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Technically Recoverable Shale Oil and Shale Gas Resources:

India and Pakistan

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Introduction

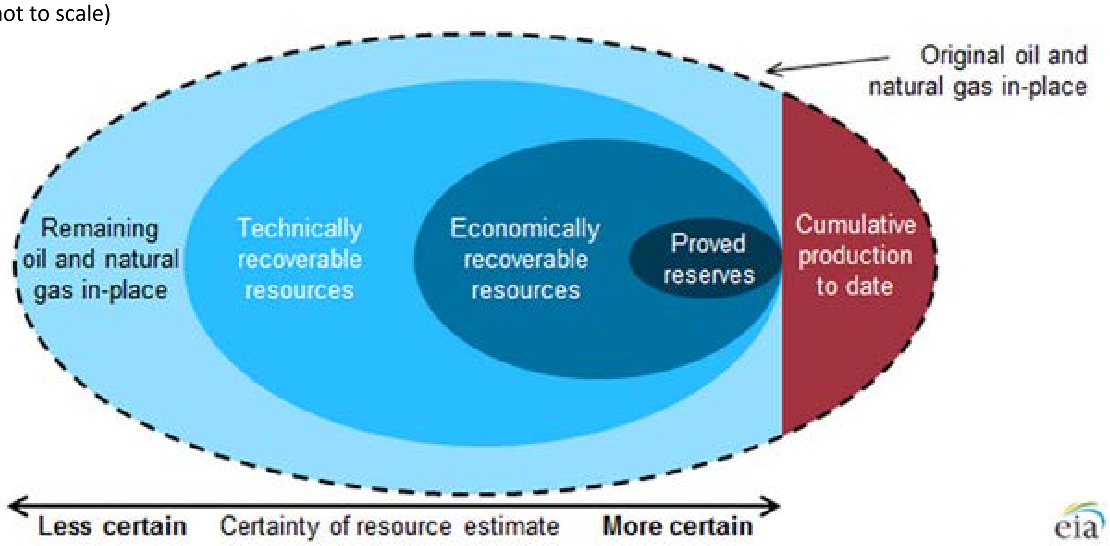
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

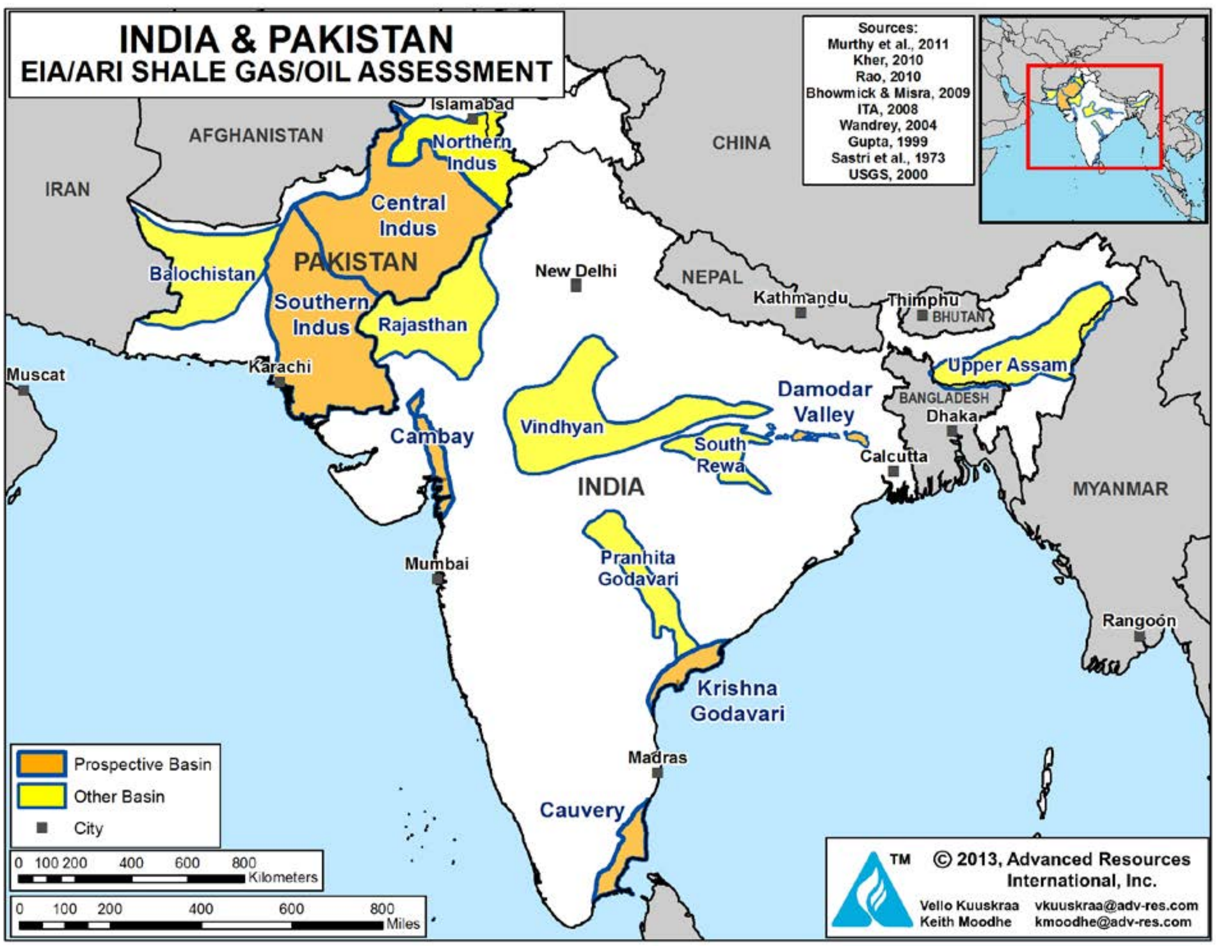
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

XXIV. INDIA/PAKISTAN

SUMMARY

India and Pakistan contain numerous basins with organic-rich shales. For India, the study assessed four priority basins: Cambay, Krishna-Godavari, Cauvery and Damodar Valley. The study also screened other basins in India, such as the Upper Assam, Vindhyan, Pranhita-Godavari, Rajasthan and South Rewa. However, in these basins the shales were thermally too immature or the data for conducting a rigorous resource assessment were not available. For Pakistan, the study addressed the areally extensive Indus Basin, Figure XXIV-1.

Figure XXIV-1. Shale Gas and Shale Oil Basins of India/Pakistan



Overall, ARI estimates a total of 1,170 Tcf of risked shale gas in-place for India/Pakistan, 584 Tcf in India and 586 Tcf in Pakistan. The risked, technically recoverable shale gas resource is estimated at 201 Tcf, with 96 Tcf in India and 105 Tcf in Pakistan, Tables XXIV-1A and XXIV-1B. In addition, we estimate risked shale oil in-place for India/Pakistan of 314 billion barrels, with 87 billion barrels in India and 227 billion barrels in Pakistan. The risked, technically recoverable shale oil resource is estimated at 12.9 billion barrels for these two countries, with 3.8 billion barrels for India and 9.1 billion barrels for Pakistan, Table XXIV-2A and XXIV-2B.

Table XXIV-1A. Shale Gas Reservoir Properties and Resources of India

Basic Data	Basin/Gross Area		Cambay (7,900 mi²)			Krishna-Godavari (7,800 mi²)			Cauvery (9,100 mi²)	Damodar Valley (2,270 mi²)
	Shale Formation		Cambay Shale			Permian-Triassic			Sattapadi-Andimadam	Barren Measure
	Geologic Age		U. Cretaceous-Tertiary			Permian-Triassic			Cretaceous	Permian-Triassic
	Depositional Environment		Marine			Marine			Marine	Marine
Physical Extent	Prospective Area (mi²)		1,060	300	580	1,100	3,900	3,000	1,010	1,080
	Thickness (ft)	Organically Rich	1,500	1,500	1,500	330	500	1,300	1,000	1,000
		Net	500	500	500	100	150	390	500	250
	Depth (ft)	Interval	6,000 - 10,000	10,000 - 13,000	13,000 - 16,400	4,000 - 6,000	6,000 - 10,000	10,000 - 16,400	7,000 - 13,000	3,300 - 6,600
		Average	8,000	11,500	14,500	5,000	8,000	13,000	10,000	5,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Normal	Slightly Overpress.
	Average TOC (wt. %)		2.6%	2.6%	2.6%	6.0%	6.0%	6.0%	2.3%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.80%	0.85%	1.15%	1.50%	1.15%	1.20%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	High	High	High	High	High
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Wet Gas
	GIP Concentration (Bcf/mi²)		55.9	170.5	228.0	6.9	57.8	204.7	119.6	62.9
	Risked GIP (Tcf)		35.5	30.7	79.4	3.4	101.4	276.4	30.2	27.2
	Risked Recoverable (Tcf)		3.6	6.1	19.8	0.2	15.2	41.5	4.5	5.4

Table XXIV-1B. Shale Gas Reservoir Properties and Resources of Pakistan

Basic Data	Basin/Gross Area		Lower Indus (169,000 mi²)			
	Shale Formation		Sembar			Ranikot
	Geologic Age		L. Cretaceous			Paleocene
	Depositional Environment		Marine			Marine
Physical Extent	Prospective Area (mi²)		26,700	25,560	31,320	26,780
	Thickness (ft)	Organically Rich	1,000	1,000	1,000	1,000
		Net	250	250	250	200
	Depth (ft)	Interval	4,000 - 6,000	6,000 - 10,000	10,000 - 16,400	6,000 - 13,000
		Average	5,000	8,000	13,000	9,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	0.85%
	Clay Content		Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi²)		14.3	57.0	82.7	17.0
	Risked GIP (Tcf)		45.9	174.7	310.8	54.8
	Risked Recoverable (Tcf)		3.7	34.9	62.2	4.4

Table XXIV-2A. Shale Oil Reservoir Properties and Resources of India

			Cambay		Krishna-Godavari		Cauvery	Damodar Valley
Basic Data	Basin/Gross Area		(7,900 mi^2)		(7,800 mi^2)		(9,100 mi^2)	(2,270 mi^2)
	Shale Formation		Cambay Shale		Permian-Triassic		Sattapadi-Andimadam	Barren Measure
	Geologic Age		U. Cretaceous-Tertiary		Permian-Triassic		Cretaceous	Permian-Triassic
	Depositional Environment		Marine		Marine		Marine	Marine
Physical Extent	Prospective Area (mi^2)		1,060	300	1,100	3,900	1,010	1,080
	Thickness (ft)	Organically Rich	1,500	1,500	330	500	1,000	1,000
		Net	500	500	100	150	500	250
	Depth (ft)	Interval	6,000 - 10,000	10,000 - 13,000	4,000 - 6,000	6,000 - 10,000	7,000 - 13,000	3,300 - 6,600
		Average	8,000	11,500	5,000	8,000	10,000	5,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Slightly Overpress.
	Average TOC (wt. %)		2.6%	2.6%	6.0%	6.0%	2.3%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	1.15%	1.20%
	Clay Content		Low/Medium	Low/Medium	High	High	High	High
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Condensate	Condensate
	OIP Concentration (MMbbl/mi^2)		79.8	19.2	17.5	6.5	30.2	12.1
	Risked OIP (B bbl)		50.8	3.5	8.7	11.5	7.6	5.2
	Risked Recoverable (B bbl)		2.54	0.17	0.26	0.34	0.23	0.21

Table XXIV-2B. Shale Oil Reservoir Properties and Resources of Pakistan

			Lower Indus		
Basic Data	Basin/Gross Area		(169,000 mi^2)		
	Shale Formation		Sembar		Ranikot
	Geologic Age		L. Cretaceous		Paleocene
	Depositional Environment		Marine		Marine
Physical Extent	Prospective Area (mi^2)		26,700	25,560	26,780
	Thickness (ft)	Organically Rich	1,000	1,000	1,000
		Net	250	250	200
	Depth (ft)	Interval	4,000 - 6,000	6,000 - 10,000	6,000 - 13,000
		Average	5,000	8,000	9,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%
	Clay Content		Low	Low	Low
Resource	Oil Phase		Oil	Condensate	Oil
	OIP Concentration (MMbbl/mi^2)		36.6	9.1	25.4
	Risked OIP (B bbl)		117.4	27.9	81.7
	Risked Recoverable (B bbl)		4.70	1.12	3.27

INTRODUCTION

Evaluating the shale gas and oil resources of India and Pakistan posed a series of challenges. Only limited publically available data exist on the geologic setting and reservoir properties of the numerous shale formations in India and Pakistan. In addition, the shale basins in these two countries are geologically highly complex.

Many of the basins in India, such as the Cambay and the Cauvery, comprised a series of extensively faulted horst and graben structures. As such, the prospective areas for shale gas and oil in these basins are often restricted to a series of isolated basin depressions (sub-basins). While the shales in these basins are thick, considerable uncertainty exists on the areal extents of the prospective areas in these basins. To account for this uncertainty, we have applied prospective area risk factors to each basin. Figures XXIV-2 shows the stratigraphic column for the key basins of India.

Recently, ONGC drilled and completed India's first shale gas well, RNSG-1, northwest of Calcutta in West Bengal. The well was drilled to a depth of 2,000 meters and reportedly had gas shows at the base of the Permian-age Barren Measure Shale. Two vertical wells (Well D-A and D-B) were previously tested in the Cambay Basin and had modest shale gas and oil production from the Cambay Black Shale.[1]

In Pakistan, the shale gas and oil assessment is restricted to the areally extensive Central and Southern Indus basins, together called the Lower Indus Basin. The shales in this basin have sourced the significant volumes of conventional oil and gas discovered and produced in Pakistan. However, to date, no shale specific exploration has been publically reported for Pakistan. Figure XXIV-3 provides the stratigraphic column for the key basins of Pakistan.

Fortunately, the technical literature on conventional oil and gas exploration in India and Pakistan often contains information on the nature of the source rocks that have charged the conventional gas and oil reservoirs, providing a valuable starting point for this resource assessment. As additional shale-directed geological and reservoir information is collected and distributed, a more rigorous assessment of India's and Pakistan's shale oil and gas resources will emerge.

Figure XXIV-2. Stratigraphic Column for India

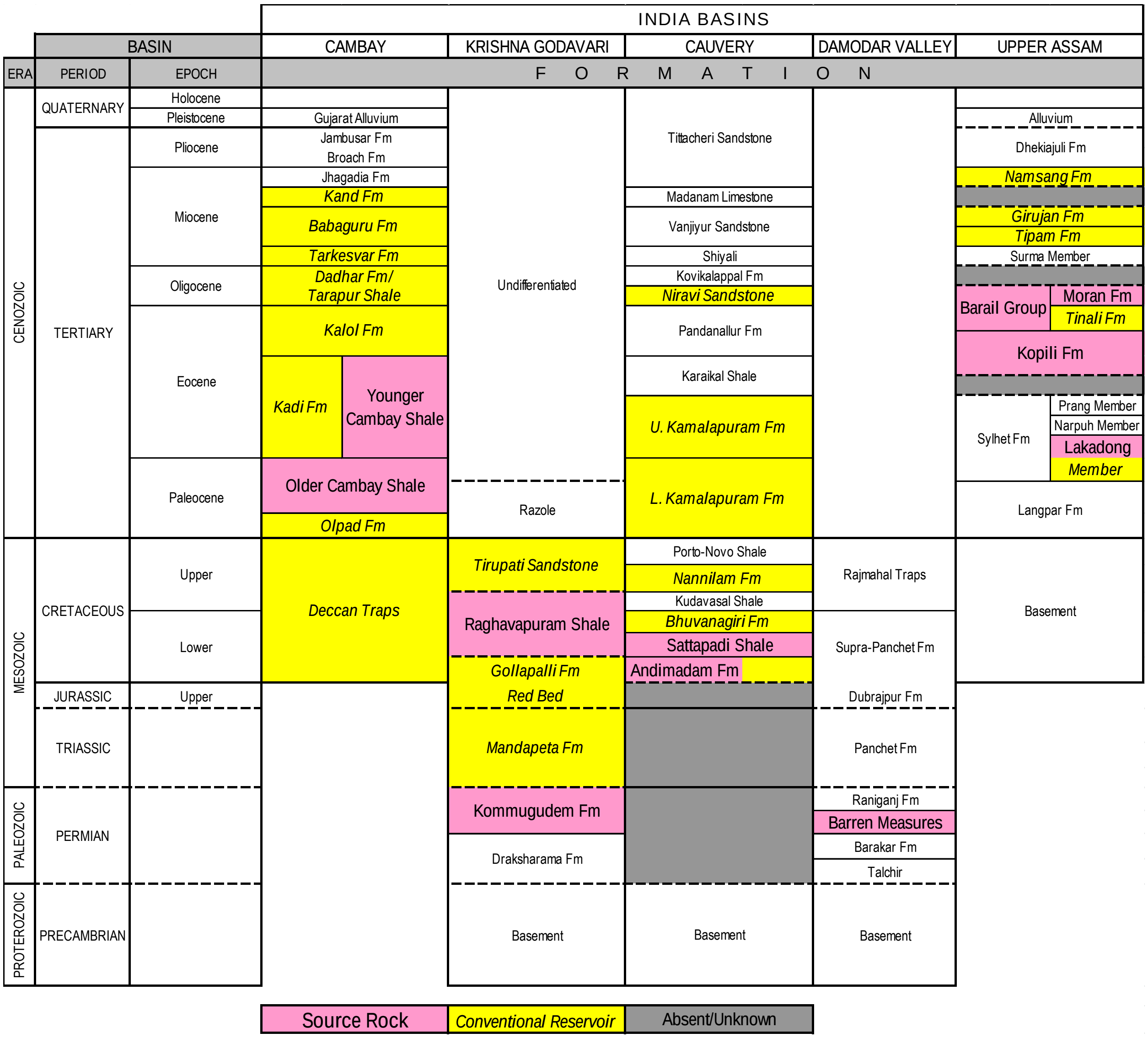


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Figure XXIV-3. Stratigraphic Column for Pakistan

ERA	PERIOD	EPOCH	SOUTHERN INDUS	CENTRAL INDUS	NORTHERN INDUS	BALOCHISTAN
	BASIN		PAKISTAN BASINS – FORMATION			
CENOZOIC	QUATERNARY	Pleistocene	Siwaliks	Siwaliks		Ormara Chatti
	TERTIARY	Pliocene				Talar/Hinglas
		Miocene	Gaj	Gaj	Kamlial Murree	Parkini Panjgur
		Oligocene	Nari	Nari		Hoshab Siahan *Amalaf*
		Eocene	*Kirthar* *Ghazij/* *Baska/Laki*	Kirthar *Sakaser* Nummal	 *Kohat* Kuldana	Wakai *Saindak* Kharan
		Paleocene	*Dunghan* Ranikot Khadro	*Dunghan* Ranikot	Patala Lockhart Hangu	Ispikan Rakhshani
MESOZOIC	CRETACEOUS	Upper	*Pab* *Mughal Kot* *Parh*	*Pab* *Mughal Kot* *Parh*	 *Kawagarh*	Humai
		Lower	*Goru* Sembar	*Goru* Sembar	*Lumshiwal* Chichali	Sinjrani
	JURASSIC	Upper	*Takatu/Chiltan*	*Samana Suk*		
		Middke	Lorolai/Datta		*Samana Suk*	
		Lower	Shirinab	Shinawari Data	Shinawari Data	
	TRIASSIC	Upper	Wulgai/Alozai	Kingriali	 Kingriali	
		Middke		Tredian Mianwali	Tredian Mianwali	
		Lower			Chidru	
PALEOZOIC	PERMIAN			Zaluch Nilawhan	Wargal Sardhai Warcha Dandot Tobra	
	CAMBRIAN		Baghanwala Juttana Kussak	*Baghanwala* *Juttana* *Kussak*	*Juttana* *Khewra*	
PROTEROZOIC	PRECAMBRIAN		Khewra Salt Range Jodhpur Basement	*Khewra* Salt Range *Jodhpur* Basement	 Salt Range Basement	

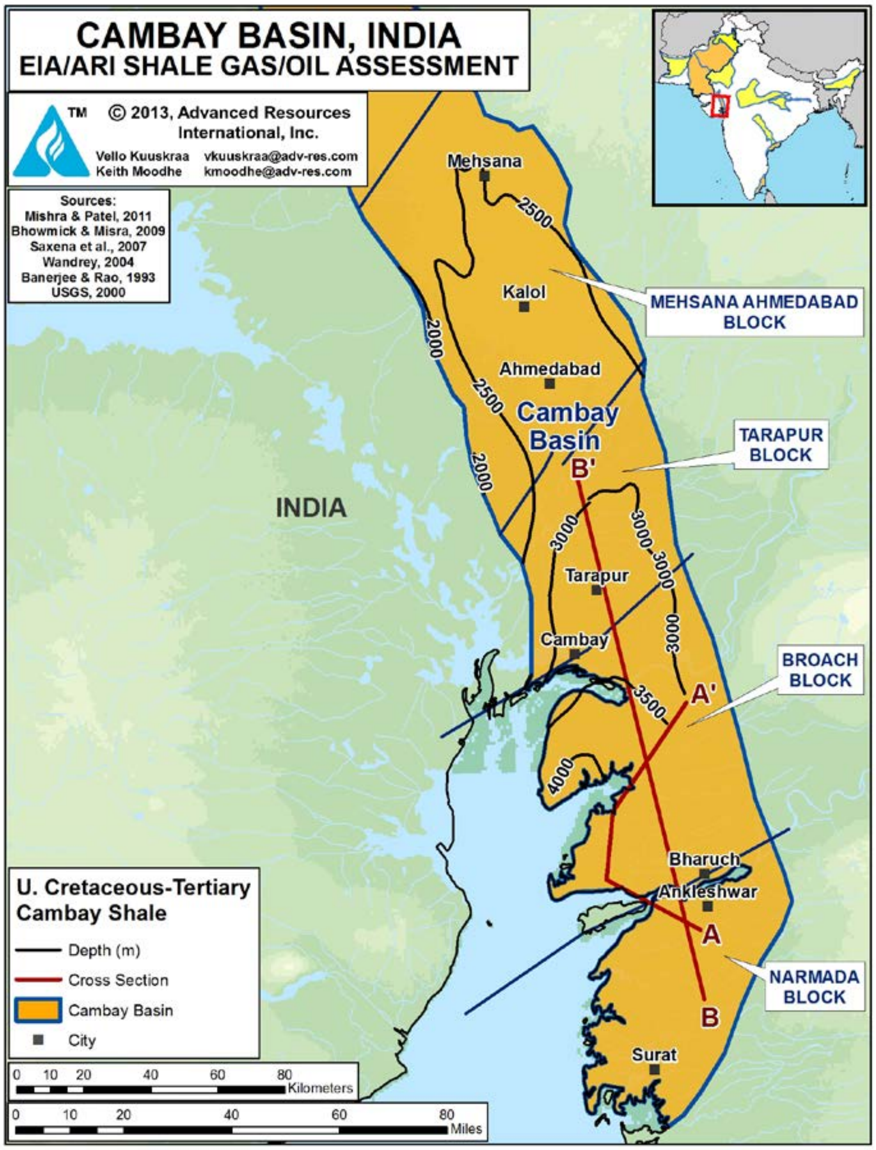
Source Rock	*Conventional Reservoir*	Absent/Unknown

1. CAMBAY BASIN, INDIA

1.1 Introduction and Geologic Setting

The Cambay Basin is an elongated, intra-cratonic Late Cretaceous to Tertiary rift basin, located in the State of Gujarat in northwest India. The basin includes four assessed fault blocks: Mehsana-Ahmedabad, Tarapur, Broach and Narmada, Figure XXIV-4.

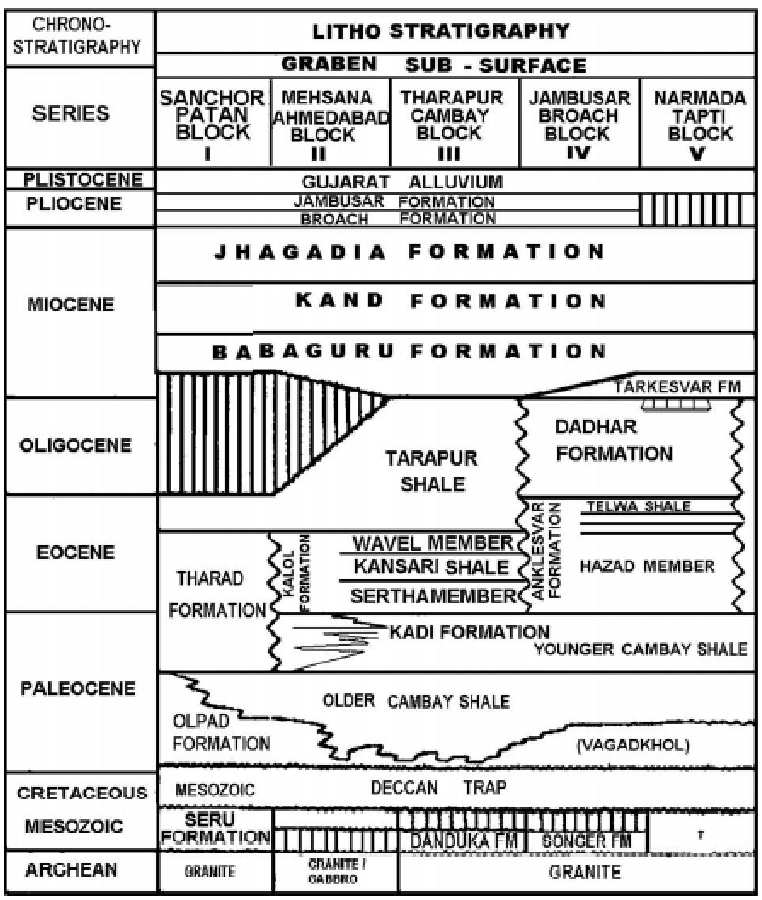
Figure XXIV-4. Depth of Cambay Black Shale, Cambay Basin



The Cambay Basin is bounded on its eastern and western sides by basin-margin faults and extends south into the offshore Gulf of Cambay, limiting its onshore area to 7,900 mi^2.[2]

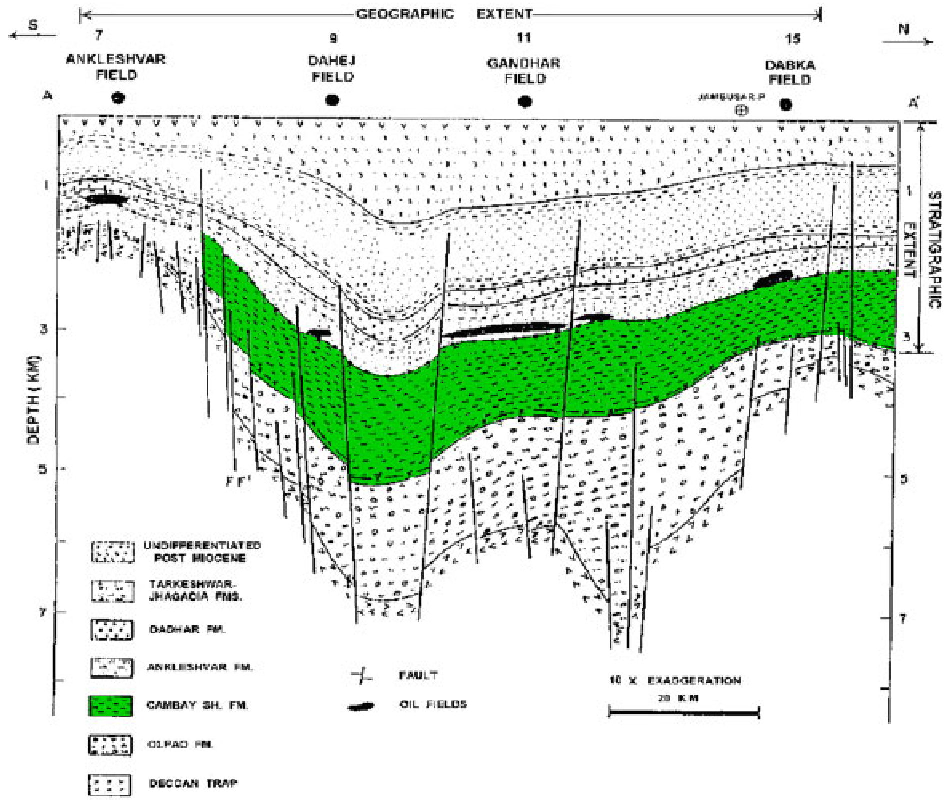
The Deccan Trap, composed of horizontal lava flows, forms the basement of the Cambay Basin. Above the Deccan Trap, separated by the Olpad Formation, is the Late Paleocene and Early Eocene Cambay Black Shale, Figure XXIV-5.[3] The Cambay Black Shale represents the marine transgressive episode in the basin. With a thermal maturity ranging from about 0.7% to 2%, the shale is in the oil, wet gas and dry gas windows.[4] For purposes of this study, we have assumed that the oil window starts at 6,000 feet of depth, that the wet gas window starts at 11,000 feet, and that the dry gas window is below 13,000 feet of depth, Figures XXIV-6 and XXIV-7.

Figure XXIV-5. Generalized Stratigraphic Column of the Cambay Basin.



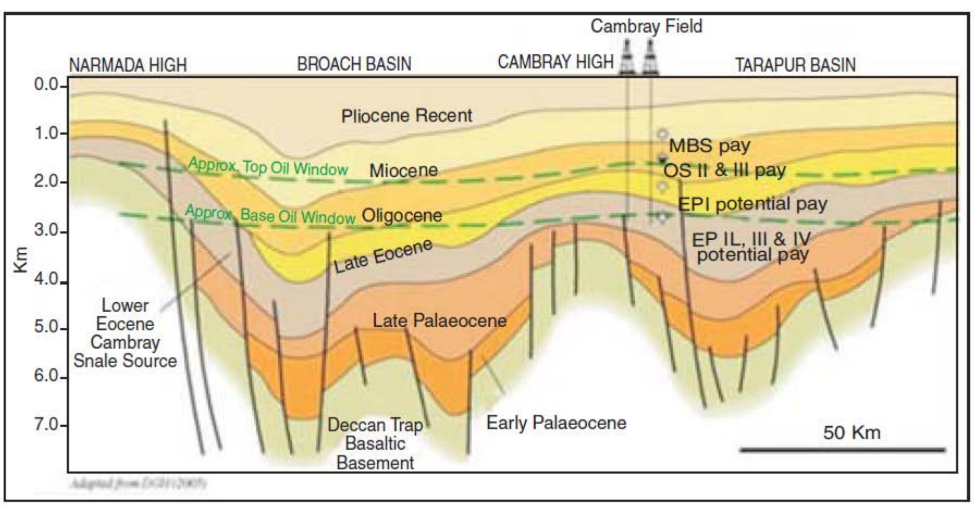
Source: Silvan, 2008

Figure XXIV-6. Cross Section of Cambay Black Shale System



Source: Shishir Kant Saxena, 2007

Figure XXIV-7. N-S Geological Cross-Section Across Cambay Basin



Source: P.K. Bhowmick and Ravi Misra, Indian Oil and Gas Potential, Glimpses of Geoscience Research in India.

The Cambay Basin contains four primary fault blocks, from north to south: (1) Mehsana-Ahmedabad; (2) Tarapur; (3) Broach; and (4) Narmada (Sivan et al., 2008).[3] Three of these blocks appear to have sufficient thermal maturity to be prospective for shale gas and oil, Table XXIV-3.[5]

Table XXIV-3. Major Fault Blocks and Shale Prospectivity of Cambay Basin

Fault Blocks		Comments
1.	Mehsana-Ahmedabad	Prospective for Shale Oil
2.	Tarapur	Prospective for Shale Oil and Wet Gas
3.	Broach	Prospective for Shale Oil and Wet/Dry Gas
4.	Narmada	Insufficient Data, Likely Immature

- ***Mehsana-Ahmedabad Block.*** Three major deep gas areas (depressions) exist in the Mehsana-Ahmedabad Block - - the Patan, Worosan and Wamaj. A deep well, Well-A, was drilled in the eastern flank of the Wamaj Low to a depth of nearly 15,000 ft, terminating below the Cambay Black Shale. In addition, a few wells were recently drilled to the Cambay Black Shale in the axial part of the graben low. A high-pressure gas zone was encountered in the Upper Olpad section next to the Cambay Shale, with methane shows increasing with depth. Geochemical modeling for this fault block indicates an oil window at 6,600 ft, a wet gas window at 11,400 ft, and a dry gas window at 13,400 ft.[6]

- ***Broach and Tarapur Blocks.*** The deeper Tankari Low in the Broach Block and the depocenter of the Tarapur Block appear to have similar thermal histories as the Mehsana-Ahmedabad Block. As such, we assumed these two areas have generally similar shale gas and oil properties as the Cambay Black Shale in the Mehsana-Ahmedabad Block.

1.2 Reservoir Properties (Prospective Area)

The depth of the prospective area of the Cambay Black Shale ranges from about 6,000 ft in the north to 16,400 ft in the lows of the southern fault blocks, averaging 8,000 ft in the oil prospective area, 11,500 ft in the wet gas and condensate prospective area, and 14,500 ft in the dry gas prospective area. Thermal gradients are high, estimated at 3^{o}F per 100 feet, contributing to accelerated thermal maturity of the organics.[7] The Cambay Black Shale interval ranges from 1,500 to more than 5,000 ft thick in the various fault blocks.[8] In the northern

Mehsana-Ahmedabad Block, the Kadi Formation forms an intervening 1,000-ft thick non-marine clastic wedge within the Cambay Black Shale interval. In this block, the shale thickness varies from 300 to 3,000 ft, with the organic-rich shale thickness, located in the lower portion of the Cambay Black Shale interval, averaging 500 net ft, Figure XXIV-8.

The organic matter in the shale is primarily Type II and Type III (terrestrial) with a TOC that ranges from 2% to 4%, averaging 2.6%, Figure XXIV-9. The shale formation is moderately over-pressured and has low to medium clay content.

Within the overall 1,940-mi^2 Cambay Black Shale prospective area in the Cambay Basin, we estimate: a 580-mi^2 area prospective for dry gas; a 300-mi^2 area prospective for wet gas and condensate; and a 1,060-mi^2 area prospective for oil, Figure XXIV-10.

1.3 Resource Assessment

The Cambay Black Shale has resource concentrations of: 228 Bcf/mi^2 of shale gas in its 580-mi^2 dry gas prospective area; 170 Bcf/mi^2 of wet gas and 19 million barrels/mi^2 of condensate in the 300-mi^2 wet gas/condensate prospective area; and 80 million barrels/mi^2 of shale oil (plus associated gas) in the 1,060-mi^2 oil prospective area.

Within the overall 1,940-mi^2 prospective area for the Cambay Black Shale in the Cambay Basin, we estimate a risked resource in-place of 146 Tcf for shale gas and 54 billion barrels for shale oil. Based on moderate to favorable reservoir properties, we estimate that the Cambay Black Shale has 30 Tcf of risked, technically recoverable shale gas and 2.7 billion barrels of risked, technically recoverable shale oil, Tables XXIV-1A and XXIV-2A.

1.4 Recent Activity

Although the shales in the Cambay Basin have been identified as a priority by India, no plans for exploring these shales have yet been publically announced. However, two shallower conventional exploration wells (targeting the oil-bearing intervals in the basin) penetrated and tested the Cambay Black Shale. Well D-A, a vertical well, had gas shows in a 90-ft section of the Cambay Basin at a depth of about 4,300 ft. After hydraulic stimulation, Well D-A produced 13 bbl/day of oil and 11 Mcfd of gas. Well D-B, an older vertical well drilled in 1989 to a depth of 6,030 ft, also encountered the Cambay Shale at about 4,300 ft. The well was subsequently hydrofractured and produced 13 bbl/day of oil and 21 Mcfd of gas.

Figure XXIV-8. Gross Thickness of Cambay Black Shale, Cambay Basin

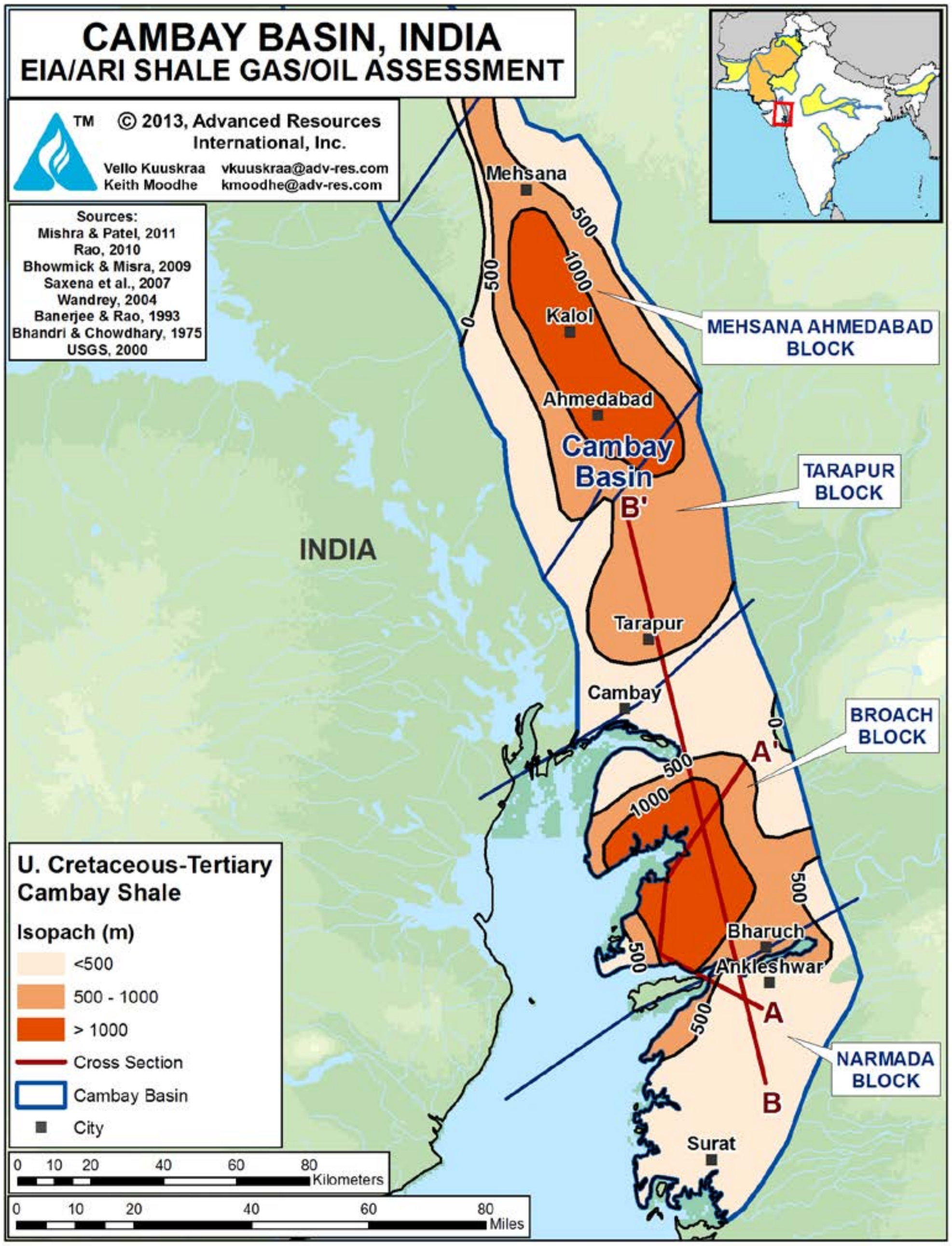


Figure XXIV-9. Organic Content of Cambay "Black Shale", Cambay Basin

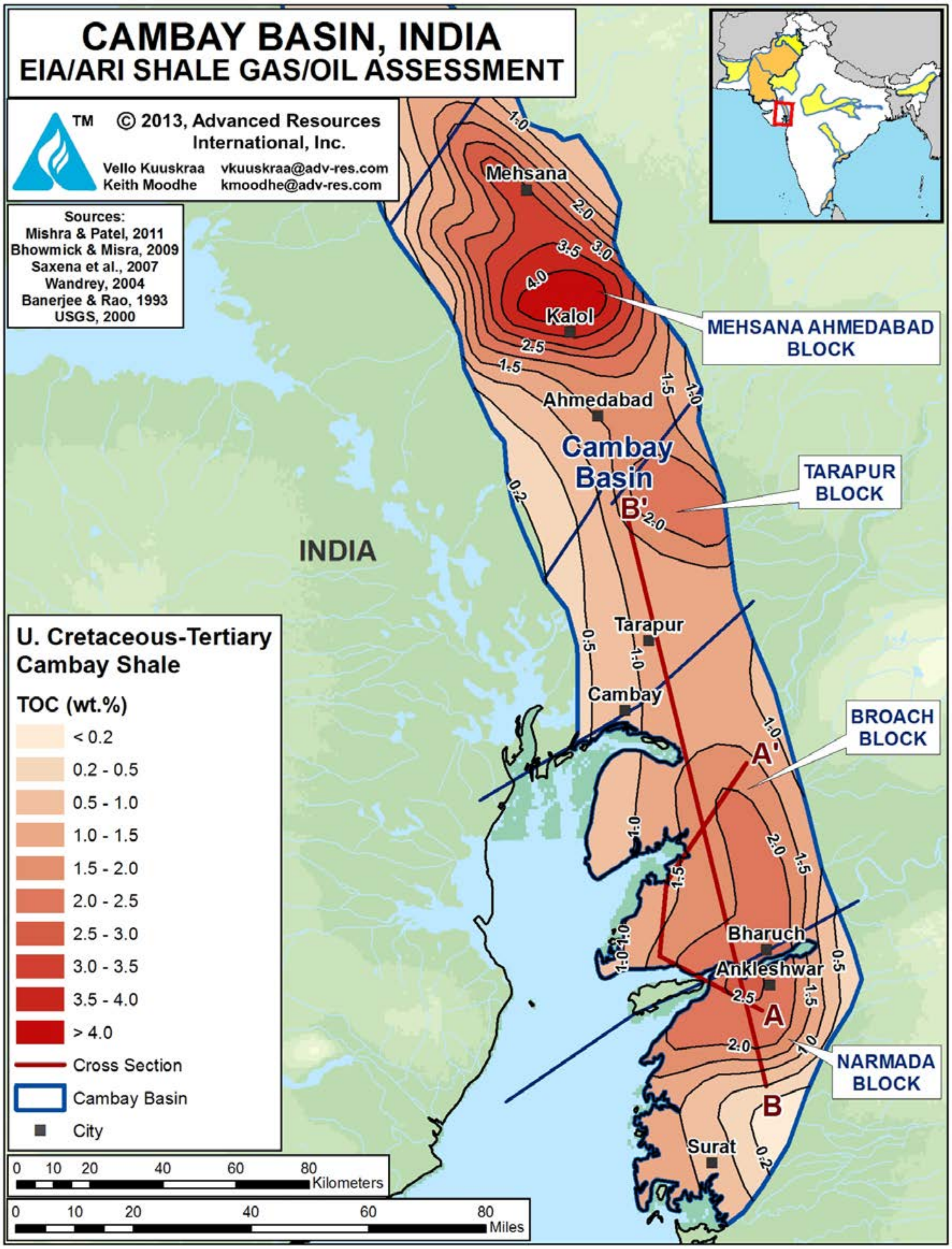
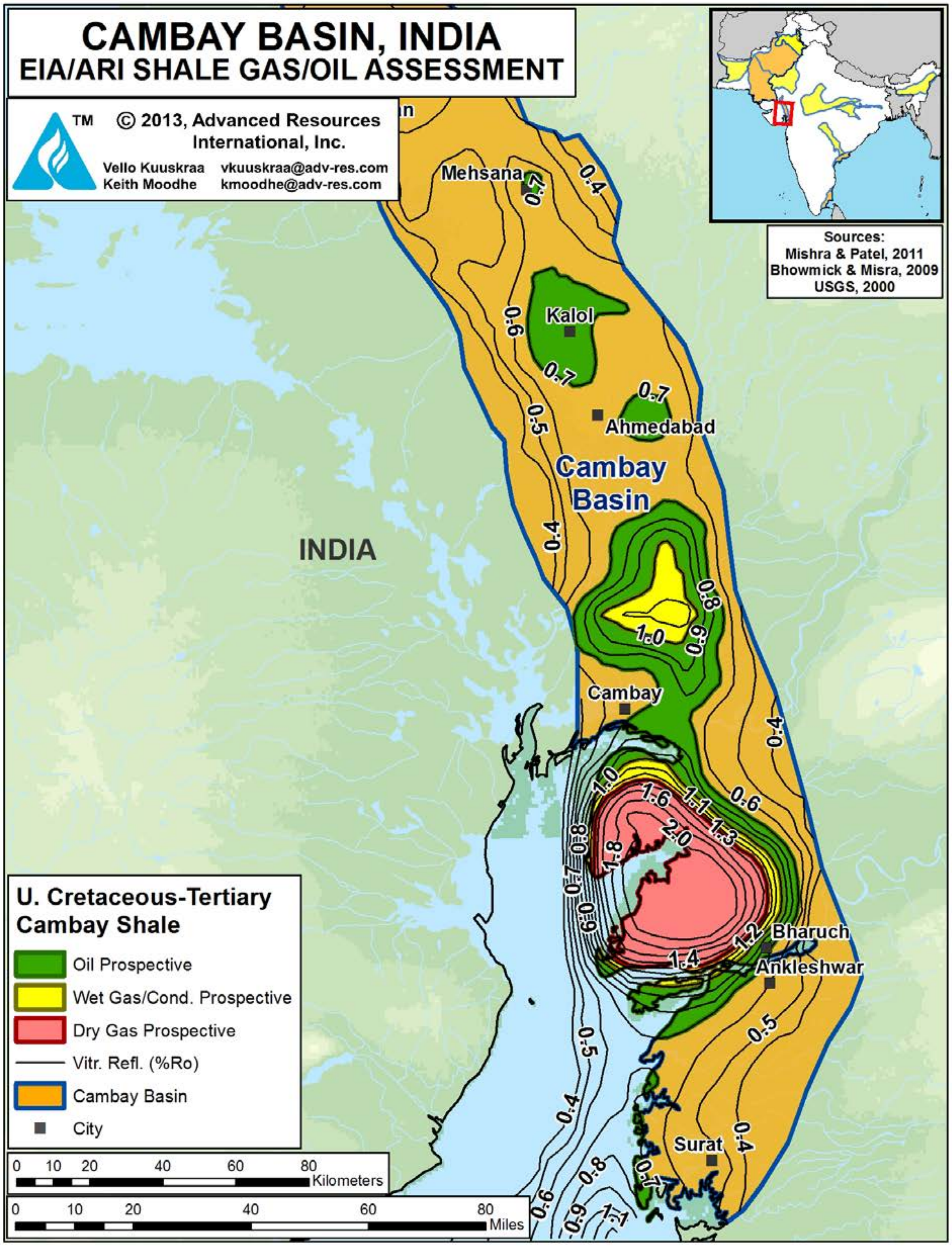


Figure XXIV-10. Prospective Areas of the Cambay Black Shale, Cambay Shale Basin

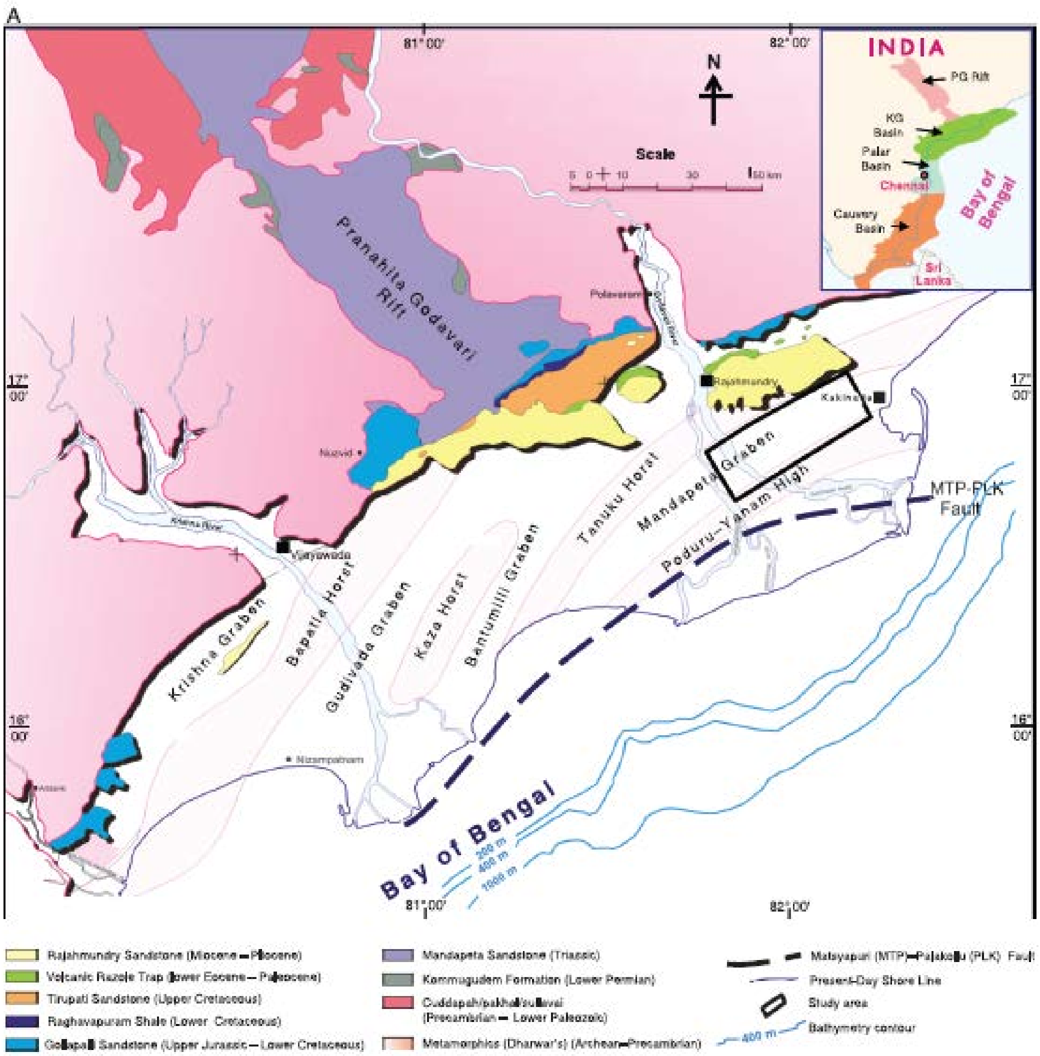


2. KRISHNA-GODAVARI BASIN, INDIA

2.1 Introduction and Geologic Setting

The Krishna-Godavari Basin covers a 7,800-mi^2 onshore area of eastern India, Figure XXIV-11.[9] The basin contains a series of organic-rich shales, including the Permian-age Kommugudem Shale and the Triassic-age Mandapeta Shale. For purposes of this assessment, these two shales have been combined into the Permian-Triassic Shale. With thermal maturities ranging from 0.7% to 2% R_o, these shales are in the oil to dry gas windows. The Upper Cretaceous Raghavapuram Shale may also have potential but was not assessed by this study.

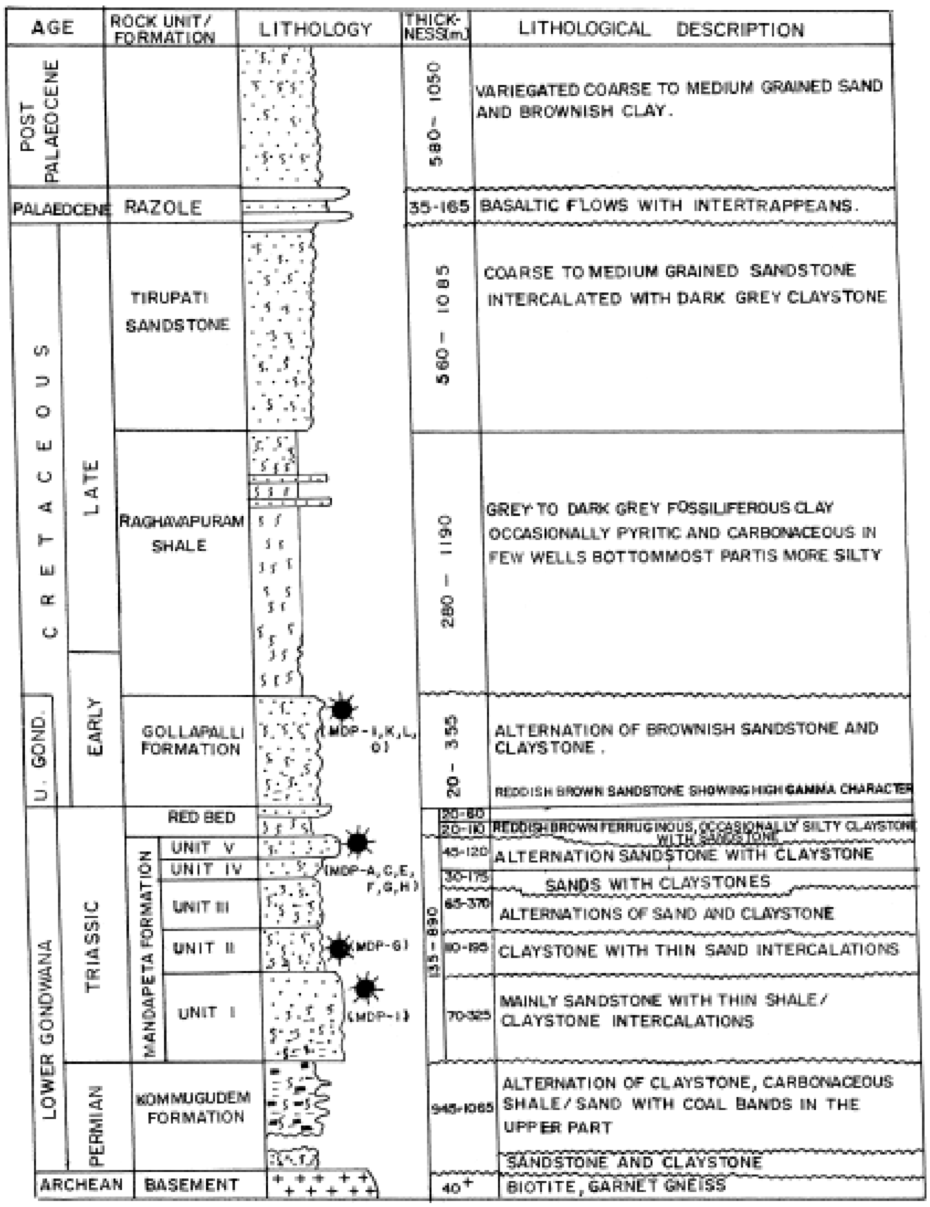
Figure XXI-11. Krishna-Godavari Basin's Onshore Horsts and Grabens



Source: Murthy, 2011.

Permian-Triassic Shale. The Kommugudem Shale, the lower unit of the Permian-Triassic Shale, is a thick Permian-age rock interval containing alternating sequences of carbonaceous shale, claystone, sand and coal, Figure XXIV-12. The Mandapeta Graben, the most extensively explored portion of the Krishna-Godavari Basin, provides much of the geologic and reservoir characterization data for this basin.[10]

Figure XXIV-12. Stratigraphic Column, Mandapeta Area, Krishna Godavari Basin



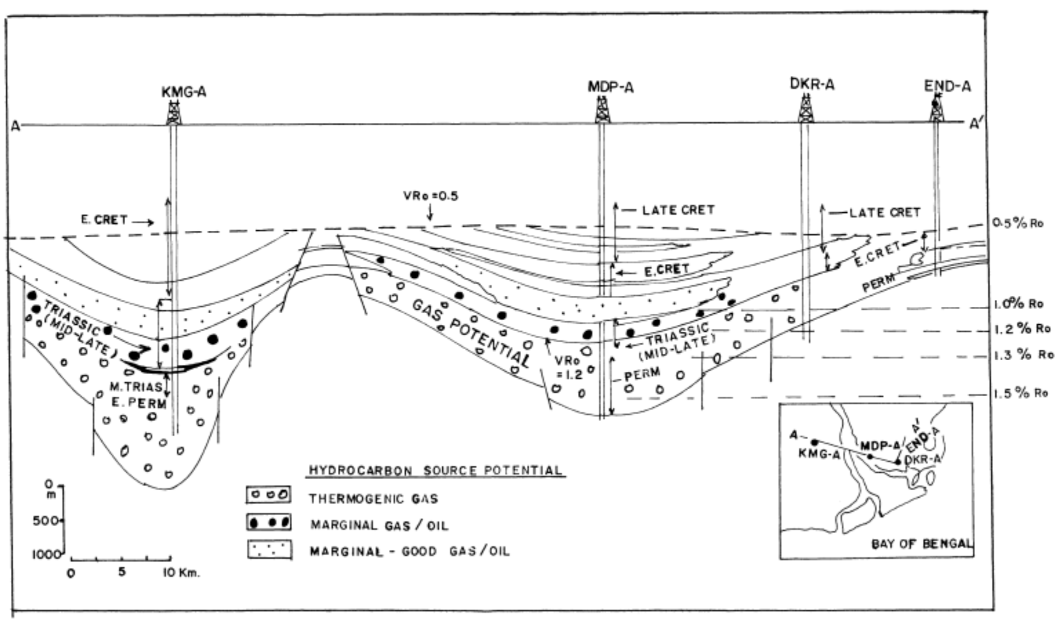
Source: Kahn, 2000.

The Kommugudem Shale was deposited in fluvial, lower deltaic, and lacustrine environments. While an effective source rock with excellent organic richness, analysis of the shale indicates hydrogen-deficient organic matter (based on low S_2 values from pyrolysis) and high levels of primary inertinite.

The basal shale in the Mandapeta Formation, the upper unit of the Permian-Triassic Shale, is a localized, thermally mature (R_o of 0.8% to 1.1%) Triassic-age shale that is considered the source rock for the oil produced from the overlying Early Cretaceous Golapalli Sandstone. The Mandapeta Formation and its basal shale are present in the Mandapeta and Bantumilli grabens but are absent in the Poduru-Yanam High (Draksharama and Endamuru areas) to the east. While the TOC of the Mandapeta Shale is generally low, 0.4% to 1.6%, we have included this Triassic shale unit into the overall Permian-Triassic sequence.

Vitrinite reflectance of the Permian-Triassic Shale in the deep graben structures ranges from 0.7% to 2% R_o, placing the shale in the oil to dry gas windows. Figure XXIV-13 illustrates the relationship of shale depth and geologic age in the Krishna-Godavari Basin to the thermal maturity (R_o) in two of the graben structures, Kommugudem (KMG) and Mandapeta (MDP).

Figure XXIV-13. Cross Section for Permian-Triassic Shale, Krishna Godavari Basin



Source: Kahn, 2000.

2.2 Reservoir Properties (Prospective Area)

In the prospective area of the Krishna-Godavari Basin, the depth of the Permian-Triassic Shale ranges from 4,000 to 16,400 ft, averaging 5,000 ft in the oil prospective area, 8,000 ft in the wet gas and condensate prospective area, and 13,000 ft in the dry gas prospective area.

To better understand the source rock quality of the Permian-Triassic Shale, 140 m of shale was tested in 10 wells. The data showed the TOC of the shale ranges up to 11%, averaging 6%, for ten rock samples taken at various depths, Table XXIV-4.

Table XXIV-4. Analysis of Ten Rock Samples, Kommugudem Shale[11]

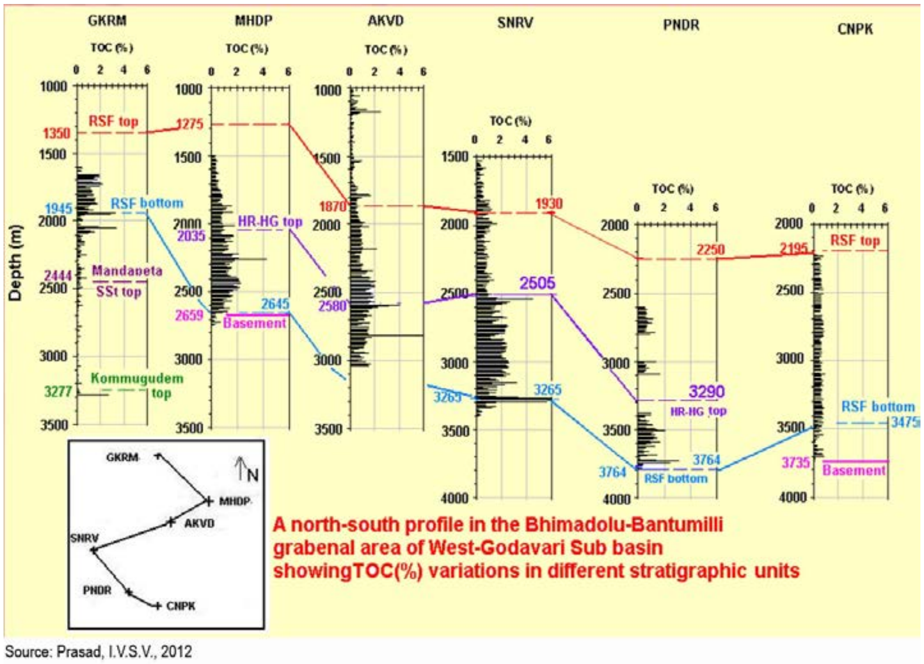
Well	Depth (m)	TOC (%)	S_2*	Shale Interval Tested (m)
AA-1	3,320-3,880	10.4	7.0	110
AA-2	3,585-3,630	4.2	2.9	45
AA-9	3,330-3,360	7.1	6.4	30
AA-10	3,880-3,920	3.1	0.6	40
AA-11	2,890-3,150	7.0	7.9	260
BW-1A	3,915-4,250	5.6	0.8	335
BW-2	2,970-3,085	8.8	5.5	115
BW-2	3,100-3,175	7.8	6.0	75
BW-9	2,800-3,040	11.2	6.9	315
DE-1	1,900-2,040	8.9	13.9	120

*Volume of hydrocarbon cracked from kerogen by heating to 550°C, measured in terms of mg hydrocarbon/g rock.

The thickness of the shale ranges from 330 to 1,300 ft, with 100 to 390 ft of net organic-rich shale, depending on prospective area. The pressure gradient of the Permian-Triassic Shale is normal. The reservoir is inferred to have moderate to high clay content based on its lacustrine deposition. We mapped an 8,000-mi^2 prospective area for the Permian-Triassic Shale in the Krishna-Godavari Basin which encompasses the oil, wet gas/condensate and dry gas windows.

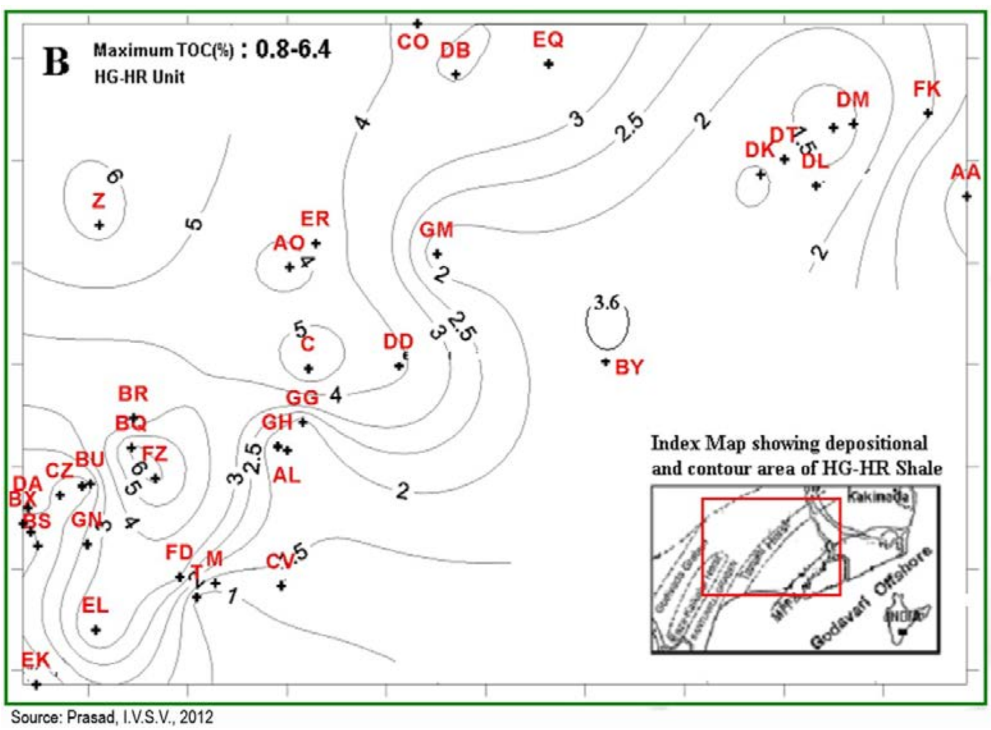
Raghavapuram Shale. The Cretaceous-age Raghavapuram Shale offers an additional potential shale resource in the Krishna-Godavari Basin. The TOC of this shale unit ranges from 0.8% to 6.4%, with the lower HG-HR Shale interval of the Raghavapuram Formation having the higher TOC values, Figures XXIV-14[12] and XXIV-15.[12] The shale becomes thermally mature for oil (Tmax 440 to 475° C) at depth below 10,600 ft.[21]

Figure XXIV-14. TOC Cross-Section for Raghavapuram Shale, Krishna-Godavari Basin



Source: Prasad, I.V.S.V., 2012.

Figure XXIV-15. TOC Isopach for Raghavapuram Shale, Krishna-Godavari Basin



Source: Prasad, I.V.S.V., 2012.

However, the great bulk of the Cretaceous Raghavapuram Shale is shallower than 10,600 ft and thus has a thermal maturity (R_o) value less the 0.7% minimum threshold used by this study. In addition, the data on the area and vertical distribution of the Raghavapuram Shale is limited. Thus, this shale has not been included in the quantitative portion of our shale resource assessment.

2.3 Resource Assessment

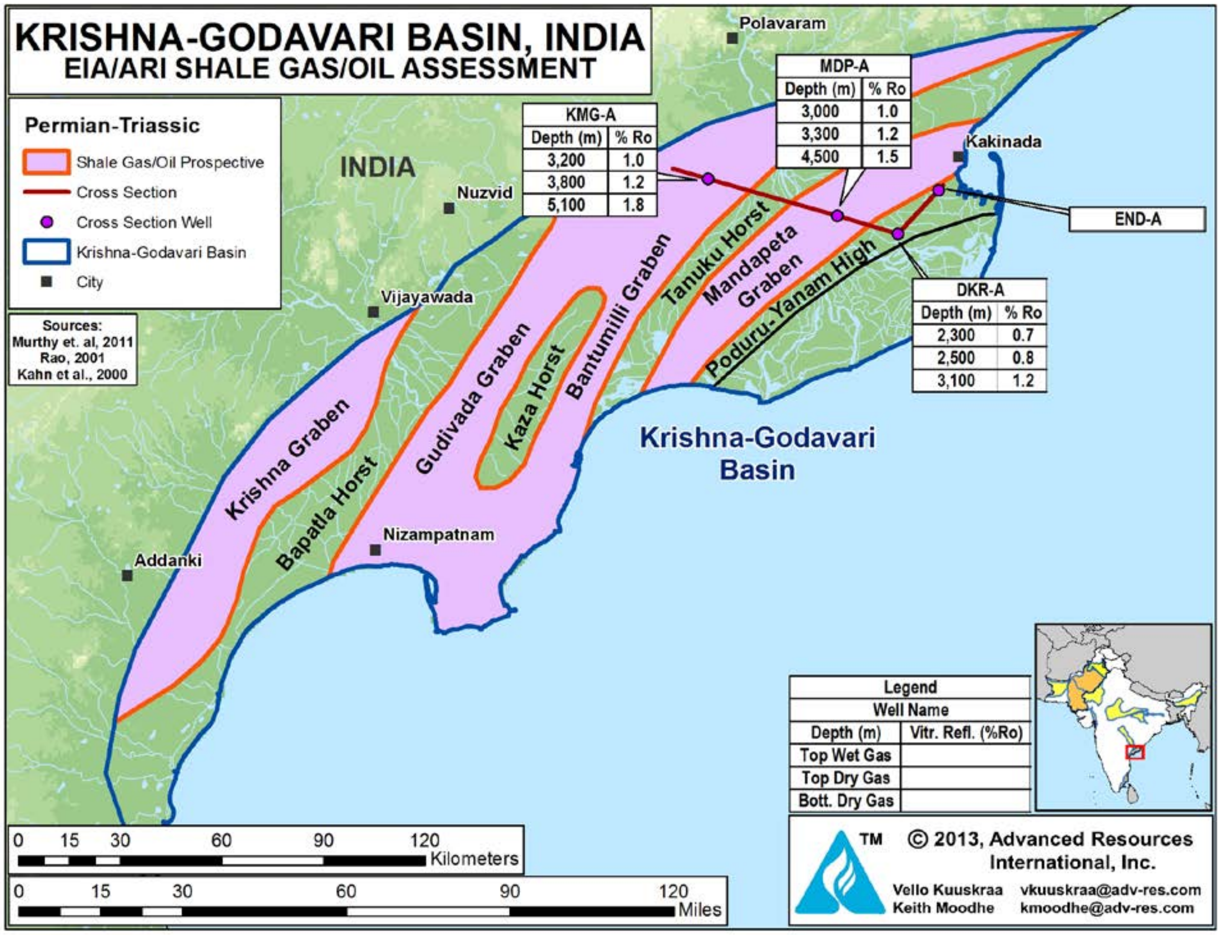
The 8,000-mi^2 prospective area of the Permian (Kommugudem) and Triassic (Mandapeta) Shale in the Krishna-Godavari Basin is limited to the four grabens (sub-basins) shown in Figure XXIV-16. The Permian-Triassic Shale has resource concentrations of: 205 Bcf/mi^2 in the 3,000-mi^2 dry gas prospective area; 58 Bcf/mi^2 of wet gas and 6 million barrels/mi^2 of condensate in the 3,900-mi^2 wet gas/condensate prospective area; and 18 million/mi^2 barrels of oil (plus associated gas) in the 1,100-mi^2 oil prospective area.

Within the overall prospective area, the Permian-Triassic Shale of the Krishna-Godavari Basin has risked shale gas in-place of 381 Tcf, with 57 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate a risked shale oil in-place for this basin of 20 billion barrels, with 0.6 billion barrels as the risked, technically recoverable shale oil resource, Tables XXIV-1A and XXIV-2A.

2.4 Recent Activity

The technical literature discusses 16 wells that have been drilled at the Mandapeta Graben into or through the Permian-Triassic Shale in search for hydrocarbons in conventional Mandapeta and Gollapalli sandstone reservoirs. The information from these 16 wells has provided valuable data for the key cross-sections and other reservoir properties essential for the shale resource assessment study of the Krishna-Godavari Basin.

Figure XXIV-16. Prospective Areas for Shale Gas and Shale Oil, Krishna-Godavari Basin

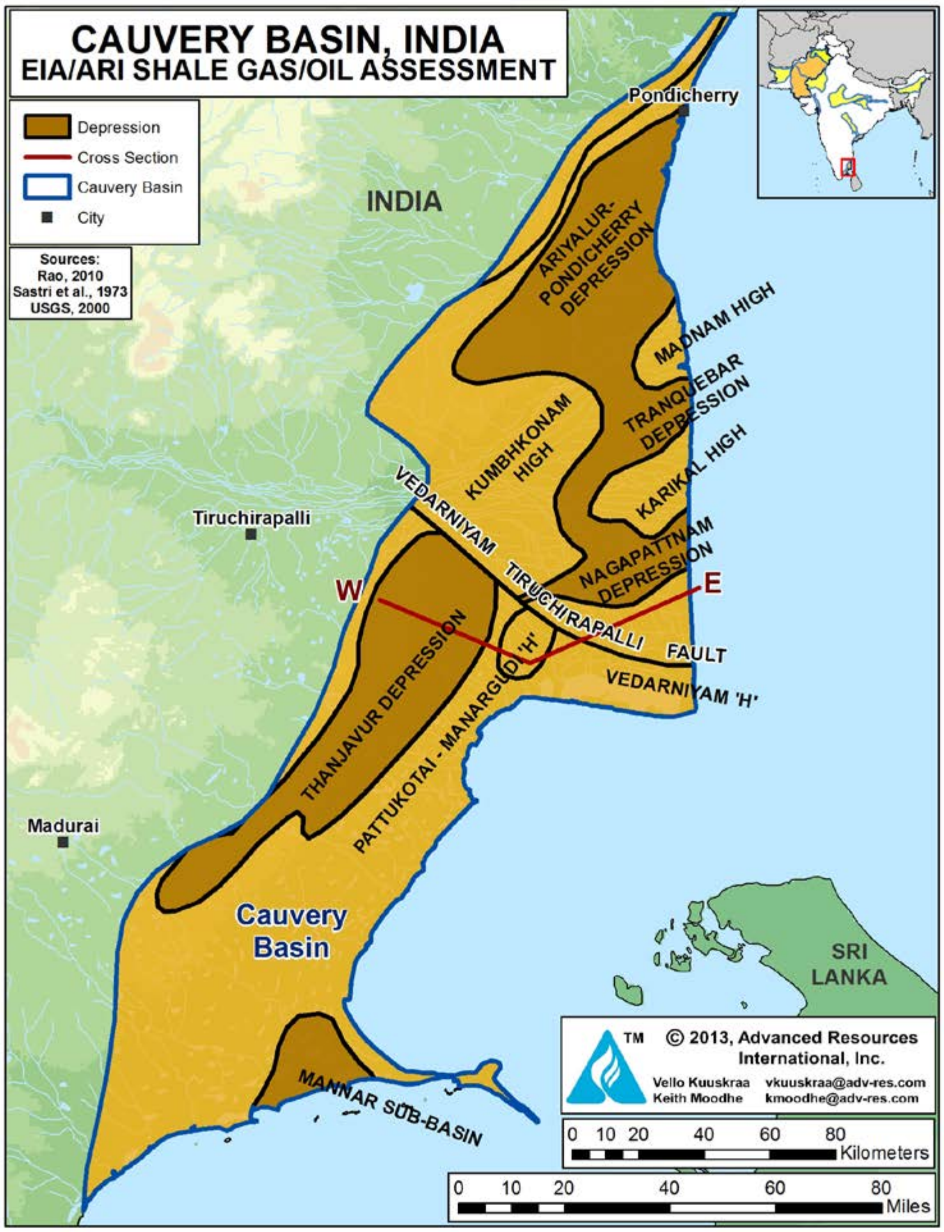


3. CAUVERY BASIN, INDIA

3.1 Introduction and Geologic Setting

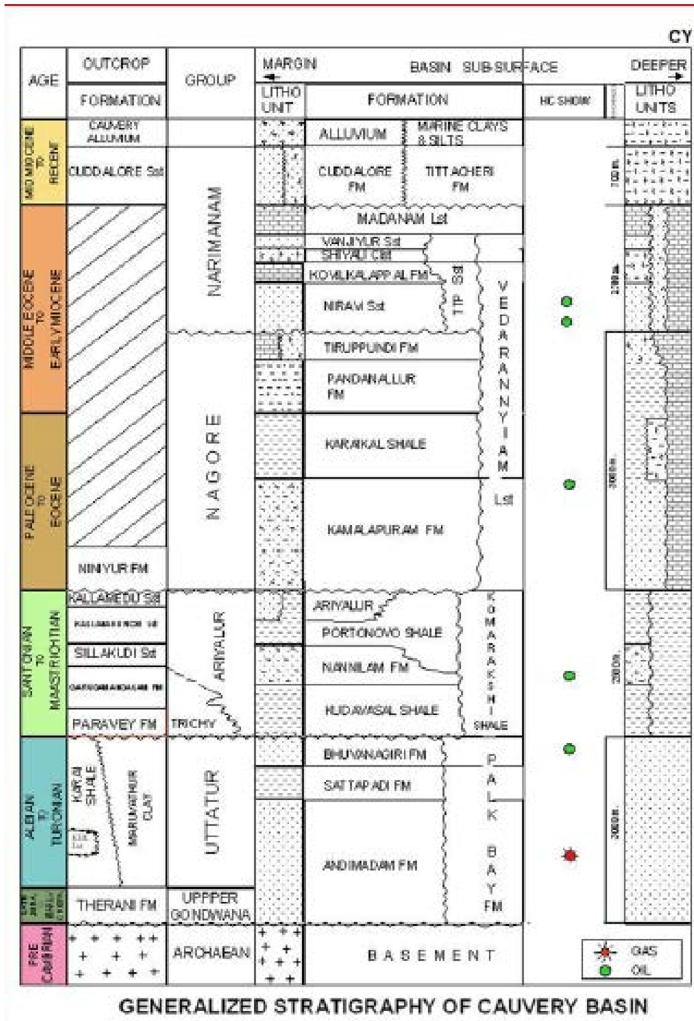
The Cauvery Basin covers an onshore area of about 9,100 mi^2 on the east coast of India, Figure XXIV-17. The basin comprises numerous horsts and grabens, with thick organic-rich source rocks in the Lower Cretaceous Andimadam Formation and Sattapadi Shale.

Figure XXIV-17. Cauvery Basin Horsts and Grabens



The gas- and oil-prone shale source rocks in the Cauvery Basin are the Lower Cretaceous Andimadam Formation and the Sattapadi Shale, Figure XXIV-18. The shale resource prospective area of the Cauvery Basin is limited to four depressions (troughs) - - Nagapattnam, Tranquebar, Ariyalur-Pondicherry and Thanjavur - - and the Mannar Sub-basin. The source rocks are generally shallow marine Type III with some Type II kerogen. The thermally mature source rocks in the shallower Sattapadi Shale and the deeper Andimadam Formation contain thermogenic wet gas and condensate.[13]

Figure XXIV-18. Generalized Stratigraphy, Cauvery Basin[15]



Source: Rao, 2010.

Advanced Resources International, Inc.

3.2 Reservoir Properties (Prospective Area)

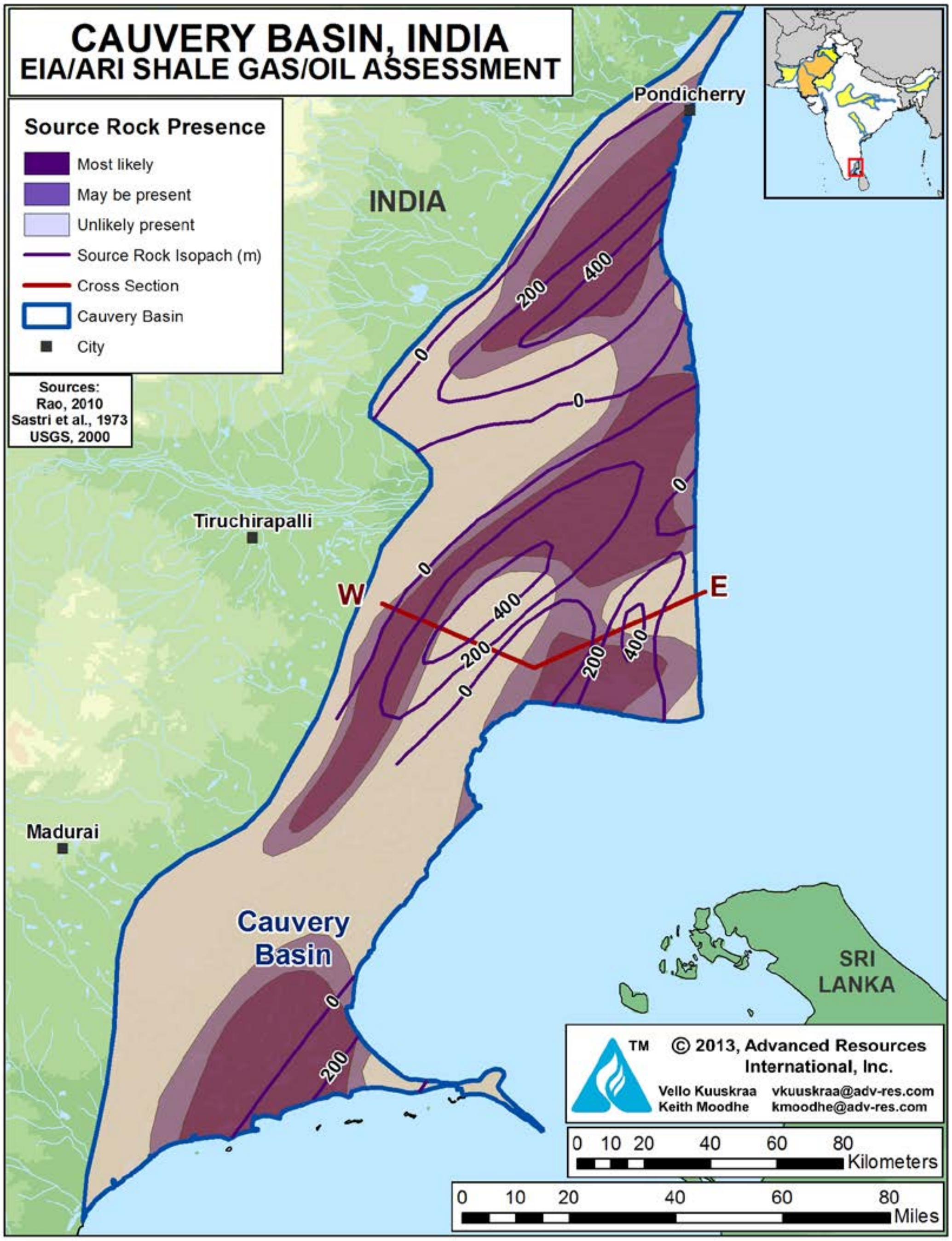
We have identified a 1,010-mi^2 wet gas and condensate prospective area for the shales in the Cauvery Basin. The thickness of the Lower Cretaceous interval is 3,000 to 5,000 ft, with the Andimadam Formation and the Sattapadi Shale accounting for the bulk of the gross interval, Figure XXIV-19. The TOC of the combined Andimadam/Sattapadi Shale is estimated at 2% to 2.5%, averaging 2.3%. The organic shales are distributed irregularly over the Cauvery Basin, Figure XXIV-20.

Figure XXIV-19. Formation Thickness, Cauvery Basin

AGE		FORMATION		THICKNESS in m
Recent to Mid. Miocene		Tittacheri Sandstone		300-500
Lower Miocene		Madanam Limestone Vanjiyur Sandstone Shiyali Clay stone	 CAP	600-1200
Oligocene		Kovilkalappal Fm. Niravi Sandstone	 PLAY	500-800
Eocene		Pandanallur Fm. Karaikal Shale Up.Kamalapuram Fm.	 CAP PLAY	200-400
Paleocene		Lr.Kamalapuram Fm.	PLAY	200-800
Creta-ceous	Upper	Porto-Novo Shale Nannilam Fm. Kudavasal Shale	CAP PLAY CAP	600-1500
	Lower	Bhuvanagiri Fm. Sattapadi Shale Andimadam Fm.	PLAY SOURCE+CAP SOURCE+PLAY	1000-1500
Archaean		Basement	PLAY	

Source: P.K. Bhowmick and Ravi Misra, Indian Oil and Gas Potential, Glimpses of Geoscience Research in India

Figure XXIV-20. Shale Isopach and Presence of Organics, Cauvery Basin



The Cauvery Basin contains a series of depressions (sub-basins) that hold potential for shale gas. Two of these - - Ariyalur-Pondicherry and Thanjavur - - contain thick, thermally mature shales.

- ***Ariyalur-Pondicherry Sub-Basin***. The Ariyalur-Pondicherry Depression (Sub-basin) is in the northern portion of the Cauvery Basin. The Lower Cretaceous Andimadam and Sattapadi Shale encompasses a thick interval at a depth of 7,000 to 13,000 ft, averaging 10,000 ft. Organic-rich gross pay thickness is 1,000 ft with net pay of about 500 ft. The thermal maturity of 1.0% to 1.3% R_o places the shale in the wet gas and condensate window. The onshore prospective area of this sub-basin is estimated at 620 mi^2, Figure XXIV-21.

- ***Thanjavur Sub-Basin.*** The Thanjavur Depression (Sub-basin), in the center of the Cauvery Basin, has a thick section of Andimadam and Sattapadi Shale at a depth of 7,000 ft (top of Sattapadi Shale) to 13,000 ft (base of Andimadam Fm), averaging 9,500 ft deep, Figure XXIV-22. The organic-rich average net pay thickness is 500 ft.[15] Given limited data, we assume the TOC and thermal maturity for the shale in this sub-basin is the same as in the Ariyalur-Pondicherry Sub-basin. The onshore prospective area with thick organic-rich shale is small, estimated at 390 mi^2, Figure XXIV-21.

3.3 Resource Assessment

In the 1,010-mi^2 prospective area of the Cauvery Basin, the combined Andimadam Formation and Sattapadi Shale have an average wet shale gas resource concentration of 120 Bcf/mi^2 and a shale condensate resource concentration of 30 million barrels/mi^2.

For the combined Andimadam Formation and Sattapadi Shale in the Cauvery Basin, we estimate risked shale gas in-place of 30 Tcf and risked shale oil in-place of 8 billion barrels. Of this, 5 Tcf of shale gas and 0.2 billion barrels of shale oil are the risked, technically recoverable shale resources.

3.4 Recent Activity

We are not aware of any shale gas or oil development in the Cauvery Basin.

Figure XXIV-21. Prospective Areas for Shale Gas and Shale Oil, Cauvery Basin

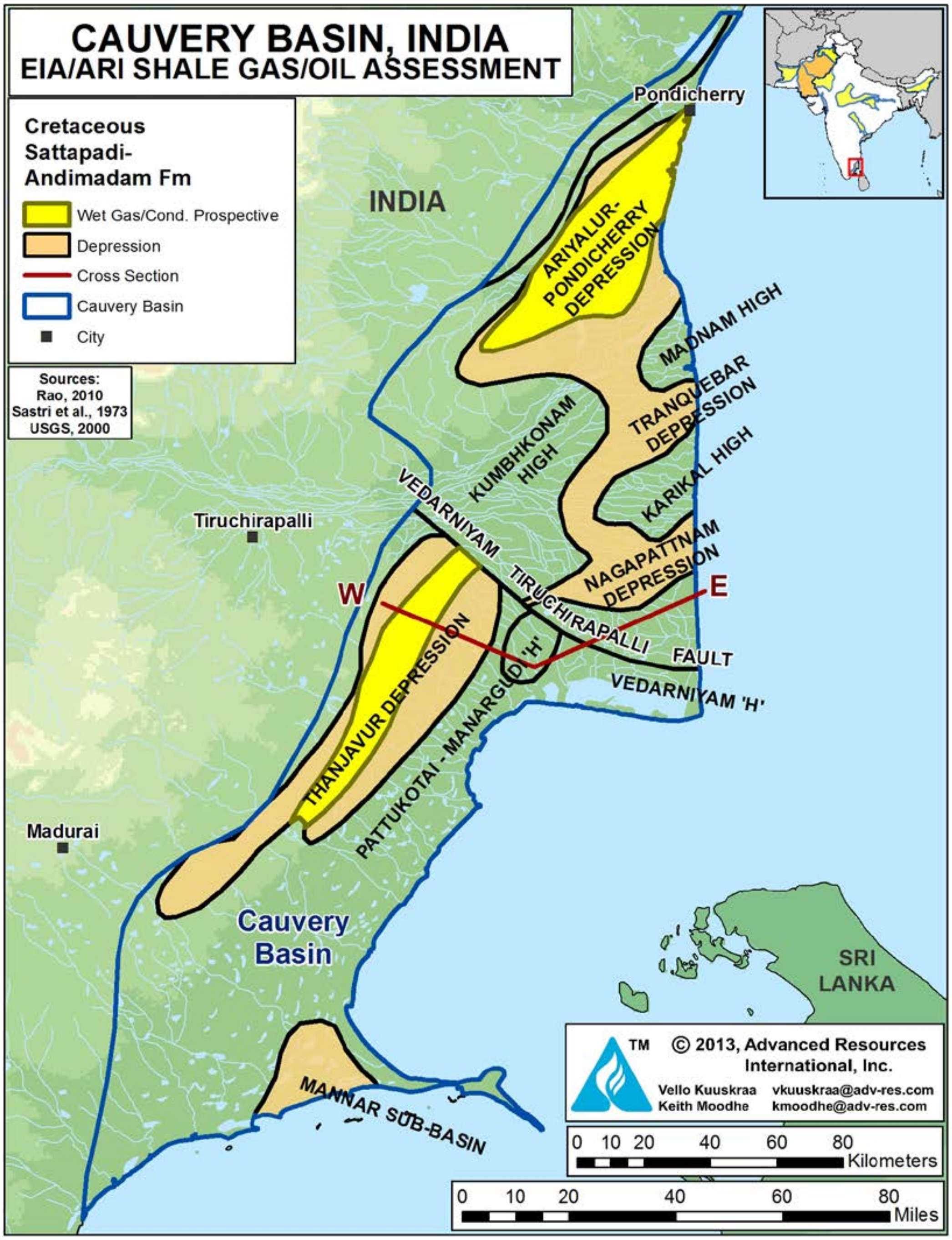
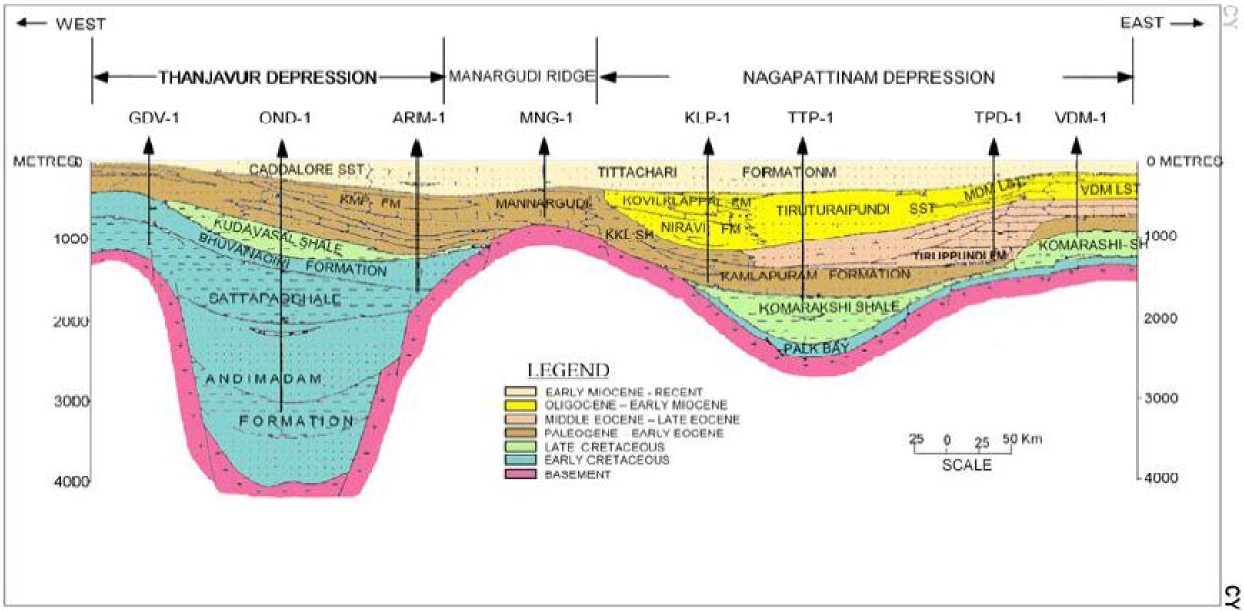


Figure XXIV-22. East to West Cross-Section Across Cauvery Basin.[15]



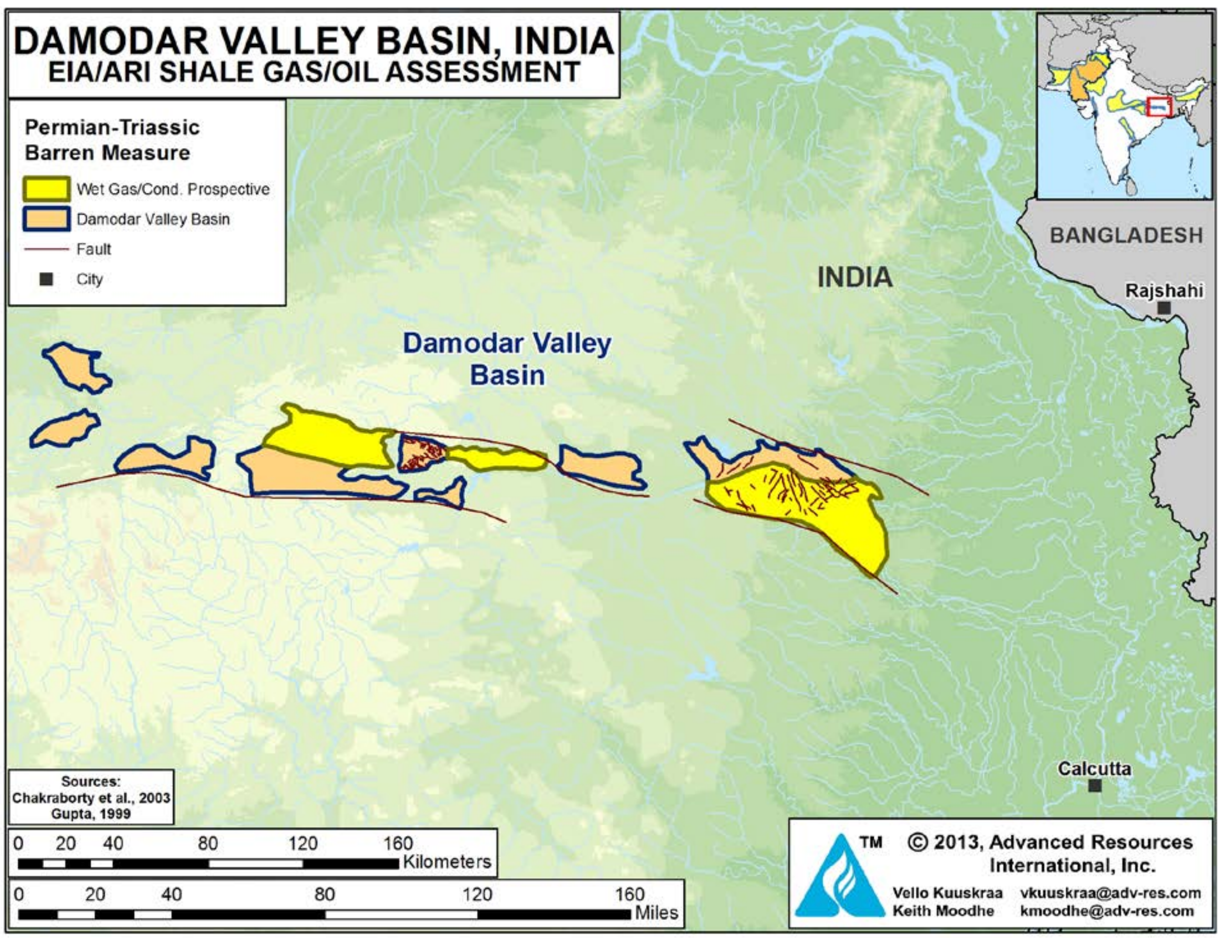
Source: Rao, 2010.

4. DAMODAR VALLEY BASIN, INDIA

4.1 Introduction and Geologic Setting

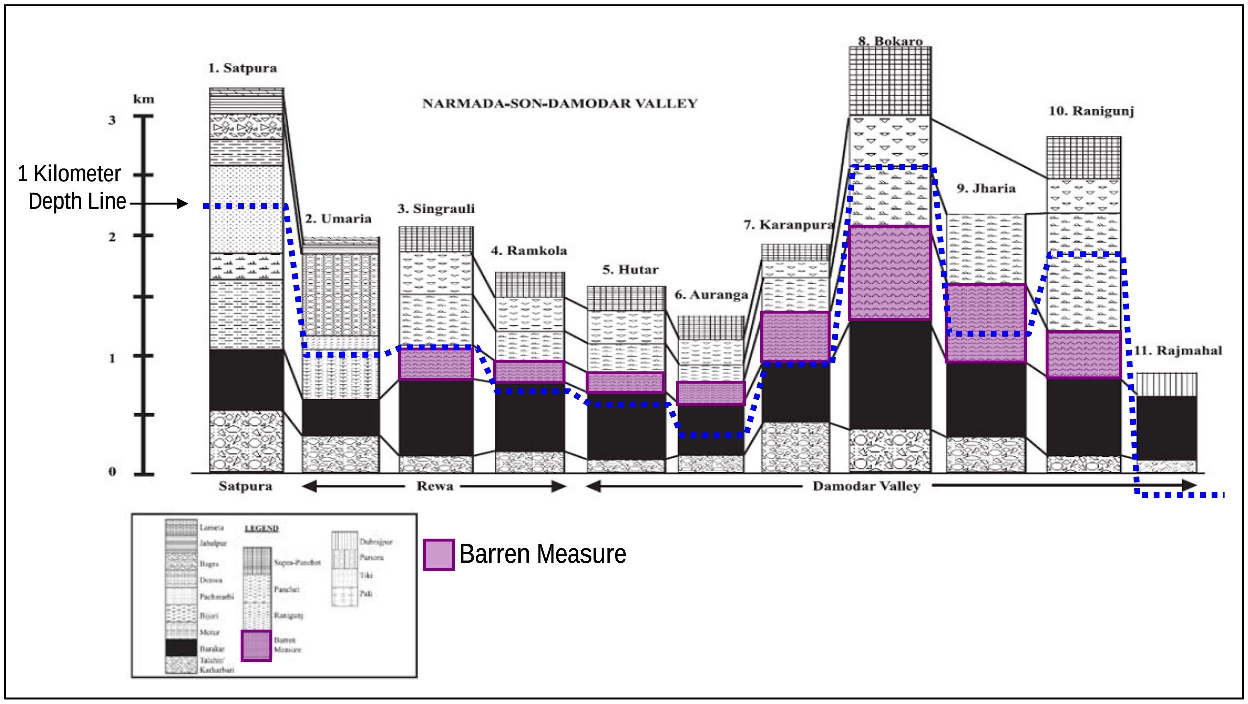
The Damodar Valley Basin is part of a group of basins collectively named the "Gondwanas", owing to their similar dispositional environment and Permo-Carboniferious through Triassic deposition. The "Gondwanas," comprising the Satpura, Pranhita-Godavari, Son-Mahanadi and Damodar Valley basins, were part of a system of rift channels in the northeast of the Gondwana super continent. Subsequent tectonic activity formed the major structural boundaries of the Gondwana basins, notably the Damodar Valley Basin, Figure XXIV-23.

Figure XXIV-23. Damodar Valley Basin and Prospectivity for Shale Gas and Shale Oil



Sedimentation in the Early Permian was primarily glacial-fluvial and lacustrine, resulting in significant deposits of coal. As such, the majority of exploration in the Damodar Valley has focused on the coal resources of the basin, which account for much of India's coal reserves. However, a marine incursion deposited a layer of early Permian Shale, called the Barren Measure Shale in this basin, Figure XXIV-24[14]. This shale formation was the target of India's first shale gas exploration well in the eastern portion of the Damodar Valley. Though present in other Gondwana basins, such as the Rewa Basin, in central India, data suggest that the Barren Measure Shale is only thermally mature in the Damodar Valley Basin.[15]

Figure XXIV-24. Regional Stratigraphic Column of the Damodar Valley Basin, India[16].



Source: Chakraborty, Chandan, 2003.

The Damodar Valley Basin comprises a series of sub-basins (from west to east) - - the Hutar, Daltonganj, Auranga, Karanpura, Ramgarh, Bokaro, Jharia and Raniganj. Though these sub-basins share a similar geologic history, tectonic events and erosion since the early Triassic have caused extensive variability in the depth and thickness of the Barren Measure Shale in these basins.

Because exploration has focused on the coal deposits within the Damodar Valley Basin, relatively little geologic data is available on the Barren Measure Shale. Thermal maturity data on coals adjoining the Barren Measure Shale suggest that the shale is within the wet gas/condensate (R_o of 1.0% to 1.3%) window, and regional studies have shown favorable TOC, with average values of 3.5%.

Present-day burial depth and lower pressures are the main limitations for the shale gas and condensate prospectively of the Barren Measure Shale in the Damodar Valley Basin. In some sub-basins, regional erosion has removed up to 3 kilometers of overlying sediments.

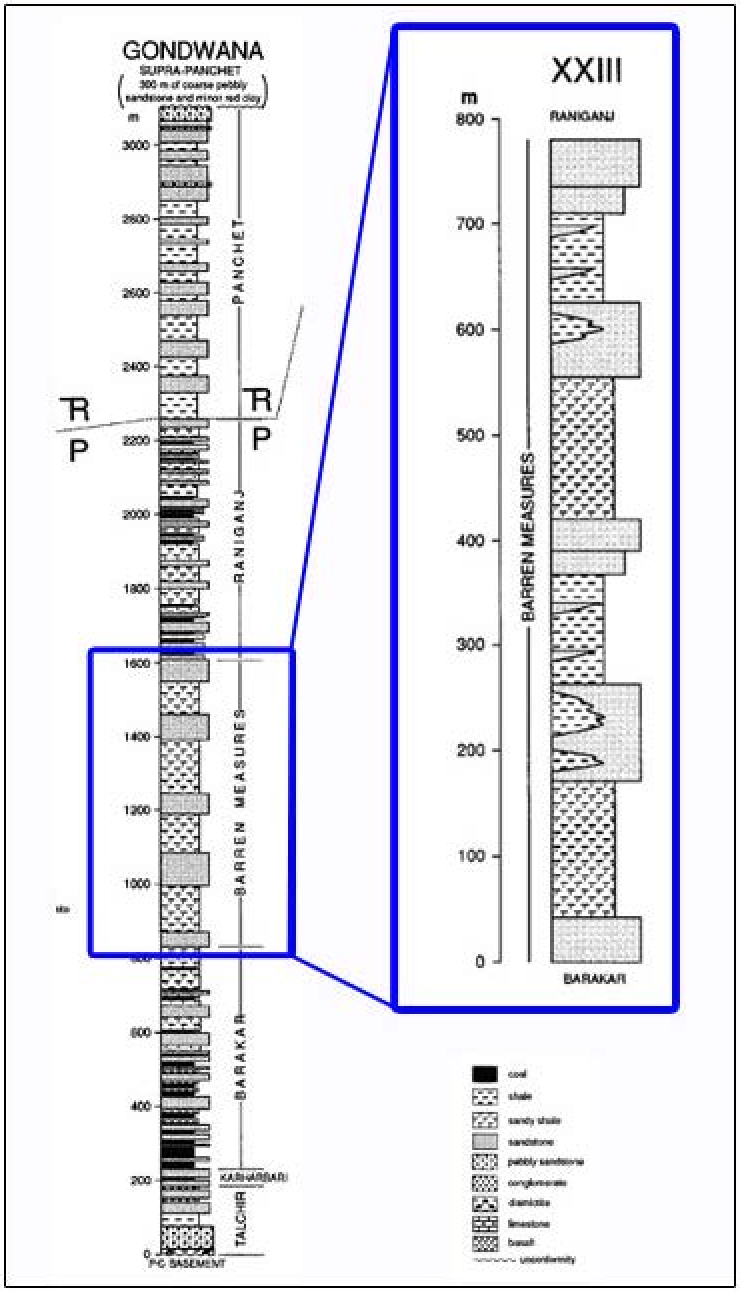
Based on the regional stratigraphic column, Figure XXIV-25,[17] and operator data, the overall 1,080-mi^2 prospective area for the Barren Measure Shale in the Damodar Valley is limited to the Bokaro, Karanpura and Raniganj sub-basins.

The prospective areas within the Bokaro (110 mi^2) and Raniganj (650 mi^2) sub-basins are limited by surface outcrops of formations of the Barren Measure Shale to the west and north, respectively. We have estimated a 320-mi^2 prospective area for the northern half of the Karanpura Basin, based on statements by Schlumberger and ONGC.[18]

4.2 Reservoir Properties (Prospective Area)

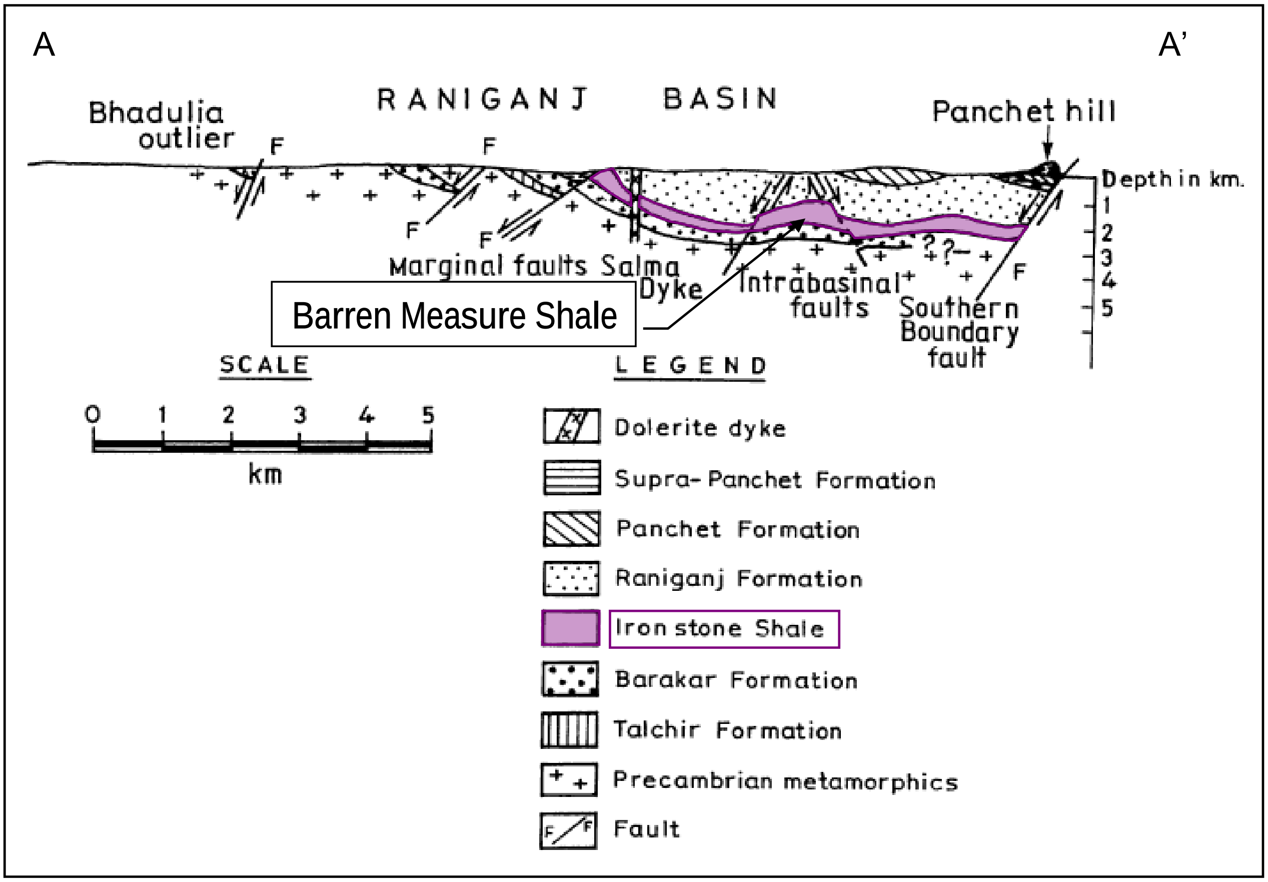
Absent data on thermal maturity and organic content specific to each of the three sub-basins, we assigned average published reservoir property values to these three sub-basins. TOC is assumed to range between 3% and 6% averaging 3.5%, based on information from INOC and ESSAR.[19,20] Thermal maturity was estimated from the coal formations surrounding the Barren Measure Shale, indicating values of 1.1% to 1.3% R_o, placing the shale within the wet gas/condensate window.[21] Depth to the Barren Measure Shale averages about 5,000 ft, based on reports from the shale gas well drilled into the Raniganj sub-basin and from regional cross sections, Figure XXIV-26. We estimate a weighted average gross interval thickness in the three prospective sub-basins of about 2,000 ft, of which about 1,000 ft is organic-rich and 250 ft is net shale.[17]

Figure XXIV-25. Generalized Stratigraphic Column of the Gondwana Basin.



Source: Veevers, J., 1995

Figure XXIV-26. Raniganj Sub-Basin Cross Section.[22]



Source: Ghosh, S. C, 2002.

4.4 Resource Assessment

Using the geologic characteristics discussed above, we estimate that the Barren Measure Shale in the Damodar Valley Basin has a wet shale gas resource concentration of 63 Bcf/mi^2 and a shale condensate resource concentration of 12 million barrels/mi^2.

Risked shale gas in-place is estimated at 27 Tcf, with the prospect area risk factor recognizing the significant faulting present in the basin. We estimate 5 Tcf of risked shale gas may be technically recoverable from the Barren Measure Shale in the Damodar Valley Basins. In addition, we estimate risked shale oil in-place of 5 billion barrels, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

4.4 Recent Activity

Along with the Cambay Basin, the Damodar Valley Basin has been set as a priority basin for shale gas exploration by the Indian government. In late September 2010, Indian National Oil and Gas Company (ONGC) spudded the country's first shale gas well, RNSG-1, in the Raniganj sub-basin of the Damodar Valley. The well was completed mid-January 2011, having reportedly encountered gas flows from the Barren Measure Shale at approximately 5,600 ft. Detailed well test and production results are not publicly available. This well was the first of a proposed four-well R&D program in the basin. The plan calls for an additional well to be drilled in the Raniganj sub-basin and for two wells to be drilled in the Karanpura sub-basin.

5. OTHER BASINS, INDIA

5.1 Upper Assam Basin

The Upper Assam Basin is an important onshore petroleum province in northeast India. The basin has produced oil and some associated gas, mainly from the Upper Eocene-Oligocene Barail Group of coals and shales. In general, the TOC in the lower source rocks ranges from 1% to 2% but reaches 10% in the Barail Group. These source rocks are in the early thermal maturity stage (beginning of the oil window) in the bulk of the Upper Assam Basin.[23] Although the shales may reach thermal maturity for oil and gas generation in the deeper parts of the basin, toward the south and southwest, no data confirming this assumption exists in the public domain. The reported thermal maturity of the Barail Group Shale ranges from R_o of 0.5% to 0.7%, placing these shales as immature for oil.[24] While the shale may reach the oil and wet gas window in the very deepest portion of the basin, the measured vitrinite reflectance is reported at only 0.7% at a depth of 14,800 ft.[25]

5.2 Pranhita-Godavari Basin

The Pranhita-Godavari Basin, located in eastern India, contains thick, organic-rich shales in Permian-age Jai Puram and Khanapur formations. While the kerogen is Type III (humic) and thus favorable for gas generation, the 0.67% R_o indicates that the shales are thermally immature.

5.3 Vindhyan Basin

The Vindhyan Basin, located in north-central India, contains a series of Proterozoic-age shales. While certain of these shales, such as the Hinota and Pulkovar, appear to have sufficient organic richness, no public data exists on their thermal maturity.

5.4 Rajasthan Basin

The Rajasthan Basin covers a large onshore area in northwest India. The basin is structurally complex and characterized by numerous small fault blocks. The Permian-age Karampur Formation is the primary source rock in this basin. While the source rock is Type III and classified as mature, only limited data are available on the reservoir properties of this shale.

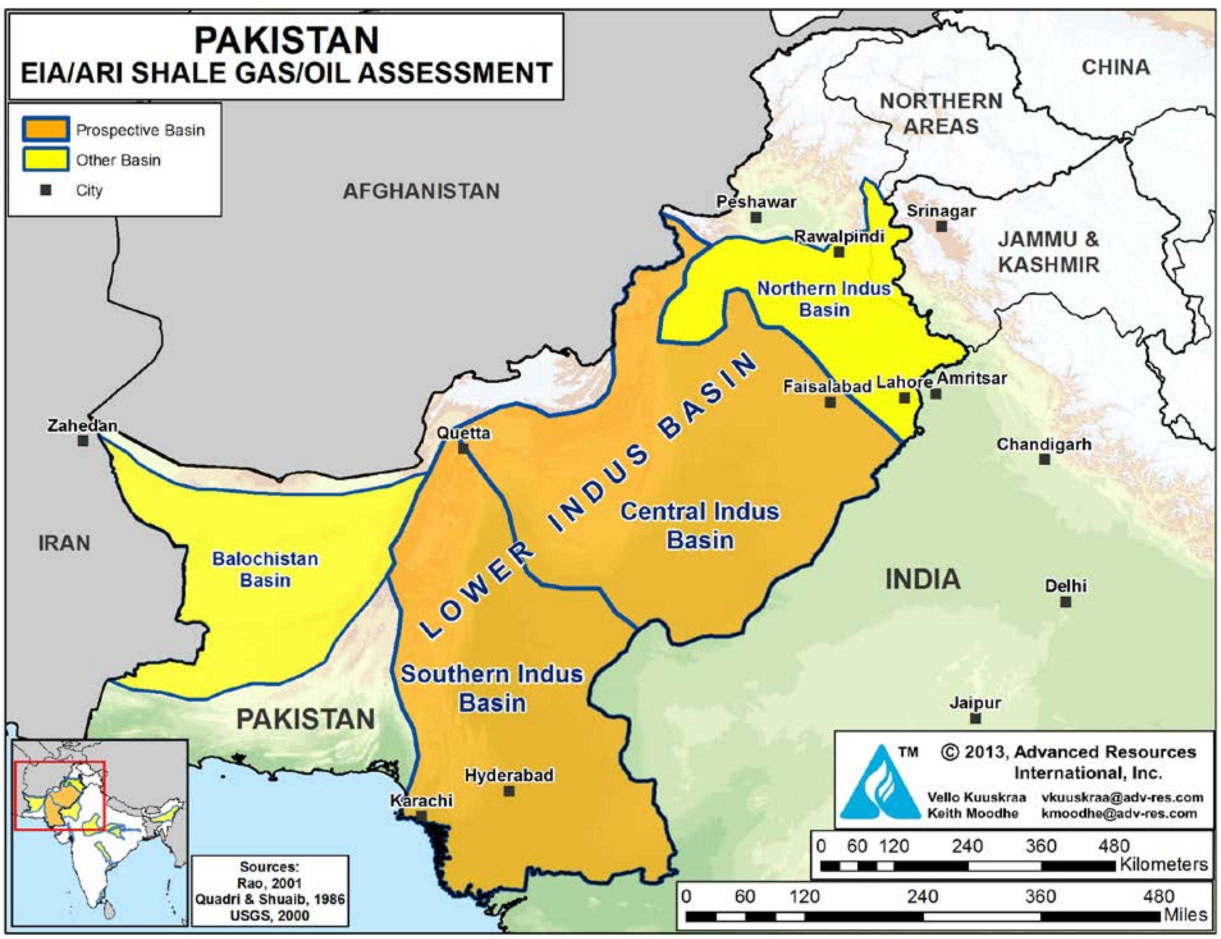
6. LOWER (SOUTHERN AND CENTRAL) INDUS BASINS, PAKISTAN

6.1 Introduction and Geologic Setting

The Southern and Central Indus basins (Lower Indus Basin) are located in Pakistan, along westerns border with India and Afghanistan. The basins are bounded by the Indian Shield on the east and highly folded and thrust mountains on the west, Figure XXIV-27.[26]

The Lower Indus Basin has commercial oil and gas discoveries in the Cretaceous-age Goru Fm sands plus additional gas discoveries in shallower formations. The shales in the Sembar Formation are considered as the primary source rocks for these discoveries. While oil and gas shows have been recorded in the Sembar Shale on the Thar Platform, as of yet no productive oil or gas wells have been drilled into the Sembar Shale.[27]

Figure XXIV-27. Outline for Southern and Central Indus Basin, Pakistan



Sembar Shale. The Lower Cretaceous Sembar Formation is the main source rock in the Lower Indus Basin. The Sembar contains shale, silty shale and marl in the western and northwestern portion of the basin and becomes sandy in the eastern part of the basin. The kerogen within the Sembar Formation is mostly Type II with some Type III.

The Lower Indus Basin covers a massive 91,000-mi^2 area of western Pakistan. Within this large basin area, for the Sembar Shale, we have identified a 31, 320-mi^2 prospective area for dry gas (R_o >1.3%), a 25,560-mi^2 prospective area for wet gas and condensate (R_o between 1.0% and 1.3%), and a 26,700-mi^2 prospective area for oil (R_o between 0.7% and 1.0%). To account for the limited data on the Sembar Shale in this large basin area, we have highly risked the prospective areas and the likelihood of development success.

The eastern boundary of the prospective area of the Sembar Shale in the Lower Indus Basin is the minimum thermal maturity criterion of R_o 0.7%. The northern and western boundaries of the prospective area are set by the limits of Sembar Formation deposition and depth. The southern boundary of the prospective area is the offshore.

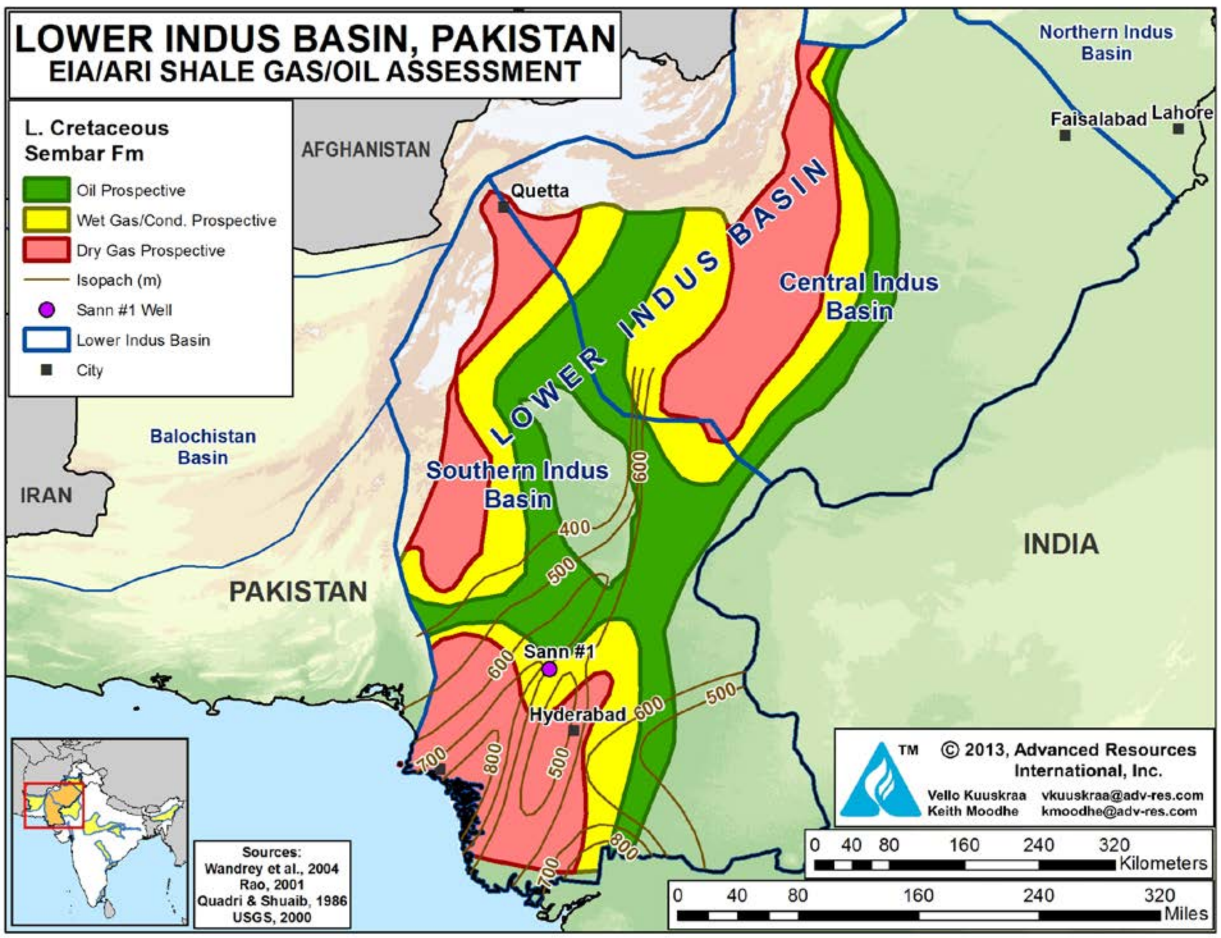
Ranikot Formation. The shales in the Paleocene Ranikot Formation are primarily in the upper carbonate unit which consists of fossiliferous limestone interbedded with dolomitic shale, calcareous sandstone and “abundant” bituminous material. The upper unit was deposited in a restricted marine environment. West of the Karachi Trough axis, the Ranikot Formation becomes dominantly shale (Korara Shale) with deep marine deposition.

Within the southern portion of the Lower Indus Basin, we have identified 26,780-mi^2 for the Ranikot Shale that appears to be prospective for oil (R_o of 0.7% to 1.0%). The eastern, northern and western boundaries of the Ranikot Shale prospective area are set by the 300 m isopach contour; the southern boundary of the prospective area is the offshore.

6.2 Reservoir Properties (Prospective Area)

Sembar Shale. The Sembar Formation was deposited under open-marine conditions.[27] In the prospective area of the Lower Indus Basin, the thickness of the Sembar Shale ranges from 1,000 to over 2,000 ft, Figure XXIV-28. We identified an organic-rich interval 1,000 ft thick with a net shale thickness of 250 ft. We estimate TOC of approximately 2% and an R_o of 1.0% to 1.6%. The Sembar Shale, in the shallower portions of the Lower Indus Basin, is in the oil and wet gas windows, with the lower limit of the oil window at about 4,000 ft and the wet gas/condensate window at 6,000 to 10,000 ft.[27] In the deeper portions of the basin below 10,000 ft, the Sembar Shale enters the dry gas window.

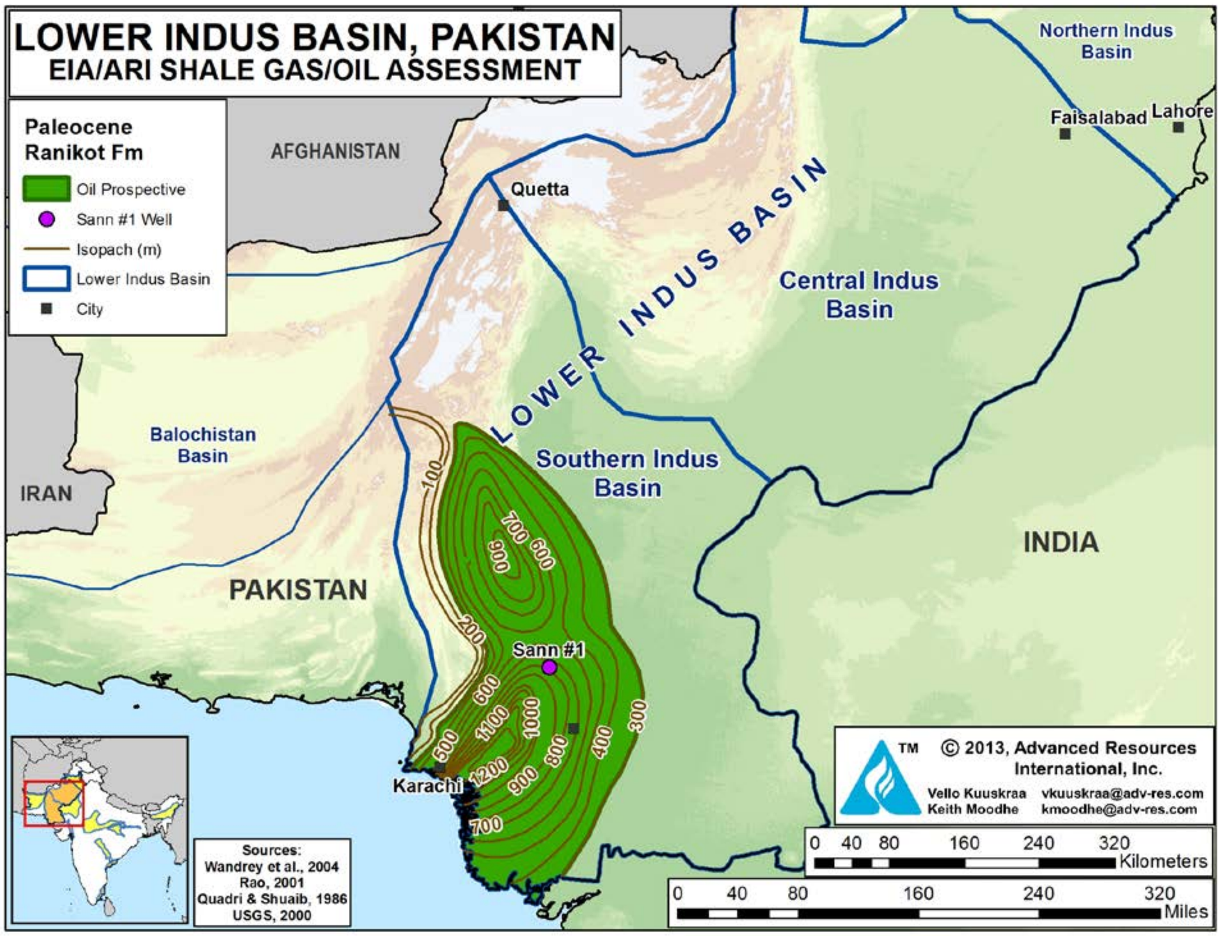
Figure XXIV-28. Isopach of Sembar Shale, Lower Indus Basin, Pakistan[26]



The thermal gradients in the basin increase from east to west, from 1.31°F/100 ft on the Thar Slope in the east to 2.39°F/100 ft in the Karachi offshore in the west. The average thermal gradient in the basin is 2.1°F/100 ft. The Sembar Shale appears to have low clay content.

Ranikot Formation. The prospective area of the Ranikot Formation has a thickness of 1,000 to 3,000 ft, with a net shale thickness of 200 ft, Figure XXIV-29. We assume 2% TOC and a thermal maturity of 0.7% to 1.0% R_o, placing the Ranikot Shale in the oil window.

Figure XXIV-29. Isopach of Ranikot Formation, Southern Indus Basin, Pakistan[26]



6.3 Resource Assessment

Within the 31,320-mi^2 dry gas prospective area, the Sembar Shale in the Lower Indus Basin has a resource concentration of 83 Bcf/mi^2. Within the 25,560-mi^2 wet gas and condensate prospective area, the Sembar Shale has resource concentrations of 57 Bcf/mi^2 of wet gas and 9 million barrels/mi^2 of condensate. Within the 26,700-mi^2 oil prospective area, the Sembar Shale has a resource concentration of 37 million barrels/mi^2.

Within the overall prospective area of the Lower Indus Basin, the Sembar Shale has risked shale gas in-place of 531 Tcf, with 101 Tcf as the risked, technically recoverable shale gas resource. In addition, the Sembar Shale has 145 billion barrels of shale oil in-place, with 5.8 billion barrels as the risked, technically recoverable shale oil resource.

Within its 26,780-mi^2 wet gas and condensate prospective area, the Ranikot Shale has resource concentrations of 17 Bcf/mi^2 of wet gas and 25 million barrels/mi^2 of shale oil/condensate. Within this prospective area of the Lower Indus Basin, the Ranikot Shale has 55 Tcf of risked shale gas in-place and 82 billion barrels of risked shale oil in-place. The risked, technically recoverable shale resources of the Ranikot Shale are 4 Tcf of wet shale gas and 3.3 billion barrels of shale oil/condensate.

6.4 Recent Activity

No publically available data has been reported on shale gas exploration or development for the Lower Indus Basin of Pakistan.

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