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Technically Recoverable Shale Oil and Shale Gas Resources:

Mongolia

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Executive Summary

Introduction

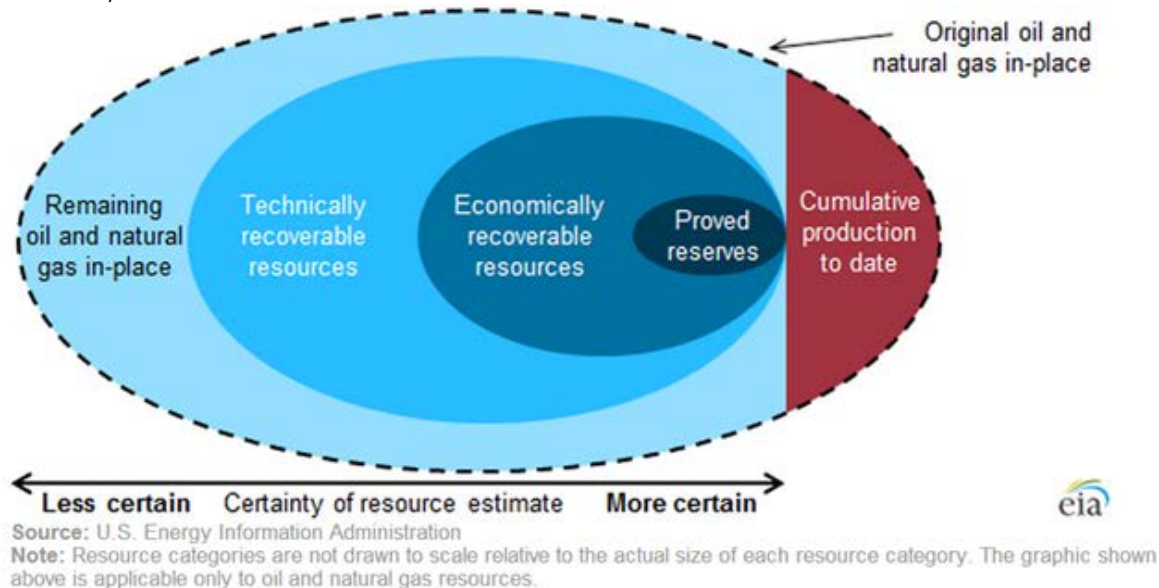
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

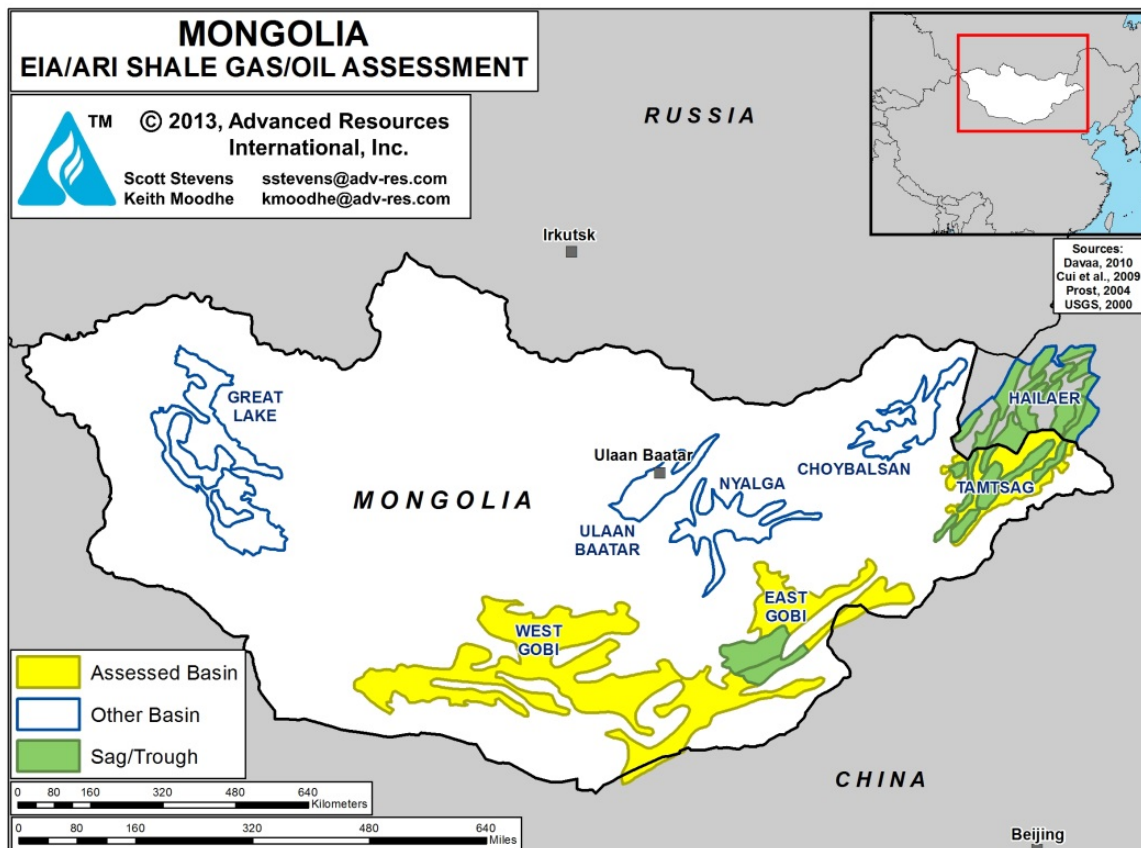
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

XXI. MONGOLIA

SUMMARY

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

Figure XXI-1. Sedimentary Basins of Mongolia



Source: ARI, 2013

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

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

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

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

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

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

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

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

INTRODUCTION

With a population of about 3 million people, Mongolia has the world's lowest population density – only 1.8 inhabitants per km² or about half that of Canada. Mining development is helping to boost Mongolia's GDP by an expected 25% per annum over the coming decade and per-capita GDP is expected to reach \$10,000 by 2020, up three-fold from the current level. Oil consumption is rising rapidly as the country develops its considerable mineral and coal deposits, including what soon may be the world's largest copper mine at Oyu Tolgoi.

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

Three of Mongolia's sedimentary basins may have limited shale oil potential, but only two basins could be quantitatively evaluated; geologic data are sparse. The most prospective

areas for both conventional and shale oil exploration are the East Gobi and Tamtsag basins. These basins are relatively small and somewhat complex structurally; only the East Gobi Basin has small commercial oil production.

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

1. EAST GOBI BASIN

1.1 Introduction and Geologic Setting

The 25,000-mi² East Gobi Basin is located in southeastern Mongolia close to the border with China, accessible along the main highway between the capitol Ulan Bataar and north-central China. Mongolia's only significant commercial oil-producing region, the basin is along strike with and similar to oil-productive Mesozoic rift basins in northeast China, where much more geologic data are available. The East Gobi Basin shares similar stratigraphy and structural geology with these adjoining basins in northwest China.

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

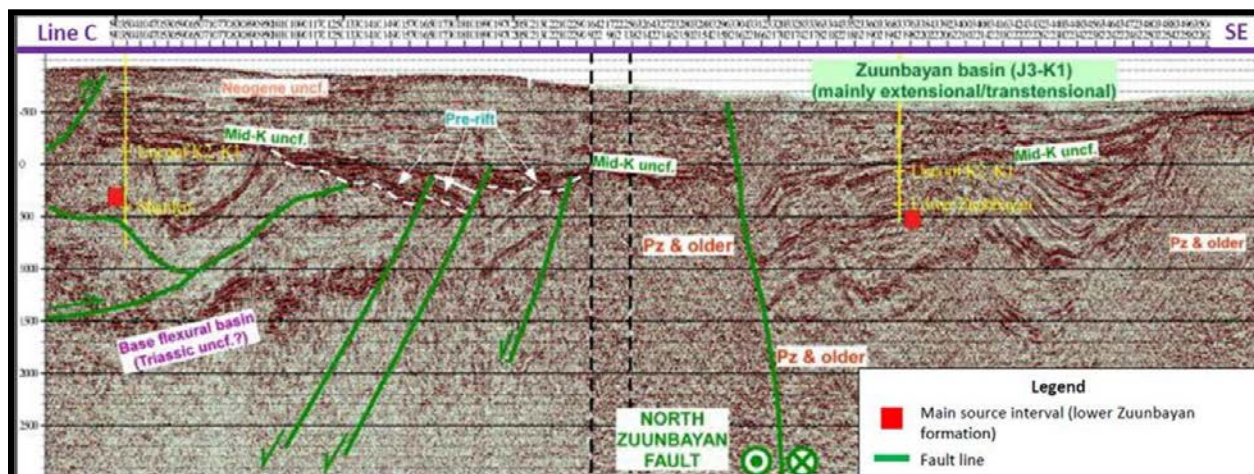
Figure XXI-2. Stratigraphy of Shale Source Rocks and Conventional Reservoirs in Mongolia

MONGOLIA			
ERA	PERIOD	EPOCH	FORMATION
CENOZOIC	QUATERNARY		Undifferentiated
	TERTIARY		
MESOZOIC	CRETACEOUS	Upper	Nemegt
			Baruungoyot
			Bayanshiree
			Sainshand/ Baruunbayan
	Lower	Zuunbayan	Upper
			Lower
		Tsagaan Tsav	Bituminous
JURASSIC	Upper	Sharlyn	
	Middle	Khamar Khoovor	
PALEOZOIC	PERMIAN		Tavan Tolgoy
	CARBONIFEROUS		
	DEVONIAN		
Source Rock		Oil & Gas	

Source: ARI, 2013

The East Gobi Basin contains four main sub-basins within a 200- by 400-mi area that is defined broadly by gravity and seismic data.² The sub-basins contain discontinuous deep depressions, separated by basement highs that are exposed over much of the region. Deep, fault-bounded troughs with good quality source rock mudstones can occur. However, the deep areas (>6,000 ft) cover only a relatively small area. The largest sub-basins are the Unegt (3,090 mi²) and Zuunbayan (1,600 mi²), Figure XXI-3. Uplifted fault blocks occur within these troughs, some forming conventional oil traps.

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



Source: Manas Petroleum Corp., 2012

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

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

Basement in the East Gobi Basin consists of metamorphosed sandstone and carbonate of the Paleozoic Tavan Tolgoi sequence. The oldest sedimentary unit is the Lower to Mid-Jurassic Khamarkhoovor Formation, a pre-rift sequence consisting of up to 2,500 ft of fluvial sandstones and lacustrine-deltaic shale, including thin coal seams. Although a potential source

rock, the Khamarkhoover seldom crops out and remains poorly understood. Unconformably overlying this unit is the Sharlyn Formation, containing up to 600 ft of fluvial sandstone and conglomerate with minor lacustrine shale.

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

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

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

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

1.2 Reservoir Properties (Prospective Area)

Within the 4,690-mi² high-graded prospective area of the Unegt and Zuunbayan troughs in the East Gobi Basin, the Lower Cretaceous Tsagaantsav Formation contains an estimated 300 ft (net) of organic-rich lacustrine shale at an average depth of 8,000 ft. TOC averages an estimated 4.0% and is oil-prone (R_o averaging 0.8%). Porosity may be significant (6%) given the silty lithology. The reservoir pressure gradient is normal.

1.3 Resource Assessment

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

1.4 Exploration Activity

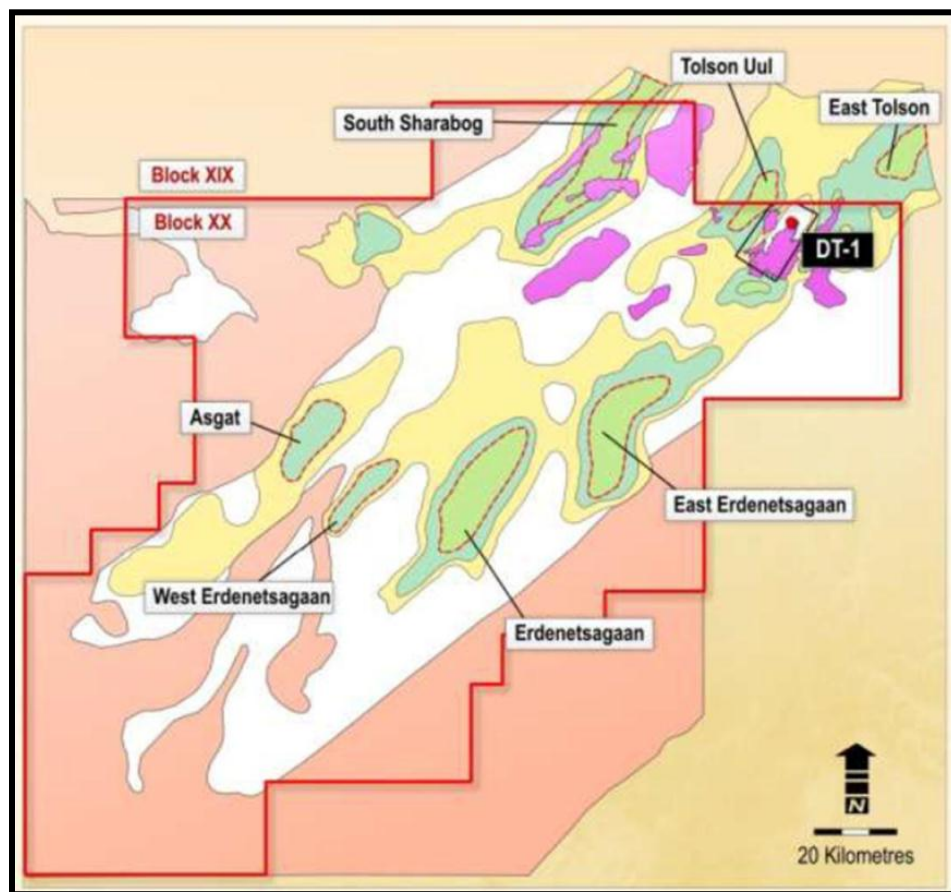
No shale oil or shale gas exploration or leasing has occurred in the East Gobi Basin. Calgary-based Manas Petroleum Corp. is conducting petroleum exploration for conventional targets in this basin but has not discussed its shale potential.⁵ London-based Petro Matad Limited is evaluating Khoid Ulaan Bulag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

2 TAMTSAG BASIN

2.1 Introduction and Geologic Setting

Although geologically similar to the East Gobi Basin, the 6,700-mi² Tamtsag Basin in extreme eastern Mongolia has no commercial oil and gas production. The basin comprises a number of isolated, fault-bounded troughs that trend WSW-ENE along an extent of about 80 by 300 km, Figure XXI-4. Just as in the East Gobi Basin, potential source rocks are the Lower Cretaceous Tsagaantsav and Zuunbayan formations, with TOC averaging about 3%.

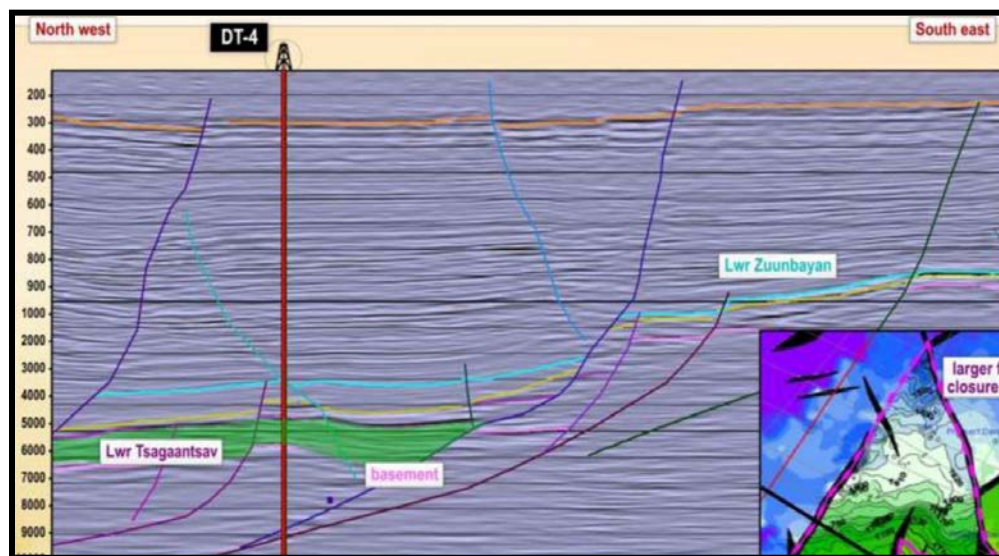
Figure XXI-4. Western Tamtsag Basin Showing Small Isolated Structural Troughs where Source Rock Shales are Buried to Over 5,000 ft and May Reach Oil-window Thermal Maturity.



Source: Petro Matad Ltd., 2012

Internally the Tamtsag Basin comprises a number of uplifted fault blocks and down-faulted grabens created by rifting and Mid-Cretaceous basin inversion, Figure XXI-5.⁷ Late Cretaceous transpression formed structural traps in conventional targets, notably tilted fault blocks and anticlines. Structural complexity is most pronounced in the southwest, decreasing towards the northeast. The basement consists of Devonian to Permian metamorphic and intrusive rocks.⁸

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



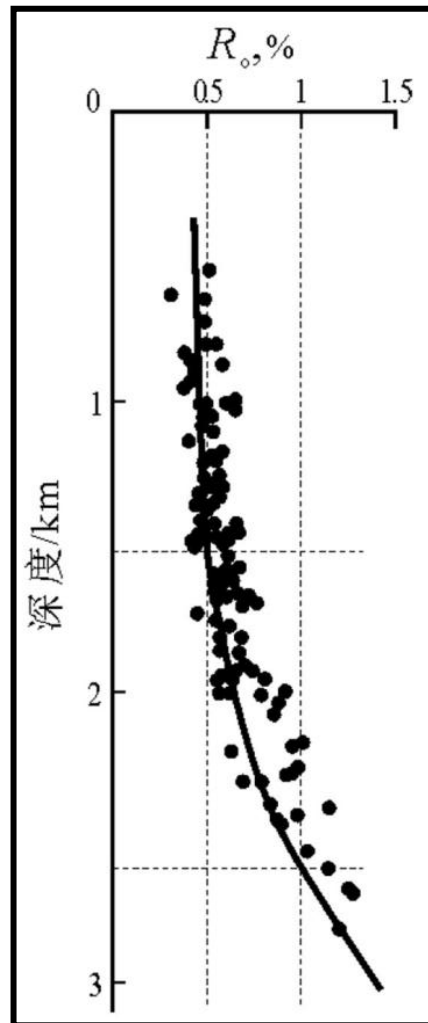
Source: Petro Matad, 2010

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

The Tamtsag Basin is on trend with the Hailaer Basin of northeastern China, a stratigraphically and genetically similar Mesozoic rift basin. Although the Hailaer Basin has not experienced shale exploration, it is oil producing and thus has much better data control. Similar to the Tamtsag, the Hailaer Basin actually comprises over 20 individual fault-bounded sub-basins. Coal deposits and carbonaceous mudstones within the upper portion of the Lower Cretaceous Nantun Formation are considered the major petroleum source rocks in the Hailaer Basin. The Hailaer Basin oil fields produce with high water cut and have locally elevated CO₂ levels.

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

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



Source: Liu et al., 2009

2.2 Reservoir Properties

Within the 5,440-mi² high-graded prospective area that is distributed amongst numerous small troughs within the Tamtsag Basin, the Lower Cretaceous Tsagaantsav Formation contains an estimated 250 feet (net) of organic-rich lacustrine shale at an average depth of 7,000 feet. TOC averages an estimated 3.0% and is oil-prone (R_o averaging 0.8%). Porosity may be significant (6%) given the silty lithology.

2.3 Resource Assessment

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

2.4 Exploration Activity

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

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