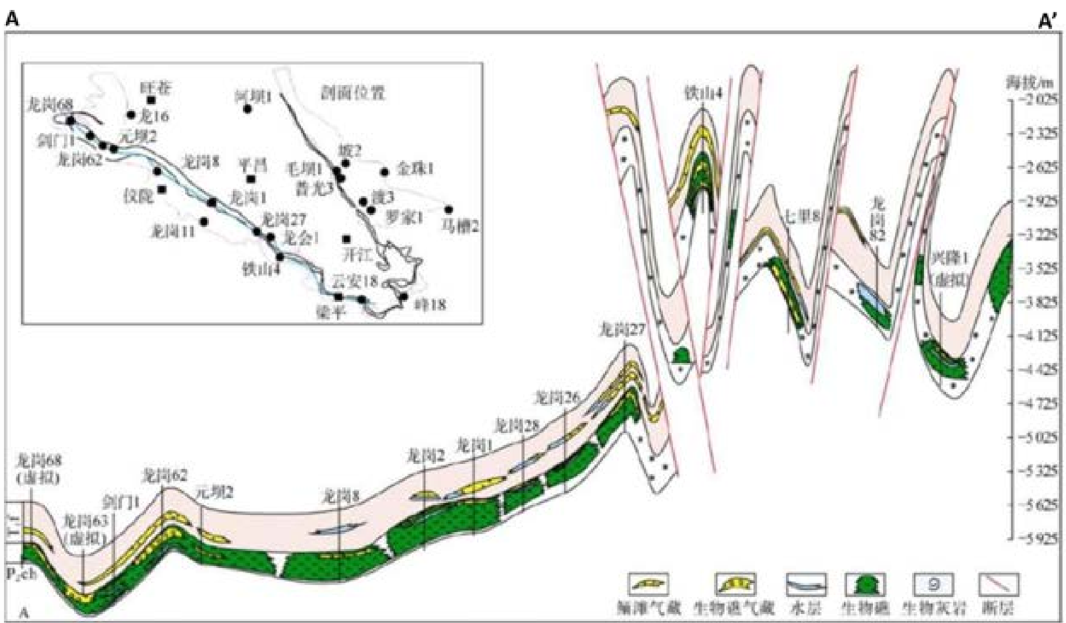


Source: ARI, 2013.

The Sichuan Basin / Yangtze Platform region behaved as a passive margin during Sinian (Precambrian) to Mesozoic time, transitioning into a foreland basin setting during the Mesozoic to Cenozoic. Three major tectonic events punctuated this time interval, including regional extension during the Caledonian and Hercynian orogenies (Ordovician to Permian), a structural transitional phase during the Indosinian to early Yanshanian orogenies, and compression during the late Yanshanian to Himalayan orogenies (Cretaceous to Neogene).[4]

The modern-day Sichuan basin comprises four tectonic zones: the Northwest Depression, Central Uplift, and the East and South Fold Belts. The Central Uplift, characterized by relatively simple structure and comparatively few faults, appears to be the most attractive region for shale gas development. In contrast, the East and South Fold Belts of the Sichuan Basin are structurally more complex, characterized by numerous closely spaced folds and faults with large offset; these areas are not considered prospective for shale gas development. For example, a cross-section through the northern Sichuan Basin shows relatively simple structural conditions in the Central Uplift transitioning abruptly into the highly faulted and deformed eastern fold belt, Figure XX-4.[5] The adjoining Yangtze Platform to the south and east is even more structurally complex, but lacks data control and is quite challenging to assess for shale development.

Figure XX-4. Northwest-Southeast Structural Cross-section of Northern Sichuan Basin, Showing Relatively Simple Structure in Central Uplift Transitioning into Highly Faulted Fold Belt in the East.



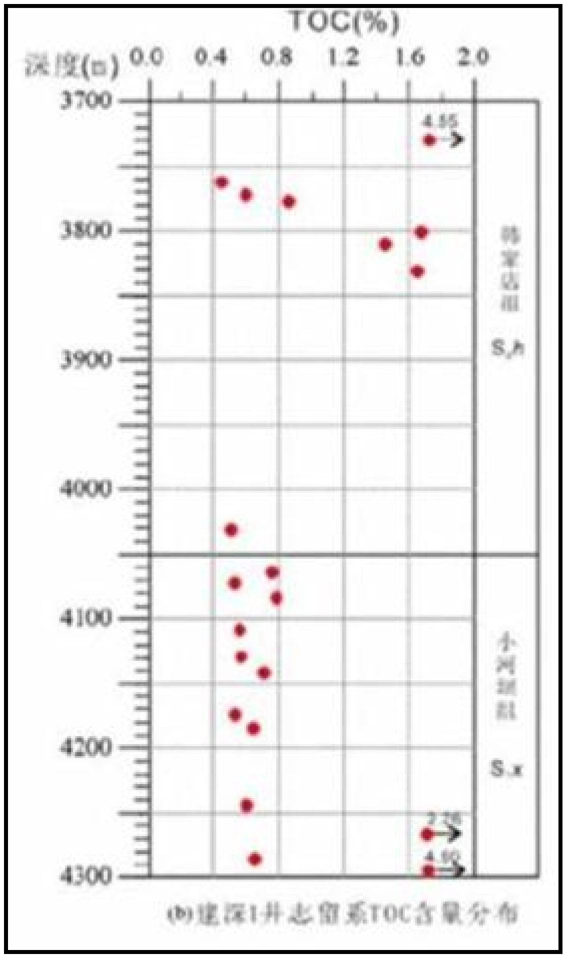
Source: Zou et al., 2011.

The new geologic data indicate that only the southwestern quadrant of the Sichuan Basin meets the standard exploration criteria for shale development: suitable shale thickness and depth, dry to wet gas thermal maturity, and absence of extreme structural complexity. The prospective area we mapped with new data is considerably smaller than in the initial 2011 EIA/ARI study. This emerging “sweet spot” in the southwest Sichuan Basin dominates China’s shale leasing and drilling activity, as it appears to offer China’s best combination of favorable geology, good access with flat surface conditions, existing pipelines, abundant water supplies, and access to major urban gas markets.

Other parts of the Sichuan Basin are structurally and/or topographically complex or have elevated H_2S contamination. The 2008 Sichuan earthquake, centered in Wenchuan County, occurred along active strike-slip faults in the northwest portion of the Sichuan Basin. This region has shale potential but was screened out due to excessive structural complexity. In addition, the conventional reservoirs in the northern portion of the Central Uplift can have extremely high hydrogen sulfide content, frequently in excess of 10% by volume, caused by thermochemical sulfate reduction (TSR).[6] Not only does H_2S reduce gas reserves and increase processing costs, it is a dangerous safety hazard as well: in 2003 a sour gas well blew out in the Luojiazai gas field, killing 233 villagers. Carbon dioxide content also can be high in the northeast Sichuan Basin (~8%). Consequently, northeast Sichuan was screened out as well.

The four main organic-rich shale targets in the Sichuan Basin are the L. Cambrian Qiongzhusi, L. Silurian Longmaxi, the L. Permian Qixia, and the U. Permian Longtan formations and their equivalents, Figure XX-2. These units sourced many of the conventional reservoirs in the Sichuan Basin. Most important is the L. Silurian Longmaxi Fm, which contains an average 1,000 ft of organically rich, black, graptolitic-bearing, siliceous to cherty shale. TOC content is mostly low to moderate at up to 4%, consisting mainly of Type II kerogen. Figure XX-5 illustrates TOC distribution in a deep conventional petroleum well, ranging from 0.4% to over 4%.[7] Thermal maturity is high and increases with depth, ranging from dry gas prone to overmature (R_o 2.4% to 3.6%). Porosity measured from the Wei-201 and Ning-201 shale wells was over 4% but this parameter is difficult to measure and frequently underestimated.[8] The Longmaxi has exhibited gas shows in at least 15 deep conventional wells in the southern Sichuan Basin.[9]

Figure XX-5. TOC Distribution of L. Silurian Longmaxi Fm in a Deep Petroleum Exploration Well, Sichuan Basin, Showing 0.4% to Over 4%.



Source: Liu et al., 2011

The second shale gas target in the Sichuan Basin is the Cambrian Qiongzhusi Formation. Although deeper than the Longmaxi and mostly screened out by the 5-km depth cutoff, the Qiongzhusi contains high-quality source rocks that provide further shale resource potential. The formation was deposited under shallow marine continental shelf conditions and has an overall thickness of 250 to 600 m. Of particular note is the 60 to 300 m of high-gamma-ray black shale, which has about 3.0% TOC (sapropelic) that is dry-gas-prone (about 3.0% R_o).

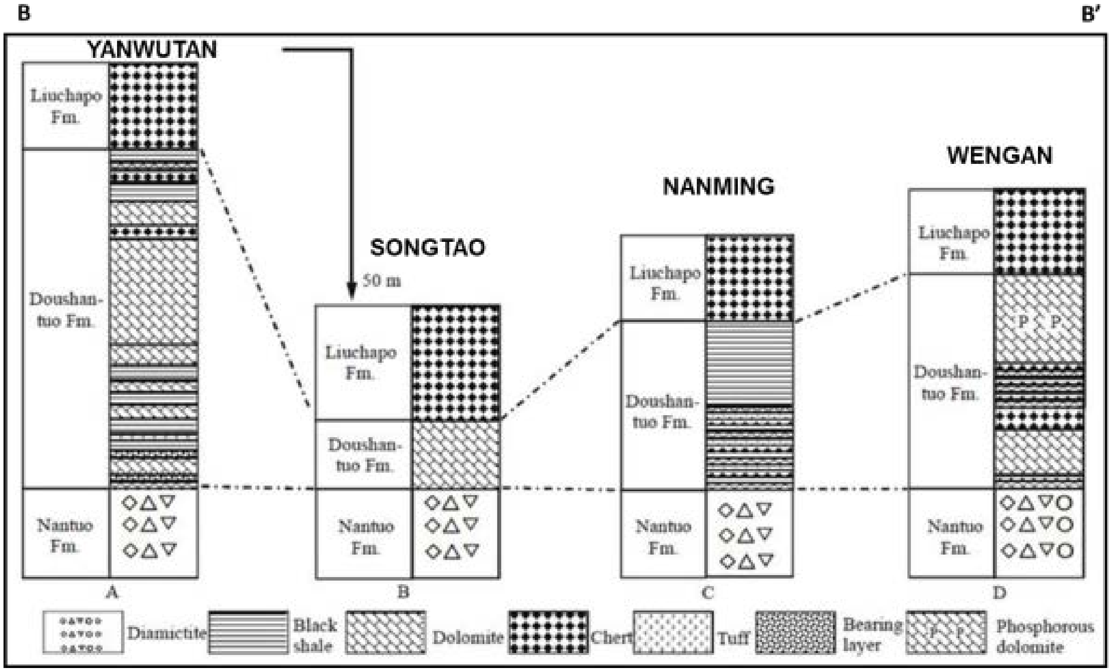
The Qiongzhusi black shale is considered the principal source rock for the Weiyuan gas field in the southern Sichuan Basin, where the organically rich hot shale is about 120 m thick out of 230 to 400 m of total formation thickness. Mineralogy appears favorably brittle, being high in quartz and other brittle minerals (65%) and fairly low in clay (30%). In 1966 a conventional gas well flowed nearly 1 million ft^3/day from an unstimulated organic-rich Qiongzhusi shale interval at a depth of 2,800 m. PetroChina recently tested the first horizontal well completed in the Qiongzhusi at Weiyuan field (see Activity below).[10]

The **Yangtze Platform** area is structurally more complex than the Sichuan Basin, with only scant well control, very little of which has been published. The Paleozoic sequence here has been tectonically deformed and partly eroded. Indeed, the shales are not continuous deposits as they are in the Sichuan Basin but rather isolated remnant basins which are difficult to high grade with current data availability. Nevertheless, Chevron and BP have expressed interest in the region, while researchers have begun to map out potentially favorable shale development areas.[11]

Our analysis of the Yangtze Platform depends heavily on outcrop and road cut studies, such as the Cambrian correlation shown in Figure XX-6; subsurface control remains weak. For example, Figure XX-7 shows TOC vs depth distribution for a 100-m thick outcrop of the L. Cambrian Xiaoyanxi Formation in the Yanwutan-Lijiatuo area, Yangtze Platform.[12] Black shale here totals nearly 100 m thick with exceptionally rich average 7.5% TOC. The underlying Sinian Liuchapo Formation consists mainly of chert with average 2.3% TOC. Figure XX-8 shows an outcrop photo of L. Cambrian black chert north of Guiyang city, Guizhou Province, displaying the unit's strong bedding and brittle character.[13]

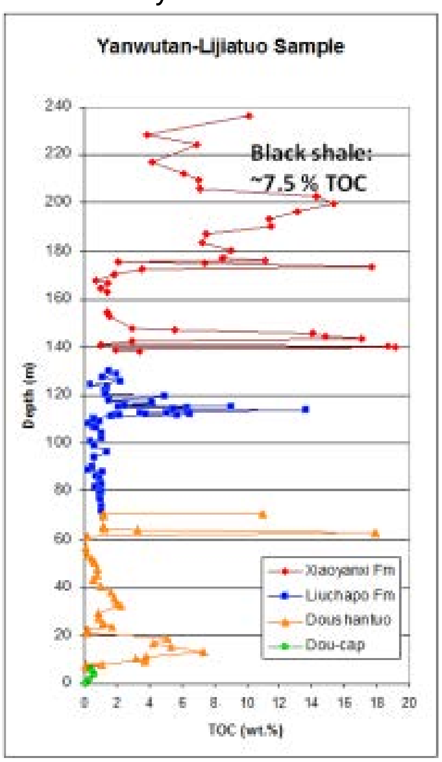
The **Jianghan Basin** is a conventional petroleum producing region covering 14,500-mi^2 in the central Yangtze Platform of Jiangxi and Hubei provinces, close to the major city of Wuhan. Jianghan is a rift basin that developed on the Central Yangtze Platform during Cretaceous to Tertiary time, induced by transpressional tectonics related to India's collision with Asia. Somewhat overlooked for shale exploration, the Jianghan Basin has Lower Paleozoic shale source rocks -- similar to those in Sichuan and the Yangtze Platform -- with suitable thickness, depth, TOC, and R_o, although even in high-graded areas they are mostly deep (4-5 km) and significantly faulted. Figure XX-9 illustrates the structural elements of the Jianghan Basin, along with ARI-proprietary shale gas data locations and the high-graded location of Cambrian, Silurian, and Permian shale leads.

Figure XX-6. Outcrop Lithology of the Cambrian Sequence Across the Western Yangtze Platform



Source: Guo et al., 2006.

Figure XX-7. TOC vs Depth Distribution at Outcrop of the L. Cambrian Xiaoyanxi Fm Black Shale, Yangtze Platform. Black Shale Totals Nearly 100 m Thick with Average 7.5% TOC. The Underlying Sinian Liuchapo Fm is Mainly Chert with 2.3% TOC.

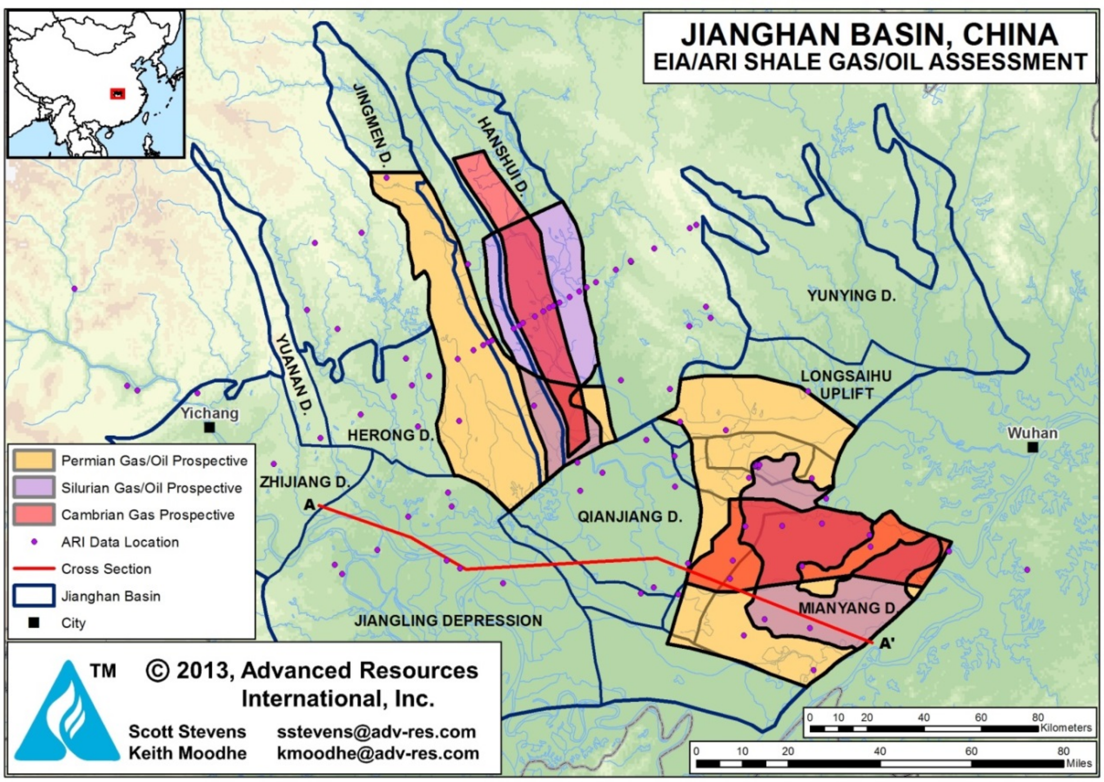


Source: Guo et al., 2007.

Figure XX-8. Outcrop Photo of L. Cambrian Black Chert North of Guiyang City, Guizhou Province. Note Bedding and Brittle Character. Pen for Scale.

Source: Yang et al., 2011.

Figure XX-9. Structural Elements Map of the Jianghan Basin Showing ARI-Proprietary Shale Gas Data Locations and Relative Size of the Prospective Areas for Silurian and Permian Shales.



Source: ARI, 2013.

The Jianghan Basin is structurally more complex than the Sichuan Basin, although less so than the Yangtze Platform. Jianghan comprises a number of small fault-bounded uplifts and depressions. Quaternary alluvium covers most of the basin surface, reflecting Neogene subsidence. Its structural history records Late Cretaceous to Paleogene extension (ENE-WSW) which originally formed the graben structures, Late Paleogence compression (EW) and graben deformation, then Neogene extension (NE-SW and NW-SE) which rejuvenated the grabens, and finally Late Neogene compression (NE-SW) which activated right-lateral strike-slip faults that continue to be active today.[14]

The Jianghan Basin contains up to 10 km of Cretaceous to Quaternary non-marine sediments overlying U. Paleozoic marine source rocks, Figure XX-10, with potential source rocks present in Sinian, L. Cambrian, U. Ordovician, L. Silurian, Jurassic, and Paleogene formations. The Eocene Qianjiang Formation is the main conventional sandstone reservoir, self-sourced by interbedded lacustrine shales and trapped within faulted anticlines overlain by cap rocks of interbedded gypsum-rich evaporites.[15]

The most prospective source rocks for shale gas development are dry-gas-prone Cambrian and Silurian units, along with liquids-rich Permian shale potential. Recent shale analysis noted the average thickness of organically rich L. Silurian Longmaxi Formation to be 120 m (390 ft).[16] Measured TOC from the L. Cambrian Shuijintuo Formation is favorable, ranging from 5.35 to 7.78%.[17] Thermal maturity data are scarce but indicate gas-prone shales (R_o 1.5% to 2.5%) in most of the basin, becoming thermally overmature in the northwest (R_o 3.5% to 5%).[18] In contrast, Eocene lacustrine shales in the Jianghan Basin are immature (R_o 0.4%), likely clay-rich, and not considered prospective for shale.

Figure XX-10. Stratigraphy of the Jianghan Basin, Highlighting Potentially Prospective Sinian, L. Cambrian, U. Ordovician, L. Silurian, Jurassic, and Paleogene Source Rocks.

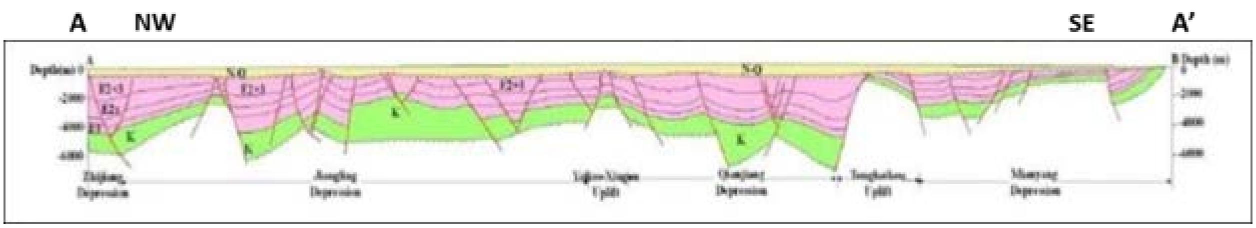
JIANGHAN BASIN			
ERA	PERIOD	EPOCH	FORMATION
CENOZOIC	QUATERNARY	Pleistocene	Pingyuan
	NEOGENE	Miocene	Guanghusai
	PALEOGENE	Oligocene	Jinghezhen
		Eocene	**Qianjiang**
			Jinsha
		Paleocene	**Xingouzhui**
			Shashi
MESOZOIC	CRETACEOUS	Upper	Paomagang
			Honghuntao
			Luojingtan
		Lower	
	JURASSIC	Middle	**Xiaximiao**
			Naijiashan
		Lower	**Tongzhuyian**
	TRIASSIC	Upper	Wanglongtan
			Jiuigang
		Middle	Badong
		Lower	Jialingjiang
			Daye
PALEOZOIC	PERMIAN	Upper	Dalong
			Wikoaping
		Lower	Maokou
			Qixia
	CARBONIFEROUS	Upper	Chuanshan
			Huanglong
		Lower	
	DEVONIAN	Middle	
	SILURIAN	Middle	Shamao
		Lower	Luoreping
			Longmaxi
	ORDOVICIAN	Upper	Wufeng
			Lingxiang
			Baota
			Miaopo
		Lower	Guniutan
			Dawan
			Honghuayuan
			Fenxiang
			Nanjinguan
	CAMBRIAN	Upper	Shanyoudong
		Middle	Qinjiamiao
		Lower	Shilongdong
			Tianheban
			Shipai
			Shuijintuo
PROTEROZOIC	SINIAN	Upper	**Dengyin**
			Duoshantuo
		Lower	Nantuo
	Source Rock		***Conventional Reservoir***

Source: ARI, 2013.

Cambrian and Silurian shales occur at non-prospective depths of 5 to over 10 km in the western depressions of the Jianghan Basin, but are shallower and may be prospective on uplifts in the east and northeast. For example, a regional cross-section shows Silurian shale at prospective depth (3-4 km) at the Yuekou, Longsaihu, Yajiao-Xingou uplifts, although significant faulting here may negatively impact shale development, Figure XX-11.[19] Similarly, a detailed cross-section of the Mianyang Depression in the eastern Jianghan Basin shows L. Silurian to be about 500-m thick (up to 1 km thick elsewhere), faulted, and 4 to 5 km deep, Figure XX-12.[20]

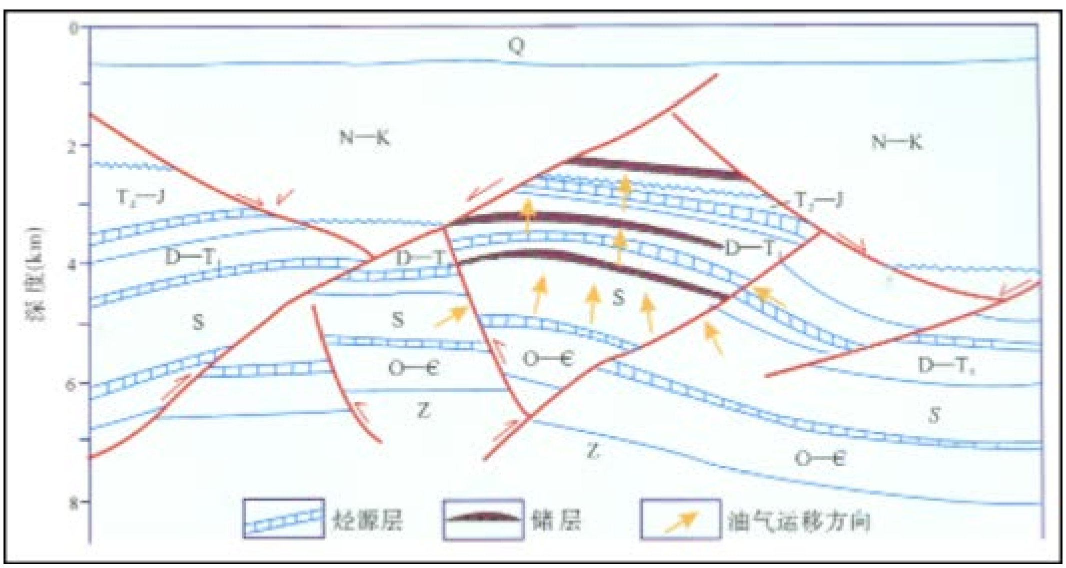
The underlying Cambrian section is about 1 km thick, faulted, and uplifted to about 2-km depth in the southeastern Jianghan Basin, Figure XX-13.[21] We identified three marine Paleozoic source-rock shale leads in the Jianghan Basin (L. Cambrian, L. Silurian, and Permian; see below).

Figure XX-11. Regional Cross Section of the Central Jianghan Basin Shows Significant Faulting Which May Impact Shale Development. Cambrian and Silurian Shales are too Deep (>5 km) to be Considered Prospective in the Troughs, but may be Suitably Shallow on the Uplifts.



Source: Zhang et al., 2010.

Figure XX-12. Detailed Cross-section from Mianyang Depression in the Eastern Jianghan Basin. The Lower Silurian Section Here ("S") is about 500-m Thick, 4 to 5 km Deep, and Significantly Faulted.



Source: Chen et al., 2005.

Figure XX-13. Localized Cross Sections in the Southeastern Jianghan Basin.
The Cambrian Section Here is Faulted and about 1 km Thick.

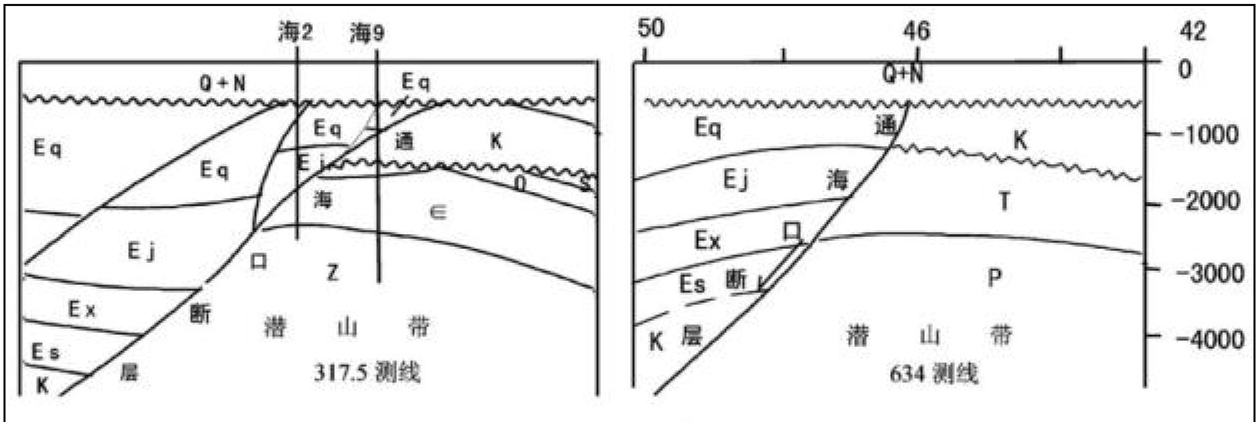


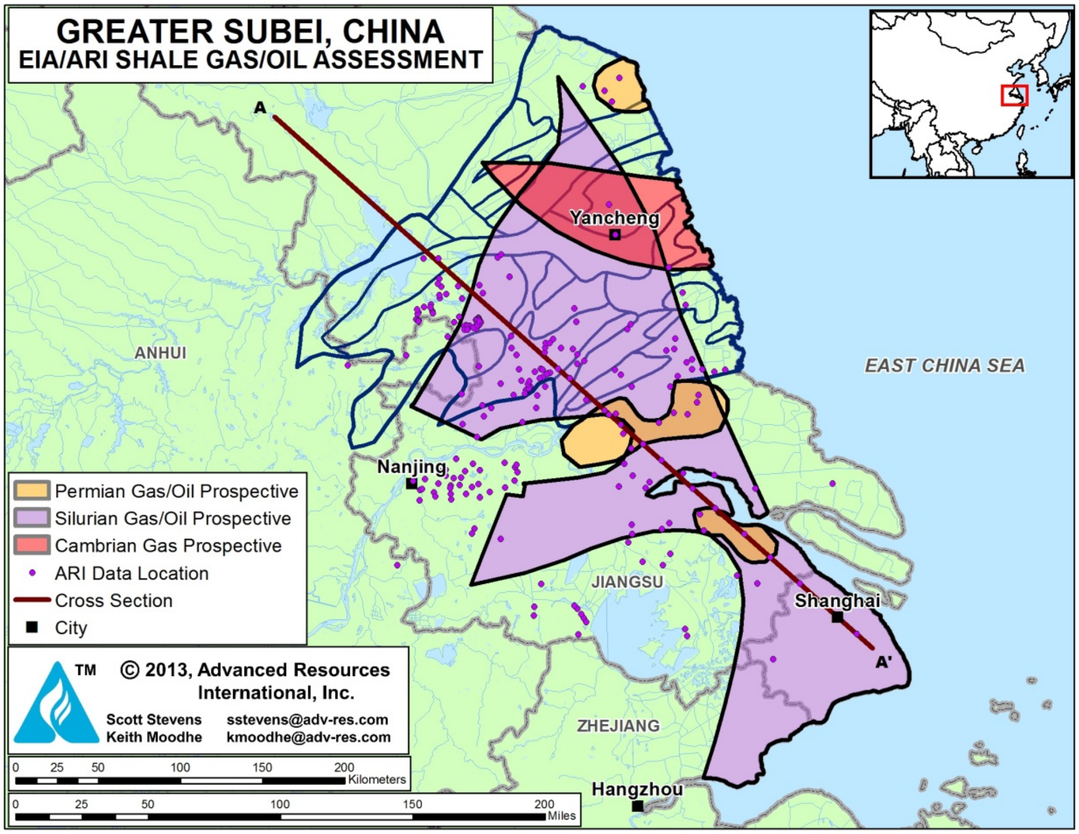
图 1 通海口潜山带构造剖面

Source: Li et al., 2007.

Subei Basin. With only 13 Chinese and 7 English articles available for this poorly documented basin, mappable geologic data are relatively sparse, Figure XX-14. The basin covers a 14,000-mi^2 portion of the lower Yangtze Platform near the coast in Jiangsu Province north of Shanghai. Small conventional oil fields have been discovered, the largest of which is Sinopec's structurally complex Jiangsu field near the center of the basin. Although situated enticingly close to prosperous East China markets, including Shanghai, the Subei Basin is structurally complex and quite deep, with Paleozoic shales mostly 3.5 to 5 km below the surface. Figure XX-15, a structural cross-section through the basin and adjoining region to Shanghai, shows major faults and the depth to Paleozoic source rock shales.[22] Detailed structure is likely to be even more complex than indicated here.

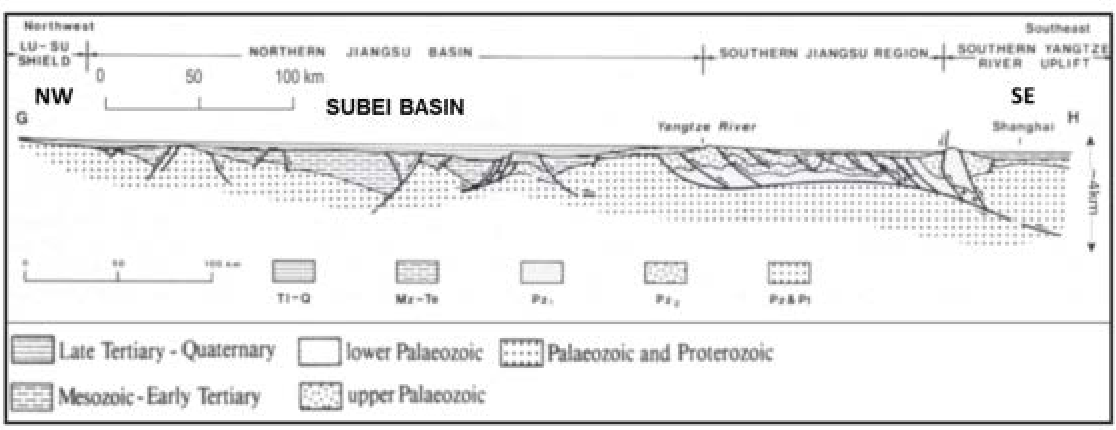
Sedimentary rocks in the Subei Basin range from L. Cambrian to Eocene, including potentially prospective marine shale source rocks of L. Cambrian, L. Silurian, and U. Permian age, Figure XX-16.[23] Conglomerates and mudstones of the U. Cretaceous to L. Paleocene Taizhou Group are the conventional petroleum targets in the basin, as well as possible source rocks themselves.

Figure XX-14. Structural Elements Map of the Subei Basin Showing ARI-proprietary Shale Gas Data Locations and Prospective Areas for L. Cambrian, L. Silurian, and U. Permian Shales.



Source: ARI, 2013.

Figure XX-15. Structural Cross-section of Subei Basin and Adjoining Region to Shanghai, Showing Major Faults and Depth to Paleozoic Source Rock Shales.



Source: Moore et al., 1986.

Figure XX-16. Stratigraphy of the Paleozoic Strata in the Subei Basin, Highlighting Potentially Prospective L. Cambrian, L. Silurian, and U. Permian Source Rocks.

ERA	PERIOD	EPOCH	MEMBER	FORMATION	LITHOLOGY / COMMENTS
PALEOZOIC	PERMIAN	**Upper**	**P_3c**	Changxing/Talung Fm	Limestones/siliceous shale, chert, limestone
			P_3l	Longtan Fm	Sandstones, mudstones, limestones, coal.
		Lower	P_2g	Kuhfeng Fm	Siltstones, siliceous shale, and chert.
			P_2q	Chihsia Fm	Dark grey limestones with chert.
			P_1c	Chuanshan Fm	Light grey limestone.
	CARBONIFEROUS	Upper	C_2h	Huanglung Fm	Light grey limestone/ dolomite.
			C_2l	Laohudong Fm	Light-dark grey dolomite.
				Hezhou Fm	Limestones, marls, dolomites.
		Lower	C_1g	Gaolishan Fm	Mudstone, siltstone, fine sandstone.
				Kinling Fm	Dark grey limestones with sandstone.
				Laokan Fm	Grey-green mudstones and sandstones, argillaceous dolomite.
	DEVONIAN		D_3w	Wutong Fm	Grey-white quartzose sandstones, conglomeratic sandstones.
	SILURIAN	Upper	S_3m/S_2f	Maoshan/Fentou Fm	Quartz sandstone, siltite mudstone, shale.
		Lower	**S_1g**	**Gaojiabian Fm**	Shale, siltstone.
	ORDOVICIAN	Upper	**O_3w**	**Wufeng Fm**	Siliceous shales, mudstones.
				Tangtou Fm	Argillaceous limestone and shale.
				Tangshan Fm	Argillaceous limestone and mudstone.
				Dawan Fm	Siliceous limestone and shale.
		Lower		Hunghuayuan Fm	Grey limestone.
				Lunshan Fm	Grey dolomite and limestone.
	CAMBRIAN	Upper/Middle	ϵ_1l, ϵ_2p	Loushanguan, Paotaishan Fms	Grey and white thick-bedded dolomite, dark grey thick-bedded limestone.
		Lower	**ϵ_1mu**	**Mufushan Fm**	Black carbonaceous shale (upper); dark grey thin-bedded limestone (lower).

Source Rock

Modified from Qi & Zhu, 2002.

The L. Cambrian Mufushan Formation is 91 to 758 m thick (gross) in the Subei Basin. Its lower portion (2 to 363 m thick) contains dark grey to black mudstones and shale. Source rock thickness is 40 to 250 m thick, averaging 120 m thick, with low-moderate organic richness (1.1 to 3.1% TOC, average 2.1%).[24] This unit appears to be gas-prone at prospective depths of 4 to 5 km. Unfortunately, the Cambrian is deeper than 5 km across nearly the entire Subei Basin and 7 to > 9 km deep to the south and west of Shanghai.

The U. Ordovician Wufeng and L. Silurian Gaojiabian formations contain siliceous shale and mudstone with low organic richness (0.6 to 1.3% TOC). These units are gas-prone at prospective depths of 3.5 to 5 km. The Wufeng Fm is 4 to 214 m thick (gross) and contains grey and black siliceous shales & mudstone. The L. Silurian Gaojiabian Fm is 25 to 1,720 m thick (gross) and contains dark grey shale with an upper layer of interbedded silty fine sandstones. The combined source rock thickness ranges from 75 to 450 m, averaging 250 m. TOC is about 1.3%, lower than in the Cambrian source rocks.

The 1-km thick U. Permian Changxing/Talung formations also contain siliceous shale and mudstone of uncertain TOC that are gas-prone at relatively shallow depths (1 – 2.5 km). Finally, black mudstones of the U. Paleocene to M. Eocene Funing Group contain oil shale interbeds that formed in a deep lake setting and sourced the basin's conventional sandstone fields; these mudstones are immature to liquids-prone (Ro ≈ 0.4% to 0.9%).[25]

1.2 Reservoir Properties (Prospective Area)

Having discussed the regional geology of the South China Shale Corridor in the preceding section, we now describe the reservoir properties specific to the high-graded prospective areas in each basin.

Sichuan Basin. The 10,070-mi^2 high-graded area defined by prospective depth and R_o distribution is located in the southwestern Sichuan basin. Here the L. Silurian Longmaxi Fm contains about 1,000 ft of organically rich, black, graptolitic-bearing, siliceous to cherty shale. TOC content is approximately 3% and dry gas prone (R_o 2.9%). In addition, the Cambrian Qiongzhusi Fm averages 500 ft thick, with 3.0% TOC within its 6,500-mi^2 prospective area, where it is in the dry gas thermal maturity window (3.2% R_o).

The Upper Permian Longtan and Lower Permian Qixia formations, best developed in the central and southeast Sichuan Basin, contain an average total 314 ft of organic-rich shale, with TOC ranging from 2-6% (average 4%). Depth to shale within the prospective area (1 to 5 km) averages 9,700 ft. These shales are dry-gas prone, with vitrinite reflectance ranging from 2.0% to 3.0% (average 2.5%).

Shale targets in the Sichuan Basin are quite different from North American shales, but the closest North American analog may be the relatively faulted central Pennsylvania portion of the Marcellus Shale play.

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Yangtze Platform. A specific prospective area could not be mapped here due to structural complexity and the paucity of data. However, activity by major oil companies in this area suggests there may be potential, perhaps in local synclinal areas. Reservoir properties of L. Cambrian and L. Silurian formations in the Yangtze Platform generally are similar to those in the Sichuan Basin. We assumed that prospective areas could be perhaps 20% of the prospective Sichuan Basin areas for each of the L. Cambrian and L. Silurian formations.

Again, the shale targets in the Yangtze Platform do not closely resemble any North American shale analogs. Perhaps the structurally complex, dry-gas prone Utica Shale play in Quebec is the closest North American approximation.

Jianghan Basin. The L. Cambrian Niutitang Formation (1,280-mi^2 high-graded lead) has the best organic richness (6.6%), is dry-gas prone (R_o ~2.25%) but also the deepest (average 13,000 ft). The L. Silurian Longmaxi Formation (1,960-mi^2 high-graded lead) has less organic richness (TOC of 2.0%), also is dry-gas prone (R_o ~2.0%), and is found at moderate depth (average 11,500 ft). Finally, the Permian Qixia/Maokou Fm (2,150-mi^2 high-graded lead) has lower organic richness (2.0%), is still dry-gas prone (R_o ~1.5%) and occurs at shallower depth (average 9,000 ft). The geothermal gradient in the Jianghan Basin is moderate, similar to that of the Sichuan Basin.[26]

The relatively faulted Marcellus Shale play in central Pennsylvania may be a distant analog for the Jianghan Basin, although Jianghan is structurally much more complex.

Subei Basin. Marine-deposited source rock shales in the L. Cambrian Mufushan Formation average 120 m thick, with 2.1% average TOC. These are gas-prone at prospective depths of 4 to 5 km. Source rocks in the the U. Ordovician Wufeng and L. Silurian Gaojiabian formations total an average 250 m thick, consisting of siliceous shale and mudstone with low 1.1% TOC; these also are gas-prone at prospective depths of 3.5 to 5 km. The U. Permian Changxing/Talung formations contain siliceous shale and mudstone of uncertain TOC (assumed to be 2%) that is gas-prone at relatively shallow depths (1 to 2.5 km).

The relatively faulted Marcellus Shale play in central Pennsylvania may be a distant analog for the Subei Basin, although Subei is structurally much more complex.

1.3 Resource Assessment

Having defined the reservoir properties of the high-graded prospective areas in the South China Shale Corridor, we now estimate the risked, technically recoverable shale resources and original shale gas and shale oil in place for each basin.

Sichuan Basin. Much of the Sichuan Basin is structurally complex and/or contaminated with H_2S and thus was screened out as non-prospective. However, the southwest quadrant of the basin has marine Paleozoic shales that are prospective. Within our high-graded prospective area, the Silurian Longmaxi Formation has an estimated 287 Tcf of risked, technically recoverable shale gas resources out of 1,146 Tcf of risked, shale gas in-place. The Cambrian Qiongzhusi Formation has 125 Tcf of risked, technically recoverable shale gas resources from 500 Tcf of risked, shale gas in-place. Permian formations have an estimated 215 Tcf of risked, recoverable shale gas resources out of a depth- and R_o-screened 715 Tcf of risked shale gas in-place.

Based on these data and assumptions, the Sichuan Basin is China's largest shale gas region, with an estimated 2,361 Tcf of risked, prospective shale gas in-place, of which 626 Tcf is considered risked, technically recoverable shale gas resources, Table XX-1. These figures exclude the majority of the basin area, which was screened out due to excessive depth, H_2S, and structural complexity issues. Further more detailed study is recommended to define and map these parameters and refine the still poorly understood shale gas resource potential of the Sichuan Basin.

Yangtze Platform. Using Sichuan Basin reservoir properties and an assumed prospective area 20% as large as Sichuan's, the L. Cambrian and L. Silurian shales of the Yangtze Platform are estimated to have 149 Tcf of risked, technically recoverable shale gas resources out of 596 Tcf of risked shale gas in-place.

Jianghan Basin. The L. Cambrian has an estimated 11 Tcf of risked, technically recoverable shale gas resources, out of a depth- and R_o-screened 46 Tcf of risked shale gas in-place. The L. Silurian Longmaxi Fm is prospective within a 1,960-mi^2 high-graded lead, adding an estimated 7 Tcf of risked, technically recoverable shale gas resources out of a depth- and R_o-screened 28 Tcf of risked shale gas in-place. The Permian Qixia/Maokou Fm is at moderate depth (9,000 ft average). ARI mapped a 3,830-mi^2 high-graded lead for the three thermal maturity windows, with an estimated 10 Tcf of risked, technically recoverable shale gas

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resources, out of a depth- and R_o-screened 40 Tcf of risked shale gas in-place. Jianghan also has a minor Permian shale oil play containing 5 billion barrels of resource in-place, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

Subei Basin. Although geologic data are scarce, ARI identified a 2,040-mi^2 high-graded lead in the L. Cambrian Mufushan Formation with an estimated 7 Tcf of risked, technically shale gas recoverable resources, out of a depth- and R_o-screened 29 Tcf of risked shale gas in-place. The L. Silurian Gaobiajian Formation appears to be prospective within a 14,990-mi^2 high-graded lead, adding an estimated 36 Tcf of risked, technically recoverable shale gas resources out of a depth- and R_o-screened 144 Tcf of risked shale gas in-place. The poorly defined Permian shale may be prospective within a 1,640-mi^2 area, with 2 Tcf of risked, technically recoverable shale gas resources out of 8 Tcf of risked shale gas in-place. Subei also has a minor Permian shale oil play containing 1 billion barrels of resource in-place with 0.1 billion barrels as the risked, technically recoverable shale oil resource.

1.4 Recent Activity

The **Sichuan Basin** by far is China's most active shale leasing and drilling area. Drilling programs currently are underway by PetroChina, Sinopec, and Shell, while numerous other Chinese and foreign companies are negotiating initial lease positions. The Ministry of Land and Resources began drilling shale delineation wells in the Sichuan Basin in 2009. PetroChina and Sinopec, which are engaged in shale development JV's in North America, each hold large legacy lease positions in the basin. Earlier this year Shell and CNPC were awarded the 3,500-km^2 Fushun-Yongchuan block, located in the southern Sichuan close to a legacy Shell tight gas exploration block. The Fushun-Yongchuan block is China's first foreign-invested production sharing contract for shale gas. Shell also is pursuing joint studies on two other Sichuan Basin shale blocks (Zitong, Jinqiu), which would give the company a total shale/tight area of 8,500 km^2 if awarded.[27]

Shale exploration drilling results in the Sichuan Basin have been mixed**.** PetroChina's first reported horizontal shale gas exploration well, located near the city of Chengdu, targeted the Silurian Longmaxi Formation. The Wei 201-H1 well, which employed a 3,540-ft long lateral and was drilled with modern logging-while-drilling technology,[28] completed its drilling phase in March 2011 after 11 months. However, this well tested a disappointing 450 Mcfd average over a 44-day period, following a large-volume, 11-stage slickwater frac completion which was monitored using real-time microseismic.[29]

Elsewhere in the Sichuan Basin, PetroChina has fracture stimulated at least five vertical wells targeting the Longmaxi Formation and two vertical wells targeting the Qiongzhusi Formation.[30] PetroChina's first horizontal Qiongzhusi well (Wei 201-H3), located in the Weiyuan gas field, is the only horizontal reported in detail by PetroChina. The well tested this 110-m thick black shale at a depth of 2,600 m, where seismic had indicated a well-developed natural fracture system.[31] Log and core analysis showed the Qiongzhusi averaged 67% quartz content, 22% clay, and 2.3% TOC but only about 2.0% porosity with 100 nD permeability (core-based). The horizontal lateral was less than half of its planned 5,000-ft length because of borehole stability problems encountered during drilling.

PetroChina's planned 9-stage fracture stimulation encountered high horizontal stress and successfully placed only 6 stages. Gas production peaked at 1.15 MMcfd and declined rapidly to 300 Mcfd, averaging 580 Mcfd during the 60-day flow test. PetroChina inferred that the fracs had planar rather than preferred complex geometry and the stimulated volume was much smaller than expected.[32] Still, the test showed the Qiongzhusi shale can be productive.

Separately, Sinopec hydro-fractured its Fangshen-1 well in Guizhou in May 2010 and expects to start commercial shale gas production in Liangping County, near Chongqing, Sichuan in 2013. Sinopec's recent Qianye-1 well in Qianjiang, also near Chongqing, reportedly peaked at 100 Mcfd.[33] No further details are available from Sinopec's shale program.

In November 2009 Shell signed the initial agreement with PetroChina to jointly explore for shale gas at the Fushun block, southern Sichuan Basin, receiving the PSC in March 2012. Shell spud its first well in December 2010, focusing on the Silurian Longmaxi Fm.[34] By April 2012 the company had drilled five deep exploration wells: one vertical data well, two vertical frac wells, and two horizontal frac wells.[35] Whole core and full petrophysical logging suites confirmed good resource potential, although in-situ well testing determined that the formation, while favorably over-pressured, had an unfavorably high stress gradient. High breakdown pressures and fluid leakoff resulted in poor stimulation. Nevertheless, one of Shell's vertical exploration wells reportedly flowed at 2.1 million ft^3/day.

Shell followed its first two vertical Sichuan wells with two horizontal production tests at the Fushun block. The company noted significant fault-related problems, such as frequent drilling out of zone and resulting doglegs that complicated well completion. Completion time improved from over 100 days/well initially to about 53 days/well, but still longer than typical 10-day completion times in North America. Shell did not report production from its horizontal wells.

ConocoPhillips recently was awarded two shale exploration blocks in the Sichuan Basin. Chevron is conducting a Joint Study with Sinopec of the Qiannan shale gas block in the Yangtze Platform, located north of Guiyang city, Guizhou Province, and just south of the Sichuan Basin. Chevron initiated seismic acquisition over the block in July 2011 and spud its first test well there during Q1 2012. BP, ConocoPhillips, ENI, ExxonMobil, Statoil, and TOTAL also have reported interest in leasing shale gas blocks in the Sichuan or Yangtze Platform. As of late 2010 BP was reported negotiating with Sinopec for a shale gas exploration block at the 2,000-km^2 Kaili block near Chevron's Qiannan block. In July 2011 ExxonMobil was reported by Sinopec to be evaluating the 3,644-km^2 Wuzhishan area in the Sichuan Basin. Statoil reported negotiating with PetroChina for a shale gas block and at one point estimated 50 MMcfd of production potential by 2015. ENI signed a memorandum of understanding with CNPC on shale gas in early 2011.

North American shale gas operators Newfield Exploration and EOG Resources also reported conducting detailed shale gas evaluations in the Sichuan Basin during the past few years. Newfield conducted a detailed joint study evaluation with PetroChina at the Weiyuan gas field but decided in 2006 not to proceed. EOG originally planned to make a decision on shale exploration in Sichuan by late 2010 but has been silent on the project for the past two years.

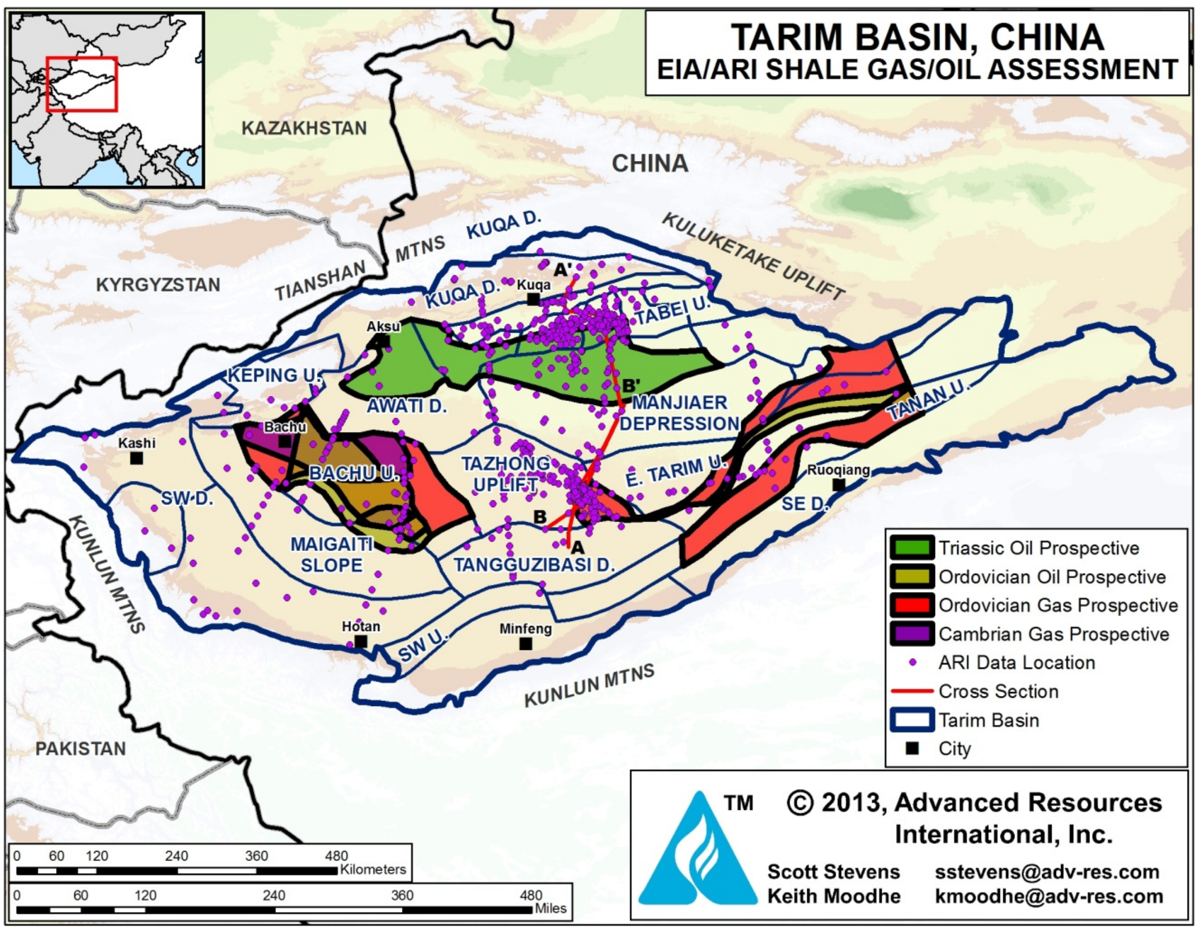
Jianghan and Subei Basins. The only reported shale activity in the Jianghan Basin was Sinopec's December 2010 report of "gas flows in a shale gas exploration well" (no details provided). The same report noted that BP was evaluating Permian shale in the 1,000-km^2 Huangqiao block, the only exploration activity noted thus far in the Subei Basin.

2 TARIM BASIN

2.1 Introduction and Geologic Setting

The Tarim Basin, located in western China's Xinjiang Autonomous Region, is the largest onshore sedimentary basin in China (234,000 mi^2). Surface elevation of this remote basin is relatively flat at about 1,000 m above sea level. The climate is dry but aquifers which underlie the lightly populated region could supply frac water. **Figure XX-17** shows the structural elements of the Tarim Basin, as well as locations of ARI-proprietary data used in conducting this study.

Figure XX-17. Structural Elements Map of the Tarim Basin Showing ARI-Proprietary Shale Gas Data Locations and Prospective Areas for Shale Gas and Shale Oil Exploration.



Source: ARI, 2013

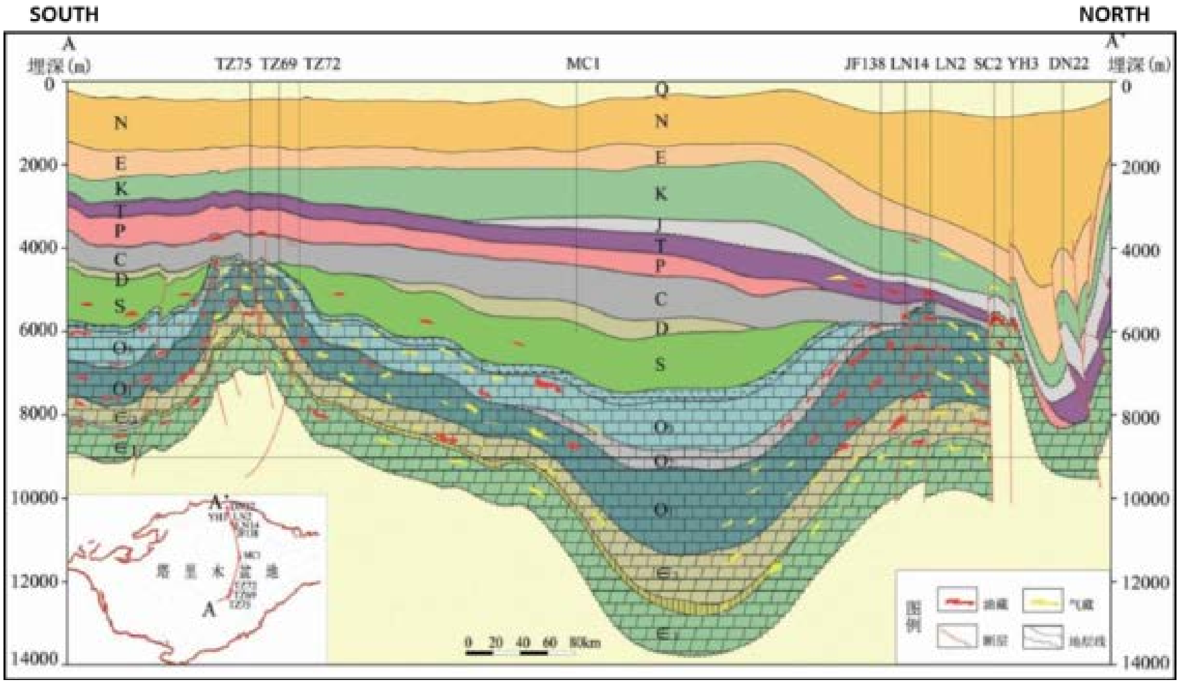
PetroChina and Sinopec produced an average 261,000 b/d of oil from conventional reservoirs in the Tarim during 2011 and are investing heavily to double output there by 2015. The basin also produced 1.6 Bcfd of natural gas in 2011 that was transported to Shanghai via the two 4,000-km West-to-East pipelines. Conventional petroleum deposits, totaling over 5 billion barrels of oil and 15 Tcf of gas, were sourced mainly by organic-rich Cambrian and Ordovician shales – considered the principal targets for shale gas and oil exploration in the Tarim Basin.

The Tarim Basin is sub-divided by fault and fold systems into a series of seven distinct structural zones, comprising three uplifts and four depressions. From north to south these include the Kuqa Depression, Tabei Uplift, North Depression, Tazhong Uplift, Southwest Depression, Tanan Uplift and Southeast Depression. Cross-section A-A', **Figure XX-18**, shows a north-to-south transect across the central Tarim Basin, revealing generally simple regional structure characterized by shallow dip angle and few faults (note extreme vertical exaggeration of 25x).[36] Unfortunately, the main Cambrian and Ordovician shale targets are buried deeper than 5 km over most of the basin, plunging to a maximum depth of 10 km or more in the structural troughs.

However, interior anticlines within the Tarim Basin include uplifted areas that appear to be (barely) depth-prospective for shale development (<5 km). For example, **Figure XX-19** shows Cambrian and Ordovician source rock shales at prospective depths ranging from 4 to 5 km across the Tazhong Uplift, but even here shale is just within the depth limit for commercial shale development.[37] Even though much of the Mid-Upper Ordovician section was locally removed by erosion during the Late Paleozoic Hercynian Orogeny, a considerable thickness of this unit remains. Geochemistry indicates that the conventional oil trapped in the Tazhong Uplift originated mainly from Ordovician rather than Cambrian source rocks.[38]

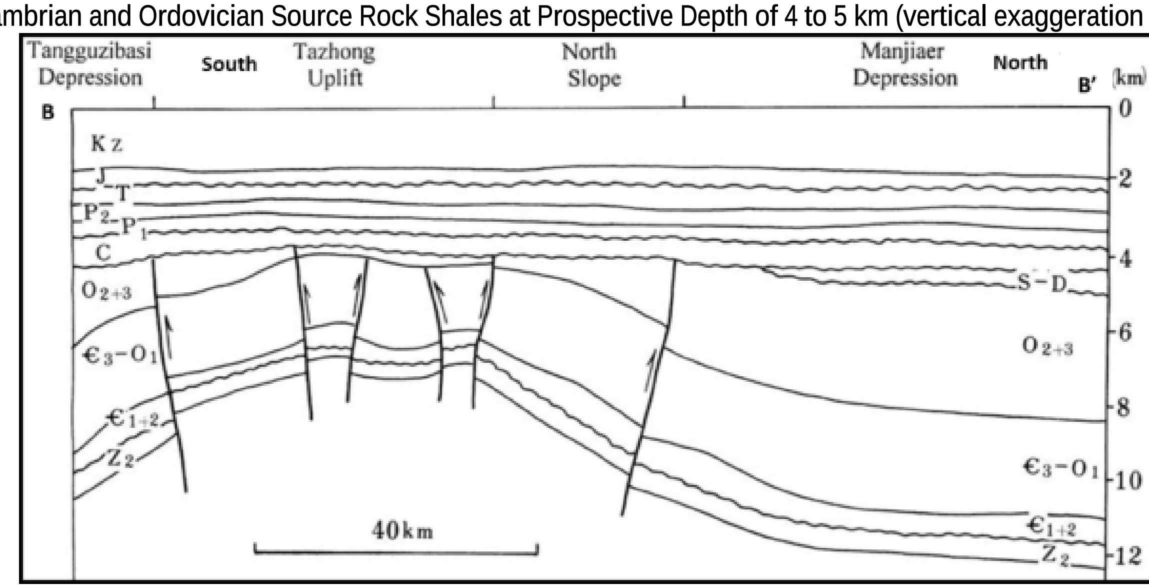
Multiple petroleum source rocks of various ages occur in the Tarim Basin, including the Cambrian, Ordovician, Carboniferous, Triassic, Cretaceous, and Tertiary, **Figure XX-20**. Marine-deposited black shales of Cambrian and particularly Ordovician age are considered the most important source rocks in the basin.[39] The Ordovician units include the Hetuao, Yijianfang, Lianglitage and equivalent formations, while L. Cambrian source rock units include the Xiaoerbulake Formation and equivalent units.

Figure XX-18. South-north Cross-section of the Central Tarim Basin Showing Generally Simple Structure as Well as Migration Pathways for Oil (Red) and Gas. Note that Cambrian and Ordovician Source Rock Shales are Too Deep (>5 km) for Commercial Shale Development in Most of the Basin, but Local Uplifts may be Prospective (vertical exaggeration = 25x).



Source: Zhu et al., 2012.

Figure XX-19. Interpreted Seismic Depth Section across the Tazhong Uplift, Tarim Basin, Showing Cambrian and Ordovician Source Rock Shales at Prospective Depth of 4 to 5 km (vertical exaggeration = 5x)



Source: Xiao et al., 2000.

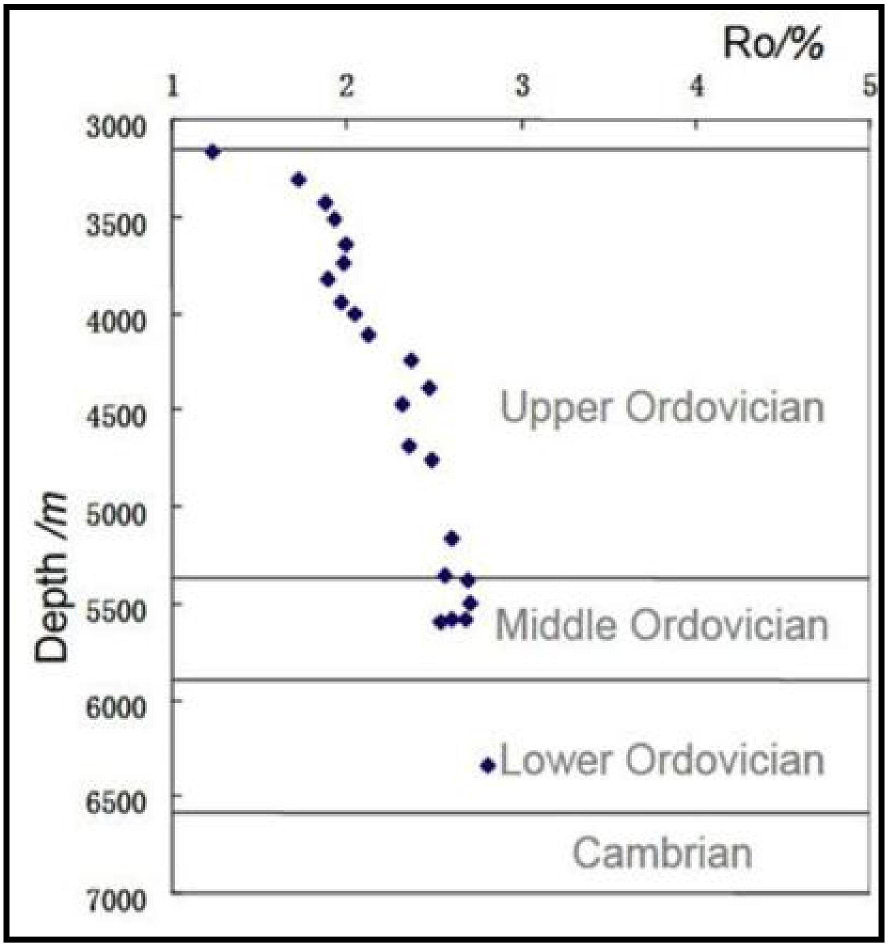
Figure XX-20. Stratigraphy of the Tarim Basin, Highlighting Prospective Cambrian, Ordovician, Carboniferous, Triassic, Cretaceous, and Tertiary Source Rocks.

TARIM BASIN					
ERA	PERIOD	EPOCH	FORMATION	AGE (Ma)	THICKNESS (m)
CENOZOIC	QUATERNARY	Q			
	TERTIARY	N_{2a}			
		N_{1w}			
		Eh			
MESOZOIC	CRETACEOUS	K_{2y}			
		K_{1y}			
	JURASSIC	J_{3k}			
		J_{2t}			
		J_{2y}			
		J1k			
	TRIASSIC				
PALEOZOIC	PERMIAN	Upper	Shazijing	290	0 - 780
			Aqiaqun		
		Middle-Lower	Aqiaqun		
	CARBONIFEROUS	Upper-Middle	Xiaohaizi	290 - 355	0 - 691
		Lower	Kalashayi		
			Bachu		
	DEVONIAN			355 - 405	0 - 241
	SILURIAN	Upper		405 - 439	0 - 517
		Middle			
		Lower			
	ORDOVICIAN	Upper	Hetuao (O_{1-2})	439 - 459	0 - 300 org-rich
		Middle	Yijianfan (O_2)	459 - 478	0 - 150 org-rich
		Lower	Lianglitage (O_3)	478 - 505	0 - 50 org-rich
	CAMBRIAN	Upper	Qiulitage	505 - 600	2918
		Middle	Awatage		125
		Lower	Xiaoerbulake		74
PROTEROZOIC	SINIAN			600+	200 - 1100
	Source Rock		***Conventional Reservoir***		

Source: ARI, 2013.

The Lower Ordovician Hetuao (O_{1-2}) shales -- important source rocks -- appear to be the most prospective, although TOC generally is under 2%. These shales range from 48 to 63 m thick and consist of carbonaceous and radiolarian-bearing siliceous mudstone that appears brittle. The Mid-Ordovician Yijianfang (O_2) Saergan Formation, present in the Keping Uplift and Awati Depression, contains black marine-deposited mudstones 10 m to 30 m thick, with TOC of 0.56% to 2.86% (average 1.56%). Upper Ordovician Lianglitage (O_3) shales occur in the Central Tarim, Bachu, and Tabei areas, where they are 20 m to 80 thick, carbonate-rich, but with relatively low TOC (average 0.93%). Thermal maturity of the Ordovician is mostly dry-gas prone, for example with R_o ranging from 2.0% to 2.6% in the Gucheng-4 well at depths of 3,200 to 5,700 m on the east flank of the Tazhong Uplift, **Figure XX-21**.[40]

Figure XX-21. Vitrinite Reflectance (R_o) of the Mid to Upper Ordovician Shale Sequence in the Gucheng-4 Well, Tarim Basin Ranges from <2% at a Depth of 3,200 m to 2.7% at a Depth of 5,700 m.

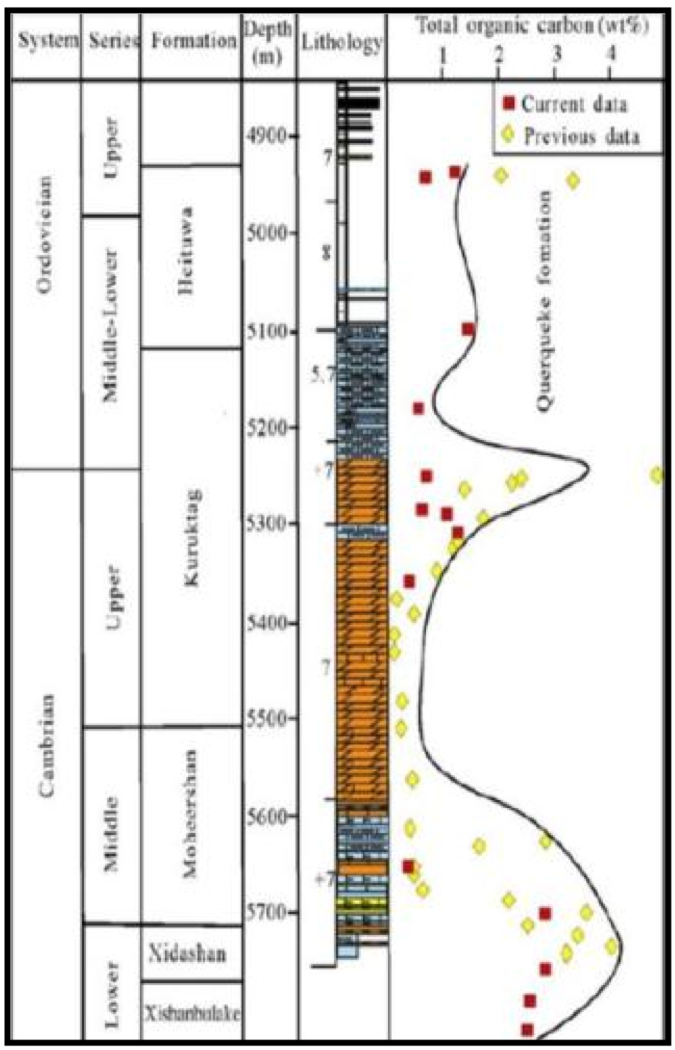


Source: Lan et al., 2009.

The Cambrian organic-rich shales, such as the Xiaoerbulake Formation, consist of abyssal to bathyal facies mudstones that are well developed in the Manjiaer Depression and the eastern Tarim and Keping Uplifts. Cambrian formations include the Qiulitage, Awatage, and Xiaoerbulake formations. TOC is fairly high (1.2% to 3.3%) in the Lower (C_1) and Middle (C_2) Cambrian Formations and exceeds 1% over about two-thirds of the Cambrian sequence. Evaporitic dolomites, potential cap rocks, occur in the middle Cambrian, with extensive salt and anhydrite beds totaling 400 to 1,400 m thick. Net organically-rich shale thickness ranges from 120 m to 415 m, averaging about 120 m (400 ft). Thermal maturity is mostly within the dry gas window (R_o > 2.5%) in deep areas.

The organic content of the Cambrian and Ordovician shales in the Tarim consists of kerogen, vitrinite-like macerals, as well as bitumen. Regionally, TOC varies widely with structural location, ranging from as much as 7% in the troughs to only 1-2% in the uplifts, reflecting the paleo depositional environment. For example**, Figure XX-22** illustrates the TOC distribution within the Lower Paleozoic section in the Milan-1 well, located on the flank of the Tadong Uplift in the eastern Tarim Basin.[41] Lower Cambrian formations in this well have up to 4% TOC, while Lower Ordovician units have mostly 2% or less TOC, although neither is at prospective depth at this particular location (5,200-5,700 m).

Figure XX-22. Stratigraphy and TOC Distribution of Cambrian and Ordovician Shales in the Milan-1 Well, Tarim Basin.



Source: Hu et al., 2009.

2.2 Reservoir Properties (Prospective Area)

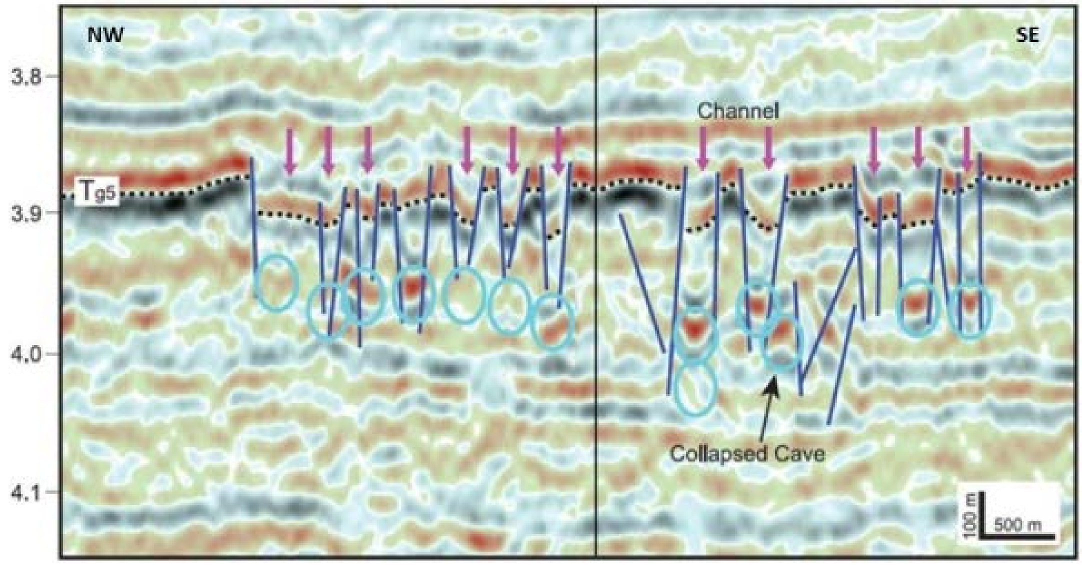
New geologic information gathered by ARI since the 2011 study indicates that shale formations in the Tarim are considerably deeper than previously mapped. The new data show that a significant amount of the Ordovician and, particularly, the Cambrian resource is subject to the 5-km prospective depth "haircut". Note that advancements in shale well drilling and completion technology could add back the large resource that exists in the 5-6 km depth range in this basin.

In addition, significant nitrogen contamination (5-20%) is prevalent in Paleozoic and Mesozoic reservoirs throughout the Tarim Basin. Elevated nitrogen apparently was caused by thermal maturation of nitrogen-rich minerals (ammonium clays, evaporates) in Cambrian and Ordovician sapropelic source rocks. Unfortunately, nitrogen concentration tends to be highest on the very structural uplifts that are most prospective for shale gas.[42]

Another potential "geohazard" is karstic collapse of Ordovician strata caused by dissolution of underlying carbonate rocks, which locally disrupts the shale strata and also may introduce copious formation water detrimental to shale gas production. Similar karsting negatively affects portions of the Barnett Shale play, locally sterilizing a small portion of the resource there.[43] **Figure XX-23**, a seismic time section from the northern Tarim Basin, shows local karst collapse structures disrupting Ordovician strata.[44] Karsting is considered a geo-hazard that would need to be avoided during shale development.

Within its 6,520-mi^2 prospective area the Cambrian organic-rich shale averages 380 ft thick, with relatively low 2% TOC in the dry-gas thermal maturity window (R_o of 2%). The L. Ordovician prospective area is approximately 19,420 mi^2, with about 300 ft of organic-rich shale that also is in the dry-gas window (R_o of 1.8%). The U. Ordovician has a 10,930-mi^2 shale gas prospective area, with 390 ft of high-TOC shale in the dry-gas window (R_o of 2.0%). A 10,450-mi^2 shale oil prospective area also exists for the U. Ordovician, averaging 300 ft of organic-rich shale with R_o of 0.9%. In addition, the L. Triassic is prospective for shale gas and oil within a 15,920-mi^2 prospective area, averaging 400 ft of high-TOC shale with R_o of 0.9%.

Figure XX-23. Seismic Time Section from Northern Tarim Basin Showing Local Karst Collapse Disrupting Ordovician Strata. Karsting is a Geo-hazard to be Avoided During Shale Development.



Source: Zeng et al., 2011.

2.3 Resource Assessment

Compared with our 2011 study, new more complete data coverage and revised mapping of the Tarim Basin indicates that Ordovician and Cambrian shales are considerably deeper than previously mapped and the prospective area is considerably smaller. Most of the basin is considered too deep for commercial shale development (>5 km), with only portions of the interior uplifts raised to prospective depth. The 20% nitrogen content and karst disruptions further reduced shale gas resources. On the other hand, we added newly recognized shale plays in the mid-upper Ordovician and L. Triassic. We now estimate that the Tarim Basin has 216 Tcf and 8 billion barrels of risked, technically recoverable shale gas and oil resources.

L. Cambrian shale covers a reduced 6,520-mi^2 high-graded area, with an estimated 44 Tcf of risked, technically recoverable shale gas resources out of 176 Tcf of risked shale gas in place. L. Ordovician shale within its 19,420-mi^2 high-graded area contains an estimated 377 Tcf of risked, shale gas in-place, with 94 Tcf of risked, technically recoverable resources. The U. Ordovician shale gas lead contains 265 Tcf of risked shale gas in-place with 61 Tcf of risked, technically recoverable shale gas resources. In addition, a 10,450-mi^2 shale oil prospect contains an estimated 31 billion barrels of risked shale oil in-place with 1.6 billion barrels of risked, technically recoverable shale oil resources.

L. Triassic shale has shale oil potential within a 15,920-mi^2 prospective area, estimated at 6.5 billion barrels of risked, technically recoverable shale oil resources out of 129 billion barrels of risked, shale oil in-place. In addition, the L. Triassic could hold an estimated 16 Tcf of risked, technically recoverable associated gas resources out of 161 Tcf of risked gas in-place.

2.4 Recent Activity

No shale gas or shale oil leasing or drilling activity has been reported in the Tarim Basin. One positive indication is the wide commercial application of horizontal drilling in the Tarim Basin during the past decade, with the technique already accounting for about half of the basin's conventional oil production.[45] This advanced drilling capability provides a good foundation for future shale development in the Tarim Basin.

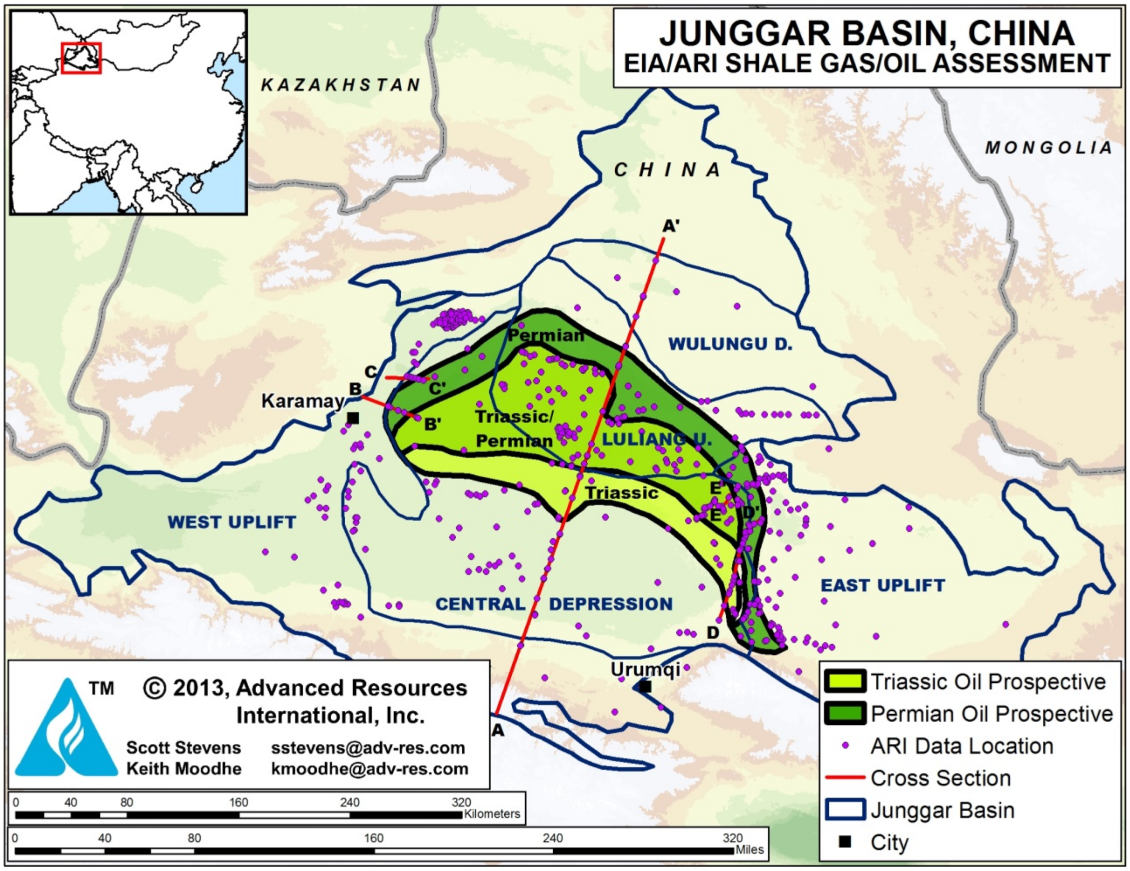
3 JUNGGAR BASIN

3.1 Introduction and Geologic Setting

Like its larger neighbor the Tarim Basin, the 62,000-mi^2 Junggar Basin is located in northwest China's Xinjiang region. However, the Junggar is less remote from markets and services than the Tarim and offers better infrastructure. Xinjiang's capital of Urumqi (population 3 million) is situated in the south-central Junggar Basin, while PetroChina's modern oil technology center is at Kelamayi. Local industry and population are growing rapidly in this resource-rich area. With mostly level surface elevation just above 1,000 m, the climate is less harsh than in the Tarim and agriculture is more developed. **Figure XX-24** shows the structural elements of the basin as well as locations of ARI-proprietary shale data used in conducting this study.

The Junggar Basin is undergoing rapid development of its rich oil, gas, and coal resources. It produced an average 218,000 bbl/day of oil and 0.5 Bcfd of natural gas during 2011, with output expected to rise to 400,000 bbl/day and 1.0 Bcfd by 2015. The Junggar has extensive and highly prospective yet completely untested shale gas and oil deposits in multiple formations and geologic settings. ARI's initial data and analysis suggest that the Junggar Basin, while not China's largest shale resource, actually may be its best overall in terms of shale geology and reservoir potential. Shell and Hess recently signed study agreements with PetroChina on shale oil projects in outlying areas of the Junggar Basin.

Figure XX-24. Structural Elements Map of the Junggar Basin Showing
ARI-Proprietary Shale Gas Data Locations and Location of Shale-Prospective Areas.



Source: ARI, 2013.

The Junggar Basin is an asymmetric cratonic basin with a thrusted southern margin and mostly gently dipping north, west and east margins. The basin contains up to 9 km of Carboniferous and younger strata, **Figure XX-25**. Four main source rocks are present: Carboniferous, Permian, Triassic, and Jurassic.[46] Of these, the Permian is considered the most important due to its very high TOC and good genetic potential, followed distantly by the Triassic. The Junggar is a thermally immature basin with abnormally low heat flow. Gas window maturities (R_o > 1%) are attained only in the North Tianshan foreland region at depths of greater than about 5 km.[47]

Figure XX-25. Stratigraphy of the Junggar Basin, Highlighting Prospective Permian and Jurassic Source Rocks.

JUNGGAR BASIN					
ERA	PERIOD	EPOCH	FORMATION	AGE (Ma)	THICKNESS (m)
CENOZOIC	QUATERNARY	Q	Xiyu	0 - 2.6	350 - 2046
	TERTIARY	N	Dushanzi	2.6 - 5.3	207 - 1996
			Taxihei	5.3 - 23.3	100 - 320
			Shawan		150 - 500
		E	Anjihaihe	23.3 - 32	44 - 800
			Ziniquanzi	32 - 65	15 - 855
MESOZOIC	CRETACEOUS	K2	Donggou	65 - 96	46 - 813
		K1	***Tugulu***	96 - 145.6	84 - 964
	JURASSIC	J3	Kalaza	145.6 - 157.1	50 - 800
			Qigu		144 - 683
		J2	**Toutunhe**	157.1 - 178	200 - 645
			Xishanyao		137 - 980
		J1	**Sangonghe**	178 - 208	148 - 882
			Badaowan		100 - 625
	TRIASSIC	T3	***Baijiantan***	208 - 227	123 - 457
		T2	***Kelamay***	227 - 241	250 - 450
		T1	***Balkouquan***	241 - 245	30 - 269
PALEOZOIC	PERMIAN	P3	***Upper Wuerhe***	245 - 257	830 - 1850
		P2	**Lower Wuerhe**	257 - 270	
			Xiazijie		850 - 1160
		P1	**Fengchen**	270 - 290	430 - 1700
			Jiamuhe		1800 - 4000
	CARBONIFEROUS	C2	***Talieguia***	290 - 320	
		C1	Baogutu	320 - 354	
	DEVONIAN			354	
	Source Rock		***Conventional Reservoir***		

Source: ARI, 2013.

Lower Carboniferous petroleum source rocks are up to 1,300 ft thick, while Upper Carboniferous source rocks reach up to 1,000 ft thick. These are described as dark grey mudstone of marine character, with TOC of 0.5% to 2.4% (Type II, III). The Carboniferous is mostly too deep (> 5 km) but shoals to less than 3 km depth in uplifted portions of the basin. The Jurassic is a coal-bearing, non-marine unit that is rich in clay, probably ductile, and thus not suitable for shale-type hydraulic stimulation. Both Jurassic and Carboniferous units have lower and more variable TOC, mainly Type III, and are considered poor quality source rocks.

The dominant Permian source rocks were deposited primarily in lacustrine and fluvial environments and have exceptionally high TOC of up to 20% (Type I/II kerogen, not coal), making them one of the world's richest.[48] The Permian is considered liquids-rich (R_o= 0.7% to

1.0%) at target depths of 2-5 km. Although Permian source rocks are too deep for commercial development in the troughs, they do shoal to prospective depth of less than 4 km along some of basin flanks and interior uplifts.

The single most important source rock is the Mid-Permian Pingdiquan Formation (known as Lucaogou in the south), a lacustrine to deltaic deposit up to 1,200 m thick present. It consists of grey to black mudstones, oil shales and dolomitic mudstones interbedded with thin sandy mudstones, shaly siltstones, siltstones and fine sandstones. Hydrocarbon source rock thickness in the Pingdiquan ranges from 50 m to a remarkable 650 m. **Figure XX-26** shows detailed stratigraphy and TOC profiles for two outcrop sections in the Permian Lucaogou Fm of the southern Junggar Basin. Approximately 300 to 700 m of organic-rich but thermally immature lacustrine mudstone is present, with TOC averaging 5% and reaching a maximum of 20%.[49]

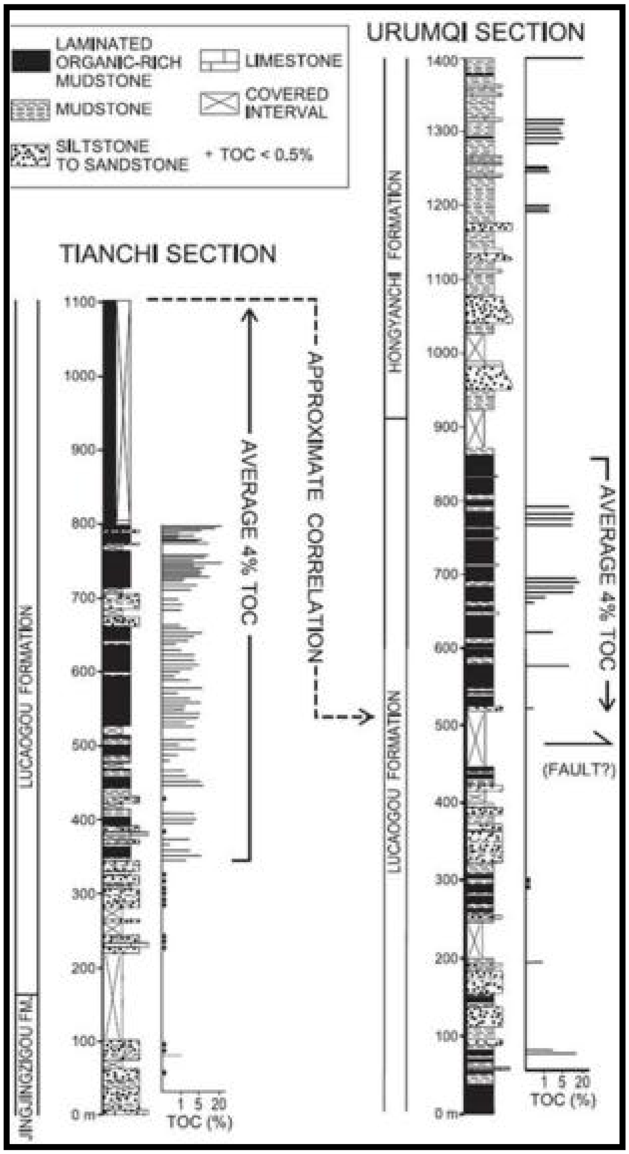
Triassic sediments are more widely distributed across the eastern Junggar Basin than the Permian, with the depocenter at the front of the Tianshan mountains. The Mid- to Upper Triassic Xiaoquangou Group (including Karamay, Huangshanjie, and Haojiiagou formations) contains up to 250 m of dark mudstones and thin coals deposited under fluvial-lacustrine conditions.

Conventional oil deposits in the eastern Junggar sourced by these units occur in the Fukang, North Dongdaohaizi, Wucaiwan, and Jimursar structural depressions (“sags”). These deposits include the Cainan, Wucaiwan, Huoshaoshan, Shanan, Beisantai, Santai and Ganhe oilfields which produce from conventional reservoirs of Carboniferous, Permian, Triassic and Jurassic age.

The Junggar Basin is characterized by much simpler structural geology than the tectonically more complex shale basins of southern China. While some edges of the Junggar Basin can be structurally complex, particularly along its thrusted southern margin, most of the basin interior has gentle dip angle and relatively few faults. Such simple structure is considered favorable for shale gas/oil development.

Advanced Resources International, Inc.

Figure XX-26. Detailed Stratigraphy and TOC Profiles for Two Outcrop Sections in the Permian Lucaogou Fm, Southern Junggar Basin. Approximately 300 to 700 m of Organic-rich but Thermally Immature Lacustrine Mudstone is Present, with TOC Averaging 4% (Maximum 20%).

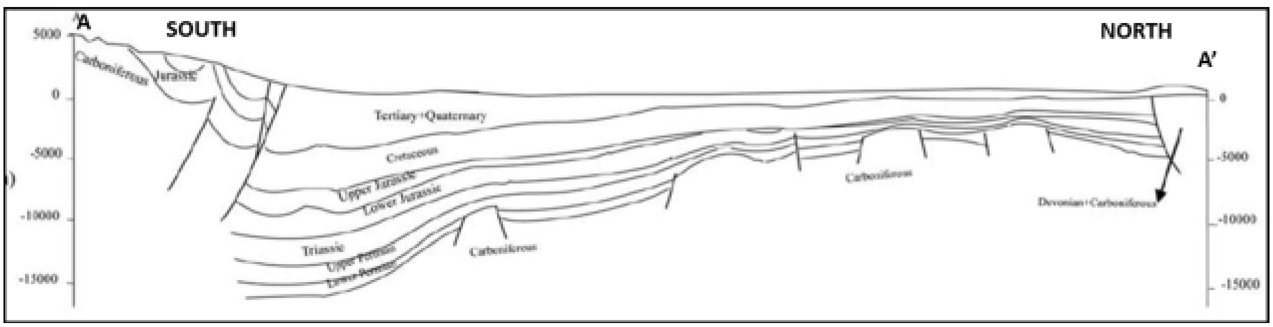


Source: Carroll and Wartes, 2003.

For example, **Figure XX-27** shows a regional north-south structural cross-section across the entire Junggar Basin, illustrating the relatively simple interior structure as well as the overthrusted southern margin.[50] Note that Permian and Jurassic source rocks are quite thick but too deep (>5 km) in most of the central basin trough. These units become shallower to the north but also thin out on structural uplifts.

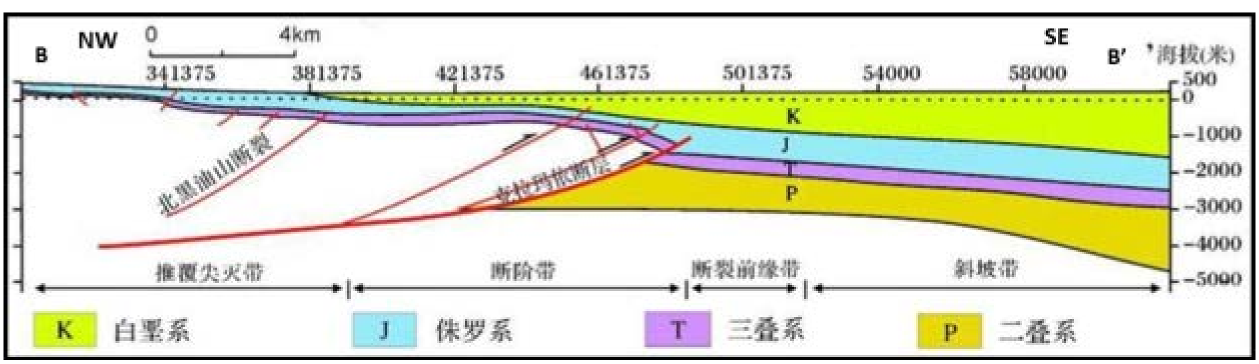
In particular, on the northwest flank of the Junggar Basin, Permian through Cretaceous strata dip quite gently (1° southeast) towards the central trough, **Figures XX-28** and **XX-29**.[51,52] Again, faults here are relatively few on the basin interior side of the section but become more prevalent along the shallow western basin margin. This gently dipping northwest margin of the Junggar Basin hosts a highly prospective shale gas/oil lead. This part of the Junggar accounts for over 40% of the basin's conventional oil reserves and has good existing infrastructure.

Figure XX-27. Regional North-south Structural Cross-section Across the Junggar Basin. The Basin has Relatively Simple Structure, Apart from its Overthrusted Southern Margin. Permian and Jurassic Source Rocks are Very Thick but Too Deep (>5 km) in the Central Basin Trough. These Units Become Shallower to the North but Thin Out on Structural Uplifts. Vertical Exaggeration is 3.7x.



Source: Qiu et al., 2008.

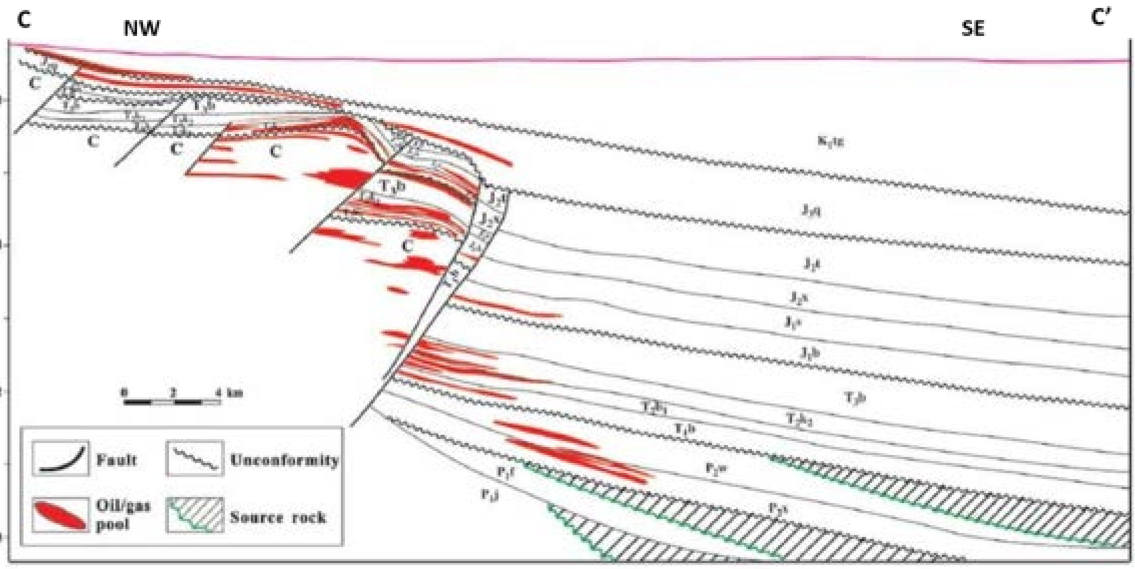
Figure XX-28. Detailed Structural Cross-section Trending Northwest-southeast Across the Northwest Margin of the Junggar Basin, Based on Seismic and Well Data. Permian (P), Triassic (T), Jurassic (J), and Cretaceous (K) Strata Dip Gently into Basin. Faults are Few in the Basin Interior but Become More Prevalent Along the Basin Margin. No vertical exaggeration.



Source: Zhu et al., 2010.

Advanced Resources International, Inc.

Figure XX-29. Structural Cross-section Trending Northwest-southeast Across the Northwest Margin of the Junggar Basin, Showing Conventional Oil Fields. Permian (P), Triassic (T), Jurassic (J), and Cretaceous (K) Strata Dip Gently into the Basin. Faults are Few in the Basin Interior but Become More Prevalent Along the Basin Margin. Vertical exaggeration is 6x.

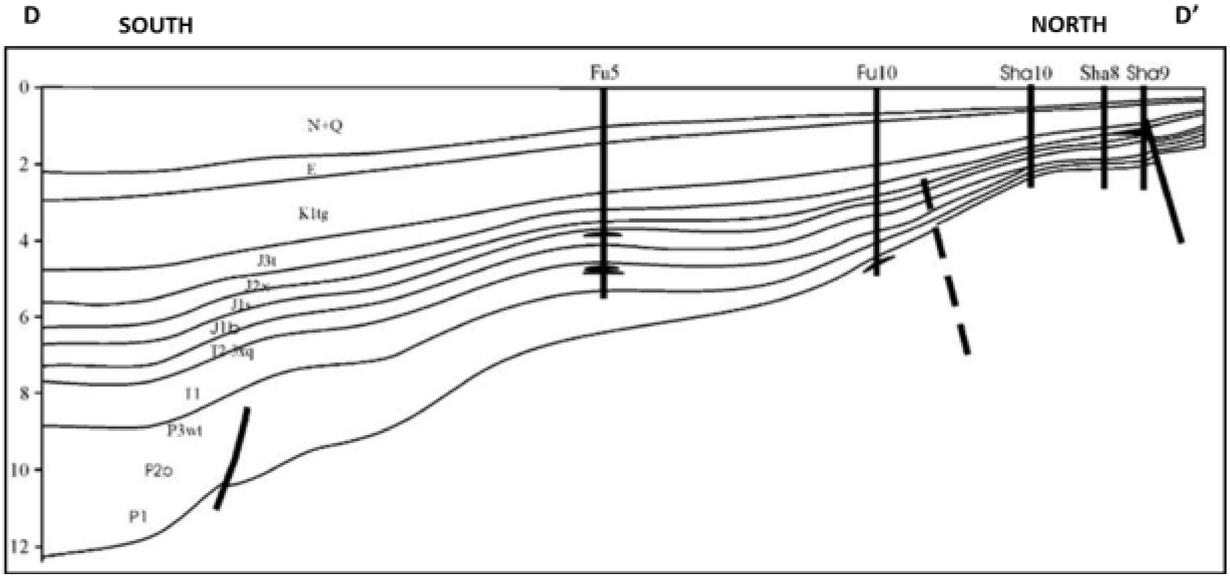


Source: Jin et al., 2008.

The southeastern Junggar Basin also has relatively simple structure. Permian and Jurassic source rock shales are thick but too deep (>5 km) near the southern basinal axis. These shales shoal but also thin onto the intra-basin high to the north, **Figure XX-30**. Even near intra-basinal uplifts structure is relatively simple. **Figure XX-31** shows conventional sandstone reservoirs in the Cainan oil field, central Junggar Basin, sourced by Permian and Jurassic shales which may be prospective for shale development further to the south in the deep Fukang Trough.[53]

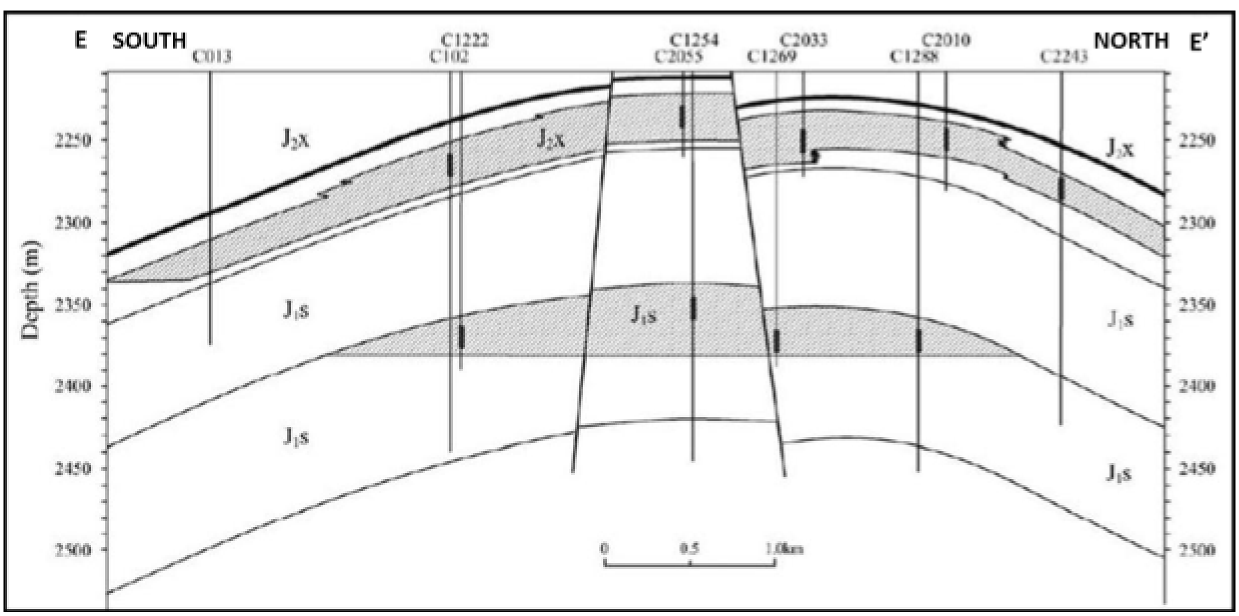
Reservoir pressure often is abnormally elevated in the Junggar Basin. For example, the Huo-10 well, located on an anticline in the southern Junggar, tested pressures of 50% to over 100% above hydrostatic levels in Eocene and Cretaceous formations at depths of 2,000 to 3,500 m, **Figure XX-32**.[54] Such overpressuring generally is favorable for shale development as it could increase shale gas storage and deliverability. As one author noted, referring here to conventional objectives: *"The Triassic and Permian overpressured bodies should hence be considered as an important objective for future* [conventional] *natural gas exploration because it is not currently feasible to penetrate into the overpressured bodies because of their deep burial depth in the study area, especially in the Changji depression."*[55]

Figure XX-30. South-north Oriented Structural Cross-section Across the Southeastern Junggar Basin. Vertical exaggeration 3.5x.



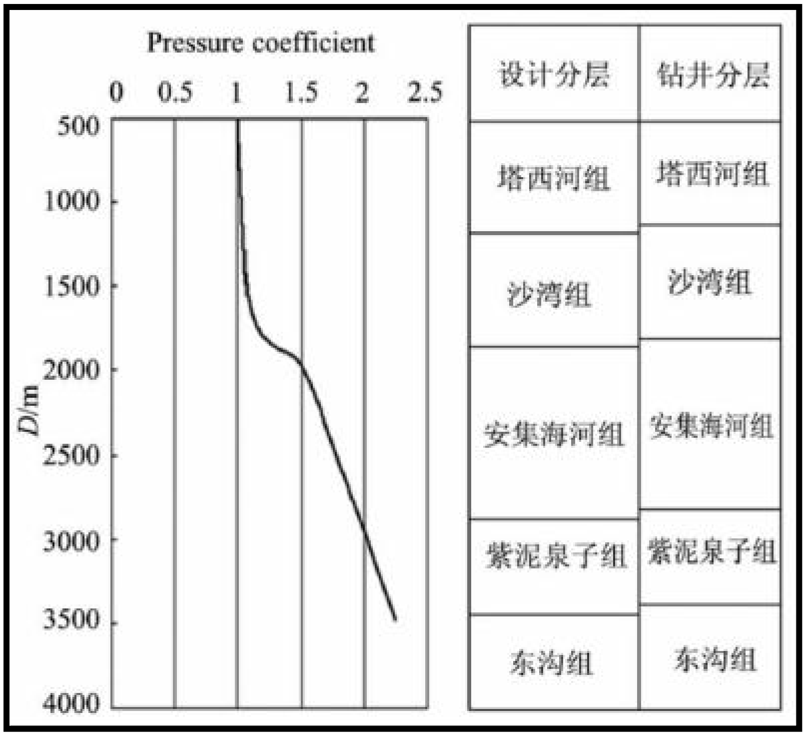
Source: Chen et al., 2003.

Figure XX-31. South-north oriented structural cross-section across the Cainan oil field, central Junggar Basin. The conventional sandstone reservoirs here were sourced by Permian and Jurassic shales in the Fukang Trough to the south, where they may be prospective for shale development. Vertical exaggeration 10x.



Source: Chen et al., 2003.

Figure XX-32. Over-Pressuring in Eocene and Cretaceous Formations at the Huo-10 Well, Southern Junggar Basin.



Source: Pa et al., 2009.

3.2 Reservoir Properties (Prospective Area)

Permian lacustrine mudstones and shales in the Junggar Basin cover a net prospective area of approximately 7,400 mi^2, based on depth and thermal maturity mapping. The net organic-rich portion of the Pingdiquan/Lucaogou formations averages about 820 ft thick and 11,500 ft deep, with average 5% TOC that is in the oil window (R_o of 0.85%).

Triassic lacustrine mudstones and shales cover a net prospective area of approximately 8,600 mi^2, based on depth and thermal maturity mapping. The net organic-rich portion of the Triassic formations averages about 820 ft thick and 10,000 ft deep, with average 4.0% TOC also in the oil window (R_o of 0.85%). No mineralogical data are available for the Permian or Triassic shales.

3.3 Resource Assessment

Highly prospective Permian lacustrine mudstones and shales in the Junggar Basin are estimated to have 5.4 billion barrels of risked, technically recoverable shale oil resources, out of 109 billion barrels of risked oil in-place. In addition, there could be 17 Tcf of risked, technically recoverable shale gas resources associated with the Permian shale oil deposits, out of 172 Tcf of risked shale gas in-place. While not China's largest shale resource base, the Junggar Basin Permian shales are considered particularly attractive based on their favorable thickness, source rock richness, over-pressuring, and simple structural setting. However, their lacustrine depositional setting is completely unlike the marine-deposited North American shales. The Junggar Basin shale appears closer to the REM sequence in Australia's Cooper Basin, which has had promising exploration testing for shale but is not yet fully commercial.

Triassic lacustrine mudstones and shales in the Junggar Basin have an estimated 6.7 billion barrels of risked, technically recoverable shale oil resources, out of 134 billion barrels of risked shale oil in-place. In addition, there could be 19 Tcf of risked, technically recoverable shale gas resources associated with the Triassic shale oil deposits, out of 187 Tcf of risked shale gas in-place. The Triassic is considered less prospective due to lower TOC, although the simple structural setting and over-pressuring are favorable.

3.4 Recent Activity

In April 2012 Shell and Hess signed joint study agreements with PetroChina's Turpan-Hami unit to evaluate shale oil in the Santanghu Basin, an outlying portion of the eastern Junggar Basin. PetroChina reported they had previously drilled 35 wells in this basin with unsatisfactory results.

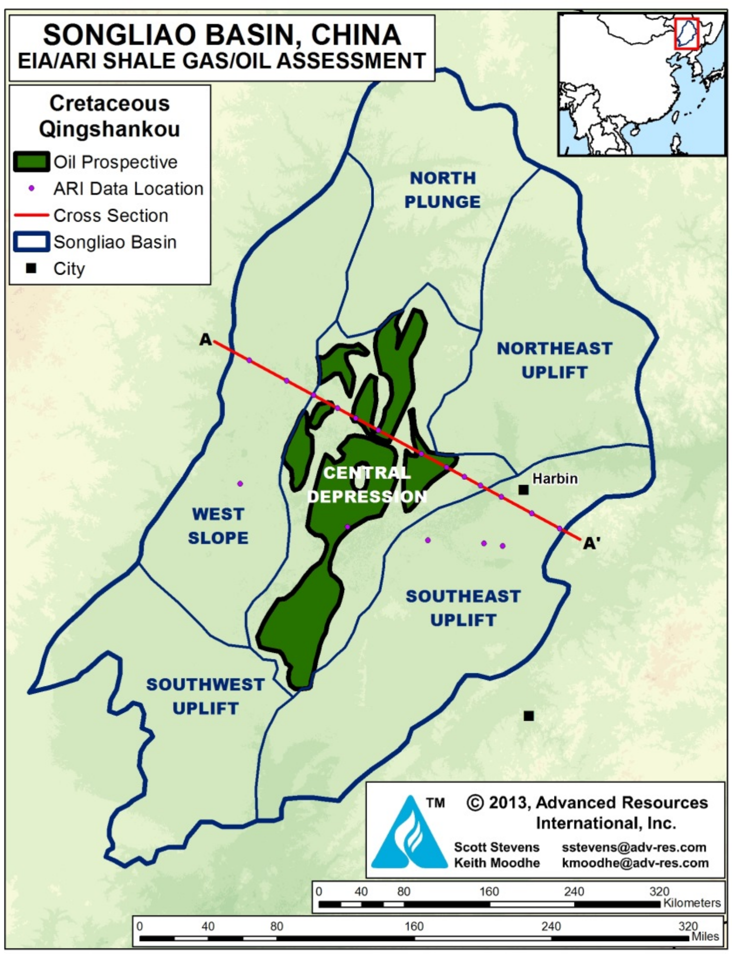
Hong Kong-based Enviro Energy's TerraWest Energy subsidiary operates a coalbed methane production sharing contract with partner PetroChina. The 655-km^2 Liuhuanggou PSC is located just west of Urumqi in the southern Junggar Basin. In addition to the CBM potential, Enviro Energy has reported on the shale potential of the block. The 300-m thick (gross) Jurassic Badaowan Formation contains coaly carbonaceous mudstone that was deposited in a non-marine environment. Third-party engineering consultancy NSAI estimated the unrisked prospective resources within the carbonaceous shale of the Jurassic Badaowan Formation of this PSC to be 1.512 Tcf (best estimate), restricted to a maximum depth of 1,500 m.[56] No shale test wells have been drilled on this property.

4 SONGLIAO BASIN

4.1 Introduction and Geologic Setting

The Songliao Basin in northeast China is an important petroleum producing region that also has shale gas and oil potential. The 108,000-mi^2 basin hosts China's largest oil field, the Daqing complex, currently producing about 800,000 bbl/day. Only in recent years has the natural gas potential of the Songliao become recognized, with new gas discoveries in mainly shallow (<1.5 km) Cretaceous sandstone and volcanic reservoirs. The thermal maturity of the Songliao Basin is relatively low and much of the conventional natural gas is believed to be of biogenic origin.[57] **Figure XX-33** shows the structural elements of the basin as well as locations of ARI-proprietary data used in conducting this study.

Figure XX-33. Prospective Shale Oil Area for the Cretaceous in the Songliao Basin, Showing ARI-Proprietary Data Locations.



Source: ARI, 2013.

Sedimentary rocks in the Songliao Basin are primarily Cretaceous non-marine deposits along with minor Upper Jurassic, Tertiary and Quaternary strata, totaling up to 7 km thick.[58] These strata rest unconformably on Precambrian to Paleozoic metamorphic and igneous rocks. The main source rocks are Lower Cretaceous organic-rich shales which formed in lacustrine settings, reflecting regional lake anoxic events, but they are unevenly distributed and concentrated in discrete sub-basins.

Figure XX-34 shows that the L. Cretaceous Shahezi, Yaojia -- and in particular the Qingshankou (Late Cenomanian) and Nenjiang formations -- are the principal source rocks (as well as important reservoirs themselves). Deposited under deepwater lacustrine conditions, these units consist of black mudstone and shale interbedded with gray siltstone. Siliciclastic rocks of alluvial and fluvial origin overlie the lacustrine shale sequences.

Figure XX-34. Stratigraphy of the Songliao Basin,
Highlighting Potentially Prospective Lower Cretaceous Source Rocks.

SONGLIAO BASIN

ERA	PERIOD	EPOCH	FORMATION	AGE (Ma)	THICKNESS (m)
CENOZOIC	QUATERNARY			0 - 2	0 - 143
	TERTIARY	Pliocene	Taikang	2 - 67	0 - 165
		Miocene	Daan		0 - 123
		Oligocene - Eocene	Yian		0 - 256
MESOZOIC	CRETACEOUS	Upper	Mingshui	67 - 92	0 - 624
			Sifangtai		0 - 413
		Lower	**Nenjiang**	***92 - 108.5***	118 - 1247
			Yaojia	***108.5 - 112***	0 - 210
			Qingshankou	***112 - 120.5***	78 - 664
			Quantou	120.5 - 131	0 - 2021
			Denglouku	131 - 144	0 - 1593
			Yingcheng		0 - 1200
			Shahezi		0 - 1000
	JURASSIC	J3	Huoshiling/Basement		0 - 2000
	Source Rock		***Conventional Reservoir***		

Source: ARI, 2013.

The Nenjiang Fm ranges from 70 to 240 m thick, while the Qingshankou Fm is 80 to 420 m thick (both gross). Burial depth ranges from 300 to 2,500 m. Shales and mudstones contain mainly clay minerals with some siltstone. TOC ranges from 1% to 5% (maximum 13%), primarily Type I-II kerogen (in the Qingshankou) and Types II-III (Nenjiang). The Qingshankou is thermally within the oil to wet gas windows (0.7% to 1.5% R_o), while the younger Nenjiang is in the oil window (maximum 0.9% R_o).

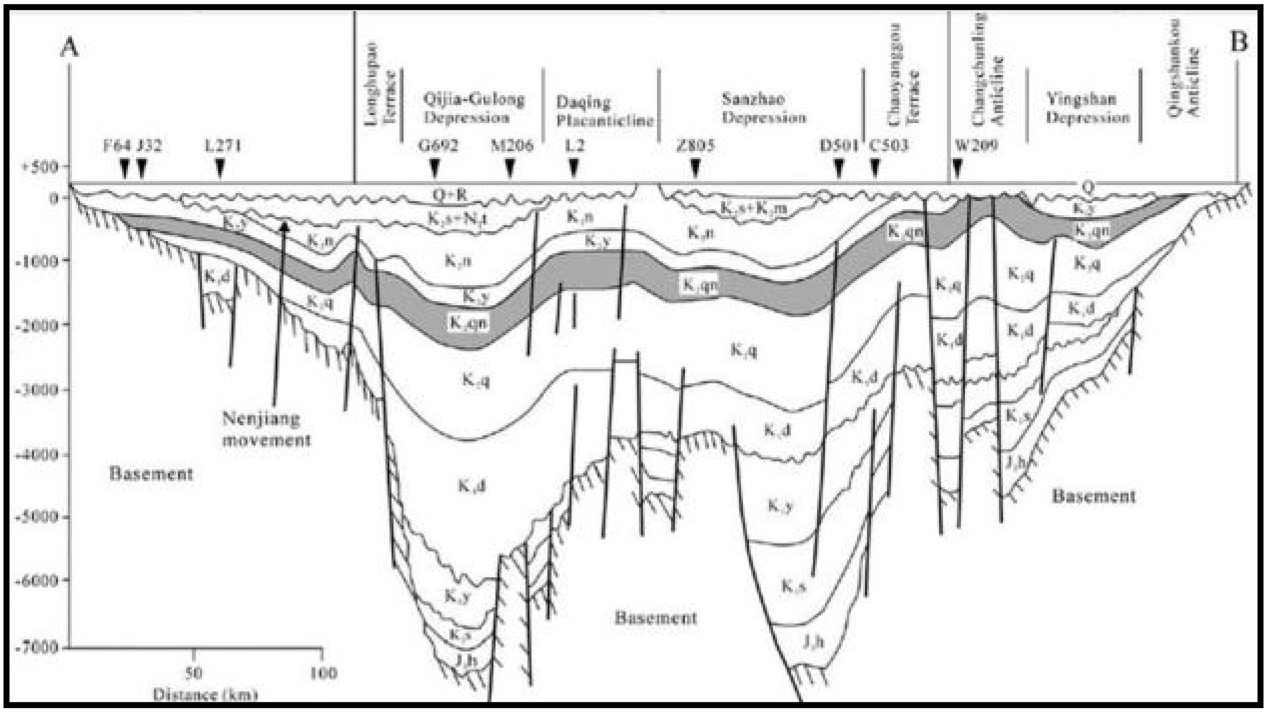
These Cretaceous source rocks are believed to have expulsed only some 20% of their hydrocarbon generation capacity. Frequently over-pressured and naturally fractured, the Nenjiang and Qingshankou shales exhibit strong gas shows and travel time delays on acoustic logs. PetroChina considers the Songliao Basin to be prospective for shale exploration and reported that commercial oil production already has occurred from shale there.[59]

The Songliao Basin comprises six main structural elements: the central depression, north plunging zone, west slope zone, northeast uplift, southeast uplift, and southwest uplift. Four distinct tectonic phases occurred in the basin: pre-rift, syn-rift, post-rift, and compression phases. Prospective L. Cretaceous units are restricted to numerous small isolated syn-rift basins, usually half-grabens trending NE-SW that range from 300 to 800 mi^2 in size.[60] This reduces the shale prospective area and also requires an understanding of each individual sub-basin's subsidence history.

Figure XX-35, a regional NW-SE trending structural cross-section, shows the alternating uplifts and depressions within the Songliao basin. Deformation is milder here than in South China but still significant with major normal faults. Organic-rich L. Cretaceous Qingshankou Formation (K_2qn), the most prospective shale oil target, ranges from 200-400 m thick and 0-2,500 m deep across the basin.[61]

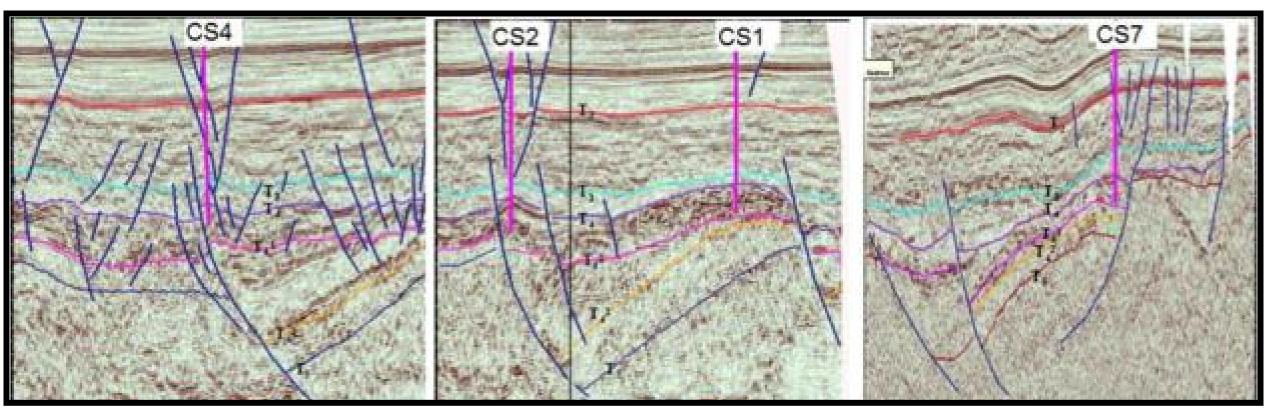
Elevated levels of carbon dioxide are common within Cretaceous sandstone and volcanic reservoirs in the Songliao Basin. About one dozen high-concentration (70-99%) CO_2 gas fields have been discovered to date, totaling 6.5 Bcf of proved reserves. Isotopes indicate the CO_2 is mainly magmatic in origin, emplaced between 72 and 48 Ma along deep-seated strike-slip faults.[62] For example, **Figure XX-36** shows seismic cross-sections in the Changling Depression of the Songliao, where northeast-trending strike-slip faults are associated with CO_2. Carbon dioxide contamination is a potential risk for shale gas exploration in the Songliao Basin, much less so for shale oil targets, although it is more likely to have migrated into high-permeability sandstones than into low-permeability shales.

Figure XX-35. Regional NW-SE Structural Cross-section of Songliao Basin. Organic-rich Cretaceous Qingshankou Formation (K2qn) is about 200-400 m thick and 0-2,500 m Deep Across the basin.



Source: Wu et al., 2009.

Figure XX-36. Seismic cross sections in Changling Depression of Songliao Basin, showing deep northeast-trending strike-slip faults associated with CO_2 contamination (scale, location not noted).



Source: Luo et al., 2011.

4.2 Reservoir Properties (Prospective Area)

Lower Cretaceous lacustrine mudstones in the Songliao Basin cover a net prospective area of approximately 6,900 mi^2, based on depth and thermal maturity mapping. The net organic-rich portion of the Qingshankou mudstones total about 1,000 ft thick and average 5,500 ft deep, with 4.0% TOC that is in the volatile oil window (average 0.9% R_o). Carbon dioxide was assumed to be about 10% in shale reservoirs. Natural fractures have been reported in certain parts of the basin but have not been quantified.

4.3 Resource Assessment

The Lower Cretaceous lacustrine mudstones and shales in the Songliao Basin are estimated to hold approximately 229 billion barrels of risked shale oil in-place with 11.5 billion barrels of risked, technically recoverable shale oil resources. Note that these deposits are located in isolated half-graben rift basins and may be difficult to extract due to the high-clay and likely ductile nature of the rock. In addition, there may be 16 Tcf of risked, technically recoverable shale gas resources associated with the shale oil deposits, out of about 155 Tcf of risked shale gas in-place.

The Songliao Basin lacks a suitable commercial North American shale analog, as it is structurally complex and of lacustrine sedimentary origin. The Eocene Green River Formation of Wyoming, which formed in an inter-montane lake setting, is a possible analog albeit of lower thermal maturity and less faulted.

4.4 Recent Activity

During 2010 Hess and PetroChina reportedly conducted a joint study of shale/tight oil potential at giant Daqing oil field in the Songliao Basin and also discussed expanding the study area. However, Hess' last update on this project came on January 26, 2011.

Separately, the Jilin Oilfield Company has drilled and massively fractured at least ten deep horizontal wells in a tight sandstone gas reservoir at Changling gas field in the southern Songliao Basin. These wells targeted the low-permeability Denglouku tight sandstone at a depth of about 3,600 m, but the technology also could be applied to tight/shale oil reservoirs. The Jilin wells typically drilled 1,200-m horizontal laterals that were stimulated in 11 stages isolated using sliding sleeves. However, the frac fluid used was heavy guar gel, rather than slickwater, and proppant was resin-coated sand. All ten wells were reportedly successful.[63]

5 OTHER BASINS

Several other sedimentary basins in China either do not appear to be prospective or have shale potential that could not be quantified due to insufficient geologic data. The Turpan-Hami Basin, east of the larger Junggar, has equivalent Permian organic-rich shale that is lacustrine in origin, oil- to wet gas-prone, and appears prospective. The Qaidam Basin, southeast of the Tarim, comprises isolated fault-bounded depressions containing Upper Triassic mudstone source rocks with high TOC; these appear oil prone but are very deep.

The Ordos Basin has simple structure but the Triassic shales have low TOC and very high clay content (40-60%). It is not clear whether a recently drilled shale test well actually produced gas from the shale formation or rather from adjacent tight sandstones which are commercially productive on a large scale in the Ordos Basin.[64] The Carboniferous and Permian mudstones in the Ordos are coaly and appear ductile. Finally, east-central China's North China Basin (Huabei) is a conventional oil and gas producing region that contains Carboniferous and Permian source rock shales that are stratigraphically and lithologically similar to those in the Ordos Basin and not considered prospective. No shale drilling has been reported in these less prospective areas.

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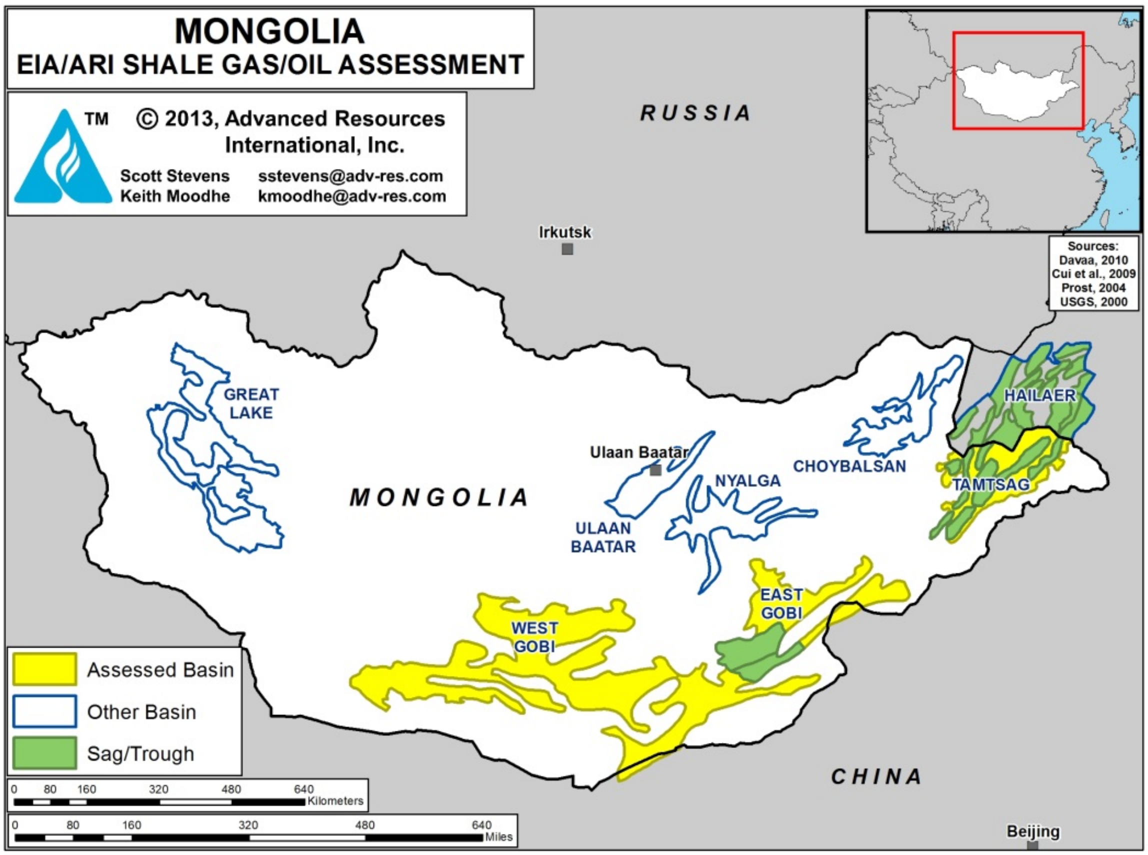
XXI. MONGOLIA

SUMMARY

Mongolia has limited but locally significant shale gas and oil potential located in the eastern and southeastern portions of the country, Figure XXI-1. The narrow and elongated Tamtsag and East Gobi rift basins - - which resemble the oil-productive basins of northeast China -- contain lacustrine mudstone and coaly source rocks within the Lower Cretaceous Tsagaantsav and equivalent formations.

Figure XXI-1. Sedimentary Basins of Mongolia



Source: ARI, 2013

Risked, technically recoverable resources are estimated at 4 Tcf of shale gas and 3.4 billion barrels of shale oil out of 55 Tcf and 85 billion barrels of risked shale gas and shale oil in-place, Tables XXI-1 and XXI-2.

Table XXI-1. Shale Gas Resources and Geologic Properties of Mongolia.

			East Gobi	Tamtsag
Basic Data	Basin/Gross Area		East Gobi ($24,560 mi^2$)	Tamtsag ($6,730 mi^2$)
Basic Data	Shale Formation		Tsagaantsav	Tsagaantsav
Basic Data	Geologic Age		L. Cretaceous	L. Cretaceous
Basic Data	Depositional Environment		Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		4,690	5,440
Physical Extent	Thickness (ft)	Organically Rich	600	500
Physical Extent	Thickness (ft)	Net	300	250
Physical Extent	Depth (ft)	Interval	6,000 - 10,000	5,000 - 9,000
Physical Extent	Depth (ft)	Average	8,000	7,000
Reservoir Properties	Reservoir Pressure		Normal	Normal
Reservoir Properties	Average TOC (wt. %)		4.0%	3.0%
Reservoir Properties	Thermal Maturity (% Ro)		0.80%	0.80%
Reservoir Properties	Clay Content		Medium	Medium
Resource	Gas Phase		Assoc. Gas	Assoc. Gas
Resource	GIP Concentration (Bcf/mi^2)		31.3	23.6
Resource	Risked GIP (Tcf)		29.3	25.7
Resource	Risked Recoverable (Tcf)		2.3	2.1

Table XXI-2. Shale Oil Resources and Geologic Properties of Mongolia.

			East Gobi	Tamtsag
Basic Data	Basin/Gross Area		East Gobi ($24,560 mi^2$)	Tamtsag ($6,730 mi^2$)
Basic Data	Shale Formation		Tsagaantsav	Tsagaantsav
Basic Data	Geologic Age		L. Cretaceous	L. Cretaceous
Basic Data	Depositional Environment		Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		4,690	5,440
Physical Extent	Thickness (ft)	Organically Rich	600	500
Physical Extent	Thickness (ft)	Net	300	250
Physical Extent	Depth (ft)	Interval	6,000 - 10,000	5,000 - 9,000
Physical Extent	Depth (ft)	Average	8,000	7,000
Reservoir Properties	Reservoir Pressure		Normal	Normal
Reservoir Properties	Average TOC (wt. %)		4.0%	3.0%
Reservoir Properties	Thermal Maturity (% Ro)		0.80%	0.80%
Reservoir Properties	Clay Content		Medium	Medium
Resource	Oil Phase		Oil	Oil
Resource	OIP Concentration ($MMbbl/mi^2$)		45.5	39.3
Resource	Risked OIP (B bbl)		43	43
Resource	Risked Recoverable (B bbl)		1.7	1.7

The organic-rich shales of Mongolia are thermally immature near the surface, locally forming combustible oil shale, but reach oil maturity (maximum R_o of 0.8 to 1.0%) in deeper areas ranging from 7,000 to 8,000 ft. However, these troughs are relatively small and disrupted by extensive faulting.

In addition, northwestern Mongolia has marine-deposited organic-rich shales of Devonian age that more closely resemble North America commercial shale lithology. Sporadic oil seeps have been reported in this remote region but no significant oil fields have been discovered. Data on this Devonian shale deposit are extremely limited. Most other areas in Mongolia are covered by non-prospective basement that lacks sedimentary strata.

Mongolia has an established conventional oil and gas investment regime with relatively low royalty (12.5%) and corporate income tax (25%). Nearly all of the country's sedimentary basins have been leased for conventional petroleum exploration. Regulations governing the development of deep shale oil/gas resources have not yet been promulgated in Mongolia. No shale leasing or exploration drilling activity has occurred, although Petro Matad Ltd. is evaluating the Khoid Ulaan Bulag oil shale deposit.

INTRODUCTION

With a population of about 3 million people, Mongolia has the world's lowest population density – only 1.8 inhabitants per km^2 or about half that of Canada. Mining development is helping to boost Mongolia's GDP by an expected 25% per annum over the coming decade and per-capita GDP is expected to reach $10,000 by 2020, up three-fold from the current level. Oil consumption is rising rapidly as the country develops its considerable mineral and coal deposits, including what soon may be the world's largest copper mine at Oyu Tolgoi.

Most of Mongolia is covered by igneous and metamorphic rocks but there are several relatively shallow and sparsely drilled sedimentary basins, Figure XXI-1. Oil production is small at about 5,000 bbl/day, limited to two oil fields in the East Gobi Basin in southeastern Mongolia near the border with China. Mongolia has no commercial natural gas production nor gas pipeline infrastructure. Petroleum drilling services are available locally in the East Gobi Basin, while additional capability may be sourced out of oil fields in northeast China.

Three of Mongolia's sedimentary basins may have limited shale oil potential, but only two basins could be quantitatively evaluated; geologic data are sparse. The most prospective

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areas for both conventional and shale oil exploration are the East Gobi and Tamtsag basins. These basins are relatively small and somewhat complex structurally; only the East Gobi Basin has small commercial oil production.

In addition, there is a non-productive and poorly defined Devonian deposit in northwest Mongolia close to the border with Russia that may have conventional and shale oil potential, although public data there are lacking. These include Riphean–Cambrian carbonates which formed on platforms of the Siberian passive margin, predating assembly of the present-day Mongolian basement. Devonian shale also is present here and oil seeps have been noted. Carboniferous–Permian coal and coaly mudstone samples immediately postdate these Paleozoic collisions and represent the beginning of non-marine deposition in central Mongolia. TOC reportedly is low (0.58% to 1.68%) and oil prone (T_{max} of 429 to 441).[1] Moreover, these source rocks are remote, poorly understood, and appear to have little shale oil potential.

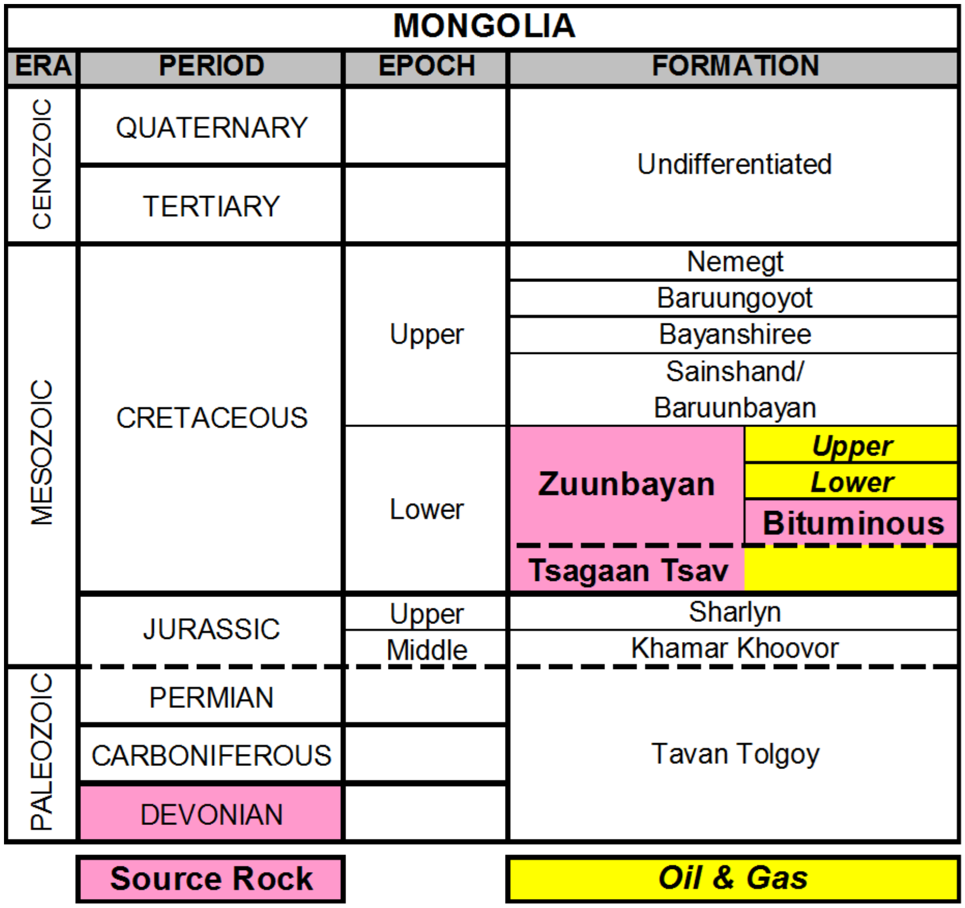
1. EAST GOBI BASIN

1.1 Introduction and Geologic Setting

The 25,000-mi^2 East Gobi Basin is located in southeastern Mongolia close to the border with China, accessible along the main highway between the capitol Ulan Bataar and north-central China. Mongolia's only significant commercial oil-producing region, the basin is along strike with and similar to oil-productive Mesozoic rift basins in northeast China, where much more geologic data are available. The East Gobi Basin shares similar stratigraphy and structural geology with these adjoining basins in northwest China.

The East Gobi Basin comprises a number of discontinuous, fault-bounded rift basins containing Jurassic to Early Cretaceous fluvial to lacustrine sediments, Figure XXI-2. The thick Lower Cretaceous shales that occur in the East Gobi Basin frequently have high TOC but were deposited under lacustrine conditions. Thermal maturity of the shale is immature at shallow depths, becoming oil prone in the deep troughs that sourced the shallow conventional oil fields.

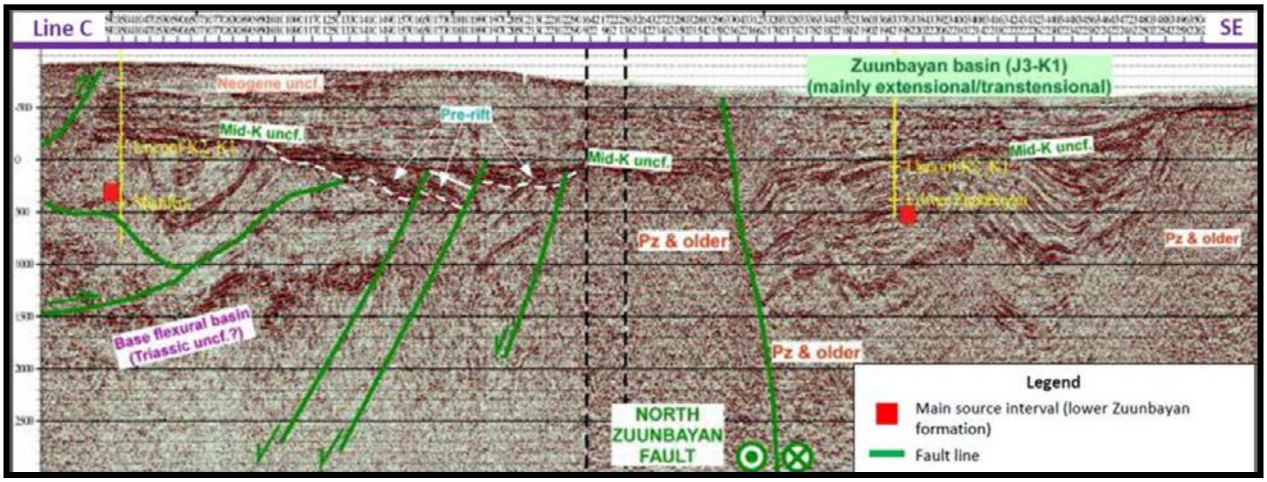
Figure XXI-2. Stratigraphy of Shale Source Rocks and Conventional Reservoirs in Mongolia



Source: ARI, 2013

The East Gobi Basin contains four main sub-basins within a 200- by 400-mi area that is defined broadly by gravity and seismic data.[2] The sub-basins contain discontinuous deep depressions, separated by basement highs that are exposed over much of the region. Deep, fault-bounded troughs with good quality source rock mudstones can occur. However, the deep areas (>6,000 ft) cover only a relatively small area. The largest sub-basins are the Unegt (3,090 mi^2) and Zuunbayan (1,600 mi^2), Figure XXI-3. Uplifted fault blocks occur within these troughs, some forming conventional oil traps.

Figure XXI-3: Seismic Line Across the Zuunbayan and Unegt Sub-basins within the East Gobi Basin Showing their Relatively Small Size and Complex Structure.



Source: Manas Petroleum Corp., 2012

Conventional reservoirs in the East Gobi Basin currently produce about 5,000 bbl/day from two small anticlinal oil fields. The Zuunbayan oil field has produced a total of about 6 million barrels from shallow depths (2,000 to 2,500 ft), while the nearby Tsagaan Els oil field has produced smaller volumes from depths of 4,265 to 4,600 ft. Both fields produce from conventional reservoirs comprising lacustrine siltstones, sandstones and conglomerates within the Tsagaantsav and Zuunbayan formations, which were sourced by the interbedded lacustrine shales. Original oil in place at the two fields totaled an estimated 150 Mmillion barrels. Oil gravity averages 28° API.[3]

Each sub-basin contains up to 13,000 ft of Middle Jurassic to Tertiary sedimentary rock, including thick lacustrine-deposited mudstone. Northeast-trending, mainly normal and strike slip (left-lateral) faults bound the sub-basins. The structural history of the region includes Mid-Jurassic to Early Cretaceous rifting (north-south extension), Early Cretaceous north-south compression and inversion along pre-existing faults, renewed sedimentation and right-lateral displacement along northeast faults during the Mid-Cretaceous, followed by post-Late Cretaceous east-west shortening.

Basement in the East Gobi Basin consists of metamorphosed sandstone and carbonate of the Paleozoic Tavan Tolgoy sequence. The oldest sedimentary unit is the Lower to Mid–Jurassic Khamarkhoovor Formation, a pre-rift sequence consisting of up to 2,500 ft of fluvial sandstones and lacustrine-deltaic shale, including thin coal seams. Although a potential source rock, the Khamarkhoover seldom crops out and remains poorly understood. Unconformably overlying this unit is the Sharlyn Formation, containing up to 600 ft of fluvial sandstone and conglomerate with minor lacustrine shale.

Overlying the Sharlyn Fm are the primary shale targets in the East Gobi Basin, the Lower Cretaceous Tsagaantsav and Zuunbayan formations. The Tsagaantsav Fm, a late synrift sequence 1,000 to 2,300 ft thick that locally can contain thick oil shale, is mainly an organic-rich shale section interbedded with dark gray sandstones and conglomerates, siltstones, bright-red tuffs, and basalt. The unit grades upward from alluvial fan to lacustrine facies, becoming a lithic sandstone reservoir at the Tsagaan Els and Zuunbayan oil fields.

A 125-m thick core section in the Tsagsaantsav Fm was described as consisting of finely laminated mudstone and micrite, dolomitic breccia, and calcareous siltstone. These fine-grained units are interbedded with grainstone and thin, normally graded sandstone beds interpreted as distal lacustrine turbidites. Anoxic, stratified lake-bottom conditions are indicated by micro-lamination, biogenic pyrite, high TOC, and carbonate precipitation. TOC ranges from 1.5% to 15% for shale, mainly oil-prone Types I and II kerogen. S1 and S2 values are above 0.5 and 10, respectively, indicating good quality source rocks. Thermal maturity is immature to middle oil window. Oil quality is waxy with 20-35% paraffin and high pour point. Oil typing indicates a lacustrine algal source.[4]

The other potential shale target is the Lower Cretaceous Zuunbayan Formation, which consists of up to 3,200 ft of sands and minor interbedded shales and tuffs deposited during Hauterivian to Albian time under non-marine to paralic environments. However, the Zuunbayan is coaly, probably clay-rich, and likely less brittle, thus not a very prospective target for shale oil development.

Deep portions (6,000 to 10,000 ft) of the Unegt, Zuunbayan, and other sub-basins in the East Gobi Basin may be oil prone and offer potential shale oil targets. Burial history modeling suggests that peak oil generation occurred during the Cretaceous (90 to 100 Ma), continuing at a lower rate to the present day. However, the East Gobi Basin is structurally complex, with numerous closely spaced faults that may limit its potential for shale oil development.

1.2 Reservoir Properties (Prospective Area)

Within the 4,690-mi^2 high-graded prospective area of the Unegt and Zuunbayan troughs in the East Gobi Basin, the Lower Cretaceous Tsagaantsav Formation contains an estimated 300 ft (net) of organic-rich lacustrine shale at an average depth of 8,000 ft. TOC averages an estimated 4.0% and is oil-prone (R_o averaging 0.8%). Porosity may be significant (6%) given the silty lithology. The reservoir pressure gradient is normal.

1.3 Resource Assessment

The Tsagaantsav Formation contains an estimated 29 Tcf of risked shale gas in-place and 43 billion barrels of risked shale oil in-place, of which 2.3 Tcf of associated shale gas and 1.7 billion barrels of shale oil may be technically recoverable (both risked), Table XXI-1. The closest international analog appears to be the oil-prone window of the REM lacustrine shales in the shallow western Cooper Basin, although these have not yet been proven commercially productive.

1.4 Exploration Activity

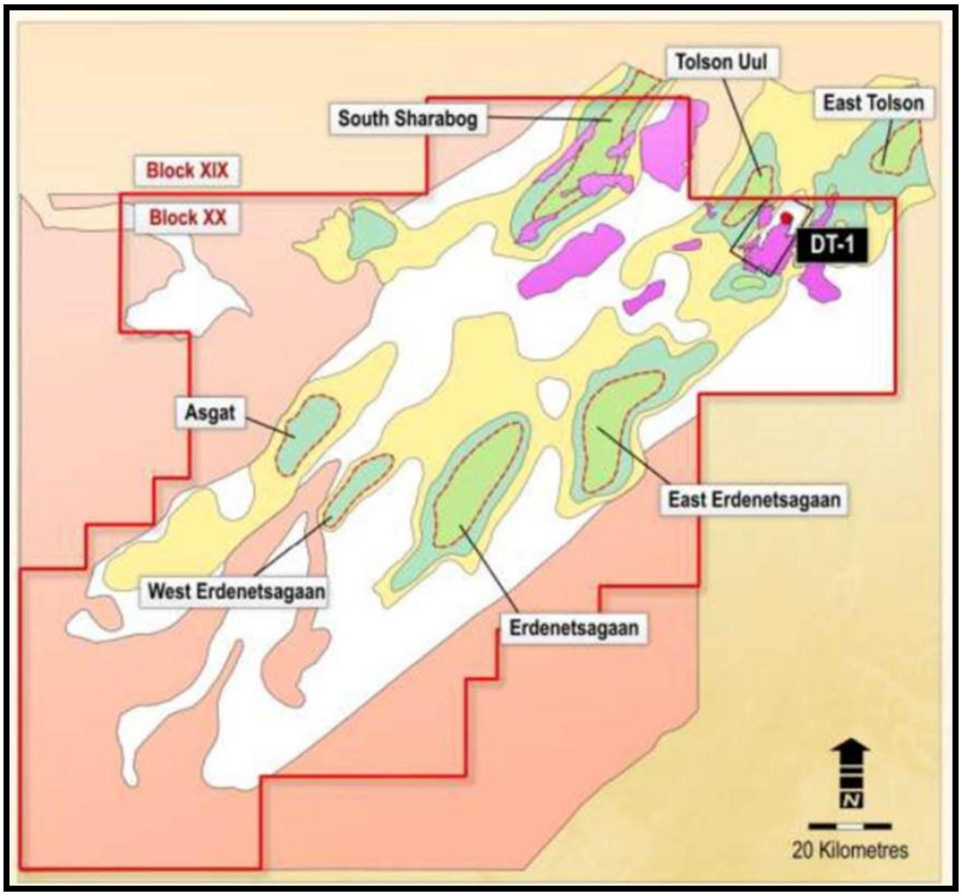
No shale oil or shale gas exploration or leasing has occurred in the East Gobi Basin. Calgary-based Manas Petroleum Corp. is conducting petroleum exploration for conventional targets in this basin but has not discussed its shale potential.[5] London-based Petro Matad Limited is evaluating Khoid Ulaan Bulag oil shale deposit in Block IV for potential mining. This deposit reportedly has similar mineralogy to the Green River Formation in Wyoming, USA, containing carbonate, quartz, and feldspar mineralogy. Extended Fischer Analysis yielded one liter of 29° API oil from a 10-kg sample.[6]

2 TAMTSAG BASIN

2.1 Introduction and Geologic Setting

Although geologically similar to the East Gobi Basin, the 6,700-mi^2 Tamtsag Basin in extreme eastern Mongolia has no commercial oil and gas production. The basin comprises a number of isolated, fault-bounded troughs that trend WSW-ENE along an extent of about 80 by 300 km, Figure XXI-4. Just as in the East Gobi Basin, potential source rocks are the Lower Cretaceous Tsagaantsav and Zuunbayan formations, with TOC averaging about 3%.

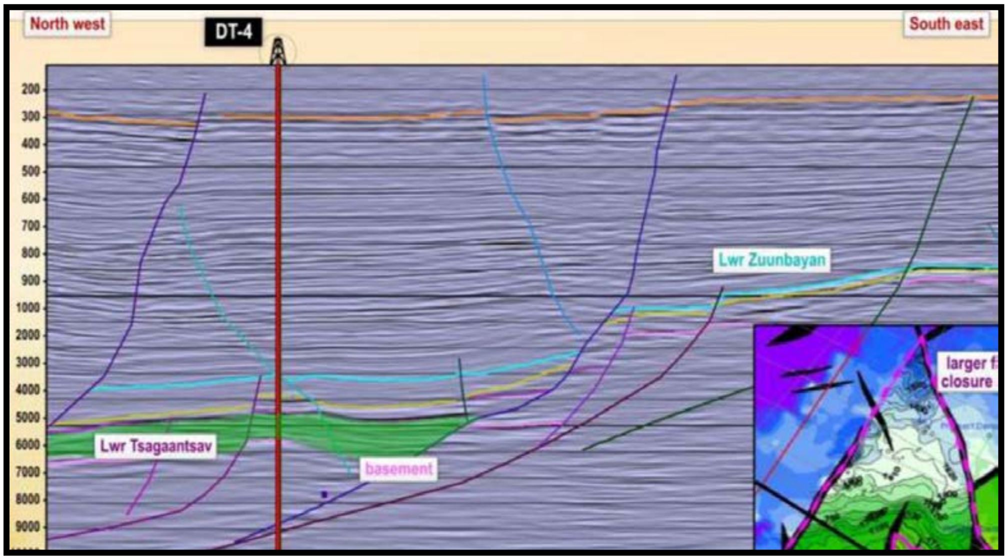
Figure XXI-4. Western Tamtsag Basin Showing Small Isolated Structural Troughs where Source Rock Shales are Buried to Over 5,000 ft and May Reach Oil-window Thermal Maturity.



Source: Petro Matad Ltd., 2012

Internally the Tamtsag Basin comprises a number of uplifted fault blocks and down-faulted grabens created by rifting and Mid-Cretaceous basin inversion, Figure XXI-5.[7] Late Cretaceous transpression formed structural traps in conventional targets, notably tilted fault blocks and anticlines. Structural complexity is most pronounced in the southwest, decreasing towards the northeast. The basement consists of Devonian to Permian metamorphic and intrusive rocks.[8]

Figure XXI-5. Seismic line in the Tsamtsag Basin Showing Source Rocks Buried to a Depth of about 6,000 ft.



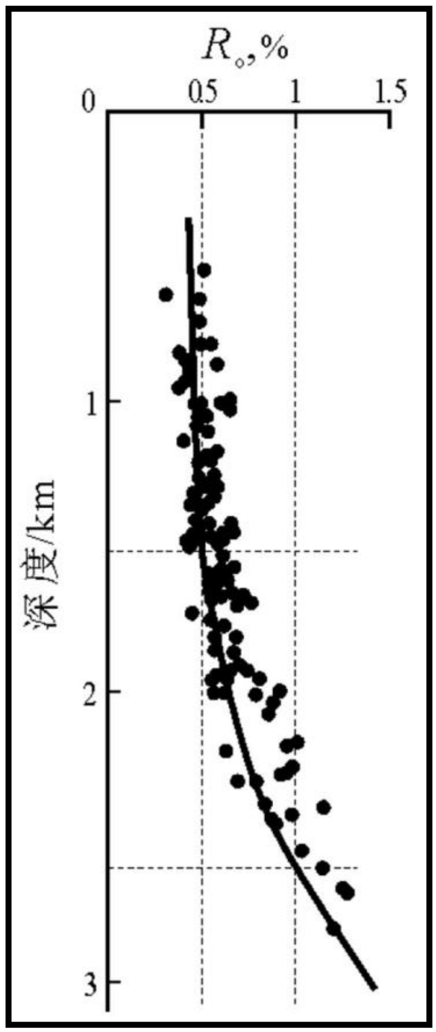
Source: Petro Matad, 2010

The Tamtsag Basin contains up to 13,000 ft of Mid-Jurassic to Tertiary non-marine and volcanic sedimentary rocks. Grain texture fines upward from coarse continental rift-fill and fluvio-deltaic conglomerates and sandstone in the lower section transitioning into lacustrine mudstones and shales. The basal Upper Jurassic consists mainly of volcanic deposits (basaltic to andesitic) with minor interbedded sediments. The overlying Lower Cretaceous deposits consist of fluvio-deltaic conglomerates and sandstones that fine upward into deepwater lacustrine shales. Younger Cenozoic conglomerates, sandstones, and mudstones cover much of the basin, concealing the Mesozoic units.[9]

The Tamtsag Basin is on trend with the Hailaer Basin of northeastern China, a stratigraphically and genetically similar Mesozoic rift basin. Although the Hailaer Basin has not experienced shale exploration, it is oil producing and thus has much better data control. Similar to the Tamtsag, the Hailaer Basin actually comprises over 20 individual fault-bounded sub-basins. Coal deposits and carbonaceous mudstones within the upper portion of the Lower Cretaceous Nantun Formation are considered the major petroleum source rocks in the Hailaer Basin. The Hailaer Basin oil fields produce with high water cut and have locally elevated CO_2 levels.

The Nantun Formation was deposited within fan delta front, pro-fan delta, marsh and lacustrine environments. Organic carbon content of the organic-rich mudstone within this unit ranges from 0.23% to 16.67%, averaging 2.56%. The mudstone becomes oil-prone (R_o above 0.7%) below a depth of about 6,500 ft, Figure XXI-6,[10] while T_{max} averages 447°C with most samples above 435°C, indicating oil-prone kerogen.[11] Limited conventional oil production occurs in the Hailaer Basin, evidently due to poor reservoir conditions and high water saturation. In addition, the Lower Cretaceous conventional sandstone reservoirs can contain elevated CO_2 levels of up to 90%, which has been isotopically linked with granite intrusions emplaced during the Yanshan Orogeny.[12]

Figure XXI-6. Vitrinite Reflectance Increases to About 0.8% Ro at a Depth of 2.5 Km in the Wuerxun Trough of China's Hailaer Basin, Adjacent to the Tamtsag Basin in Mongolia.



Source: Liu et al., 2009

2.2 Reservoir Properties

Within the 5,440-mi^2 high-graded prospective area that is distributed amongst numerous small troughs within the Tamtsag Basin, the Lower Cretaceous Tsagaantsav Formation contains an estimated 250 feet (net) of organic-rich lacustrine shale at an average depth of 7,000 feet. TOC averages an estimated 3.0% and is oil-prone (R_o averaging 0.8%). Porosity may be significant (6%) given the silty lithology.

2.3 Resource Assessment

The Tsagaantsav Formation contains an estimated 26 Tcf of shale gas and 43 billion barrels of shale oil in-place, of which 2.1 Tcf of associated gas and 1.7 billion barrels of shale oil may be technically recoverable (both risked), Table XXI-1. The closest international analog appears to be the oil-prone window of the REM lacustrine shales in the shallow western Cooper Basin, although these have not yet been proven commercially productive.

2.4 Exploration Activity

No shale oil or shale gas exploration or leasing has occurred in the Tamtsag Basin, nor does the basin produce oil or gas from conventional reservoirs. PetroChina is currently conducting exploration drilling for conventional reservoirs in this basin.

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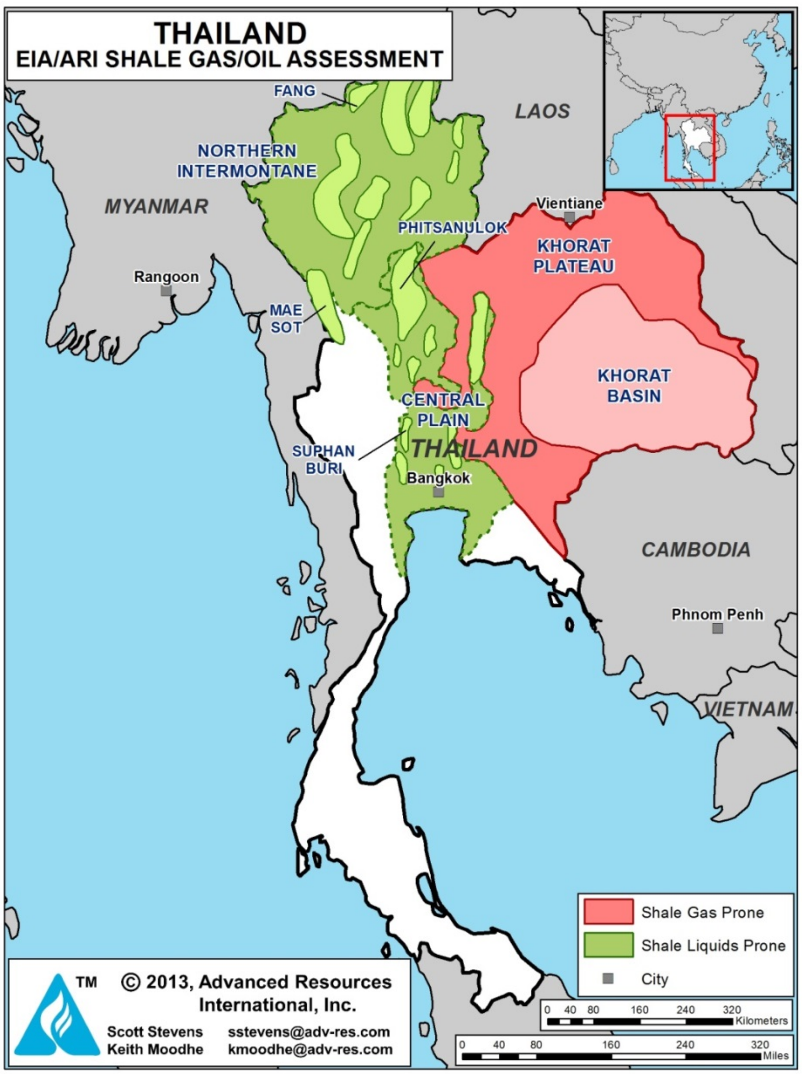
XXII. THAILAND

SUMMARY

While no shale gas/oil exploration activity has been reported to date in Thailand, this large Southeast Asian country has significant prospective shale gas and shale oil potential, in the Khorat, Northern Intermontane and Central Plains basins, Figure XXII-1.

Figure XXII-1. Prospective Shale Gas and Shale Oil Basins of Thailand.



Source: ARI, 2013

The Khorat Basin in northeast Thailand has an estimated 5 Tcf of risked technically recoverable shale gas resources, Table XXII-1. In addition, shale oil potential in the Northern Intermontane and Central Plains basins could be substantial but was not quantified due to the paucity of available public data. Block faulting has disrupted Thailand's onshore shale basins and may complicate future shale drilling and development. Overall, Thailand's shale gas/oil potential is promising but needs to be better defined by further data gathering and analysis.

Table XXII-1. Shale Gas Reservoir Properties and Resources of Thailand.

Basic Data	Basin/Gross Area		Khorat (32,400 mi^2)
	Shale Formation		Nam Duk Fm
	Geologic Age		Permian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		1,750
	Thickness (ft)	Organically Rich	400
		Net	200
	Depth (ft)	Interval	6,000 - 12,000
		Average	9,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		3.0%
	Thermal Maturity (% Ro)		2.50%
	Clay Content		Low
Resource	Gas Phase		Dry Gas
	GIP Concentration (Bcf/mi^2)		83.0
	Risked GIP (Tcf)		21.8
	Risked Recoverable (Tcf)		5.4

Thailand's greatest potential appears to be shale gas deposits contained in Permian and Triassic shale source rocks in the Khorat, the country's largest onshore sedimentary basin. These shales can be locally thick, organic-rich, dry gas prone, deeply buried, and over-pressured. Deposited under shallow marine conditions, they are likely to mineralogically brittle and suitable for hydraulic fracturing. The Khorat Basin has an existing gas pipeline network, local drilling rigs, and active independent oil and gas producers which could facilitate shale gas development.

Thailand's shale oil potential appears to be more limited. Small isolated sub-basins within the Northern Intermontane and Central Plains basins contain organic-rich shales of Oligocene to Early Miocene age. These units sourced the basin's conventional oil deposits, including the 30,000-b/d Sirikit-1 oil field. Thermally immature oil shale deposits that are locally mined at the surface may contain mobile hydrocarbons at depth. However, these low-rank Tertiary shales were deposited under lacustrine sedimentary conditions and may be high in clay content with low "frackability".

INTRODUCTION

During the past three decades Thailand has built up a substantial oil and natural gas production industry. The country produced 393,000 b/d of crude oil and liquids in 2011 and 3.6 Bcfd of natural gas in 2011.[1] Nearly 90% of its current petroleum output comes from offshore fields in the Gulf of Thailand, with only limited production from small onshore fields. Approximately 40% of Thailand's primary energy consumption is supplied by natural gas, including most of the country's power generation and growing vehicle fuel usage.

Essentially all of the oil and gas currently produced in Thailand comes from conventional sandstone and carbonate reservoirs. While a handful of coalbed methane exploration wells were drilled in Thailand during 2004-6, without commercial success, and some low-permeability carbonates are being targeted in conventional anticlinal traps in the Khorat, there have been no reports of unconventional shale/tight oil or gas exploration & development to date. The only tangible sign of activity for Thailand's unconventional resources was an MOU signed between Statoil and PTTEP in January 2011 covering potential joint studies of conventional and unconventional resources in Thailand and other countries.[2]

ARI's review of published geologic literature indicates that Thailand has three main onshore sedimentary basins which may have unconventional oil and gas potential, Figure XXII-1. These include the large Khorat Basin in the northeast; a series of smaller, isolated pull-apart basins (such as Mae Sot) in the Northern Intermontane Basin, where shale oil deposits are being mined; and the similarly complex Central Plains Basin, which hosts the 30,000-b/d Sirikit-1 oil field.

Permo-Triassic shale source rocks in the Khorat Basin, thought to have sourced the overlying Permian carbonate conventional reservoirs, may offer Thailand's best shale gas resource potential. These marine-deposited shales are thick, organic-rich, within the dry gas thermal maturity window, often over-pressured, and may be mineralogically brittle. The Khorat Basin hosts an existing gas pipeline network, a local supply of suitable drilling rigs, and a small group of active independent oil and gas producers.

Oil-prone shale/tight resources in Thailand appear to be less prospective, although available geologic information is scanter. The most obvious oil-prone shale potential is the downdip extension of lacustrine oil shale (solid mineral) deposits which are mined on a small scale in the northern inter-montane basins. Similar shale/tight oil deposits also may be present in the Central Plains Basin. These oil-prone shales appear less prospective due to their lacustrine origin, low apparent thermal maturity, as well as the general paucity of publicly available subsurface geologic data.

1. KHORAT BASIN

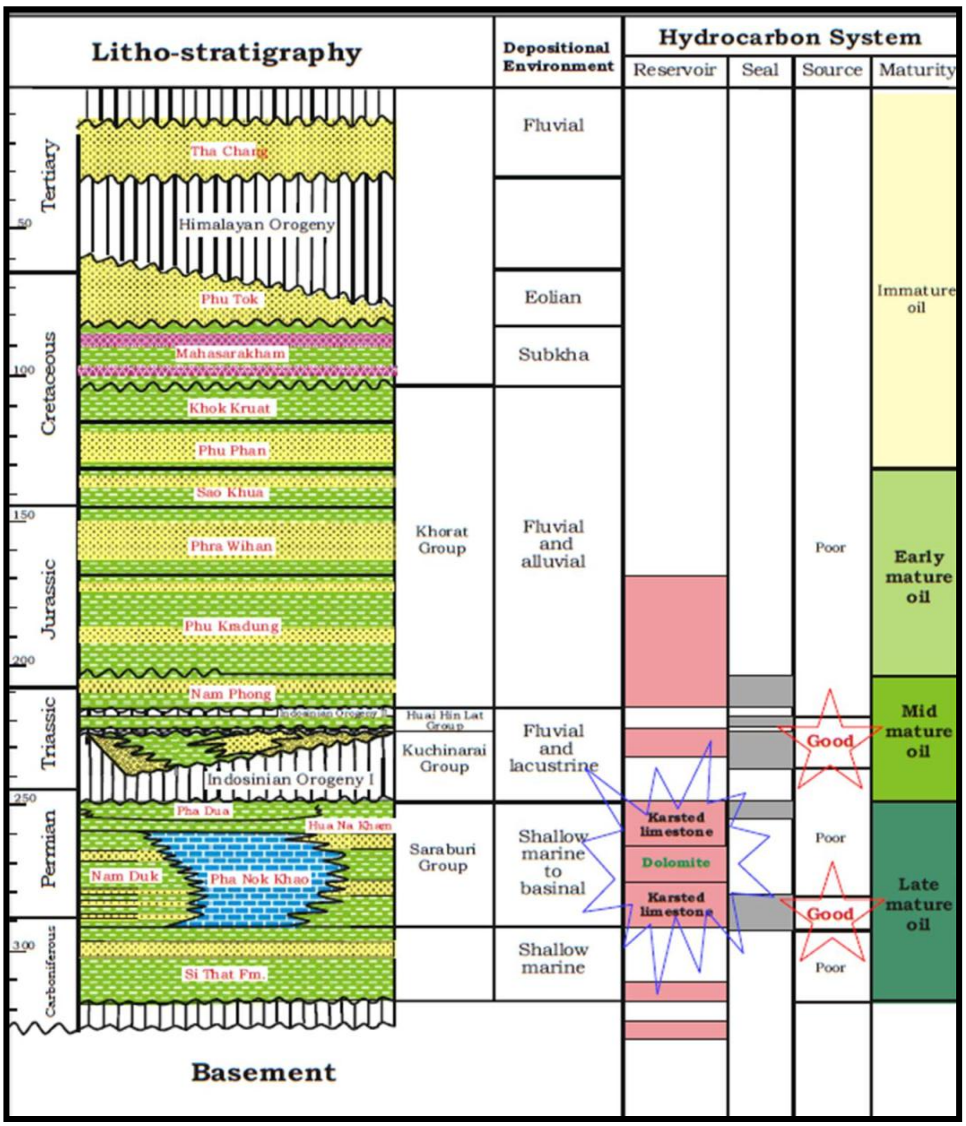
1.1 Introduction and Geologic Setting

The Khorat Basin in northeast Thailand appears to have the country's best shale gas potential. Thailand's largest onshore sedimentary basin, the 35,000-mi^2 petroliferous Khorat lies within the southern half of the Khorat Plateau, a large roughly circular physiographic province. Ringed by mountain ranges, the Plateau itself is relatively flat with 200-m average elevation. Drained by the Moin and Chi Rivers, the Khorat Plateau receives less rainfall than central Thailand, with more extreme dry and wet seasonality. The local economy of this rural area is mainly agricultural based, with few large cities or industrial centers.

The Khorat Basin is separated from the Sakon Nakhon Basin to the north by the Phu Phan anticline. The Khorat rests on the Indochina tectonic microplate, which is bordered by the Shan Thai and South China plates to the west and north, respectively. Its sedimentary sequence comprises a series of Late Cambrian through Recent strata, which are interrupted by numerous unconformities and dominated by Permo-Carboniferous, Triassic/Mesozoic, and Tertiary/ Quaternary deposits. Figure XXII-2 illustrates the stratigraphy and petroleum systems of the Khorat Basin.[3] The shallow marine to basinal Permian Saraburi Group is considered the primary source rock, while the fluvial to lacustrine Triassic Kuchinarai and Huai Hin Lat Groups offer additional source rock potential. Permian dolomite and karsted limestones form the main conventional petroleum reservoirs.

The structural Khorat Basin depression was initiated during the Middle Paleozoic, with widespread deposition of clastic and carbonate sedimentary rocks, beginning with the Carboniferous Si That Formation.[4] Tectonic extension during the Early Permian broke the basin apart into numerous horst and graben blocks separated by high-angle normal faults. Carbonate reef deposits of the Pha Nok Khao Formation formed on regional highs, while clastic and shale deposits of the Nam Duk Formation were deposited in the troughs, with some areas approaching 20,000 feet thick. Mixed sediments of the Hua Na Kham Formation were then deposited during the Middle to Upper Permian. Later basin-scale compression and inversion caused regional uplift and thrusting. Seismic and thermal maturity data indicate that uplift and erosion removed 3,000 to 9,000 feet of sedimentary cover during this event.

Figure XXII-2. Stratigraphy and Petroleum Systems of the Khorat Basin. Shallow Marine Permian Saraburi Group is the Primary Source Rock. The Fluvial to Lacustrine Triassic Kuchinarai and Huai Hin Lat Groups Also Have Potential. Permian Dolomite and Karsted Limestones are the Main Conventional Petroleum Reservoirs.



Source: Thailand Ministry of Energy, 2007.

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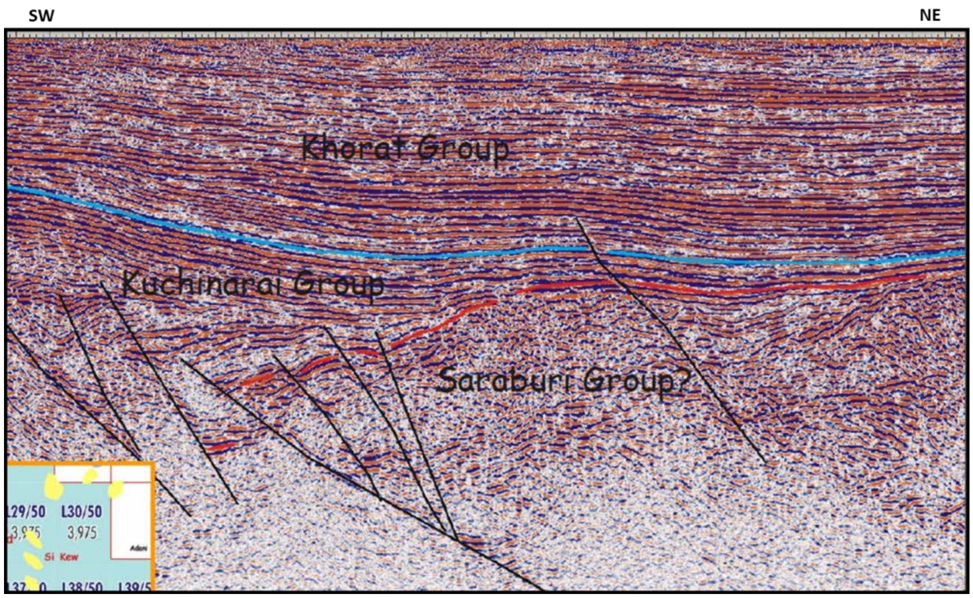
Following the Indosinian orogeny, Early Triassic continental and lacustrine sediments of the Kuchinarai Group began to unconformably fill the extensional grabens of the Khorat Basin. A second orogenic collision marked by volcanics followed, after which Late Triassic fluvial clastics were deposited. A further erosional or non-depositional hiatus occurred until the Middle to Late Jurassic, after which non-marine clastics and shales of the Khorat Group were deposited. After a Middle Cretaceous period of deformation and volcanic events, evaporites and clastics of the Mahasarakham Formation were deposited. Finally, the Tertiary Himalayan orogeny brought about regional uplift and erosion, removing up to 6,000 feet of rock.

Figure XXII-3 shows a southwest-northeast oriented seismic time section from the western Khorat Basin. It highlights possible Permian Saraburi Group and Triassic Kuchinarai Group source rock shales and carbonates, which may be prospective for shale gas exploration. These strata are overlain by fluvial and alluvial clastic rocks of the Jurassic Khorat Group; these are not considered prospective due to their low TOC content. Note significant faulting of the Saraburi Group and, to a lesser extent, Kuchinarai Group rocks.

Figure XXII-4 is a south-north oriented seismic time section from the eastern Khorat Basin. Here, the low-TOC Carboniferous Si That Formation is overlain by possible conventional reservoirs of the Permian Pha Nok Khao Formation. The primary Saraburi Formation source rock does not appear to be present in this part of the basin, while the Huai Hin Lat Formation source rock is relatively thin. These Carboniferous, Permian, and Triassic rocks were block faulted and overlain by fluvial and alluvial clastic rocks of the Jurassic Khorat Group. This preliminary information suggests that the western Khorat Basin may be more prospective for shale gas exploration than the east.

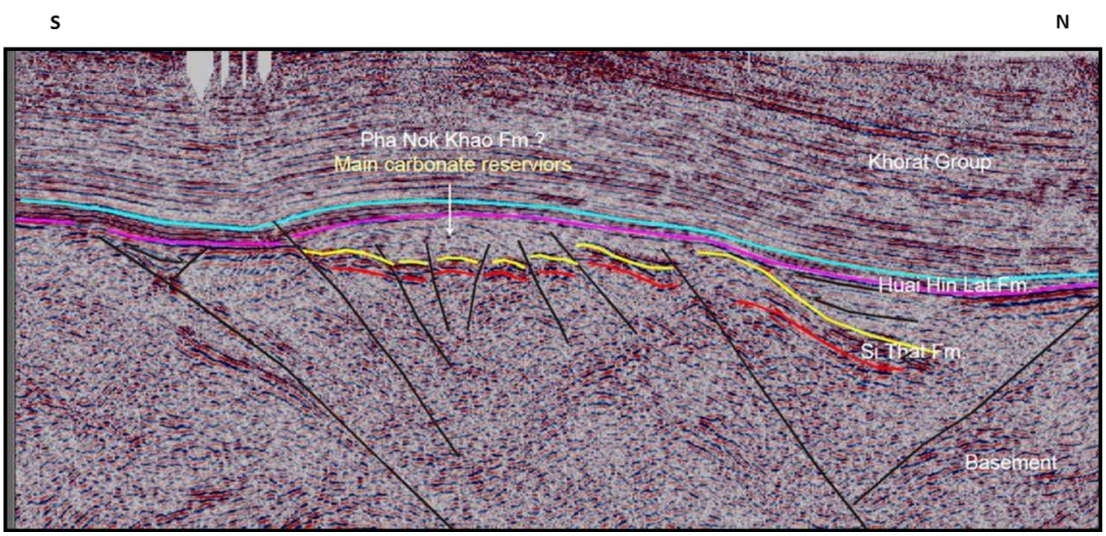
Figure XXII-5 is a schematic, non-directional cross-section of the Khorat Basin illustrating conventional petroleum play concepts. Note the Permo-Triassic source rock shales -- the primary targets -- are quite discontinuous, block faulted, and eroded in many portions of the basin. The patchy shale distribution and structural and erosional complexity are likely to complicate shale gas exploration in the Khorat Basin.

Figure XXII-3. Southwest-Northeast Seismic Time Section in Western Khorat Basin, Shows Permian Saraburi Group and Triassic Kuchinarai Group Source Rock Shales and Carbonates, Overlain by Fluvial and Alluvial Clastic Rocks of the Jurassic Khorat Group.



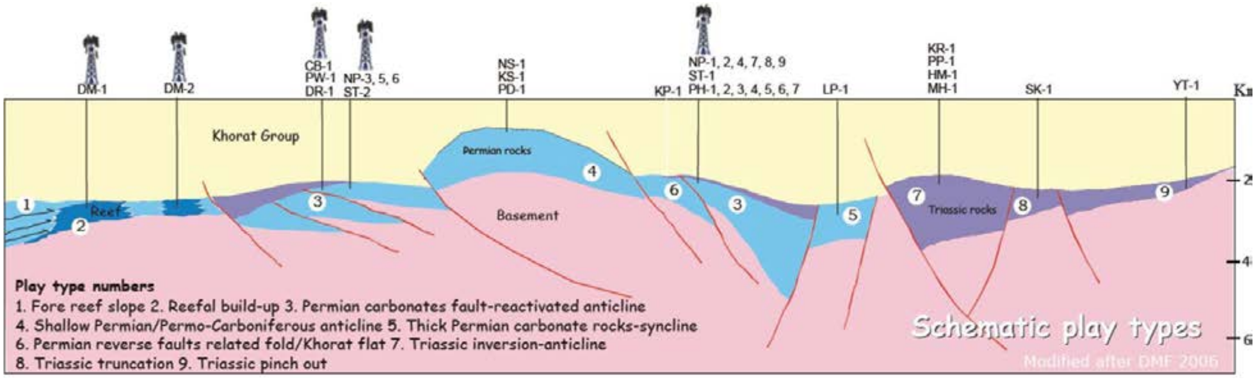
Source: Thailand Ministry of Energy, 2007.

Figure XXII-4. South-North Seismic Time Section from Eastern Khorat Basin, Showing Low-TOC Carboniferous Si That Formation Overlain by Conventional Reservoirs of the Permian Pha Nok Khao Formation. The Saraburi Formation Source Rock Does Not Appear to be Present in this Part of the Basin, While the Huai Hin Lat Formation Source Rock is Relatively Thin. Note Significant Faulting of the Permo-Carboniferous Sequence.



Source: Thailand Ministry of Energy, 2007.

Figure XXII-5. Schematic Non-directional Cross-section of the Khorat Basin, Showing Conventional Petroleum Play Concepts. Note the Primary Permo-Triassic Source Rock Shales are Discontinuous, Block Faulted, and Partly Eroded across the Basin. This Structural Complexity may Complicate Shale Gas Exploration.



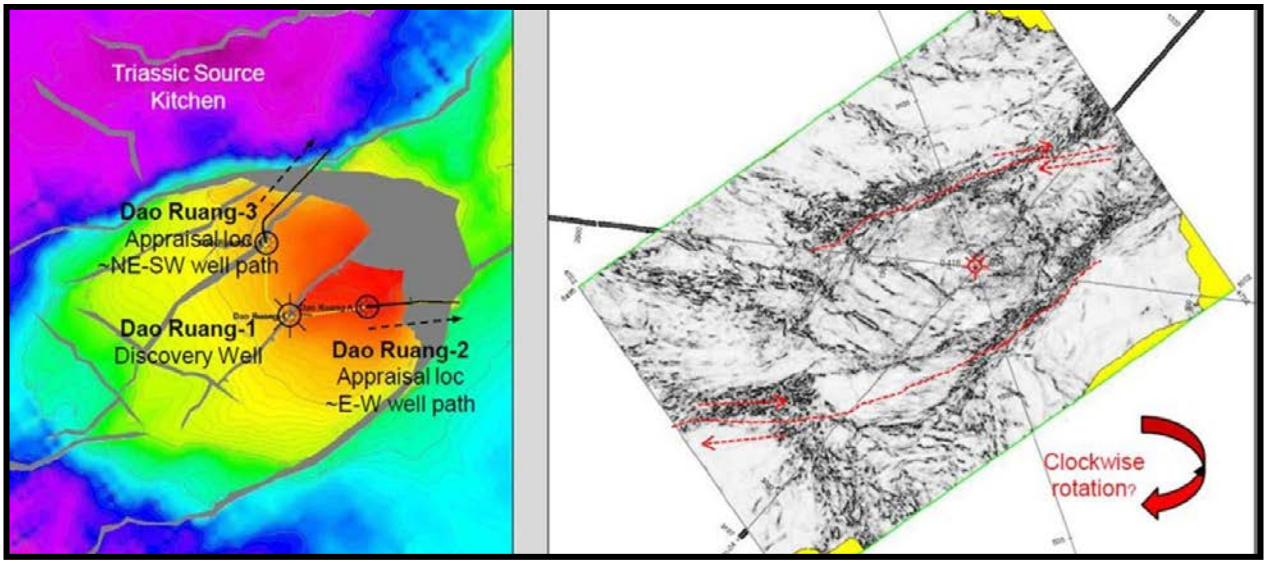
Source: Thailand Ministry of Energy, 2007.

Although the Khorat Basin is overmature for oil, a small number of conventional natural gas discoveries have been made. These fields target Permian carbonate and Triassic clastic reservoirs within anticlines and stratigraphic traps. Natural gas likely was sourced by older organic-rich Permo-Triassic shales, with gas being generated during the Early Tertiary following Cretaceous burial, and then possibly migrating along fractures and faults caused by extensional rifting.[5]

Figure XXII-6 illustrates a detailed seismic structure time map and structural interpretation of a small gas field in the central Khorat Basin. Note the deep Triassic source rock “kitchen”, the uplifted anticlinal fold that formed a conventional gas trap, and the interpreted clockwise rotation along strike-slip faults that created this local structure.

UK-based independent Salamander Energy holds several license blocks in the Khorat Basin. At last report, Salamander was acquiring 3D seismic, conducting basin modeling, and planning its first exploration well in 2012-13 to test conventional Permian carbonate targets.[6] Earlier this year Yanchang Petroleum, China’s fourth largest state-owned petroleum company, reportedly entered into a contract with Thailand’s Ministry of Energy to explore natural gas opportunities in the Khorat. Coastal Energy and Hess also have interests in Khorat Basin blocks but have not reported activity in the past two years.[7,8]

Figure XXII-6. Seismic Structure Time Map and Interpretation of Small Gas Field in the Khorat Basin. Note Deep Triassic Source Rock "Kitchen", Anticlinal Fold, and Interpreted Clockwise Rotation along Strike-Slip Faults.



Source: Salamander Energy PLC.

1.2 Reservoir Properties (Prospective Area)

Thick, organic-rich source rock shales and carbonates of Permian and Triassic age occur at prospective depth in the Khorat Basin, although mapping the location and size of depth-screened areas is not possible with current data. These shales are thermally dry-gas-prone to over-mature, with little or no liquids potential. Deposited under shallow marine to basinal sedimentary conditions, these shales are thought to have sourced the conventional Permian carbonate and Triassic clastic reservoirs of this region, including two significant producing gas fields.

Shallow marine shales also occur in the Carboniferous Si That Formation, typically at depths below 13,000 feet.[9] However, basin maturity modeling estimates that this unit is thermally over-mature and not prospective for shale gas development (R_o of 3 to 4%). The Early Permian Nam Duk Formation contains several thousand feet of continental to shallow marine sediments, including some organic-rich shale. TOC reportedly can exceed 3%, while depth ranges from 8,000 to more than 10,000 feet and the formation often is over-pressured. The calculated vitrinite reflectance is over 2.5%, thus the Nam Duk Fm is a potential dry gas shale target that is unlikely to be prospective for liquids.

Fluvial and lacustrine deposits of the Triassic Kuchinarai Group also have been identified as petroleum source rocks in the Khorat Basin, with high-TOC intervals of unreported thickness. The Kuchinarai Group reportedly averages a prospective 6,500 to 7,000 feet deep within the basin. Thermal maturity modeling suggests it reaches the dry gas window, with no liquids potential (R_o> 2.0%).

1.3 Resource Assessment

As discussed above, the Permian Nam Duk Formation contains organic-rich shales with suitable depth and thermal maturity and appears to be the most prospective target for shale gas development. Additional shale gas potential may exist in other organic-rich shales, such as the Triassic Kuchinarai Fm, but these were not assessed due to lack of data. The limited publicly available data on the Khorat Basin is not sufficient to constrain the regional distribution of suitable thickness, depth, TOC, thermal maturity, and prospective area. Average values for these parameters were estimated and augmented by analogs with commercial North American shale plays that have been more thoroughly studied.

A good North American analog for the Nam Duk Fm could be the Wolfcamp Shale in the Permian Basin, West Texas.[10] These formations share similar age (Lower Permian), depositional setting (shallow marine), thickness (>1,000 ft), lithology (high in carbonate, low in clay), TOC content (average 3%), over-pressuring (uncertain in the Khorat but assumed to be 0.6 vs 0.7 psi/ft for the Wolfcamp). The Khorat Basin appears to be structurally more deformed and faulted than the Permian Basin but the difference is not extreme. Furthermore, the Permian Basin Wolfcamp is less thermally maturity, ranging from the black oil to wet gas windows, thus the analogy is imperfect.

The Nam Duk Fm is well over 1,000 ft thick, with reported average 9,000 ft depth, 3% average TOC, and falls within the dry-gas thermal maturity window (R_o > 2.5%). The Nam Duk is discontinuously present within the basin due to uplift and erosion. Prospective area could not be rigorously mapped due to lack of data but is assumed to be 5% of the Khorat Basin area (~1,750 mi^2). Net organic-rich shale thickness also is uncertain but is assumed to be 200 feet, much less than 20% of formation thickness. Known to be over-pressured but not known to what extent, the pressure gradient was assumed to be 0.6 psi/ft, slightly below the Wolfcamp analog. ARI assumed 6% porosity based on the Wolfcamp analog.

Based on these data and assumptions, the Nam Duk Formation in the Khorat Basin was estimated to have 22 Tcf of risked shale gas in-place, with 5 Tcf of risked, technically recoverable shale gas resources, Table XXII-1. More detailed study is recommended to define and map these parameters and estimate the full shale gas resource potential of the Khorat Basin.

1.4 Recent Activity

No shale gas activity has been reported in Thailand's Khorat Plateau.

2. CENTRAL PLAINS BASIN

2.1 Introduction and Geologic Setting

Thailand's Central Plains Basin is located in the south-central portion of the country, including the Bangkok region and the highly productive rice-growing regions of the lower Chao Praya River. Covering a 25,000-mi^2 area, the Central Plains Basin is not a continuous deposit like the Khorat but rather comprises a number of small, deep, north-south trending and discontinuous half-grabens of Tertiary age, formed due to transpressional pull-apart tectonics. The province includes the prominent Phitsanulok, Suphan Buri, Kamphaeng Saen, and Petchabun petroliferous sub-basins, among others.

The Central Plains Basin is oil-prone and currently produces oil from conventional Miocene sandstone reservoirs as well as pre-Tertiary fractured granites. Miocene lacustrine-deposited shales, which are organic-rich and considered the primary source rocks in this basin, appear to have Thailand's best potential for shale oil exploration. However, shale oil prospects which may be identified by future work are likely to be limited in size, reflecting the small discontinuous nature of the sub-basins.

Similar to most of Thailand's basins, the structural history of the Central Plain is punctuated by periods of extension and subsequent erosion. Lacustrine shales and sediments were deposited during Oligocene to Early Miocene time.[11] An active margin developed in the Middle Miocene, depositing interbedded fluvial sandstones and mudstones. Alluvial-fluvial sediments were then deposited towards the end of the Tertiary and into the Quaternary. In some areas, up to 26,000 feet of Cenozoic strata have been preserved.

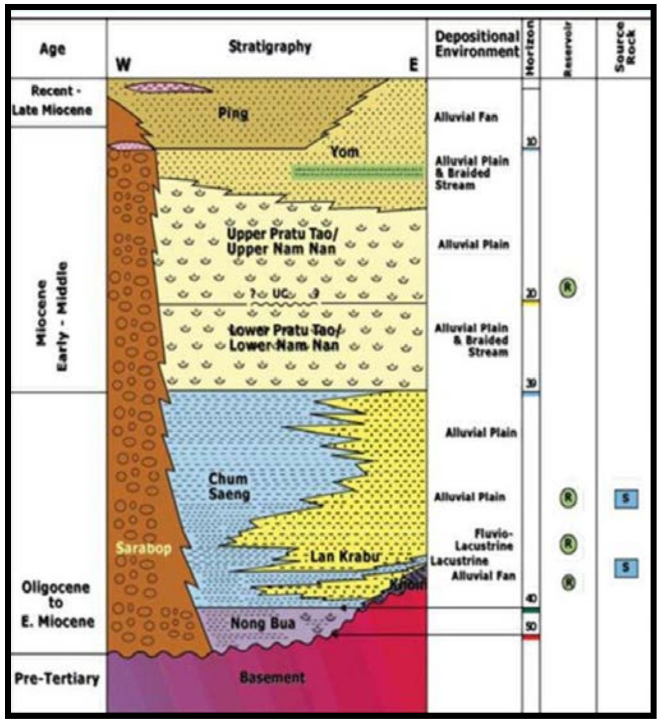
Middle Miocene sandstones (and more recently pre-Tertiary granites) are the primary conventional target in the various Central Plains sub-basins, such as at Sirikit field within the Phitsanulok Basin. Thailand's largest onshore oil field, the Sirikit (now called S-1) commenced production in the early 1980's, with over 250 wells drilled and 170 MMBO produced to date. The oil is inferred to have been sourced from the underlying lacustrine shales. PTTEP acquired the S1 field from Thai Shell in 2003 and plans to extract an additional 40 to 50 MMbbls over the next 10 years. During Q3-2012 PTTEP produced an average 30,000 b/d of oil from Sirikit-1, while continuing to drill new development wells there. PTTEP's onshore focus has been on advanced drilling and exploration techniques.[12]

In the Phitsanulok Basin, the main organic-rich lacustrine shales comprise the Early Miocene Chumsaeng Fm, which was deposited in a deep lake environment. Stratigraphically equivalent sediments are also noted in the Suphan Buri and other sub-basins, usually unnamed. These type I/II source rocks display high to variable TOC (average >2.0%[13]), with high hydrogen indices reaching over 700 mg HC/g.[14] Gross thickness averages 1,300 feet, with a net organic-rich shale interval of at least 600 feet. In the deeper parts of Central Plain basins, the Chumsaeng and Early Miocene lacustrine shales may reach maximum depths of nearly 15,000 feet. Oil generation depths in the smaller Suphan Buri Basin average 7,000 feet, suggesting a large range in thermally mature depths for liquids production.

Figure XXII-7 illustrates the stratigraphy and conventional petroleum systems of the Central Basin. Oligocene Nong Bua and Sarabop formations, the oldest sedimentary rocks in the Central Basin, rest unconformably on pre-Tertiary basement. Fluvial to lacustrine shales within the Oligocene to Early Miocene Chum Saeng Group act as the main source rocks. Clastic rocks of the Oligocene Lan Krabur and Miocene Pratu Nam Nan formations, deposited under alluvial plains settings, are the conventional reservoir targets. These in turn are overlain by Late Miocene to Recent alluvial fan deposits sourced by regional uplift associated with the Himalayan Orogeny.

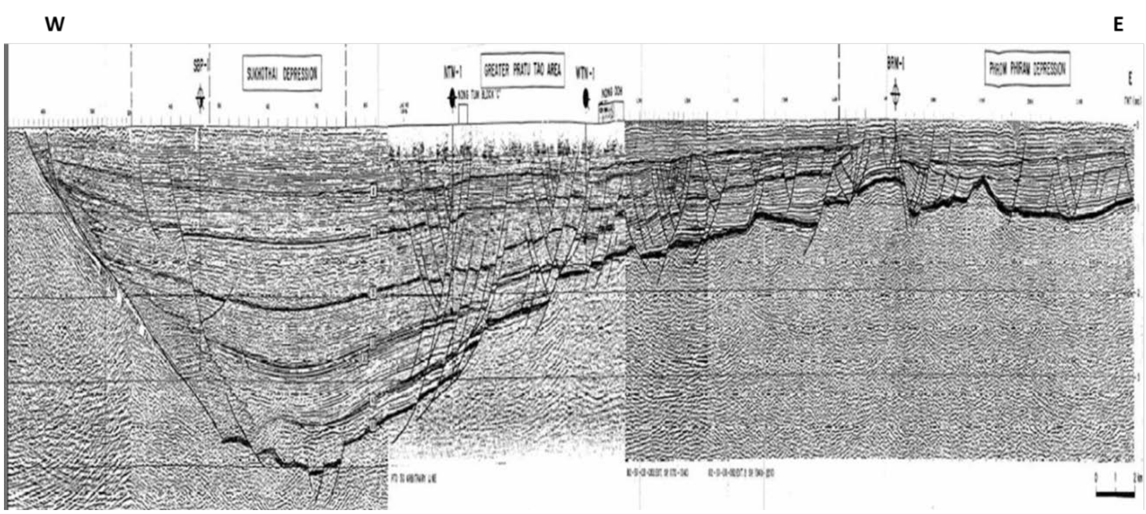
Figure XXII-8 shows a west-east oriented, uninterpreted seismic time section from the Phitsanulok Basin, one of numerous sub-basins within the overall Central Plains Basin. The main source rocks are fluvial to lacustrine shales within the Oligocene to Early Miocene Chum Saeng Group, which appear to be discontinuously present on top of pre-Miocene basement. Significant normal faulting may hinder shale oil development in this basin.

Figure XXII-7. Stratigraphy and Petroleum Systems of Thailand's Central Basin. Fluvial to Lacustrine Shales within the Oligocene to Early Miocene Chum Saeng Group are the Main Source Rocks, while Alluvial Plain Clastics of the Oligocene Lan Krabur and Miocene Pratu Nam Nan Formations are Conventional Targets.



Source: Thailand Ministry of Energy, 2007

Figure XXII-8. West-East Seismic Time Section in the Phitsanulok Sub-basin within the Central Plains Basin. The Main Source Rocks are Fluvial to Lacustrine Shales within the Oligocene to Early Miocene Chum Saeng Group, Discontinuously Present on Top of Pre-Miocene Basement. Note Significant Normal Faulting.



Source: Thailand Ministry of Energy, 2007

3. NORTHERN INTERMONTANE BASIN

3.1 Introduction and Geologic Setting

Thailand's Northern Intermontane Basin is a large loosely defined area covering the north-central and northwestern portions of the country. Similar to the Central Plains Basin and quite unlike the relatively continuous Khorat Basin, the Northern Intermontane Basin comprises numerous small and completely isolated structural troughs that are separated by uplifts. Several of these pull-apart basins, such as the Fang Basin, produce oil in anticlinal traps from conventional sandstone reservoirs that were sourced by organic-rich Miocene lacustrine shales. In addition, solid oil shale mineral resources near the surface in the Mae Sot Basin are under small-scale mining development. These organic-rich lacustrine-deposited shales may become thermally more mature and contain mobile oil in the deeper troughs, although ARI could not map this due to very sparse data control.

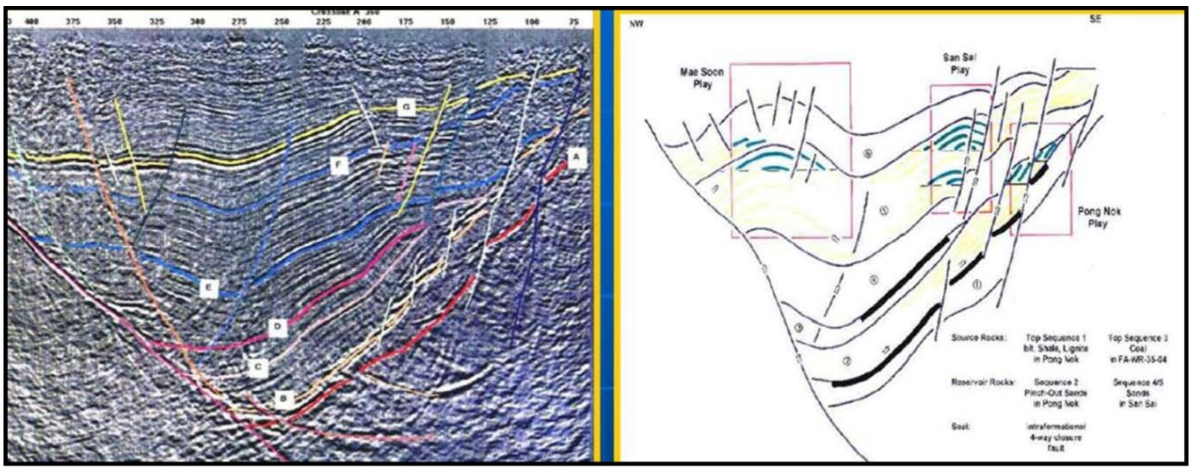
Mae Sot Sub-Basin. The Mae Sot Sub-basin of northwestern Thailand is one of the more prominent intermontane basins in this topographically mostly rugged Northern Intermontane region. This north-south trending basin extends over an area of approximately 900 mi^2, with one-third of the area extending across the Moei River into Myanmar on the west.[15] Gently undulating hills and alluvial plains comprise the topography of the basin itself, which averages about 650 feet above sea level.

The Mae Sot Basin is divided into north and south sub-basins, with the southern region having the thickest sedimentary section. It contains mainly non-marine Cenozoic sedimentary units overlying Permian to Jurassic carbonate and clastic rocks that were deposited in pull-apart basins and half grabens. These units include the Mae Ramat, Mae Pa, and Mae Sot formations, the latter recognized for its oil shale deposits.

Hydrocarbon exploration of the Mae Sot Basin began with Swiss and Japanese geologists in the late 1930's. In 1947 Thailand's Department of Mineral Resources conducted an oil shale reserve evaluation. During the 1980's, the German and Japanese governments conducted feasibility analyses of the oil shale potential. Since 2000 Thailand's Mineral Fuels Division has renewed its research on Thailand's oil shale deposits.

Fang Sub-Basin. The crescent-shaped Fang Sub-basin in the far north of Thailand, located about 150 km north of Chiang Mai, is a fault-bounded intermontane depocenter containing Cenozoic sediments, Figure XXII-9. The 220-mi^2 trough trends NW-SE and borders a steep mountain range to the east. The Fang Basin is generally flat with slightly rolling hills and an average elevation of 1,500 feet above sea level.[16] A high geothermal gradient exists throughout the half-graben, evidenced by hot springs in the northern region. Site of Thailand's first commercial oil field, over 240 wells have been drilled to date in the Fang Sub-Basin.

Figure XXII-9. Stratigraphy and Petroleum Systems of Thailand's Central Basin. Fluvial to Lacustrine Shales within the Oligocene to Early Miocene Chum Saeng Group are the Main Source Rocks, while Alluvial Plain Clastics of Oligocene Lan Krabur and Miocene Pratu Nam Nan Formations are Conventional Targets.



Source: Thailand Ministry of Energy, 2007

During the early Tertiary, extensional faults and rifting associated with the Indian and Himalayan collision opened up the basin. Syn-rift sequences of alluvial-fluvial and lacustrine sediments were deposited during the Eocene to Miocene, followed by post-rift sequences of younger alluvium and marked by a significant unconformity. Overlying these rocks are undifferentiated gravels, sands, soils, and clays of Quaternary to Recent age. Total thickness of the sedimentary sequence reaches 10,000 ft.

The stratigraphy of the Tertiary rocks generally can be divided into two units, the Mae Fang and underlying Mae Sot formations. Interbedded coarse sandstone and red to yellow claystone occur in the Late Miocene to Pleistocene Mae Fang Formation; these were deposited in an alluvial-fluvial environment and average 1,400 feet thick. Below this unit, fluvial sandstone layers within the Mae Sot Formation have been the principle reservoirs for conventional oil field production in the basin, beginning in the 1920's. As the Northern Intermontane region's most productive locale, the Fang Basin has yielded six oil fields, although the Pong Nok and Chaiprakarn were abandoned in the mid 1980's. These reservoirs apparently were sourced by lacustrine mudstones and shales within the Mae Sot Formation itself, most likely the main shale oil exploration target within the Fang Basin.

3.2 Reservoir Properties (Prospective Area)

Mae Sot Sub-Basin. The Paleocene Mae Ramat Formation contains mostly alluvial conglomerate, sandstone, limestone, and mudstone units that unconformably overlie pre-Tertiary strata.[17] The Mae Ramat Fm is up to 700 feet thick and deeper than 3,300 feet (the maximum total depth of available well data). Overlying the Mae Ramat Fm is the Upper Oligocene Mae Pa Formation, which contains lacustrine and fluvial deposits, including shales and marls, along with prevalent limestone lenses in the southern sub-basin. Minor oil shale deposits can occur within the 300-ft thick Mae Pa Fm, albeit interbedded with large amounts of low-TOC strata. The Mae Pa Fm averages about 3,000 ft deep. Overall, the Mae Ramat and Mae Pa formations are not considered viable source rocks due to lack of organic richness, undetermined shale thickness and low thermal maturity.

The most organically rich shale in the Mae Sot Basin is the Miocene Mae Sot Formation, which is dominated by shale with minor clastics. One interval within the Mae Sot Fm contains relatively thin (10 to 15 feet) oil shales beds within sandy shale assemblages, although maximum thickness can exceed 33 feet. Rock mineralogy is dominated by quartz, feldspar, calcite, dolomite, and clay (proportions not reported). In the northern sub-basin, these lacustrine oil shale deposits are grey to green and nearly 100 feet thick. Kerogen consists mainly of exinite, with immobile oil content ranging from 2.5 to 62 gallons per ton (1% to 26% by weight). Oil shale grade is highest in the middle-lower section of the unit. This formation is typically about 2,000 feet deep across much of the Mae Sot Basin. Overall, the Mae Sot Formation appears too shallow and immature for shale oil development, with R_o well below the 0.7% threshold.

Fang Sub-Basin. The Mae Sot Formation of Miocene to Pliocene age can be divided into three units: a lower section of brown to reddish sandstone; a middle zone of organic-rich lacustrine claystone, shale, and coal with interbedded sandstone; and an upper layer of gray claystone, mudstone, and sandstone along with fossil inclusions. The conventional sandstone

Advanced Resources International, Inc.

reservoirs have 25% porosity and 0.2 to 2.0 Darcies of permeability. The crude oil ranges from 16 to 38 degrees API gravity.[18]

The rich bituminous shales of the middle unit are the recognized source rock, with calculated total organic carbon averaging 15% (Type I or II).[19] Gross formation thickness can be up to 2,100 feet, while high-TOC shale intervals interbedded with sandstone average 300 feet thick (net). The formation was penetrated in conventional wells at depths of 3,000 to 3,500 feet, but these likely were drilled on structural highs. Absent vitrinite reflectance data burial history modeling suggests an R_o of 0.5% is not reached until about 4,000-ft depth. The minimum depth for mobile oil generation (0.7% R_o) may be about 6,000 ft. Only a small portion of the Fang Basin appears to meet these screening criteria. ARI is unable to quantify such a prospective area given limited available data.

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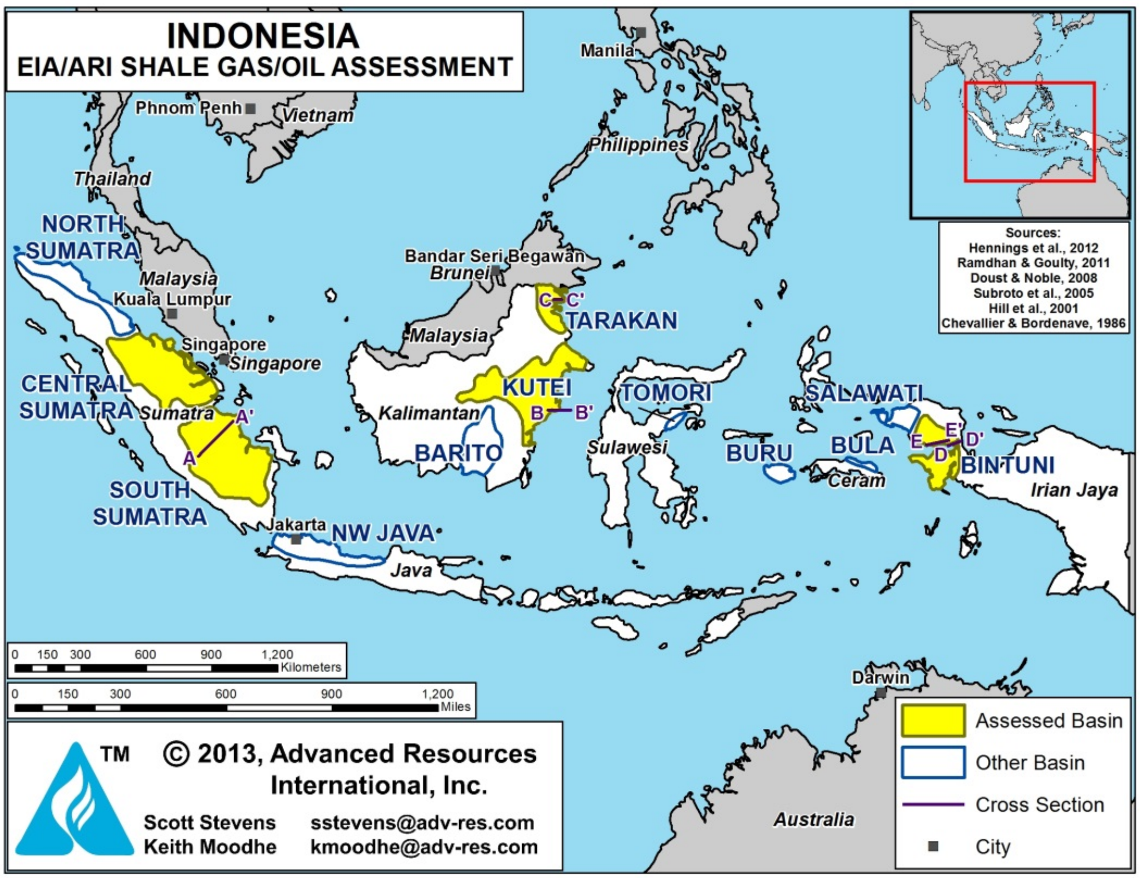
XXIII. INDONESIA

SUMMARY

Indonesia has shale gas and shale oil potential within selected marine-deposited formations, as well as more extensive shale resources within non-marine and often coaly shale deposits, Figure XXIII-1. The best overall potential appears to be mostly oil-prone, lacustrine-deposited shales within the Central and South Sumatra basins, which sourced the prolific nearby conventional oil and gas fields. Kalimantan's Kutei and Tarakan basins also have thick lacustrine source rock shales with oil and gas potential.

Figure XXIII-1. Shale Basins of Indonesia



Source: ARI, 2013

Indonesia has an estimated 46 Tcf and 7.9 billion barrels of risked, technically recoverable shale gas and shale oil resources out of 303 Tcf and 234 billion barrels of risked shale gas and shale oil in-place, Tables XXIII-1 and XXIII-2. Several companies (AWE, Bukit, NuEnergy) have reported early-stage evaluations of shale gas potential in Sumatra, but no PSC's have been awarded nor has shale-related drilling activity been reported.

Table XXIII-1. Shale Gas Reservoir Properties and Resources of Indonesia.

			C. Sumatra	S. Sumatra	Kutei	Tarakan			Bintuni
Basic Data	Basin/Gross Area		(36,860 mi^2)	(45,170 mi^2)	(35,840 mi^2)	(7,510 mi^2)			(15,200 mi^2)
	Shale Formation		Brown Shale	Talang Akar	Balikpapan	Naintupo	Meliat	Tabul	Aifam Group
	Geologic Age		Paleogene	Eocene-Oligocene	Mid.-U. Miocene	L. Miocene	Mid. Miocene	U. Miocene	Permian
	Depositional Environment		Lacustrine	Lacustrine	Lacustrine	Lacustrine	Lacustrine	Lacustrine	Marine
Physical Extent	Prospective Area (mi^2)		4,700	15,490	1,630	1,010	880	510	3,340
	Thickness (ft)	Organically Rich	295	918	900	750	1,000	1,500	1,000
		Net	266	367	450	375	400	600	500
	Depth (ft)	Interval	6,560 - 10,496	3,300 - 8,000	3,300 - 15,000	6,600 - 16,000	3,300 - 13,120	3,300 - 6,600	5,000 - 15,000
		Average	8,530	7,000	9,000	11,500	10,000	5,000	9,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Highly Overpress.	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		6.0%	5.0%	4.0%	5.0%	3.0%	3.0%	1.5%
	Thermal Maturity (% Ro)		0.80%	0.70%	0.70%	1.50%	1.15%	0.70%	1.50%
	Clay Content		Medium	High	High	High	High	High	Low
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Assoc. Gas	Dry Gas	Wet Gas	Assoc. Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		19.6	25.0	62.1	170.7	142.3	37.3	213.8
	Risked GIP (Tcf)		41.5	67.8	16.2	34.5	25.1	3.8	114.3
	Risked Recoverable (Tcf)		3.3	4.1	1.3	5.2	3.8	0.2	28.6

Table XXIII-2. Shale Oil Reservoir Properties and Resources of Indonesia.

			C. Sumatra	S. Sumatra	Kutei	Tarakan	
Basic Data	Basin/Gross Area		(36,860 mi^2)	(45,170 mi^2)	(35,840 mi^2)	(7,510 mi^2)	
	Shale Formation		Brown Shale	Talang Akar	Balikpapan	Meliat	Tabul
	Geologic Age		Paleogene	Eocene-Oligocene	Mid.-U. Miocene	Mid. Miocene	U. Miocene
	Depositional Environment		Lacustrine	Lacustrine	Lacustrine	Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		4,700	15,490	1,630	880	510
	Thickness (ft)	Organically Rich	295	918	900	1,000	1,500
		Net	266	367	450	400	600
	Depth (ft)	Interval	6,560 - 10,496	3,300 - 8,000	3,300 - 15,000	3,300 - 13,120	3,300 - 6,600
		Average	8,530	7,000	9,000	10,000	5,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Highly Overpress.	Normal	Normal
	Average TOC (wt. %)		6.0%	5.0%	4.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.80%	0.70%	0.70%	1.15%	0.70%
	Clay Content		Medium	High	High	High	High
Resource	Oil Phase		Oil	Oil	Oil	Condensate	Oil
	OIP Concentration (MMbbl/mi^2)		32.8	50.2	64.7	7.1	103.7
	Risked OIP (B bbl)		69.4	136.2	16.9	1.3	10.6
	Risked Recoverable (B bbl)		2.77	4.09	0.68	0.04	0.32

In general, western Indonesia has comparatively simple structure but is dominated by the non-marine shale types, whereas eastern Indonesia has abundant marine shale deposits but is structurally more complex. Eastern Indonesia (Sulawesi, Seram, Buru, Irian Jaya) is tectonically more complex but has excellent marine-deposited shale source rocks.

INTRODUCTION

Indonesia is the world's fourth most populous country (250 million) and a major producer of coal, oil, and natural gas. Formerly an oil exporter and OPEC member, Indonesia's declining oil production and increasing domestic consumption have made the country a net oil importer since 2004. In 2011 Indonesia produced an average 2.5 million bbl/day of crude oil from 4.0 billion barrels of proved reserves, while consuming 3.1 million bbl/day. Indonesia remains a major exporter of LNG and pipeline-conveyed natural gas, producing an average 7.4 Bcfd during 2011 while exporting 3.7 Bcfd.[1] However, Indonesia's domestic gas consumption is rising faster than its output. Gas prices have risen significantly in recent years and new LNG import terminals are being constructed in Java, Indonesia's most densely populated island.

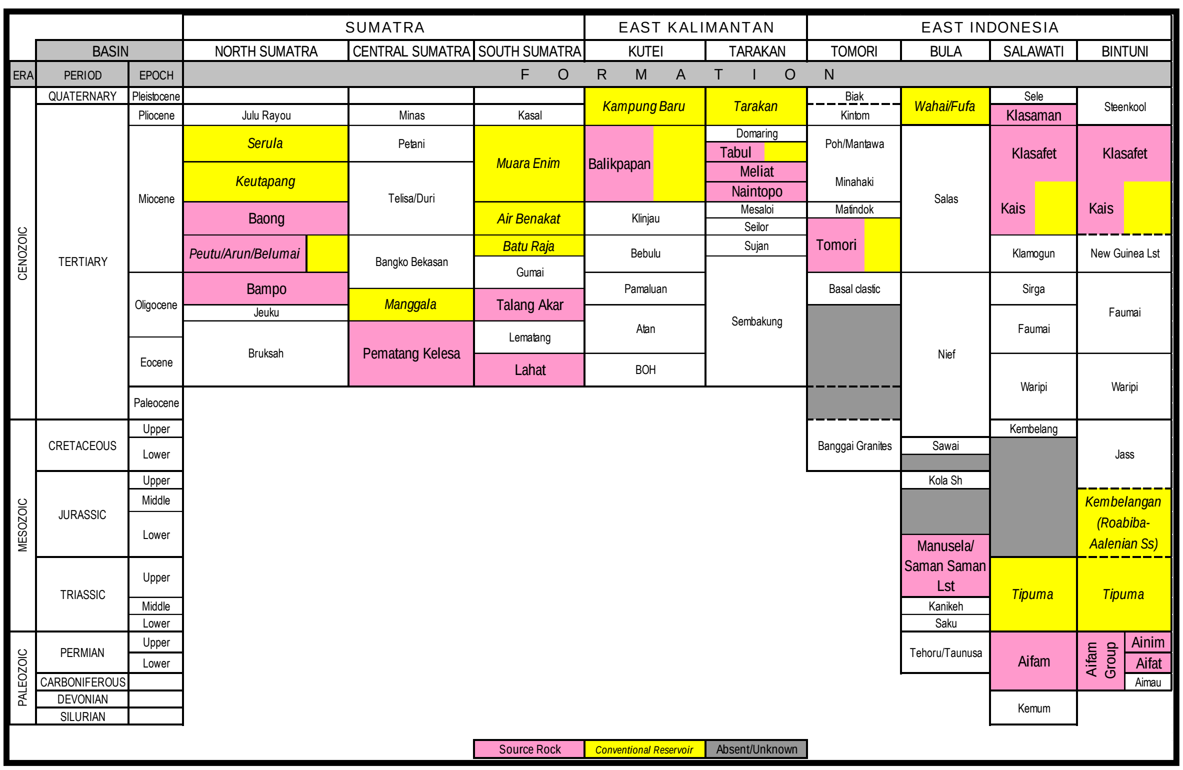
Indonesia's Ministry of Energy and Mineral Resources (MIGAS) administers upstream investment policy and awards exploration and production licenses in the country's oil and gas industry. A separate organization BPMIGAS administers the implementation of these licenses and work programs. However, a recent (November 2012) judicial decision by Indonesia's highest court unexpectedly dissolved BPMIGAS, directing MIGAS to implement oil and gas investment. Indonesia's 2001 Oil and Gas Law is expected to be revised during 2013 to clarify these significant changes and clear up the current regulatory uncertainty.

Domestic and foreign companies are active in Indonesia's oil and gas sector, with foreign companies operating the bulk of production. Pertamina, Indonesia's wholly state-owned oil company, plans to eventually transition into a listed company with significant private ownership. PGN (Perusahaan Gas Negara), the dominant natural gas pipeline operator that is partly state- and publicly owned, is gradually moving into the upstream business as well, including pursuing unconventional gas development. Foreign companies active in Indonesia include Chevron, Total, ConocoPhillips, ExxonMobil, and BP, as well as numerous smaller Indonesian and foreign operators.

ARI's review of published geologic literature indicates that Indonesia has a number of onshore sedimentary basins which may have shale gas/oil potential. These include the Central and South Sumatra basins on Sumatra Island; the Kutei and Tarakan basins in Kalimantan; and smaller, structurally complex basins in eastern Indonesia (Salawati, Bintuni, Tomori). Other basins in Indonesia appear to be less prospective due to low TOC, high clay and CO_2 contents, and/or excessive structural complexity.

The petroleum source rocks in onshore Indonesian basins are relatively young, mostly Eocene to Pliocene, with older Permian source rocks present in the east, Figure XXIII-2. Their depositional setting ranges from deepwater marine in eastern Indonesia to mostly lacustrine and deltaic environments in central and western Indonesia. Many of Indonesia's organic-rich shales are non-marine coaly deposits that may not be brittle enough for shale development. MIGAS, the upstream oil and gas regulator in Indonesia, has estimated the country's shale gas resources at 574 Tcf. However, neither the methodology nor the basis of this estimate has been reported.

Figure XXIII-2. Stratigraphy of Source Rocks and Conventional Petroleum Reservoirs in Indonesia.



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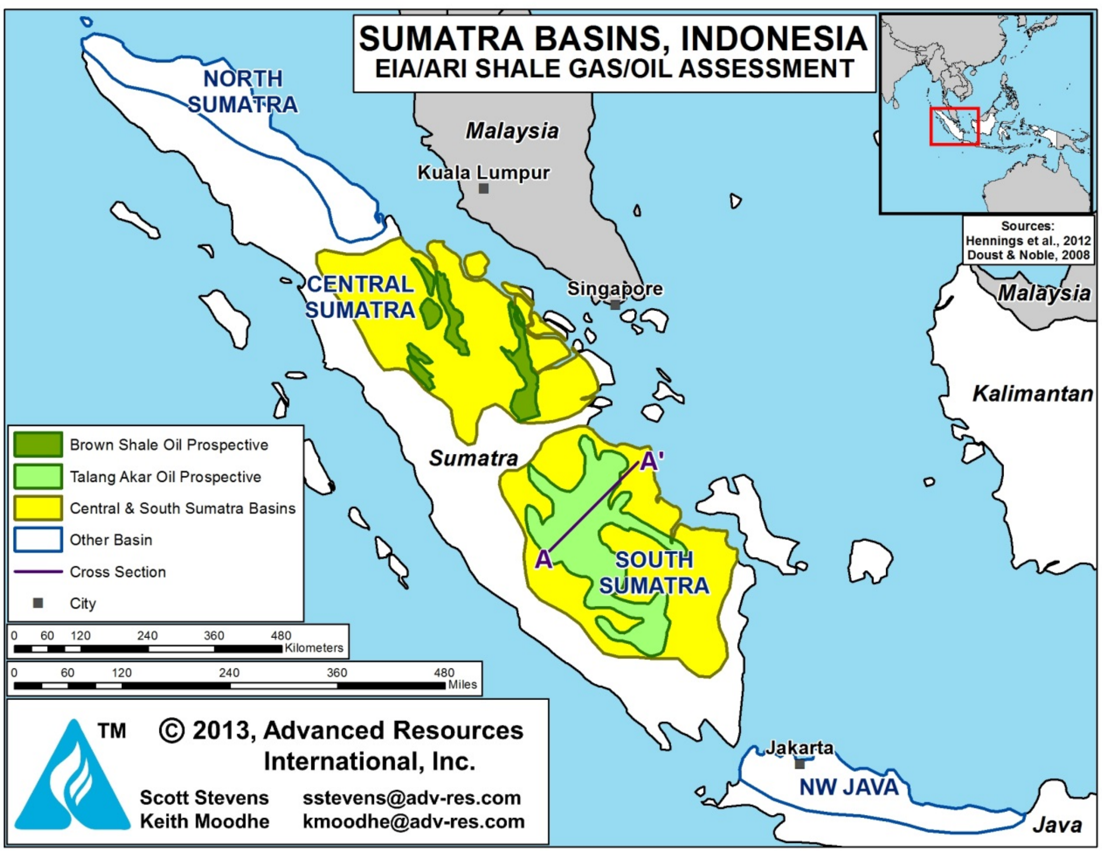
1 NORTH, CENTRAL, AND SOUTH SUMATRA BASINS

1.1 Introduction and Geologic Setting

Sumatra has shale oil and gas potential in three deep basin complexes: the North, Central, and South Sumatra basins, Figure XXIII-3. The North Sumatra Basin produces mainly conventional gas both onshore and offshore. However, gas production has declined sharply in this basin and the Arun LNG export facility is being converted to handle LNG imports. The Central Sumatra Basin produces mainly oil onshore, notably 300,000 bbl/day from the Duri thermal EOR field, and is a major consumer of natural gas for steam fuel. The South Sumatra Basin produces both oil and increasing volumes of gas from onshore fields. Major coal and coalbed methane deposits also occur in South and Central Sumatra, while North Sumatra is largely barren of coal. All three basins are back-arc tectonic settings containing young, rapidly deposited and poorly lithified sedimentary rocks. Heat flow and CO_2 content often are elevated.

Figure XXIII-3. Prospective Shale Areas in the Central and South Sumatra Basins, Indonesia.



Source: ARI, 2013

North Sumatra Basin. A series of north–south trending ridges and grabens, formed during the Early Oligocene, became filled with predominantly marine deposits. These include deep marine claystones, shales and shallow water limestones on structural highs, while shallow water deltaic facies formed in the southeast. The main source rocks are the Middle Miocene Lower Baong shale and the Early Miocene Belumai calcareous shale. The Late Oligocene Bampo black shale, which formed in localized thick and euxinic deposits, is another potential source rock.[2] The Bampo contains thick, deep marine claystones, mudstones and dark shales and is the main source rock for gas fields in the northern part of the North Sumatra Basin.

Thermal maturity of the Baong, Belumai, and Bampo shales is gas-prone but TOC is low, seldom exceeding 1% (Type III) while clay is abundant (mostly smectite). CO_2 and H_2S contamination are fairly common: output from the Arun gas field averages about 20% CO_2, while the Peutu carbonate reservoir contains 82% CO_2. Overall, these source rocks appear to be too low in TOC and possibly ductile due to their shallow depth, rapid burial, high clay content, and young age. There have been no reports of shale exploration activity in the North Sumatra Basin and we do not consider it to be prospective for shale gas/oil development.

Central Sumatra Basin. Sumatra's most important oil-producing region, the Central Sumatra Basin is a trans-tensional pull-apart basin bounded by major strike-slip faults to the north and south. It developed during the Late Cretaceous to Early Tertiary in a back-arc setting as a result of the Indian Ocean plate subducting at an oblique angle beneath Southeast Asia. The basin comprises a series of north-south trending fault-bounded troughs that are separated by uplifted horst blocks. The troughs became filled with non-marine clastic, lacustrine, and marine sediments. Sedimentation began with deposition of continental sediments followed by a transgressive/regressive marine cycle that started in Late Oligocene or Early Miocene. The Paleogene Pematang Group, Lower Miocene Sihapas Group, and Middle Miocene/ Pliocene Petani Group are the main Tertiary units.

The Brown Shale Formation within the Pematang Group is considered the most important oil-generating formation in the South Sumatra Basin, having generated an estimated 60 billion barrels and sourced the giant Duri and Minas oil fields.[3,4] The overlying marine Menggala sandstones are the main conventional petroleum reservoirs in Central Sumatra, consisting of well-sorted quartzose to subarkosic sandstones with average >20% porosity and 1,500 mD of permeability.

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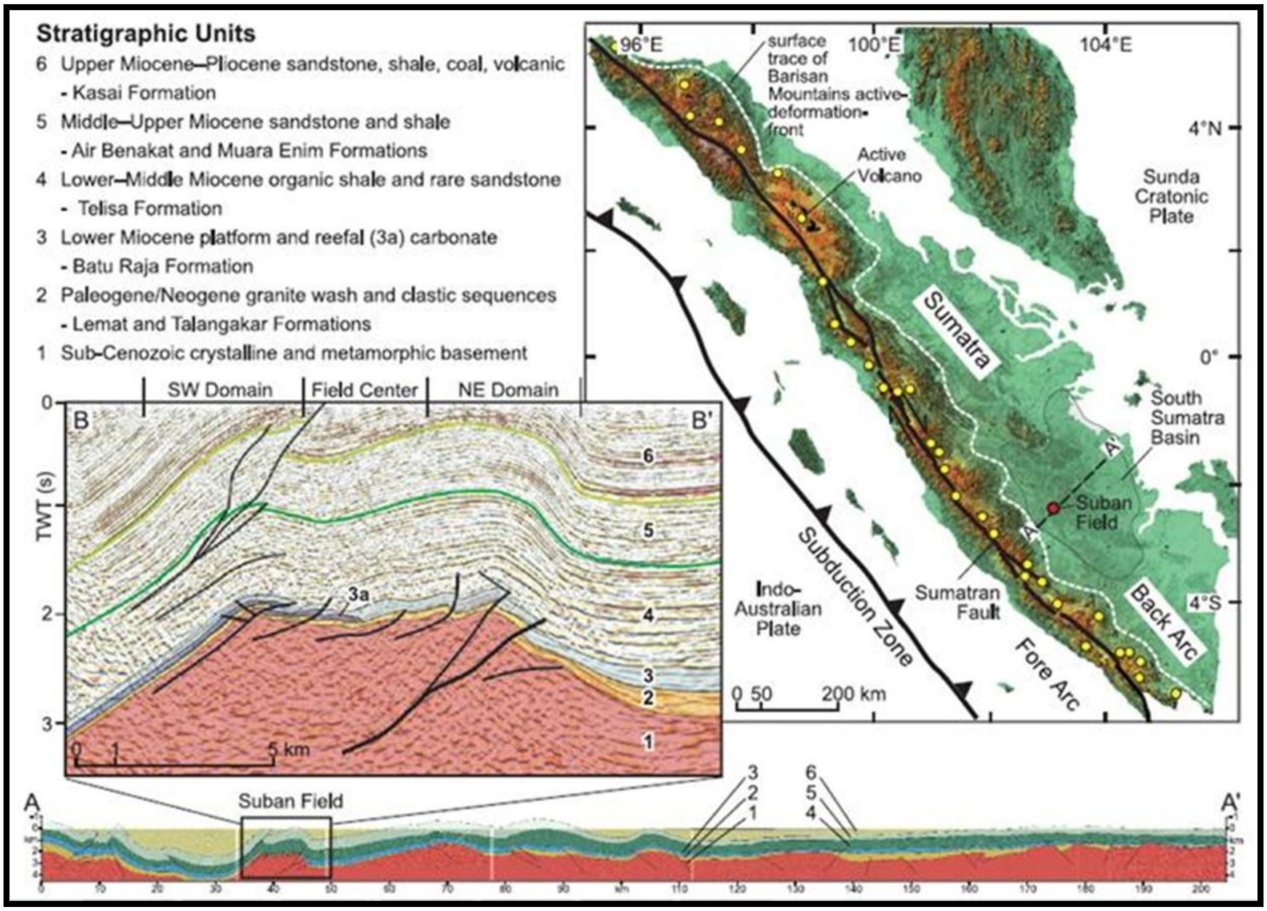
The Brown Shale is a lacustrine-formed unit, deposited in a freshwater to brackish lake system with anoxic bottom conditions. Variation in oil composition within the basin is attributed to local facies changes which reflect the distribution of productivity and paleoclimate conditions during source rock deposition that resulted in varying proportions of algal and terrigenous organic matter. The organic-rich portion of the Brown Shale is about 295 ft thick and is 6600 to 10,500 ft deep in the troughs (average depth 8,500 ft). Mean TOC for this unit throughout the basin is approximately 3.7%, reaching 7.3% at the well-exposed Karbindo coal mine, with mean 25.3 mg HC/g rock petroleum generation capacity.[5]

Two organic-rich facies occur within the Brown Shale Formation. The deep lacustrine facies consist of dark brown to black, well laminated, non-calcareous shales, containing 1 to 15% TOC that consists of Types I and II kerogen. The shallow lacustrine facies consists of red-brown laminated carbonate and terrigenous mudstones with occasional coal stringers. This unit contains average 3.4% TOC, derived from algae that resulted in oil-prone Type I kerogen.[6]

The Keruh, Kiliran, Sangkarewang, Lakat, and Kelesa Formations also can be organic rich, but these are relatively immature thermally and may not be brittle. The U. Miocene to L. Pliocene Binio Formation, part of the Petani Group, contains a sequence of medium- to light grey claystones and minor sandstones that are charged with low-CO_2 and isotopically light biogenic gas. The Binio Fm is overlain by the Late Pliocene Korinci Formation, a regressive sequence of claystones, siltstones, sandstones, and minor coal deposited under a fluvial environment.[7] The Binio and Korinci formations are not considered to be prospective for shale gas/oil development.

South Sumatra Basin. This basin is a significant conventional oil and gas producing area as well as a focus of coalbed methane exploration. The basin contains late Eocene to early Oligocene deposits of clastic sediments in transpressional pull-apart depressions. Thermal subsidence followed rifting in the late Oligocene to the early Miocene, enabling marine incursions to deposit fine-grained marine sequences in lows and reefal buildups on high-standing blocks. Continued subsidence drowned the carbonate system and caused deposition of organic-rich deep-water shales and marls that later became gas-prone hydrocarbon source rocks. Northeast-directed compression and tectonic inversion began in the mid-Miocene, Figure XXIII-4. An estimated 50-90% of the faults in the basin are potentially active and may be at risk of being triggered during large-scale hydraulic fracturing.[8]

Figure XXIII-4. Regional and Detailed Cross Sections of the South Sumatra Basin, Indonesia.



Source: Hennings et al., 2012

Petroleum source rock shales in the South Sumatra Basin include alluvial, lacustrine, and brackish-water sediments in the Lahat Formation and coals and coaly shales in the Talang Akar Formation.[9] These units reach a gross thickness of approximately 1 km. Mid-late Eocene to early Oligocene in age, the Lahat can be oil- or gas-prone depending on location.

Because of limited data, the Lahat Formation was not quantitatively assessed. The Talang Akar Formation is up to over 1 km thick in the South Palembang sub-basin, averaging 1,300 ft thick. TOC ranges from 1.7% to 8.5%, locally reaching 16%. Thermal maturity is low (R_o 0.5%) down to about 6,000 ft depth, increasing to about 0.9% R_o at a depth of 8,000 ft, averaging about 0.7% R_o at 7,000 ft.

The Miocene Muara Enim Formation of the South Sumatra Basin contains important coal and coalbed methane resources that were deposited in a coastal plain environment during an overall regressive cycle, resulting in a thick sequence of mainly clastic sandstone, siltstone, coal, and coaly shale.[10] Thermal maturity is quite low, reaching only about 0.4% to 0.45% R_o within troughs up to 4,000 ft deep. Overall, the Muara Enim Fm is a coaly and probably non-brittle non-marine deposit, too shallow and thermally immature to be favorable for shale development.

1.2 Reservoir Properties (Prospective Area)

The general location of the prospective deep troughs in the Central and South Sumatra basins is well constrained by public data but, unfortunately, not the detailed depth distribution of the shale formations.[11] However, proprietary maps developed by ARI for coalbed methane exploration in these basins provided improved control on depth and thermal maturity, indicating that about 5% of the total basin area could be depth- and thermal-prospective for shale oil. The North Sumatra Basin is not considered prospective.

Central Sumatra. The high-graded prospective area for the Brown Shale Formation in the Central Sumatra Basin is estimated at 4,700-mi^2 based on the extent of the deep troughs. Within this prospective area the Brown Shale averages 266 ft thick (net) with an average depth of 8,530 ft. Average TOC is estimated at 6.0% and is in the oil window (R_o of 0.8%). Pressure gradient is normal and the clay content is considered medium.

South Sumatra Basin. The Eocene to Oligocene Talang Akar Formation is prospective within a large 15,490-mi^2 area and estimated to have a 367-ft thick high-graded zone with average 5% TOC and 0.7% R_o. The pressure gradient is normal and the clay content is considered high.

1.3 Resource Assessment

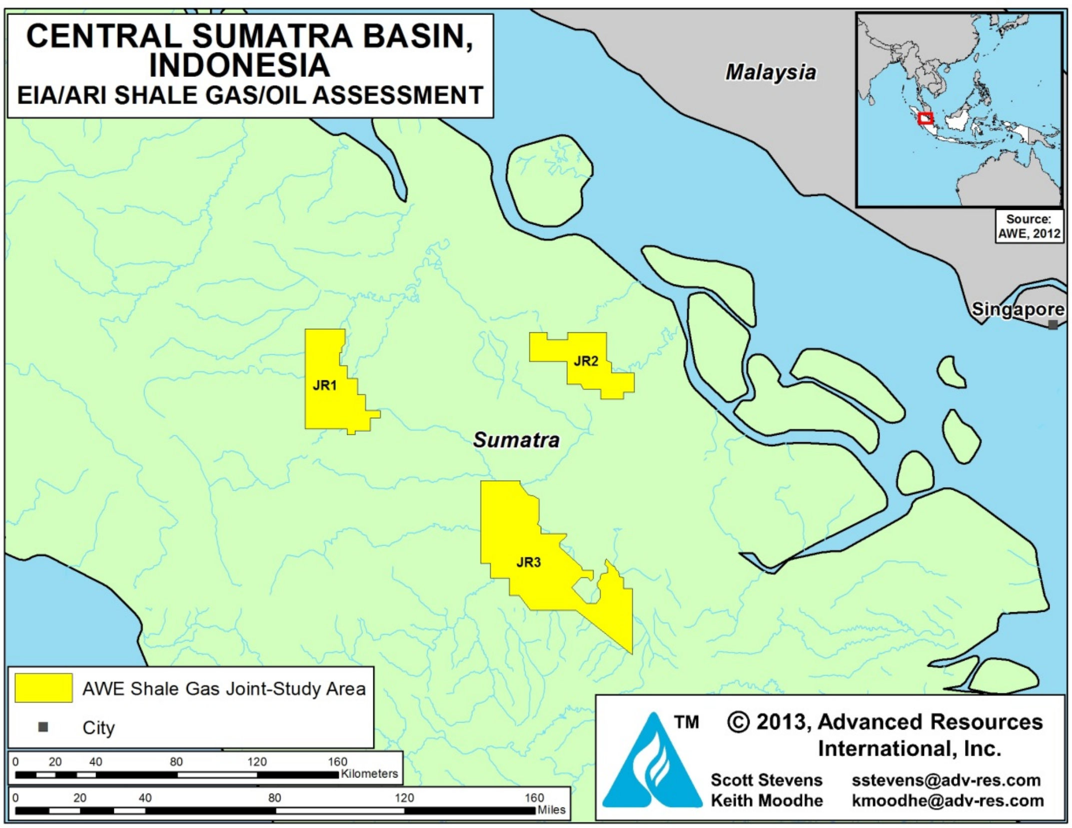
Central Sumatra Basin. Risked, technically recoverable resources from the Brown Shale are estimated at 3.3 Tcf of associated gas and 2.8 billion barrels of shale oil out of 42 Tcf and 69 billion barrels of shale gas and shale oil in-place (all figures risked). ARI considers the shale oil resource in the Central Sumatra Basin to be the most prospective shale potential in Indonesia, particularly given the extensive drilling and transportation infrastructure already present in what is the country's most important oil-producing region.

South Sumatra Basin. The Talang Akar Formation has an estimated 4.1 Tcf and 4.1 billion barrels of technically recoverable shale gas and shale oil resources, out of 68 Tcf and 136 billion barrels of shale gas and oil in-place (all figures are risked). While larger than the estimated Brown Shale oil resource in Central Sumatra, there is much less public data available on the Talang Akar.

1.4 Shale Leasing and Exploration Activity

Four shale gas joint studies totaling 5,000 km^2 in the Central Sumatra Basin were initiated by MIGAS in March 2012, Figure XXIII-5. (Note that although classified as shale gas studies, the main source rocks here actually are in the oil window.) Four companies are evaluating these blocks, including Bukit Energy Inc., AWE Limited, and New Zealand Oil & Gas (NZOG).[12] Although Indonesia does not yet have formal shale licensing regulations, these joint studies eventually could lead to Indonesia's first shale gas PSCs.

Figure XXIII-5. Location of Several Approved Shale Gas Joint-Study Areas in The Central Sumatra Basin.



Source: Modified from AWE Limited, April 2012

Calgary-based Bukit is a small private oil and gas E&P company that operates or participates in several conventional petroleum licenses in the Central and North Sumatra basins. Bukit also has applied for unconventional shale gas/oil exploration blocks in Sumatra and anticipates an award during 2013.

Earlier this year Australia-based AWE announced that they planned to make a decision about their study during Q3 2012, but to date no decision has been released.[13] New Zealand based NZOG holds conventional petroleum PSC's in the Central (Kisaran) and Northern (Bohorok) Sumatra basins, partnering with Bukit in each block, and also reports it is evaluating shale gas opportunities nearby. No shale-related drilling has been disclosed in Sumatra or anywhere in Indonesia.

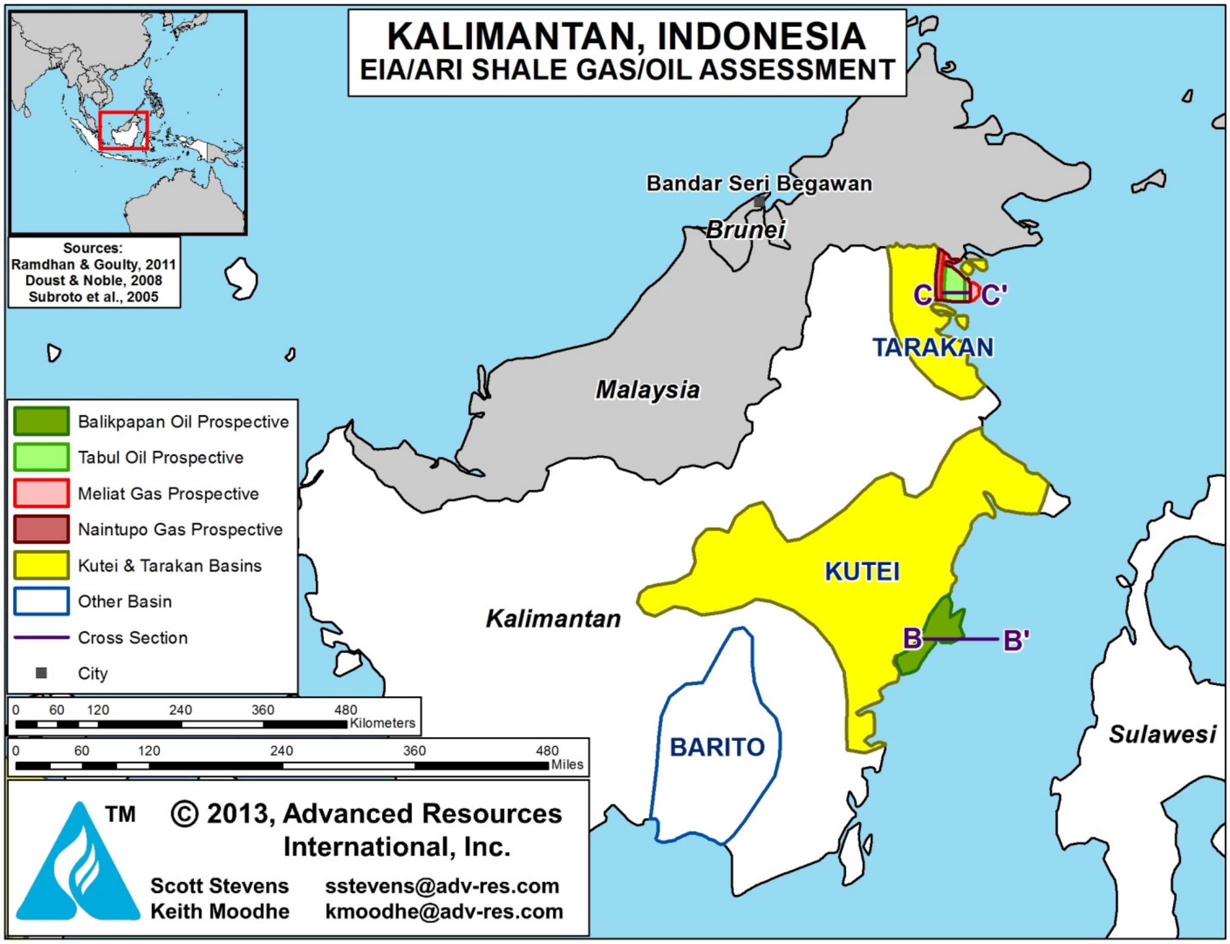
2 KUTEI AND TARAKAN BASINS

2.1 Introduction and Geologic Setting

The Kutei (or Kutai) is Indonesia's largest sedimentary basin, its 36,000-mi^2 onshore portion centered around the Mahakam Delta in eastern Kalimantan, Figure XXIII-6. The Kutei is the second largest oil and gas producing region in Indonesia after Central Sumatra as well as Indonesia's largest gas producer. The Bontang LNG export facility on the coast is the main gas market within this lightly populated region, with a capacity of 22.5 million t/yr. However, Bontang has been operating at about 16 million t/yr due to declining conventional gas production in East Kalimantan.

The 7,510-mi^2 Tarakan Basin, located north up the coast in northeast Kalimantan, contains a similar sedimentary sequence as the Kutei Basin. Fluvio-deltaic to shallow marine shales of Late Eocene age are overlain by Oligocene to Early Miocene open marine carbonate platforms. Finally Mid-Miocene to Quaternary fluvio-deltaic sandstone, shales, and coals were deposited. The entire sequence has been gently deformed with NE-SW trending folds. The main source rocks are Mid-Late Miocene coals and coaly shales of the Tabul Formation, while fluvial-deltaic sandstones of the Tabul and Plio-Pleistocene Tarakan Formation are the main conventional reservoirs.

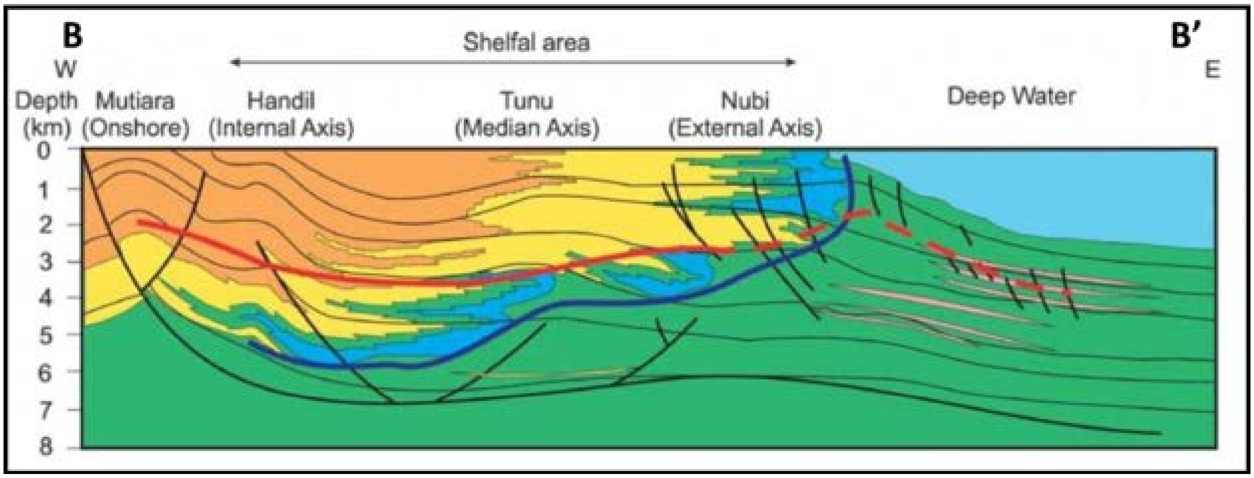
Figure XXIII-6. Prospective Shale Areas in the Kutei and Tarakan Basins, Eastern Kalimantan.



Source: ARI, 2013

The Kutei Basin is bounded by the Mangkaliat Platform on the north, the Kuching High on the west, and the Paternoster High on the south. It developed by rifting and syn-rift deposition during the mid-late Eocene. Deep marine sediments were deposited in the basin center during the late Eocene to late Oligocene, with a carbonate platform developed along the basin edge. Figure XXIII-7 shows the general structure of the Kutei Basin and illustrates that these marine mudrocks are mostly deeper than 5 km in the onshore basin extent.

Figure XXIII-7. Generalized East-West Trending Structural Cross-Section Across the Kutei Basin, Showing Marine Mudrocks Mostly Deeper than 5 Km in the Onshore Areas.



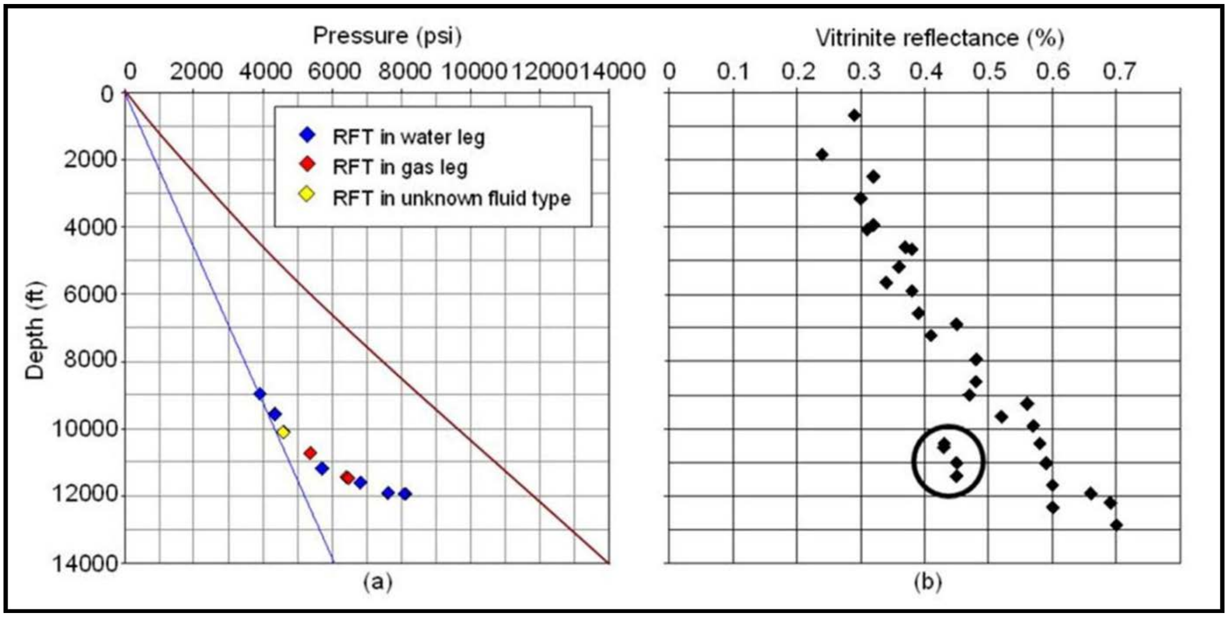
Source: Ramdhan and Gouty, 2011

The main source rocks recognized in the Kutei Basin are Mid-Late Miocene mudstones and carbonaceous shales, with essentially all of the conventional oil and gas production sourced from these shallower Neogene fluvio-deltaic deposits. These source rocks also are the principal shale gas/oil exploration targets in the basin. Prograding deposition during the early Miocene formed deltaic sediments, which are rich in Type III organic matter in coal seams and coaly mudstones. Thermal maturity of this sequence in the deeper troughs is oil-prone, ranging from 0.6% to 0.9% R_o.[14]

The mostly deltaic Miocene shales of the Balikpapan Group in the Kutei Basin are characterized by a depositional environment rich in land-plant material and containing Type III kerogen.[15] TOC ranges from 2% to 6% (average 4%) but some intervals have over 20% TOC. The interbedded shale, sand, and coal sequence is over 3,000 feet thick in many areas. Depth to the top of the oil generative zone (0.7% R_o) averages 9,000 feet in the onshore Kutei Basin, while Miocene rocks become overmature for gas below 19,000 ft depth. Shale oil potential appears to be largely confined to the eastern Kalimantan coast and productive Mahakam Delta.

Structural deformation started during the middle Miocene, forming steep north-south trending anticlines with more gentle synclines. Rapid deposition followed by basin unloading during the Neogene resulted in significant overpressure, caused by gas generation and water being trapped in lithifying sandstones due to interbedded mudstone seals. Overpressuring, ranging up to more than twice hydrostatic levels (1.0 psi/ft), is present throughout the coastal portion of the Kutei Basin starting below a depth of about 7,000 ft and accelerating markedly below about 12,000 ft, Figure XXIII-8.[16] The average surface temperature in the Kutei Basin is 30°C and the average geothermal gradient is about 30°C/km.

Figure XXIII-8. Pressure Gradients in the Kutei Basin Can Reach 1.0 psi/ft Below Depths of About 12,000 ft. Thermal Maturity is Oil-Prone to Immature, with a Very Low Ro/Depth Gradient.



Source: Ramdhan and Gouty, 2011

Further north in the Tarakan Basin, the basin contains Eocene to Miocene deep marine deposits overlain by mostly non-marine clastic sediments of Miocene and younger age that were deposited under deltaic conditions. The principal source rock is the Late Miocene Tabul Formation, along with the Early Miocene Naintupo and Middle Miocene Meliat formations.[17] Unfortunately, these three source rocks are coal-rich deltaic deposits that are considered less prospective for shale gas exploration.

The Naintupo contains deltaic sequences of shale with fair to good organic carbon content, ranging from 1.6% to 12.1% (average 5%). Kerogen is mainly Type III along with some Type II. Well penetrations indicate the Naintupo Fm is 1,000 to 1,500 feet thick (average 1,250 ft thick). Depth ranges from 6,000 ft to over 16,000 feet (average 11,500 ft). Well data and burial history modeling indicate the Naintupo Fm is in the dry gas window (R_o 1.3% to 2.0%, averaging 1.5%). Local structural uplifts may elevate the Naintupo to shallower and thermally less mature levels, where it could be oil prone.

The overlying Middle Miocene Meliat Formation includes shales and claystones along with sandstone, coal, and dolomite layers. Total organic carbon of the deltaic clays ranges from 0.7% to 6.5% (average 3% TOC), mainly Type III kerogen. The Meliat Formation ranges from 3,300 to 6,600 ft thick (average 5,000). Depth varies from 3,300 feet on basin highs to over 13,000 feet in the troughs (average depth 10,000 ft). Thermal history analysis indicates the Meliat has wet gas maturity (1.0 to 1.3% R_o).

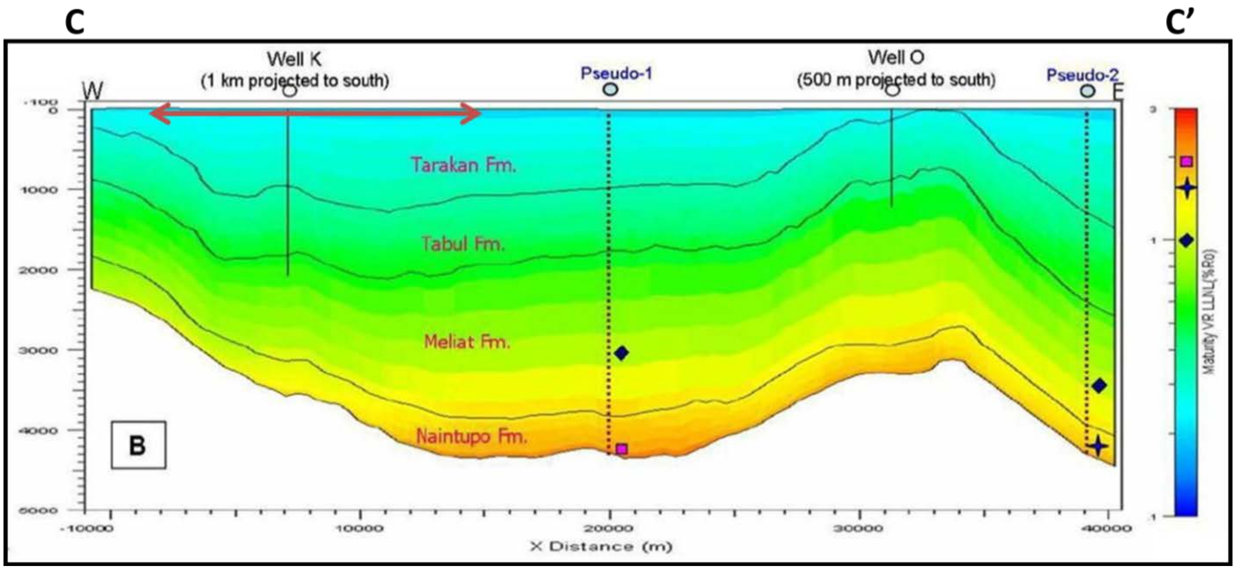
The predominant source rocks of the Tarakan Basin are shales of the Late Miocene Tabul Formation, again a non-marine, deltaic sequence. TOC ranges from 0.5% to 4%, higher in coal-rich sequences. Both lithologies contain mixtures of Type II and III kerogen. The Tabul Formation averages about 3,300 feet thick, of which approximately 1,500 feet is organic-rich, while depth ranges from 3,300 feet to 6,600 feet. Well data and modeling indicate vitrinite reflectance averages 0.7%, in the oil window.

2.2 Reservoir Properties (Prospective Area)

Kutei Basin. Lacustrine mudstones and carbonaceous shales in the Mid-Late Miocene Balikpapan Fm are estimated to be prospective within a 1,630-mi^2 area near the Mahakam Delta, based on limited cross-section data and augmented by ARI-proprietary coalbed methane mapping. These shales are oil-prone (R_o 0.7%) even at average 9,000 ft depth within this thermally immature basin. Net thickness is estimated at 450 ft, with average 4.0% TOC. Reservoir pressure is elevated above hydrostatic.

Tarakan Basin. Three shale-bearing targets are present at varying thermal maturity (oil- to gas-prone). Depth was estimated based on limited cross-section data and proprietary coalbed methane maps developed by ARI. Figure XXIII-9 is a west-east trending structural cross-section across the onshore north-central Tarakan Basin, showing generally simple structural conditions. The L. Miocene Tabul Fm averages 600 ft thick (net) and 5,000 ft deep within its 510-mi^2 prospective area, and has 3.0% average TOC that is in the oil window (0.7% R_o). The Meliat Formation occurs at 10,000-ft average depth and is mostly in the wet gas window (R_o 1.15%), while the Naintupo Formation averages 11,500 ft deep and is dry-gas-prone (R_o 1.5%).

Figure XXIII-9. West-East Trending Structural Cross-section Across the Onshore North-Central Tarakan Basin, Showing Generally Simple Structural Conditions. Source Rocks of the Tabul Formation Occur at Prospective Depths of 1 to 2 Km with Oil-prone R_o of 0.6% to 0.7%. Vertical Exaggeration = 3x.



Source: Subroto et al., 2005

2.3 Resource Assessment

Kutei Basin. Based on the geologic conditions described above, the Balikpapan Fm in the Kutei Basin has an estimated 1.3 Tcf and 0.7 billion barrels of risked, technically recoverable shale gas and shale oil resources, out of risked shale gas and oil in-place of 16 Tcf and 17 billion barrels. Note that this unit is coaly and may not be brittle.

Tarakan Basin. The oil-prone Tabul Formation has an estimated 0.2 Tcf and 0.3 billion barrels of technically recoverable shale gas and shale oil resources, out of 3.8 Tcf and 10.6 billion barrels of shale gas and shale oil in-place (risked). The gas-prone Naintupo and Meliat formations have an estimated 5 and 4 Tcf of risked, technically recoverable shale gas resources out of 35 and 25 Tcf of risked shale gas in-place, respectively. In addition, the Meliat Fm has a small volume (0.04 billion barrels) of technically recoverable condensate from shale.

2.4 Activity

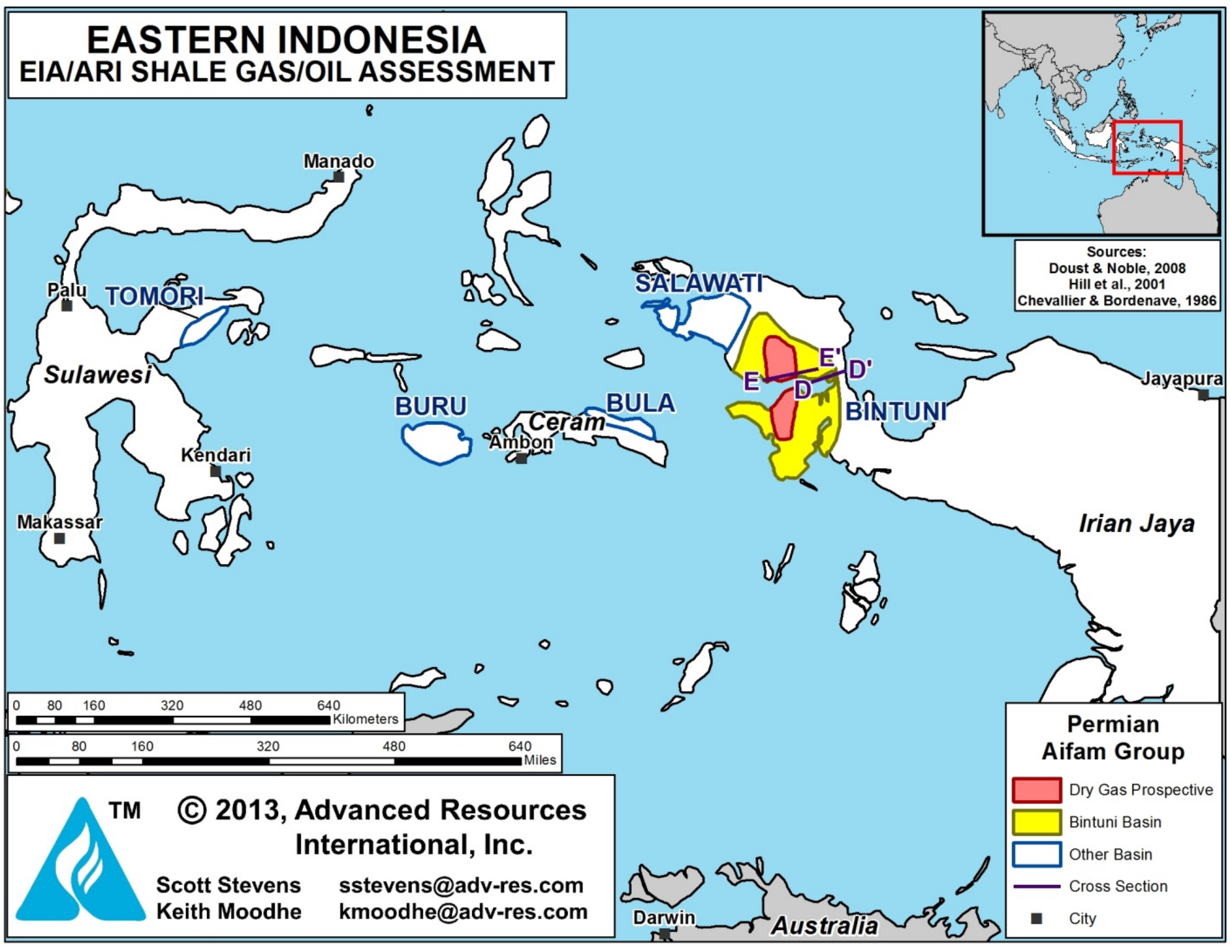
No shale gas/oil leasing or exploration activity has been reported in the Kutei or Tarakan basins.

3 EASTERN INDONESIA BASINS

3.1 Introduction and Geologic Settings

Eastern Indonesian sedimentary basins are markedly different from those in western Indonesia, with significantly older deposits generally reflecting a more marine character.[18] Sulawesi and the islands of eastern Indonesia have some of the country's only marine-deposited (non-lacustrine) shale. Thermal maturity is higher too, predominately in the dry gas window. These basins tend to be small and tectonically complex, thus we group them into a single Eastern Indonesian region for analysis, Figure XXIII-10.

Figure XXIII-10. Prospective Shale Areas in Eastern Indonesia.



Source: ARI, 2013

The Salawati and Bintuni basins in the Bird's Head region of western West Papua contain thick source rocks of Permian age that are rich in Type III coals with some contribution from overmature Jurassic marine shales containing Types II/III kerogen. However, the main source rock is Late Miocene marine shales and marlstones of the Kais and Klasafet formations, which contain Types II/III kerogen. The Klasafet is overlain by thick regressive shales and sandstones of the Plio-Pleistocene Klasaman Formation.[19] Marine marlstones and shales of the Klasaman and Kais/Klasafet formations are potential shale oil targets. They contain mainly Type II/III kerogen, albeit with relatively low TOC of 0.3% to 1.1%.[20] The Klasafet is 1,000 to over 2,000 feet thick in deep troughs, with depth ranging from 5,000 ft in the east to over 12,000 ft in the Sele Strait and Salawati Island to the north and west. Thermal maturity reaches wet gas levels (1.0% R_o) at a depth of 10,000 feet.[21]

The Klasaman Formation contains organic-rich shales with average 1.7% TOC (range 0.6% to 2.3%), mainly Type II and III kerogen. It ranges from 3,000 to 5,000 ft thick in the Salawati Basin, about 15 to 20% of which contains elevated TOC above 1%. Depth ranges from less than 3,000 ft to more than 10,000 ft. Biomarker data indicate the Klasaman sourced oil seeps in the north, where calculated vitrinite reflectance values approach 0.7% R_o and up to 1.0% in deeper parts of the Salawati Basin.

Bintuni Basin. The Bintuni Basin, located in the eastern side of the Bird's Head region, appears to have the simplest structural conditions and best shale prospectivity in the eastern Indonesia region. The Bintuni Basin is bordered to the east by the Lengguru Fold/Thrust Belt. The stratigraphic section resembles that of the Salawati Basin, with preserved Paleozoic, Mesozoic, and Tertiary units. Basement consists of Silurian and Devonian metamorphic rocks. These are unconformably overlain by Carboniferous and Upper Permian clastic sediments and shales of shallow marine origin (Aifam Group). Next are interbedded fluvial shales and sandstones of the Triassic-Jurassic Tipuma Formation and Cretaceous deltaic shales of the Kembelangen Formation.

Limited oil production from New Guinea Group limestones (Kais/Klasafet equivalent) occurred during the 1930's. In the 1990's ARCO Indonesia discovered the Wiriagar Deep gas field, which produces from Middle Jurassic "Roabiba" and "Aalenian" sandstone reservoirs and is exported via the Tangguh LNG facility.[22] Some source rock studies discount the Klasafet shales, since they are typically immature and low in organic content, mostly under 1% TOC.[23]

More important are the Permian and Jurassic sediments, analyzed below for shale oil potential. The Aifat and Ainim formations are the respective lower and upper members of the Permian Aifam Group and considered to be the main hydrocarbon generating rocks in the Bintuni. The older Aifat consists of black marine calcareous shales. Limited data show relatively modest TOC of 1.0% to 1.8%, averaging 1.5%. Gross thickness can exceed 3,500 feet, while depth can exceed 12,000 ft in the Bintuni Basin.

The overlying Ainim Formation also contains calcareous shales, although deposited in a more deltaic setting. Source rock thickness is approximately 2,400 feet. Depth averages about 10,000 feet. This unit contains adequate organic matter with abundant coal seams. Hydrogen index is over 300 mg HC/g. Vitrinite reflectance is sharply lower (0.66% R_o) in the overlying Ainim compared with the older Aifat, indicating an unconformity within the Permian.

In addition to the Permian, the Jurassic Tipuma Formation may be a potential hydrocarbon source. The Tipuma contains sandstones and carbonaceous shales. Analyses of the shallow marine shales indicate maximum TOC of 4.5 and 7.6%, mainly humic kerogen. The Tipuma ranges from 4,000 to nearly 8,000 feet deep. Near the Bintuni Basin's western limit, the Jurassic shales are in the immature-mature oil window, at about 0.6% R_o.

The Tomori Basin of eastern Sulawesi shares many similarities with the Salawati/Bintuni basins, from which it was transported along strike-slip faults. The Tomori is a foreland basin within the greater Banggai-Sula micro-continent, a fold-thrust system that developed following Pliocene collision and thrusting of continental crust over ophiolitic material. Oil and gas exploration began during the 1980's, resulting in the discovery of the Senoro "giant" gas field in 2001.[24] Oil and gas are produced from fractured limestones of the Lower Miocene, sourced by shales within the contemporaneous Tomori Formation, which is similar to the Klasafet Fm.

The Lower Miocene Tomori Fm, ranging from 500 to 1,000 ft thick, also is a potential target for shale exploration. It comprises marine and carbonaceous shale along with some limestone and coal, with the upper section typically more deltaic in origin. TOC is fairly high, averaging 2 to 4% and consisting of Type II/III kerogen. The lower marine section contains higher Type II kerogen but TOC generally is less than 1%. The Tomori Fm attains 0.5% R_o at a depth of 7,200 ft, becoming gas prone (> 1.0% R_o) below a depth of about 11,300 ft.[25]

Finally, the Bula Basin in northeast Seram island contains Mesozoic to Mid-Tertiary open marine pelagic and oceanic deposits, including clays, limestones, and thin sandstones. This assemblage later collided with Irian Jaya and the Australian continental shelf.26 Conventional oil, sourced from Triassic-Jurassic marine carbonate Type II mudstone source rocks, is produced from fractured Jurassic limestone as well as from Plio-Pleistocene marginal marine sandstones and limestones.[27]

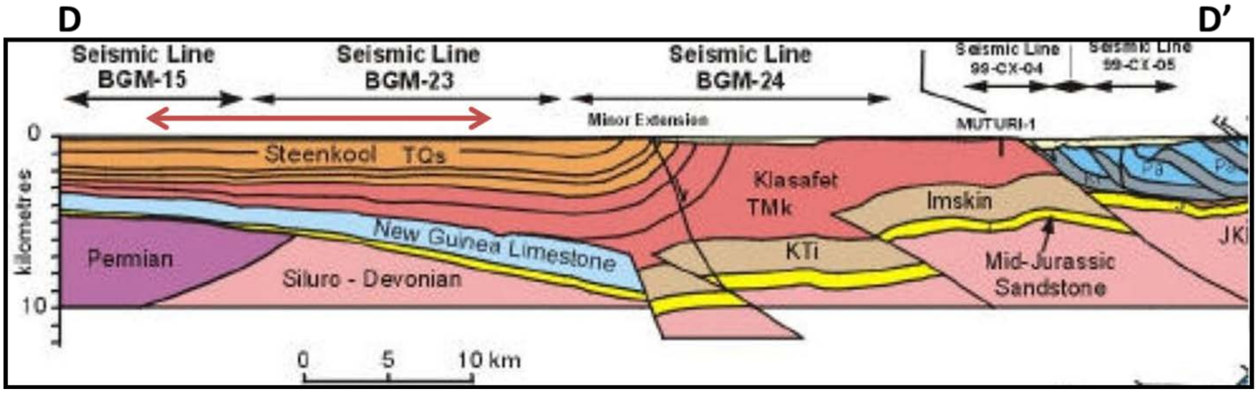
3.2 Reservoir Properties (Prospective Area)

Only the Bintuni Basin had sufficient data to evaluate shale gas/oil reservoir properties and resources, while the other areas (Salawati, Tomori, Bula) lacked adequate data for detailed analysis.

Bintuni Basin. Figure XXIII-1 shows a WSW-ENE trending structural cross-section across the east-central Bintuni Basin.[28] According to this interpretation, the Permian shales here are too deep but marine shales within the Klasafet Fm dip gently to the east and are at prospective depths of 2.5 to 5 km, although as noted above these appear to have low TOC. Further east this unit is structurally deformed by thrusting and not considered prospective. The prospective Klasafet shale area is inferred to be a north-south elongated rectangle just west of the Lengguru Fold and Thrust belt, but this unit was not assessed due to its low TOC (<1%).

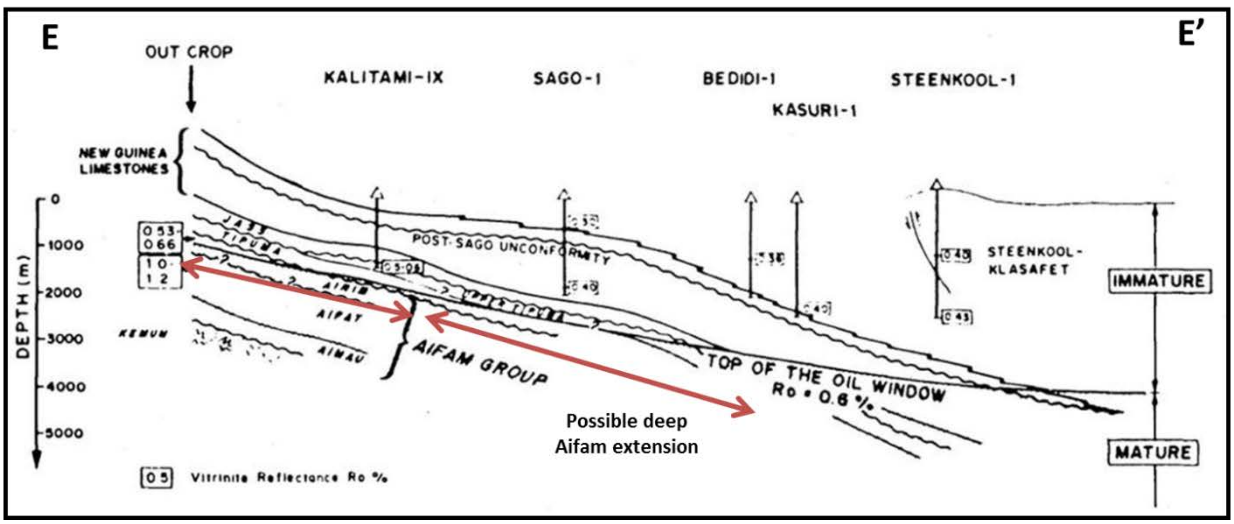
Figure XXIII-12 shows a west-east trending structural cross-section across the west-central Bintuni Basin. Here the organic-rich and prospective Permian Aifam Group (Aifat and Ainim formations) is about 1.0 to 3.5 km deep (possibly deeper further to the east), structurally simple, and within the volatile oil to wet gas windows (R_o of 1.0% to 1.2%). The prospective Aifam Group shale region is assumed to be a north-south elongated rectangle in the west-central Bintuni Basin.

Figure XXIII-11. Generalized WSW-ENE Trending Structural Cross-section Across the Bintuni Basin, Showing Marine Shales in the Klasafet Fm Dipping Gently to the East at Prospective Depths of 2.5 to 5 Km. Further East this Unit is Structurally Deformed and Not Prospective.



Source: Hill et al., 2001

Figure XXIII-12. West-east Structural Cross-section Across West-central Bintuni Basin. Here the Organic-rich and Prospective Permian Aifam Group (Aifat and Ainim formations) is about 1.0 to 3.5 Km Deep, Structurally Simple, and Within the Volatile Oil to Wet Gas Windows (R_o of 1.0% to 1.2%).



Source: Chevalier et al., 1986

3.3 Resource Assessment

Bintuni Basin. The prospective areas of the Permian Aifam Group has an estimated 29 Tcf of technically recoverable shale gas resources out of 114 Tcf of gas in-place (both risked), as defined by the R_o contours of 1.2% to 1.8%. This marine-deposited unit could be the best shale gas target in Indonesia, although its location is relatively remote from market and services.

3.4 Shale Leasing and Exploration Activity

No shale gas/oil leasing or exploration activity has been reported in eastern Indonesia.

4 OTHER BASINS

Indonesia's other onshore sedimentary basins appear to have limited potential for shale gas/oil development. These areas contain mainly non-marine sequences of sandstone, siltstone, coal, and coaly shale that are not considered stable and brittle enough for horizontal frac shale well completions.

- Bengkulu Basin**.** Located in southwest Sumatra across the Barisan Mountains from the South Sumatra Basin, this relatively small and structurally deformed fore-arc basin contains predominantly non-marine clastic and sedimentary rocks of Eocene through Pleistocene age. Geochemical analyses have identified the Mid-Late Miocene Lemau Formation as a potential source rock. This unit consists of mudstone, calcareous mudstone, coal seams, sandstone, and conglomerate deposited in a mainly shallow marine environment that transitioned into mangrove and freshwater environments.[29] Intense faulting, steep structural dips, low thermal maturity (R_o averages 0.40%), and coaly non-brittle lithology all appear to make the Bengkulu Basin unsuitable for shale gas/oil development.

- Ombilin Basin**.** This small non-producing basin is located in west-central Sumatra along the eastern side of the Barisan Mountains. It is a transpressional pull-apart basin that developed during the Eocene to Middle Oligocene and was later deformed into tightly spaced folds trending northwest-southeast. The basal Eocene Brani and Oligocene Sangkarewang formations were deposited in lacustrine rift settings. This later evolved into fluvial deposits of the Late Oligocene Sawahtambang Formation, followed by the marine Miocene Ombilin Formation which resulted from a global sea level rise and transgression.

  Several shallow coal mines are in operation along the edge of the Ombilin Basin, but only a few conventional oil & gas exploration wells have been drilled. These encountered conventional sandstone reservoirs containing natural gas with high levels of

CO_2 (50-90%). Geochemical analyses indicate that shales within the Sangkarewang, Sawahlunto, and Ombilin formations are the best source rocks in the basin. These units contain Type III kerogen that mostly has reached the oil window (T_{max} 435-447° C).[30] Overall, the complex structure, high CO_2 content, and non-brittle nature of the Ombilin Basin shales appears to make them poorly suited for shale gas/oil development.

- The Northwest Java Basin northeast of Jakarta is one of the larger of the small graben structures on Java Island. The Jatibarang sub-basin, the onshore extension of the larger Northwest Java Basin, formed by rifting during the Eocene when volcaniclastics, tuffs and interbedded lacustrine shales were deposited.[31] Subsidence continued into the Late Oligocene and Early Miocene, forming a sequence of shale, coal, and sandstones deposited in fluvio-deltaic, coastal, and shallow marine environments. Deposition evolved to mainly carbonate during the Middle Miocene. By Late Miocene to Quaternary time subsidence diminished, with deposition of regressive clastics and platform carbonates.

  Miocene sandstone is the primary conventional oil and gas reservoir in the Jatibarang Basin, sourced mainly by carbonaceous shale and coal of the Late Oligocene Upper Talang Akar Formation. Organic material consists mainly of Type II and III kerogen. Total organic carbon (TOC) reaches 40-70% in coal, while the shales also can be fairly organic-rich (0.5 to 9%).[32] The inter-bedded shale-clastic sequence can be over 1,000 ft thick, comprising coal seams, limestone, and sandstone. Depth to the Talang Akar is about 7,500 to 11,500 ft. These non-marine to marginal marine source rocks can be oil and gas prone, becoming increasingly more mature offshore. Shales in the Jatibarang Basin are coaly and unlikely to be brittle enough for hydraulic fracturing in horizontal wells.

- The Barito Basin in southern Kalimantan is a large (70,000 km^2 onshore extent), structurally simple basin containing up to 6 km of Eocene and younger sedimentary rocks which unconformably overlie the igneous and metamorphic basement. Minor conventional oil production (of 30-40° API gravity) occurs in the northern Barito, but most of the basin is non-productive. Recent coalbed methane exploration is underway in the southern Barito.

  The Middle Eocene to late Early Oligocene Tanjung Formation is the most important petroleum source rock, consisting of fluvial and marginal marine clastic strata, including thin coal deposits.[33] The formation is over 3,300 ft thick in Tanjung Field in the north.[34] High-TOC shale and marl is concentrated in its upper section, which reaches 2,400 ft thick in the deep southern Barito Basin.[35] Depth to the Tanjung ranges from 3,000 to 12,000 ft, averaging about 6,000 ft deep in the shallow conventional anticlinal fields. TOC is uncertain. The Tanjung has entered the oil window throughout much of the basin, reaching dry gas maturity in the deepest regions. However, the shales within the Tanjung Fm are coaly and probably not brittle.

Overlying the Tanjung Fm are shallow carbonate rocks of the Late Oligocene to Early Miocene Berai Formation, which record a regional marine transgression. Above these, the overlying Plio-Pleistocene Warukin Formation contains marginal marine to fluvial-deltaic sedimentary rocks, including thick, low-rank, sub-bituminous coal deposits. The lack of significant conventional oil and gas production in the Barito Basin, apart from its northernmost edge, is considered a negative factor and makes this basin unattractive for shale gas/oil exploration.

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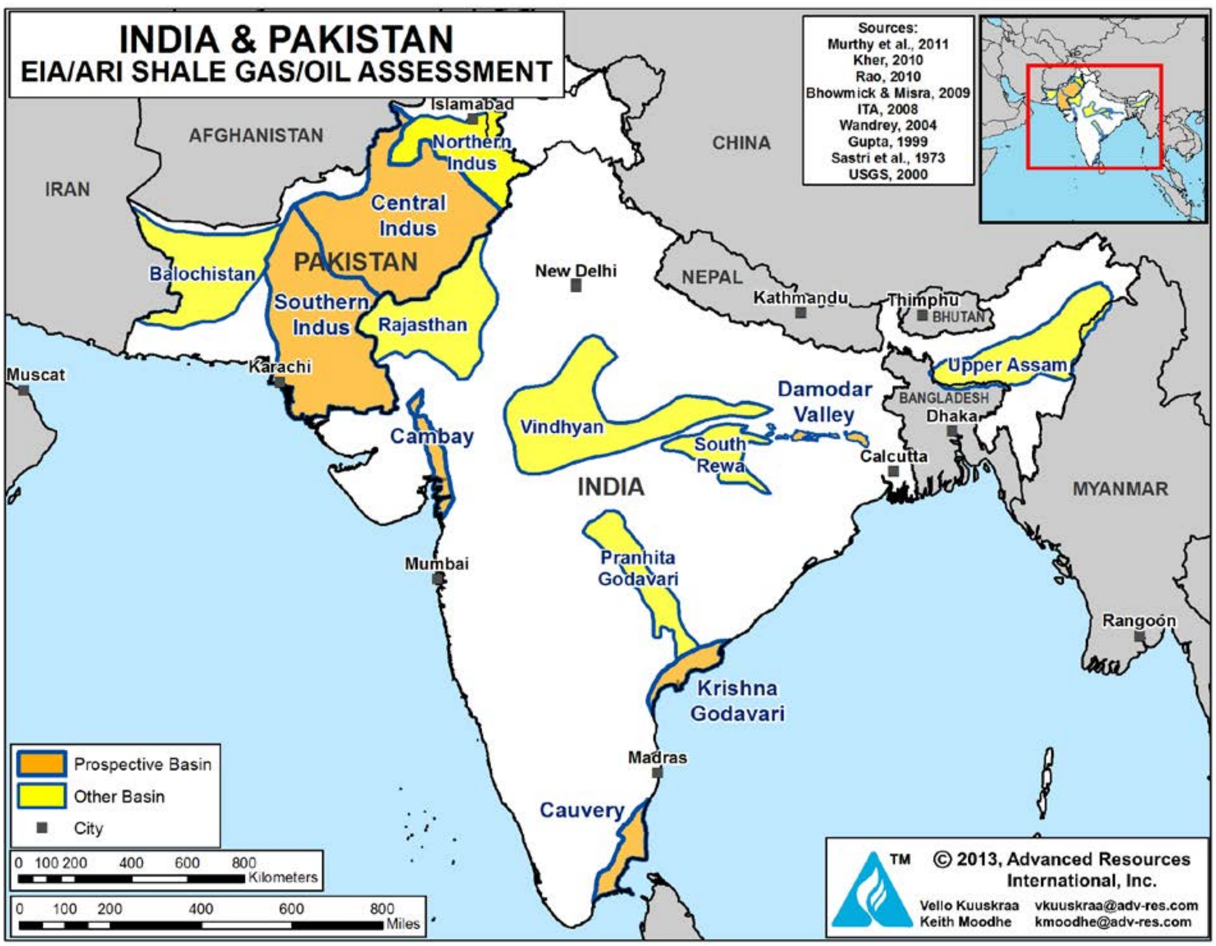
XXIV. INDIA/PAKISTAN

SUMMARY

India and Pakistan contain numerous basins with organic-rich shales. For India, the study assessed four priority basins: Cambay, Krishna-Godavari, Cauvery and Damodar Valley. The study also screened other basins in India, such as the Upper Assam, Vindhyan, Pranhita-Godavari, Rajasthan and South Rewa. However, in these basins the shales were thermally too immature or the data for conducting a rigorous resource assessment were not available. For Pakistan, the study addressed the areally extensive Indus Basin, Figure XXIV-1.

Figure XXIV-1. Shale Gas and Shale Oil Basins of India/Pakistan



Overall, ARI estimates a total of 1,170 Tcf of risked shale gas in-place for India/Pakistan, 584 Tcf in India and 586 Tcf in Pakistan. The risked, technically recoverable shale gas resource is estimated at 201 Tcf, with 96 Tcf in India and 105 Tcf in Pakistan, Tables XXIV-1A and XXIV-1B. In addition, we estimate risked shale oil in-place for India/Pakistan of 314 billion barrels, with 87 billion barrels in India and 227 billion barrels in Pakistan. The risked, technically recoverable shale oil resource is estimated at 12.9 billion barrels for these two countries, with 3.8 billion barrels for India and 9.1 billion barrels for Pakistan, Table XXIV-2A and XXIV-2B.

Table XXIV-1A. Shale Gas Reservoir Properties and Resources of India

Basic Data	Basin/Gross Area		Cambay (7,900 mi^2)			Krishna-Godavari (7,800 mi^2)			Cauvery (9,100 mi^2)	Damodar Valley (2,270 mi^2)
	Shale Formation		Cambay Shale			Permian-Triassic			Sattapadi-Andimadam	Barren Measure
	Geologic Age		U. Cretaceous-Tertiary			Permian-Triassic			Cretaceous	Permian-Triassic
	Depositional Environment		Marine			Marine			Marine	Marine
Physical Extent	Prospective Area (mi^2)		1,060	300	580	1,100	3,900	3,000	1,010	1,080
	Thickness (ft)	Organically Rich	1,500	1,500	1,500	330	500	1,300	1,000	1,000
		Net	500	500	500	100	150	390	500	250
	Depth (ft)	Interval	6,000 - 10,000	10,000 - 13,000	13,000 - 16,400	4,000 - 6,000	6,000 - 10,000	10,000 - 16,400	7,000 - 13,000	3,300 - 6,600
		Average	8,000	11,500	14,500	5,000	8,000	13,000	10,000	5,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Normal	Slightly Overpress.
	Average TOC (wt. %)		2.6%	2.6%	2.6%	6.0%	6.0%	6.0%	2.3%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.80%	0.85%	1.15%	1.50%	1.15%	1.20%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	High	High	High	High	High
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Wet Gas
	GIP Concentration (Bcf/mi^2)		55.9	170.5	228.0	6.9	57.8	204.7	119.6	62.9
	Risked GIP (Tcf)		35.5	30.7	79.4	3.4	101.4	276.4	30.2	27.2
	Risked Recoverable (Tcf)		3.6	6.1	19.8	0.2	15.2	41.5	4.5	5.4

Table XXIV-1B. Shale Gas Reservoir Properties and Resources of Pakistan

Basic Data	Basin/Gross Area		Lower Indus (169,000 mi^2)			
	Shale Formation		Sembar			Ranikot
	Geologic Age		L. Cretaceous			Paleocene
	Depositional Environment		Marine			Marine
Physical Extent	Prospective Area (mi^2)		26,700	25,560	31,320	26,780
	Thickness (ft)	Organically Rich	1,000	1,000	1,000	1,000
		Net	250	250	250	200
	Depth (ft)	Interval	4,000 - 6,000	6,000 - 10,000	10,000 - 16,400	6,000 - 13,000
		Average	5,000	8,000	13,000	9,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	0.85%
	Clay Content		Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		14.3	57.0	82.7	17.0
	Risked GIP (Tcf)		45.9	174.7	310.8	54.8
	Risked Recoverable (Tcf)		3.7	34.9	62.2	4.4

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Table XXIV-2A. Shale Oil Reservoir Properties and Resources of India

Basic Data	Basin/Gross Area		Cambay ($7,900\ mi^2$)		Krishna-Godavari ($7,800\ mi^2$)		Cauvery ($9,100\ mi^2$)	Damodar Valley ($2,270\ mi^2$)
	Shale Formation		Cambay Shale		Permian-Triassic		Sattapadi-Andimadam	Barren Measure
	Geologic Age		U. Cretaceous-Tertiary		Permian-Triassic		Cretaceous	Permian-Triassic
	Depositional Environment		Marine		Marine		Marine	Marine
Physical Extent	Prospective Area (mi^2)		1,060	300	1,100	3,900	1,010	1,080
	Thickness (ft)	Organically Rich	1,500	1,500	330	500	1,000	1,000
		Net	500	500	100	150	500	250
	Depth (ft)	Interval	6,000 - 10,000	10,000 - 13,000	4,000 - 6,000	6,000 - 10,000	7,000 - 13,000	3,300 - 6,600
		Average	8,000	11,500	5,000	8,000	10,000	5,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Slightly Overpress.
	Average TOC (wt. %)		2.6%	2.6%	6.0%	6.0%	2.3%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	1.15%	1.20%
	Clay Content		Low/Medium	Low/Medium	High	High	High	High
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Condensate	Condensate
	OIP Concentration ($MMbbl/mi^2$)		79.8	19.2	17.5	6.5	30.2	12.1
	Risked OIP (B bbl)		50.8	3.5	8.7	11.5	7.6	5.2
	Risked Recoverable (B bbl)		2.54	0.17	0.26	0.34	0.23	0.21

Table XXIV-2B. Shale Oil Reservoir Properties and Resources of Pakistan

Basic Data	Basin/Gross Area		Lower Indus ($169,000\ mi^2$)		
	Shale Formation		Sembar		Ranikot
	Geologic Age		L. Cretaceous		Paleocene
	Depositional Environment		Marine		Marine
Physical Extent	Prospective Area (mi^2)		26,700	25,560	26,780
	Thickness (ft)	Organically Rich	1,000	1,000	1,000
		Net	250	250	200
	Depth (ft)	Interval	4,000 - 6,000	6,000 - 10,000	6,000 - 13,000
		Average	5,000	8,000	9,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%
	Clay Content		Low	Low	Low
Resource	Oil Phase		Oil	Condensate	Oil
	OIP Concentration ($MMbbl/mi^2$)		36.6	9.1	25.4
	Risked OIP (B bbl)		117.4	27.9	81.7
	Risked Recoverable (B bbl)		4.70	1.12	3.27

INTRODUCTION

Evaluating the shale gas and oil resources of India and Pakistan posed a series of challenges. Only limited publically available data exist on the geologic setting and reservoir properties of the numerous shale formations in India and Pakistan. In addition, the shale basins in these two countries are geologically highly complex.

Many of the basins in India, such as the Cambay and the Cauvery, comprised a series of extensively faulted horst and graben structures. As such, the prospective areas for shale gas and oil in these basins are often restricted to a series of isolated basin depressions (sub-basins). While the shales in these basins are thick, considerable uncertainty exists on the areal extents of the prospective areas in these basins. To account for this uncertainty, we have applied prospective area risk factors to each basin. Figures XXIV-2 shows the stratigraphic column for the key basins of India.

Recently, ONGC drilled and completed India's first shale gas well, RNSG-1, northwest of Calcutta in West Bengal. The well was drilled to a depth of 2,000 meters and reportedly had gas shows at the base of the Permian-age Barren Measure Shale. Two vertical wells (Well D-A and D-B) were previously tested in the Cambay Basin and had modest shale gas and oil production from the Cambay Black Shale.[1]

In Pakistan, the shale gas and oil assessment is restricted to the areally extensive Central and Southern Indus basins, together called the Lower Indus Basin. The shales in this basin have sourced the significant volumes of conventional oil and gas discovered and produced in Pakistan. However, to date, no shale specific exploration has been publically reported for Pakistan. Figure XXIV-3 provides the stratigraphic column for the key basins of Pakistan.

Fortunately, the technical literature on conventional oil and gas exploration in India and Pakistan often contains information on the nature of the source rocks that have charged the conventional gas and oil reservoirs, providing a valuable starting point for this resource assessment. As additional shale-directed geological and reservoir information is collected and distributed, a more rigorous assessment of India's and Pakistan's shale oil and gas resources will emerge.

Figure XXIV-2. Stratigraphic Column for India

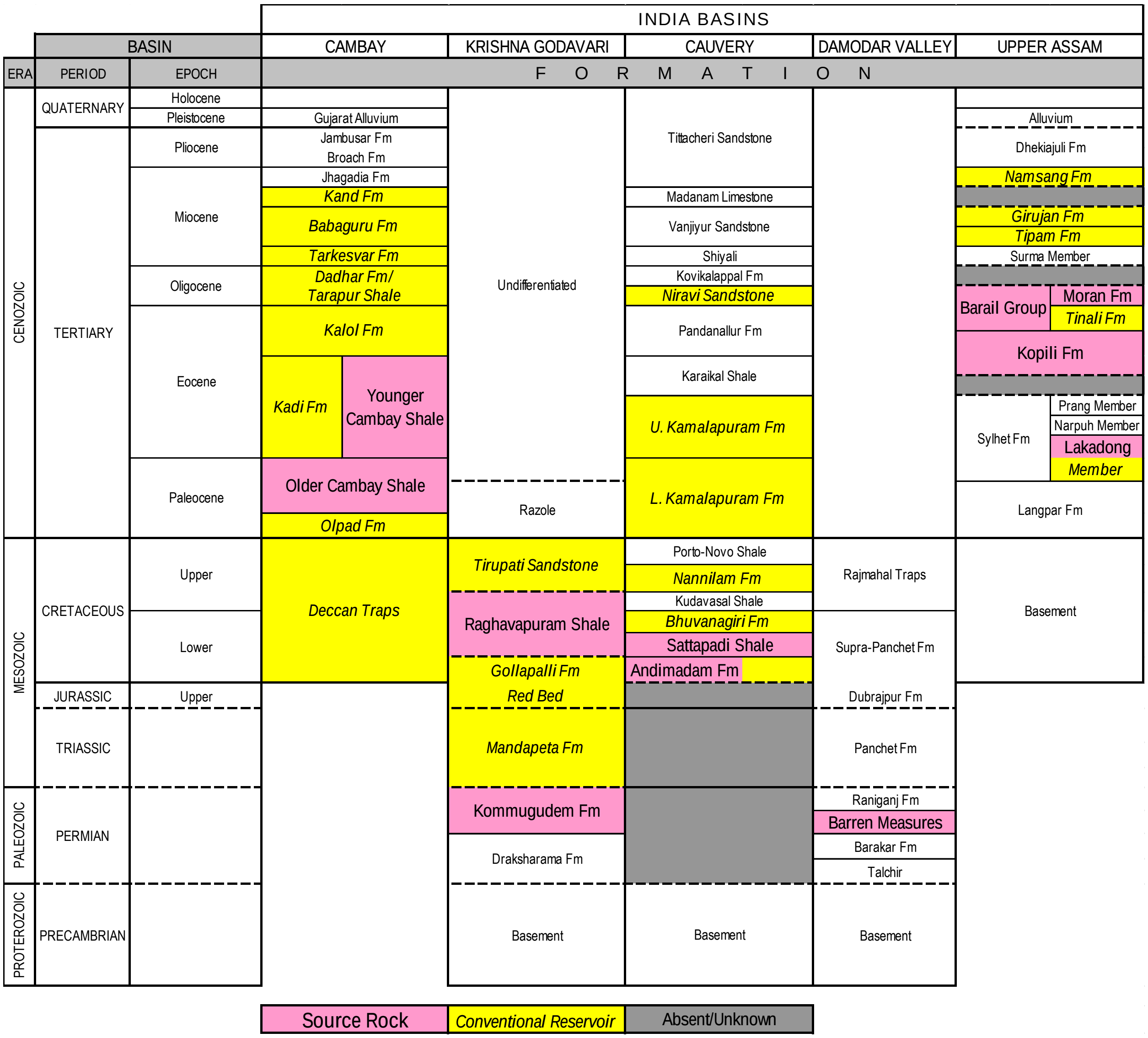


Figure XXIV-3. Stratigraphic Column for Pakistan

ERA	PERIOD	EPOCH	SOUTHERN INDUS	CENTRAL INDUS	NORTHERN INDUS	BALOCHISTAN
	BASIN		PAKISTAN BASINS			
			FORMATION			
CENOZOIC	QUATERNARY	Pleistocene	Siwaliks	Siwaliks		Ormara Chatti
CENOZOIC	TERTIARY	Pliocene				Talar/Hinglas
CENOZOIC	TERTIARY	Miocene	Gaj	Gaj	Kamlial Murree	Parkini Panjgur
CENOZOIC	TERTIARY	Oligocene	Nari	Nari		Hoshab Siahan *Amalaf*
CENOZOIC	TERTIARY	Eocene	*Kirthar* *Ghazij/* *Baska/Laki*	Kirthar *Sakaser* Nummal	 *Kohat* Kuldana	Wakai *Saindak* Kharan
CENOZOIC	TERTIARY	Paleocene	*Dunghan* Ranikot Khadro	*Dunghan* Ranikot	Patala Lockhart Hangu	Ispikan Rakhshani
MESOZOIC	CRETACEOUS	Upper	*Pab* *Mughal Kot* *Parh*	*Pab* *Mughal Kot* *Parh*	 *Kawagarh*	Humai
MESOZOIC	CRETACEOUS	Lower	*Goru* Sembar	*Goru* Sembar	*Lumshiwal* Chichali	Sinjrani
MESOZOIC	JURASSIC	Upper	*Takatu/Chiltan*	*Samana Suk*		
MESOZOIC	JURASSIC	Middke	Lorolai/Datta		*Samana Suk*	
MESOZOIC	JURASSIC	Lower	Shirinab	Shinawari Data	Shinawari Data	
MESOZOIC	TRIASSIC	Upper	Wulgai/Alozai	Kingriali	 Kingriali	
MESOZOIC	TRIASSIC	Middke		Tredian Mianwali	Tredian Mianwali	
MESOZOIC	TRIASSIC	Lower			Chidru	
PALEOZOIC	PERMIAN			Zaluch Nilawhan	Wargal Sardhai Warcha Dandot Tobra	
PALEOZOIC	CAMBRIAN		Baghanwala Juttana Kussak	*Baghanwala* *Juttana* *Kussak*	*Juttana* *Khewra*	
PROTEROZOIC	PRECAMBRIAN		Khewra Salt Range Jodhpur Basement	*Khewra* Salt Range *Jodhpur* Basement	 Salt Range Basement	

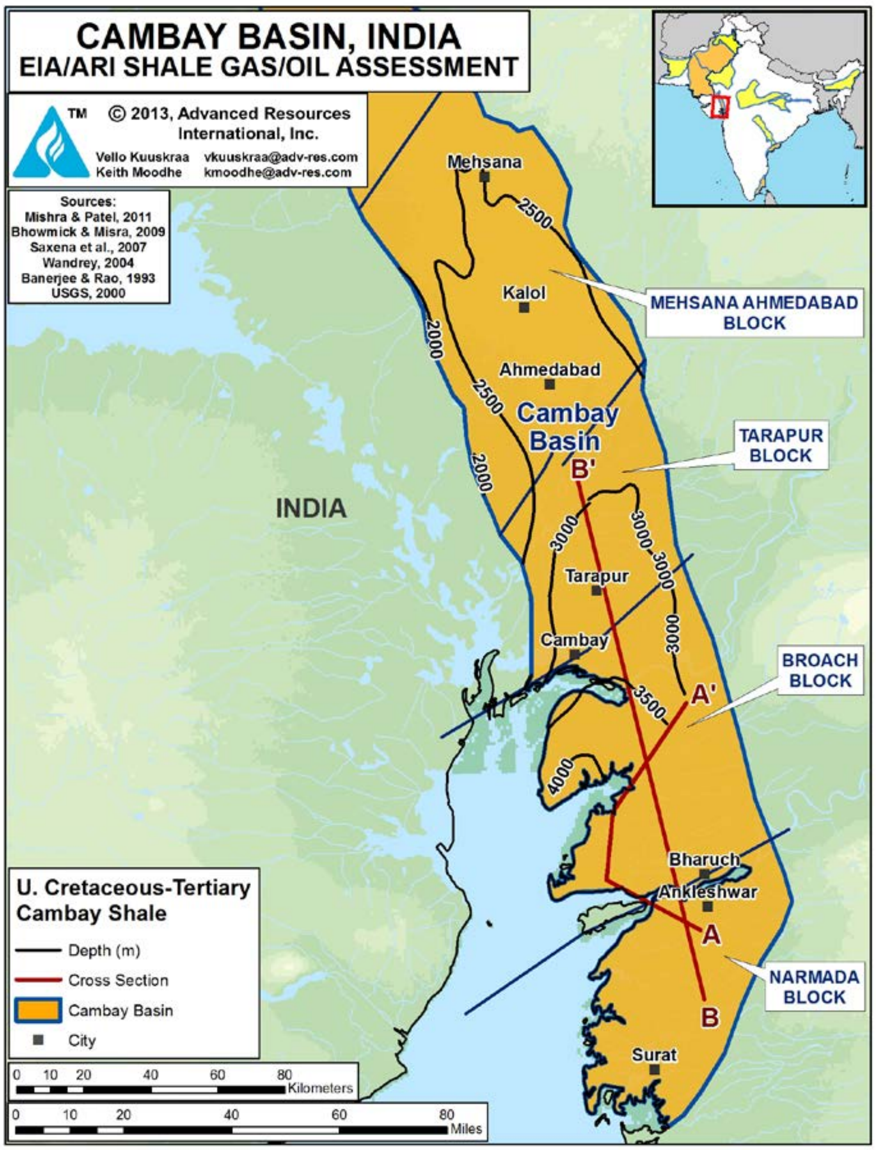
Source Rock	*Conventional Reservoir*	Absent/Unknown

1. CAMBAY BASIN, INDIA

1.1 Introduction and Geologic Setting

The Cambay Basin is an elongated, intra-cratonic Late Cretaceous to Tertiary rift basin, located in the State of Gujarat in northwest India. The basin includes four assessed fault blocks: Mehsana-Ahmedabad, Tarapur, Broach and Narmada, Figure XXIV-4.

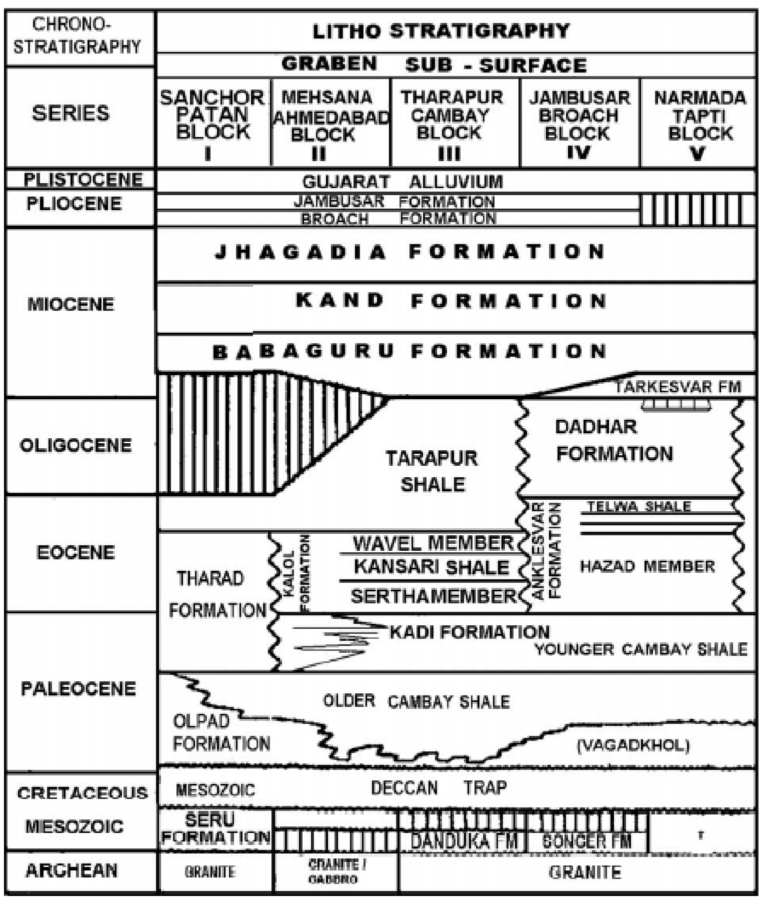
Figure XXIV-4. Depth of Cambay Black Shale, Cambay Basin



The Cambay Basin is bounded on its eastern and western sides by basin-margin faults and extends south into the offshore Gulf of Cambay, limiting its onshore area to 7,900 mi^2.[2]

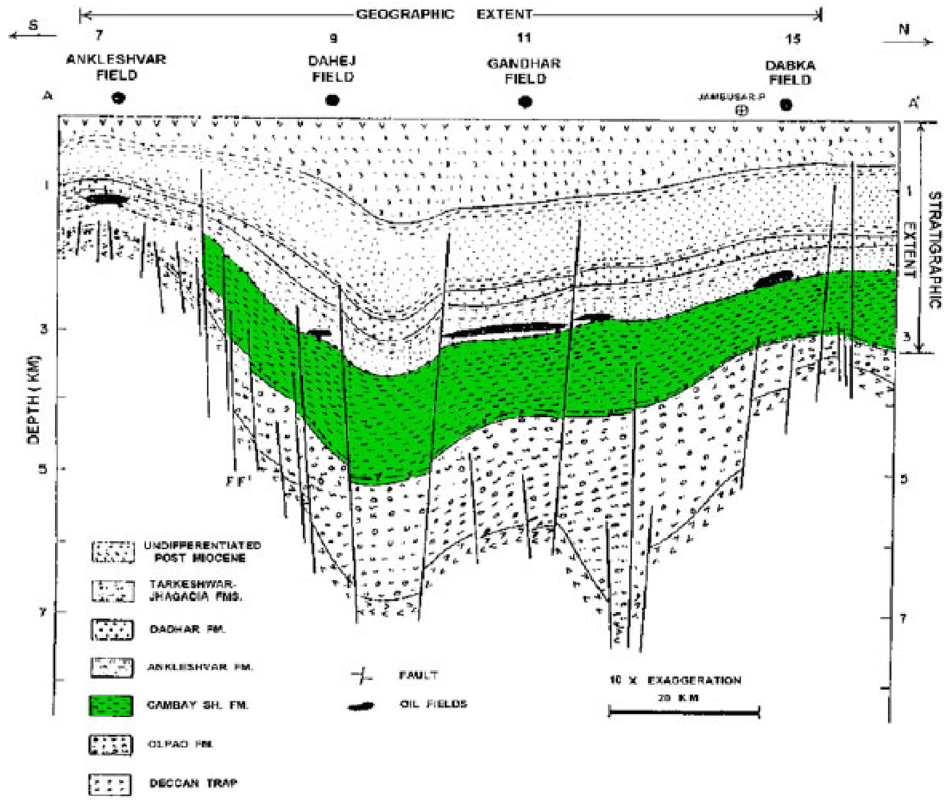
The Deccan Trap, composed of horizontal lava flows, forms the basement of the Cambay Basin. Above the Deccan Trap, separated by the Olpad Formation, is the Late Paleocene and Early Eocene Cambay Black Shale, Figure XXIV-5.[3] The Cambay Black Shale represents the marine transgressive episode in the basin. With a thermal maturity ranging from about 0.7% to 2%, the shale is in the oil, wet gas and dry gas windows.[4] For purposes of this study, we have assumed that the oil window starts at 6,000 feet of depth, that the wet gas window starts at 11,000 feet, and that the dry gas window is below 13,000 feet of depth, Figures XXIV-6 and XXIV-7.

Figure XXIV-5. Generalized Stratigraphic Column of the Cambay Basin.



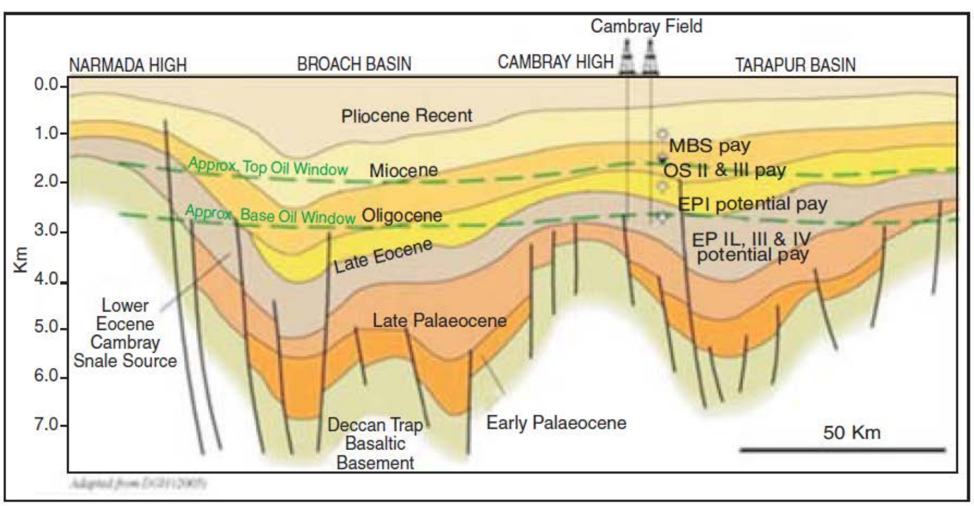
Source: Silvan, 2008

Figure XXIV-6. Cross Section of Cambay Black Shale System



Source: Shishir Kant Saxena, 2007

Figure XXIV-7. N-S Geological Cross-Section Across Cambay Basin



Source: P.K. Bhowmick and Ravi Misra, Indian Oil and Gas Potential, Glimpses of Geoscience Research in India.

The Cambay Basin contains four primary fault blocks, from north to south: (1) Mehsana-Ahmedabad; (2) Tarapur; (3) Broach; and (4) Narmada (Sivan et al., 2008).[3] Three of these blocks appear to have sufficient thermal maturity to be prospective for shale gas and oil, Table XXIV-3.[5]

Table XXIV-3. Major Fault Blocks and Shale Prospectivity of Cambay Basin

Fault Blocks		Comments
1.	Mehsana-Ahmedabad	Prospective for Shale Oil
2.	Tarapur	Prospective for Shale Oil and Wet Gas
3.	Broach	Prospective for Shale Oil and Wet/Dry Gas
4.	Narmada	Insufficient Data, Likely Immature

- ***Mehsana-Ahmedabad Block.*** Three major deep gas areas (depressions) exist in the Mehsana-Ahmedabad Block - - the Patan, Worosan and Wamaj. A deep well, Well-A, was drilled in the eastern flank of the Wamaj Low to a depth of nearly 15,000 ft, terminating below the Cambay Black Shale. In addition, a few wells were recently drilled to the Cambay Black Shale in the axial part of the graben low. A high-pressure gas zone was encountered in the Upper Olpad section next to the Cambay Shale, with methane shows increasing with depth. Geochemical modeling for this fault block indicates an oil window at 6,600 ft, a wet gas window at 11,400 ft, and a dry gas window at 13,400 ft.[6]

- ***Broach and Tarapur Blocks.*** The deeper Tankari Low in the Broach Block and the depocenter of the Tarapur Block appear to have similar thermal histories as the Mehsana-Ahmedabad Block. As such, we assumed these two areas have generally similar shale gas and oil properties as the Cambay Black Shale in the Mehsana-Ahmedabad Block.

1.2 Reservoir Properties (Prospective Area)

The depth of the prospective area of the Cambay Black Shale ranges from about 6,000 ft in the north to 16,400 ft in the lows of the southern fault blocks, averaging 8,000 ft in the oil prospective area, 11,500 ft in the wet gas and condensate prospective area, and 14,500 ft in the dry gas prospective area. Thermal gradients are high, estimated at 3^{o}F per 100 feet, contributing to accelerated thermal maturity of the organics.[7] The Cambay Black Shale interval ranges from 1,500 to more than 5,000 ft thick in the various fault blocks.[8] In the northern

Mehsana-Ahmedabad Block, the Kadi Formation forms an intervening 1,000-ft thick non-marine clastic wedge within the Cambay Black Shale interval. In this block, the shale thickness varies from 300 to 3,000 ft, with the organic-rich shale thickness, located in the lower portion of the Cambay Black Shale interval, averaging 500 net ft, Figure XXIV-8.

The organic matter in the shale is primarily Type II and Type III (terrestrial) with a TOC that ranges from 2% to 4%, averaging 2.6%, Figure XXIV-9. The shale formation is moderately over-pressured and has low to medium clay content.

Within the overall 1,940-mi^2 Cambay Black Shale prospective area in the Cambay Basin, we estimate: a 580-mi^2 area prospective for dry gas; a 300-mi^2 area prospective for wet gas and condensate; and a 1,060-mi^2 area prospective for oil, Figure XXIV-10.

1.3 Resource Assessment

The Cambay Black Shale has resource concentrations of: 228 Bcf/mi^2 of shale gas in its 580-mi^2 dry gas prospective area; 170 Bcf/mi^2 of wet gas and 19 million barrels/mi^2 of condensate in the 300-mi^2 wet gas/condensate prospective area; and 80 million barrels/mi^2 of shale oil (plus associated gas) in the 1,060-mi^2 oil prospective area.

Within the overall 1,940-mi^2 prospective area for the Cambay Black Shale in the Cambay Basin, we estimate a risked resource in-place of 146 Tcf for shale gas and 54 billion barrels for shale oil. Based on moderate to favorable reservoir properties, we estimate that the Cambay Black Shale has 30 Tcf of risked, technically recoverable shale gas and 2.7 billion barrels of risked, technically recoverable shale oil, Tables XXIV-1A and XXIV-2A.

1.4 Recent Activity

Although the shales in the Cambay Basin have been identified as a priority by India, no plans for exploring these shales have yet been publically announced. However, two shallower conventional exploration wells (targeting the oil-bearing intervals in the basin) penetrated and tested the Cambay Black Shale. Well D-A, a vertical well, had gas shows in a 90-ft section of the Cambay Basin at a depth of about 4,300 ft. After hydraulic stimulation, Well D-A produced 13 bbl/day of oil and 11 Mcfd of gas. Well D-B, an older vertical well drilled in 1989 to a depth of 6,030 ft, also encountered the Cambay Shale at about 4,300 ft. The well was subsequently hydrofractured and produced 13 bbl/day of oil and 21 Mcfd of gas.

Figure XXIV-8. Gross Thickness of Cambay Black Shale, Cambay Basin

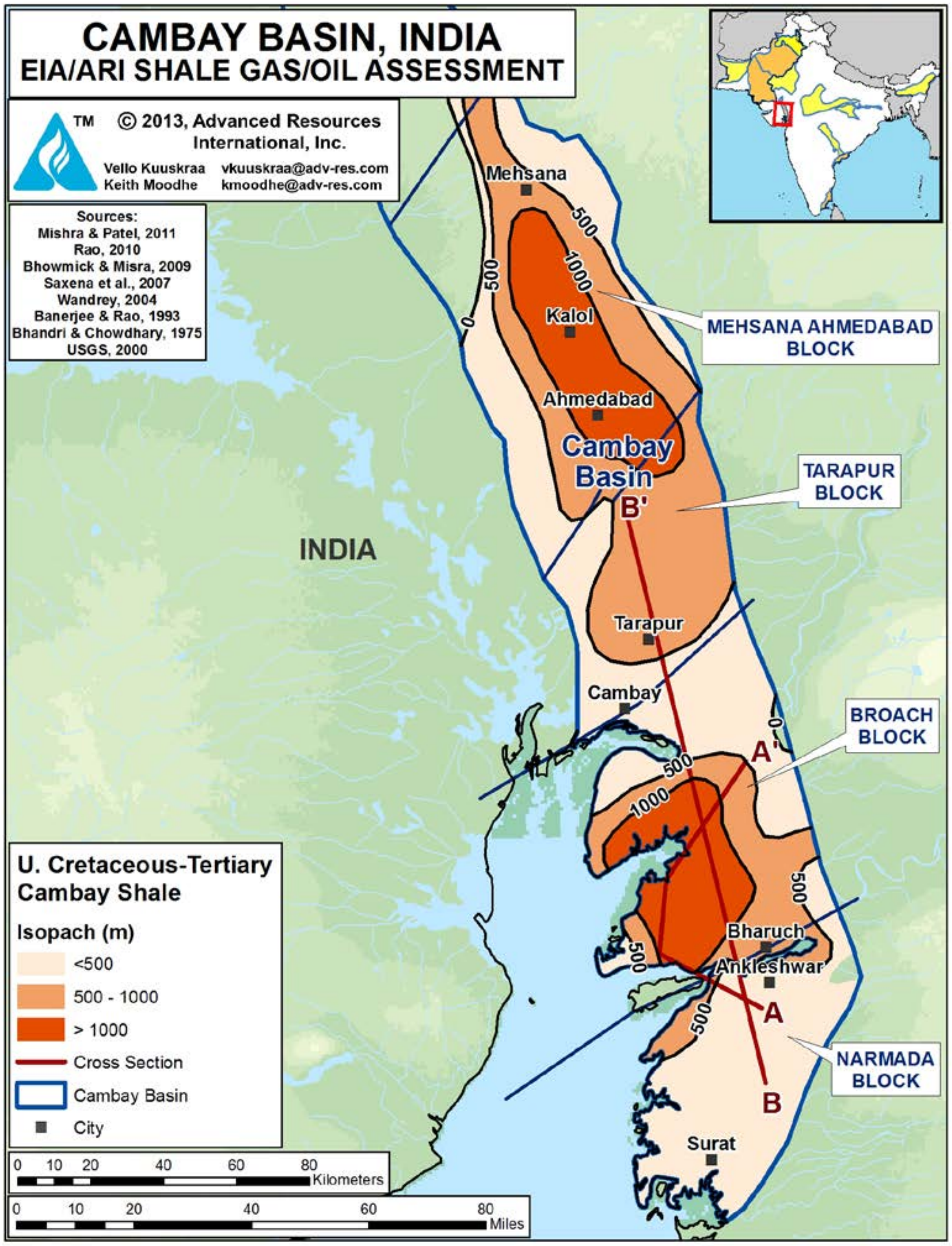


Figure XXIV-9. Organic Content of Cambay "Black Shale", Cambay Basin

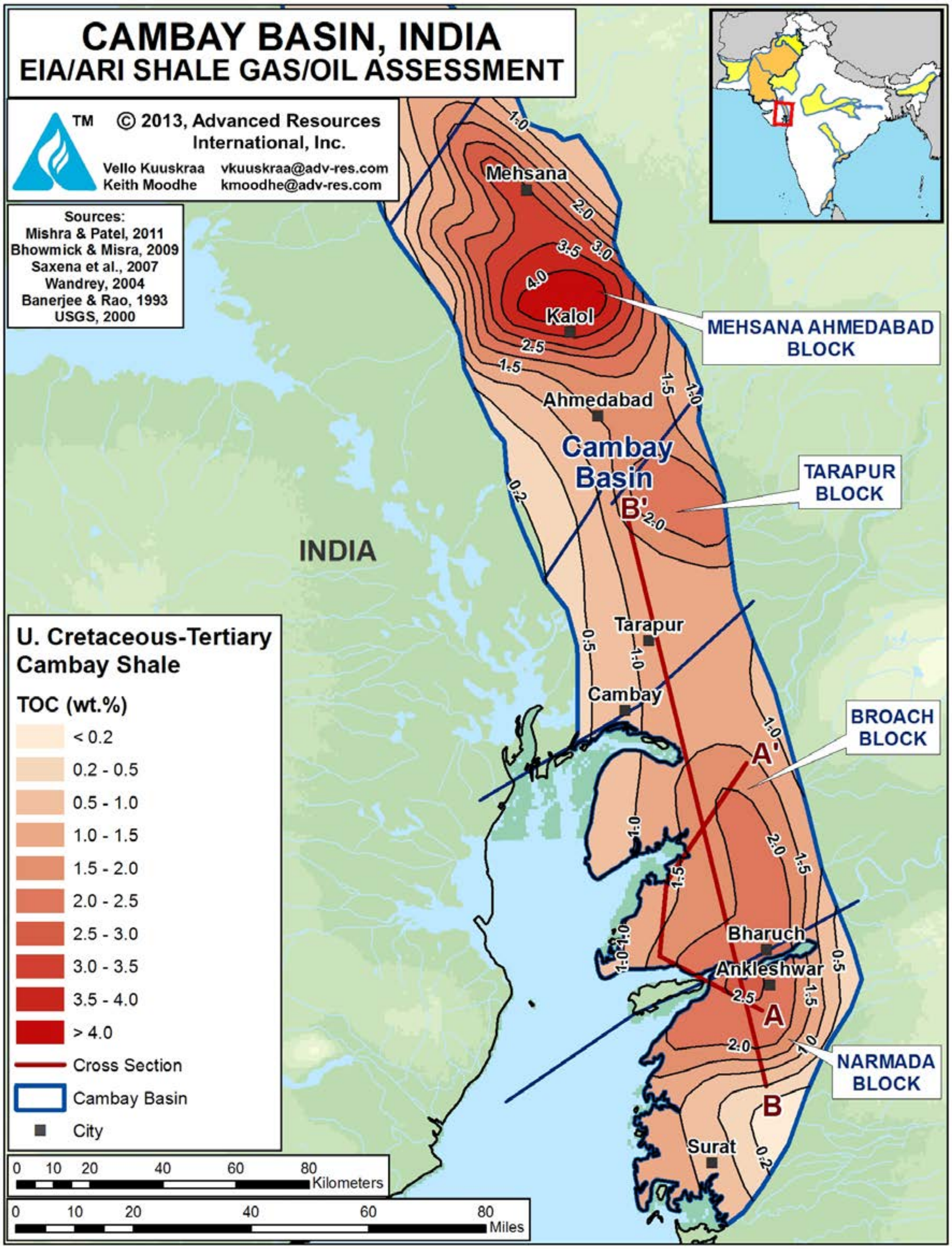
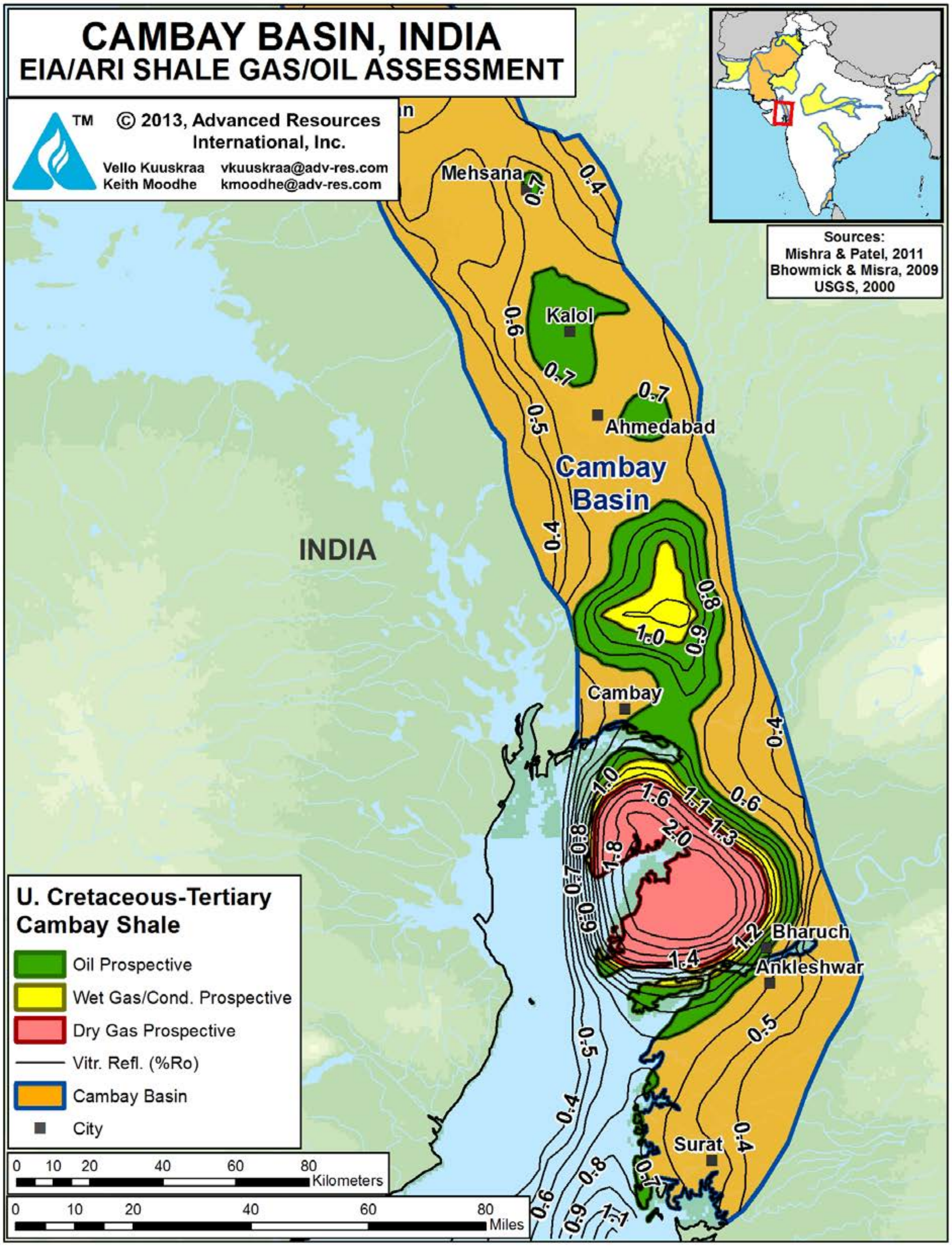


Figure XXIV-10. Prospective Areas of the Cambay Black Shale, Cambay Shale Basin

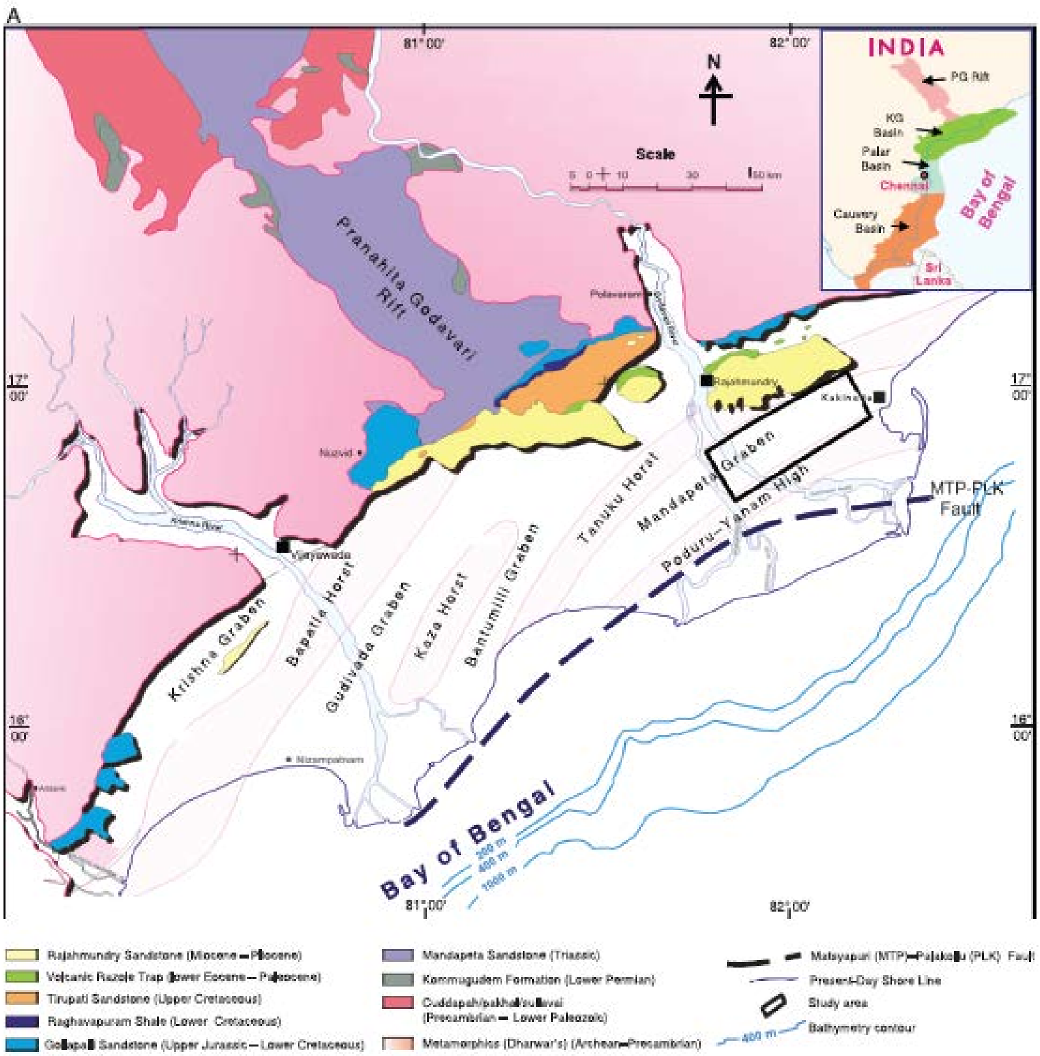


2. KRISHNA-GODAVARI BASIN, INDIA

2.1 Introduction and Geologic Setting

The Krishna-Godavari Basin covers a 7,800-mi^2 onshore area of eastern India, Figure XXIV-11.[9] The basin contains a series of organic-rich shales, including the Permian-age Kommugudem Shale and the Triassic-age Mandapeta Shale. For purposes of this assessment, these two shales have been combined into the Permian-Triassic Shale. With thermal maturities ranging from 0.7% to 2% R_o, these shales are in the oil to dry gas windows. The Upper Cretaceous Raghavapuram Shale may also have potential but was not assessed by this study.

Figure XXI-11. Krishna-Godavari Basin's Onshore Horsts and Grabens



Source: Murthy, 2011.

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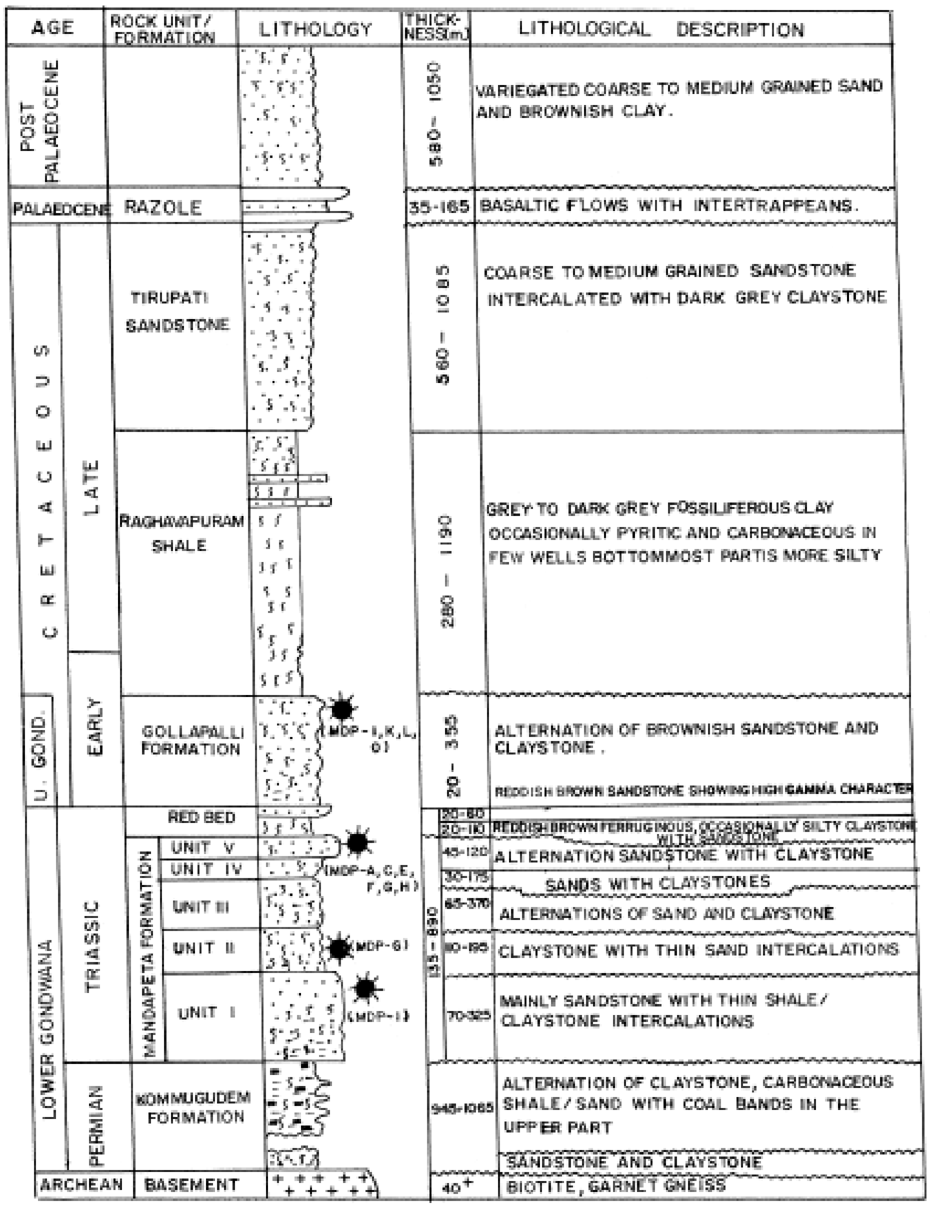
Permian-Triassic Shale. The Kommugudem Shale, the lower unit of the Permian-Triassic Shale, is a thick Permian-age rock interval containing alternating sequences of carbonaceous shale, claystone, sand and coal, Figure XXIV-12. The Mandapeta Graben, the most extensively explored portion of the Krishna-Godavari Basin, provides much of the geologic and reservoir characterization data for this basin.[10]

Figure XXIV-12. Stratigraphic Column, Mandapeta Area, Krishna Godavari Basin



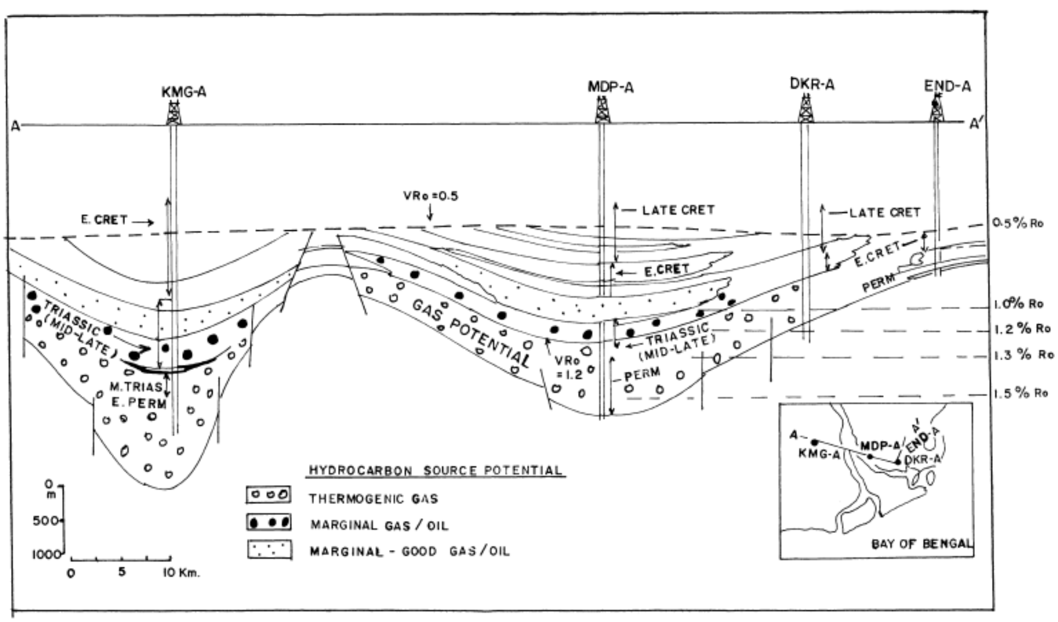
Source: Kahn, 2000.

The Kommugudem Shale was deposited in fluvial, lower deltaic, and lacustrine environments. While an effective source rock with excellent organic richness, analysis of the shale indicates hydrogen-deficient organic matter (based on low S_2 values from pyrolysis) and high levels of primary inertinite.

The basal shale in the Mandapeta Formation, the upper unit of the Permian-Triassic Shale, is a localized, thermally mature (R_o of 0.8% to 1.1%) Triassic-age shale that is considered the source rock for the oil produced from the overlying Early Cretaceous Golapalli Sandstone. The Mandapeta Formation and its basal shale are present in the Mandapeta and Bantumilli grabens but are absent in the Poduru-Yanam High (Draksharama and Endamuru areas) to the east. While the TOC of the Mandapeta Shale is generally low, 0.4% to 1.6%, we have included this Triassic shale unit into the overall Permian-Triassic sequence.

Vitrinite reflectance of the Permian-Triassic Shale in the deep graben structures ranges from 0.7% to 2% R_o, placing the shale in the oil to dry gas windows. Figure XXIV-13 illustrates the relationship of shale depth and geologic age in the Krishna-Godavari Basin to the thermal maturity (R_o) in two of the graben structures, Kommugudem (KMG) and Mandapeta (MDP).

Figure XXIV-13. Cross Section for Permian-Triassic Shale, Krishna Godavari Basin



Source: Kahn, 2000.

2.2 Reservoir Properties (Prospective Area)

In the prospective area of the Krishna-Godavari Basin, the depth of the Permian-Triassic Shale ranges from 4,000 to 16,400 ft, averaging 5,000 ft in the oil prospective area, 8,000 ft in the wet gas and condensate prospective area, and 13,000 ft in the dry gas prospective area.

To better understand the source rock quality of the Permian-Triassic Shale, 140 m of shale was tested in 10 wells. The data showed the TOC of the shale ranges up to 11%, averaging 6%, for ten rock samples taken at various depths, Table XXIV-4.

Table XXIV-4. Analysis of Ten Rock Samples, Kommugudem Shale[11]

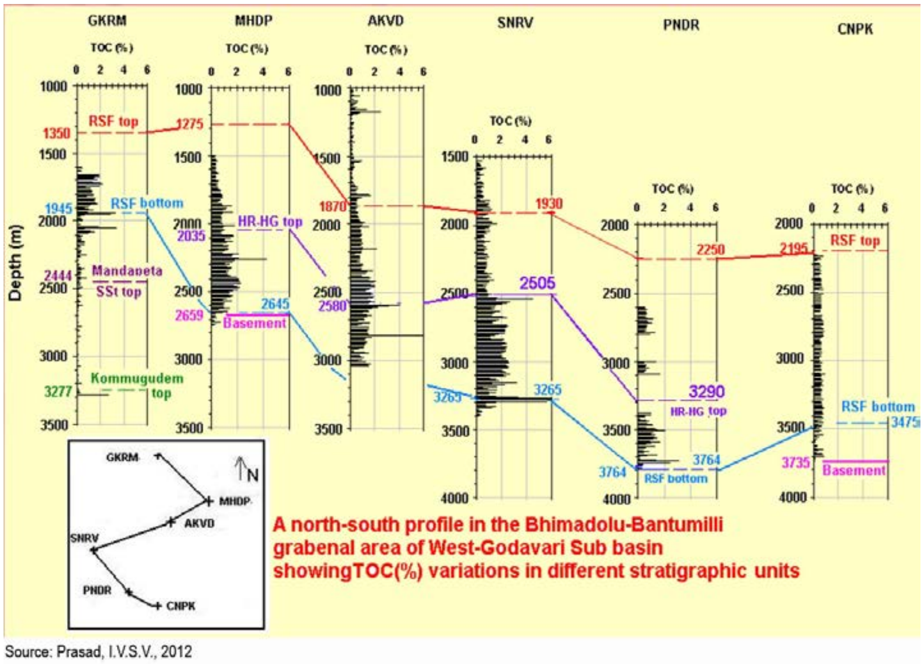
Well	Depth (m)	TOC (%)	S_2*	Shale Interval Tested (m)
AA-1	3,320-3,880	10.4	7.0	110
AA-2	3,585-3,630	4.2	2.9	45
AA-9	3,330-3,360	7.1	6.4	30
AA-10	3,880-3,920	3.1	0.6	40
AA-11	2,890-3,150	7.0	7.9	260
BW-1A	3,915-4,250	5.6	0.8	335
BW-2	2,970-3,085	8.8	5.5	115
BW-2	3,100-3,175	7.8	6.0	75
BW-9	2,800-3,040	11.2	6.9	315
DE-1	1,900-2,040	8.9	13.9	120

*Volume of hydrocarbon cracked from kerogen by heating to 550^{o}C, measured in terms of mg hydrocarbon/g rock.

The thickness of the shale ranges from 330 to 1,300 ft, with 100 to 390 ft of net organic-rich shale, depending on prospective area. The pressure gradient of the Permian-Triassic Shale is normal. The reservoir is inferred to have moderate to high clay content based on its lacustrine deposition. We mapped an 8,000-mi^2 prospective area for the Permian-Triassic Shale in the Krishna-Godavari Basin which encompasses the oil, wet gas/condensate and dry gas windows.

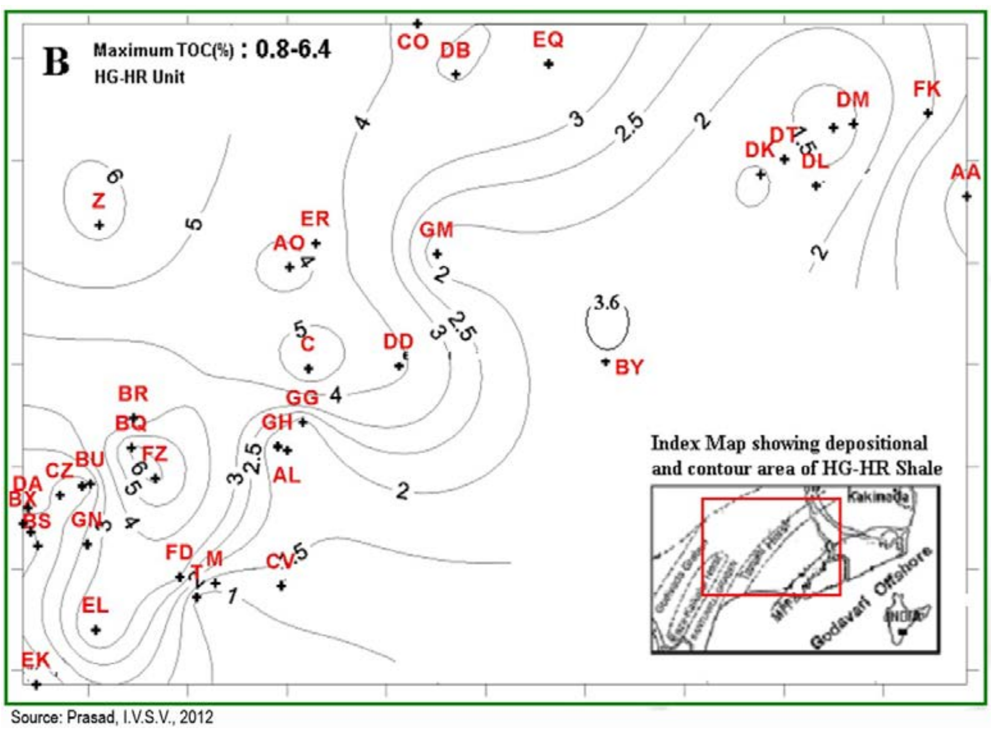
Raghavapuram Shale. The Cretaceous-age Raghavapuram Shale offers an additional potential shale resource in the Krishna-Godavari Basin. The TOC of this shale unit ranges from 0.8% to 6.4%, with the lower HG-HR Shale interval of the Raghavapuram Formation having the higher TOC values, Figures XXIV-14[12] and XXIV-15.[12] The shale becomes thermally mature for oil (Tmax 440 to 475^{o} C) at depth below 10,600 ft.[21]

Figure XXIV-14. TOC Cross-Section for Raghavapuram Shale, Krishna-Godavari Basin



Source: Prasad, I.V.S.V., 2012.

Figure XXIV-15. TOC Isopach for Raghavapuram Shale, Krishna-Godavari Basin



Source: Prasad, I.V.S.V., 2012.

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However, the great bulk of the Cretaceous Raghavapuram Shale is shallower than 10,600 ft and thus has a thermal maturity (R_o) value less the 0.7% minimum threshold used by this study. In addition, the data on the area and vertical distribution of the Raghavapuram Shale is limited. Thus, this shale has not been included in the quantitative portion of our shale resource assessment.

2.3 Resource Assessment

The 8,000-mi^2 prospective area of the Permian (Kommugudem) and Triassic (Mandapeta) Shale in the Krishna-Godavari Basin is limited to the four grabens (sub-basins) shown in Figure XXIV-16. The Permian-Triassic Shale has resource concentrations of: 205 Bcf/mi^2 in the 3,000-mi^2 dry gas prospective area; 58 Bcf/mi^2 of wet gas and 6 million barrels/mi^2 of condensate in the 3,900-mi^2 wet gas/condensate prospective area; and 18 million/mi^2 barrels of oil (plus associated gas) in the 1,100-mi^2 oil prospective area.

Within the overall prospective area, the Permian-Triassic Shale of the Krishna-Godavari Basin has risked shale gas in-place of 381 Tcf, with 57 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate a risked shale oil in-place for this basin of 20 billion barrels, with 0.6 billion barrels as the risked, technically recoverable shale oil resource, Tables XXIV-1A and XXIV-2A.

2.4 Recent Activity

The technical literature discusses 16 wells that have been drilled at the Mandapeta Graben into or through the Permian-Triassic Shale in search for hydrocarbons in conventional Mandapeta and Gollapalli sandstone reservoirs. The information from these 16 wells has provided valuable data for the key cross-sections and other reservoir properties essential for the shale resource assessment study of the Krishna-Godavari Basin.

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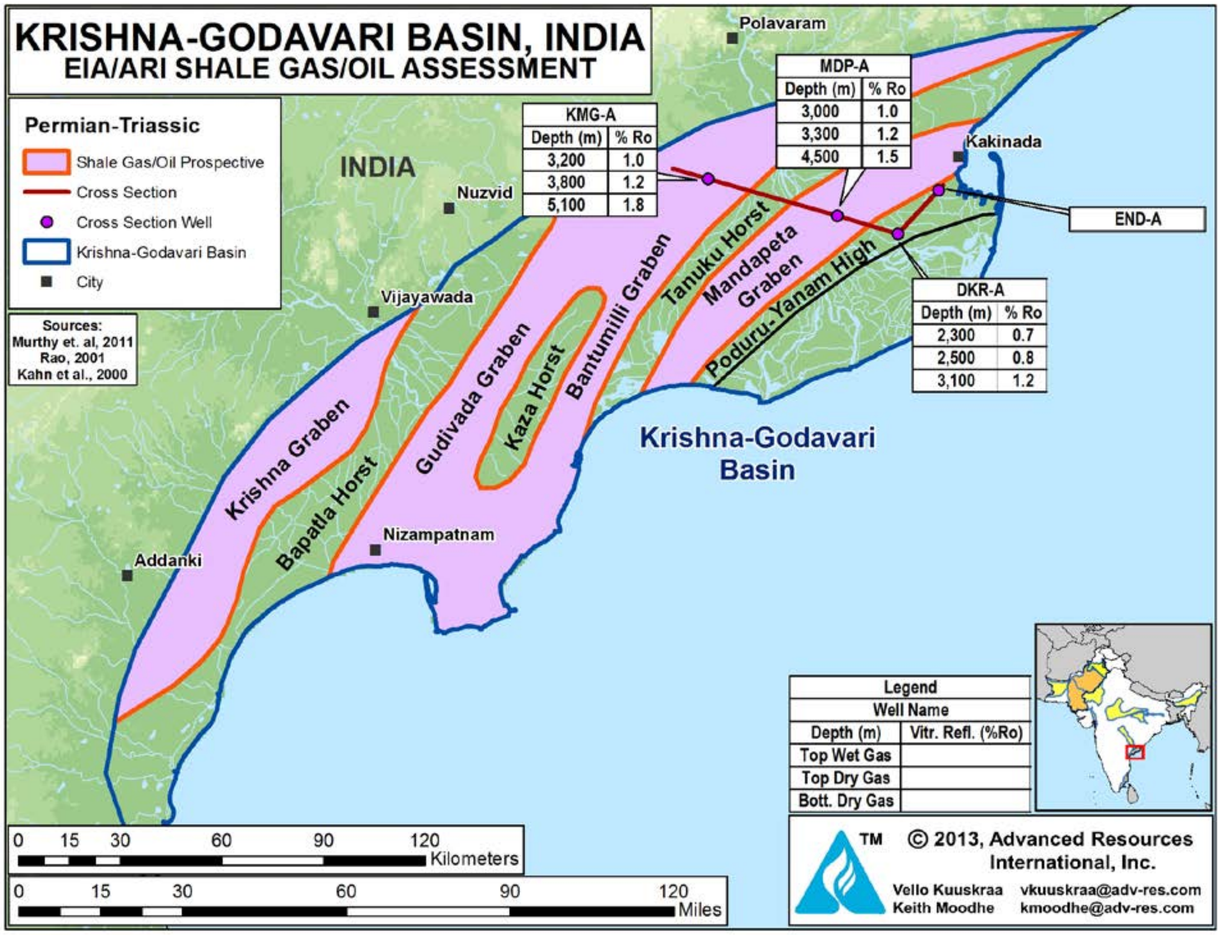
Figure XXIV-16. Prospective Areas for Shale Gas and Shale Oil, Krishna-Godavari Basin

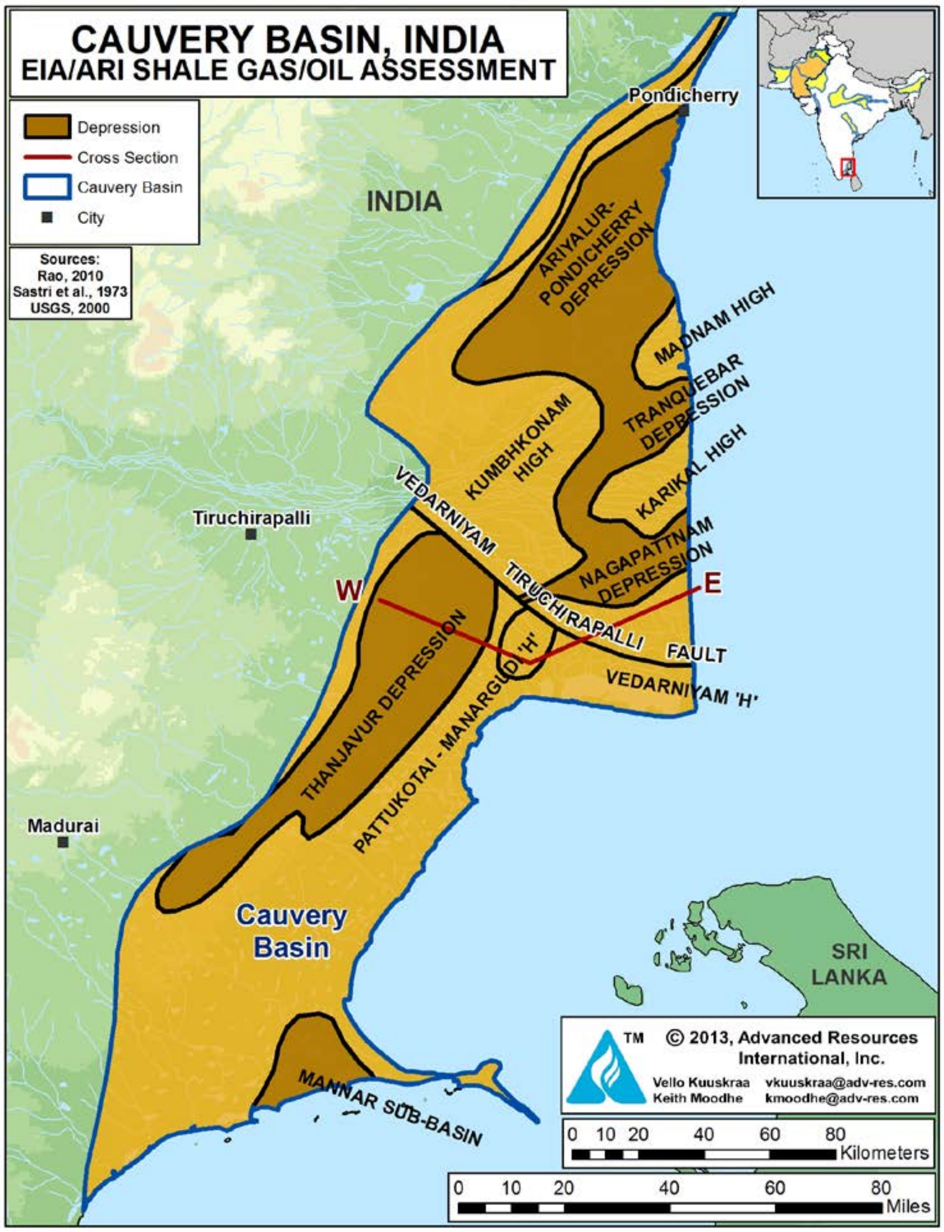


3. CAUVERY BASIN, INDIA

3.1 Introduction and Geologic Setting

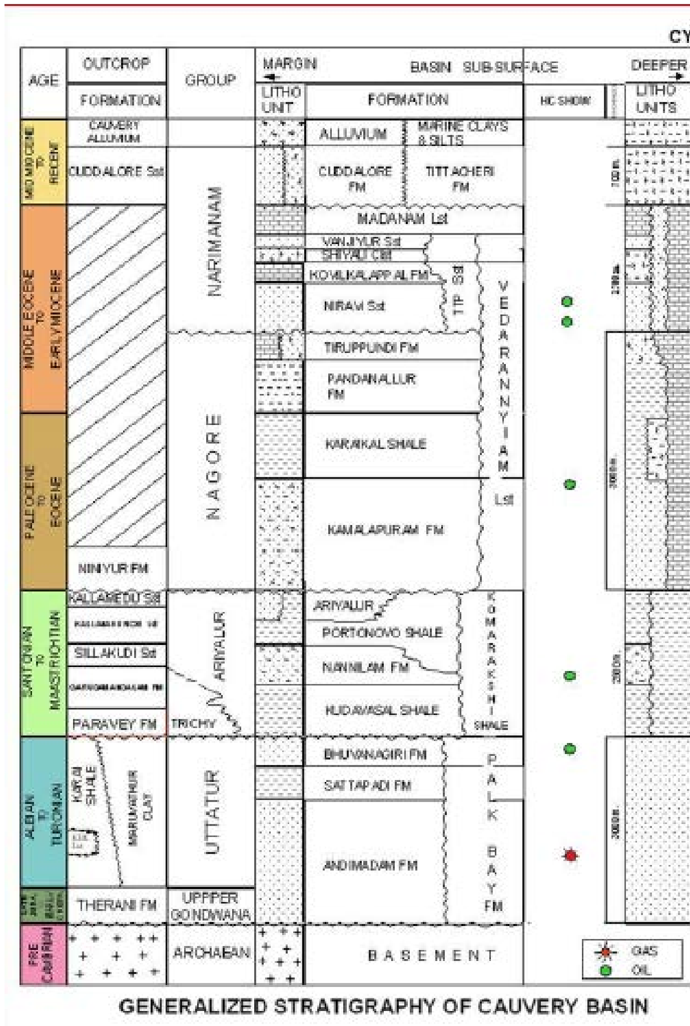
The Cauvery Basin covers an onshore area of about 9,100 mi^2 on the east coast of India, Figure XXIV-17. The basin comprises numerous horsts and grabens, with thick organic-rich source rocks in the Lower Cretaceous Andimadam Formation and Sattapadi Shale.

Figure XXIV-17. Cauvery Basin Horsts and Grabens



The gas- and oil-prone shale source rocks in the Cauvery Basin are the Lower Cretaceous Andimadam Formation and the Sattapadi Shale, Figure XXIV-18. The shale resource prospective area of the Cauvery Basin is limited to four depressions (troughs) - - Nagapattnam, Tranquebar, Ariyalur-Pondicherry and Thanjavur - - and the Mannar Sub-basin. The source rocks are generally shallow marine Type III with some Type II kerogen. The thermally mature source rocks in the shallower Sattapadi Shale and the deeper Andimadam Formation contain thermogenic wet gas and condensate.[13]

Figure XXIV-18. Generalized Stratigraphy, Cauvery Basin[15]



Source: Rao, 2010.

3.2 Reservoir Properties (Prospective Area)

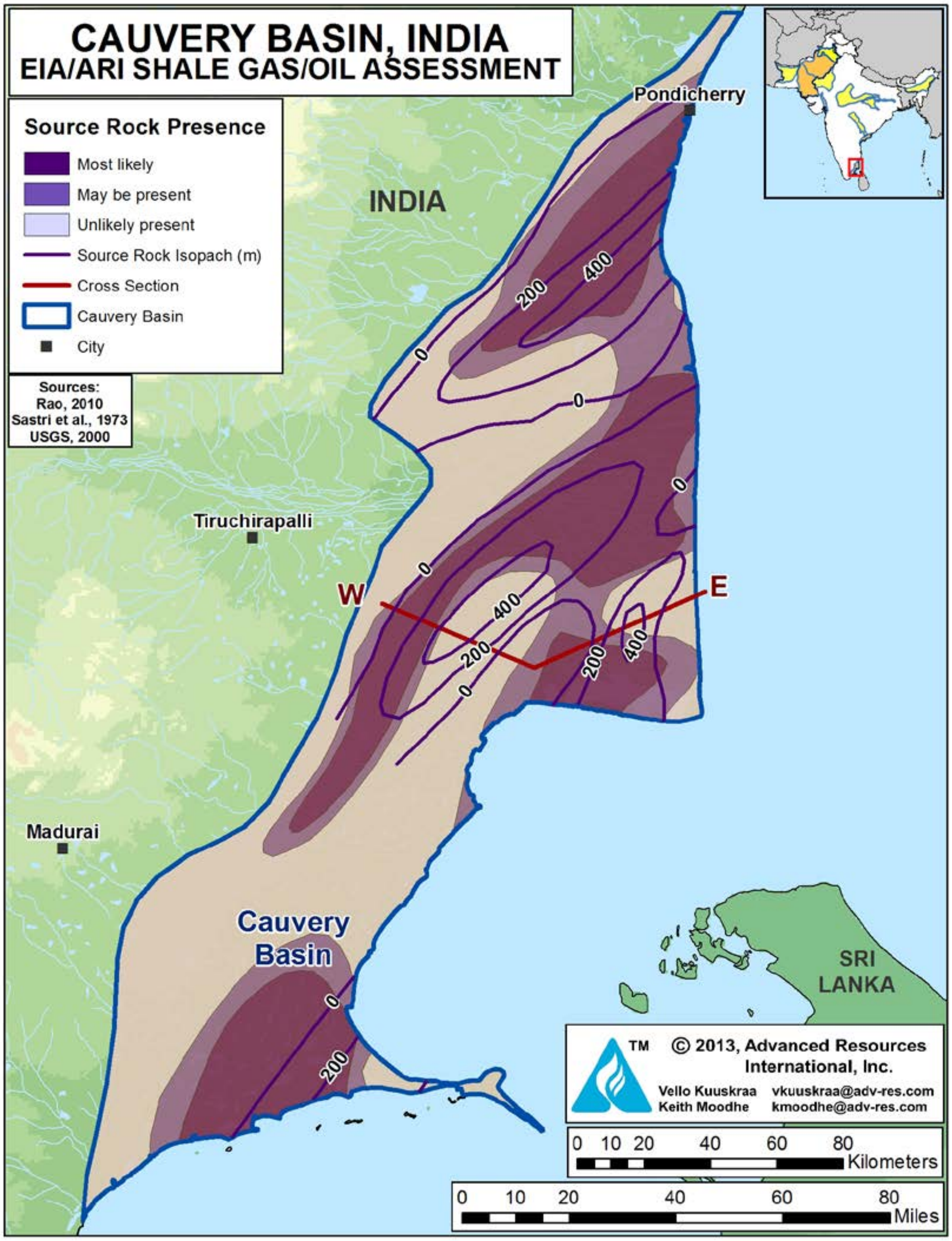
We have identified a 1,010-mi^2 wet gas and condensate prospective area for the shales in the Cauvery Basin. The thickness of the Lower Cretaceous interval is 3,000 to 5,000 ft, with the Andimadam Formation and the Sattapadi Shale accounting for the bulk of the gross interval, Figure XXIV-19. The TOC of the combined Andimadam/Sattapadi Shale is estimated at 2% to 2.5%, averaging 2.3%. The organic shales are distributed irregularly over the Cauvery Basin, Figure XXIV-20.

Figure XXIV-19. Formation Thickness, Cauvery Basin

AGE		FORMATION		THICKNESS in m
Recent to Mid. Miocene		Tittacheri Sandstone		300-500
Lower Miocene		Madanam Limestone Vanjiyur Sandstone Shiyali Clay stone	 CAP	600-1200
Oligocene		Kovilkalappal Fm. Niravi Sandstone	 PLAY	500-800
Eocene		Pandanallur Fm. Karaikal Shale Up.Kamalapuram Fm.	 CAP PLAY	200-400
Paleocene		Lr.Kamalapuram Fm.	PLAY	200-800
Creta-ceous	Upper	Porto-Novo Shale Nannilam Fm. Kudavasal Shale	CAP PLAY CAP	600-1500
	Lower	Bhuvanagiri Fm. Sattapadi Shale Andimadam Fm.	PLAY SOURCE+CAP SOURCE+PLAY	1000-1500
Archaean		Basement	PLAY	

Source: P.K. Bhowmick and Ravi Misra, Indian Oil and Gas Potential, Glimpses of Geoscience Research in India

Figure XXIV-20. Shale Isopach and Presence of Organics, Cauvery Basin



The Cauvery Basin contains a series of depressions (sub-basins) that hold potential for shale gas. Two of these - - Ariyalur-Pondicherry and Thanjavur - - contain thick, thermally mature shales.

- ***Ariyalur-Pondicherry Sub-Basin***. The Ariyalur-Pondicherry Depression (Sub-basin) is in the northern portion of the Cauvery Basin. The Lower Cretaceous Andimadam and Sattapadi Shale encompasses a thick interval at a depth of 7,000 to 13,000 ft, averaging 10,000 ft. Organic-rich gross pay thickness is 1,000 ft with net pay of about 500 ft. The thermal maturity of 1.0% to 1.3% R_o places the shale in the wet gas and condensate window. The onshore prospective area of this sub-basin is estimated at 620 mi^2, Figure XXIV-21.

- ***Thanjavur Sub-Basin.*** The Thanjavur Depression (Sub-basin), in the center of the Cauvery Basin, has a thick section of Andimadam and Sattapadi Shale at a depth of 7,000 ft (top of Sattapadi Shale) to 13,000 ft (base of Andimadam Fm), averaging 9,500 ft deep, Figure XXIV-22. The organic-rich average net pay thickness is 500 ft.[15] Given limited data, we assume the TOC and thermal maturity for the shale in this sub-basin is the same as in the Ariyalur-Pondicherry Sub-basin. The onshore prospective area with thick organic-rich shale is small, estimated at 390 mi^2, Figure XXIV-21.

3.3 Resource Assessment

In the 1,010-mi^2 prospective area of the Cauvery Basin, the combined Andimadam Formation and Sattapadi Shale have an average wet shale gas resource concentration of 120 Bcf/mi^2 and a shale condensate resource concentration of 30 million barrels/mi^2.

For the combined Andimadam Formation and Sattapadi Shale in the Cauvery Basin, we estimate risked shale gas in-place of 30 Tcf and risked shale oil in-place of 8 billion barrels. Of this, 5 Tcf of shale gas and 0.2 billion barrels of shale oil are the risked, technically recoverable shale resources.

3.4 Recent Activity

We are not aware of any shale gas or oil development in the Cauvery Basin.

Figure XXIV-21. Prospective Areas for Shale Gas and Shale Oil, Cauvery Basin

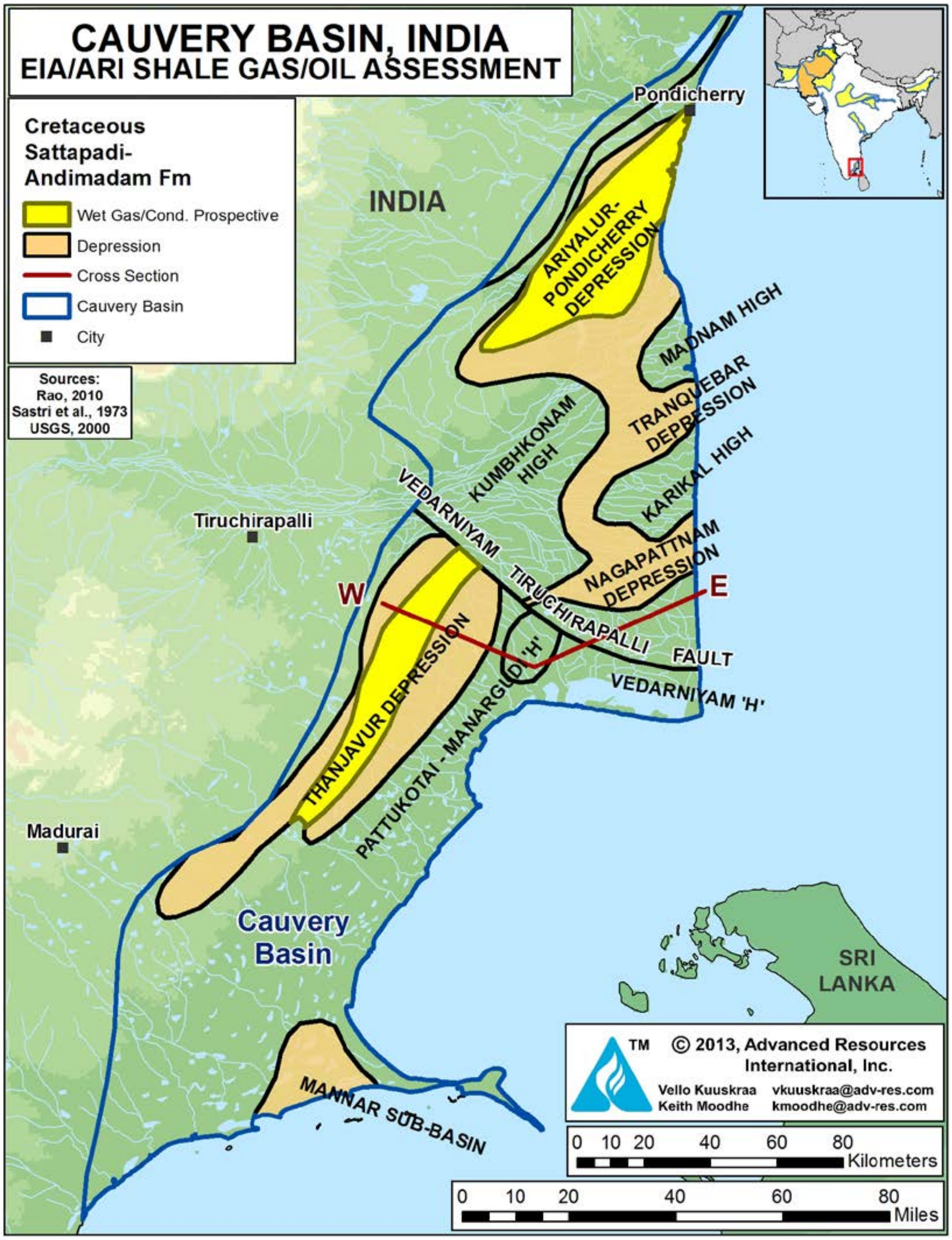
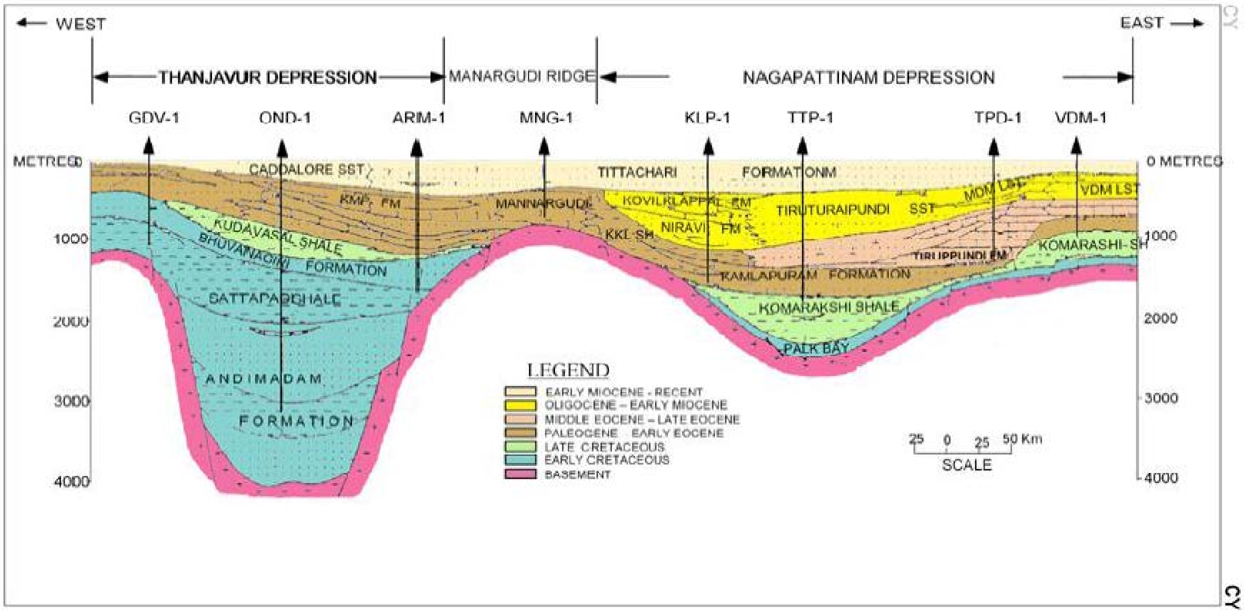


Figure XXIV-22. East to West Cross-Section Across Cauvery Basin.[15]



Source: Rao, 2010.

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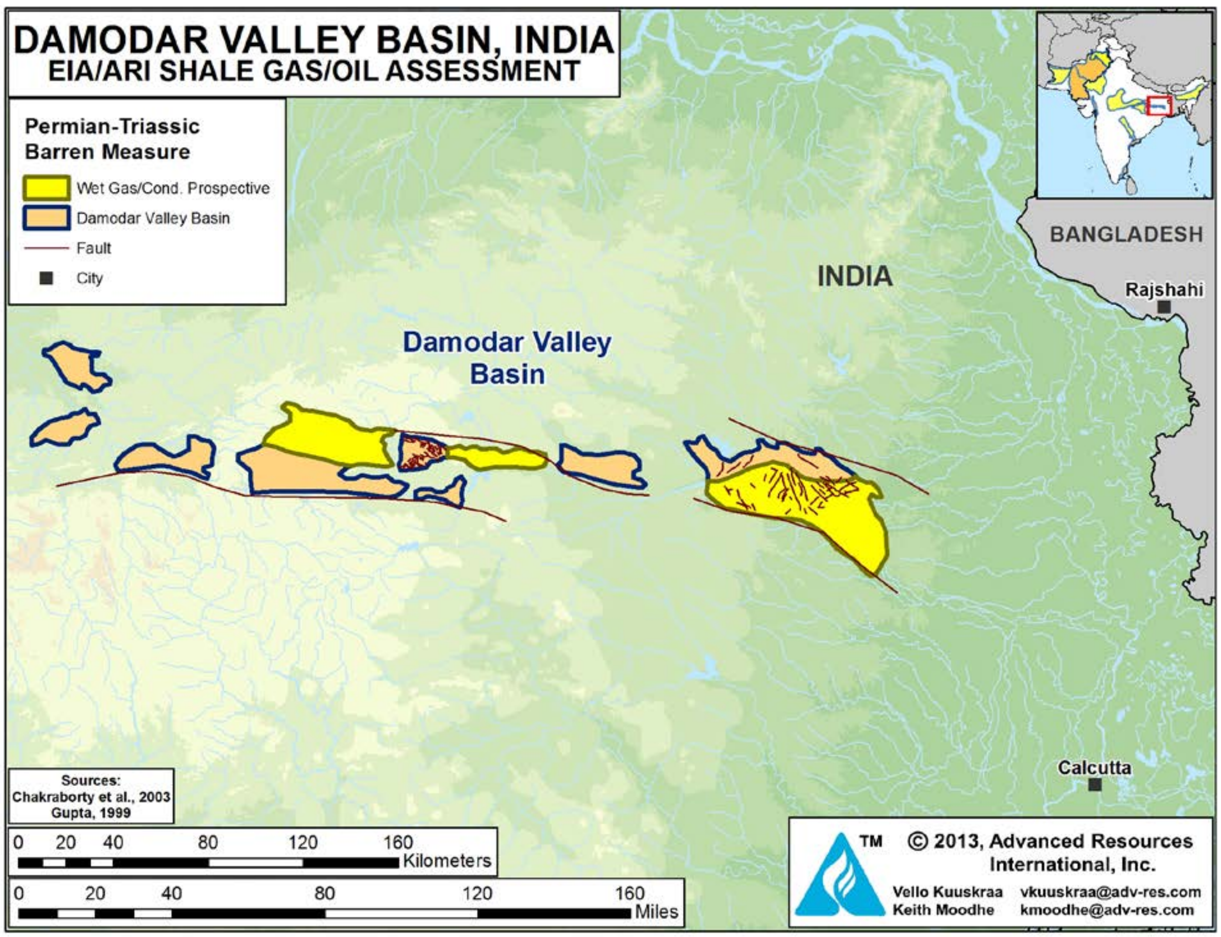
4. DAMODAR VALLEY BASIN, INDIA

4.1 Introduction and Geologic Setting

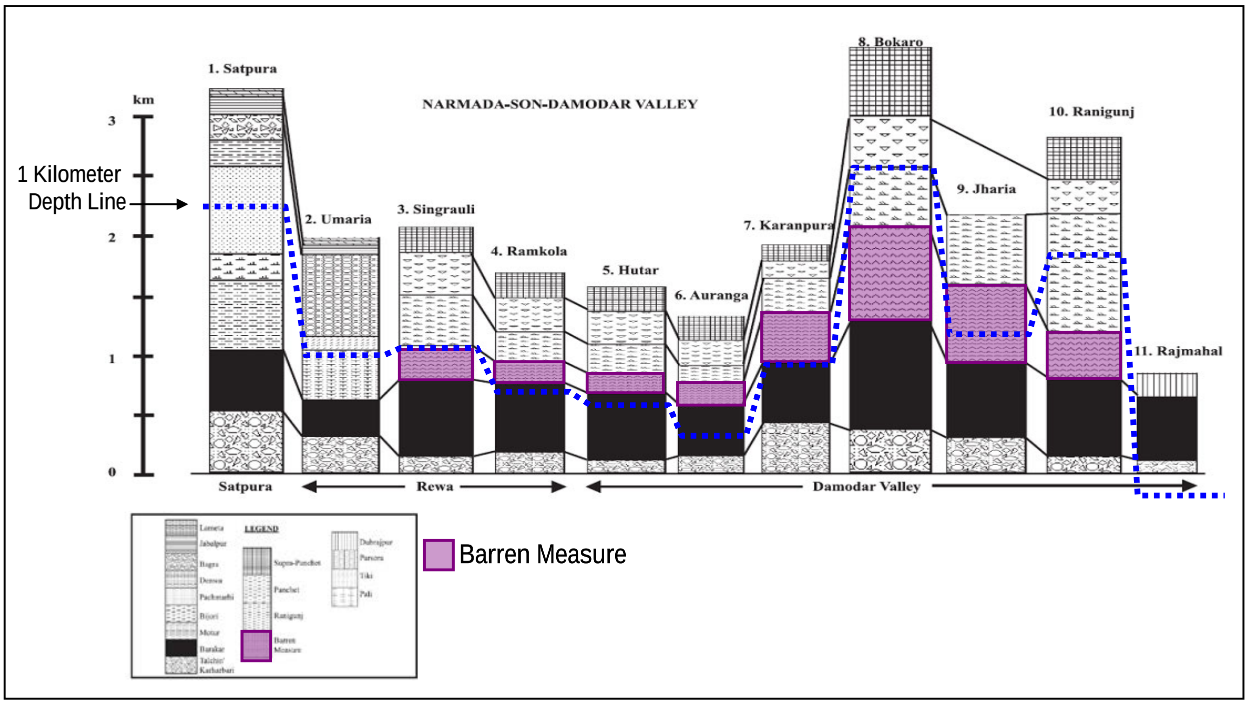
The Damodar Valley Basin is part of a group of basins collectively named the "Gondwanas", owing to their similar dispositional environment and Permo-Carboniferious through Triassic deposition. The "Gondwanas," comprising the Satpura, Pranhita-Godavari, Son-Mahanadi and Damodar Valley basins, were part of a system of rift channels in the northeast of the Gondwana super continent. Subsequent tectonic activity formed the major structural boundaries of the Gondwana basins, notably the Damodar Valley Basin, Figure XXIV-23.

Figure XXIV-23. Damodar Valley Basin and Prospectivity for Shale Gas and Shale Oil



Sedimentation in the Early Permian was primarily glacial-fluvial and lacustrine, resulting in significant deposits of coal. As such, the majority of exploration in the Damodar Valley has focused on the coal resources of the basin, which account for much of India's coal reserves. However, a marine incursion deposited a layer of early Permian Shale, called the Barren Measure Shale in this basin, Figure XXIV-24[14]. This shale formation was the target of India's first shale gas exploration well in the eastern portion of the Damodar Valley. Though present in other Gondwana basins, such as the Rewa Basin, in central India, data suggest that the Barren Measure Shale is only thermally mature in the Damodar Valley Basin.[15]

Figure XXIV-24. Regional Stratigraphic Column of the Damodar Valley Basin, India[16].



Source: Chakraborty, Chandan, 2003.

The Damodar Valley Basin comprises a series of sub-basins (from west to east) - - the Hutar, Daltonganj, Auranga, Karanpura, Ramgarh, Bokaro, Jharia and Raniganj. Though these sub-basins share a similar geologic history, tectonic events and erosion since the early Triassic have caused extensive variability in the depth and thickness of the Barren Measure Shale in these basins.

Because exploration has focused on the coal deposits within the Damodar Valley Basin, relatively little geologic data is available on the Barren Measure Shale. Thermal maturity data on coals adjoining the Barren Measure Shale suggest that the shale is within the wet gas/condensate (R_o of 1.0% to 1.3%) window, and regional studies have shown favorable TOC, with average values of 3.5%.

Present-day burial depth and lower pressures are the main limitations for the shale gas and condensate prospectively of the Barren Measure Shale in the Damodar Valley Basin. In some sub-basins, regional erosion has removed up to 3 kilometers of overlying sediments.

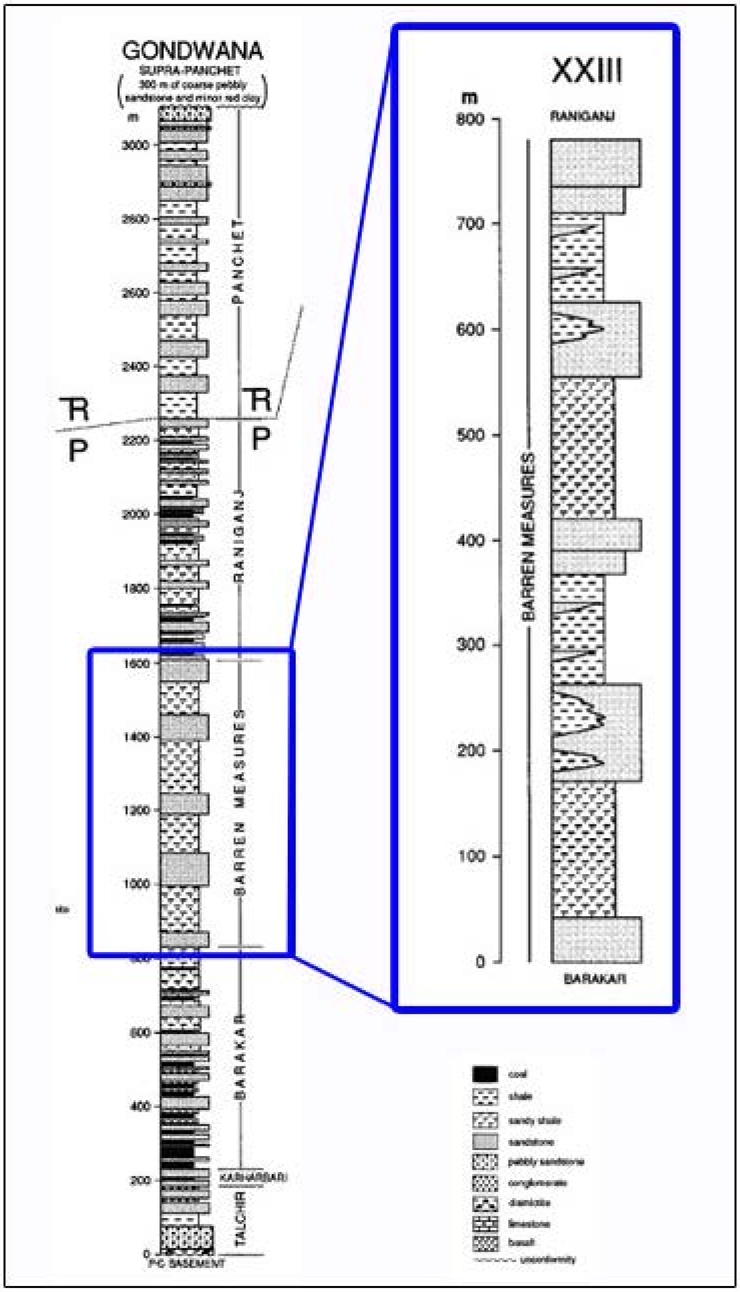
Based on the regional stratigraphic column, Figure XXIV-25,[17] and operator data, the overall 1,080-mi^2 prospective area for the Barren Measure Shale in the Damodar Valley is limited to the Bokaro, Karanpura and Raniganj sub-basins.

The prospective areas within the Bokaro (110 mi^2) and Raniganj (650 mi^2) sub-basins are limited by surface outcrops of formations of the Barren Measure Shale to the west and north, respectively. We have estimated a 320-mi^2 prospective area for the northern half of the Karanpura Basin, based on statements by Schlumberger and ONGC.[18]

4.2 Reservoir Properties (Prospective Area)

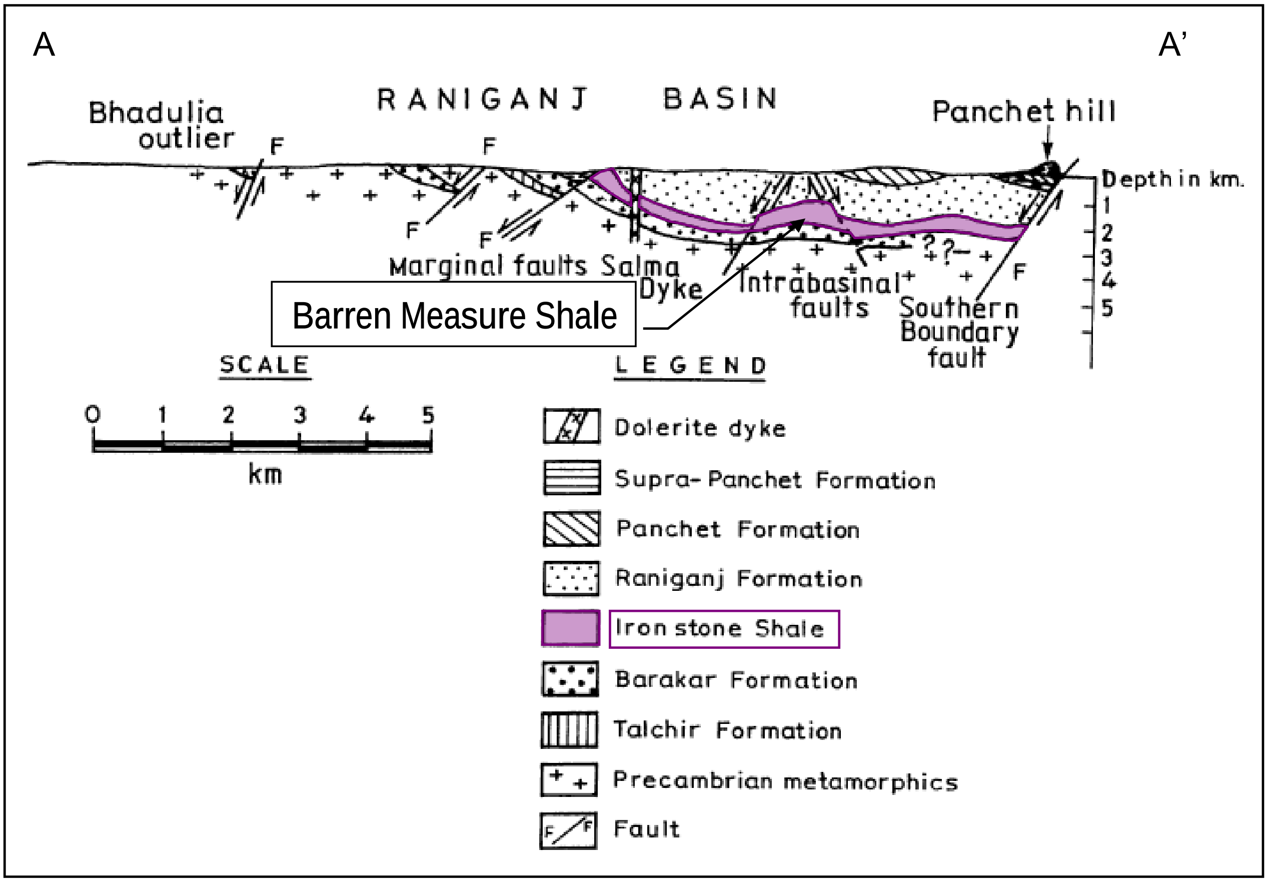
Absent data on thermal maturity and organic content specific to each of the three sub-basins, we assigned average published reservoir property values to these three sub-basins. TOC is assumed to range between 3% and 6% averaging 3.5%, based on information from INOC and ESSAR.[19,20] Thermal maturity was estimated from the coal formations surrounding the Barren Measure Shale, indicating values of 1.1% to 1.3% R_o, placing the shale within the wet gas/condensate window.[21] Depth to the Barren Measure Shale averages about 5,000 ft, based on reports from the shale gas well drilled into the Raniganj sub-basin and from regional cross sections, Figure XXIV-26. We estimate a weighted average gross interval thickness in the three prospective sub-basins of about 2,000 ft, of which about 1,000 ft is organic-rich and 250 ft is net shale.[17]

Figure XXIV-25. Generalized Stratigraphic Column of the Gondwana Basin.



Source: Veevers, J., 1995

Figure XXIV-26. Raniganj Sub-Basin Cross Section.[22]



Source: Ghosh, S. C, 2002.

4.4 Resource Assessment

Using the geologic characteristics discussed above, we estimate that the Barren Measure Shale in the Damodar Valley Basin has a wet shale gas resource concentration of 63 Bcf/mi^2 and a shale condensate resource concentration of 12 million barrels/mi^2.

Risked shale gas in-place is estimated at 27 Tcf, with the prospect area risk factor recognizing the significant faulting present in the basin. We estimate 5 Tcf of risked shale gas may be technically recoverable from the Barren Measure Shale in the Damodar Valley Basins. In addition, we estimate risked shale oil in-place of 5 billion barrels, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

4.4 Recent Activity

Along with the Cambay Basin, the Damodar Valley Basin has been set as a priority basin for shale gas exploration by the Indian government. In late September 2010, Indian National Oil and Gas Company (ONGC) spudded the country's first shale gas well, RNSG-1, in the Raniganj sub-basin of the Damodar Valley. The well was completed mid-January 2011, having reportedly encountered gas flows from the Barren Measure Shale at approximately 5,600 ft. Detailed well test and production results are not publicly available. This well was the first of a proposed four-well R&D program in the basin. The plan calls for an additional well to be drilled in the Raniganj sub-basin and for two wells to be drilled in the Karanpura sub-basin.

5. OTHER BASINS, INDIA

5.1 Upper Assam Basin

The Upper Assam Basin is an important onshore petroleum province in northeast India. The basin has produced oil and some associated gas, mainly from the Upper Eocene-Oligocene Barail Group of coals and shales. In general, the TOC in the lower source rocks ranges from 1% to 2% but reaches 10% in the Barail Group. These source rocks are in the early thermal maturity stage (beginning of the oil window) in the bulk of the Upper Assam Basin.[23] Although the shales may reach thermal maturity for oil and gas generation in the deeper parts of the basin, toward the south and southwest, no data confirming this assumption exists in the public domain. The reported thermal maturity of the Barail Group Shale ranges from R_o of 0.5% to 0.7%, placing these shales as immature for oil.[24] While the shale may reach the oil and wet gas window in the very deepest portion of the basin, the measured vitrinite reflectance is reported at only 0.7% at a depth of 14,800 ft.[25]

5.2 Pranhita-Godavari Basin

The Pranhita-Godavari Basin, located in eastern India, contains thick, organic-rich shales in Permian-age Jai Puram and Khanapur formations. While the kerogen is Type III (humic) and thus favorable for gas generation, the 0.67% R_o indicates that the shales are thermally immature.

5.3 Vindhyan Basin

The Vindhyan Basin, located in north-central India, contains a series of Proterozoic-age shales. While certain of these shales, such as the Hinota and Pulkovar, appear to have sufficient organic richness, no public data exists on their thermal maturity.

5.4 Rajasthan Basin

The Rajasthan Basin covers a large onshore area in northwest India. The basin is structurally complex and characterized by numerous small fault blocks. The Permian-age Karampur Formation is the primary source rock in this basin. While the source rock is Type III and classified as mature, only limited data are available on the reservoir properties of this shale.

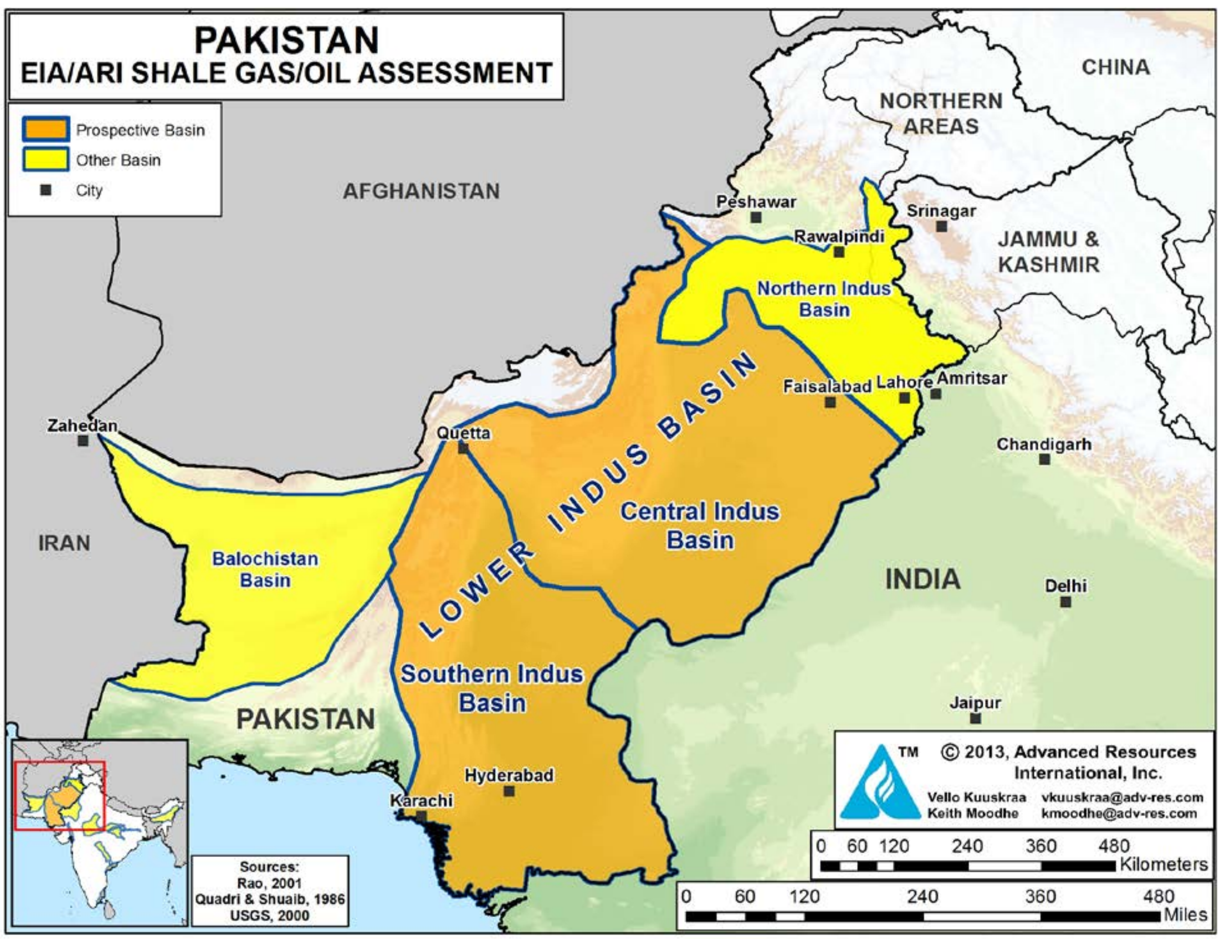
6. LOWER (SOUTHERN AND CENTRAL) INDUS BASINS, PAKISTAN

6.1 Introduction and Geologic Setting

The Southern and Central Indus basins (Lower Indus Basin) are located in Pakistan, along westerns border with India and Afghanistan. The basins are bounded by the Indian Shield on the east and highly folded and thrust mountains on the west, Figure XXIV-27.[26]

The Lower Indus Basin has commercial oil and gas discoveries in the Cretaceous-age Goru Fm sands plus additional gas discoveries in shallower formations. The shales in the Sembar Formation are considered as the primary source rocks for these discoveries. While oil and gas shows have been recorded in the Sembar Shale on the Thar Platform, as of yet no productive oil or gas wells have been drilled into the Sembar Shale.[27]

Figure XXIV-27. Outline for Southern and Central Indus Basin, Pakistan



Sembar Shale. The Lower Cretaceous Sembar Formation is the main source rock in the Lower Indus Basin. The Sembar contains shale, silty shale and marl in the western and northwestern portion of the basin and becomes sandy in the eastern part of the basin. The kerogen within the Sembar Formation is mostly Type II with some Type III.

The Lower Indus Basin covers a massive 91,000-mi^2 area of western Pakistan. Within this large basin area, for the Sembar Shale, we have identified a 31, 320-mi^2 prospective area for dry gas (R_o >1.3%), a 25,560-mi^2 prospective area for wet gas and condensate (R_o between 1.0% and 1.3%), and a 26,700-mi^2 prospective area for oil (R_o between 0.7% and 1.0%). To account for the limited data on the Sembar Shale in this large basin area, we have highly risked the prospective areas and the likelihood of development success.

The eastern boundary of the prospective area of the Sembar Shale in the Lower Indus Basin is the minimum thermal maturity criterion of R_o 0.7%. The northern and western boundaries of the prospective area are set by the limits of Sembar Formation deposition and depth. The southern boundary of the prospective area is the offshore.

Ranikot Formation. The shales in the Paleocene Ranikot Formation are primarily in the upper carbonate unit which consists of fossiliferous limestone interbedded with dolomitic shale, calcareous sandstone and “abundant” bituminous material. The upper unit was deposited in a restricted marine environment. West of the Karachi Trough axis, the Ranikot Formation becomes dominantly shale (Korara Shale) with deep marine deposition.

Within the southern portion of the Lower Indus Basin, we have identified 26,780-mi^2 for the Ranikot Shale that appears to be prospective for oil (R_o of 0.7% to 1.0%). The eastern, northern and western boundaries of the Ranikot Shale prospective area are set by the 300 m isopach contour; the southern boundary of the prospective area is the offshore.

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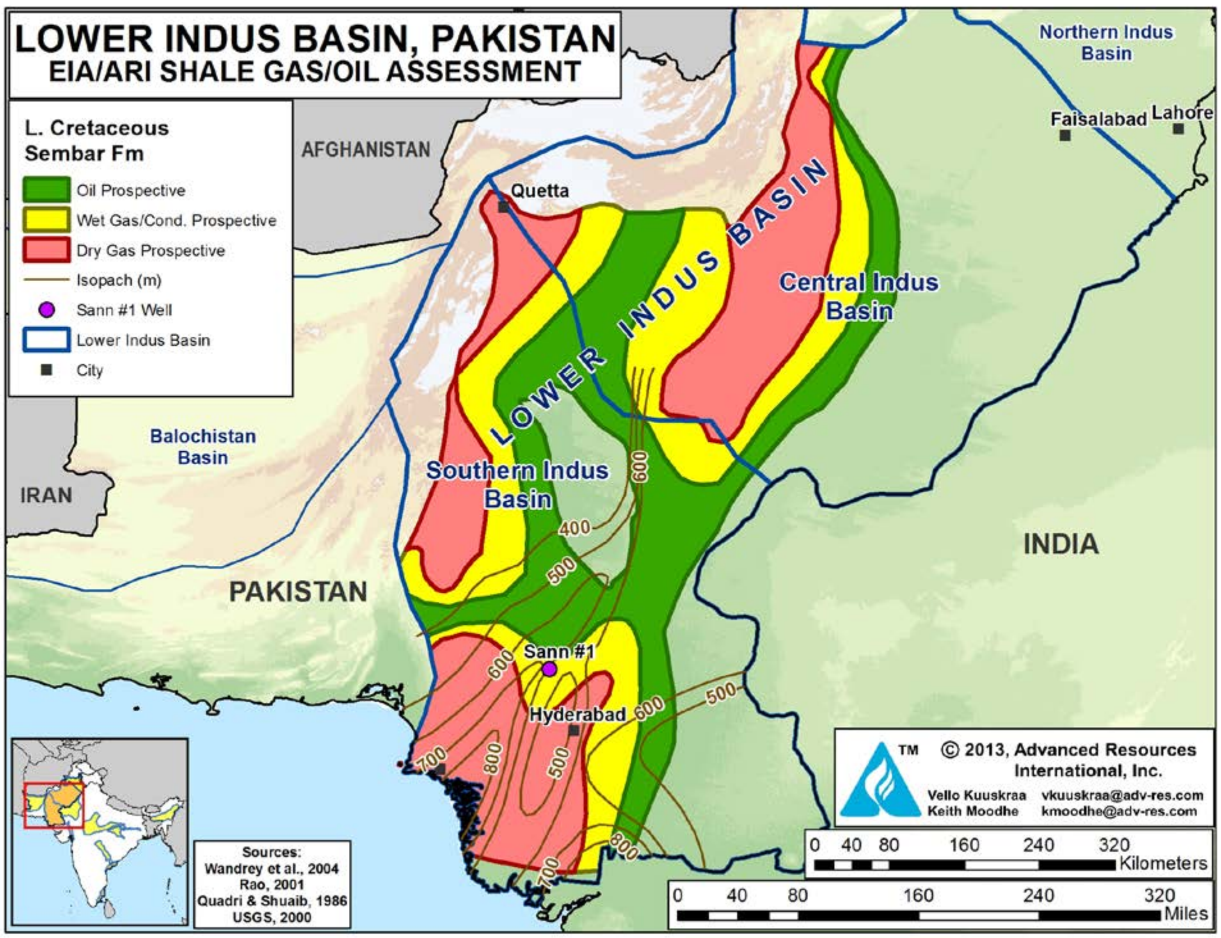
6.2 Reservoir Properties (Prospective Area)

Sembar Shale. The Sembar Formation was deposited under open-marine conditions.[27] In the prospective area of the Lower Indus Basin, the thickness of the Sembar Shale ranges from 1,000 to over 2,000 ft, Figure XXIV-28. We identified an organic-rich interval 1,000 ft thick with a net shale thickness of 250 ft. We estimate TOC of approximately 2% and an R_o of 1.0% to 1.6%. The Sembar Shale, in the shallower portions of the Lower Indus Basin, is in the oil and wet gas windows, with the lower limit of the oil window at about 4,000 ft and the wet gas/condensate window at 6,000 to 10,000 ft.[27] In the deeper portions of the basin below 10,000 ft, the Sembar Shale enters the dry gas window.

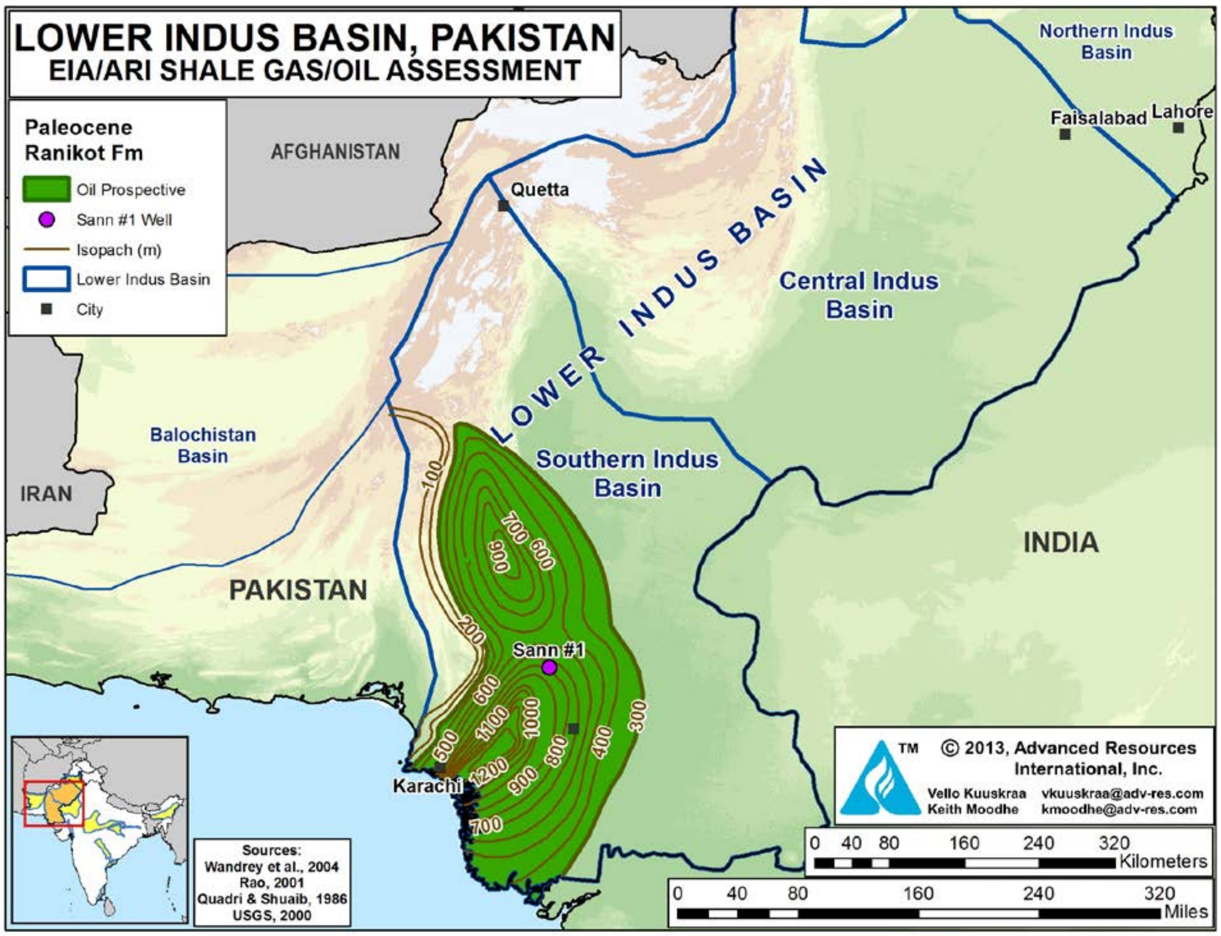
Figure XXIV-28. Isopach of Sembar Shale, Lower Indus Basin, Pakistan[26]



The thermal gradients in the basin increase from east to west, from 1.31°F/100 ft on the Thar Slope in the east to 2.39°F/100 ft in the Karachi offshore in the west. The average thermal gradient in the basin is 2.1°F/100 ft. The Sembar Shale appears to have low clay content.

Ranikot Formation. The prospective area of the Ranikot Formation has a thickness of 1,000 to 3,000 ft, with a net shale thickness of 200 ft, Figure XXIV-29. We assume 2% TOC and a thermal maturity of 0.7% to 1.0% R_o, placing the Ranikot Shale in the oil window.

Figure XXIV-29. Isopach of Ranikot Formation, Southern Indus Basin, Pakistan[26]



6.3 Resource Assessment

Within the 31,320-mi^2 dry gas prospective area, the Sembar Shale in the Lower Indus Basin has a resource concentration of 83 Bcf/mi^2. Within the 25,560-mi^2 wet gas and condensate prospective area, the Sembar Shale has resource concentrations of 57 Bcf/mi^2 of wet gas and 9 million barrels/mi^2 of condensate. Within the 26,700-mi^2 oil prospective area, the Sembar Shale has a resource concentration of 37 million barrels/mi^2.

Within the overall prospective area of the Lower Indus Basin, the Sembar Shale has risked shale gas in-place of 531 Tcf, with 101 Tcf as the risked, technically recoverable shale gas resource. In addition, the Sembar Shale has 145 billion barrels of shale oil in-place, with 5.8 billion barrels as the risked, technically recoverable shale oil resource.

Within its 26,780-mi^2 wet gas and condensate prospective area, the Ranikot Shale has resource concentrations of 17 Bcf/mi^2 of wet gas and 25 million barrels/mi^2 of shale oil/condensate. Within this prospective area of the Lower Indus Basin, the Ranikot Shale has 55 Tcf of risked shale gas in-place and 82 billion barrels of risked shale oil in-place. The risked, technically recoverable shale resources of the Ranikot Shale are 4 Tcf of wet shale gas and 3.3 billion barrels of shale oil/condensate.

6.4 Recent Activity

No publically available data has been reported on shale gas exploration or development for the Lower Indus Basin of Pakistan.

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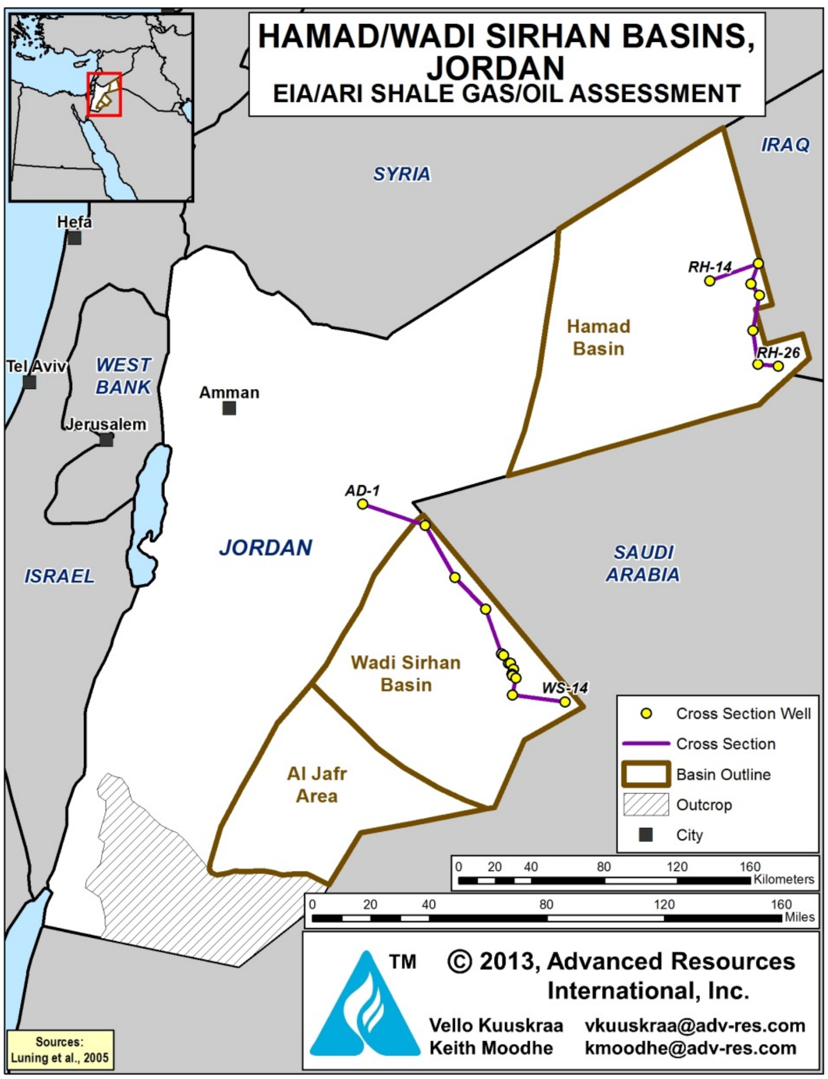
XXV. JORDAN

SUMMARY

Jordan has two basins with potential for shale gas and oil, the Hamad (Risha area) and Wadi Sirhan, Figure XXV. The target horizon is the organic-rich Silurian-age Batra Shale within the larger Mudawwara Formation.

Figure XXV-1. Base Map and Cross-Section Location, Jordan.



Source: ARI, 2013.

Our assessment is that the Batra Shale in these two basins contains 35 Tcf of risked shale gas in-place with 7 Tcf of risked, technically recoverable shale gas resource, Table XXV-1. In addition, we estimate that the Batra Shale holds 4 billion barrels of risked shale oil in-place, with about 0.1 billion barrels of risked, technically recoverable shale oil resource, Table XXV-2.

Table XXV-1. Shale Gas Reservoir Properties and Resources of Jordan

			Hamad	Wadi Sirhan
Basic Data	Basin/Gross Area		Hamad ($6,700 mi^2$)	Wadi Sirhan ($4,700 mi^2$)
	Shale Formation		Batra	Batra
	Geologic Age		Silurian	Silurian
	Depositional Environment		Marine	Marine
Physical Extent	Prospective Area (mi^2)		3,300	1,050
	Thickness (ft)	Organically Rich	160	120
		Net	80	60
	Depth (ft)	Interval	6,500 - 10,000	4,500 - 6,500
		Average	8,500	5,500
Reservoir Properties	Reservoir Pressure		Normal	Normal
	Average TOC (wt. %)		2.0%	4.0%
	Thermal Maturity (% Ro)		1.30%	0.80%
	Clay Content		Medium	Medium
Resource	Gas Phase		Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		25.3	3.7
	Risked GIP (Tcf)		33.4	1.6
	Risked Recoverable (Tcf)		6.7	0.2

Source: ARI 2013.

Table XXV-2. Shale Oil Reservoir Properties and Resources of Jordan

Basic Data	Basin/Gross Area		Wadi Sirhan (4,700 mi^2)
	Shale Formation		Batra
	Geologic Age		Silurian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		1,050
	Thickness (ft)	Organically Rich	120
		Net	60
	Depth (ft)	Interval	4,500 - 6,500
		Average	5,500
Reservoir Properties	Reservoir Pressure		Normal
	Average TOC (wt. %)		4.0%
	Thermal Maturity (% Ro)		0.80%
	Clay Content		Medium
Resource	Oil Phase		Oil
	OIP Concentration (MMbbl/mi^2)		8.8
	Risked OIP (B bbl)		3.7
	Risked Recoverable (B bbl)		0.15

Source: ARI, 2013.

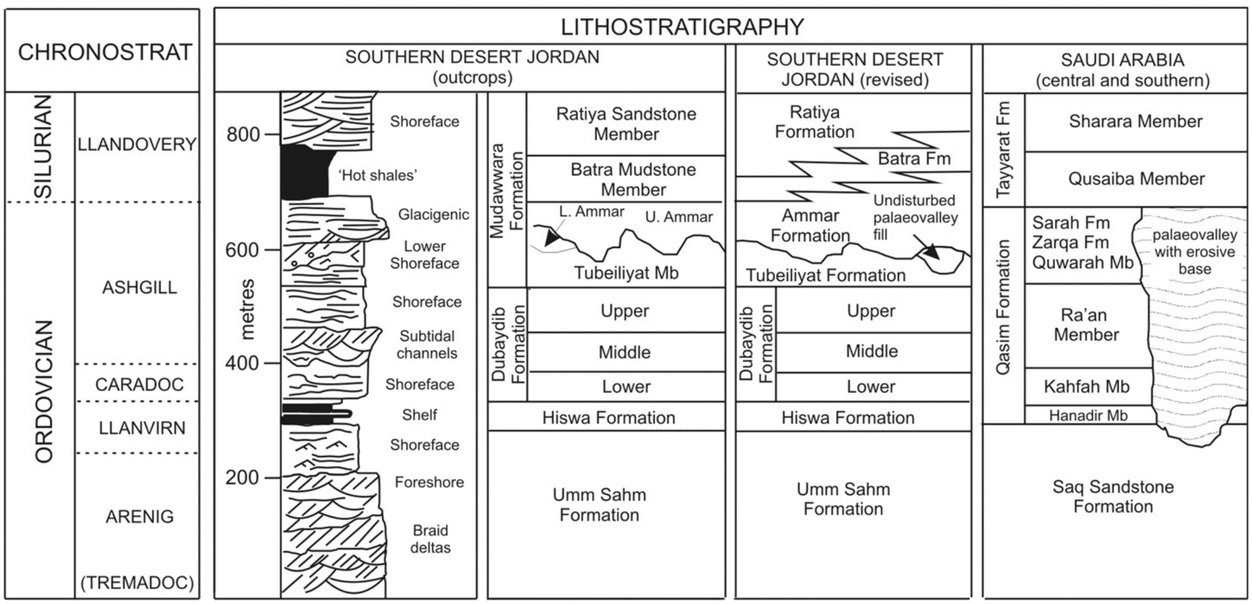
INTRODUCTION

Eastern Jordan contains Silurian-age organic-rich marine shales in the Batra Member of the Mudawwara Formation. Similar Silurian organic-rich shales are a major source of hydrocarbons in North Africa, Iraq and Saudi Arabia. The Batra Shale is time equivalent to the Tanezzuft Formation in Libya and the Qusaiba Shale of the Qalibah Formation in Saudi Arabia.[1] These Lower Silurian-age shales are often called “Hot Shales” because of their high uranium content, having gamma-ray values of >150 API units, Figure XXV-2.[2]

Additional organically enriched marine shales exist in the uppermost Ordovician-age Risha Formation. These shales are 60 to 120 feet thick and have thermal maturities for dry gas.[3,4] However, the TOC values of these Upper Ordovician shales generally range from 0.5% to 1.5%, below the TOC cut-off set forth for this study.

For the shale gas and oil resource assessment of Jordan, we have drawn heavily on the most valuable geological work and publications of Luning (2000,[1] 2005[3]), Armstrong (2005,[5] 2009[2]), Keegan (1990[6]), and Ahlbrandt (1997[7]). In addition, Jordan's Petroleum Directorate within the Natural Resources Authority provided important information in their 2006 publication entitled, "Petroleum Exploration Opportunities in Jordan".[8]

Figure XXV-2. Lithostratigraphy for the Ordovician and Silurian of Jordan and Saudi Arabia,



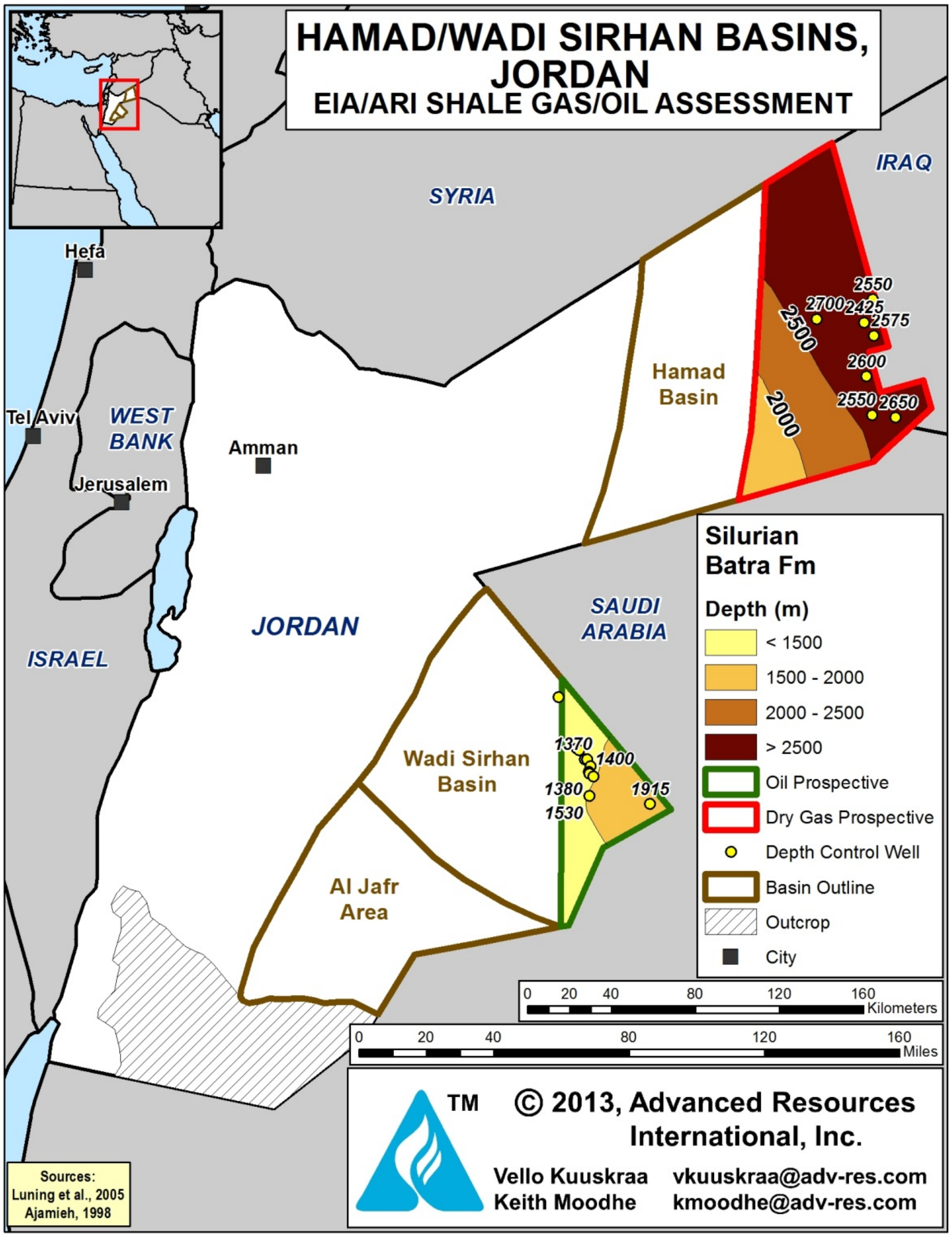
Source: Lithostratigraphy and chronostratigraphy for the Ordovician and Silurian of Jordan and Saudi Arabia, showing generalized depositional environments for outcrops in the Southern Desert region of Jordan (redrawn from Turner et al., 2005). Armstrong (2009)

1. GEOLOGIC SETTING

The Batra Shale is present in the sub-surface in the Hamad (Risha area) and Wadi Sirhan basins of eastern Jordan, as well as in the near-surface in the Al Jafr area and outcrops of the Southern Desert of Jordan. The Hercynian sub-crop establishes western limits of the Batra Shale in Jordan. The Syria, Iraq and Saudi Arabia borders with Jordan set the northern, southern and eastern limits of the Jordan portion of this shale deposit. The Batra Shale is a Type I/II marine shale, deposited along the margins of the receding Gondwana shelf. Figure XXV-3 provides the depth and areal extent for the prospective areas of Batra Shale in Jordan.[3]

The Batra Shale contains three distinct organic-rich intervals - - a highly organic-rich unit called the "Lower Hot Shale", a middle unit within lower organic content, and the "Upper Hot Shale".[3] We have included the "Lower Hot Shale" and the "Upper Hot Shale" units in our resource assessment.

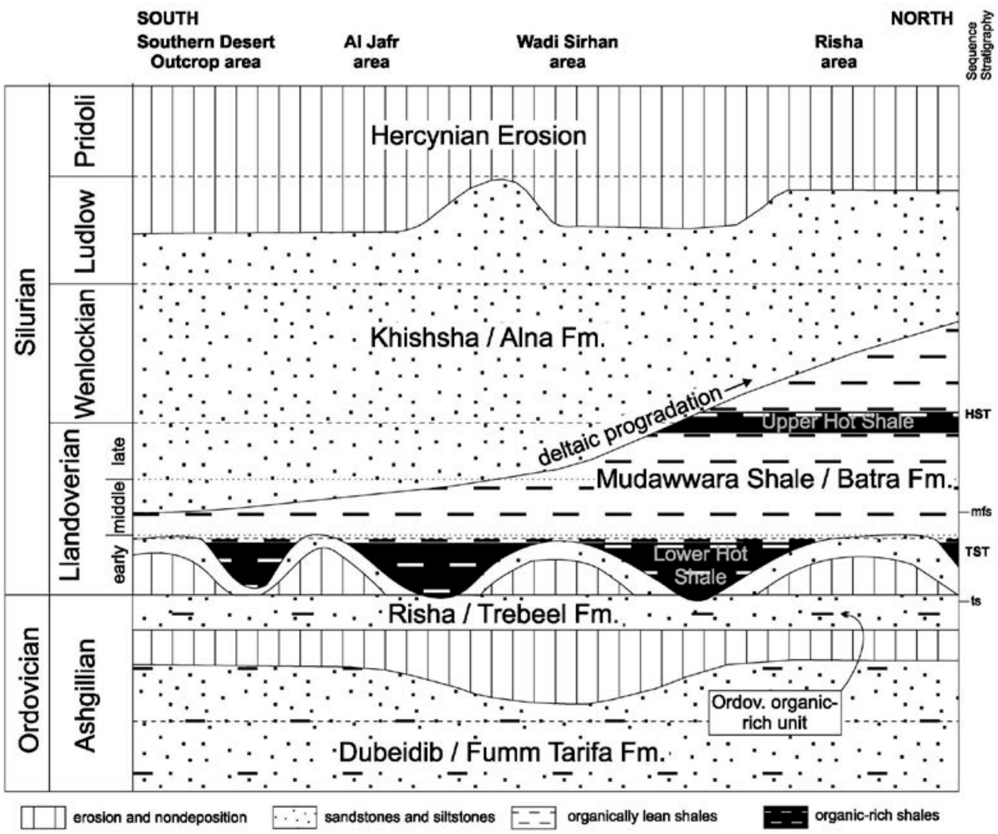
Figure XXV-3. Depth and Prospective Areas - - Batra Shale, Jordan



Source: ARI, 2013.

The “Lower Hot Shale” unit, deposited at the base of the Batra Shale and above the underlying Dubaydib Formation, is present in southeastern Jordan (Wadi Sirhan Basin). The “Lower Hot Shale” thins to the west, north and south in the Wadi Sirhan area. The “Upper Hot Shale” exists in the Hamad Basin’s Risha gas field area along the Iraqi border. The “Upper Hot Shale” is at the top of the Batra Shale interval, XXV-Figure 4.[3]

Figure XXV-4. Chonostratigraphy of the Upper Ordovician-Silurian in Jordan.



Source: S. Luning, 2005.

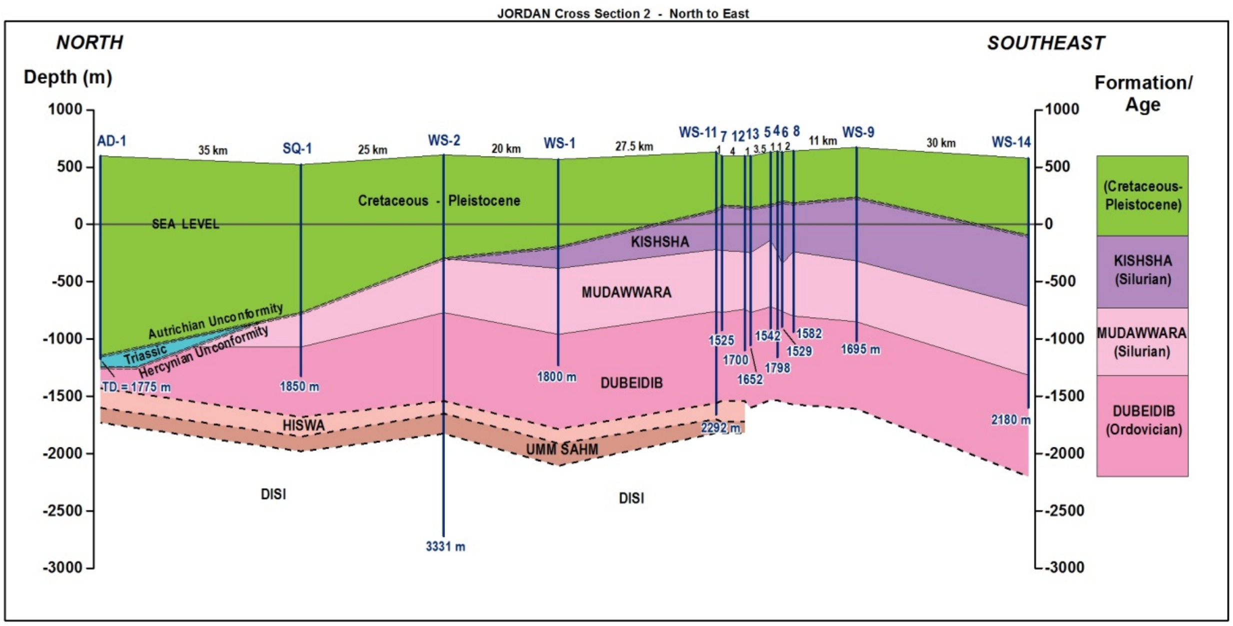
The thermal maturity of the Batra Shale increases from south to north and from west to east. The shale is immature to early-mature in the Al Jafr area, becomes middle-mature (oil window) in the Wadi Sirhan area, and is late to post-mature (gas window) in the Hamad Basin’s Risha area.[3,7] The determination of the thermal maturity for the Batra Shale has been approximated using graptolite reflectance and maximum temperature. (Vitrinite did not yet exist during early Silurian time.)

As shown in Figure XXV-3, we have mapped a prospective area of 1,050 mi^2 for the "Lower Hot Shale" in the oil-prone Wadi Sirhan area and a prospective area of 3,300 mi^2 for the "Upper Hot Shale" in the gas-prone Risha area.

2. RESERVOIR PROPERTIES (PROSPECTIVE AREA)

Lower Hot Shale. In the Wadi Sirhan prospective area, the depth of the "Lower Hot Shale" ranges from 4,500 to 6,500 ft, averaging 5,500 ft. Based on analog data, we assume that the shale in this area is at normal pressure. The organic-rich gross interval of the "Lower Hot Shale" unit in the Wadi Sirhan prospective area ranges from 30 to 100 ft, with an average net pay of about 60 ft (using 150 API units of background gamma radiation). Figure XXV-5 provides a north to south cross-section for the Batra Shale in the Wadi Sirhan area.[8] (Figure XXV-1 provides the cross-section locations.[3,8])

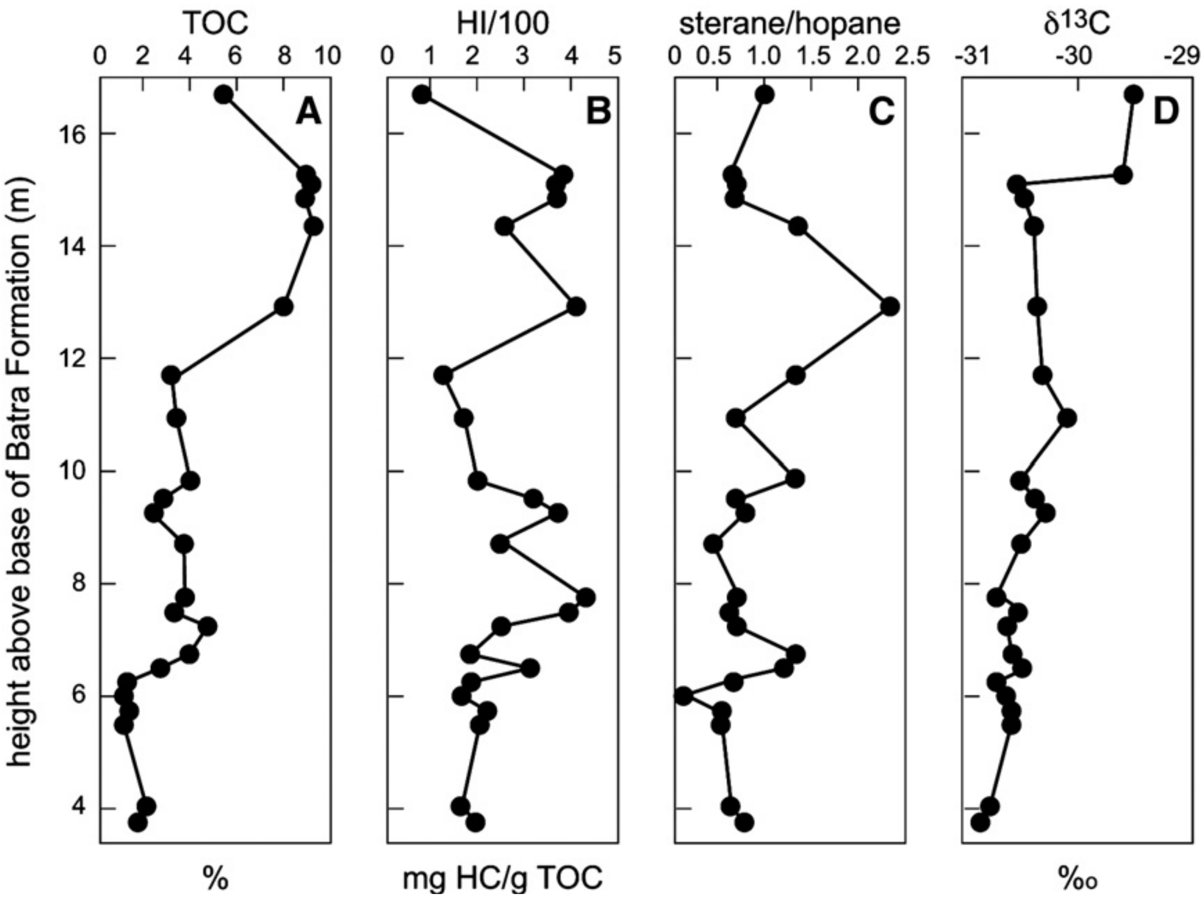
Figure XXV-5. North to South Regional Cross-Section, Wadi Sirhan Basin.



Source: NRA Petroleum Directorate Jordan, 2006.

The TOC of the “Lower Hot Shale” unit ranges from 1.5% to 9%, with an average value of about 4%, Figure XXV-6.[2] The thermal maturity of the shale unit is estimated at 0.7% to 1.0% R_o equivalent, averaging 0.8% R_o. We have used other Silurian-age “hot shale” deposits as analogs for supplemental reservoir data for the “Lower Hot Shale” in the Wadi Sirhan Basin.

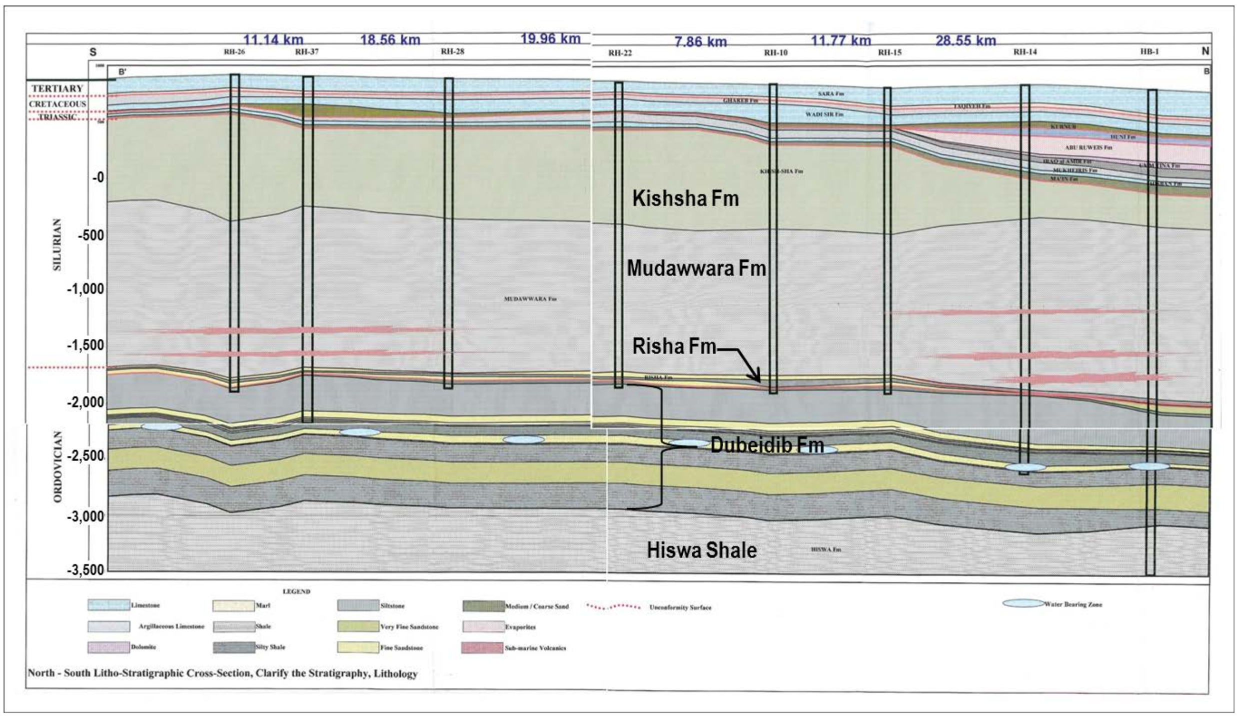
Figure XXV-6. Bulk Organic Carbon, Biomarker and Stable Carbon Isotope Data.



(A) Total organic carbon (TOC) content of the bulk sediment. (B) Hydrogen index (HI) of the bulk sediment (mg hydrocarbons (HC)/g TOC). (C) Steranes/17α-hopanes ratio shows its highest value at 12.94m above the base of the Batra formation. (D) δ13C values of organic carbon (OC) versus Vienna Peedee belemnite (VPDB) in parts per mil (‰).Source: Armstrong (2009)

Upper Hot Shale. In the Hamad Basin/Risha prospective area, the depth of the “Upper Hot Shale” ranges from 6,500 to 10,000 ft, averaging 8,500 ft. Based on limited well test data, we assume that the shale is at normal pressure. The organic-rich gross interval of the “Upper Hot Shale” unit in the Risha prospective area is about 160 ft thick, with an average net pay of about 80 ft, based on a minimum 2% TOC value cutoff. Figure XXV-7 provides a north to south cross-section for the Batra Shale in the Risha area (see Figure XXV-1 for cross-section location.).[8] The average TOC value is about 2%, after exclusion of the lower TOC value intervals using the net to gross pay ratio. The thermal maturity of the “Upper Hot Shale” is estimated at above 1.2% R_o equivalent[3]. We have used analog data from other Silurian-age “hot shale” deposits for supplemental reservoirs data for the “Upper Hot Shale” unit in the Hamad Basin (Risha Area).

Figure XXV-7. Regional Geologic Cross-Section, Eastern Hamad Basin (Risha Area).

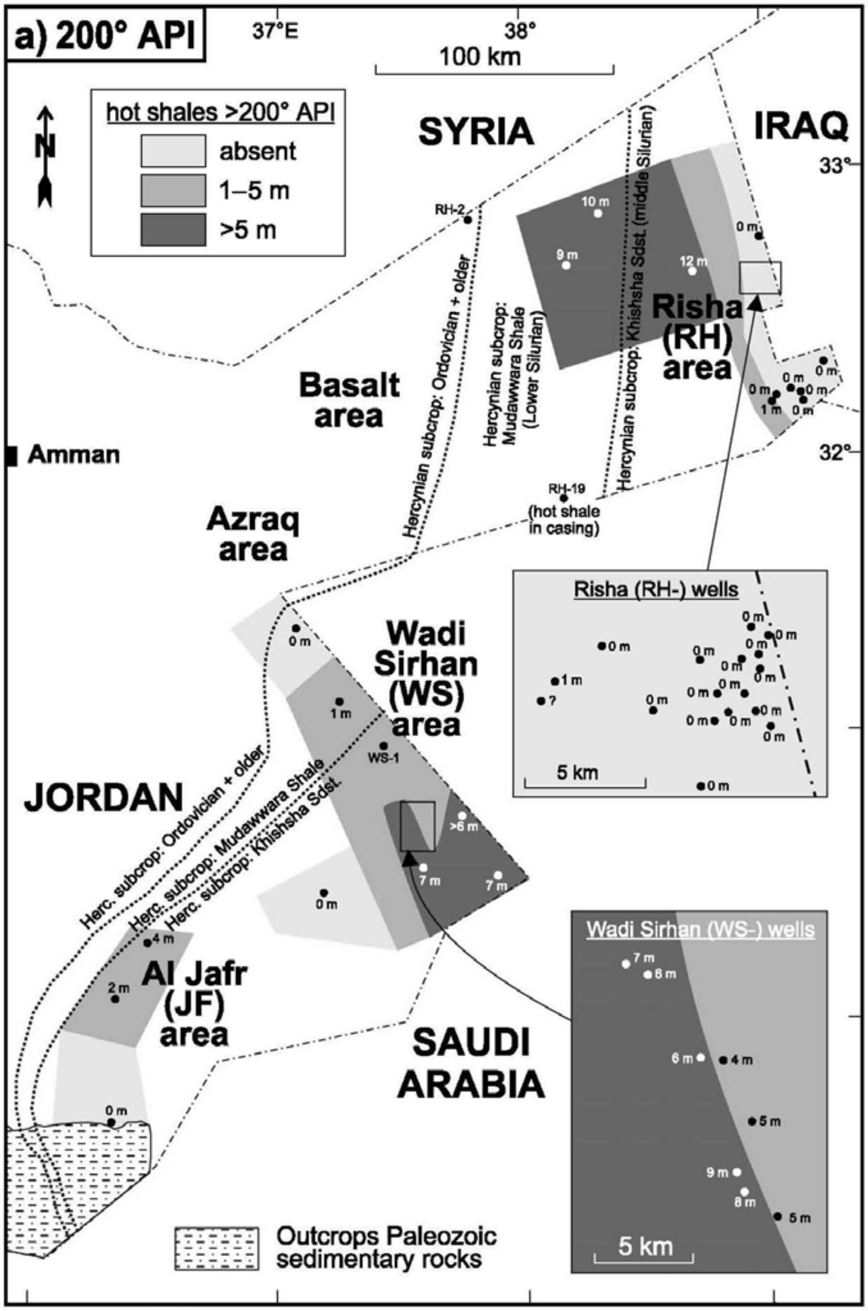


JAF028356.PPT

Source: NRA Petroleum Directorate Jordan, 2006

Figure XXV-8 is an isopach map for the Batra Shale using the 150 API gamma-ray background value for determining organically rich shale.[3]

Figure XXV-8. Isopach Map of Organic-Rich Silurian Shales with Total Gamma-Ray Values Exceeding 150 API Corresponding to Organic Richness.



Source: Luning, 2005

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3. RESOURCE ASSESSMENT

Wadi Sirhan Basin. The prospective area for the Lower Batra Shale in the Wadi Sirhan Basin is limited on the west by the thinning and thermal maturity of the shale and on the east by the Jordanian border. Within the 1,050-mi^2 prospective area for oil, the Batra Shale has a resource concentration of 9 million barrels of oil per mi^2 plus moderate volumes of shale associated gas.

The risked resource in-place for the shale oil prospective area of the Wadi Sirhan Basin is estimated at 4 billion barrels of oil plus 2 Tcf of associated shale gas. Based on moderately favorable reservoir properties, we estimate a risked, technically recoverable shale oil resource of 0.1 billion barrels plus small volumes of associated shale gas for the Batra Shale in the Wadi Sirhan Basin.

Hamad/Risha Area. The prospective area for the Upper Batra Shale in the Hamad Basin/Risha area is limited on the west by the pinch-out of the shale and on the north, south and east by the Jordanian border. Within the 3,300-mi^2 prospective area for wet and dry gas, the Batra Shale has a resource concentration of 25 Bcf/mi^2.

The risked shale resource in-place for the gas prospective area is estimated at 33 Tcf. Based on moderately favorable reservoir properties, we estimate a risked, technically recoverable shale gas resource of about 7 Tcf for the Batra Shale in the Hamad Basin/Risha area.

4. RECENT ACTIVITY

A number of deep exploration wells have been drilled in the Wadi Sirhan area prospecting for oil. One well (Wadi Sirhan #4) is reported to have produced 25 barrels per day of 42^{o} API oil from sandstones associated with the Batra Shale, while other exploration wells have reported shows of light oil.[8] However, much of the data from these deep exploration wells remains confidential. Another series of wells (31) have been drilled in the Hamad Basin/Risha area into the Risha tight sandstone member of the Ordovician-age Dubaydib Formation. Five of the wells are reported to be producing at a combined rate of 30 MMcfd.[7] The Batra Shale, in the overlying Silurian-age Mudawwara Formation, is considered the source of this gas accumulation.

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XXVI. TURKEY

SUMMARY

This resource assessment addresses two shale basins in Turkey - - the Southeast Anatolia Basin in southern Turkey and the Thrace Basin in western Turkey, Figure XXVI-1. These two basins have active shale oil and gas exploration underway by the Turkish national petroleum company (TPAO) and several international companies. Turkey may also have shale gas resources in the Sivas and Salt Lake basins. However, only limited reservoir data are available for these two lightly explored basins.

Figure XXVI-1. Major Shale Basins of Turkey

Source: ARI, 2013.

We estimate that the Dadas Shale in the SE Anatolian Basin and the Hamitabat Shale in the Thrace Basin contain 163 Tcf of risked shale gas in-place, with 24 Tcf as the risked, technically recoverable shale gas resource, Table XXVI-1. In addition, we estimate that these two shale basins also contain 94 billion barrels of risked shale oil in-place, with 4.7 billion barrels as the risked, technically recoverable shale oil resource, Table XXVI-2.

Table XXVI-1. Shale Gas Reservoir Properties and Resources of Turkey

Basic Data	Basin/Gross Area		SE Anatolian ($32,100\ mi^2$)		Thrace ($6,500\ mi^2$)		
	Shale Formation		Dadas		Hamitabat		
	Geologic Age		Silurian-Devonian		M. - L. Eocene		
	Depositional Environment		Marine		Marine		
Physical Extent	Prospective Area (mi^2)		3,540	500	150	210	680
	Thickness (ft)	Organically Rich	394	377	500	500	500
		Net	216	207	250	250	250
	Depth (ft)	Interval	6,000 - 11,500	5,500 - 13,000	10,000 - 13,000	13,000 - 16,400	14,000 - 16,400
		Average	9,000	9,500	11,500	14,500	15,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.6%	3.6%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	2.00%
	Clay Content		Med./High	Med./High	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		48.2	91.4	34.7	81.8	104.1
	Risked GIP (Tcf)		102.4	27.4	1.9	6.2	25.5
	Risked Recoverable (Tcf)		10.2	6.9	0.1	1.2	5.1

Table XXVI-2. Shale Oil Reservoir Properties and Resources of Turkey

Basic Data	Basin/Gross Area		SE Anatolian ($32,100\ mi^2$)		Thrace ($6,500\ mi^2$)	
	Shale Formation		Dadas		Hamitabat	
	Geologic Age		Silurian-Devonian		M. - L. Eocene	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		3,540	500	150	210
	Thickness (ft)	Organically Rich	394	377	500	500
		Net	216	207	250	250
	Depth (ft)	Interval	6,000 - 11,500	5,500 - 13,000	10,000 - 13,000	13,000 - 16,400
		Average	9,000	9,500	11,500	14,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.6%	3.6%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Med./High	Med./High	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration ($MMbbl/mi^2$)		41.0	14.2	33.8	8.0
	Risked OIP (B bbl)		87.1	4.2	1.8	0.6
	Risked Recoverable (B bbl)		4.36	0.21	0.07	0.02

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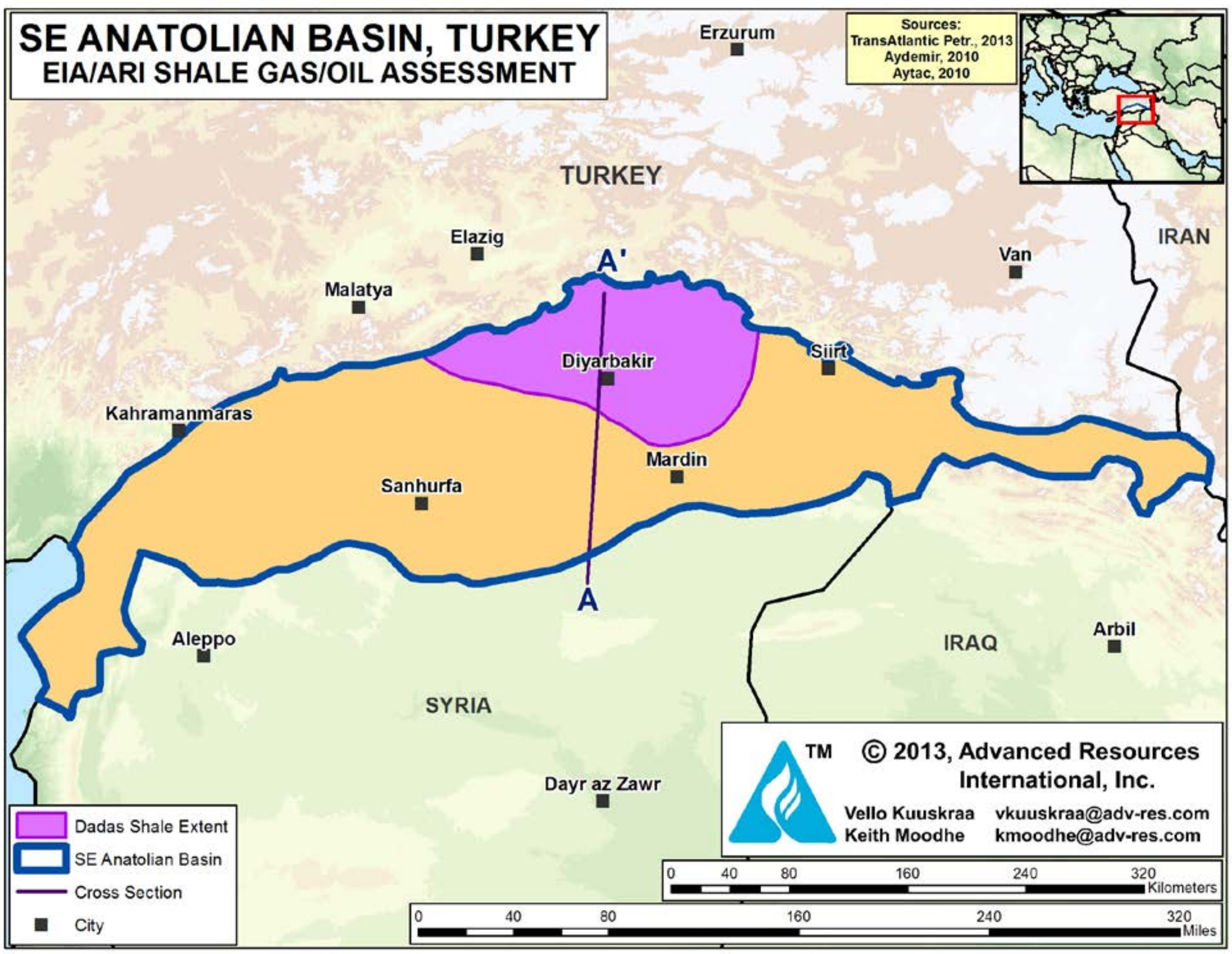
1. SOUTHEAST ANATOLIAN BASIN

1.1 Introduction and Geologic Setting

The SE Anatolian Basin covers a large, 32,100-mi^2 area in southeastern Turkey. The basin contains the Silurian Dadas Shale, located in the central basin portion of the basin, Figure XXVI-2. The basin is bounded on the north by the Zagros suture zone, which marks the juncture of the Arabian and Eurasian tectonic plates. The basin is bounded on the south and east by the Syria, Iraq and Turkey border. The SE Anatolian Basin is an active, primarily oil-prone basin with about 100 oil field discoveries to date. While the bulk of the oil production is from Mardin Group carbonate formations, the basin also has deep Paleozoic reservoirs such as the Bedinan Sandstone that contains light, 40^o to 50^o API gravity oil.

Figure XXVI-2. Outline and Depositional Limit of Dadas Shale, SE Anatolian Basin



Source: ARI, 2013.

In the early Paleozoic, Silurian-age shale formations were deposited throughout the northern Gondwana super-continent (present day North Africa and the Middle East), following sea level rise caused by melting of Ordovician-age glaciers. Regional lows and offshore deltas with anoxic conditions preserved organic-rich sediments. The SE Anatolian Basin was part of the northern edge of the Gondwana super-continent, which later separated to form the Arabian plate. As such, the SE Anatolian Basin shares similar geology with the oil-producing regions of Saudi Arabia and Iraq, although it experienced more intense faulting and thrusting from collision with the Eurasian Plate.

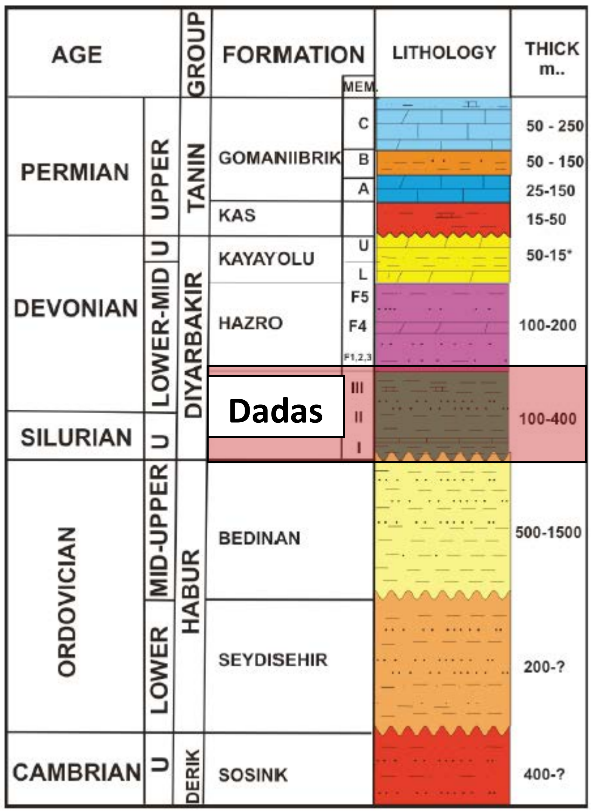
The SE Anatolian Basin contains three source rocks - - the deep Silurian Dadas Shale, the Late Cretaceous Karabogaz organic-rich limestone, and the organic-rich deposits in the Triassic-Jurassic Jodi Group.[1] The most prospective of these source rocks is the Silurian Dadas Shale, the basal member of which, called Dadas I, is the organic-rich shale interval evaluatedin this resource study, Figure XXVI-3.[2] In general, the Dadas Shale is oil prone but may be wet gas-prone in the deeper northern area of the basin.

ARI mapped a 4,040-mi^2 area of the Dadas Shale in the north-central portion of the SE Anatolian Basin as prospective for shale gas and shale oil development. The prospective area is bounded on the east by the 10-m Dadas I Shale isopach, on the south and west by the -1,500-m sub-sea depth contour for the Dadas Shale (approximately equivalent to an R_o of 0.7%), and on the north by the Hazro Uplift.[2] Figure XXVI-4[1] provides a north to south cross-section through the center of the basin, illustrating the presence and depth of the Dadas Shale. (The location of the cross-section is shown on Figure XXVI-2).

1.2 Reservoir Properties (Prospective Area)

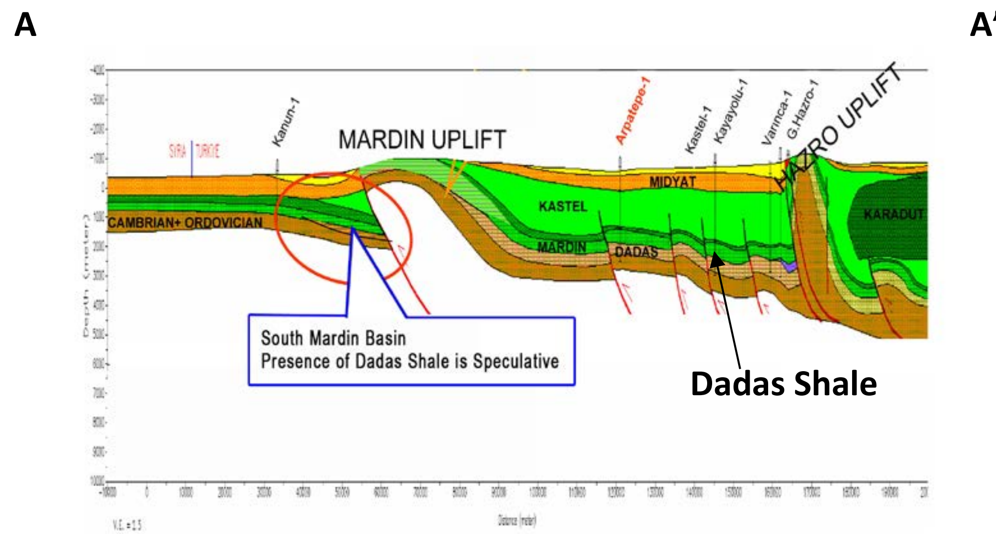
The Dadas Shale of the SE Anatolian Basin contains a 3,540-mi^2 central area prospective for shale oil and a smaller, northern 500-mi^2 prospective area for wet gas and condensate, Figure XXVI-5. Because of limited data on vitrinite reflectance, we have used Tmax of 455^{o}C as a proxy for the R_o of 1.0% boundary between the oil prone and the wet gas/condensate prone area, Figure XXVI-6.[3] The southern 0.7%-R_o boundary for the oil window follows the -1,500-m sub-sea depth contour for the Dadas Shale.

Figure XXVI-3. SW Anatolia Basin Stratigraphic Column[2]



Source: A. Aydemir, 2010.

Figure XXVI-4. SW Anatolian Basin Cross-Section[1]



Source: E. Aytac, 2010.

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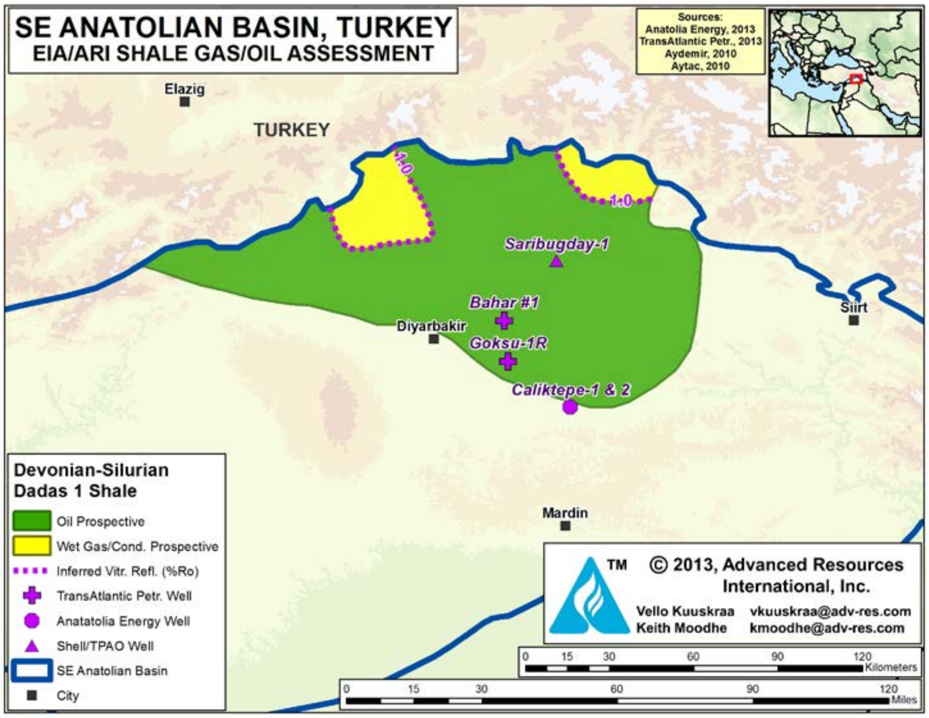
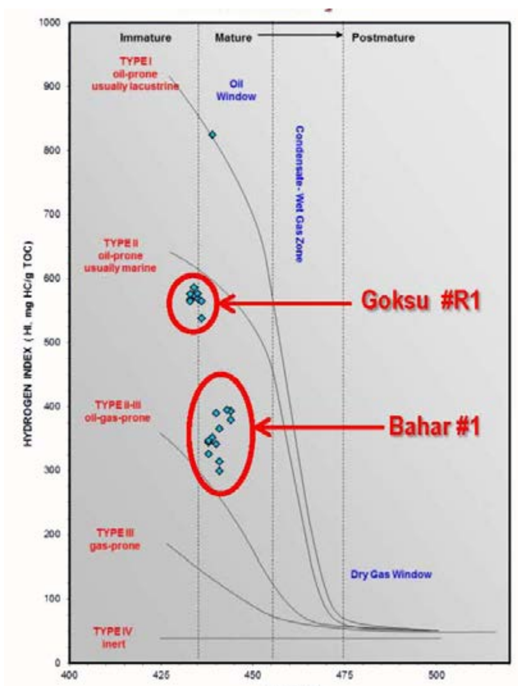
Figure XXVI-5. Dadas Shale Prospective Area, SE Anatolian Basin, Turkey



Source: ARI, 2013

Figure XXVI-6. Relationship of Tmax and Thermal Maturity for Basal Dadas I Shale



Source: M. Mitchell, 2013.

A series of key wells provided valuable information on the reservoir properties of the Dadas Shale. The key wells included: (1) the Goksu-#1R (with 30 feet of core, detailed rock mineralogy and micro-seismic data); (2) the Bahir-#1 (with core-based vitrinite reflectance information and reservoir pressure data); and (3) the Caliktepe-#2 (with 5 Dadas Shale cores). The location of these three key reservoir characterization wells, plus the Shell/TPAO Saribugday-#1 well are shown on Figure XXVI-5.

The depth of the Dadas Shale in the SE Anatolian Basin ranges from 6,000 ft to 13,000 ft, averaging 9,000 ft in the oil window and 9,500 ft in the wet gas and condensate window. The total Dadas Shale Formation has an extensive gross thickness of over 1,000 ft, with, its lower, 200-ft thick basal portion considered the primary organic-rich source rock.[2]

Based on core analyses information from the key wells discussed above, the Dadas I Shale contains Type II (oil and gas) marine kerogen with a TOC of 2% to 7%, averaging 3.6%. The formation oil samples tested at 40^o to 50^o API. The shale matrix has a porosity of 6% to 7% with low water saturation. The mineralogy of the Dadas Shale in the Bahir #1 well showed moderately high clay (34%) with 39% quartz.[3] The formation is over-pressured.

1.3 Resource Assessment

Within the 3,540-mi^2 oil prospective area, the Dadas Shale in the SE Anatolian Basin has an estimated resource concentration of 41 million barrels/mi^2 of oil plus associated gas. We estimate 87 billion barrels of risked shale oil in-place and 102 Tcf of associated shale gas in-place, with 4.4 billion barrels of shale oil and 10 Tcf of associated shale gas as the risked, technically recoverable shale resources.

Within the 500-mi^2 wet gas and condensate area, the Dadas Shale has resource concentrations of 91 Bcf/mi^2 for wet gas and 14 million barrels/mi^2 for condensate. We estimate the Dadas Shale contains a risked wet shale gas in-place of 27 Tcf, with 7 Tcf as the risked, technically recoverable shale gas resource. This area also holds risked shale oil/condensate in-place of 4 billion barrels, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

Overall, we estimate that the Dadas I Shale in the SE Anatolian Basin contains 91 billion barrels of risked shale oil in-place and 130 Tcf of risked shale gas in-place, with 4.6 billion barrels of shale oil/condensate and 17 Tcf of wet shale gas as the risked, technically recoverable shale resources.

While the Dadas Shale formation has relatively favorable properties for gas development, the prospective areas exhibit heavy faulting and the shale has moderate clay content, two factors that could pose significant development risks.

1.4 Recent Activity

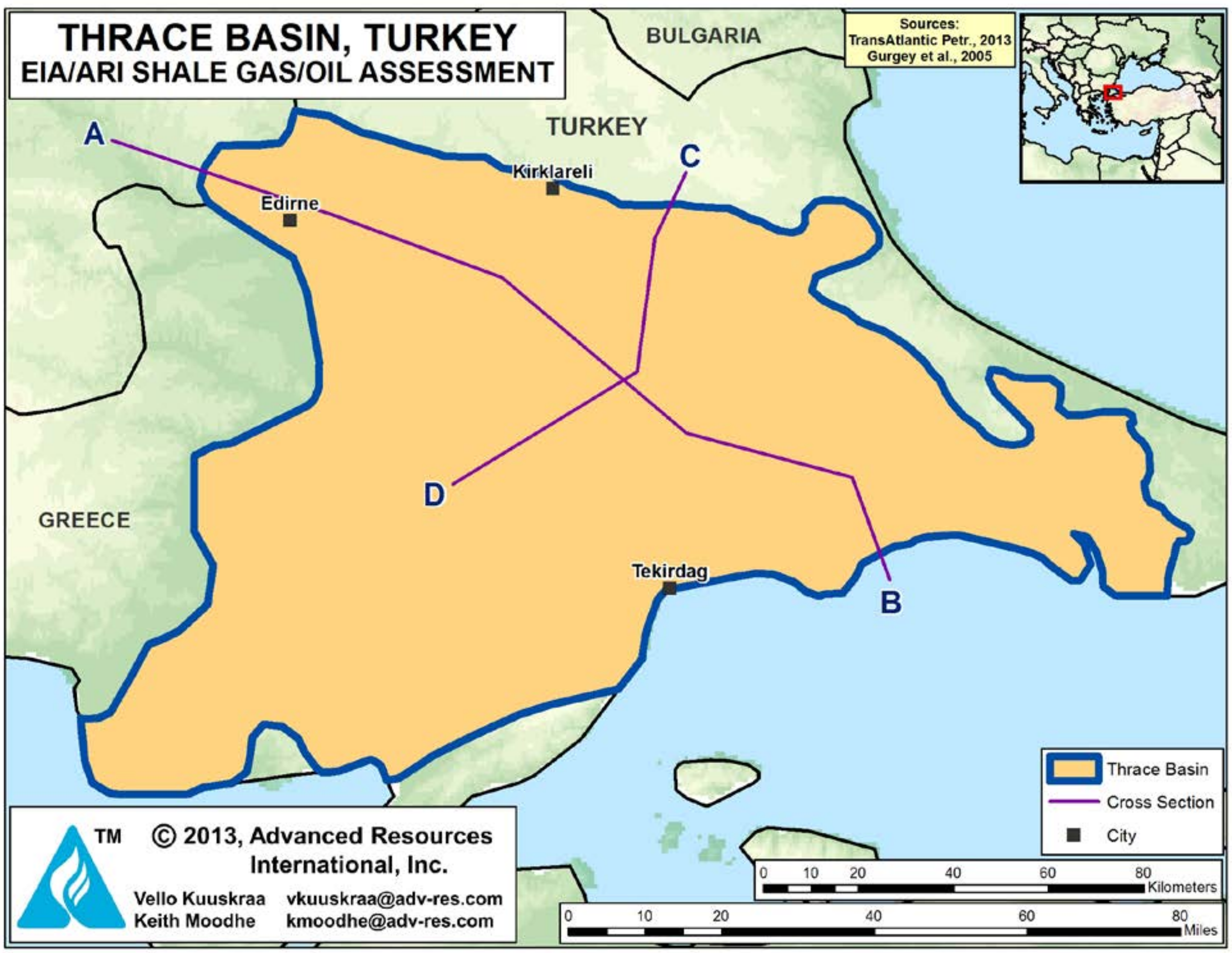
TPAO, the Turkish National Oil Company, and Shell are currently drilling the Saribugday-#1 well in License Area 4925 testing the Dadas Shale. Shell has announced a five-well exploration program for the area. Anatolia Energy drilled their first Dadas Shale evaluation well, Caliktepe-#2, on their Bismil lease area in early January, 2012.[4] The shale section in the well was cored, providing valuable information on the reservoir properties of the Dadas Shale, as reported earlier in this chapter. TransAtlantic Petroleum reported flowing gas and light oil from their two Dadas Shale test wells, Goksu-#1 and Bahir-#1. TPAO reported their Oiksor well flowed 152 barrels of 60^{o} API gravity oil during a three-hour test in the Dadas Shale.

2. THRACE BASIN

2.1 Introduction and Geologic Setting

The Thrace Basin covers an 6,500-mi^2 area in the European portion of Turkey. The Basin is bordered on the north by the Istranca Massif, by the Rhodope Massif on the west and the Sakarya Massif on the south, Figure XXVI-7. Tertiary-age (Eocene through Miocene) deposits reach nearly 30,000 ft thick in the center of the basin. Following the discovery of the Hamitabat Gas Field in 1970, the Thrace Basin became Turkey's most important gas producing area, accounting for 85% of the country's total gas production. About 350 wells have been drilled in thirteen gas fields and three oil fields in this basin. The Thrace Basin is primarily a tight sand gas play, sourced by adjoining and deeper shales.

Figure XXVI-7. Outline and Depositional Limits of the Thrace Basin



Source: ARI, 2013.

The Thrace Basin contains two shale source rock formations with oil and gas potential, the Middle Eocene Hamitabat Formation and the Lower Oligocene Mezardere Formation, Figure XXVI-8.[5] The Hamitabat Formation contains a thick sequence of sandstone, shale and marl deposited in a shallow marine environment. The Mezardere Formation, deposited in a deltaic environment, contains inter-bedded layers of sandstone, shale and marl. In the deeper areas of the basin, these shales have sufficient thermal maturity to be in the gas window.

The prospective areas for the shales in the Thrace Basin are based on total organic content, appropriate depth and adequate thermal maturity. Because of their complex depositional environments, accurately locating prospective shale intervals within the Mezardere and Hamitabat formations requires detailed geologic data, and a more extensive set of cross-sections than were available for this basin, Figure XXVI-9.[5]

The 1,040-mi^2 prospective area identified for the Hamitabat Formation is based primarily on depth and thermal maturity data. The Hamitabat Formation contains modest-size oil (150-mi^2) and wet gas/condensate (210 mi^2) areas and a larger, 680-mi^2 prospective area for dry gas. However, a major portion of the dry gas area in the center of the basin is deeper than the 5,000-m threshold used for this analysis and thus was not included in this prospective area. While we mapped the areal extent and thermal maturity of the Mezardere Shale, we did not identify a prospective area for this shale because the recent core data showed TOC values less than 2%.[6]

2.2 Reservoir Properties (Prospective Area)

Hamitabat Shale. The deepest and oldest shale formation in the Thrace Basin, the Hamitabat Shale is also the most thermally mature. The shale is in the dry gas window at depths of 14,000 to 16,400 ft in the center of the basin, with R_o ranging from 1.3% to over 2.5%.[7] Organic content is highly variable throughout the formation, ranging from fractions of a percent to above 6%. Within the prospective area, TOC ranges from 1% to 4%, averaging 2%. The net shale of the Hamitabat Shale averages 250 feet, Figure XXVI-10.[8]

Mezardere Shale. The Mezardere Shale is a second thick, regionally extensive shale interval in the Thrace Basin, Figure XXVI-11.[8] However, because of low organic content (<2%), this shale formation has not been quantitatively assessed.

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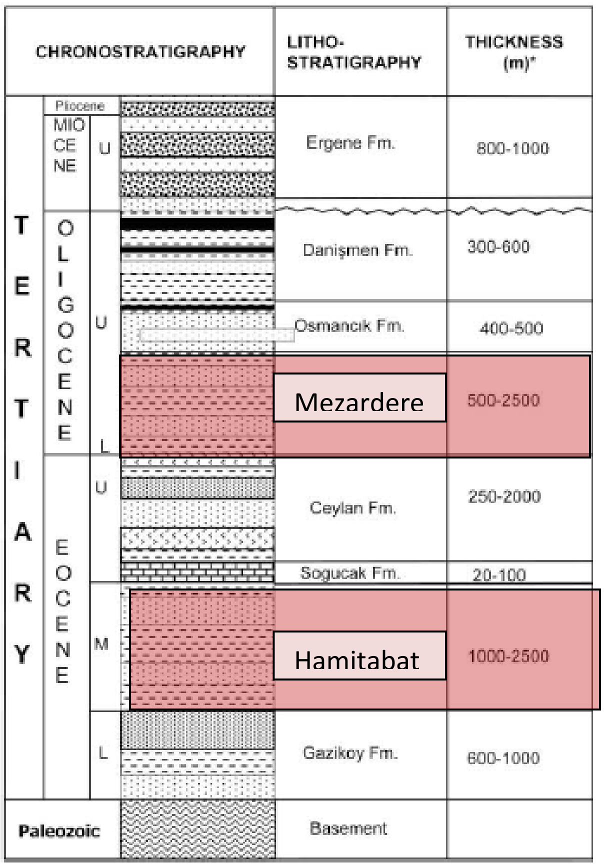
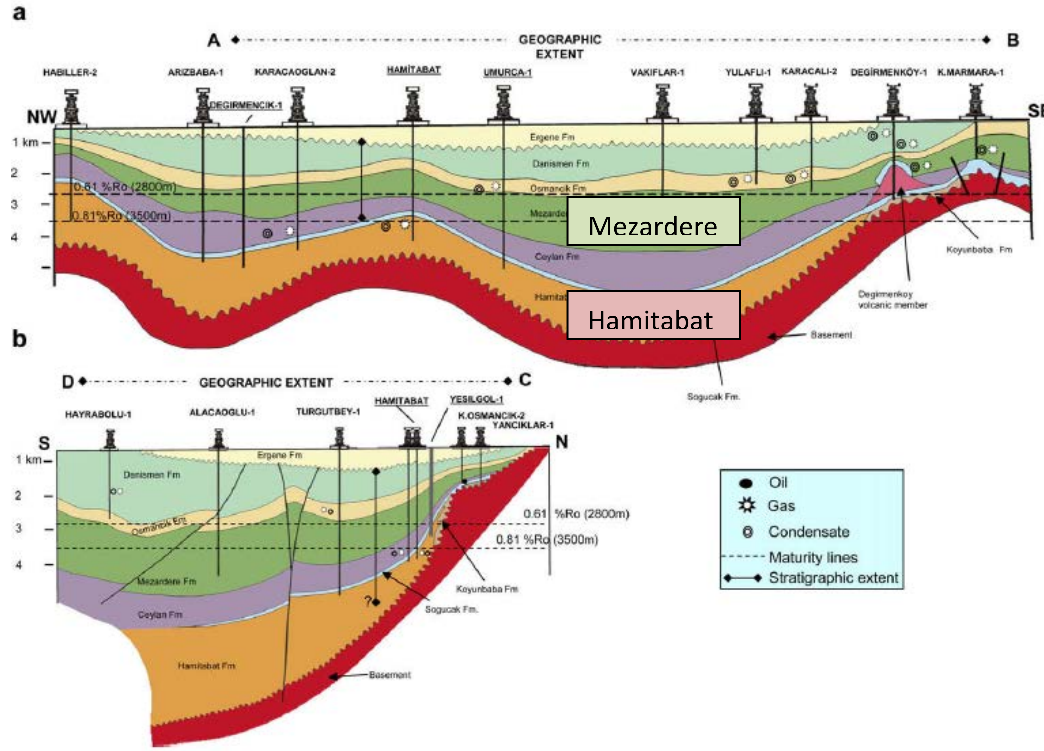
Figure XXVI-8. Thrace Basin Stratigraphic Column[5]



Source: Gürgey, Kadir, 2005.

Figure XXVI-9. Thrace Basin Cross Section[5]



Source: Gürgey, Kadir, 2005.

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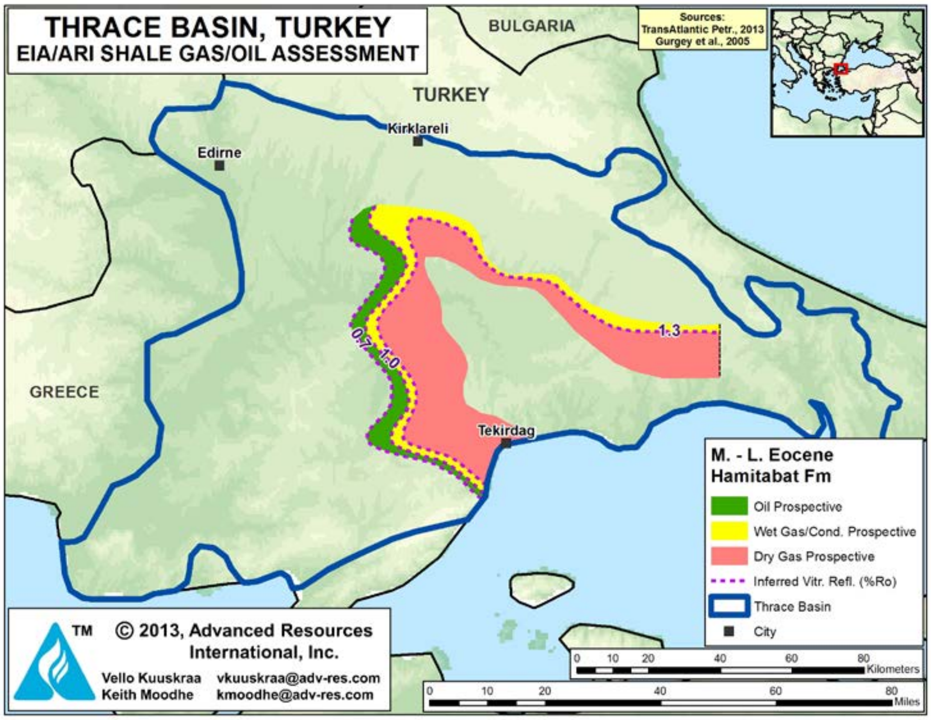
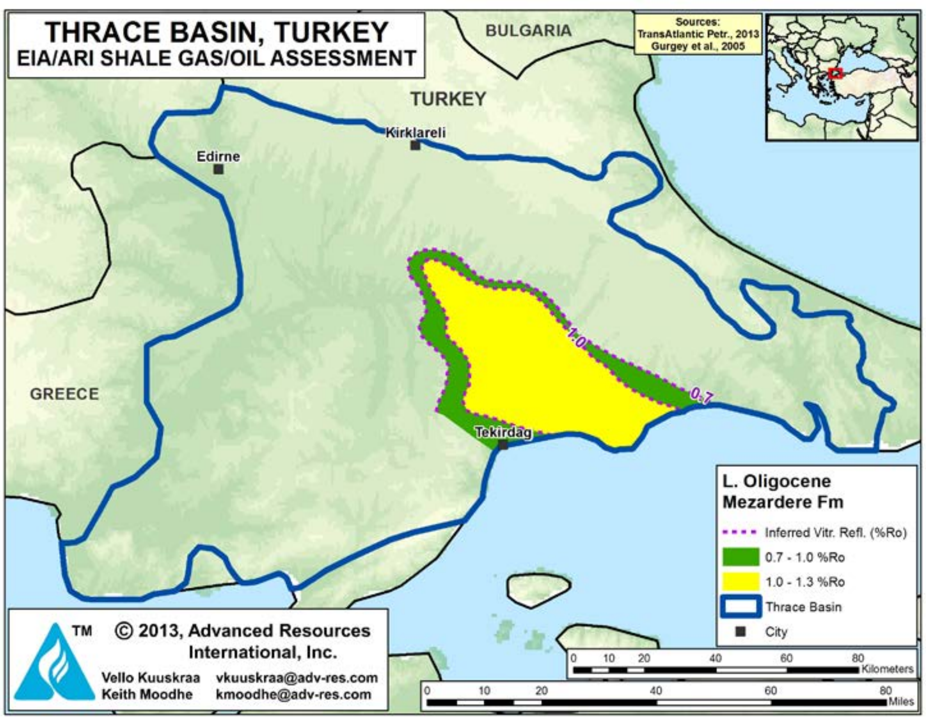
Figure XXVI-10. Hamitabat Shale Formation of the Thrace Basin, NW Turkey



Source: ARI, 2013.

Figure XXVI-11. Mezardere Shale Formation of the Thrace Basin, NW Turkey



Source: ARI, 2013.

2.3 Resource Assessment

Within their respective prospective areas, ARI calculates a dry shale gas resource concentration of 104 Bcf/mi^2, a wet shale gas resource of 82 Bcf/mi^2, and a shale oil resource concentration of 34 million barrels/mi^2 for the Hamitabat Shale.

The Hamitabat Shale contains risked shale gas in-place of 34 Tcf, with 6 Tcf as the technically recoverable shale gas resource, Table XXVI-1. The Hamitabat Shale also contains risked shale oil/condensate in-place of 2 billion barrels, with 0.1 billion barrels as the technically recoverable shale oil resource.

2.4 Recent Activity

Much of the activity in the Thrace Basin is for tight gas, particularly by TPAO and TransAtlantic Petroleum. While these companies have begun to appraise the shale gas and oil in this basin, no information has been released on shale well tests or performance.

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