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Technically Recoverable Shale Oil and Shale Gas Resources:

Poland

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Executive Summary

Introduction

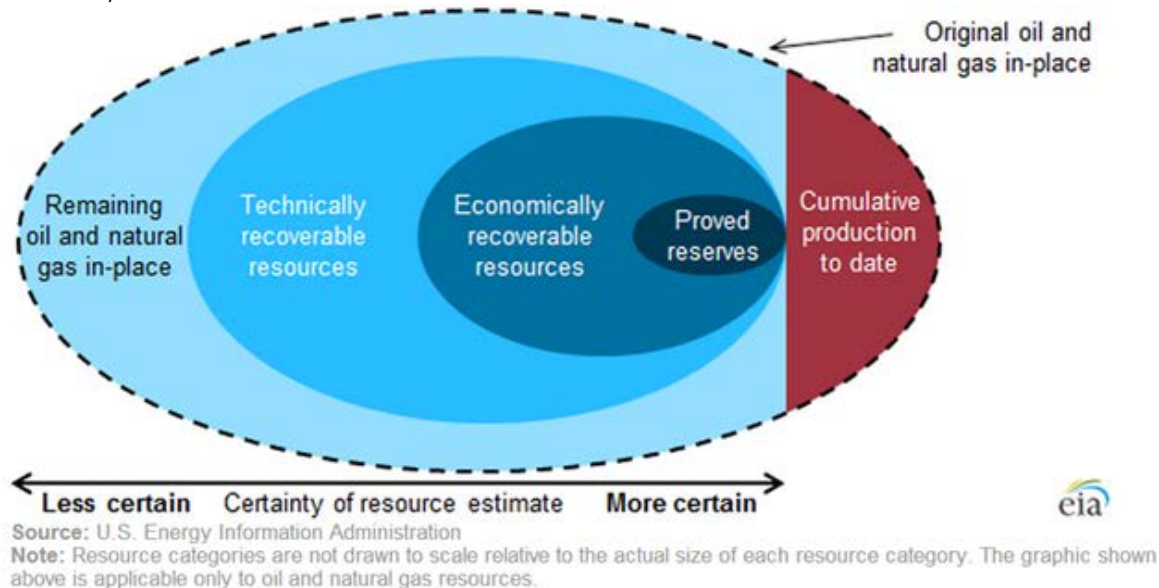
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

VIII. POLAND (INCLUDING LITHUANIA AND KALININGRAD)

SUMMARY

Poland has some of Europe's most favorable infrastructure and public support for shale development. The Baltic Basin in northern Poland remains the most prospective region with a relatively simple structural setting. The Podlasie and Lublin basins also have potential but are structurally complex, with closely spaced faults which may limit horizontal shale drilling. A fourth area, the Fore-Sudetic Monocline in southwest Poland, is less recognized but has non-marine coaly shale potential similar to Australia's Cooper Basin.

Figure VIII-1: Location of Assessed Shale Basins in Poland.



Source: Modified from San Leon Energy, 2012

Poland's risked, technically recoverable shale resources are estimated at 146 Tcf of shale gas and 1.8 billion barrels of shale oil in four assessed basins, Tables VIII-1 and VIII-2. Lithuania adds 0.4 Tcf and 0.3 billion barrels of risked, technically recoverable shale gas and shale oil resources, Table VIII-3. Kaliningrad adds 2.0 Tcf and 1.2 billion barrels of risked, technically recoverable shale gas and shale oil resources, Table VIII-3. Initial exploration has confirmed the shale resource potential but suggests that reservoir conditions are more challenging than originally anticipated by industry. New data collected since our 2011 resource assessment resulted in a 20% reduction in EIA/ARI's estimate of Poland's shale resources, on an energy-equivalent basis.

Table VIII-1: Shale Gas Reservoir Properties and Resources of Poland.

Basic Data	Basin/Gross Area	Baltic/Warsaw Trough (16,200 mi ²)			Lublin (4,980 mi ²)	Podlasie (6,600 mi ²)			Fore Sudetic (19,700 mi ²)	
	Shale Formation	Llandovery			Llandovery	Llandovery			Carboniferous	
	Geologic Age	L. Sil - Ord. - U. Cambrian			L.Sil-Ord-U.Cambrian	L. Sil - Ord. - U. Cambrian			Carboniferous	
	Depositional Environment	Marine			Marine	Marine			Lacustrine	
Physical Extent	Prospective Area (mi ²)	830	2,070	5,680	2,390	1,000	1,100	860	9,070	
	Thickness (ft)	Organically Rich	820	820	820	415	540	540	540	330
		Net	451	451	451	228	297	297	297	182
	Depth (ft)	Interval	6,500 - 9,800	7 - 13,000	9 - 16,000	7,000 - 16,000	6 - 9,000	6,500 - 11,500	10 - 16,000	8 - 16,000
Average		8,200	10,000	12,500	11,000	7,500	9,500	12,500	12,000	
Reservoir Properties	Reservoir Pressure	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.	
	Average TOC (wt. %)	3.9%	3.9%	3.9%	3.0%	3.0%	3.0%	3.0%	3.0%	
	Thermal Maturity (% Ro)	0.85%	1.15%	1.80%	1.35%	0.85%	1.15%	1.80%	1.60%	
	Clay Content	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium	
Resource	Gas Phase	Assoc. Gas	Wet Gas	Dry Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Dry Gas	
	GIP Concentration (Bcf/mi ²)	36.6	131.0	181.1	91.2	27.4	82.3	122.4	67.2	
	Risked GIP (Tcf)	12.1	108.5	411.5	45.8	6.6	21.7	25.3	106.7	
	Risked Recoverable (Tcf)	1.2	21.7	82.3	9.2	0.7	4.3	5.1	21.3	

Source: ARI, 2013

Table VIII-2: Shale Oil Reservoir Properties and Resources of Poland.

Basic Data	Basin/Gross Area		Baltic/Warsaw Trough (16,200 mi ²)		Podlasie (6,600 mi ²)	
	Shale Formation		Llandovery		Llandovery	
	Geologic Age		L. Sil - Ord. - U. Cambrian		L. Sil - Ord. - U. Cambrian	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi ²)		830	2,070	1,000	1,100
	Thickness (ft)	Organically Rich	820	820	540	540
		Net	451	451	297	297
	Depth (ft)	Interval	6,500 - 9,800	7,000 - 13,000	6,000 - 9,000	6,500 - 11,500
Average		8,200	10,000	7,500	9,500	
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		3.9%	3.9%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi ²)		42.2	12.8	36.2	11.1
	Risky OIP (B bbl)		14.0	10.6	8.7	2.9
	Risky Recoverable (B bbl)		0.70	0.53	0.43	0.15

Source: ARI, 2013.

Table VIII-3: Shale Gas and Shale Oil Reservoir Properties and Resources of Lithuania/Kaliningrad

Basic Data	Basin/Gross Area		Baltic (90,000 mi ²)		Basic Data	Basin/Gross Area		Baltic (90,000 mi ²)	
	Shale Formation		Llandovery			Shale Formation		Llandovery	
	Geologic Age		L. Sil - Ord. - U. Cambrian			Geologic Age		L. Sil - Ord. - U. Cambrian	
	Depositional Environment		Marine			Depositional Environment		Marine	
Physical Extent	Prospective Area (mi ²)		3,030		Physical Extent	Prospective Area (mi ²)		3,030	
	Thickness (ft)	Organically Rich	575			Thickness (ft)	Organically Rich	575	
		Net	316				Net	316	
	Depth (ft)	Interval	6,500 - 9,800			Depth (ft)	Interval	6,500 - 9,800	
Average		8,000		Average	8,000				
Reservoir Properties	Reservoir Pressure		Mod. Overpress.		Reservoir Properties	Reservoir Pressure		Mod. Overpress.	
	Average TOC (wt. %)		3.9%			Average TOC (wt. %)		3.9%	
	Thermal Maturity (% Ro)		0.85%			Thermal Maturity (% Ro)		0.85%	
	Clay Content		Medium			Clay Content		Medium	
Resource	Gas Phase		Assoc. Gas		Resource	Oil Phase		Oil	
	GIP Concentration (Bcf/mi ²)		25.2			OIP Concentration (MMbbl/mi ²)		29.8	
	Risky GIP (Tcf)		24.5			Risky OIP (B bbl)		28.9	
	Risky Recoverable (Tcf)		2.4			Risky Recoverable (B bbl)		1.45	

Poland's shale industry is still at an early exploratory, pre-commercial phase. About 30 vertical exploration wells and a half-dozen vertical and two horizontal production test wells have been drilled to date. However, early results have not met industry's high initial expectations. Last year, ExxonMobil abandoned the fault-prone Lublin and Podlasie basins after drilling two

vertical test wells. ConocoPhillips and Chevron are moving cautiously towards drilling their initial test wells in the Baltic and Lublin basins, respectively. And even in the geologically favorable Baltic Basin, Marathon and Talisman recently exited after expressing “disappointment” with reservoir quality and being “not particularly enthused by results we’ve had to date.” Meanwhile, the government debates rolling back some favorable shale investment terms, by introducing higher taxes and mandating government back-in rights.

Yet, it is too soon to dismiss Poland’s extensive shale potential. Derisking shale plays in North America typically requires drilling about 100 wells, while achieving economies of scale requires many hundreds more. E&P companies continue to explore Poland’s shale potential in over 100 geologically diverse licenses. State oil company PGNiG, which controls the country’s largest shale lease position, reported test gas production from its first stimulated vertical shale well and recently drilled a horizontal offset well. Determining best-practices operations remains a key challenge, including locating the best completion zones within the thick shale sequence, achieving better execution of hydraulic fracture stimulations, and reducing the current several-fold higher well cost differential compared with North America.

INTRODUCTION

With an established onshore conventional oil and gas production industry as well as recent experience with coalbed methane exploration, Poland offers Europe’s best prospects for developing a viable shale gas/oil industry. Shale leasing and development in Poland began in 2007 when the Ministry of Environment implemented highly favorable policies for shale gas development, including a simple tax and royalty fiscal system.

The current investment terms for shale gas development include a 1,200-km² maximum block size, minimal signature fees of 50 Euros/block, freedom from mandatory government back-in rights, and reduced production royalties of \$0.06/Mcf and \$1.60/bbl. The typical shale contract comprises an initial 5-year exploration period, which can be extended, followed by a 30-year production period. Industry’s response has been strong: over 100 shale gas exploration licenses have been awarded, covering more than 35,000 km², no less than one-third of the country’s area.

However, more recently the government is discussing modifications to the shale fiscal terms which may increase profit taxes on shale gas production to 40% or more, while establishing a government-owned entity to gain a minority equity stake in shale gas development projects. These changes, if implemented, could significantly reduce industry investment in shale exploration at a time of disillusionment with early well results.

The initial results from some 30 vertical and two horizontal shale wells have been less successful than hoped. Production rates and reservoir quality have been lower than expected, with one operator testing ~4% porosity and ~40% clay content in several wells. Hydraulic fracturing operations to stimulate production from the shale also have been sub-par. However, as exploration continues, operators may successfully identify the geologic sweet spots, while service companies are likely to improve their implementation of North American drilling and stimulation technology.

GEOLOGIC OVERVIEW

Poland has four main basins where Paleozoic shales are prospective and exploration activity is taking place, Figure VIII-1. Discussed separately in Sections 1-4, these include the Baltic Basin and Warsaw Trough in northern Poland, the Podlasie Depression and the Lublin Basin in east Poland, and the Fore-Sudetic Monocline in the southwest.¹ A fifth region, the Carpathian Foreland belt of southeastern Poland, could be prospective for oil-prone Jurassic shales, but this area is structurally complex and has not yet been targeted for shale leasing.

The Paleozoic sedimentary sequence in Poland contains several marine-deposited shale deposits which in places are thick, organic-rich and buried at prospective depths of 1,000 to 5,000 m. Most areas are in the gas-prone thermal maturity window, with smaller liquids-rich areas occurring in the north and east. Organic matter generally is dominated by Type II kerogen. Abundant geologic data exists on these Paleozoic shales. They have been subjected to extensive study as they are considered the main source rocks for Poland's conventional oil and gas fields. Basic shale exploration maps can be accurately constructed in most regions.

However, the distribution of favorable shale rock properties -- particularly the combination of high porosity and brittle mineralogy with low clay content -- is still poorly understood. Several of the early shale exploration wells have tested lower-than-expected porosity. And whereas quartz content in selected areas can be favorably high (40-80%), some

recent shale drilling has tested high clay content (30-40%), which is less conducive to effective fracture stimulation. In addition, the local structural geology often is poorly known, in particular the extent and precise location of problematic faults which may interfere with shale drilling and completion. Consequently, considerable exploration drilling and seismic surveys are still needed to define potential sweet spots.

The main stratigraphic targets for shale gas/oil exploration in Poland are the Lower Silurian and Ordovician marine-deposited shales. The thinner but thermally more mature Cambrian shale is emerging as a secondary objective, while non-marine Carboniferous shales also have potential.

- **Lower Silurian** (Llandovery-Wenlock) graptolitic black shale is the primary shale exploration target in Poland. The Silurian section comprises several hundred to several thousand meters of shale and siltstone, with TOC generally increasing towards the bottom of the section. The most prospective portion is approximately 500 m of high-resistivity, high-TOC section in the Llandovery, Wenlock and lowest Ludlow, consisting of dark gray to black, dense siltstones and shales. Natural fractures are common and usually filled with calcite, although the matrix is non-calcareous. The Llandovery generally averages 1.5% to 2.5% TOC but is richer in the central Baltic Basin, while the Podlasie Basin averages 6% TOC and TOC can be high in the northwest Lublin Basin as well. The Wenlock is richest in the eastern Baltic and southeastern Lublin basins.
- **Ordovician.** Marine-deposited graptolitic black shales in Poland are part of a regional deposit extending from Scandinavia to Russia.² These include Early Ordovician Dictyonema Shale, which comprises fine-grained, non-metamorphosed, organic-rich deposits.
- **Cambrian.** Although not evaluated in the previous 2011 EIA/ARI assessment, the Cambrian also contains organic-rich shale that increasingly is being targeted for exploration. PGNiG and Lane Energy have reported test gas production from the Cambrian. Up to 700 m of Cambrian section is present, mostly tight sandstone but with thin shales near the top. Cambrian units include the Zarnowiec and Upper Vendians, which represent the transition from continental alluvial fan deposits to shallow marine terrigenous sedimentary environments.

The Lower Cambrian is dominated by quartz sandstones interbedded with shales, while the relatively thin Mid-Cambrian Alum Shale is a transgressive, sediment-starved sequence containing high TOC.³ The Upper Cambrian to Tremadocian shale, present only in the northern part of the Baltic Basin, contains high average TOC of 3-12% but is quite thin (several to 50 m).

- **Carboniferous Coaly Shales.** Non-marine, lacustrine-deposited carbonaceous shale sequences of Carboniferous age are widely present in Poland.⁴ These organic-rich units, such as the Anthracosia Shales, are associated with economically important coal deposits. Although considered good source rocks for natural gas, as well as coalbed methane exploration targets in their own right, these coal-shale packages may not be brittle enough for effective shale development. However, comparable deposits in the Cooper Basin of Australia recently have produced shale gas. San Leon Energy is testing the Carboniferous shales in southwest Poland's Fore-Sudetic Monocline.

In addition to these four main stratigraphic targets that were assessed, additional organic-rich shale candidates exist in Poland but were excluded from this study. These apparently less prospective shales include:

- **Upper Permian Kupferschiefer Shale.** Stratigraphically positioned between the L. Permian Rotliegendes tight sandstone and the U. Permian Zechstein evaporite sequence, the Kupferschiefer Shale is present in the Fore-Sudetic Monocline and Lublin basins as well as in other areas of Poland. The Kupferschiefer is a black shale that was deposited under anoxic marine conditions, typically containing 7% to 16% TOC.⁵ However, the economically important metal sulfides (pyrite, spalerite, galena) that also occur in high concentrations in this shale may interfere with fracture stimulation and gas production. None of the Poland shale operators have reported targeting the Kupferschiefer.
- **Mesozoic and Tertiary Shales.** Numerous younger, organically rich black shales also occur in the Carpathian Foredeep Basin of southeast Poland, but these generally are non-marine and mostly thermally immature.⁶ For example, the Oligocene to early Miocene Menilite black shale, with 4-8% TOC (mainly Type II kerogen), is considered a high-quality source rock for conventional oil and gas fields in the Carpathian fold belt. In addition, up to 200 m of organic-rich sandy mudstone and claystone with average 4% TOC is present in the Jurassic (Bathonian-Aalenian) foreland platform. Finally, the Upper Jurassic organic-rich Mikulov marls, about 1400-m thick with 0.2% to 10% TOC, are considered world-class source rocks in the nearby Vienna Basin.⁷ The Mikulov may be present in the subthrust of the Polish Carpathians but appears too deep and structurally complex to be prospective for shale development.

PGI AND USGS ASSESSMENTS OF POLAND SHALE GAS RESOURCES

In 2012 the Polish Geological Institute (PGI) and the U.S. Geological Survey (USGS) collaborated on a preliminary shale gas and shale oil assessment of Poland. PGI and USGS released separate independent assessments of the technically recoverable shale gas and shale oil resources within Lower Paleozoic formations in the Baltic, Podlasie, and Lublin basins. The PGI study drew heavily on earlier detailed shale mapping and analysis conducted by Poprawa and colleagues at PGI.⁸ Both the PGI and USGS studies were based on conventional oil and gas logs, core, and seismic data collected during the 1970-80's. Neither study cited recent data measured from shale industry exploration programs in Poland.

PGI estimated technically recoverable shale gas resources in the onshore Baltic-Podlasie-Lublin region to be 230.5 to 619.4 billion m³ (8 to 22 Tcf), with an additional 1.569 to 1.956 billion barrels of oil (their "higher probability range" estimate).⁹ The corresponding USGS estimate was about 1.345 Tcf and 0.168 billion barrels (mean estimate), or roughly 10% of PGI's estimate.¹⁰

The PGI and USGS resource estimates both are considerably less than EIA/ARI's current estimate of 146 Tcf and 1.8 billion barrels for Paleozoic shale gas and oil in Poland, Tables VIII-1 and VIII-2. Part of the difference arises because PGI excluded the Lublin Basin, while PGI and USGS both excluded the Fore-Sudetic Monocline, two large regions where shale gas drilling and gas production are underway. But most of the difference is because these researchers followed a different methodology and used different assumptions. The key differences among the PGI, USGS, and EIA/ARI studies are as follows:

- **Methodology.** PGI and the USGS followed the methodology used by the USGS for assessing shale gas and shale oil resources in the United States, wherein empirical shale production data are analyzed to estimate per-well recoveries.¹¹ In Poland's case there are no empirical shale production data. PGI considered but rejected individual US shale plays as analogs for Poland, instead selecting for its mean estimate a range of EURs "on the lower end" of 26 shale gas plays evaluated by the USGS. The USGS methodology for its Poland assessment has not been published but appears similar.

EIA/ARI followed a different (volumetric) approach: calculating the prospective gas in-place and then estimating likely recovery factors based on multiple analogous North American shale plays.

- **Per-Well Recovery.** PGI and USGS estimated that per-well recoveries in Poland would be lower than those calculated by the USGS for many shale plays in the USA. For Poland, the USGS estimated average shale gas and oil EUR's of 0.245 Bcf/well and 34,000 bbl/well on 160-acre spacing. PGI estimated an average 0.4 Bcf/well recovery for Poland on implied 150-acre well spacing, with maximum of 1.0 Bcf/well and minimum of 0.04 Bcf/well.

However, improved technology has significantly increased per-well recovery in most US shale plays in recent years. For example, recent Marcellus Shale wells are performing much better than the wells initially drilled in this play during 2007-10. In addition, vertical wells have not been employed for Marcellus development since about 2009, after which new development has been entirely based on horizontal wells.

Using production data available at the time, which included many early vertical wells, the 2011 USGS Marcellus study estimated a mean 1.15 Bcf gas recovery per 149-acre cell within their main Interior Marcellus play.¹² This equates to approximately 0.82 Bcf/well recovery on the tighter 107-acre well spacing (6 wells per mi²) that is commonly used in the Marcellus today.

However, Marcellus operators recently are reporting that improved drilling and completion technology has steadily boosted their average horizontal well recoveries to between 5 and 11 Bcf/well at present. Indeed, the average per-well recovery reported by 10 large Marcellus operators, which account for most of the gas production in this play, has risen to 7.1 Bcf/well, Table VIII-4.¹³ Other US shale plays have seen increases in per-well recovery in recent years due to improved technology, underscoring the need for continuous appraisal of even proven shale plays.

The EIA/ARI study does not explicitly estimate per-well recovery for Poland, but we do estimate recovery efficiency. Assuming 80-acre spacing and relatively low gas recoveries of 10% to 20%, our equivalent per-well recoveries in Poland range from 1 to 4 Bcf/well. This has not yet been confirmed by well testing in Poland but the industry there is still in the early exploration phase. Our assumption of higher per-well recovery potential, based in part on more current US data, is a major reason why the EIA/ARI shale resource estimate is so much larger than the PGI and USGS estimates.

- **Basins Assessed.** The PGI assessment is limited to the Baltic and Podlasie basins; the Lublin Basin was excluded due to low TOC. However, PGNiG, Chevron, Marathon and other companies are continuing to explore for shale gas in the Lublin Basin. PKN Orlen recently drilled the first horizontal well there and is preparing to fracture stimulate. The USGS Poland map indicates they assessed the Baltic, Podlasie, and Lublin basins. The current EIA/ARI assessment covers the Baltic, Podlasie, and Lublin basins but also includes the Fore-Sudetic Monocline, where shale gas leasing and drilling are underway.

Table VIII-4 : Comparison of Marcellus and Poland Shale Gas Per-Well Recovery Estimates

Source	Mean Estimated Ultimate Recovery Bcf/107-acre Well		Current Net Production Million ft ³ /d	Proved Reserves + Risked Resources		Report Date	Location in play
	Bcf/well	Source		Tcf	Source		
Chesapeake	5.2	Chesapeake	800	39.0	Chesapeake	2/21/2013	PA & WV
Range Resources	8.5	Range	600	30.0	Range	3/4/2013	NE PA
Shell	-	-	295	24.1	ARI est	5/28/2010	PA & WV
Statoil	-	-	451	18.9	Statoil	2/28/2013	PA & WV
ExxonMobil	-	-	-	17.6	ARI est	8/23/2012	PA & WV
EQT Corp.	7.3	EQT	800	15.0	EQT	2/5/2013	PA & WV
Consol/Noble Energy	5.9	Consol	280	14.8	Noble	2/7/2013	PA & WV
Chevron Atlas Reliance	-	-	158	13.0	Atlas	5/6/2010	SW PA
Talisman Energy	5.0	Talisman	450	8.0	Talisman	2/13/2013	NE PA
Ultra Petroleum	6.0	Ultra	194	7.4	Ultra	3/4/2013	NE PA
Anadarko Corp.	8.0	Anadarko	330	6.0	Anadarko	2/20/2013	NE PA
Cabot Oil & Gas	11.0	Cabot	930	5.3	ARI est	2/28/2013	NE PA
Chevron Chief Oil	-	-	140	5.0	Chevron	5/4/2011	SW PA
BG Exco JV	-	-	-	4.8	Exco	5/10/2010	Central PA
Southwestern Energy	8.0	Southwestern	300	4.7	ARI est	3/1/2013	NE PA
National Fuel Gas	6.0	NFG	194	4.1	ARI est	2/7/2013	Central PA
Operator Marcellus Mean or Total	7.1	Operators	5,922	218			PA & WV
USGS Interior Marcellus Equiv 107-Ac Mean Est	0.82	USGS	-	81.4		11/23/2011	PA & WV
PGI Poland Mean Shale Gas 150-Ac Est	0.40	PGI	0	8 to 22		3/1/2012	Baltic-Podlasie
USGS Poland Mean Shale Gas 160-Ac Est	0.25	USGS	0	1.3		7/1/2012	Baltic-Podlasie

- TOC.** PGI screened out the Lublin Basin because their log analysis did not identify significant shale layers thicker than 15 m with TOC above 2%. However, they noted the evaluation process was “not easy and straightforward” due to the poor quality of the 40- to 50-year-old core and log data. EIA/ARI, relying on more recent shale exploration data and published source rock studies, developed a more optimistic view that shallower portions of the deep Lublin Basin still may have prospective shale targets.

In summary, the EIA/ARI shale gas/oil resource estimate for Poland is larger because it includes two additional shale plays (Podlasie and Fore-Sudetic Monocline), incorporates more recent shale industry data, and assumes higher recovery factors more consistent with (but still considerably less than) actual Marcellus Shale well performance.

1. BALTIC BASIN

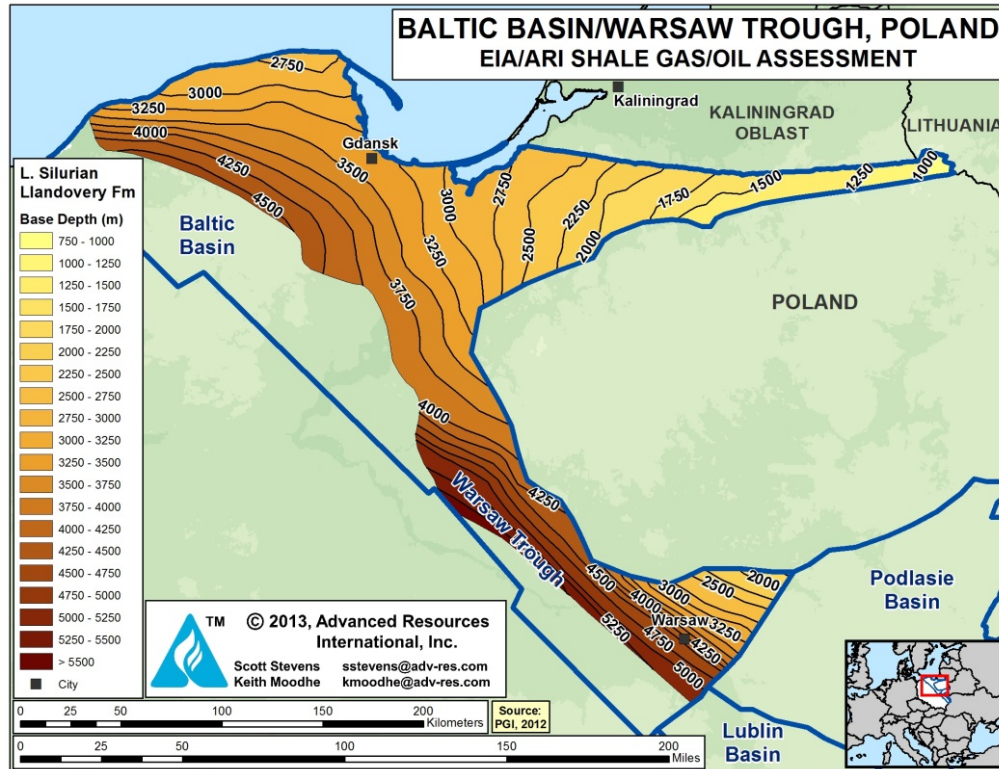
1.1 Introduction and Geologic Setting

The 16,200-mi² Baltic Basin in northern Poland, Lithuania and Kaliningrad is a rare (for Europe), relatively tectonically quiescent area that contains a sequence of Paleozoic to Mesozoic deposits, including Lower Paleozoic organic-rich shales that are prospective for shale gas and oil development.¹⁴ These mostly marine-deposited shales are separated by regional unconformities related to Caledonian, Variscan, and Alpine tectonics. A small portion of the basin extends into Lithuania and the Kaliningrad Oblast.

Figure VIII-2 illustrates the depth to the Lower Silurian Llandovery Shale, one of the principal targets for exploration in the Baltic Basin, highlighting the 1 to 5 km prospective depth window. The basin's structure is much simpler than most other areas in Poland and Europe. Faulting does occur but it is more widely spaced and less severe. In addition, the shale strata dip gently in this basin, Figure VIII-3. Detailed seismic sections identify fairly broad areas which appear to be intact and free of faulting in places, Figure VIII-4. Faulting in the Baltic Basin is most likely related to uplift during the Devonian (Caledonian Orogeny), coupled with relatively rapid deposition during the late Paleozoic and Mesozoic.

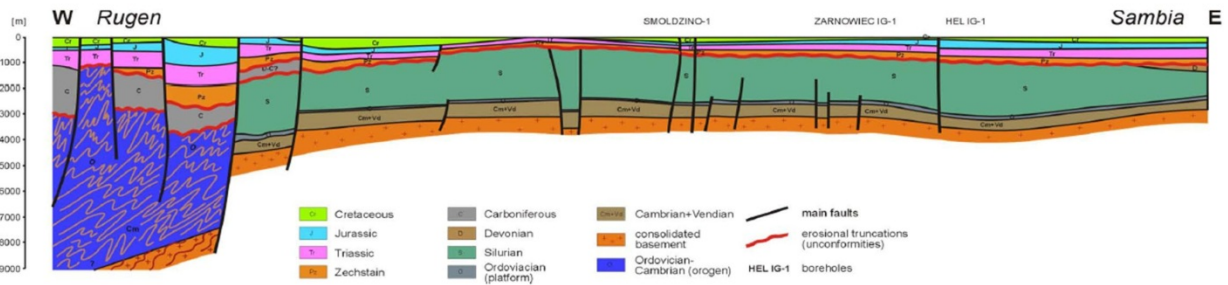
The Baltic Basin formed as a result of late Precambrian rifting followed by early Paleozoic post-rift downwarping of the East European Platform. The basin's southwest boundary is defined by the northwest-southeast trending Trans-European Suture Zone (TESZ), a deformed fault zone, while the Mazury-Belarus High defines the eastern boundary. The basin extends to the north into the Baltic Sea.

Figure VIII-2: Baltic Basin Map Showing Depth To Lower Silurian Llandovery Shale.



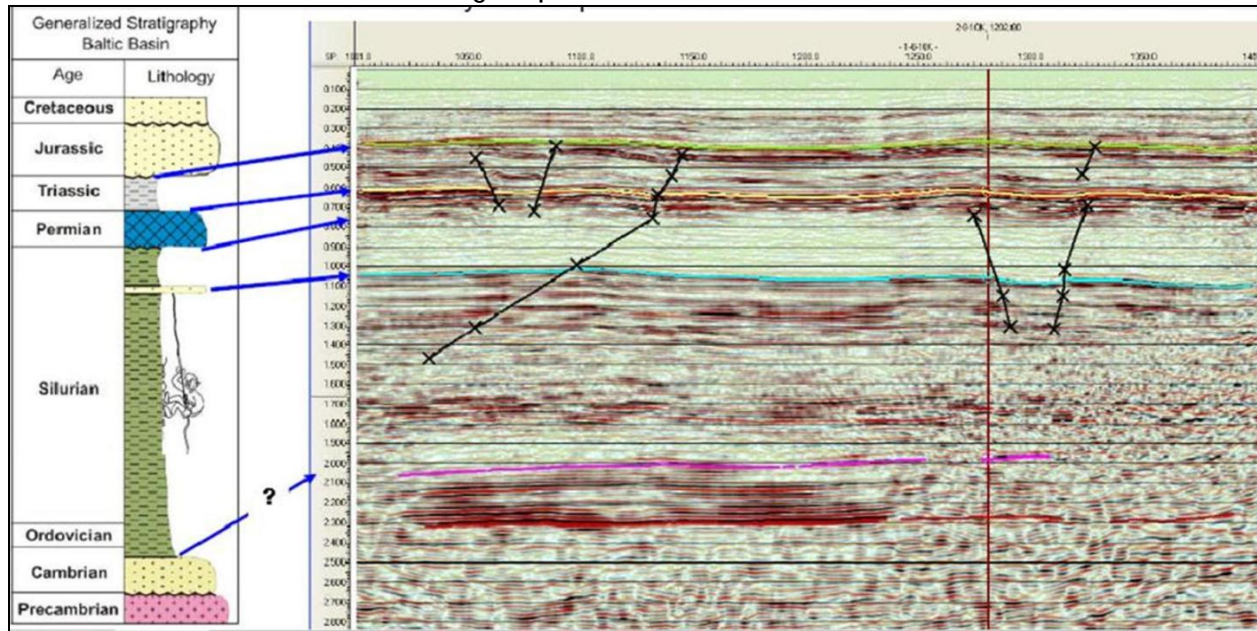
Source: Modified from Polish Geological Institute, 2012

Figure VIII-3: Structural Cross-Section in North Poland Baltic Basin Showing Relatively Simple Structure and Widely Spaced Faults.



Source: Modified from San Leon Energy, 2012

Figure VIII-4: Detailed Seismic Section in North Poland Baltic Basin
Showing Simple Structure and Few Faults.



Source: LNG Energy Ltd.

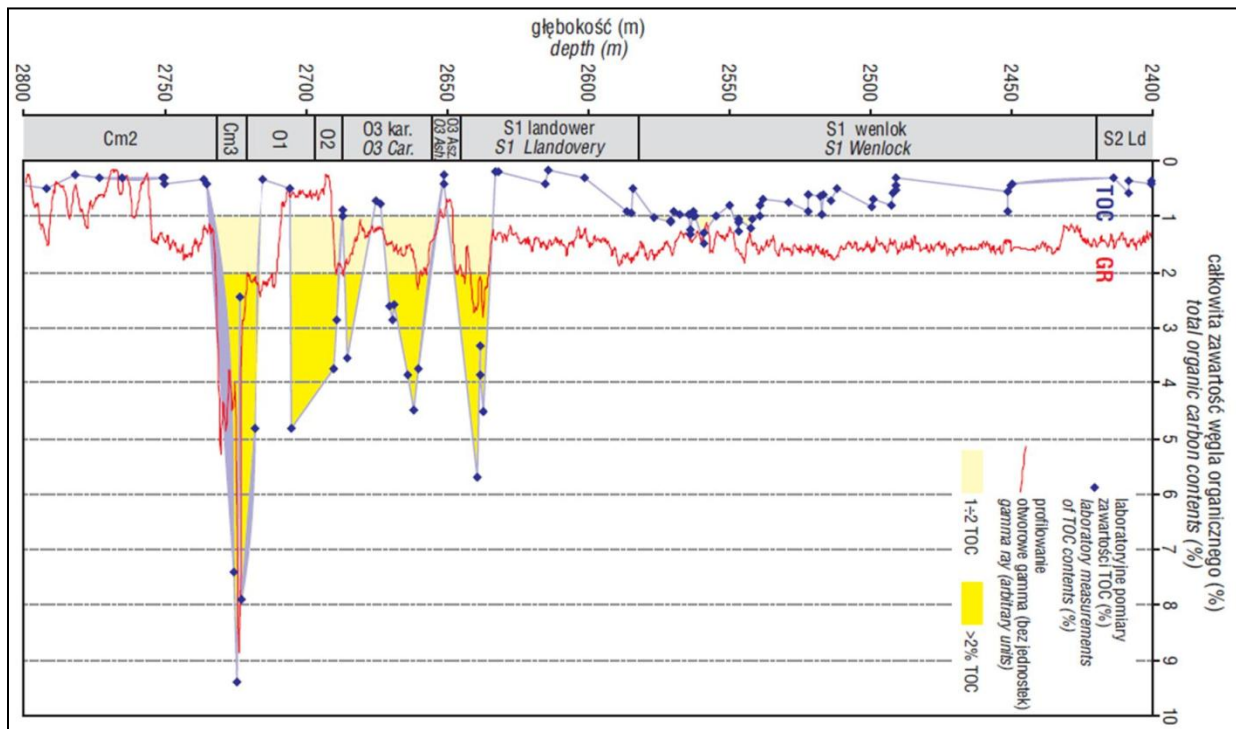
Organic-rich shales of Paleozoic age within the Baltic Basin are relatively flat lying, high in TOC, thermally mature in the gas to oil windows, and among the most prospective in Europe for shale development. Figure VIII-5 exhibits organic-rich shales that are typically present within the Lower Silurian, Ordovician, and Cambrian strata. TOC distribution in the Zarnowiec IG-1 conventional well, northern Baltic Basin, shows several high TOC zones totaling about 75 m thick, with good correlation of gamma ray log and core data. These Lower Paleozoic deposits form a package of quite thick, laterally extensive, dark grey to black organic-rich rocks that contain marine (type II/III) kerogen. The main shale targets in the Baltic Basin include:

- **Cambrian.** Up to 700 m of Cambrian sandstone and shale is present, including the Zarnowiec and other Upper Vendian units. These represent a transition from continental alluvial fan deposits to shallow marine terrigenous sedimentary environments.
- **Ordovician.** Deposited under deep water marine conditions, the Ordovician is thinner, ranging from 80 to 200 m. The Lower Ordovician Arenig and Lower Caradoc formations are predominately marly limestone interbedded with claystone and siltstone. The overlying Upper and Middle Caradoc Formation consists of graptolite-rich black shale.
- **Silurian.** The overlying Silurian sequence is extremely thick at up to 3 km in the southwest near the TESZ, but more typically 1 km thick in the shale exploration areas.

The Silurian shale is locally interbedded with dolomitic limestone. The thick middle Silurian Wenlock and thin Lower Silurian Llandovery formations contain dark grey to black organic shale that commonly exhibits strong gas shows in exploration wells.

The Ordovician and Silurian shales are overlain by more than 200 m of anhydrite and halite (salt) of the Permian Zechstein Formation, a weak zone that frequently decouples the younger overlying section from the Paleozoic strata. Finally a 1,200-m thick sequence of overlying Mesozoic sandstones and claystone is capped by a thin veneer of Tertiary sand and gravel. Additional potential source rock shales are present in the Upper Jurassic and Lower Cretaceous in the Baltic Basin but were not assessed due to low thermal maturity. These Mesozoic shales locally have TOC >1.5% but are thermally immature (R_o 0.5% to 0.7%) at well depths of 1.5 to 3.2 km.¹⁵

Figure VIII-5: TOC Distribution in L. Paleozoic, Zarnowiec IG-1 Conventional Well, Northern Baltic Basin, Shows Several High TOC Zones Totaling About 75 m Thick. Note Good Correlation of Gamma Ray Log and Core Data.



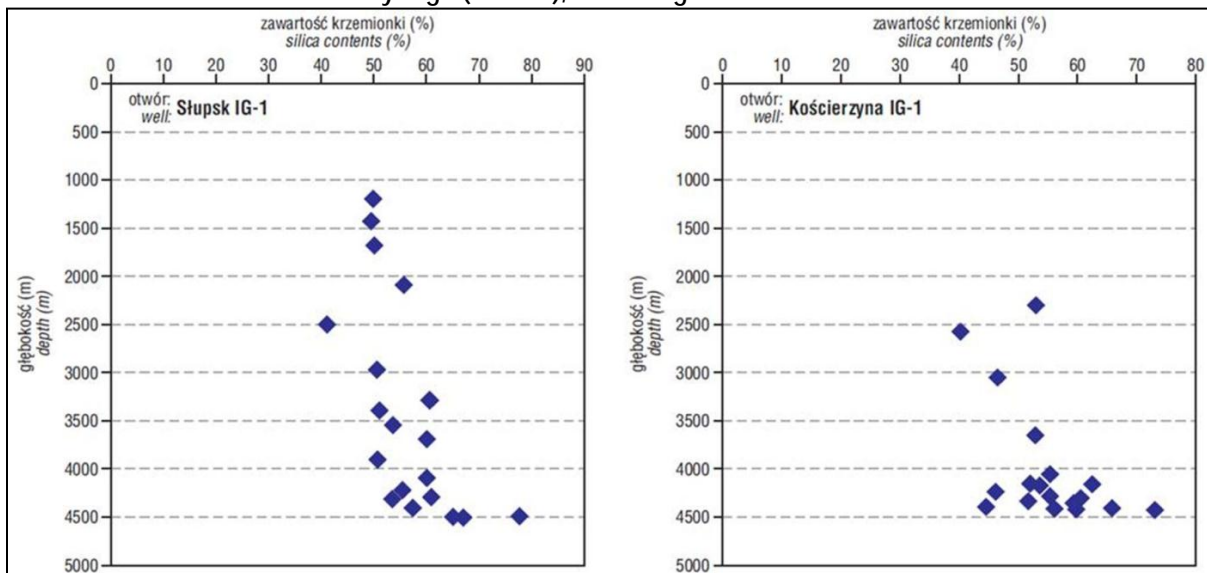
Source: Poprawy, 2010

1.2 Reservoir Properties (Prospective Area)

The combined Lower Silurian, Ordovician, and Cambrian section in the Baltic Basin totals from 1,000 to 3,500 feet thick. The organic-rich shale interval for the Lower Paleozoic is estimated to average 820 ft thick, of which approximately 55% is considered net thickness. TOC averages about 3.9%. Silica content from two older western Baltic Basin wells measured relatively high (40-80%), Figure VIII-6, indicating brittle rock conditions. However, high clay content (33-44%) has been reported from two of BNK's recent shale exploration wells.

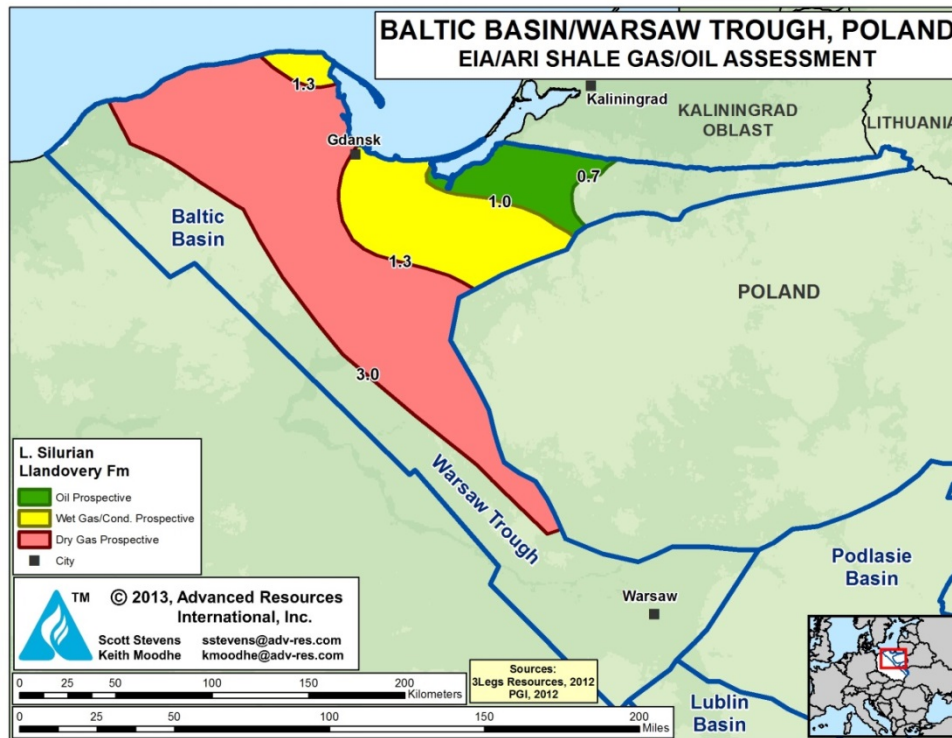
Thermal maturity ranges from oil- to gas-prone, Figure VIII-7, increasing steadily with depth in the basin as illustrated in the Gdansk IG-1 well, Figure VIII-8. The average depth ranges from 8,200 ft in the oil window, to 10,000 ft in the wet gas window area, to 12,500 ft in the oil window. Porosity is estimated at 4% based on recent exploration results. The basin is slightly over-pressured with an estimated 0.50 psi/ft gradient. Gas impurities such as CO₂ or N₂ appear low in most of the basin.

Figure VIII-6: Silica Content in the Lower Paleozoic From Two Western Baltic Basin Wells is Relatively High (40-80%), Indicating Brittle Rock Conditions.



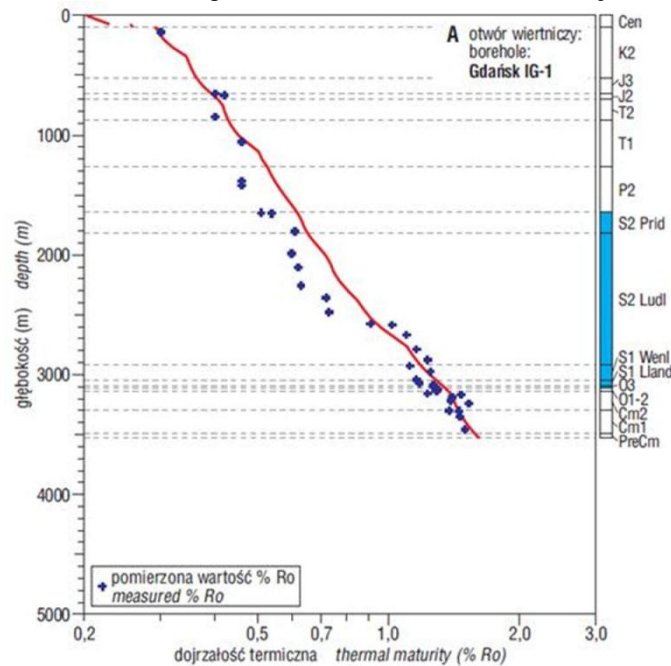
Source: Krzemińskiego & Poprawy, 2006 in Poprawy, 2010

Figure VIII-7: Baltic Basin Map Showing Thermal Maturity Windows and Prospective Area for Lower Silurian Llandovery Shale, Poland



Source: Contours modified from San Leon Energy, 2012 and Polish Geological Institute, 2012

Figure VIII-8: Thermal Maturity Increases Steadily with Depth in the Gdansk IG-1 Well Central Baltic Basin, Reaching Oil- and Then Gas-Prone Maturity in the Paleozoic.



Source: Poprawa, 2010

1.3 Resource Assessment

Total risked, technically recoverable shale resources in the Poland portion of the Baltic Basin and Warsaw Trough are estimated at 105 Tcf of shale gas and 1.2 billion barrels of shale oil and condensate.

Dry Gas Window. The mapped prospective area for Poland's dry gas window in the Baltic Basin is estimated at 5,680 mi². Lower Paleozoic shale (comprising the L. Silurian, Ordovician, and Cambrian) has a favorable resource concentration of approximately 181 Bcf/mi². Risked, technically recoverable shale gas resources are estimated at 82 Tcf, out of a risked shale gas in-place of 412 Tcf.

Wet Gas Window. The wet gas prospective area covers about 2,070 mi². Risked, technically recoverable resources are estimated at 22 Tcf of shale gas and 0.5 billion barrels of shale condensate from 109 Tcf and 14 billion barrels of risked, in-place shale gas and shale oil resources.

Oil Window. The much smaller oil window within the northern Baltic Basin prospective area covers about 830 mi². Risked technically recoverable resources are estimated to be about 0.7 billion barrels of shale oil and condensate and 1.2 Tcf of associated shale gas, out of a risked in-place shale oil and condensate resource of 14 billion barrels.

1.4 Exploration Activity

Poland, and in particular the Baltic Basin, has a large existing data set of well logs and seismic to guide shale exploration. Over 200 petroleum exploration wells have been drilled targeting conventional oil and gas plays in Poland, penetrating shale formations and providing general information on thickness, depth, TOC and thermal maturity. Seismically, the Lower Paleozoic shales can be difficult to image due to acoustic interference caused by the 200-m thick overlying Zechstein salt. Regional modern 2D and localized 3D seismic data are being acquired by shale operators over their licenses to aid in siting well locations, particularly to avoid problematic faults.

Since 2010 the smaller independent E&P companies have pioneering shale exploration in the Baltic Basin, including Lane Energy, BNK Petroleum, San Leon Energy, and others. More recently large oil companies (ConocoPhillips, Marathon, Talisman) have farmed into some of these positions or acquired their own blocks. PGNiG is active but has focused mainly outside of

the Baltic Basin. Thus far the Poland shale test programs have had limited success with modest gas flow rates. Key challenges seem to be locating the best stratigraphic zones in which to position the lateral, as well as successfully implementing hydraulic stimulation programs.

A brief summary of operator activities in the Baltic Basin is provided below, including the limited public geologic and reservoir results released to date:

- **PGNiG**, the national oil and gas company of Poland, holds 15 shale gas exploration licenses. Last year the company reported plans to invest \$0.5 billion in shale gas development with several Polish state-owned partners. PGNiG has drilled at least four shale gas exploration wells to date in the Baltic Basin, producing shale gas from the Cambrian in two vertical wells from depths of about 3,000 m, while logging gas shows in the Ordovician and L. Silurian. The company recently drilled its first horizontal well nearby (Lubocino-2H) and targets commercial production in the Baltic Basin starting 2016.¹⁶
- **ConocoPhillips** has farmed into three of **Lane Energy's** (subsidiary of 3Legs Resources PLC) shale blocks in the western Baltic Basin. Lane Energy has tested low gas rates (90 and 500 Mcfd) from two stimulated horizontal shale wells. ConocoPhillips recently became the operator of these blocks, shifting focus to the liquids-rich window in the north. The company recently spud its first Poland shale well, the vertical Strzeszewo LE-1, in an area with 3D seismic coverage.¹⁷

Lane's Lebien LE-2H well, a vertical well stimulated with a single-stage fracture treatment, produced an average 27 Mcf from the Upper Ordovician during a 5-day test. The well was re-entered in 2011 and a 1-km lateral was drilled into the Ordovician and stimulated with a large 13-stage frac treatment. This horizontal well produced at an initial 2.2 MMcfd, stabilizing at about 500 Mcfd on nitrogen lift during a 17-day test, making it the highest production for a shale well in Poland to date.

Lane's Warblino LE-1H well encountered hole instability while drilling into the U. Cambrian shale. The well was re-drilled with a 500-m lateral and stimulated with a 7-stage gel frac, testing 18 to 90 Mcfd on lift assist.

- **Marathon** and partner **Nexen** have acquired new seismic and drilled at least one shale well in the Baltic Basin.¹⁸ Marathon's most recent remarks (May 2012) on Poland noted "disappointment" with the reservoir quality. Currently, Marathon is conducting injectivity tests to determine whether to proceed with hydraulic stimulation.

- **Talisman** and **San Leon Energy** have drilled three vertical shale wells in the Baltic Basin, logging gas and some liquids shows throughout the Cambrian, Ordovician, and Silurian section. San Leon reported that it may drill its first horizontal shale well during 2Q-2013, with a planned 1,000+ m lateral completed with a multi-stage frac. However, Talisman's most recent remarks (October 2012) noted "we're not particularly enthused by results we've had to date. It's a difficult thing."¹⁹
- **BNK Petroleum** has drilled five vertical shale wells in the Baltic Basin (\$12 million/well). Porosity (3-4%) was lower than expected in over-pressured L. Paleozoic shale; clay content was fairly high (30-40%). The company estimated total GIP concentration of up to 135 Bcf/mi², including 86 Bcf/mi² in the target Ordovician and L. Silurian shale zones (total 110 m thick). The Leborg S-1 well flared gas from several intervals, but a fracture stimulation was unsuccessful due to high stress and inadequate pump capacity.

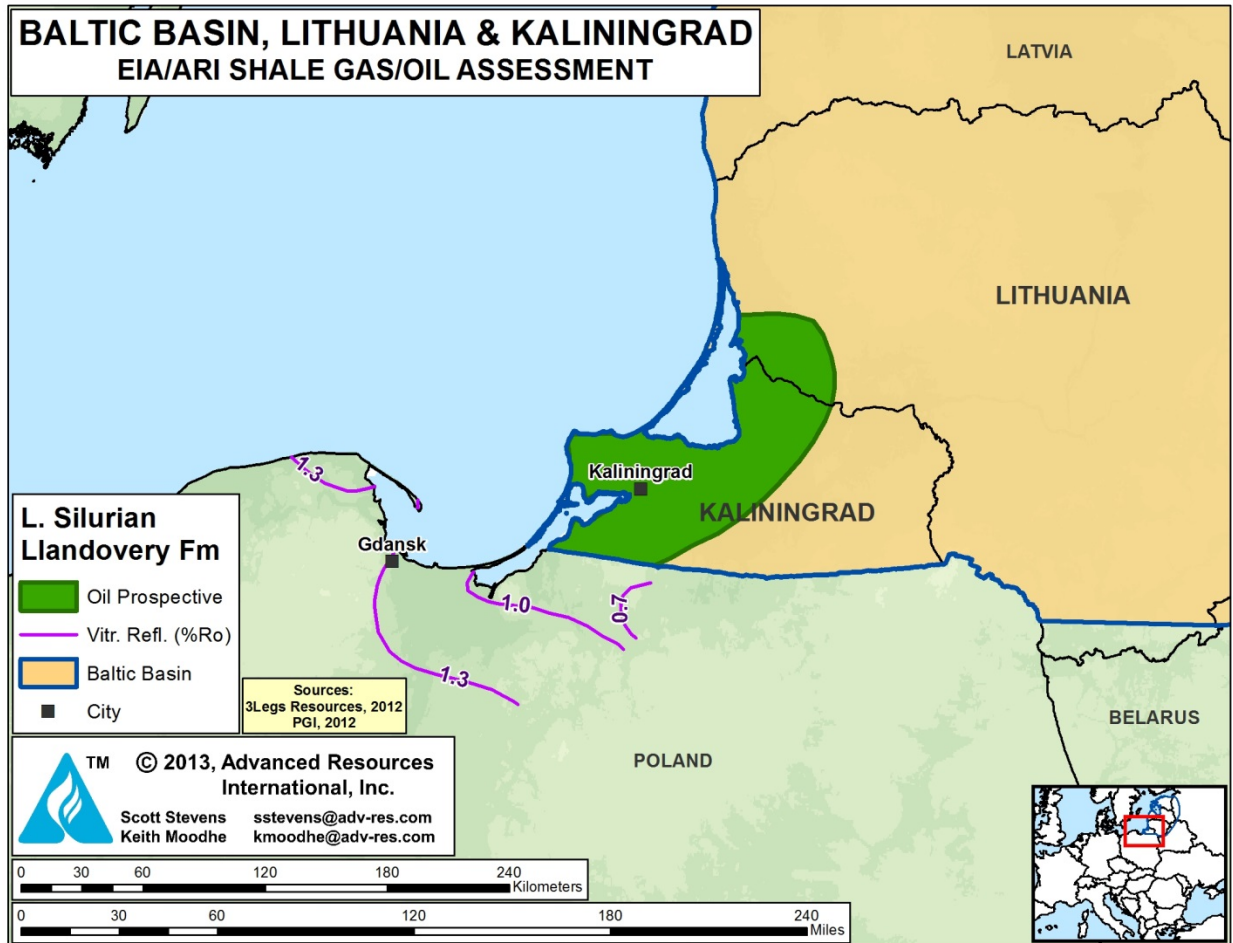
1.5 Lithuania

For the northeastern extension of the Baltic Basin into Lithuania, we estimate a risked 6 billion barrels of shale oil and 4 Tcf of associated shale gas in-place in the prospective area (Figure VIII-9), with 0.3 billion barrels of shale oil and 0.4 Tcf of associated shale gas as the risked, technically recoverable shale resources.

1.6 Russia (Kaliningrad Oblast)

For the northeastern extension of the Baltic Basin into Russia's Kaliningrad Oblast, we estimate a risked 23 billion barrels of shale oil and 20 Tcf of associated shale gas in-place in the prospective area (Figure VIII-9), with 1.2 billion barrels of shale oil and 2 Tcf of associated shale gas as the risked, technically recoverable shale resources.

Figure VIII-9. Baltic Basin Map Showing Thermal Maturity Windows and Prospective Area for Llandovery Shale, Lithuania and Kaliningrad



2. LUBLIN BASIN

2.1 Introduction and Geologic Setting

The 5,000-mi² Lublin Basin may be considered the southeastern extension of the Baltic Basin, with which it shares generally similar shale stratigraphy and lithology, Figure VIII-10. However, the Lublin Basin's structural geology is significantly more complex, with seismic sections showing numerous closely spaced faults. In addition, the basin is mostly too deep while shale TOC appears to be relatively low.

Although the Lublin Basin is experiencing early-stage shale gas exploration, it appears somewhat less prospective and was assessed separately from the Baltic Basin. Several vertical shale wells have been drilled, while the first horizontal well was drilled in late 2012 and is planned to be stimulated soon. PGNiG, Chevron, Marathon, and other companies are active.

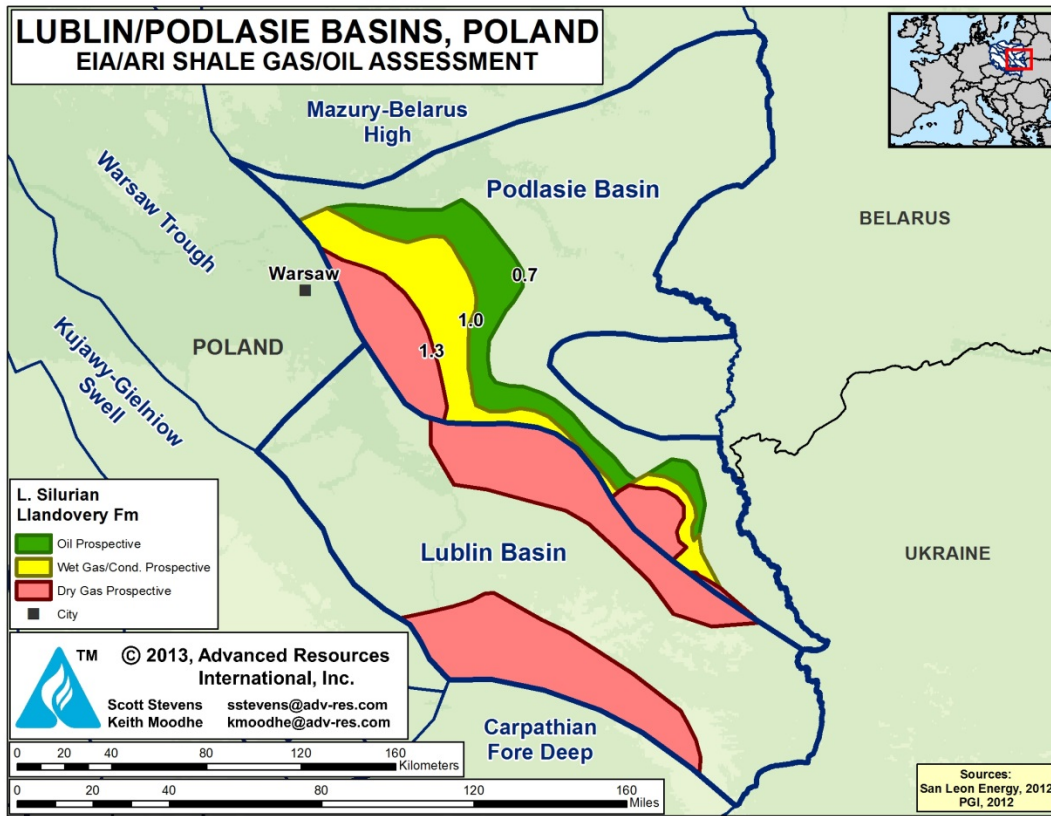
Figure VIII-11 illustrates the extent of faulting and sub-salt tectonic decoupling of the Lower Paleozoic in the Lublin Basin.²⁰ Figure VIII-12 shows hydrological flow within the Devonian strata, including closely spaced faults and steep dips.²¹ Major fault systems in the basin include the northwest-southeast trending Kock, Izbeca-Zamosc, Ursynow-Kazimierz, and Holy Cross faults. Clearly, the Lublin Basin is structurally more complex than the Baltic Basin.

Several small conventional natural gas fields have been discovered in the Lublin Basin, such as the Ciecierzyn-Melgiew Field which produces from Devonian carbonate reservoirs. Source rocks include Silurian and Ordovician shales, but marine limestones and claystones of the Devonian Bychawa Formation are considered more significant.²² The Lublin Basin also contains significant coal and coalbed methane deposits in Carboniferous strata, which continue to the southeast into the Lvov-Volhynia Basin of Ukraine.²³

2.2 Reservoir Properties (Prospective Area)

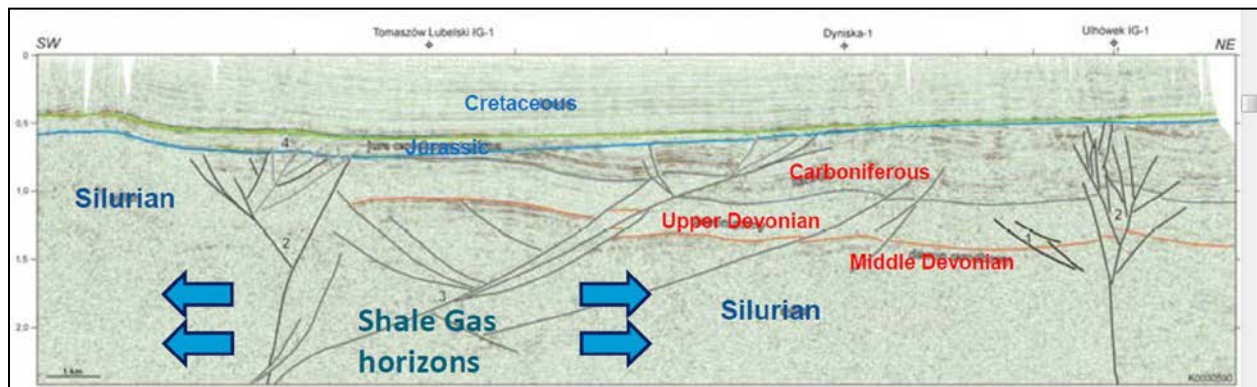
The combined Lower Silurian, Ordovician, and Cambrian section in the Lublin Basin totals from 330 to 1,100 feet thick. The organic-rich shale interval for the Lower Paleozoic is estimated to average 415 ft thick, of which about 55% is considered net pay. A good example is the Lopiennik IG-1 well, Figure VIII-13, showing about 150 m of gas-bearing Paleozoic shale with TOC of 0.2% to 1.4%.²⁴

Figure VIII-10: Lublin and Podlasie Basin Map Showing Depth to Lower Silurian Llandovery Shale.



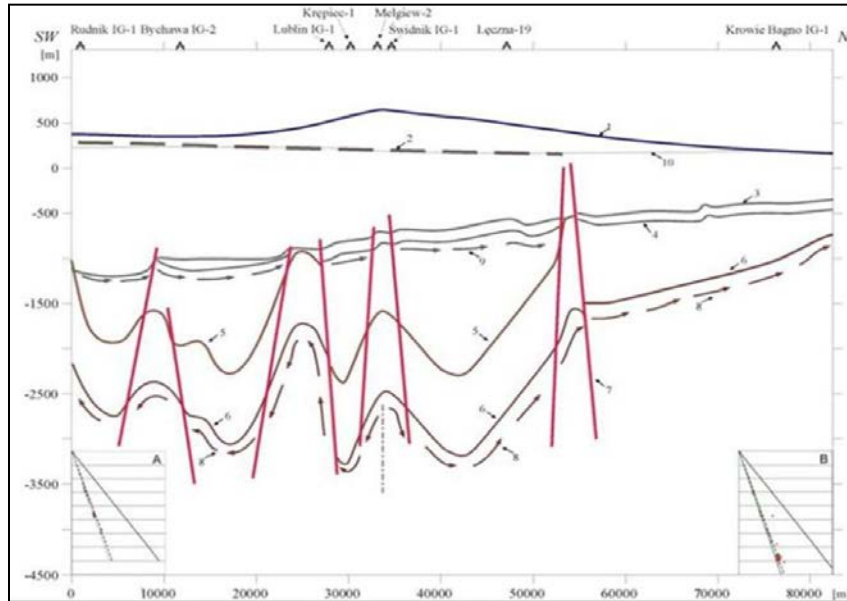
Source: Modified from Polish Geological Institute, 2012

Figure VIII-11: Seismic Section in Lublin Basin Showing Relatively Complex Structure and Numerous Faults, as Well as Poor Image Quality in Deep Lower Paleozoic.



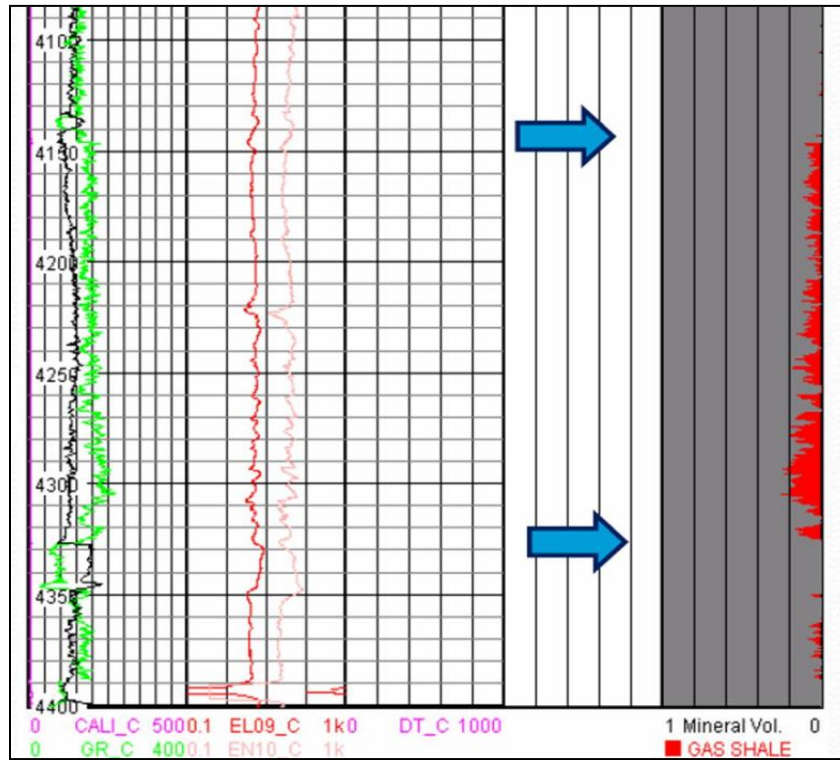
Source: Zywiecki and Lewis, 2011

Figure VIII-12: Hydrological Cross-Section in the Lublin Basin, Poland.



Source: Zawisza, 2006

Figure VIII-13: Well Log Showing Approximately 150 m of Gas-Bearing Shale with TOC of 0.2 to 1.4% in the Lopiennik IG-1 Well, Lublin Basin



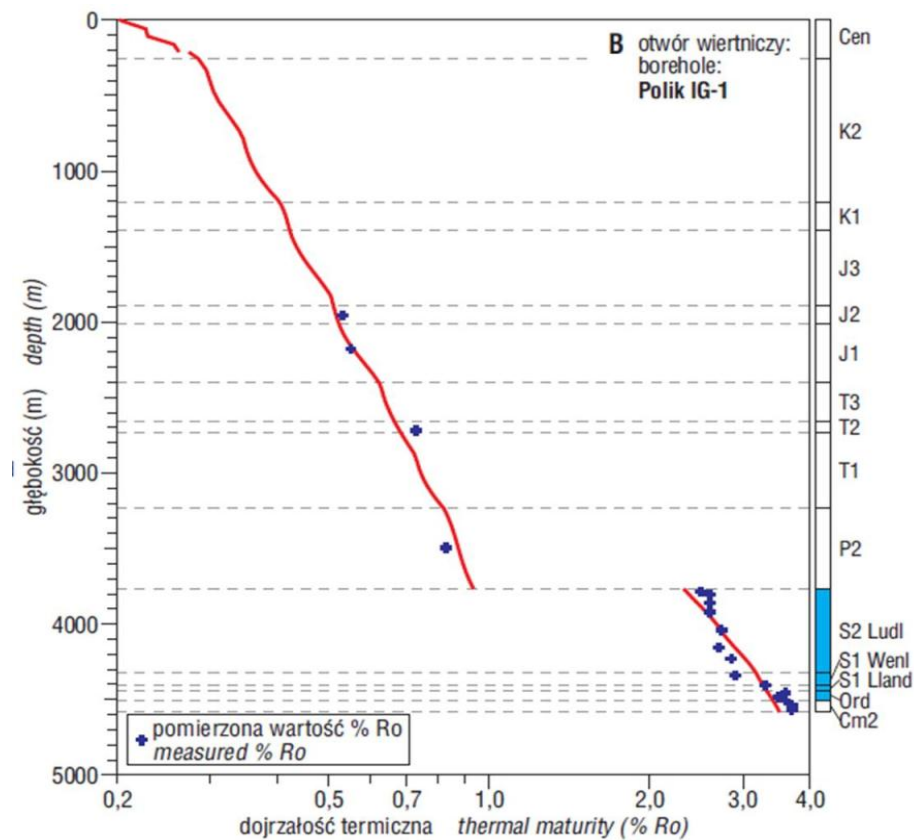
Source: Zywiecki and Lewis, 2011

However, TOC often is higher in core analyses than calculated from older logs, averaging about 3% in the Lublin Basin. The thermal maturity of the Paleozoic is in the dry gas window to overmature, increasing steadily with depth as illustrated in the Polik IG-1 well, Figure VIII-14. Depth to the shale averages approximately 11,000 ft. Porosity is estimated at about 5%. The pressure gradient in the Devonian section is slightly over-pressured, about 2-10% above the hydrostatic gradient.²⁵ Gas impurities such as CO₂ or N₂ appear to be negligible.

2.3 Resource Assessment

The 2,390-mi² prospective area mapped in the Lublin Basin is entirely within the dry gas thermal maturity window. The Lower Paleozoic shale (L. Silurian, Ordovician, and Cambrian) has a moderate resource concentration of approximately 91 Bcf/mi². Risked, technically recoverable shale gas is estimated at 9 Tcf, out of risked, shale gas in-place of 46 Tcf.

Figure VIII-14: Thermal Maturity In The Paleozoic Increases Abruptly Below the Unconformity in the Polik IG-1 Well, Lublin Basin, Reaching Gas-Prone and Then Over-Maturity.



Source: Poprawy, 2010

2.4 Exploration Activity

PGNiG, ExxonMobil, Chevron, Marathon and other companies have been pursuing shale gas exploration in the Lublin basin. In March 2012 **PGNiG** began drilling the **Lubycza Królewska** well in the Tomaszów Lubelski license. The vertical well is planned for 4,300-m TD using a 2000-HP Drillmec 2000 Walking Rig, currently Poland's most advanced drilling rig, and targets Lower Paleozoic shales at depths of 2,300 to 4,300 m.²⁶

In 2009 **ExxonMobil** leased six licenses in the Lublin and Podlasie basins of eastern Poland. The company drilled two vertical shale gas test wells (Krupe 1 and Siennica 1), locating one well in each basin. However, ExxonMobil terminated its Poland shale gas exploration efforts in mid-2012 after failing to demonstrate "sustained commercial hydrocarbon flow rates."²⁷

In late 2012 ExxonMobil sold two of the licenses (Wodynie-Lukow and Wolomin in the Podlasie Basin) to **PKN Orlen**. PKN Orlen holds 10 shale gas licenses totaling nearly 9,000 km² (including the two former ExxonMobil blocks). In late October 2012, PKN reported drilling the first horizontal well in the Lublin Basin, which it plans to hydraulically stimulate.

In 2009 **Chevron** acquired and currently operates four shale gas exploration blocks totaling 4,433 km² in the Lublin Basin of southeast Poland. In October 2011 Chevron completed a 12-month 2-D seismic acquisition program across the four licenses to help plan a multi-well exploration drilling campaign. The company completed its first wells in the Grabowiec and Frampol licenses during Q1 2012; results have not been disclosed.

Marathon Oil also holds shale exploration blocks in the Lublin Basin. The company has acquired seismic data but has not reported testing results. PGNiG also holds licenses in the Lublin Basin and drilled the vertical **Markowola-1** shale well in the in the Pionki-Kazimierz license during 2010. The well was fracture stimulated by Halliburton and reportedly achieved "mixed" results.

3. PODLASIE BASIN

3.1 Introduction and Geologic Setting

Like the Lublin Basin, the 6,600-mi² Podlasie Depression (Basin) may be considered a southeastern extension of the Baltic Basin, with which it shares generally similar shale stratigraphy and lithology. However, whereas the Podlasie is structurally more complex than the Baltic Basin, it is less complex than the Lublin Basin and thus is separately assessed. Eight key older conventional exploration wells have been drilled in the basin, including the Wyszków IG 1 borehole (TD 2388 m) which penetrated organic-rich Silurian, Ordovician, and Cambrian shale deposits.²⁸ Organic matter measurements in older core were low, but some operators have noted that fresh shale core samples yield higher values.

3.2 Reservoir Properties (Prospective Area)

The combined organic-rich shale interval within the Lower Paleozoic is estimated to average 540 ft thick, of which about 55% is considered net. TOC averages about 3%. The thermal maturity of the Lower Paleozoic shale ranges from dry gas in the deeper portion of the basin, to wet gas and eventually oil at shallower levels. Depth to shale averages about 7,500 ft to 12,500 ft. Porosity is estimated at about 5%. The basin is slightly over-pressured with an estimated 0.50 psi/ft gradient. Gas impurities such as CO₂ or N₂ appear to be minimal in most of the basin.

3.3 Resource Assessment

Dry Gas Window. The mapped prospective area within the dry gas window of the Podlasie Basin is estimated at 860 mi². Lower Paleozoic shale (L. Silurian, Ordovician, and Cambrian) has a moderate resource concentration of 122 Bcf/mi². Risked, technically recoverable shale gas is estimated at 5 Tcf, out of risked shale gas in-place of about 25 Tcf.

Wet Gas Window. The wet gas window is prospective within an area of 1,100 mi². Risked technically recoverable shale resources are estimated at 4 Tcf of shale gas and 0.2 billion barrels of shale condensate from risked, in-place resources of 22 Tcf and nearly 3 billion barrels, respectively.

Oil Window. The oil window, mapped in the eastern Podlasie Basin, is prospective within an area of approximately 1,000 mi². Risked, technically recoverable shale resources are estimated at 0.4 billion barrels of shale oil and condensate along with 0.7 Tcf of associated shale gas, from an in-place risked shale oil resource of nearly 9 billion barrels.

3.4 Exploration Activity

Several operators hold shale gas exploration licenses in the Podlasie Depression. Marathon drilled one vertical shale exploration well in the basin but has not released results.

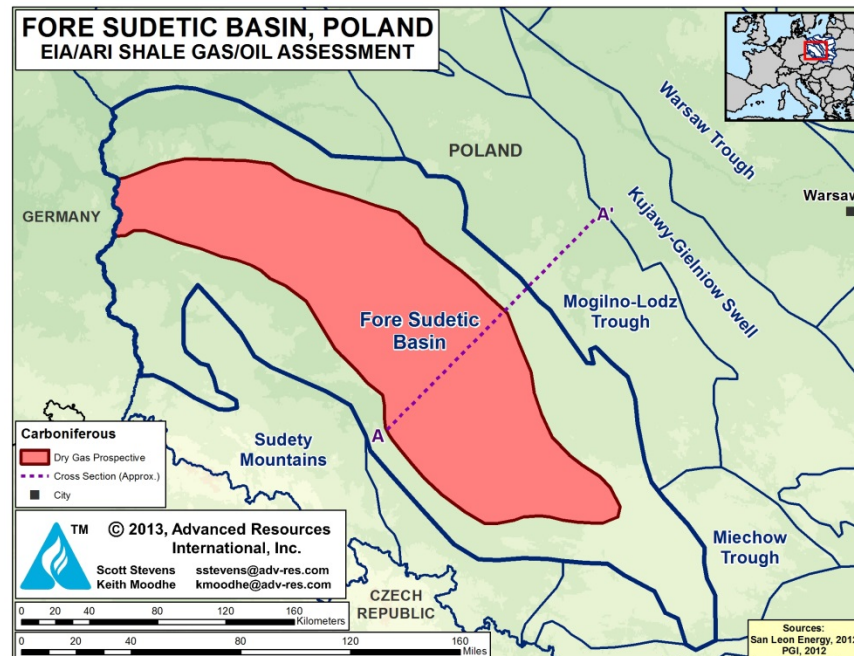
4. FORE-SUDETIC MONOCLINE

4.1 Introduction and Geologic Setting

Unconventional gas plays, mainly tight sandstone but potentially including shale gas, are being pursued in the Fore-Sudetic Monocline of southwestern Poland, Figure VIII-15. While the marine-deposited Lower Paleozoic shales are too deep to be prospective in this region, the overlying Carboniferous non-marine shales may be present at depths of 2 to 5 km. Shale exploration is less active here than in the Baltic Basin, but at least two companies (San Leon, PGNiG) have reported leasing and drilling.

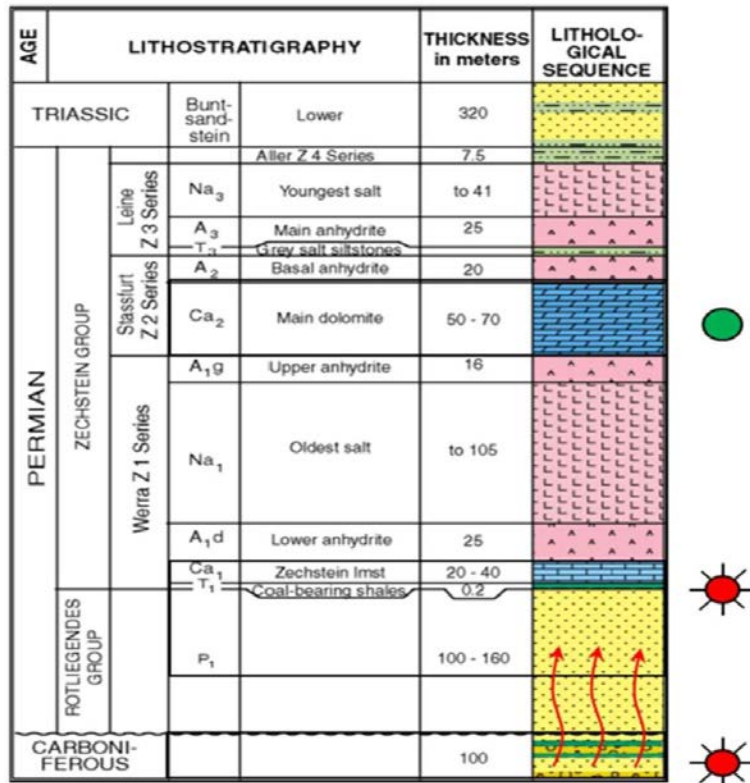
The nearly 20,000-mi² Fore-Sudetic Monocline is considered a southern continuation of the Mid-Polish Trough, where Paleozoic and younger strata shoal to shale-prospective depths of about 2 to 5 km.²⁹ The Lower Permian Rotliegend sandstone has been developed for tight gas production in this province for several decades, Figure VIII-16. Figure VIII-17, a regional southwest-northeast cross-section, indicates that the structural geology is relatively simple, although additional faults are likely to be present. Indeed, San Leon Energy has noted that the poor quality seismic available in this region masks the true geologic structure, thus the company recently acquired four 3D seismic surveys totaling 650 km² and over 1,000 km of 2D seismic.

Figure VIII-15: Fore-Sudetic Monocline of Southwestern Poland, Showing Shale Prospective Area.



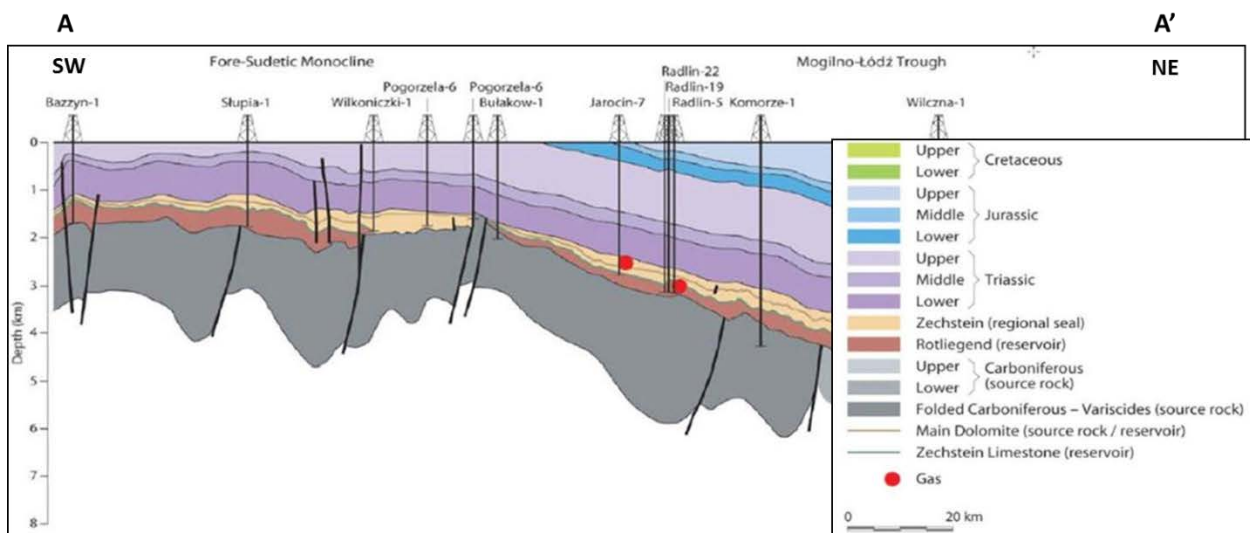
Source: ARI, 2013.

Figure VIII-16: Stratigraphy of the Carboniferous and Younger Formations in the Fore-Sudetic Monocline.



Source: San Leon Energy, 2012

Figure VIII-17: Structural Cross-Section In The Fore-Sudetic Monocline Of Southwest Poland Baltic Basin Showing Relatively Simple Structure And Widely Spaced Faults (vertical exaggeration = 10x).



Source: San Leon Energy, November 2012

A thick non-marine, coal-bearing Carboniferous sequence is present, with multiple targets of tight sandstone, deep coal seams, and carbonaceous shales. The Carboniferous underlies the Rotliegend sandstone and sourced it with natural gas, which FX Energy reported averages about 80% methane and 20% carbon dioxide.³⁰ The overall stratigraphic sequence in the Carboniferous appears broadly similar to that of the REM shale-sandstone-coal sequence in the Cooper Basin of Australia, where initial shale gas production has been reported. San Leon Energy, FX Energy, PGNiG and other companies are actively exploring for shale gas here but scant data have been released.

San Leon Energy disclosed that it is evaluating the Carboniferous shale gas potential of the Pre-Sudetic Monocline, which reportedly is structurally simple and over-pressured.³¹ Note that the organic-rich shales in the Pre-Sudetic Monocline were deposited in a non-marine setting and are associated with coal deposits, thus may be clay-rich and ductile. Lower Paleozoic marine-deposited rocks, similar to those present in the Baltic Basin, underlie the Carboniferous in this region, but are likely too deep to be prospective and thus were not assessed.

4.2 Reservoir Properties (Prospective Area)

San Leon Energy estimates the Carboniferous shale in the Fore-Sudetic Monocline contains 1% to 5% TOC, is in the dry gas thermal maturity window (R_o of 1.3% to 2.0%), and contains 20% to 60% silica with 2% to 8% total porosity. ARI estimated the organic-rich shale interval to be 330 ft thick, with about half considered as net pay (165 ft). Depth averages 12,000 ft, ranging from 8,000 to 16,000 ft. The basin is reported to be slightly over-pressured. Significant levels of nitrogen contamination (20%) are expected, based on the typical composition of produced gas from the overlying Rotliegend sandstone.

4.3 Resource Assessment

The large but poorly constrained 9,070-mi² prospective area mapped in the Fore-Sudetic Monocline based on depth appears to be entirely within the dry gas thermal maturity window. The Carboniferous shale is estimated to have moderate resource concentration of approximately 67 Bcf/mi². Risked technically recoverable resources are estimated at 21 Tcf, out of risked shale gas in-place of 107 Tcf.

4.4 Exploration Activity

The only shale gas exploration well announced to date in the region is San Leon's vertical well, which tested the Carboniferous shales. The 3,520-m deep **Siciniy-2** well logged continuous gas shows across the 1-km thick Carboniferous section. Two tight sandstone intervals totaling 185 m thick and three shale zones were identified, both highly fractured in core. The quartz content of the shale was described as high. San Leon estimated total gas in place at 450 Bcf/mi², of which 280 Bcf/mi² is in sandstone and 170 Bcf/mi² in shale. At last report, the company planned to frac the well.

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