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Technically Recoverable Shale Oil and Shale Gas Resources:

China

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Executive Summary

Introduction

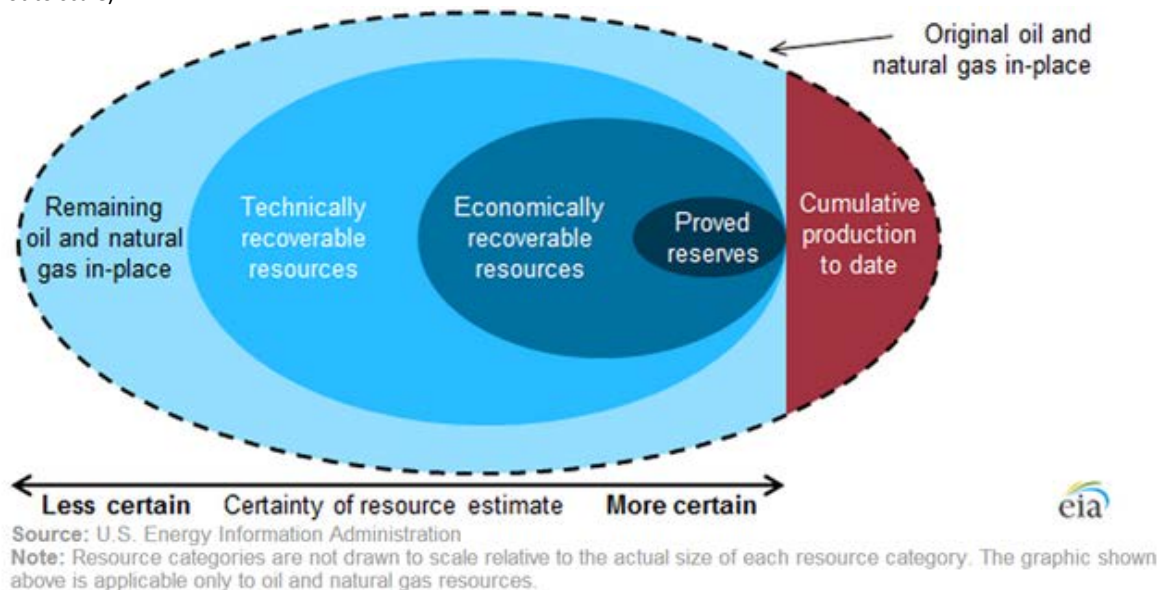
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. This chapter is from the 2013 EIA world shale report [Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States](#).

Resource categories

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource, which is the focus of this supplement as in the 2013 report, and an economically recoverable resource. Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production. Recent experience with shale gas and tight oil in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable drilling rigs and, preexisting gathering and pipeline infrastructure; and the availability of water resources for use in hydraulic fracturing. See Figure 1.

Figure 1. Stylized representation of oil and natural gas resource categorizations

(not to scale)



Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known

ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

For many purposes, oil and natural gas resources are usefully classified into four categories:

- Remaining oil and gas in-place (original oil and gas in-place minus cumulative production at a specific date)
- Technically recoverable resources
- Economically recoverable resources
- Proved reserves

The oil and natural gas volumes reported for each resource category are estimates based on a combination of facts and assumptions regarding the geophysical characteristics of the rocks, the fluids trapped within those rocks, the capability of extraction technologies, and the prices received and costs paid to produce oil and natural gas. The uncertainty in estimated volumes declines across the resource categories (see figure above) based on the relative mix of facts and assumptions used to create these resource estimates. Oil and gas in-place estimates are based on fewer facts and more assumptions, while proved reserves are based mostly on facts and fewer assumptions.

Remaining oil and natural gas in-place (original oil and gas in-place minus cumulative production). The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.

Technically recoverable resources. The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

The geophysical characteristics of the rock (e.g., resistance to fluid flow) and the physical properties of the hydrocarbons (e.g., viscosity) prevent oil and gas extraction technology from producing 100% of the original oil and gas in-place.

Economically recoverable resources. The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.

U.S. government agencies, including EIA, report estimates of technically recoverable resources (rather than economically recoverable resources) because any particular estimate of economically recoverable resources is tied to a specific set of prices and costs. This makes it difficult to compare estimates made by other parties using different price and cost assumptions. Also, because prices and costs can change over relatively short periods, an estimate of economically recoverable resources that is based on the prevailing prices and costs at a particular time can quickly become obsolete.

Proved reserves. The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced. Like economically recoverable resources, proved reserves shrink or grow as prices and costs change. The U.S. Securities and Exchange Commission regulates the reporting of company financial assets, including those proved oil and gas reserve assets reported by public oil and gas companies.

Each year EIA updates its report of proved U.S. oil and natural gas reserves and its estimates of unproved technically recoverable resources for shale gas, tight gas, and tight oil resources. These reserve and resource estimates are used in developing EIA's [Annual Energy Outlook](#) projections for oil and natural gas production.

- Proved oil and gas reserves are reported in EIA's [U.S. Crude Oil and Natural Gas Proved Reserves](#).
- Unproved technically recoverable oil and gas resource estimates are reported in EIA's [Assumptions](#) report of the Annual Energy Outlook. Unproved technically recoverable oil and gas resources equal total technically recoverable resources minus the proved oil and gas reserves.

Over time, oil and natural gas resource volumes are reclassified, going from one resource category into another category, as production technology develops and markets evolve.

Additional information regarding oil and natural gas resource categorization is available from the [Society of Petroleum Engineers](#) and the [United Nations](#).

Methodology

The shale formations assessed in this supplement as in the previous report were selected for a combination of factors that included the availability of data, country-level natural gas import dependence, observed large shale formations, and observations of activities by companies and governments directed at shale resource development. Shale formations were excluded from the analysis if one of the following conditions is true: (1) the geophysical characteristics of the shale formation are unknown; (2) the average total carbon content is less than 2 percent; (3) the vertical depth is less than 1,000 meters (3,300 feet) or greater than 5,000 meters (16,500 feet), or (4) relatively large undeveloped oil or natural gas resources.

The consultant relied on publicly available data from technical literature and studies on each of the selected international shale gas formations to first provide an estimate of the “risked oil and natural gas in-place,” and then to estimate the unproved technically recoverable oil and natural gas resource for that shale formation. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

The risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation's success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates. The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by matching a shale formation's geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource. The specific tasks carried out to implement the assessment include:

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.

2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*¹ and *adsorbed gas*² that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.³ For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources⁴ represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

Based on U.S. shale production experience, the recovery factors used in this supplement as in the previous report for shale gas generally ranged from 20 percent to 30 percent, with values as low as 15 percent and as high as 35 percent being applied in exceptional cases. Because of oil's viscosity and capillary forces, oil does not flow through rock fractures as easily as natural gas. Consequently, the recovery factors for shale oil are typically lower than they are for shale gas, ranging from 3 percent to 7 percent of the oil in-place with exceptional cases being as high as 10 percent or as low as 1 percent. The consultant selected the recovery factor based on U.S. shale production recovery rates, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery. The recovery rates used in this analysis are based on an extrapolation of shale well production over 30 years. Because a shale's geophysical characteristics vary significantly throughout the formation and analog matching is never exact, a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.

Key exclusions

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

¹ Free gas is natural gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.

² Adsorbed gas is natural gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the natural gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.

³ The recovery factor pertains to percent of the original oil or natural gas in-place that is produced over the life of a production well.

⁴ Referred to as risked recoverable resources in the consultant report.

production. In addition, several other exclusions were made for this supplement as in the previous report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

Some of the key exclusions for this supplement as in the previous report include:

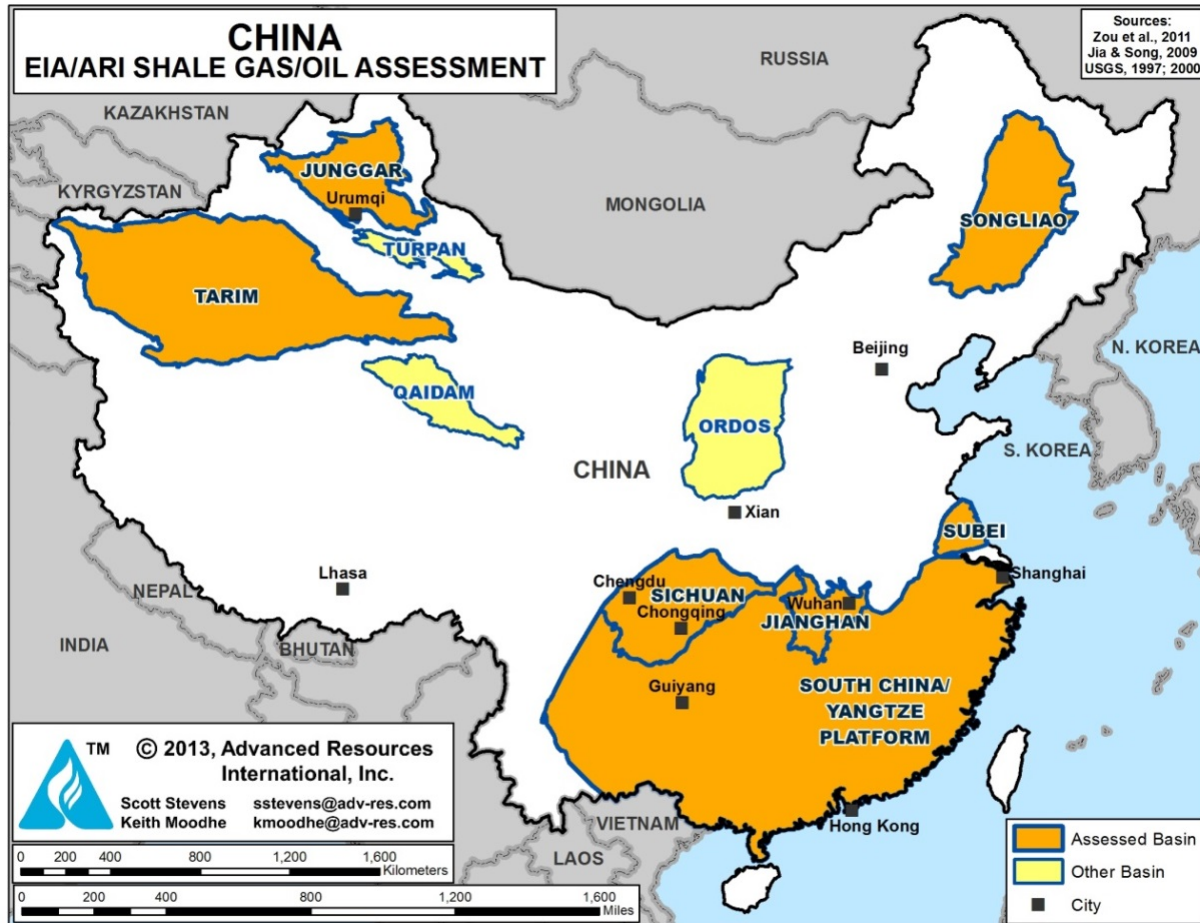
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
3. **Assessed formations without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional shale formations would likely increase the estimated resource.
4. **Countries outside the scope of the report**, the inclusion of which would likely add to estimated resources in shale formations. It is acknowledged that potentially productive shales exist in most of the countries in the Middle East and the Caspian region, including those holding substantial non-shale oil and natural gas resources.
5. **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

XX. CHINA

SUMMARY

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

Figure XX-1. China's Seven Most Prospective Shale Gas and Shale Oil Basins are the Jiangnan, 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, Jiangnan 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
	Risky GIP (Tcf)		499.6	1,146.1	715.2	181.0	414.7
	Risky 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		Jiangnan (14,440 mi ²)					
	Shale Formation		Niutitang/Shujintuo	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
	Risky GIP (Tcf)		45.7	8.2	19.8	1.8	10.6	27.7
	Risky 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/Gaobiaojian		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		Jiangan (14,440 mi ²)			Greater Subei (55,000 mi ²)	
	Shale Formation		Longmaxi	Qixia/Maokou		Wufeng/Gaobijian	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.

Basic Data	Basin/Gross Area		Tarim (234,200 mi ²)		Junggar (62,100 mi ²)		Songliao (108,000 mi ²)
	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, Jiangnan, 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 H₂S. The adjacent Yangtze Platform and the Jiangnan 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 ft³/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, Jiangnan, 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-Low er	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		200 - 500	
		Lower	Maokou			
		Qixia-Liangshan				
	CARBONIFEROUS	Mississippian	Huanglong	270 - 320	0 - 500	
	SILURIAN	Upper		320 - 570	0 - 1500	
		Lower	Longmaxi		0 - 600	
	ORDOVICIAN					
	CAMBRIAN	Upper		Xixiangchi	0 - 2500	
		Middle		Yuxiansi		
Lower			Qiongzhusi			
PROTEROZOIC	SINIAN	Upper	Dengying	570 - 850	200 - 1100	
			Doushantuo		0 - 400	
	Lower					
PRE-SINIAN				850		

Source Rock
Conventional Reservoir

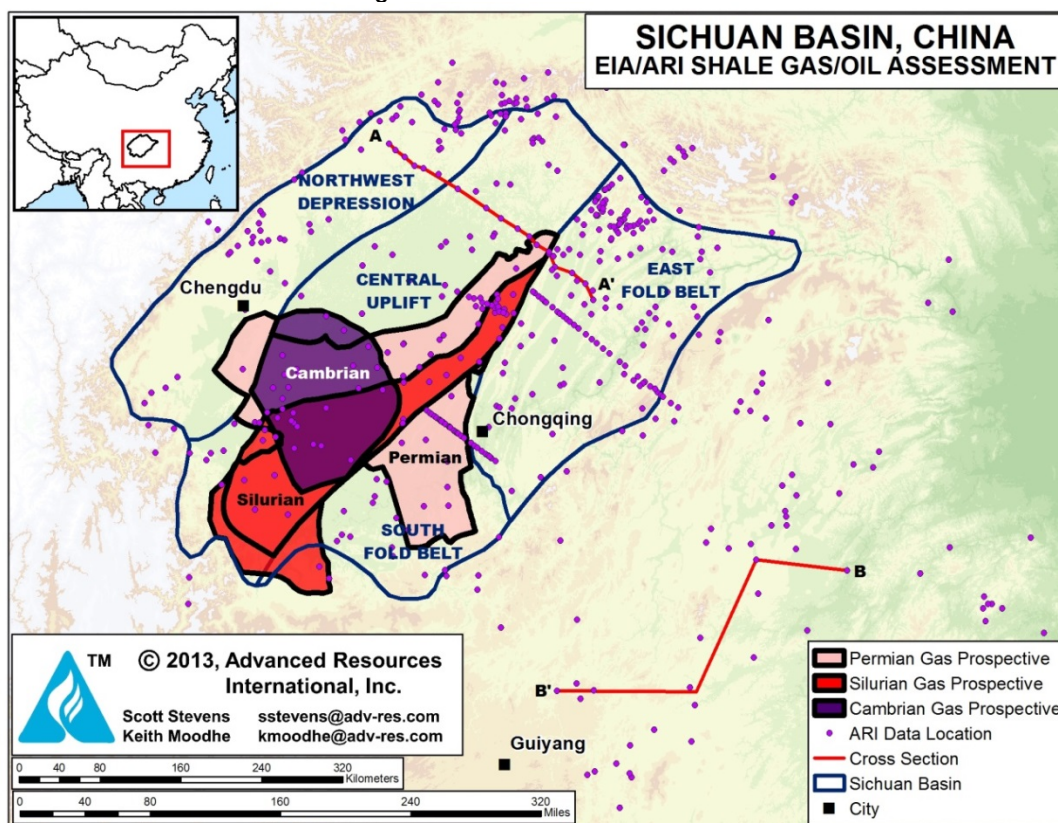
Source: ARI, 2013.

The **Sichuan Basin** covers a large 74,500-mi² 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 H₂S concentrations (up to 50%) and CO₂ (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.



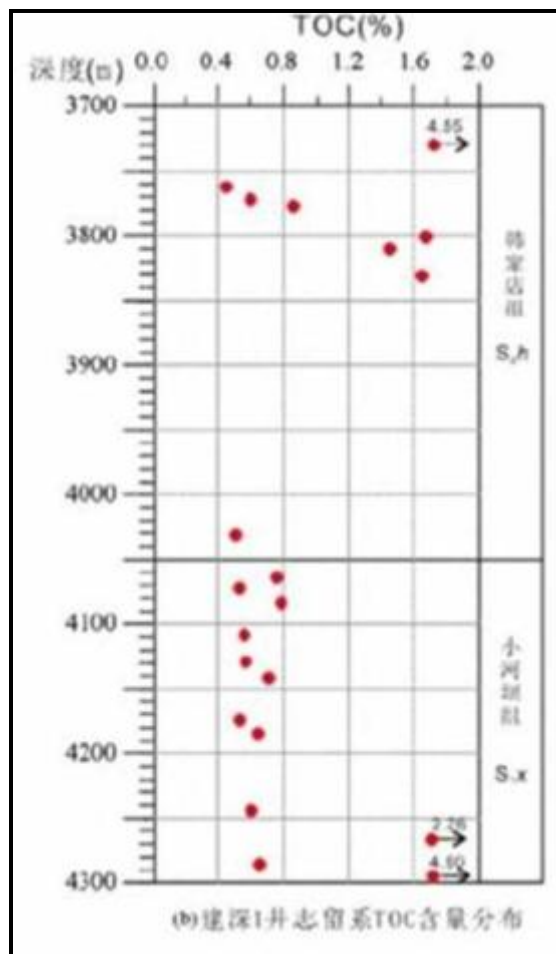
Source: ARI, 2013.

The 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 H₂S 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 H₂S 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 Luoheizai 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

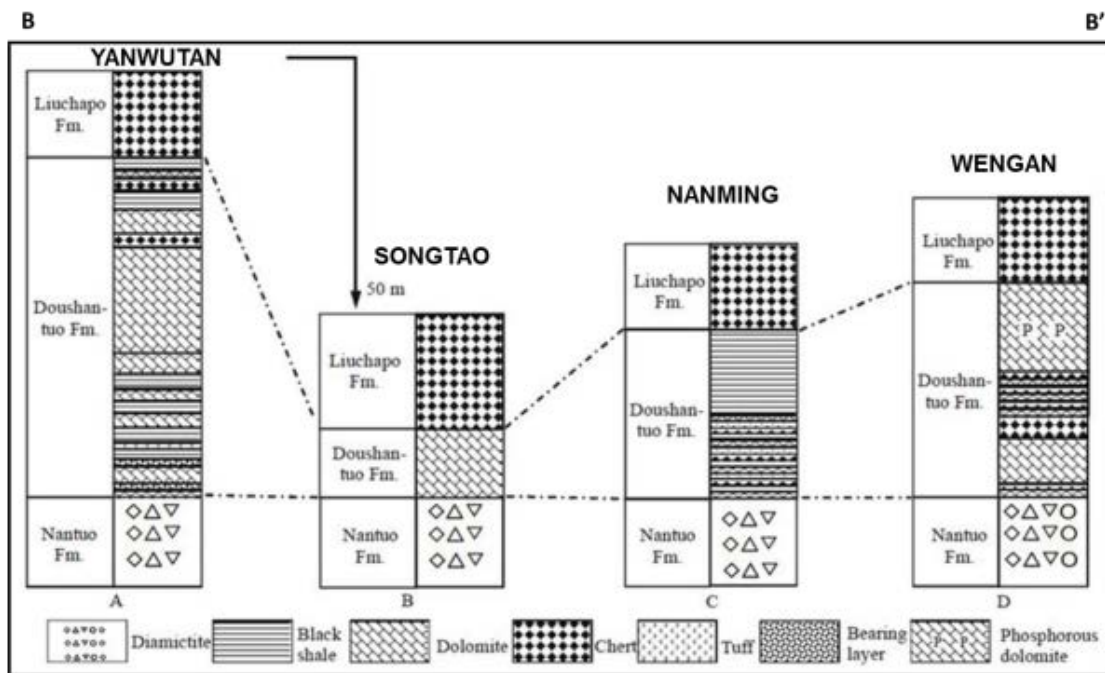
quartz and other brittle minerals (65%) and fairly low in clay (30%). In 1966 a conventional gas well flowed nearly 1 million ft³/day from an unstimulated organic-rich Qiongzhusi shale interval at a depth of 2,800 m. PetroChina recently tested the first horizontal well completed in the Qiongzhusi at 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

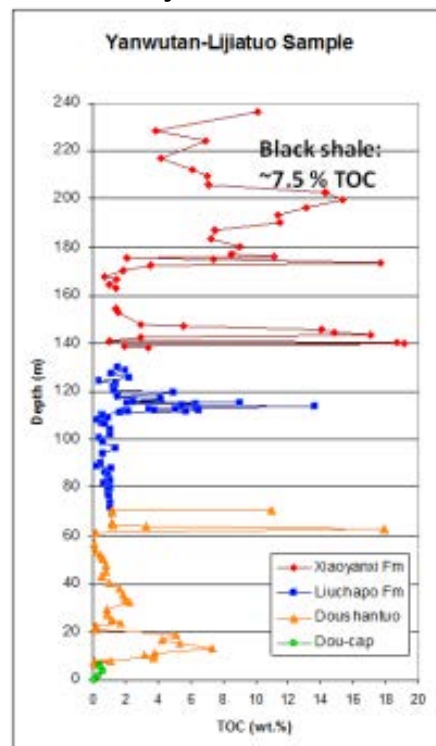
The **Jiangnan Basin** is a conventional petroleum producing region covering 14,500-mi² in the central Yangtze Platform of Jiangxi and Hubei provinces, close to the major city of Wuhan. Jiangnan is a rift basin that developed on the Central Yangtze Platform during Cretaceous to Tertiary time, induced by transpressional tectonics related to India's collision with Asia. Somewhat overlooked for shale exploration, the Jiangnan 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 Jiangnan 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.



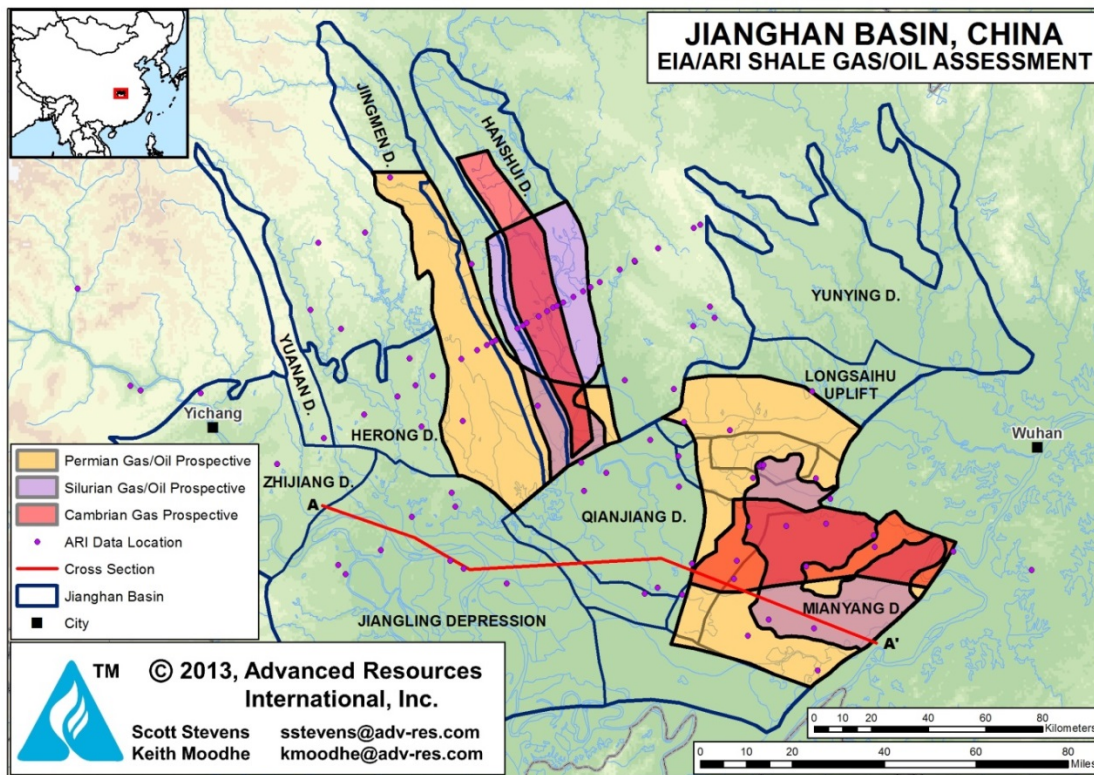
Source: Guo et al., 2007.

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 Jiangnan Basin Showing ARI-Proprietary Shale Gas Data Locations and Relative Size of the Prospective Areas for Silurian and Permian Shales.



Source: ARI, 2013.

The Jiangnan Basin is structurally more complex than the Sichuan Basin, although less so than the Yangtze Platform. Jiangnan 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 Paleogene 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 Jiangnan 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 Jiangnan Basin are immature (R_o 0.4%), likely clay-rich, and not considered prospective for shale.

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

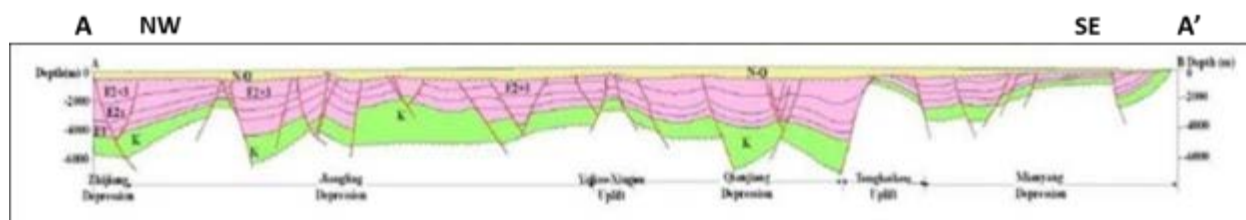
JIANGNAN BASIN				
ERA	PERIOD	EPOCH	FORMATION	
CENOZOIC	QUATERNARY	Pleistocene	Pingyuan	
	NEOGENE	Miocene	Guanghusai	
		Oligocene	Jinghezhen	
	PALEOGENE	Eocene	Qianjiana	
		Paleocene	Xingouzhuai	
MESOZOIC	CRETACEOUS	Upper	Paomagang	
		Lower	Honghuntao Luojiangtan	
	JURASSIC	Middle	Xiaximiao	
		Lower	Naijiashan Tongzhuyian	
	TRIASSIC	Upper	Wanglongtan	
		Middle	Jiugang Badong	
		Lower	Jialingjiang Daye	
	PALEOZOIC	PERMIAN	Upper	Dalong Wikoaping Maokou
			Lower	Qixia
		CARBONIFEROUS	Upper	Chuanshan
Lower			Huanglong	
DEVONIAN		Middle		
		Middle	Shamao	
SILURIAN		Lower	Luoreping Longmaxi	
		ORDOVICIAN	Upper	Wufeng Lingxiang
Baota				
Lower			Miaopo Guniutan Dawan Honghuayuan Fenxiang Nanjinguan	
	CAMBRIAN		Upper	Shanyoudong
Middle		Qinjiamao Shilongdong		
Lower		Tianheban Shipai Shujintuo		
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 Jiangnan 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 Jiangnan 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

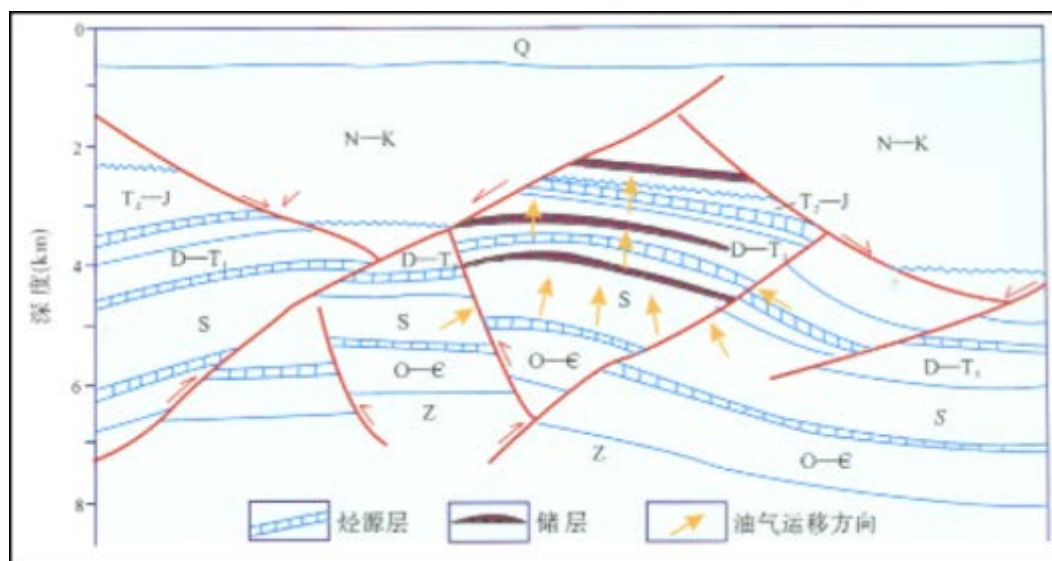
The underlying Cambrian section is about 1 km thick, faulted, and uplifted to about 2-km depth in the southeastern Jiangnan Basin, Figure XX-13.²¹ We identified three marine Paleozoic source-rock shale leads in the Jiangnan Basin (L. Cambrian, L. Silurian, and Permian; see below).

Figure XX-11. Regional Cross Section of the Central Jiangnan 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.



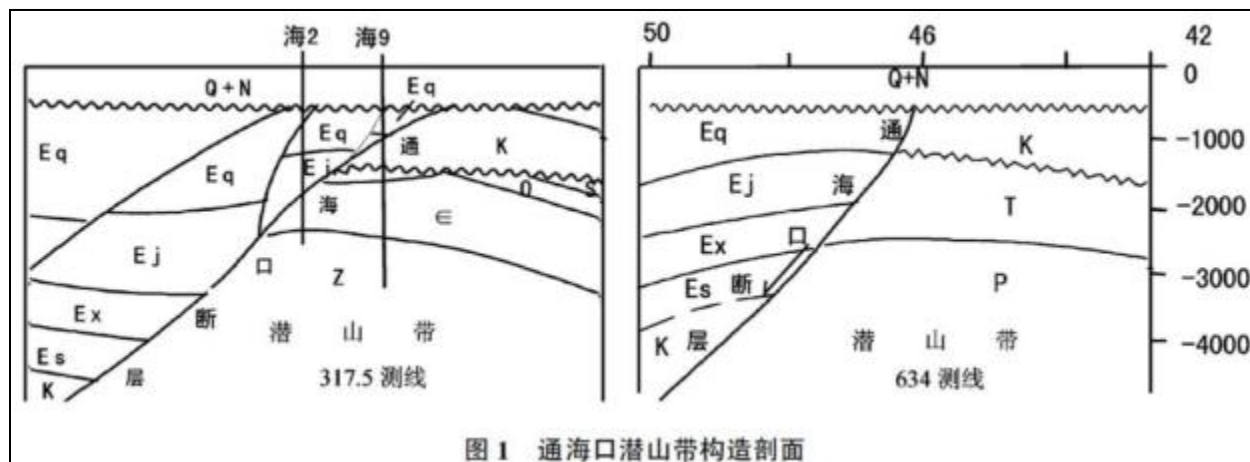
Source: Zhang et al., 2010.

Figure XX-12. Detailed Cross-section from Mianyang Depression in the Eastern Jiangnan 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 Jiangnan Basin.
The Cambrian Section Here is Faulted and about 1 km Thick.

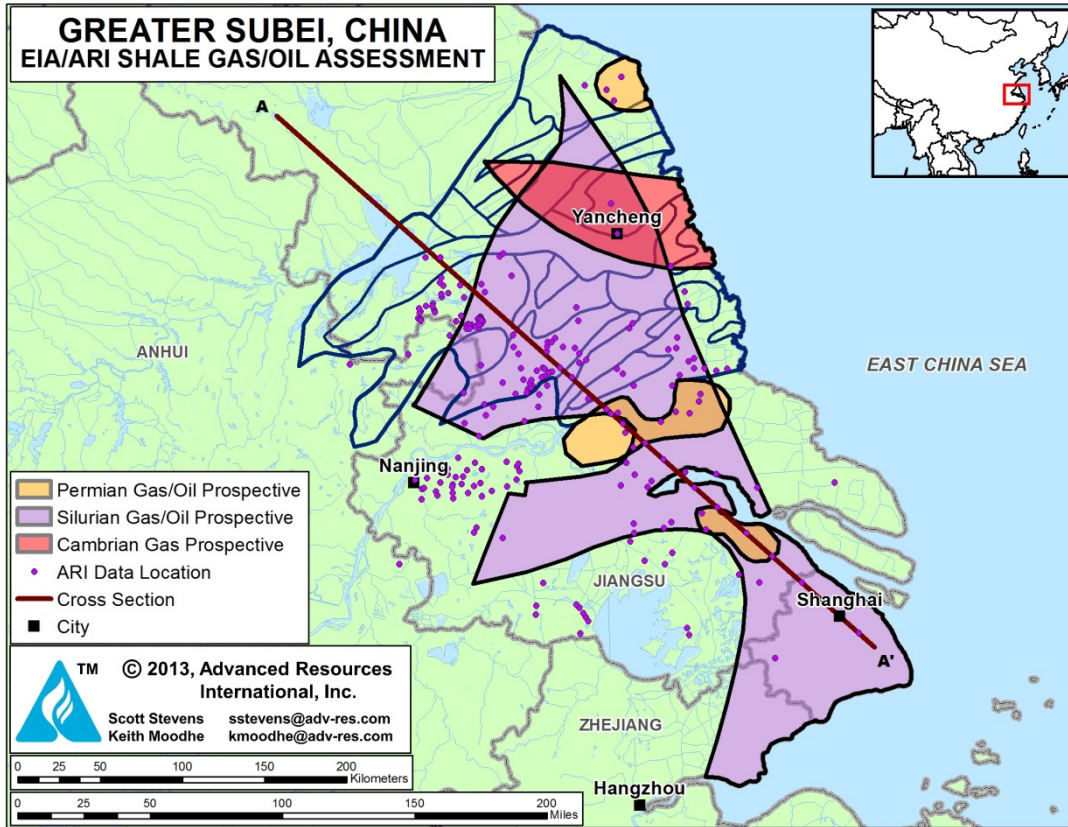


Source: Li et al., 2007.

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-mi² 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.

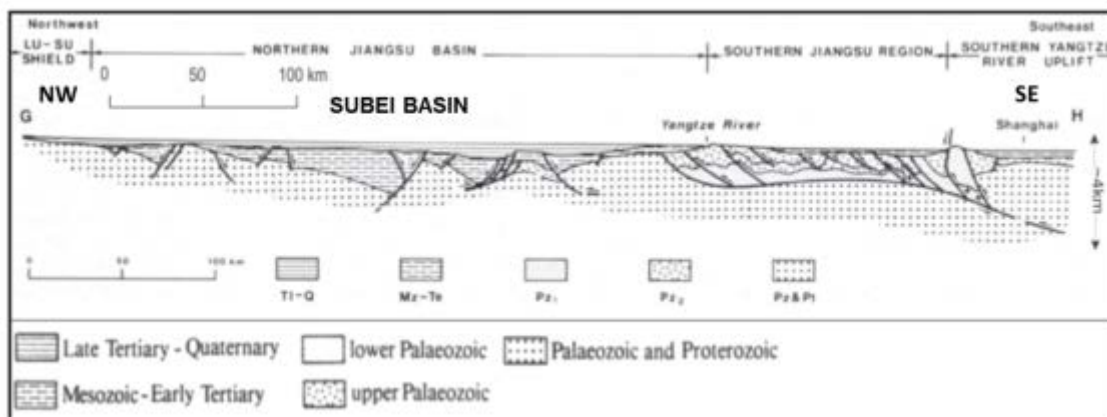
Sedimentary rocks in the Subei Basin range from L. Cambrian to Eocene, including potentially prospective marine shale source rocks of L. Cambrian, L. Silurian, and U. Permian age, Figure XX-16.²³ Conglomerates and mudstones of the U. Cretaceous to L. Paleocene Taizhou Group are the conventional petroleum 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}	Chihhsia 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/S2f}	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	Є _{1l} , Є _{2p}	Loushanguan, Paotaishan Fms	Grey and white thick-bedded dolomite, dark grey thick-bedded limestone.	
	Lower	Є _{1mu}	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 ($R_o \approx 0.4\%$ 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-mi² 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-mi² 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.

Jiangnan Basin. The L. Cambrian Niutitang Formation (1,280-mi² high-graded lead) has the best organic richness (6.6%), is dry-gas prone ($R_o \sim 2.25\%$) but also the deepest (average 13,000 ft). The L. Silurian Longmaxi Formation (1,960-mi² high-graded lead) has less organic richness (TOC of 2.0%), also is dry-gas prone ($R_o \sim 2.0\%$), and is found at moderate depth (average 11,500 ft). Finally, the Permian Qixia/Maokou Fm (2,150-mi² high-graded lead) has lower organic richness (2.0%), is still dry-gas prone ($R_o \sim 1.5\%$) and occurs at shallower depth (average 9,000 ft). The geothermal gradient in the Jiangnan 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 Jiangnan Basin, although Jiangnan 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 H₂S 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, H₂S, 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.

Jiangnan 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-mi² 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-mi² 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. Jiangnan 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-mi² 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-mi² 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-mi² 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-km² 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 km² 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 ft³/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-km² Kaili block near Chevron's Qiannan block. In July 2011 ExxonMobil was reported by Sinopec to be evaluating the 3,644-km² 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.

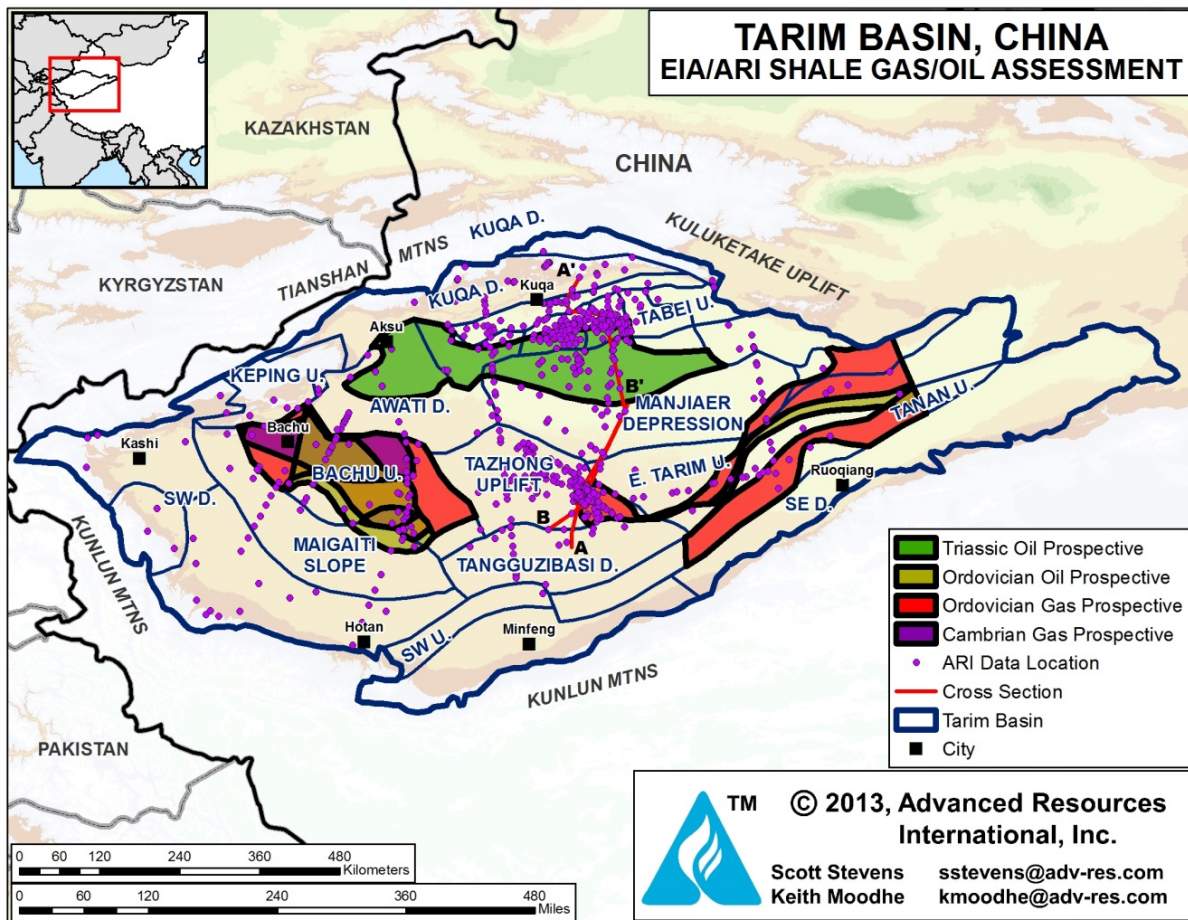
Jiangnan and Subei Basins. The only reported shale activity in the Jiangnan Basin was Sinopec's December 2010 report of "gas flows in a shale gas exploration well" (no details provided). The same report noted that BP was evaluating Permian shale in the 1,000-km² Huangqiao block, the only exploration 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 mi²). 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

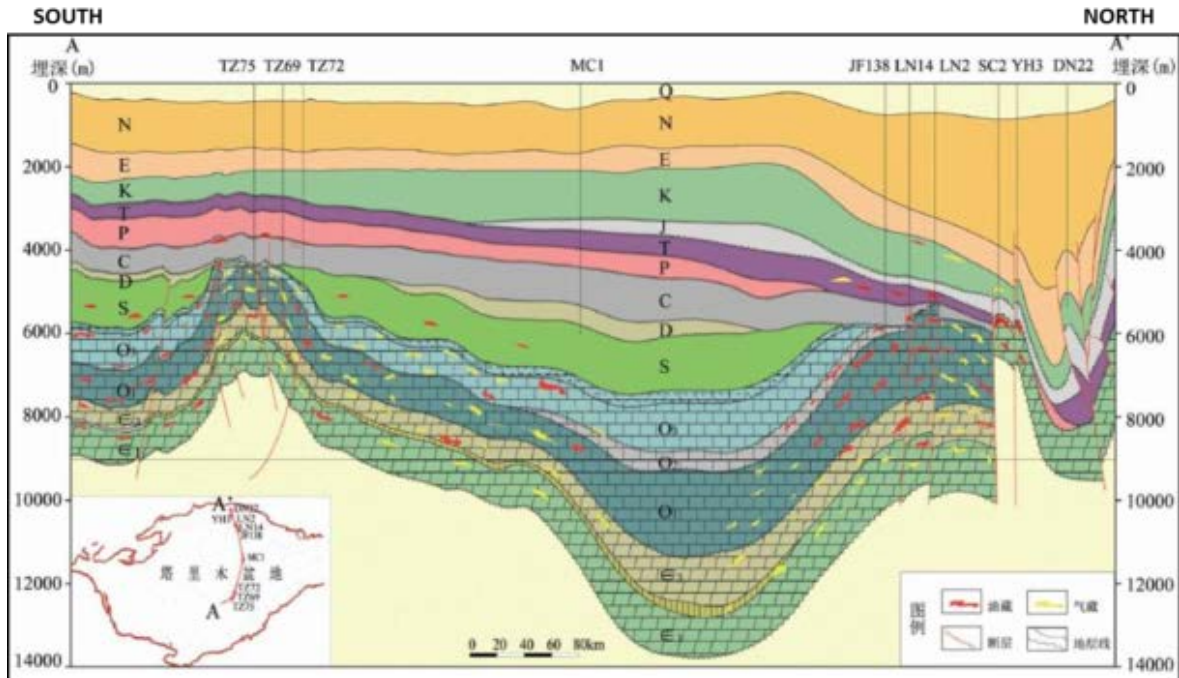
PetroChina and Sinopec produced an average 261,000 b/d of oil from conventional reservoirs in the Tarim during 2011 and are investing heavily to double output there by 2015. The basin also produced 1.6 Bcfd of natural gas in 2011 that was transported to Shanghai via the two 4,000-km West-to-East pipelines. 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

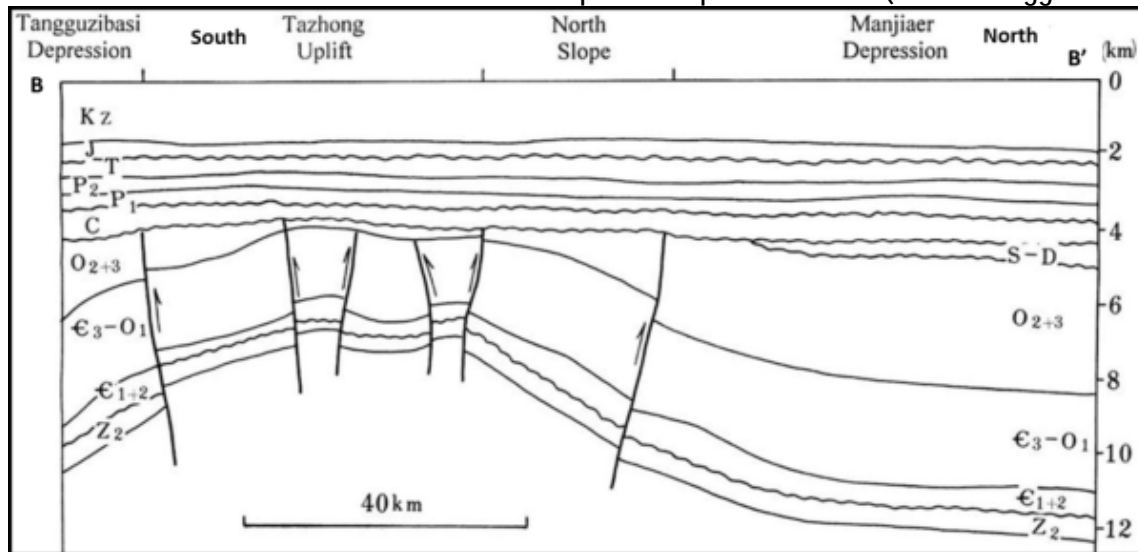
Multiple petroleum source rocks of various ages occur in the Tarim Basin, including the Cambrian, Ordovician, Carboniferous, Triassic, Cretaceous, and Tertiary, **Figure XX-20**. Marine-deposited black shales of Cambrian and particularly Ordovician age are considered the most important source rocks in 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.

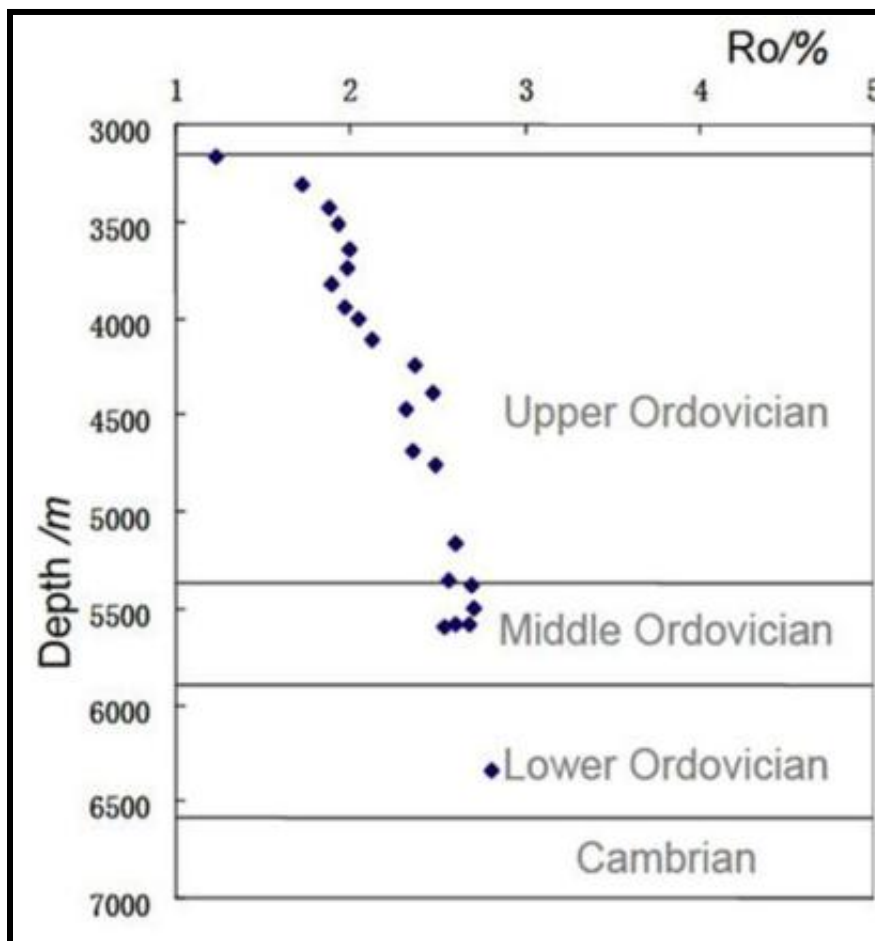
Figure XX-20. Stratigraphy of the Tarim Basin, Highlighting Prospective Cambrian, Ordovician, Carboniferous, Triassic, Cretaceous, and Tertiary Source Rocks.

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} J _{1k}			
	TRIASSIC				
PALEOZOIC	PERMIAN	Upper	Shazijing Aqiaqun	290	0 - 780
		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	Hetuoao (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	Xiaerbulake		74	
PROTEROZOIC	SINIAN			600+	200 - 1100
Source Rock		Conventional Reservoir			

Source: ARI, 2013.

The Lower Ordovician Hetuoao (O₁₋₂) 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 (O₂) 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 (O₃) 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.

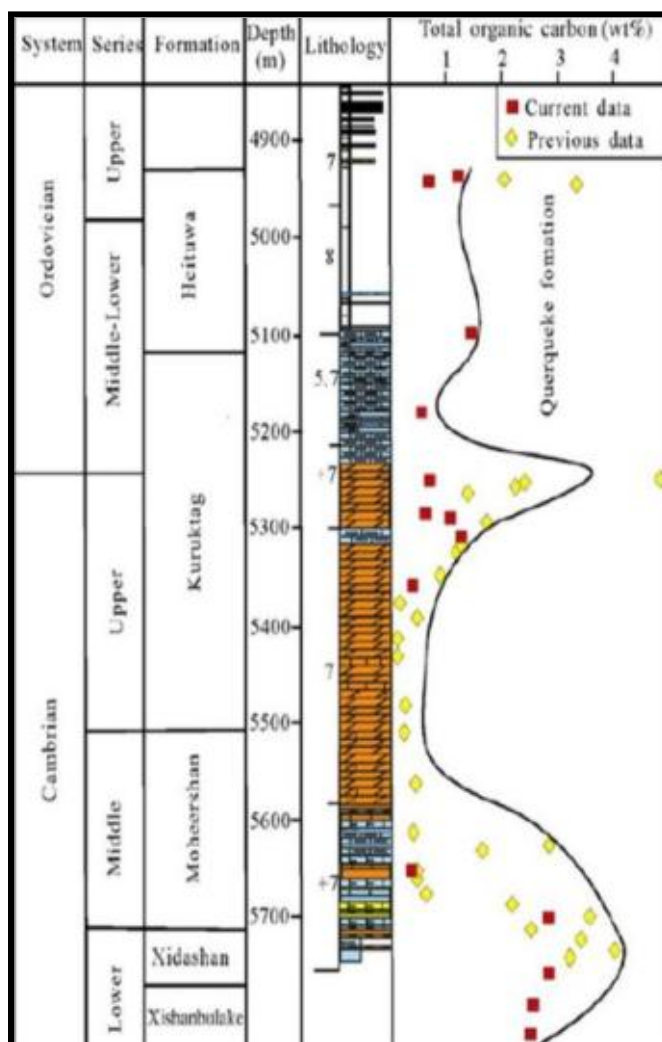


Source: Lan et al., 2009.

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)

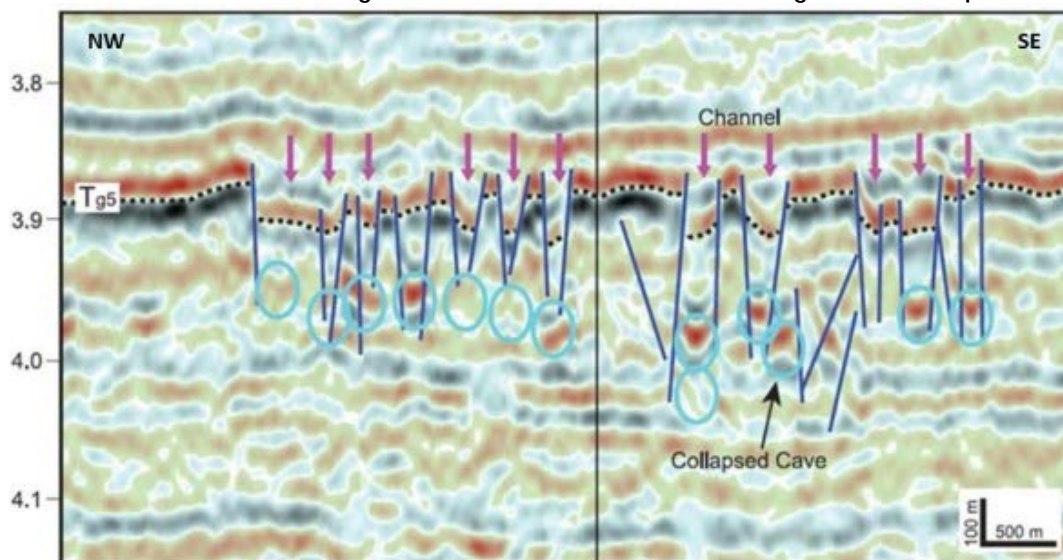
New geologic information gathered by ARI since the 2011 study indicates that shale formations in the Tarim are considerably deeper than previously mapped. The new data show that a significant amount of the Ordovician and, particularly, the Cambrian resource is subject to the 5-km prospective depth “haircut”. 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 geohazard that would need to be avoided during shale development.

Within its 6,520-mi² 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 mi², 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-mi² shale gas prospective area, with 390 ft of high-TOC shale in the dry-gas window (R_o of 2.0%). A 10,450-mi² 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-mi² 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-mi² 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-mi² 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-mi² 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-mi² 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.

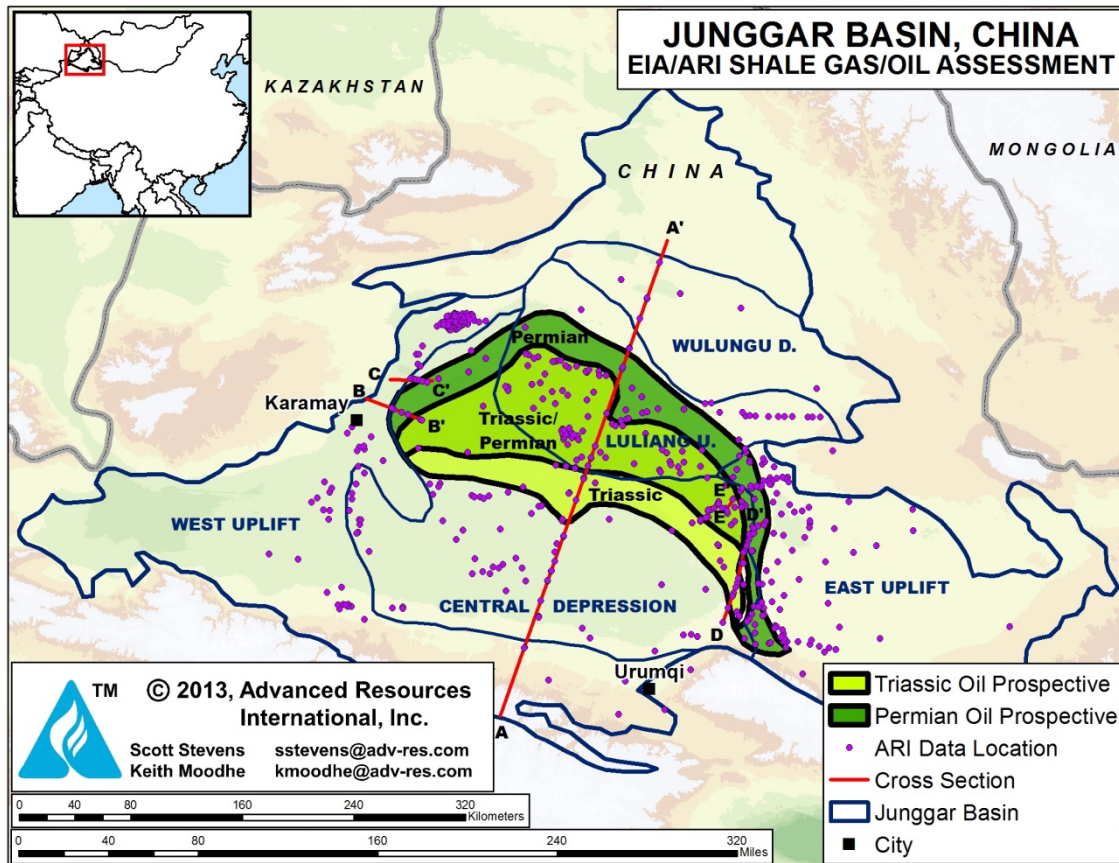
3 JUNGGAR BASIN

3.1 Introduction and Geologic Setting

Like its larger neighbor the Tarim Basin, the 62,000-mi² 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-Pro prospective Areas.



Source: ARI, 2013.

The Junggar Basin is an asymmetric cratonic basin with a thrustured 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
			Taxihe	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	Bajiantan	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		430 - 1700
		P1	Fengchen	270 - 290	1800 - 4000
	Jiamuhe				
	CARBONIFEROUS	C2	Taliegua	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.

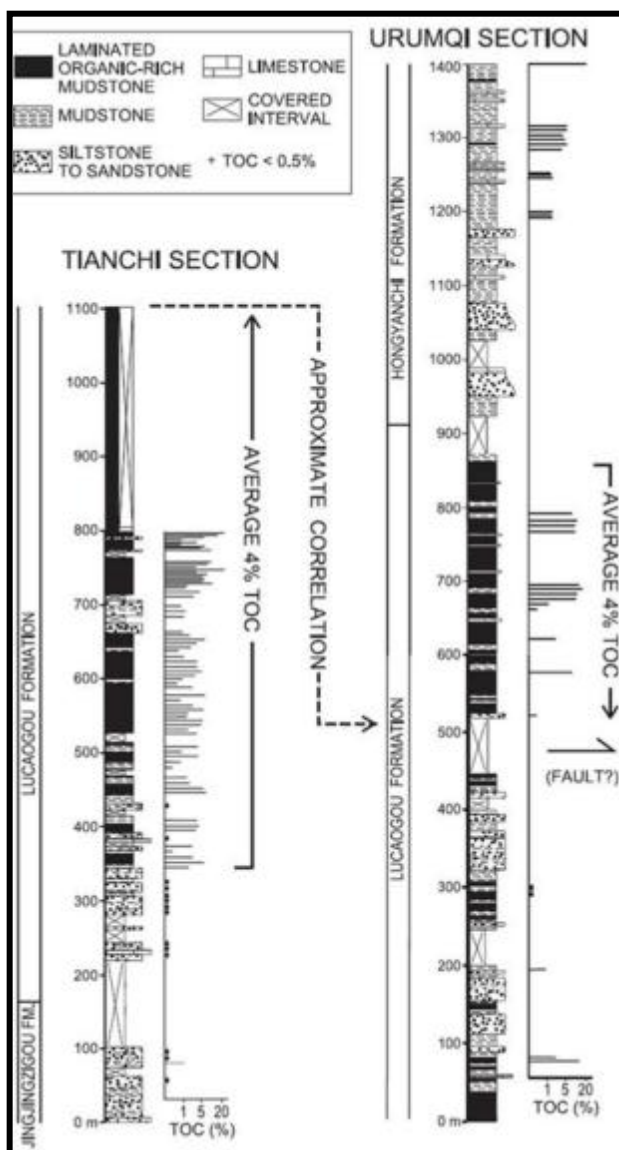
The single most important source rock is the Mid-Permian Pingdiquan Formation (known as Lucaogou in the south), a lacustrine to deltaic deposit up to 1,200 m thick present. It consists of grey to black mudstones, oil shales and dolomitic mudstones interbedded with thin sandy mudstones, shaly siltstones, 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 Haojiagou 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 thrust 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%).

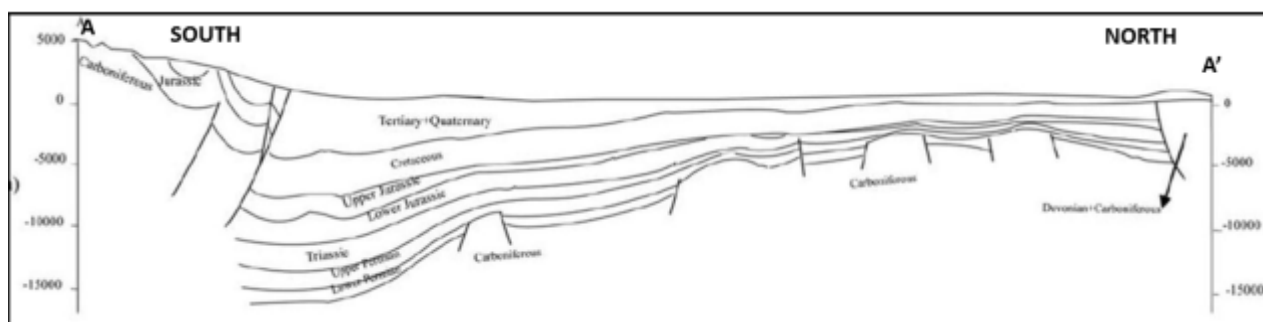


Source: Carroll and Wartes, 2003.

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 overthrust 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.

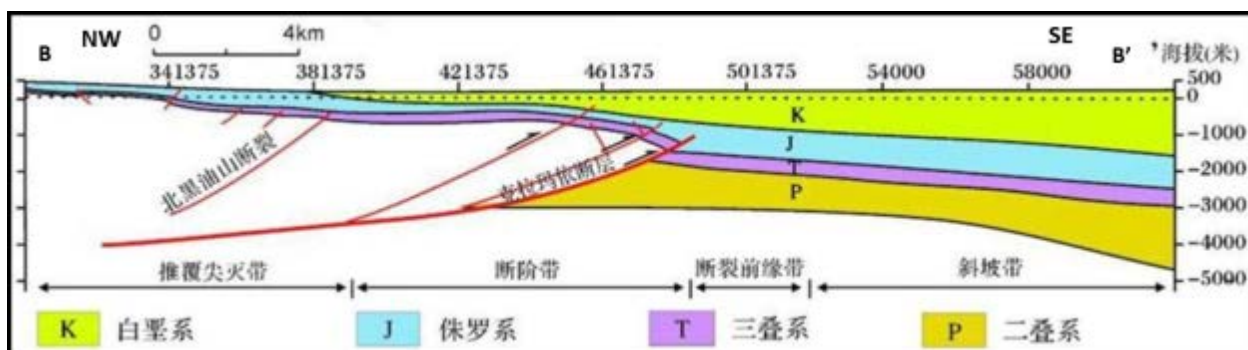
In particular, on the northwest flank of the Junggar Basin, Permian through Cretaceous strata dip quite gently (1° southeast) towards the central trough, **Figures XX-28 and XX-29**.^{51,52} Again, faults here are relatively few on the basin interior side of the section but become more prevalent along 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.



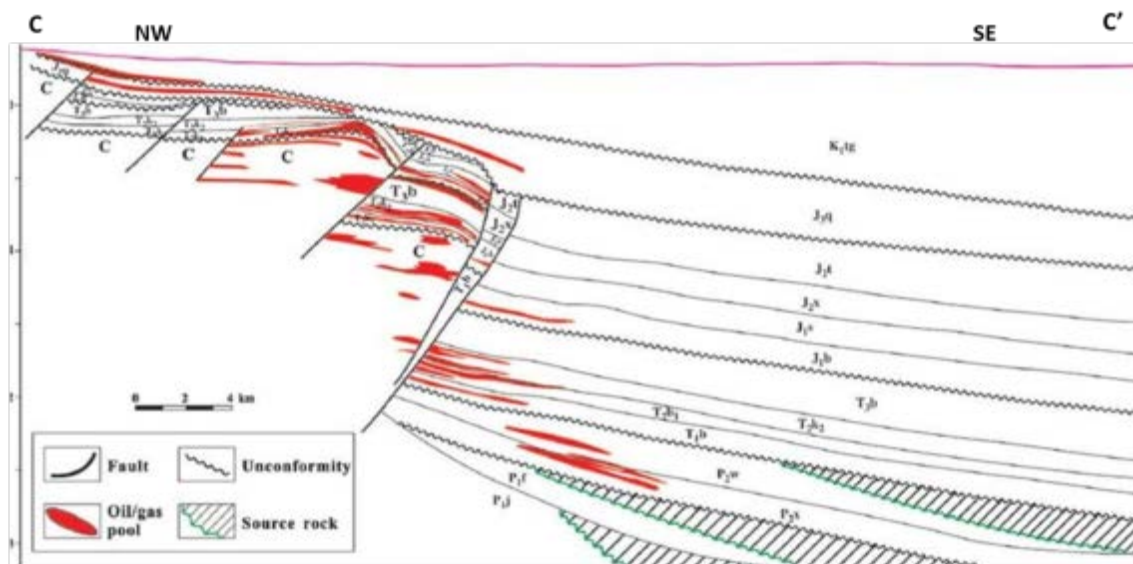
Source: Qiu et al., 2008.

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.

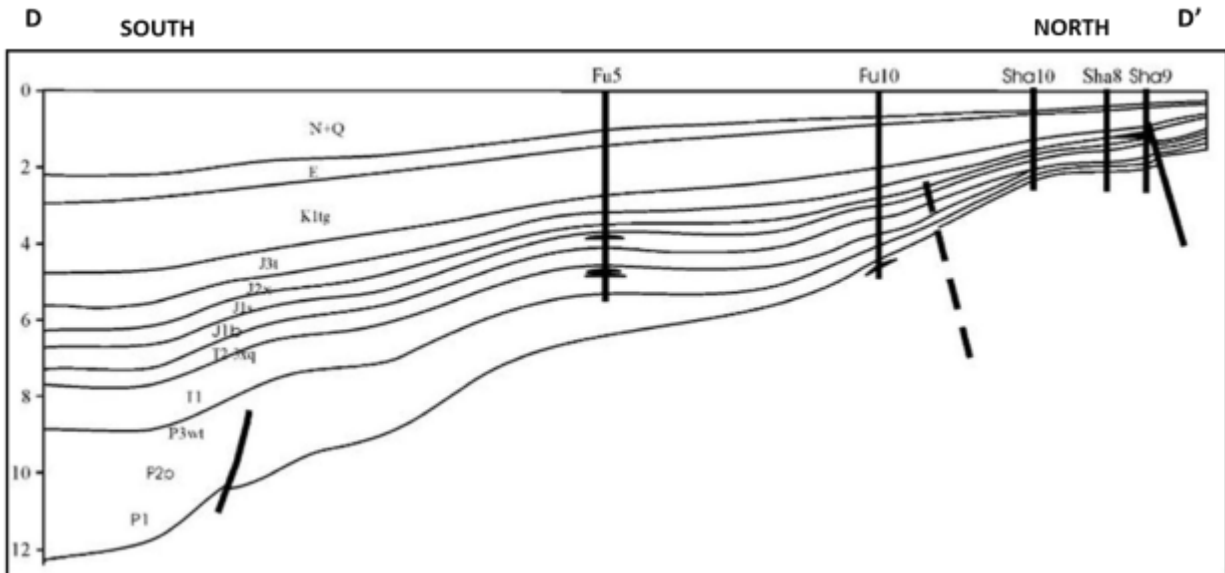


Source: Jin et al., 2008.

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

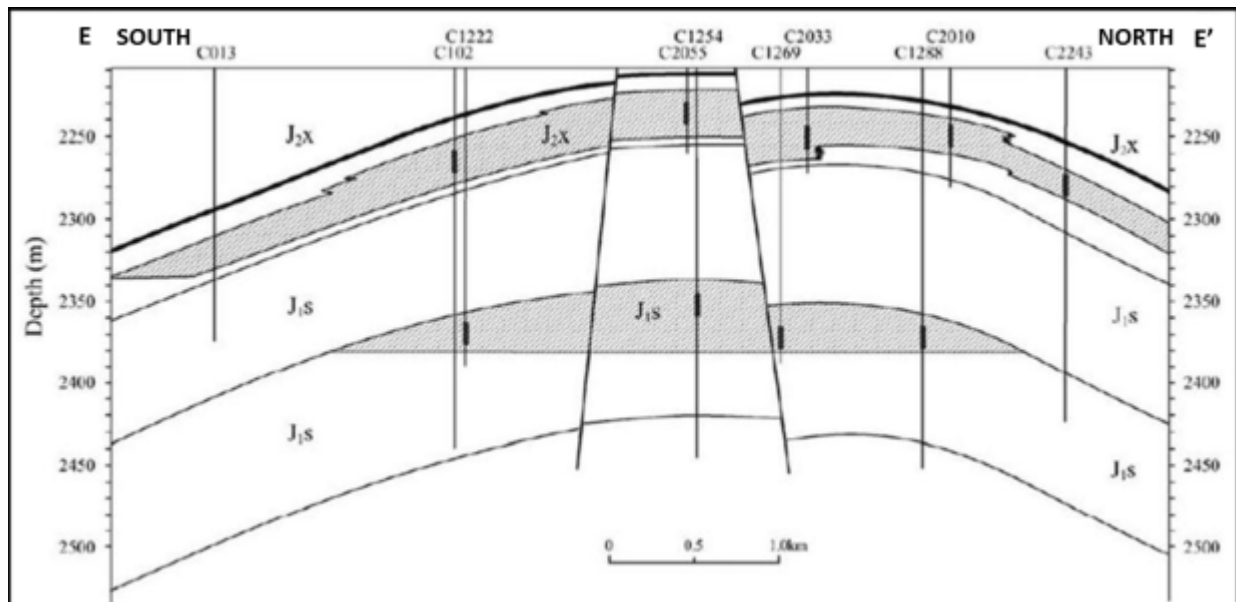
Reservoir pressure often is abnormally elevated in the Junggar Basin. For example, the Huo-10 well, located on an anticline in the southern Junggar, tested pressures of 50% to over 100% above hydrostatic levels in Eocene and Cretaceous formations at depths of 2,000 to 3,500 m, **Figure XX-32**.⁵⁴ Such 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.



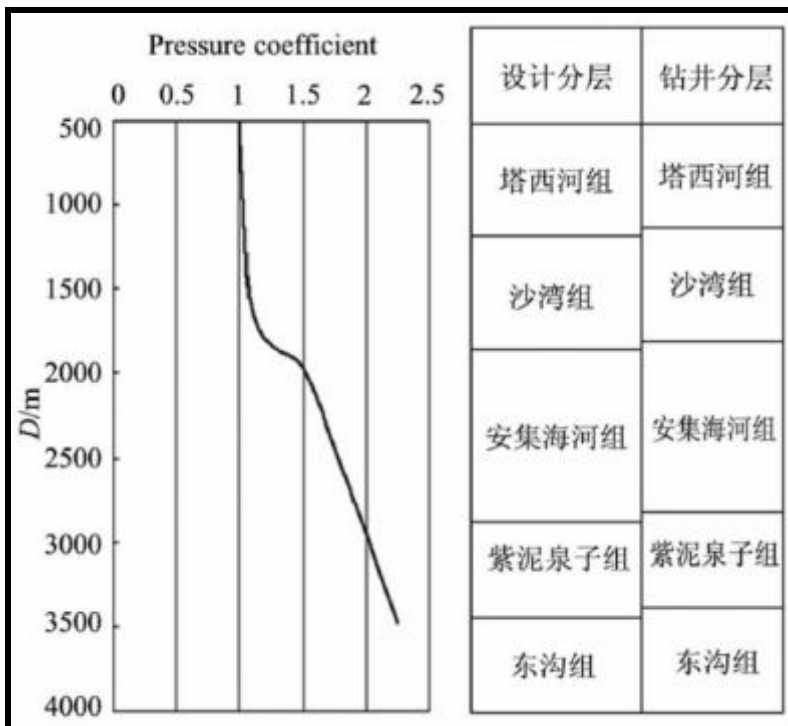
Source: Chen et al., 2003.

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 mi², 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 mi², 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.

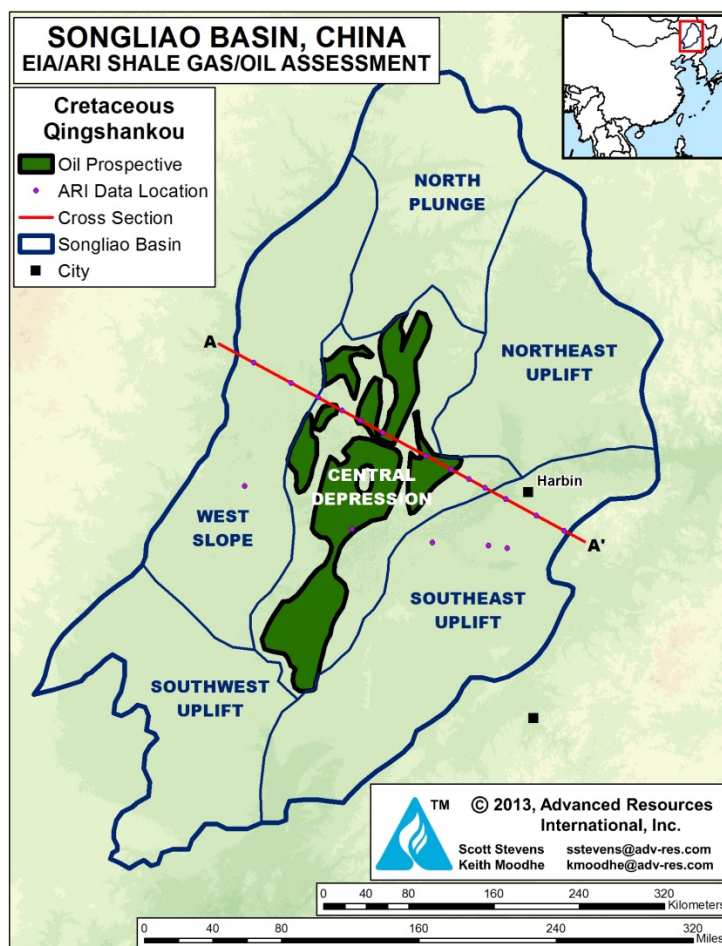
Hong Kong-based Enviro Energy's TerraWest Energy subsidiary operates a coalbed methane production sharing contract with partner PetroChina. The 655-km² Liuhuanguou PSC is located just west of Urumqi in the southern Junggar Basin. In addition to the CBM potential, Enviro Energy has reported on the shale 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-mi² 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).

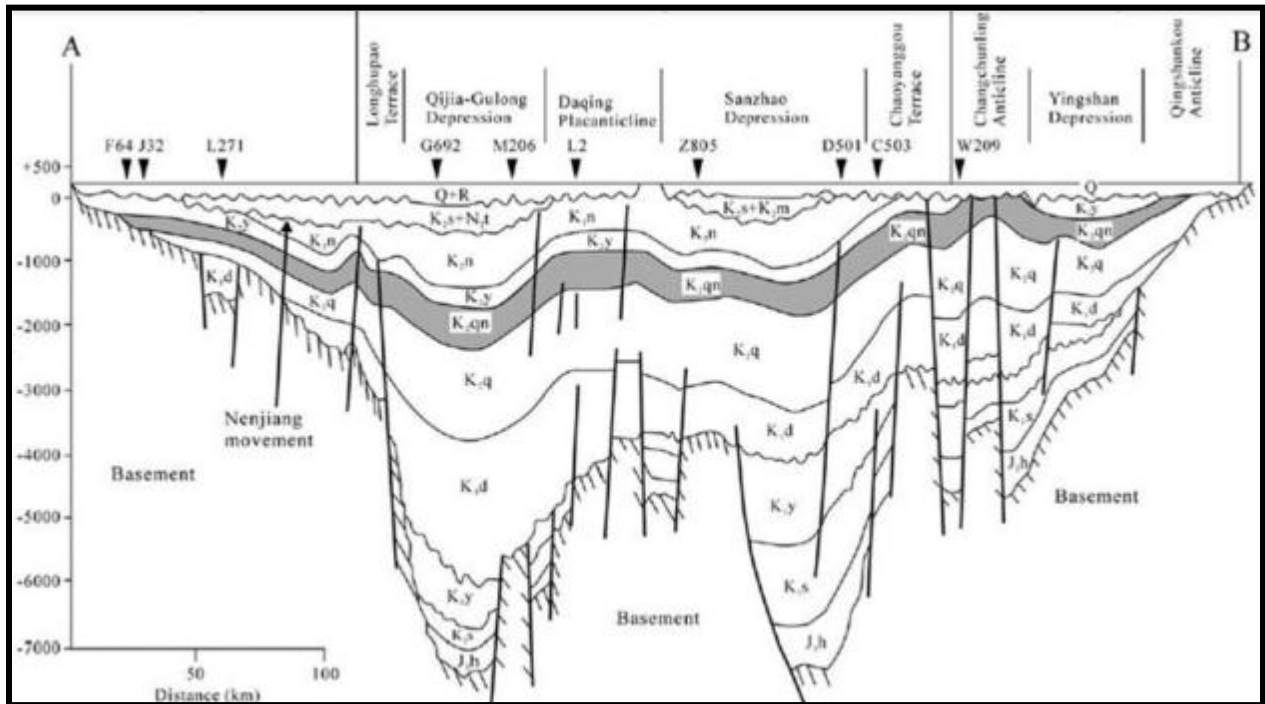
These Cretaceous source rocks are believed to have expelled only some 20% of their hydrocarbon generation capacity. Frequently over-pressured and naturally fractured, the Nenjiang and Qingshankou shales exhibit strong gas shows and travel time delays on acoustic logs. PetroChina considers the Songliao 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 mi² 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

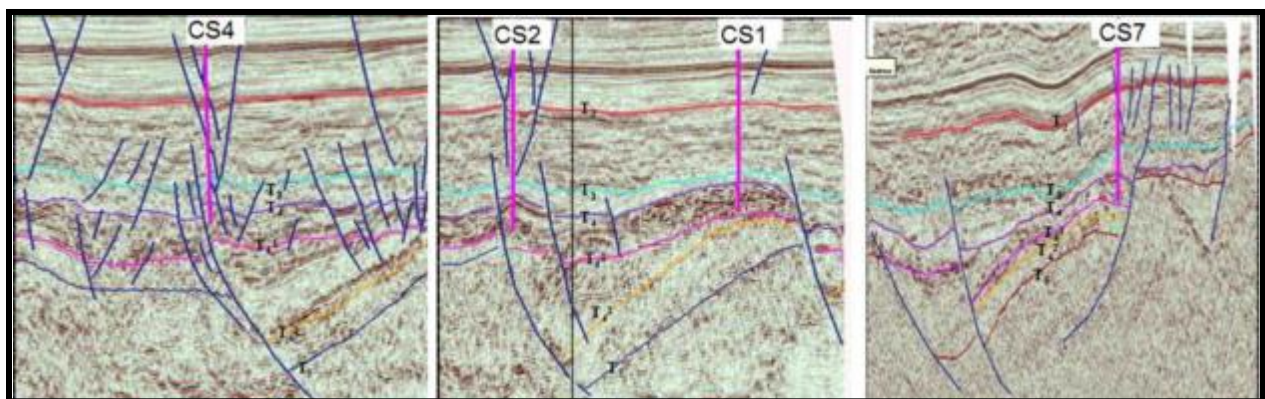
Elevated levels of carbon dioxide are common within Cretaceous sandstone and volcanic reservoirs in the Songliao Basin. About one dozen high-concentration (70-99%) CO_2 gas fields have been discovered to date, totaling 6.5 Bcf of proved reserves. Isotopes indicate the CO_2 is mainly magmatic in origin, 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 CO₂ 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 mi², 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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