Independent Statistics & Analysis
U.S. Energy Information Administration

Technically Recoverable Shale Oil and Shale Gas Resources:

Oman

September 2015

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Contents

Executive Summary

Introduction

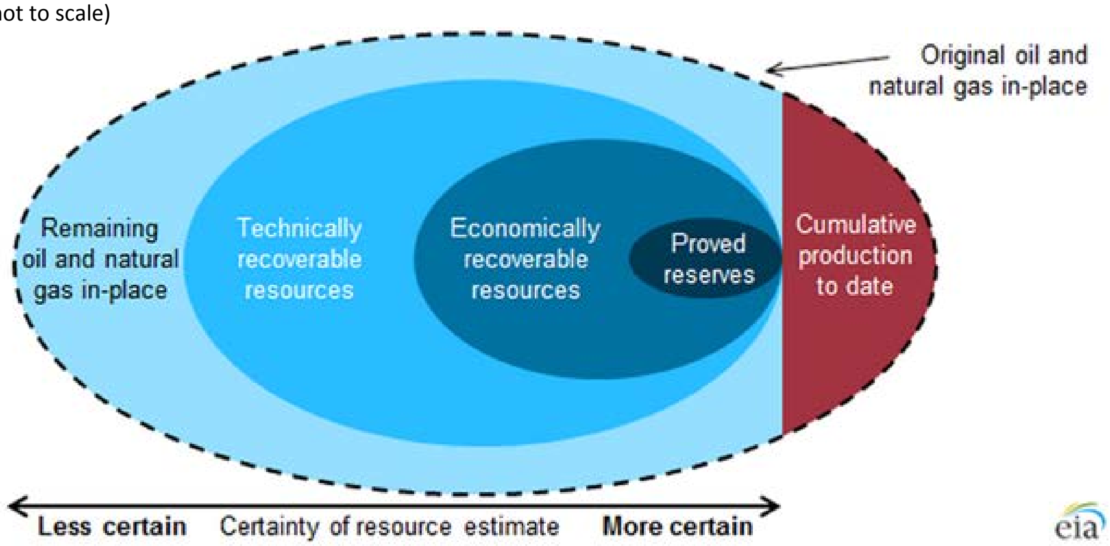
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

[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.

Key exclusions

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

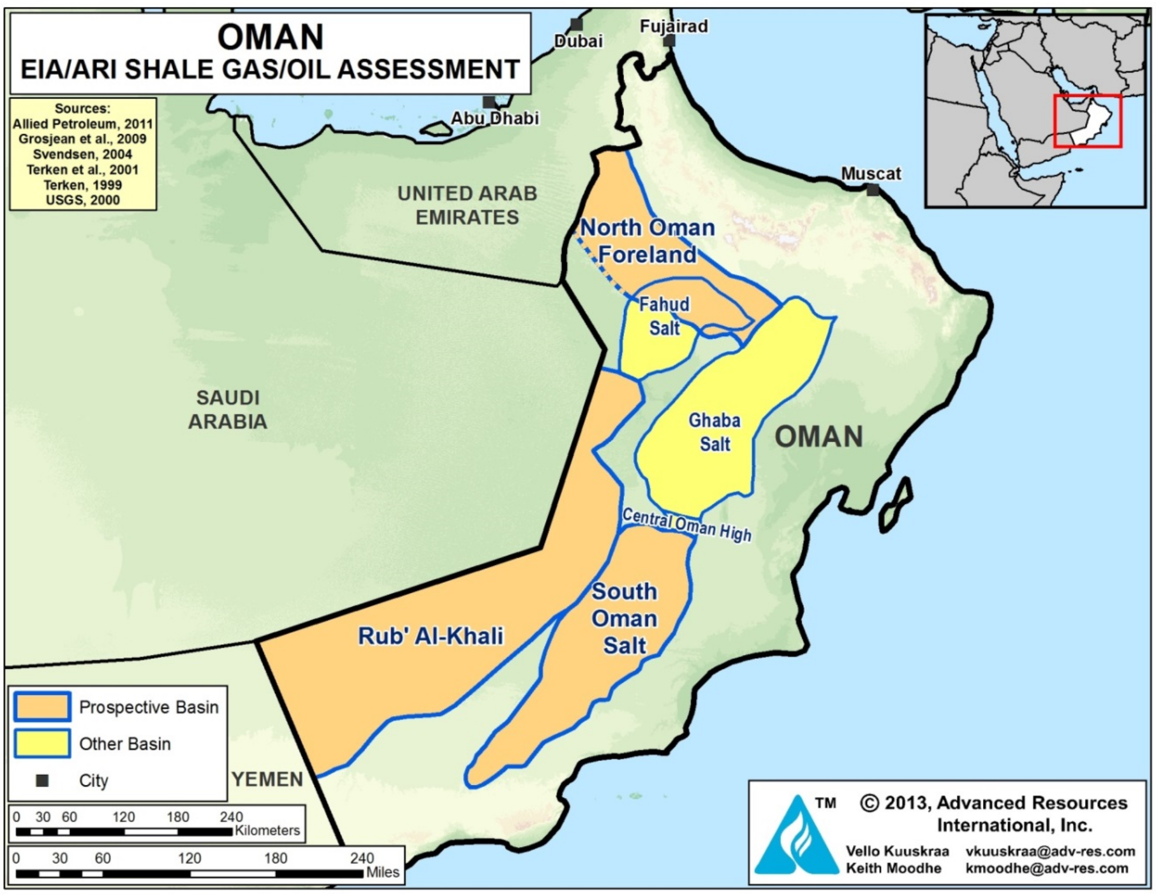
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

OMAN

SUMMARY

Oman has three basin areas with potential for shale gas and oil - - the South Oman Salt Basin, the North Oman Foreland Basin, and the south-eastern edge of the Rub' Al-Khali Basin, Figure 1. Each of these three basins contains a distinct petroleum system with associated shales and source rocks. In addition, late Precambrian-Cambrian Huqf Supergroup shales and source rocks exist in the Fahud and Ghaba Salt basins. However, the depth of these shales is generally below 5,000 m, the shale formation depth limit established for this study, and these are not assessed.

Figure 1. Oman's Shale Gas and Shale Oil Basins



Source: ARI, 2014.

Our assessment is that the shale source rocks in these three basins contain 116 billion barrels of risked shale oil in-place, with 6.2 billion barrels as the risked, technically recoverable shale oil resource, Table 1. In addition, we estimate that these three basins contain 315 Tcf of associated, wet and dry shale gas in-place, with 48 Tcf as the risked, technically recoverable shale gas resource, Table 2.

Table 1. Shale Oil Reservoir Properties and Resources of Oman

Basic Data	Basin/Gross Area		S. Oman Salt (10,400 mi^2)			N. Oman Foreland (7,800 mi^2)	Rub' Al-Khali/Oman (22,000 mi^2)	
	Shale Formation		Thuleilat Shale	Athel	U Shale	Natih	Sahmah Shale	
	Geologic Age		L. Cambrian	L. Cambrian	L. Cambrian	M. Cretaceous	Silurian	
	Depositional Environment		Marine	Marine	Marine	Marine	Marine	
Physical Extent	Prospective Area (mi^2)		1,480	1,480	1,480	2,380	3,680	3,350
	Thickness (ft)	Organically Rich	390	740	260	120	125	150
		Net	293	444	195	108	113	135
	Depth (ft)	Interval	5,500 - 14,000	6,500 - 15,000	7,500 - 16,000	3,000 - 9,000	9,000 - 10,500	10,500 - 12,500
		Average	9,000	10,000	11,000	4,500	10,000	11,400
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Normal	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		6.8%	3.2%	4.9%	5.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		1.15%	1.15%	1.15%	0.80%	0.85%	1.20%
	Clay Content		Medium	Low	Medium	Medium	Medium	Medium
Resource	Oil Phase		Condensate	Condensate	Condensate	Oil	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		14.7	55.7	8.8	19.9	13.3	5.3
	Risked OIP (B bbl)		10.9	41.3	6.5	23.6	24.4	8.9
	Risked Recoverable (B bbl)		0.43	2.89	0.26	0.94	1.22	0.44

Source: ARI, 2014.

Table 2. Shale Gas Reservoir Properties and Resources of Oman

Basic Data	Basin/Gross Area		S. Oman Salt (10,400 mi^2)			N. Oman Foreland (7,800 mi^2)	Rub' Al-Khali/Oman (22,000 mi^2)		
	Shale Formation		Thuleilat Shale	Athel	U Shale	Natih	Sahmah Shale		
	Geologic Age		L. Cambrian	L. Cambrian	L. Cambrian	M. Cretaceous	Silurian		
	Depositional Environment		Marine	Marine	Marine	Marine	Marine		
Physical Extent	Prospective Area (mi^2)		1,480	1,480	1,480	2,380	3,680	3,350	2,370
	Thickness (ft)	Organically Rich	390	740	260	120	125	150	190
		Net	293	444	195	108	113	135	171
	Depth (ft)	Interval	5,500 - 14,000	6,500 - 15,000	7,500 - 16,000	3,000 - 9,000	9,000 - 10,500	10,500 - 12,500	12,500 - 13,000
		Average	9,000	10,000	11,000	4,500	10,000	11,400	12,800
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Normal	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		6.8%	3.2%	4.9%	5.0%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		1.15%	1.15%	1.15%	0.80%	0.85%	1.20%	1.70%
	Clay Content		Medium	Low	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Wet Gas	Wet Gas	Wet Gas	Assoc. Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		41.4	171.3	29.3	6.8	12.5	11.3	72.6
	Risked GIP (Tcf)		30.6	126.7	21.7	8.2	23.0	18.9	86.0
	Risked Recoverable (Tcf)		2.4	17.7	1.7	0.7	2.3	1.9	21.5

Source: ARI, 2014.

INTRODUCTION

During the late Precambrian-Cambrian, Oman was located on the eastern portion of the Arabian Plate and was originally part of the Gondwana continent. The progressive breakup of the Gondwana continent significantly influenced the tectonic and depositional history of the rock units and petroleum systems present in Oman, creating a complex structural setting for the shale resource evaluation.

Oman contains the one of the world's oldest known commercial oil and gas deposits in the Late Precambrian-Cambrian Huqf Supergroup, including the thick Ara Group shales and siliceous source rocks. However, much of the shale resource in the basal Huqf Supergroup is deposited below 5,000m and is thus not included in the quantitative portion of this resource assessment. Section IV of this chapter discusses the Late Precambrian-Cambrian Huqf Supergroup shales in the Fahud and Ghaba basins of Oman.

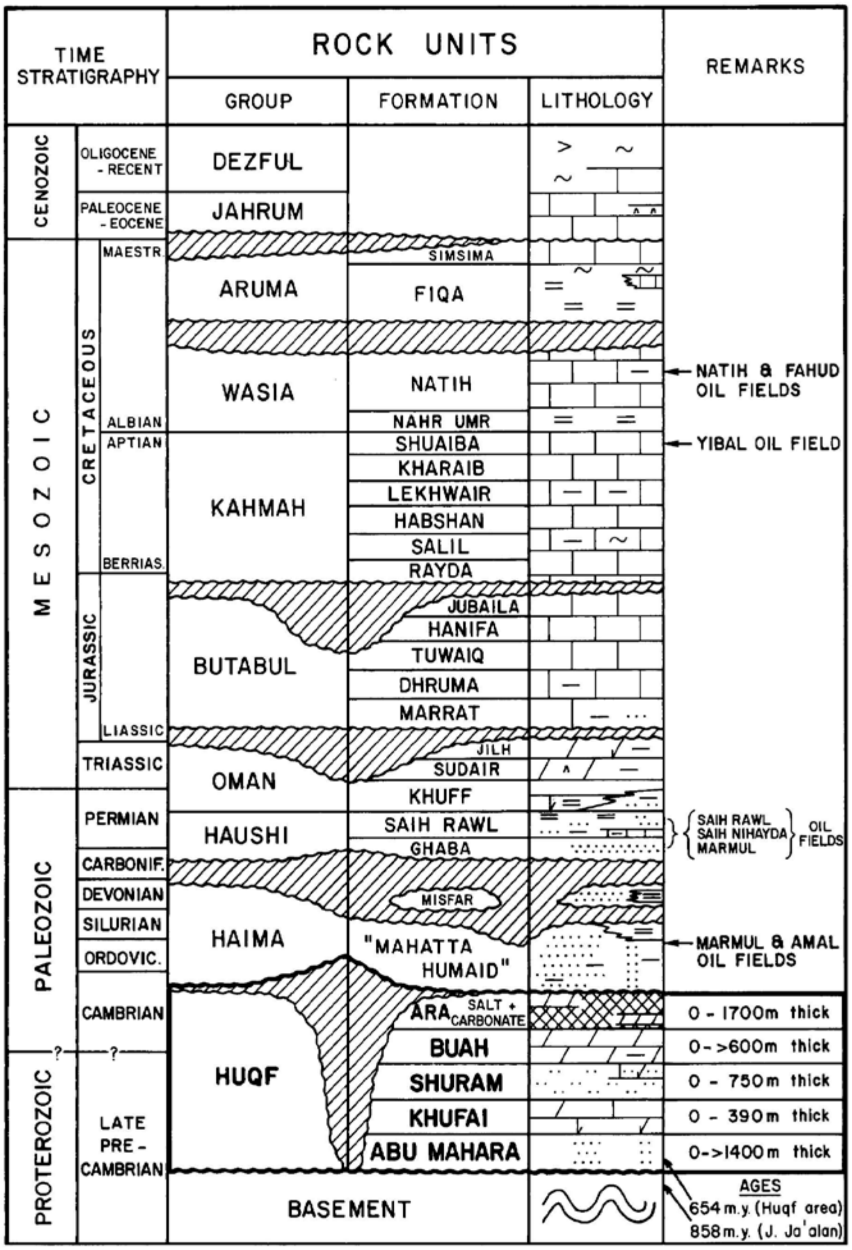
Oman is a significant producer of hydrocarbons, providing an estimated 920 thousand barrels of oil and 2.6 Bcf of natural gas per day in 2012, from 5.5 billion barrels of proved conventional oil reserves and 30 Tcf of proved conventional natural gas reserves.[1] After five decades of exploration, many of the conventional oil and gas plays of Oman have been discovered, leading to renewed interest in exploring and producing shale gas and shale oil.

The organic-rich shales, that have served as the source rock for the discovered conventional oil and gas reserves of Oman, are the focus of this resource assessment. Specifically, this study addresses the shale source rocks in three basins:

- ***South Oman Salt Basin***. The Late Precambrian-Cambrian Ara Formation shales within the Huqf Group in the South Oman Salt Basin,
- ***North Oman Foreland Basin***. The Middle Cretaceous Natih Shale within the Wasia Group in the North Oman Foreland Basin, and
- ***Rub' Al-Khali Basin***. The Silurian Sahmah Shale within the Haima Group in Oman's southeastern portion of the much larger Rub' Al-Khali Basin that extends into Saudi Arabia.

Figures 2[2] and 3[3] provide the stratigraphic sequence of the reservoir rock units and source rocks of Oman. The figures identify the Ara Group, Thuleilat, Athel and U shale source rocks at the base of the column. The figures also identify the Haima Group Silurian Sahmah Shale and the Wasia Group Cretaceous Natih Shale.

Figure 2. Stratigraphic Column and Rock Units for Oman



Source: Gorin et al., 1982

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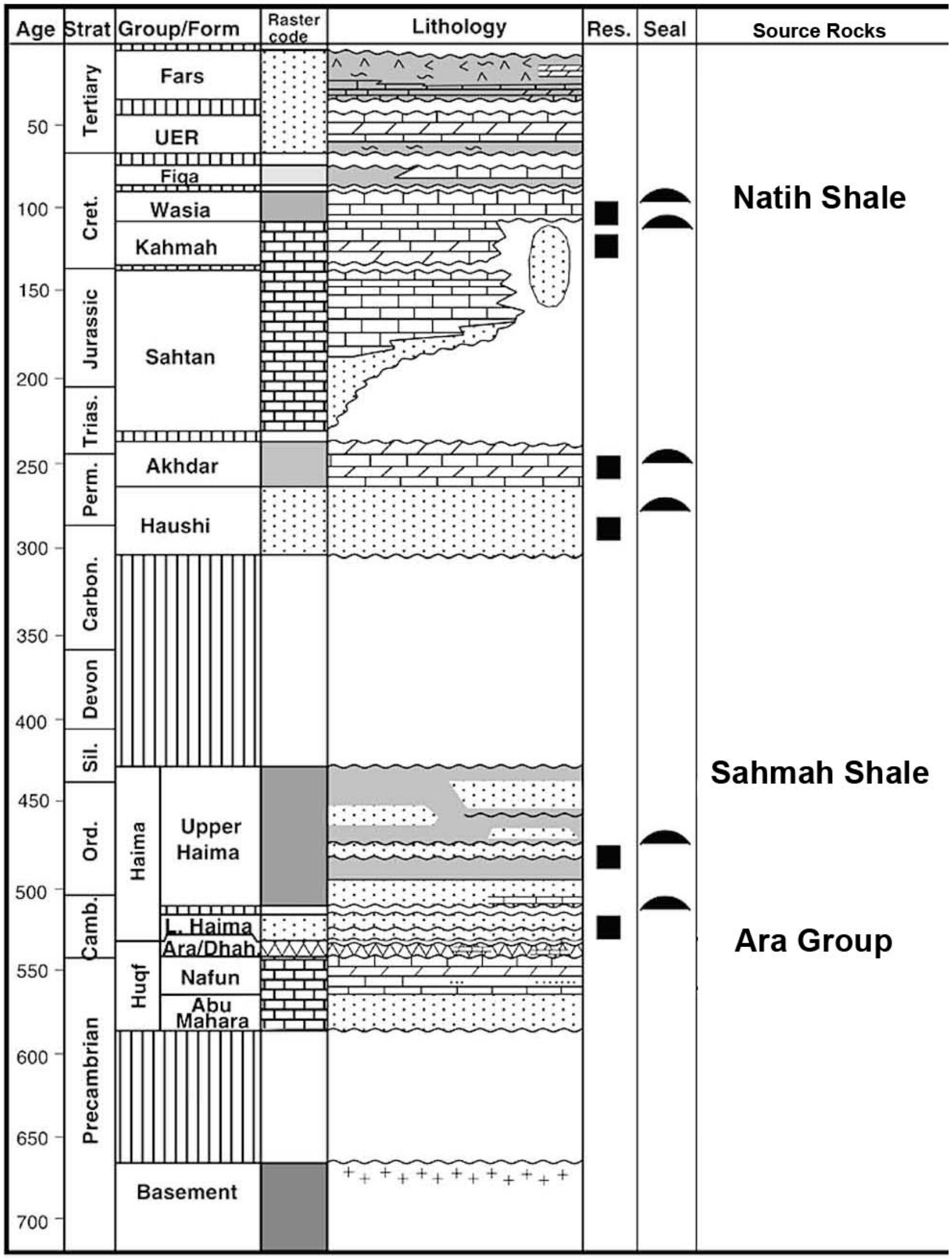
Figure 3. Lithology, Reservoir, Seal and Key Source Rocks of Oman



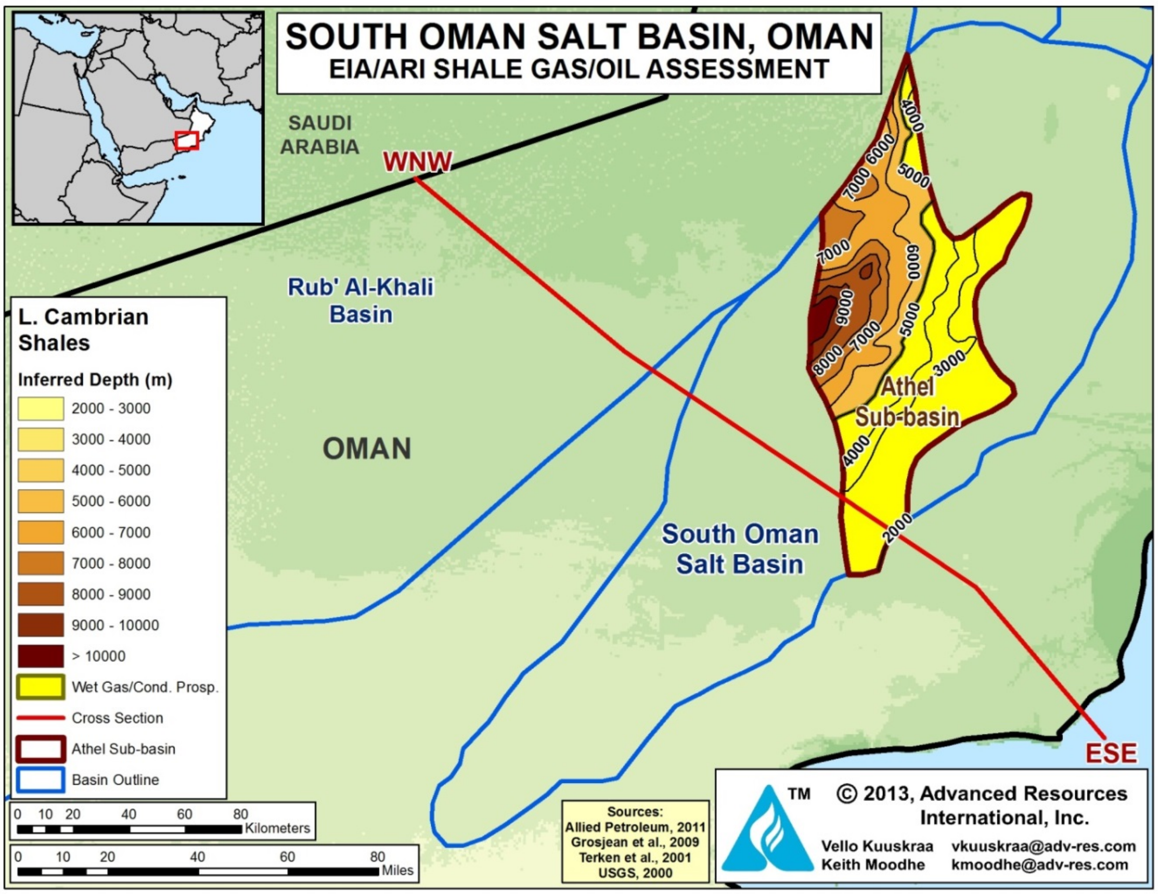
Source: Modified from Terken et al., 2001

1. SOUTH OMAN SALT BASIN

1.1 Introduction and Geologic Setting

The South Oman Salt Basin is located in south-central Oman, south of the Central Oman High. The Oman Salt Basin reaches a depth in excess of 30,000 ft in the basin center, shallowing to above 15,000 ft along the basin's eastern flank. Of particular interest is the Athel sub-basin in the center of the South Oman Salt Basin and its "world class" source rocks of the Ara A4 Formation (one of the upper units of the Huqf Supergroup). These shale source rocks are the Thuleilat Shale, the Athel (Al Shomou) Silicilyte and the U Shale. Figure 4 provides the outline of the South Oman Salt Basin, highlighting the Athel Sub-basin.

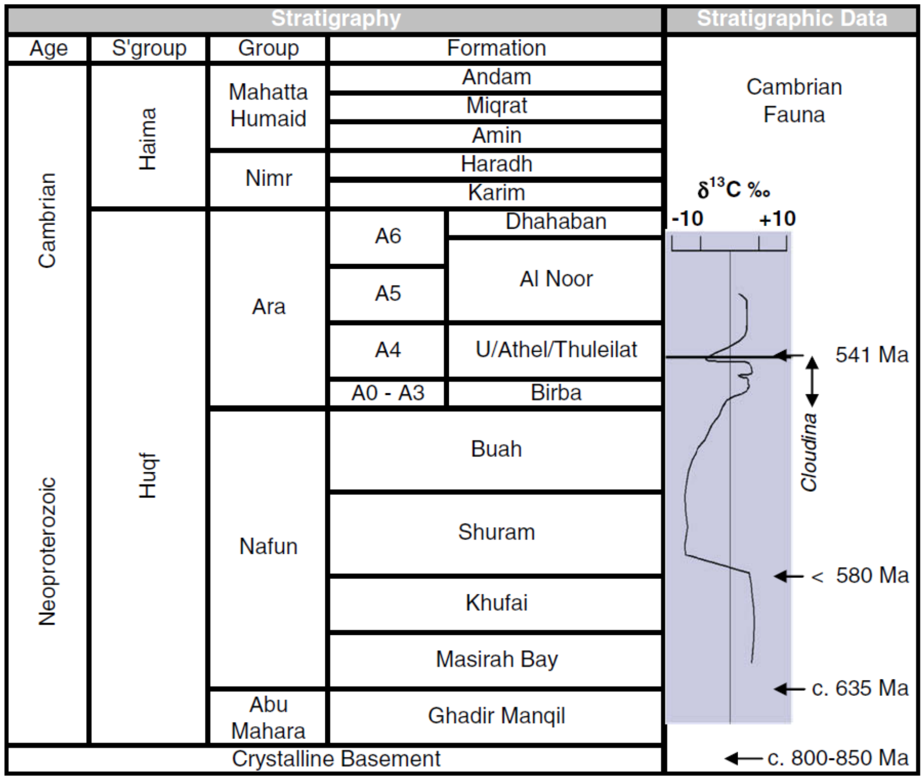
Figure 4. Location Map South Oman Salt Basin



Source: ARI, 2014

Figure 5 provides a generalized stratigraphic column for the Precambrian-Cambrian sequence and the Ara A4 formations addressed by this resource assessment.[4]

Figure 5. Generalized Stratigraphic Column Early Cambrian Strata of South Oman Salt Basin (modified from Amthor et al., 2005)

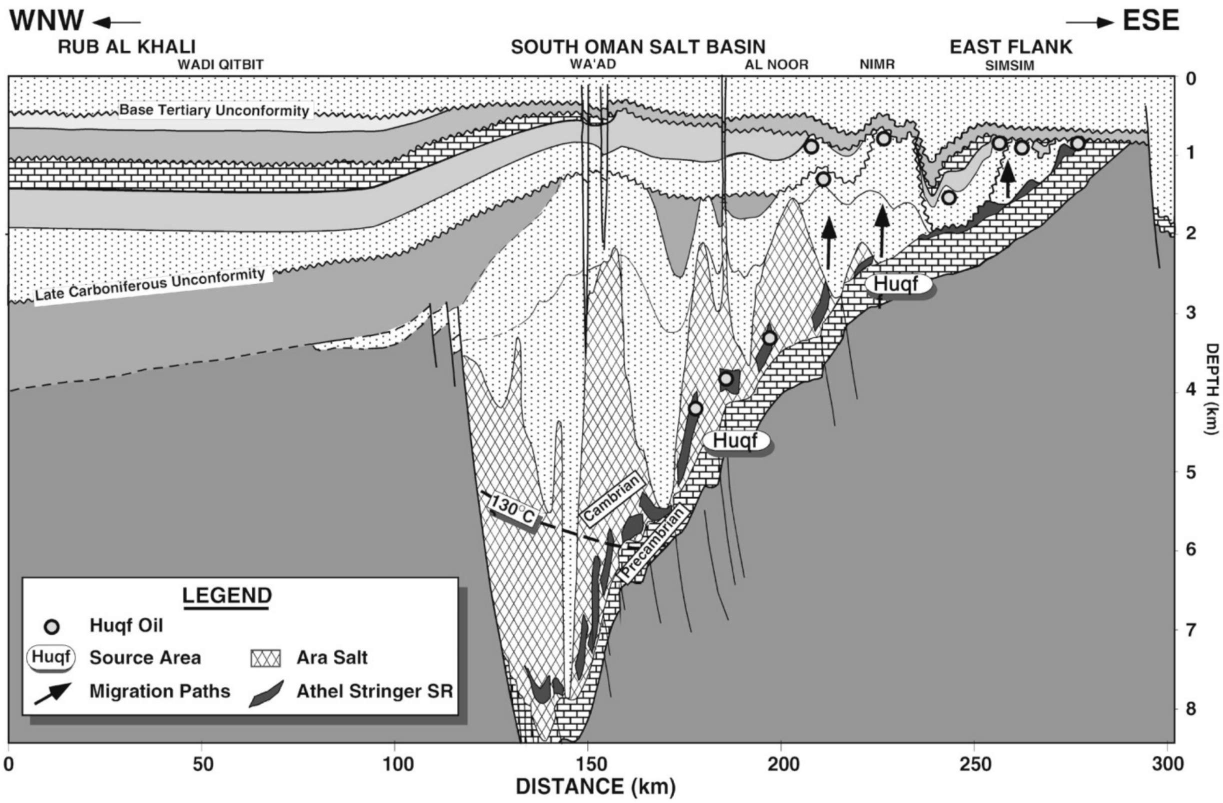


Source: Grosjean et al., 2008

The Ara A4 shales and source rocks shallow to prospective depth (less than 5,000 m) along the eastern portion of the Athel Sub-basin. The NNW-to-ESE cross-section, Figure 6, across the southeastern portion of the Athel sub-basin, shows both the geologic and depositional complexity of the Ara Formation and its shallowing to the east. Only about half of the Athel sub-basin is in the prospective depth range established for this shale resource assessment.

Recent information on the Thuleilat, Athel and U source rocks has been assembled from a series 12 of exploration wells, including seven cored wells in different portions of the Althel sub-basin. One well, the ALNR-2, was fully cored through the Al Shoumou (Athel) Formation and encountered 1,300 feet of section. In the remaining wells, more limited core samples and wireline data were gathered.[5]

Figure 6. WNW-to-ESE Cross-Section, South Oman Salt Basin



Source: Terken et al., 2001

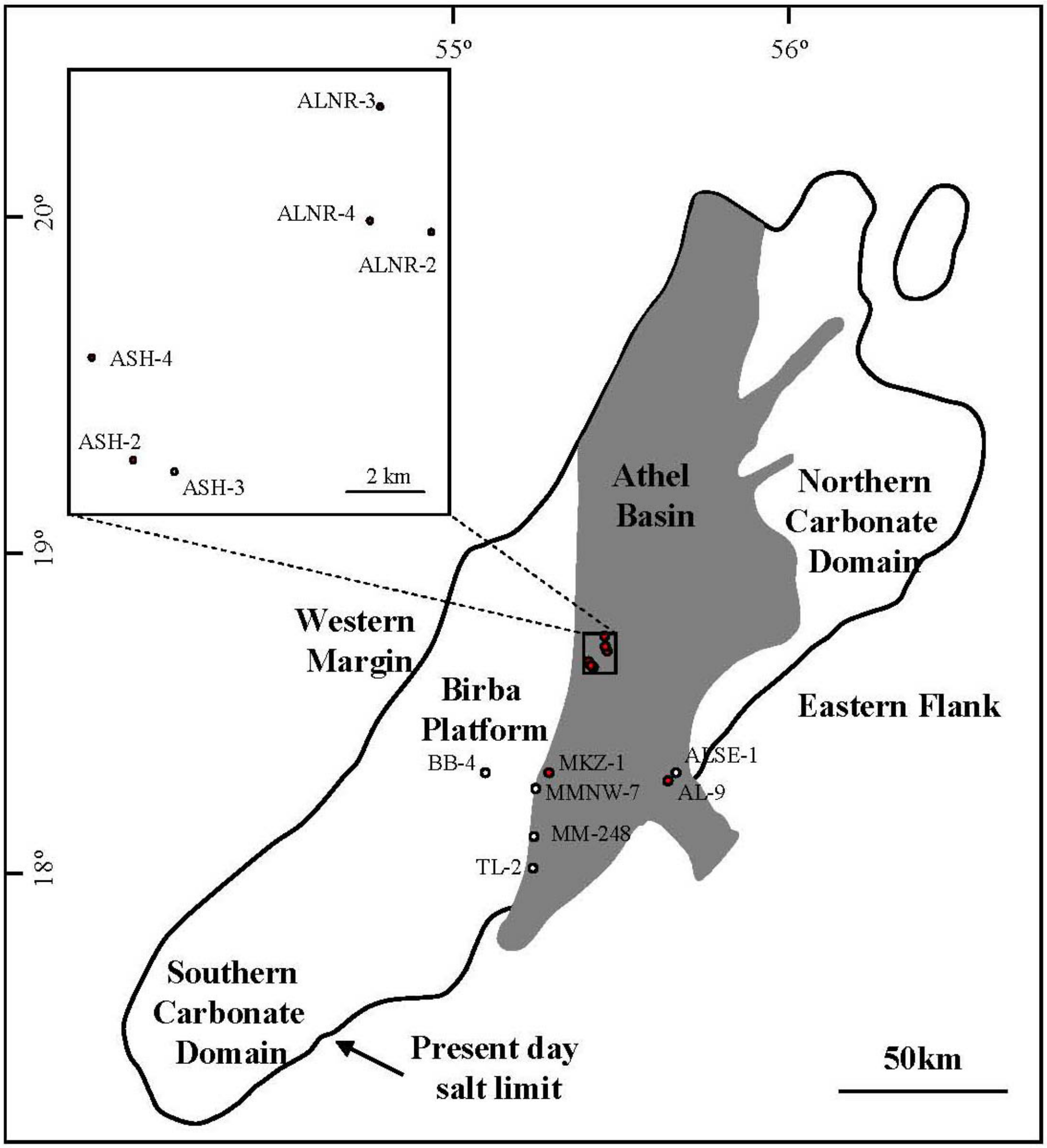
1.2 Reservoir Properties (Prospective Area)

The prospective area of the Ara Group shales and source rocks covers an area of 1,480 mi^2. Within this area, Rock-Eval analyses indicate that the Athel Silicilyte (the intrasalt siliceous Al Shomou Formation) is a primary source rock and generated large volumes of oil at relatively low temperatures. The organic matter in these marine source rocks is predominantly Type II/I kerogen. The Athel (Al Shomou) source rocks are bounded by two organic-rich shale units - - the upper Thuleilat and the basal U shales.

Recently acquired data, assembled for a PhD thesis, provided valuable new information on the shales and source rocks of the Athel sub-basin.[5] This information along with prior publications on the geology of Oman and the South Oman Salt Basin were used to establish the foundation for this shale resource assessment.

Figure 7 shows the exploration well locations in the Athel sub-basin.[5] Figure 8 provides information on depth, gross interval and the core points for the six wells in which the Athel Silicilyte was sampled.[5] Table 3 provides information on the intervals and samples collected from the core wells.[5] Table 4 provides information on TOC values for two of the Ara Group formations.[6]

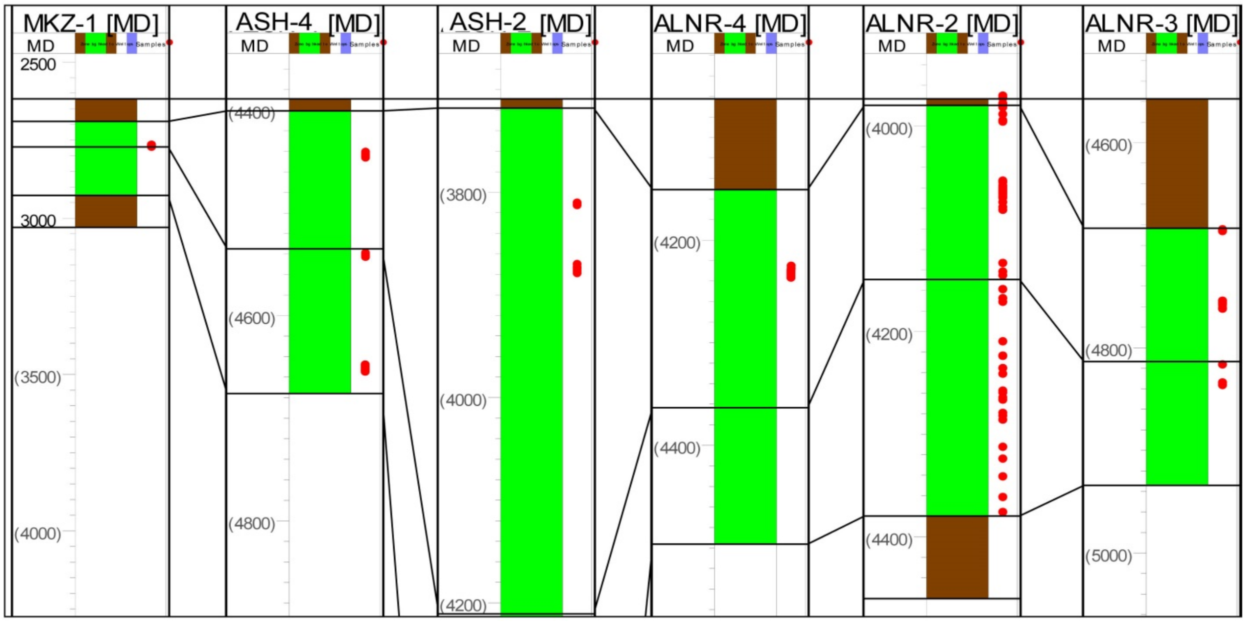
Figure 7. South Oman Salt Basin Showing the Athel Basin (grey), Carbonate Platforms (white) and Locations of Study Wells.



Source: Al Rajaibi, 2011

Figure 8. Wells From Which the Athel Silicilyte (Green) Was Sampled.

Red Circles Show Sampled Intervals



Source: Al Rajaibi, 2011

Table 3. Intervals and Number of the Samples Collected.

Well	Formation	Interval Depth/ M Measure Depth (MD)	No. of Samples
ALNR-2	Athel Silicilyte	3967-4374	48
ALNR-3	Athel Silicilyte	3861-3683,4750-4786 and 4812-4832	16
ALNR-4	Athel Silicilyte	4220-4230	8
ASH-2	Athel Silicilyte	3810-3811 and 3867-3876	8
ASH-4	Athel Silicilyte	4438-4444, 4543-4547 and 4645-4652	20
MKZ-1	Athel Silicilyte	2768.6-2774.7	7
AL-9	U Shale	5676.5-5706.8	10
Total			117

Source: Al Rajaibi, 2011

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Table 4. TOC Data by Formation and Well

Formation	Well code	Depth (m)	TOC (%wt)
Thuleilat Shale	At	1000 - 1102	8.0
	Ma	2068 - 2084	10.4
	Th	1417.5 - 1483	6.4
	Th	1520 - 1547	2.5
Athel Silicylite	At	1198 - 1425	3.4
	Ma	2104 - 2120	3.4
	Ma	2240 - 2352	2.3
	Th	1551 - 1602	4.3
	Th	1628 - 1742	2.6
U Shale	At	1425 - 1527	3.5
	At	1527 - 1650	4.9
	At	1773 - 1872	5.7
	Ma	2420 - 2460	6.4
	Th	1751 - 1833	4.0

Source: Grosjean et al., 2008

Thuleilat Shale. The depth of the Thuleilat Shale in the Athel sub-basin ranges from 5,500 to 14,000 ft, averaging 9,000 ft in the prospective area. The gross thickness of the shale is 390 ft, with a net organic-rich thickness of 293 ft. The TOC of the Thuleilat Shale ranges from 2.5% to 10.4%, averaging 6.8% and contains Type I /II kerogen.[6] The thermal maturity ranges from 1.0 to 1.3% Ro, indicating that the Thuleilat Shale is in the wet gas/condensate window.[3]

Athel (Al Shomou) Silicilyte. The Athel Silicilyte is a geologically unique source and reservoir rock entrapped within a series of salt domes. Silicilyte, also called chert, is a siliceous sedimentary rock containing a variety of quartz made of extremely fine-grained, microcrystalline, or cryptocrystalline silica. Silicilyte might encompass some clastic content in the form of clayey matter. The content of clastic matter varies from 0 to about 25%. The presence of this clayey content makes Silicilyte display properties similar to those exhibited by other shale formations such as the Monterey Shale of California.

At the time of deposition, the basin was restricted shallow-marine bounded by carbonate platforms along the basin's rift margins. The waters in the basin were anaerobic, helping preserve large amounts of organic matter as the hydrocarbon source. The rock matrix consists of up to 80% microcrystalline quartz. However, the small modal crystal size of 2 to 3 microns leads to small rock pore throats and thus low permeability. Rock Eval data suggests the hydrocarbons in the Athel Silicilyte were generated in situ.[7]

The depth of the Athel (Al Shomou) Silicilyte ranges from 6,500 to 15,000 ft in the prospective area of the Athel Sub-basin. The formation is overpressured, with two distinct trends - - one hydrostatic to slightly overpressured and one highly overpressured, reaching almost lithostatic pressure (1 psi/ft) at the upper end of the range in pressure gradients.[8] The organic-rich gross interval of the Athel (Al Shomou) Silicilyte ranges from 50 to 400 m (165 to 1,320 ft) with an average gross thickness of 225 m (740 ft) and a net thickness of 135 m (445 ft).[6]

The TOC of the Athel Silicilyte ranges from 2.3% and 4.3% (averaging 3.2%) contains Type I/II kerogen.[5] The thermal maturity of the Athel Silicilyte ranges from 1.0% to 1.3% Ro, providing light, 45^o API gravity oil and wet gas.[6] The Athel Silicilyte is reported to have high porosity, ranging up to 30%, averaging 12%, and a high hydrocarbon saturation of about 80%. The formation consists of 80% quartz, 10% clay, plus other minerals.[7]

U Shale. The depth of the U Shale ranges from 7,500 to 16,000 ft, averaging 11,000 ft in the prospective area of the Athel Sub-basin. The gross thickness of the shale is 260 ft, with a net organic-rich thickness of 195 ft. The TOC of the U Shale ranges from 3.5% to 6.4%, averaging 4.9% and contains mature Type I/II kerogen.[6] The thermal maturity ranges from 1.0% to 1.3% Ro, indicating that the U Shale contains wet gas and condensate.[3]

1.3 Resource Assessment

The prospective area of the Ara A4 shales and source rocks is constrained on the west by the 5,000m depth limit of the Athel sub-basin. On the north, south and east the prospective area is bounded by the limits of Ara A4 silicilite and shale deposition. Within the 1,480 mi^2 prospective area of the Athel sub-basin, the three Ara A4 shales and source rocks hold 59 billion barrels of risked shale oil in-place and 179 Tcf of risked shale gas in-place. The risked, technically recoverable shale resource is estimated at 3.6 billion barrels for shale oil/condensate and 22 Tcf for wet shale gas.

Thuleilat Shale. Within its 1,480 mi^2 prospective area, the Thuleilat Shale has resource concentrations of 15 million barrels of oil/condensate and 41 Bcf of wet gas per square mile. The risked resource in-place for the Thuleilat Shale in the prospective area of the Athel sub-basin (South Oman Salt Basin) is estimated at 11 billion barrels of oil/condensate and 31 Tcf of wet gas. Based on moderately favorable reservoir properties, we estimate a risked, technically recoverable shale oil resource of 0.4 billion barrels and 2 Tcf of risked, technically recoverable wet gas for the Thuleilat Shale.

Athel (Al Shomou) Silicilyte. Within its 1,480 mi^2 prospective area, the Athel Silicilyte has resource concentrations of 55.7 million barrels of oil/condensate and 171 Bcf of wet gas per square mile. The risked resource in-place for the Athel Silicilyte in the prospective area of the Athel sub-basin (South Oman Salt Basin) is estimated at 41 billion barrels of oil/condensate and 127 Tcf of wet gas. Based on favorable reservoir properties, we estimate a risked, technically recoverable shale oil resource of 2.9 billion barrels and 18 Tcf of risked, technically recoverable wet gas for the Athel Silicilyte.

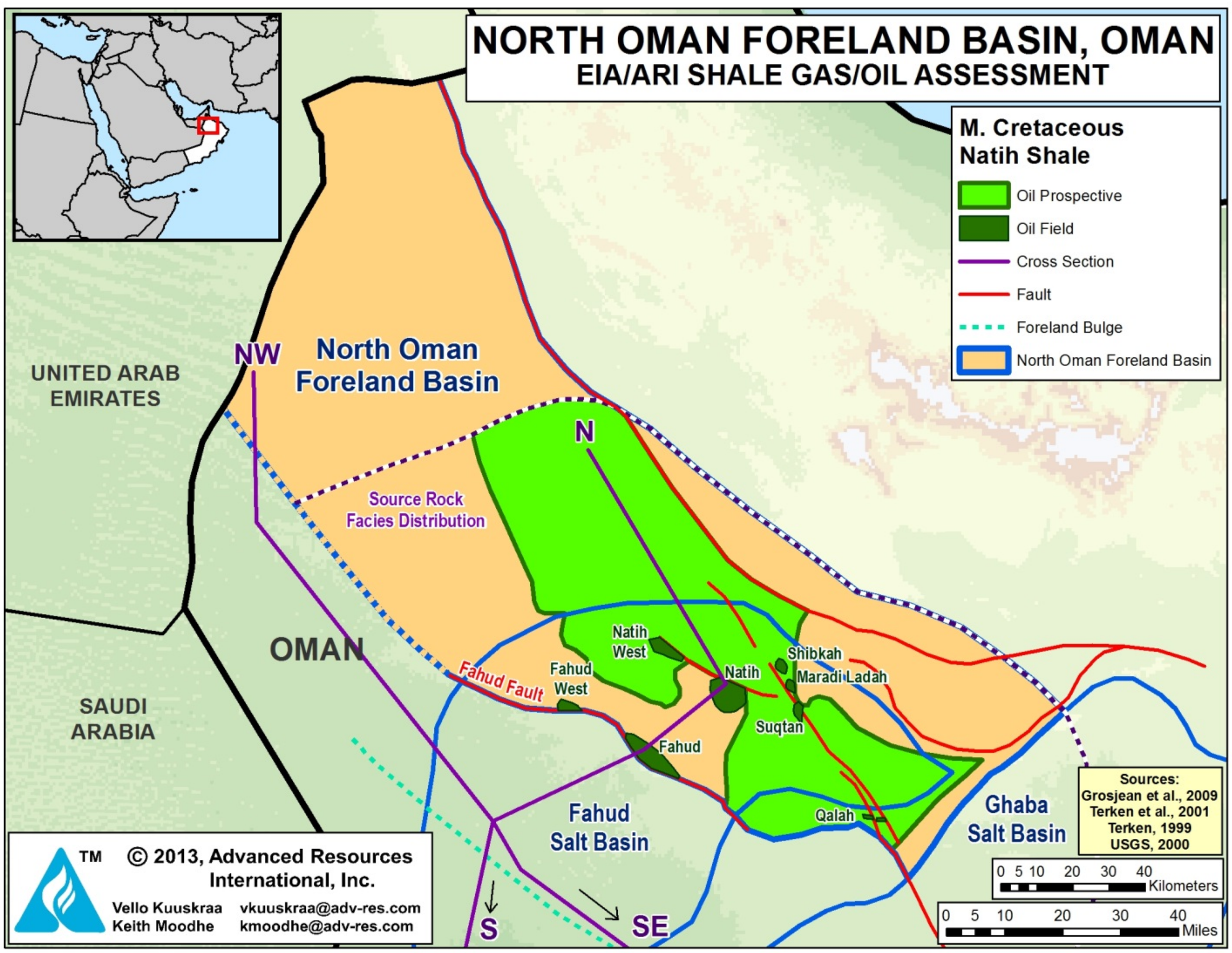
U Shale. Within its 1,480 mi^2 prospective area, the U Shale has resource concentrations of 9 million barrels of oil/condensate and 29 Bcf of wet gas per square mile. The risked resource in-place for the U Shale in the prospective area of the Athel sub-basin (South Oman Salt Basin) is estimated at 7 billion barrels of oil/condensate and 22 Tcf of wet gas. Based on moderately favorable reservoir properties, we estimate a risked, technically recoverable shale oil resource of 0.3 billion barrels and 2 Tcf of risked, technically recoverable wet gas for the U Shale.

2. NORTH OMAN FORELAND BASIN

2.1 Introduction and Geologic Setting

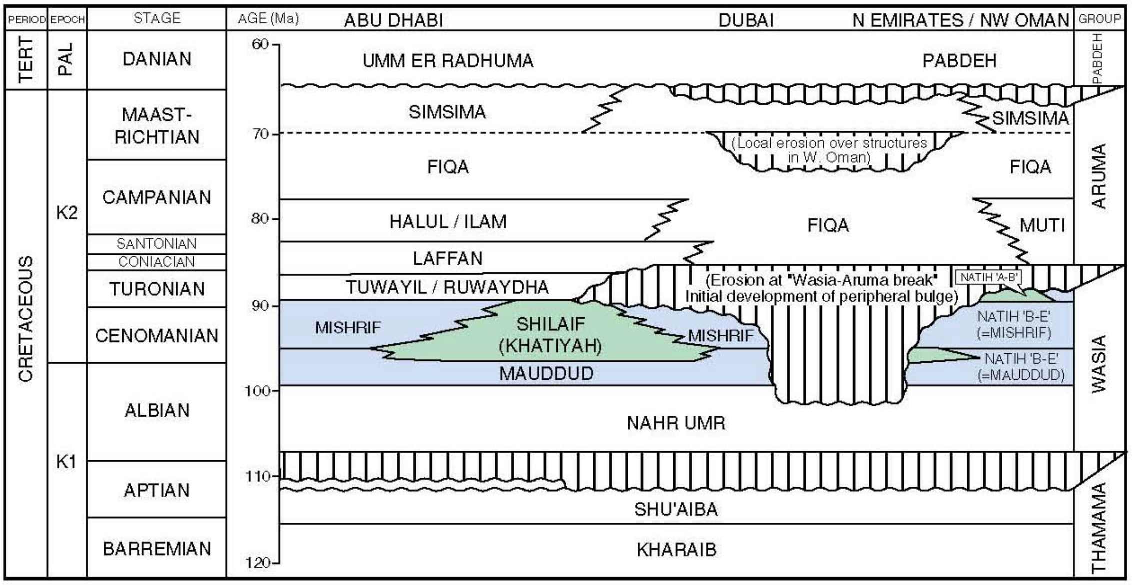
The North Oman Foreland Basin, that contains the Middle Cretaceous Natih Shale and Petroleum System, is primarily located north of the Fahud Salt Basin, Figure 9. The Natih Formation and its associated shale source rock units are part of the Wasia Group of Late Albion to Early Turonian-age, and are age-equivalent to the Mishrif, Mouddud and Shilaif formations in the United Arab Emirates. The stratigraphic column for the Cretaceous shales in southern Arabian Gulf and Oman, is provided as Figure 10.[9] Figure 11 illustrates the complex initial compressive and subsequent extensional history of this basin and the effects of tectonics on the deposition and structure of the Natih Formation.[10]

Figure 9. North Oman Foreland Basin and Cross-Section Locations



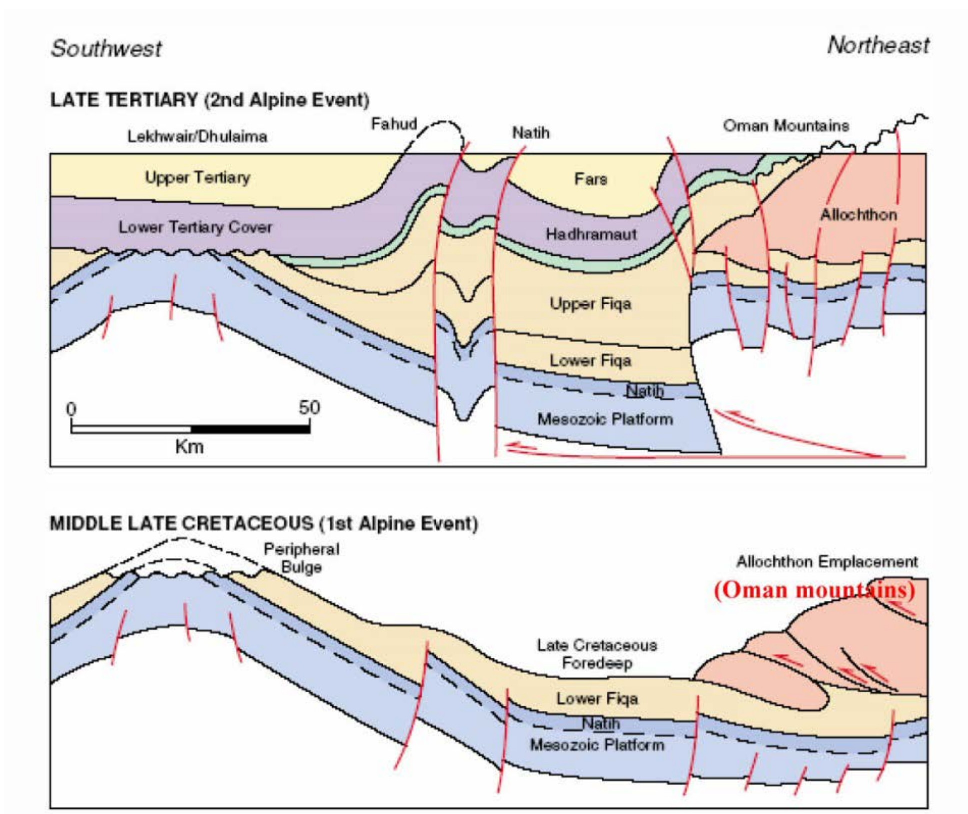
Source: ARI 2014

Figure 10. Stratigraphic Column for Cretaceous Rocks in Southern Arabian Group



Source: Van Buchem, F.S.P. et al., 1996

Figure 11. Tectonic History and Cross-Section of the Natih Petroleum System



Source: Terken, 1999.

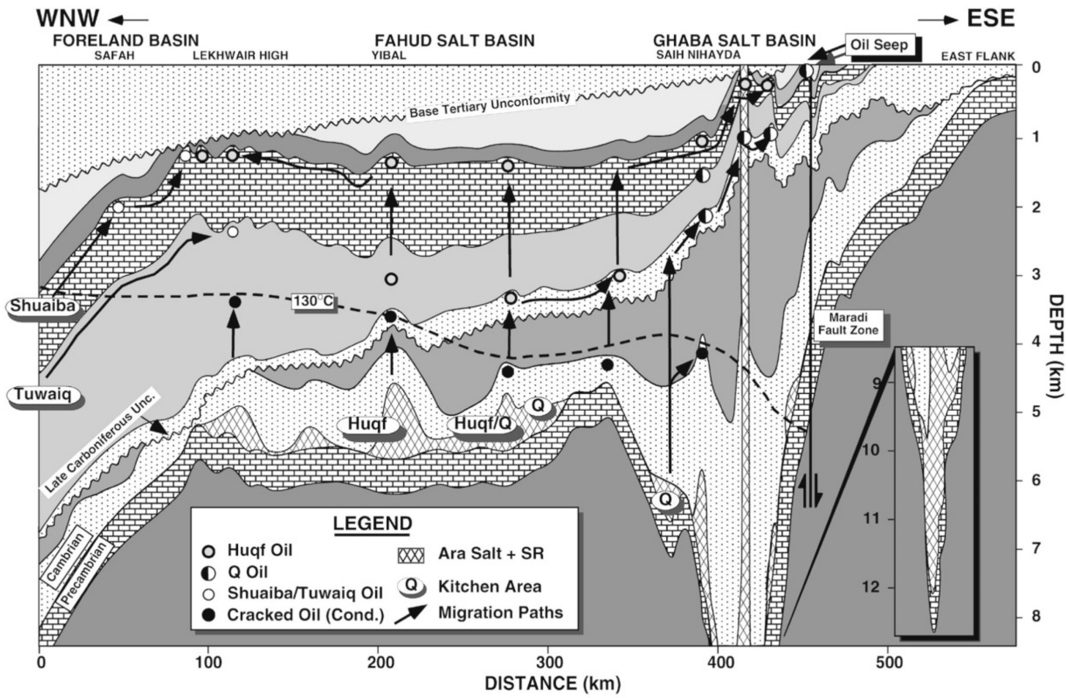
The North Oman Foreland Basin and the Natih Petroleum System are bounded on the east by the Oman Mountain Thrust Front, on the west by the Middle-Late Cretaceous upthurst, called the Peripheral Bulge, on the south by the Fahud fault, and on the north by the border of Oman and the United Arab Emirates.

The Natih Formation is 1,300 feet thick and consists of a series of seven mostly carbonate litho-stratigraphic units, A through G. Natih Units B and E are underlain by organic-rich, shaly limestone intervals that also include clay-rich marls, Figure 17.[3] The organics in these two source rocks consist of Type I and Type II kerogen. Given its moderate depth and source rock types, the Natih Shale is mainly oil prone, with gas generation in only the deepest areas of this foreland basin.

The regional structural setting of the North Oman Foreland Basin is defined by some 200 exploration wells plus seismic. The eastern and southern portions of the basin are complex due to compression from the Oman Mountains and the deep seated Fahud and Natih fault systems. Partial cross-sections for the Natih Formation and its lateral extent are shown by two cross-sections, Figures 12 and 13.[3]

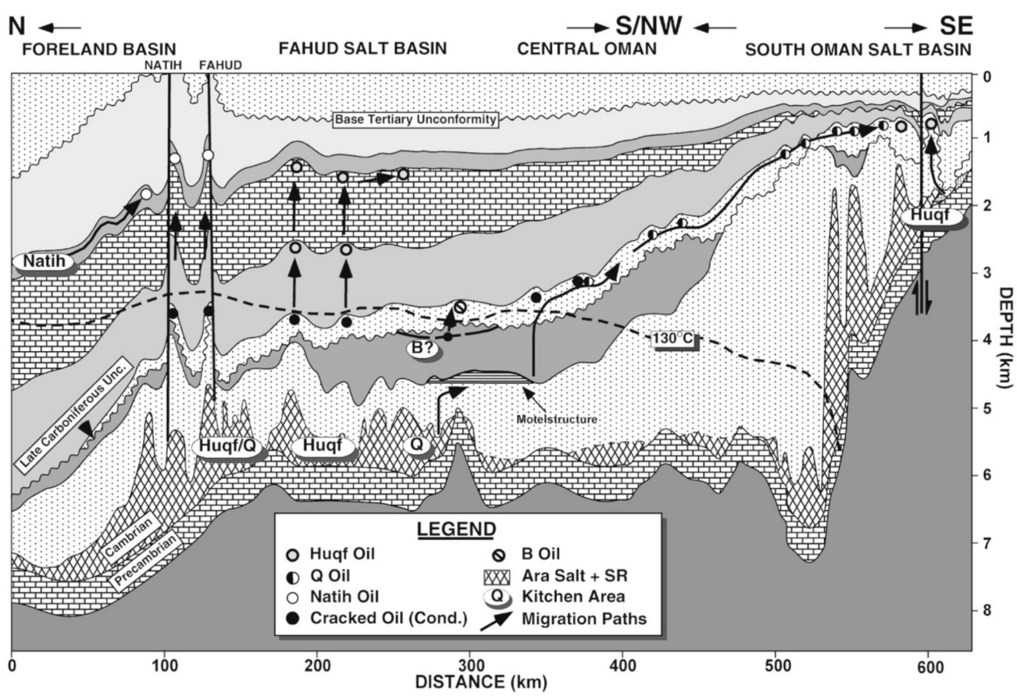
While the areal extent of the Cretaceous Natih Shale and Petroleum System in the North Oman Foreland Basin is limited, encompassing about 7,800 mi^2, past work indicates the Natih is a most efficient hydrocarbon system. Basin modeling indicates that the shale source rocks of Natih Petroleum System have generated 88 billion barrels of hydrocarbons, with over 8 billion barrels of oil in-place discovered to date and nearly 2 billion barrels booked as proved reserves in numerous oil fields. Much of this medium gravity, 32^o API oil is trapped in two giant structures - - the Natih (630 million barrels) and the Fahud (910 million barrels) oil fields.

Figure 12. Northwest-to-Southeast Cross-Section, Foreland and Other Basins of Oman



Source: Terken et al., 2001

Figure 13. North-to-South Cross-Section, Foreland and Other Basins of Oman



Source: Terken et al., 2001

2.2 Reservoir Properties (Prospective Area)

Natih B Shale. The prospective area of the Natih B Shale in the North Oman Foreland Basin encompasses 2,380 mi^2. In this prospective area, the depth of shale generally ranges from 3,000 to 9,000 ft, averaging about 4,500 ft. The shale is assumed to be normally pressured. The gross reservoir interval in the prospective area ranges from 150 to 180 ft in thickness, with an average organic-rich net pay of about 108 ft. Figure 14 provides the gamma ray and resistivity logs for the Natih-3 well, identifying the depth and thickness of the Natih B Shale.[10]

The TOC of the Natih B Shale ranges from 2% to 15%, averaging about 5%.[10] The shale has thermal maturity that ranges from 0.7% to 0.9% Ro, averaging 0.8% Ro as illustrated on the burial history graph of the Natih Formation, Figure 15.[10]

Natih E Shale. The North Oman Foreland Basin also contains a deeper Natih E Shale. However, because of its lower TOC and considerably lower thickness, the Natih E Shale is not considered as prospective and has not been quantitatively assessed in this study.

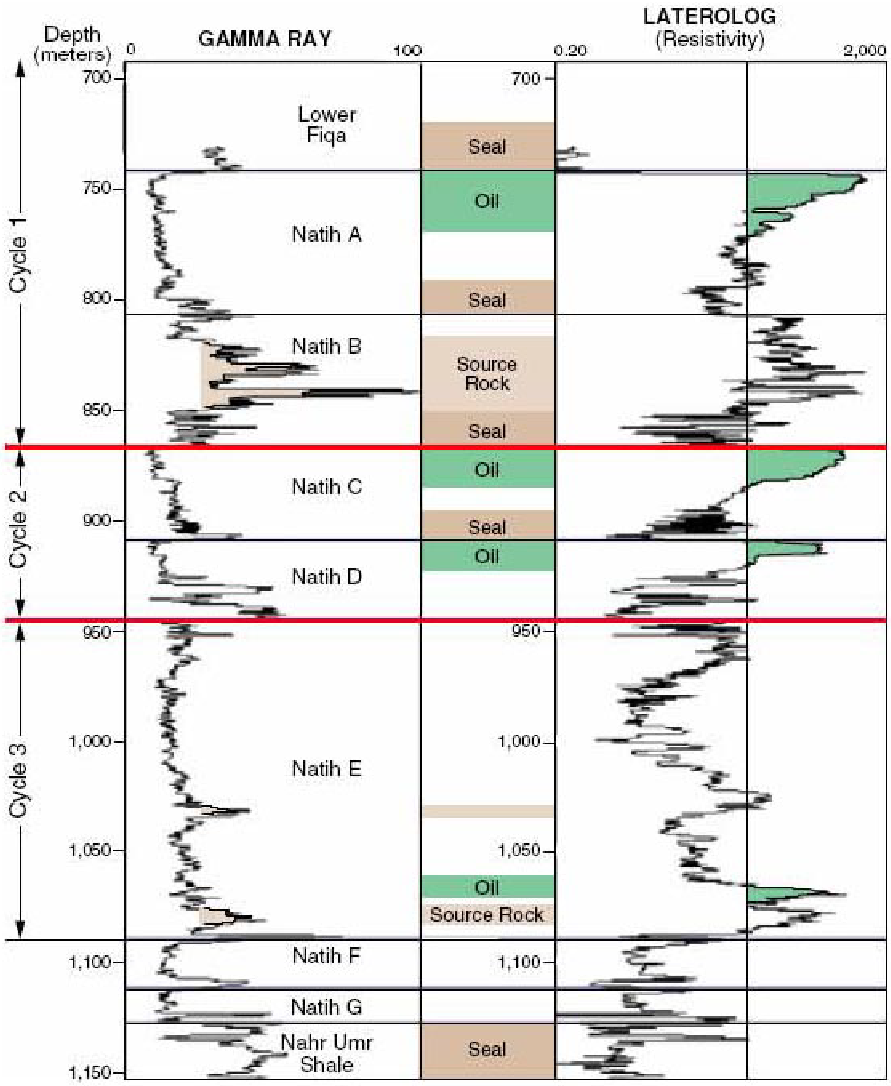
2.3 Resource Assessment

The prospective area for the Natih B Shale is constrained by the Oman Mountain Thrust Front on the east, the Middle-Late Cretaceous upthrust on the west, and the Fahud fault (Fahud Salt Basin) to the south. The extent of the shale source rock is limited by a platform carbonate rim facies.[9]

Within the 2,380-mi^2 prospective area for oil, the Natih B Shale has a resource concentration of 20 million barrels of oil per mi^2 plus modest volumes of associated gas.

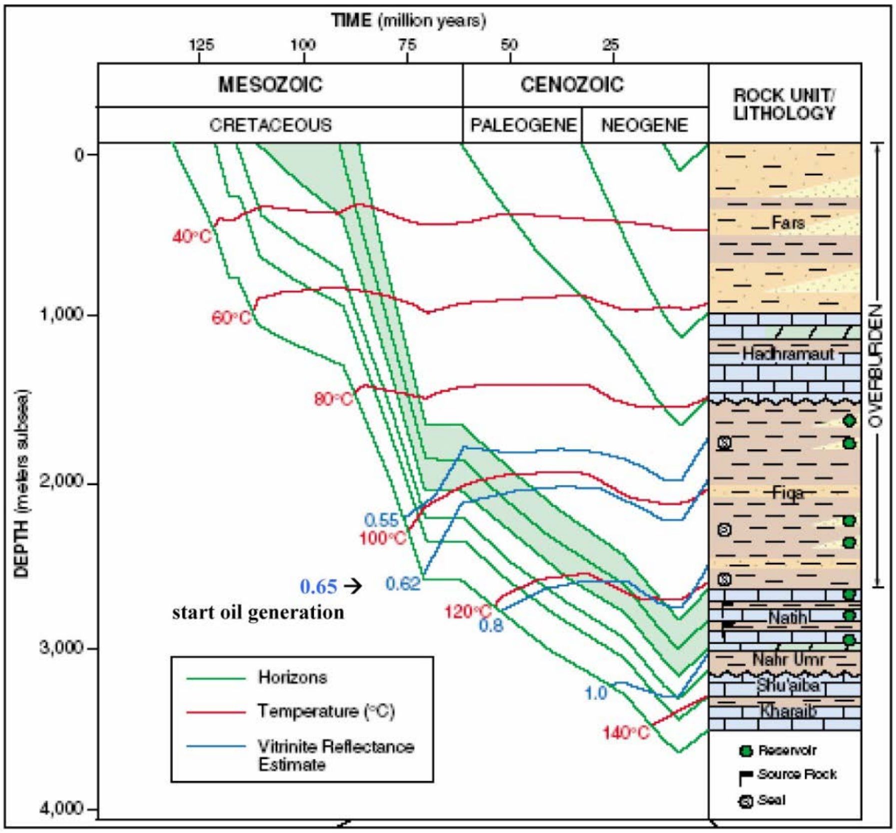
The risked resource in-place for the shale oil prospective area of the North Oman Foreland Basin is estimated at 24 billion barrels plus 8 Tcf of associated shale gas. Based on moderately favorable reservoir properties, we estimate a risked, technically recoverable shale oil resource of 0.9 billion barrels plus nearly 1 Tcf of associated shale gas for the Natih B Shale.

Figure 14. Natih-3 Well Log Showing Major Sequences and Litho-Stratigraphic Units.



Source: Terken, 1999

Figure 15. Burial History of the Natih Petroleum System, Foreland Basin, Oman.



Source: Terken, 1999

3. RUB' AL-KHALI BASIN

3.1 Introduction and Geologic Setting

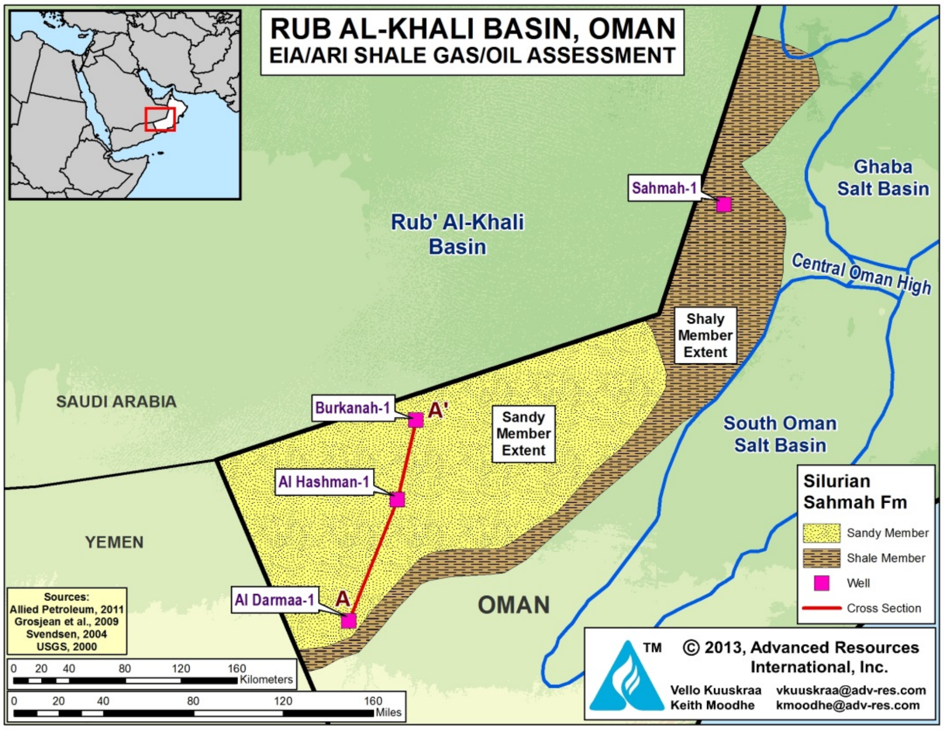
The Rub' Al-Khali ("the empty quarter") Basin, located mainly in southeastern Saudi Arabia, extends across the Saudi Arabi border into west-central Oman. The basin is underlain by the "world class" Lower Silurian Sahmah Shale ("hot shale") that has served as the source rock for much of the oil and gas produced in Northern Africa as well as the Middle East. In Oman, this shale unit is called the Sahmah Shale and is equivalent to the Qusaiba Shale of the Qalibah Formation in Saudi Arabia, the Butra Shale in Jordan, and the Tanezzuft Shale in Libya.

The Sahmah Formation Shale Member extends across an area of about 22,000 mi^2 of the Rub' Al-Khali Basin in Oman and is overlain in part by the Sahmah Formation Sandy Member, Figure 16. Using a 100 ft cut-off value for the Lower Silurian Sahmah Shale, the prospective area for shale hydrocarbons is estimated at 9,400 mi^2. A series of deep exploration wells - - Al Darmaa-1, Al Hashman-1, Burkanah-1 and the Suhmah-1 discovery well - - provide control for the thicker, higher maturity Sahmah Shale in the southwestern portion of Oman as well as information on the areal extent of favorable shale deposition to the north, Figure 16.

The Sahmah Shale is a Type I/Type II marine shale providing both oil and gas depending on its thermal maturity. In Oman, the Sahmah Shale is thermally immature along its shallower eastern basin area, becoming progressively more mature as the shale deepens toward the Oman/Saudi Arabia border. As such, this basin area has oil, wet gas/condensate, and dry gas windows.

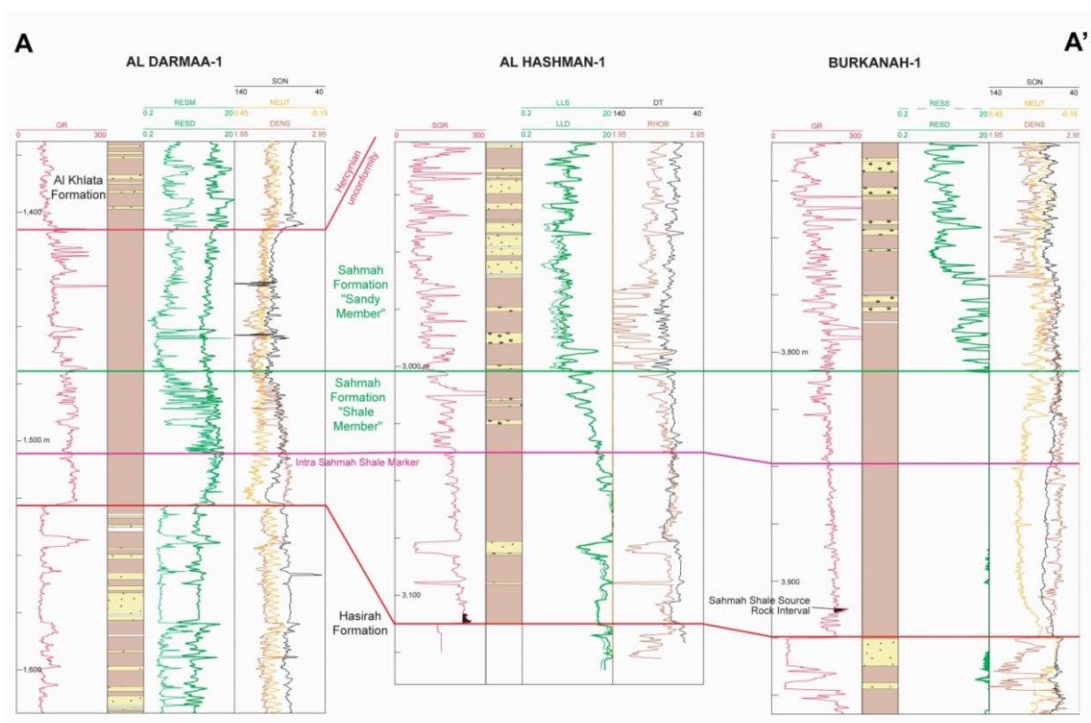
The information for the Sahmah Shale has been derived from a total of 16 exploration wells that have been drilled in the Oman portion of the basin, including the most recent Al Darmaa-1 and Burkanah-1 wells in the east portion of the basin, noted on Figure 16. A three-well cross-section, incorporating two of the recently drilled wells, shows the correlation of the Sahmah Shale and Sahmah Sandy Member in the southern portion of the Rub' Al-Khali Basin, Figure 17.[11]

Figure 16. Areal Extent of Silurian Sahmah Shale, Rub' Al-Khali Basin, Oman



Source: ARI, 2014

Figure 17. Well Log Correlation, Sahmah Shale Member, Rub' Al-Khali Basin, Oman



Source: Svendsen, N.B., 2004

3.2 Reservoir Properties (Prospective Area)

The depth of the basal Silurian Sahmah Shale in the 9,400 mi^2 prospective area, in the eastern margin of the Rub' Al-Khali Basin in Oman, ranges from 9,000 to 13,000 ft. The dry gas prospective area is at 12,800 ft of depth, the wet gas/condensate prospective area is at 11,400 ft of depth, and the oil prospective area is at 10,000 ft of depth. Based on analog data we assume that the shale in this area is moderately overpressured. The organic-rich gross interval of the Sahmah Shale is typically 100 to 200 ft and has a favorable net to gross ratio. (The equivalent Silurian Qusaiba Shale in the Rub' Al-Khali Basin of Saudi Arabia can reach a thickness of 250 ft with TOC values as high as 14% although typically the Qusaiba Shale has 100 feet of net thickness and a TOC of 4%.)[12] Figure 18 provides an isopach map of the Sahmah Shale, illustrating shale thickening toward the west-central portion of the prospective area along the Oman and Saudi Arabia border. The net pay in the dry gas prospective area averages 171 ft. In the wet gas/condensate prospective area the net pay averages 135 ft. In the oil prospective area the net pay averages 113 ft.

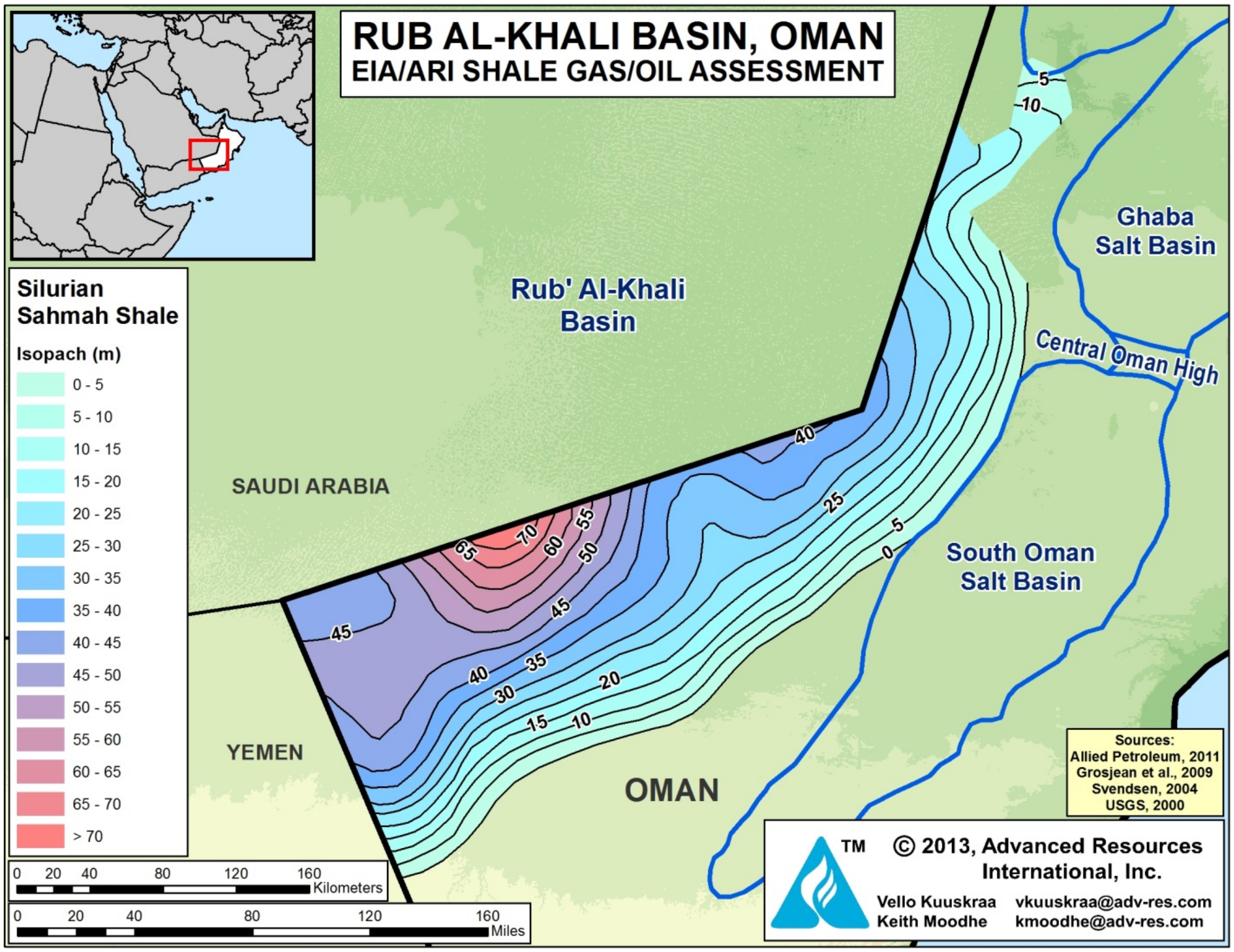
The TOC of the Sahmah Shale ranges from 2% to 4%, with an average value of 3%, as shown by the TOC measurements from sidewall cores and cuttings in the Burkanah-1 well, Figure 19.[11] The thermal maturity of the shale in the oil prospective area ranges from 0.7% to 1.0% Ro. In the wet gas/condensate area, the thermal maturity ranges from 1.0% to 1.4% Ro, and in the dry gas prospective area, toward the basin center, the thermal maturity ranges from 1.4% to 2% Ro. Figure 20 illustrates the three thermal maturity windows of the Sahmah Shale in Oman's portion of the Rub' Al-Khali Basin.

3.3 Resource Assessment

The prospective area of the basal Silurian Sahmah Shale in the Rub' Al-Khali Basin of Oman is limited on the west by the Oman/Saudi Arabia border, on the east and north by the 100 ft gross pay contour, and on the south by the Oman/Yemen border.

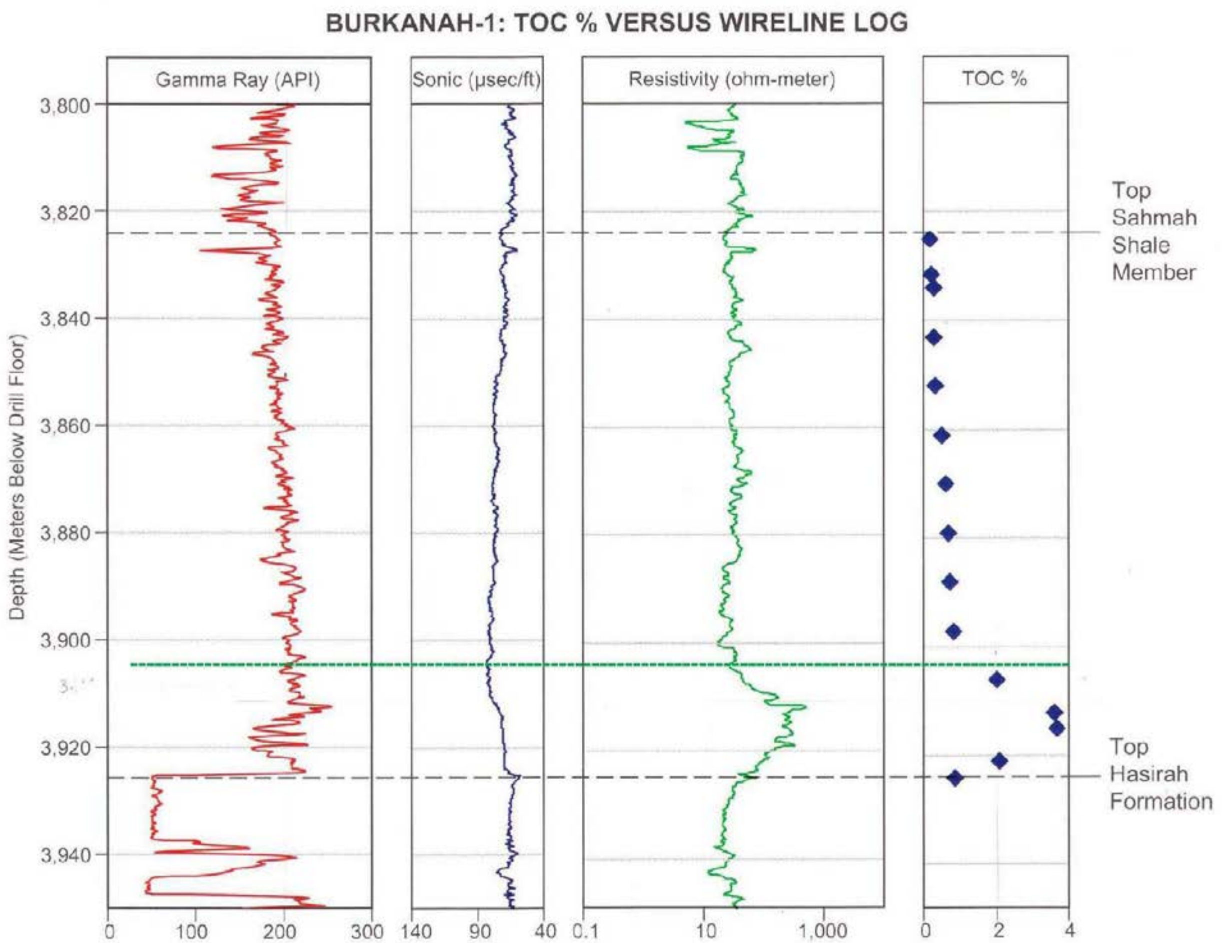
Within the 3,680 mi^2 prospective area for oil, the Sahmah Shale has a resource concentration of 13 million barrels of oil/mi^2 plus associated shale gas. Within the 3,350 mi^2 prospective area for wet gas and condensate, the Sahmah Shale has resource concentrations of 11 Bcf/mi^2 for wet gas and 5 million barrels/mi^2 for condensate. Within the 2,370 mi^2 prospective area for dry gas, the Sahmah Shale has a resource concentration of 73 Bcf/mi^2.

Figure 18. Basal Silurian Sahmah Shale Isopach Map



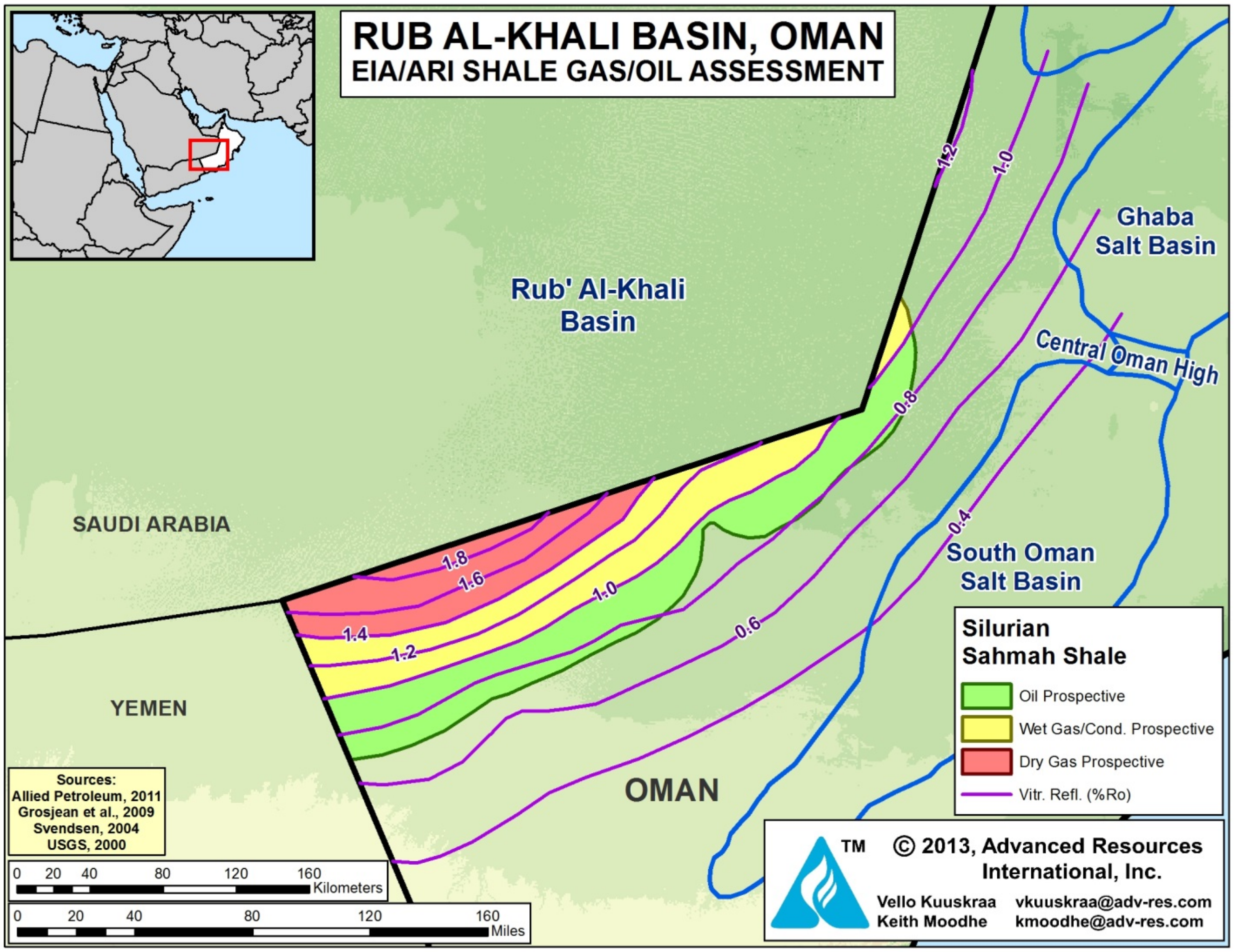
Source: ARI, 2014

Figure 19. Total Organic Content (TOC) Measurement in the Sahmah Shale from Sidewall Cores and Ditch Cuttings Posted with Wireline Logs for Burkanah-1.



Source: Svendsen, N.B., 2004

Figure 20. Sahmah Shale Vitrinite Reflectance



Source: ARI, 2014

The risked resource in-place for the shale oil prospective area of the Rub' Al-Khali Basin of Oman is estimated at 24 billion barrels of oil plus 23 Tcf of associated shale gas. Based on moderately favorable reservoir properties, we estimate a risked, technically recoverable shale oil resource of 1.2 billion barrels plus 2 Tcf of associated shale gas. The risked resource in-place for the wet gas/condensate area of the Oman portion of this basin is estimated at 19 Tcf of wet gas and 9 billion barrels of condensate, with 2 Tcf of wet gas and 0.4 billion barrels of condensate as the risked, technically recoverable resources. The risked resource in-place for the dry gas prospective area of the Rub' Al-Khali Basin of Oman is estimated at 86 Tcf, with a risked, technically recoverable shale gas resource of 22 Tcf.

3.4 Recent Activity

In late 2011, Oman's government signed an Exploration and Production Sharing Agreement (EPSA) with the Canadian-based oil company Allied Petroleum Exploration Inc. (APEX) for developing Block 36 in the southern portion of the Rub' Al-Khali Basin in Oman. Block 36 encompasses an area of 18,556 km^2 (7,165 mi^2). While the primary targets of the exploration program are the conventional structures, Block 36 appears to be extensively underlain by the Lower Silurian Sahmah Shale that serves as the key source rock.

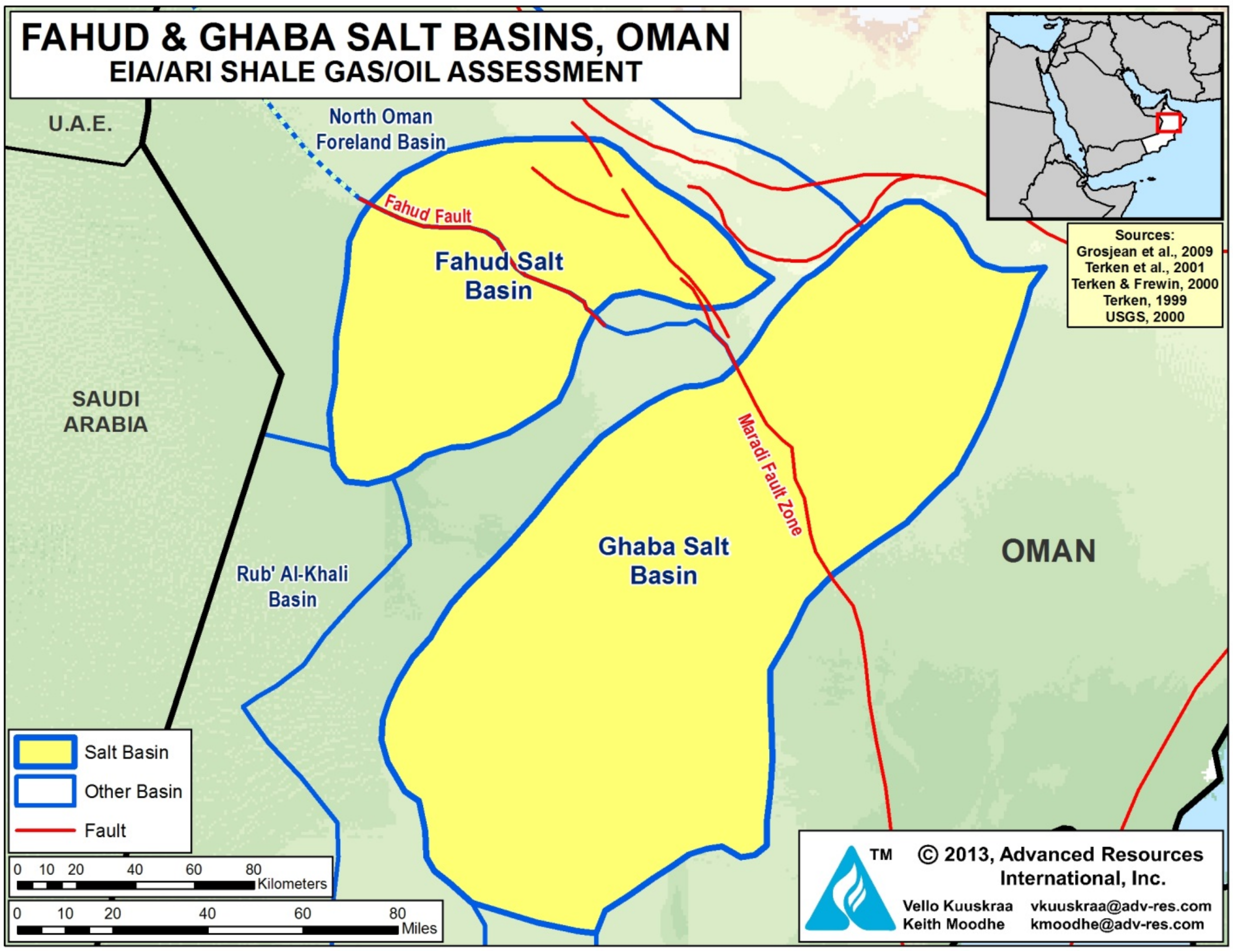
In mid-2013, APEX farmed out 75% of its Block 36 lease area to DNO International, with DNO proposing to drill two exploration wells and shoot a minimum of 600 miles of 2D seismic.[13]

4. FAHUD AND GHABA SALT BASIN

4.1 Introduction and Geologic Setting

The Fahud and Ghaba Salt basins contain the Late Precambrian-Cambrian Huqf Supergroup source rocks, including the Abu Mahara, Kutai, Shuram, Buah and Ara Formations, Figure 21.

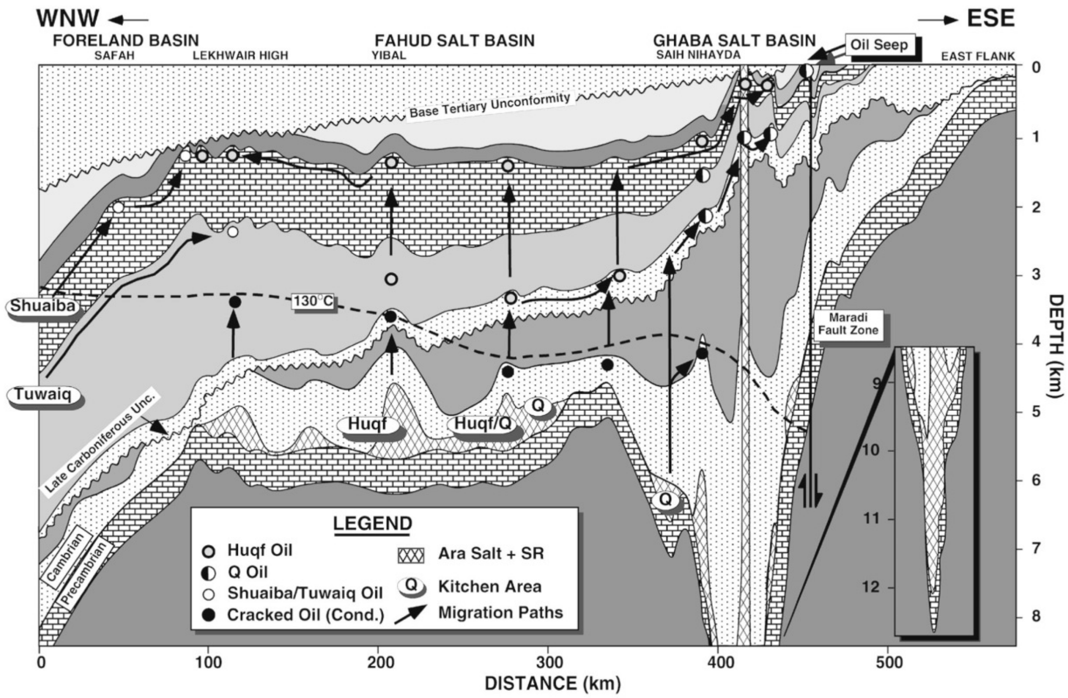
Figure 21. Fahud and Ghaba Salt Basin



Source: ARI, 2014

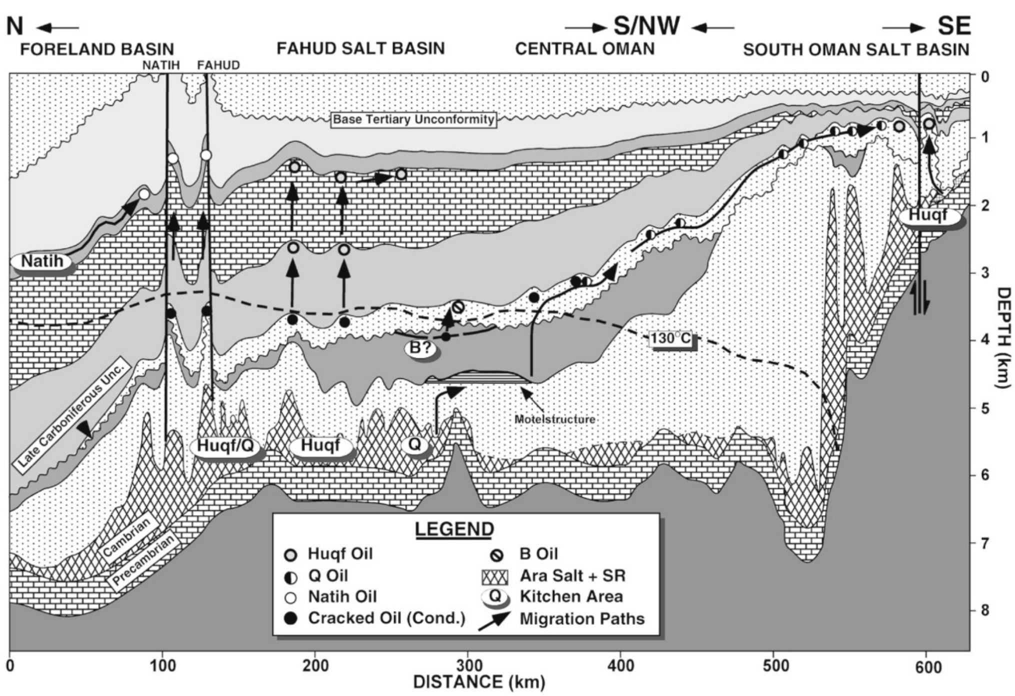
However, as shown on a series of north-to-south cross-sections, except in the South Oman Salt Basin, the Huqt Supergroup formations are too deeply buried (below the 5,000 m shale formation cut-off established for this study) to be included in the quantitative portion of the shale resource assessment, Figures 22 and 23.

Figure 22. Northwest-to-Southeast Cross-Section, Fahud and Ghaba Salt Basins of Oman



Source: Terken et al., 2001

Figure 23. North-to-South Cross-Section, Fahud and Ghaba Salt Basins of Oman



Source: Terken et al., 2001

Advanced Resources International, Inc.

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