Independent Statistics & Analysis
U.S. Energy Information Administration

Technically Recoverable Shale Oil and Shale Gas Resources:

Algeria

September 2015

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Contents

Executive Summary

Introduction

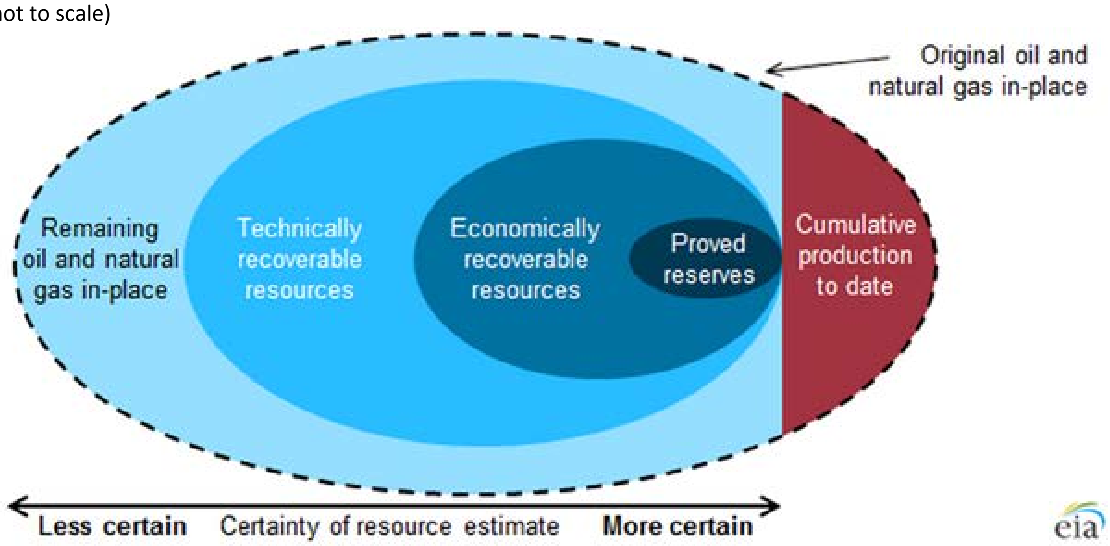
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. This chapter is from the 2013 EIA world shale report Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States.

Resource categories

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 supplement as in the 2013 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 and tight oil 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. See Figure 1.

Figure 1. Stylized representation of oil and natural gas resource categorizations

(not to scale)



Source: U.S. Energy Information Administration
Note: Resource categories are not drawn to scale relative to the actual size of each resource category. The graphic shown above is applicable only to oil and natural gas resources.

Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

For many purposes, oil and natural gas resources are usefully classified into four categories:

- Remaining oil and gas in-place (original oil and gas in-place minus cumulative production at a specific date)
- Technically recoverable resources
- Economically recoverable resources
- Proved reserves

The oil and natural gas volumes reported for each resource category are estimates based on a combination of facts and assumptions regarding the geophysical characteristics of the rocks, the fluids trapped within those rocks, the capability of extraction technologies, and the prices received and costs paid to produce oil and natural gas. The uncertainty in estimated volumes declines across the resource categories (see figure above) based on the relative mix of facts and assumptions used to create these resource estimates. Oil and gas in-place estimates are based on fewer facts and more assumptions, while proved reserves are based mostly on facts and fewer assumptions.

Remaining oil and natural gas in-place (original oil and gas in-place minus cumulative production). The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.

Technically recoverable resources. The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

The geophysical characteristics of the rock (e.g., resistance to fluid flow) and the physical properties of the hydrocarbons (e.g., viscosity) prevent oil and gas extraction technology from producing 100% of the original oil and gas in-place.

Economically recoverable resources. The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.

U.S. government agencies, including EIA, report estimates of technically recoverable resources (rather than economically recoverable resources) because any particular estimate of economically recoverable resources is tied to a specific set of prices and costs. This makes it difficult to compare estimates made by other parties using different price and cost assumptions. Also, because prices and costs can change over relatively short periods, an estimate of economically recoverable resources that is based on the prevailing prices and costs at a particular time can quickly become obsolete.

Proved reserves. The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced. Like economically recoverable resources, proved reserves shrink or grow as prices and costs change. The U.S. Securities and Exchange Commission regulates the reporting of company financial assets, including those proved oil and gas reserve assets reported by public oil and gas companies.

Each year EIA updates its report of proved U.S. oil and natural gas reserves and its estimates of unproved technically recoverable resources for shale gas, tight gas, and tight oil resources. These reserve and resource estimates are used in developing EIA's Annual Energy Outlook projections for oil and natural gas production.

- Proved oil and gas reserves are reported in EIA's U.S. Crude Oil and Natural Gas Proved Reserves.
- Unproved technically recoverable oil and gas resource estimates are reported in EIA's Assumptions report of the Annual Energy Outlook. Unproved technically recoverable oil and gas resources equal total technically recoverable resources minus the proved oil and gas reserves.

Over time, oil and natural gas resource volumes are reclassified, going from one resource category into another category, as production technology develops and markets evolve.

Additional information regarding oil and natural gas resource categorization is available from the Society of Petroleum Engineers and the United Nations.

Methodology

The shale formations assessed in this supplement as in the previous 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*[1] and *adsorbed gas*[2] 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.[3] 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[4] 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 supplement as in the previous 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 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

---

[1] 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.

[2] 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.

[3] 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.

[4] Referred to as risked recoverable resources in the consultant report.

production. In addition, several other exclusions were made for this supplement as in the previous 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 supplement as in the previous report include:

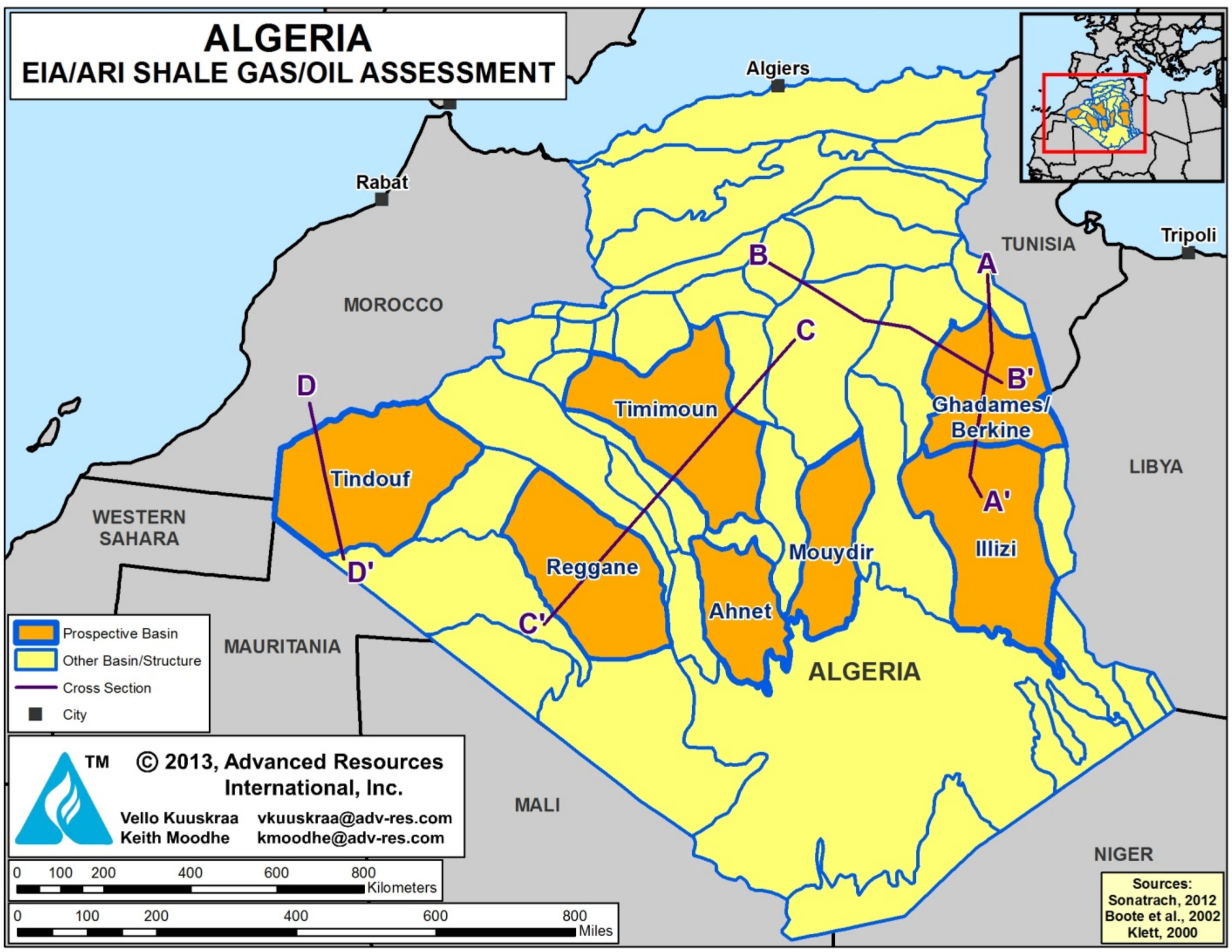
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
3. **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.
4. **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 non-shale oil and natural gas resources.
5. **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

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 (40,000 mi²)				Tindouf (77,000 mi²)	
Basic Data	Basin/Gross Area		Reggane (40,000 mi²)				Tindouf (77,000 mi²)	
	Shale Formation		Frasnian		Tannezuft		Tannezuft	
	Geologic Age		U. Devonian		Silurian		Silurian	
	Depositional Environment		Marine		Marine		Marine	
Physical Extent	Prospective Area (mi²)		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/mi²)		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 (117,000 mi²)			Illizi (44,900 mi²)	Ahnet (20,200 mi²)	Reggane (40,000 mi²)		Tindouf (77,000 mi²)
Basic Data	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 (mi²)		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/mi²)		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

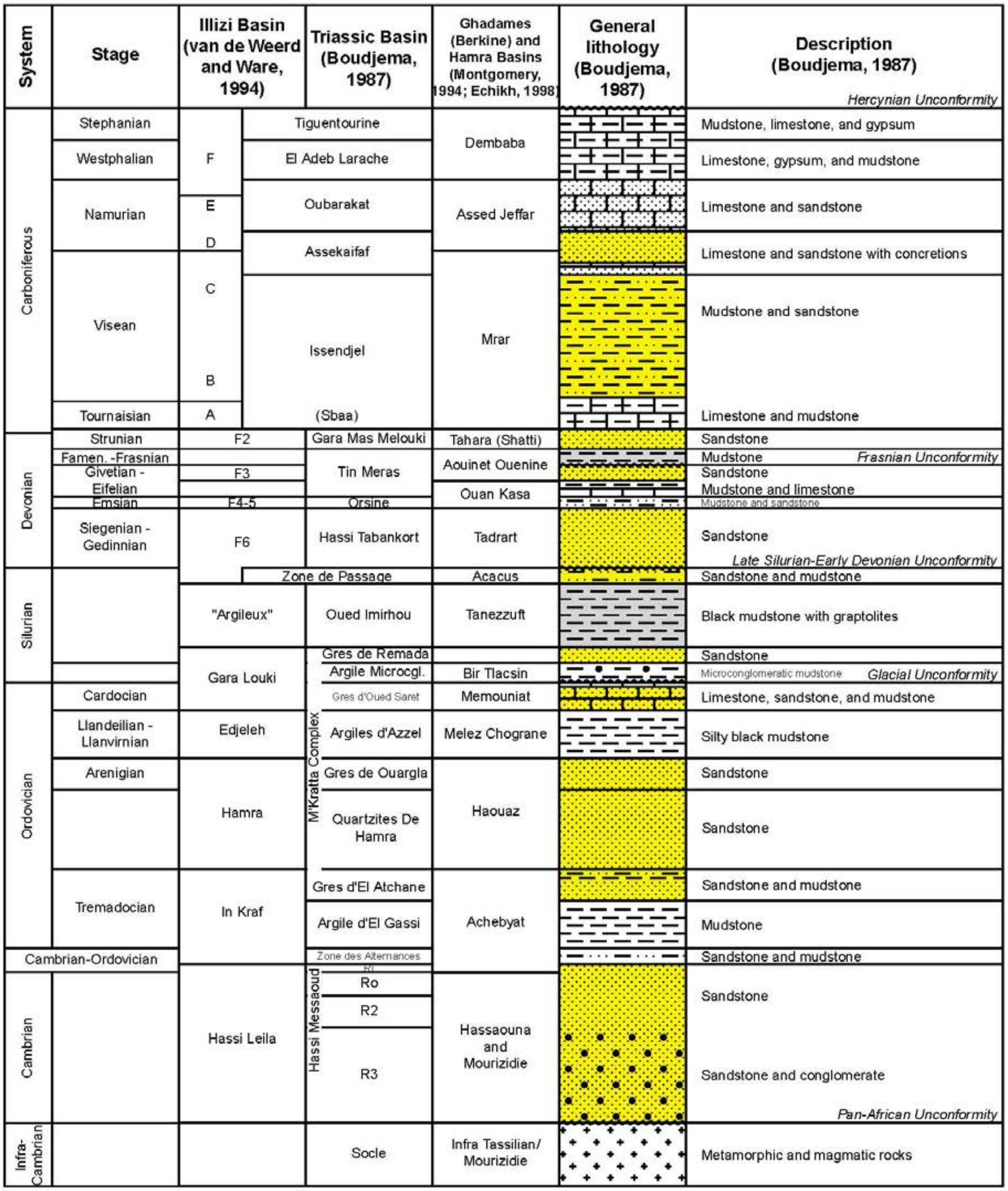
For most of Paleozoic time, North Africa (including Algeria) was a single massive depositional basin.[1] The separation and subsequent collision of Laurasia and Gondwana (the Hercynian event) established the seven individual basin outlines and uplift structures of present day Algeria.[2] Two major transgressions, 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.

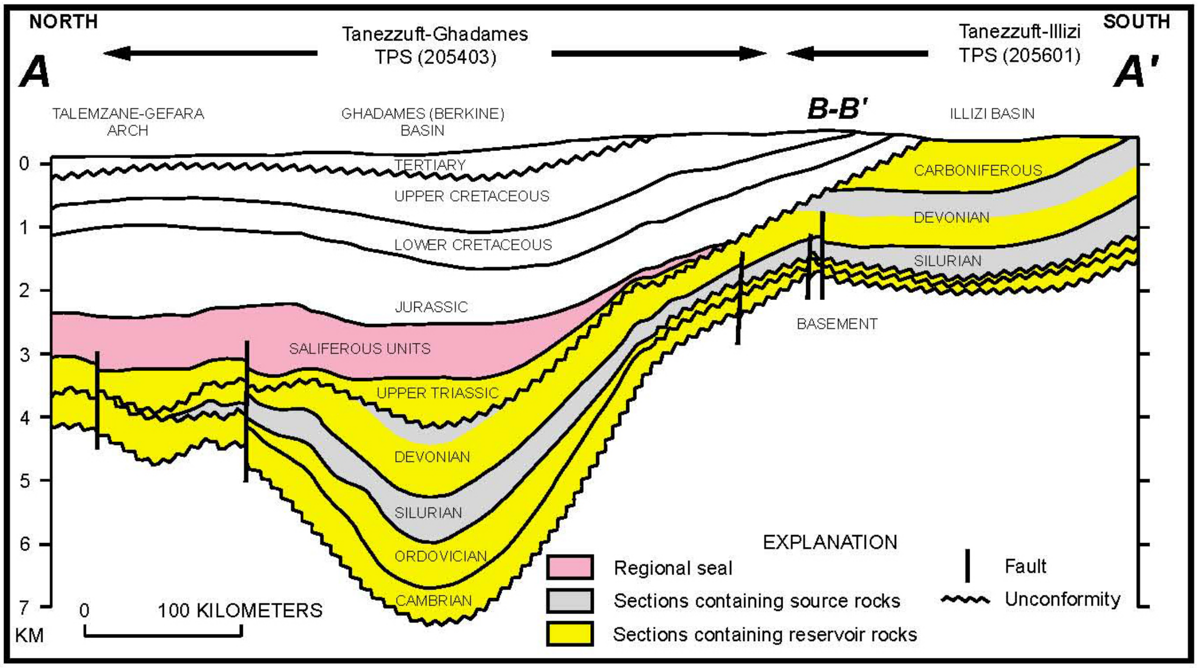
The following series of three regional cross-sections provides a useful perspective of the depositional and structural setting for six of these basins, Figures XV-3,[4] XV-4[4] and XV-5.[1] Figure XV-1(provided previously) shows the location of these three cross-sections.

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.)



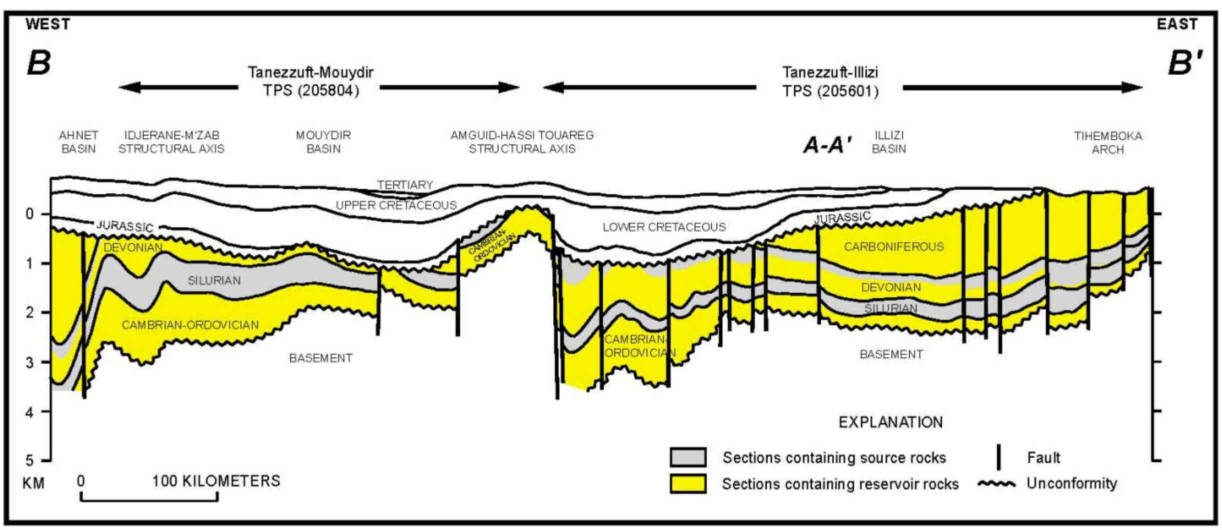
Source: Klett, 2000A.

Figure XV-3. Cross Section A-A': Ghadames (Berkline) and Illizi Basins



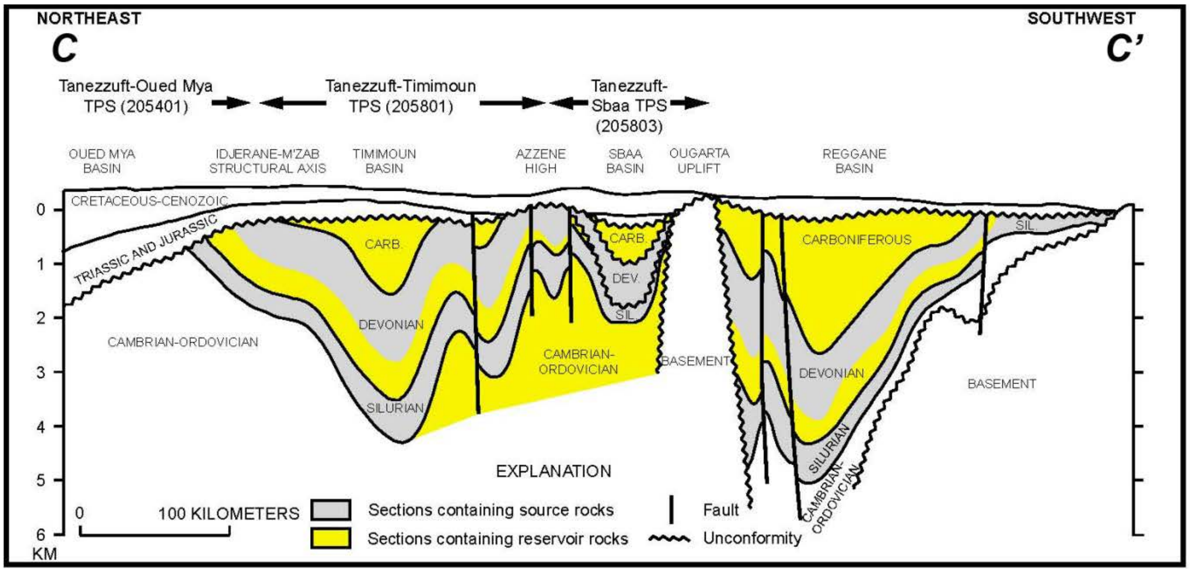
Source: Klett, 2000A.

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

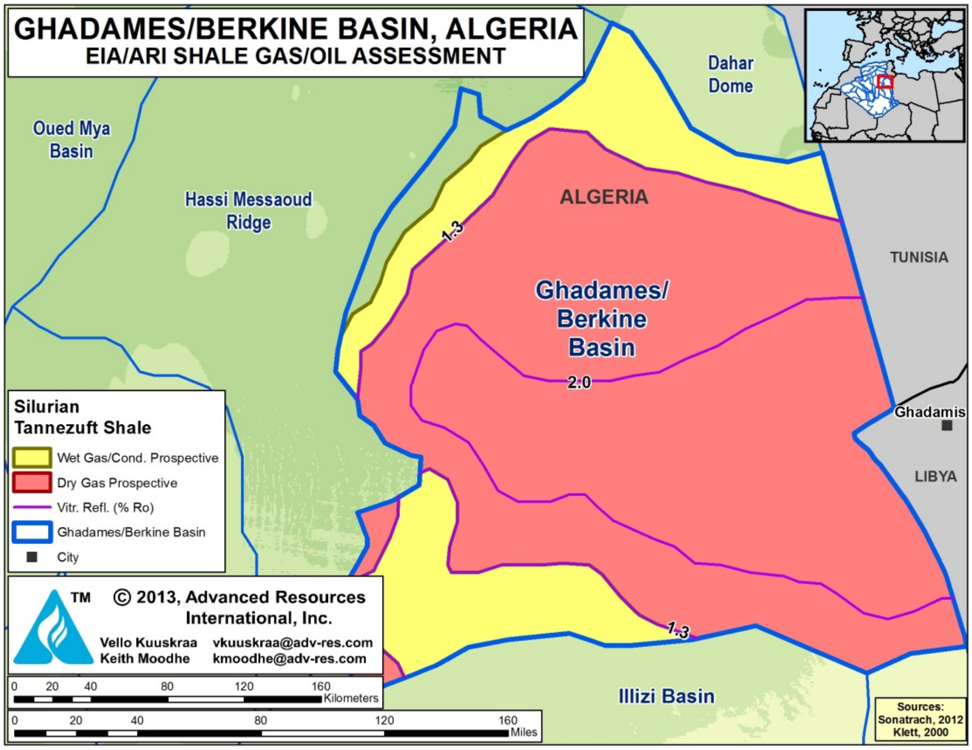
The Ghadames (Berkine) Basin is a large intra-cratonic basin underlying eastern Algeria, southern Tunisia and western Libya. The basin contains a series of reverse faults, providing structural traps for conventional oil and gas sourced from Devonian- and Silurian-age shales. The central, deep portion 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.

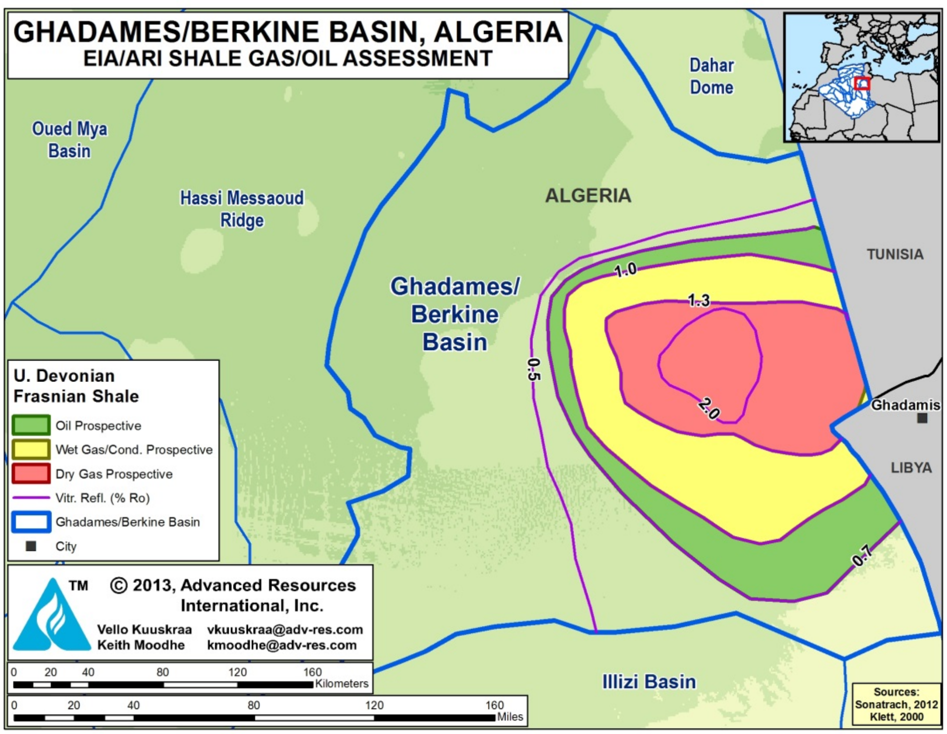
Deposited above the Tannezuft is the areally more limited and thermally less mature Upper Devonian Frasnian Shale. We have mapped a 10,040-mi^2 higher quality prospective area for the Frasnian Shale in the Ghadames Basin of Algeria. The western, northern and southern boundaries of the Frasnian Shale 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)

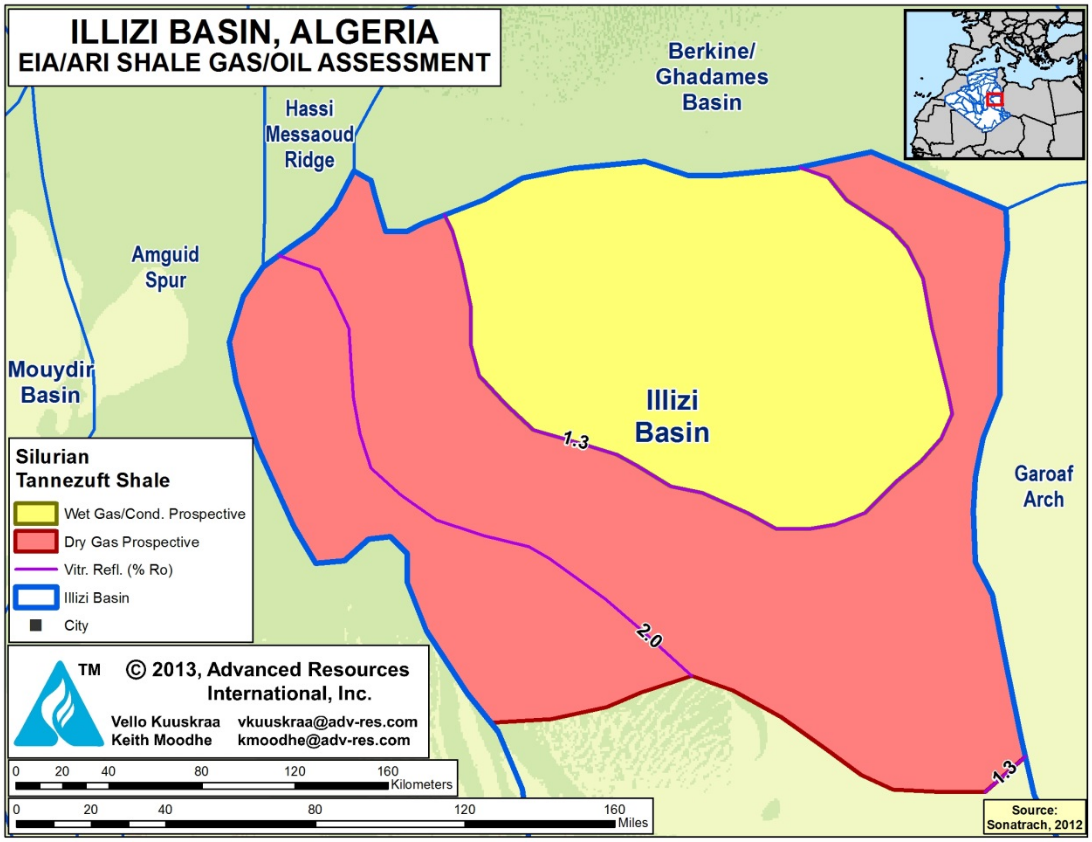
Only the Silurian Tannezuft Shale is assessed as prospective in the Illizi Basin. (The Upper Devonian Frasnian Shale in the Illizi Basin has been excluded because of insufficient thickness and low thermal maturity.) The depth of the Tannezuft Shale ranges from 3,000 to 8,000 ft, averaging 5,000 ft in 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.

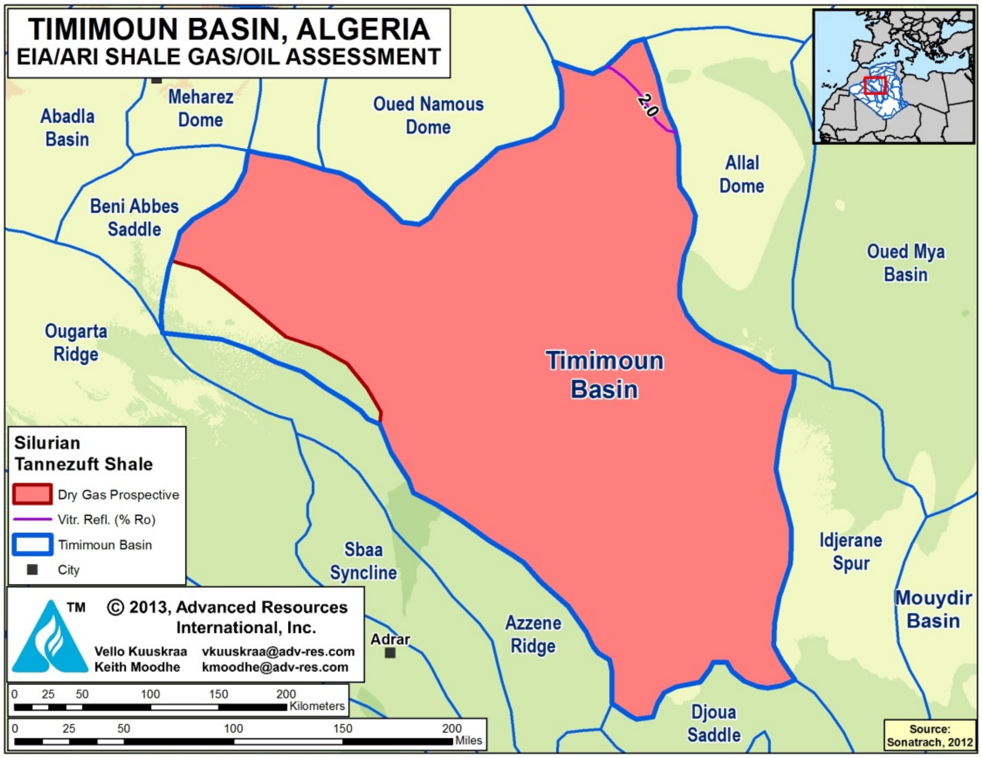
We mapped a 41,670-mi^2 dry gas prospective area for the Tannezuft Shale that covers essentially all of the Timimoun Basin, excluding a small area along the north-western portion of the basin where the Silurian is absent, Figure XV-9. In addition, we mapped a 32,040-mi^2 Frasnian Shale dry gas prospective 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.

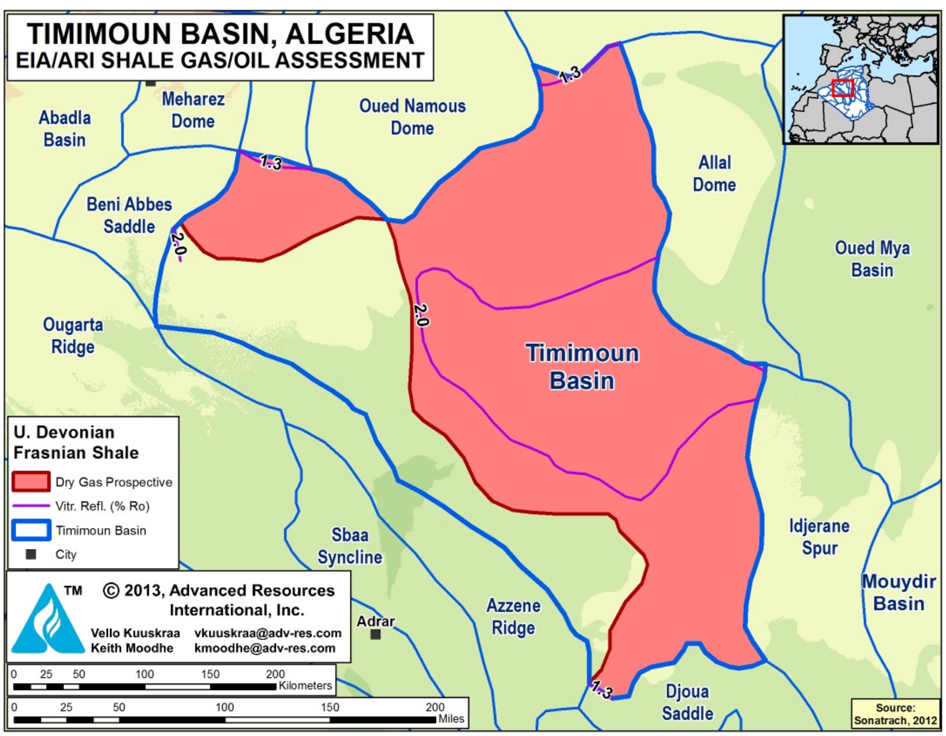
Upper Devonian Frasnian Formation. The depth of the dry gas prospective area of the Upper Devonian Frasnian Shale in the Timimoun Basin ranges from about 3,300 ft along the basin edge to about 9,000 ft in the basin center, averaging 6,000 ft. The thickness of the gross shale interval is 200 ft, with 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.

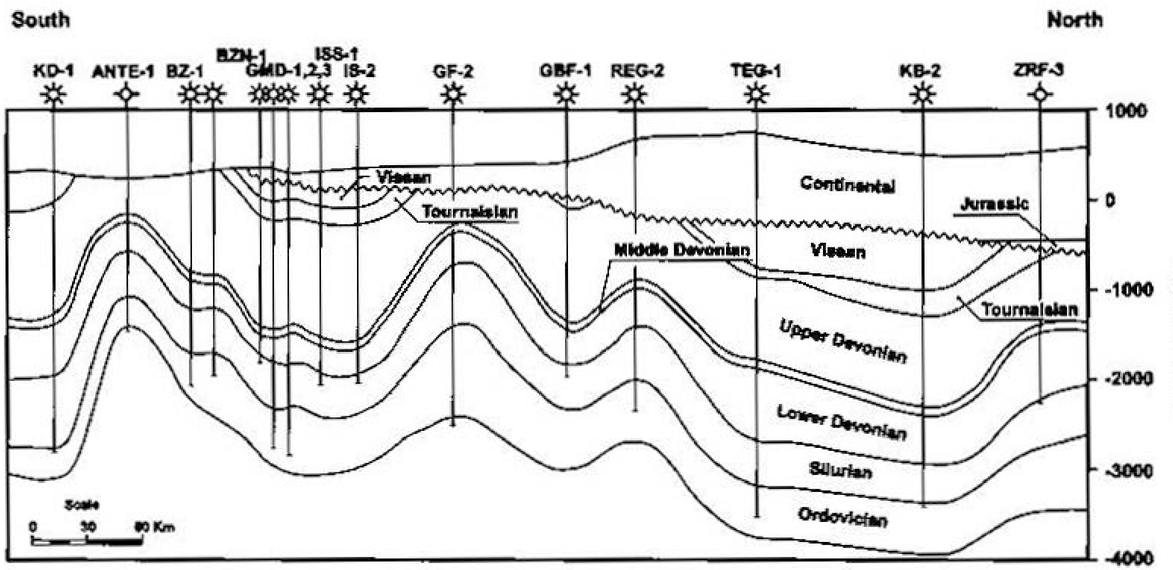
Upper Devonian Frasnian Shale. The Frasnian Shale, within the 32,040-mi^2 dry gas prospective area of the Timimoun Basin, has a resource concentration of 73 Bcf/mi^2. The risked shale gas resource in-place in the prospective area is 467 Tcf, with 93 Tcf as the risked, technically recoverable shale gas resource.

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]

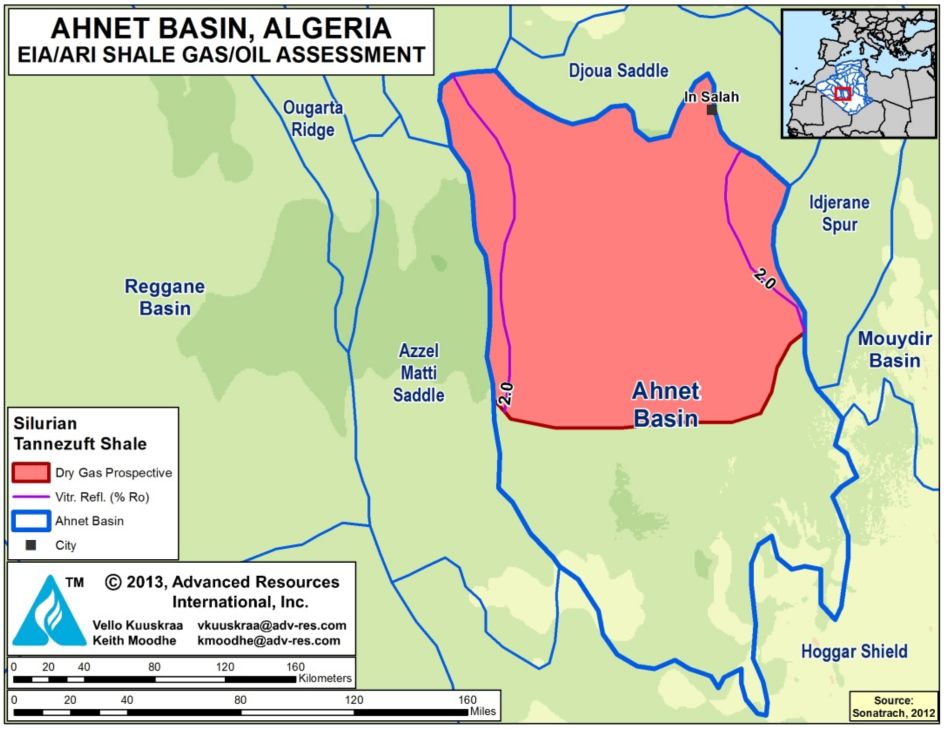
Figure XV-11. Schematic Cross Section of the Ahnet Basin, Algeria



Source: Logan, P. and Duddy, I., 1998.

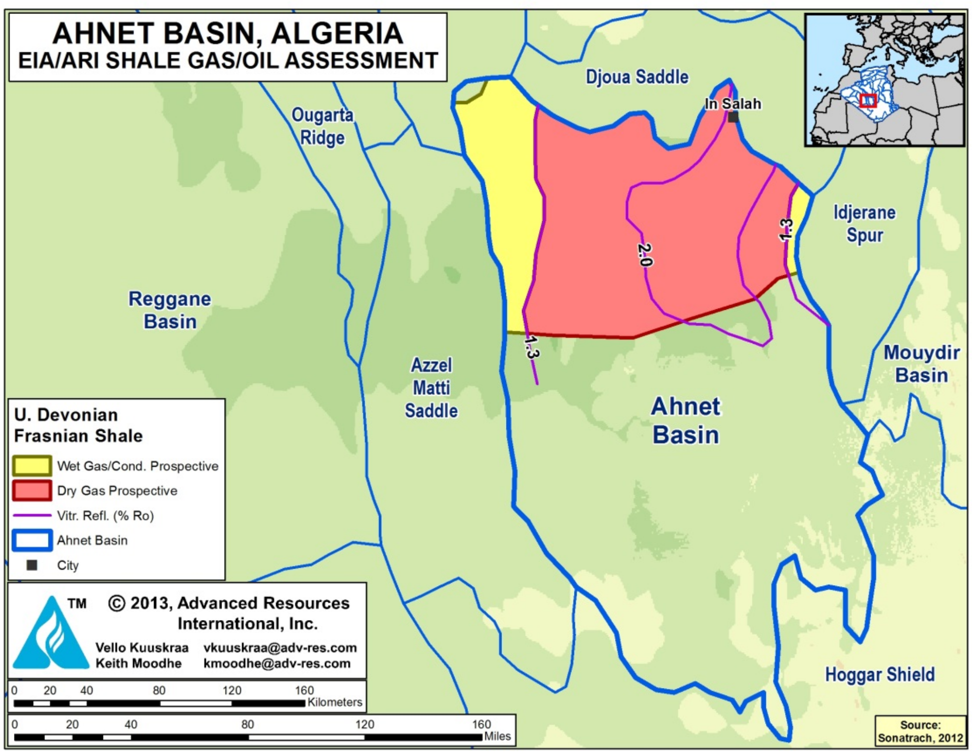
The Ahnet Basin contains the Silurian Tannezuft and Upper Devonian Frasnian formations and their organic-rich shale intervals. In some portions of the basin, the Paleozoic section was eroded during Hercynian deformation. However, up to 4 km of Paleozoic deposits remain intact in the center of the basin.[9] 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.

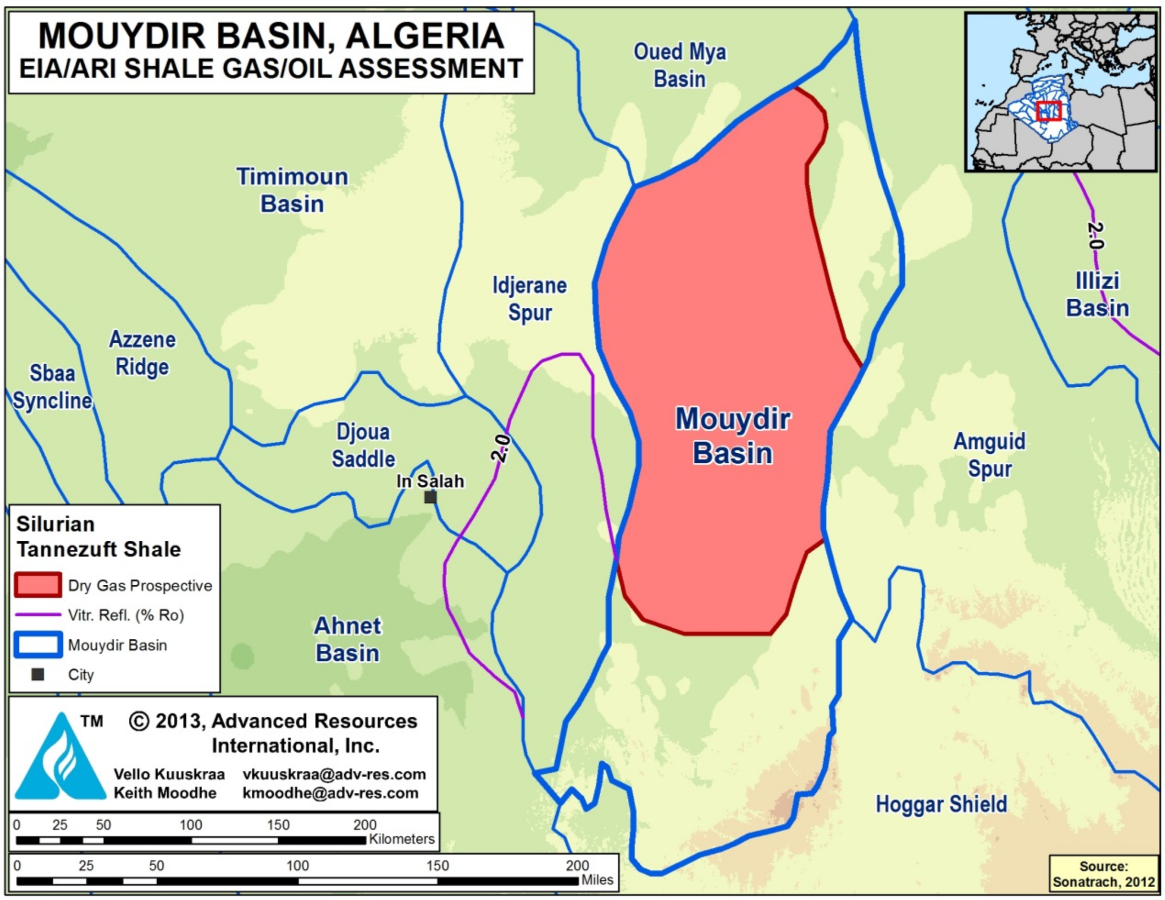
5. MOUYDIR BASIN

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.

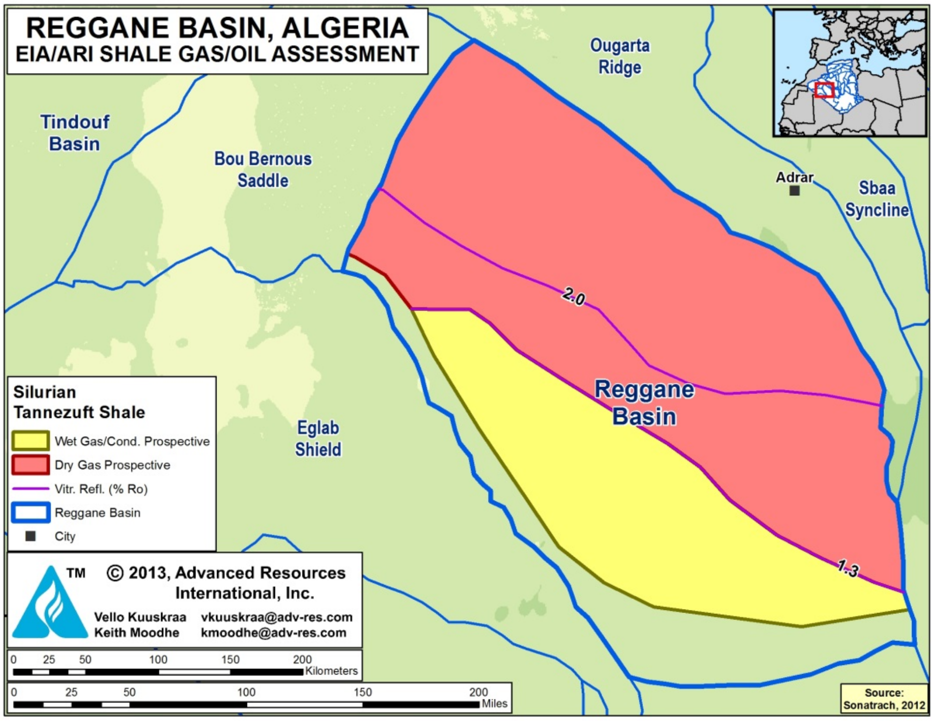
We have mapped prospective areas of 34,750 mi^2 for the Silurian Tannezuft Shale and 4,680 mi^2 for the Upper Devonian Frasnian Shale in the eastern portions of the Reggane Basin, Figures XV-16 and XV-17.

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]

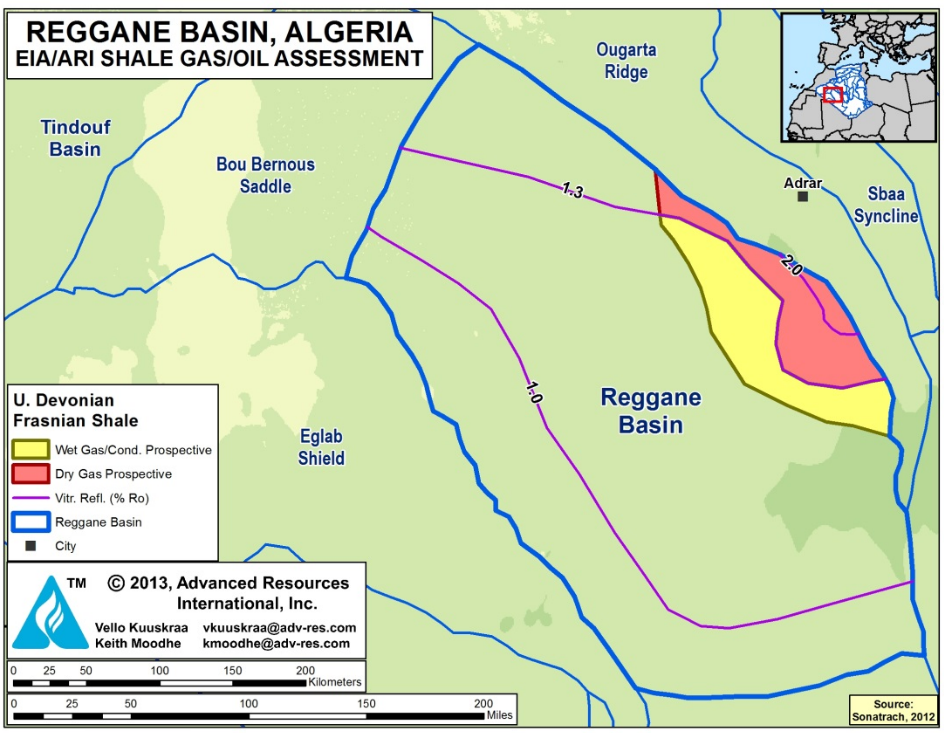
Upper Devonian Frasnian Formation. The depth of the shallower Upper Devonian Frasnian Shale in the Reggane Basin ranges from 5,500 ft to 16,000 ft, averaging about 10,500 ft in the prospective area, with the wet gas/condensate area shallower and the dry gas area somewhat deeper.[9] The thickness of the 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



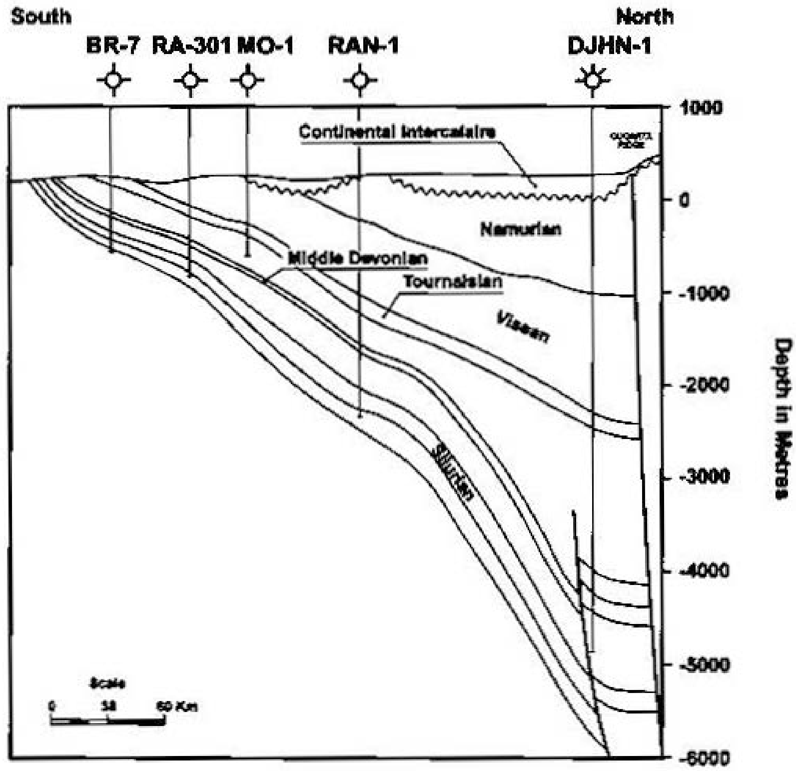
Source: ARI, 2013.

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.

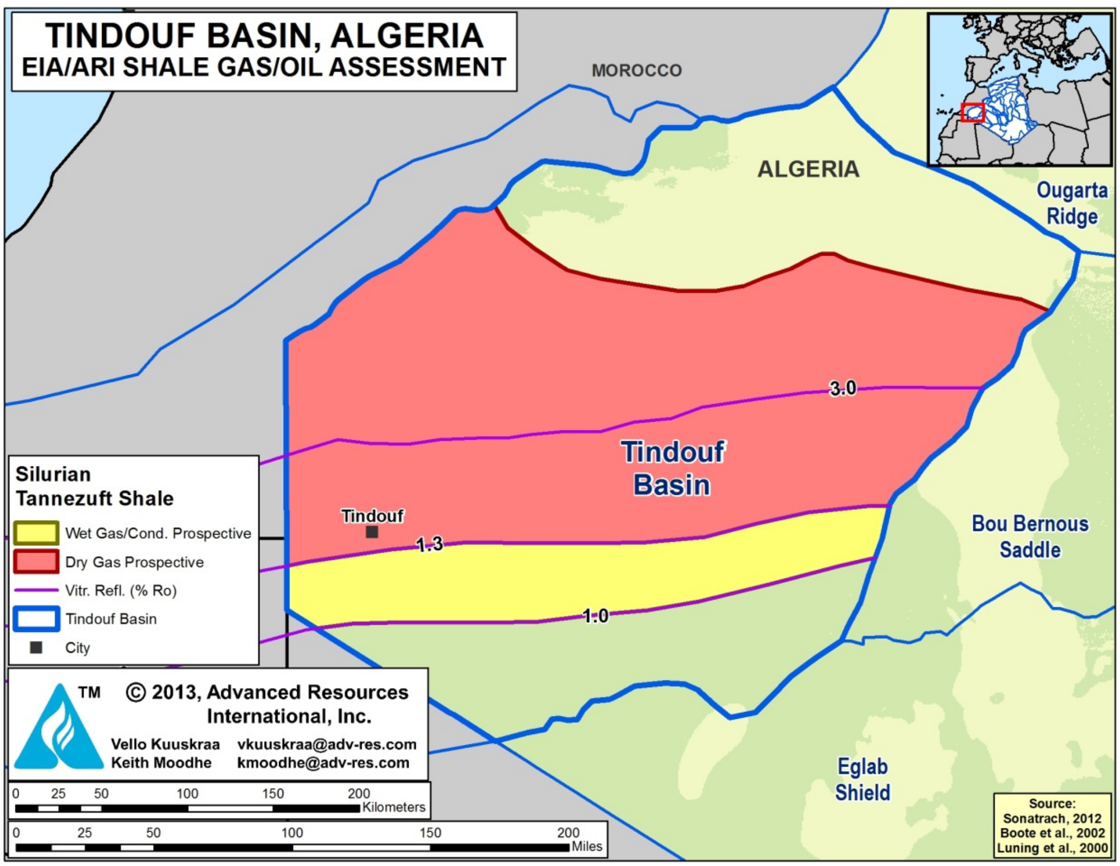
7. TINDOUF BASIN

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

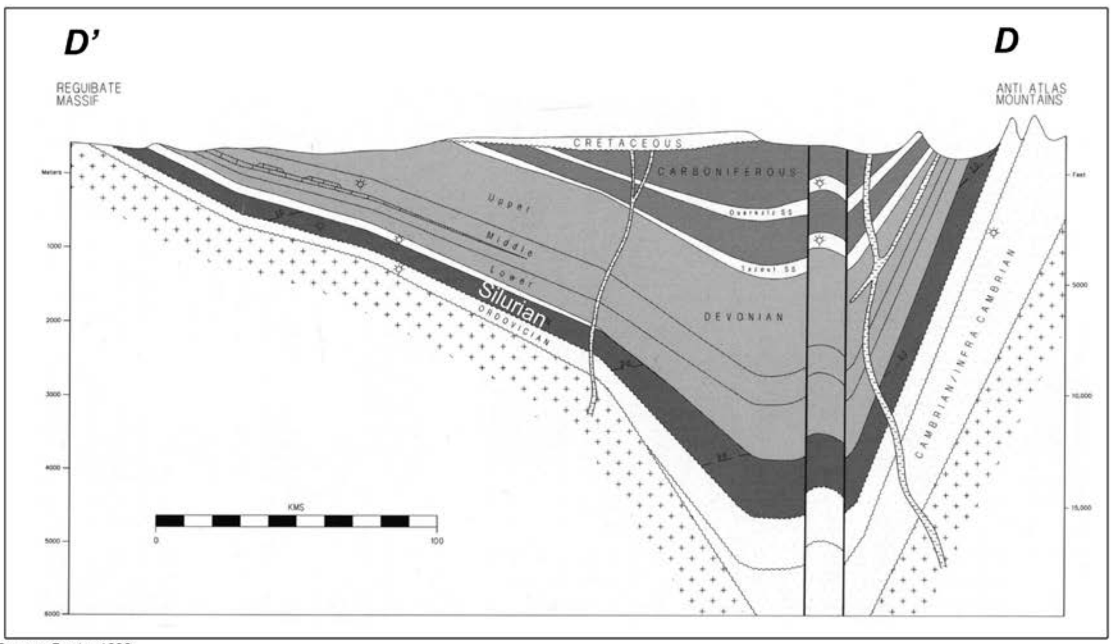


Source: ARI, 2013.

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.

REFERENCES

[1] Klett, T.R., 2000. "Total Petroleum Systems of the Grand Erg/Ahnet Province, Algeria and Morocco—The Tanezzuft-Timimoun, Tanezzuft-Ahnet, Tanezzuft-Sbaa, Tanezzuft-Mouydir, Tanezzuft-Benoud, and Tanezzuft-Béchar/Abadla." U.S. Geological Survey Bulletin 2202-B.

[2] Peterson, J.A., 1985. "Geology and Petroleum Resources of North-Central and Northeastern Africa." U.S. Geological Survey Open-File Report 85-709, 54 p.

[3] Aliev, M. et al., 1971. "Geological Structures and Estimation of Oil and Gas in the Sahara in Algeria: Spain." Altamira-Rotopress, S.A., 265 p.

[4] Klett, T.R., 2000. "Total Petroleum Systems of the Illizi Province, Algeria and Libya—Tanezzuft-Illizi." U.S. Geological Survey Bulletin 2202–A.

[5] Boudjema, A., 1987. "Evolution Structurale du Bassin Petrolier «Triasique» du Sahara Nord Oriental (Algerie)." Thèse a l'Université de Paris-Sud, Centre d'Orsay, 290 p.

[6] Daniels, R.P., and Emme, J.J., 1995. "Petroleum System Model, Eastern Algeria, from Source Rock to Accumulation; When, Where, and How?" Proceedings of the Seminar on Source Rocks and Hydrocarbon Habitat in Tunisia; Entreprise Tunisienne d'Activités Petrolieres Memoir 9, p. 101–124.

[7] Yahi, N., Schaefer, R.G., and Littke, R., 2001. "Petroleum Generation and Accumulation in the Berkine Basin, Eastern Algeria." American Association of Petroleum Geologists, Bulletin, vol. 85, no. 8, p. 1439-1467.

[8] Acheche, M.H., M'Rabet, A., Ghariani, H., Ouahchi, A., and Montgomery, S.L., 2001. "Ghadames Basin, Southern Tunisia: A Reappraisal of Triassic Reservoirs and Future Prospectivity." American Association of Petroleum Geologists, Bulletin, vol. 85, no. 5, p. 765-780.

[9] Logan, P. and Duddy, I., 1998. "An Investigation of the Thermal History of the Ahnet and Reggane Basins, Central Algeria, and the Consequences for Hydrocarbon Generation and Accumulation." In: Macgregor, D.S., Moody, R.T.J. and Clark-Lowes, D.D. (eds.), 1998, Petroleum, Geology of North Africa. Geological Society, London, Special Publication No. 132, 131-155.

[10] Rahmani, A., Kaced, M. and Arab, M., 2012. "The Potential of Shale Gas Plays in Algeria." Sonatrach Amont/International Gas Union Shale Gas Workshop, Oran, Algeria, February.

[11] Kaddour , A. 2012. "Shale Gas Development in Algeria: Possible Synergy with Conventionals." Shale Gas Workshop 27- 28 February, Oran.

[12] Belhameche, F. and Saadallah, N., 2007. "Hydrocarbons Potential of the Tindouf Basin (Algeria)." SONATRACH EXPLORATION, Boumerdes, Algeria, AAPG Search and Discovery Article #90072, American Association of Petroleum Geologists, European Region Conference, Athens, Greece.

[13] Boote, D. R. D., Clark-Lowes, D.D., and Traut, M.W., 1998. "Palaeozoic Petroleum Systems of North Africa." Geological Society, London, Special Publications 132, no. 1, p. 7-68.