Independent Statistics & Analysis
U.S. Energy Information Administration

Technically Recoverable Shale Oil and Shale Gas Resources:

Libya

September 2015

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Executive Summary

Introduction

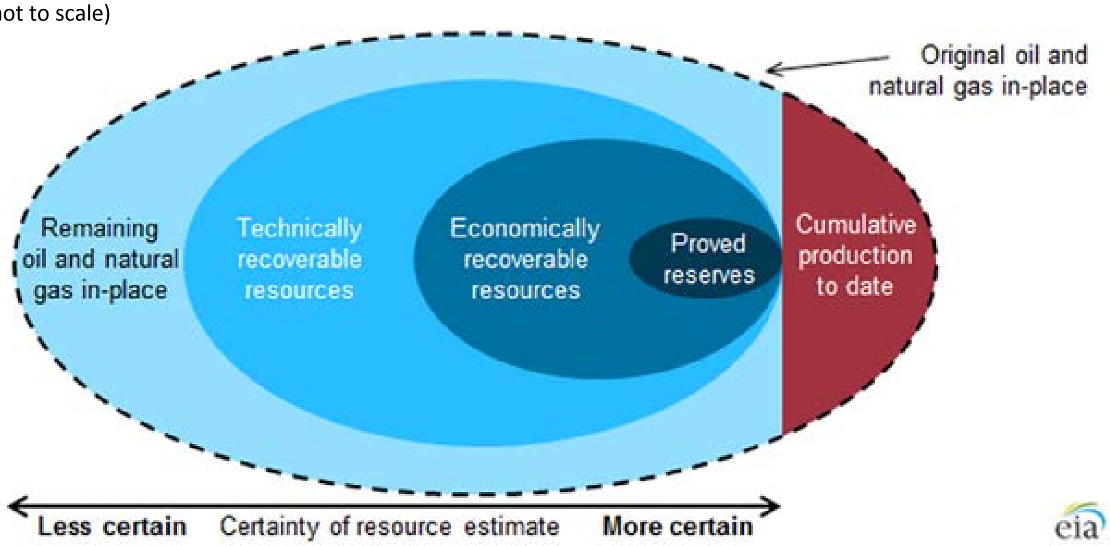
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically 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

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[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:

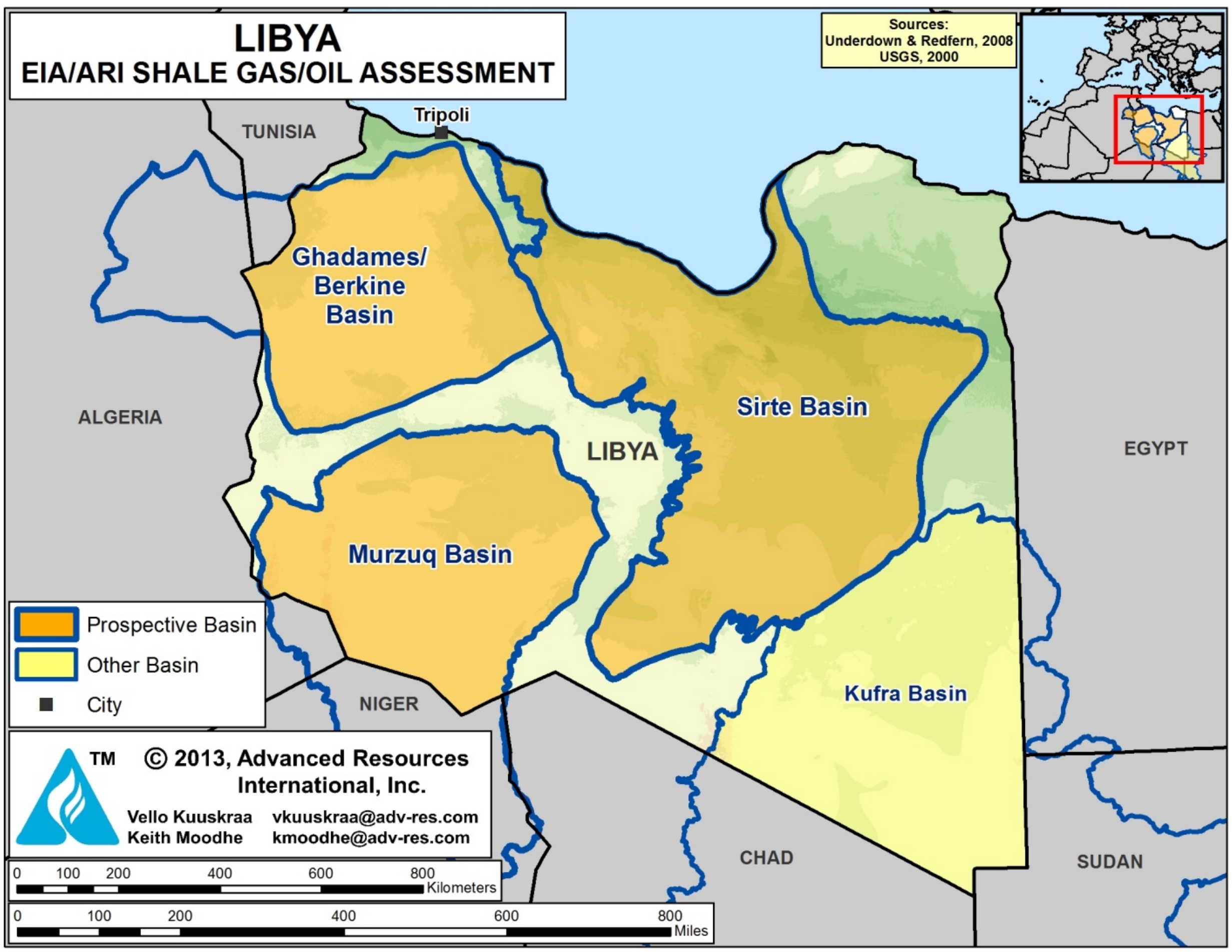
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas 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.

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.

Basic Data	Basin/Gross Area		Ghadames (117,000 mi²)			
	Shale Formation		Tannezuft		Frasnian	
	Geologic Age		L. Silurian		U. Devonian	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi²)		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/mi²)		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 mi²)		Murzuq (97,000 mi²)
	Shale Formation		Sirte/Rachmat	Etel Fm	Tannezuft
	Geologic Age		U. Cretaceous	U. Cretaceous	L. Silurian
	Depositional Environment		Marine	Marine	Marine
Physical Extent	Prospective Area (mi²)		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/mi²)		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

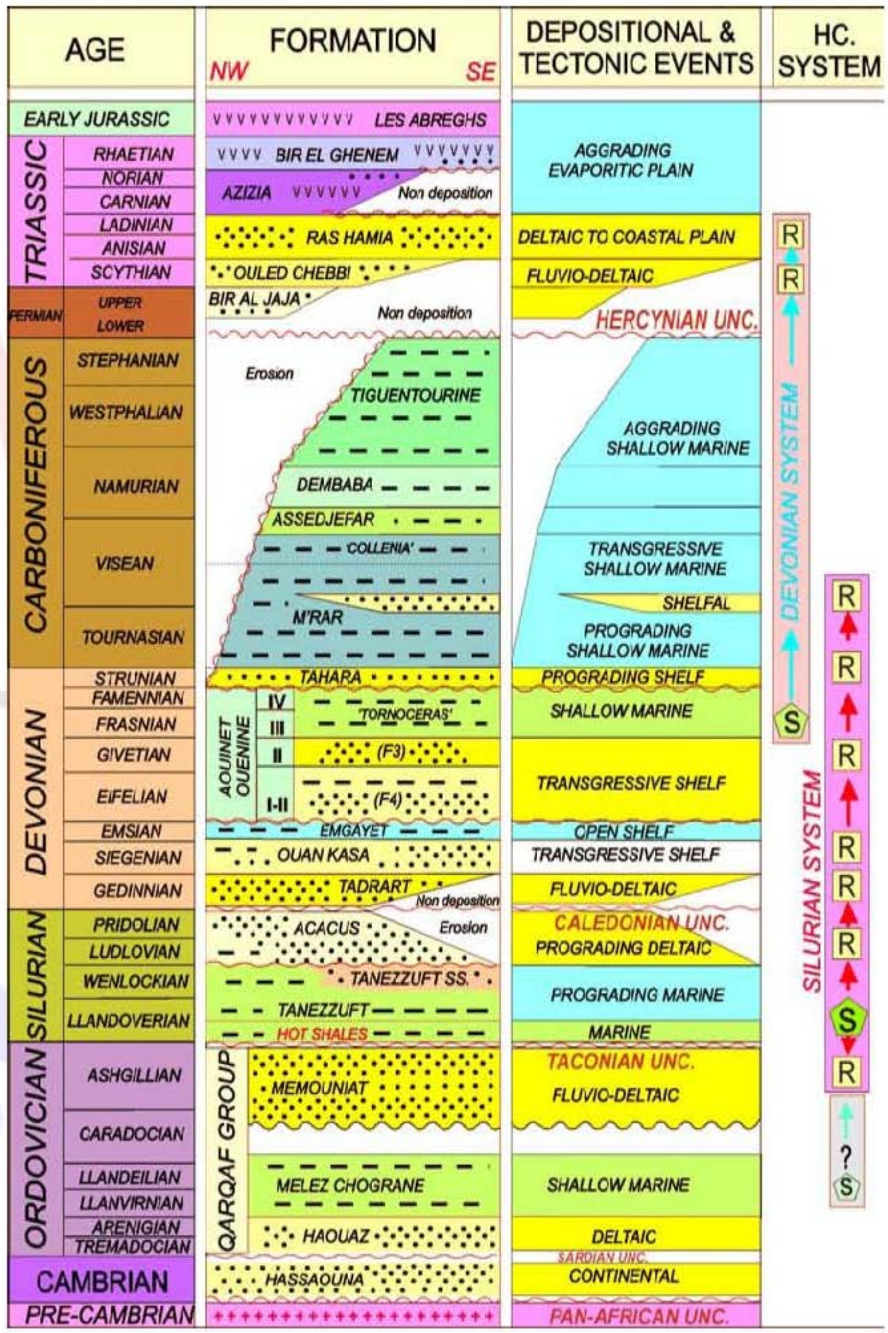
The Ghadames (Berkine) Basin is a large intra-cratonic basin underlying eastern Algeria and southern Tunisia. It encompasses an 84,000-mi^2 area in northwestern Libya and hosts two significant shale formations, the Lower Silurian Tannezuft and the Upper Devonian Frasnian, Figure XVII-2.[1]

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.

Figure XVII-2. Ghadames Basin Stratigraphic Column



Source: Seddiq Hussein, 2004.

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]

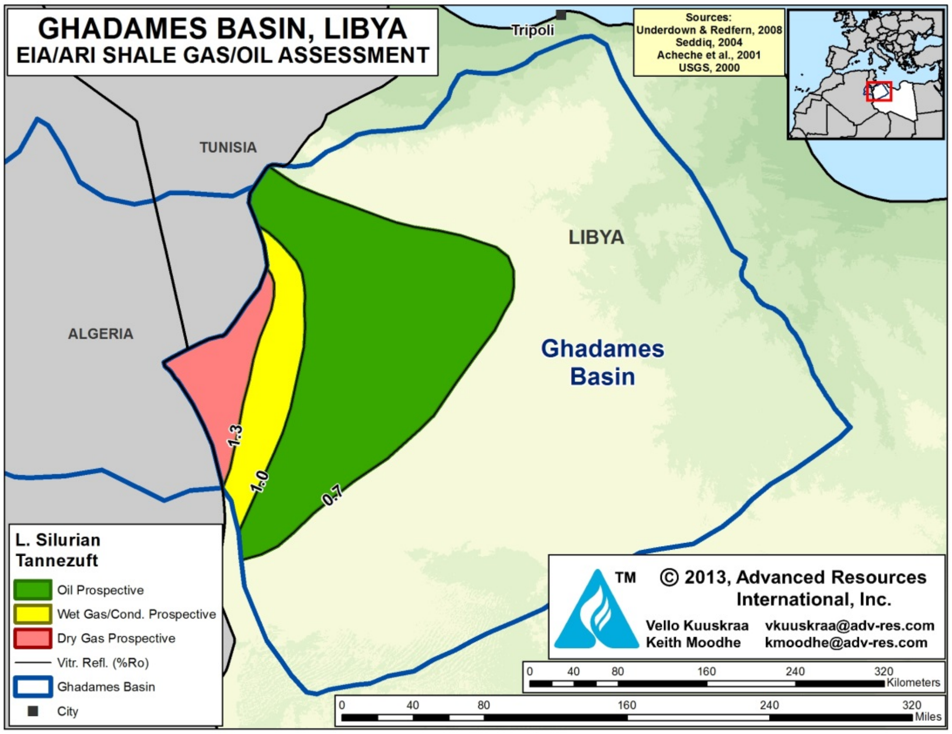
Upper Devonian Frasnian Formation. The depth of the prospective area of the overlying Upper Devonian Frasnian Shale in the Ghadames (Berkine) Basin of Libya ranges from 8,000 to 12,000 ft, averaging 8,500 ft in the oil-prone area; 9,500 ft in the wet gas/condensate area; and 11,500 ft in the dry gas 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.

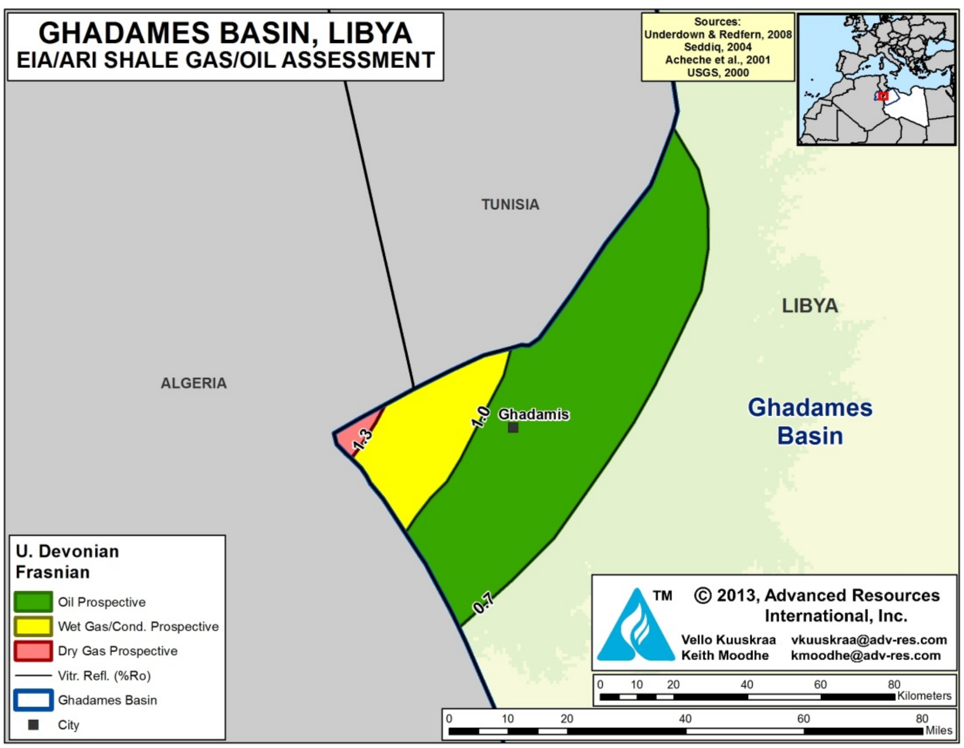
The risked resource in-place for the prospective areas of the Tannezuft Shale is 104 billion barrels of shale oil/condensate and 240 Tcf of wet and dry shale gas. Given concerns with presence of clays but otherwise favorable reservoir properties, we estimate a risked, technically recoverable shale oil/condensate 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.

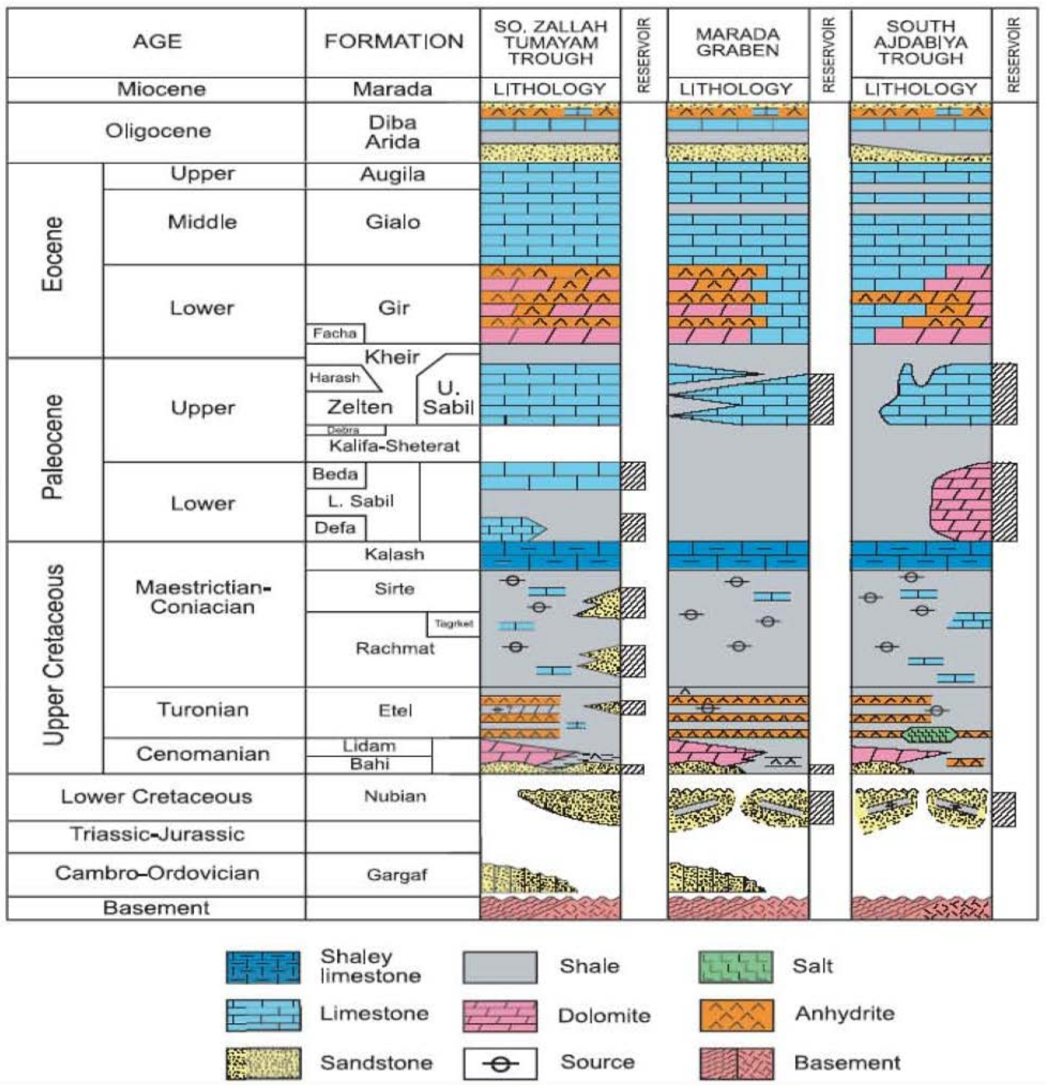
The risked resource in-place for the prospective areas is 23 billion barrels of oil/condensate and 33 Tcf of wet/dry shale gas, with risked, recoverable shale oil of 1.2 billion barrels and 4 Tcf of wet/dry shale gas.

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

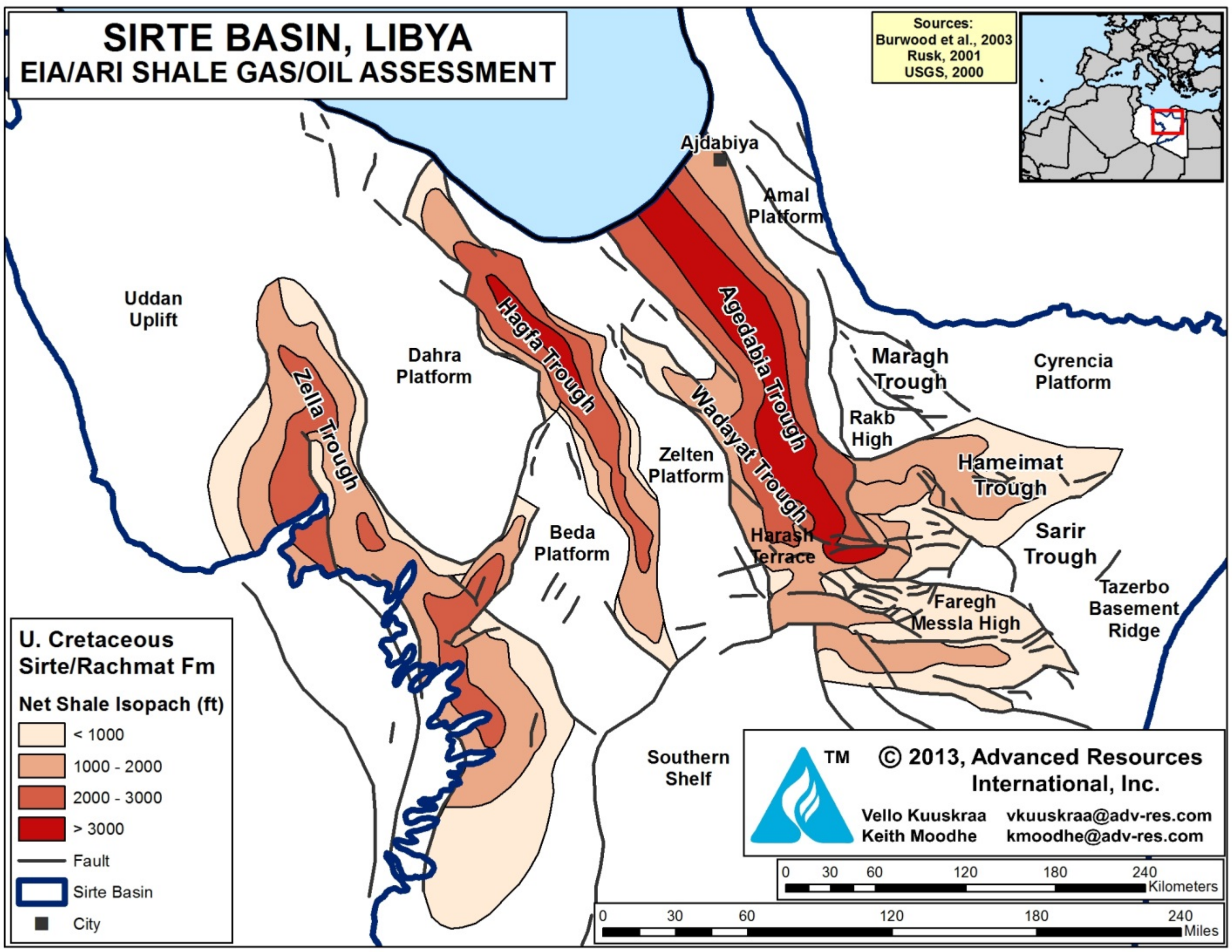


Source: Seddiq Hussein, 2004

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

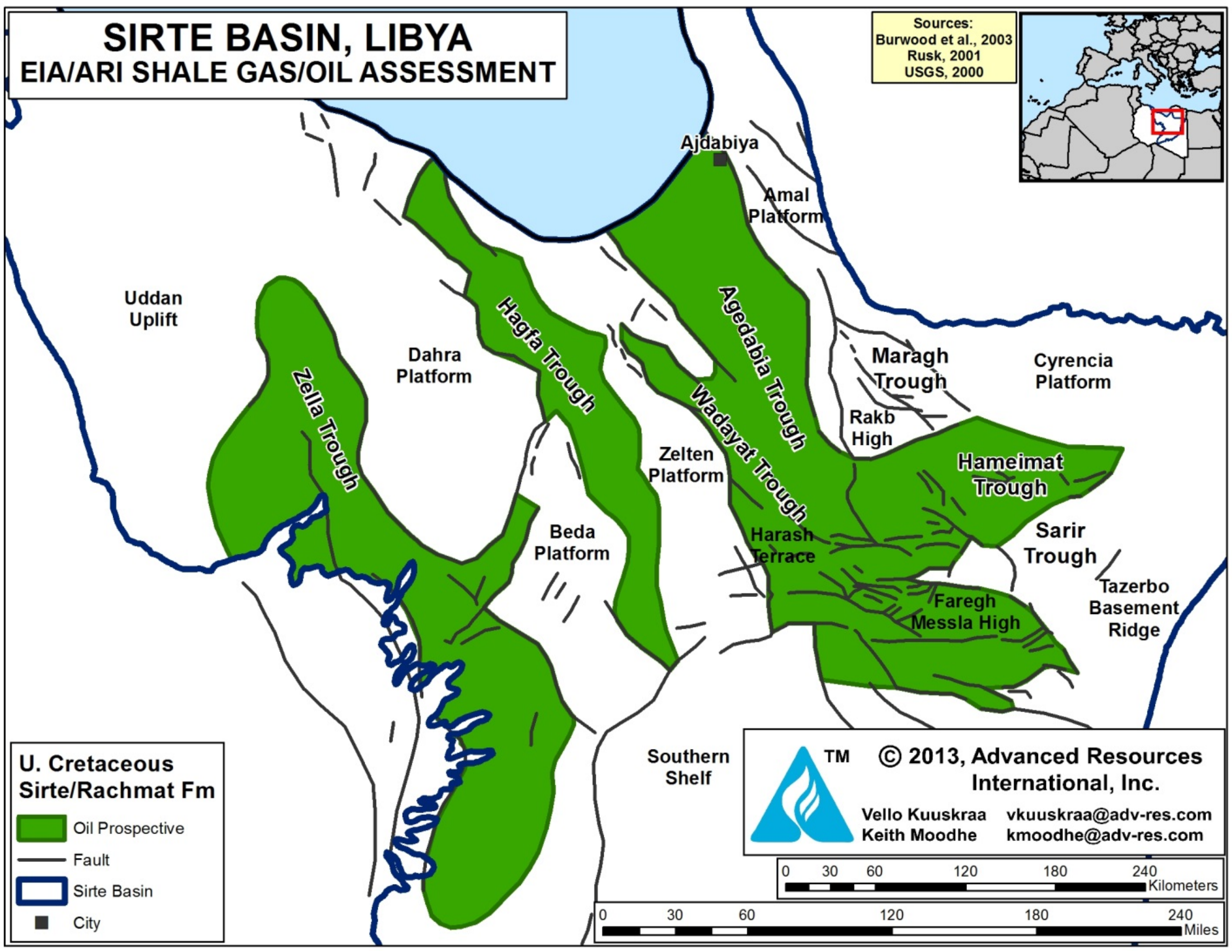


Source: ARI, 2013

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%).

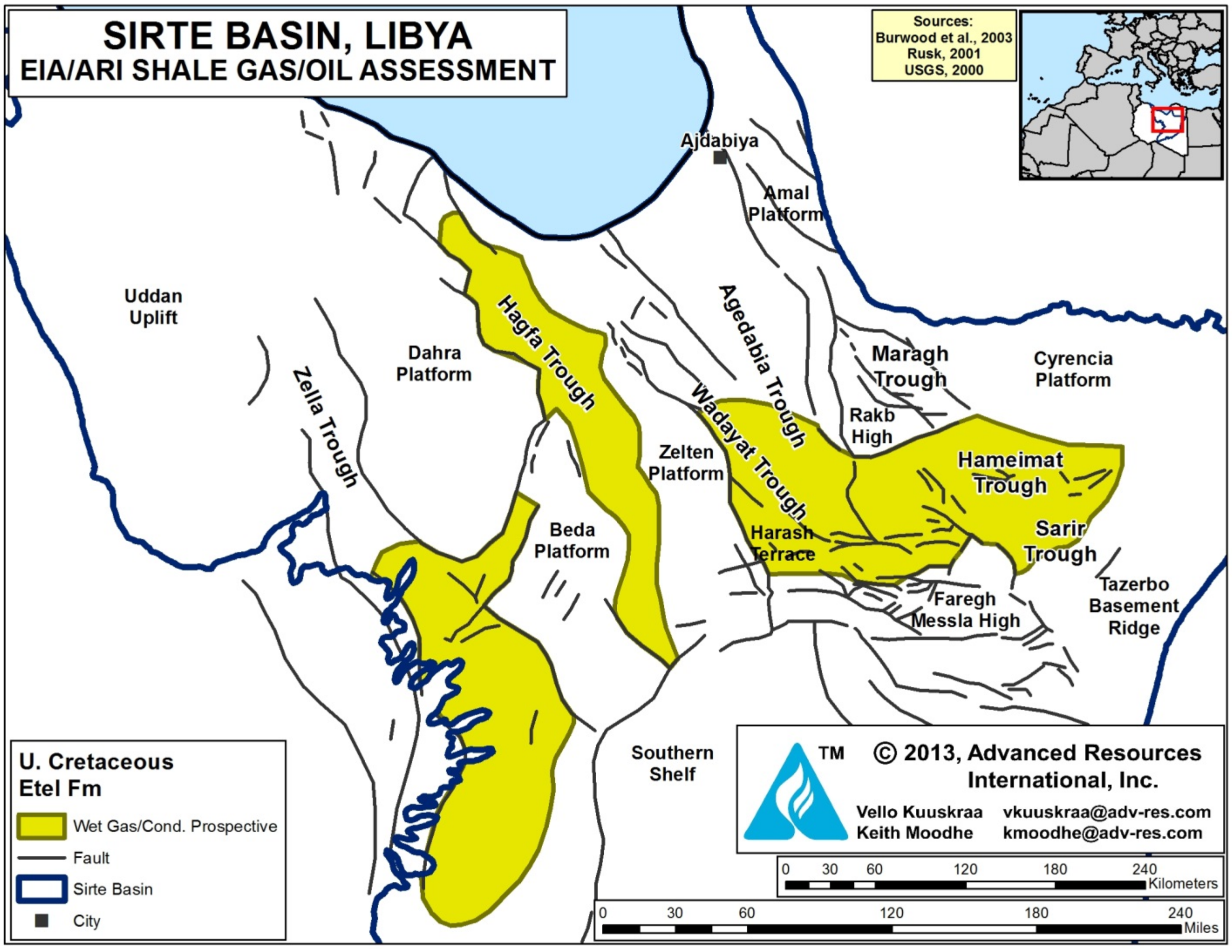
Figure XVII-7. Sirte Basin, Sirte/Rachmat Shale Prospective Area



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.

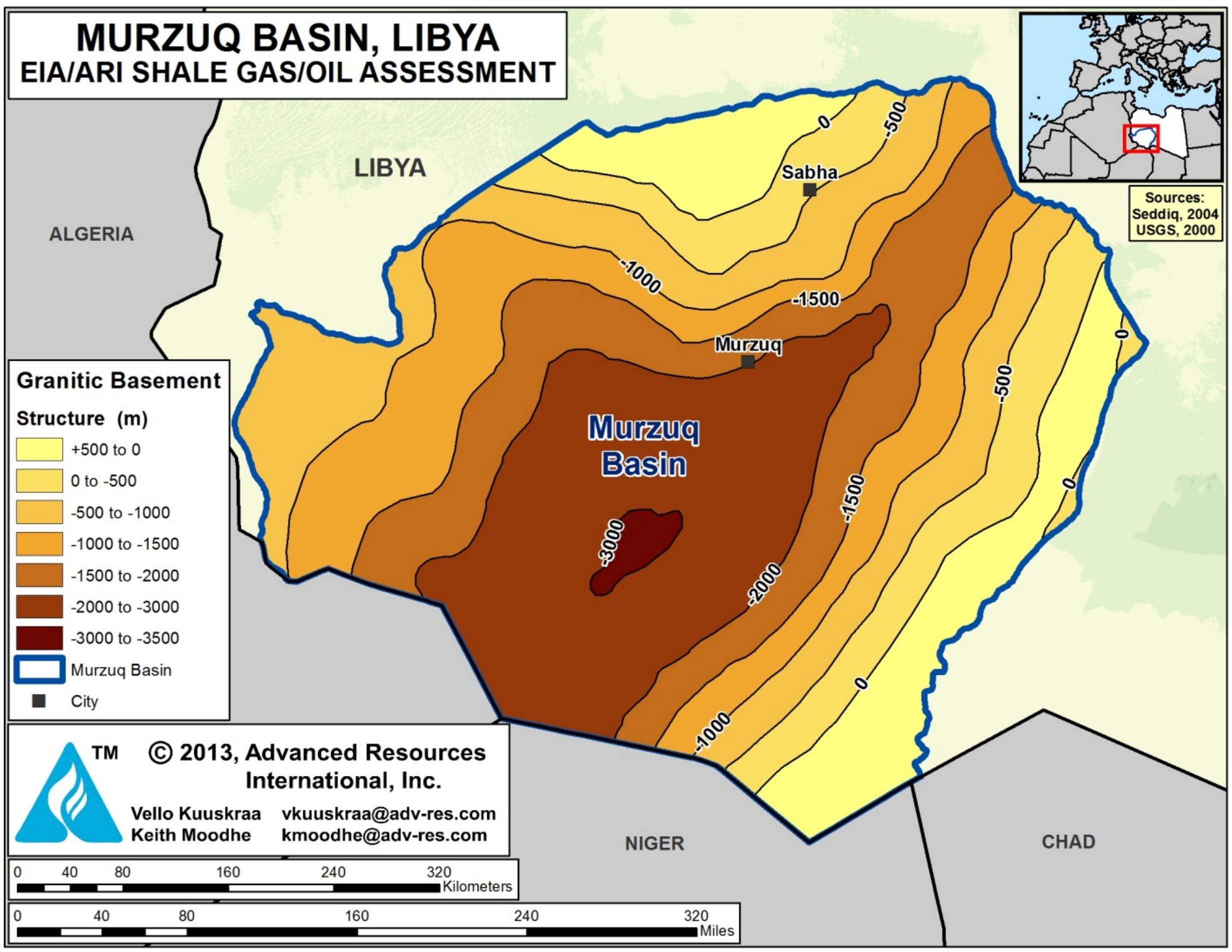
Etel Shale. The Upper Cretaceous Etel Shale has a prospective area of 19,920 mi^2 for wet gas and condensate. The Etel Shale has resource concentrations of 6 million barrels of oil and 37 Bcf of wet gas per square mile. With risked resources in-place of 51 billion barrels of oil/condensate and 298 Tcf 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.

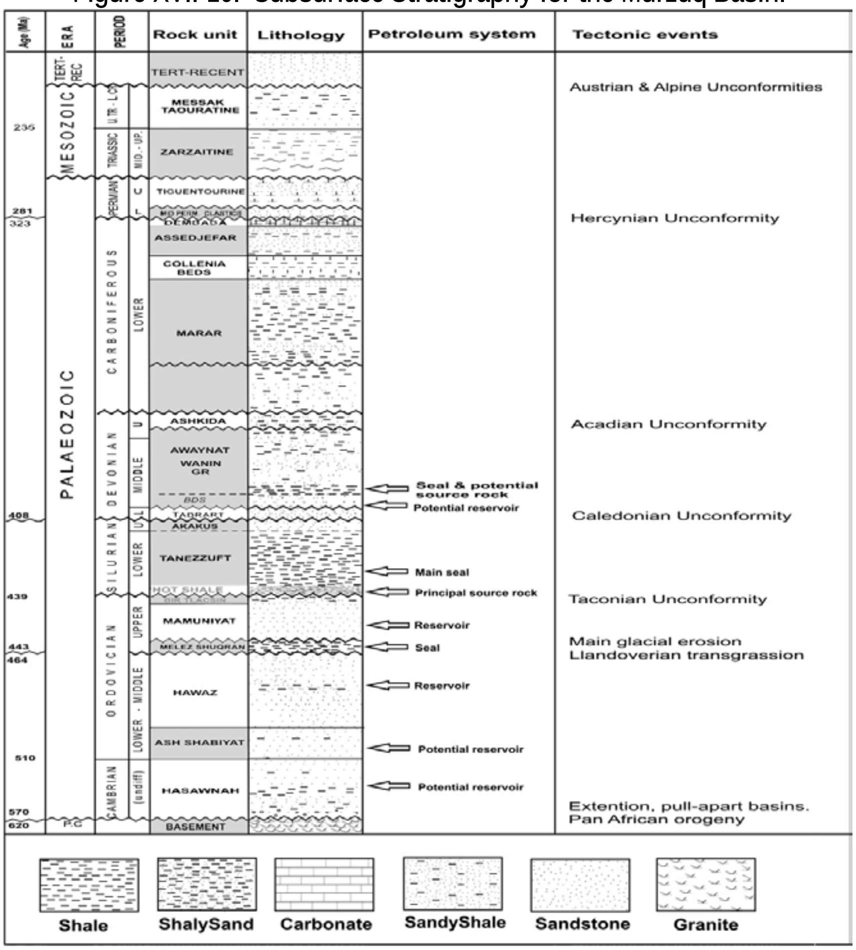
Figure XVII-9. Basin Outline and Structural Contour Map (Granitic Basement) for the Murzuq Basin



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.

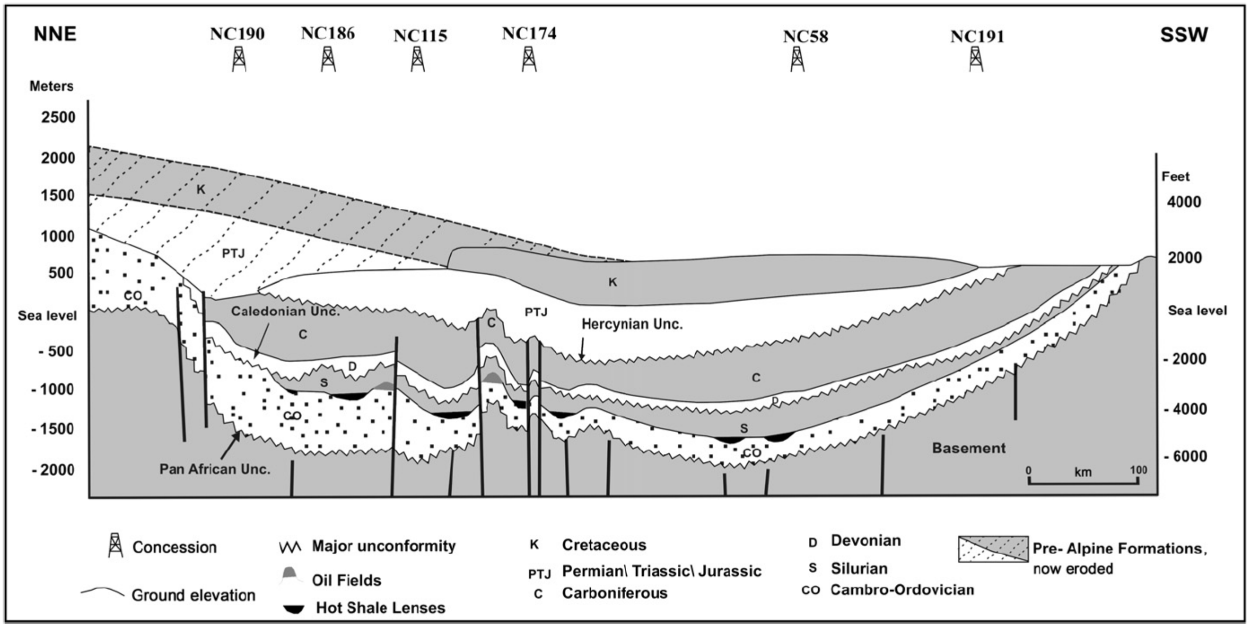


Source: Belaid at al., 2010

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



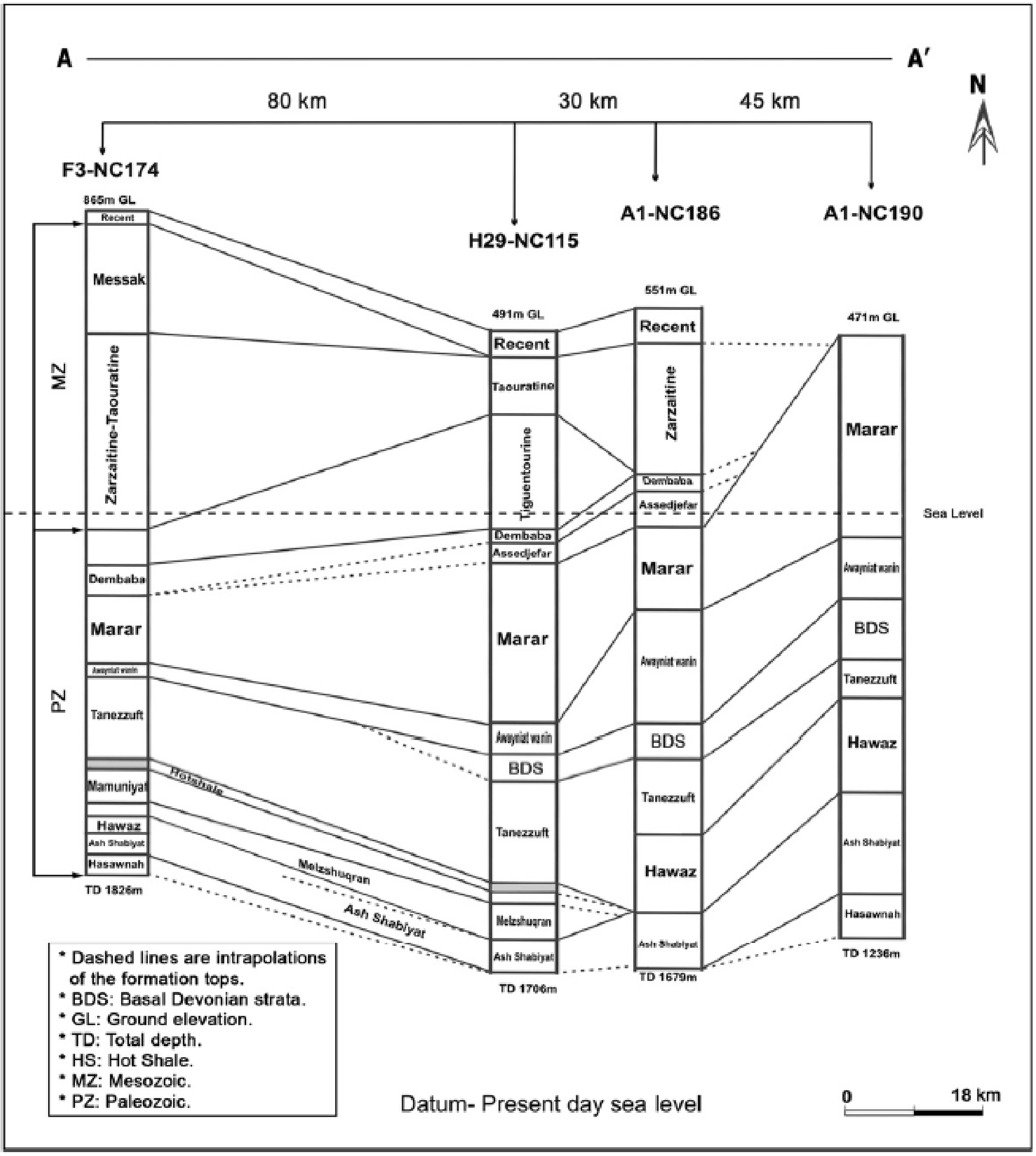
Source: Belaid at al., 2010

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).

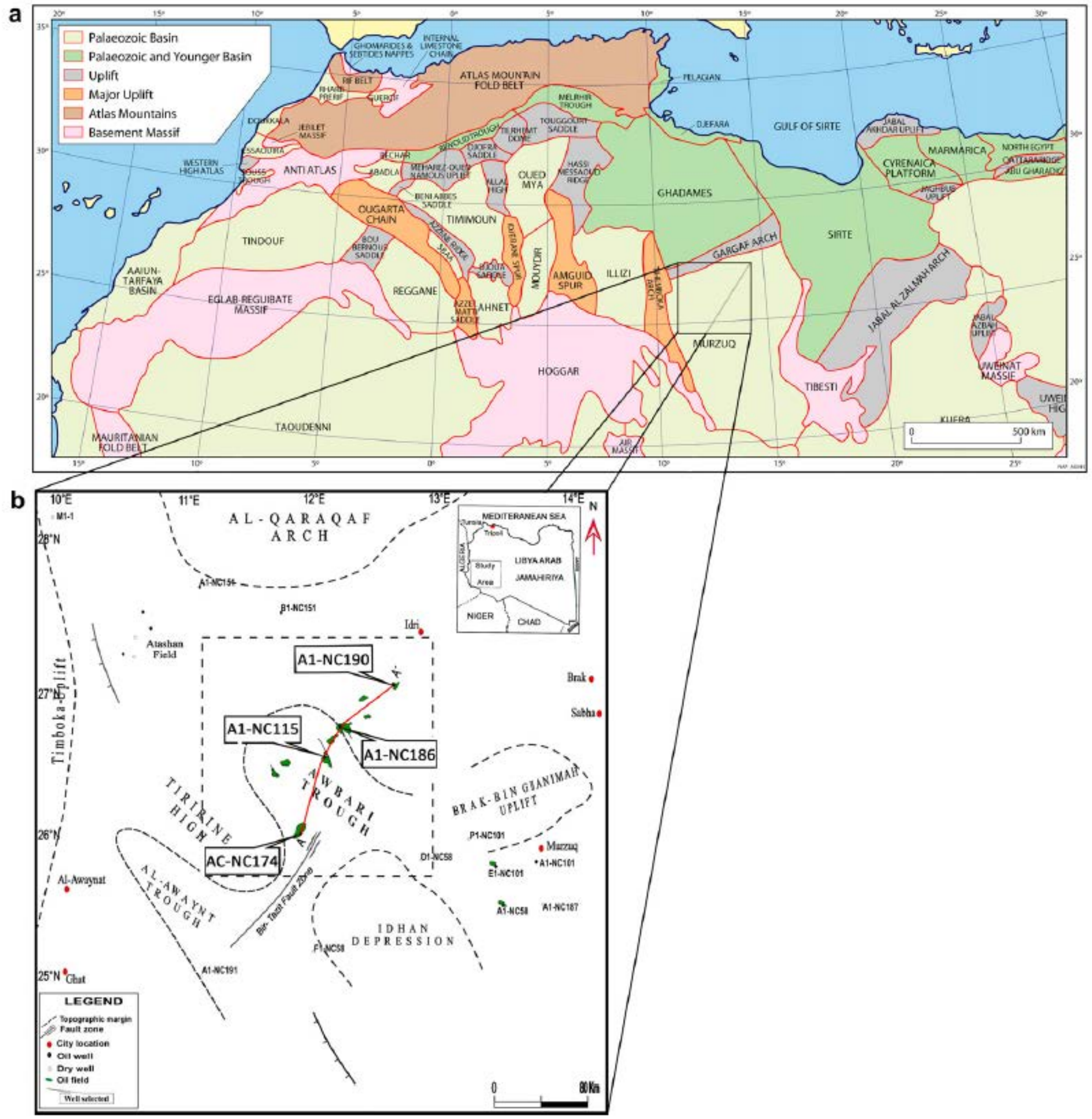
Lower Silurian Tannezuft Shale. The Silurian Tannezuft Formation (early Llandoverian) consists of dark gray to black graptolitic shales with intervals of siltstone and fine-grained sandstone deposited in a marine environment.[5]

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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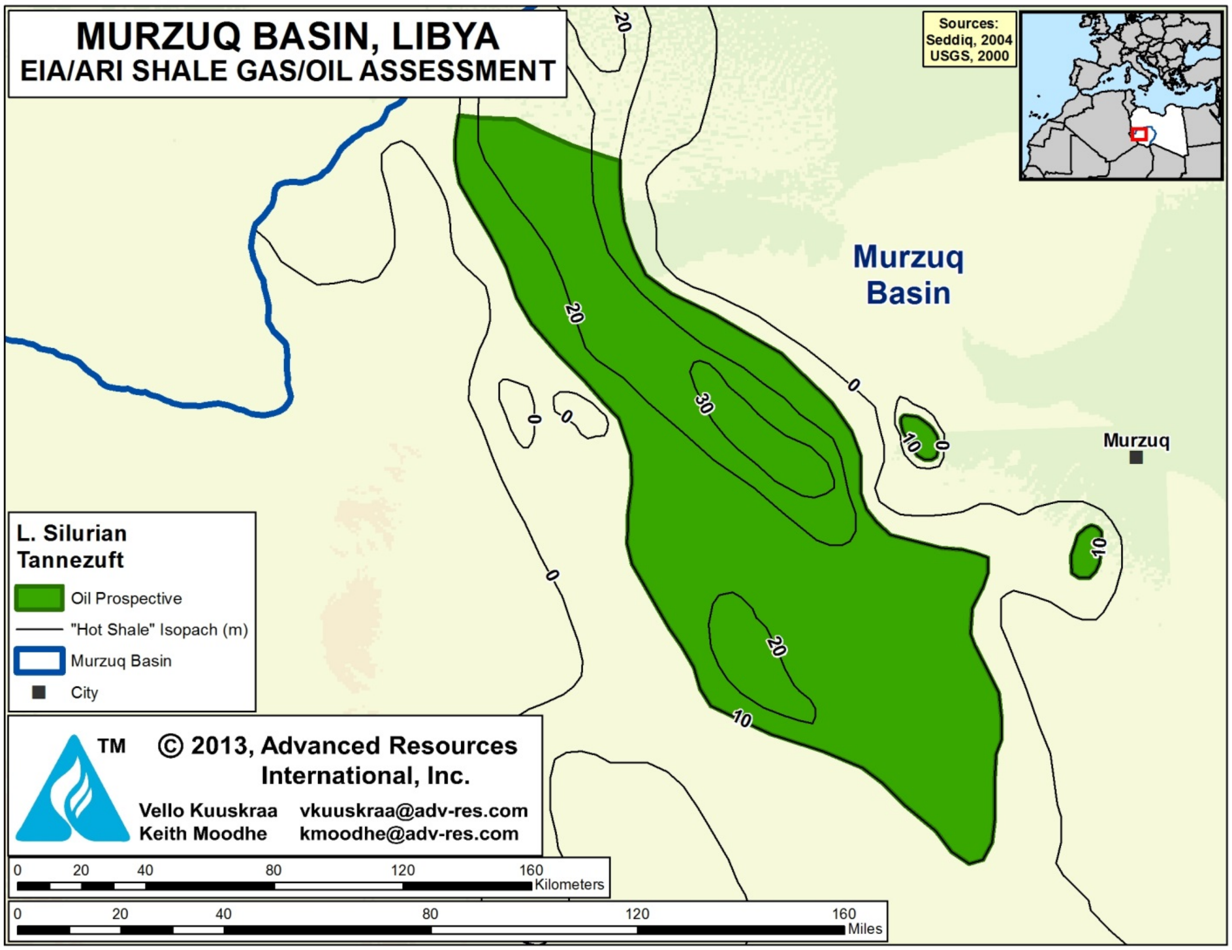
We have mapped a 5,670-mi^2 oil-prospective area in the center of the Murzuq Basin, Figure XVII-14. The depth of the Tannezuft "hot shale" in the prospective area of the Murzuq Basin ranges from 3,300 ft on the flanks to 10,000 ft in the central part of the basin.[6] The outcrops of the Tannezuft Formation 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

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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]

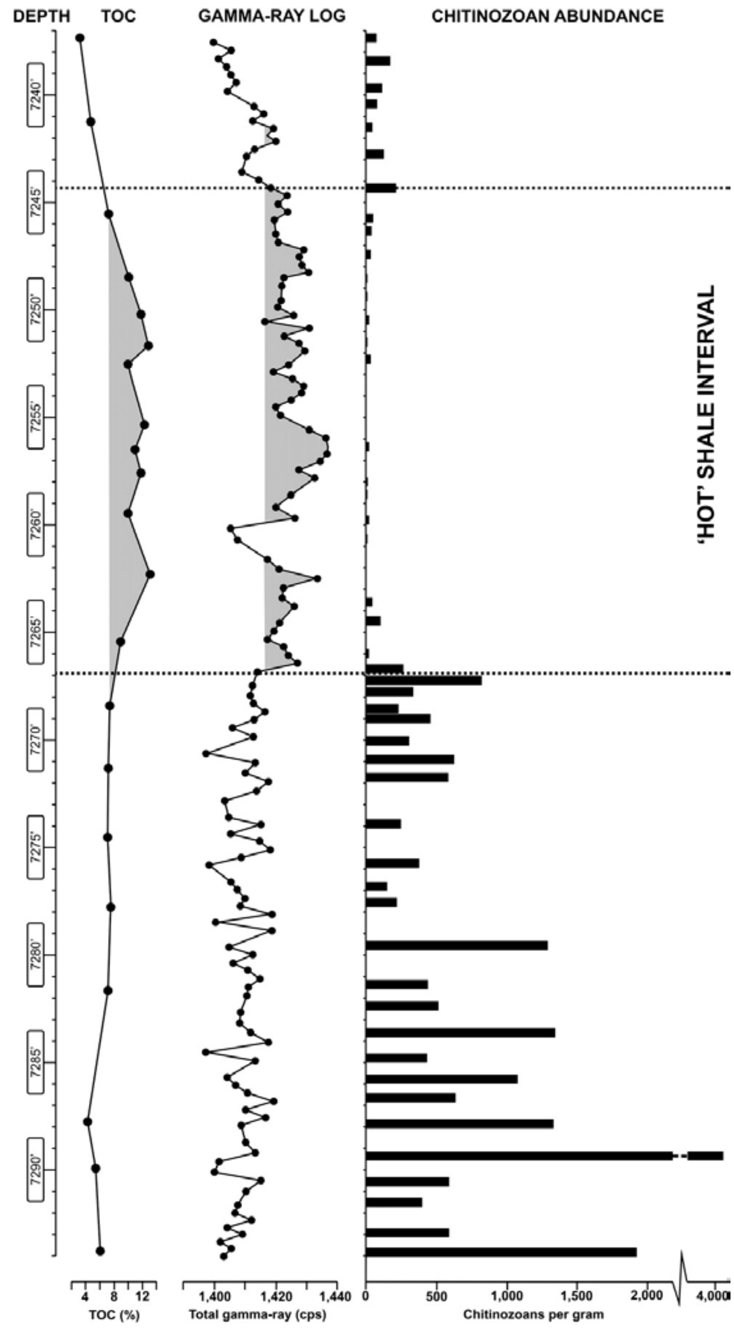
Upper Silurian Tannezuft Shale. An in-depth geochemical investigation was performed recently on a series of representative shale samples from the Upper Silurian Tannezuft Formation of the Murzuq Basin.[5] The purpose of this study was to establish the source rock quality of the extensive Silurian Tannezuft "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]

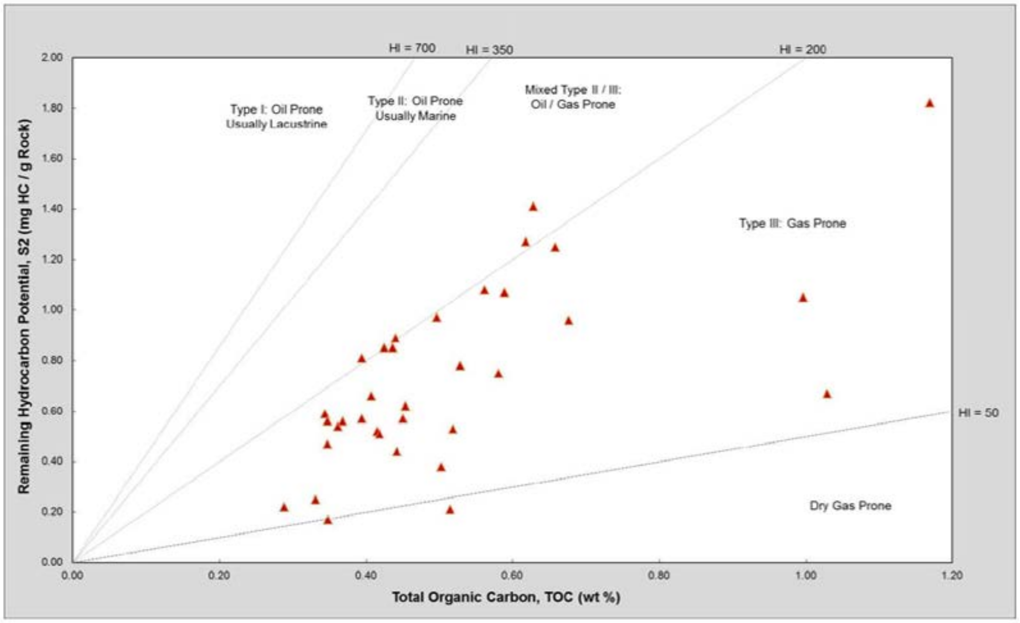
Figure XVII-15. TOC Values within the E1-NC174 Core.
Modified from Luning et al. 2003.



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

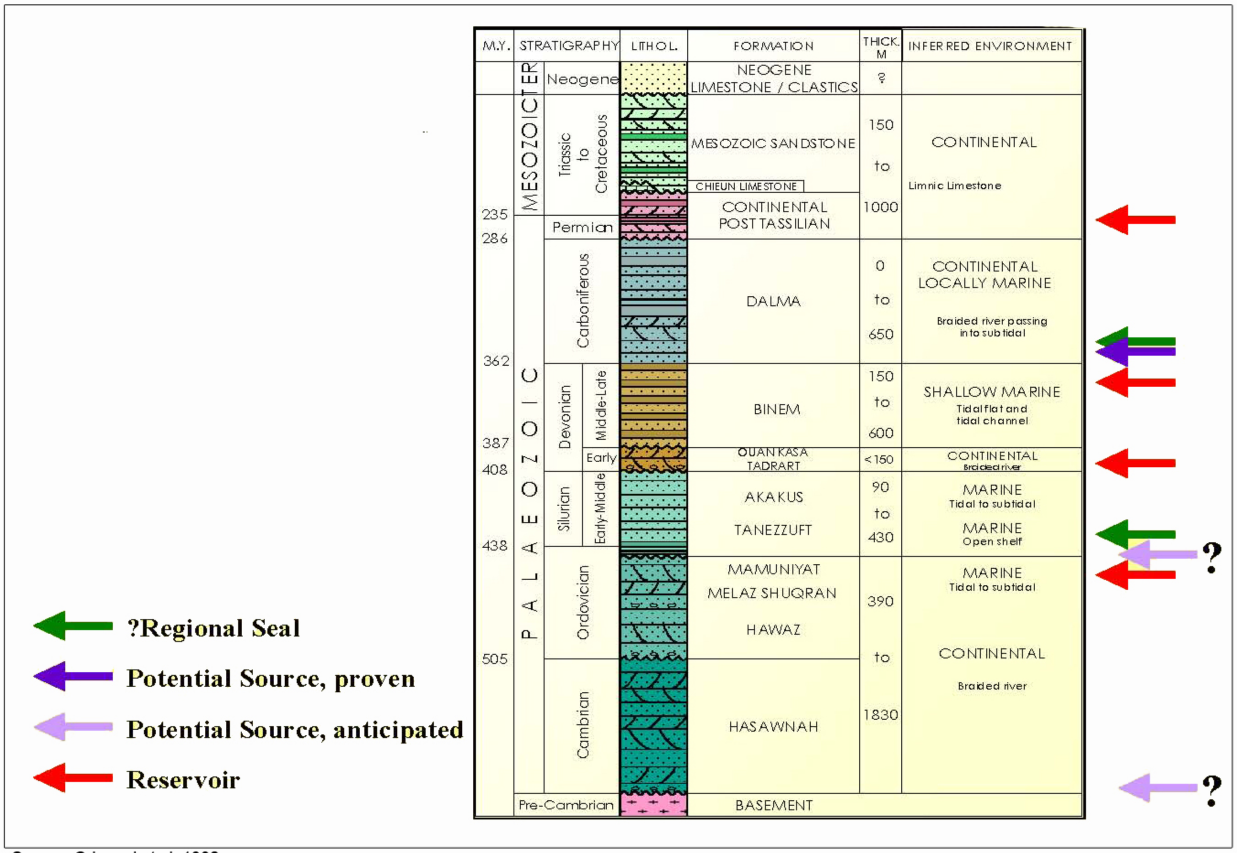
The Kufra Basin is a large 400,000-km^2, remote intra-cratonic sag basin located in southeastern Libya. The Paleozoic structural and deposition history of the Kufra Basin is similar to that of the Murzuq Basin, discussed earlier in this chapter. However, there is considerable uncertainty as to the presence 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.

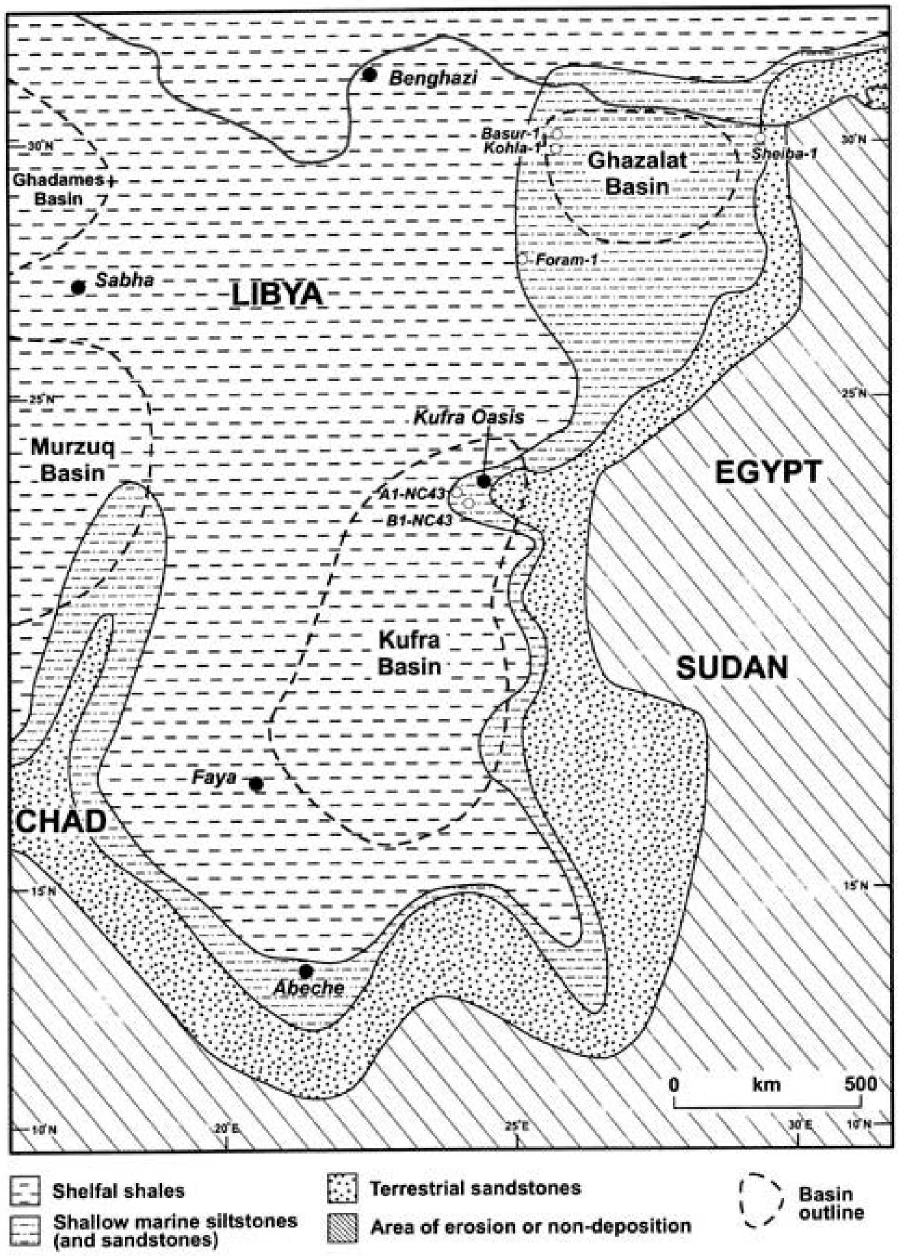
Lower Silurian, organic-rich shales may be present in the western part of the Kufra Basin.[11] However, the areal distribution of this shale unit is laterally highly variable with Silurian basal "hot shale" occurrences deposited as linear features and patches, surrounded by areas in which the basal "hot 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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