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U.S. Energy Information Administration

Technically Recoverable Shale Oil and Shale Gas Resources:

Morocco

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Introduction

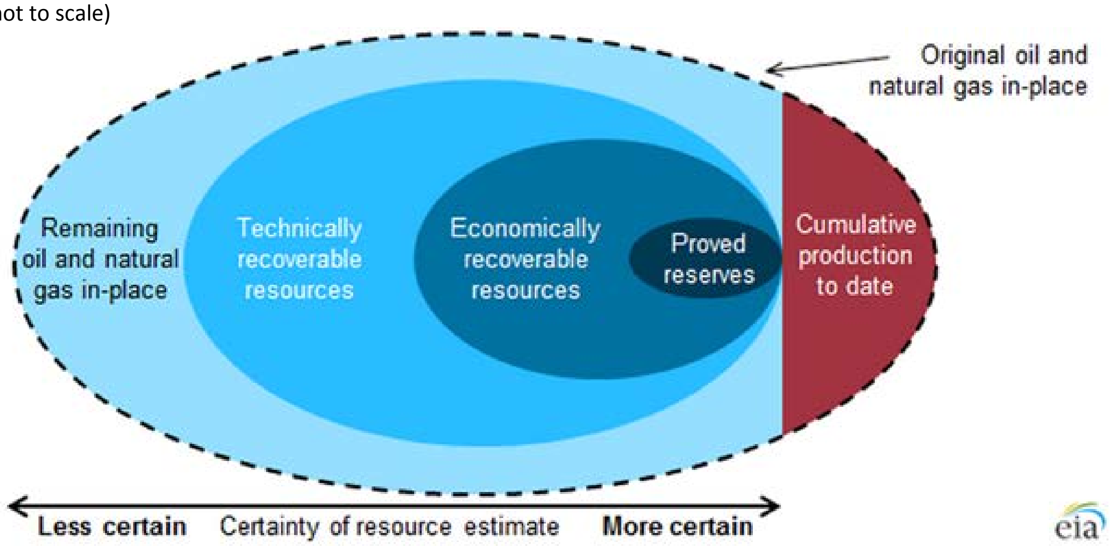
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

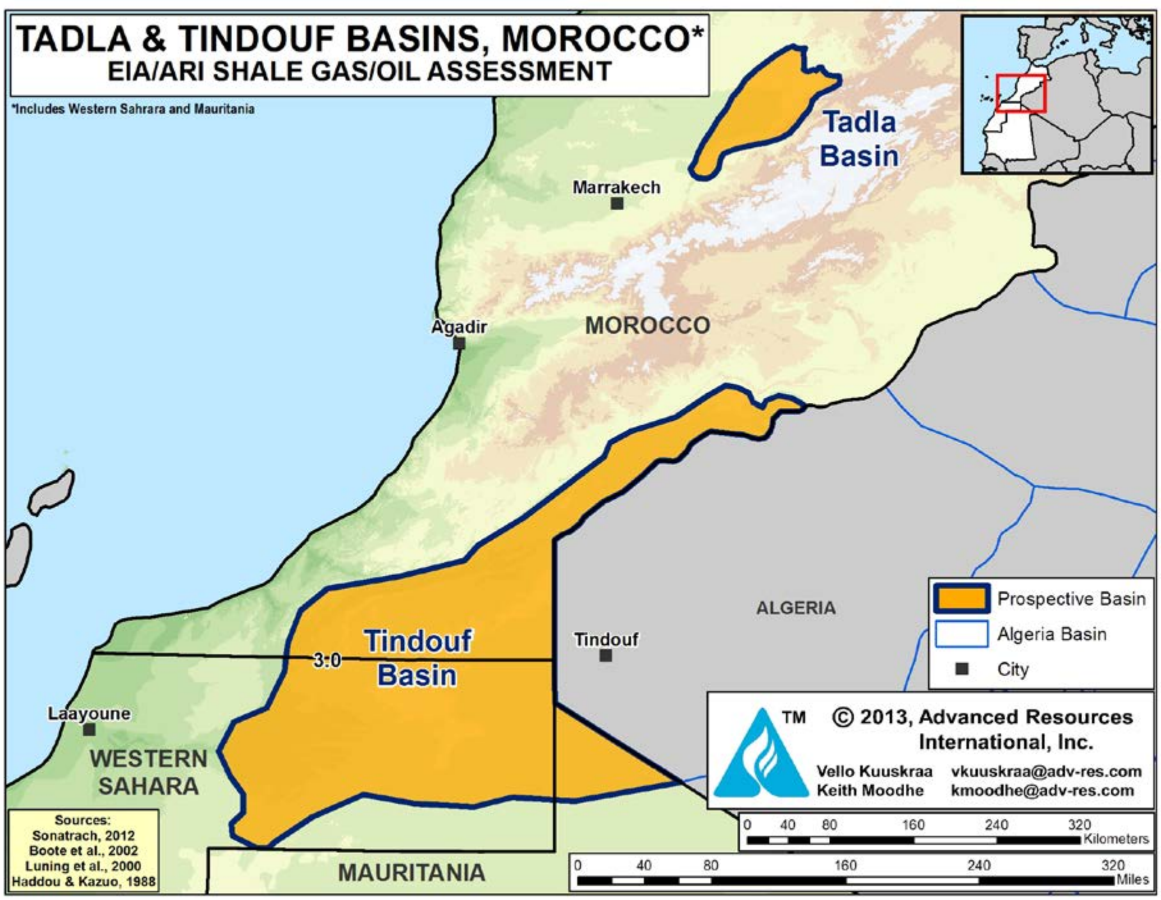
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

XIV. MOROCCO (INCLUDING WESTERN SAHARA AND MAURITANIA)

SUMMARY

In addition to large accumulations of Late-Cretaceous immature oil shale (kerogen) at depths suitable for surface mining[1], Morocco and its two neighboring countries, Mauritania and Western Sahara, also possess organic-rich Silurian- and Devonian-age shale gas and shale oil potential in the Tindouf and Tadla basins, Figure XIV-1. Mapping and resource characterization of these shales is challenging because regional deformation, erosion and subsidence of the shale deposits have led to their discontinuous and complex present day distribution.

Figure XIV-1. Shale Gas Basins of Morocco, Western Sahara and Mauritania



Source: ARI, 2013.

ARI estimates that the Tindouf and Tadla basins contain risked shale gas in-place of 95 Tcf, with 20 Tcf of risked, technically recoverable shale gas resources, Table XIV-1. In addition, these two basins contain risked shale oil/condensate in-place of 5 billion barrels, with 0.2 billion barrels of risked, technically recoverable shale oil/condensate resources, Table XIV-2.

Table XIV-1. Reservoir Properties and Shale Gas Resources of Morocco, Sahara Desert and Mauritania

Basic Data	Basin/Gross Area		Tindouf (77,000 mi^2)			Tadla (2,800 mi^2)
	Shale Formation		L. Silurian			L. Silurian
	Geologic Age		L. Silurian			L. Silurian
	Depositional Environment		Marine			Marine
Physical Extent	Prospective Area (mi^2)		2,020	4,670	12,380	1,670
	Thickness (ft)	Organically Rich	60	60	60	328
		Net	54	54	54	197
	Depth (ft)	Interval	6,600 - 11,000	6,600 - 13,000	6,600 - 14,000	3,280 - 9,840
		Average	9,000	10,000	11,000	6,560
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Underpress.
	Average TOC (wt. %)		4.0%	4.0%	4.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	2.80%	2.25%
	Clay Content		Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		6.8	18.9	22.0	49.0
	Risked GIP (Tcf)		2.7	17.7	54.5	20.5
	Risked Recoverable (Tcf)		0.3	3.5	13.6	3.1

Table XIV-2. Reservoir Properties and Shale Oil Resources of Morocco, Sahara Desert and Mauritania

Basic Data	Basin/Gross Area		Tindouf (77,000 mi^2)	
	Shale Formation		L. Silurian	
	Geologic Age		L. Silurian	
	Depositional Environment		Marine	
Physical Extent	Prospective Area (mi^2)		2,020	4,670
	Thickness (ft)	Organically Rich	60	60
		Net	54	54
	Depth (ft)	Interval	6,600 - 11,000	6,600 - 13,000
		Average	9,000	10,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		4.0%	4.0%
	Thermal Maturity (% Ro)		0.85%	1.15%
	Clay Content		Medium	Medium
Resource	Oil Phase		Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		7.9	1.7
	Risked OIP (B bbl)		3.2	1.6
	Risked Recoverable (B bbl)		0.16	0.08

INTRODUCTION

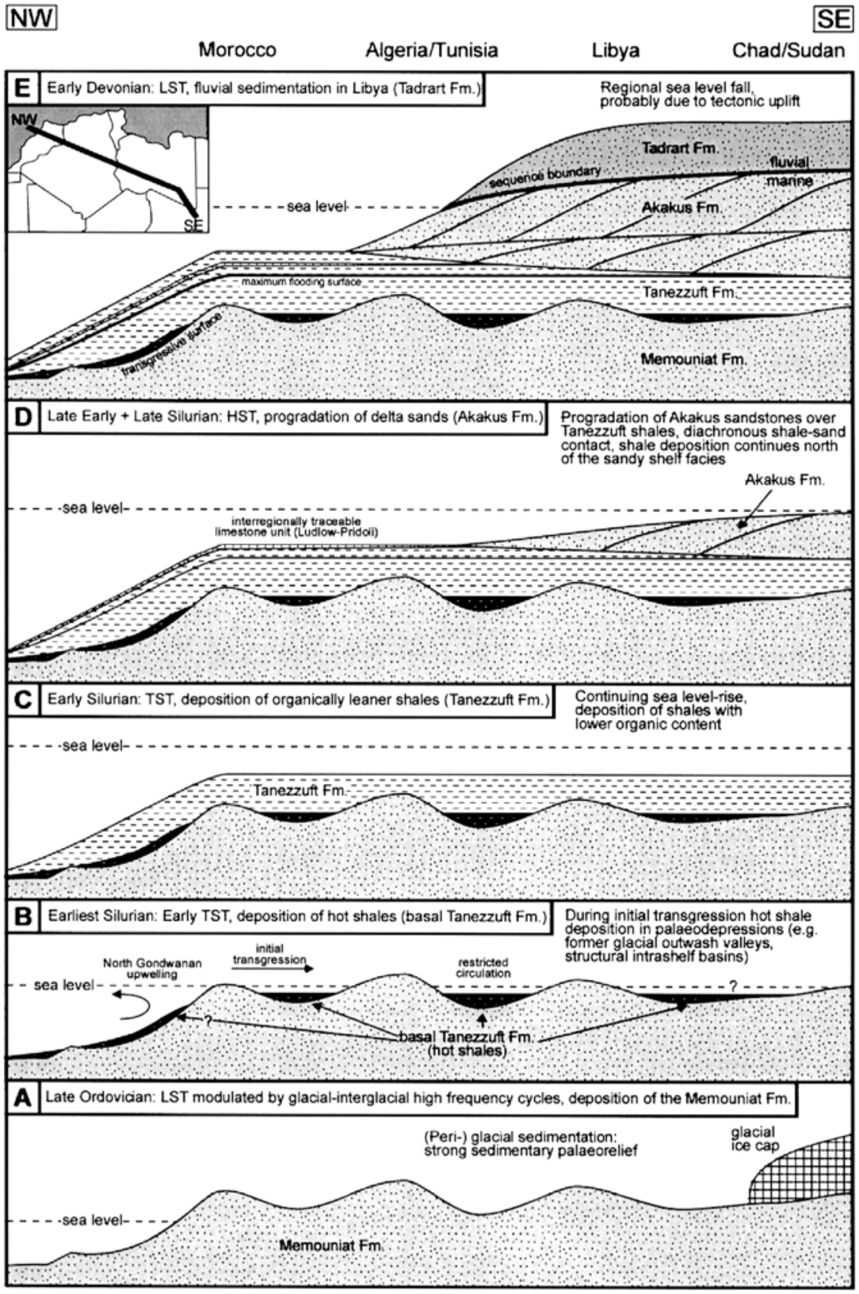
The primary shale resource on Morocco, Mauritania and Western Sahara is the lower Silurian "Hot Shale," which consists of thin but very organic-rich layers of marine organic matter deposited during a regional anoxic event. Data from wells drilled across the country confirm the presence of organic-rich Silurian shales, although not always within the current formally established boundaries of hydrocarbon basins.

The presence of a thick Silurian section, observed in many Moroccan hydrocarbon basins, does not guarantee the presence of organic-rich shale, as areas that were regional highs during the early Silurian may not have received organic-rich sediments, Figure XIV-2.[2]

Accurately identifying promising shale basins and estimating their resource potential in such geologically complex areas requires significant amounts of data, which are not widely available in Morocco and its neighboring countries because of limited well drilling and data confidentiality. As this data becomes more publically available, a more rigorous shale gas and oil resource assessment of Morocco may be possible.

This report assesses the two basins which appear to have the highest potential for shale gas and oil resources based on publically available data: the Tindouf (Zag) Basin in the south of Morocco (extending into Algeria, Western Sahara, and Mauritania), and the central Moroccan Tadla Basin.

Figure XIV-2. Sedimentary Depositional Environment in Morocco, Ordovician-Devonian[2]



1. TINDOUF BASIN

1.1 Geologic Setting

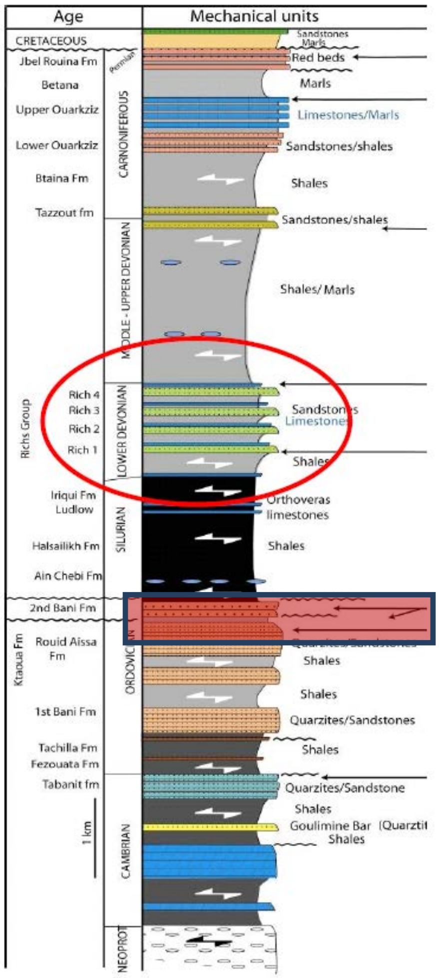
The Tindouf Basin is the westernmost of the major North African Paleozoic basins, covering a 31,660-mi^2 area in Morocco, Western Sahara and Mauritania. The basin is bounded by the Atlas Mountains and Ougarta Arch to the north and the Reguibate Massif in the south. Although once covered unconformably by a blanket of Mesozoic to early Tertiary sediments, the Paleozoic now crops out over much of the region. The Tindouf Basin is an asymmetric depression with a broad gentle southern flank and a steeply dipping, more structurally complex northern margin.

The Tindouf Basin was a large sediment depocenter from late Ordovician to Carboniferous time, accumulating multiple layers of organic-rich Silurian, Devonian (Frasnian) and Carboniferous (Visean) shales, Figure XIV-3.[3] However, these deposits were affected by the Hercynian deformation and the prospectivity of these shale formations is uncertain. High heat flow through the basin caused the Tindouf Basin shales to reach high maturity during the Carboniferous. Uplift and erosion of these shales may have caused significant underpressuring, as the shales were not buried deep enough to replenish hydrocarbons dissipated during the Hercynian orogeny.

This report focuses on the Lower Silurian "Hot Shale," which has greater data availability and higher confidence of remaining gas saturation in this shale interval. Through mapping of depth and thermal maturity, we have identified a 19,070-mi^2 prospective area in the Morocco, Mauritania and Western Sahara portion of the Tindouf Basin. The northern boundary of the prospective area is the 1,000-meter depth contour on the upthrusted northern portion of the basin, Figure XIV-4.[4] The southern boundary is the 0.7% R_o thermal maturity contour. The eastern boundary is the Algeria Border.

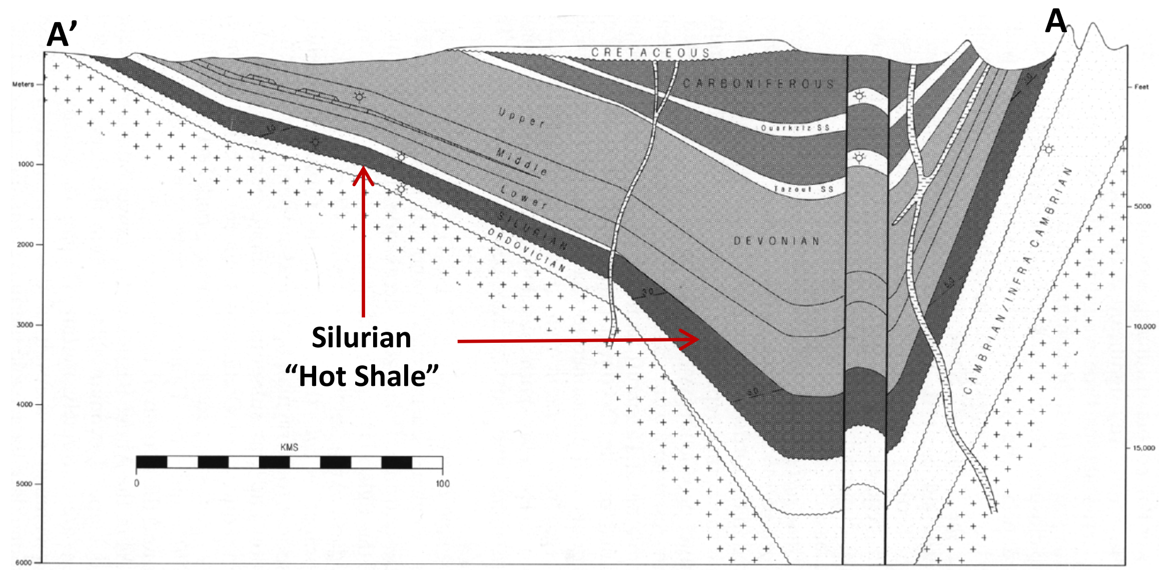
While the drilling density in the basin is extremely low, with an average of only one well per 5,000 mi^2, the data suggest that organic-rich, basal Silurian shales were deposited throughout the basin.[2] Additional well and seismic data have been collected by various international companies in partnership with Moroccan oil company, ONHYM, but these data are not yet in the public domain.

Figure XIV-3. Tindouf Basin Stratigraphic Column



Source: Longreach Petroleum Corporate Presentation, 2010

Figure XIV-4. Tindouf Basin Cross Section

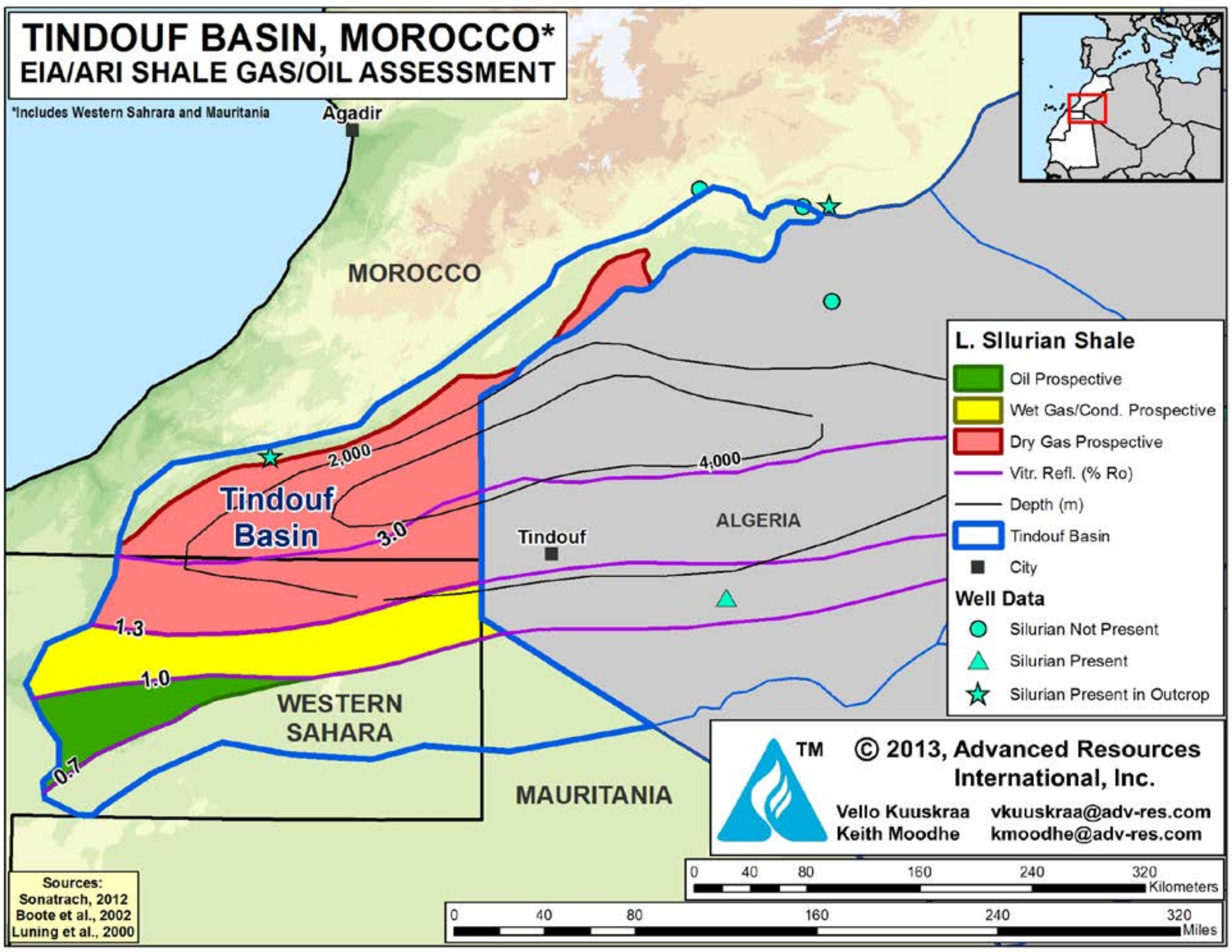


Source: Boote, 2002.

1.2 Reservoir Properties (Prospective Area)

Within the Tindouf Basin's prospective area, the depth to the Silurian "Hot Shale" ranges from 6,600 to 14,000 ft, Figure XIV-5. Present day TOC content ranges from 1% to 7%, averaging 4%. It is likely that the TOC content was higher during the time of hydrocarbon generation, due to the basin's very high thermal maturity.[5] Thermal maturity increases to the north across the basin, ranging from 0.7% to over 3% R_o.[4] Organic-rich net shale thickness is estimated at 54 ft, based on data from a well drilled in the southern flank of the basin.[6]

Figure XIV-5. Tindouf Basin Prospective Area, Morocco, Western Sahara and Mauritania



Source: ARI, 2013

1.3 Resource Assessment

We estimate that the wet and dry gas prospective area of the Silurian "Hot Shale" in the Morocco, Mauritania and Western Sahara portions of the Tindouf Basin has a resource concentration of 19 to 22 Bcf/mi^2. The oil prospective area of the Silurian "Hot Shale" has a resource concentration of 8 million barrels/mi^2 plus associated gas. While the shale formation is organic-rich, it is thin, limiting its resource concentration.

Within the overall 19,020-mi^2 prospective area, the Lower Silurian "Hot Shale" in the Tindouf Basin contains a 12,380-mi^2 area prospective for dry gas, a 4,670-mi^2 area prospective for wet shale gas and shale condensate, and a 2,020-mi^2 area prospective for shale oil. The risked shale gas in-place for the Tindouf Basin is estimated at 75 Tcf, with 17 Tcf as the risked, technically recoverable shale gas resource. In addition, the Tindouf Basin has an estimated 5 billion barrels of shale oil/condensate in-place, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

1.4 Recent Activity

The Moroccan national oil and gas company, ONHYM, has been evaluating the country's shale gas potential since mid-2010. It has plans to collect seismic data followed by the drilling of a shale gas exploration well. The well is proposed to be drilled in partnership with San Leon Energy (Ireland) and Longreach Oil and Gas (Canada) on the Zag exploration license.[7]

2. TADLA BASIN

2.1 Geologic Setting

The Talda Basin is a 2,800-mi^2 intra-cratonic basin located in central Morocco within the Moroccan Mesta. The basin contains nearly 16,500 feet of Paleozoic through Cenozoic sedimentary strata, Figure XIV-6. Paleozoic rocks dominate the sediments in this basin, except in areas where uplift has caused their erosion, Figure XIV-7. The Talda Basin is bounded by the Central Massif in the north, the Atlas Mountains in the east, the Jebiliet Massif in the south, and the Rehamna Massif in the west. The Fkih Ben Salah Fault divides the basin into a southeast section, characterized by complex tectonics including heavy folding and faulting, and a northwest section, with thick carboniferous strata and minor, infrequent faulting.[8]

As in the Tindouf Basin, regional uplifting during the Hercynian and Alpine events exposed the Silurian, Devonian and Ordovician shales after they had matured and begun to generate hydrocarbons. While these shales were subsequently buried on the western edge of the basin by approximately 6,500 ft of Cretaceous and Tertiary sediments, it is unlikely that the shales generated additional hydrocarbons after reburial.[8] As such, this basin is at high risk for underpressuring, although data are not available to confirm this assumption.

The 1,670-mi^2 prospective area of the Tadla Basin is bounded by the 1,000-m depth contour, various faults and the Atlas Mountain range to the east, Figure XIV-8. Little data are available in the southern portion of the basin where the prospective area is bounded by the apparent lack of organic-rich Silurian strata.

2.2 Reservoir Properties (Prospective Area)

The Lower Silurian "Hot Shale" in the Tadla Basin reaches maximum depth west of the Fkih Ben Salah Fault, ranging from 3,280 to 9,840 ft.[8] To the east, the shale becomes shallower. Average depth in the prospective area is estimated at 6,560 ft. Where it has not been eroded, the Silurian section can reach up to 800 feet thick, with over 300 feet of organic-rich shale, of which 200 ft is net shale.[9] TOC data from outcrops suggest that the organic content reaches 10-12%,[10] but deep well data from inside the prospective area indicates TOC values closer to 2%. The Silurian shale is thermally highly mature over the prospective area; R_o values of 1.5% to 3% place the shale in the dry gas window.[8]

Figure XIV-6. Tadla Basin Stratigraphic Column[8]

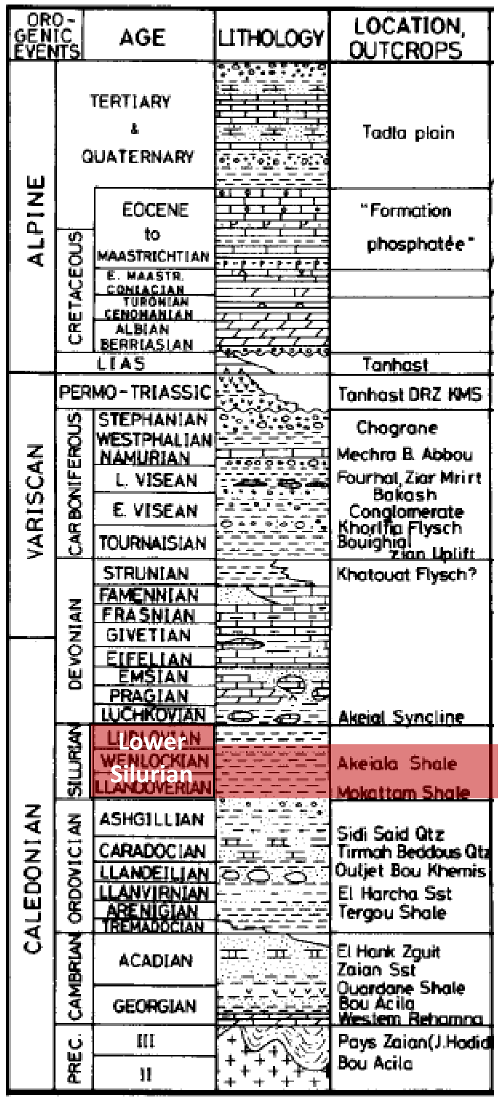
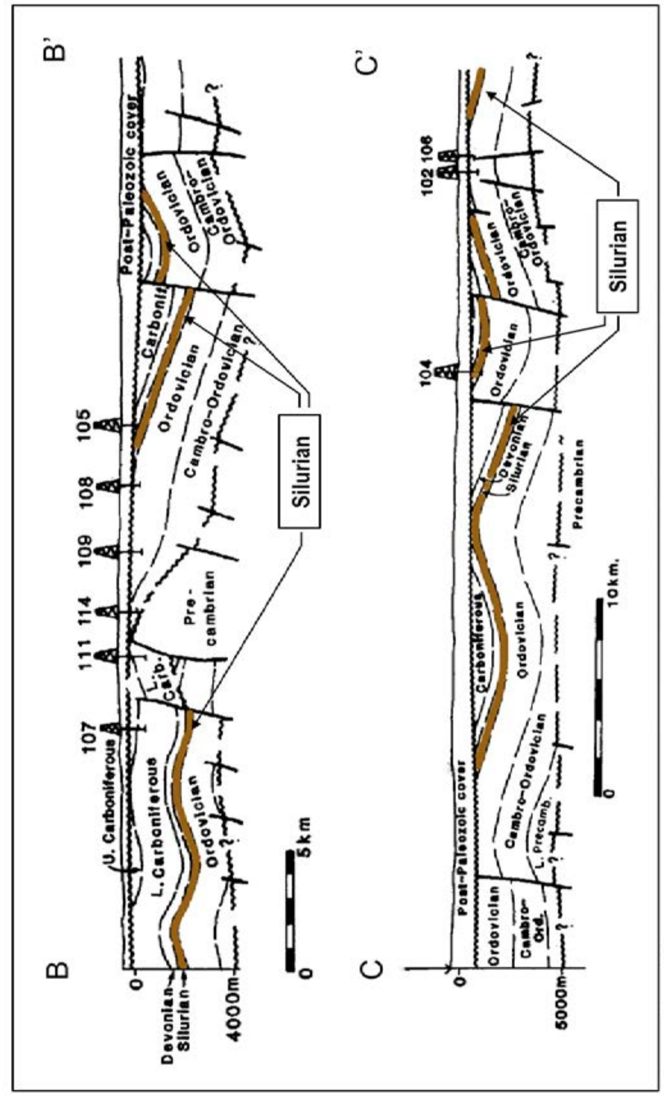


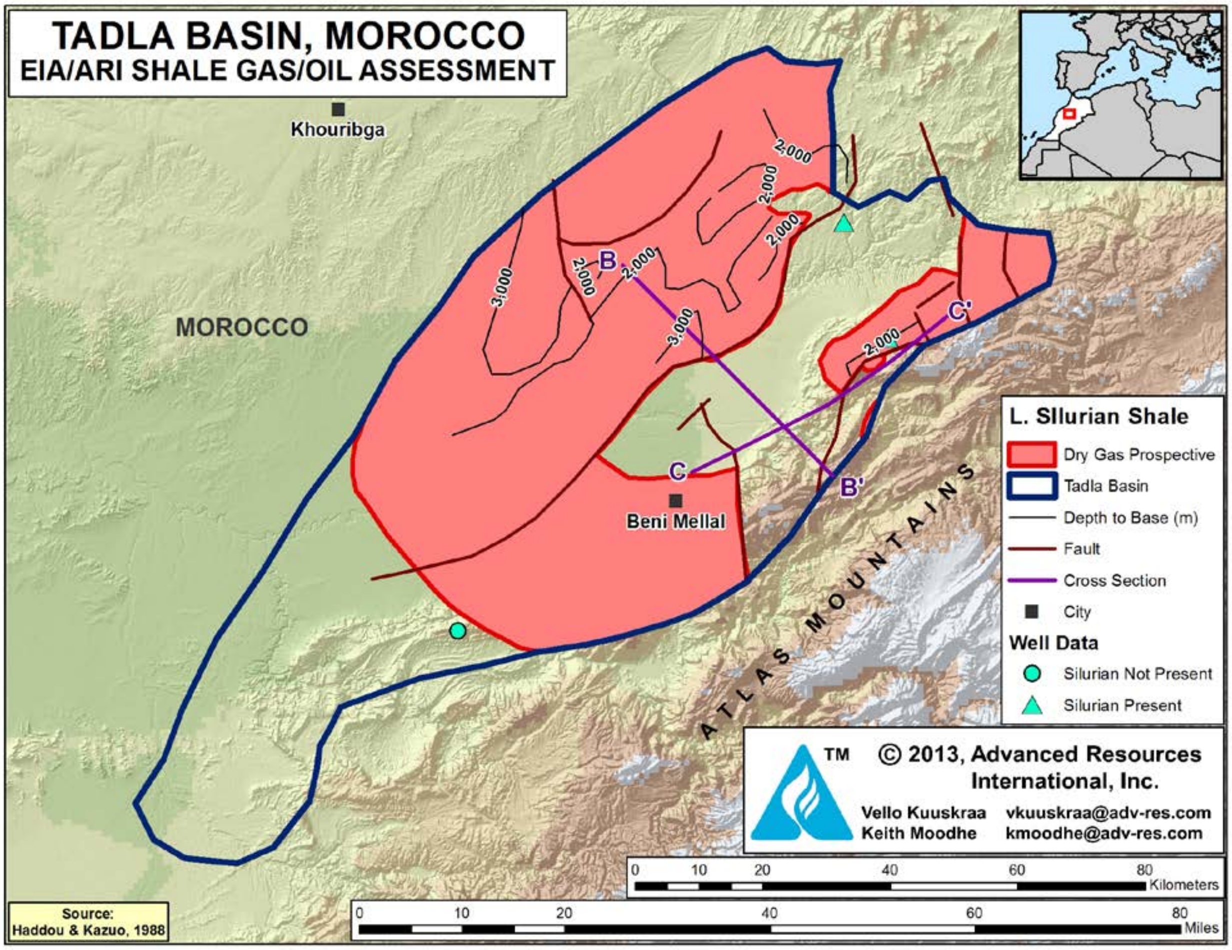
Figure XIV-7. Tadla Basin Cross Sections[8]



Source: Jabour, 1988.

Advanced Resources International, Inc.

Figure XIV-8. Tadla Basin Prospective Area, Morocco



Source: ARI, 2013

2.3 Resource Assessment

The Silurian "Hot Shale" in the Tadla Basin's 1,670-mi² prospective area has a moderate 49-Bcf/mi² dry gas resource concentration. The basin contains an estimated 20 Tcf of risked shale gas in-place, with 3 Tcf as the risked, technically recoverable shale gas resource.

2.4 Recent Activity

No shale gas exploration activity has been reported in the Tadla Basin of Morocco.

3. SHALE RESOURCES BY COUNTRY

3.1 Morocco

Morocco has a 1,670-mi^2 dry gas prospective area in the Tadla Basin and an 8,000-mi^2 dry gas prospective area in the Tindouf Basin. Within these two prospective areas, Morocco has 56 Tcf of risked shale gas in-place, with 12 Tcf as the risked, technically recoverable shale gas resource.

3.2 Western Sahara

The Western Sahara portion of the Tindouf Basin has a 4,380-mi^2 dry gas prospective area, a 4,670-mi^2 wet shale gas/condensate prospective area, and a 2,020-mi^2 shale oil prospective area. Within these prospective areas, Western Sahara has an estimated 39 Tcf of risked dry, wet and associated shale gas in-place, with 8 Tcf as the risked, technically recoverable shale gas resource. In addition, Western Sahara has 5 billion barrels of risked shale oil/condensate in-place, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

3.3 Mauritania

Mauritania has a small 50-mi^2 wet shale gas/condensate prospective area in the Tindouf Basin containing only minor shale gas and oil resources.

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