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Technically Recoverable Shale Oil and Shale Gas Resources:

Russia

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Executive Summary

Introduction

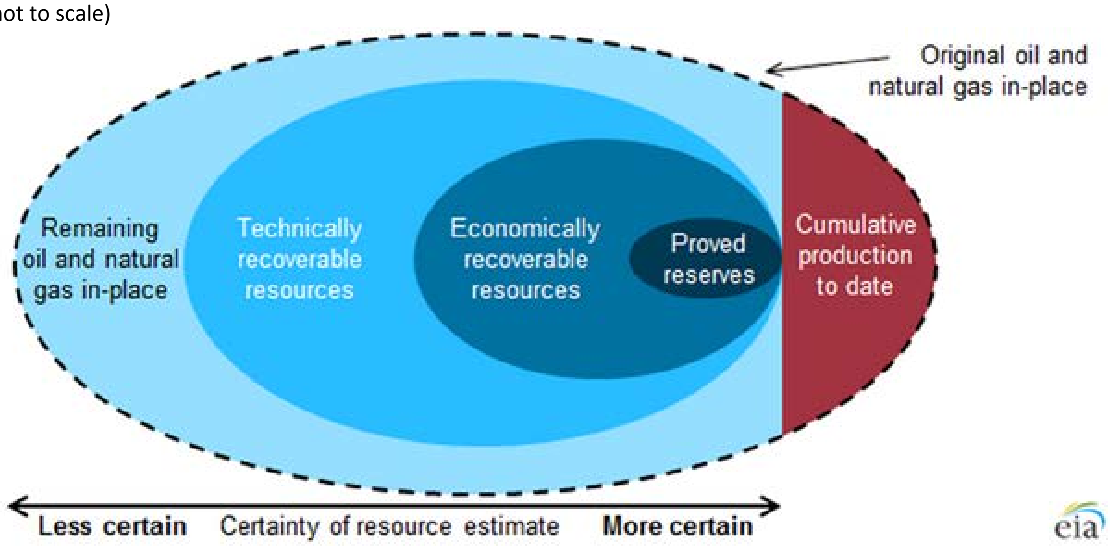
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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



Source: U.S. Energy Information Administration
Note: Resource categories are not drawn to scale relative to the actual size of each resource category. The graphic shown above is applicable only to oil and natural gas resources.

Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

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

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

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

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

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

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

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

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

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

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

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

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

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

Methodology

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

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

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

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

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

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

Key exclusions

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

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[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:

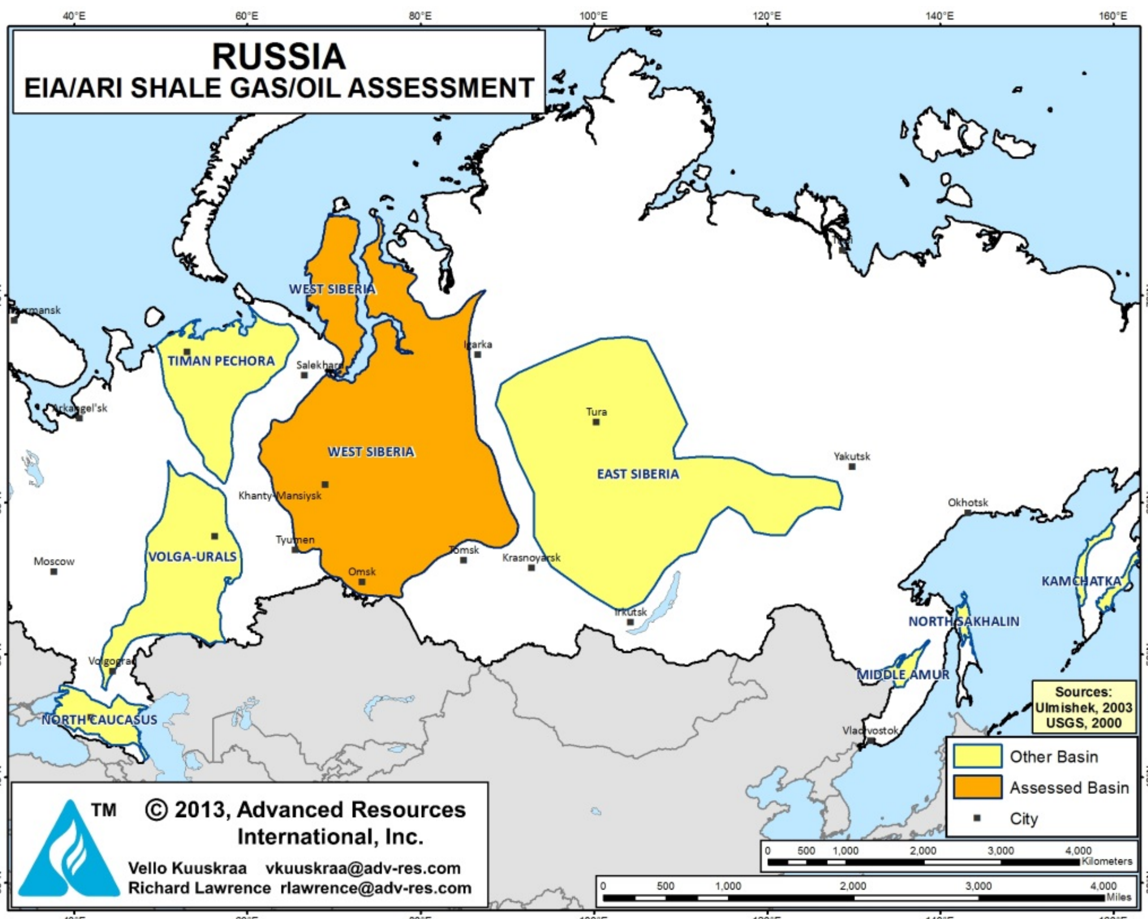
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

IX. RUSSIA

SUMMARY

Our shale gas and shale oil resources assessment for Russia addresses the Upper Jurassic Bazhenov Shale in the West Siberian Basin, Figure IX-1. This organically rich, siliceous shale is the principle source rock for the conventional gas and oil produced from the West Siberian Basin. We also examined other shale basins (e.g., Timan-Pechora) but were not able to assemble sufficient, publicly available data for a quantitative resource assessment.

Figure IX-1. Prospective Shale Gas and Shale Oil Basins of Russia



Source: ARI, 2013

For the Bazhenov Shale, we estimate 1,243 billion barrels of risked shale oil in-place, with 74.6 billion barrels as the risked, technically recoverable shale oil resource, Table IX-1. In addition, we estimate 1,920 Tcf of risked shale gas in-place, with 285 Tcf as the risked, technically recoverable shale gas resource, Table IX-2.

Table IX-1. Shale Oil Reservoir Properties and Resources of Russia

Basic Data	Basin/Gross Area		West Siberian (1,350,000 mi^2)			
	Shale Formation		Bazhenov Central	Bazhenov North		
	Geologic Age		U. Jurassic - L. Cretaceous	U. Jurassic - L. Cretaceous		
	Depositional Environment		Marine	Marine		
Physical Extent	Prospective Area (mi^2)		116,200	74,400	14,800	10,540
	Thickness (ft)	Organically Rich	100	100	100	100
		Net	85	85	85	85
	Depth (ft)	Interval	6,500 - 12,000	6,500 - 13,000	8,500 - 15,000	10,000 - 16,000
		Average	8,200	9,800	12,000	13,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		10.0%	5.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	0.85%	1.15%	1.45%
	Clay Content		Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		22.9	19.4	42.0	66.0
	Risked GIP (Tcf)		1,196.0	378.9	163.0	182.5
	Risked Recoverable (Tcf)		143.5	45.5	40.8	54.8

Source: ARI, 2013

Table IX-2. Shale Gas Reservoir Properties and Resources of Russia

Basic Data	Basin/Gross Area		West Siberian (1,350,000 mi^2)		
	Shale Formation		Bazhenov Central	Bazhenov North	
	Geologic Age		U. Jurassic - L. Cretaceous	U. Jurassic - L. Cretaceous	
	Depositional Environment		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		116,200	74,400	14,800
	Thickness (ft)	Organically Rich	100	100	100
		Net	85	85	85
	Depth (ft)	Interval	6,500 - 12,000	6,500 - 13,000	6,500 - 13,000
		Average	8,200	9,800	12,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		10.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	0.85%	1.15%
	Clay Content		Low	Low	Low
Resource	Oil Phase		Oil	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		18.5	13.4	4.3
	Risked OIP (B bbl)		964.8	261.5	16.8
	Risked Recoverable (B bbl)		57.89	15.69	1.01

Source: ARI, 2013

1. WEST SIBERIAN BASIN

1.1 Introduction and Geologic Setting

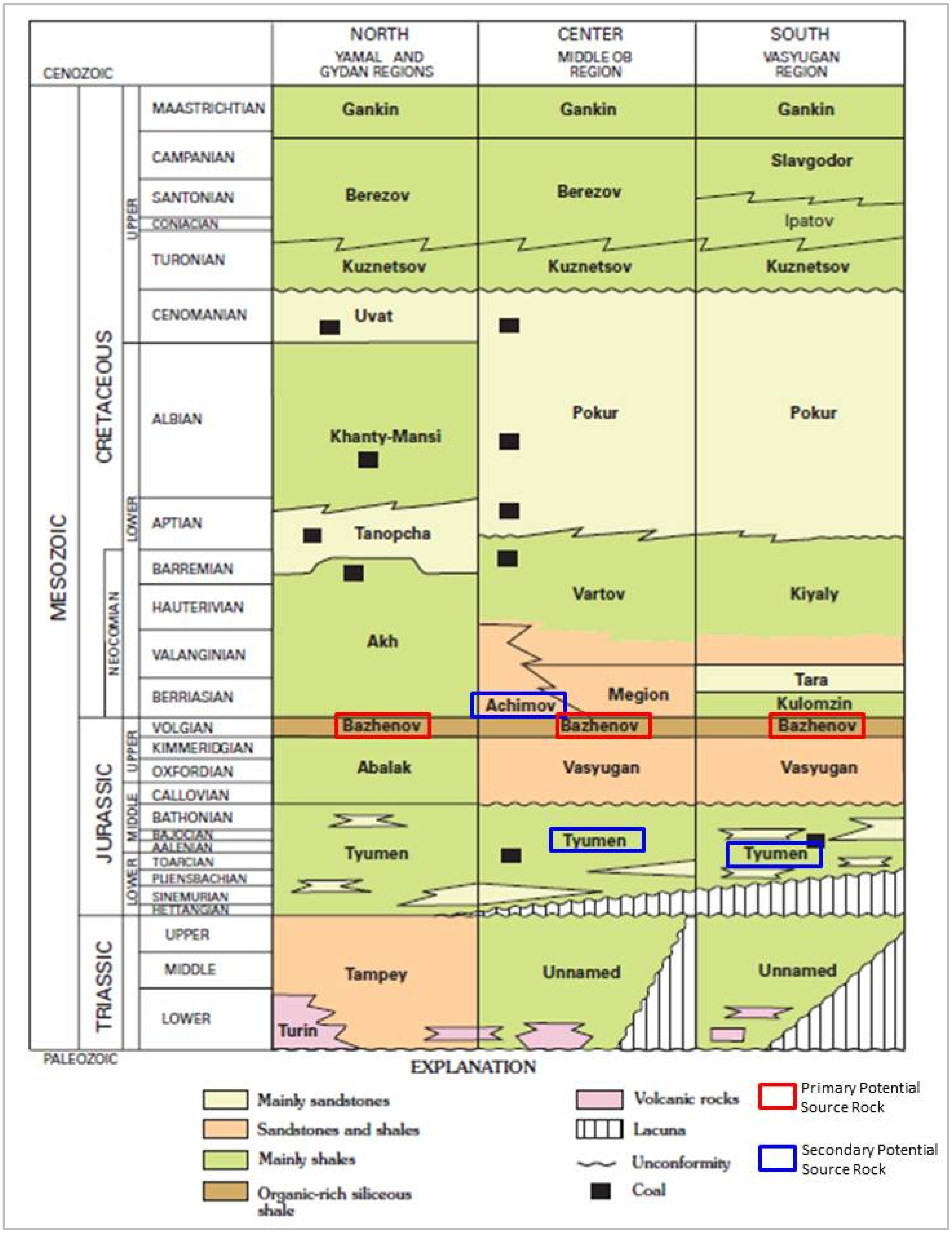
The 850,000-mi^2 West Siberian Basin is the largest petroleum basin in the world[1]. The basin lies between the Ural Mountains to the west and the Yenisey River to the east, while extending north offshore under the Kara Sea and reaching south to the border with Kazakhstan, Figure IX-1.

Conventional oil and gas production has taken place in the basin since the 1960's, with reservoirs found predominately in Cretaceous sandstone formations. Oil production occurs mainly in the southern and central regions of the basin, with gas fields more prevalent in the north. The West Siberian Basin contains tens of giant and super-giant fields such as the Samotlor oil field (28 billion barrels of original oil reserves) in the central Middle Ob petroleum region and the 350-Tcf Urengoy gas field north of the Arctic Circle. Although the West Siberian Basin still delivers over 60% of Russia's annual oil production, its output peaked in the late 1980's. Declining conventional production is stimulating interest in finding new oil and gas production from unconventional resources.

The Upper Jurassic Bazhenov Shale, a marine shale rich in TOC, is considered the main source rock for the Western Siberian Basin's conventional oil reservoirs. The Bazhenov Shale, the primary shale addressed in this resource assessment, has been selectively drilled, providing shows and variable quantities of oil production.

Other formations that may contain shales with gas and oil potential are the Lower Jurassic Tyumen and Lower Cretaceous Achimov formations, Figure IX-2. The Tyumen Formation is not considered prospective in the northern areas of the basin where it is projected to be at depths greater than 16,400 ft (5,000 m). The publicly available data for the Achimov Formation is not sufficient for a quantitative resource assessment. As such, these two formations were excluded from our shale gas and shale oil assessment.

Figure IX-2: Stratigraphic Column of the West Siberian Basin



Source: Modified from Ulmishek, 2003

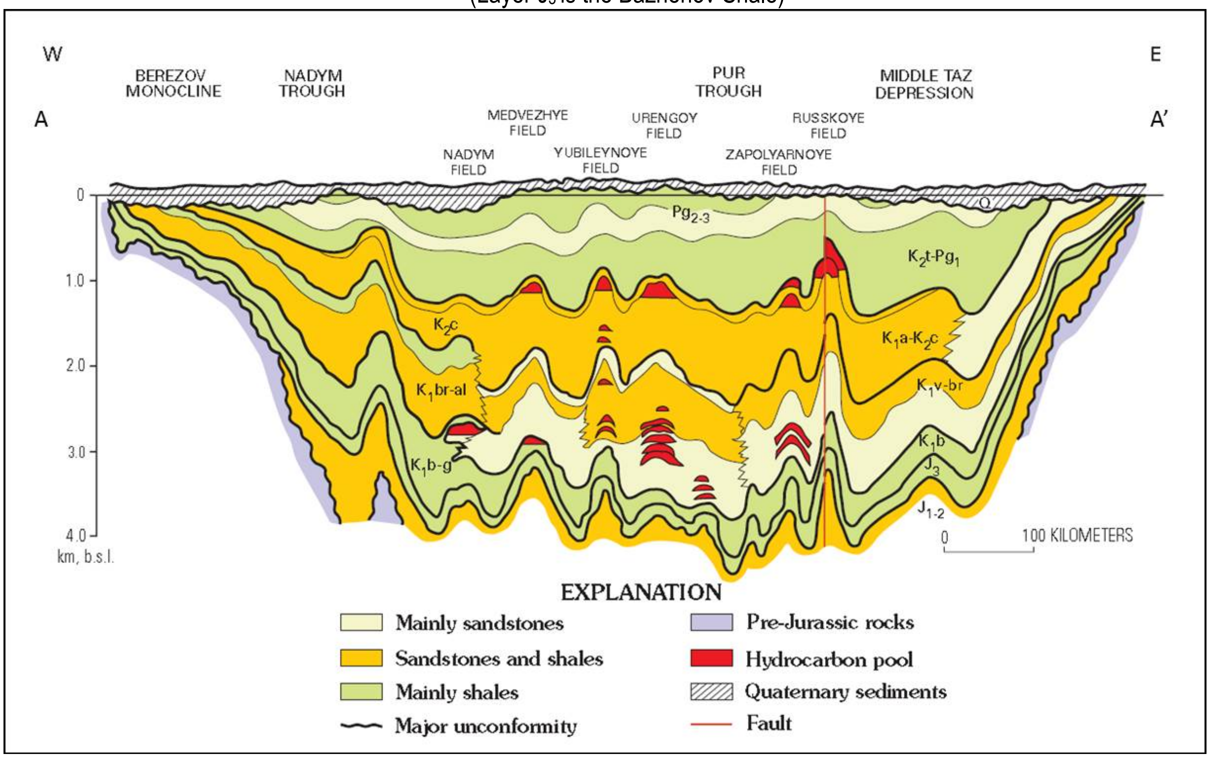
Advanced Resources International, Inc.

The West Siberian Basin is an intra-cratonic sag basin containing over 4,000 m (13,000 ft) of Mesozoic and Cenozoic sediments. Basement rocks of Paleozoic age were deeply eroded prior to the Triassic period, with subsequent early Triassic continental rifting primarily responsible for the formation of the basin. Major Triassic rifts and faults are oriented in a predominantly north-south alignment, influencing the structural alignment of large anticlines and synclines that formed in the late Mesozoic. The central tectonic element of the basin is the Triassic Koltogor-Urengoy graben, which extends 1800 km north-to-south and is 10 to 80 km wide.[2]

The majority of discovered conventional oil and gas reserves are found in gentle anticlinal uplifted structural traps, located on regional arches, Figure IX-3. Faults, where present, have a displacement of only a few tens of meters and seldom penetrate above the Lower-Middle Jurassic Tyumen Formation.

Figure IX-3. Cross-Section Across Central West Siberian Basin.
(See Figure 4 for location; vertical exaggeration 100x)

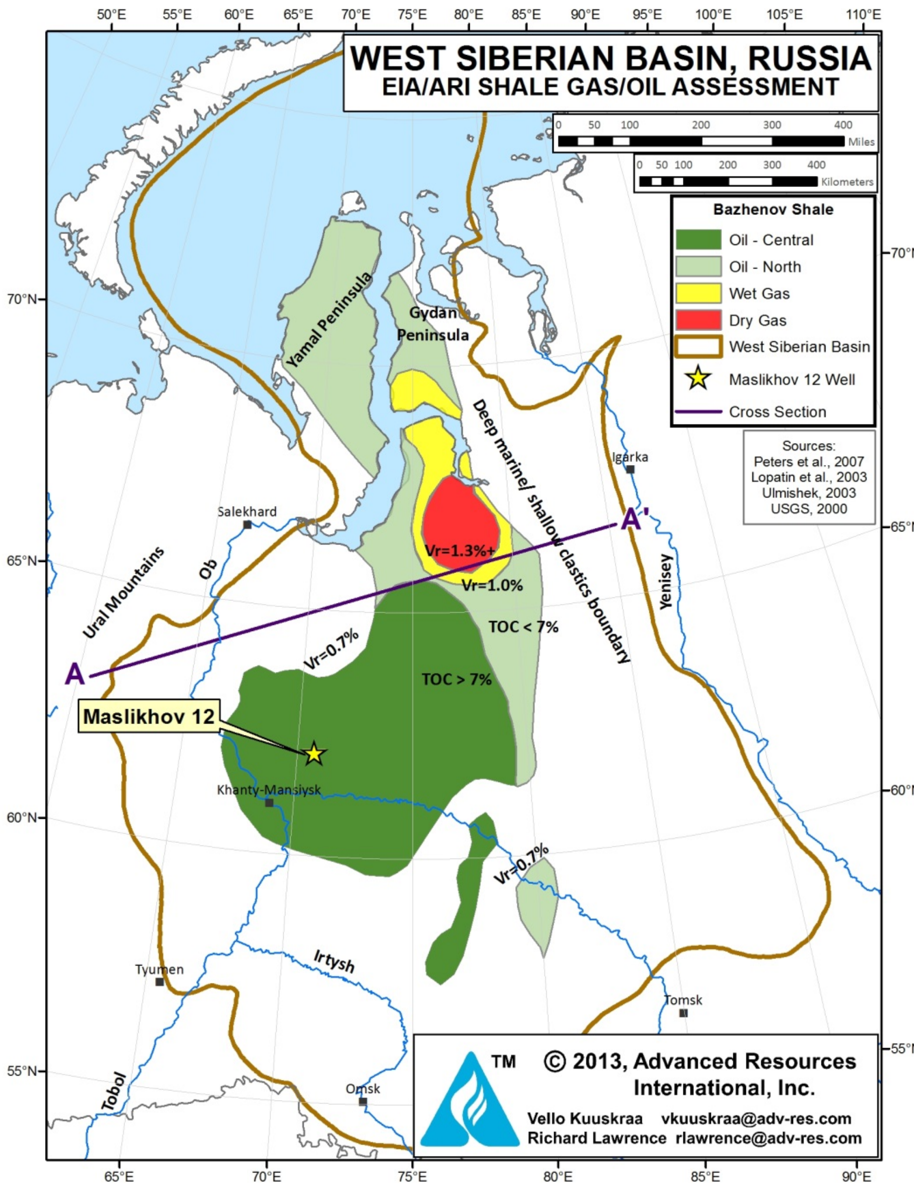
(Layer J_3 is the Bazhenov Shale)



Source: Ulmishek, USGS 2003.

We have partitioned the Bazhenov Shale in the Western Siberian Basin into two areas based on TOC and thermal maturity: Bazhenov North and Bazhenov Central.,. Bazhenov North, with a prospective area of 99,740 mi^2 and an average TOC of 5%, contains oil, wet gas/condensate and dry gas. Bazhenov Central, with a prospective area of 116,200 mi^2 and a high average TOC of 10%, is thermally mature for shale oil, Figure IX-4.[3,4]

Figure IX-4. West Siberian Basin, Prospective Areas for Shale Gas and Shale Oil



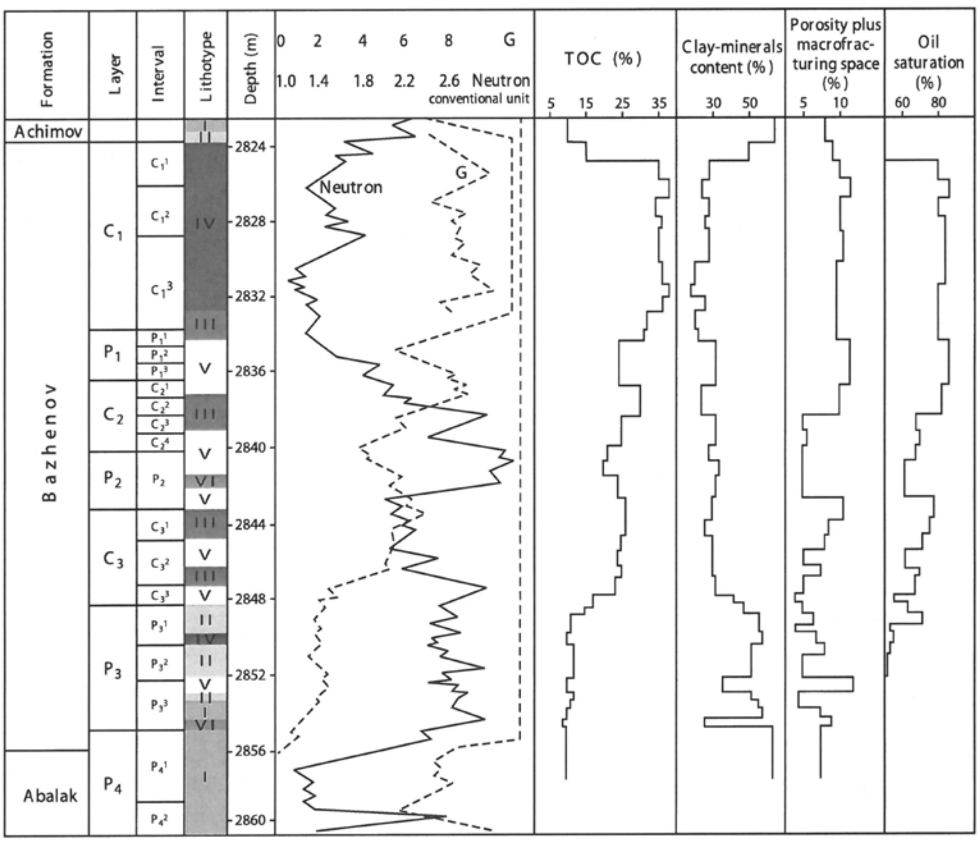
Source: ARI, 2013.

1.2 Reservoir Properties (Prospective Area)

The Upper Jurassic Bazhenov Shale is present across much of the West Siberian Basin, outcropping at the basin edges and reaching depths of over 16,400 ft (5,000 m) in the central northern region. The shale's gross thickness typically ranges from 65 to 160 ft (20 to 50 m), but can reach up to 200 ft (60 m) in localized areas.

The Bazhenov Shale was deposited in a deep marine, anoxic environment and is composed primarily of siliceous argillites, rich in planktonic Type II organic matter.[5] TOC contents are generally highest in the central region of the Basin, typically exceeding 15%, Figure IX-5.[6] TOC values decrease towards the periphery of the basin and to the north where the TOC typically ranges from 2 to 7%. TOC averages 5% in Bazhenov North and 10% in Bazhenov Central.[5]

Figure IX-5. Reservoir Properties of the Bazhenov Shale from Maslikhov Well.



Source: Lopatin et al., 2003.

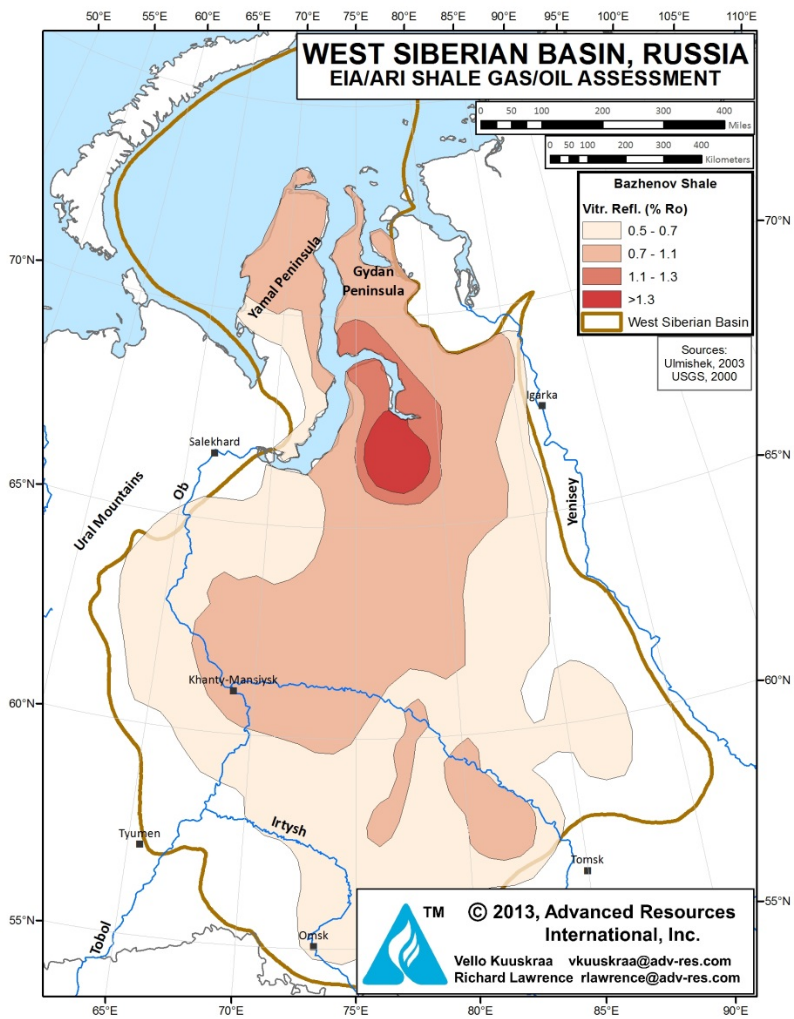
The literature describes the Bazhenov as being over-pressured, caused by oil generation and expulsion as the shales passed through the "oil window". Measured shut-in bottom-hole pressures in the Salym oil field region are reported in some wells to be abnormally high, up to 70% above normal hydrostatic pressure.[7] Temperature gradients are also high. Clay content is usually reported as less than 20%.

The Bazhenov reservoir structure consists of layers of high-TOC shale interbedded with carbonate/dolomite layers.[8] The shales are the source of the oil, with the fractured carbonate layers providing additional reservoir capacity. This is somewhat analogous to the Bakken Shale play of North Dakota, which comprises a carbonate reservoir "sandwiched" between two oil rich/saturated shales.

Bazhenov North is prospective for oil, wet gas/condensate and dry gas. The 74,400-mi^2 area prospective for shale oil in Bazhenov North is defined by vitrinite reflectance (R_o) values between 0.7% and 1.0%, TOC content greater than 2%, and reservoir depth greater than 3,300 ft. The 14,800-mi^2 area prospective for wet gas and condensate in Bazhenov North is defined by R_o values between 1.0% and 1.3%. The 10,540-mi^2 area prospective for dry gas is defined by R_o values greater than 1.3%, Figure IX-6A. The Bazhenov North prospective area is further constrained on the east side of the basin, where the Bazhenov Shale changes from a deep marine shale to shallow clastic deposit, Figure IX-6B.

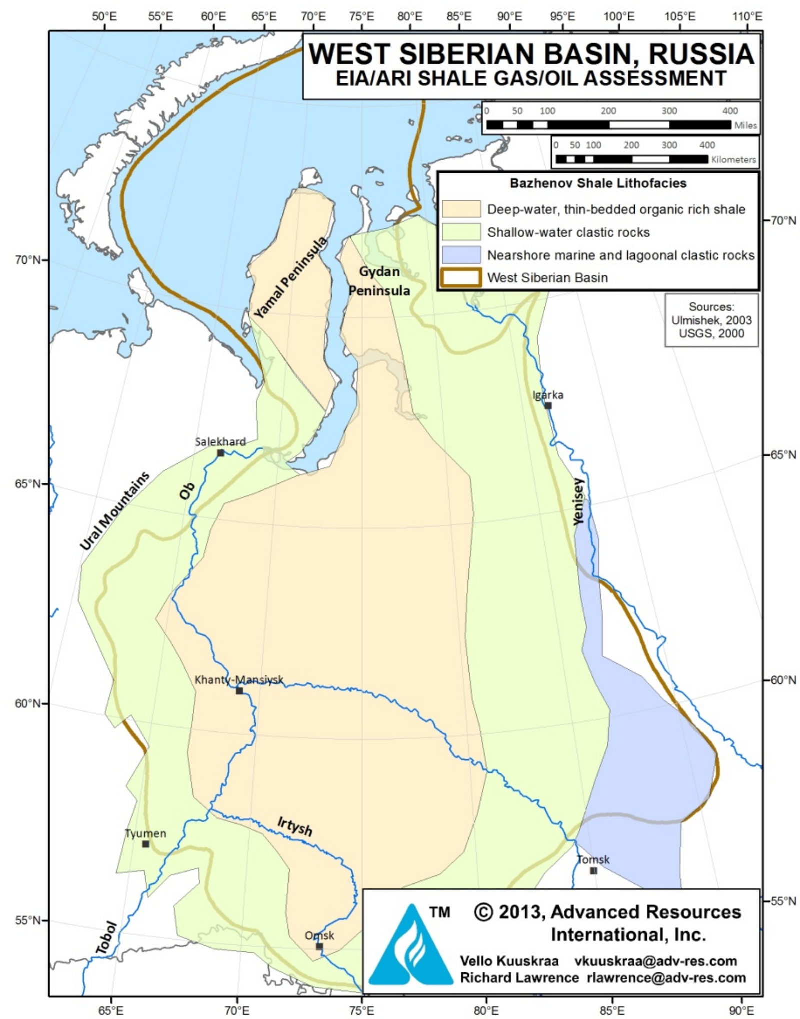
Bazhenov Central contains a 116,200-mi^2 prospective area for oil, with a thermal maturity (R_o) of 0.7 to 1.0%. The TOC content of the shale is high in Bazhenov Central, averaging 10%. Similarly, the Bazhenov Central prospective area is limited on the east by the marine shale to clastic sediments facies change.

Figure IX-6A. West Siberian Basin - Vitrinite Reflectance



Source: ARI, 2013.

Figure IX-6B. West Siberian Basin - Lithofacies Map



Source: ARI, 2013.

1.3 Resource Assessment

The shale oil in the Bazhenov North prospective area has an estimated resource concentration of 13 million barrels/mi^2 plus associated gas in the oil window; resource concentrations of 4 million barrels/mi^2 and 42 Bcf/mi^2 in the wet gas/condensate window; and a resource concentration of 66 Bcf/mi^2 in the dry gas window. The shale in the Bazhenov Central prospective area has an estimated resource concentration of 18 million barrels/mi^2 plus associated gas in the oil window.

For the total Bazhenov shale prospective area in the West Siberian Basin, we estimate a risked shale oil in-place of 1,243 billion barrels, with 74.6 billion barrels as the risked, technically recoverable shale oil resource, Table IX-1. In addition, for this prospective area, we estimate a risked shale gas in-place of 1,920 Tcf, with 285 Tcf as the risked, technically recoverable shale gas resource, Table IX-2.

In its 2011 Annual Report, Rosneft estimated the company had 4.4 billion barrels of recoverable oil resources from the Bazhenov "suite" on its license areas in Western Siberia.[9]

1.4 Recent Activity

The majority of Russia's current oil production (nearly two thirds) comes from large fields in the West Siberian Basin, located between the Ural Mountains and the Central Siberian Plateau, with the remaining oil production coming mainly from the Volga-Urals region, the Timan-Pechora Basin, the north Caucasus Region, and the Sakhelin Basin.

The oldest fields have produced since the 1940s and production rates are declining, even with the new technical focus on secondary recovery and hydro-fracturing. Exploration for conventional oil and gas is in the more remote East Siberian Basin and in the higher cost Arctic region. As such, Russian oil companies are becoming interested in the drilling and production techniques used in the U.S. to develop their unconventional oil and gas resources. Rosneft, Russia's national oil company, has signed agreements with ExxonMobil and Statoil with the aim of using horizontal drilling and large scale stimulation techniques to unlock the vast shale gas and shale oil resources of Russia.

To date, Rosneft and Exxon Mobil have announced plans to begin drilling the Bazhenov Shale in 2013, after completion of their geologic study. Gazprom Neft and Shell, as part of their West Siberia JV, proposed to start drilling the Bazhenov Shale in early 2014 near the Salym oil field, which has a history of Bazhenov Shale oil production. Lukoil has announced plans to test the Bazhenov reservoir in two area of West Siberia.[10]

Development of the Bazhenov Shale is complicated by Russia's current tax regime, which is geared towards conventional reservoirs. The Russian government is currently working on a proposal to change the mineral extraction tax (MET) for "tight oil" reservoirs with a permeability of less than 2 millidarcies (mD).[11] It is possible that shale gas and shale oil reservoirs would be incorporated into the proposed change in the MET.

2. TIMAN-PECHORA BASIN

The Timan-Pechora Basin covers an onshore area of about 122,000 mi^2 on the Arctic Circle of northern Russia, Figure IX-1. The principle source rock in this basin is the Upper Devonian (Frasnian) organic-rich shale in the Domanik Formation.[12]

These source rocks, composed of thin-bedded, dark siliceous shales, limestones and marls, were deposited in a deep water marine setting. The source rocks contain Type I and II kerogen with total organic content (TOC) ranging from 1% to 15%, typically averaging 5%[13]. These source rocks are present, with adequate thickness and maturity, over much of the Timan-Pechora Basin except for the southwestern margin. With thermal maturity of 0.6% to 1.0%, these source rocks are primarily in the oil window. The mineralogy of the shale appears to be favorable, with low (<10%) clay.[14]

While the gross thickness of the Domanik interval can range from 100 m to 300 m (330 to 1,000 ft), publicly available information is lacking on its net organic-rich interval, its porosity and pressure. The Domanik Formation has been correlated with the Duvernay Formation/Shale in Western Canada Sedimentary Basin.[13]

At current time, the publicly available geologic and reservoir data are insufficient to prepare a quantitative shale oil and gas resource assessment for the Domanik Shale in the Timan-Pechora Basin. Other source rocks and shales also exist in this basin, but have been excluded from the assessment. The Late Jurassic to Early Cretaceous (Kimmeridgian) shales in this basin have high TOC but are reported to be thermally immature. The Silurian-Ordovician shales in this basin appear to have low TOC of 0.5% to 1.5%.[12]

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