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Technically Recoverable Shale Oil and Shale Gas Resources:

Turkey

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Executive Summary

Introduction

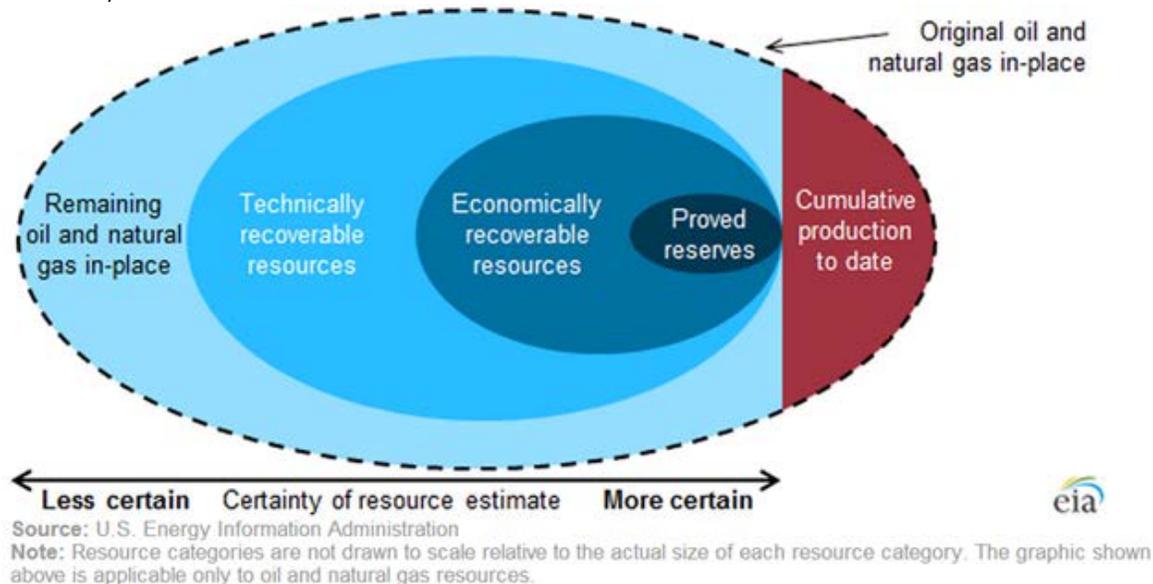
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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



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 resources⁴ 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:

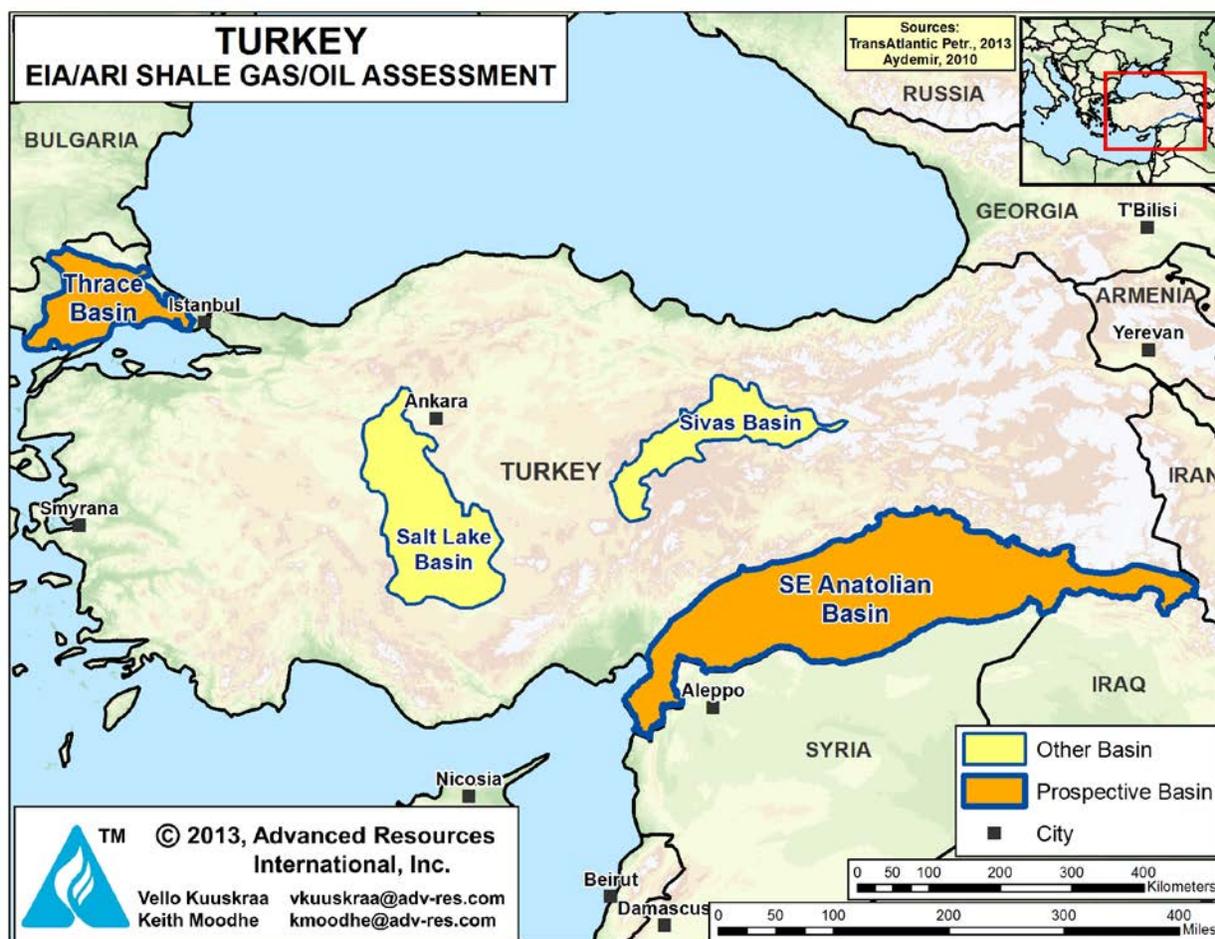
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

XXVI. TURKEY

SUMMARY

This resource assessment addresses two shale basins in Turkey - - the Southeast Anatolia Basin in southern Turkey and the Thrace Basin in western Turkey, Figure XXVI-1. These two basins have active shale oil and gas exploration underway by the Turkish national petroleum company (TPAO) and several international companies. Turkey may also have shale gas resources in the Sivas and Salt Lake basins. However, only limited reservoir data are available for these two lightly explored basins.

Figure XXVI-1. Major Shale Basins of Turkey



Source: ARI, 2013.

May 17, 2013

XXVI-1

We estimate that the Dadas Shale in the SE Anatolian Basin and the Hamitabat Shale in the Thrace Basin contain 163 Tcf of risked shale gas in-place, with 24 Tcf as the risked, technically recoverable shale gas resource, Table XXVI-1. In addition, we estimate that these two shale basins also contain 94 billion barrels of risked shale oil in-place, with 4.7 billion barrels as the risked, technically recoverable shale oil resource, Table XXVI-2.

Table XXVI-1. Shale Gas Reservoir Properties and Resources of Turkey

Basic Data	Basin/Gross Area		SE Anatolian (32,100 mi ²)		Thrace (6,500 mi ²)		
	Shale Formation		Dadas		Hamitabat		
	Geologic Age		Silurian-Devonian		M. - L. Eocene		
	Depositional Environment		Marine		Marine		
Physical Extent	Prospective Area (mi ²)		3,540	500	150	210	680
	Thickness (ft)	Organically Rich	394	377	500	500	500
		Net	216	207	250	250	250
	Depth (ft)	Interval	6,000 - 11,500	5,500 - 13,000	10,000 - 13,000	13,000 - 16,400	14,000 - 16,400
Average		9,000	9,500	11,500	14,500	15,000	
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.6%	3.6%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	2.00%
	Clay Content		Med./High	Med./High	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi ²)		48.2	91.4	34.7	81.8	104.1
	Risked GIP (Tcf)		102.4	27.4	1.9	6.2	25.5
	Risked Recoverable (Tcf)		10.2	6.9	0.1	1.2	5.1

Table XXVI-2. Shale Oil Reservoir Properties and Resources of Turkey

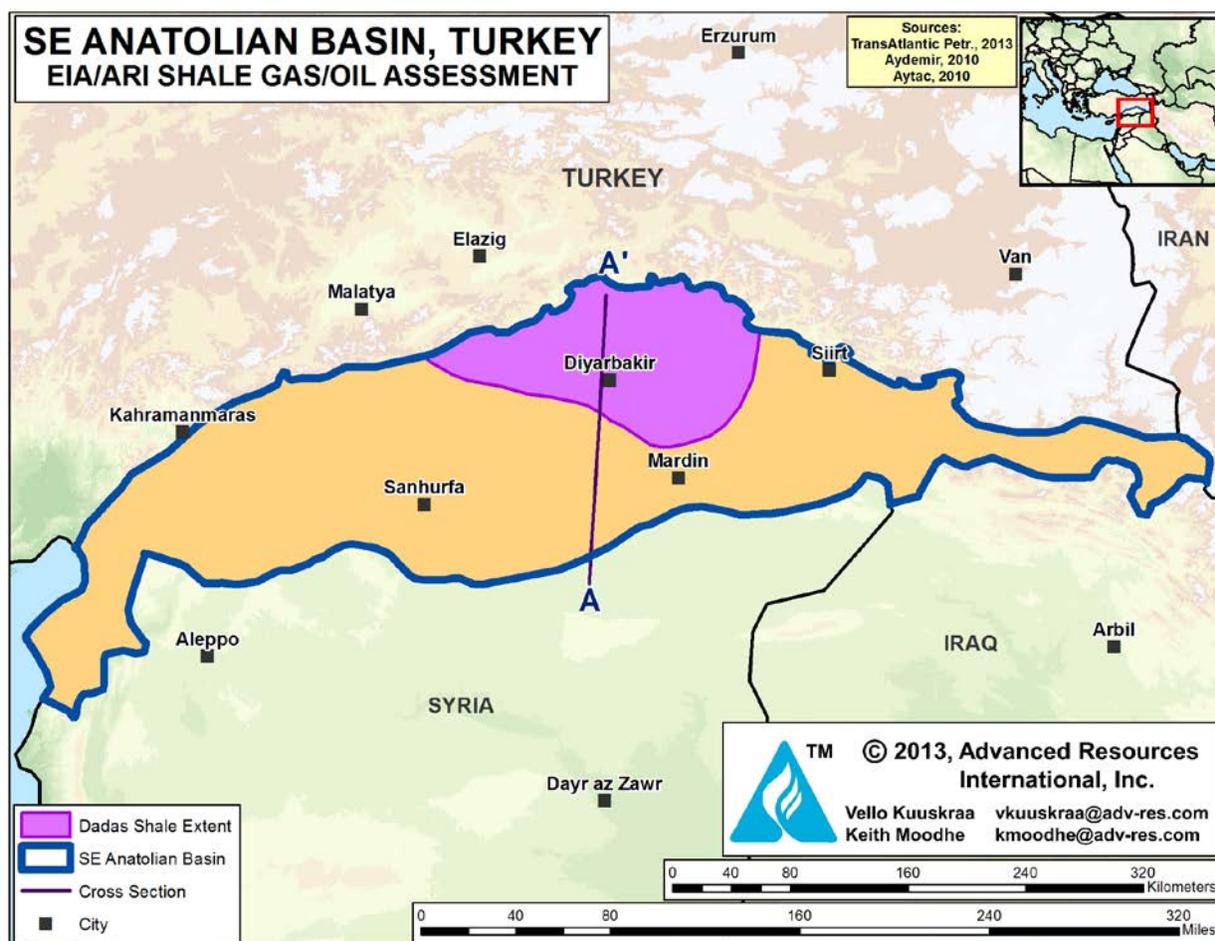
Basic Data	Basin/Gross Area		SE Anatolian (32,100 mi ²)		Thrace (6,500 mi ²)	
	Shale Formation		Dadas		Hamitabat	
	Geologic Age		Silurian-Devonian		M. - L. Eocene	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi ²)		3,540	500	150	210
	Thickness (ft)	Organically Rich	394	377	500	500
		Net	216	207	250	250
	Depth (ft)	Interval	6,000 - 11,500	5,500 - 13,000	10,000 - 13,000	13,000 - 16,400
Average		9,000	9,500	11,500	14,500	
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.6%	3.6%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Med./High	Med./High	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi ²)		41.0	14.2	33.8	8.0
	Risked OIP (B bbl)		87.1	4.2	1.8	0.6
	Risked Recoverable (B bbl)		4.36	0.21	0.07	0.02

1. SOUTHEAST ANATOLIAN BASIN

1.1 Introduction and Geologic Setting

The SE Anatolian Basin covers a large, 32,100-mi² area in southeastern Turkey. The basin contains the Silurian Dadas Shale, located in the central basin portion of the basin, Figure XXVI-2. The basin is bounded on the north by the Zagros suture zone, which marks the juncture of the Arabian and Eurasian tectonic plates. The basin is bounded on the south and east by the Syria, Iraq and Turkey border. The SE Anatolian Basin is an active, primarily oil-prone basin with about 100 oil field discoveries to date. While the bulk of the oil production is from Mardin Group carbonate formations, the basin also has deep Paleozoic reservoirs such as the Bedinan Sandstone that contains light, 40° to 50° API gravity oil.

Figure XXVI-2. Outline and Depositional Limit of Dadas Shale, SE Anatolian Basin



Source: ARI, 2013.

In the early Paleozoic, Silurian-age shale formations were deposited throughout the northern Gondwana super-continent (present day North Africa and the Middle East), following sea level rise caused by melting of Ordovician-age glaciers. Regional lows and offshore deltas with anoxic conditions preserved organic-rich sediments. The SE Anatolian Basin was part of the northern edge of the Gondwana super-continent, which later separated to form the Arabian plate. As such, the SE Anatolian Basin shares similar geology with the oil-producing regions of Saudi Arabia and Iraq, although it experienced more intense faulting and thrusting from collision with the Eurasian Plate.

The SE Anatolian Basin contains three source rocks - - the deep Silurian Dadas Shale, the Late Cretaceous Karabogaz organic-rich limestone, and the organic-rich deposits in the Triassic-Jurassic Jodi Group.¹ The most prospective of these source rocks is the Silurian Dadas Shale, the basal member of which, called Dadas I, is the organic-rich shale interval evaluated in this resource study, Figure XXVI-3.² In general, the Dadas Shale is oil prone but may be wet gas-prone in the deeper northern area of the basin.

ARI mapped a 4,040-mi² area of the Dadas Shale in the north-central portion of the SE Anatolian Basin as prospective for shale gas and shale oil development. The prospective area is bounded on the east by the 10-m Dadas I Shale isopach, on the south and west by the -1,500-m sub-sea depth contour for the Dadas Shale (approximately equivalent to an R_o of 0.7%), and on the north by the Hazro Uplift.² Figure XXVI-4¹ provides a north to south cross-section through the center of the basin, illustrating the presence and depth of the Dadas Shale. (The location of the cross-section is shown on Figure XXVI-2).

1.2 Reservoir Properties (Prospective Area)

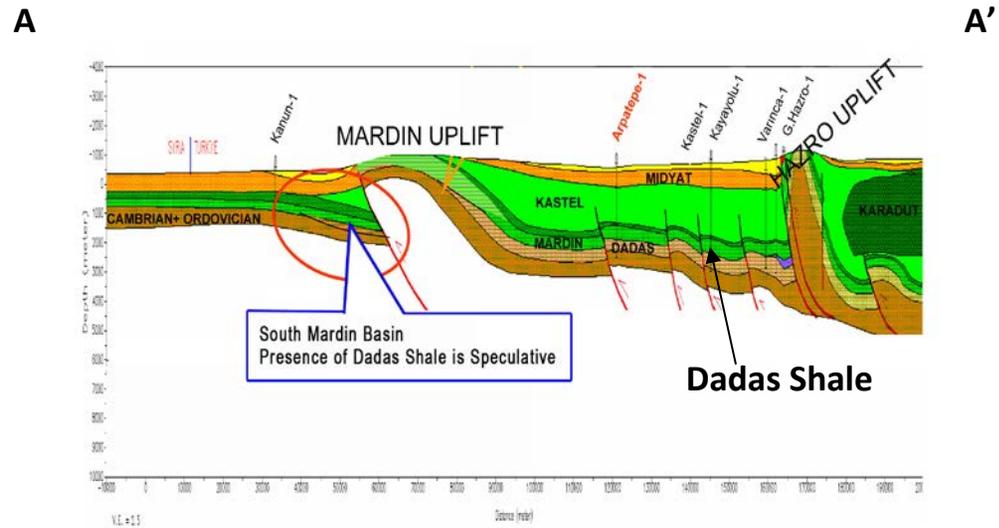
The Dadas Shale of the SE Anatolian Basin contains a 3,540-mi² central area prospective for shale oil and a smaller, northern 500-mi² prospective area for wet gas and condensate, Figure XXVI-5. Because of limited data on vitrinite reflectance, we have used T_{max} of 455°C as a proxy for the R_o of 1.0% boundary between the oil prone and the wet gas/condensate prone area, Figure XXVI-6.³ The southern 0.7%- R_o boundary for the oil window follows the -1,500-m sub-sea depth contour for the Dadas Shale.

Figure XXVI-3. SW Anatolia Basin Stratigraphic Column²

AGE	GROUP	FORMATION	MEM.	LITHOLOGY	THICK m..
PERMIAN	UPPER	TANIN	C	[Lithology]	50 - 250
			B	[Lithology]	50 - 150
			A	[Lithology]	25-150
		KAS		[Lithology]	15-50
DEVONIAN	LOWER-MID U	DIYARBAKIR	KAYAYOLU	[Lithology]	50-15*
			L	[Lithology]	
			F5	[Lithology]	
			F4	[Lithology]	100-200
SILURIAN	U	Dadas	III	[Lithology]	100-400
			II	[Lithology]	
			I	[Lithology]	
ORDOVICIAN	LOWER MID-UPPER	HABUR	BEDINAN	[Lithology]	500-1500
			SEYDISEHIR	[Lithology]	200-?
CAMBRIAN	U	DERIK	SOSINK	[Lithology]	400-?

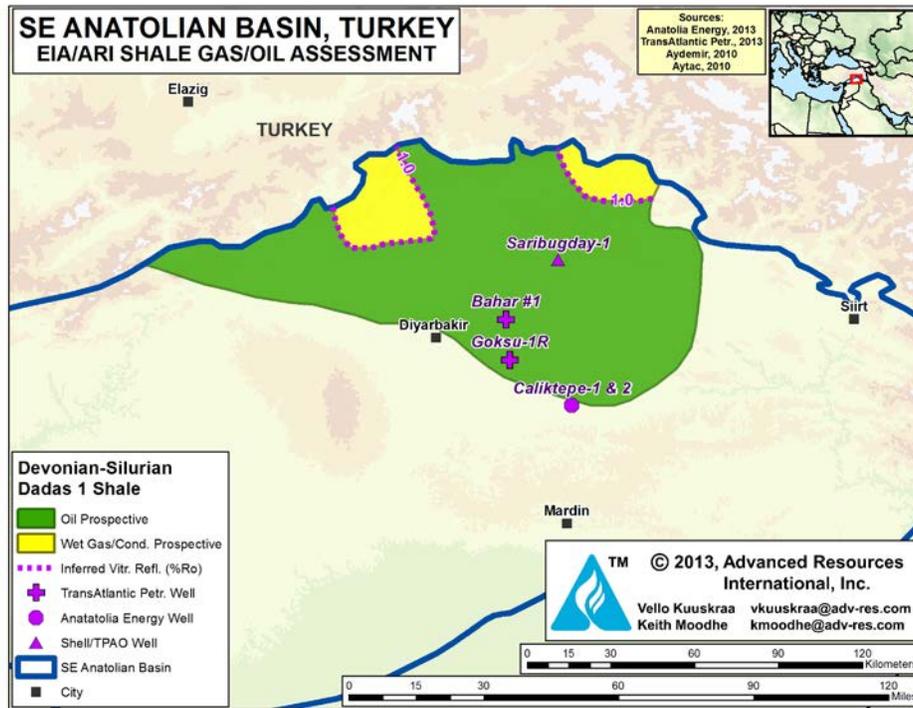
Source: A. Aydemir, 2010.

Figure XXVI-4. SW Anatolian Basin Cross-Section¹



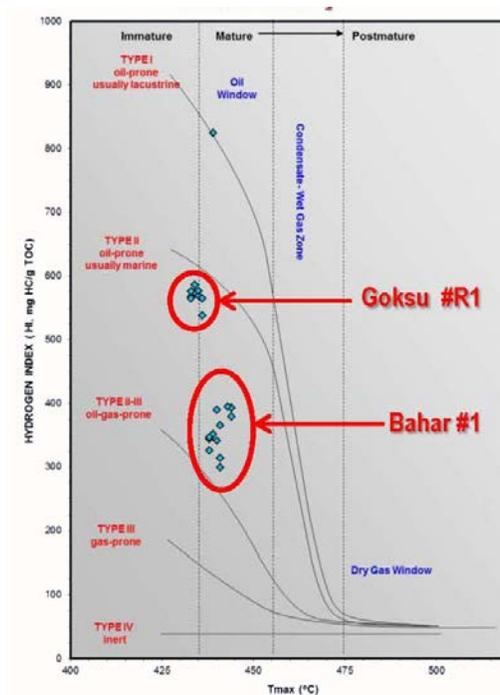
Source: E. Aytac, 2010.

Figure XXVI-5. Dadas Shale Prospective Area, SE Anatolian Basin, Turkey



Source: ARI, 2013

Figure XXVI-6. Relationship of Tmax and Thermal Maturity for Basal Dadas I Shale



Source: M. Mitchell, 2013.

A series of key wells provided valuable information on the reservoir properties of the Dadas Shale. The key wells included: (1) the Goksu-#1R (with 30 feet of core, detailed rock mineralogy and micro-seismic data); (2) the Bahir-#1 (with core-based vitrinite reflectance information and reservoir pressure data); and (3) the Caliktepe-#2 (with 5 Dadas Shale cores). The location of these three key reservoir characterization wells, plus the Shell/TPAO Saribugday-#1 well are shown on Figure XXVI-5.

The depth of the Dadas Shale in the SE Anatolian Basin ranges from 6,000 ft to 13,000 ft, averaging 9,000 ft in the oil window and 9,500 ft in the wet gas and condensate window. The total Dadas Shale Formation has an extensive gross thickness of over 1,000 ft, with its lower, 200-ft thick basal portion considered the primary organic-rich source rock.²

Based on core analyses information from the key wells discussed above, the Dadas I Shale contains Type II (oil and gas) marine kerogen with a TOC of 2% to 7%, averaging 3.6%. The formation oil samples tested at 40° to 50° API. The shale matrix has a porosity of 6% to 7% with low water saturation. The mineralogy of the Dadas Shale in the Bahir #1 well showed moderately high clay (34%) with 39% quartz.³ The formation is over-pressured.

1.3 Resource Assessment

Within the 3,540-mi² oil prospective area, the Dadas Shale in the SE Anatolian Basin has an estimated resource concentration of 41 million barrels/mi² of oil plus associated gas. We estimate 87 billion barrels of risked shale oil in-place and 102 Tcf of associated shale gas in-place, with 4.4 billion barrels of shale oil and 10 Tcf of associated shale gas as the risked, technically recoverable shale resources.

Within the 500-mi² wet gas and condensate area, the Dadas Shale has resource concentrations of 91 Bcf/mi² for wet gas and 14 million barrels/mi² for condensate. We estimate the Dadas Shale contains a risked wet shale gas in-place of 27 Tcf, with 7 Tcf as the risked, technically recoverable shale gas resource. This area also holds risked shale oil/condensate in-place of 4 billion barrels, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

Overall, we estimate that the Dadas I Shale in the SE Anatolian Basin contains 91 billion barrels of risked shale oil in-place and 130 Tcf of risked shale gas in-place, with 4.6 billion barrels of shale oil/condensate and 17 Tcf of wet shale gas as the risked, technically recoverable shale resources.

While the Dadas Shale formation has relatively favorable properties for gas development, the prospective areas exhibit heavy faulting and the shale has moderate clay content, two factors that could pose significant development risks.

1.4 Recent Activity

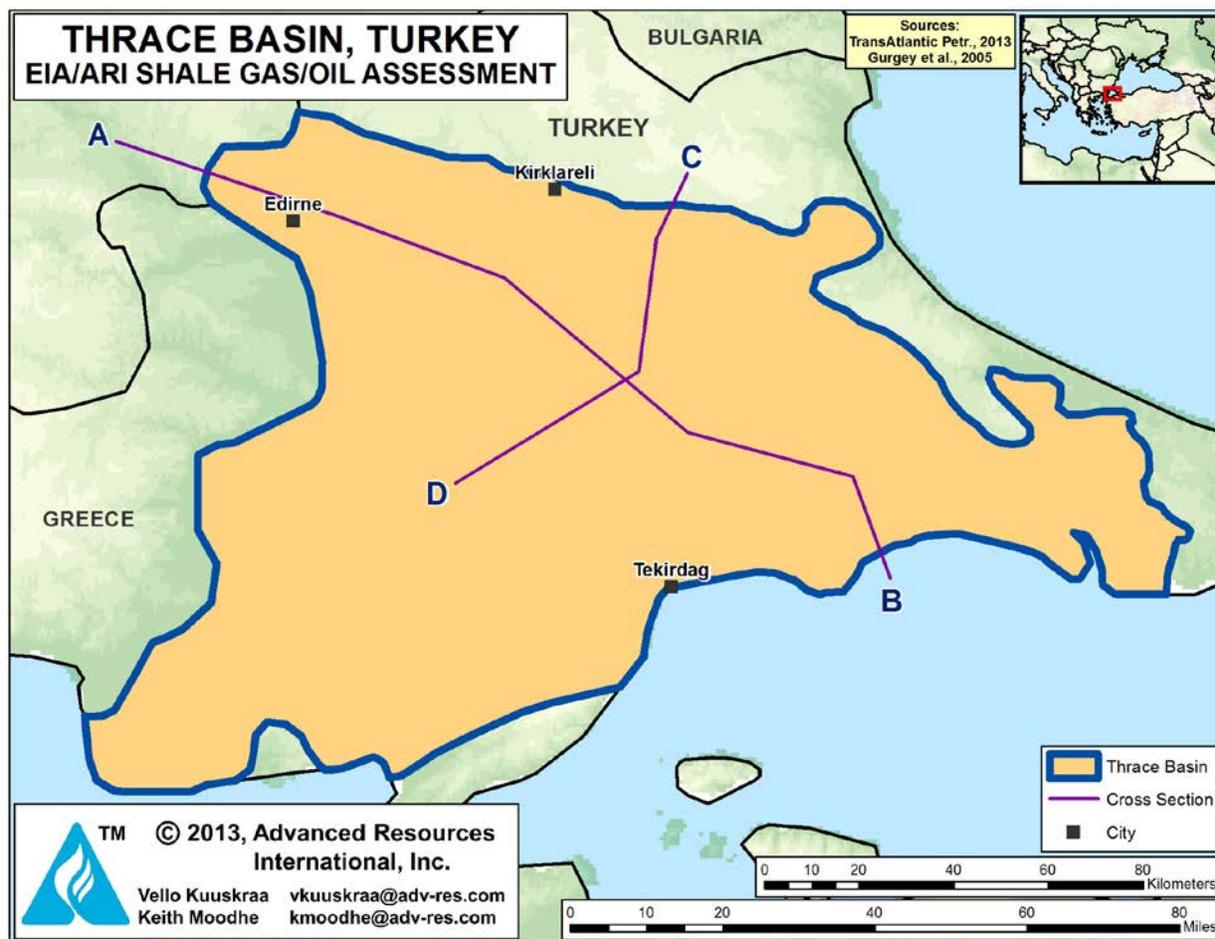
TPAO, the Turkish National Oil Company, and Shell are currently drilling the Saribugday-#1 well in License Area 4925 testing the Dadas Shale. Shell has announced a five-well exploration program for the area. Anatolia Energy drilled their first Dadas Shale evaluation well, Caliktepe-#2, on their Bismil lease area in early January, 2012.⁴ The shale section in the well was cored, providing valuable information on the reservoir properties of the Dadas Shale, as reported earlier in this chapter. TransAtlantic Petroleum reported flowing gas and light oil from their two Dadas Shale test wells, Goksu-#1 and Bahir-#1. TPAO reported their Oikсор well flowed 152 barrels of 60° API gravity oil during a three-hour test in the Dadas Shale.

2. THRACE BASIN

2.1 Introduction and Geologic Setting

The Thrace Basin covers an 6,500-mi² area in the European portion of Turkey. The Basin is bordered on the north by the Istranca Massif, by the Rhodope Massif on the west and the Sakarya Massif on the south, Figure XXVI-7. Tertiary-age (Eocene through Miocene) deposits reach nearly 30,000 ft thick in the center of the basin. Following the discovery of the Hamitabat Gas Field in 1970, the Thrace Basin became Turkey's most important gas producing area, accounting for 85% of the country's total gas production. About 350 wells have been drilled in thirteen gas fields and three oil fields in this basin. The Thrace Basin is primarily a tight sand gas play, sourced by adjoining and deeper shales.

Figure XXVI-7. Outline and Depositional Limits of the Thrace Basin



Source: ARI, 2013.

The Thrace Basin contains two shale source rock formations with oil and gas potential, the Middle Eocene Hamitabat Formation and the Lower Oligocene Mezardere Formation, Figure XXVI-8.⁵ The Hamitabat Formation contains a thick sequence of sandstone, shale and marl deposited in a shallow marine environment. The Mezardere Formation, deposited in a deltaic environment, contains inter-bedded layers of sandstone, shale and marl. In the deeper areas of the basin, these shales have sufficient thermal maturity to be in the gas window.

The prospective areas for the shales in the Thrace Basin are based on total organic content, appropriate depth and adequate thermal maturity. Because of their complex depositional environments, accurately locating prospective shale intervals within the Mezardere and Hamitabat formations requires detailed geologic data, and a more extensive set of cross-sections than were available for this basin, Figure XXVI-9.⁵

The 1,040-mi² prospective area identified for the Hamitabat Formation is based primarily on depth and thermal maturity data. The Hamitabat Formation contains modest-size oil (150-mi²) and wet gas/condensate (210 mi²) areas and a larger, 680-mi² prospective area for dry gas. However, a major portion of the dry gas area in the center of the basin is deeper than the 5,000-m threshold used for this analysis and thus was not included in this prospective area. While we mapped the areal extent and thermal maturity of the Mezardere Shale, we did not identify a prospective area for this shale because the recent core data showed TOC values less than 2%.⁶

2.2 Reservoir Properties (Prospective Area)

Hamitabat Shale. The deepest and oldest shale formation in the Thrace Basin, the Hamitabat Shale is also the most thermally mature. The shale is in the dry gas window at depths of 14,000 to 16,400 ft in the center of the basin, with R_o ranging from 1.3% to over 2.5%.⁷ Organic content is highly variable throughout the formation, ranging from fractions of a percent to above 6%. Within the prospective area, TOC ranges from 1% to 4%, averaging 2%. The net shale of the Hamitabat Shale averages 250 feet, Figure XXVI-10.⁸

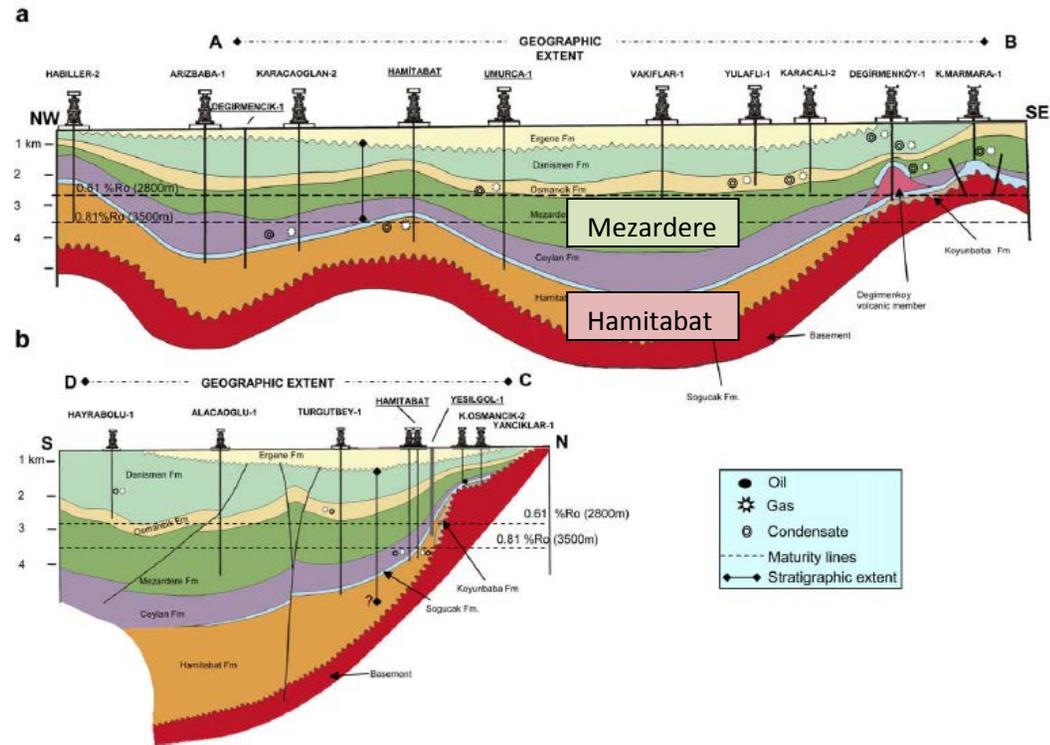
Mezardere Shale. The Mezardere Shale is a second thick, regionally extensive shale interval in the Thrace Basin, Figure XXVI-11.⁸ However, because of low organic content (<2%), this shale formation has not been quantitatively assessed.

Figure XXVI-8. Thrace Basin Stratigraphic Column⁵

CHRONOSTRATIGRAPHY		LITHO-STRATIGRAPHY	THICKNESS (m) ^a	
TERTIARY	MIOCENE	Ergene Fm.	800-1000	
		Danişmen Fm.	300-600	
	OLIGOCENE	Osmancık Fm.	400-500	
		Mezardere	500-2500	
	Eocene	Ceylan Fm.	250-2000	
		Sogucak Fm.	20-100	
	Paleocene	Hamitabat	1000-2500	
		Gazikoy Fm.	600-1000	
	Paleozoic		Basement	

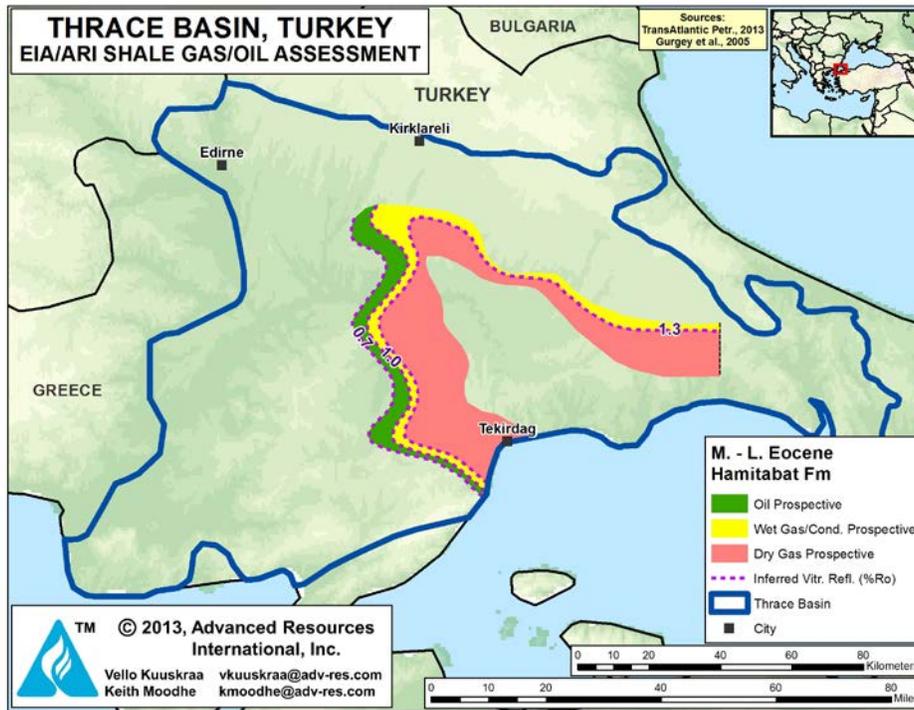
Source: Gürgey, Kadir, 2005.

Figure XXVI-9. Thrace Basin Cross Section⁵



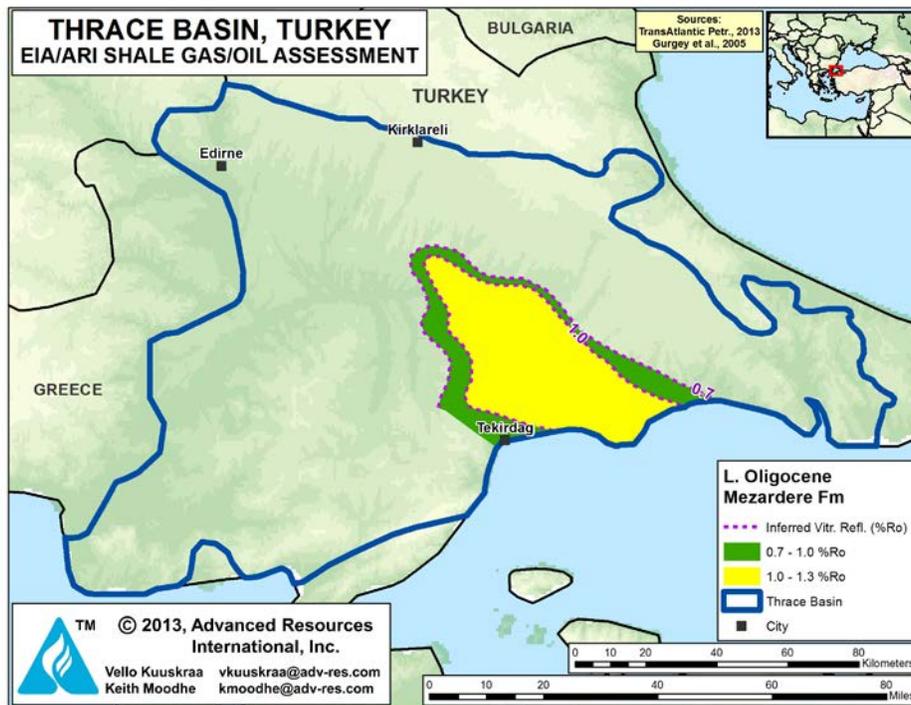
Source: Gürgey, Kadir, 2005.

Figure XXVI-10. Hamitabat Shale Formation of the Thrace Basin, NW Turkey



Source: ARI, 2013.

Figure XXVI-11. Mezardere Shale Formation of the Thrace Basin, NW Turkey



Source: ARI, 2013.

2.3 Resource Assessment

Within their respective prospective areas, ARI calculates a dry shale gas resource concentration of 104 Bcf/mi², a wet shale gas resource of 82 Bcf/mi², and a shale oil resource concentration of 34 million barrels/mi² for the Hamitabat Shale.

The Hamitabat Shale contains risked shale gas in-place of 34 Tcf, with 6 Tcf as the technically recoverable shale gas resource, Table XXVI-1. The Hamitabat Shale also contains risked shale oil/condensate in-place of 2 billion barrels, with 0.1 billion barrels as the technically recoverable shale oil resource.

2.4 Recent Activity

Much of the activity in the Thrace Basin is for tight gas, particularly by TPAO and TransAtlantic Petroleum. While these companies have begun to appraise the shale gas and oil in this basin, no information has been released on shale well tests or performance.

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