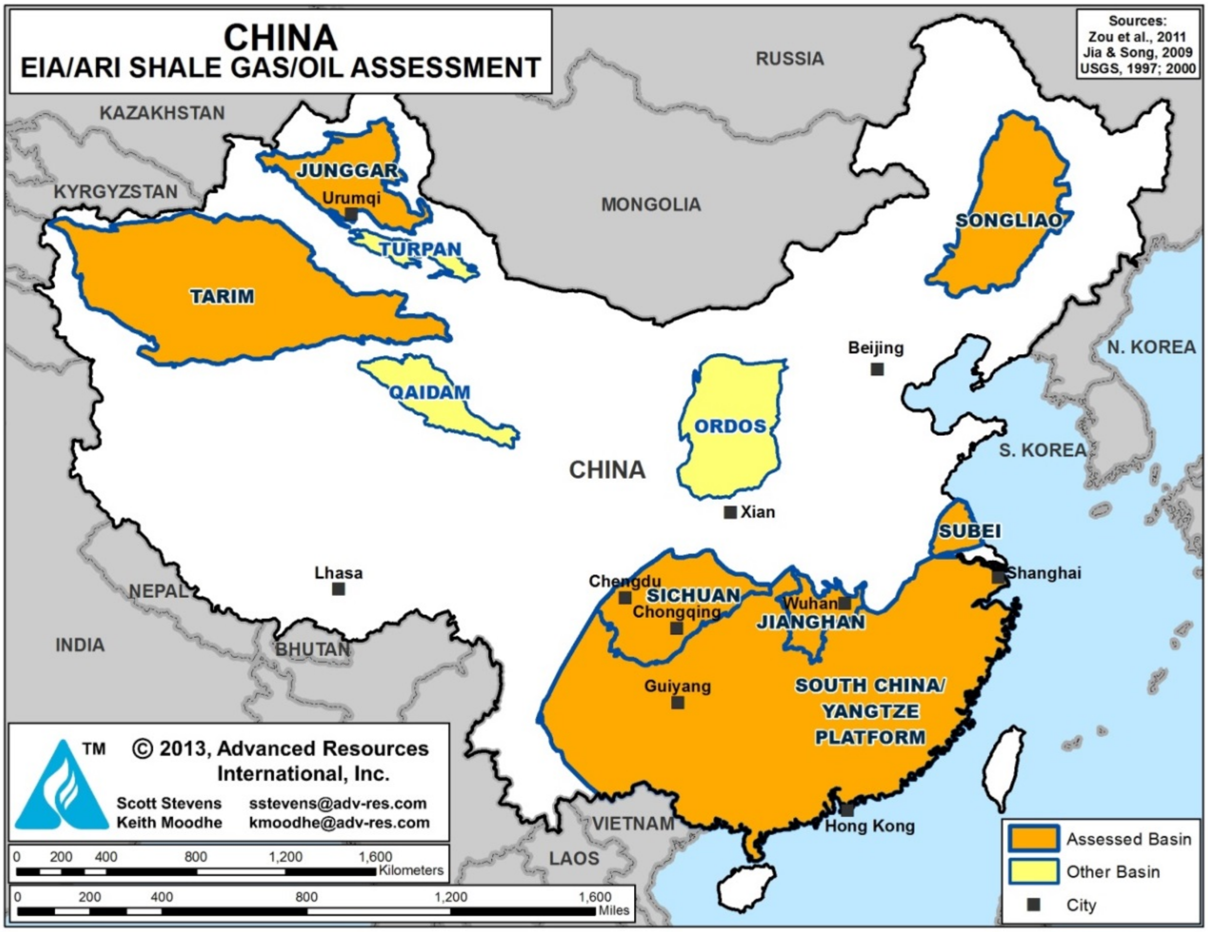
XX. CHINA

SUMMARY

China has abundant shale gas and shale oil potential in seven prospective basins: Sichuan, Tarim, Junggar, Songliao, the Yangtze Platform, Jianghan and Subei, Figure XX-1.

Figure XX-1. China's Seven Most Prospective Shale Gas and Shale Oil Basins are the Jianghan, Junggar, Sichuan, Songliao, Subei, Tarim, and Yangtze Platform.



Source: ARI, 2013.

China has an estimated 1,115 Tcf of risked, technically recoverable shale gas, mainly in marine- and lacustrine-deposited source rock shales of the Sichuan (626 Tcf), Tarim (216 Tcf), Junggar (36 Tcf), and Songliao (16 Tcf) basins. Additional risked, technically recoverable shale gas resources totaling 222 Tcf exist in the smaller, structurally more complex Yangtze Platform, Jianghan and Subei basins. The risked shale gas in-place for China is estimated at 4,746 Tcf, tables XX-1A through XX-1E.

China's also has considerable shale oil potential which is geologically less defined. Risked, technically recoverable shale oil resources in the Junggar, Tarim, and Songliao basins are estimated at 32.2 billion barrels, out of 643 billion barrels of risked, prospective shale oil in place), Table XX-2A through XX-2C. However, China's shale oil resources tend to be waxy and are stored mostly in lacustrine-deposited shales, which may be clay-rich and less favorable for hydraulic stimulation.

The shale gas and shale oil resource assessment for China represents a major upgrade from our prior year 2011 EIA/ARI shale gas assessment. Importantly, this update assessment incorporates a significant new information from ARI's proprietary data base of geologic data extracted from about 600 published technical articles (mostly Chinese language) as well as recent drilling data.

Shale gas leasing and exploration drilling already are underway in China, focused in the Sichuan Basin and Yangtze Platform areas and led by PetroChina, Sinopec, and Shell and the government has set an ambitious but probably unachievable target for shale gas production of 5.8 to 9.7 Bcfd by 2020.

Table XX-1A. China Shale Gas Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Sichuan (74,500 mi^2)			Yangtze Platform (611,000 mi^2)	
	Shale Formation		Qiongzhusi	Longmaxi	Permian	L. Cambrian	L. Silurian
	Geologic Age		L. Cambrian	L. Silurian	Permian	L. Cambrian	L. Silurian
	Depositional Environment		Marine	Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		6,500	10,070	20,900	3,250	5,035
	Thickness (ft)	Organically Rich	500	1,000	314	500	1,000
		Net	275	400	251	275	400
	Depth (ft)	Interval	10,000 - 16,400	9,000 - 15,500	3,280 - 16,400	10,000 - 16,400	9,000 - 15,500
		Average	13,200	11,500	9,700	13,200	11,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Normal	Normal
	Average TOC (wt. %)		3.0%	3.2%	4.0%	3.0%	3.2%
	Thermal Maturity (% Ro)		3.20%	2.90%	2.50%	3.20%	2.90%
	Clay Content		Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		109.8	162.6	114.1	99.4	147.1
	Risked GIP (Tcf)		499.6	1,146.1	715.2	181.0	414.7
	Risked Recoverable (Tcf)		124.9	286.5	214.5	45.2	103.7

Table XX-1B. China Shale Gas Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Jianghan (14,440 mi^2)					
	Shale Formation		Niutitang/Shuijintuo	Longmaxi		Qixia/Maokou		
	Geologic Age		L. Cambrian	L. Silurian		Permian		
	Depositional Environment		Marine	Marine		Marine		
Physical Extent	Prospective Area (mi^2)		1,280	670	1,230	650	1,100	2,080
	Thickness (ft)	Organically Rich	533	394	394	700	700	700
		Net	267	197	197	175	175	175
	Depth (ft)	Interval	9,840 - 16,400	8,200 - 12,000	10,000 - 14,760	3,300 - 7,000	7,000 - 10,000	10,000 - 13,120
		Average	13,120	10,000	12,380	5,500	8,500	11,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		6.6%	2.0%	2.0%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		2.25%	1.15%	2.00%	0.85%	1.15%	1.80%
	Clay Content		Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		148.9	51.0	67.1	14.1	48.3	66.6
	Risked GIP (Tcf)		45.7	8.2	19.8	1.8	10.6	27.7
	Risked Recoverable (Tcf)		11.4	1.6	4.9	0.2	2.7	6.9

Table XX-1C. China Shale Gas Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Greater Subei (55,000 mi^2)				
	Shale Formation		Mufushan	Wufeng/Gaobiajian		U. Permian	
	Geologic Age		L. Cambrian	U. Ordovician-L. Silurian		U. Permian	
	Depositional Environment		Marine	Marine		Marine	
Physical Extent	Prospective Area (mi^2)		2,040	5,370	9,620	1,350	290
	Thickness (ft)	Organically Rich	400	820	820	500	500
		Net	300	246	246	150	150
	Depth (ft)	Interval	13,000 - 16,400	11,500 - 13,500	13,500 - 16,400	3,300 - 8,200	8,000 - 1,000
		Average	14,700	12,500	14,500	5,800	9,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.1%	1.1%	1.1%	2.0%	2.0%
	Thermal Maturity (% Ro)		1.20%	1.15%	1.45%	1.15%	1.35%
	Clay Content		Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		118.6	66.0	87.8	35.8	55.4
	Risked GIP (Tcf)		29.0	42.5	101.4	5.8	1.9
	Risked Recoverable (Tcf)		7.3	10.6	25.4	1.5	0.5

Table XX-1D. China Shale Gas Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Tarim (234,200 mi^2)				
	Shale Formation		L. Cambrian	L. Ordovician	M.-U. Ordovician		Ketuer
	Geologic Age		L. Cambrian	L. Ordovician	M.-U. Ordovician		L. Triassic
	Depositional Environment		Marine	Marine	Marine		Lacustrine
Physical Extent	Prospective Area (mi^2)		6,520	19,420	10,450	10,930	15,920
	Thickness (ft)	Organically Rich	380	300	300	390	400
		Net	240	170	160	240	200
	Depth (ft)	Interval	11,000 - 16,400	10,000 - 16,400	8,610 - 12,670	9,840 - 16,400	9,500 - 16,400
		Average	14,620	13,690	10,790	12,180	13,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.4%	2.1%	2.5%	3.0%
	Thermal Maturity (% Ro)		2.0%	1.80%	0.90%	2.00%	0.90%
	Clay Content		Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Assoc. Gas	Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		77.1	59.8	12.6	85.0	40.5
	Risked GIP (Tcf)		175.9	377.5	32.8	232.3	161.2
	Risked Recoverable (Tcf)		44.0	94.4	3.3	58.1	16.1

Table XX-1E. China Shale Gas Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Junggar (62,100 mi^2)		Songliao (108,000 mi^2)
	Shale Formation		Pingdiquan/Lucaogou	Triassic	Qingshankou
	Geologic Age		Permian	Triassic	Cretaceous
	Depositional Environment		Lacustrine	Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		7,400	8,600	6,900
	Thickness (ft)	Organically Rich	820	820	1,000
		Net	410	410	500
	Depth (ft)	Interval	6,600 - 16,400	5,000 - 16,400	3,300 - 8,200
		Average	11,500	10,000	5,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		0.85%	0.85%	0.90%
	Clay Content		Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		64.7	60.5	45.0
	Risked GIP (Tcf)		172.4	187.5	155.4
	Risked Recoverable (Tcf)		17.2	18.7	15.5

Table XX-2A. China Shale Oil Resources and Geologic Properties.

Basic Data	Basin/Gross Area		Jianghan (14,440 mi^2)			Greater Subei (55,000 mi^2)	
	Shale Formation		Longmaxi	Qixia/Maokou		Wufeng/Gaobiajian	U. Permian
	Geologic Age		L. Silurian	Permian		U. Ordovician-L. Silurian	U. Permian
	Depositional Environment		Marine	Marine		Marine	Marine
Physical Extent	Prospective Area (mi^2)		670	650	1,100	5,370	1,350
	Thickness (ft)	Organically Rich	394	700	700	820	500
		Net	197	175	175	246	150
	Depth (ft)	Interval	8,200 - 12,000	3,300 - 7,000	7,000 - 10,000	11,500 - 13,500	3,300 - 8,200
		Average	10,000	5,500	8,500	12,500	5,800
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	1.1%	2.0%
	Thermal Maturity (% Ro)		1.15%	0.85%	1.15%	1.15%	1.15%
	Clay Content		Low	Low	Low	Low	Low
Resource	Oil Phase		Condensate	Oil	Condensate	Condensate	Condensate
	OIP Concentration (MMbbl/mi^2)		5.0	28.5	5.7	7.0	6.2
	Risked OIP (B bbl)		0.8	3.7	1.3	4.5	1.0
	Risked Recoverable (B bbl)		0.04	0.18	0.06	0.23	0.05

Table XX-2B. China Shale Oil Resources and Geologic Properties.

			Tarim (234,200 mi²)		Junggar (62,100 mi²)		Songliao (108,000 mi²)
Basic Data	Basin/Gross Area						
	Shale Formation		M.-U. Ordovician	Ketuer	Pingdiquan/Lucaogou	Triassic	Qingshankou
	Geologic Age		M.-U. Ordovician	L. Triassic	Permian	Triassic	Cretaceous
	Depositional Environment		Marine	Lacustrine	Lacustrine	Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		10,450	15,920	7,400	8,600	6,900
	Thickness (ft)	Organically Rich	300	400	820	820	1,000
		Net	160	200	410	410	500
	Depth (ft)	Interval	8,610 - 12,670	9,500 - 16,400	6,600 - 16,400	5,000 - 16,400	3,300 - 8,200
		Average	10,790	13,000	11,500	10,000	5,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Highly Overpress.	Highly Overpress.	Mod. Overpress.
	Average TOC (wt. %)		2.1%	3.0%	5.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		0.90%	0.90%	0.85%	0.85%	0.90%
	Clay Content		Low	Low	Medium	Medium	Medium
Resource	Oil Phase		Oil	Oil	Oil	Oil	Oil
	OIP Concentration (MMbbl/mi^2)		11.9	32.5	40.9	43.3	66.4
	Risked OIP (B bbl)		31.1	129.5	108.9	134.1	229.2
	Risked Recoverable (B bbl)		1.55	6.47	5.44	6.70	11.46

Initial drilling confirms China's shale gas and oil resource potential, but rapid commercialization may be challenging due to the typically complex geologic structure (faulting, high tectonic stress), restricted access to geologic data, and the high cost and rudimentary state of in-country horizontal drilling and fracturing services.

1. **South China "Shale Corridor": Sichuan, Jianghan, Subei Basins** and **Yangtze Platform**. These areas have classic marine-deposited, quartz-rich, black shales of Cambrian and Silurian age that are roughly comparable to North American analogs. The Sichuan Basin -- China's premier shale gas area -- has existing gas pipelines, abundant surface water supplies, and close proximity to major cities. Current exploration is focusing on the southwest quadrant of the basin, which is relatively less faulted and low in H_2S. The adjacent Yangtze Platform and the Jianghan and Subei basins are structurally complex with poor data control, but also located close to major cities centers and still considered prospective.

   Shale targets in the southwestern portion of the Sichuan Basin are brittle and dry-gas mature, but lower in TOC (~2%) than North American shales and furthermore still quite faulted. PetroChina's first horizontal shale well required 11 months to drill (vs 2 weeks in North America). The induced fractures grew planar due to high stress and this well produced a disappointing initial rate of 560 Mcfd. Shell tested 2.1 million ft^3/day from a vertical well, but noted hole instability and out-of-zone deviation while drilling horizontally nearby. Sinopec, BP, Chevron, ConocoPhillips, Statoil, TOTAL and others also have expressed interest in the region. Assuming its significant geologic and operational issues can be solved, the Sichuan may become China's premier shale gas basin, capable of providing several Bcfd of supply within 20 years.

2. The **Tarim Basin** has relatively deep shale gas potential in marine-deposited black shales of Cambrian and Ordovician age that are rich in carbonate and often graptolitic. No shale leasing or drilling have been reported, probably because of this basin's remoteness and extreme depth of the shale. Structure is relatively simple but the shales are mostly too deep, reaching prospective depth only on uplifts where TOC unfortunately tends to be low (1-2%). Nitrogen contamination (~20%) and karstic collapse structures also are issues. Shallower, lower-rank Ordovician shale and Triassic lacustrine mudstone have potential. Horizontal wells already account for half of conventional oil production in the Tarim Basin, providing a good foundation for application in future shale development.

3. **Junggar Basin**, while not the largest shale resource in China, may have its best shale geology. Permian source rocks are extremely thick (average 1,000 ft), rich (4% average TOC; 20% maximum) and over-pressured. Triassic source rocks are leaner but also appear prospective. The structural geology of the basin is favorably simple, while thermal maturity ranges from oil to wet gas within the prospective area. Large, continuous shale oil and wet gas leads were identified. The main risk in the Junggar Basin is the lacustrine rather than marine depositional origin of the shale and the concomitant issues of brittleness and "frack-ability". Shell and Hess are evaluating shale oil prospects in the similar, smaller Santanghu Basin just east of the Junggar Basin.

4. **Songliao Basin**, China's largest oil-producing region, the Songliao has thick Lower Cretaceous source rock shales in the oil to wet gas windows. While these organic-rich shales are lacustrine in origin and unfavorably rich in clay minerals, they have the advantages of being over-pressured and naturally fractured. Prospective shales occur in isolated half-grabens at depths of 300 to 2,500 m but faulting is intense. PetroChina considers the Songliao Basin to be prospective for shale exploration and has already

noted commercial shale oil production here. Hess and PetroChina have jointly conducted a study of shale/tight oil potential at giant Daqing oil field. Jilin Oilfield has drilled and hydraulically fractured deep horizontal wells into a tight sandstone gas reservoir. Their 1,200-m lateral, 11-stage frac technology could be applied to shale oil reservoirs in the Songliao Basin.

5. **Other Basins.** Several other sedimentary basins in China have shale potential but could not be quantified due to low geologic quality or insufficient data control. The Turpan-Hami Basin, east of the larger Junggar, has equivalent Permian organic-rich shales that are lacustrine in origin, oil- to wet gas-prone, and appear prospective. The Qaidam Basin, southeast of the Tarim, comprises isolated fault-bounded depressions containing Upper Triassic mudstone source rocks with high TOC; these appear oil prone but are very deep. The Ordos Basin has simple structure but its Triassic shales have low TOC and high clay content (80%), while Carboniferous and Permian mudstones are coaly and ductile. No shale drilling has been reported in these less prospective areas.

INTRODUCTION

China has abundant shale gas and shale oil resource potential that is at the early stage of delineation, evaluation, and testing. China's government is prioritizing shale development on legal, technological, and commercial fronts. In December 2011 the State Council approved a petition from the Ministry of Land and Resources' (MLR) to separate the ownership of shale gas from conventional resources, although the ownership of shale oil resources remains unclear. In March 2012 the Twelfth Five-Year Plan for Shale Gas Development envisioned large-scale commercial development of China's shale resources, while fiscal incentives and subsidies to support shale investment are under consideration.

However, the prevailing industry view, which is shared by ARI, is that geologic and industry conditions are considerably less favorable in China than in North America. Numerous challenges seem certain to complicate and slow commercial development compared with North America. In particular, most Chinese shale basins are tectonically complex with numerous faults -- some seismically active -- which is not conducive to shale development. Similar issues have slowed China's production of coalbed methane, a distantly related unconventional gas resource. CBM output is still under 0.5 Bcfd following 20 years of commercial development.

Furthermore, China's service sector is just beginning to acquire the necessary capability for large-scale horizontal drilling combined with massive multi-stage hydraulic stimulation. Only a small number of horizontal shale gas and oil wells have been tested thus far, with generally low but at least meaningful production rates. Significant commercial production appears some years in the future. Considerable work is needed to define the geologic sweet spots, develop the service sector's capacity to effectively and economically drill and stimulate modern horizontal shale wells, and install the extensive surface infrastructure needed to transport product to market.

Industry is cautious regarding China's likely pace of shale gas development. Even in its best area, PetroChina engineers observed: "the Sichuan Basin's considerable structural complexity, with extensive folding and faulting, appears to be a significant risk for shale development."[1] And a BP official recently noted: "It will be a long time before China could commercialize its shale resources in a large way."[2] The National Energy Administration's mean shale gas output target of 7.7 Bcfd by 2020 appears ambitious in this context.

Another issue is data availability. Much of the basic geologic and well data that commonly is publicly available in other countries – and essential for resource and prospect evaluation -- is considered by China to be state secrets. To overcome these data limitations, ARI has drawn on its extensive proprietary China shale geology data base, compiled from approximately 400 technical papers published in Chinese language. Data locations plotted on our China maps provide an indication of geologic control (or lack thereof).

Four main onshore regions assessed by this study have shale gas and oil potential, Figure XX-1. These include:

- South China Shale Corridor (Sichuan, Jianghan, Subei basins and Yangtze Platform).
- The Tarim, Junggar, and Songliao basins in northern China.

Additional basins exist but may lack data control or do not appear to have large shale gas/oil potential (e.g., Ordos, Qaidam, Turpan-Hami).

1. SOUTH CHINA SHALE CORRIDOR : SICHUAN, JIANGHAN, SUBEI BASINS, YANGTZE PLATFORM

1.1 Introduction and Geologic Setting

Organic-rich marine shales, mostly gas-prone to thermally over-mature, underlie a vast area of south-central and eastern China. This “Shale Corridor” comprises the Sichuan Basin and adjoining Yangtze Platform in Sichuan, Yunnan, Guizhou, Hubei, and western Hunan provinces, as well as the smaller Jianghan and Subei basins in southeastern China. Within this broad region, Paleozoic shales in the Sichuan Basin and Yangtze Platform offer some of China’s most prospective shale gas potential. However, while the essential rock quality in this region appears favorable and not dissimilar with certain North American shales (e.g., Marcellus, Barnett), significant exploration challenges still exist. These include locally excessive depth and high thermal maturity and -- most concerning – intense faulting and structural complexity.

The overall sedimentary sequence in the South China Shale Corridor is 6 to 12 km thick and includes multiple organic-rich shales of marine and non-marine origin within Pre-Cambrian, Cambrian, Ordovician, Silurian, Devonian, Permian, Triassic, and Eocene formations. Figure XX-2 illustrates the stratigraphy of the Sichuan Basin and Yangtze Platform, highlighting potentially prospective L. Cambrian, L. Silurian, and U. Permian source rocks.

Paleozoic shales in the South China Shale Corridor -- the most prospective of this sequence and the closest in character to productive North American shales -- typically are thick, carbon- and quartz-rich, of marine depositional origin, and mostly thermally mature within the dry-gas to over-mature windows. In contrast, the Triassic and Eocene shales were deposited primarily within freshwater lacustrine (rather than marine) environments and tend to be clay-rich, probably more ductile, and thus less prospective. Our work -- consistent with published information by PetroChina, Shell, and others -- indicates that the Lower Cambrian, Lower Silurian, and Upper Permian marine shales in the Sichuan Basin, Yangtze Platform, and adjoining regions offer some of China’s best promise for shale gas development.

Figure XX-2. Stratigraphy of the Sichuan Basin and Yangtze Platform, Highlighting Potentially Prospective L. Cambrian, L. Silurian, and U. Permian Source Rocks.

SICHUAN BASIN

ERA	PERIOD	EPOCH	FORMATION	AGE (Ma)	THICKNESS (m)
CENOZOIC	QUATERNARY			0 - 3	0 - 380
	TERTIARY	Upper		3 - 25	0 - 300
		Lower		25 - 80	0 - 800
MESOZOIC	CRETACEOUS			80 - 140	0 - 2000
	JURASSIC	Upper	Penglaizhen	140 - 195	650 - 1400
		Middle	Suining		340 - 500
			Shaximiao		600 - 2800
		Middle-Lower	Ziliujing		200 - 900
	TRIASSIC	Upper	Xujiahe	195 - 205	250 - 3000
		Middle	Leikoupo	205 - 230	900 - 1700
		Lower	Jialingjiang		
			Feixianguan		
PALEOZOIC	PERMIAN	Upper	Changxing	230 - 270	200 - 500
			Longtan		
		Lower	Maokou		200 - 500
			Qixia-Liangshan		
	CARBONIFEROUS	Mississippian	Huanglong	270 - 320	0 - 500
	SILURIAN	Upper		320 - 570	0 - 1500
		Lower	Longmaxi		
	ORDOVICIAN				0 - 600
	CAMBRIAN	Upper	Xixiangchi		0 - 2500
		Middle	Yuxiansi		
		Lower	Qiongzhusi		
PROTEROZOIC	SINIAN	Upper	Dengying	570 - 850	200 - 1100
			Doushantuo		
		Lower			0 - 400
	PRE-SINIAN			850	

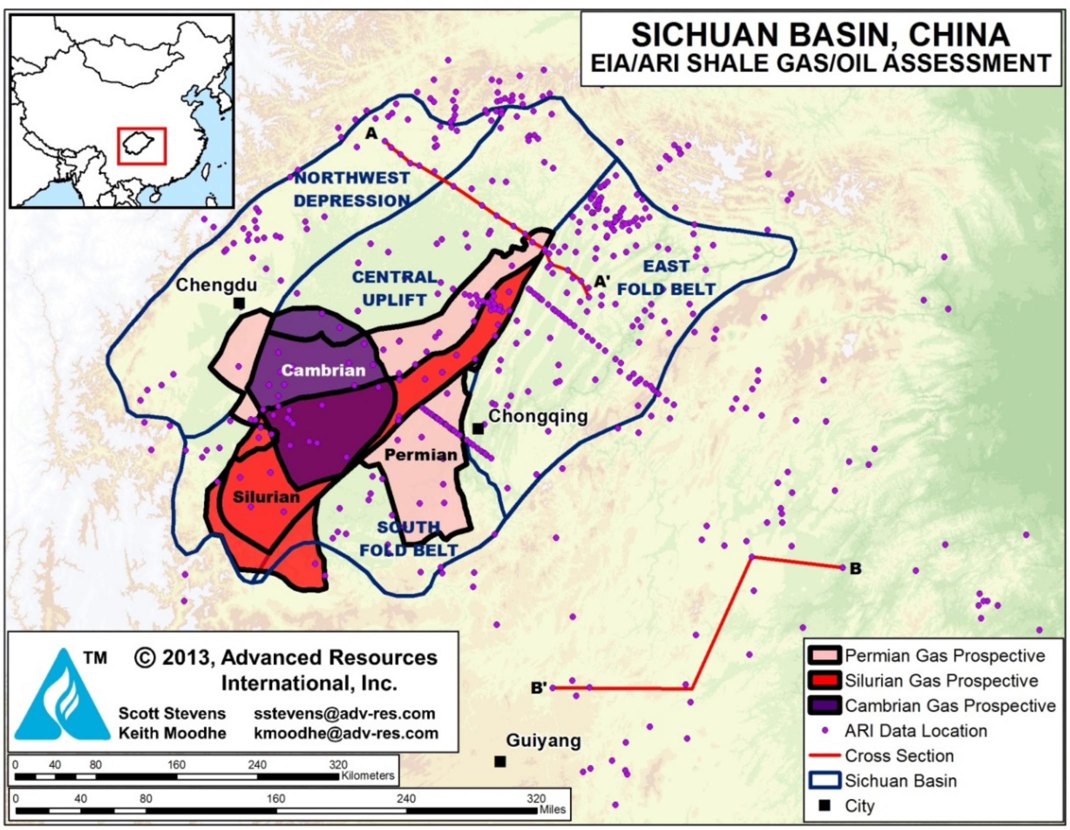
Source Rock | Conventional Reservoir

Source: ARI, 2013.

The **Sichuan Basin** covers a large 74,500-mi^2 area in south-central China, while the structurally more complex and sparsely drilled Yangtze Platform covers a larger but discontinuous area to the south and east. The Sichuan Basin currently produces about 1.5 Bcfd of natural gas from conventional and low-permeability sandstones and carbonates. These reservoirs occur mainly in the Triassic Xujiahe and Feixianguan formations, stored in complex structural-stratigraphic traps (mainly faulted anticlines) that are distributed across the basin. A limited volume of oil also is produced from overlying Jurassic sandstones. The conventional oil and gas fields are underlain and were sourced by deeper organic-rich Paleozoic marine shales, the main target of current shale gas exploration. Proterozoic to L. Paleozoic gas fields also have been discovered more recently. Extremely high H_2S concentrations (up to 50%) and CO_2 (up to 18%) occur in sour gas fields such as Puguang in the northeast part of the basin. Levels of these contaminants are much lower in the south but can still be locally significant.[3]

A number of technical journal articles have been published on the Sichuan Basin in both Chinese and English, with the volume and quality of public reports increasing in recent years. ARI extracted a substantial data base on Sichuan Basin source rock shale geology from 47 Chinese and 20 English language technical articles, comprising 23 cross-sections, 714 well/outcrop locations, and 1,462 total samples, Figure XX-3. This data set provides good control of shale thickness, depth, structural geology, thermal maturity, and organic content. We provide selected examples of specific geologic data to illustrate our conclusions. We then mapped and characterized the three distinct Paleozoic shale leads discussed below.

Figure XX-3. Structural Elements of Sichuan Basin and Adjoining Yangtze Platform Showing ARI-Proprietary Shale Data Locations and High-Graded Areas for Cambrian, Silurian, Permian Shales.

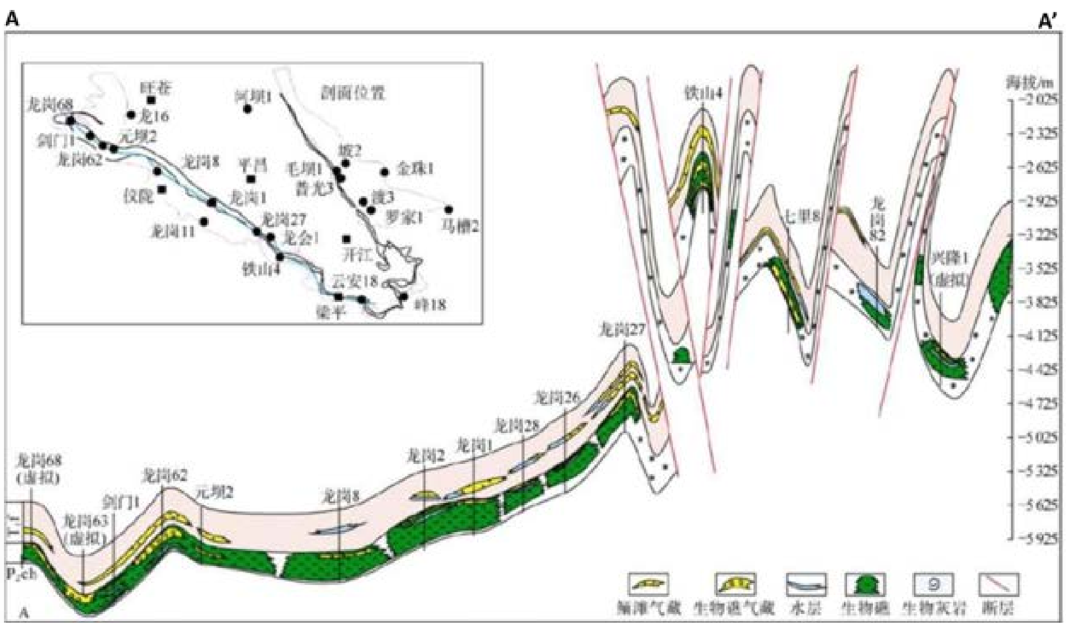


Source: ARI, 2013.

The Sichuan Basin / Yangtze Platform region behaved as a passive margin during Sinian (Precambrian) to Mesozoic time, transitioning into a foreland basin setting during the Mesozoic to Cenozoic. Three major tectonic events punctuated this time interval, including regional extension during the Caledonian and Hercynian orogenies (Ordovician to Permian), a structural transitional phase during the Indosinian to early Yanshanian orogenies, and compression during the late Yanshanian to Himalayan orogenies (Cretaceous to Neogene).[4]

The modern-day Sichuan basin comprises four tectonic zones: the Northwest Depression, Central Uplift, and the East and South Fold Belts. The Central Uplift, characterized by relatively simple structure and comparatively few faults, appears to be the most attractive region for shale gas development. In contrast, the East and South Fold Belts of the Sichuan Basin are structurally more complex, characterized by numerous closely spaced folds and faults with large offset; these areas are not considered prospective for shale gas development. For example, a cross-section through the northern Sichuan Basin shows relatively simple structural conditions in the Central Uplift transitioning abruptly into the highly faulted and deformed eastern fold belt, Figure XX-4.[5] The adjoining Yangtze Platform to the south and east is even more structurally complex, but lacks data control and is quite challenging to assess for shale development.

Figure XX-4. Northwest-Southeast Structural Cross-section of Northern Sichuan Basin, Showing Relatively Simple Structure in Central Uplift Transitioning into Highly Faulted Fold Belt in the East.



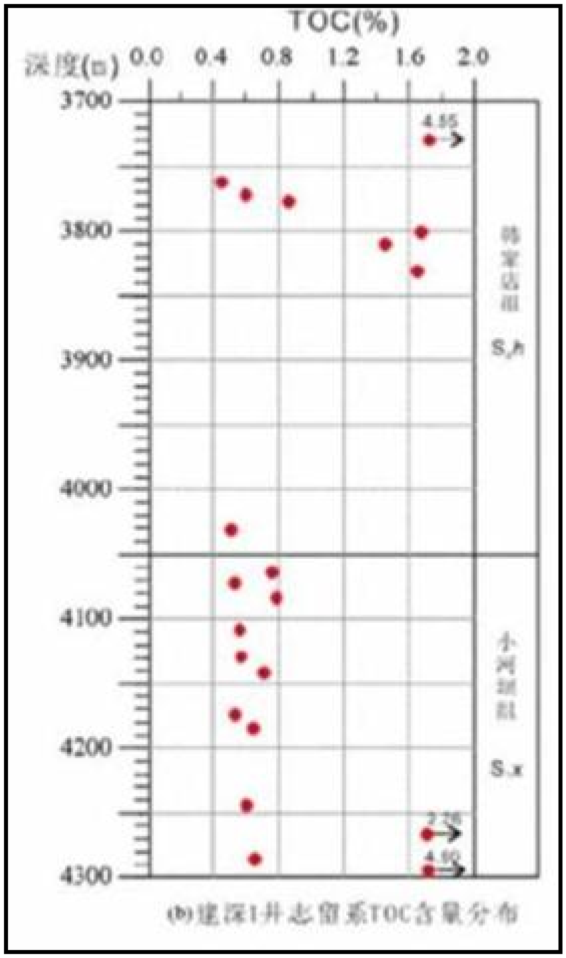
Source: Zou et al., 2011.

The new geologic data indicate that only the southwestern quadrant of the Sichuan Basin meets the standard exploration criteria for shale development: suitable shale thickness and depth, dry to wet gas thermal maturity, and absence of extreme structural complexity. The prospective area we mapped with new data is considerably smaller than in the initial 2011 EIA/ARI study. This emerging “sweet spot” in the southwest Sichuan Basin dominates China’s shale leasing and drilling activity, as it appears to offer China’s best combination of favorable geology, good access with flat surface conditions, existing pipelines, abundant water supplies, and access to major urban gas markets.

Other parts of the Sichuan Basin are structurally and/or topographically complex or have elevated H_2S contamination. The 2008 Sichuan earthquake, centered in Wenchuan County, occurred along active strike-slip faults in the northwest portion of the Sichuan Basin. This region has shale potential but was screened out due to excessive structural complexity. In addition, the conventional reservoirs in the northern portion of the Central Uplift can have extremely high hydrogen sulfide content, frequently in excess of 10% by volume, caused by thermochemical sulfate reduction (TSR).[6] Not only does H_2S reduce gas reserves and increase processing costs, it is a dangerous safety hazard as well: in 2003 a sour gas well blew out in the Luojiazai gas field, killing 233 villagers. Carbon dioxide content also can be high in the northeast Sichuan Basin (~8%). Consequently, northeast Sichuan was screened out as well.

The four main organic-rich shale targets in the Sichuan Basin are the L. Cambrian Qiongzhusi, L. Silurian Longmaxi, the L. Permian Qixia, and the U. Permian Longtan formations and their equivalents, Figure XX-2. These units sourced many of the conventional reservoirs in the Sichuan Basin. Most important is the L. Silurian Longmaxi Fm, which contains an average 1,000 ft of organically rich, black, graptolitic-bearing, siliceous to cherty shale. TOC content is mostly low to moderate at up to 4%, consisting mainly of Type II kerogen. Figure XX-5 illustrates TOC distribution in a deep conventional petroleum well, ranging from 0.4% to over 4%.[7] Thermal maturity is high and increases with depth, ranging from dry gas prone to overmature (R_o 2.4% to 3.6%). Porosity measured from the Wei-201 and Ning-201 shale wells was over 4% but this parameter is difficult to measure and frequently underestimated.[8] The Longmaxi has exhibited gas shows in at least 15 deep conventional wells in the southern Sichuan Basin.[9]

Figure XX-5. TOC Distribution of L. Silurian Longmaxi Fm in a Deep Petroleum Exploration Well, Sichuan Basin, Showing 0.4% to Over 4%.



Source: Liu et al., 2011

The second shale gas target in the Sichuan Basin is the Cambrian Qiongzhusi Formation. Although deeper than the Longmaxi and mostly screened out by the 5-km depth cutoff, the Qiongzhusi contains high-quality source rocks that provide further shale resource potential. The formation was deposited under shallow marine continental shelf conditions and has an overall thickness of 250 to 600 m. Of particular note is the 60 to 300 m of high-gamma-ray black shale, which has about 3.0% TOC (sapropelic) that is dry-gas-prone (about 3.0% R_o).

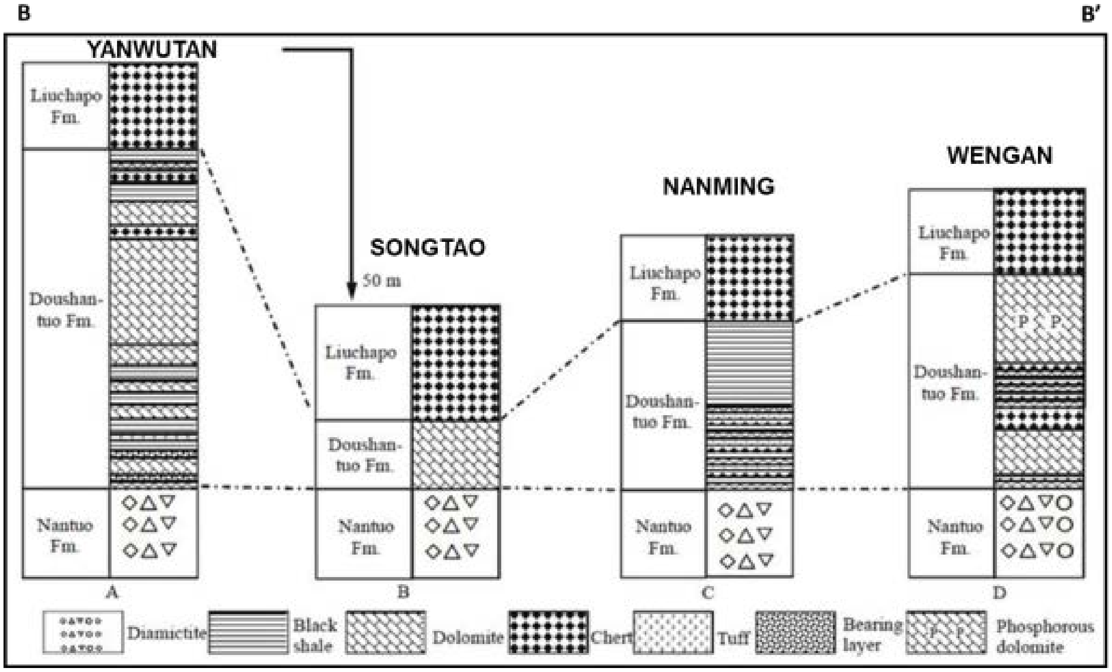
The Qiongzhusi black shale is considered the principal source rock for the Weiyuan gas field in the southern Sichuan Basin, where the organically rich hot shale is about 120 m thick out of 230 to 400 m of total formation thickness. Mineralogy appears favorably brittle, being high in quartz and other brittle minerals (65%) and fairly low in clay (30%). In 1966 a conventional gas well flowed nearly 1 million ft^3/day from an unstimulated organic-rich Qiongzhusi shale interval at a depth of 2,800 m. PetroChina recently tested the first horizontal well completed in the Qiongzhusi at Weiyuan field (see Activity below).[10]

The **Yangtze Platform** area is structurally more complex than the Sichuan Basin, with only scant well control, very little of which has been published. The Paleozoic sequence here has been tectonically deformed and partly eroded. Indeed, the shales are not continuous deposits as they are in the Sichuan Basin but rather isolated remnant basins which are difficult to high grade with current data availability. Nevertheless, Chevron and BP have expressed interest in the region, while researchers have begun to map out potentially favorable shale development areas.[11]

Our analysis of the Yangtze Platform depends heavily on outcrop and road cut studies, such as the Cambrian correlation shown in Figure XX-6; subsurface control remains weak. For example, Figure XX-7 shows TOC vs depth distribution for a 100-m thick outcrop of the L. Cambrian Xiaoyanxi Formation in the Yanwutan-Lijiatuo area, Yangtze Platform.[12] Black shale here totals nearly 100 m thick with exceptionally rich average 7.5% TOC. The underlying Sinian Liuchapo Formation consists mainly of chert with average 2.3% TOC. Figure XX-8 shows an outcrop photo of L. Cambrian black chert north of Guiyang city, Guizhou Province, displaying the unit's strong bedding and brittle character.[13]

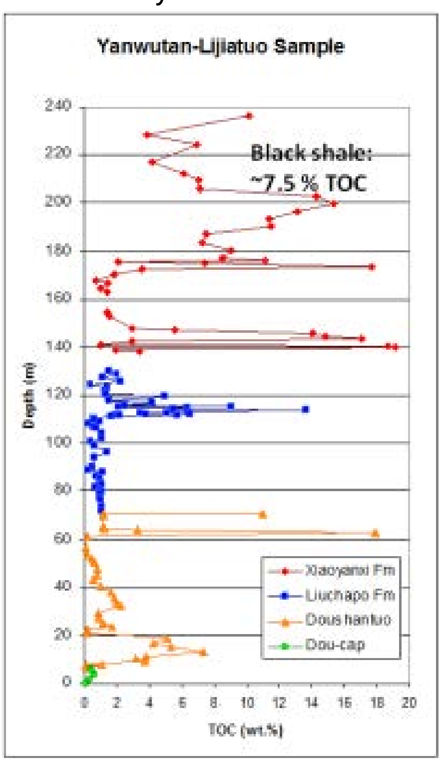
The **Jianghan Basin** is a conventional petroleum producing region covering 14,500-mi^2 in the central Yangtze Platform of Jiangxi and Hubei provinces, close to the major city of Wuhan. Jianghan is a rift basin that developed on the Central Yangtze Platform during Cretaceous to Tertiary time, induced by transpressional tectonics related to India's collision with Asia. Somewhat overlooked for shale exploration, the Jianghan Basin has Lower Paleozoic shale source rocks -- similar to those in Sichuan and the Yangtze Platform -- with suitable thickness, depth, TOC, and R_o, although even in high-graded areas they are mostly deep (4-5 km) and significantly faulted. Figure XX-9 illustrates the structural elements of the Jianghan Basin, along with ARI-proprietary shale gas data locations and the high-graded location of Cambrian, Silurian, and Permian shale leads.

Figure XX-6. Outcrop Lithology of the Cambrian Sequence Across the Western Yangtze Platform



Source: Guo et al., 2006.

Figure XX-7. TOC vs Depth Distribution at Outcrop of the L. Cambrian Xiaoyanxi Fm Black Shale, Yangtze Platform. Black Shale Totals Nearly 100 m Thick with Average 7.5% TOC. The Underlying Sinian Liuchapo Fm is Mainly Chert with 2.3% TOC.

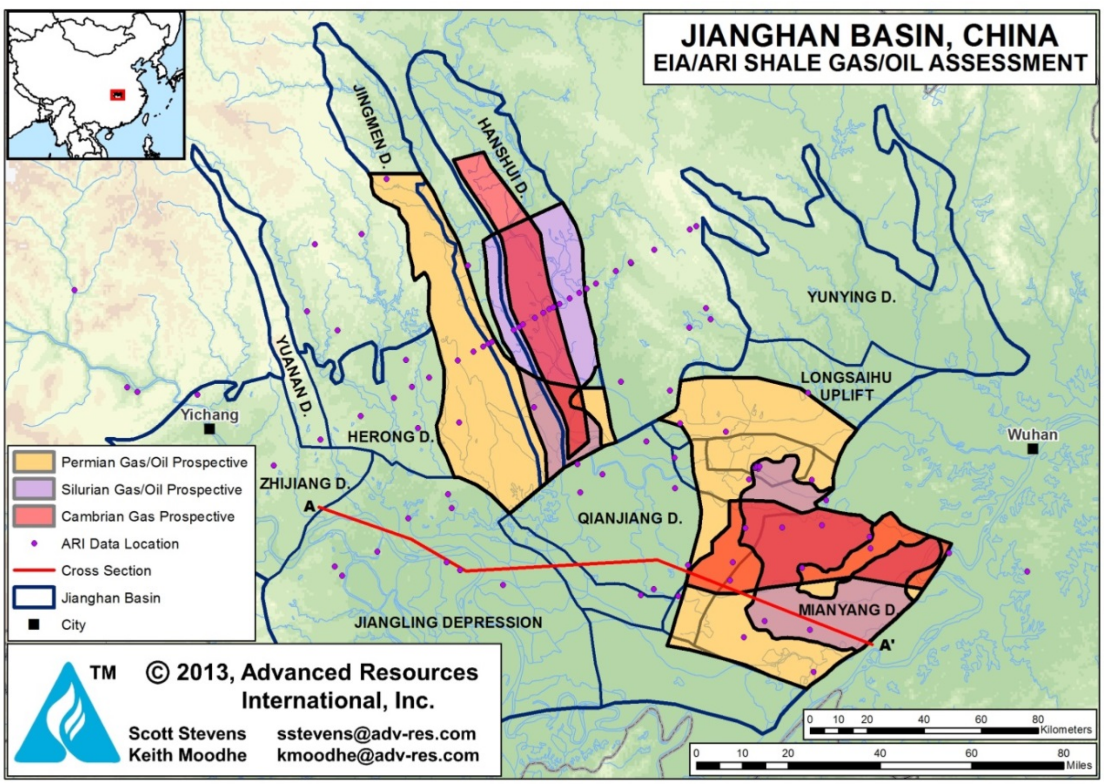


Source: Guo et al., 2007.

Figure XX-8. Outcrop Photo of L. Cambrian Black Chert North of Guiyang City, Guizhou Province. Note Bedding and Brittle Character. Pen for Scale.

Source: Yang et al., 2011.

Figure XX-9. Structural Elements Map of the Jianghan Basin Showing ARI-Proprietary Shale Gas Data Locations and Relative Size of the Prospective Areas for Silurian and Permian Shales.



Source: ARI, 2013.

The Jianghan Basin is structurally more complex than the Sichuan Basin, although less so than the Yangtze Platform. Jianghan comprises a number of small fault-bounded uplifts and depressions. Quaternary alluvium covers most of the basin surface, reflecting Neogene subsidence. Its structural history records Late Cretaceous to Paleogene extension (ENE-WSW) which originally formed the graben structures, Late Paleogence compression (EW) and graben deformation, then Neogene extension (NE-SW and NW-SE) which rejuvenated the grabens, and finally Late Neogene compression (NE-SW) which activated right-lateral strike-slip faults that continue to be active today.[14]

The Jianghan Basin contains up to 10 km of Cretaceous to Quaternary non-marine sediments overlying U. Paleozoic marine source rocks, Figure XX-10, with potential source rocks present in Sinian, L. Cambrian, U. Ordovician, L. Silurian, Jurassic, and Paleogene formations. The Eocene Qianjiang Formation is the main conventional sandstone reservoir, self-sourced by interbedded lacustrine shales and trapped within faulted anticlines overlain by cap rocks of interbedded gypsum-rich evaporites.[15]

The most prospective source rocks for shale gas development are dry-gas-prone Cambrian and Silurian units, along with liquids-rich Permian shale potential. Recent shale analysis noted the average thickness of organically rich L. Silurian Longmaxi Formation to be 120 m (390 ft).[16] Measured TOC from the L. Cambrian Shuijintuo Formation is favorable, ranging from 5.35 to 7.78%.[17] Thermal maturity data are scarce but indicate gas-prone shales (R_o 1.5% to 2.5%) in most of the basin, becoming thermally overmature in the northwest (R_o 3.5% to 5%).[18] In contrast, Eocene lacustrine shales in the Jianghan Basin are immature (R_o 0.4%), likely clay-rich, and not considered prospective for shale.

Figure XX-10. Stratigraphy of the Jianghan Basin, Highlighting Potentially Prospective Sinian, L. Cambrian, U. Ordovician, L. Silurian, Jurassic, and Paleogene Source Rocks.

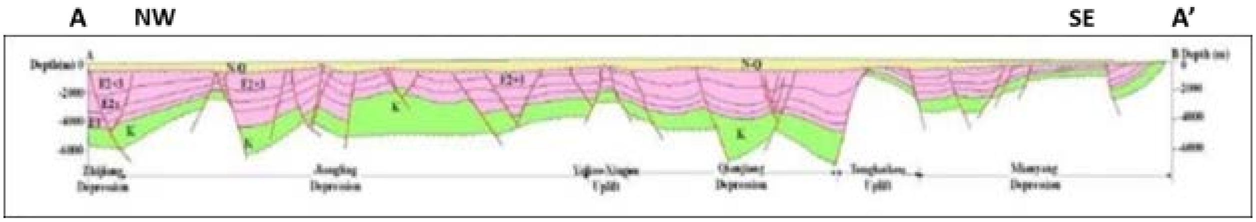
JIANGHAN BASIN			
ERA	**PERIOD**	**EPOCH**	**FORMATION**
CENOZOIC	QUATERNARY	Pleistocene	Pingyuan
	NEOGENE	Miocene	Guanghusai
	PALEOGENE	Oligocene	Jinghezhen
		Eocene	**Qianjiang**
			Jinsha
		Paleocene	**Xingouzhui**
			Shashi
MESOZOIC	CRETACEOUS	Upper	Paomagang
			Honghuntao
			Luojingtan
		Lower	
	JURASSIC	Middle	**Xiaximiao**
			Naijiashan
		Lower	**Tongzhuyian**
	TRIASSIC	Upper	Wanglongtan
			Jiuigang
		Middle	Badong
		Lower	Jialingjiang
			Daye
PALEOZOIC	PERMIAN	Upper	Dalong
			Wikoaping
		Lower	Maokou
			Qixia
	CARBONIFEROUS	Upper	Chuanshan
			Huanglong
		Lower	
	DEVONIAN	Middle	
	SILURIAN	Middle	Shamao
		Lower	Luoreping
			Longmaxi
	ORDOVICIAN	Upper	Wufeng
			Lingxiang
			Baota
			Miaopo
		Lower	Guniutan
			Dawan
			Honghuayuan
			Fenxiang
			Nanjinguan
	CAMBRIAN	Upper	Shanyoudong
		Middle	Qinjiamiao
		Lower	Shilongdong
			Tianheban
			Shipai
			Shuijintuo
PROTEROZOIC	SINIAN	Upper	**Dengyin**
			Duoshantuo
		Lower	Nantuo
	Source Rock		***Conventional Reservoir***

Source: ARI, 2013.

Cambrian and Silurian shales occur at non-prospective depths of 5 to over 10 km in the western depressions of the Jianghan Basin, but are shallower and may be prospective on uplifts in the east and northeast. For example, a regional cross-section shows Silurian shale at prospective depth (3-4 km) at the Yuekou, Longsaihu, Yajiao-Xingou uplifts, although significant faulting here may negatively impact shale development, Figure XX-11.[19] Similarly, a detailed cross-section of the Mianyang Depression in the eastern Jianghan Basin shows L. Silurian to be about 500-m thick (up to 1 km thick elsewhere), faulted, and 4 to 5 km deep, Figure XX-12.[20]

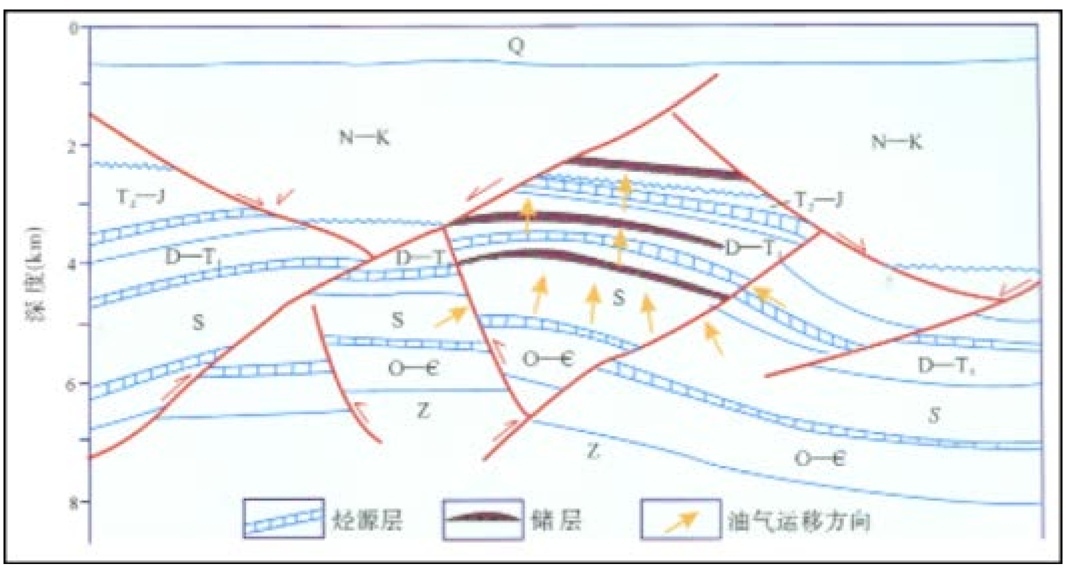
The underlying Cambrian section is about 1 km thick, faulted, and uplifted to about 2-km depth in the southeastern Jianghan Basin, Figure XX-13.[21] We identified three marine Paleozoic source-rock shale leads in the Jianghan Basin (L. Cambrian, L. Silurian, and Permian; see below).

Figure XX-11. Regional Cross Section of the Central Jianghan Basin Shows Significant Faulting Which May Impact Shale Development. Cambrian and Silurian Shales are too Deep (>5 km) to be Considered Prospective in the Troughs, but may be Suitably Shallow on the Uplifts.



Source: Zhang et al., 2010.

Figure XX-12. Detailed Cross-section from Mianyang Depression in the Eastern Jianghan Basin. The Lower Silurian Section Here ("S") is about 500-m Thick, 4 to 5 km Deep, and Significantly Faulted.



Source: Chen et al., 2005.

Figure XX-13. Localized Cross Sections in the Southeastern Jianghan Basin.
The Cambrian Section Here is Faulted and about 1 km Thick.

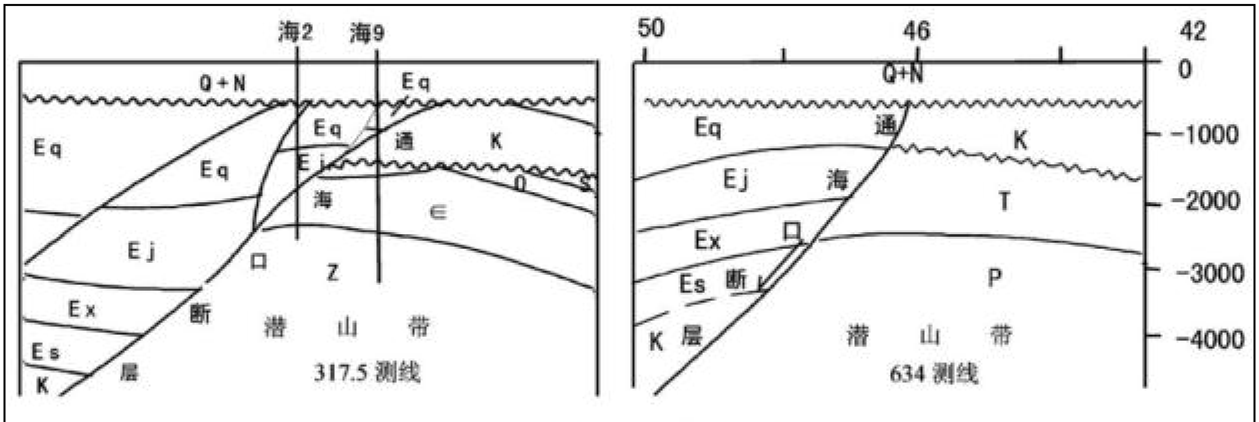


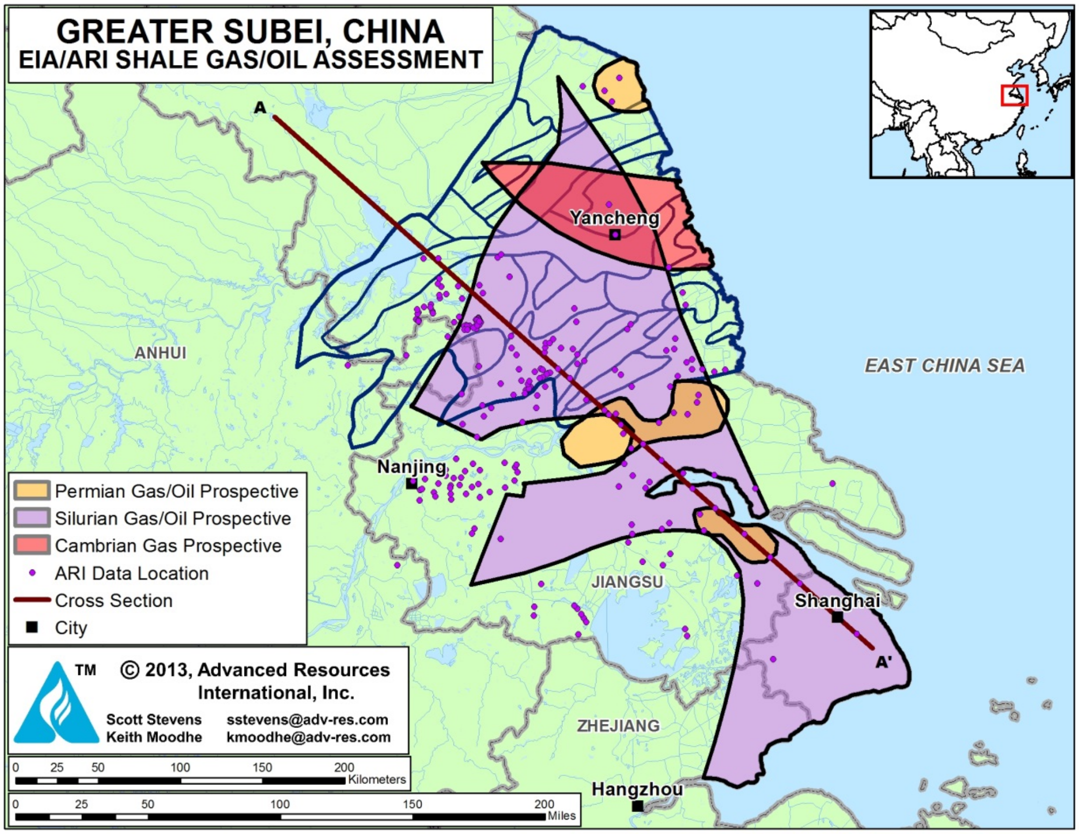
图 1 通海口潜山带构造剖面

Source: Li et al., 2007.

Subei Basin. With only 13 Chinese and 7 English articles available for this poorly documented basin, mappable geologic data are relatively sparse, Figure XX-14. The basin covers a 14,000-mi^2 portion of the lower Yangtze Platform near the coast in Jiangsu Province north of Shanghai. Small conventional oil fields have been discovered, the largest of which is Sinopec's structurally complex Jiangsu field near the center of the basin. Although situated enticingly close to prosperous East China markets, including Shanghai, the Subei Basin is structurally complex and quite deep, with Paleozoic shales mostly 3.5 to 5 km below the surface. Figure XX-15, a structural cross-section through the basin and adjoining region to Shanghai, shows major faults and the depth to Paleozoic source rock shales.[22] Detailed structure is likely to be even more complex than indicated here.

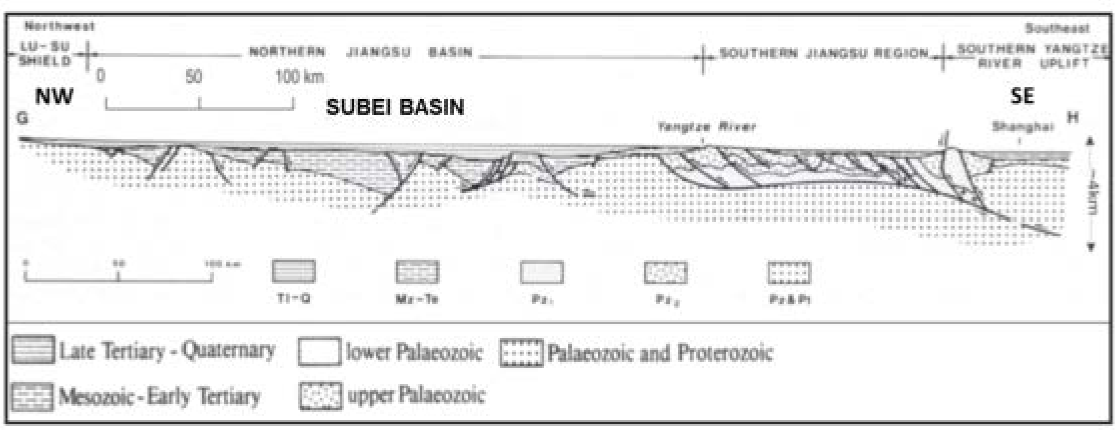
Sedimentary rocks in the Subei Basin range from L. Cambrian to Eocene, including potentially prospective marine shale source rocks of L. Cambrian, L. Silurian, and U. Permian age, Figure XX-16.[23] Conglomerates and mudstones of the U. Cretaceous to L. Paleocene Taizhou Group are the conventional petroleum targets in the basin, as well as possible source rocks themselves.

Figure XX-14. Structural Elements Map of the Subei Basin Showing ARI-proprietary Shale Gas Data Locations and Prospective Areas for L. Cambrian, L. Silurian, and U. Permian Shales.



Source: ARI, 2013.

Figure XX-15. Structural Cross-section of Subei Basin and Adjoining Region to Shanghai, Showing Major Faults and Depth to Paleozoic Source Rock Shales.



Source: Moore et al., 1986.

Figure XX-16. Stratigraphy of the Paleozoic Strata in the Subei Basin, Highlighting Potentially Prospective L. Cambrian, L. Silurian, and U. Permian Source Rocks.

ERA	PERIOD	EPOCH	MEMBER	FORMATION	LITHOLOGY / COMMENTS
PALEOZOIC	PERMIAN	**Upper**	**P_3c**	Changxing/Talung Fm	Limestones/siliceous shale, chert, limestone
			P_3l	Longtan Fm	Sandstones, mudstones, limestones, coal.
		Lower	P_2g	Kuhfeng Fm	Siltstones, siliceous shale, and chert.
			P_2q	Chihsia Fm	Dark grey limestones with chert.
			P_1c	Chuanshan Fm	Light grey limestone.
	CARBONIFEROUS	Upper	C_2h	Huanglung Fm	Light grey limestone/ dolomite.
			C_2l	Laohudong Fm	Light-dark grey dolomite.
				Hezhou Fm	Limestones, marls, dolomites.
		Lower	C_1g	Gaolishan Fm	Mudstone, siltstone, fine sandstone.
				Kinling Fm	Dark grey limestones with sandstone.
				Laokan Fm	Grey-green mudstones and sandstones, argillaceous dolomite.
	DEVONIAN		D_3w	Wutong Fm	Grey-white quartzose sandstones, conglomeratic sandstones.
	SILURIAN	Upper	S_3m/S_2f	Maoshan/Fentou Fm	Quartz sandstone, siltite mudstone, shale.
		Lower	**S_1g**	**Gaojiabian Fm**	Shale, siltstone.
	ORDOVICIAN	Upper	**O_3w**	**Wufeng Fm**	Siliceous shales, mudstones.
				Tangtou Fm	Argillaceous limestone and shale.
				Tangshan Fm	Argillaceous limestone and mudstone.
				Dawan Fm	Siliceous limestone and shale.
		Lower		Hunghuayuan Fm	Grey limestone.
				Lunshan Fm	Grey dolomite and limestone.
	CAMBRIAN	Upper/Middle	$\in_1 l$, $\in_2 p$	Loushanguan, Paotaishan Fms	Grey and white thick-bedded dolomite, dark grey thick-bedded limestone.
		Lower	**$\in_1 mu$**	**Mufushan Fm**	Black carbonaceous shale (upper); dark grey thin-bedded limestone (lower).

Source Rock

Modified from Qi & Zhu, 2002.

The L. Cambrian Mufushan Formation is 91 to 758 m thick (gross) in the Subei Basin. Its lower portion (2 to 363 m thick) contains dark grey to black mudstones and shale. Source rock thickness is 40 to 250 m thick, averaging 120 m thick, with low-moderate organic richness (1.1 to 3.1% TOC, average 2.1%).[24] This unit appears to be gas-prone at prospective depths of 4 to 5 km. Unfortunately, the Cambrian is deeper than 5 km across nearly the entire Subei Basin and 7 to > 9 km deep to the south and west of Shanghai.

The U. Ordovician Wufeng and L. Silurian Gaojiabian formations contain siliceous shale and mudstone with low organic richness (0.6 to 1.3% TOC). These units are gas-prone at prospective depths of 3.5 to 5 km. The Wufeng Fm is 4 to 214 m thick (gross) and contains grey and black siliceous shales & mudstone. The L. Silurian Gaojiabian Fm is 25 to 1,720 m thick (gross) and contains dark grey shale with an upper layer of interbedded silty fine sandstones. The combined source rock thickness ranges from 75 to 450 m, averaging 250 m. TOC is about 1.3%, lower than in the Cambrian source rocks.

The 1-km thick U. Permian Changxing/Talung formations also contain siliceous shale and mudstone of uncertain TOC that are gas-prone at relatively shallow depths (1 – 2.5 km). Finally, black mudstones of the U. Paleocene to M. Eocene Funing Group contain oil shale interbeds that formed in a deep lake setting and sourced the basin's conventional sandstone fields; these mudstones are immature to liquids-prone (Ro ≈ 0.4% to 0.9%).[25]

1.2 Reservoir Properties (Prospective Area)

Having discussed the regional geology of the South China Shale Corridor in the preceding section, we now describe the reservoir properties specific to the high-graded prospective areas in each basin.

Sichuan Basin. The 10,070-mi^2 high-graded area defined by prospective depth and R_o distribution is located in the southwestern Sichuan basin. Here the L. Silurian Longmaxi Fm contains about 1,000 ft of organically rich, black, graptolitic-bearing, siliceous to cherty shale. TOC content is approximately 3% and dry gas prone (R_o 2.9%). In addition, the Cambrian Qiongzhusi Fm averages 500 ft thick, with 3.0% TOC within its 6,500-mi^2 prospective area, where it is in the dry gas thermal maturity window (3.2% R_o).

The Upper Permian Longtan and Lower Permian Qixia formations, best developed in the central and southeast Sichuan Basin, contain an average total 314 ft of organic-rich shale, with TOC ranging from 2-6% (average 4%). Depth to shale within the prospective area (1 to 5 km) averages 9,700 ft. These shales are dry-gas prone, with vitrinite reflectance ranging from 2.0% to 3.0% (average 2.5%).

Shale targets in the Sichuan Basin are quite different from North American shales, but the closest North American analog may be the relatively faulted central Pennsylvania portion of the Marcellus Shale play.

Yangtze Platform. A specific prospective area could not be mapped here due to structural complexity and the paucity of data. However, activity by major oil companies in this area suggests there may be potential, perhaps in local synclinal areas. Reservoir properties of L. Cambrian and L. Silurian formations in the Yangtze Platform generally are similar to those in the Sichuan Basin. We assumed that prospective areas could be perhaps 20% of the prospective Sichuan Basin areas for each of the L. Cambrian and L. Silurian formations.

Again, the shale targets in the Yangtze Platform do not closely resemble any North American shale analogs. Perhaps the structurally complex, dry-gas prone Utica Shale play in Quebec is the closest North American approximation.

Jianghan Basin. The L. Cambrian Niutitang Formation (1,280-mi^2 high-graded lead) has the best organic richness (6.6%), is dry-gas prone (R_o ~2.25%) but also the deepest (average 13,000 ft). The L. Silurian Longmaxi Formation (1,960-mi^2 high-graded lead) has less organic richness (TOC of 2.0%), also is dry-gas prone (R_o ~2.0%), and is found at moderate depth (average 11,500 ft). Finally, the Permian Qixia/Maokou Fm (2,150-mi^2 high-graded lead) has lower organic richness (2.0%), is still dry-gas prone (R_o ~1.5%) and occurs at shallower depth (average 9,000 ft). The geothermal gradient in the Jianghan Basin is moderate, similar to that of the Sichuan Basin.[26]

The relatively faulted Marcellus Shale play in central Pennsylvania may be a distant analog for the Jianghan Basin, although Jianghan is structurally much more complex.

Subei Basin. Marine-deposited source rock shales in the L. Cambrian Mufushan Formation average 120 m thick, with 2.1% average TOC. These are gas-prone at prospective depths of 4 to 5 km. Source rocks in the the U. Ordovician Wufeng and L. Silurian Gaojiabian formations total an average 250 m thick, consisting of siliceous shale and mudstone with low 1.1% TOC; these also are gas-prone at prospective depths of 3.5 to 5 km. The U. Permian Changxing/Talung formations contain siliceous shale and mudstone of uncertain TOC (assumed to be 2%) that is gas-prone at relatively shallow depths (1 to 2.5 km).

The relatively faulted Marcellus Shale play in central Pennsylvania may be a distant analog for the Subei Basin, although Subei is structurally much more complex.

1.3 Resource Assessment

Having defined the reservoir properties of the high-graded prospective areas in the South China Shale Corridor, we now estimate the risked, technically recoverable shale resources and original shale gas and shale oil in place for each basin.

Sichuan Basin. Much of the Sichuan Basin is structurally complex and/or contaminated with H_2S and thus was screened out as non-prospective. However, the southwest quadrant of the basin has marine Paleozoic shales that are prospective. Within our high-graded prospective area, the Silurian Longmaxi Formation has an estimated 287 Tcf of risked, technically recoverable shale gas resources out of 1,146 Tcf of risked, shale gas in-place. The Cambrian Qiongzhusi Formation has 125 Tcf of risked, technically recoverable shale gas resources from 500 Tcf of risked, shale gas in-place. Permian formations have an estimated 215 Tcf of risked, recoverable shale gas resources out of a depth- and R_o-screened 715 Tcf of risked shale gas in-place.

Based on these data and assumptions, the Sichuan Basin is China's largest shale gas region, with an estimated 2,361 Tcf of risked, prospective shale gas in-place, of which 626 Tcf is considered risked, technically recoverable shale gas resources, Table XX-1. These figures exclude the majority of the basin area, which was screened out due to excessive depth, H_2S, and structural complexity issues. Further more detailed study is recommended to define and map these parameters and refine the still poorly understood shale gas resource potential of the Sichuan Basin.

Yangtze Platform. Using Sichuan Basin reservoir properties and an assumed prospective area 20% as large as Sichuan's, the L. Cambrian and L. Silurian shales of the Yangtze Platform are estimated to have 149 Tcf of risked, technically recoverable shale gas resources out of 596 Tcf of risked shale gas in-place.

Jianghan Basin. The L. Cambrian has an estimated 11 Tcf of risked, technically recoverable shale gas resources, out of a depth- and R_o-screened 46 Tcf of risked shale gas in-place. The L. Silurian Longmaxi Fm is prospective within a 1,960-mi^2 high-graded lead, adding an estimated 7 Tcf of risked, technically recoverable shale gas resources out of a depth- and R_o-screened 28 Tcf of risked shale gas in-place. The Permian Qixia/Maokou Fm is at moderate depth (9,000 ft average). ARI mapped a 3,830-mi^2 high-graded lead for the three thermal maturity windows, with an estimated 10 Tcf of risked, technically recoverable shale gas resources, out of a depth- and R_o-screened 40 Tcf of risked shale gas in-place. Jianghan also has a minor Permian shale oil play containing 5 billion barrels of resource in-place, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

Subei Basin. Although geologic data are scarce, ARI identified a 2,040-mi^2 high-graded lead in the L. Cambrian Mufushan Formation with an estimated 7 Tcf of risked, technically shale gas recoverable resources, out of a depth- and R_o-screened 29 Tcf of risked shale gas in-place. The L. Silurian Gaobiajian Formation appears to be prospective within a 14,990-mi^2 high-graded lead, adding an estimated 36 Tcf of risked, technically recoverable shale gas resources out of a depth- and R_o-screened 144 Tcf of risked shale gas in-place. The poorly defined Permian shale may be prospective within a 1,640-mi^2 area, with 2 Tcf of risked, technically recoverable shale gas resources out of 8 Tcf of risked shale gas in-place. Subei also has a minor Permian shale oil play containing 1 billion barrels of resource in-place with 0.1 billion barrels as the risked, technically recoverable shale oil resource.

1.4 Recent Activity

The **Sichuan Basin** by far is China's most active shale leasing and drilling area. Drilling programs currently are underway by PetroChina, Sinopec, and Shell, while numerous other Chinese and foreign companies are negotiating initial lease positions. The Ministry of Land and Resources began drilling shale delineation wells in the Sichuan Basin in 2009. PetroChina and Sinopec, which are engaged in shale development JV's in North America, each hold large legacy lease positions in the basin. Earlier this year Shell and CNPC were awarded the 3,500-km^2 Fushun-Yongchuan block, located in the southern Sichuan close to a legacy Shell tight gas exploration block. The Fushun-Yongchuan block is China's first foreign-invested production sharing contract for shale gas. Shell also is pursuing joint studies on two other Sichuan Basin shale blocks (Zitong, Jinqiu), which would give the company a total shale/tight area of 8,500 km^2 if awarded.[27]

Shale exploration drilling results in the Sichuan Basin have been mixed**.** PetroChina's first reported horizontal shale gas exploration well, located near the city of Chengdu, targeted the Silurian Longmaxi Formation. The Wei 201-H1 well, which employed a 3,540-ft long lateral and was drilled with modern logging-while-drilling technology,[28] completed its drilling phase in March 2011 after 11 months. However, this well tested a disappointing 450 Mcfd average over a 44-day period, following a large-volume, 11-stage slickwater frac completion which was monitored using real-time microseismic.[29]

Elsewhere in the Sichuan Basin, PetroChina has fracture stimulated at least five vertical wells targeting the Longmaxi Formation and two vertical wells targeting the Qiongzhusi Formation.[30] PetroChina's first horizontal Qiongzhusi well (Wei 201-H3), located in the Weiyuan gas field, is the only horizontal reported in detail by PetroChina. The well tested this 110-m thick black shale at a depth of 2,600 m, where seismic had indicated a well-developed natural fracture system.[31] Log and core analysis showed the Qiongzhusi averaged 67% quartz content, 22% clay, and 2.3% TOC but only about 2.0% porosity with 100 nD permeability (core-based). The horizontal lateral was less than half of its planned 5,000-ft length because of borehole stability problems encountered during drilling.

PetroChina's planned 9-stage fracture stimulation encountered high horizontal stress and successfully placed only 6 stages. Gas production peaked at 1.15 MMcfd and declined rapidly to 300 Mcfd, averaging 580 Mcfd during the 60-day flow test. PetroChina inferred that the fracs had planar rather than preferred complex geometry and the stimulated volume was much smaller than expected.[32] Still, the test showed the Qiongzhusi shale can be productive.

Separately, Sinopec hydro-fractured its Fangshen-1 well in Guizhou in May 2010 and expects to start commercial shale gas production in Liangping County, near Chongqing, Sichuan in 2013. Sinopec's recent Qianye-1 well in Qianjiang, also near Chongqing, reportedly peaked at 100 Mcfd.[33] No further details are available from Sinopec's shale program.

In November 2009 Shell signed the initial agreement with PetroChina to jointly explore for shale gas at the Fushun block, southern Sichuan Basin, receiving the PSC in March 2012. Shell spud its first well in December 2010, focusing on the Silurian Longmaxi Fm.[34] By April 2012 the company had drilled five deep exploration wells: one vertical data well, two vertical frac wells, and two horizontal frac wells.[35] Whole core and full petrophysical logging suites confirmed good resource potential, although in-situ well testing determined that the formation, while favorably over-pressured, had an unfavorably high stress gradient. High breakdown pressures and fluid leakoff resulted in poor stimulation. Nevertheless, one of Shell's vertical exploration wells reportedly flowed at 2.1 million ft^3/day.

Shell followed its first two vertical Sichuan wells with two horizontal production tests at the Fushun block. The company noted significant fault-related problems, such as frequent drilling out of zone and resulting doglegs that complicated well completion. Completion time improved from over 100 days/well initially to about 53 days/well, but still longer than typical 10-day completion times in North America. Shell did not report production from its horizontal wells.

ConocoPhillips recently was awarded two shale exploration blocks in the Sichuan Basin. Chevron is conducting a Joint Study with Sinopec of the Qiannan shale gas block in the Yangtze Platform, located north of Guiyang city, Guizhou Province, and just south of the Sichuan Basin. Chevron initiated seismic acquisition over the block in July 2011 and spud its first test well there during Q1 2012. BP, ConocoPhillips, ENI, ExxonMobil, Statoil, and TOTAL also have reported interest in leasing shale gas blocks in the Sichuan or Yangtze Platform. As of late 2010 BP was reported negotiating with Sinopec for a shale gas exploration block at the 2,000-km^2 Kaili block near Chevron's Qiannan block. In July 2011 ExxonMobil was reported by Sinopec to be evaluating the 3,644-km^2 Wuzhishan area in the Sichuan Basin. Statoil reported negotiating with PetroChina for a shale gas block and at one point estimated 50 MMcfd of production potential by 2015. ENI signed a memorandum of understanding with CNPC on shale gas in early 2011.

North American shale gas operators Newfield Exploration and EOG Resources also reported conducting detailed shale gas evaluations in the Sichuan Basin during the past few years. Newfield conducted a detailed joint study evaluation with PetroChina at the Weiyuan gas field but decided in 2006 not to proceed. EOG originally planned to make a decision on shale exploration in Sichuan by late 2010 but has been silent on the project for the past two years.

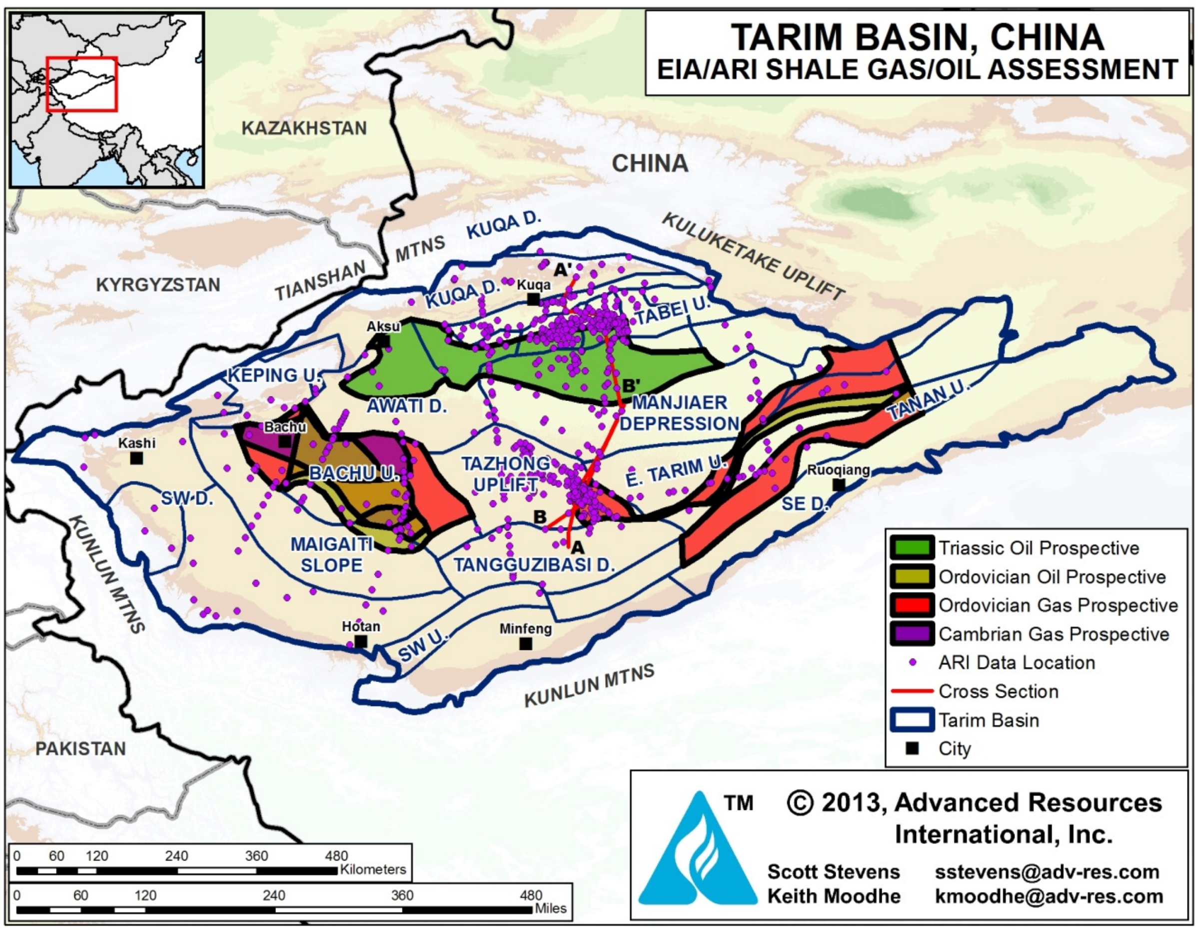
Jianghan and Subei Basins. The only reported shale activity in the Jianghan Basin was Sinopec's December 2010 report of "gas flows in a shale gas exploration well" (no details provided). The same report noted that BP was evaluating Permian shale in the 1,000-km^2 Huangqiao block, the only exploration activity noted thus far in the Subei Basin.

2 TARIM BASIN

2.1 Introduction and Geologic Setting

The Tarim Basin, located in western China's Xinjiang Autonomous Region, is the largest onshore sedimentary basin in China (234,000 mi^2). Surface elevation of this remote basin is relatively flat at about 1,000 m above sea level. The climate is dry but aquifers which underlie the lightly populated region could supply frac water. **Figure XX-17** shows the structural elements of the Tarim Basin, as well as locations of ARI-proprietary data used in conducting this study.

Figure XX-17. Structural Elements Map of the Tarim Basin Showing ARI-Proprietary Shale Gas Data Locations and Prospective Areas for Shale Gas and Shale Oil Exploration.



Source: ARI, 2013

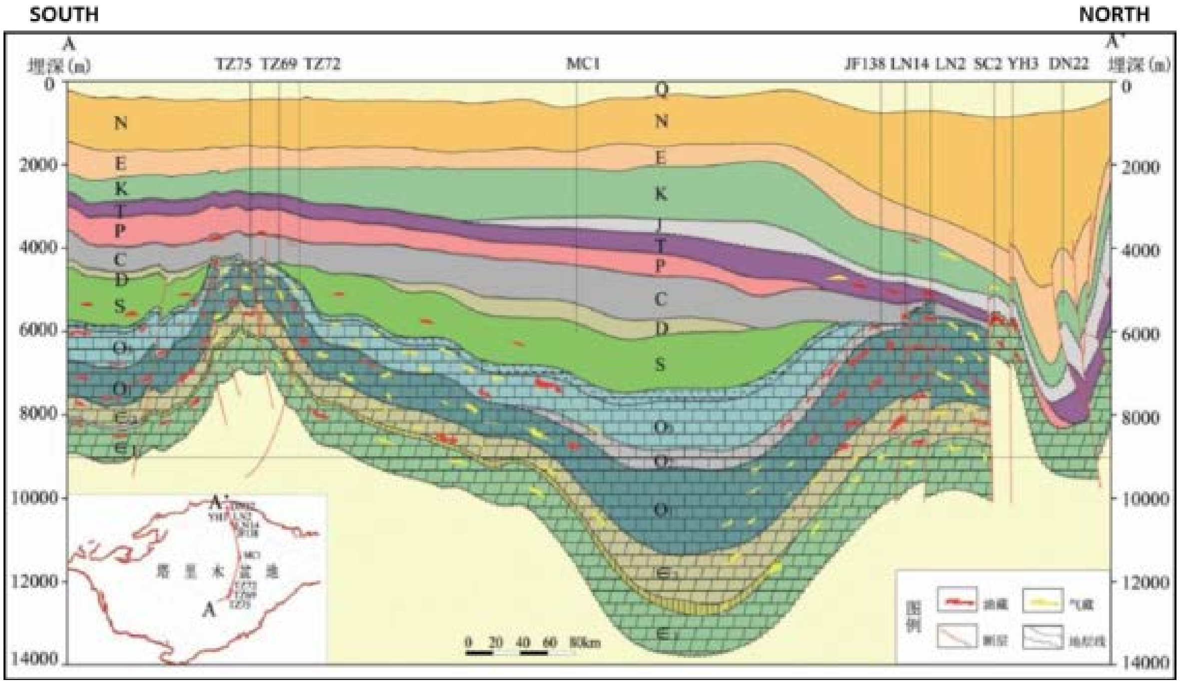
PetroChina and Sinopec produced an average 261,000 b/d of oil from conventional reservoirs in the Tarim during 2011 and are investing heavily to double output there by 2015. The basin also produced 1.6 Bcfd of natural gas in 2011 that was transported to Shanghai via the two 4,000-km West-to-East pipelines. Conventional petroleum deposits, totaling over 5 billion barrels of oil and 15 Tcf of gas, were sourced mainly by organic-rich Cambrian and Ordovician shales – considered the principal targets for shale gas and oil exploration in the Tarim Basin.

The Tarim Basin is sub-divided by fault and fold systems into a series of seven distinct structural zones, comprising three uplifts and four depressions. From north to south these include the Kuqa Depression, Tabei Uplift, North Depression, Tazhong Uplift, Southwest Depression, Tanan Uplift and Southeast Depression. Cross-section A-A', **Figure XX-18**, shows a north-to-south transect across the central Tarim Basin, revealing generally simple regional structure characterized by shallow dip angle and few faults (note extreme vertical exaggeration of 25x).[36] Unfortunately, the main Cambrian and Ordovician shale targets are buried deeper than 5 km over most of the basin, plunging to a maximum depth of 10 km or more in the structural troughs.

However, interior anticlines within the Tarim Basin include uplifted areas that appear to be (barely) depth-prospective for shale development (<5 km). For example, **Figure XX-19** shows Cambrian and Ordovician source rock shales at prospective depths ranging from 4 to 5 km across the Tazhong Uplift, but even here shale is just within the depth limit for commercial shale development.[37] Even though much of the Mid-Upper Ordovician section was locally removed by erosion during the Late Paleozoic Hercynian Orogeny, a considerable thickness of this unit remains. Geochemistry indicates that the conventional oil trapped in the Tazhong Uplift originated mainly from Ordovician rather than Cambrian source rocks.[38]

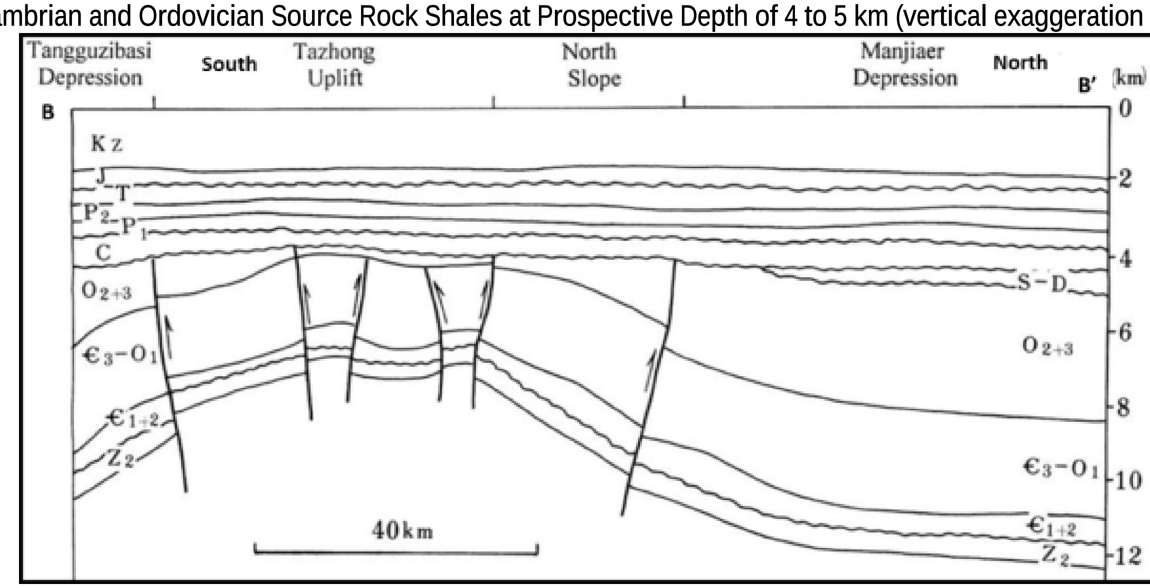
Multiple petroleum source rocks of various ages occur in the Tarim Basin, including the Cambrian, Ordovician, Carboniferous, Triassic, Cretaceous, and Tertiary, **Figure XX-20**. Marine-deposited black shales of Cambrian and particularly Ordovician age are considered the most important source rocks in the basin.[39] The Ordovician units include the Hetuao, Yijianfang, Lianglitage and equivalent formations, while L. Cambrian source rock units include the Xiaoerbulake Formation and equivalent units.

Figure XX-18. South-north Cross-section of the Central Tarim Basin Showing Generally Simple Structure as Well as Migration Pathways for Oil (Red) and Gas. Note that Cambrian and Ordovician Source Rock Shales are Too Deep (>5 km) for Commercial Shale Development in Most of the Basin, but Local Uplifts may be Prospective (vertical exaggeration = 25x).



Source: Zhu et al., 2012.

Figure XX-19. Interpreted Seismic Depth Section across the Tazhong Uplift, Tarim Basin, Showing Cambrian and Ordovician Source Rock Shales at Prospective Depth of 4 to 5 km (vertical exaggeration = 5x)



Source: Xiao et al., 2000.

Figure XX-20. Stratigraphy of the Tarim Basin, Highlighting Prospective Cambrian, Ordovician, Carboniferous, Triassic, Cretaceous, and Tertiary Source Rocks.

TARIM BASIN

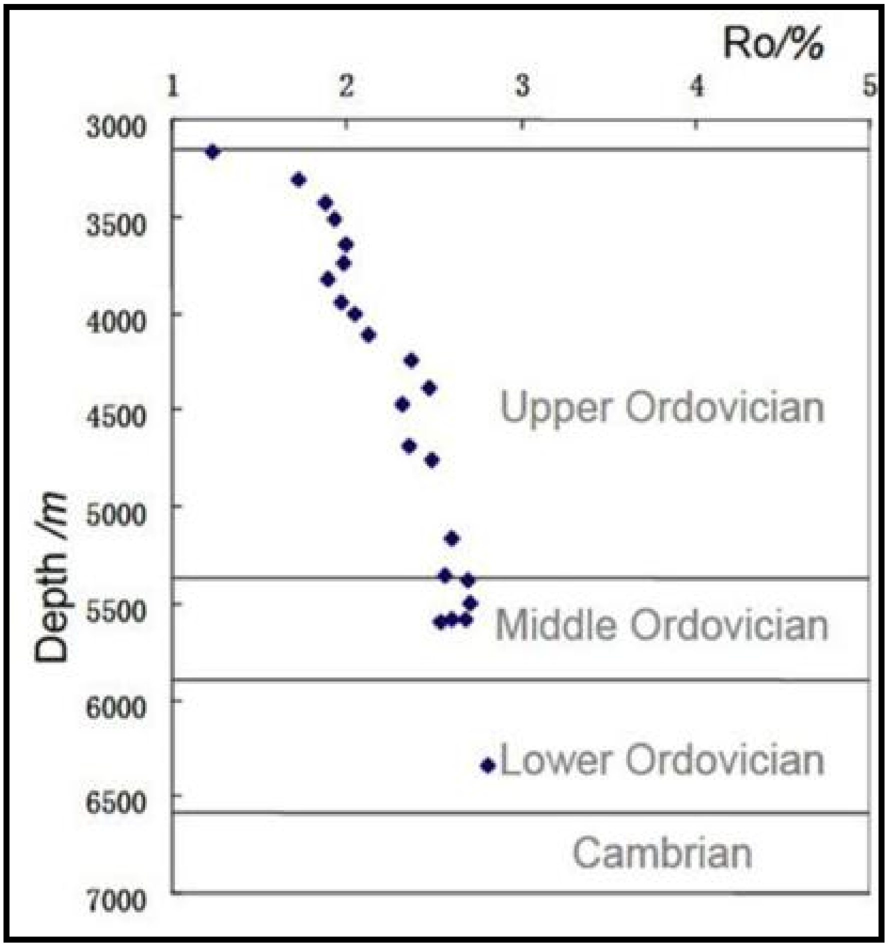
ERA	PERIOD	EPOCH	FORMATION	AGE (Ma)	THICKNESS (m)
CENOZOIC	QUATERNARY	Q			
	TERTIARY	N_{2a}			
		N_{1w}			
		Eh			
MESOZOIC	CRETACEOUS	K_{2y}			
		K_{1y}			
	JURASSIC	J_{3k}			
		J_{2t}			
		J_{2y}			
		J1k			
	TRIASSIC				
PALEOZOIC	PERMIAN	Upper	Shazijing	290	0 - 780
			Aqiaqun		
		Middle-Lower	Aqiaqun		
	CARBONIFEROUS	Upper-Middle	Xiaohaizi	290 - 355	0 - 691
		Lower	Kalashayi		
			Bachu		
	DEVONIAN			355 - 405	0 - 241
	SILURIAN	Upper		405 - 439	0 - 517
		Middle			
		Lower			
	ORDOVICIAN	Upper	Hetuao (O_{1-2})	439 - 459	0 - 300 org-rich
		Middle	Yijianfan (O_2)	459 - 478	0 - 150 org-rich
		Lower	Lianglitage (O_3)	478 - 505	0 - 50 org-rich
	CAMBRIAN	Upper	Qiulitage	505 - 600	2918
		Middle	Awatage		125
		Lower	Xiaoerbulake		74
PROTEROZOIC	SINIAN			600+	200 - 1100

Source Rock *Conventional Reservoir*

Source: ARI, 2013.

The Lower Ordovician Hetuao (O_{1-2}) shales -- important source rocks -- appear to be the most prospective, although TOC generally is under 2%. These shales range from 48 to 63 m thick and consist of carbonaceous and radiolarian-bearing siliceous mudstone that appears brittle. The Mid-Ordovician Yijianfang (O_2) Saergan Formation, present in the Keping Uplift and Awati Depression, contains black marine-deposited mudstones 10 m to 30 m thick, with TOC of 0.56% to 2.86% (average 1.56%). Upper Ordovician Lianglitage (O_3) shales occur in the Central Tarim, Bachu, and Tabei areas, where they are 20 m to 80 thick, carbonate-rich, but with relatively low TOC (average 0.93%). Thermal maturity of the Ordovician is mostly dry-gas prone, for example with R_o ranging from 2.0% to 2.6% in the Gucheng-4 well at depths of 3,200 to 5,700 m on the east flank of the Tazhong Uplift, **Figure XX-21**.[40]

Figure XX-21. Vitrinite Reflectance (R_o) of the Mid to Upper Ordovician Shale Sequence in the Gucheng-4 Well, Tarim Basin Ranges from <2% at a Depth of 3,200 m to 2.7% at a Depth of 5,700 m.

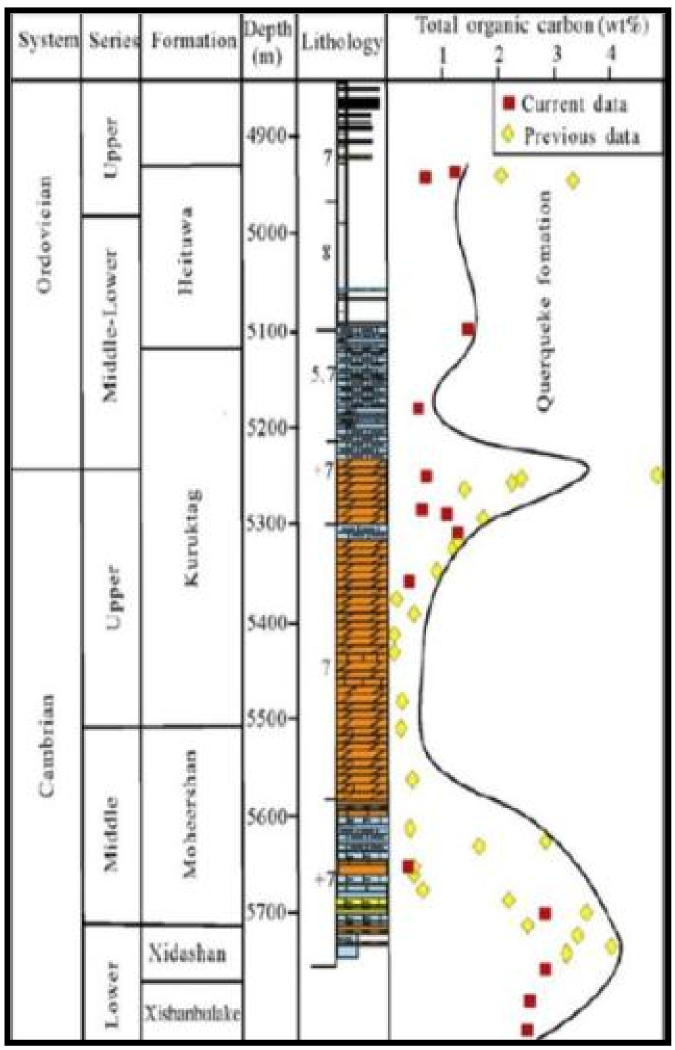


Source: Lan et al., 2009.

The Cambrian organic-rich shales, such as the Xiaoerbulake Formation, consist of abyssal to bathyal facies mudstones that are well developed in the Manjiaer Depression and the eastern Tarim and Keping Uplifts. Cambrian formations include the Qiulitage, Awatage, and Xiaoerbulake formations. TOC is fairly high (1.2% to 3.3%) in the Lower (C_1) and Middle (C_2) Cambrian Formations and exceeds 1% over about two-thirds of the Cambrian sequence. Evaporitic dolomites, potential cap rocks, occur in the middle Cambrian, with extensive salt and anhydrite beds totaling 400 to 1,400 m thick. Net organically-rich shale thickness ranges from 120 m to 415 m, averaging about 120 m (400 ft). Thermal maturity is mostly within the dry gas window (R_o > 2.5%) in deep areas.

The organic content of the Cambrian and Ordovician shales in the Tarim consists of kerogen, vitrinite-like macerals, as well as bitumen. Regionally, TOC varies widely with structural location, ranging from as much as 7% in the troughs to only 1-2% in the uplifts, reflecting the paleo depositional environment. For example**, Figure XX-22** illustrates the TOC distribution within the Lower Paleozoic section in the Milan-1 well, located on the flank of the Tadong Uplift in the eastern Tarim Basin.[41] Lower Cambrian formations in this well have up to 4% TOC, while Lower Ordovician units have mostly 2% or less TOC, although neither is at prospective depth at this particular location (5,200-5,700 m).

Figure XX-22. Stratigraphy and TOC Distribution of Cambrian and Ordovician Shales in the Milan-1 Well, Tarim Basin.



Source: Hu et al., 2009.

2.2 Reservoir Properties (Prospective Area)

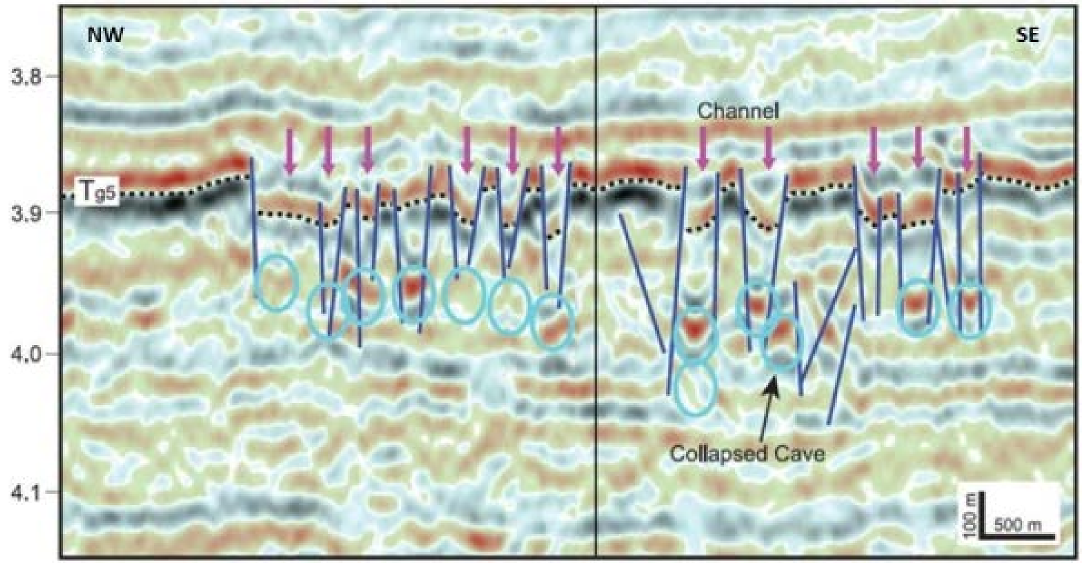
New geologic information gathered by ARI since the 2011 study indicates that shale formations in the Tarim are considerably deeper than previously mapped. The new data show that a significant amount of the Ordovician and, particularly, the Cambrian resource is subject to the 5-km prospective depth “haircut”. Note that advancements in shale well drilling and completion technology could add back the large resource that exists in the 5-6 km depth range in this basin.

In addition, significant nitrogen contamination (5-20%) is prevalent in Paleozoic and Mesozoic reservoirs throughout the Tarim Basin. Elevated nitrogen apparently was caused by thermal maturation of nitrogen-rich minerals (ammonium clays, evaporates) in Cambrian and Ordovician sapropelic source rocks. Unfortunately, nitrogen concentration tends to be highest on the very structural uplifts that are most prospective for shale gas.[42]

Another potential “geohazard” is karstic collapse of Ordovician strata caused by dissolution of underlying carbonate rocks, which locally disrupts the shale strata and also may introduce copious formation water detrimental to shale gas production. Similar karsting negatively affects portions of the Barnett Shale play, locally sterilizing a small portion of the resource there.[43] **Figure XX-23**, a seismic time section from the northern Tarim Basin, shows local karst collapse structures disrupting Ordovician strata.[44] Karsting is considered a geo-hazard that would need to be avoided during shale development.

Within its 6,520-mi^2 prospective area the Cambrian organic-rich shale averages 380 ft thick, with relatively low 2% TOC in the dry-gas thermal maturity window (R_o of 2%). The L. Ordovician prospective area is approximately 19,420 mi^2, with about 300 ft of organic-rich shale that also is in the dry-gas window (R_o of 1.8%). The U. Ordovician has a 10,930-mi^2 shale gas prospective area, with 390 ft of high-TOC shale in the dry-gas window (R_o of 2.0%). A 10,450-mi^2 shale oil prospective area also exists for the U. Ordovician, averaging 300 ft of organic-rich shale with R_o of 0.9%. In addition, the L. Triassic is prospective for shale gas and oil within a 15,920-mi^2 prospective area, averaging 400 ft of high-TOC shale with R_o of 0.9%.

Figure XX-23. Seismic Time Section from Northern Tarim Basin Showing Local Karst Collapse Disrupting Ordovician Strata. Karsting is a Geo-hazard to be Avoided During Shale Development.



Source: Zeng et al., 2011.

2.3 Resource Assessment

Compared with our 2011 study, new more complete data coverage and revised mapping of the Tarim Basin indicates that Ordovician and Cambrian shales are considerably deeper than previously mapped and the prospective area is considerably smaller. Most of the basin is considered too deep for commercial shale development (>5 km), with only portions of the interior uplifts raised to prospective depth. The 20% nitrogen content and karst disruptions further reduced shale gas resources. On the other hand, we added newly recognized shale plays in the mid-upper Ordovician and L. Triassic. We now estimate that the Tarim Basin has 216 Tcf and 8 billion barrels of risked, technically recoverable shale gas and oil resources.

L. Cambrian shale covers a reduced 6,520-mi^2 high-graded area, with an estimated 44 Tcf of risked, technically recoverable shale gas resources out of 176 Tcf of risked shale gas in place. L. Ordovician shale within its 19,420-mi^2 high-graded area contains an estimated 377 Tcf of risked, shale gas in-place, with 94 Tcf of risked, technically recoverable resources. The U. Ordovician shale gas lead contains 265 Tcf of risked shale gas in-place with 61 Tcf of risked, technically recoverable shale gas resources. In addition, a 10,450-mi^2 shale oil prospect contains an estimated 31 billion barrels of risked shale oil in-place with 1.6 billion barrels of risked, technically recoverable shale oil resources.

L. Triassic shale has shale oil potential within a 15,920-mi^2 prospective area, estimated at 6.5 billion barrels of risked, technically recoverable shale oil resources out of 129 billion barrels of risked, shale oil in-place. In addition, the L. Triassic could hold an estimated 16 Tcf of risked, technically recoverable associated gas resources out of 161 Tcf of risked gas in-place.

2.4 Recent Activity

No shale gas or shale oil leasing or drilling activity has been reported in the Tarim Basin. One positive indication is the wide commercial application of horizontal drilling in the Tarim Basin during the past decade, with the technique already accounting for about half of the basin's conventional oil production.[45] This advanced drilling capability provides a good foundation for future shale development in the Tarim Basin.

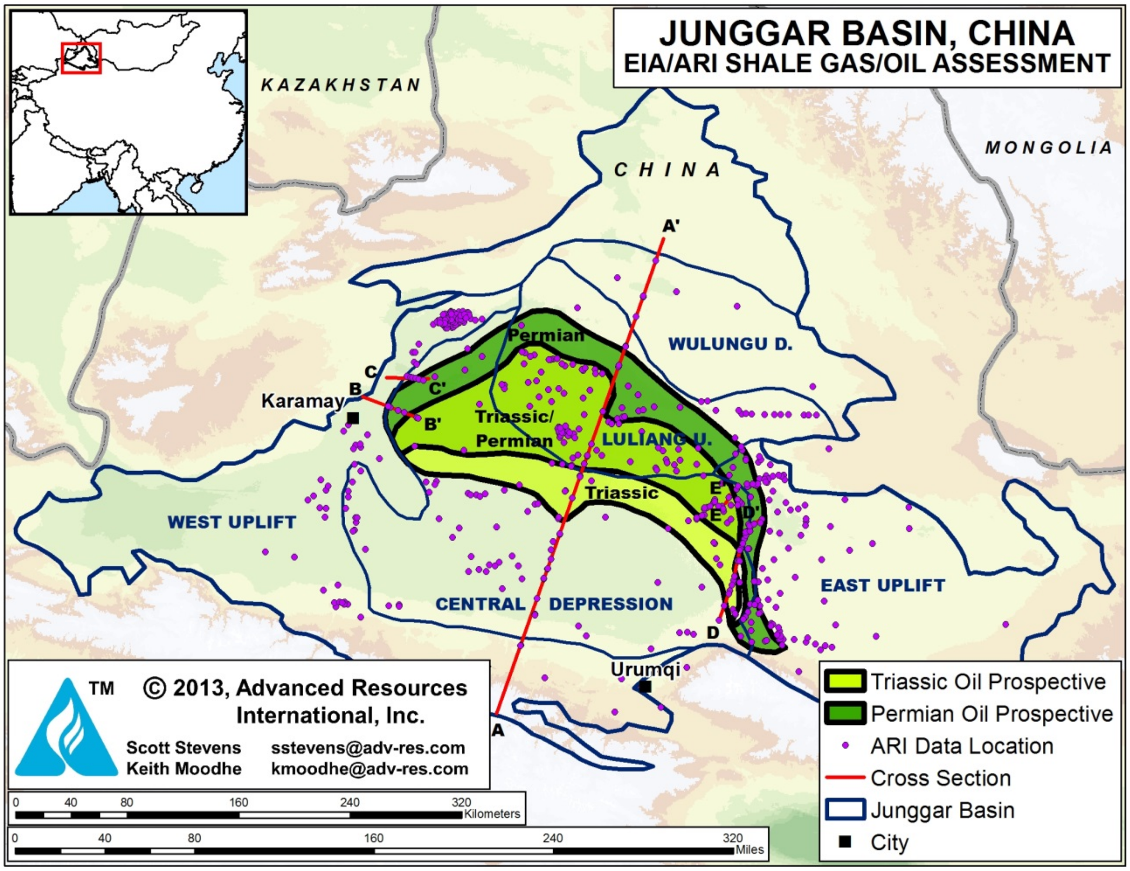
3 JUNGGAR BASIN

3.1 Introduction and Geologic Setting

Like its larger neighbor the Tarim Basin, the 62,000-mi^2 Junggar Basin is located in northwest China's Xinjiang region. However, the Junggar is less remote from markets and services than the Tarim and offers better infrastructure. Xinjiang's capital of Urumqi (population 3 million) is situated in the south-central Junggar Basin, while PetroChina's modern oil technology center is at Kelamayi. Local industry and population are growing rapidly in this resource-rich area. With mostly level surface elevation just above 1,000 m, the climate is less harsh than in the Tarim and agriculture is more developed. **Figure XX-24** shows the structural elements of the basin as well as locations of ARI-proprietary shale data used in conducting this study.

The Junggar Basin is undergoing rapid development of its rich oil, gas, and coal resources. It produced an average 218,000 bbl/day of oil and 0.5 Bcfd of natural gas during 2011, with output expected to rise to 400,000 bbl/day and 1.0 Bcfd by 2015. The Junggar has extensive and highly prospective yet completely untested shale gas and oil deposits in multiple formations and geologic settings. ARI's initial data and analysis suggest that the Junggar Basin, while not China's largest shale resource, actually may be its best overall in terms of shale geology and reservoir potential. Shell and Hess recently signed study agreements with PetroChina on shale oil projects in outlying areas of the Junggar Basin.

Figure XX-24. Structural Elements Map of the Junggar Basin Showing
ARI-Proprietary Shale Gas Data Locations and Location of Shale-Prospective Areas.



Source: ARI, 2013.

The Junggar Basin is an asymmetric cratonic basin with a thrusted southern margin and mostly gently dipping north, west and east margins. The basin contains up to 9 km of Carboniferous and younger strata, **Figure XX-25**. Four main source rocks are present: Carboniferous, Permian, Triassic, and Jurassic.[46] Of these, the Permian is considered the most important due to its very high TOC and good genetic potential, followed distantly by the Triassic. The Junggar is a thermally immature basin with abnormally low heat flow. Gas window maturities (R_o > 1%) are attained only in the North Tianshan foreland region at depths of greater than about 5 km.[47]

Figure XX-25. Stratigraphy of the Junggar Basin, Highlighting Prospective Permian and Jurassic Source Rocks.

JUNGGAR BASIN					
ERA	**PERIOD**	**EPOCH**	**FORMATION**	**AGE (Ma)**	**THICKNESS (m)**
CENOZOIC	QUATERNARY	Q	Xiyu	0 - 2.6	350 - 2046
	TERTIARY	N	Dushanzi	2.6 - 5.3	207 - 1996
			Taxihei	5.3 - 23.3	100 - 320
			Shawan		150 - 500
		E	Anjihaihe	23.3 - 32	44 - 800
			Ziniquanzi	32 - 65	15 - 855
MESOZOIC	CRETACEOUS	K2	Donggou	65 - 96	46 - 813
		K1	*Tugulu*	96 - 145.6	84 - 964
	JURASSIC	J3	Kalaza	145.6 - 157.1	50 - 800
			Qigu		144 - 683
		J2	**Toutunhe**	157.1 - 178	200 - 645
			Xishanyao		137 - 980
		J1	**Sangonghe**	178 - 208	148 - 882
			Badaowan		100 - 625
	TRIASSIC	T3	*Baijiantan*	208 - 227	123 - 457
		T2	*Kelamay*	227 - 241	250 - 450
		T1	*Balkouquan*	241 - 245	30 - 269
PALEOZOIC	PERMIAN	P3	*Upper Wuerhe*	245 - 257	830 - 1850
		P2	**Lower Wuerhe**	257 - 270	
			Xiazijie		850 - 1160
		P1	**Fengchen**	270 - 290	430 - 1700
			Jiamuhe		1800 - 4000
	CARBONIFEROUS	C2	*Talieguia*	290 - 320	
		C1	Baogutu	320 - 354	
	DEVONIAN			354	
	Source Rock		*Conventional Reservoir*		

Source: ARI, 2013.

Lower Carboniferous petroleum source rocks are up to 1,300 ft thick, while Upper Carboniferous source rocks reach up to 1,000 ft thick. These are described as dark grey mudstone of marine character, with TOC of 0.5% to 2.4% (Type II, III). The Carboniferous is mostly too deep (> 5 km) but shoals to less than 3 km depth in uplifted portions of the basin. The Jurassic is a coal-bearing, non-marine unit that is rich in clay, probably ductile, and thus not suitable for shale-type hydraulic stimulation. Both Jurassic and Carboniferous units have lower and more variable TOC, mainly Type III, and are considered poor quality source rocks.

The dominant Permian source rocks were deposited primarily in lacustrine and fluvial environments and have exceptionally high TOC of up to 20% (Type I/II kerogen, not coal), making them one of the world's richest.[48] The Permian is considered liquids-rich (R_o= 0.7% to

1.0%) at target depths of 2-5 km. Although Permian source rocks are too deep for commercial development in the troughs, they do shoal to prospective depth of less than 4 km along some of basin flanks and interior uplifts.

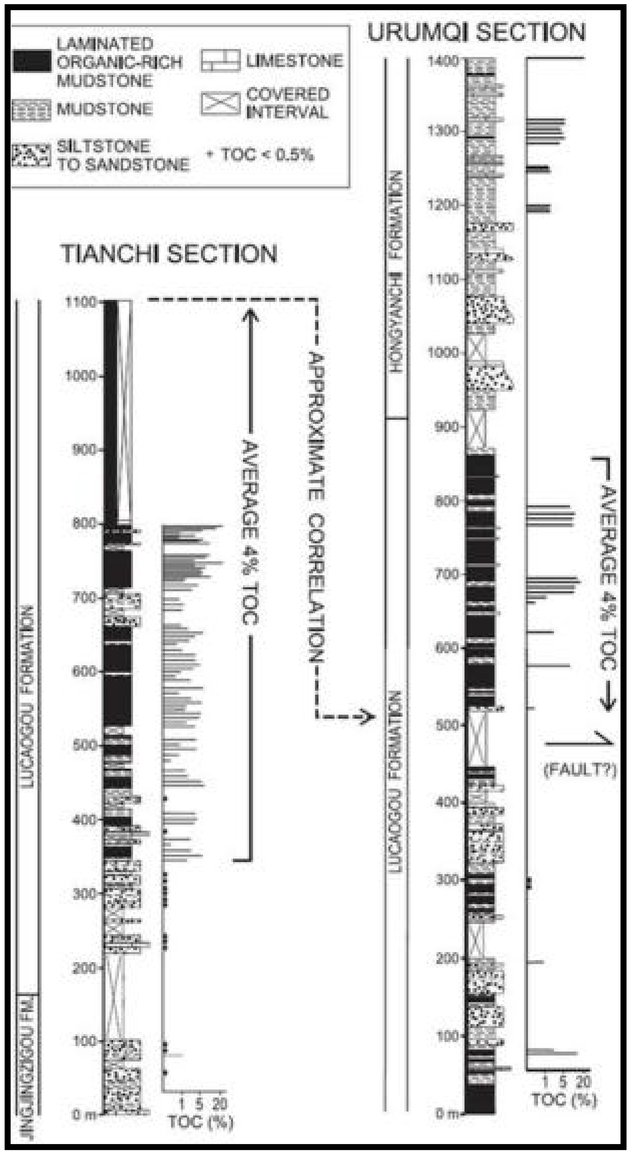
The single most important source rock is the Mid-Permian Pingdiquan Formation (known as Lucaogou in the south), a lacustrine to deltaic deposit up to 1,200 m thick present. It consists of grey to black mudstones, oil shales and dolomitic mudstones interbedded with thin sandy mudstones, shaly siltstones, siltstones and fine sandstones. Hydrocarbon source rock thickness in the Pingdiquan ranges from 50 m to a remarkable 650 m. **Figure XX-26** shows detailed stratigraphy and TOC profiles for two outcrop sections in the Permian Lucaogou Fm of the southern Junggar Basin. Approximately 300 to 700 m of organic-rich but thermally immature lacustrine mudstone is present, with TOC averaging 5% and reaching a maximum of 20%.[49]

Triassic sediments are more widely distributed across the eastern Junggar Basin than the Permian, with the depocenter at the front of the Tianshan mountains. The Mid- to Upper Triassic Xiaoquangou Group (including Karamay, Huangshanjie, and Haojiiagou formations) contains up to 250 m of dark mudstones and thin coals deposited under fluvial-lacustrine conditions.

Conventional oil deposits in the eastern Junggar sourced by these units occur in the Fukang, North Dongdaohaizi, Wucaiwan, and Jimursar structural depressions (“sags”). These deposits include the Cainan, Wucaiwan, Huoshaoshan, Shanan, Beisantai, Santai and Ganhe oilfields which produce from conventional reservoirs of Carboniferous, Permian, Triassic and Jurassic age.

The Junggar Basin is characterized by much simpler structural geology than the tectonically more complex shale basins of southern China. While some edges of the Junggar Basin can be structurally complex, particularly along its thrusted southern margin, most of the basin interior has gentle dip angle and relatively few faults. Such simple structure is considered favorable for shale gas/oil development.

Figure XX-26. Detailed Stratigraphy and TOC Profiles for Two Outcrop Sections in the Permian Lucaogou Fm, Southern Junggar Basin. Approximately 300 to 700 m of Organic-rich but Thermally Immature Lacustrine Mudstone is Present, with TOC Averaging 4% (Maximum 20%).

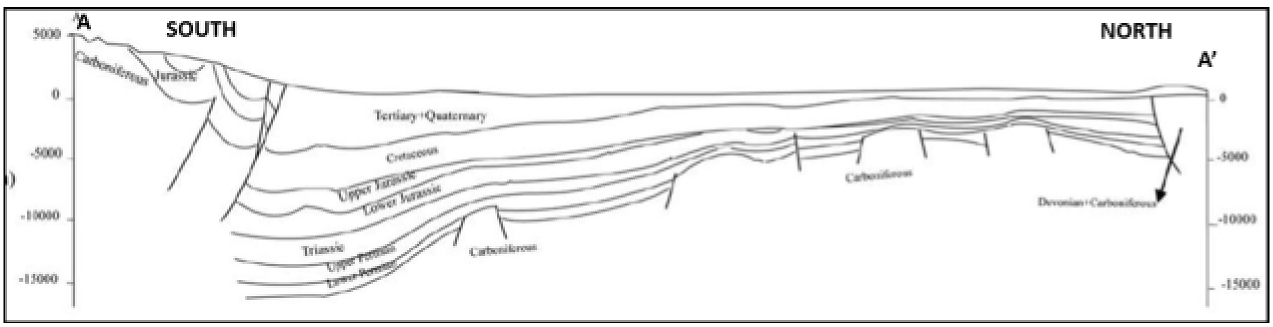


Source: Carroll and Wartes, 2003.

For example, **Figure XX-27** shows a regional north-south structural cross-section across the entire Junggar Basin, illustrating the relatively simple interior structure as well as the overthrusted southern margin.[50] Note that Permian and Jurassic source rocks are quite thick but too deep (>5 km) in most of the central basin trough. These units become shallower to the north but also thin out on structural uplifts.

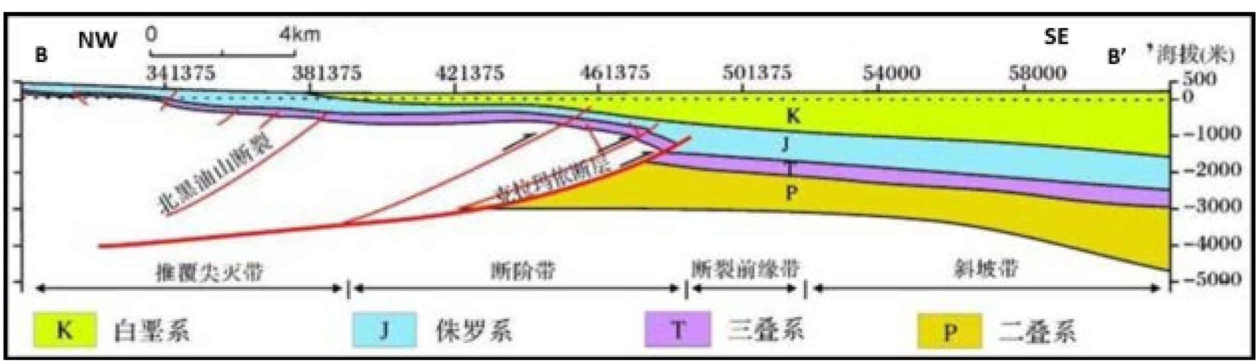
In particular, on the northwest flank of the Junggar Basin, Permian through Cretaceous strata dip quite gently (1° southeast) towards the central trough, **Figures XX-28** and **XX-29**.[51,52] Again, faults here are relatively few on the basin interior side of the section but become more prevalent along the shallow western basin margin. This gently dipping northwest margin of the Junggar Basin hosts a highly prospective shale gas/oil lead. This part of the Junggar accounts for over 40% of the basin's conventional oil reserves and has good existing infrastructure.

Figure XX-27. Regional North-south Structural Cross-section Across the Junggar Basin. The Basin has Relatively Simple Structure, Apart from its Overthrusted Southern Margin. Permian and Jurassic Source Rocks are Very Thick but Too Deep (>5 km) in the Central Basin Trough. These Units Become Shallower to the North but Thin Out on Structural Uplifts. Vertical Exaggeration is 3.7x.



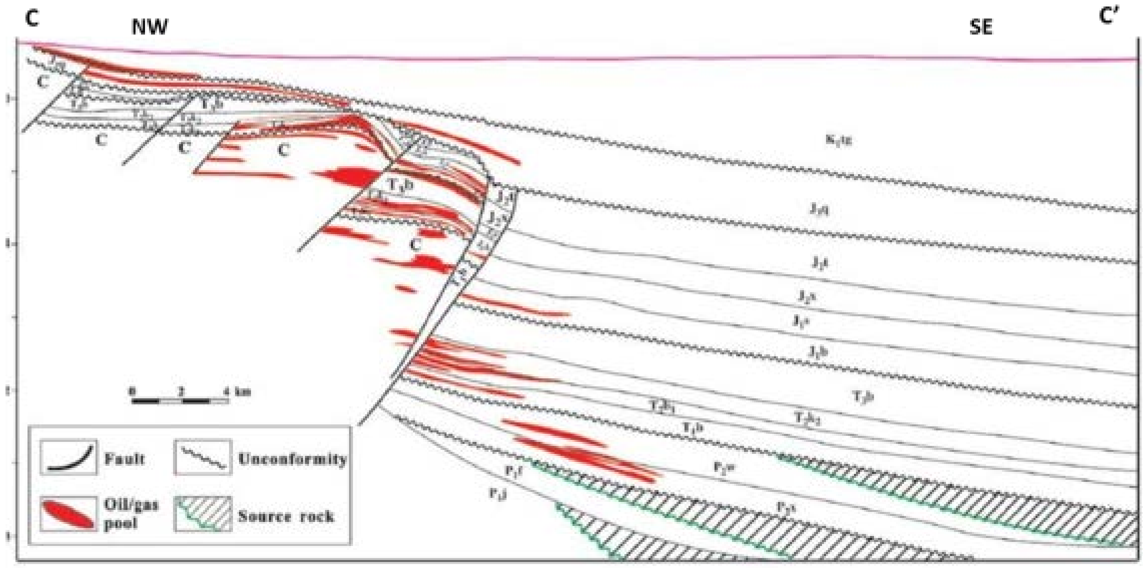
Source: Qiu et al., 2008.

Figure XX-28. Detailed Structural Cross-section Trending Northwest-southeast Across the Northwest Margin of the Junggar Basin, Based on Seismic and Well Data. Permian (P), Triassic (T), Jurassic (J), and Cretaceous (K) Strata Dip Gently into Basin. Faults are Few in the Basin Interior but Become More Prevalent Along the Basin Margin. No vertical exaggeration.



Source: Zhu et al., 2010.

Figure XX-29. Structural Cross-section Trending Northwest-southeast Across the Northwest Margin of the Junggar Basin, Showing Conventional Oil Fields. Permian (P), Triassic (T), Jurassic (J), and Cretaceous (K) Strata Dip Gently into the Basin. Faults are Few in the Basin Interior but Become More Prevalent Along the Basin Margin. Vertical exaggeration is 6x.

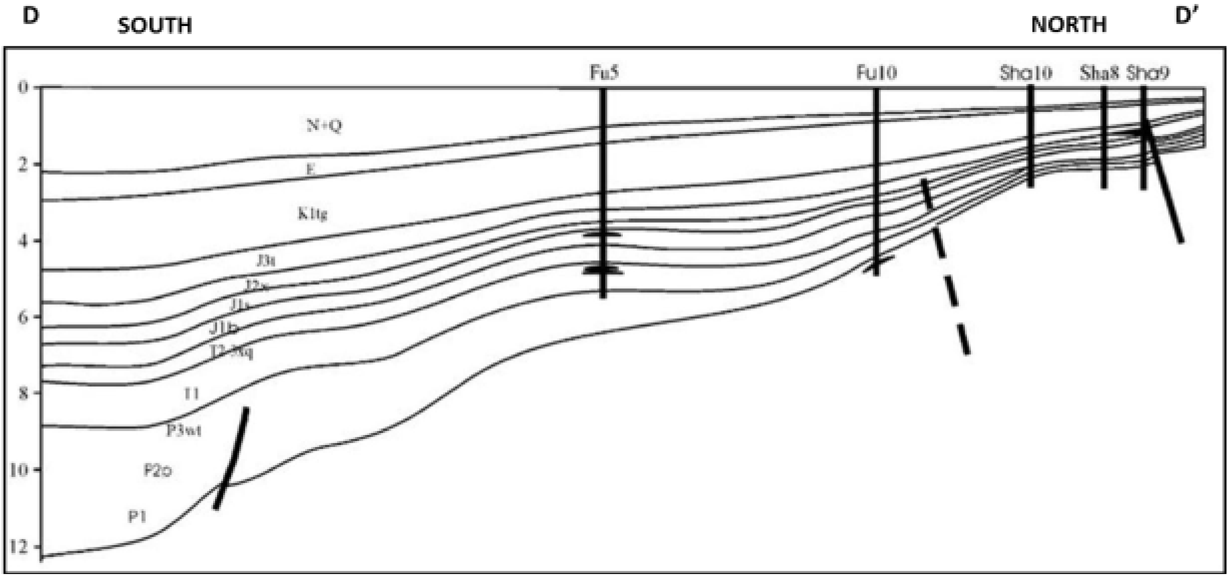


Source: Jin et al., 2008.

The southeastern Junggar Basin also has relatively simple structure. Permian and Jurassic source rock shales are thick but too deep (>5 km) near the southern basinal axis. These shales shoal but also thin onto the intra-basin high to the north, **Figure XX-30**. Even near intra-basinal uplifts structure is relatively simple. **Figure XX-31** shows conventional sandstone reservoirs in the Cainan oil field, central Junggar Basin, sourced by Permian and Jurassic shales which may be prospective for shale development further to the south in the deep Fukang Trough.[53]

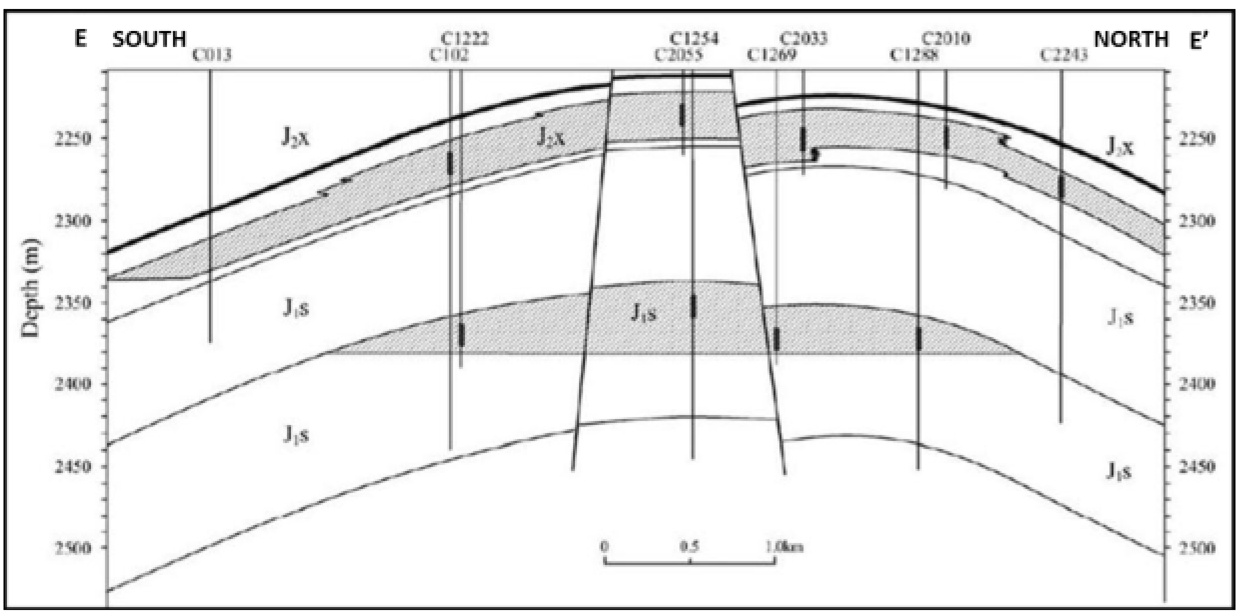
Reservoir pressure often is abnormally elevated in the Junggar Basin. For example, the Huo-10 well, located on an anticline in the southern Junggar, tested pressures of 50% to over 100% above hydrostatic levels in Eocene and Cretaceous formations at depths of 2,000 to 3,500 m, **Figure XX-32**.[54] Such overpressuring generally is favorable for shale development as it could increase shale gas storage and deliverability. As one author noted, referring here to conventional objectives: *"The Triassic and Permian overpressured bodies should hence be considered as an important objective for future* [conventional] *natural gas exploration because it is not currently feasible to penetrate into the overpressured bodies because of their deep burial depth in the study area, especially in the Changji depression."*[55]

Figure XX-30. South-north Oriented Structural Cross-section Across the Southeastern Junggar Basin. Vertical exaggeration 3.5x.



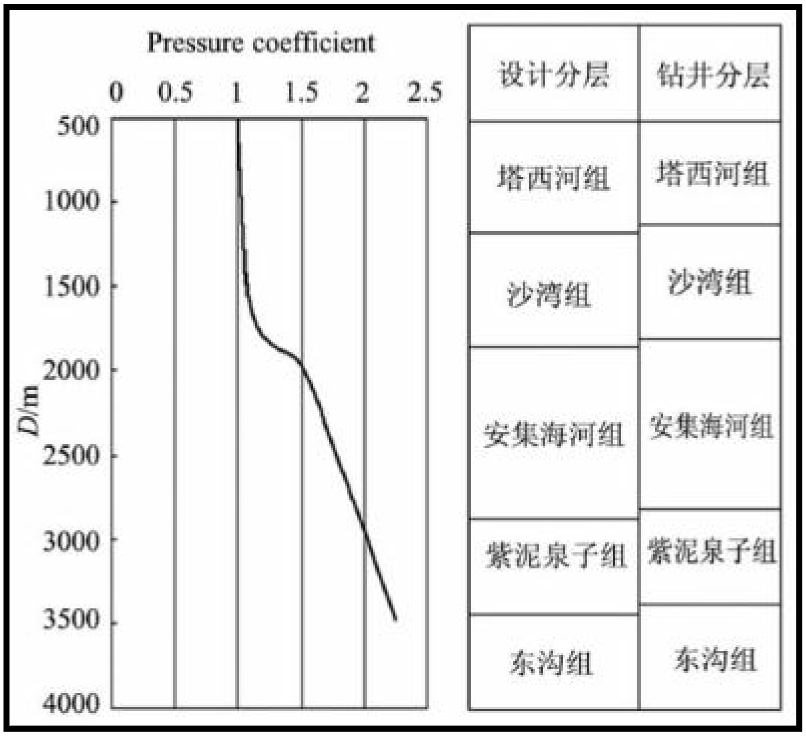
Source: Chen et al., 2003.

Figure XX-31. South-north oriented structural cross-section across the Cainan oil field, central Junggar Basin. The conventional sandstone reservoirs here were sourced by Permian and Jurassic shales in the Fukang Trough to the south, where they may be prospective for shale development. Vertical exaggeration 10x.



Source: Chen et al., 2003.

Figure XX-32. Over-Pressuring in Eocene and Cretaceous Formations at the Huo-10 Well, Southern Junggar Basin.



Source: Pa et al., 2009.

3.2 Reservoir Properties (Prospective Area)

Permian lacustrine mudstones and shales in the Junggar Basin cover a net prospective area of approximately 7,400 mi^2, based on depth and thermal maturity mapping. The net organic-rich portion of the Pingdiquan/Lucaogou formations averages about 820 ft thick and 11,500 ft deep, with average 5% TOC that is in the oil window (R_o of 0.85%).

Triassic lacustrine mudstones and shales cover a net prospective area of approximately 8,600 mi^2, based on depth and thermal maturity mapping. The net organic-rich portion of the Triassic formations averages about 820 ft thick and 10,000 ft deep, with average 4.0% TOC also in the oil window (R_o of 0.85%). No mineralogical data are available for the Permian or Triassic shales.

3.3 Resource Assessment

Highly prospective Permian lacustrine mudstones and shales in the Junggar Basin are estimated to have 5.4 billion barrels of risked, technically recoverable shale oil resources, out of 109 billion barrels of risked oil in-place. In addition, there could be 17 Tcf of risked, technically recoverable shale gas resources associated with the Permian shale oil deposits, out of 172 Tcf of risked shale gas in-place. While not China's largest shale resource base, the Junggar Basin Permian shales are considered particularly attractive based on their favorable thickness, source rock richness, over-pressuring, and simple structural setting. However, their lacustrine depositional setting is completely unlike the marine-deposited North American shales. The Junggar Basin shale appears closer to the REM sequence in Australia's Cooper Basin, which has had promising exploration testing for shale but is not yet fully commercial.

Triassic lacustrine mudstones and shales in the Junggar Basin have an estimated 6.7 billion barrels of risked, technically recoverable shale oil resources, out of 134 billion barrels of risked shale oil in-place. In addition, there could be 19 Tcf of risked, technically recoverable shale gas resources associated with the Triassic shale oil deposits, out of 187 Tcf of risked shale gas in-place. The Triassic is considered less prospective due to lower TOC, although the simple structural setting and over-pressuring are favorable.

3.4 Recent Activity

In April 2012 Shell and Hess signed joint study agreements with PetroChina's Turpan-Hami unit to evaluate shale oil in the Santanghu Basin, an outlying portion of the eastern Junggar Basin. PetroChina reported they had previously drilled 35 wells in this basin with unsatisfactory results.

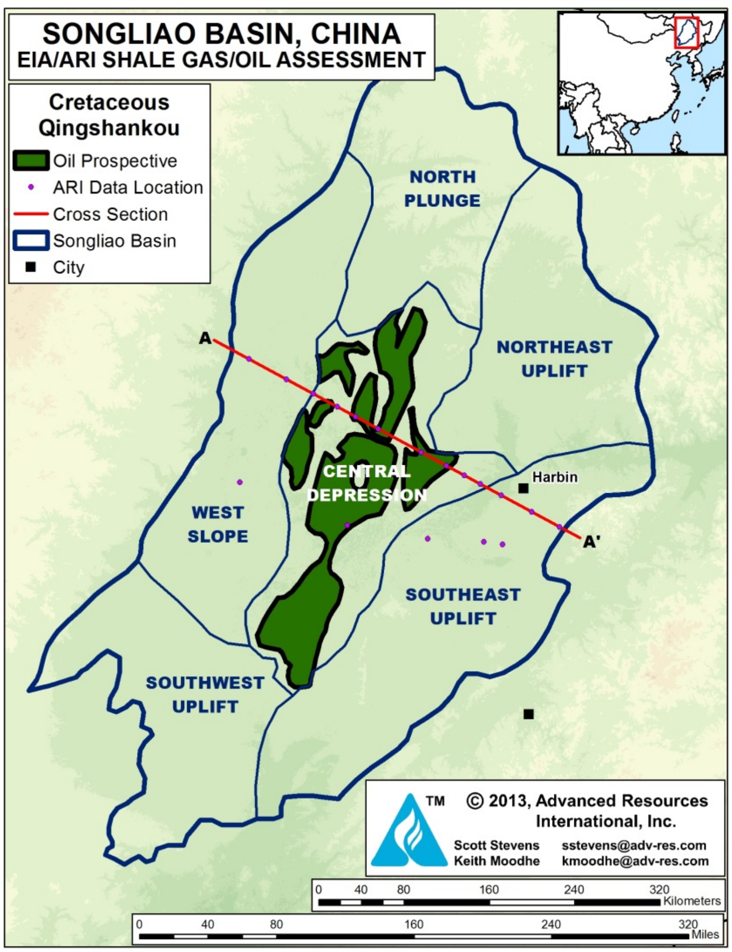
Hong Kong-based Enviro Energy's TerraWest Energy subsidiary operates a coalbed methane production sharing contract with partner PetroChina. The 655-km^2 Liuhuanggou PSC is located just west of Urumqi in the southern Junggar Basin. In addition to the CBM potential, Enviro Energy has reported on the shale potential of the block. The 300-m thick (gross) Jurassic Badaowan Formation contains coaly carbonaceous mudstone that was deposited in a non-marine environment. Third-party engineering consultancy NSAI estimated the unrisked prospective resources within the carbonaceous shale of the Jurassic Badaowan Formation of this PSC to be 1.512 Tcf (best estimate), restricted to a maximum depth of 1,500 m.[56] No shale test wells have been drilled on this property.

4 SONGLIAO BASIN

4.1 Introduction and Geologic Setting

The Songliao Basin in northeast China is an important petroleum producing region that also has shale gas and oil potential. The 108,000-mi^2 basin hosts China's largest oil field, the Daqing complex, currently producing about 800,000 bbl/day. Only in recent years has the natural gas potential of the Songliao become recognized, with new gas discoveries in mainly shallow (<1.5 km) Cretaceous sandstone and volcanic reservoirs. The thermal maturity of the Songliao Basin is relatively low and much of the conventional natural gas is believed to be of biogenic origin.[57] **Figure XX-33** shows the structural elements of the basin as well as locations of ARI-proprietary data used in conducting this study.

Figure XX-33. Prospective Shale Oil Area for the Cretaceous in the Songliao Basin, Showing ARI-Proprietary Data Locations.



Source: ARI, 2013.

Sedimentary rocks in the Songliao Basin are primarily Cretaceous non-marine deposits along with minor Upper Jurassic, Tertiary and Quaternary strata, totaling up to 7 km thick.[58] These strata rest unconformably on Precambrian to Paleozoic metamorphic and igneous rocks. The main source rocks are Lower Cretaceous organic-rich shales which formed in lacustrine settings, reflecting regional lake anoxic events, but they are unevenly distributed and concentrated in discrete sub-basins.

Figure XX-34 shows that the L. Cretaceous Shahezi, Yaojia -- and in particular the Qingshankou (Late Cenomanian) and Nenjiang formations -- are the principal source rocks (as well as important reservoirs themselves). Deposited under deepwater lacustrine conditions, these units consist of black mudstone and shale interbedded with gray siltstone. Siliciclastic rocks of alluvial and fluvial origin overlie the lacustrine shale sequences.

Figure XX-34. Stratigraphy of the Songliao Basin,
Highlighting Potentially Prospective Lower Cretaceous Source Rocks.

SONGLIAO BASIN					
ERA	PERIOD	EPOCH	FORMATION	AGE (Ma)	THICKNESS (m)
CENOZOIC	QUATERNARY			0 - 2	0 - 143
	TERTIARY	Pliocene	Taikang	2 - 67	0 - 165
		Miocene	Daan		0 - 123
		Oligocene - Eocene	Yian		0 - 256
MESOZOIC	CRETACEOUS	Upper	Mingshui	67 - 92	0 - 624
			Sifangtai		0 - 413
		Lower	**Nenjiang**	***92 - 108.5***	118 - 1247
			Yaojia	***108.5 - 112***	0 - 210
			Qingshankou	***112 - 120.5***	78 - 664
			Quantou	120.5 - 131	0 - 2021
			Denglouku	131 - 144	0 - 1593
			Yingcheng		0 - 1200
			Shahezi		0 - 1000
	JURASSIC	J3	Huoshiling/Basement		0 - 2000
	Source Rock		***Conventional Reservoir***		

Source: ARI, 2013.

The Nenjiang Fm ranges from 70 to 240 m thick, while the Qingshankou Fm is 80 to 420 m thick (both gross). Burial depth ranges from 300 to 2,500 m. Shales and mudstones contain mainly clay minerals with some siltstone. TOC ranges from 1% to 5% (maximum 13%), primarily Type I-II kerogen (in the Qingshankou) and Types II-III (Nenjiang). The Qingshankou is thermally within the oil to wet gas windows (0.7% to 1.5% R_o), while the younger Nenjiang is in the oil window (maximum 0.9% R_o).

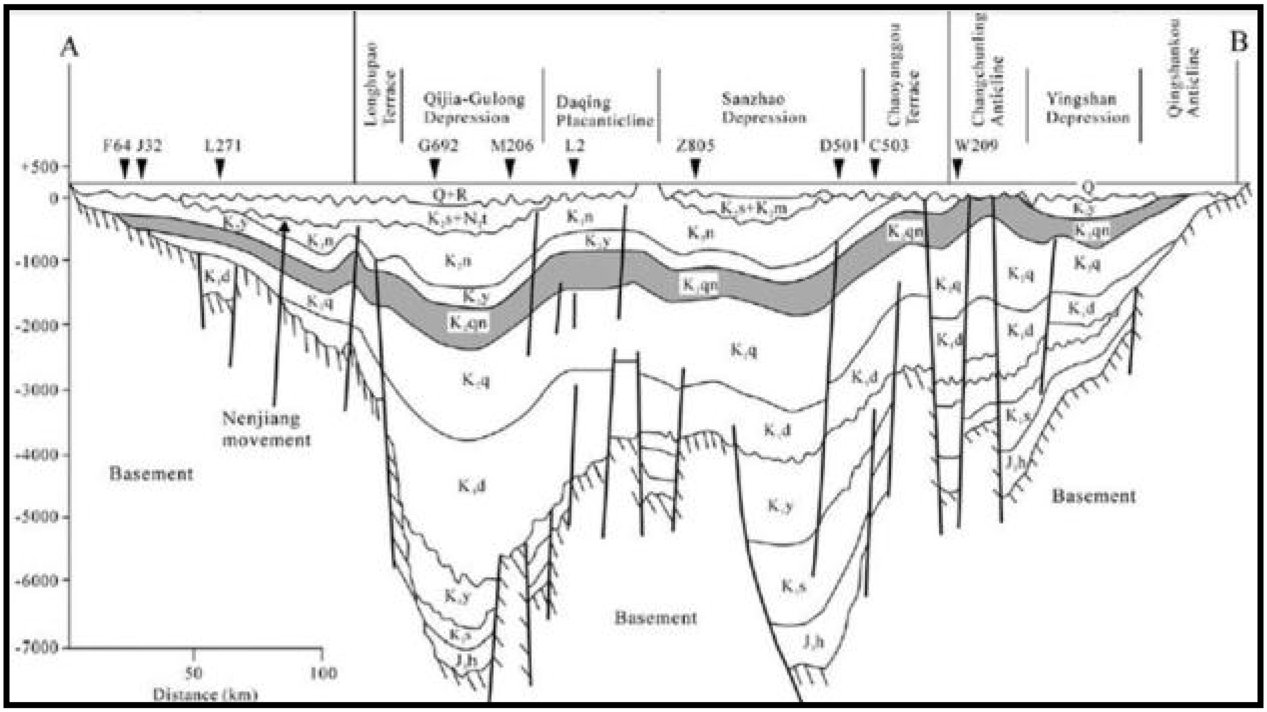
These Cretaceous source rocks are believed to have expulsed only some 20% of their hydrocarbon generation capacity. Frequently over-pressured and naturally fractured, the Nenjiang and Qingshankou shales exhibit strong gas shows and travel time delays on acoustic logs. PetroChina considers the Songliao Basin to be prospective for shale exploration and reported that commercial oil production already has occurred from shale there.[59]

The Songliao Basin comprises six main structural elements: the central depression, north plunging zone, west slope zone, northeast uplift, southeast uplift, and southwest uplift. Four distinct tectonic phases occurred in the basin: pre-rift, syn-rift, post-rift, and compression phases. Prospective L. Cretaceous units are restricted to numerous small isolated syn-rift basins, usually half-grabens trending NE-SW that range from 300 to 800 mi^2 in size.[60] This reduces the shale prospective area and also requires an understanding of each individual sub-basin's subsidence history.

Figure XX-35, a regional NW-SE trending structural cross-section, shows the alternating uplifts and depressions within the Songliao basin. Deformation is milder here than in South China but still significant with major normal faults. Organic-rich L. Cretaceous Qingshankou Formation (K_2qn), the most prospective shale oil target, ranges from 200-400 m thick and 0-2,500 m deep across the basin.[61]

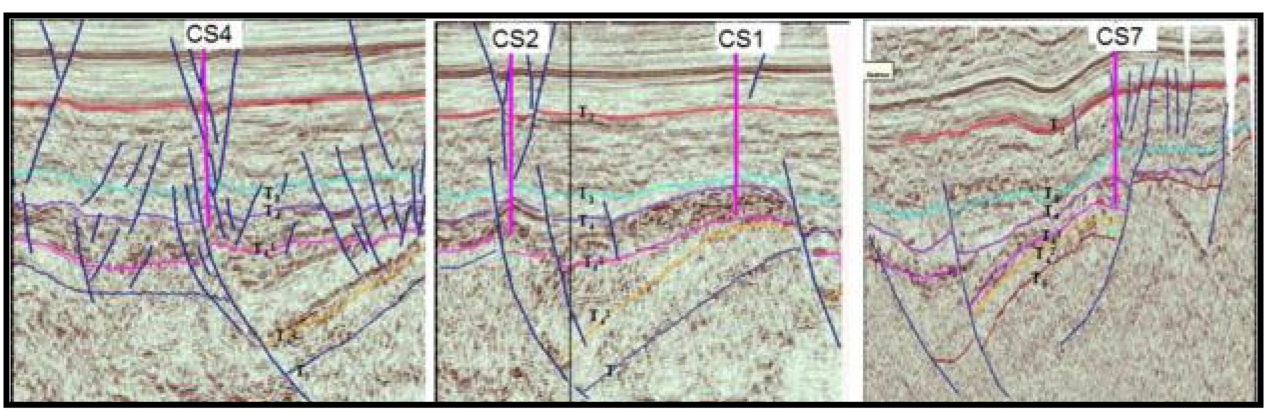
Elevated levels of carbon dioxide are common within Cretaceous sandstone and volcanic reservoirs in the Songliao Basin. About one dozen high-concentration (70-99%) CO_2 gas fields have been discovered to date, totaling 6.5 Bcf of proved reserves. Isotopes indicate the CO_2 is mainly magmatic in origin, emplaced between 72 and 48 Ma along deep-seated strike-slip faults.[62] For example, **Figure XX-36** shows seismic cross-sections in the Changling Depression of the Songliao, where northeast-trending strike-slip faults are associated with CO_2. Carbon dioxide contamination is a potential risk for shale gas exploration in the Songliao Basin, much less so for shale oil targets, although it is more likely to have migrated into high-permeability sandstones than into low-permeability shales.

Figure XX-35. Regional NW-SE Structural Cross-section of Songliao Basin. Organic-rich Cretaceous Qingshankou Formation (K2qn) is about 200-400 m thick and 0-2,500 m Deep Across the basin.



Source: Wu et al., 2009.

Figure XX-36. Seismic cross sections in Changling Depression of Songliao Basin, showing deep northeast-trending strike-slip faults associated with CO_2 contamination (scale, location not noted).



Source: Luo et al., 2011.

4.2 Reservoir Properties (Prospective Area)

Lower Cretaceous lacustrine mudstones in the Songliao Basin cover a net prospective area of approximately 6,900 mi^2, based on depth and thermal maturity mapping. The net organic-rich portion of the Qingshankou mudstones total about 1,000 ft thick and average 5,500 ft deep, with 4.0% TOC that is in the volatile oil window (average 0.9% R_o). Carbon dioxide was assumed to be about 10% in shale reservoirs. Natural fractures have been reported in certain parts of the basin but have not been quantified.

4.3 Resource Assessment

The Lower Cretaceous lacustrine mudstones and shales in the Songliao Basin are estimated to hold approximately 229 billion barrels of risked shale oil in-place with 11.5 billion barrels of risked, technically recoverable shale oil resources. Note that these deposits are located in isolated half-graben rift basins and may be difficult to extract due to the high-clay and likely ductile nature of the rock. In addition, there may be 16 Tcf of risked, technically recoverable shale gas resources associated with the shale oil deposits, out of about 155 Tcf of risked shale gas in-place.

The Songliao Basin lacks a suitable commercial North American shale analog, as it is structurally complex and of lacustrine sedimentary origin. The Eocene Green River Formation of Wyoming, which formed in an inter-montane lake setting, is a possible analog albeit of lower thermal maturity and less faulted.

4.4 Recent Activity

During 2010 Hess and PetroChina reportedly conducted a joint study of shale/tight oil potential at giant Daqing oil field in the Songliao Basin and also discussed expanding the study area. However, Hess' last update on this project came on January 26, 2011.

Separately, the Jilin Oilfield Company has drilled and massively fractured at least ten deep horizontal wells in a tight sandstone gas reservoir at Changling gas field in the southern Songliao Basin. These wells targeted the low-permeability Denglouku tight sandstone at a depth of about 3,600 m, but the technology also could be applied to tight/shale oil reservoirs. The Jilin wells typically drilled 1,200-m horizontal laterals that were stimulated in 11 stages isolated using sliding sleeves. However, the frac fluid used was heavy guar gel, rather than slickwater, and proppant was resin-coated sand. All ten wells were reportedly successful.[63]

5 OTHER BASINS

Several other sedimentary basins in China either do not appear to be prospective or have shale potential that could not be quantified due to insufficient geologic data. The Turpan-Hami Basin, east of the larger Junggar, has equivalent Permian organic-rich shale that is lacustrine in origin, oil- to wet gas-prone, and appears prospective. The Qaidam Basin, southeast of the Tarim, comprises isolated fault-bounded depressions containing Upper Triassic mudstone source rocks with high TOC; these appear oil prone but are very deep.

The Ordos Basin has simple structure but the Triassic shales have low TOC and very high clay content (40-60%). It is not clear whether a recently drilled shale test well actually produced gas from the shale formation or rather from adjacent tight sandstones which are commercially productive on a large scale in the Ordos Basin.[64] The Carboniferous and Permian mudstones in the Ordos are coaly and appear ductile. Finally, east-central China's North China Basin (Huabei) is a conventional oil and gas producing region that contains Carboniferous and Permian source rock shales that are stratigraphically and lithologically similar to those in the Ordos Basin and not considered prospective. No shale drilling has been reported in these less prospective areas.

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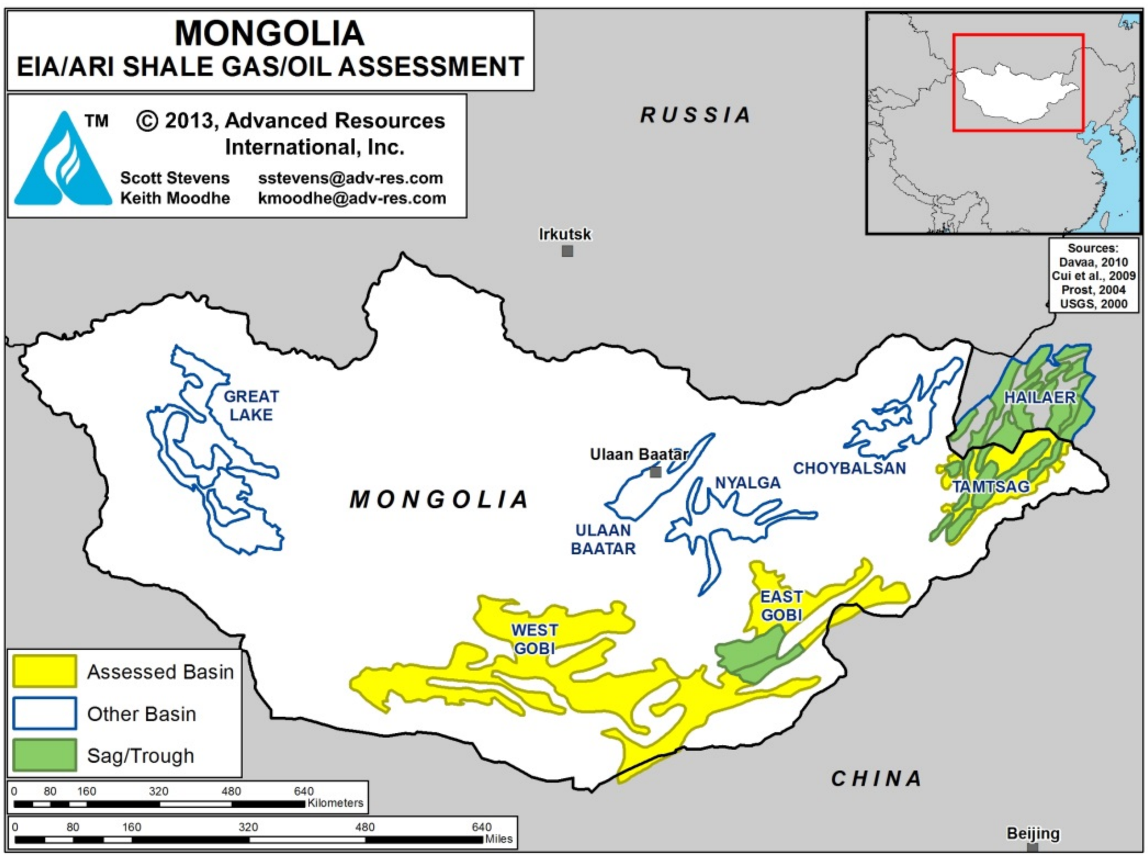
XXI. MONGOLIA

SUMMARY

Mongolia has limited but locally significant shale gas and oil potential located in the eastern and southeastern portions of the country, Figure XXI-1. The narrow and elongated Tamtsag and East Gobi rift basins - - which resemble the oil-productive basins of northeast China -- contain lacustrine mudstone and coaly source rocks within the Lower Cretaceous Tsagaantsav and equivalent formations.

Figure XXI-1. Sedimentary Basins of Mongolia



Source: ARI, 2013

Risked, technically recoverable resources are estimated at 4 Tcf of shale gas and 3.4 billion barrels of shale oil out of 55 Tcf and 85 billion barrels of risked shale gas and shale oil in-place, Tables XXI-1 and XXI-2.

Table XXI-1. Shale Gas Resources and Geologic Properties of Mongolia.

			East Gobi	Tamtsag
Basic Data	Basin/Gross Area		East Gobi (24,560 mi^2)	Tamtsag (6,730 mi^2)
	Shale Formation		Tsagaantsav	Tsagaantsav
	Geologic Age		L. Cretaceous	L. Cretaceous
	Depositional Environment		Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		4,690	5,440
	Thickness (ft)	Organically Rich	600	500
		Net	300	250
	Depth (ft)	Interval	6,000 - 10,000	5,000 - 9,000
		Average	8,000	7,000
Reservoir Properties	Reservoir Pressure		Normal	Normal
	Average TOC (wt. %)		4.0%	3.0%
	Thermal Maturity (% Ro)		0.80%	0.80%
	Clay Content		Medium	Medium
Resource	Gas Phase		Assoc. Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		31.3	23.6
	Risked GIP (Tcf)		29.3	25.7
	Risked Recoverable (Tcf)		2.3	2.1

Table XXI-2. Shale Oil Resources and Geologic Properties of Mongolia.

			East Gobi	Tamtsag
Basic Data	Basin/Gross Area		East Gobi (24,560 mi^2)	Tamtsag (6,730 mi^2)
	Shale Formation		Tsagaantsav	Tsagaantsav
	Geologic Age		L. Cretaceous	L. Cretaceous
	Depositional Environment		Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		4,690	5,440
	Thickness (ft)	Organically Rich	600	500
		Net	300	250
	Depth (ft)	Interval	6,000 - 10,000	5,000 - 9,000
		Average	8,000	7,000
Reservoir Properties	Reservoir Pressure		Normal	Normal
	Average TOC (wt. %)		4.0%	3.0%
	Thermal Maturity (% Ro)		0.80%	0.80%
	Clay Content		Medium	Medium
Resource	Oil Phase		Oil	Oil
	OIP Concentration (MMbbl/mi^2)		45.5	39.3
	Risked OIP (B bbl)		43	43
	Risked Recoverable (B bbl)		1.7	1.7

The organic-rich shales of Mongolia are thermally immature near the surface, locally forming combustible oil shale, but reach oil maturity (maximum R_o of 0.8 to 1.0%) in deeper areas ranging from 7,000 to 8,000 ft. However, these troughs are relatively small and disrupted by extensive faulting.

In addition, northwestern Mongolia has marine-deposited organic-rich shales of Devonian age that more closely resemble North America commercial shale lithology. Sporadic oil seeps have been reported in this remote region but no significant oil fields have been discovered. Data on this Devonian shale deposit are extremely limited. Most other areas in Mongolia are covered by non-prospective basement that lacks sedimentary strata.

Mongolia has an established conventional oil and gas investment regime with relatively low royalty (12.5%) and corporate income tax (25%). Nearly all of the country's sedimentary basins have been leased for conventional petroleum exploration. Regulations governing the development of deep shale oil/gas resources have not yet been promulgated in Mongolia. No shale leasing or exploration drilling activity has occurred, although Petro Matad Ltd. is evaluating the Khoid Ulaan Bulag oil shale deposit.

INTRODUCTION

With a population of about 3 million people, Mongolia has the world's lowest population density – only 1.8 inhabitants per km^2 or about half that of Canada. Mining development is helping to boost Mongolia's GDP by an expected 25% per annum over the coming decade and per-capita GDP is expected to reach $10,000 by 2020, up three-fold from the current level. Oil consumption is rising rapidly as the country develops its considerable mineral and coal deposits, including what soon may be the world's largest copper mine at Oyu Tolgoi.

Most of Mongolia is covered by igneous and metamorphic rocks but there are several relatively shallow and sparsely drilled sedimentary basins, Figure XXI-1. Oil production is small at about 5,000 bbl/day, limited to two oil fields in the East Gobi Basin in southeastern Mongolia near the border with China. Mongolia has no commercial natural gas production nor gas pipeline infrastructure. Petroleum drilling services are available locally in the East Gobi Basin, while additional capability may be sourced out of oil fields in northeast China.

Three of Mongolia's sedimentary basins may have limited shale oil potential, but only two basins could be quantitatively evaluated; geologic data are sparse. The most prospective areas for both conventional and shale oil exploration are the East Gobi and Tamtsag basins. These basins are relatively small and somewhat complex structurally; only the East Gobi Basin has small commercial oil production.

In addition, there is a non-productive and poorly defined Devonian deposit in northwest Mongolia close to the border with Russia that may have conventional and shale oil potential, although public data there are lacking. These include Riphean–Cambrian carbonates which formed on platforms of the Siberian passive margin, predating assembly of the present-day Mongolian basement. Devonian shale also is present here and oil seeps have been noted. Carboniferous–Permian coal and coaly mudstone samples immediately postdate these Paleozoic collisions and represent the beginning of non-marine deposition in central Mongolia. TOC reportedly is low (0.58% to 1.68%) and oil prone (T_{max} of 429 to 441).[1] Moreover, these source rocks are remote, poorly understood, and appear to have little shale oil potential.

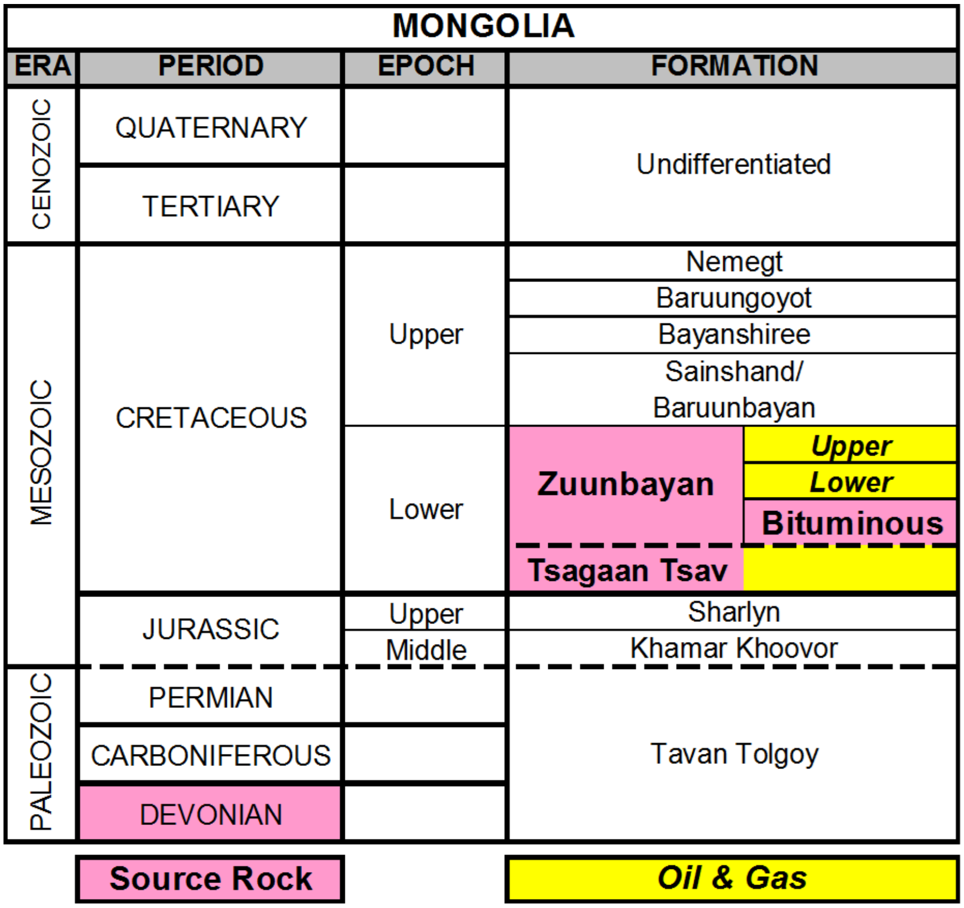
1. EAST GOBI BASIN

1.1 Introduction and Geologic Setting

The 25,000-mi^2 East Gobi Basin is located in southeastern Mongolia close to the border with China, accessible along the main highway between the capitol Ulan Bataar and north-central China. Mongolia's only significant commercial oil-producing region, the basin is along strike with and similar to oil-productive Mesozoic rift basins in northeast China, where much more geologic data are available. The East Gobi Basin shares similar stratigraphy and structural geology with these adjoining basins in northwest China.

The East Gobi Basin comprises a number of discontinuous, fault-bounded rift basins containing Jurassic to Early Cretaceous fluvial to lacustrine sediments, Figure XXI-2. The thick Lower Cretaceous shales that occur in the East Gobi Basin frequently have high TOC but were deposited under lacustrine conditions. Thermal maturity of the shale is immature at shallow depths, becoming oil prone in the deep troughs that sourced the shallow conventional oil fields.

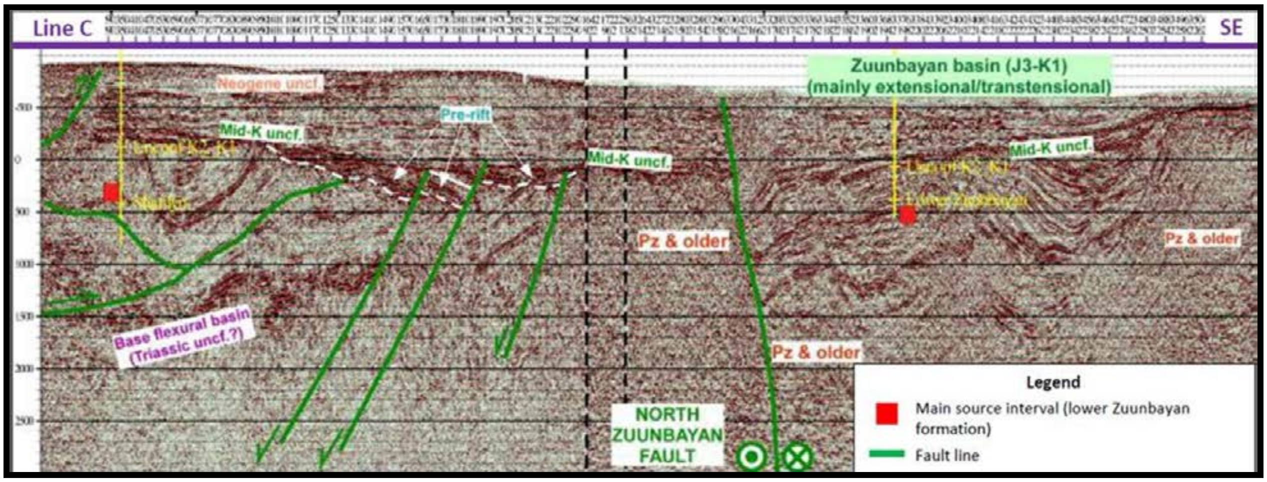
Figure XXI-2. Stratigraphy of Shale Source Rocks and Conventional Reservoirs in Mongolia



Source: ARI, 2013

The East Gobi Basin contains four main sub-basins within a 200- by 400-mi area that is defined broadly by gravity and seismic data.[2] The sub-basins contain discontinuous deep depressions, separated by basement highs that are exposed over much of the region. Deep, fault-bounded troughs with good quality source rock mudstones can occur. However, the deep areas (>6,000 ft) cover only a relatively small area. The largest sub-basins are the Unegt (3,090 mi^2) and Zuunbayan (1,600 mi^2), Figure XXI-3. Uplifted fault blocks occur within these troughs, some forming conventional oil traps.

Figure XXI-3: Seismic Line Across the Zuunbayan and Unegt Sub-basins within the East Gobi Basin Showing their Relatively Small Size and Complex Structure.



Source: Manas Petroleum Corp., 2012

Conventional reservoirs in the East Gobi Basin currently produce about 5,000 bbl/day from two small anticlinal oil fields. The Zuunbayan oil field has produced a total of about 6 million barrels from shallow depths (2,000 to 2,500 ft), while the nearby Tsagaan Els oil field has produced smaller volumes from depths of 4,265 to 4,600 ft. Both fields produce from conventional reservoirs comprising lacustrine siltstones, sandstones and conglomerates within the Tsagaantsav and Zuunbayan formations, which were sourced by the interbedded lacustrine shales. Original oil in place at the two fields totaled an estimated 150 Mmillion barrels. Oil gravity averages 28° API.[3]

Each sub-basin contains up to 13,000 ft of Middle Jurassic to Tertiary sedimentary rock, including thick lacustrine-deposited mudstone. Northeast-trending, mainly normal and strike slip (left-lateral) faults bound the sub-basins. The structural history of the region includes Mid-Jurassic to Early Cretaceous rifting (north-south extension), Early Cretaceous north-south compression and inversion along pre-existing faults, renewed sedimentation and right-lateral displacement along northeast faults during the Mid-Cretaceous, followed by post-Late Cretaceous east-west shortening.

Basement in the East Gobi Basin consists of metamorphosed sandstone and carbonate of the Paleozoic Tavan Tolgoy sequence. The oldest sedimentary unit is the Lower to Mid–Jurassic Khamarkhoovor Formation, a pre-rift sequence consisting of up to 2,500 ft of fluvial sandstones and lacustrine-deltaic shale, including thin coal seams. Although a potential source rock, the Khamarkhoover seldom crops out and remains poorly understood. Unconformably overlying this unit is the Sharlyn Formation, containing up to 600 ft of fluvial sandstone and conglomerate with minor lacustrine shale.

Overlying the Sharlyn Fm are the primary shale targets in the East Gobi Basin, the Lower Cretaceous Tsagaantsav and Zuunbayan formations. The Tsagaantsav Fm, a late synrift sequence 1,000 to 2,300 ft thick that locally can contain thick oil shale, is mainly an organic-rich shale section interbedded with dark gray sandstones and conglomerates, siltstones, bright-red tuffs, and basalt. The unit grades upward from alluvial fan to lacustrine facies, becoming a lithic sandstone reservoir at the Tsagaan Els and Zuunbayan oil fields.

A 125-m thick core section in the Tsagsaantsav Fm was described as consisting of finely laminated mudstone and micrite, dolomitic breccia, and calcareous siltstone. These fine-grained units are interbedded with grainstone and thin, normally graded sandstone beds interpreted as distal lacustrine turbidites. Anoxic, stratified lake-bottom conditions are indicated by micro-lamination, biogenic pyrite, high TOC, and carbonate precipitation. TOC ranges from 1.5% to 15% for shale, mainly oil-prone Types I and II kerogen. S1 and S2 values are above 0.5 and 10, respectively, indicating good quality source rocks. Thermal maturity is immature to middle oil window. Oil quality is waxy with 20-35% paraffin and high pour point. Oil typing indicates a lacustrine algal source.[4]

The other potential shale target is the Lower Cretaceous Zuunbayan Formation, which consists of up to 3,200 ft of sands and minor interbedded shales and tuffs deposited during Hauterivian to Albian time under non-marine to paralic environments. However, the Zuunbayan is coaly, probably clay-rich, and likely less brittle, thus not a very prospective target for shale oil development.

Deep portions (6,000 to 10,000 ft) of the Unegt, Zuunbayan, and other sub-basins in the East Gobi Basin may be oil prone and offer potential shale oil targets. Burial history modeling suggests that peak oil generation occurred during the Cretaceous (90 to 100 Ma), continuing at a lower rate to the present day. However, the East Gobi Basin is structurally complex, with numerous closely spaced faults that may limit its potential for shale oil development.

1.2 Reservoir Properties (Prospective Area)

Within the 4,690-mi^2 high-graded prospective area of the Unegt and Zuunbayan troughs in the East Gobi Basin, the Lower Cretaceous Tsagaantsav Formation contains an estimated 300 ft (net) of organic-rich lacustrine shale at an average depth of 8,000 ft. TOC averages an estimated 4.0% and is oil-prone (R_o averaging 0.8%). Porosity may be significant (6%) given the silty lithology. The reservoir pressure gradient is normal.

1.3 Resource Assessment

The Tsagaantsav Formation contains an estimated 29 Tcf of risked shale gas in-place and 43 billion barrels of risked shale oil in-place, of which 2.3 Tcf of associated shale gas and 1.7 billion barrels of shale oil may be technically recoverable (both risked), Table XXI-1. The closest international analog appears to be the oil-prone window of the REM lacustrine shales in the shallow western Cooper Basin, although these have not yet been proven commercially productive.

1.4 Exploration Activity

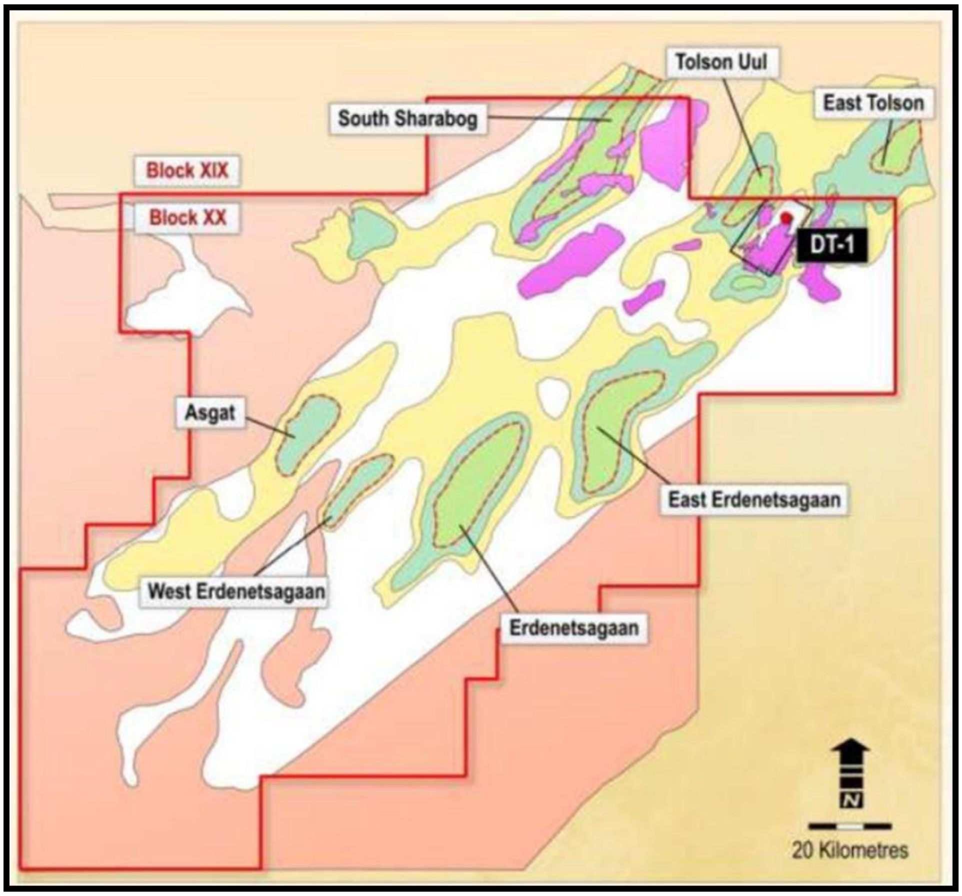
No shale oil or shale gas exploration or leasing has occurred in the East Gobi Basin. Calgary-based Manas Petroleum Corp. is conducting petroleum exploration for conventional targets in this basin but has not discussed its shale potential.[5] London-based Petro Matad Limited is evaluating Khoid Ulaan Bulag oil shale deposit in Block IV for potential mining. This deposit reportedly has similar mineralogy to the Green River Formation in Wyoming, USA, containing carbonate, quartz, and feldspar mineralogy. Extended Fischer Analysis yielded one liter of 29° API oil from a 10-kg sample.[6]

2 TAMTSAG BASIN

2.1 Introduction and Geologic Setting

Although geologically similar to the East Gobi Basin, the 6,700-mi^2 Tamtsag Basin in extreme eastern Mongolia has no commercial oil and gas production. The basin comprises a number of isolated, fault-bounded troughs that trend WSW-ENE along an extent of about 80 by 300 km, Figure XXI-4. Just as in the East Gobi Basin, potential source rocks are the Lower Cretaceous Tsagaantsav and Zuunbayan formations, with TOC averaging about 3%.

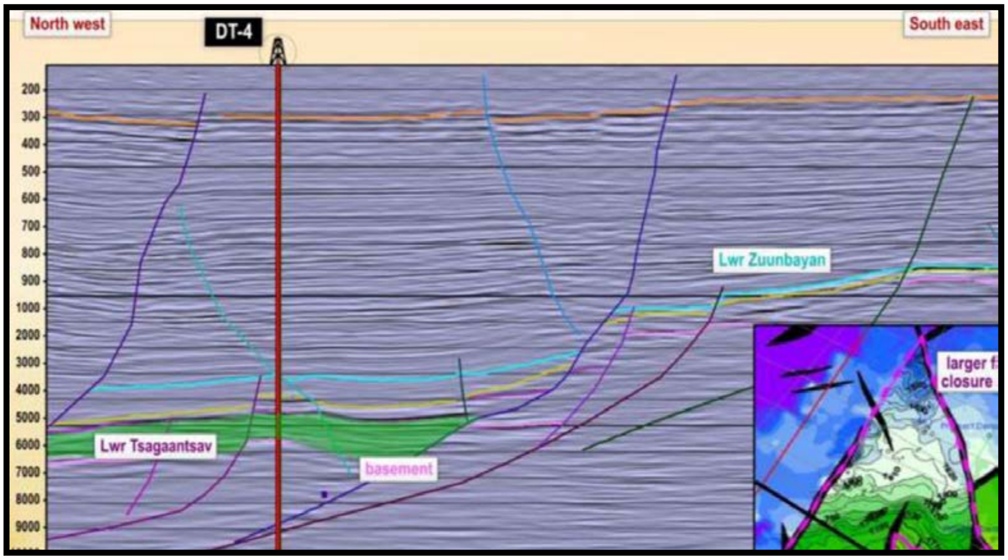
Figure XXI-4. Western Tamtsag Basin Showing Small Isolated Structural Troughs where Source Rock Shales are Buried to Over 5,000 ft and May Reach Oil-window Thermal Maturity.



Source: Petro Matad Ltd., 2012

Internally the Tamtsag Basin comprises a number of uplifted fault blocks and down-faulted grabens created by rifting and Mid-Cretaceous basin inversion, Figure XXI-5.[7] Late Cretaceous transpression formed structural traps in conventional targets, notably tilted fault blocks and anticlines. Structural complexity is most pronounced in the southwest, decreasing towards the northeast. The basement consists of Devonian to Permian metamorphic and intrusive rocks.[8]

Figure XXI-5. Seismic line in the Tsamtsag Basin Showing Source Rocks Buried to a Depth of about 6,000 ft.



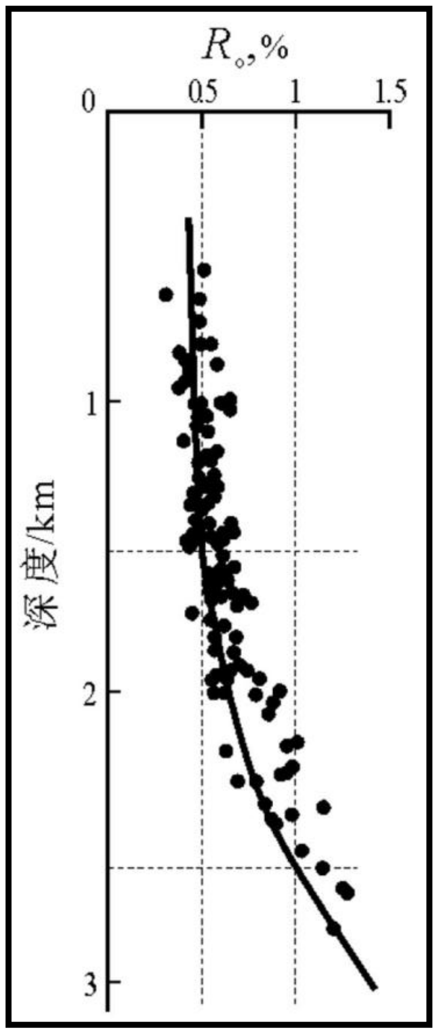
Source: Petro Matad, 2010

The Tamtsag Basin contains up to 13,000 ft of Mid-Jurassic to Tertiary non-marine and volcanic sedimentary rocks. Grain texture fines upward from coarse continental rift-fill and fluvio-deltaic conglomerates and sandstone in the lower section transitioning into lacustrine mudstones and shales. The basal Upper Jurassic consists mainly of volcanic deposits (basaltic to andesitic) with minor interbedded sediments. The overlying Lower Cretaceous deposits consist of fluvio-deltaic conglomerates and sandstones that fine upward into deepwater lacustrine shales. Younger Cenozoic conglomerates, sandstones, and mudstones cover much of the basin, concealing the Mesozoic units.[9]

The Tamtsag Basin is on trend with the Hailaer Basin of northeastern China, a stratigraphically and genetically similar Mesozoic rift basin. Although the Hailaer Basin has not experienced shale exploration, it is oil producing and thus has much better data control. Similar to the Tamtsag, the Hailaer Basin actually comprises over 20 individual fault-bounded sub-basins. Coal deposits and carbonaceous mudstones within the upper portion of the Lower Cretaceous Nantun Formation are considered the major petroleum source rocks in the Hailaer Basin. The Hailaer Basin oil fields produce with high water cut and have locally elevated CO_2 levels.

The Nantun Formation was deposited within fan delta front, pro-fan delta, marsh and lacustrine environments. Organic carbon content of the organic-rich mudstone within this unit ranges from 0.23% to 16.67%, averaging 2.56%. The mudstone becomes oil-prone (R_o above 0.7%) below a depth of about 6,500 ft, Figure XXI-6,[10] while T_{max} averages 447°C with most samples above 435°C, indicating oil-prone kerogen.[11] Limited conventional oil production occurs in the Hailaer Basin, evidently due to poor reservoir conditions and high water saturation. In addition, the Lower Cretaceous conventional sandstone reservoirs can contain elevated CO_2 levels of up to 90%, which has been isotopically linked with granite intrusions emplaced during the Yanshan Orogeny.[12]

Figure XXI-6. Vitrinite Reflectance Increases to About 0.8% Ro at a Depth of 2.5 Km in the Wuerxun Trough of China's Hailaer Basin, Adjacent to the Tamtsag Basin in Mongolia.



Source: Liu et al., 2009

2.2 Reservoir Properties

Within the 5,440-mi^2 high-graded prospective area that is distributed amongst numerous small troughs within the Tamtsag Basin, the Lower Cretaceous Tsagaantsav Formation contains an estimated 250 feet (net) of organic-rich lacustrine shale at an average depth of 7,000 feet. TOC averages an estimated 3.0% and is oil-prone (R_o averaging 0.8%). Porosity may be significant (6%) given the silty lithology.

2.3 Resource Assessment

The Tsagaantsav Formation contains an estimated 26 Tcf of shale gas and 43 billion barrels of shale oil in-place, of which 2.1 Tcf of associated gas and 1.7 billion barrels of shale oil may be technically recoverable (both risked), Table XXI-1. The closest international analog appears to be the oil-prone window of the REM lacustrine shales in the shallow western Cooper Basin, although these have not yet been proven commercially productive.

2.4 Exploration Activity

No shale oil or shale gas exploration or leasing has occurred in the Tamtsag Basin, nor does the basin produce oil or gas from conventional reservoirs. PetroChina is currently conducting exploration drilling for conventional reservoirs in this basin.

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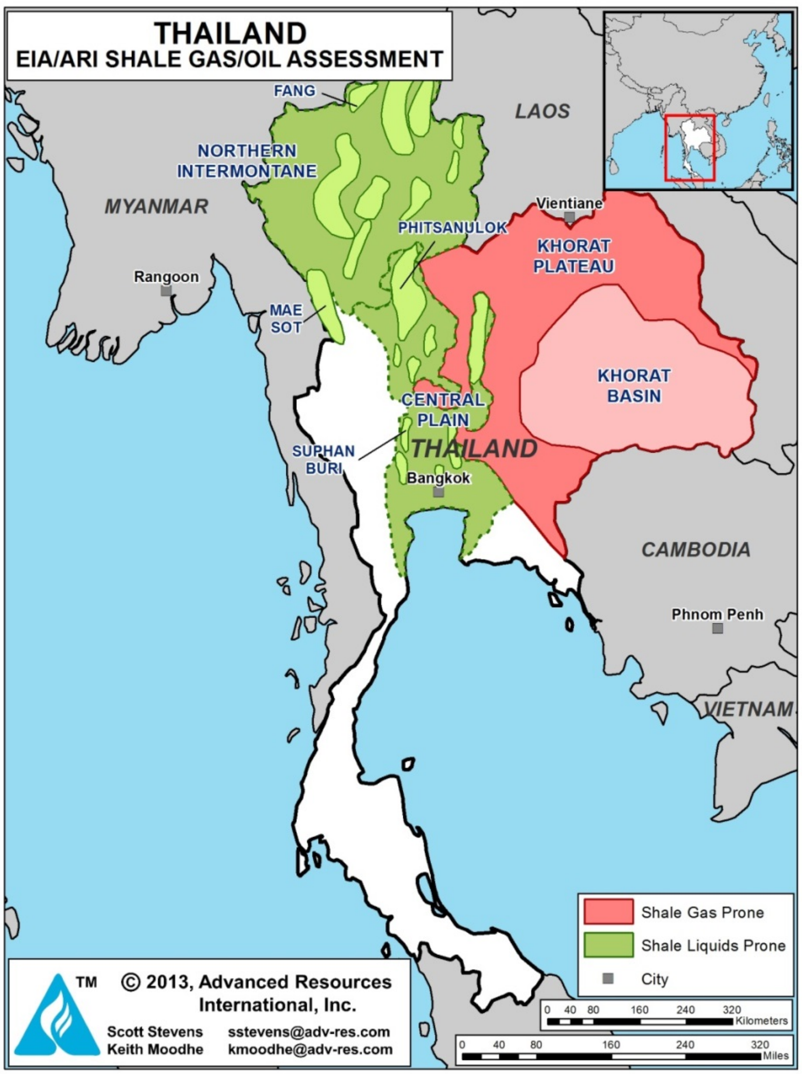
XXII. THAILAND

SUMMARY

While no shale gas/oil exploration activity has been reported to date in Thailand, this large Southeast Asian country has significant prospective shale gas and shale oil potential, in the Khorat, Northern Intermontane and Central Plains basins, Figure XXII-1.

Figure XXII-1. Prospective Shale Gas and Shale Oil Basins of Thailand.



Source: ARI, 2013

The Khorat Basin in northeast Thailand has an estimated 5 Tcf of risked technically recoverable shale gas resources, Table XXII-1. In addition, shale oil potential in the Northern Intermontane and Central Plains basins could be substantial but was not quantified due to the paucity of available public data. Block faulting has disrupted Thailand's onshore shale basins and may complicate future shale drilling and development. Overall, Thailand's shale gas/oil potential is promising but needs to be better defined by further data gathering and analysis.

Table XXII-1. Shale Gas Reservoir Properties and Resources of Thailand.

Basic Data	Basin/Gross Area		Khorat (32,400 mi^2)
	Shale Formation		Nam Duk Fm
	Geologic Age		Permian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		1,750
	Thickness (ft)	Organically Rich	400
		Net	200
	Depth (ft)	Interval	6,000 - 12,000
		Average	9,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		3.0%
	Thermal Maturity (% Ro)		2.50%
	Clay Content		Low
Resource	Gas Phase		Dry Gas
	GIP Concentration (Bcf/mi^2)		83.0
	Risked GIP (Tcf)		21.8
	Risked Recoverable (Tcf)		5.4

Thailand's greatest potential appears to be shale gas deposits contained in Permian and Triassic shale source rocks in the Khorat, the country's largest onshore sedimentary basin. These shales can be locally thick, organic-rich, dry gas prone, deeply buried, and over-pressured. Deposited under shallow marine conditions, they are likely to mineralogically brittle and suitable for hydraulic fracturing. The Khorat Basin has an existing gas pipeline network, local drilling rigs, and active independent oil and gas producers which could facilitate shale gas development.

Thailand's shale oil potential appears to be more limited. Small isolated sub-basins within the Northern Intermontane and Central Plains basins contain organic-rich shales of Oligocene to Early Miocene age. These units sourced the basin's conventional oil deposits, including the 30,000-b/d Sirikit-1 oil field. Thermally immature oil shale deposits that are locally mined at the surface may contain mobile hydrocarbons at depth. However, these low-rank Tertiary shales were deposited under lacustrine sedimentary conditions and may be high in clay content with low “frackability”.

INTRODUCTION

During the past three decades Thailand has built up a substantial oil and natural gas production industry. The country produced 393,000 b/d of crude oil and liquids in 2011 and 3.6 Bcfd of natural gas in 2011.[1] Nearly 90% of its current petroleum output comes from offshore fields in the Gulf of Thailand, with only limited production from small onshore fields. Approximately 40% of Thailand’s primary energy consumption is supplied by natural gas, including most of the country’s power generation and growing vehicle fuel usage.

Essentially all of the oil and gas currently produced in Thailand comes from conventional sandstone and carbonate reservoirs. While a handful of coalbed methane exploration wells were drilled in Thailand during 2004-6, without commercial success, and some low-permeability carbonates are being targeted in conventional anticlinal traps in the Khorat, there have been no reports of unconventional shale/tight oil or gas exploration & development to date. The only tangible sign of activity for Thailand’s unconventional resources was an MOU signed between Statoil and PTTEP in January 2011 covering potential joint studies of conventional and unconventional resources in Thailand and other countries.[2]

ARI’s review of published geologic literature indicates that Thailand has three main onshore sedimentary basins which may have unconventional oil and gas potential, Figure XXII-1. These include the large Khorat Basin in the northeast; a series of smaller, isolated pull-apart basins (such as Mae Sot) in the Northern Intermontane Basin, where shale oil deposits are being mined; and the similarly complex Central Plains Basin, which hosts the 30,000-b/d Sirikit-1 oil field.

Permo-Triassic shale source rocks in the Khorat Basin, thought to have sourced the overlying Permian carbonate conventional reservoirs, may offer Thailand’s best shale gas resource potential. These marine-deposited shales are thick, organic-rich, within the dry gas thermal maturity window, often over-pressured, and may be mineralogically brittle. The Khorat Basin hosts an existing gas pipeline network, a local supply of suitable drilling rigs, and a small group of active independent oil and gas producers.

Oil-prone shale/tight resources in Thailand appear to be less prospective, although available geologic information is scanter. The most obvious oil-prone shale potential is the downdip extension of lacustrine oil shale (solid mineral) deposits which are mined on a small scale in the northern inter-montane basins. Similar shale/tight oil deposits also may be present in the Central Plains Basin. These oil-prone shales appear less prospective due to their lacustrine origin, low apparent thermal maturity, as well as the general paucity of publicly available subsurface geologic data.

1. KHORAT BASIN

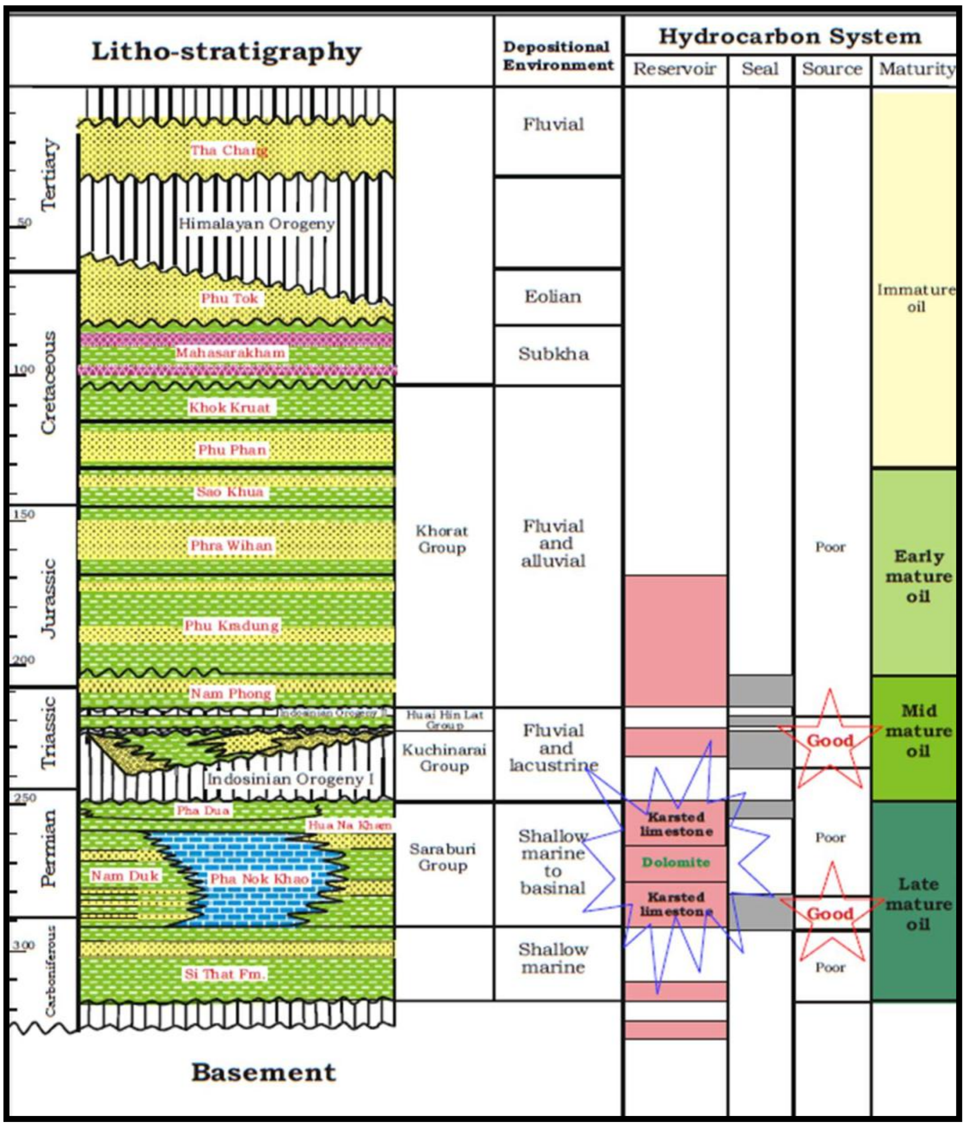
1.1 Introduction and Geologic Setting

The Khorat Basin in northeast Thailand appears to have the country's best shale gas potential. Thailand's largest onshore sedimentary basin, the 35,000-mi^2 petroliferous Khorat lies within the southern half of the Khorat Plateau, a large roughly circular physiographic province. Ringed by mountain ranges, the Plateau itself is relatively flat with 200-m average elevation. Drained by the Moin and Chi Rivers, the Khorat Plateau receives less rainfall than central Thailand, with more extreme dry and wet seasonality. The local economy of this rural area is mainly agricultural based, with few large cities or industrial centers.

The Khorat Basin is separated from the Sakon Nakhon Basin to the north by the Phu Phan anticline. The Khorat rests on the Indochina tectonic microplate, which is bordered by the Shan Thai and South China plates to the west and north, respectively. Its sedimentary sequence comprises a series of Late Cambrian through Recent strata, which are interrupted by numerous unconformities and dominated by Permo-Carboniferous, Triassic/Mesozoic, and Tertiary/ Quaternary deposits. Figure XXII-2 illustrates the stratigraphy and petroleum systems of the Khorat Basin.[3] The shallow marine to basinal Permian Saraburi Group is considered the primary source rock, while the fluvial to lacustrine Triassic Kuchinarai and Huai Hin Lat Groups offer additional source rock potential. Permian dolomite and karsted limestones form the main conventional petroleum reservoirs.

The structural Khorat Basin depression was initiated during the Middle Paleozoic, with widespread deposition of clastic and carbonate sedimentary rocks, beginning with the Carboniferous Si That Formation.[4] Tectonic extension during the Early Permian broke the basin apart into numerous horst and graben blocks separated by high-angle normal faults. Carbonate reef deposits of the Pha Nok Khao Formation formed on regional highs, while clastic and shale deposits of the Nam Duk Formation were deposited in the troughs, with some areas approaching 20,000 feet thick. Mixed sediments of the Hua Na Kham Formation were then deposited during the Middle to Upper Permian. Later basin-scale compression and inversion caused regional uplift and thrusting. Seismic and thermal maturity data indicate that uplift and erosion removed 3,000 to 9,000 feet of sedimentary cover during this event.

Figure XXII-2. Stratigraphy and Petroleum Systems of the Khorat Basin. Shallow Marine Permian Saraburi Group is the Primary Source Rock. The Fluvial to Lacustrine Triassic Kuchinarai and Huai Hin Lat Groups Also Have Potential. Permian Dolomite and Karsted Limestones are the Main Conventional Petroleum Reservoirs.



Source: Thailand Ministry of Energy, 2007.

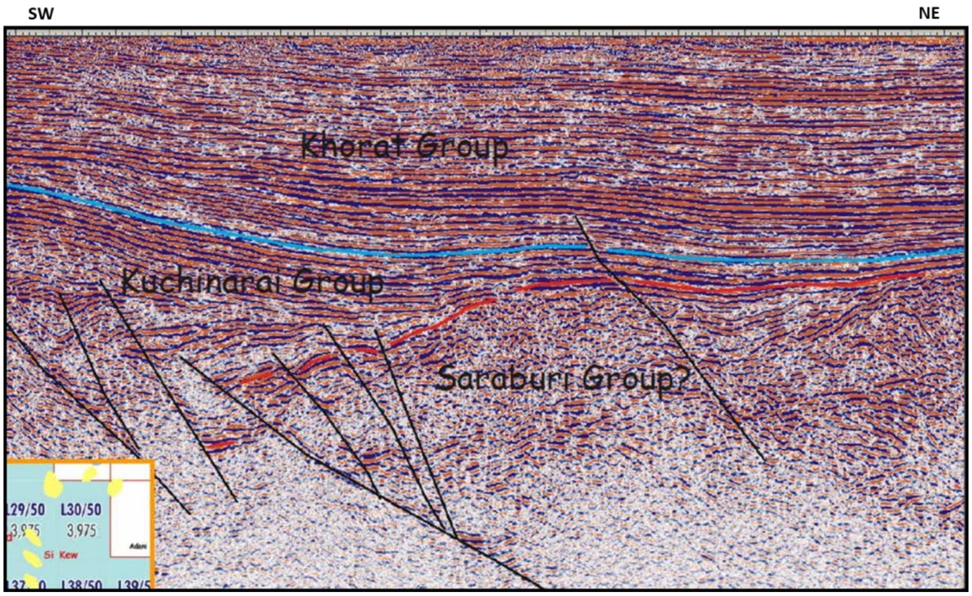
Following the Indosinian orogeny, Early Triassic continental and lacustrine sediments of the Kuchinarai Group began to unconformably fill the extensional grabens of the Khorat Basin. A second orogenic collision marked by volcanics followed, after which Late Triassic fluvial clastics were deposited. A further erosional or non-depositional hiatus occurred until the Middle to Late Jurassic, after which non-marine clastics and shales of the Khorat Group were deposited. After a Middle Cretaceous period of deformation and volcanic events, evaporites and clastics of the Mahasarakham Formation were deposited. Finally, the Tertiary Himalayan orogeny brought about regional uplift and erosion, removing up to 6,000 feet of rock.

Figure XXII-3 shows a southwest-northeast oriented seismic time section from the western Khorat Basin. It highlights possible Permian Saraburi Group and Triassic Kuchinarai Group source rock shales and carbonates, which may be prospective for shale gas exploration. These strata are overlain by fluvial and alluvial clastic rocks of the Jurassic Khorat Group; these are not considered prospective due to their low TOC content. Note significant faulting of the Saraburi Group and, to a lesser extent, Kuchinarai Group rocks.

Figure XXII-4 is a south-north oriented seismic time section from the eastern Khorat Basin. Here, the low-TOC Carboniferous Si That Formation is overlain by possible conventional reservoirs of the Permian Pha Nok Khao Formation. The primary Saraburi Formation source rock does not appear to be present in this part of the basin, while the Huai Hin Lat Formation source rock is relatively thin. These Carboniferous, Permian, and Triassic rocks were block faulted and overlain by fluvial and alluvial clastic rocks of the Jurassic Khorat Group. This preliminary information suggests that the western Khorat Basin may be more prospective for shale gas exploration than the east.

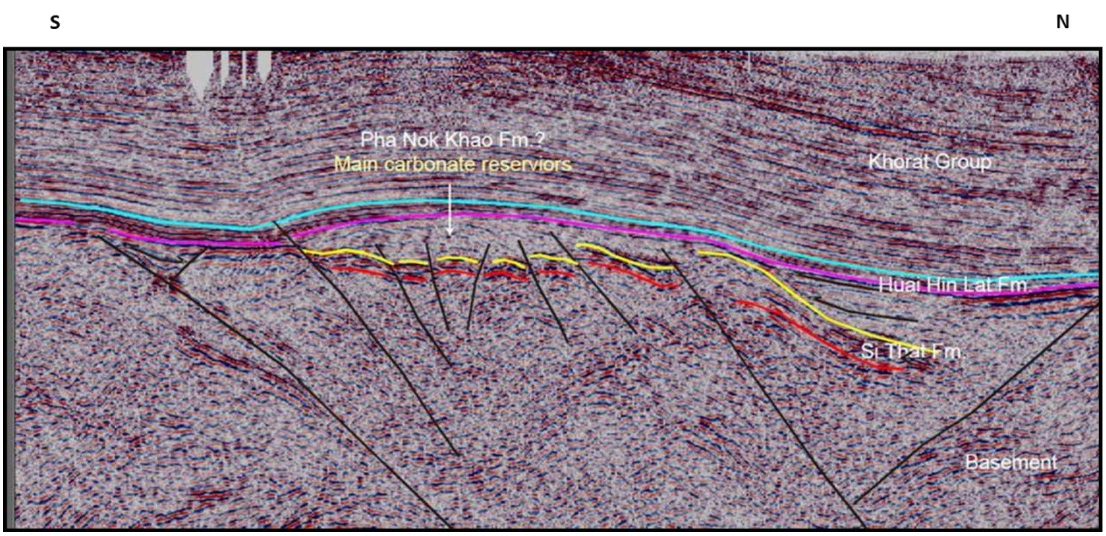
Figure XXII-5 is a schematic, non-directional cross-section of the Khorat Basin illustrating conventional petroleum play concepts. Note the Permo-Triassic source rock shales -- the primary targets -- are quite discontinuous, block faulted, and eroded in many portions of the basin. The patchy shale distribution and structural and erosional complexity are likely to complicate shale gas exploration in the Khorat Basin.

Figure XXII-3. Southwest-Northeast Seismic Time Section in Western Khorat Basin, Shows Permian Saraburi Group and Triassic Kuchinarai Group Source Rock Shales and Carbonates, Overlain by Fluvial and Alluvial Clastic Rocks of the Jurassic Khorat Group.



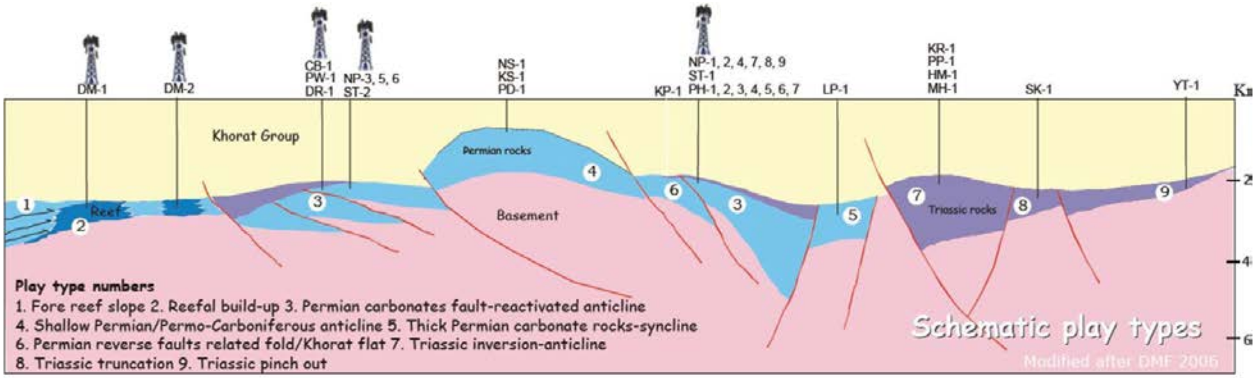
Source: Thailand Ministry of Energy, 2007.

Figure XXII-4. South-North Seismic Time Section from Eastern Khorat Basin, Showing Low-TOC Carboniferous Si That Formation Overlain by Conventional Reservoirs of the Permian Pha Nok Khao Formation. The Saraburi Formation Source Rock Does Not Appear to be Present in this Part of the Basin, While the Huai Hin Lat Formation Source Rock is Relatively Thin. Note Significant Faulting of the Permo-Carboniferous Sequence.



Source: Thailand Ministry of Energy, 2007.

Figure XXII-5. Schematic Non-directional Cross-section of the Khorat Basin, Showing Conventional Petroleum Play Concepts. Note the Primary Permo-Triassic Source Rock Shales are Discontinuous, Block Faulted, and Partly Eroded across the Basin. This Structural Complexity may Complicate Shale Gas Exploration.



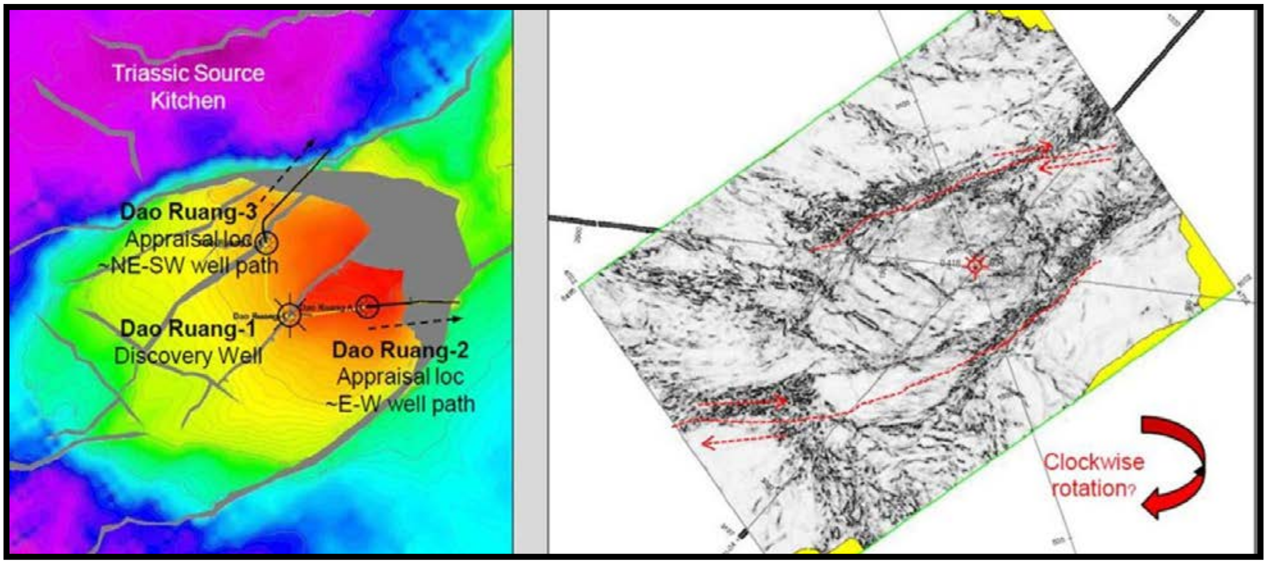
Source: Thailand Ministry of Energy, 2007.

Although the Khorat Basin is overmature for oil, a small number of conventional natural gas discoveries have been made. These fields target Permian carbonate and Triassic clastic reservoirs within anticlines and stratigraphic traps. Natural gas likely was sourced by older organic-rich Permo-Triassic shales, with gas being generated during the Early Tertiary following Cretaceous burial, and then possibly migrating along fractures and faults caused by extensional rifting.[5]

Figure XXII-6 illustrates a detailed seismic structure time map and structural interpretation of a small gas field in the central Khorat Basin. Note the deep Triassic source rock "kitchen", the uplifted anticlinal fold that formed a conventional gas trap, and the interpreted clockwise rotation along strike-slip faults that created this local structure.

UK-based independent Salamander Energy holds several license blocks in the Khorat Basin. At last report, Salamander was acquiring 3D seismic, conducting basin modeling, and planning its first exploration well in 2012-13 to test conventional Permian carbonate targets.[6] Earlier this year Yanchang Petroleum, China's fourth largest state-owned petroleum company, reportedly entered into a contract with Thailand's Ministry of Energy to explore natural gas opportunities in the Khorat. Coastal Energy and Hess also have interests in Khorat Basin blocks but have not reported activity in the past two years.[7,8]

Figure XXII-6. Seismic Structure Time Map and Interpretation of Small Gas Field in the Khorat Basin. Note Deep Triassic Source Rock "Kitchen", Anticlinal Fold, and Interpreted Clockwise Rotation along Strike-Slip Faults.



Source: Salamander Energy PLC.

1.2 Reservoir Properties (Prospective Area)

Thick, organic-rich source rock shales and carbonates of Permian and Triassic age occur at prospective depth in the Khorat Basin, although mapping the location and size of depth-screened areas is not possible with current data. These shales are thermally dry-gas-prone to over-mature, with little or no liquids potential. Deposited under shallow marine to basinal sedimentary conditions, these shales are thought to have sourced the conventional Permian carbonate and Triassic clastic reservoirs of this region, including two significant producing gas fields.

Shallow marine shales also occur in the Carboniferous Si That Formation, typically at depths below 13,000 feet.[9] However, basin maturity modeling estimates that this unit is thermally over-mature and not prospective for shale gas development (R_o of 3 to 4%). The Early Permian Nam Duk Formation contains several thousand feet of continental to shallow marine sediments, including some organic-rich shale. TOC reportedly can exceed 3%, while depth ranges from 8,000 to more than 10,000 feet and the formation often is over-pressured. The calculated vitrinite reflectance is over 2.5%, thus the Nam Duk Fm is a potential dry gas shale target that is unlikely to be prospective for liquids.

Fluvial and lacustrine deposits of the Triassic Kuchinarai Group also have been identified as petroleum source rocks in the Khorat Basin, with high-TOC intervals of unreported thickness. The Kuchinarai Group reportedly averages a prospective 6,500 to 7,000 feet deep within the basin. Thermal maturity modeling suggests it reaches the dry gas window, with no liquids potential (R_o> 2.0%).

1.3 Resource Assessment

As discussed above, the Permian Nam Duk Formation contains organic-rich shales with suitable depth and thermal maturity and appears to be the most prospective target for shale gas development. Additional shale gas potential may exist in other organic-rich shales, such as the Triassic Kuchinarai Fm, but these were not assessed due to lack of data. The limited publicly available data on the Khorat Basin is not sufficient to constrain the regional distribution of suitable thickness, depth, TOC, thermal maturity, and prospective area. Average values for these parameters were estimated and augmented by analogs with commercial North American shale plays that have been more thoroughly studied.

A good North American analog for the Nam Duk Fm could be the Wolfcamp Shale in the Permian Basin, West Texas.[10] These formations share similar age (Lower Permian), depositional setting (shallow marine), thickness (>1,000 ft), lithology (high in carbonate, low in clay), TOC content (average 3%), over-pressuring (uncertain in the Khorat but assumed to be 0.6 vs 0.7 psi/ft for the Wolfcamp). The Khorat Basin appears to be structurally more deformed and faulted than the Permian Basin but the difference is not extreme. Furthermore, the Permian Basin Wolfcamp is less thermally maturity, ranging from the black oil to wet gas windows, thus the analogy is imperfect.

The Nam Duk Fm is well over 1,000 ft thick, with reported average 9,000 ft depth, 3% average TOC, and falls within the dry-gas thermal maturity window (R_o > 2.5%). The Nam Duk is discontinuously present within the basin due to uplift and erosion. Prospective area could not be rigorously mapped due to lack of data but is assumed to be 5% of the Khorat Basin area (~1,750 mi^2). Net organic-rich shale thickness also is uncertain but is assumed to be 200 feet, much less than 20% of formation thickness. Known to be over-pressured but not known to what extent, the pressure gradient was assumed to be 0.6 psi/ft, slightly below the Wolfcamp analog. ARI assumed 6% porosity based on the Wolfcamp analog.

Based on these data and assumptions, the Nam Duk Formation in the Khorat Basin was estimated to have 22 Tcf of risked shale gas in-place, with 5 Tcf of risked, technically recoverable shale gas resources, Table XXII-1. More detailed study is recommended to define and map these parameters and estimate the full shale gas resource potential of the Khorat Basin.

1.4 Recent Activity

No shale gas activity has been reported in Thailand's Khorat Plateau.

2. CENTRAL PLAINS BASIN

2.1 Introduction and Geologic Setting

Thailand's Central Plains Basin is located in the south-central portion of the country, including the Bangkok region and the highly productive rice-growing regions of the lower Chao Praya River. Covering a 25,000-mi^2 area, the Central Plains Basin is not a continuous deposit like the Khorat but rather comprises a number of small, deep, north-south trending and discontinuous half-grabens of Tertiary age, formed due to transpressional pull-apart tectonics. The province includes the prominent Phitsanulok, Suphan Buri, Kamphaeng Saen, and Petchabun petroliferous sub-basins, among others.

The Central Plains Basin is oil-prone and currently produces oil from conventional Miocene sandstone reservoirs as well as pre-Tertiary fractured granites. Miocene lacustrine-deposited shales, which are organic-rich and considered the primary source rocks in this basin, appear to have Thailand's best potential for shale oil exploration. However, shale oil prospects which may be identified by future work are likely to be limited in size, reflecting the small discontinuous nature of the sub-basins.

Similar to most of Thailand's basins, the structural history of the Central Plain is punctuated by periods of extension and subsequent erosion. Lacustrine shales and sediments were deposited during Oligocene to Early Miocene time.[11] An active margin developed in the Middle Miocene, depositing interbedded fluvial sandstones and mudstones. Alluvial-fluvial sediments were then deposited towards the end of the Tertiary and into the Quaternary. In some areas, up to 26,000 feet of Cenozoic strata have been preserved.

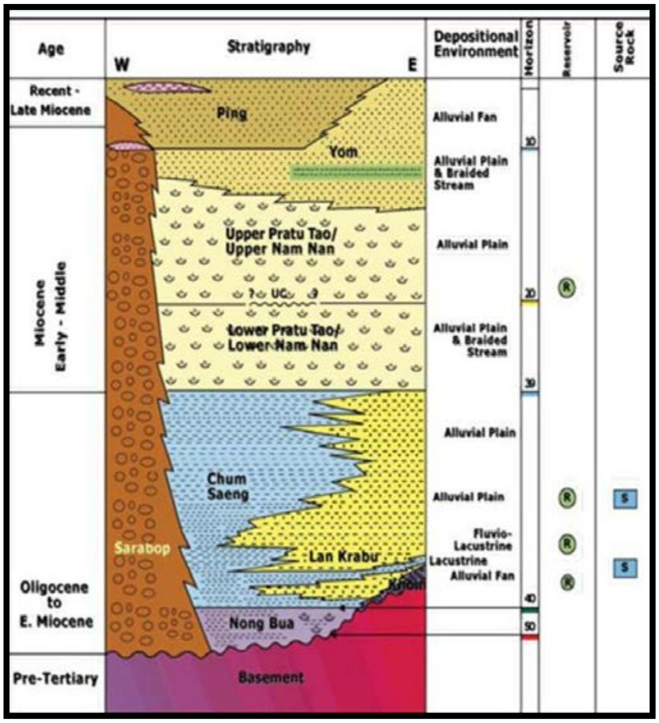
Middle Miocene sandstones (and more recently pre-Tertiary granites) are the primary conventional target in the various Central Plains sub-basins, such as at Sirikit field within the Phitsanulok Basin. Thailand's largest onshore oil field, the Sirikit (now called S-1) commenced production in the early 1980's, with over 250 wells drilled and 170 MMBO produced to date. The oil is inferred to have been sourced from the underlying lacustrine shales. PTTEP acquired the S1 field from Thai Shell in 2003 and plans to extract an additional 40 to 50 MMbbls over the next 10 years. During Q3-2012 PTTEP produced an average 30,000 b/d of oil from Sirikit-1, while continuing to drill new development wells there. PTTEP's onshore focus has been on advanced drilling and exploration techniques.[12]

In the Phitsanulok Basin, the main organic-rich lacustrine shales comprise the Early Miocene Chumsaeng Fm, which was deposited in a deep lake environment. Stratigraphically equivalent sediments are also noted in the Suphan Buri and other sub-basins, usually unnamed. These type I/II source rocks display high to variable TOC (average >2.0%[13]), with high hydrogen indices reaching over 700 mg HC/g.[14] Gross thickness averages 1,300 feet, with a net organic-rich shale interval of at least 600 feet. In the deeper parts of Central Plain basins, the Chumsaeng and Early Miocene lacustrine shales may reach maximum depths of nearly 15,000 feet. Oil generation depths in the smaller Suphan Buri Basin average 7,000 feet, suggesting a large range in thermally mature depths for liquids production.

Figure XXII-7 illustrates the stratigraphy and conventional petroleum systems of the Central Basin. Oligocene Nong Bua and Sarabop formations, the oldest sedimentary rocks in the Central Basin, rest unconformably on pre-Tertiary basement. Fluvial to lacustrine shales within the Oligocene to Early Miocene Chum Saeng Group act as the main source rocks. Clastic rocks of the Oligocene Lan Krabur and Miocene Pratu Nam Nan formations, deposited under alluvial plains settings, are the conventional reservoir targets. These in turn are overlain by Late Miocene to Recent alluvial fan deposits sourced by regional uplift associated with the Himalayan Orogeny.

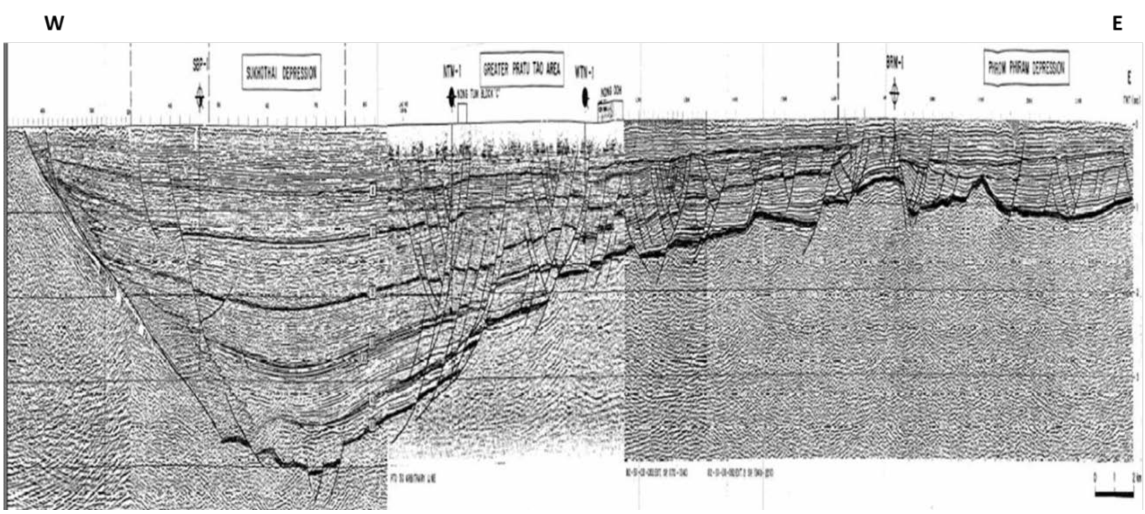
Figure XXII-8 shows a west-east oriented, uninterpreted seismic time section from the Phitsanulok Basin, one of numerous sub-basins within the overall Central Plains Basin. The main source rocks are fluvial to lacustrine shales within the Oligocene to Early Miocene Chum Saeng Group, which appear to be discontinuously present on top of pre-Miocene basement. Significant normal faulting may hinder shale oil development in this basin.

Figure XXII-7. Stratigraphy and Petroleum Systems of Thailand's Central Basin. Fluvial to Lacustrine Shales within the Oligocene to Early Miocene Chum Saeng Group are the Main Source Rocks, while Alluvial Plain Clastics of the Oligocene Lan Krabur and Miocene Pratu Nam Nan Formations are Conventional Targets.



Source: Thailand Ministry of Energy, 2007

Figure XXII-8. West-East Seismic Time Section in the Phitsanulok Sub-basin within the Central Plains Basin. The Main Source Rocks are Fluvial to Lacustrine Shales within the Oligocene to Early Miocene Chum Saeng Group, Discontinuously Present on Top of Pre-Miocene Basement. Note Significant Normal Faulting.



Source: Thailand Ministry of Energy, 2007

3. NORTHERN INTERMONTANE BASIN

3.1 Introduction and Geologic Setting

Thailand's Northern Intermontane Basin is a large loosely defined area covering the north-central and northwestern portions of the country. Similar to the Central Plains Basin and quite unlike the relatively continuous Khorat Basin, the Northern Intermontane Basin comprises numerous small and completely isolated structural troughs that are separated by uplifts. Several of these pull-apart basins, such as the Fang Basin, produce oil in anticlinal traps from conventional sandstone reservoirs that were sourced by organic-rich Miocene lacustrine shales. In addition, solid oil shale mineral resources near the surface in the Mae Sot Basin are under small-scale mining development. These organic-rich lacustrine-deposited shales may become thermally more mature and contain mobile oil in the deeper troughs, although ARI could not map this due to very sparse data control.

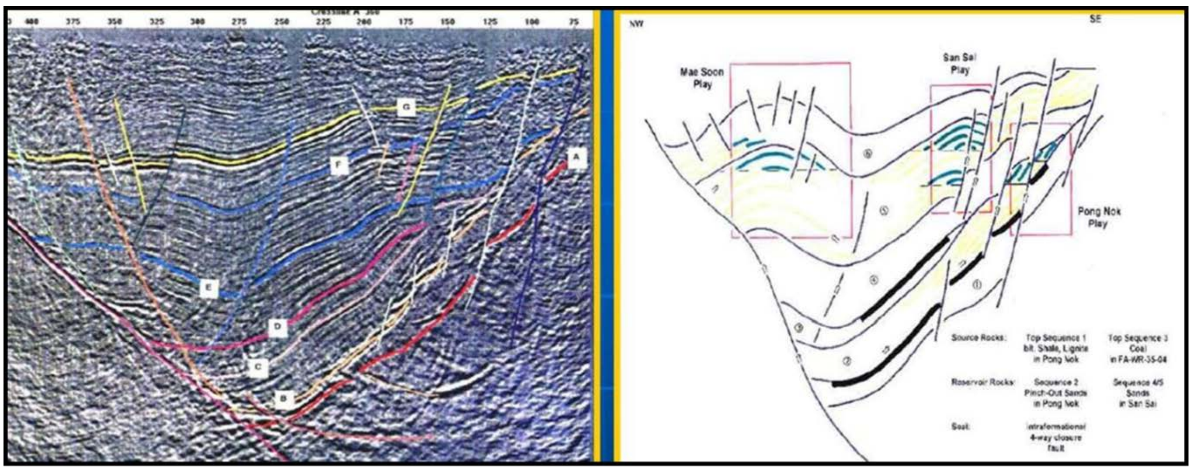
Mae Sot Sub-Basin. The Mae Sot Sub-basin of northwestern Thailand is one of the more prominent intermontane basins in this topographically mostly rugged Northern Intermontane region. This north-south trending basin extends over an area of approximately 900 mi^2, with one-third of the area extending across the Moei River into Myanmar on the west.[15] Gently undulating hills and alluvial plains comprise the topography of the basin itself, which averages about 650 feet above sea level.

The Mae Sot Basin is divided into north and south sub-basins, with the southern region having the thickest sedimentary section. It contains mainly non-marine Cenozoic sedimentary units overlying Permian to Jurassic carbonate and clastic rocks that were deposited in pull-apart basins and half grabens. These units include the Mae Ramat, Mae Pa, and Mae Sot formations, the latter recognized for its oil shale deposits.

Hydrocarbon exploration of the Mae Sot Basin began with Swiss and Japanese geologists in the late 1930's. In 1947 Thailand's Department of Mineral Resources conducted an oil shale reserve evaluation. During the 1980's, the German and Japanese governments conducted feasibility analyses of the oil shale potential. Since 2000 Thailand's Mineral Fuels Division has renewed its research on Thailand's oil shale deposits.

Fang Sub-Basin. The crescent-shaped Fang Sub-basin in the far north of Thailand, located about 150 km north of Chiang Mai, is a fault-bounded intermontane depocenter containing Cenozoic sediments, Figure XXII-9. The 220-mi^2 trough trends NW-SE and borders a steep mountain range to the east. The Fang Basin is generally flat with slightly rolling hills and an average elevation of 1,500 feet above sea level.[16] A high geothermal gradient exists throughout the half-graben, evidenced by hot springs in the northern region. Site of Thailand's first commercial oil field, over 240 wells have been drilled to date in the Fang Sub-Basin.

Figure XXII-9. Stratigraphy and Petroleum Systems of Thailand's Central Basin. Fluvial to Lacustrine Shales within the Oligocene to Early Miocene Chum Saeng Group are the Main Source Rocks, while Alluvial Plain Clastics of Oligocene Lan Krabur and Miocene Pratu Nam Nan Formations are Conventional Targets.



Source: Thailand Ministry of Energy, 2007

During the early Tertiary, extensional faults and rifting associated with the Indian and Himalayan collision opened up the basin. Syn-rift sequences of alluvial-fluvial and lacustrine sediments were deposited during the Eocene to Miocene, followed by post-rift sequences of younger alluvium and marked by a significant unconformity. Overlying these rocks are undifferentiated gravels, sands, soils, and clays of Quaternary to Recent age. Total thickness of the sedimentary sequence reaches 10,000 ft.

The stratigraphy of the Tertiary rocks generally can be divided into two units, the Mae Fang and underlying Mae Sot formations. Interbedded coarse sandstone and red to yellow claystone occur in the Late Miocene to Pleistocene Mae Fang Formation; these were deposited in an alluvial-fluvial environment and average 1,400 feet thick. Below this unit, fluvial sandstone layers within the Mae Sot Formation have been the principle reservoirs for conventional oil field production in the basin, beginning in the 1920's. As the Northern Intermontane region's most productive locale, the Fang Basin has yielded six oil fields, although the Pong Nok and Chaiprakarn were abandoned in the mid 1980's. These reservoirs apparently were sourced by lacustrine mudstones and shales within the Mae Sot Formation itself, most likely the main shale oil exploration target within the Fang Basin.

3.2 Reservoir Properties (Prospective Area)

Mae Sot Sub-Basin. The Paleocene Mae Ramat Formation contains mostly alluvial conglomerate, sandstone, limestone, and mudstone units that unconformably overlie pre-Tertiary strata.[17] The Mae Ramat Fm is up to 700 feet thick and deeper than 3,300 feet (the maximum total depth of available well data). Overlying the Mae Ramat Fm is the Upper Oligocene Mae Pa Formation, which contains lacustrine and fluvial deposits, including shales and marls, along with prevalent limestone lenses in the southern sub-basin. Minor oil shale deposits can occur within the 300-ft thick Mae Pa Fm, albeit interbedded with large amounts of low-TOC strata. The Mae Pa Fm averages about 3,000 ft deep. Overall, the Mae Ramat and Mae Pa formations are not considered viable source rocks due to lack of organic richness, undetermined shale thickness and low thermal maturity.

The most organically rich shale in the Mae Sot Basin is the Miocene Mae Sot Formation, which is dominated by shale with minor clastics. One interval within the Mae Sot Fm contains relatively thin (10 to 15 feet) oil shales beds within sandy shale assemblages, although maximum thickness can exceed 33 feet. Rock mineralogy is dominated by quartz, feldspar, calcite, dolomite, and clay (proportions not reported). In the northern sub-basin, these lacustrine oil shale deposits are grey to green and nearly 100 feet thick. Kerogen consists mainly of exinite, with immobile oil content ranging from 2.5 to 62 gallons per ton (1% to 26% by weight). Oil shale grade is highest in the middle-lower section of the unit. This formation is typically about 2,000 feet deep across much of the Mae Sot Basin. Overall, the Mae Sot Formation appears too shallow and immature for shale oil development, with R_o well below the 0.7% threshold.

Fang Sub-Basin. The Mae Sot Formation of Miocene to Pliocene age can be divided into three units: a lower section of brown to reddish sandstone; a middle zone of organic-rich lacustrine claystone, shale, and coal with interbedded sandstone; and an upper layer of gray claystone, mudstone, and sandstone along with fossil inclusions. The conventional sandstone reservoirs have 25% porosity and 0.2 to 2.0 Darcies of permeability. The crude oil ranges from 16 to 38 degrees API gravity.[18]

The rich bituminous shales of the middle unit are the recognized source rock, with calculated total organic carbon averaging 15% (Type I or II).[19] Gross formation thickness can be up to 2,100 feet, while high-TOC shale intervals interbedded with sandstone average 300 feet thick (net). The formation was penetrated in conventional wells at depths of 3,000 to 3,500 feet, but these likely were drilled on structural highs. Absent vitrinite reflectance data burial history modeling suggests an R_o of 0.5% is not reached until about 4,000-ft depth. The minimum depth for mobile oil generation (0.7% R_o) may be about 6,000 ft. Only a small portion of the Fang Basin appears to meet these screening criteria. ARI is unable to quantify such a prospective area given limited available data.

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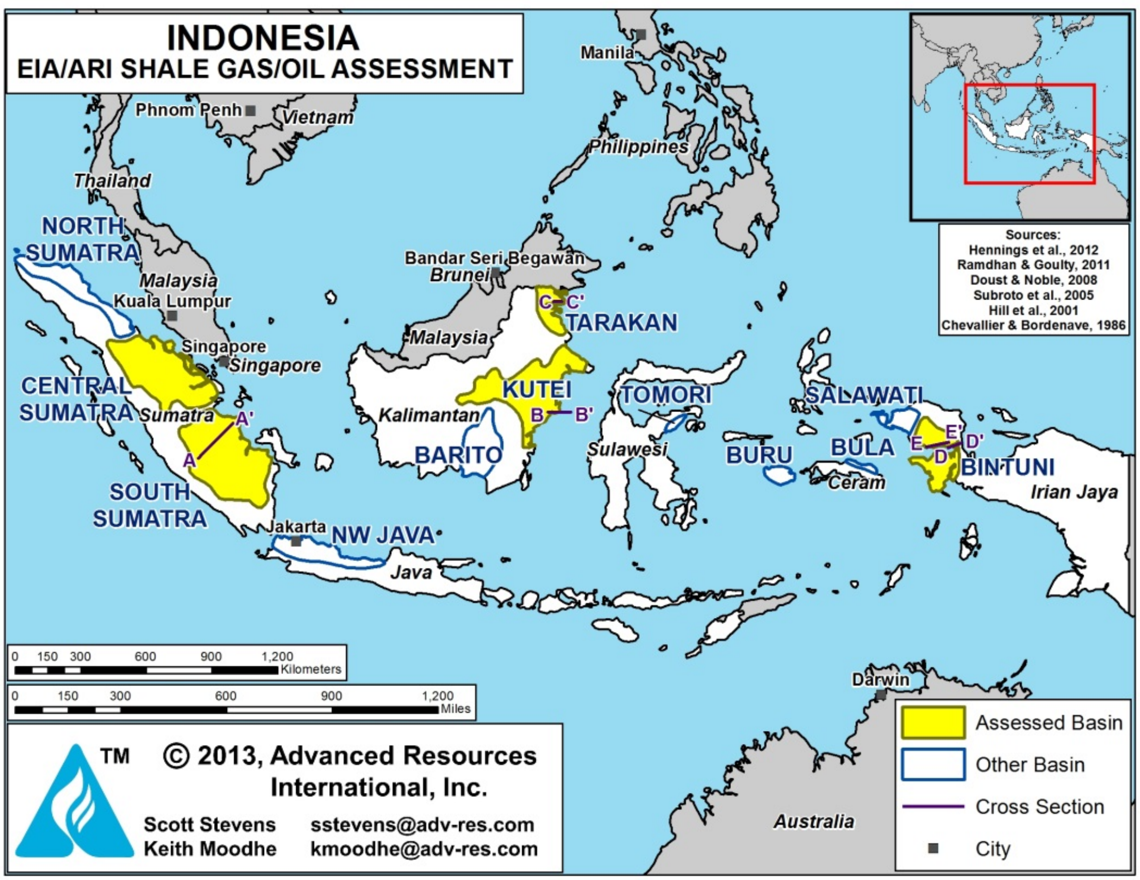
XXIII. INDONESIA

SUMMARY

Indonesia has shale gas and shale oil potential within selected marine-deposited formations, as well as more extensive shale resources within non-marine and often coaly shale deposits, Figure XXIII-1. The best overall potential appears to be mostly oil-prone, lacustrine-deposited shales within the Central and South Sumatra basins, which sourced the prolific nearby conventional oil and gas fields. Kalimantan's Kutei and Tarakan basins also have thick lacustrine source rock shales with oil and gas potential.

Figure XXIII-1. Shale Basins of Indonesia



Source: ARI, 2013

Indonesia has an estimated 46 Tcf and 7.9 billion barrels of risked, technically recoverable shale gas and shale oil resources out of 303 Tcf and 234 billion barrels of risked shale gas and shale oil in-place, Tables XXIII-1 and XXIII-2. Several companies (AWE, Bukit, NuEnergy) have reported early-stage evaluations of shale gas potential in Sumatra, but no PSC's have been awarded nor has shale-related drilling activity been reported.

Table XXIII-1. Shale Gas Reservoir Properties and Resources of Indonesia.

			C. Sumatra	S. Sumatra	Kutei	Tarakan			Bintuni
Basic Data	Basin/Gross Area		(36,860 mi²)	(45,170 mi²)	(35,840 mi²)	(7,510 mi²)			(15,200 mi²)
	Shale Formation		Brown Shale	Talang Akar	Balikpapan	Naintupo	Meliat	Tabul	Aifam Group
	Geologic Age		Paleogene	Eocene-Oligocene	Mid.-U. Miocene	L. Miocene	Mid. Miocene	U. Miocene	Permian
	Depositional Environment		Lacustrine	Lacustrine	Lacustrine	Lacustrine	Lacustrine	Lacustrine	Marine
Physical Extent	Prospective Area (mi²)		4,700	15,490	1,630	1,010	880	510	3,340
	Thickness (ft)	Organically Rich	295	918	900	750	1,000	1,500	1,000
		Net	266	367	450	375	400	600	500
	Depth (ft)	Interval	6,560 - 10,496	3,300 - 8,000	3,300 - 15,000	6,600 - 16,000	3,300 - 13,120	3,300 - 6,600	5,000 - 15,000
		Average	8,530	7,000	9,000	11,500	10,000	5,000	9,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Highly Overpress.	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		6.0%	5.0%	4.0%	5.0%	3.0%	3.0%	1.5%
	Thermal Maturity (% Ro)		0.80%	0.70%	0.70%	1.50%	1.15%	0.70%	1.50%
	Clay Content		Medium	High	High	High	High	High	Low
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Assoc. Gas	Dry Gas	Wet Gas	Assoc. Gas	Dry Gas
	GIP Concentration (Bcf/mi²)		19.6	25.0	62.1	170.7	142.3	37.3	213.8
	Risked GIP (Tcf)		41.5	67.8	16.2	34.5	25.1	3.8	114.3
	Risked Recoverable (Tcf)		3.3	4.1	1.3	5.2	3.8	0.2	28.6

Table XXIII-2. Shale Oil Reservoir Properties and Resources of Indonesia.

			C. Sumatra	S. Sumatra	Kutei	Tarakan	
Basic Data	Basin/Gross Area		(36,860 mi²)	(45,170 mi²)	(35,840 mi²)	(7,510 mi²)	
	Shale Formation		Brown Shale	Talang Akar	Balikpapan	Meliat	Tabul
	Geologic Age		Paleogene	Eocene-Oligocene	Mid.-U. Miocene	Mid. Miocene	U. Miocene
	Depositional Environment		Lacustrine	Lacustrine	Lacustrine	Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi²)		4,700	15,490	1,630	880	510
	Thickness (ft)	Organically Rich	295	918	900	1,000	1,500
		Net	266	367	450	400	600
	Depth (ft)	Interval	6,560 - 10,496	3,300 - 8,000	3,300 - 15,000	3,300 - 13,120	3,300 - 6,600
		Average	8,530	7,000	9,000	10,000	5,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Highly Overpress.	Normal	Normal
	Average TOC (wt. %)		6.0%	5.0%	4.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.80%	0.70%	0.70%	1.15%	0.70%
	Clay Content		Medium	High	High	High	High
Resource	Oil Phase		Oil	Oil	Oil	Condensate	Oil
	OIP Concentration (MMbbl/mi²)		32.8	50.2	64.7	7.1	103.7
	Risked OIP (B bbl)		69.4	136.2	16.9	1.3	10.6
	Risked Recoverable (B bbl)		2.77	4.09	0.68	0.04	0.32

In general, western Indonesia has comparatively simple structure but is dominated by the non-marine shale types, whereas eastern Indonesia has abundant marine shale deposits but is structurally more complex. Eastern Indonesia (Sulawesi, Seram, Buru, Irian Jaya) is tectonically more complex but has excellent marine-deposited shale source rocks.

INTRODUCTION

Indonesia is the world's fourth most populous country (250 million) and a major producer of coal, oil, and natural gas. Formerly an oil exporter and OPEC member, Indonesia's declining oil production and increasing domestic consumption have made the country a net oil importer since 2004. In 2011 Indonesia produced an average 2.5 million bbl/day of crude oil from 4.0 billion barrels of proved reserves, while consuming 3.1 million bbl/day. Indonesia remains a major exporter of LNG and pipeline-conveyed natural gas, producing an average 7.4 Bcfd during 2011 while exporting 3.7 Bcfd.[1] However, Indonesia's domestic gas consumption is rising faster than its output. Gas prices have risen significantly in recent years and new LNG import terminals are being constructed in Java, Indonesia's most densely populated island.

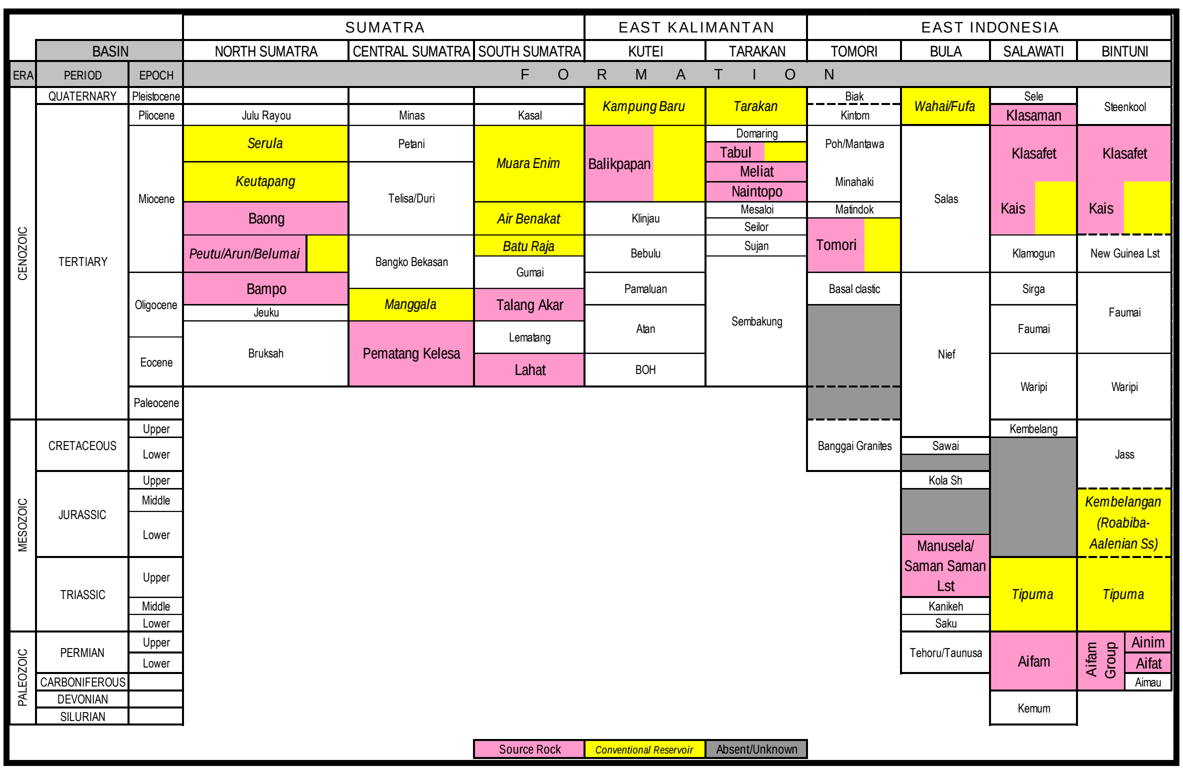
Indonesia's Ministry of Energy and Mineral Resources (MIGAS) administers upstream investment policy and awards exploration and production licenses in the country's oil and gas industry. A separate organization BPMIGAS administers the implementation of these licenses and work programs. However, a recent (November 2012) judicial decision by Indonesia's highest court unexpectedly dissolved BPMIGAS, directing MIGAS to implement oil and gas investment. Indonesia's 2001 Oil and Gas Law is expected to be revised during 2013 to clarify these significant changes and clear up the current regulatory uncertainty.

Domestic and foreign companies are active in Indonesia's oil and gas sector, with foreign companies operating the bulk of production. Pertamina, Indonesia's wholly state-owned oil company, plans to eventually transition into a listed company with significant private ownership. PGN (Perusahaan Gas Negara), the dominant natural gas pipeline operator that is partly state- and publicly owned, is gradually moving into the upstream business as well, including pursuing unconventional gas development. Foreign companies active in Indonesia include Chevron, Total, ConocoPhillips, ExxonMobil, and BP, as well as numerous smaller Indonesian and foreign operators.

ARI's review of published geologic literature indicates that Indonesia has a number of onshore sedimentary basins which may have shale gas/oil potential. These include the Central and South Sumatra basins on Sumatra Island; the Kutei and Tarakan basins in Kalimantan; and smaller, structurally complex basins in eastern Indonesia (Salawati, Bintuni, Tomori). Other basins in Indonesia appear to be less prospective due to low TOC, high clay and CO_2 contents, and/or excessive structural complexity.

The petroleum source rocks in onshore Indonesian basins are relatively young, mostly Eocene to Pliocene, with older Permian source rocks present in the east, Figure XXIII-2. Their depositional setting ranges from deepwater marine in eastern Indonesia to mostly lacustrine and deltaic environments in central and western Indonesia. Many of Indonesia's organic-rich shales are non-marine coaly deposits that may not be brittle enough for shale development. MIGAS, the upstream oil and gas regulator in Indonesia, has estimated the country's shale gas resources at 574 Tcf. However, neither the methodology nor the basis of this estimate has been reported.

Figure XXIII-2. Stratigraphy of Source Rocks and Conventional Petroleum Reservoirs in Indonesia.

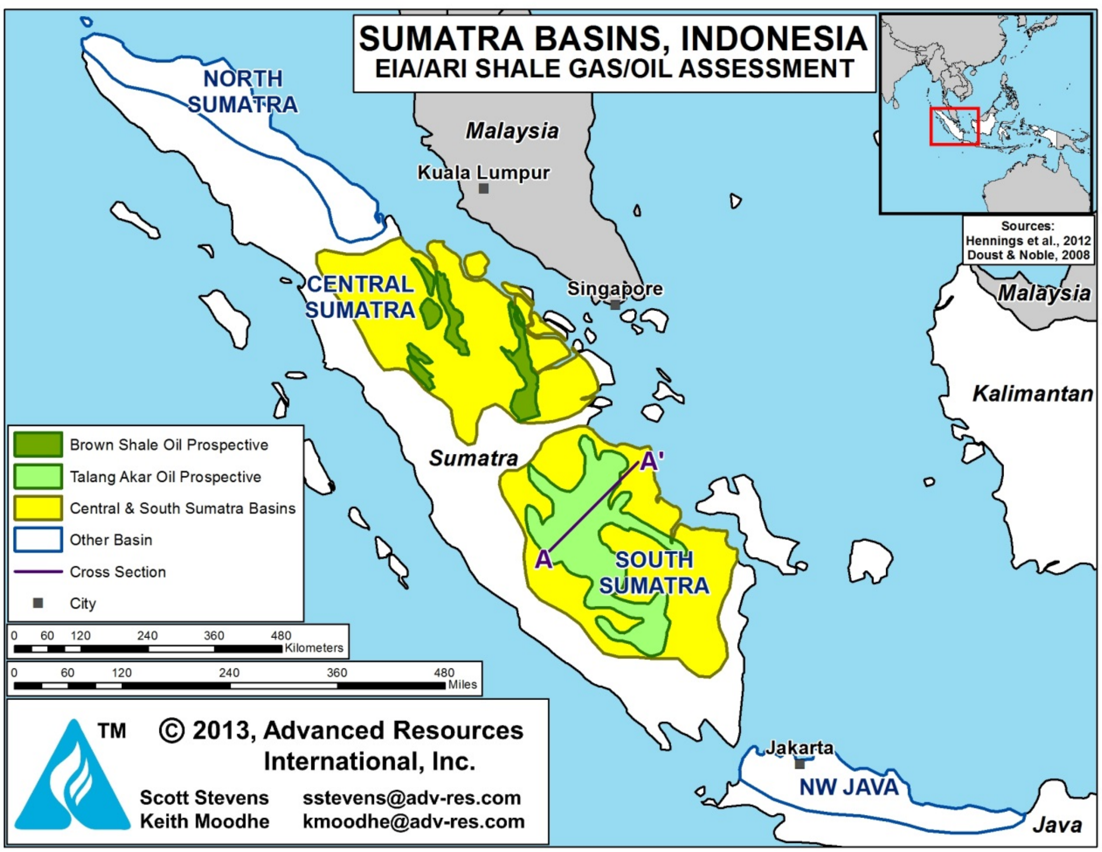


1 NORTH, CENTRAL, AND SOUTH SUMATRA BASINS

1.1 Introduction and Geologic Setting

Sumatra has shale oil and gas potential in three deep basin complexes: the North, Central, and South Sumatra basins, Figure XXIII-3. The North Sumatra Basin produces mainly conventional gas both onshore and offshore. However, gas production has declined sharply in this basin and the Arun LNG export facility is being converted to handle LNG imports. The Central Sumatra Basin produces mainly oil onshore, notably 300,000 bbl/day from the Duri thermal EOR field, and is a major consumer of natural gas for steam fuel. The South Sumatra Basin produces both oil and increasing volumes of gas from onshore fields. Major coal and coalbed methane deposits also occur in South and Central Sumatra, while North Sumatra is largely barren of coal. All three basins are back-arc tectonic settings containing young, rapidly deposited and poorly lithified sedimentary rocks. Heat flow and CO_2 content often are elevated.

Figure XXIII-3. Prospective Shale Areas in the Central and South Sumatra Basins, Indonesia.



Source: ARI, 2013

North Sumatra Basin. A series of north–south trending ridges and grabens, formed during the Early Oligocene, became filled with predominantly marine deposits. These include deep marine claystones, shales and shallow water limestones on structural highs, while shallow water deltaic facies formed in the southeast. The main source rocks are the Middle Miocene Lower Baong shale and the Early Miocene Belumai calcareous shale. The Late Oligocene Bampo black shale, which formed in localized thick and euxinic deposits, is another potential source rock.[2] The Bampo contains thick, deep marine claystones, mudstones and dark shales and is the main source rock for gas fields in the northern part of the North Sumatra Basin.

Thermal maturity of the Baong, Belumai, and Bampo shales is gas-prone but TOC is low, seldom exceeding 1% (Type III) while clay is abundant (mostly smectite). CO_2 and H_2S contamination are fairly common: output from the Arun gas field averages about 20% CO_2, while the Peutu carbonate reservoir contains 82% CO_2. Overall, these source rocks appear to be too low in TOC and possibly ductile due to their shallow depth, rapid burial, high clay content, and young age. There have been no reports of shale exploration activity in the North Sumatra Basin and we do not consider it to be prospective for shale gas/oil development.

Central Sumatra Basin. Sumatra's most important oil-producing region, the Central Sumatra Basin is a trans-tensional pull-apart basin bounded by major strike-slip faults to the north and south. It developed during the Late Cretaceous to Early Tertiary in a back-arc setting as a result of the Indian Ocean plate subducting at an oblique angle beneath Southeast Asia. The basin comprises a series of north-south trending fault-bounded troughs that are separated by uplifted horst blocks. The troughs became filled with non-marine clastic, lacustrine, and marine sediments. Sedimentation began with deposition of continental sediments followed by a transgressive/regressive marine cycle that started in Late Oligocene or Early Miocene. The Paleogene Pematang Group, Lower Miocene Sihapas Group, and Middle Miocene/ Pliocene Petani Group are the main Tertiary units.

The Brown Shale Formation within the Pematang Group is considered the most important oil-generating formation in the South Sumatra Basin, having generated an estimated 60 billion barrels and sourced the giant Duri and Minas oil fields.[3,4] The overlying marine Menggala sandstones are the main conventional petroleum reservoirs in Central Sumatra, consisting of well-sorted quartzose to subarkosic sandstones with average >20% porosity and 1,500 mD of permeability.

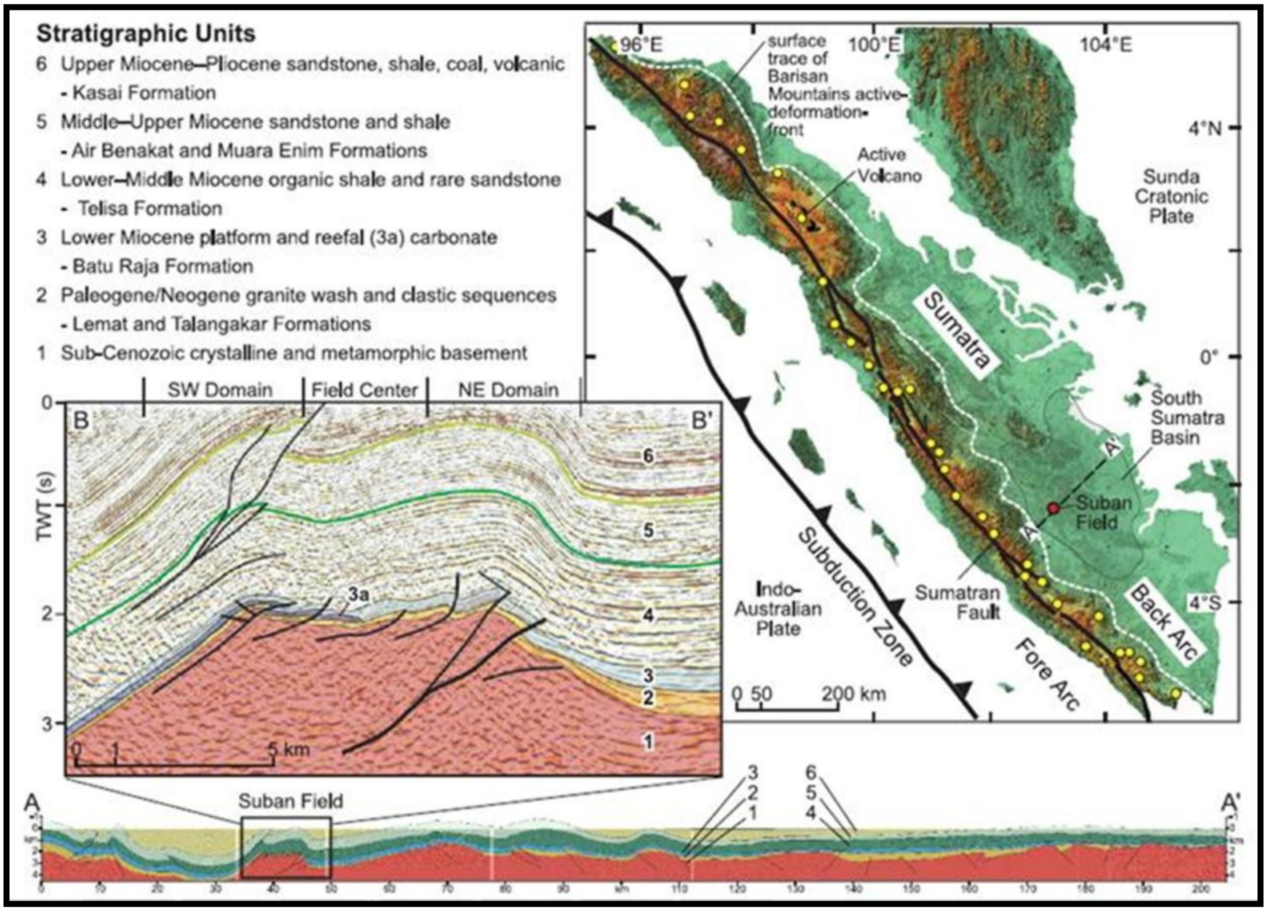
The Brown Shale is a lacustrine-formed unit, deposited in a freshwater to brackish lake system with anoxic bottom conditions. Variation in oil composition within the basin is attributed to local facies changes which reflect the distribution of productivity and paleoclimate conditions during source rock deposition that resulted in varying proportions of algal and terrigenous organic matter. The organic-rich portion of the Brown Shale is about 295 ft thick and is 6600 to 10,500 ft deep in the troughs (average depth 8,500 ft). Mean TOC for this unit throughout the basin is approximately 3.7%, reaching 7.3% at the well-exposed Karbindo coal mine, with mean 25.3 mg HC/g rock petroleum generation capacity.[5]

Two organic-rich facies occur within the Brown Shale Formation. The deep lacustrine facies consist of dark brown to black, well laminated, non-calcareous shales, containing 1 to 15% TOC that consists of Types I and II kerogen. The shallow lacustrine facies consists of red-brown laminated carbonate and terrigenous mudstones with occasional coal stringers. This unit contains average 3.4% TOC, derived from algae that resulted in oil-prone Type I kerogen.[6]

The Keruh, Kiliran, Sangkarewang, Lakat, and Kelesa Formations also can be organic rich, but these are relatively immature thermally and may not be brittle. The U. Miocene to L. Pliocene Binio Formation, part of the Petani Group, contains a sequence of medium- to light grey claystones and minor sandstones that are charged with low-CO_2 and isotopically light biogenic gas. The Binio Fm is overlain by the Late Pliocene Korinci Formation, a regressive sequence of claystones, siltstones, sandstones, and minor coal deposited under a fluvial environment.[7] The Binio and Korinci formations are not considered to be prospective for shale gas/oil development.

South Sumatra Basin. This basin is a significant conventional oil and gas producing area as well as a focus of coalbed methane exploration. The basin contains late Eocene to early Oligocene deposits of clastic sediments in transpressional pull-apart depressions. Thermal subsidence followed rifting in the late Oligocene to the early Miocene, enabling marine incursions to deposit fine-grained marine sequences in lows and reefal buildups on high-standing blocks. Continued subsidence drowned the carbonate system and caused deposition of organic-rich deep-water shales and marls that later became gas-prone hydrocarbon source rocks. Northeast-directed compression and tectonic inversion began in the mid-Miocene, Figure XXIII-4. An estimated 50-90% of the faults in the basin are potentially active and may be at risk of being triggered during large-scale hydraulic fracturing.[8]

Figure XXIII-4. Regional and Detailed Cross Sections of the South Sumatra Basin, Indonesia.



Source: Hennings et al., 2012

Petroleum source rock shales in the South Sumatra Basin include alluvial, lacustrine, and brackish-water sediments in the Lahat Formation and coals and coaly shales in the Talang Akar Formation.[9] These units reach a gross thickness of approximately 1 km. Mid-late Eocene to early Oligocene in age, the Lahat can be oil- or gas-prone depending on location.

Because of limited data, the Lahat Formation was not quantitatively assessed. The Talang Akar Formation is up to over 1 km thick in the South Palembang sub-basin, averaging 1,300 ft thick. TOC ranges from 1.7% to 8.5%, locally reaching 16%. Thermal maturity is low (R_o 0.5%) down to about 6,000 ft depth, increasing to about 0.9% R_o at a depth of 8,000 ft, averaging about 0.7% R_o at 7,000 ft.

The Miocene Muara Enim Formation of the South Sumatra Basin contains important coal and coalbed methane resources that were deposited in a coastal plain environment during an overall regressive cycle, resulting in a thick sequence of mainly clastic sandstone, siltstone, coal, and coaly shale.[10] Thermal maturity is quite low, reaching only about 0.4% to 0.45% R_o within troughs up to 4,000 ft deep. Overall, the Muara Enim Fm is a coaly and probably non-brittle non-marine deposit, too shallow and thermally immature to be favorable for shale development.

1.2 Reservoir Properties (Prospective Area)

The general location of the prospective deep troughs in the Central and South Sumatra basins is well constrained by public data but, unfortunately, not the detailed depth distribution of the shale formations.[11] However, proprietary maps developed by ARI for coalbed methane exploration in these basins provided improved control on depth and thermal maturity, indicating that about 5% of the total basin area could be depth- and thermal-prospective for shale oil. The North Sumatra Basin is not considered prospective.

Central Sumatra. The high-graded prospective area for the Brown Shale Formation in the Central Sumatra Basin is estimated at 4,700-mi^2 based on the extent of the deep troughs. Within this prospective area the Brown Shale averages 266 ft thick (net) with an average depth of 8,530 ft. Average TOC is estimated at 6.0% and is in the oil window (R_o of 0.8%). Pressure gradient is normal and the clay content is considered medium.

South Sumatra Basin. The Eocene to Oligocene Talang Akar Formation is prospective within a large 15,490-mi^2 area and estimated to have a 367-ft thick high-graded zone with average 5% TOC and 0.7% R_o. The pressure gradient is normal and the clay content is considered high.

1.3 Resource Assessment

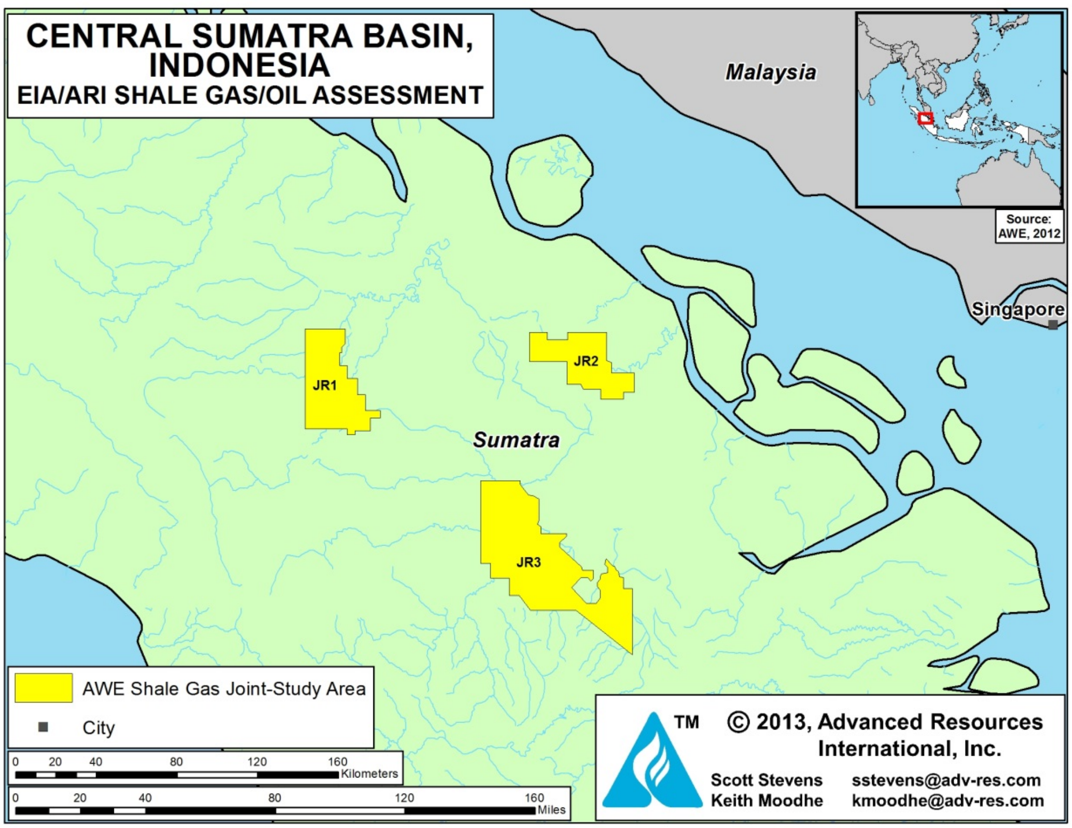
Central Sumatra Basin. Risked, technically recoverable resources from the Brown Shale are estimated at 3.3 Tcf of associated gas and 2.8 billion barrels of shale oil out of 42 Tcf and 69 billion barrels of shale gas and shale oil in-place (all figures risked). ARI considers the shale oil resource in the Central Sumatra Basin to be the most prospective shale potential in Indonesia, particularly given the extensive drilling and transportation infrastructure already present in what is the country's most important oil-producing region.

South Sumatra Basin. The Talang Akar Formation has an estimated 4.1 Tcf and 4.1 billion barrels of technically recoverable shale gas and shale oil resources, out of 68 Tcf and 136 billion barrels of shale gas and oil in-place (all figures are risked). While larger than the estimated Brown Shale oil resource in Central Sumatra, there is much less public data available on the Talang Akar.

1.4 Shale Leasing and Exploration Activity

Four shale gas joint studies totaling 5,000 km^2 in the Central Sumatra Basin were initiated by MIGAS in March 2012, Figure XXIII-5. (Note that although classified as shale gas studies, the main source rocks here actually are in the oil window.) Four companies are evaluating these blocks, including Bukit Energy Inc., AWE Limited, and New Zealand Oil & Gas (NZOG).[12] Although Indonesia does not yet have formal shale licensing regulations, these joint studies eventually could lead to Indonesia's first shale gas PSCs.

Figure XXIII-5. Location of Several Approved Shale Gas Joint-Study Areas in The Central Sumatra Basin.



Source: Modified from AWE Limited, April 2012

Calgary-based Bukit is a small private oil and gas E&P company that operates or participates in several conventional petroleum licenses in the Central and North Sumatra basins. Bukit also has applied for unconventional shale gas/oil exploration blocks in Sumatra and anticipates an award during 2013.

Earlier this year Australia-based AWE announced that they planned to make a decision about their study during Q3 2012, but to date no decision has been released.[13] New Zealand based NZOG holds conventional petroleum PSC's in the Central (Kisaran) and Northern (Bohorok) Sumatra basins, partnering with Bukit in each block, and also reports it is evaluating shale gas opportunities nearby. No shale-related drilling has been disclosed in Sumatra or anywhere in Indonesia.

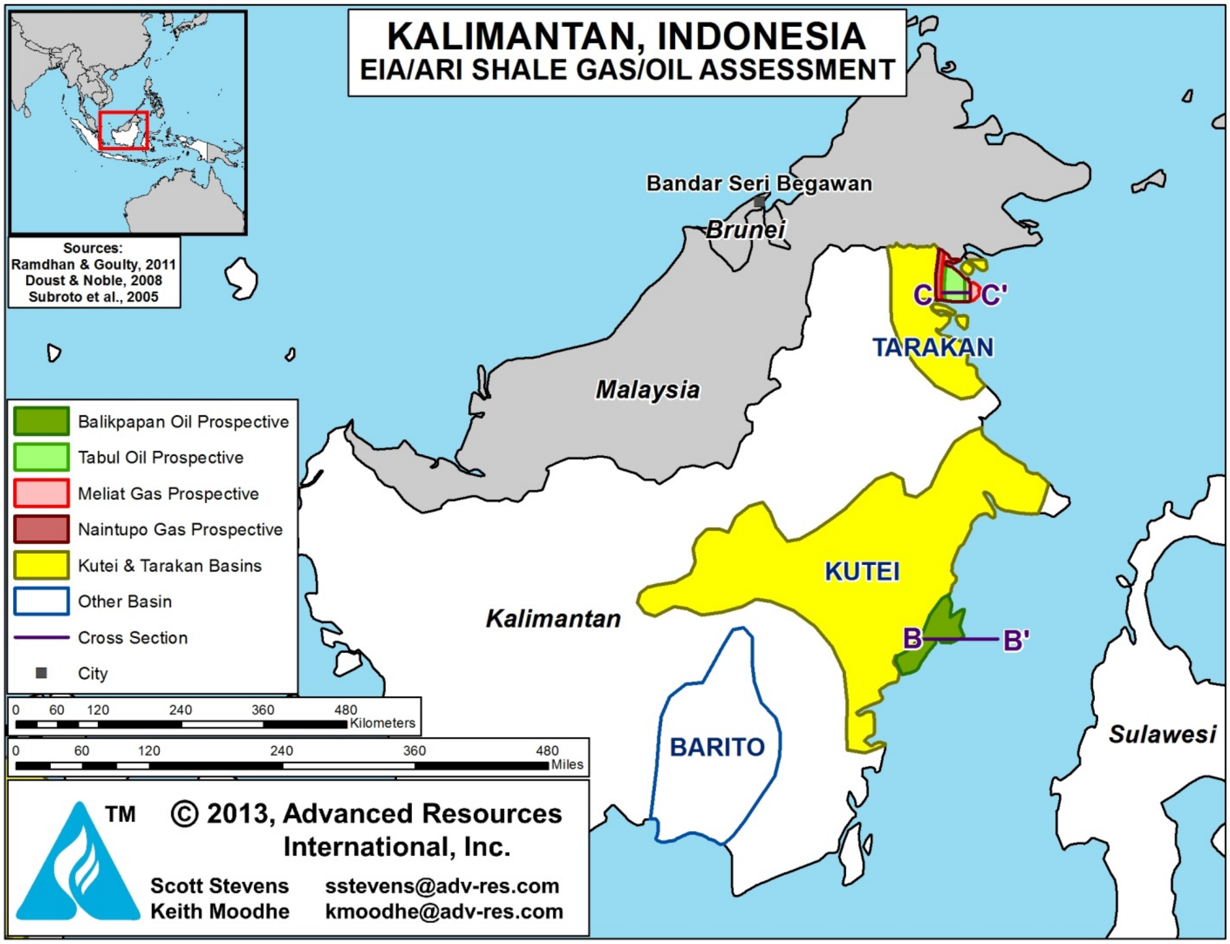
2 KUTEI AND TARAKAN BASINS

2.1 Introduction and Geologic Setting

The Kutei (or Kutai) is Indonesia's largest sedimentary basin, its 36,000-mi^2 onshore portion centered around the Mahakam Delta in eastern Kalimantan, Figure XXIII-6. The Kutei is the second largest oil and gas producing region in Indonesia after Central Sumatra as well as Indonesia's largest gas producer. The Bontang LNG export facility on the coast is the main gas market within this lightly populated region, with a capacity of 22.5 million t/yr. However, Bontang has been operating at about 16 million t/yr due to declining conventional gas production in East Kalimantan.

The 7,510-mi^2 Tarakan Basin, located north up the coast in northeast Kalimantan, contains a similar sedimentary sequence as the Kutei Basin. Fluvio-deltaic to shallow marine shales of Late Eocene age are overlain by Oligocene to Early Miocene open marine carbonate platforms. Finally Mid-Miocene to Quaternary fluvio-deltaic sandstone, shales, and coals were deposited. The entire sequence has been gently deformed with NE-SW trending folds. The main source rocks are Mid-Late Miocene coals and coaly shales of the Tabul Formation, while fluvial-deltaic sandstones of the Tabul and Plio-Pleistocene Tarakan Formation are the main conventional reservoirs.

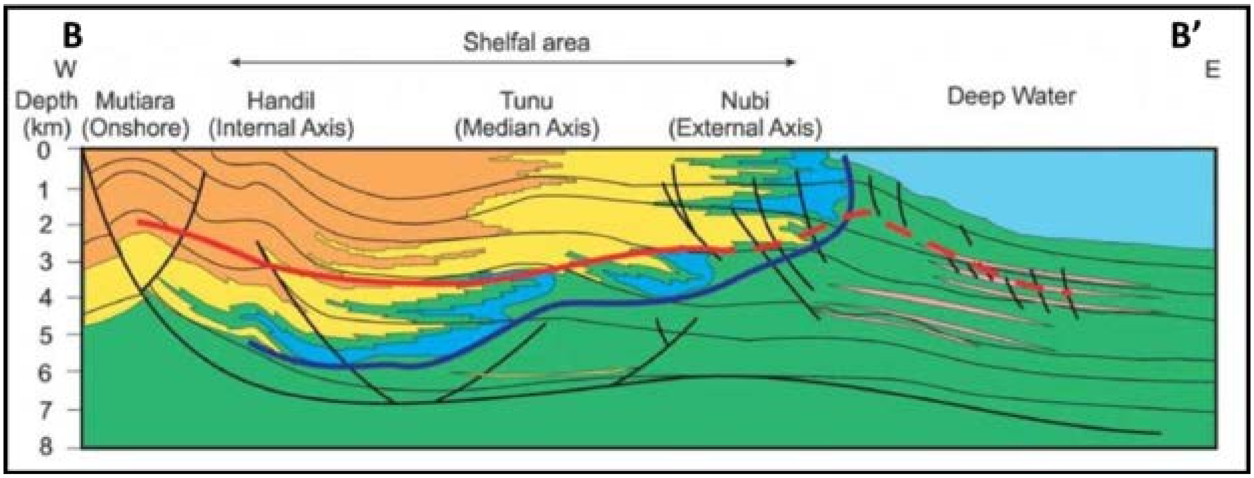
Figure XXIII-6. Prospective Shale Areas in the Kutei and Tarakan Basins, Eastern Kalimantan.



Source: ARI, 2013

The Kutei Basin is bounded by the Mangkaliat Platform on the north, the Kuching High on the west, and the Paternoster High on the south. It developed by rifting and syn-rift deposition during the mid-late Eocene. Deep marine sediments were deposited in the basin center during the late Eocene to late Oligocene, with a carbonate platform developed along the basin edge. Figure XXIII-7 shows the general structure of the Kutei Basin and illustrates that these marine mudrocks are mostly deeper than 5 km in the onshore basin extent.

Figure XXIII-7. Generalized East-West Trending Structural Cross-Section Across the Kutei Basin, Showing Marine Mudrocks Mostly Deeper than 5 Km in the Onshore Areas.



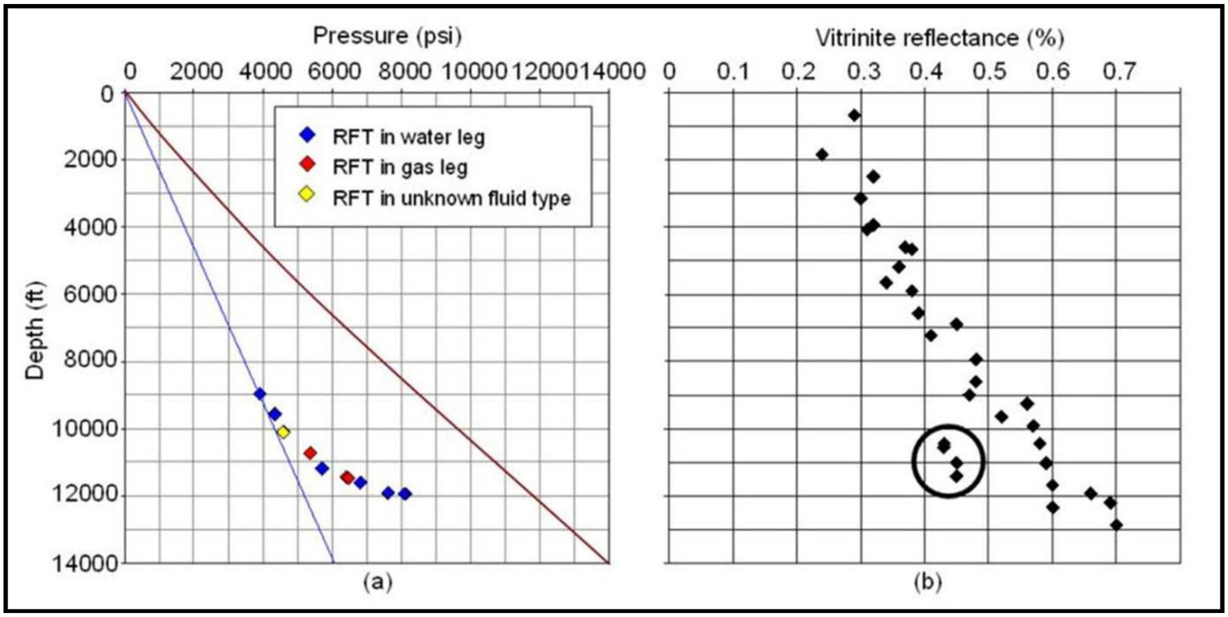
Source: Ramdhan and Gouty, 2011

The main source rocks recognized in the Kutei Basin are Mid-Late Miocene mudstones and carbonaceous shales, with essentially all of the conventional oil and gas production sourced from these shallower Neogene fluvio-deltaic deposits. These source rocks also are the principal shale gas/oil exploration targets in the basin. Prograding deposition during the early Miocene formed deltaic sediments, which are rich in Type III organic matter in coal seams and coaly mudstones. Thermal maturity of this sequence in the deeper troughs is oil-prone, ranging from 0.6% to 0.9% R_o.[14]

The mostly deltaic Miocene shales of the Balikpapan Group in the Kutei Basin are characterized by a depositional environment rich in land-plant material and containing Type III kerogen.[15] TOC ranges from 2% to 6% (average 4%) but some intervals have over 20% TOC. The interbedded shale, sand, and coal sequence is over 3,000 feet thick in many areas. Depth to the top of the oil generative zone (0.7% R_o) averages 9,000 feet in the onshore Kutei Basin, while Miocene rocks become overmature for gas below 19,000 ft depth. Shale oil potential appears to be largely confined to the eastern Kalimantan coast and productive Mahakam Delta.

Structural deformation started during the middle Miocene, forming steep north-south trending anticlines with more gentle synclines. Rapid deposition followed by basin unloading during the Neogene resulted in significant overpressure, caused by gas generation and water being trapped in lithifying sandstones due to interbedded mudstone seals. Overpressuring, ranging up to more than twice hydrostatic levels (1.0 psi/ft), is present throughout the coastal portion of the Kutei Basin starting below a depth of about 7,000 ft and accelerating markedly below about 12,000 ft, Figure XXIII-8.[16] The average surface temperature in the Kutei Basin is 30°C and the average geothermal gradient is about 30°C/km.

Figure XXIII-8. Pressure Gradients in the Kutei Basin Can Reach 1.0 psi/ft Below Depths of About 12,000 ft. Thermal Maturity is Oil-Prone to Immature, with a Very Low Ro/Depth Gradient.



Source: Ramdhan and Gouty, 2011

Further north in the Tarakan Basin, the basin contains Eocene to Miocene deep marine deposits overlain by mostly non-marine clastic sediments of Miocene and younger age that were deposited under deltaic conditions. The principal source rock is the Late Miocene Tabul Formation, along with the Early Miocene Naintupo and Middle Miocene Meliat formations.[17] Unfortunately, these three source rocks are coal-rich deltaic deposits that are considered less prospective for shale gas exploration.

The Naintupo contains deltaic sequences of shale with fair to good organic carbon content, ranging from 1.6% to 12.1% (average 5%). Kerogen is mainly Type III along with some Type II. Well penetrations indicate the Naintupo Fm is 1,000 to 1,500 feet thick (average 1,250 ft thick). Depth ranges from 6,000 ft to over 16,000 feet (average 11,500 ft). Well data and burial history modeling indicate the Naintupo Fm is in the dry gas window (R_o 1.3% to 2.0%, averaging 1.5%). Local structural uplifts may elevate the Naintupo to shallower and thermally less mature levels, where it could be oil prone.

The overlying Middle Miocene Meliat Formation includes shales and claystones along with sandstone, coal, and dolomite layers. Total organic carbon of the deltaic clays ranges from 0.7% to 6.5% (average 3% TOC), mainly Type III kerogen. The Meliat Formation ranges from 3,300 to 6,600 ft thick (average 5,000). Depth varies from 3,300 feet on basin highs to over 13,000 feet in the troughs (average depth 10,000 ft). Thermal history analysis indicates the Meliat has wet gas maturity (1.0 to 1.3% R_o).

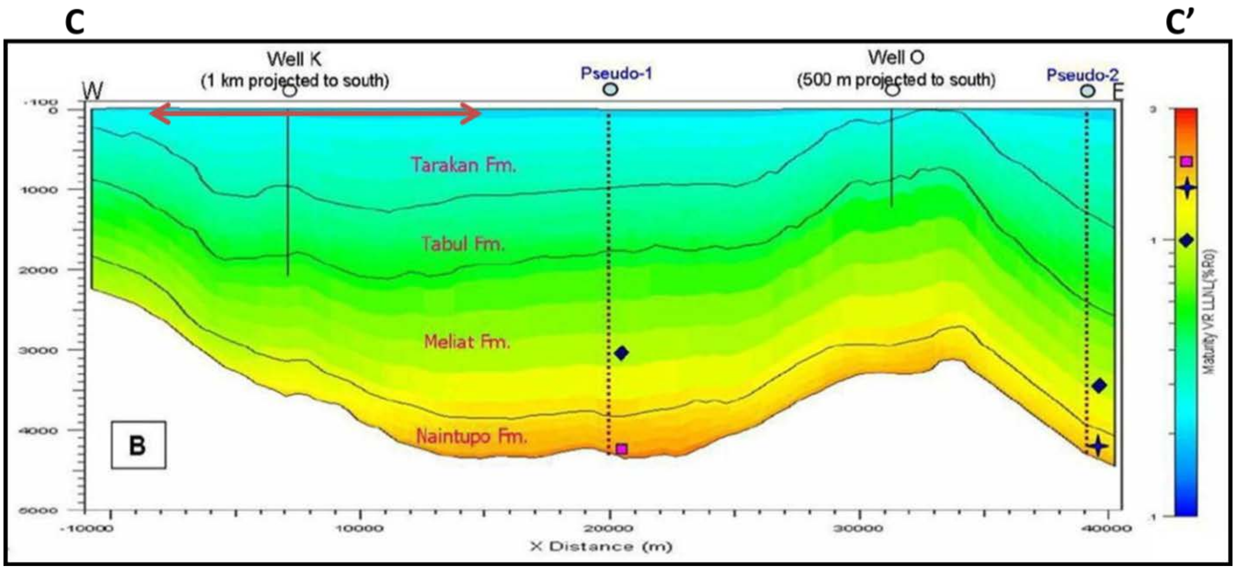
The predominant source rocks of the Tarakan Basin are shales of the Late Miocene Tabul Formation, again a non-marine, deltaic sequence. TOC ranges from 0.5% to 4%, higher in coal-rich sequences. Both lithologies contain mixtures of Type II and III kerogen. The Tabul Formation averages about 3,300 feet thick, of which approximately 1,500 feet is organic-rich, while depth ranges from 3,300 feet to 6,600 feet. Well data and modeling indicate vitrinite reflectance averages 0.7%, in the oil window.

2.2 Reservoir Properties (Prospective Area)

Kutei Basin. Lacustrine mudstones and carbonaceous shales in the Mid-Late Miocene Balikpapan Fm are estimated to be prospective within a 1,630-mi^2 area near the Mahakam Delta, based on limited cross-section data and augmented by ARI-proprietary coalbed methane mapping. These shales are oil-prone (R_o 0.7%) even at average 9,000 ft depth within this thermally immature basin. Net thickness is estimated at 450 ft, with average 4.0% TOC. Reservoir pressure is elevated above hydrostatic.

Tarakan Basin. Three shale-bearing targets are present at varying thermal maturity (oil- to gas-prone). Depth was estimated based on limited cross-section data and proprietary coalbed methane maps developed by ARI. Figure XXIII-9 is a west-east trending structural cross-section across the onshore north-central Tarakan Basin, showing generally simple structural conditions. The L. Miocene Tabul Fm averages 600 ft thick (net) and 5,000 ft deep within its 510-mi^2 prospective area, and has 3.0% average TOC that is in the oil window (0.7% R_o). The Meliat Formation occurs at 10,000-ft average depth and is mostly in the wet gas window (R_o 1.15%), while the Naintupo Formation averages 11,500 ft deep and is dry-gas-prone (R_o 1.5%).

Figure XXIII-9. West-East Trending Structural Cross-section Across the Onshore North-Central Tarakan Basin, Showing Generally Simple Structural Conditions. Source Rocks of the Tabul Formation Occur at Prospective Depths of 1 to 2 Km with Oil-prone R_o of 0.6% to 0.7%. Vertical Exaggeration = 3x.



Source: Subroto et al., 2005

2.3 Resource Assessment

Kutei Basin. Based on the geologic conditions described above, the Balikpapan Fm in the Kutei Basin has an estimated 1.3 Tcf and 0.7 billion barrels of risked, technically recoverable shale gas and shale oil resources, out of risked shale gas and oil in-place of 16 Tcf and 17 billion barrels. Note that this unit is coaly and may not be brittle.

Tarakan Basin. The oil-prone Tabul Formation has an estimated 0.2 Tcf and 0.3 billion barrels of technically recoverable shale gas and shale oil resources, out of 3.8 Tcf and 10.6 billion barrels of shale gas and shale oil in-place (risked). The gas-prone Naintupo and Meliat formations have an estimated 5 and 4 Tcf of risked, technically recoverable shale gas resources out of 35 and 25 Tcf of risked shale gas in-place, respectively. In addition, the Meliat Fm has a small volume (0.04 billion barrels) of technically recoverable condensate from shale.

2.4 Activity

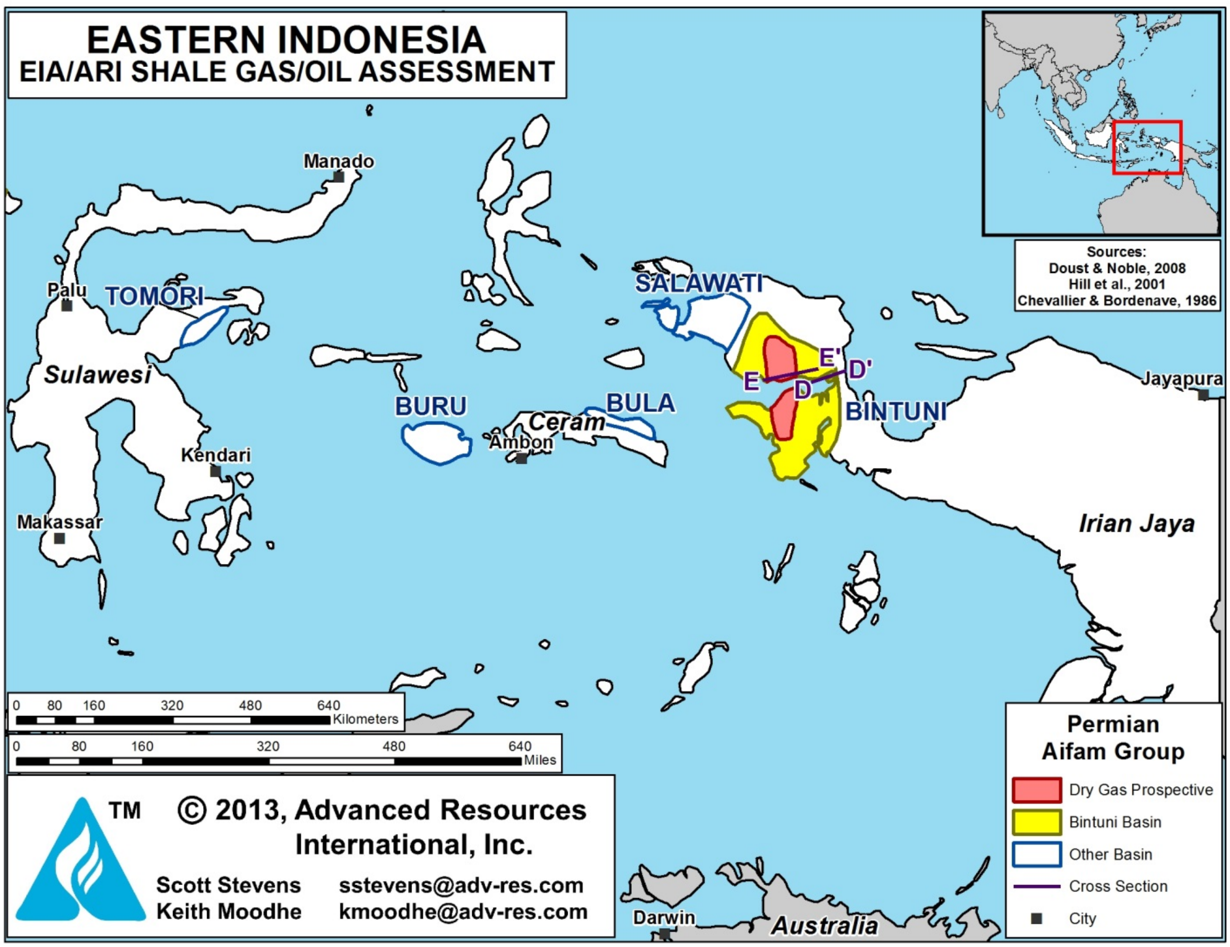
No shale gas/oil leasing or exploration activity has been reported in the Kutei or Tarakan basins.

3 EASTERN INDONESIA BASINS

3.1 Introduction and Geologic Settings

Eastern Indonesian sedimentary basins are markedly different from those in western Indonesia, with significantly older deposits generally reflecting a more marine character.[18] Sulawesi and the islands of eastern Indonesia have some of the country's only marine-deposited (non-lacustrine) shale. Thermal maturity is higher too, predominately in the dry gas window. These basins tend to be small and tectonically complex, thus we group them into a single Eastern Indonesian region for analysis, Figure XXIII-10.

Figure XXIII-10. Prospective Shale Areas in Eastern Indonesia.



Source: ARI, 2013

The Salawati and Bintuni basins in the Bird's Head region of western West Papua contain thick source rocks of Permian age that are rich in Type III coals with some contribution from overmature Jurassic marine shales containing Types II/III kerogen. However, the main source rock is Late Miocene marine shales and marlstones of the Kais and Klasafet formations, which contain Types II/III kerogen. The Klasafet is overlain by thick regressive shales and sandstones of the Plio-Pleistocene Klasaman Formation.[19] Marine marlstones and shales of the Klasaman and Kais/Klasafet formations are potential shale oil targets. They contain mainly Type II/III kerogen, albeit with relatively low TOC of 0.3% to 1.1%.[20] The Klasafet is 1,000 to over 2,000 feet thick in deep troughs, with depth ranging from 5,000 ft in the east to over 12,000 ft in the Sele Strait and Salawati Island to the north and west. Thermal maturity reaches wet gas levels (1.0% R_o) at a depth of 10,000 feet.[21]

The Klasaman Formation contains organic-rich shales with average 1.7% TOC (range 0.6% to 2.3%), mainly Type II and III kerogen. It ranges from 3,000 to 5,000 ft thick in the Salawati Basin, about 15 to 20% of which contains elevated TOC above 1%. Depth ranges from less than 3,000 ft to more than 10,000 ft. Biomarker data indicate the Klasaman sourced oil seeps in the north, where calculated vitrinite reflectance values approach 0.7% R_o and up to 1.0% in deeper parts of the Salawati Basin.

Bintuni Basin. The Bintuni Basin, located in the eastern side of the Bird's Head region, appears to have the simplest structural conditions and best shale prospectivity in the eastern Indonesia region. The Bintuni Basin is bordered to the east by the Lengguru Fold/Thrust Belt. The stratigraphic section resembles that of the Salawati Basin, with preserved Paleozoic, Mesozoic, and Tertiary units. Basement consists of Silurian and Devonian metamorphic rocks. These are unconformably overlain by Carboniferous and Upper Permian clastic sediments and shales of shallow marine origin (Aifam Group). Next are interbedded fluvial shales and sandstones of the Triassic-Jurassic Tipuma Formation and Cretaceous deltaic shales of the Kembelangen Formation.

Limited oil production from New Guinea Group limestones (Kais/Klasafet equivalent) occurred during the 1930's. In the 1990's ARCO Indonesia discovered the Wiriagar Deep gas field, which produces from Middle Jurassic "Roabiba" and "Aalenian" sandstone reservoirs and is exported via the Tangguh LNG facility.[22] Some source rock studies discount the Klasafet shales, since they are typically immature and low in organic content, mostly under 1% TOC.[23]

More important are the Permian and Jurassic sediments, analyzed below for shale oil potential. The Aifat and Ainim formations are the respective lower and upper members of the Permian Aifam Group and considered to be the main hydrocarbon generating rocks in the Bintuni. The older Aifat consists of black marine calcareous shales. Limited data show relatively modest TOC of 1.0% to 1.8%, averaging 1.5%. Gross thickness can exceed 3,500 feet, while depth can exceed 12,000 ft in the Bintuni Basin.

The overlying Ainim Formation also contains calcareous shales, although deposited in a more deltaic setting. Source rock thickness is approximately 2,400 feet. Depth averages about 10,000 feet. This unit contains adequate organic matter with abundant coal seams. Hydrogen index is over 300 mg HC/g. Vitrinite reflectance is sharply lower (0.66% R_o) in the overlying Ainim compared with the older Aifat, indicating an unconformity within the Permian.

In addition to the Permian, the Jurassic Tipuma Formation may be a potential hydrocarbon source. The Tipuma contains sandstones and carbonaceous shales. Analyses of the shallow marine shales indicate maximum TOC of 4.5 and 7.6%, mainly humic kerogen. The Tipuma ranges from 4,000 to nearly 8,000 feet deep. Near the Bintuni Basin's western limit, the Jurassic shales are in the immature-mature oil window, at about 0.6% R_o.

The Tomori Basin of eastern Sulawesi shares many similarities with the Salawati/Bintuni basins, from which it was transported along strike-slip faults. The Tomori is a foreland basin within the greater Banggai-Sula micro-continent, a fold-thrust system that developed following Pliocene collision and thrusting of continental crust over ophiolitic material. Oil and gas exploration began during the 1980's, resulting in the discovery of the Senoro "giant" gas field in 2001.[24] Oil and gas are produced from fractured limestones of the Lower Miocene, sourced by shales within the contemporaneous Tomori Formation, which is similar to the Klasafet Fm.

The Lower Miocene Tomori Fm, ranging from 500 to 1,000 ft thick, also is a potential target for shale exploration. It comprises marine and carbonaceous shale along with some limestone and coal, with the upper section typically more deltaic in origin. TOC is fairly high, averaging 2 to 4% and consisting of Type II/III kerogen. The lower marine section contains higher Type II kerogen but TOC generally is less than 1%. The Tomori Fm attains 0.5% R_o at a depth of 7,200 ft, becoming gas prone (> 1.0% R_o) below a depth of about 11,300 ft.[25]

Finally, the Bula Basin in northeast Seram island contains Mesozoic to Mid-Tertiary open marine pelagic and oceanic deposits, including clays, limestones, and thin sandstones. This assemblage later collided with Irian Jaya and the Australian continental shelf.26 Conventional oil, sourced from Triassic-Jurassic marine carbonate Type II mudstone source rocks, is produced from fractured Jurassic limestone as well as from Plio-Pleistocene marginal marine sandstones and limestones.[27]

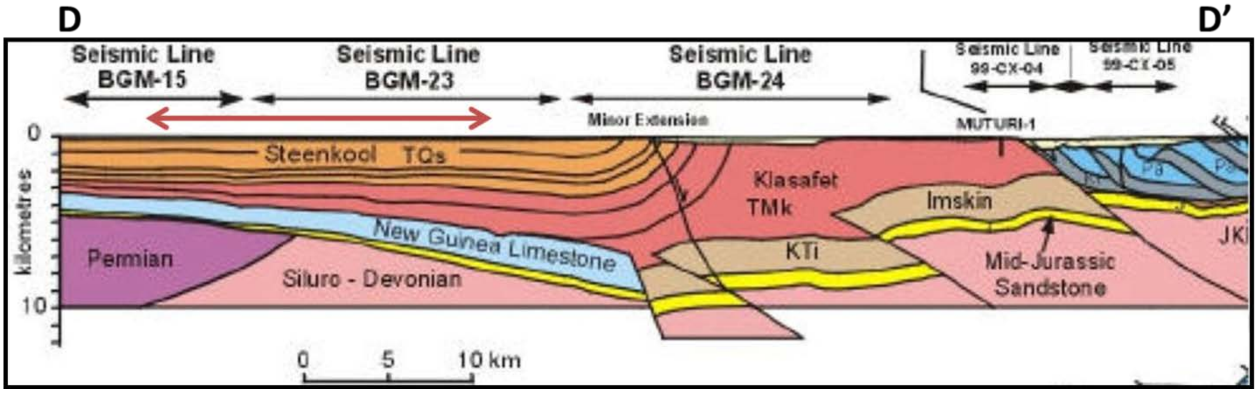
3.2 Reservoir Properties (Prospective Area)

Only the Bintuni Basin had sufficient data to evaluate shale gas/oil reservoir properties and resources, while the other areas (Salawati, Tomori, Bula) lacked adequate data for detailed analysis.

Bintuni Basin. Figure XXIII-1 shows a WSW-ENE trending structural cross-section across the east-central Bintuni Basin.[28] According to this interpretation, the Permian shales here are too deep but marine shales within the Klasafet Fm dip gently to the east and are at prospective depths of 2.5 to 5 km, although as noted above these appear to have low TOC. Further east this unit is structurally deformed by thrusting and not considered prospective. The prospective Klasafet shale area is inferred to be a north-south elongated rectangle just west of the Lengguru Fold and Thrust belt, but this unit was not assessed due to its low TOC (<1%).

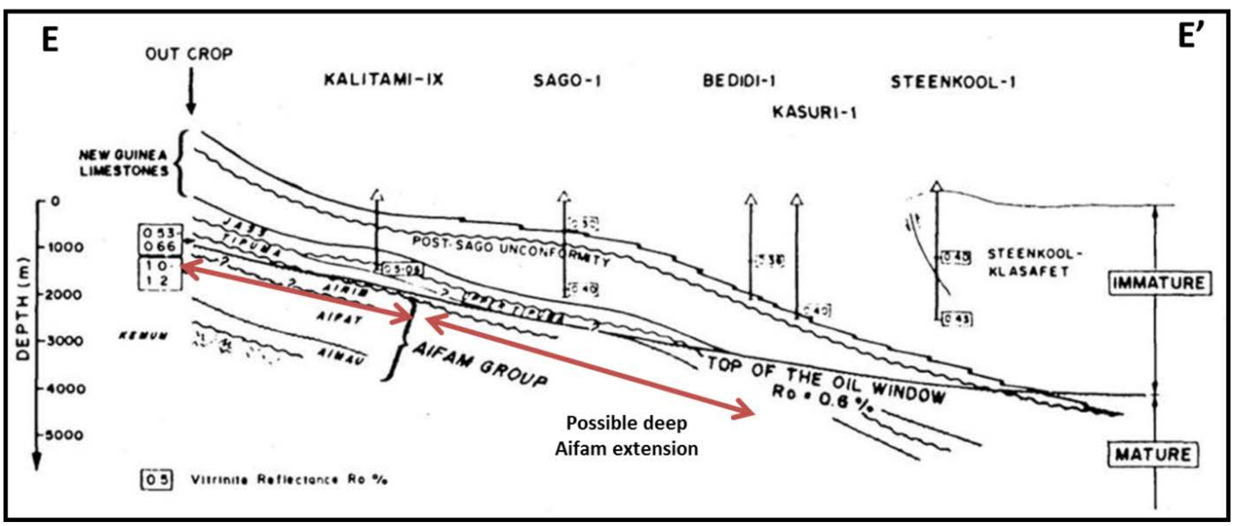
Figure XXIII-12 shows a west-east trending structural cross-section across the west-central Bintuni Basin. Here the organic-rich and prospective Permian Aifam Group (Aifat and Ainim formations) is about 1.0 to 3.5 km deep (possibly deeper further to the east), structurally simple, and within the volatile oil to wet gas windows (R_o of 1.0% to 1.2%). The prospective Aifam Group shale region is assumed to be a north-south elongated rectangle in the west-central Bintuni Basin.

Figure XXIII-11. Generalized WSW-ENE Trending Structural Cross-section Across the Bintuni Basin, Showing Marine Shales in the Klasafet Fm Dipping Gently to the East at Prospective Depths of 2.5 to 5 Km. Further East this Unit is Structurally Deformed and Not Prospective.



Source: Hill et al., 2001

Figure XXIII-12. West-east Structural Cross-section Across West-central Bintuni Basin. Here the Organic-rich and Prospective Permian Aifam Group (Aifat and Ainim formations) is about 1.0 to 3.5 Km Deep, Structurally Simple, and Within the Volatile Oil to Wet Gas Windows (R_o of 1.0% to 1.2%).



Source: Chevalier et al., 1986

3.3 Resource Assessment

Bintuni Basin. The prospective areas of the Permian Aifam Group has an estimated 29 Tcf of technically recoverable shale gas resources out of 114 Tcf of gas in-place (both risked), as defined by the R_o contours of 1.2% to 1.8%. This marine-deposited unit could be the best shale gas target in Indonesia, although its location is relatively remote from market and services.

3.4 Shale Leasing and Exploration Activity

No shale gas/oil leasing or exploration activity has been reported in eastern Indonesia.

4 OTHER BASINS

Indonesia's other onshore sedimentary basins appear to have limited potential for shale gas/oil development. These areas contain mainly non-marine sequences of sandstone, siltstone, coal, and coaly shale that are not considered stable and brittle enough for horizontal frac shale well completions.

- Bengkulu Basin**.** Located in southwest Sumatra across the Barisan Mountains from the South Sumatra Basin, this relatively small and structurally deformed fore-arc basin contains predominantly non-marine clastic and sedimentary rocks of Eocene through Pleistocene age. Geochemical analyses have identified the Mid-Late Miocene Lemau Formation as a potential source rock. This unit consists of mudstone, calcareous mudstone, coal seams, sandstone, and conglomerate deposited in a mainly shallow marine environment that transitioned into mangrove and freshwater environments.[29] Intense faulting, steep structural dips, low thermal maturity (R_o averages 0.40%), and coaly non-brittle lithology all appear to make the Bengkulu Basin unsuitable for shale gas/oil development.

- Ombilin Basin**.** This small non-producing basin is located in west-central Sumatra along the eastern side of the Barisan Mountains. It is a transpressional pull-apart basin that developed during the Eocene to Middle Oligocene and was later deformed into tightly spaced folds trending northwest-southeast. The basal Eocene Brani and Oligocene Sangkarewang formations were deposited in lacustrine rift settings. This later evolved into fluvial deposits of the Late Oligocene Sawahtambang Formation, followed by the marine Miocene Ombilin Formation which resulted from a global sea level rise and transgression.

  Several shallow coal mines are in operation along the edge of the Ombilin Basin, but only a few conventional oil & gas exploration wells have been drilled. These encountered conventional sandstone reservoirs containing natural gas with high levels of

CO_2 (50-90%). Geochemical analyses indicate that shales within the Sangkarewang, Sawahlunto, and Ombilin formations are the best source rocks in the basin. These units contain Type III kerogen that mostly has reached the oil window (T_{max} 435-447° C).[30] Overall, the complex structure, high CO_2 content, and non-brittle nature of the Ombilin Basin shales appears to make them poorly suited for shale gas/oil development.

- The Northwest Java Basin northeast of Jakarta is one of the larger of the small graben structures on Java Island. The Jatibarang sub-basin, the onshore extension of the larger Northwest Java Basin, formed by rifting during the Eocene when volcaniclastics, tuffs and interbedded lacustrine shales were deposited.[31] Subsidence continued into the Late Oligocene and Early Miocene, forming a sequence of shale, coal, and sandstones deposited in fluvio-deltaic, coastal, and shallow marine environments. Deposition evolved to mainly carbonate during the Middle Miocene. By Late Miocene to Quaternary time subsidence diminished, with deposition of regressive clastics and platform carbonates.

  Miocene sandstone is the primary conventional oil and gas reservoir in the Jatibarang Basin, sourced mainly by carbonaceous shale and coal of the Late Oligocene Upper Talang Akar Formation. Organic material consists mainly of Type II and III kerogen. Total organic carbon (TOC) reaches 40-70% in coal, while the shales also can be fairly organic-rich (0.5 to 9%).[32] The inter-bedded shale-clastic sequence can be over 1,000 ft thick, comprising coal seams, limestone, and sandstone. Depth to the Talang Akar is about 7,500 to 11,500 ft. These non-marine to marginal marine source rocks can be oil and gas prone, becoming increasingly more mature offshore. Shales in the Jatibarang Basin are coaly and unlikely to be brittle enough for hydraulic fracturing in horizontal wells.

- The Barito Basin in southern Kalimantan is a large (70,000 km^2 onshore extent), structurally simple basin containing up to 6 km of Eocene and younger sedimentary rocks which unconformably overlie the igneous and metamorphic basement. Minor conventional oil production (of 30-40° API gravity) occurs in the northern Barito, but most of the basin is non-productive. Recent coalbed methane exploration is underway in the southern Barito.

  The Middle Eocene to late Early Oligocene Tanjung Formation is the most important petroleum source rock, consisting of fluvial and marginal marine clastic strata, including thin coal deposits.[33] The formation is over 3,300 ft thick in Tanjung Field in the north.[34] High-TOC shale and marl is concentrated in its upper section, which reaches 2,400 ft thick in the deep southern Barito Basin.[35] Depth to the Tanjung ranges from 3,000 to 12,000 ft, averaging about 6,000 ft deep in the shallow conventional anticlinal fields. TOC is uncertain. The Tanjung has entered the oil window throughout much of the basin, reaching dry gas maturity in the deepest regions. However, the shales within the Tanjung Fm are coaly and probably not brittle.

Overlying the Tanjung Fm are shallow carbonate rocks of the Late Oligocene to Early Miocene Berai Formation, which record a regional marine transgression. Above these, the overlying Plio-Pleistocene Warukin Formation contains marginal marine to fluvial-deltaic sedimentary rocks, including thick, low-rank, sub-bituminous coal deposits. The lack of significant conventional oil and gas production in the Barito Basin, apart from its northernmost edge, is considered a negative factor and makes this basin unattractive for shale gas/oil exploration.

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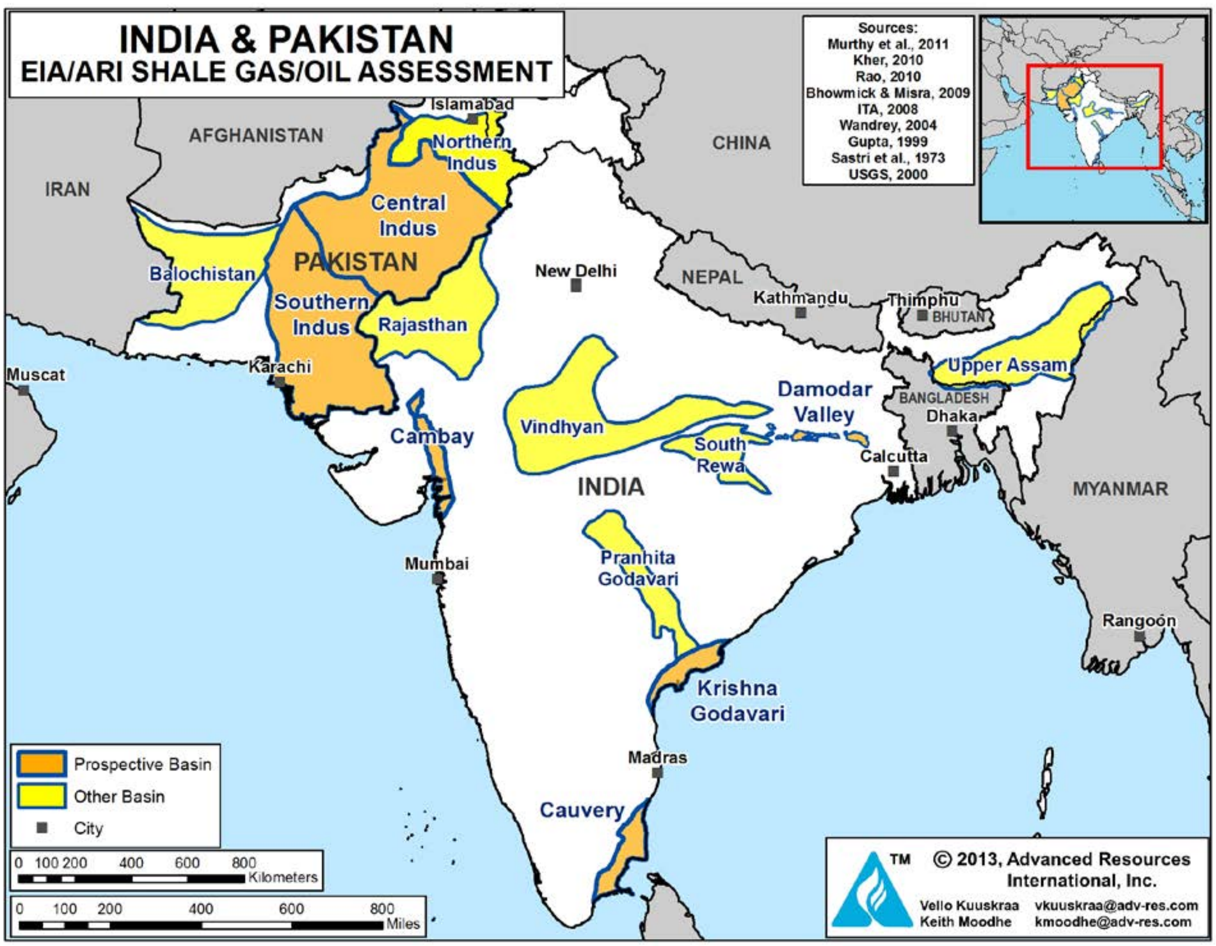
XXIV. INDIA/PAKISTAN

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 ($7,900\ mi^2$)			Krishna-Godavari ($7,800\ mi^2$)			Cauvery ($9,100\ mi^2$)	Damodar Valley ($2,270\ mi^2$)
	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	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/mi^2)		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 ($169,000\ mi^2$)			
	Shale Formation		Sembar			Ranikot
	Geologic Age		L. Cretaceous			Paleocene
	Depositional Environment		Marine			Marine
Physical Extent	Prospective Area (mi^2)		26,700	25,560	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/mi^2)		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

	Basin/Gross Area		Cambay ($7,900\ mi^2$)		Krishna-Godavari ($7,800\ mi^2$)		Cauvery ($9,100\ mi^2$)	Damodar Valley ($2,270\ mi^2$)
Basic Data	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

	Basin/Gross Area		Lower Indus ($169,000\ mi^2$)		
Basic Data	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

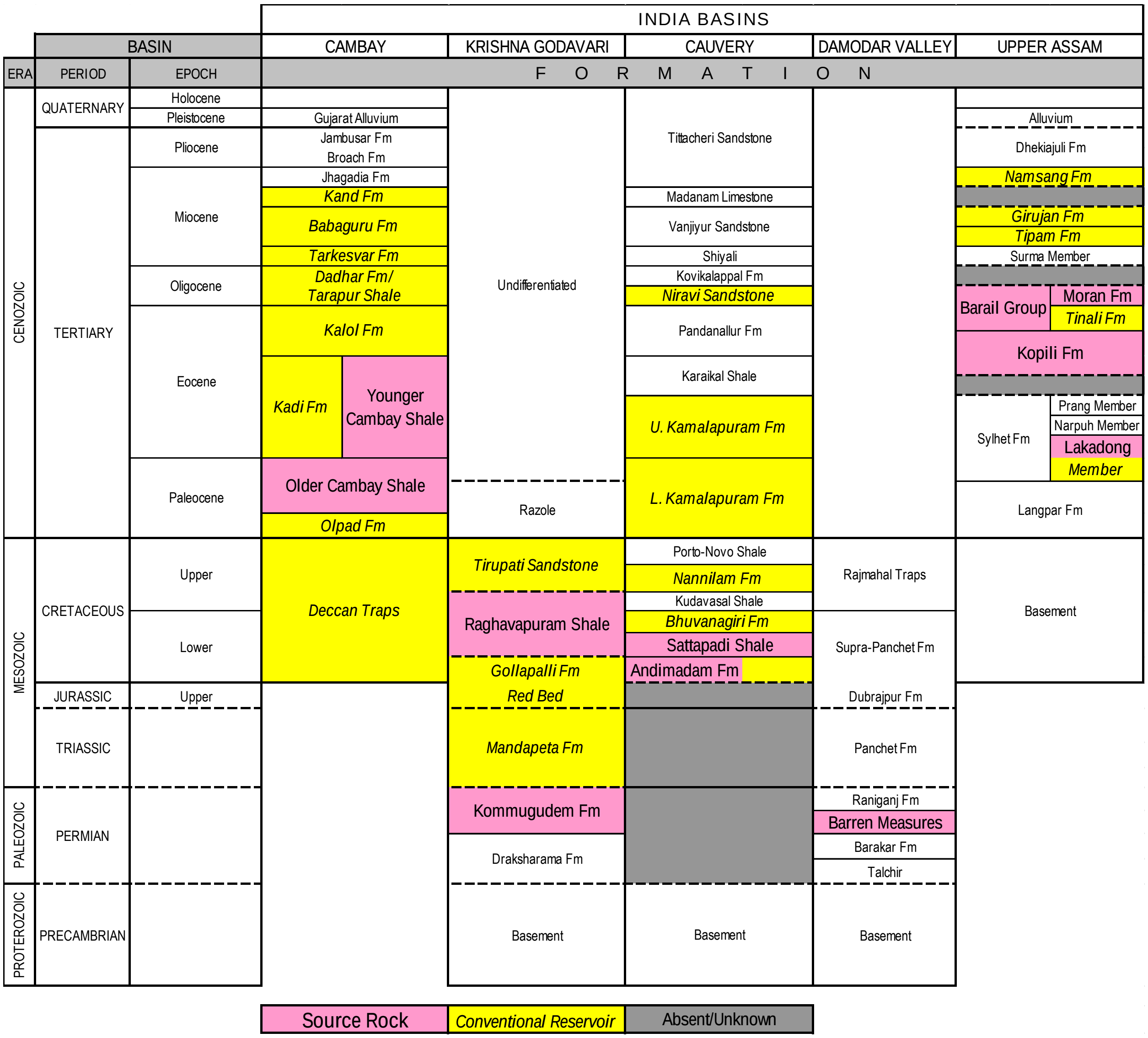


Figure XXIV-3. Stratigraphic Column for Pakistan

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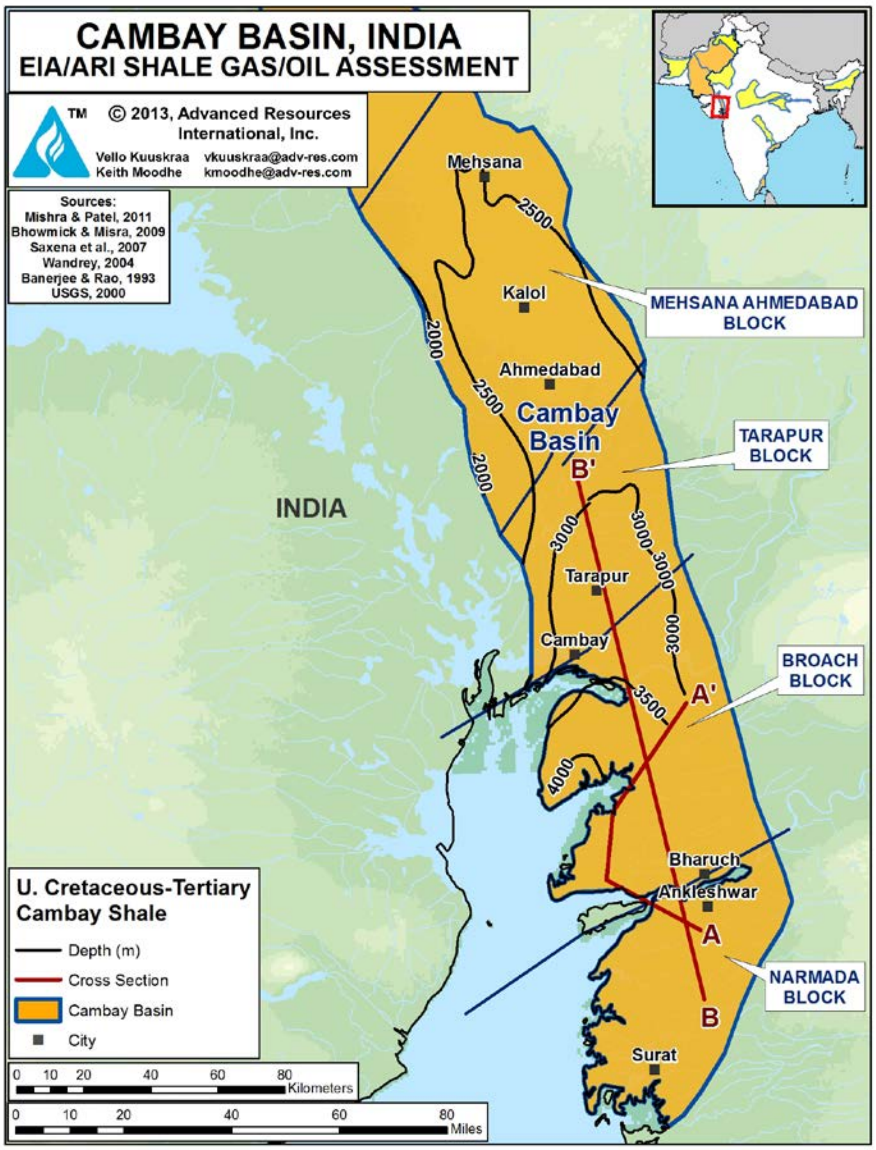
1. CAMBAY BASIN, INDIA

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.

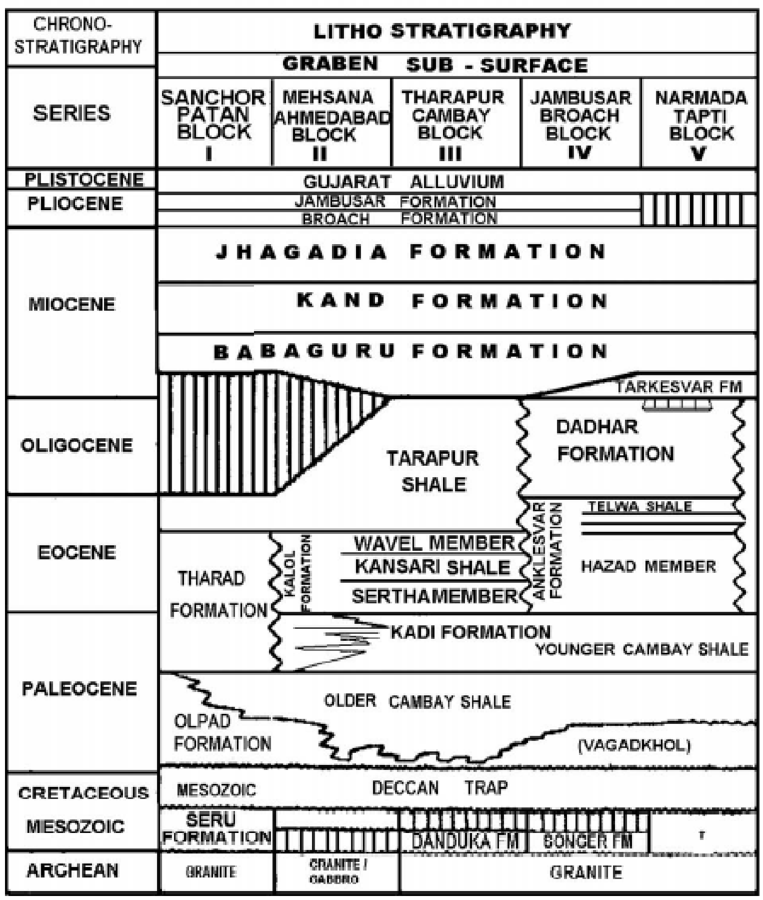
Figure XXIV-4. Depth of Cambay Black Shale, Cambay Basin



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]

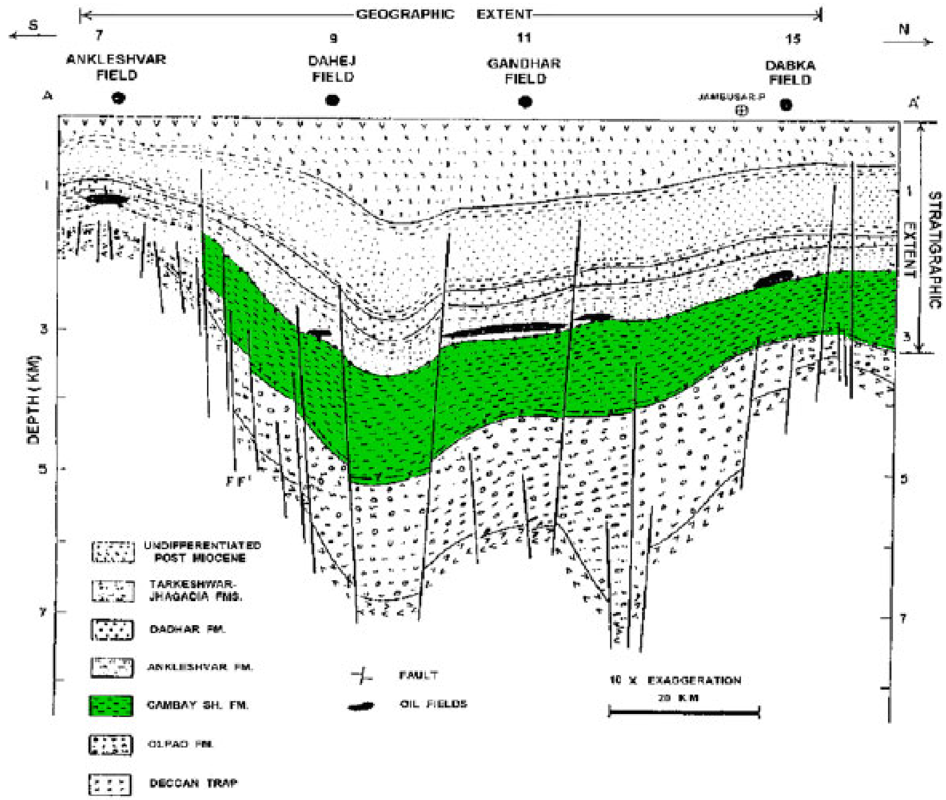
The Deccan Trap, composed of horizontal lava flows, forms the basement of the Cambay Basin. Above the Deccan Trap, separated by the Olpad Formation, is the Late Paleocene and Early Eocene Cambay Black Shale, Figure XXIV-5.[3] The Cambay Black Shale represents the marine transgressive episode in the basin. 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.



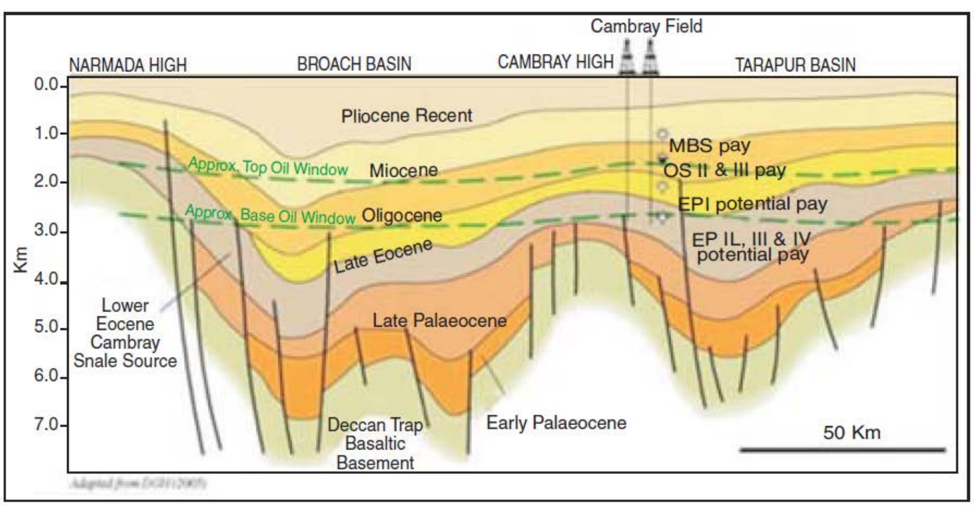
Source: Silvan, 2008

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

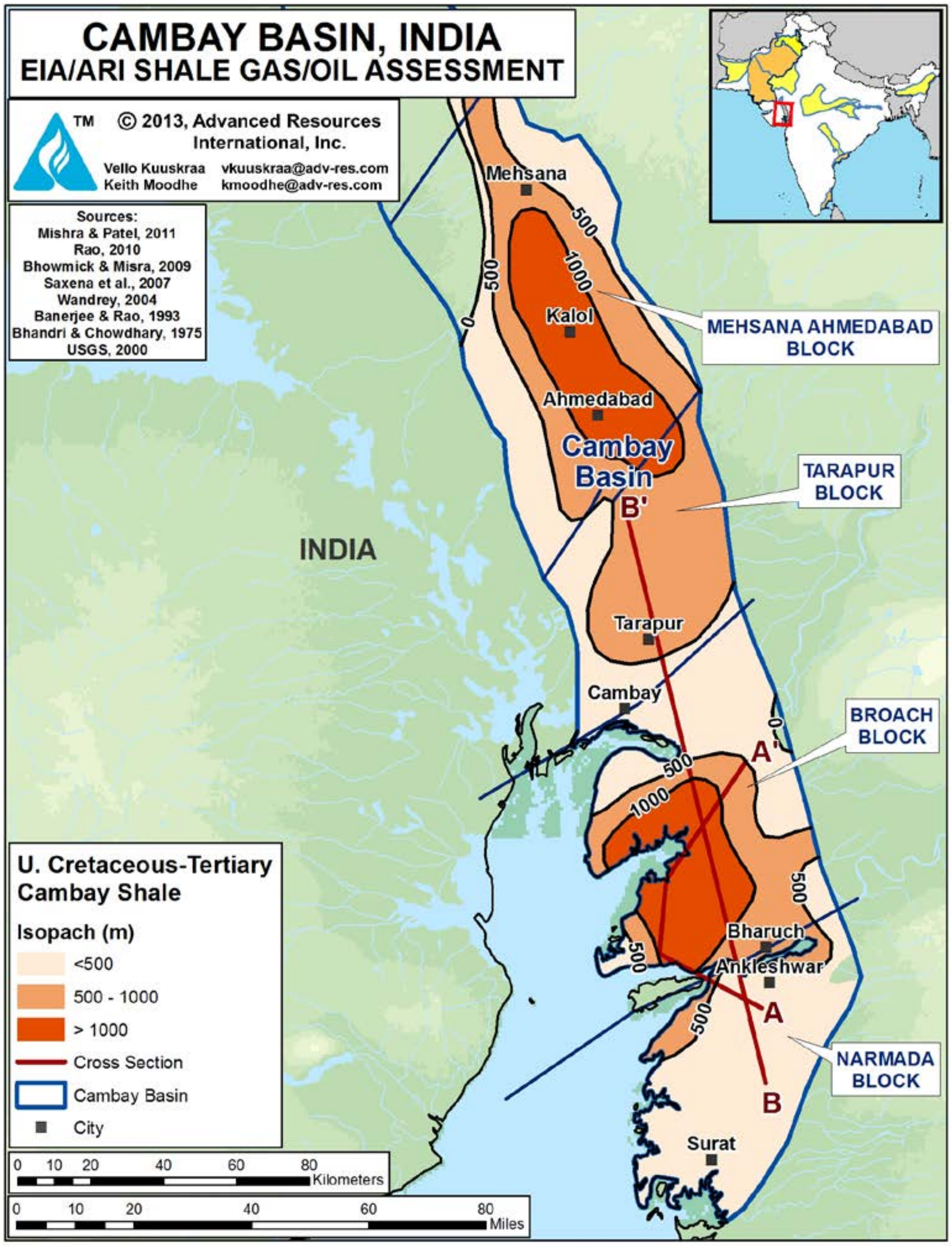


Figure XXIV-9. Organic Content of Cambay "Black Shale", Cambay Basin

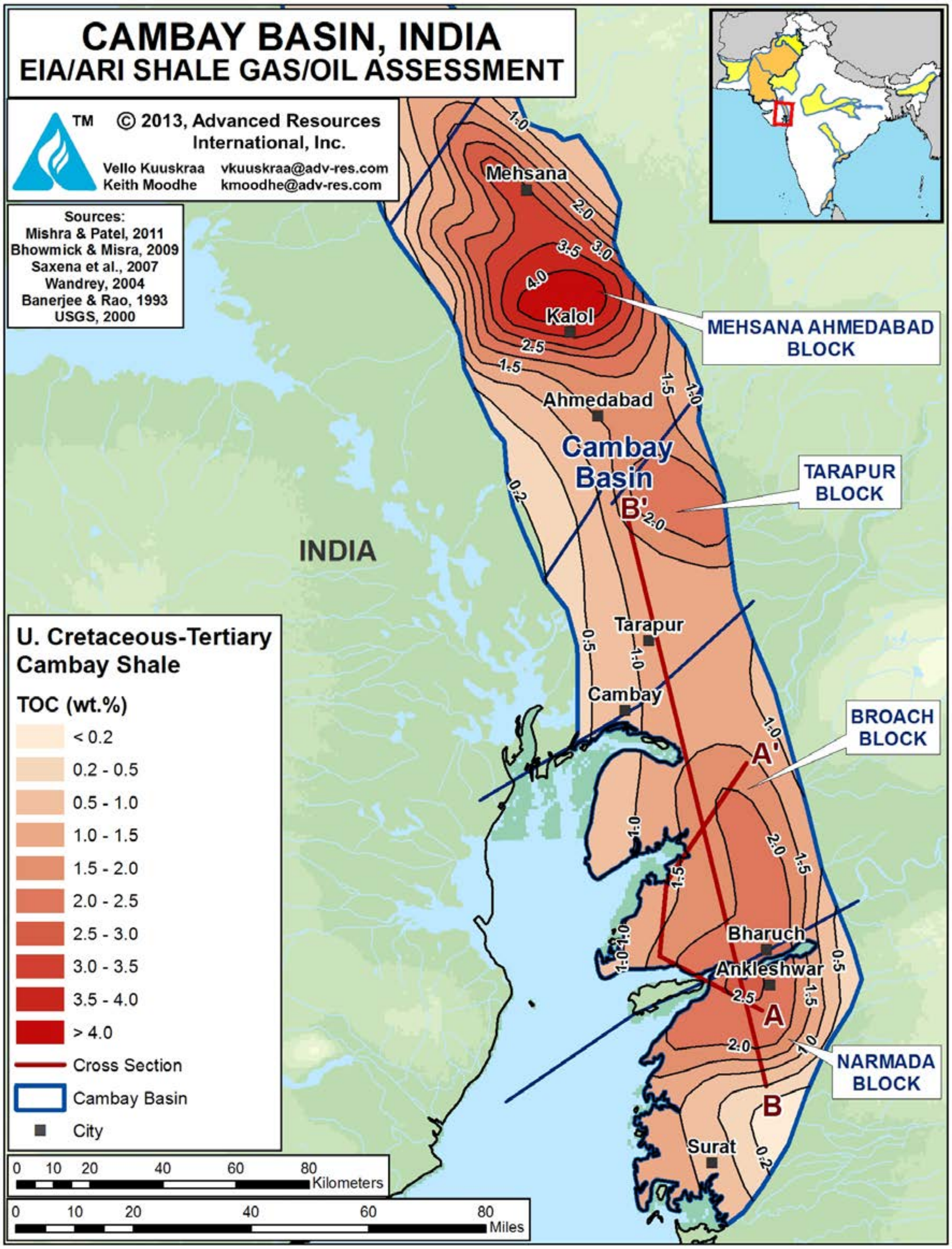
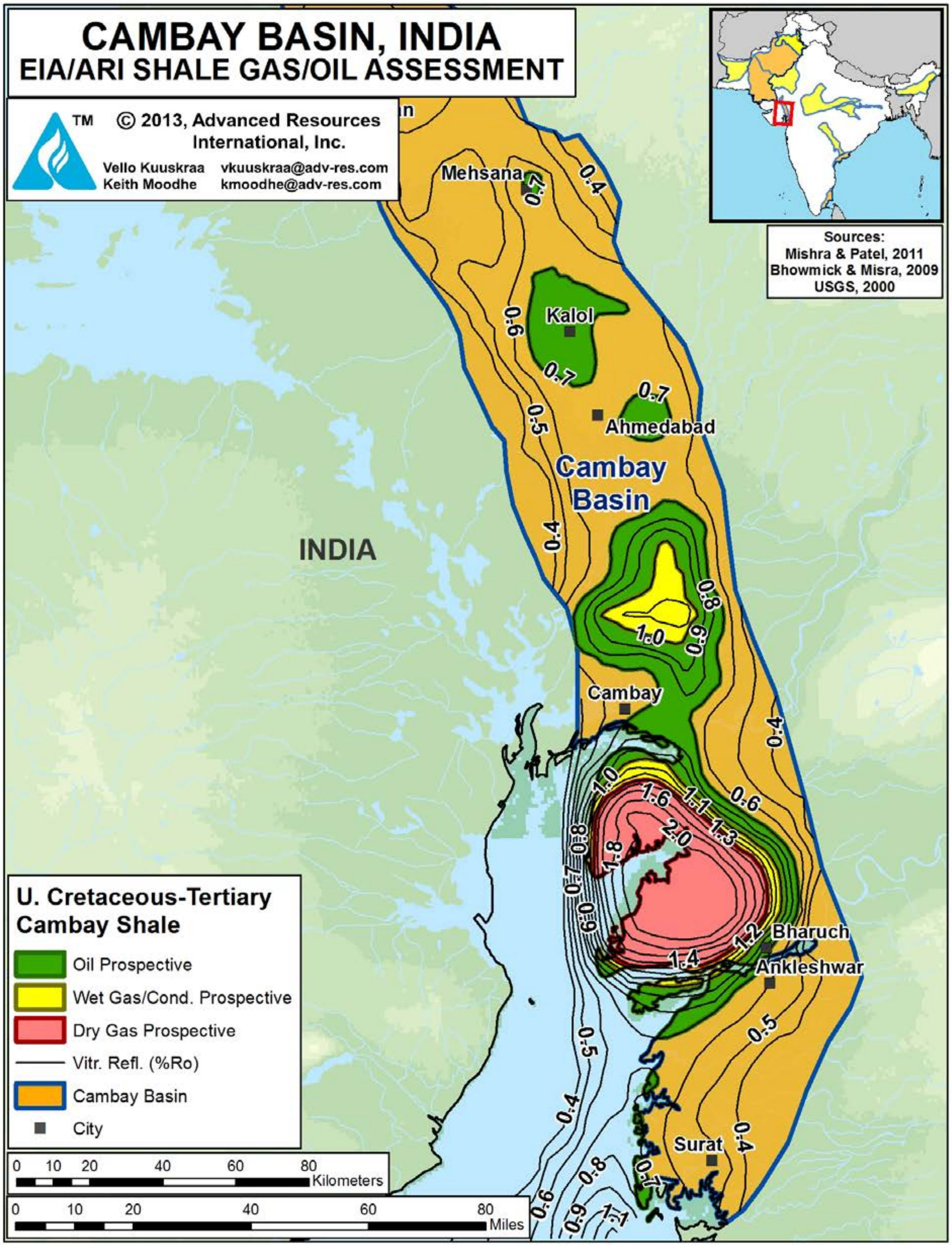


Figure XXIV-10. Prospective Areas of the Cambay Black Shale, Cambay Shale Basin

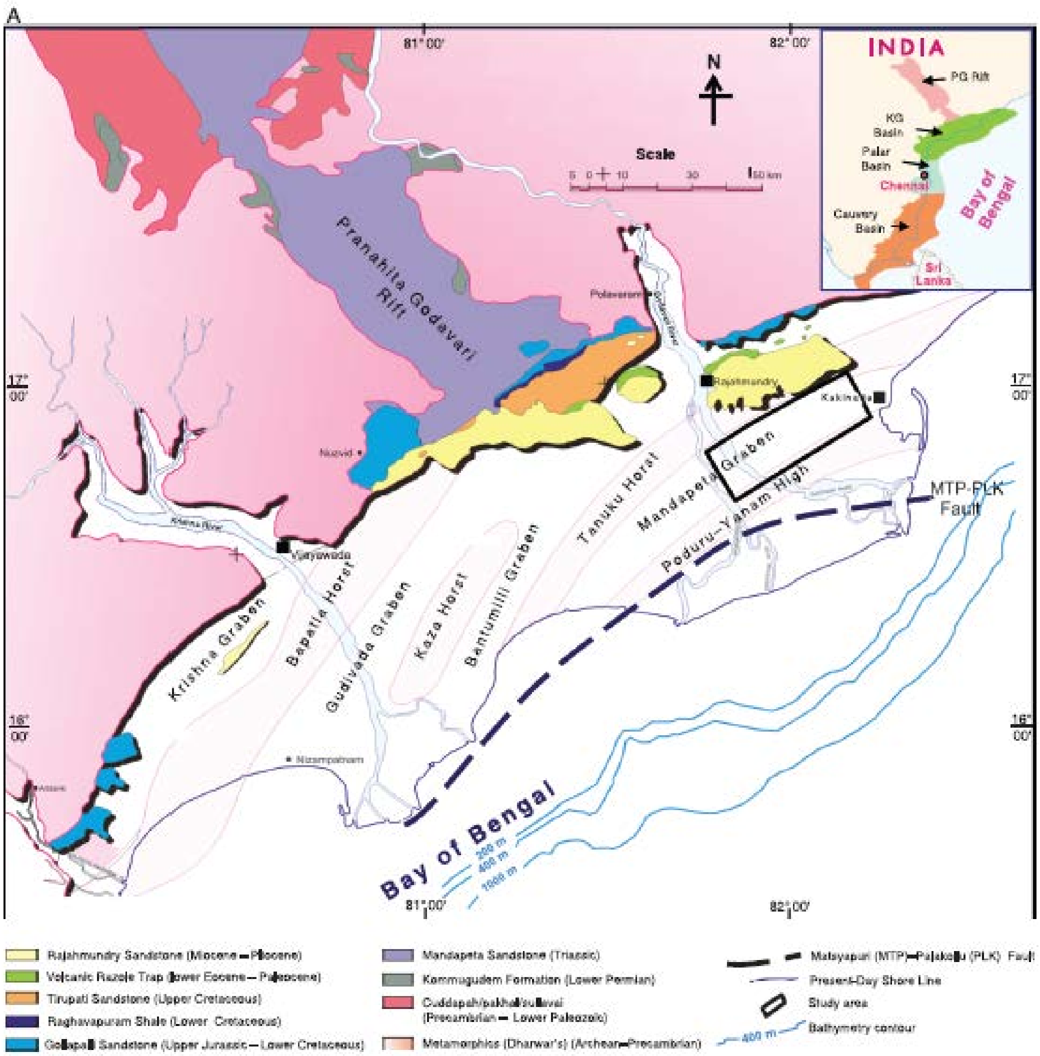


2. KRISHNA-GODAVARI BASIN, INDIA

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.

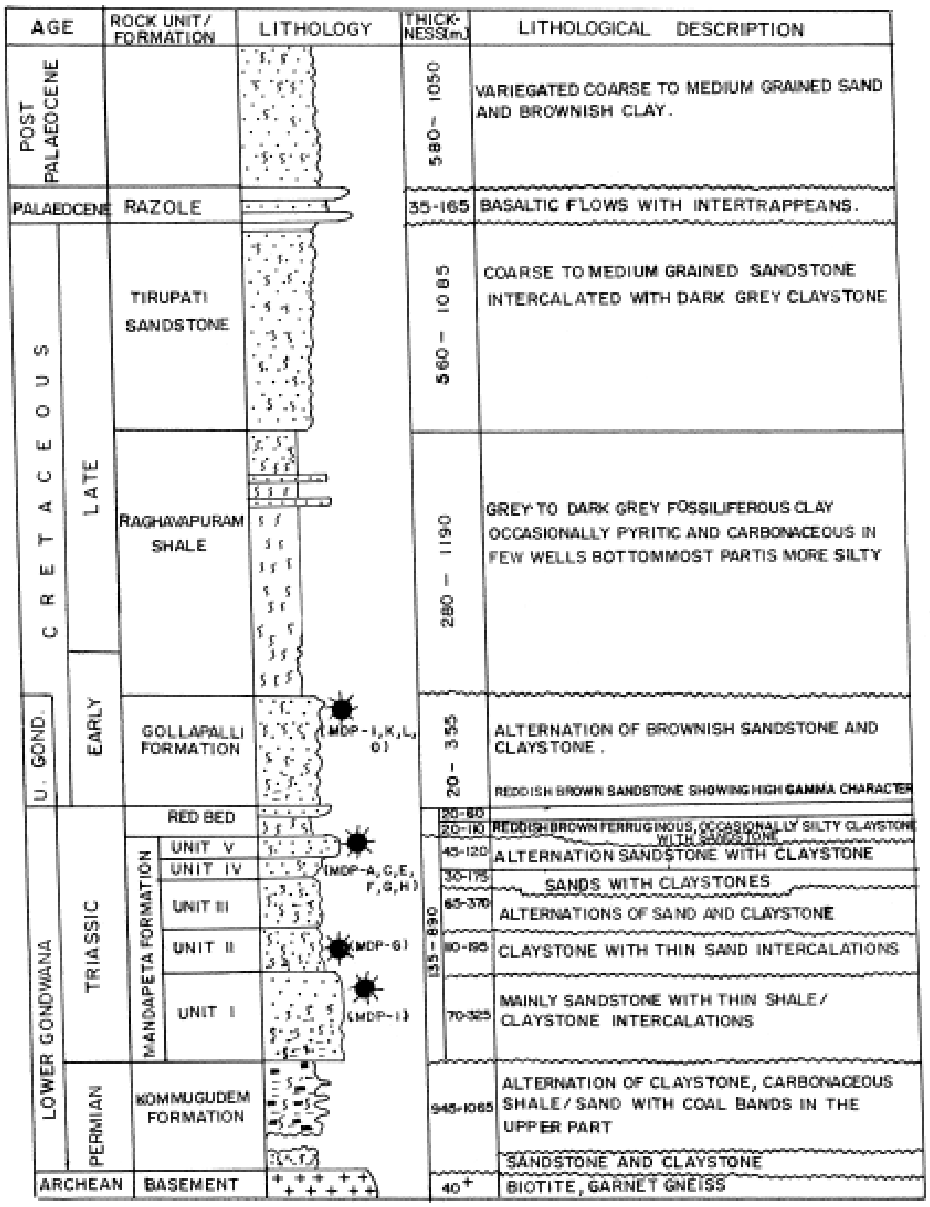
Figure XXI-11. Krishna-Godavari Basin's Onshore Horsts and Grabens



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



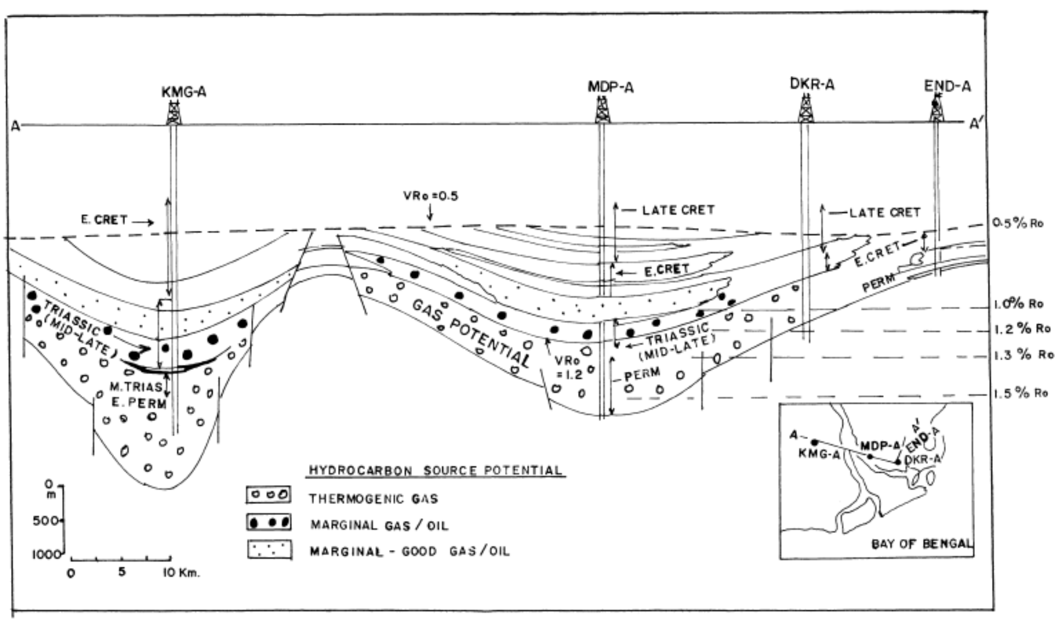
Source: Kahn, 2000.

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.

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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]

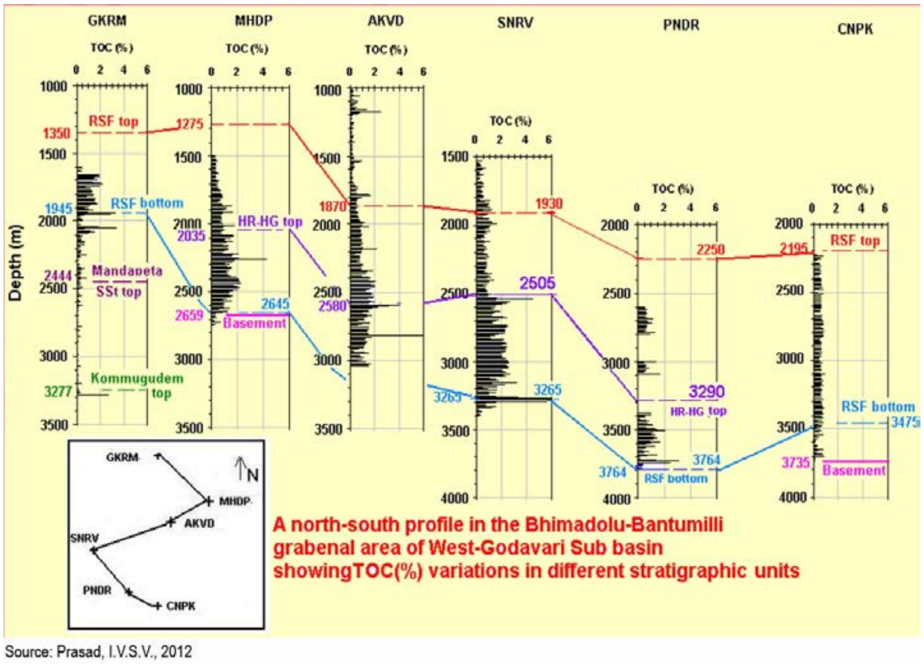
Well	Depth (m)	TOC (%)	S_2*	Shale Interval Tested (m)
AA-1	3,320-3,880	10.4	7.0	110
AA-2	3,585-3,630	4.2	2.9	45
AA-9	3,330-3,360	7.1	6.4	30
AA-10	3,880-3,920	3.1	0.6	40
AA-11	2,890-3,150	7.0	7.9	260
BW-1A	3,915-4,250	5.6	0.8	335
BW-2	2,970-3,085	8.8	5.5	115
BW-2	3,100-3,175	7.8	6.0	75
BW-9	2,800-3,040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

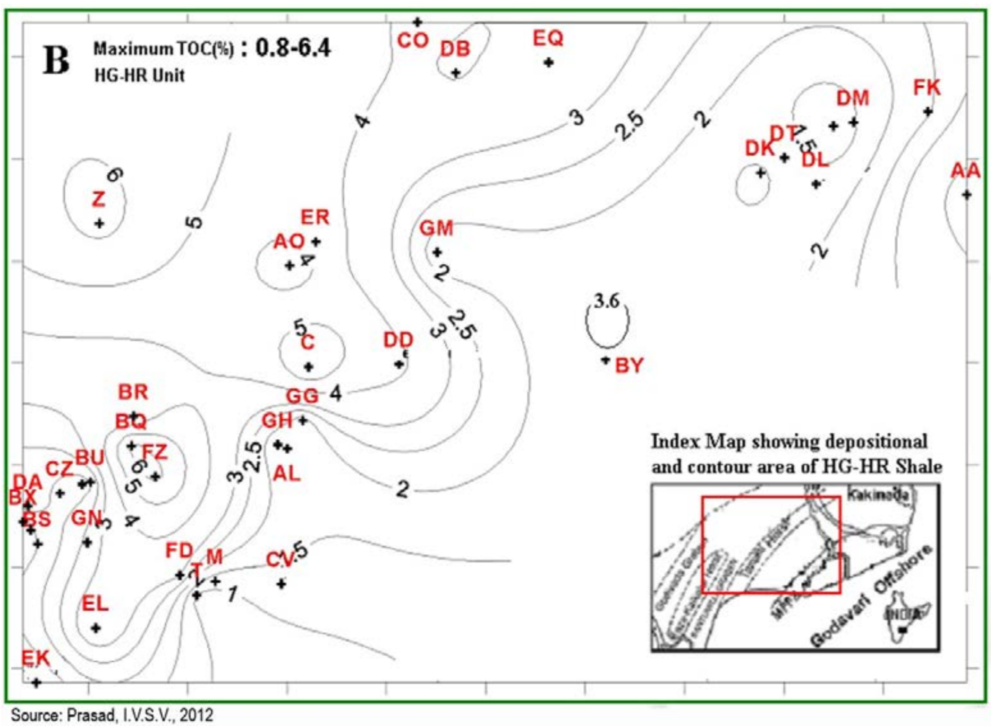
Raghavapuram Shale. The Cretaceous-age Raghavapuram Shale offers an additional potential shale resource in the Krishna-Godavari Basin. The TOC of this shale unit ranges from 0.8% to 6.4%, with the lower HG-HR Shale interval of the Raghavapuram Formation having the higher TOC values, Figures XXIV-14[12] 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.

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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

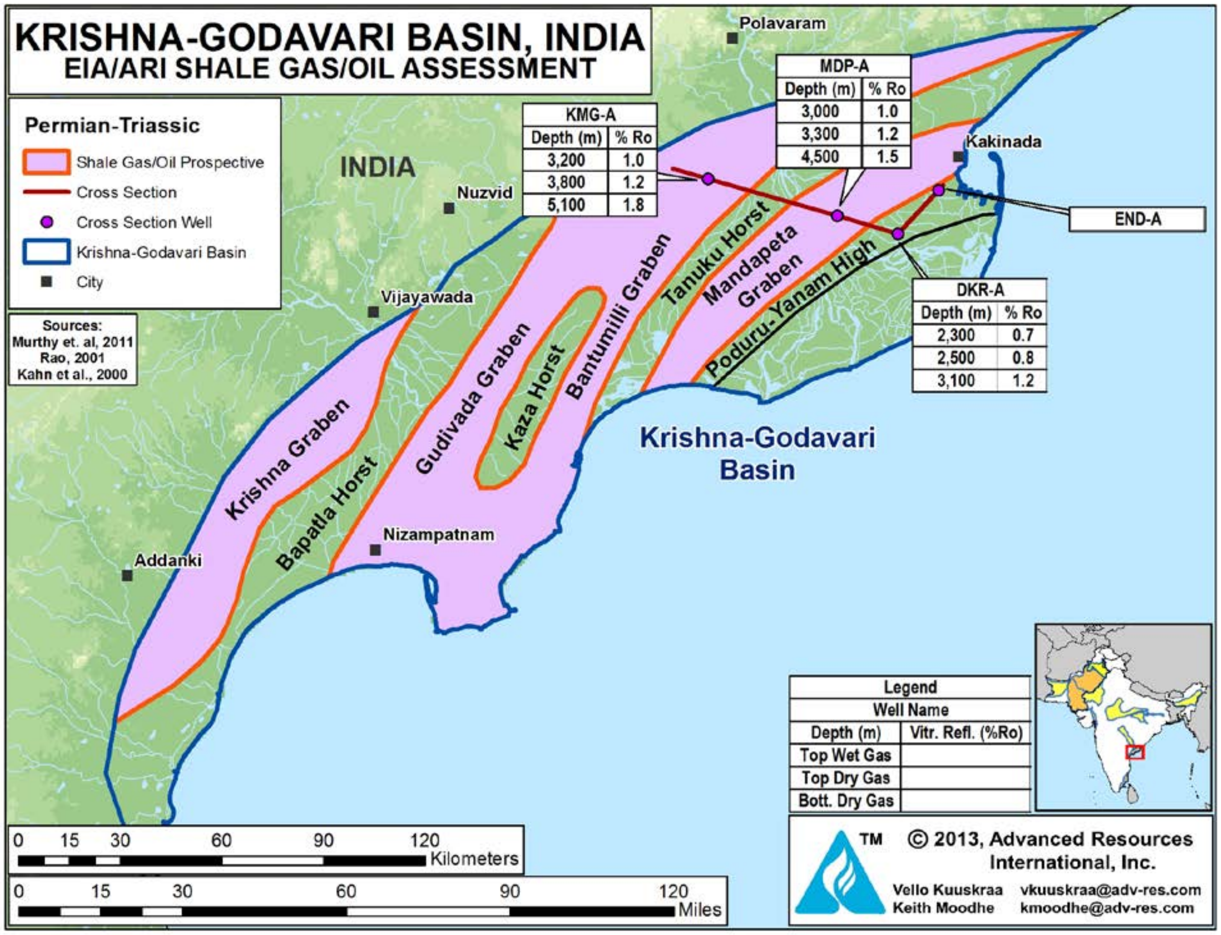
The 8,000-mi^2 prospective area of the Permian (Kommugudem) and Triassic (Mandapeta) Shale in the Krishna-Godavari Basin is limited to the four grabens (sub-basins) shown in Figure XXIV-16. The Permian-Triassic Shale has resource concentrations of: 205 Bcf/mi^2 in the 3,000-mi^2 dry gas prospective area; 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

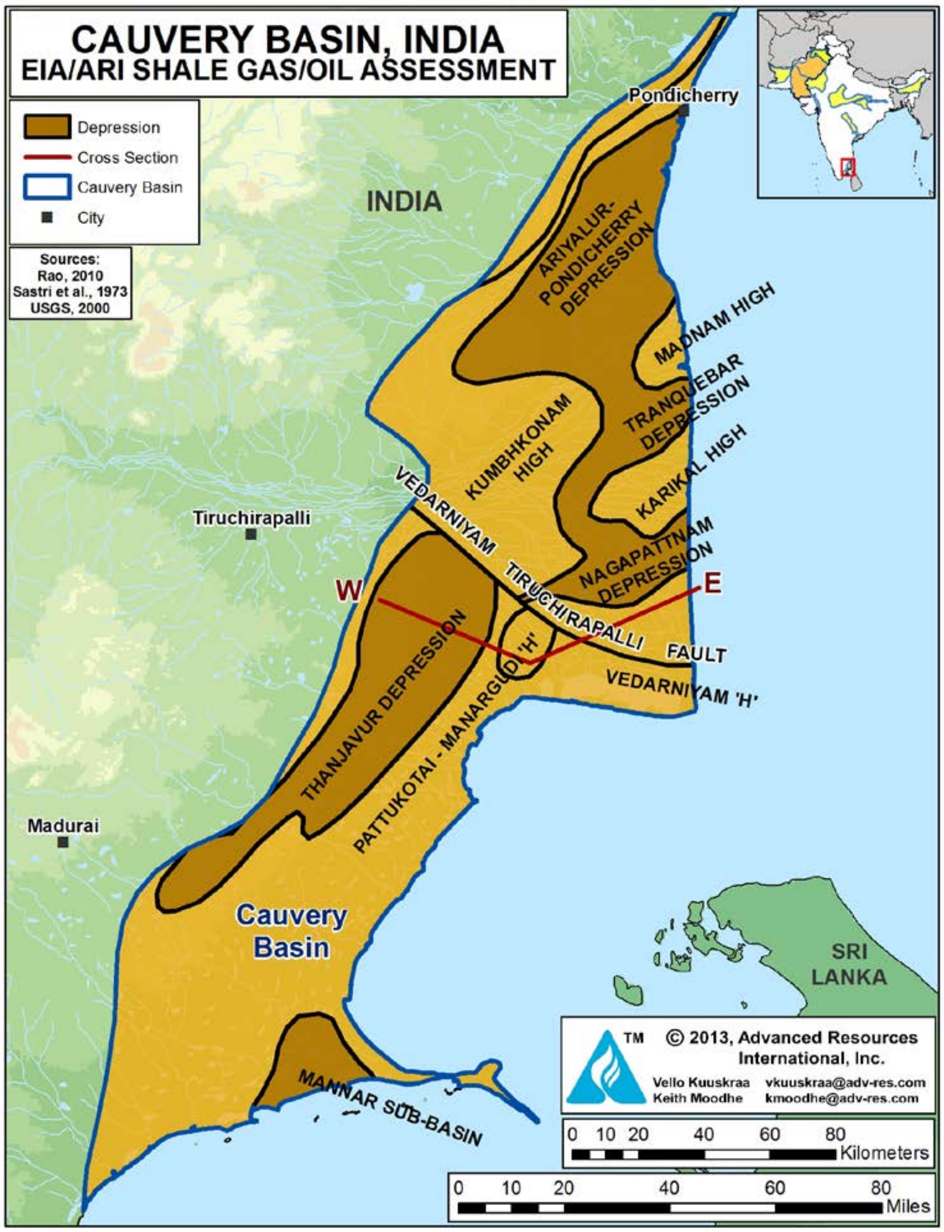


3. CAUVERY BASIN, INDIA

3.1 Introduction and Geologic Setting

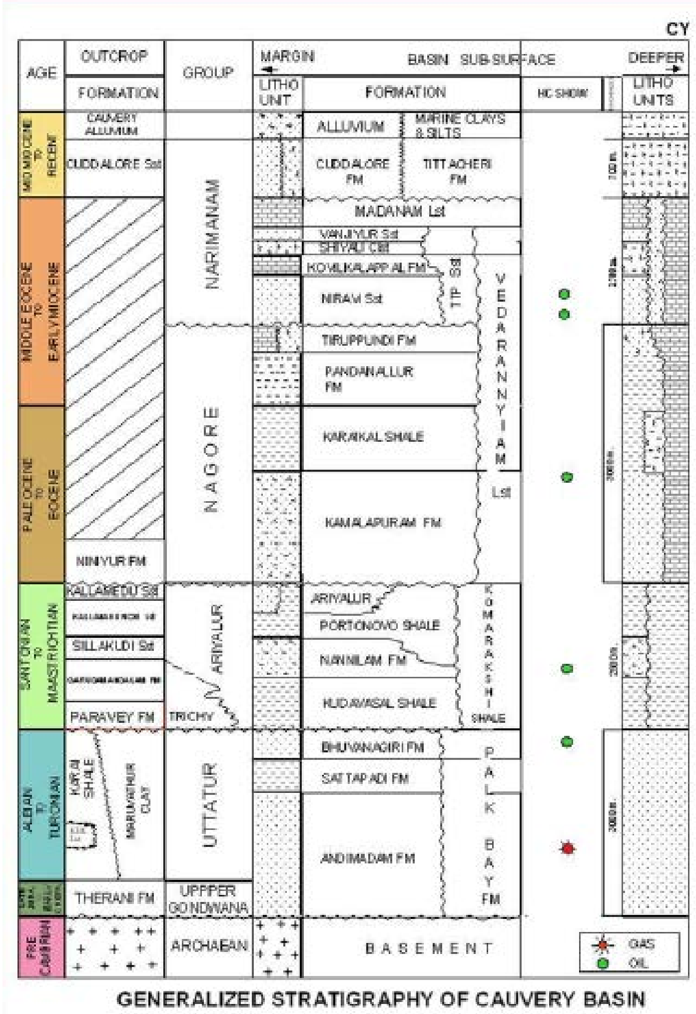
The Cauvery Basin covers an onshore area of about 9,100 mi^2 on the east coast of India, Figure XXIV-17. The basin comprises numerous horsts and grabens, with thick organic-rich source rocks in the Lower Cretaceous Andimadam Formation and Sattapadi Shale.

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.

3.2 Reservoir Properties (Prospective Area)

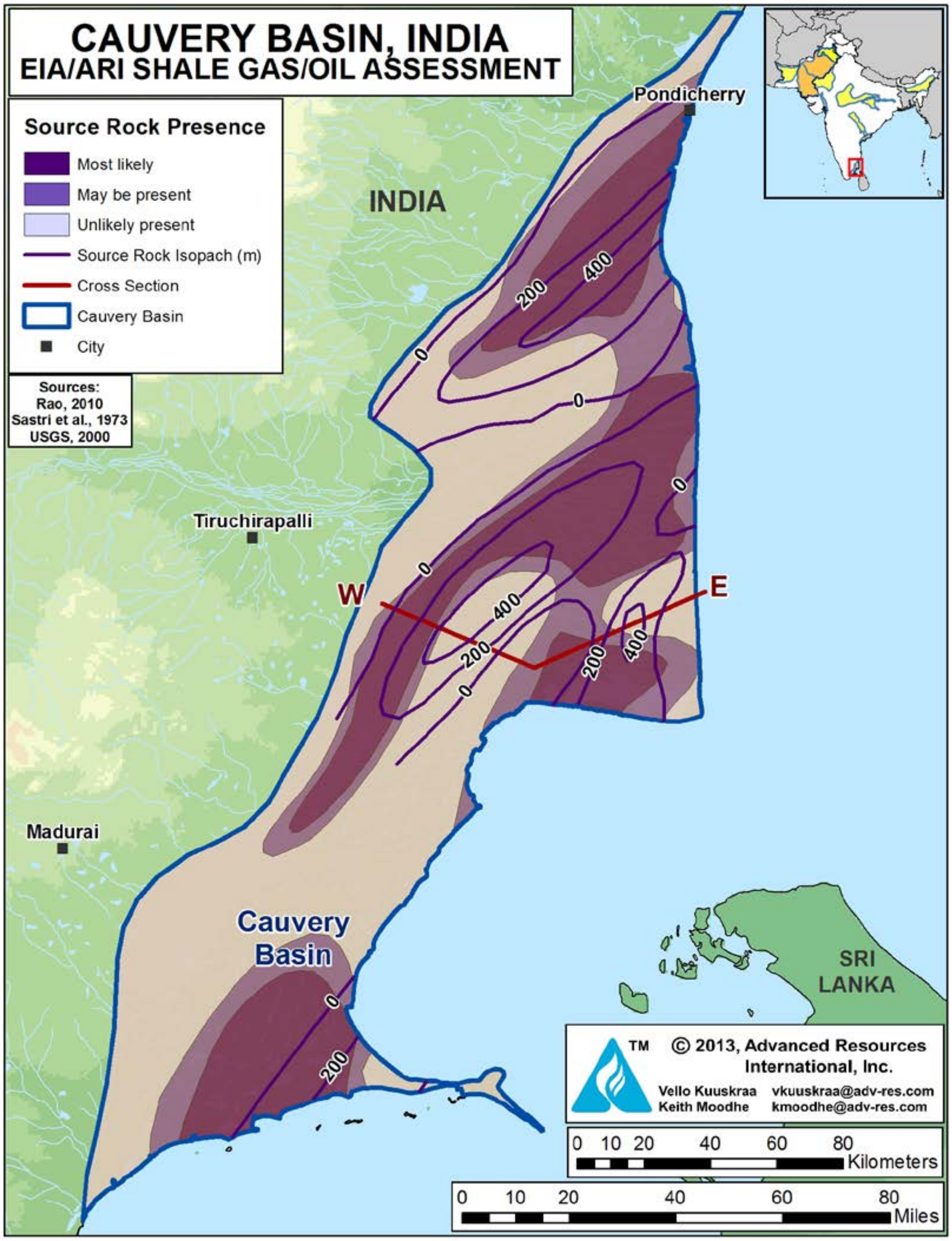
We have identified a 1,010-mi^2 wet gas and condensate prospective area for the shales in the Cauvery Basin. The thickness of the Lower Cretaceous interval is 3,000 to 5,000 ft, with the Andimadam Formation and the Sattapadi Shale accounting for the bulk of the gross interval, Figure XXIV-19. The TOC 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		600-1200
		Shiyali Clay stone	CAP	
Oligocene		Kovilkalappal Fm.		500-800
		Niravi Sandstone	PLAY	
Eocene		Pandanallur Fm.		
		Karaikal Shale	CAP	200-400
		Up.Kamalapuram Fm.	PLAY	
Paleocene		Lr.Kamalapuram Fm.	PLAY	200-800
Creta-ceous	Upper	Porto-Novo Shale	CAP	
		Nannilam Fm.	PLAY	600-1500
		Kudavasal Shale	CAP	
	Lower	Bhuvanagiri Fm.	PLAY	
		Sattapadi Shale	SOURCE+CAP	1000-1500
		Andimadam Fm.	SOURCE+PLAY	
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

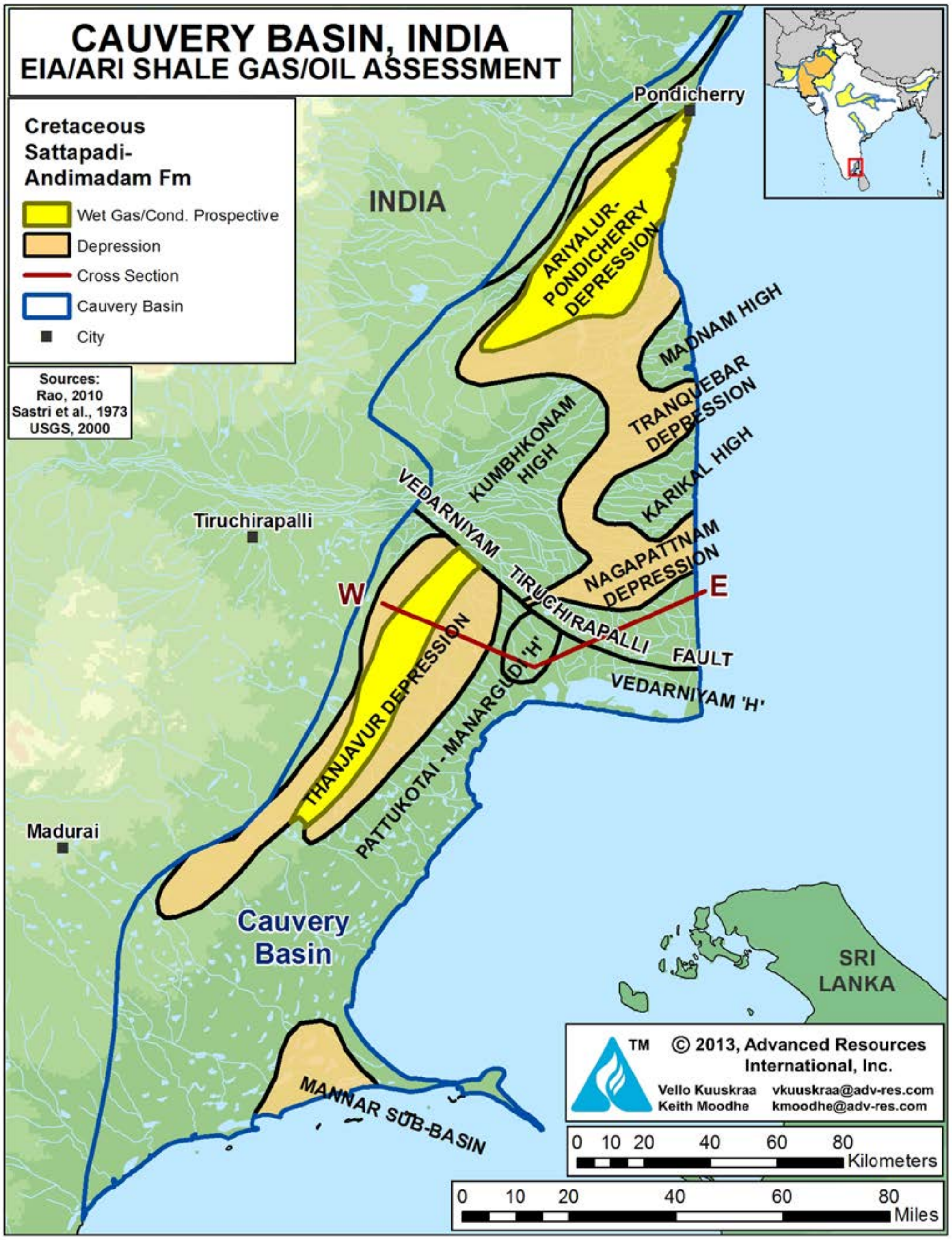
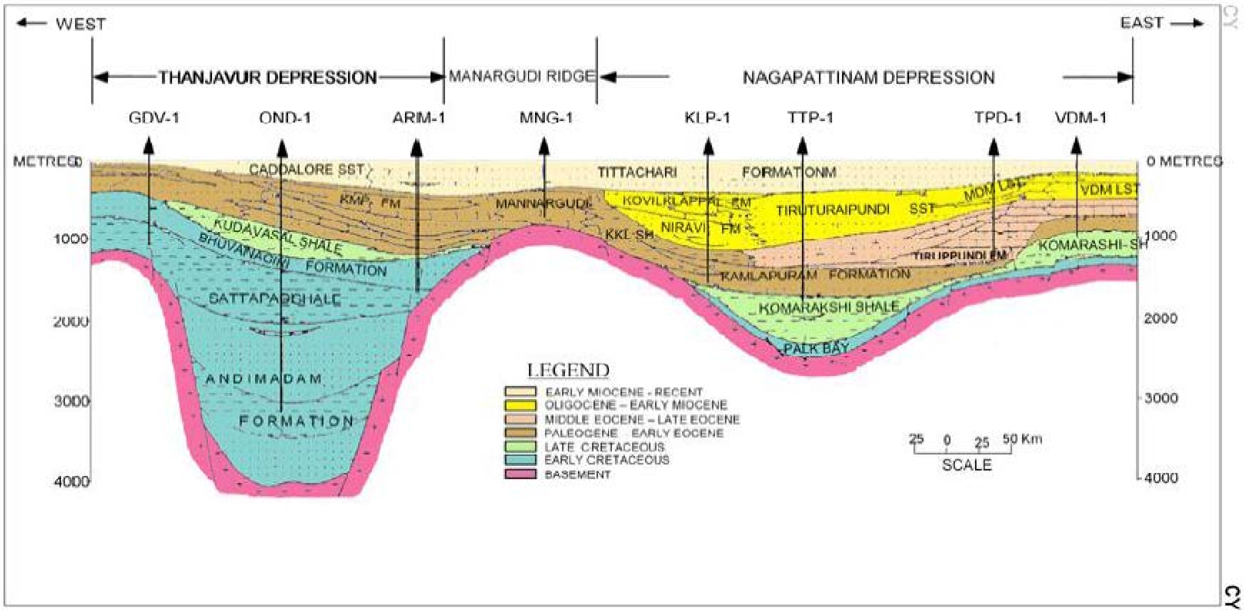


Figure XXIV-22. East to West Cross-Section Across Cauvery Basin.[15]



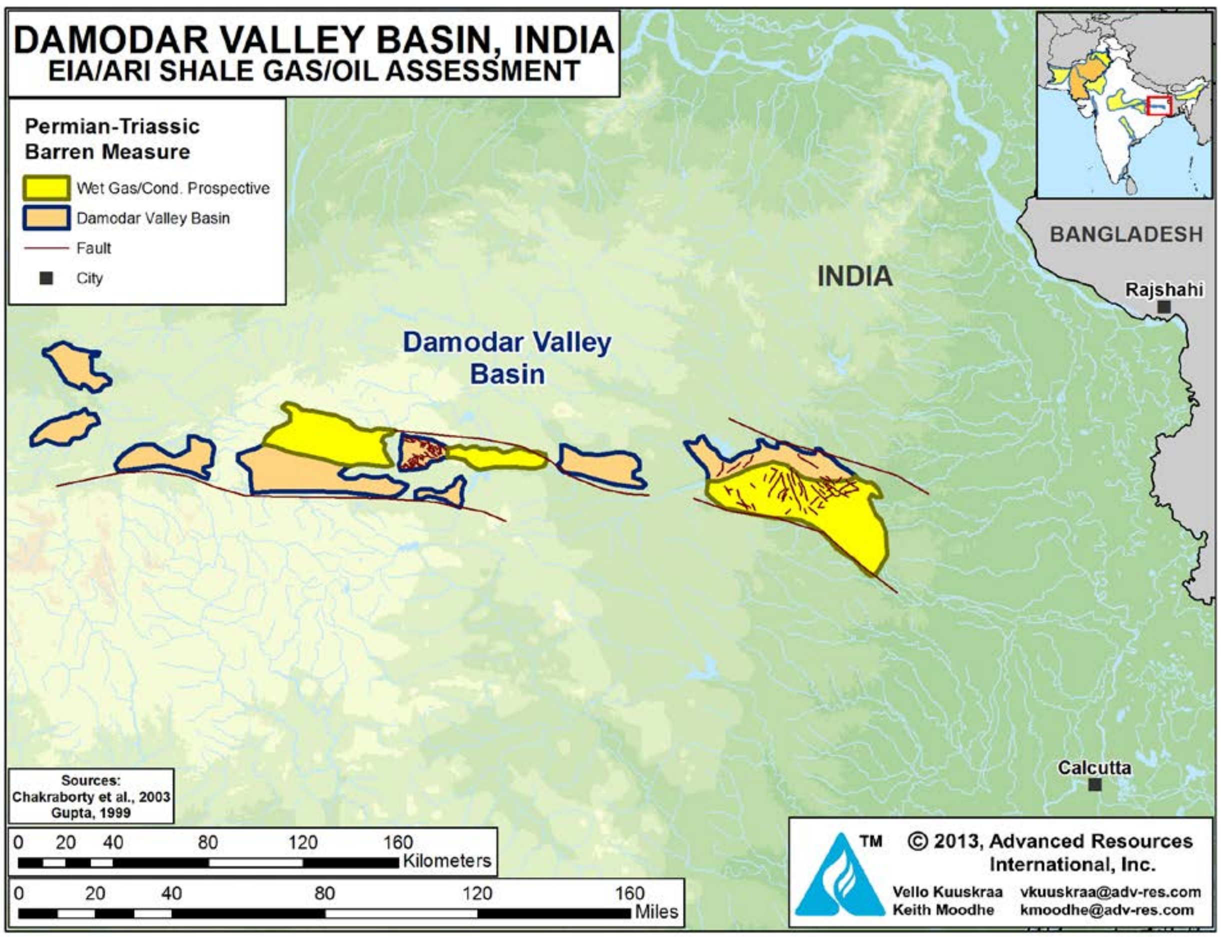
Source: Rao, 2010.

4. DAMODAR VALLEY BASIN, INDIA

4.1 Introduction and Geologic Setting

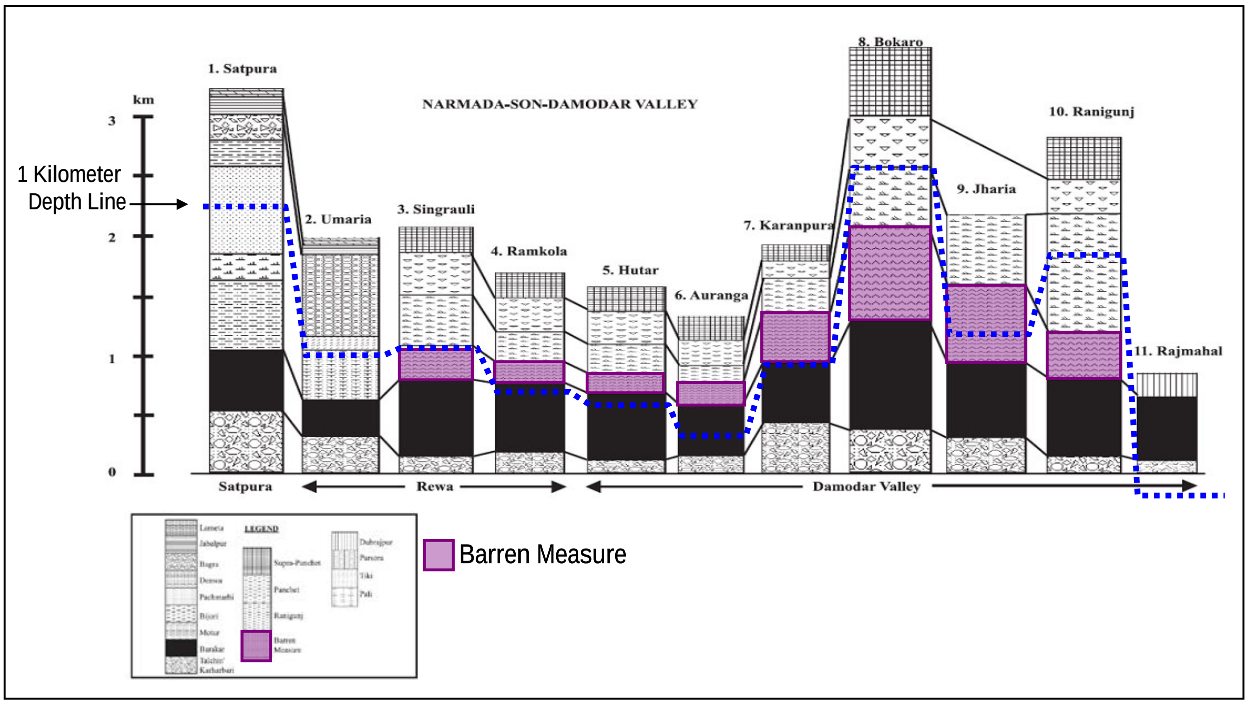
The Damodar Valley Basin is part of a group of basins collectively named the "Gondwanas", owing to their similar dispositional environment and Permo-Carboniferious through Triassic deposition. The "Gondwanas," comprising the Satpura, Pranhita-Godavari, Son-Mahanadi and Damodar Valley basins, were part 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.

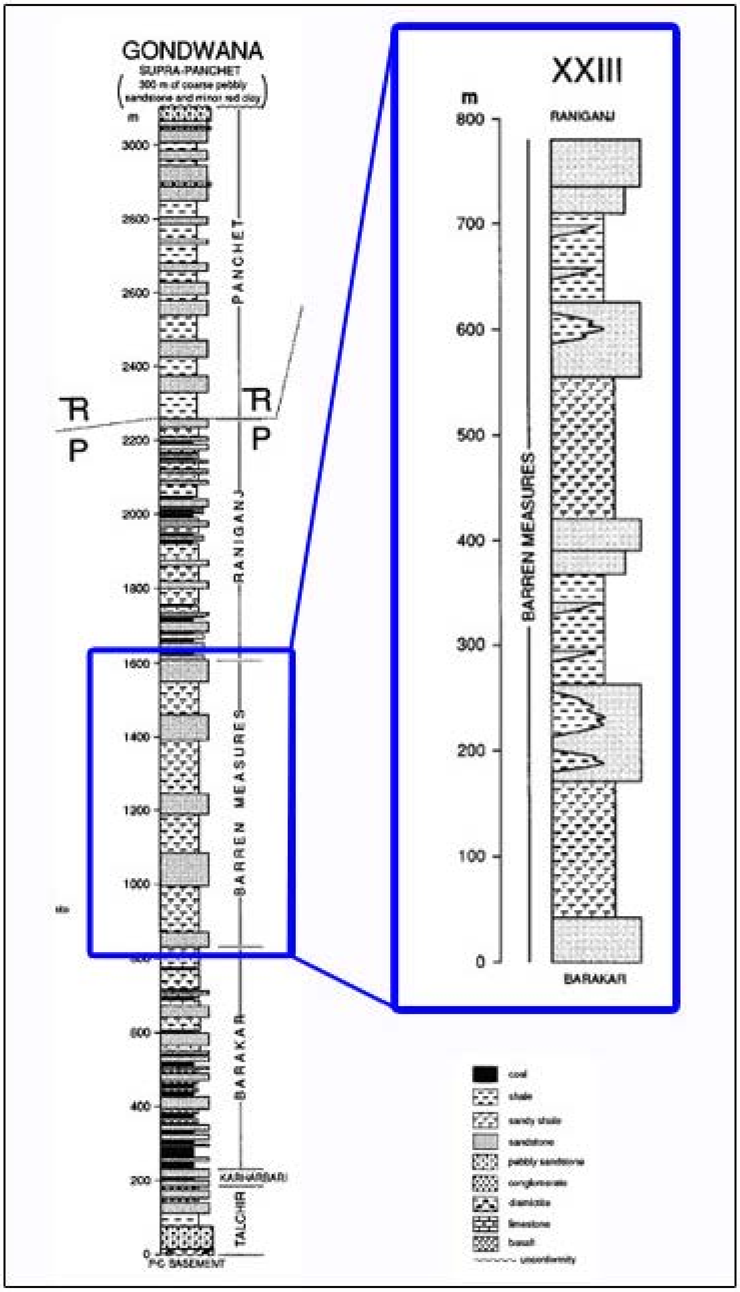
Based on the regional stratigraphic column, Figure XXIV-25,[17] and operator data, the overall 1,080-mi^2 prospective area for the Barren Measure Shale in the Damodar Valley is limited to the Bokaro, Karanpura and Raniganj sub-basins.

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)

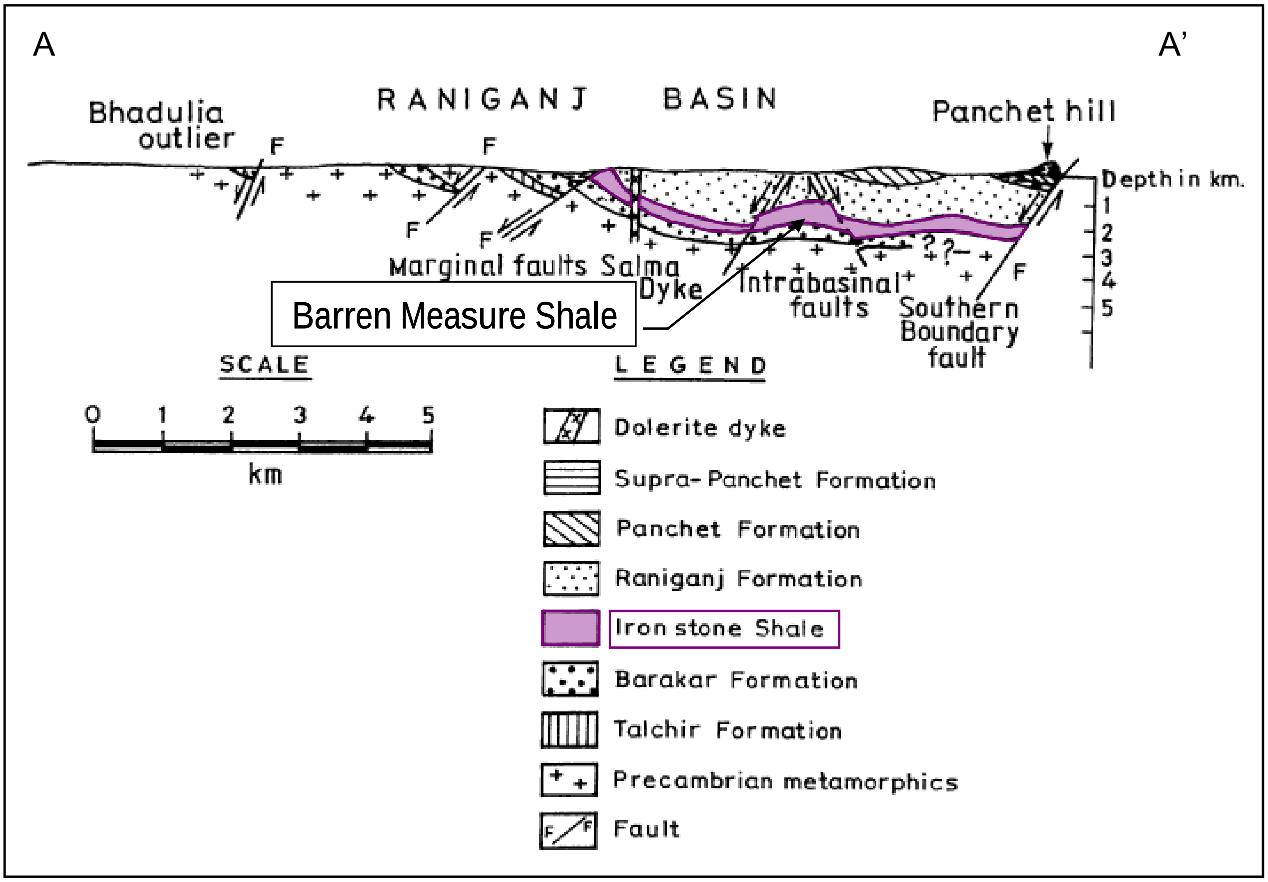
Absent data on thermal maturity and organic content specific to each of the three sub-basins, we assigned average published reservoir property values to these three sub-basins. TOC is assumed to range between 3% and 6% averaging 3.5%, based on information from INOC and ESSAR.[19,20] Thermal maturity 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.

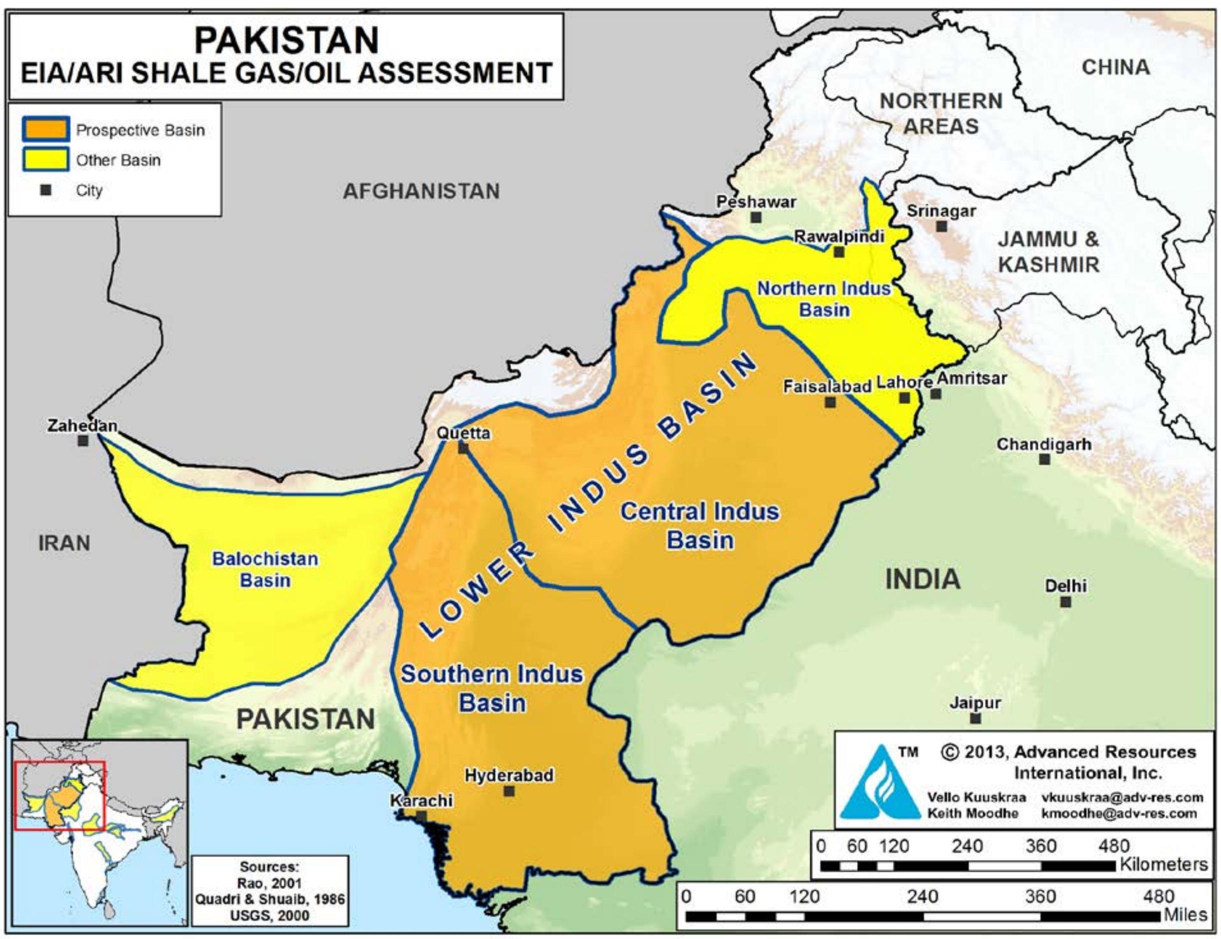
6. LOWER (SOUTHERN AND CENTRAL) INDUS BASINS, PAKISTAN

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.

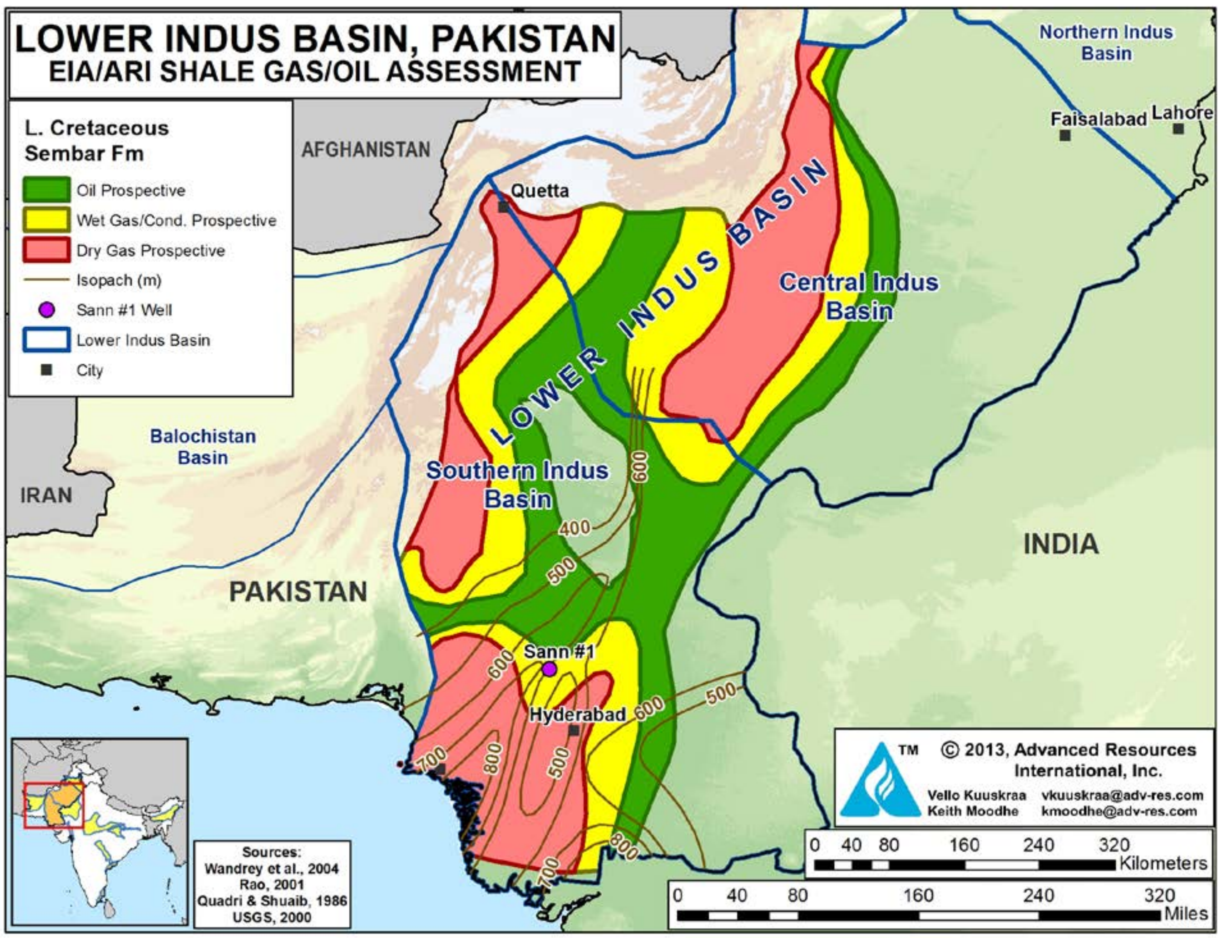
Ranikot Formation. The shales in the Paleocene Ranikot Formation are primarily in the upper carbonate unit which consists of fossiliferous limestone interbedded with dolomitic shale, calcareous sandstone and “abundant” bituminous material. The upper unit was deposited in a restricted marine environment. 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.

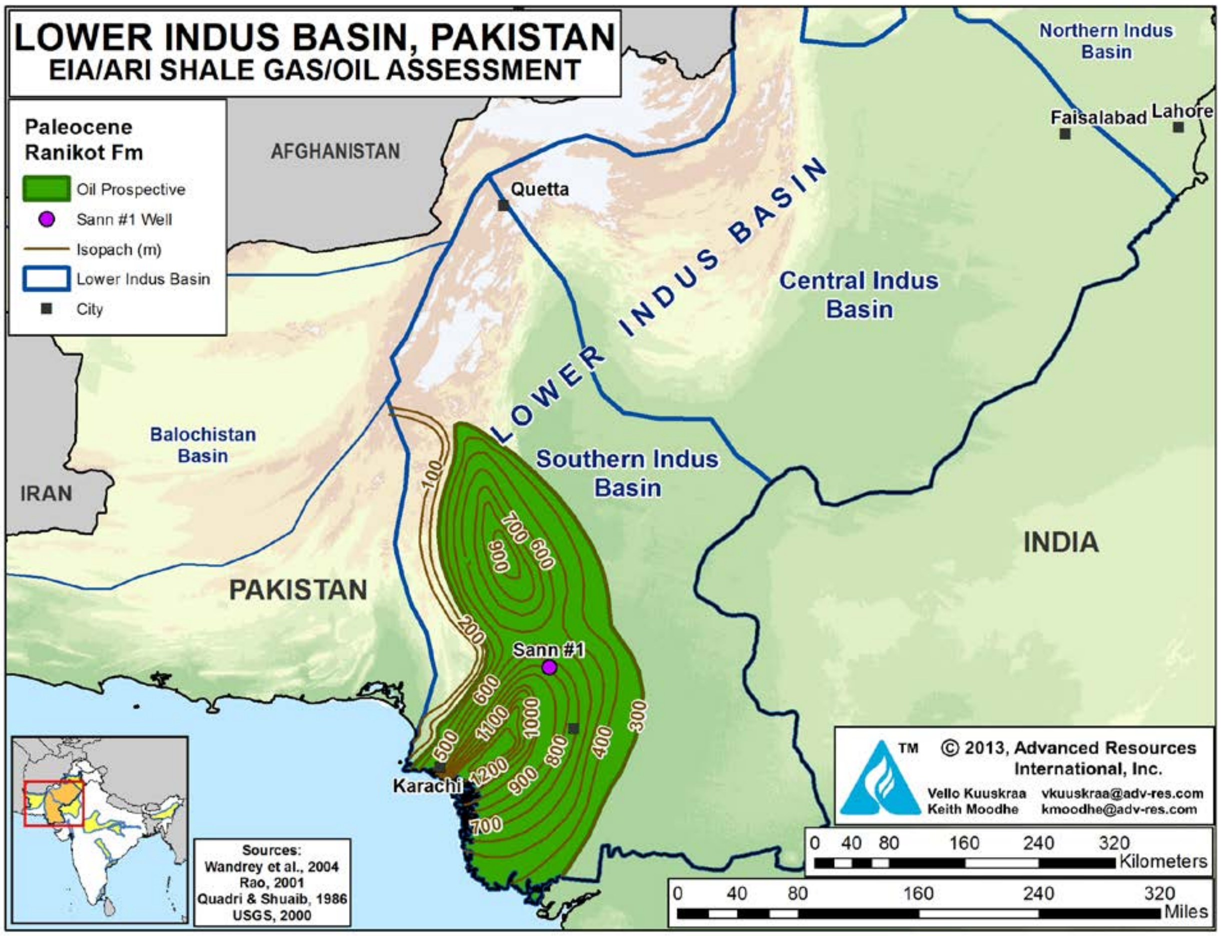
Figure XXIV-28. Isopach of Sembar Shale, Lower Indus Basin, Pakistan[26]



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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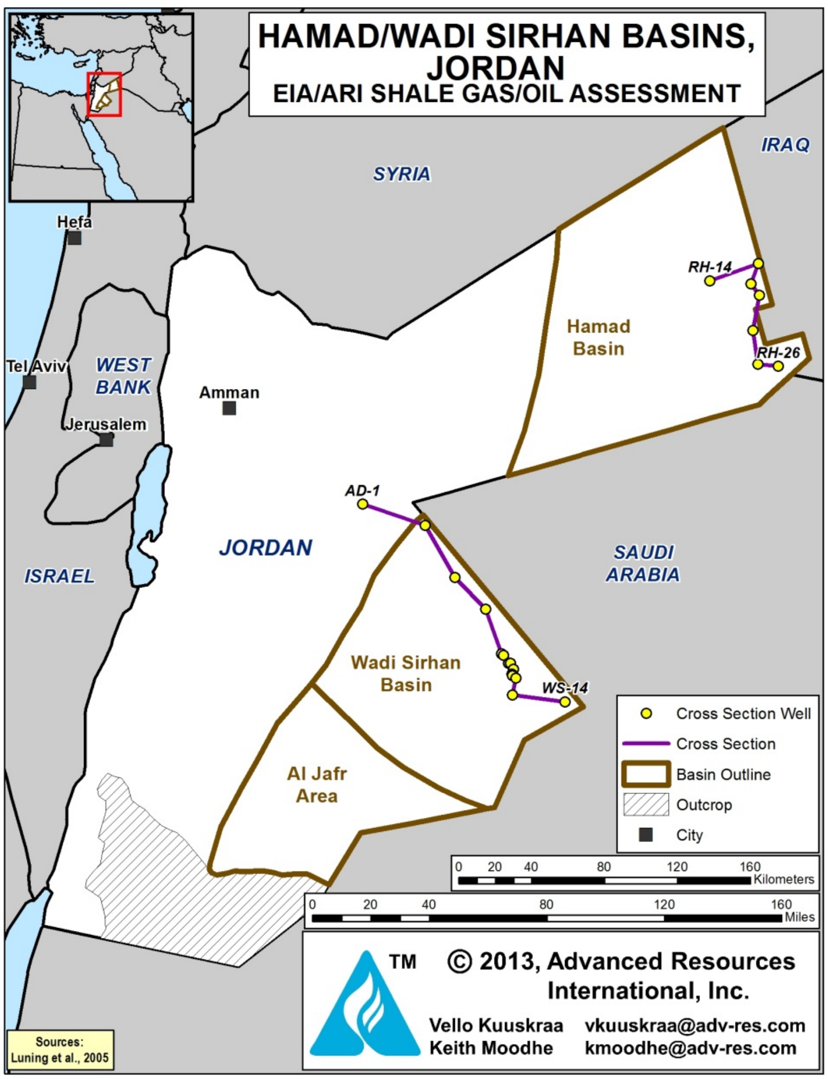
XXV. JORDAN

SUMMARY

Jordan has two basins with potential for shale gas and oil, the Hamad (Risha area) and Wadi Sirhan, Figure XXV. The target horizon is the organic-rich Silurian-age Batra Shale within the larger Mudawwara Formation.

Figure XXV-1. Base Map and Cross-Section Location, Jordan.



Source: ARI, 2013.

Our assessment is that the Batra Shale in these two basins contains 35 Tcf of risked shale gas in-place with 7 Tcf of risked, technically recoverable shale gas resource, Table XXV-1. In addition, we estimate that the Batra Shale holds 4 billion barrels of risked shale oil in-place, with about 0.1 billion barrels of risked, technically recoverable shale oil resource, Table XXV-2.

Table XXV-1. Shale Gas Reservoir Properties and Resources of Jordan

			Hamad	Wadi Sirhan
Basic Data	Basin/Gross Area		Hamad ($6,700\ mi^2$)	Wadi Sirhan ($4,700\ mi^2$)
	Shale Formation		Batra	Batra
	Geologic Age		Silurian	Silurian
	Depositional Environment		Marine	Marine
Physical Extent	Prospective Area (mi^2)		3,300	1,050
	Thickness (ft)	Organically Rich	160	120
		Net	80	60
	Depth (ft)	Interval	6,500 - 10,000	4,500 - 6,500
		Average	8,500	5,500
Reservoir Properties	Reservoir Pressure		Normal	Normal
	Average TOC (wt. %)		2.0%	4.0%
	Thermal Maturity (% Ro)		1.30%	0.80%
	Clay Content		Medium	Medium
Resource	Gas Phase		Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		25.3	3.7
	Risked GIP (Tcf)		33.4	1.6
	Risked Recoverable (Tcf)		6.7	0.2

Source: ARI 2013.

Table XXV-2. Shale Oil Reservoir Properties and Resources of Jordan

Basic Data	Basin/Gross Area		Wadi Sirhan (4,700 mi²)
	Shale Formation		Batra
	Geologic Age		Silurian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi²)		1,050
	Thickness (ft)	Organically Rich	120
		Net	60
	Depth (ft)	Interval	4,500 - 6,500
		Average	5,500
Reservoir Properties	Reservoir Pressure		Normal
	Average TOC (wt. %)		4.0%
	Thermal Maturity (% Ro)		0.80%
	Clay Content		Medium
Resource	Oil Phase		Oil
	OIP Concentration (MMbbl/mi²)		8.8
	Risked OIP (B bbl)		3.7
	Risked Recoverable (B bbl)		0.15

Source: ARI, 2013.

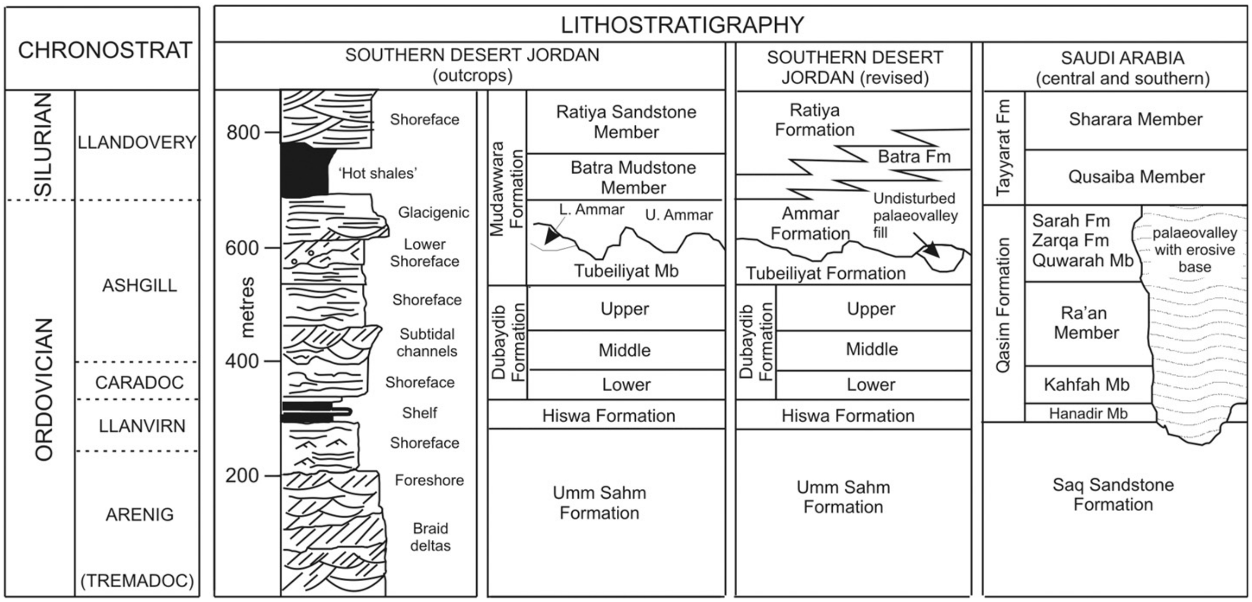
INTRODUCTION

Eastern Jordan contains Silurian-age organic-rich marine shales in the Batra Member of the Mudawwara Formation. Similar Silurian organic-rich shales are a major source of hydrocarbons in North Africa, Iraq and Saudi Arabia. The Batra Shale is time equivalent to the Tanezzuft Formation in Libya and the Qusaiba Shale of the Qalibah Formation in Saudi Arabia.[1] These Lower Silurian-age shales are often called “Hot Shales” because of their high uranium content, having gamma-ray values of >150 API units, Figure XXV-2.[2]

Additional organically enriched marine shales exist in the uppermost Ordovician-age Risha Formation. These shales are 60 to 120 feet thick and have thermal maturities for dry gas.[3,4] However, the TOC values of these Upper Ordovician shales generally range from 0.5% to 1.5%, below the TOC cut-off set forth for this study.

For the shale gas and oil resource assessment of Jordan, we have drawn heavily on the most valuable geological work and publications of Luning (2000,[1] 2005[3]), Armstrong (2005,[5] 2009[2]), Keegan (1990[6]), and Ahlbrandt (1997[7]). In addition, Jordan's Petroleum Directorate within the Natural Resources Authority provided important information in their 2006 publication entitled, "Petroleum Exploration Opportunities in Jordan".[8]

Figure XXV-2. Lithostratigraphy for the Ordovician and Silurian of Jordan and Saudi Arabia,



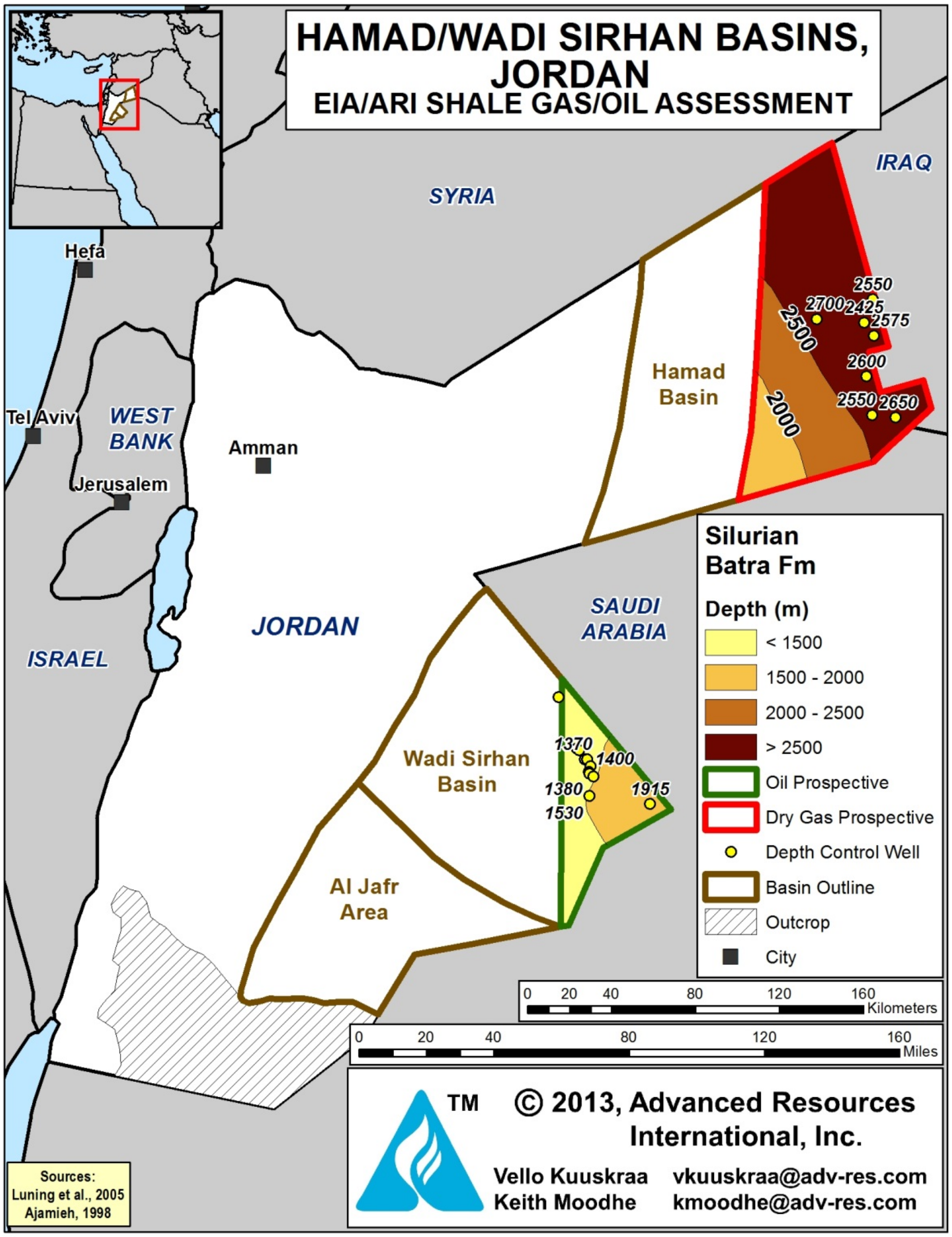
Source: Lithostratigraphy and chronostratigraphy for the Ordovician and Silurian of Jordan and Saudi Arabia, showing generalized depositional environments for outcrops in the Southern Desert region of Jordan (redrawn from Turner et al., 2005). Armstrong (2009)

1. GEOLOGIC SETTING

The Batra Shale is present in the sub-surface in the Hamad (Risha area) and Wadi Sirhan basins of eastern Jordan, as well as in the near-surface in the Al Jafr area and outcrops of the Southern Desert of Jordan. The Hercynian sub-crop establishes western limits of the Batra Shale in Jordan. The Syria, Iraq and Saudi Arabia borders with Jordan set the northern, southern and eastern limits of the Jordan portion of this shale deposit. The Batra Shale is a Type I/II marine shale, deposited along the margins of the receding Gondwana shelf. Figure XXV-3 provides the depth and areal extent for the prospective areas of Batra Shale in Jordan.[3]

The Batra Shale contains three distinct organic-rich intervals - - a highly organic-rich unit called the "Lower Hot Shale", a middle unit within lower organic content, and the "Upper Hot Shale".[3] We have included the "Lower Hot Shale" and the "Upper Hot Shale" units in our resource assessment.

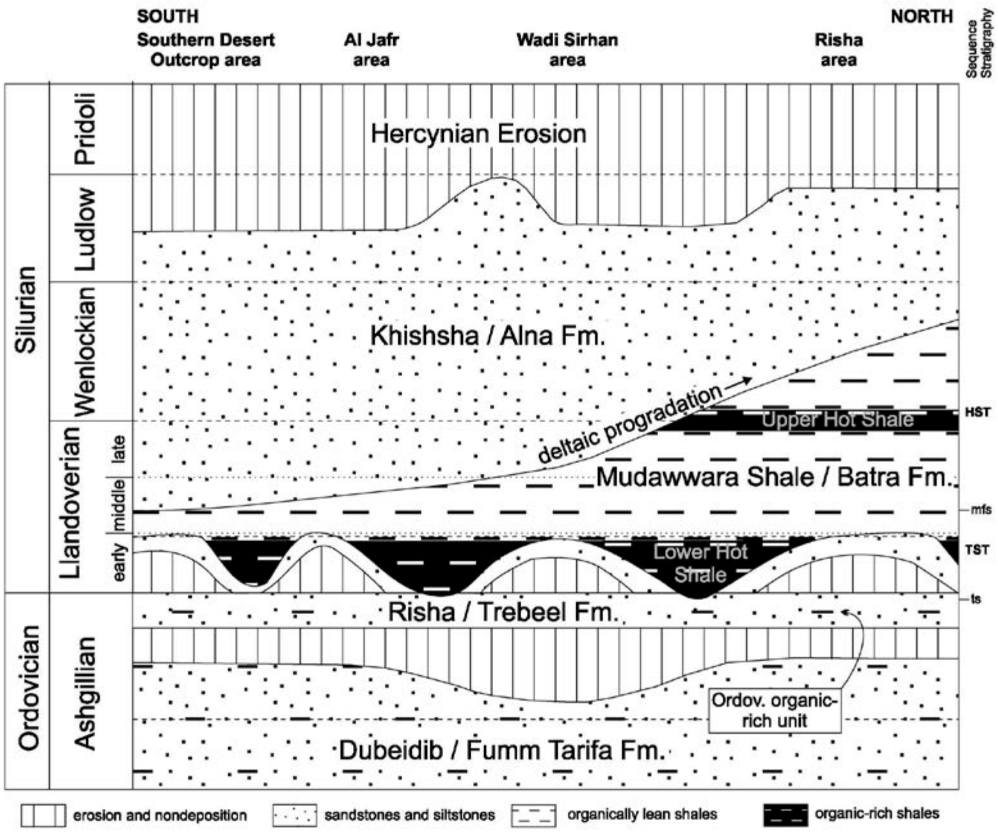
Figure XXV-3. Depth and Prospective Areas - - Batra Shale, Jordan



Source: ARI, 2013.

The "Lower Hot Shale" unit, deposited at the base of the Batra Shale and above the underlying Dubaydib Formation, is present in southeastern Jordan (Wadi Sirhan Basin). The "Lower Hot Shale" thins to the west, north and south in the Wadi Sirhan area. The "Upper Hot Shale" exists in the Hamad Basin's Risha gas field area along the Iraqi border. The "Upper Hot Shale" is at the top of the Batra Shale interval, XXV-Figure 4.[3]

Figure XXV-4. Chonostratigraphy of the Upper Ordovician-Silurian in Jordan.



Source: S. Luning, 2005.

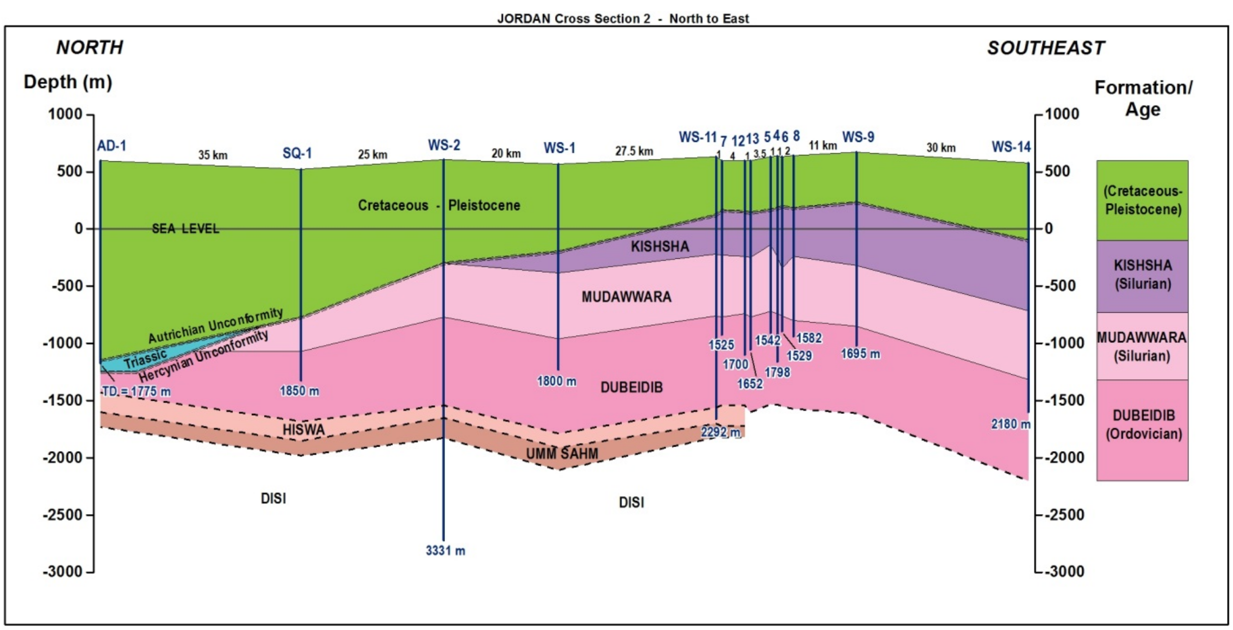
The thermal maturity of the Batra Shale increases from south to north and from west to east. The shale is immature to early-mature in the Al Jafr area, becomes middle-mature (oil window) in the Wadi Sirhan area, and is late to post-mature (gas window) in the Hamad Basin's Risha area.[3,7] The determination of the thermal maturity for the Batra Shale has been approximated using graptolite reflectance and maximum temperature. (Vitrinite did not yet exist during early Silurian time.)

As shown in Figure XXV-3, we have mapped a prospective area of 1,050 mi^2 for the "Lower Hot Shale" in the oil-prone Wadi Sirhan area and a prospective area of 3,300 mi^2 for the "Upper Hot Shale" in the gas-prone Risha area.

2. RESERVOIR PROPERTIES (PROSPECTIVE AREA)

Lower Hot Shale. In the Wadi Sirhan prospective area, the depth of the "Lower Hot Shale" ranges from 4,500 to 6,500 ft, averaging 5,500 ft. Based on analog data, we assume that the shale in this area is at normal pressure. The organic-rich gross interval of the "Lower Hot Shale" unit in the Wadi Sirhan prospective area ranges from 30 to 100 ft, with an average net pay of about 60 ft (using 150 API units of background gamma radiation). Figure XXV-5 provides a north to south cross-section for the Batra Shale in the Wadi Sirhan area.[8] (Figure XXV-1 provides the cross-section locations.[3,8])

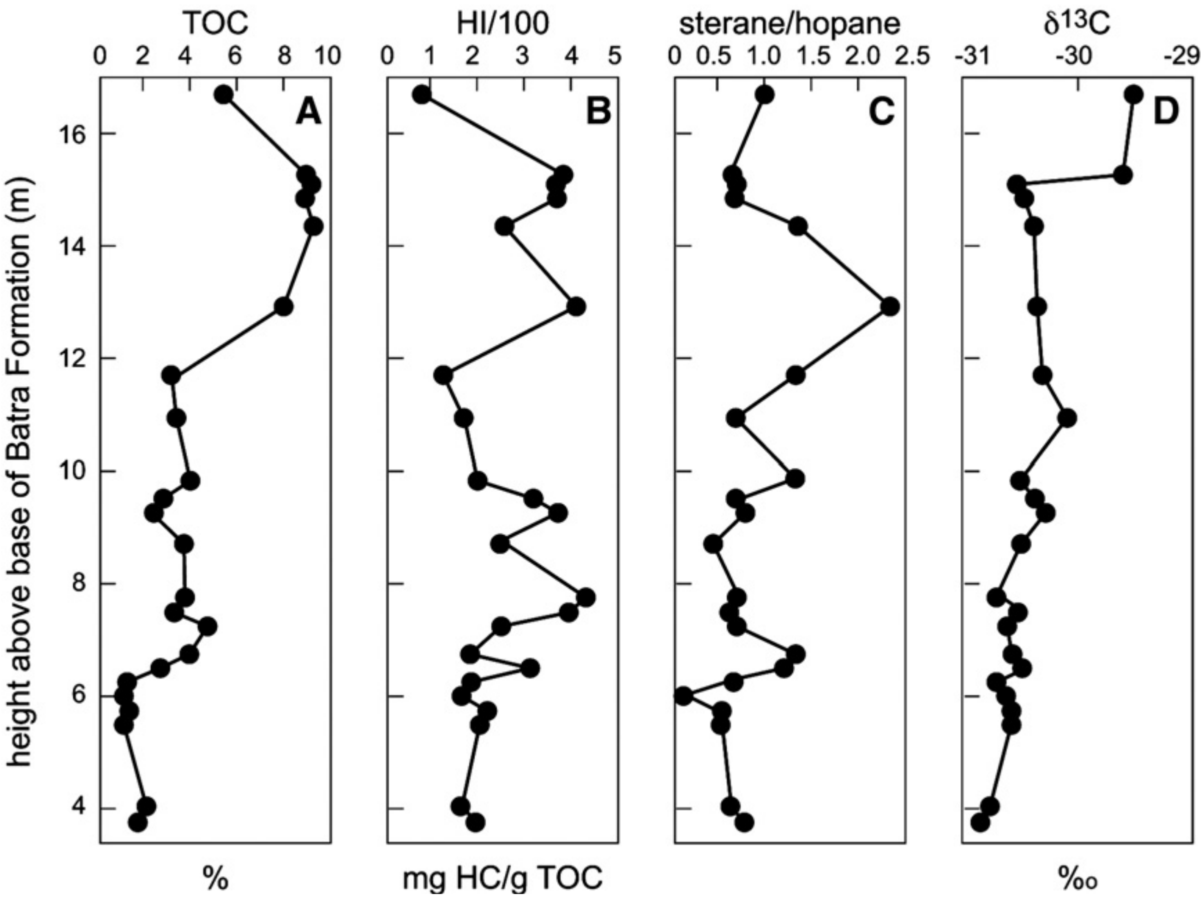
Figure XXV-5. North to South Regional Cross-Section, Wadi Sirhan Basin.



Source: NRA Petroleum Directorate Jordan, 2006.

The TOC of the "Lower Hot Shale" unit ranges from 1.5% to 9%, with an average value of about 4%, Figure XXV-6.[2] The thermal maturity of the shale unit is estimated at 0.7% to 1.0% R_o equivalent, averaging 0.8% R_o. We have used other Silurian-age "hot shale" deposits as analogs for supplemental reservoir data for the "Lower Hot Shale" in the Wadi Sirhan Basin.

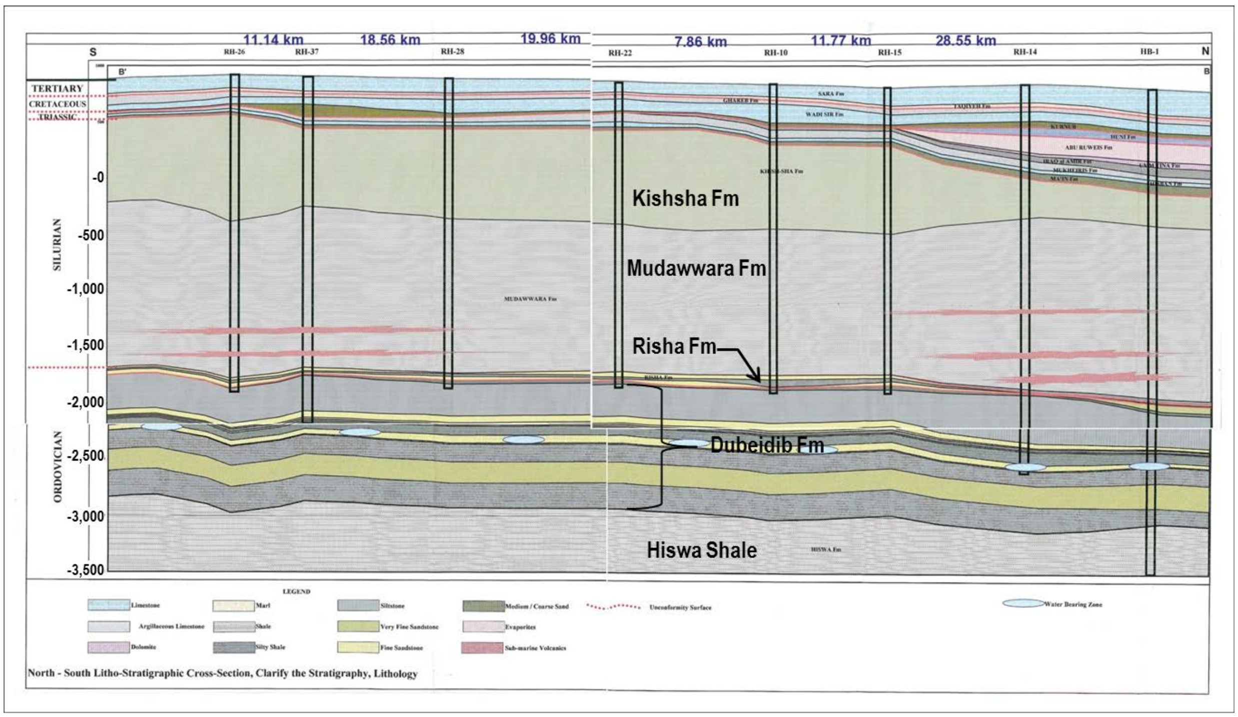
Figure XXV-6. Bulk Organic Carbon, Biomarker and Stable Carbon Isotope Data.



(A) Total organic carbon (TOC) content of the bulk sediment. (B) Hydrogen index (HI) of the bulk sediment (mg hydrocarbons (HC)/g TOC). (C) Steranes/17α-hopanes ratio shows its highest value at 12.94m above the base of the Batra formation. (D) δ13C values of organic carbon (OC) versus Vienna Peedee belemnite (VPDB) in parts per mil (‰).Source: Armstrong (2009)

Upper Hot Shale. In the Hamad Basin/Risha prospective area, the depth of the "Upper Hot Shale" ranges from 6,500 to 10,000 ft, averaging 8,500 ft. Based on limited well test data, we assume that the shale is at normal pressure. The organic-rich gross interval of the "Upper Hot Shale" unit in the Risha prospective area is about 160 ft thick, with an average net pay of about 80 ft, based on a minimum 2% TOC value cutoff. Figure XXV-7 provides a north to south cross-section for the Batra Shale in the Risha area (see Figure XXV-1 for cross-section location.).[8] The average TOC value is about 2%, after exclusion of the lower TOC value intervals using the net to gross pay ratio. The thermal maturity of the "Upper Hot Shale" is estimated at above 1.2% R_o equivalent[3]. We have used analog data from other Silurian-age "hot shale" deposits for supplemental reservoirs data for the "Upper Hot Shale" unit in the Hamad Basin (Risha Area).

Figure XXV-7. Regional Geologic Cross-Section, Eastern Hamad Basin (Risha Area).

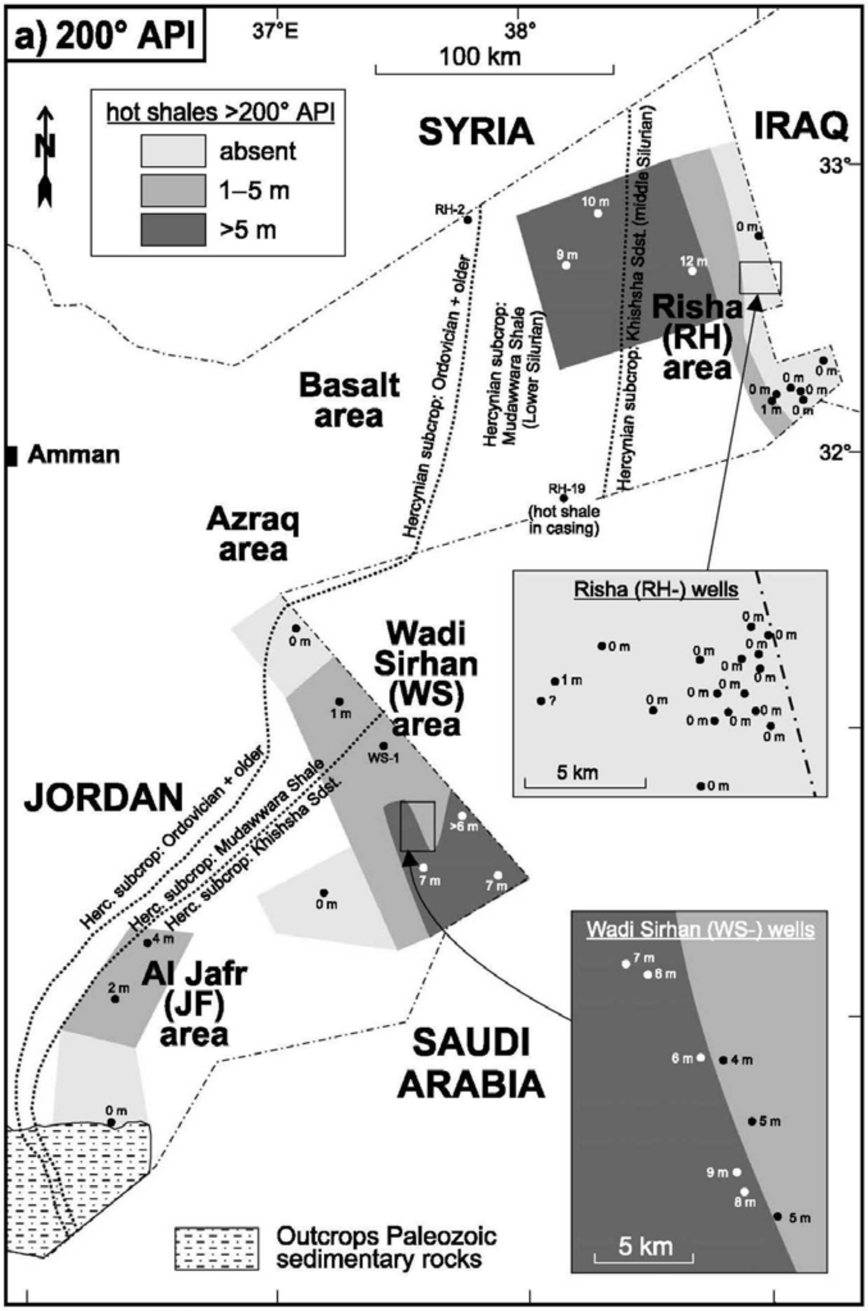


JAF028356.PPT

Source: NRA Petroleum Directorate Jordan, 2006

Figure XXV-8 is an isopach map for the Batra Shale using the 150 API gamma-ray background value for determining organically rich shale.[3]

Figure XXV-8. Isopach Map of Organic-Rich Silurian Shales with Total Gamma-Ray Values Exceeding 150 API Corresponding to Organic Richness.



Source: Luning, 2005

3. RESOURCE ASSESSMENT

Wadi Sirhan Basin. The prospective area for the Lower Batra Shale in the Wadi Sirhan Basin is limited on the west by the thinning and thermal maturity of the shale and on the east by the Jordanian border. Within the 1,050-mi^2 prospective area for oil, the Batra Shale has a resource concentration of 9 million barrels of oil per mi^2 plus moderate volumes of shale associated gas.

The risked resource in-place for the shale oil prospective area of the Wadi Sirhan Basin is estimated at 4 billion barrels of oil plus 2 Tcf of associated shale gas. Based on moderately favorable reservoir properties, we estimate a risked, technically recoverable shale oil resource of 0.1 billion barrels plus small volumes of associated shale gas for the Batra Shale in the Wadi Sirhan Basin.

Hamad/Risha Area. The prospective area for the Upper Batra Shale in the Hamad Basin/Risha area is limited on the west by the pinch-out of the shale and on the north, south and east by the Jordanian border. Within the 3,300-mi^2 prospective area for wet and dry gas, the Batra Shale has a resource concentration of 25 Bcf/mi^2.

The risked shale resource in-place for the gas prospective area is estimated at 33 Tcf. Based on moderately favorable reservoir properties, we estimate a risked, technically recoverable shale gas resource of about 7 Tcf for the Batra Shale in the Hamad Basin/Risha area.

4. RECENT ACTIVITY

A number of deep exploration wells have been drilled in the Wadi Sirhan area prospecting for oil. One well (Wadi Sirhan #4) is reported to have produced 25 barrels per day of 42^o API oil from sandstones associated with the Batra Shale, while other exploration wells have reported shows of light oil.[8] However, much of the data from these deep exploration wells remains confidential. Another series of wells (31) have been drilled in the Hamad Basin/Risha area into the Risha tight sandstone member of the Ordovician-age Dubaydib Formation. Five of the wells are reported to be producing at a combined rate of 30 MMcfd.[7] The Batra Shale, in the overlying Silurian-age Mudawwara Formation, is considered the source of this gas accumulation.

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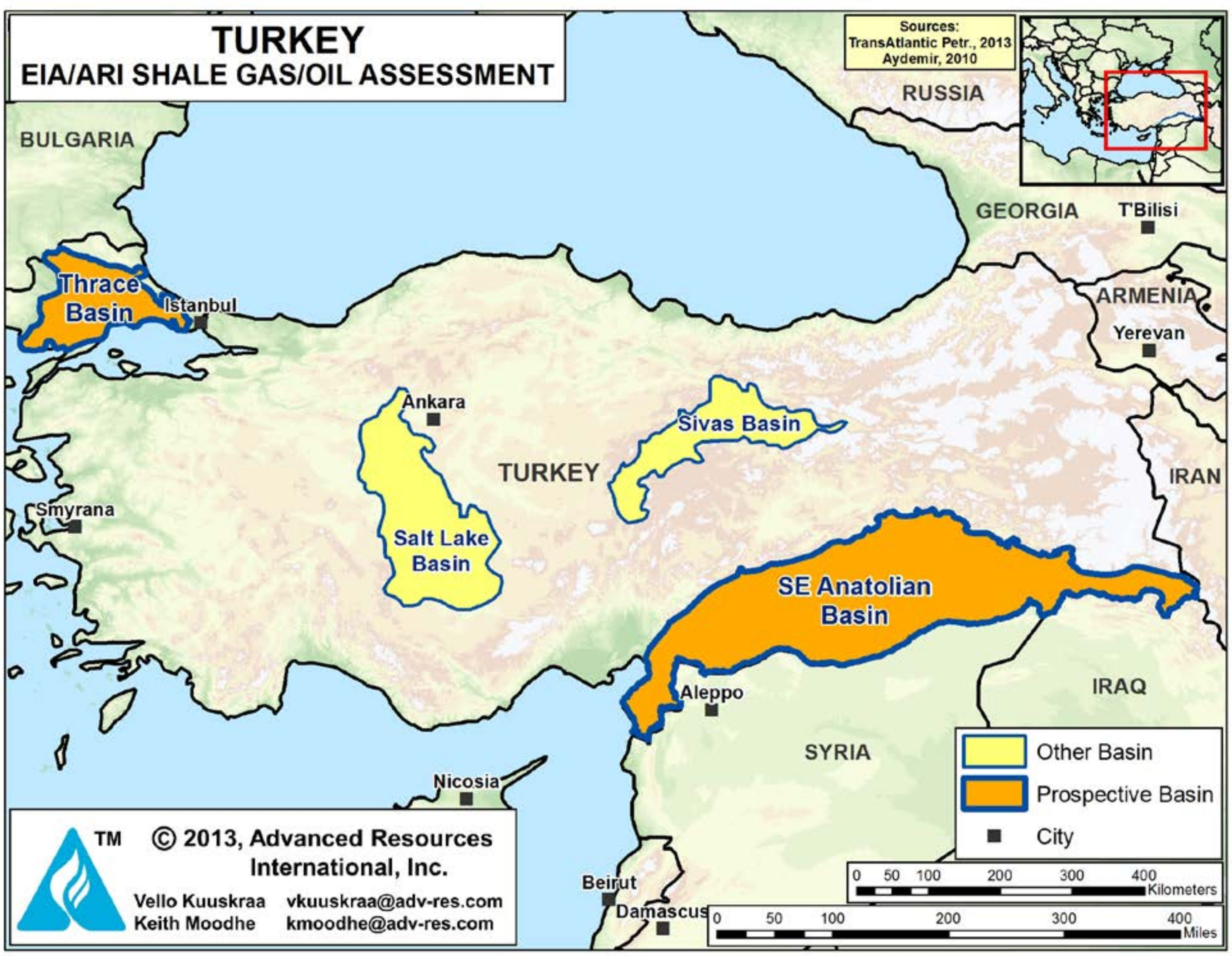
XXVI. TURKEY

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.

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

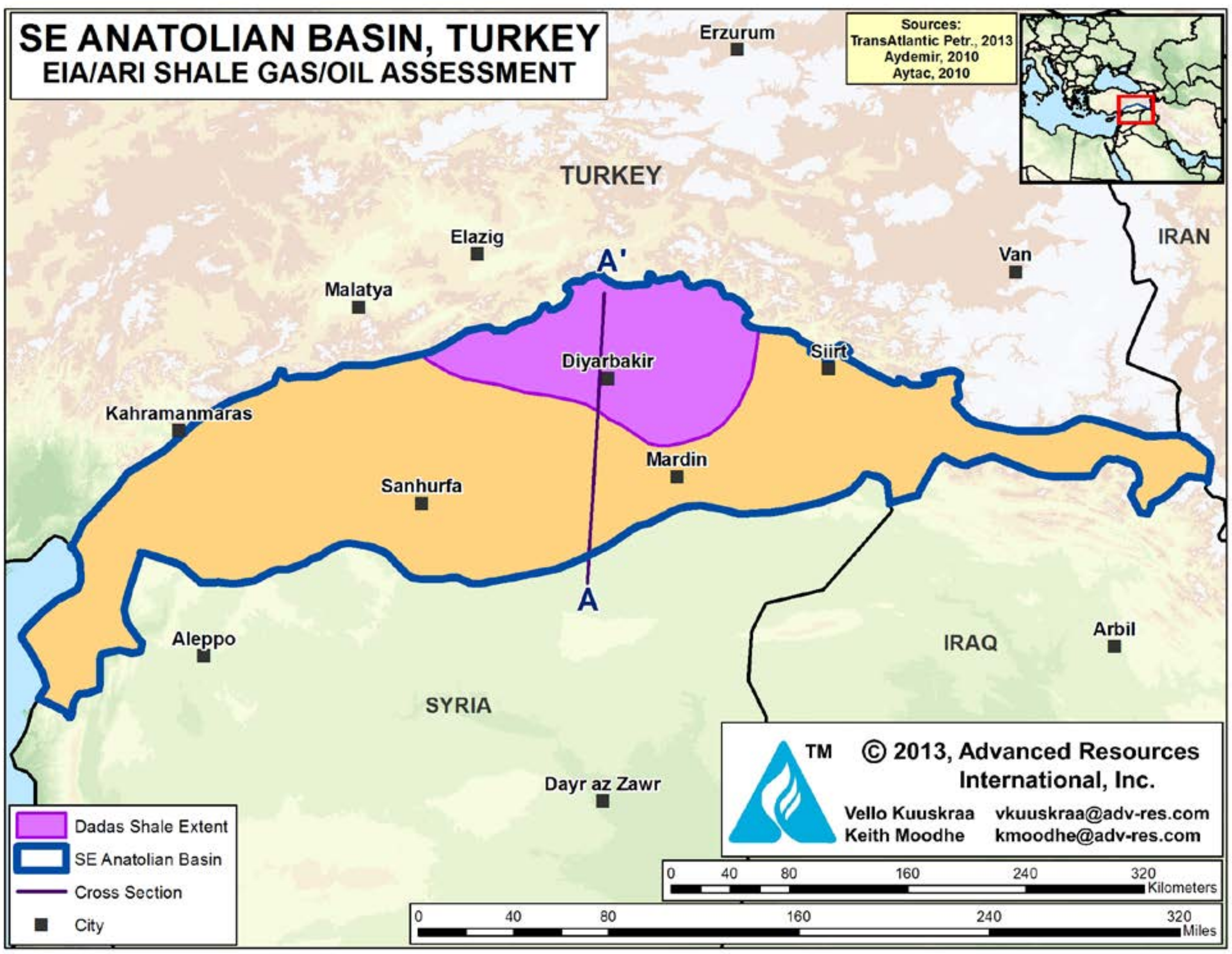
Basic Data	Basin/Gross Area		SE Anatolian (32,100 mi^2)		Thrace (6,500 mi^2)	
	Shale Formation		Dadas		Hamitabat	
	Geologic Age		Silurian-Devonian		M. - L. Eocene	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		3,540	500	150	210
	Thickness (ft)	Organically Rich	394	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-mi^2 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^o to 50^o 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.

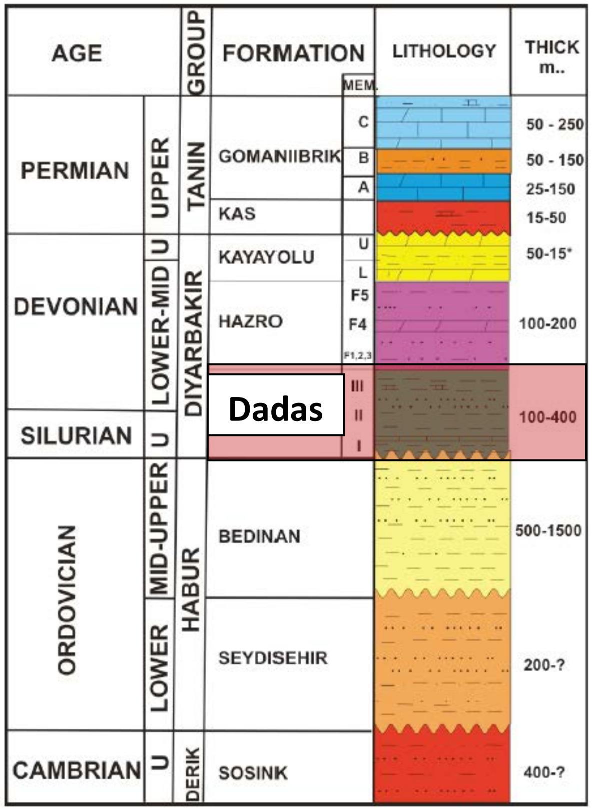
The SE Anatolian Basin contains three source rocks - - the deep Silurian Dadas Shale, the Late Cretaceous Karabogaz organic-rich limestone, and the organic-rich deposits in the Triassic-Jurassic Jodi Group.[1] The most prospective of these source rocks is the Silurian Dadas Shale, the basal member of which, called Dadas I, is the organic-rich shale interval evaluatedin 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-mi^2 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-4[1] 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)

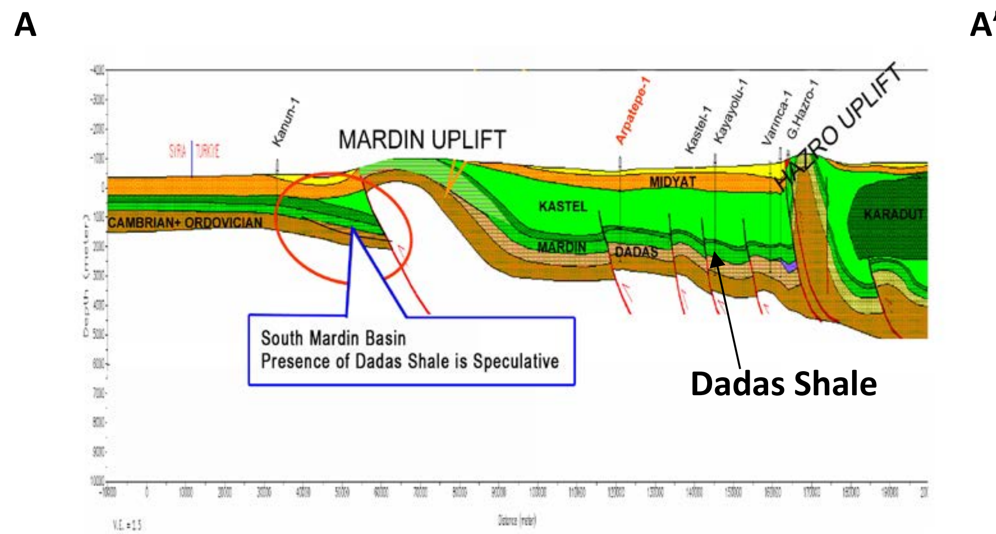
The Dadas Shale of the SE Anatolian Basin contains a 3,540-mi^2 central area prospective for shale oil and a smaller, northern 500-mi^2 prospective area for wet gas and condensate, Figure XXVI-5. Because of limited data on vitrinite reflectance, we have used Tmax of 455^{o}C as a proxy for the R_o of 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 Column[2]



Source: A. Aydemir, 2010.

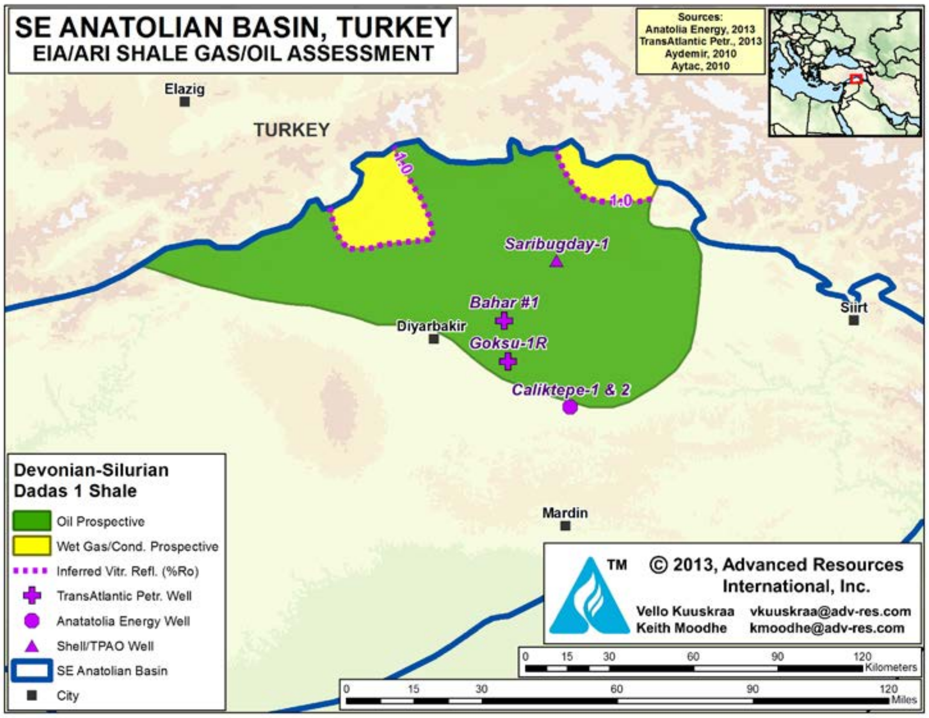
Figure XXVI-4. SW Anatolian Basin Cross-Section[1]



Source: E. Aytac, 2010.

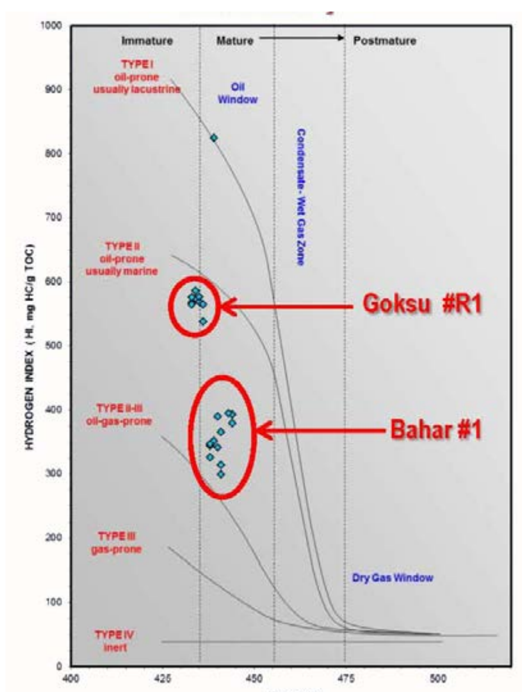
Advanced Resources International, Inc.

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^{o} to 50^{o} 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-mi^2 oil prospective area, the Dadas Shale in the SE Anatolian Basin has an estimated resource concentration of 41 million barrels/mi^2 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-mi^2 wet gas and condensate area, the Dadas Shale has resource concentrations of 91 Bcf/mi^2 for wet gas and 14 million barrels/mi^2 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

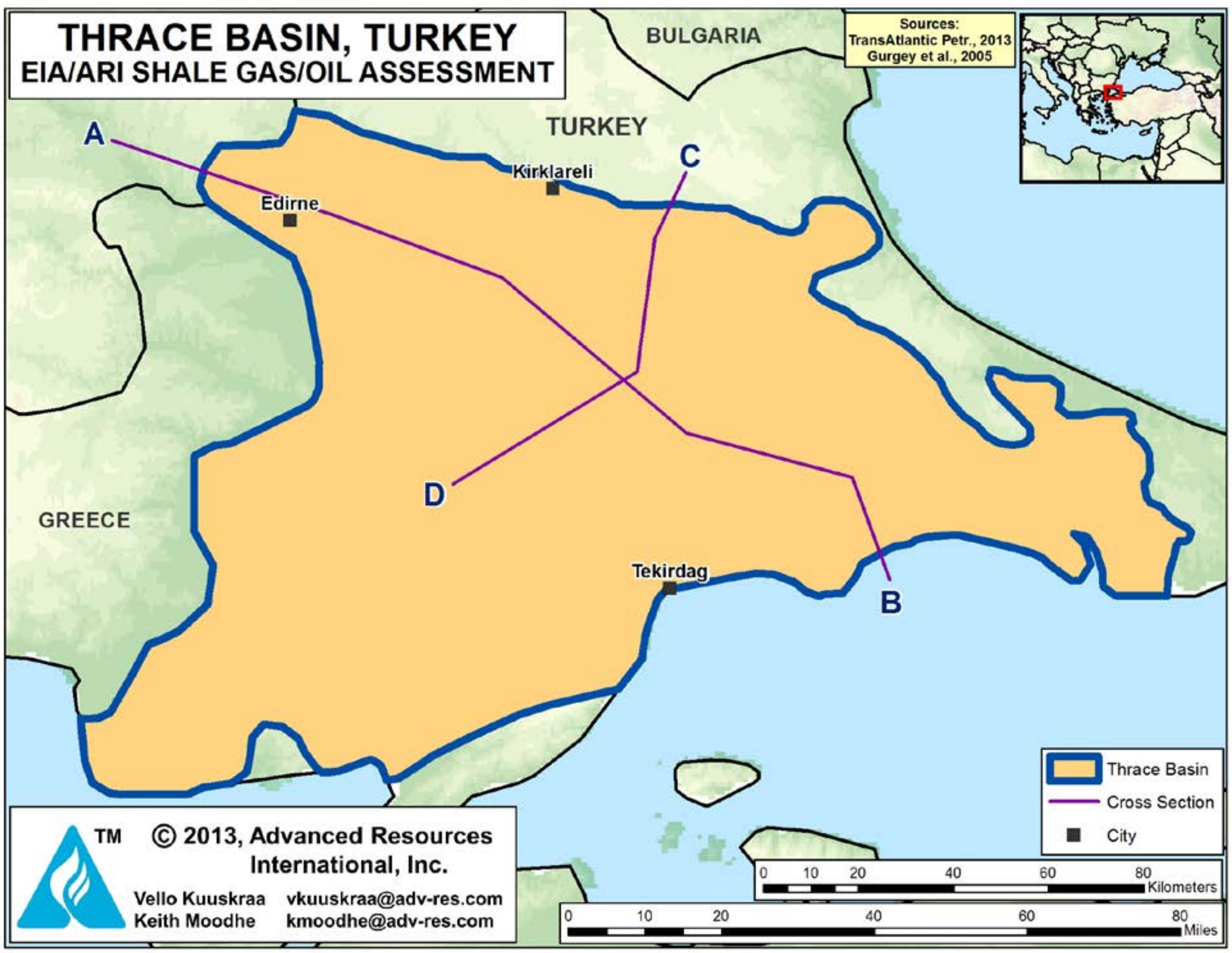
TPAO, the Turkish National Oil Company, and Shell are currently drilling the Saribugday-#1 well in License Area 4925 testing the Dadas Shale. Shell has announced a five-well exploration program for the area. Anatolia Energy drilled their first Dadas Shale evaluation well, Caliktepe-#2, on their Bismil 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 Oiksor well flowed 152 barrels of 60^{o} 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-mi^2 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]

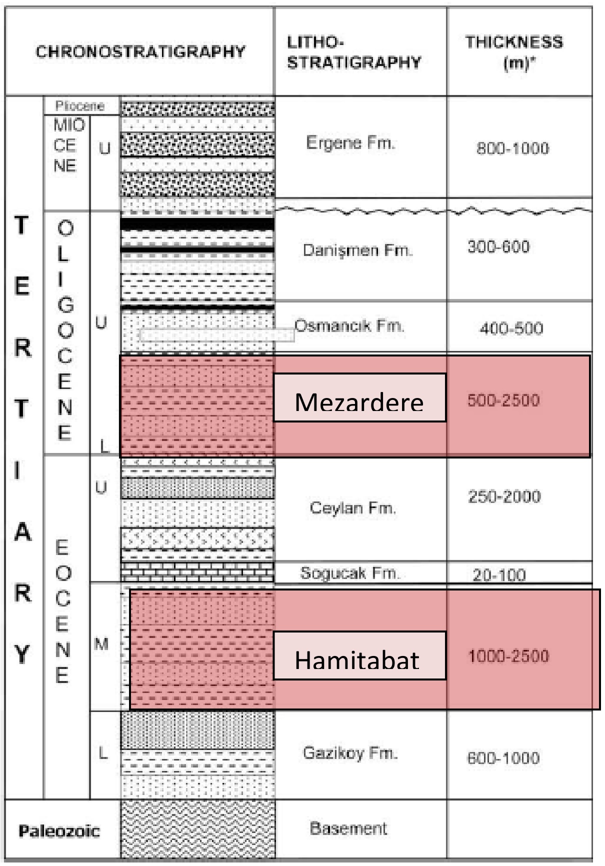
The 1,040-mi^2 prospective area identified for the Hamitabat Formation is based primarily on depth and thermal maturity data. The Hamitabat Formation contains modest-size oil (150-mi^2) and wet gas/condensate (210 mi^2) areas and a larger, 680-mi^2 prospective area for dry gas. However, a major portion 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]

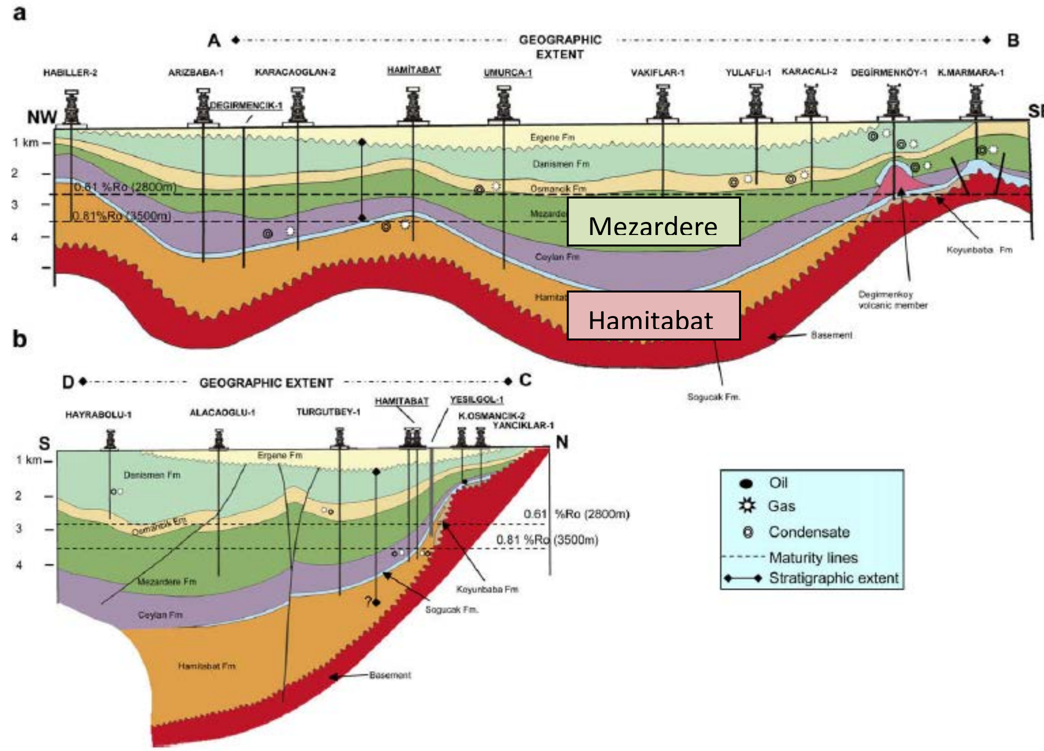
Mezardere Shale. The Mezardere Shale is a second thick, regionally extensive shale interval in the Thrace Basin, Figure XXVI-11.[8] However, because of low organic content (<2%), this shale formation has not been quantitatively assessed.

Figure XXVI-8. Thrace Basin Stratigraphic Column[5]



Source: Gürgey, Kadir, 2005.

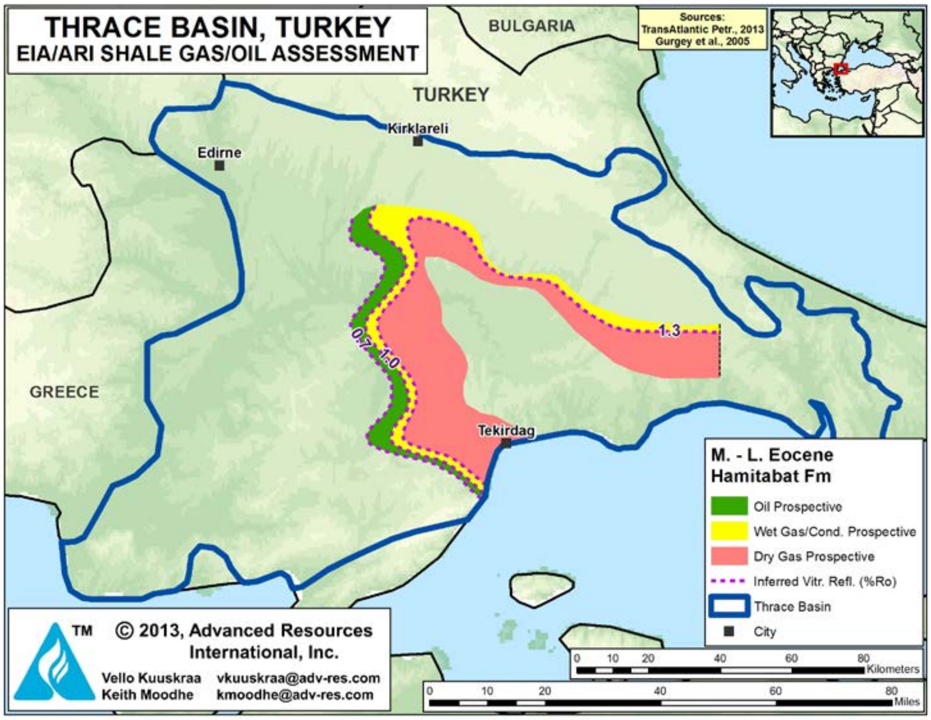
Figure XXVI-9. Thrace Basin Cross Section[5]



Source: Gürgey, Kadir, 2005.

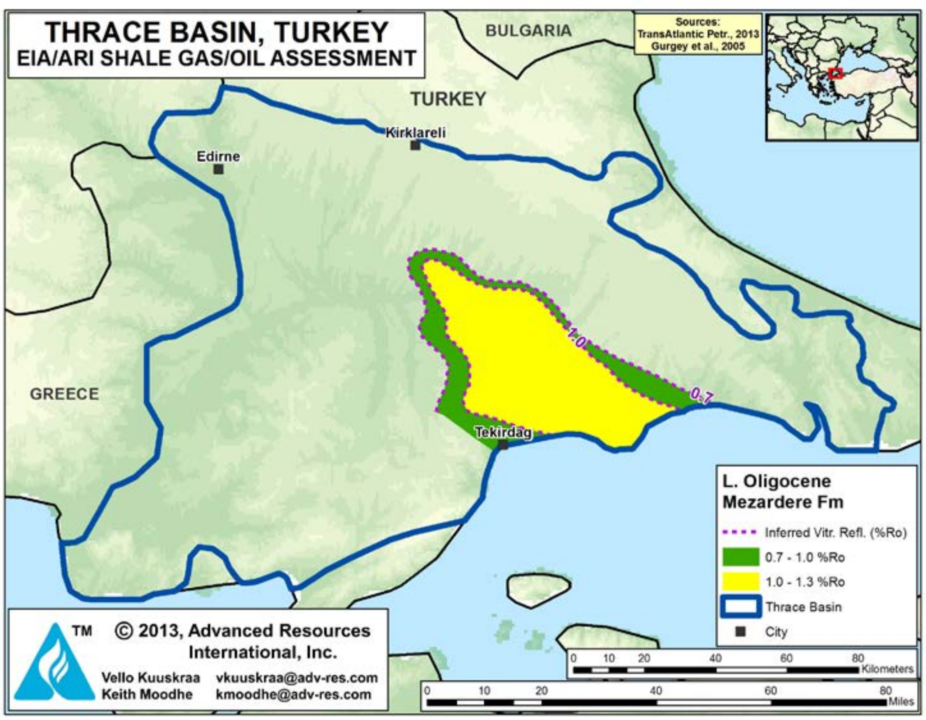
Advanced Resources International, Inc.

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/mi^2, a wet shale gas resource of 82 Bcf/mi^2, and a shale oil resource concentration of 34 million barrels/mi^2 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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