# 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.

| | | | | Baltic/Warsaw Trough (16,200 mi²) | | Podlasie (6,600 mi²) | |
|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | | Baltic/Warsaw Trough (16,200 mi²) | | Podlasie (6,600 mi²) | |
| | Shale Formation | | | Llandovery | | Llandovery | |
| | Geologic Age | | | L. Sil - Ord. - U. Cambrian | | L. Sil - Ord. - U. Cambrian | |
| | Depositional Environment | | | Marine | | Marine | |
| Physical Extent | Prospective Area (mi²) | | | 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/mi²) | | | 42.2 | 12.8 | 36.2 | 11.1 |
| | Risked OIP (B bbl) | | | 14.0 | 10.6 | 8.7 | 2.9 |
| | Risked 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

| | | | Baltic (90,000 mi²) |
|---|---|---|---|
| Basic Data | Basin/Gross Area | | Baltic (90,000 mi²) |
| | Shale Formation | | Llandovery |
| | Geologic Age | | L. Sil - Ord. - U. Cambrian |
| | Depositional Environment | | Marine |
| Physical Extent | Prospective Area (mi²) | | 3,030 |
| | Thickness (ft) | Organically Rich | 575 |
| | | Net | 316 |
| | Depth (ft) | Interval | 6,500 - 9,800 |
| | | Average | 8,000 |
| Reservoir Properties | Reservoir Pressure | | Mod. Overpress. |
| | Average TOC (wt. %) | | 3.9% |
| | Thermal Maturity (% Ro) | | 0.85% |
| | Clay Content | | Medium |
| Resource | Gas Phase | | Assoc. Gas |
| | GIP Concentration (Bcf/mi²) | | 25.2 |
| | Risked GIP (Tcf) | | 24.5 |
| | Risked Recoverable (Tcf) | | 2.4 |

| | | | Baltic (90,000 mi²) |
|---|---|---|---|
| Basic Data | Basin/Gross Area | | Baltic (90,000 mi²) |
| | Shale Formation | | Llandovery |
| | Geologic Age | | L. Sil - Ord. - U. Cambrian |
| | Depositional Environment | | Marine |
| Physical Extent | Prospective Area (mi²) | | 3,030 |
| | Thickness (ft) | Organically Rich | 575 |
| | | Net | 316 |
| | Depth (ft) | Interval | 6,500 - 9,800 |
| | | Average | 8,000 |
| Reservoir Properties | Reservoir Pressure | | Mod. Overpress. |
| | Average TOC (wt. %) | | 3.9% |
| | Thermal Maturity (% Ro) | | 0.85% |
| | Clay Content | | Medium |
| Resource | Oil Phase | | Oil |
| | OIP Concentration (MMbbl/mi²) | | 29.8 |
| | Risked OIP (B bbl) | | 28.9 |
| | Risked 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-km$^2$ 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 km$^2$, 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 Kupfershiefer 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-Aalenia) 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 $m^3$ (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 $mi^2$) 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 | Proved Reserves + Risked Resources | | Report Date | Location in play |
|---|---|---|---|---|---|---|---|
| | Bcf/well | Source | Million $ft^3$/d | 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

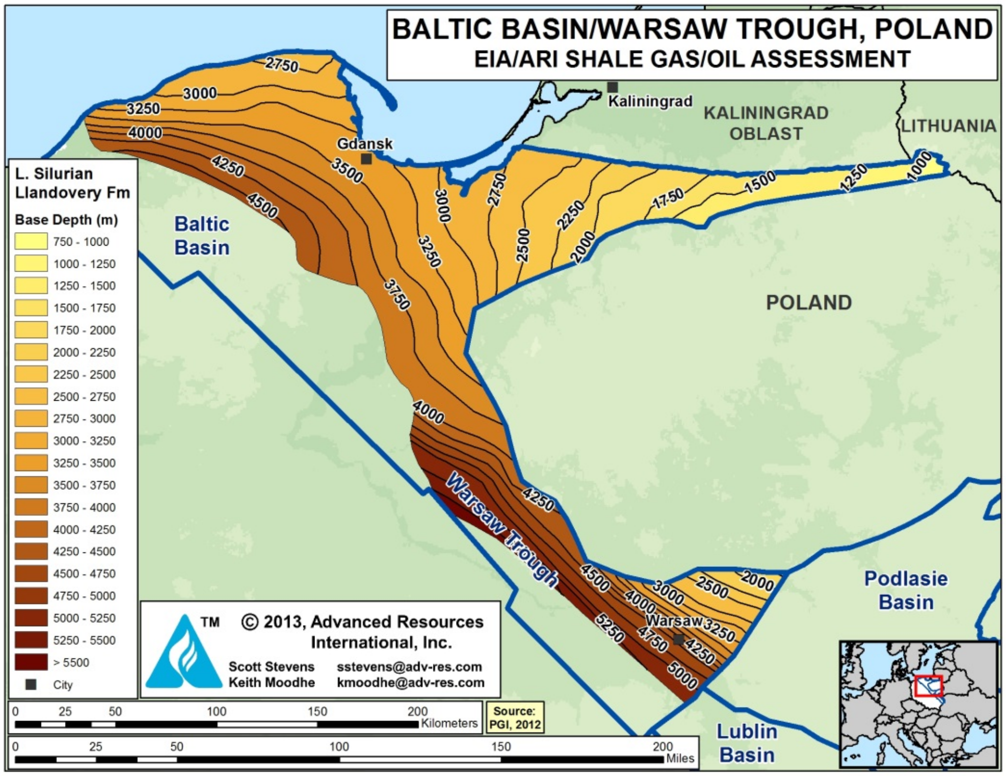
## 1.1 Introduction and Geologic Setting

The 16,200-mi$^2$ 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.

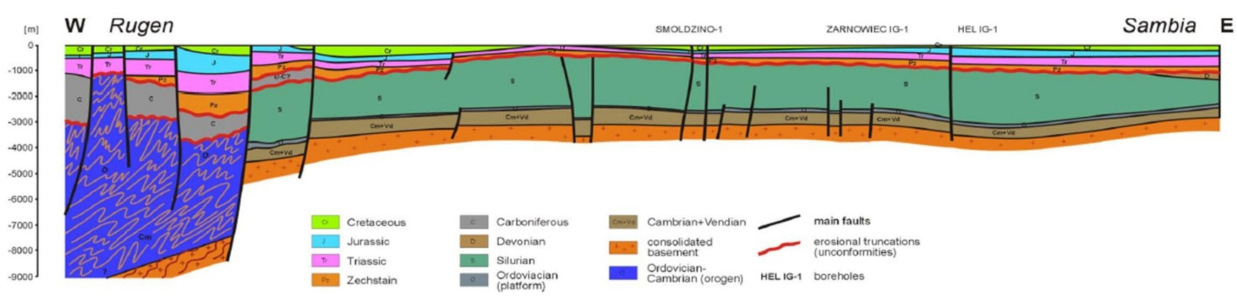
The Baltic Basin formed as a result of late Precambrian rifting followed by early Paleozoic post-rift downwarping of the East European Platform. The basin's southwest boundary is defined by the northwest-southeast trending Trans-European Suture Zone (TESZ), a deformed fault zone, while the Mazury-Belarus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



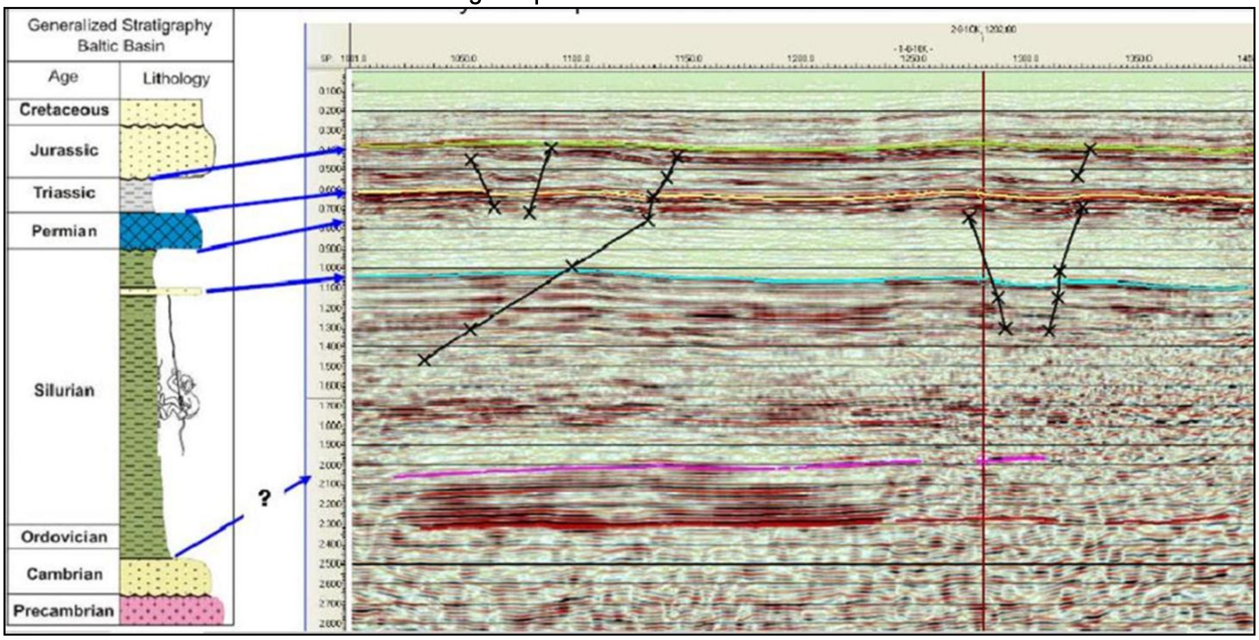

Source: Modified from Polish Geological Institute, 2012

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.

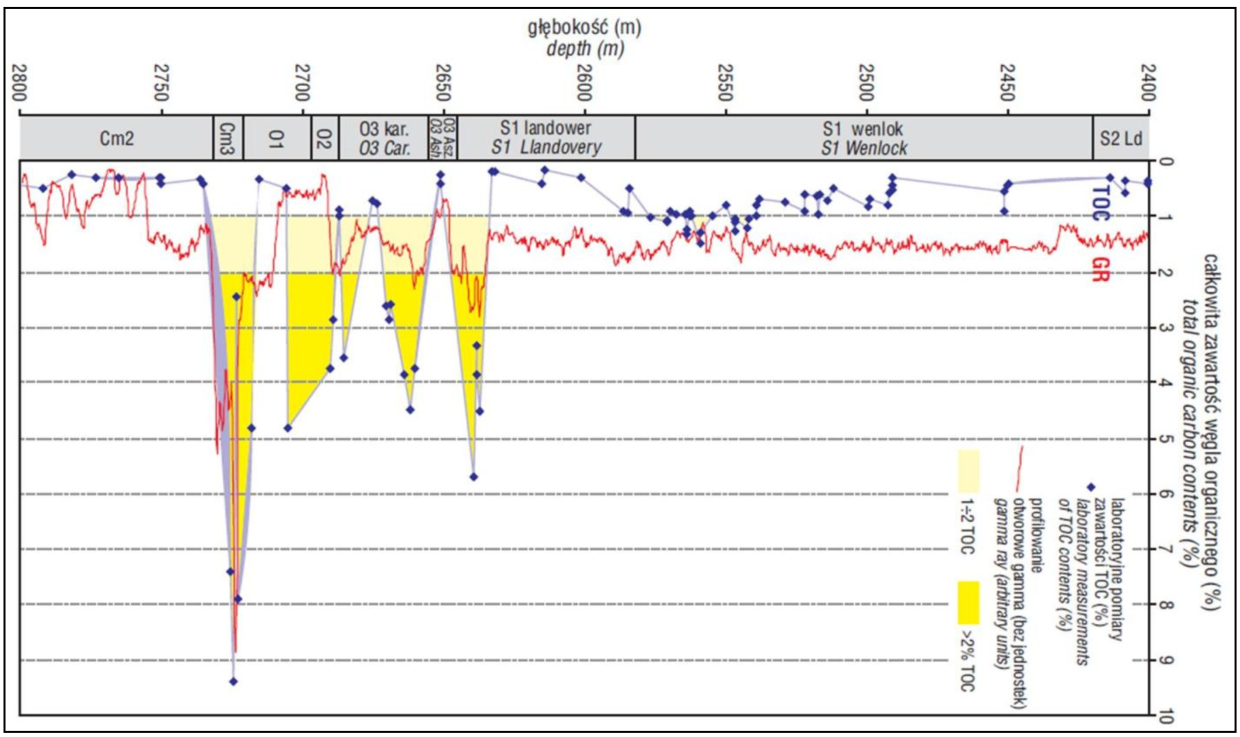
Organic-rich shales of Paleozoic age within the Baltic Basin are relatively flat lying, high in TOC, thermally mature in the gas to oil windows, and among the most prospective in Europe for shale development. Figure VIII-5 exhibits organic-rich shales that are typically present within the Lower Silurian, 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.



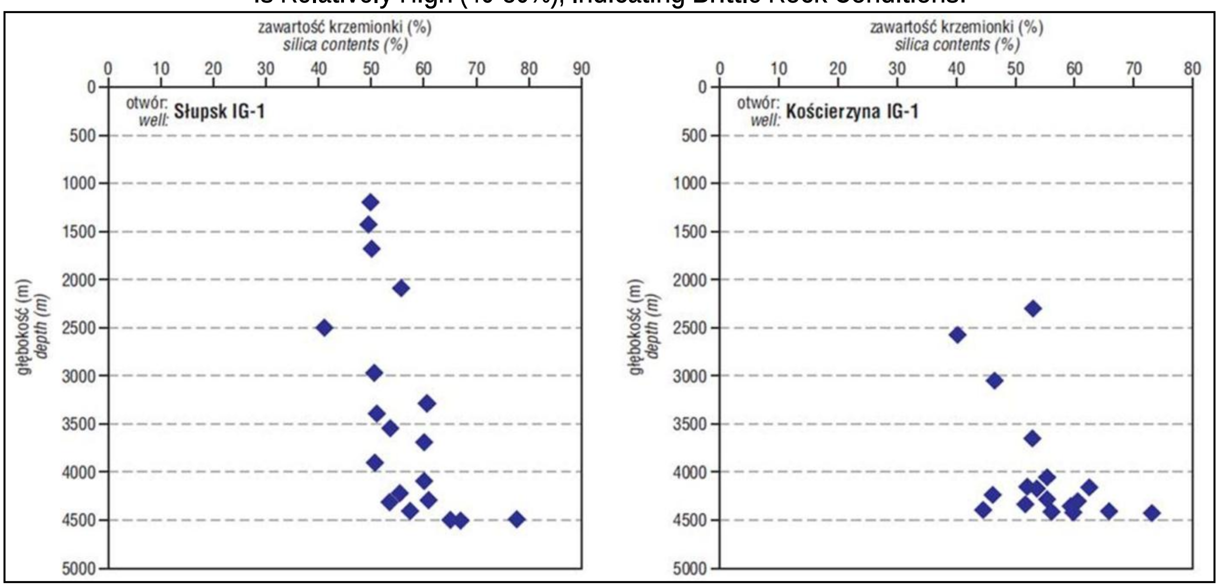

Source: Poprawy, 2010

## 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.

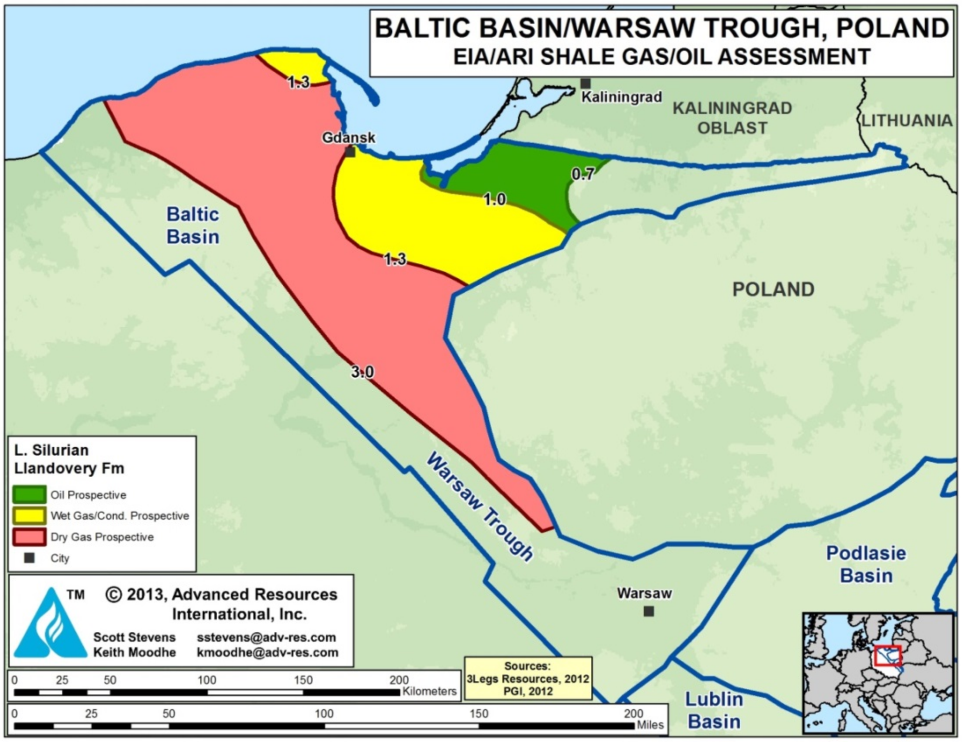
Thermal maturity ranges from oil- to gas-prone, Figure VIII-7, increasing steadily with depth in the basin as illustrated in the Gdansk IG-1 well, Figure VIII-8. The average depth ranges from 8,200 ft in the oil window, to 10,000 ft in the wet gas window area, to 12,500 ft in the oil window. Porosity 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 $CO_2$ or $N_2$ 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.



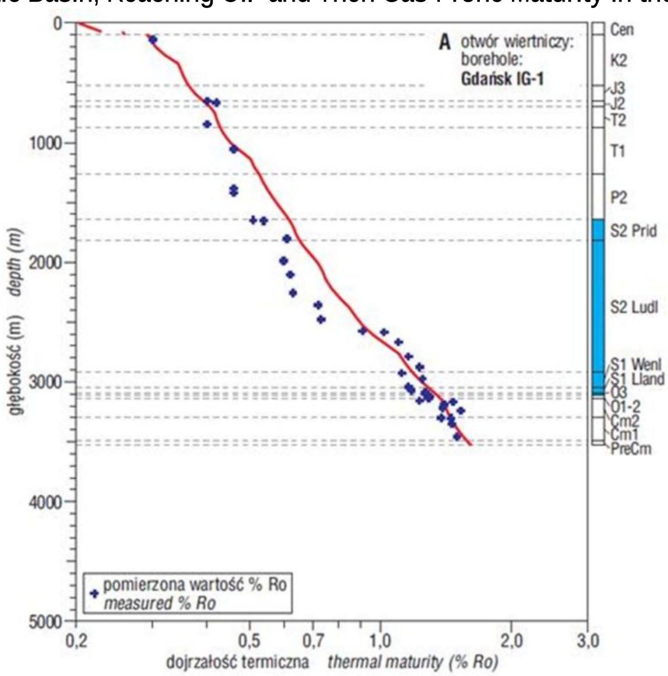

Source: Krzemiñskiego & Poprawy, 2006 in Poprawy, 2010

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 $mi^2$. Lower Paleozoic shale (comprising the L. Silurian, Ordovician, and Cambrian) has a favorable resource concentration of approximately 181 $Bcf/mi^2$. 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 $mi^2$. 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 $mi^2$. 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 ($12 million/well). Porosity (3-4%) was lower than expected in over-pressured L. Paleozoic shale; clay content was fairly high (30-40%). The company estimated total GIP concentration of up to 135 Bcf/mi$^2$, including 86 Bcf/mi$^2$ in the target Ordovician and L. Silurian shale zones (total 110 m thick). The Lebork S-1 well flared gas from several intervals, but a fracture stimulation was unsuccessful due to high stress and inadequate pump capacity.

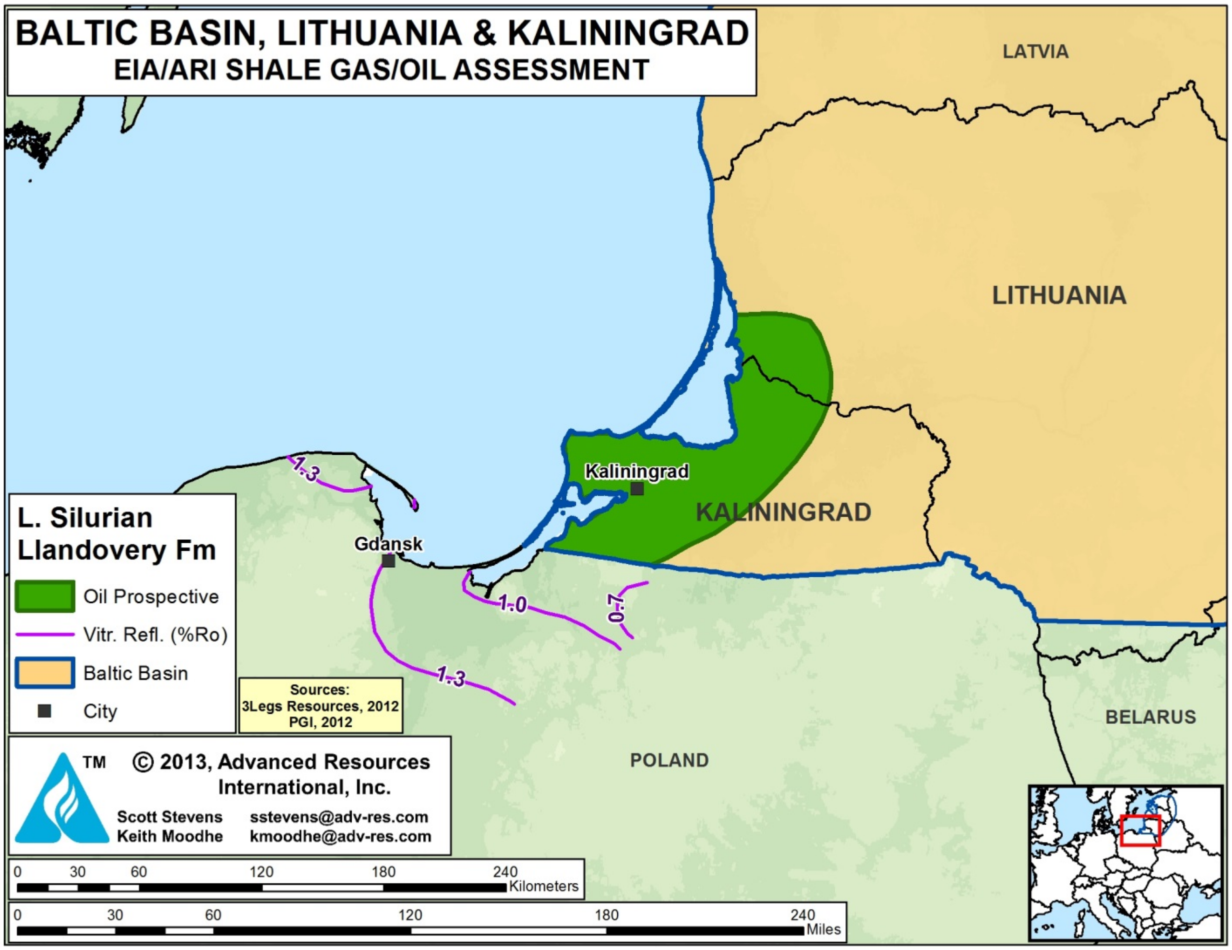
## 1.5 Lithuania

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-$mi^2$ 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.

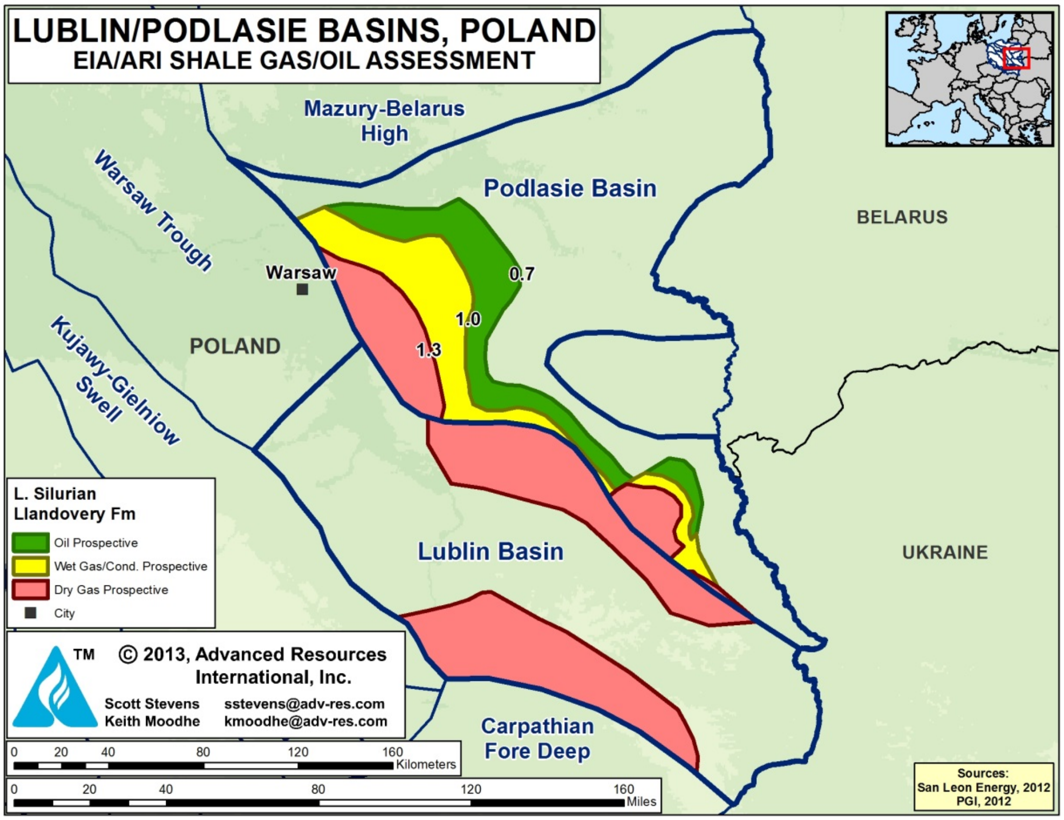
Figure VIII-11 illustrates the extent of faulting and sub-salt tectonic decoupling of the Lower Paleozoic in the Lublin Basin.[20] Figure VIII-12 shows hydrological flow within the Devonian strata, including closely spaced faults and steep dips.[21] Major fault systems in the basin include the northwest-southeast 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-Mełgiew 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)

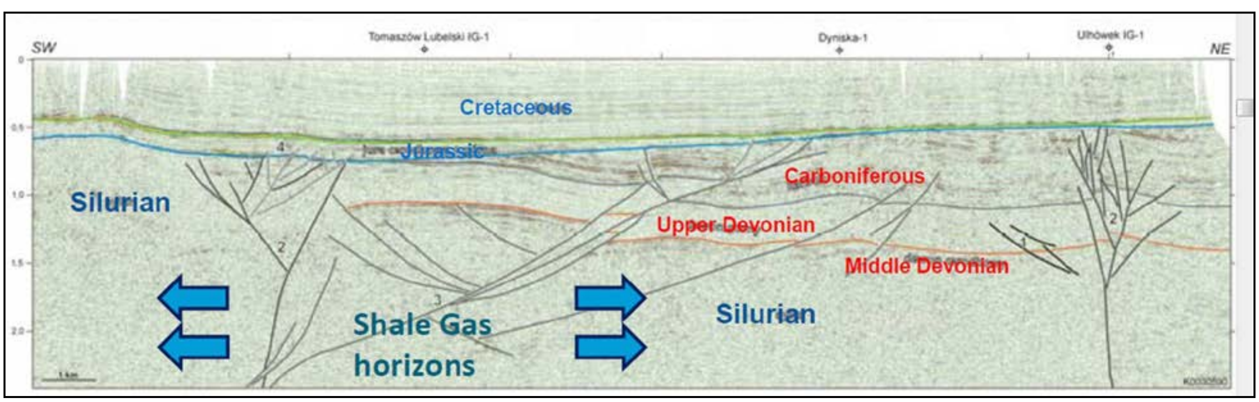
The combined Lower Silurian, Ordovician, and Cambrian section in the Lublin Basin totals from 330 to 1,100 feet thick. The organic-rich shale interval for the Lower Paleozoic is estimated to average 415 ft thick, of which about 55% is considered net pay. A good example is the Lopiennik IG-1 well, Figure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



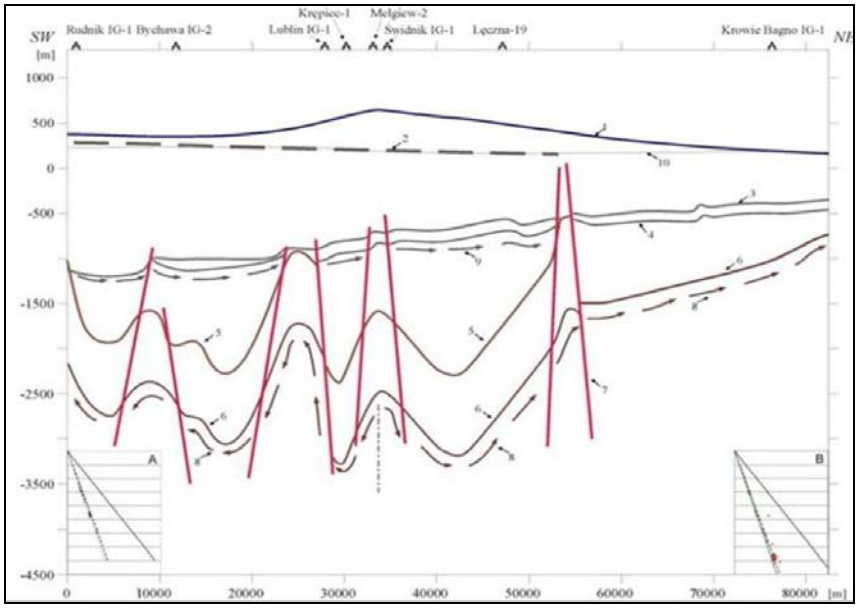

Source: Modified from Polish Geological Institute, 2012

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.



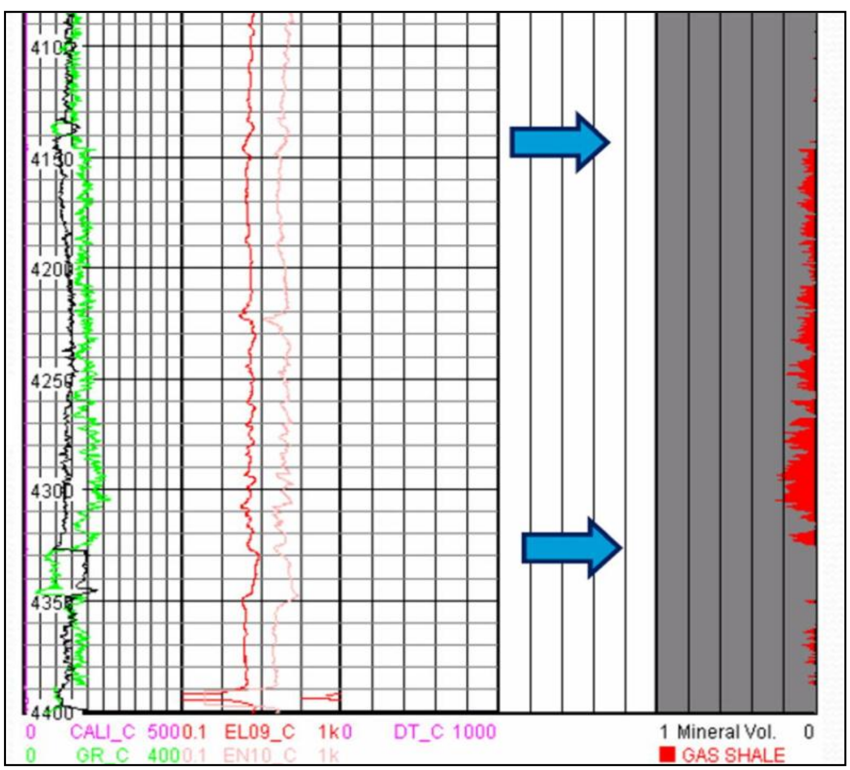

Source: Zywiecki and Lewis, 2011

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



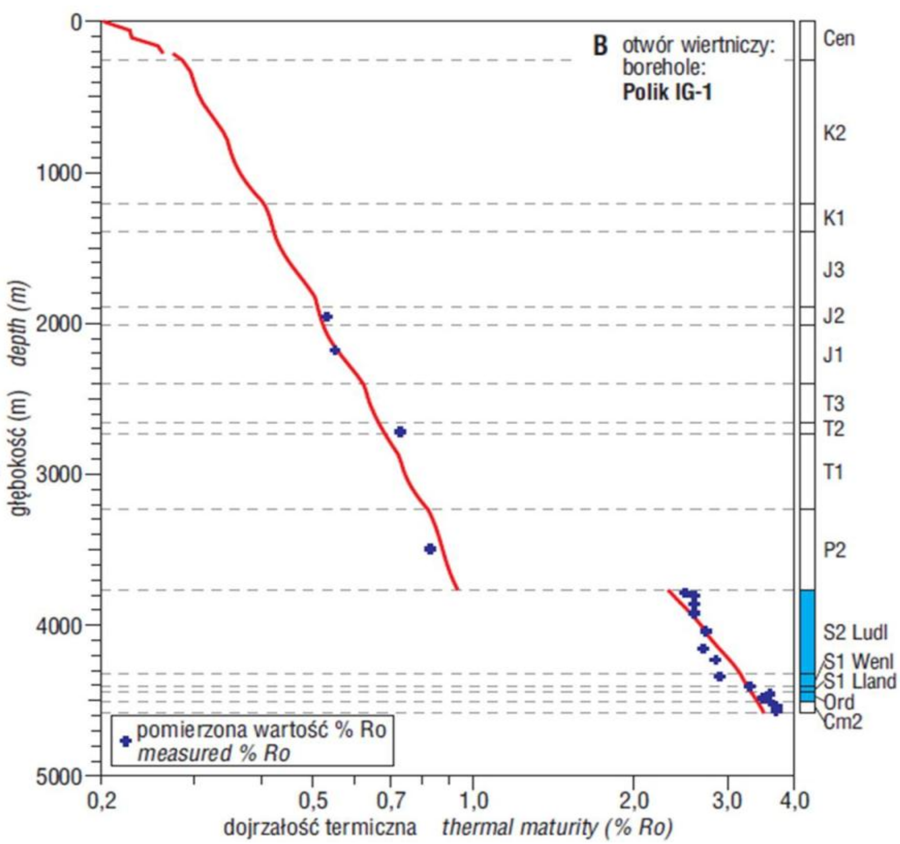

Source: Zywiecki and Lewis, 2011

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 $CO_2$ or $N_2$ appear to be negligible.

## 2.3 Resource Assessment

The 2,390-mi$^2$ 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/mi$^2$. 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 $km^2$ (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 $km^2$ 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-mi$^2$ 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 $CO_2$ or $N_2$ 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 mi$^2$. Lower Paleozoic shale (L. Silurian, Ordovician, and Cambrian) has a moderate resource concentration of 122 Bcf/mi$^2$. 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 mi$^2$. 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 $mi^2$. 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.

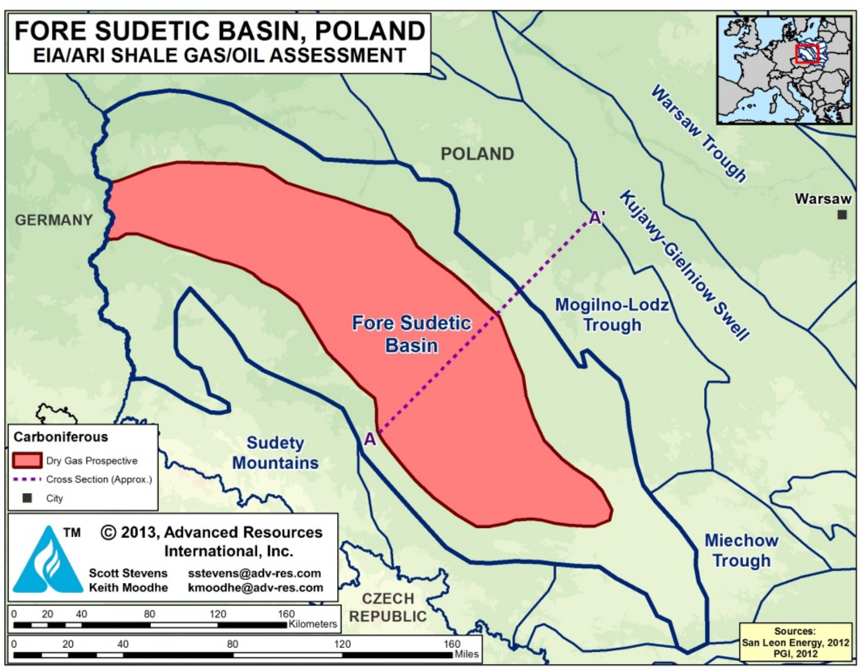
# 4. FORE-SUDETIC MONOCLINE

## 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.

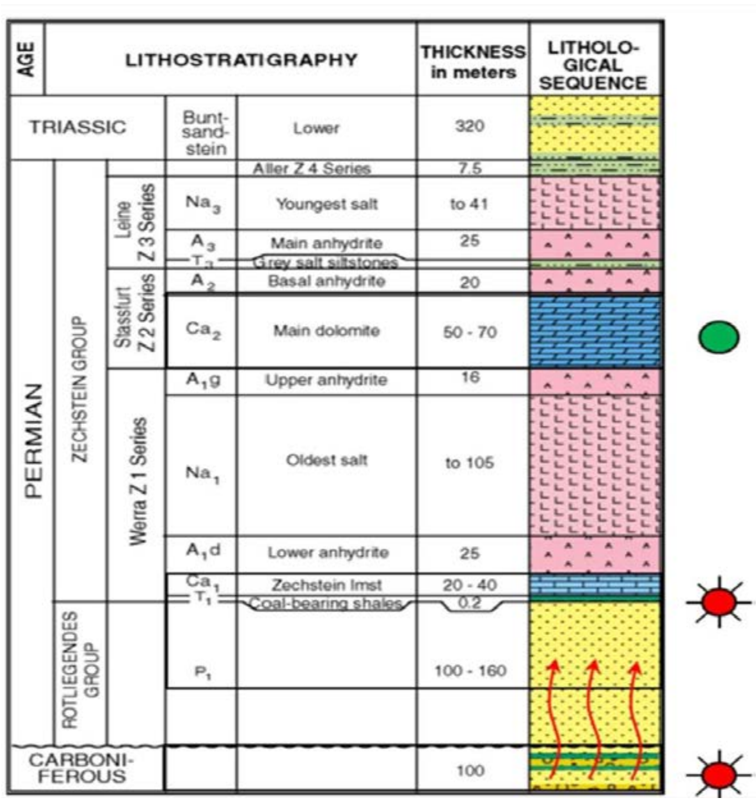
The nearly 20,000-mi$^2$ Fore-Sudetic Monocline is considered a southern continuation of the Mid-Polish Trough, where Paleozoic and younger strata shoal to shale-prospective depths of about 2 to 5 km.[29] The Lower Permian Rotliegend sandstone has been developed for tight gas production in this province 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 km$^2$ and over 1,000 km of 2D seismic.

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



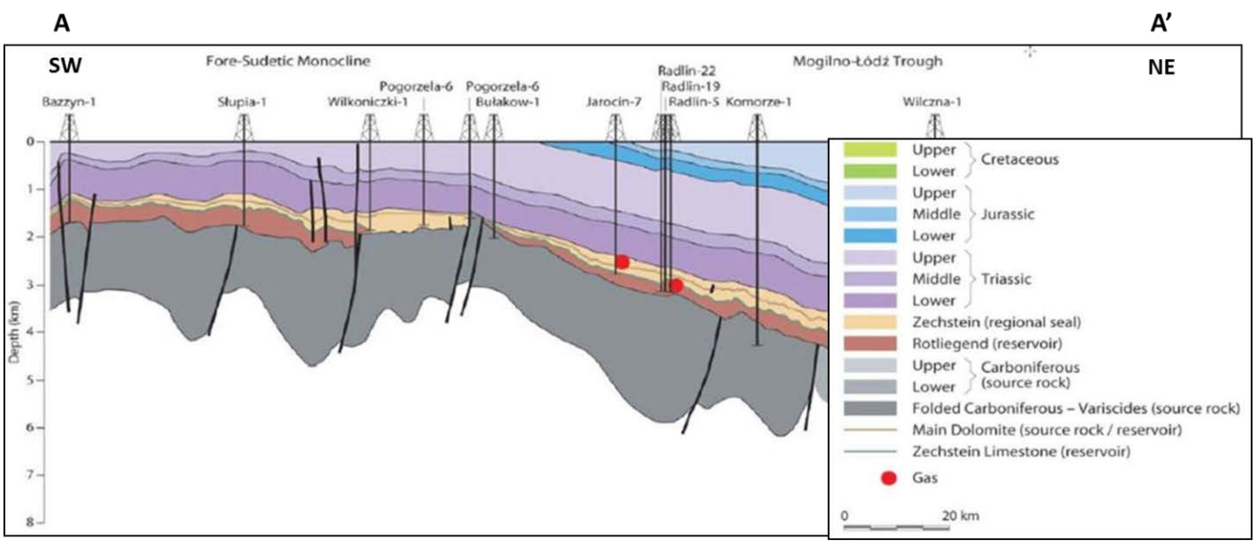

Source: ARI, 2013.

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-mi$^2$ 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/mi$^2$. 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/mi$^2$, of which 280 Bcf/mi$^2$ is in sandstone and 170 Bcf/mi$^2$ in shale. At last report, the company planned to frac the well.

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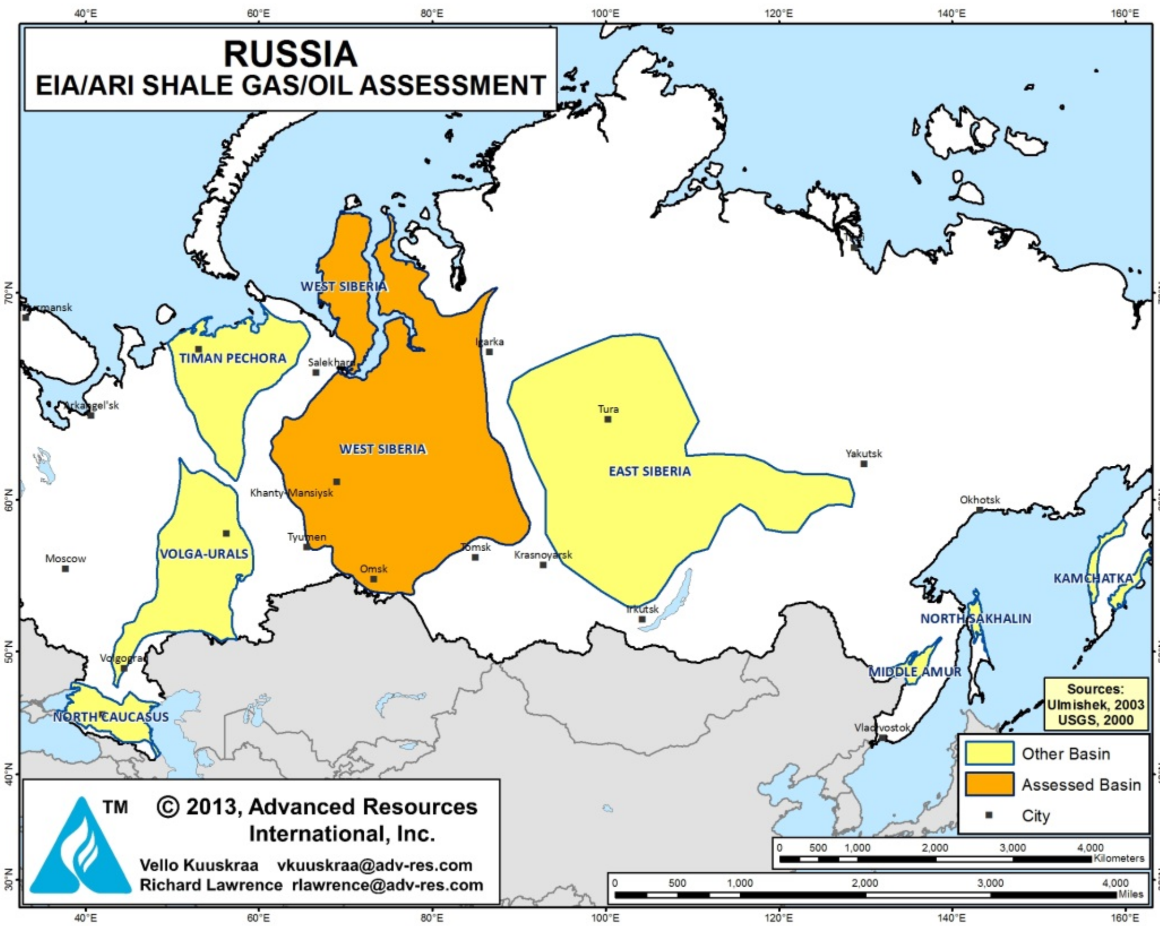
# IX. RUSSIA

## 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

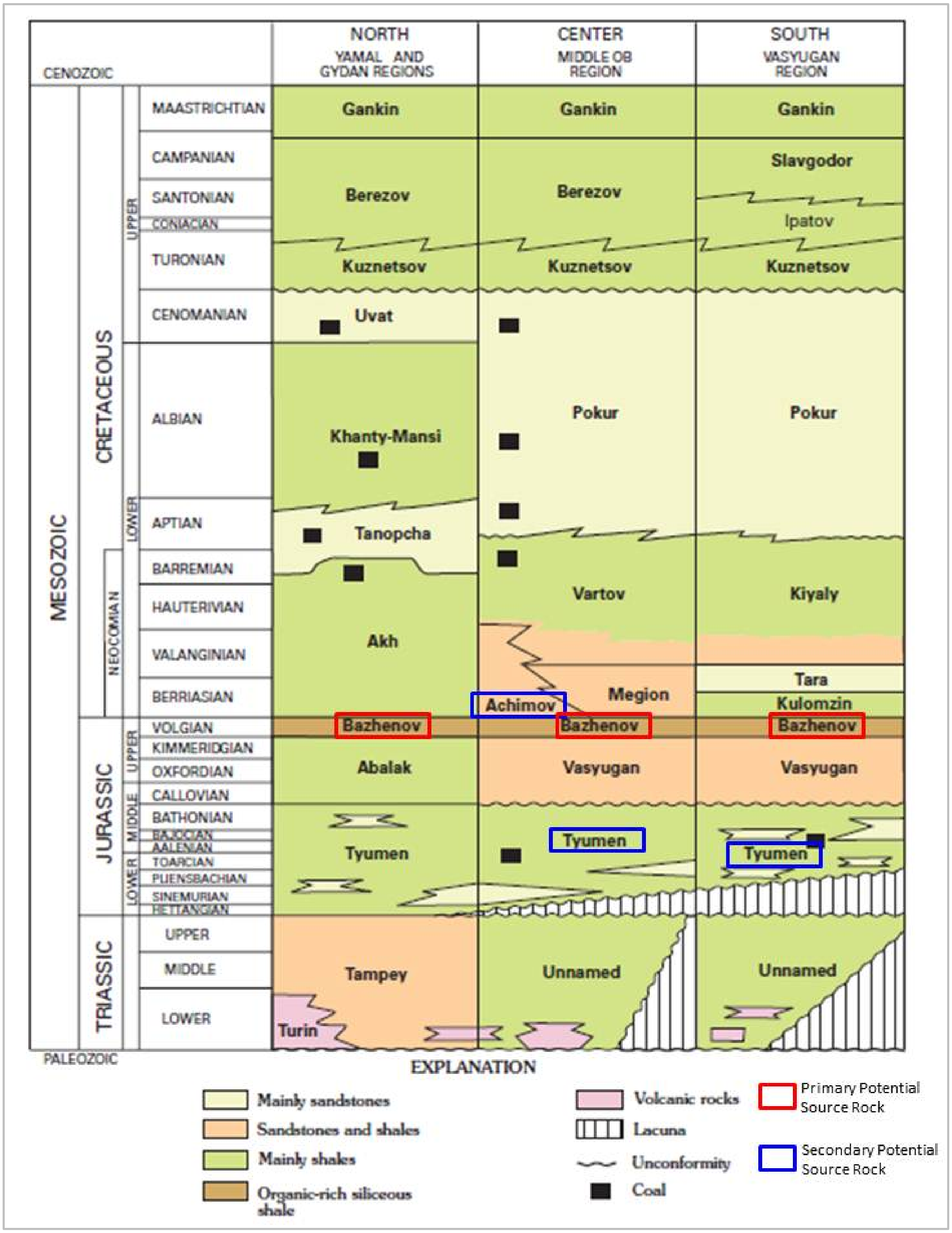
The 850,000-mi$^2$ West Siberian Basin is the largest petroleum basin in the world[1]. The basin lies between the Ural Mountains to the west and the Yenisey River to the east, while extending north offshore under the Kara Sea and reaching south to the border with Kazakhstan, Figure IX-1.

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



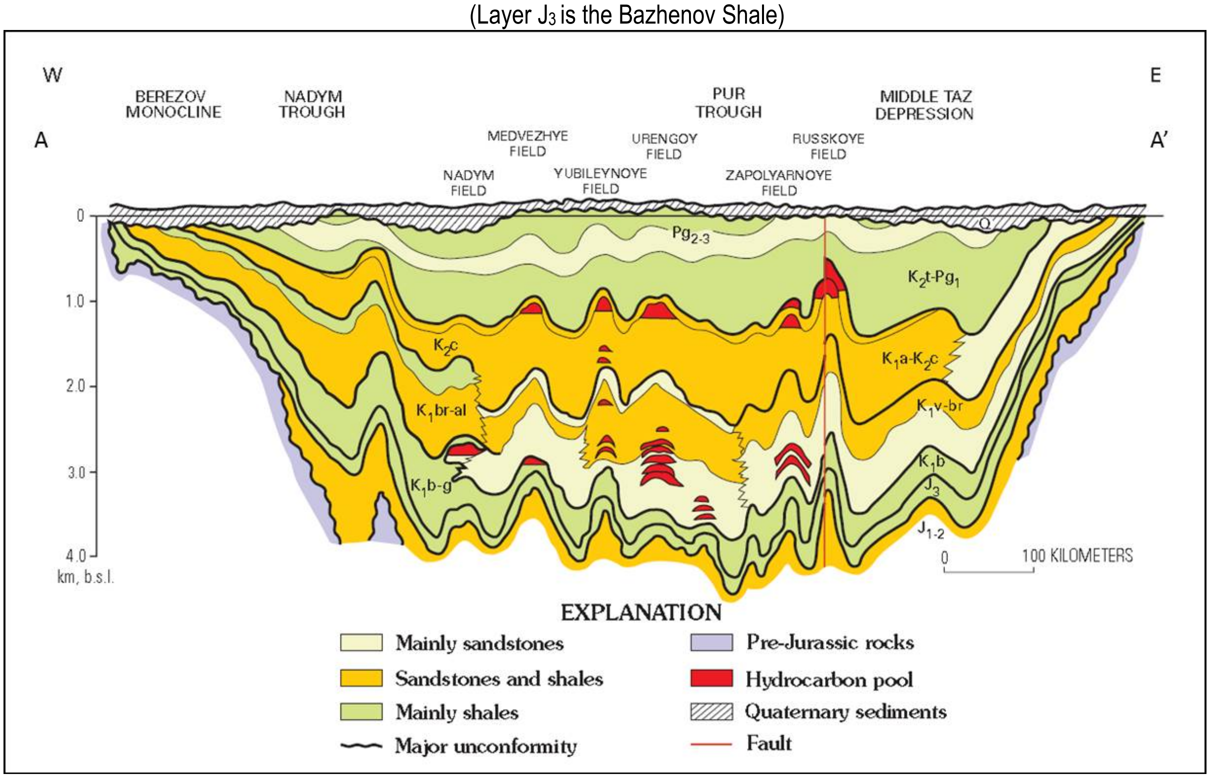

Source: Modified from Ulmishek, 2003

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)

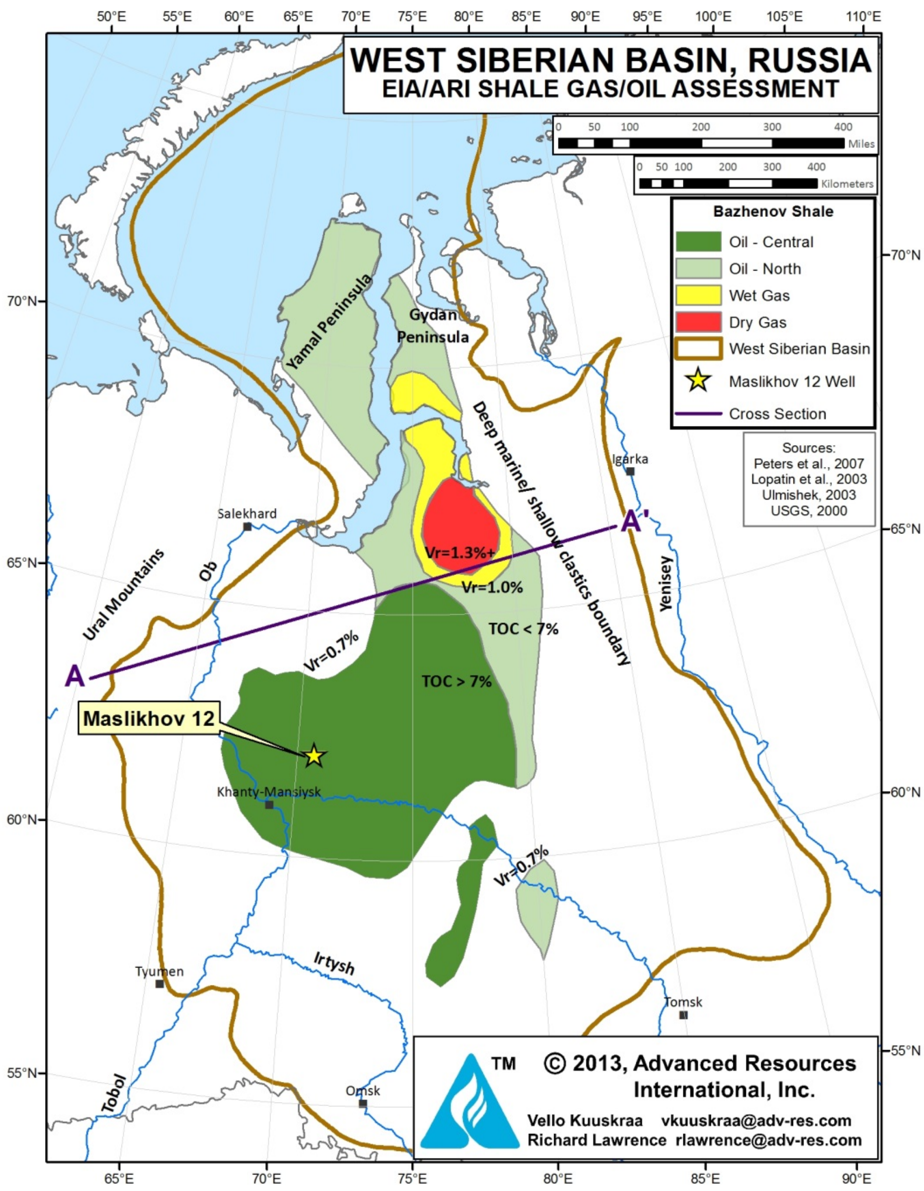
(Layer $J_3$ is the Bazhenov Shale)




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



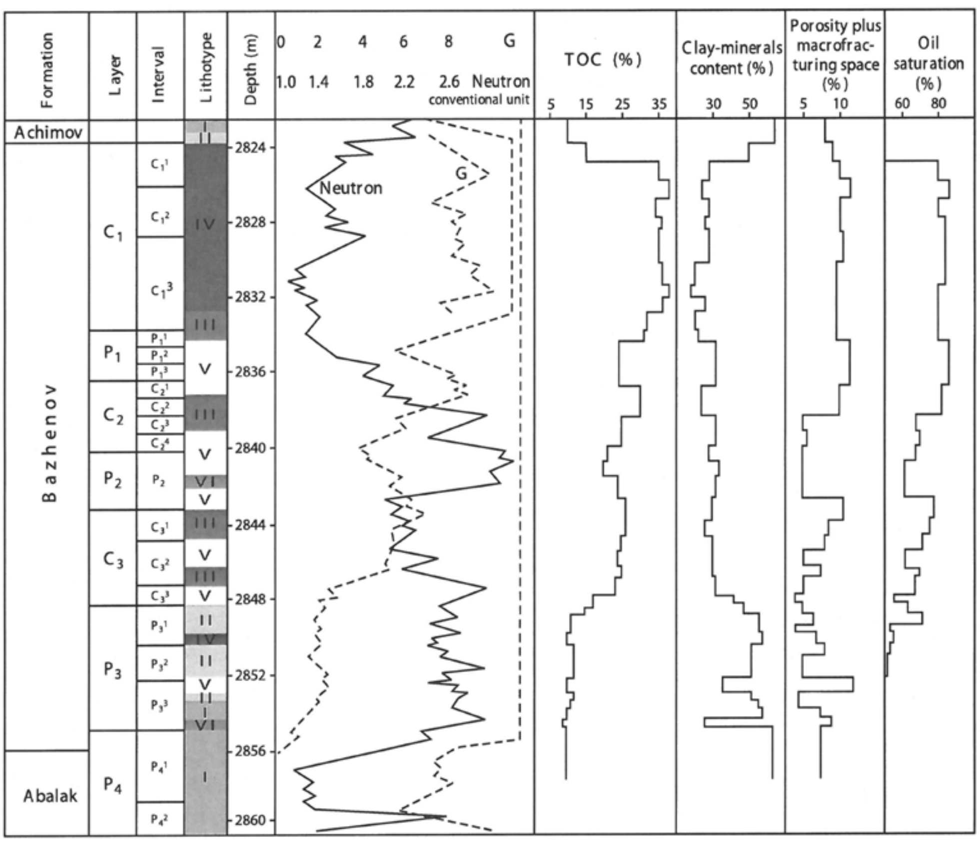

Source: ARI, 2013.

## 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.

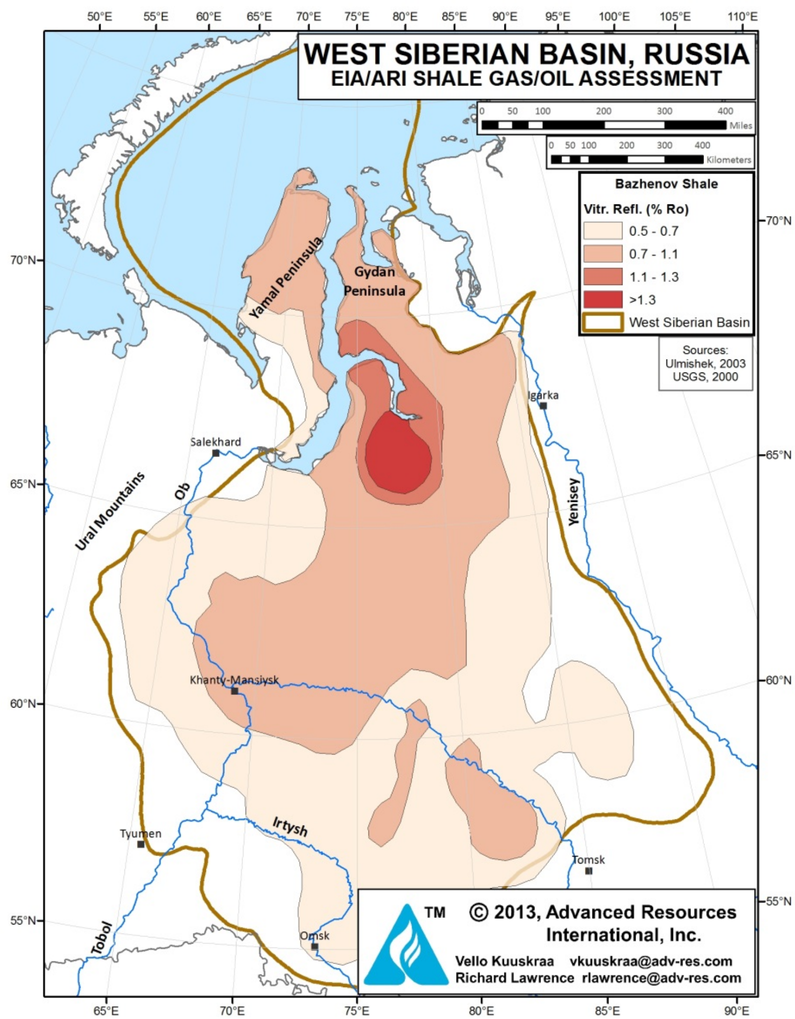
The literature describes the Bazhenov as being over-pressured, caused by oil generation and expulsion as the shales passed through the "oil window". Measured shut-in bottom-hole pressures in the Salym oil field region are reported in some wells to be abnormally high, up to 70% above normal hydrostatic 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.

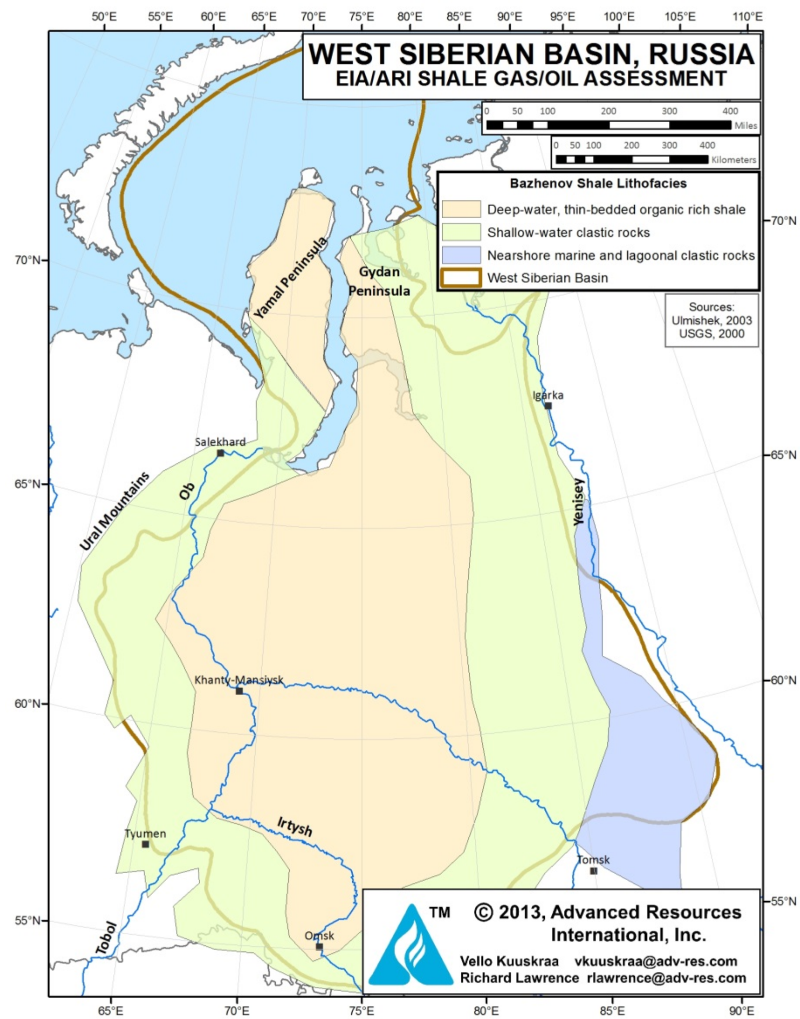
Bazhenov Central contains a 116,200-mi$^2$ prospective area for oil, with a thermal maturity ($R_o$) of 0.7 to 1.0%. The TOC content of the shale is high in Bazhenov Central, averaging 10%. Similarly, the Bazhenov Central prospective area is limited on the east by the marine shale to clastic sediments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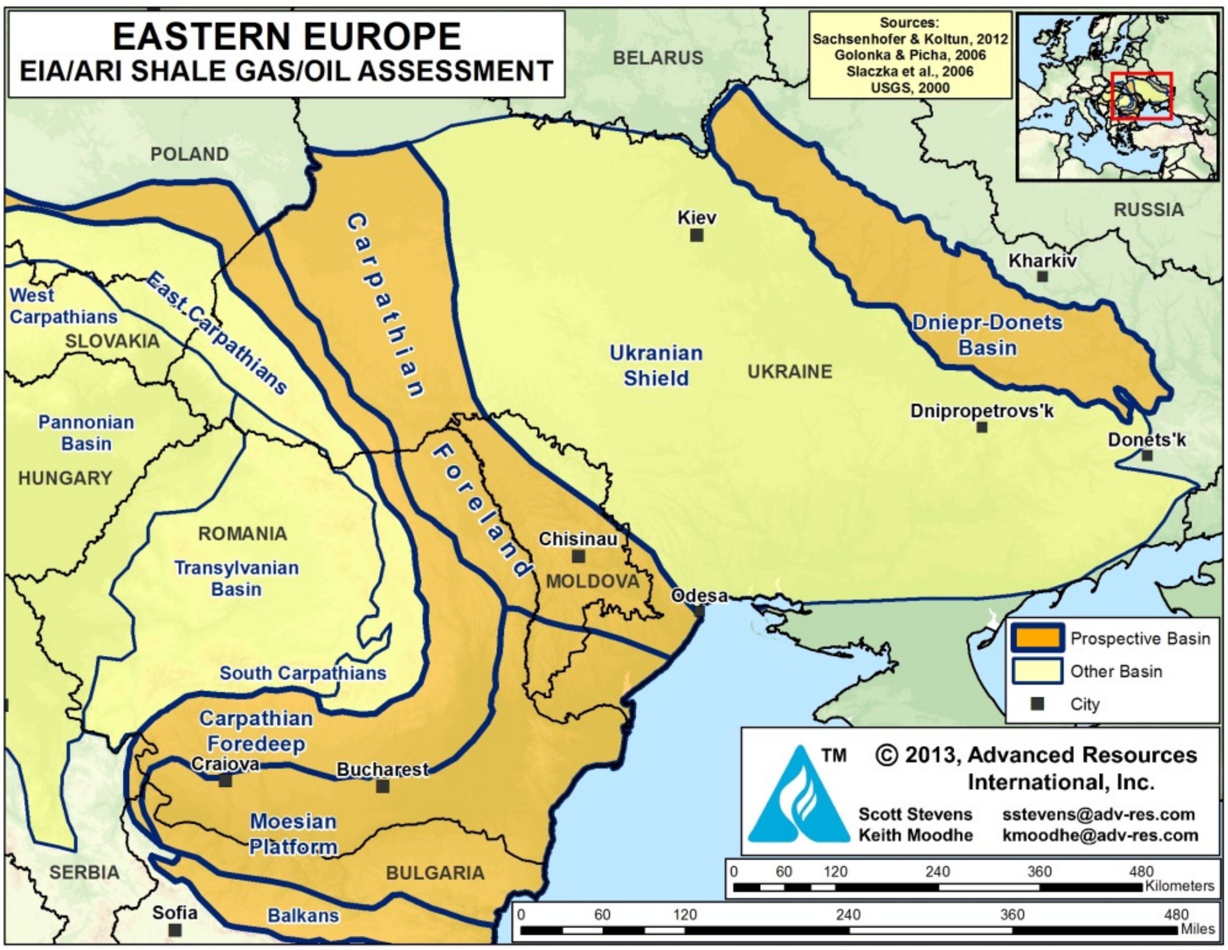
# X. EASTERN EUROPE (BULGARIA, ROMANIA, UKRAINE)

## SUMMARY

Eastern Europe (ex. Poland, assessed separately) has significant prospective shale gas and oil resources in three sedimentary basins: the Dniepr-Donets Basin, the Carpathian Foreland Basin, and the Moesian Platform, Figure X-1. Shale exploration is underway in Ukraine and Romania, while Bulgaria currently has a moratorium on shale development.

Figure X-1: Prospective Shale Basins of Eastern Europe




Source: ARI, 2013.

The total risked, technically recoverable shale resource potential for the three basins is estimated at 195 Tcf of shale gas and 1.6 billion barrels of shale oil and condensate, Tables X-1 and X-2. Our new, larger interpretation of the shale resource is based on recent shale leasing, drilling, and seismic activities that were stimulated in part by the 2011 EIA/ARI study.

Table X-1: Shale Gas Reservoir Properties and Resources, Eastern Europe.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Carpathian Foreland ($70,000 mi^2$) | Dniepr-Donets ($23,200 mi^2$) | | | Moesian Platform ($45,000 mi^2$) | | |
| | Shale Formation | | L. Silurian | L. Carboniferous | | | L. Silurian | | Etropole |
| | Geologic Age | | L. Silurian | L. Carboniferous | | | L. Silurian | | L. Jurassic |
| | Depositional Environment | | Marine | Marine | | | Marine | | Marine |
| Physical Extent | Prospective Area ($mi^2$) | | 16,080 | 1,460 | 2,680 | 6,010 | 840 | 760 | 7,940 |
| | Thickness (ft) | Organically Rich | 1,000 | 700 | 700 | 700 | 600 | 600 | 650 |
| | | Net | 400 | 350 | 350 | 350 | 450 | 450 | 260 |
| | Depth (ft) | Interval | 3,300 - 16,400 | 3,300 - 16,400 | 3,300 - 16,400 | 3,300 - 16,400 | 6,600 - 16,400 | 13,000 - 16,400 | 5,000 - 16,400 |
| | | Average | 10,000 | 11,000 | 12,000 | 13,000 | 11,000 | 14,000 | 10,000 |
| Reservoir Properties | Reservoir Pressure | | Normal | Normal | Mod. Overpress. | Mod. Overpress. | Normal | Normal | Highly Overpress. |
| | Average TOC (wt. %) | | 2.0% | 4.5% | 4.5% | 4.5% | 3.0% | 3.0% | 3.0% |
| | Thermal Maturity (% Ro) | | 2.50% | 0.90% | 1.15% | 2.00% | 1.15% | 2.00% | 1.15% |
| | Clay Content | | Medium | Low | Low | Low | Medium | Medium | Medium |
| Resource | Gas Phase | | Dry Gas | Assoc. Gas | Wet Gas | Dry Gas | Wet Gas | Dry Gas | Wet Gas |
| | GIP Concentration ($Bcf/mi^2$) | | 112.7 | 49.2 | 118.5 | 195.2 | 121.9 | 154.4 | 106.7 |
| | Risked GIP (Tcf) | | 362.5 | 14.4 | 63.5 | 234.6 | 22.5 | 25.8 | 148.2 |
| | Risked Recoverable (Tcf) | | 72.5 | 1.4 | 15.9 | 58.6 | 4.5 | 5.2 | 37.1 |

Source: ARI 2013.

Table X-2: Shale Oil Reservoir Properties and Resources, Eastern Europe.

| | | | | | | |
|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Dniepr-Donets ($23,200 mi^2$) | | Moesian Platform ($45,000 mi^2$) | |
| | Shale Formation | | L. Carboniferous | | L. Silurian | Etropole |
| | Geologic Age | | L. Carboniferous | | L. Silurian | L. Jurassic |
| | Depositional Environment | | Marine | | Marine | Marine |
| Physical Extent | Prospective Area ($mi^2$) | | 1,460 | 2,680 | 840 | 7,940 |
| | Thickness (ft) | Organically Rich | 700 | 700 | 600 | 650 |
| | | Net | 350 | 350 | 450 | 260 |
| | Depth (ft) | Interval | 3,300 - 16,400 | 3,300 - 16,400 | 6,600 - 16,400 | 5,000 - 16,400 |
| | | Average | 11,000 | 12,000 | 11,000 | 10,000 |
| Reservoir Properties | Reservoir Pressure | | Normal | Mod. Overpress. | Normal | Highly Overpress. |
| | Average TOC (wt. %) | | 4.5% | 4.5% | 3.0% | 3.0% |
| | Thermal Maturity (% Ro) | | 0.90% | 1.15% | 1.15% | 1.15% |
| | Clay Content | | Low | Low | Medium | Medium |
| Resource | Oil Phase | | Oil | Condensate | Condensate | Condensate |
| | OIP Concentration ($MMbbl/mi^2$) | | 45.3 | 18.1 | 8.9 | 5.0 |
| | Risked OIP (B bbl) | | 13.2 | 9.7 | 1.6 | 7.9 |
| | Risked Recoverable (B bbl) | | 0.66 | 0.48 | 0.08 | 0.40 |

Source: ARI 2013.

The main shale targets in Eastern Europe are marine-deposited black shales within the Lower Carboniferous of the Dniepr-Donets Basin (TRR of 76 Tcf and 1.2 billion barrels); the Silurian of the Carpathian Foreland Basin (73 Tcf); and the Silurian and Jurassic Etropole shale deposits of the Moesian Platform (47 Tcf and 0.5 billion barrels). By country, the estimates are Ukraine (128 Tcf and 1.2 billion barrels); Romania (51 Tcf and 0.3 billion barrels); and Bulgaria (17 Tcf and 0.2 billion barrels). Compared with North America, the shale geology of Eastern Europe is more complex, although faulting appears less prevalent than in other parts of Europe.

Shale resource assessments are reported to be underway in Ukraine, Romania, and Bulgaria but no official assessments have been published yet. To date only one shale-focused exploration core well has been drilled in the region (Bulgaria); no production testing has occurred. In Ukraine, Shell recently signed a Production Sharing Agreement in the Dniepr-Donets Basin, committing at least $200 million for exploration, while Chevron reportedly has been negotiating for a block in the Ukraine portion of the Carpathian Foreland Basin. Chevron's previously awarded shale blocks in Romania and Bulgaria have been put on hold.

## INTRODUCTION

Since EIA/ARI's initial shale assessment first defined the potential in 2011, several Eastern European countries have begun to investigate their shale gas/ and shale oil resource potential. International oil and gas companies, including Chevron and Shell, have negotiated shale exploration licenses in Bulgaria, Romania, and Poland. The countries of Eastern Europe are taking various approaches to shale exploration. Ukraine currently welcomes shale investment. On the other hand, Bulgaria and Romania have placed shale exploration on hold, after initially proceeding with shale leasing.

**Ukraine.** The Ukraine State Service of Geology and Mineral Resources (Gosgeonedra) has announced shale gas resources in the country of 7 trillion $m^3$ ($Tm^3$) or 247 Tcf.[1] However, the basis for this estimate has not been released and the figure includes some tight gas resources. The newly created Geological Research and Production Center in Poltava plans to coordinate shale gas studies in Ukraine, while monitoring water quality in drilling areas. Ukraine's current Production Sharing Agreement (PSA) involves a 5-year exploration period and up to 45 years for development. Tender fees are modest: $60,000 for the tender and $10,000 for the geologic information package.

On February 23, 2012 the Ukraine government announced a tender for shale exploration and development in the Oleska and Yuzovska blocks of western and eastern Ukraine, respectively. Shell, ExxonMobil, Chevron, ENI, and TNK-BP initially responded to the tender. In January 2013, Ukraine awarded the first shale gas PSA, signing with Shell at the World Economic Forum in Davos, Switzerland. Shell's 50-year PSA permit at Yuzovska in the eastern Dniepr-Donets Basin covers an area of 7,886 $km^2$ and assigns oil and gas rights to all strata to a depth of 10 km, including tight and basin-centered gas. The contract allows for 70% investor recovery and a 16.5% government revenue share.

Chevron has been in negotiations with the government for a PSA at the Oleska field in western Ukraine. This block is along strike with Poland's Lublin basin, where Chevron already holds shale licenses. Duration and terms likely would be similar to those granted to Shell.

**Bulgaria.** While the country lacks a shale-specific investment regime, Bulgaria's conventional oil and gas production terms are attractive. Production licenses extend for 35 years, with royalties ranging from 2.5% to 30% on a sliding scale, with a 10% corporate income tax. The Economy and Energy Minister has suggested that Bulgaria's shale gas resources could be in the range of 0.3 to 1.0 $Tm^3$ (11 to 35 Tcf), but no supporting study has been released. The Shale Gas Research Group, a newly formed consortium of Sofia University and Bulgaria's Institutes of Geology and Organic Chemistry, is conducting long-term studies of organic-rich shale deposits in Bulgaria.[2]

However, during the past year public opposition to shale gas development has increased dramatically in Bulgaria. This opposition has been led by environmental organizers, with no effective counter-balancing information campaign offered by the petroleum industry or the government, such as exists in Poland. In January 2012 the government banned all shale gas exploration and production, whether or not it involves hydraulic fracturing. The performance of the shale industry in Poland and the UK is expected to influence the future political acceptance and government policies in Romania and Bulgaria.[3]

**Romania.** Romania also recently banned shale gas exploration and production, although some local observers believe its ban would be easier to reverse than Bulgaria's. In May 2012 the newly elected Romanian government began an informal (i.e., not legislated) ban on shale gas exploration activities, pending the outcome of European-level studies on the health, safety, and environmental aspects of shale gas development.

Romania lacks specific regulations for shale gas development, thus shale applications fall under the country's conventional petroleum terms. In 2011 the National Agency for Mineral Resources, which regulates petroleum operations in Romania, initiated a study of the country's shale gas deposits, in cooperation with the national research institute GeoEcoMar and three universities (Bucharest, Iasi and Cluj). No further details are available.

More than a dozen companies have expressed interest in shale gas exploration in Romania. Beginning in March 2012 Chevron was awarded four shale gas exploration licenses totaling 9,000 km$^2$, three blocks located in Dobruja and one in the Moldova region. Hungary's MOL was awarded three shale gas permits in northwestern Romania (Voivozi, Adea, and Curtici). Sterling Resources and partner TransAtlantic Petroleum jointly hold the 5,800-km$^2$ Sud Craiova license of southwest Romania. Finally, state-owned energy firm Romgaz reported that it discovered shale gas resources in 5 out of 20 of its exploration wells in Transylvania, noting that it had applied hydraulic fracturing technology in Romania as early as the mid-1990's. All of these projects are on hold due to Romania's shale ban.

## GEOLOGIC OVERVIEW

Eastern Europe has three distinct shale-prospective areas with shale gas and oil potential in Paleozoic and Mesozoice marine-deposited black shales. Within the Paleozoic, the Carboniferous and Silurian black shales are most prospective, while the mid-Jurassic shales are most prospective for oil and gas within the Mesozoic. Other organic-rich shales exist locally but these tend to be less widespread and/or are thermally less mature, and thus were not assessed.

- **Carpathian Foreland Basin.** The moderately complex Lviv-Volyn Basin of western Ukraine is similar to the Lublin Basin in southeast Poland. However, the Silurian black shale belt becomes structurally simpler as it trends towards the southeast across southwestern Ukraine and northern Romania until it reaches the Black Sea. This deep Paleozoic belt north of the Carpathian Foldbelt is called the Carpathian Foreland Basin.
- **Dniepr-Donets Basin.** This well-defined Late Paleozoic basin in eastern Ukraine and southern Belarus contains prospective organic-rich L. Carboniferous black shales.
- **Moesian Platform.** Silurian and Jurassic black shales are present across Romania and Bulgaria. Note that the Moesian Platform shale plays are less well defined than the previous two plays and may be considerably larger than assessed here.

Other basins in Eastern Europe contain organic-rich source rock shales but these were deemed to be less prospective. The large Pannonian-Transylvanian basin of Hungary, Romania, Serbia and Montenegro, Slovenia, and Bosnia and Herzogovina has Paleozoic shale which appears too deep for shale development. The Carpathian, Balkan, and related fold belts appear much too structurally complex to be prospective.

## 1. CARPATHIAN FORELAND BASIN (UKRAINE-ROMANIA-MOLDOVA)

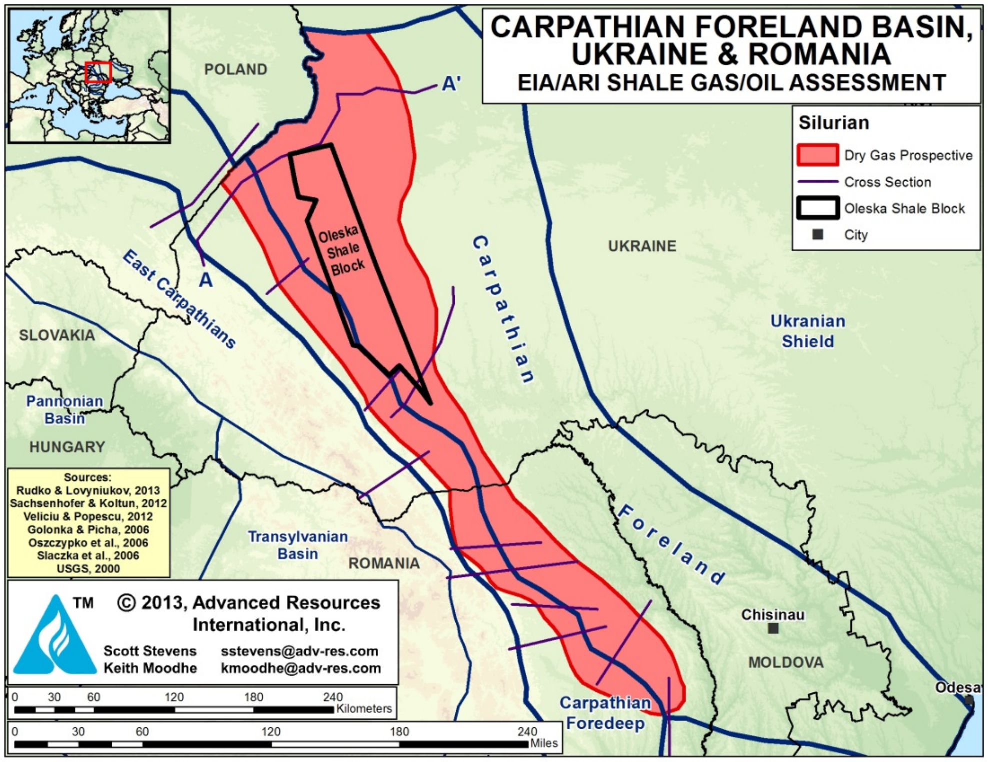
### 1.1 Introduction and Geologic Setting

Prospective marine black shales of Silurian age extend continuously within a 50- to 200- km wide Paleozoic belt, from Poland all the way to the Black Sea. In western Ukraine, Silurian deposits of southeast Poland's Lublin Basin continue into the adjoining Lviv-Volyn Basin, where 62 conventional oil and gas fields have been developed. Much of the Lviv-Volyn Basin appears to be too deep and faulted for shale development.

However, the Silurian belt becomes wider and structurally simpler as it continues further to the southeast across western Ukraine and northern Romania, Figure X-2. After some tectonic disturbance, the Silurian belt re-enters southern Ukraine and eastern Romania in the Scythian Platform before heading out into the Black Sea. It then briefly re-emerges onto land on the Crimean Peninsula near Odessa before continuing offshore. The North Dobrogea Orogen separates this belt from the Silurian of the Moesian Platform to the south[4], which was separately assessed. We refer to the Silurian belt as the Carpathian Foreland Basin, but other researchers have named it the Lviv-Moldava Slope.[5]

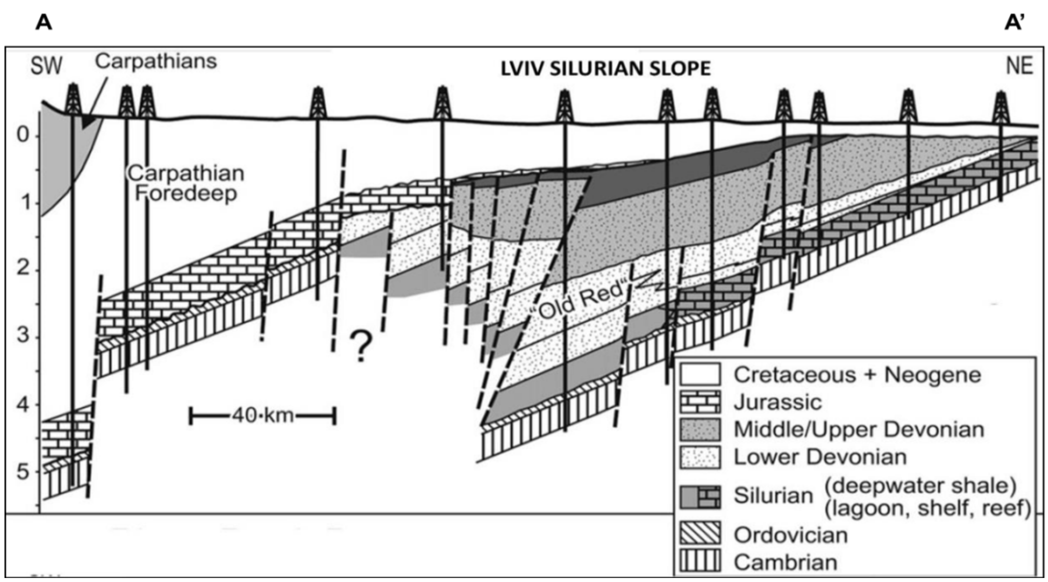
The Carpathian Foreland Basin has good shale gas development potential in Silurian black shales. As the foreland basin to the Carpathian thrust belt, this shale belt dips gently to the southwest and is characterized by mostly simple structure with few faults, Figure X-3. Further to the south, the structurally complex Carpathian region also contains multiple rich marine source rocks. These include the 500-m thick Jurassic Kokhanivka Formation with up to 12% TOC, the 200-m thick L. Cretaceous Spas and Shypot formations with 2-7% TOC, and the Oligo-Miocene Lower Menilite Formation with up to 20% TOC. However, the Carpathian region is intensely faulted with complex nappe tectonics, Figure X-4,[6,7] and was not assessed.

Figure X-2: Carpathian Foreland Basin Showing Shale-Prospective Areas.



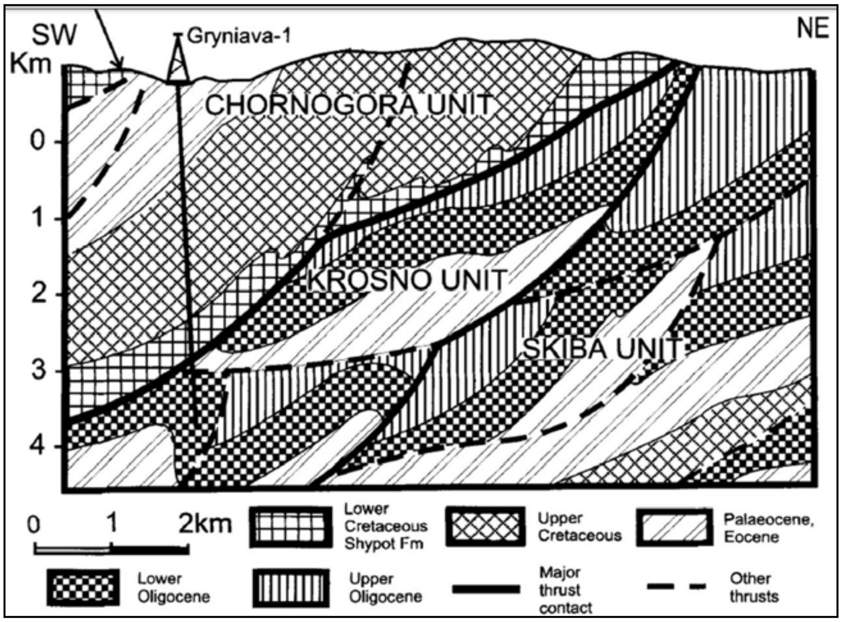

Source: ARI 2013

Figure X-3: Cross-Section of Lviv Slope Portion of the Carpathian Foreland Basin in Western Ukraine




Source: Sachsenhofer et al., 2012

Figure X-4: Cross-Section of a Nappe Structure in the Carpathian Thrust Belt

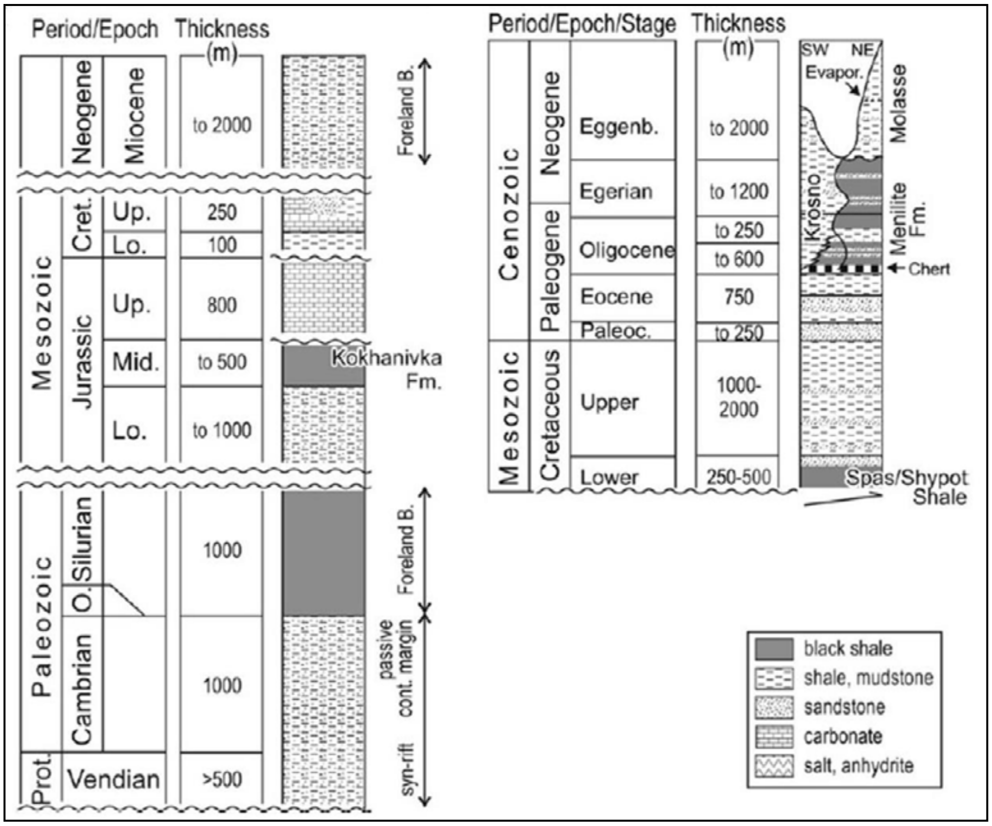



Source: Koltun et al., 1998

The Silurian is the main petroleum source rock and shale gas exploration targets in the Carpathian Foreland Basin, Figure X-5. Compared with Poland, the reservoir characteristics of the Silurian shale in western Ukraine are less certain. About 400 to 1,000 m of deep-water Silurian shale is present, transitioning eastward into thinner, shallow-water carbonates. The Ludlow member of the Silurian is considered the most prospective interval. The Ludlow ranges from 400 to 600 m thick and occurs at depths of 2 to 3 km in western Ukraine.

Silurian shale TOC may be lower in Ukraine than in Poland, at least based on the single well data point available (IS-1). Most TOC measurements at a depth range of 1,400 to 1,592 m in this well were less than 1%. However, the original TOC is estimated at 3% prior to thermal alteration. Given the depositional environmental of the Silurian, it is likely that higher TOC exists in places. Thermal maturity mapping, calculated from conodant alternation index, indicates the Silurian is entirely in the dry gas window ($R_o$ of 1.3% to 3.5%). Several (possibly spurious) over-mature values of 5% $R_o$ also were measured. Maturation is believed to have occurred prior to the Mesozoic. As Sachsenhofer and Koltun (2012) noted: "additional investigations are needed to investigate lateral and vertical variations of TOC contents and refine the maturity patterns in Lower Paleozoic rocks."

Figure X-5: Stratigraphy of Carpathian Foreland Basin Showing Thick Black Shales of Silurian and Mid-Jurassic-Age (left). L. Cretaceous and Paleogene Source Rocks Occur in the Carpathians (right).




Source: Sachsenhofer et al., 2012

The Kovel-1 petroleum well is a key stratigraphic test drilled during the late 1980s in western Volynia, northwestern Ukraine. The well is located along the transition between the structurally complex Lublin-Lviv basins on the west and the less deformed Volynia region of the Slope. The Kovel-1 well cored Ordovician at a depth of about 250 m; Silurian apparently had been eroded in this uplifted location.[8]

## 1.2 Reservoir Properties (Prospective Area)

Based on geologic control from regional cross-sections, the total estimated shale gas prospective area in the Carpathian Foreland Basin is estimated to be approximately 16,080 mi$^2$, of which 11,520 mi$^2$ is in Ukraine and 4,560 mi$^2$ in Romania. The target organic-rich portion of the 500-m thick Ludlow Member of the Silurian is estimated to average 1,000 ft thick gross and 10,000 ft deep within the prospective region, and have 4% porosity. TOC averages a relatively low 2.0% and is in the dry gas window ($R_o$ average 2.5%). The pressure gradient is assumed to be hydrostatic (0.43 psi/ft).

### 1.3 Resource Assessment

Risked, technically recoverable resources from Silurian black shale in the Carpathian Foreland Basin are estimated to be 73 Tcf (52 Tcf in Ukraine and 21 Tcf in Romania), out of a risked shale gas in-place of 363 Tcf, Table X-1. The play has a moderately high resource concentration of about 113 Bcf/mi$^2$, reflecting the significant thickness of the organic-rich shale that is present.

Ukraine's State Commission on Mineral Resources has estimated that the Oleska shale gas license area in the Lviv-Volyn Basin has about 0.8 to 1.5 trillion m$^3$ (28 to 53 Tcf) of shale gas resources. Whether this estimate reflects in-place or recoverable resources was not specified.

An independent assessment of Silurian shale gas resources in the Romanian portion of the Carpathian Foreland Basin arrived at a Mean Estimate of 5.6 Tcf technically recoverable out of 279 Tcf of gas in-place. This estimate utilized EIA/ARI's 2011 methodology, but key assumptions (thickness, porosity, risk) were not specified, nor was Ukraine evaluated.[9]

### 1.4 Recent Activity

Chevron reportedly is in negotiations with the government to develop a shale gas project in the Oleska block of western Ukraine. The government recently removed its self-imposed deadline of May 2013 for completing this deal. Chevron also initially acquired the 6,257-km$^2$ Barlad shale gas permit in northeastern Romania close to Moldova, but the status of this block is unclear following the shale ban in Romania.

In 2012 ENI acquired half of LLC WestGasInvest, which controls nine unconventional gas licenses totaling 3,800-km$^2$ in the Lviv Basin of western Ukraine, which may include shale gas potential. The company and its partners, including UK-based Cadogan Petroleum, plan to spend about $55 million exploring for shale gas in the Lviv basin from 2012 through 2015.

# 2. DNIEPR-DONETS BASIN (EAST UKRAINE)

## 2.1 Introduction and Geologic Setting

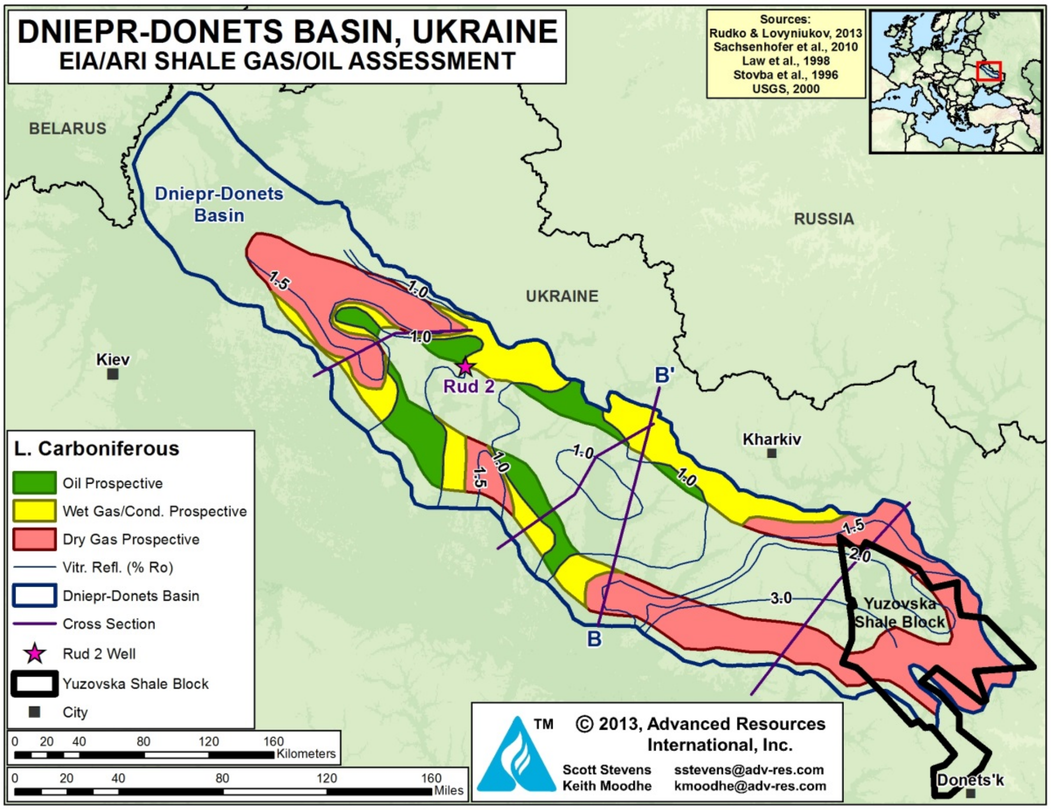
The Dniepr-Donets Basin (DDB) in eastern Ukraine is a Mid-to Late-Devonian failed rift basin on the Eastern European Craton, Figure X-6. The basin contains a thick sequence of Lower Carboniferous black shale which may be prospective for oil and gas development. Economically important Carboniferous coal deposits and tight sands of the Moscovian overlie these shales,[10] but this coaly sequence does not appear to be a prospective shale target.

The DDB accounts for most of Ukraine's onshore petroleum reserves and is comparatively well understood, with several thousand oil and gas wells, some of which reached depths of over 5 km. Lower Carboniferous black shales and coal seams are the main source rocks, while overlying clastic Carboniferous sandstones provide conventional reservoirs within mainly structural traps. To the northwest the DDB continues into the Pripyat Trough of southern Belarus, which appears to be too shallow and low in TOC for shale development. To the southeast the basin continues into the Donbas Foldbelt of southwestern Russia.

Roughly symmetrical, the DDB is about 700 km long, 40 to 70 km wide, and trends northwest-southeast.[11] It comprises a series of half grabens bounded by large-displacement faults (h= 100 m to 2 km). The individual blocks are quite sizeable (50-100 km by 20-40 km), although numerous smaller faults are locally present. The basin contains as much as 15 km of Devonian and younger sedimentary rocks, which includes 1 to 2 km of mostly Devonian (Frasnian) salt deposited under restricted rift conditions. Figure X-7 is a structural cross-section showing depth to the L. Carboniferous (L. Visian) black shale as well as salt flows in the basin.[12]

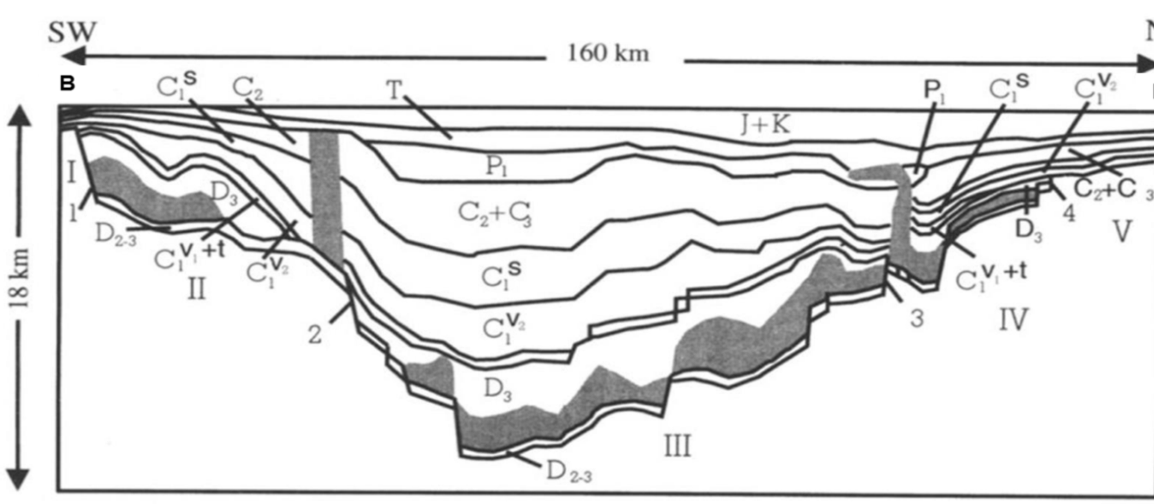
L. Carboniferous black shale overlies the Devonian salt interval. This black shale and the overlying coal seams sourced most of the conventional oil and gas fields in the basin. The entire Carboniferous section ranges up to 11 km thick in the DDB and is up to 15 km deep near its base along the basin axis. In the northwest portion of the DDB the Carboniferous is continental in origin, but transitions into partly shallow marine depositional cycles, each of which is typically 50 m thick and contains an organic-rich shallow marine shale layer.

Figure X-6: Dniepr-Donets Basin Showing Shale-Prospective Areas




Source: ARI, 2013

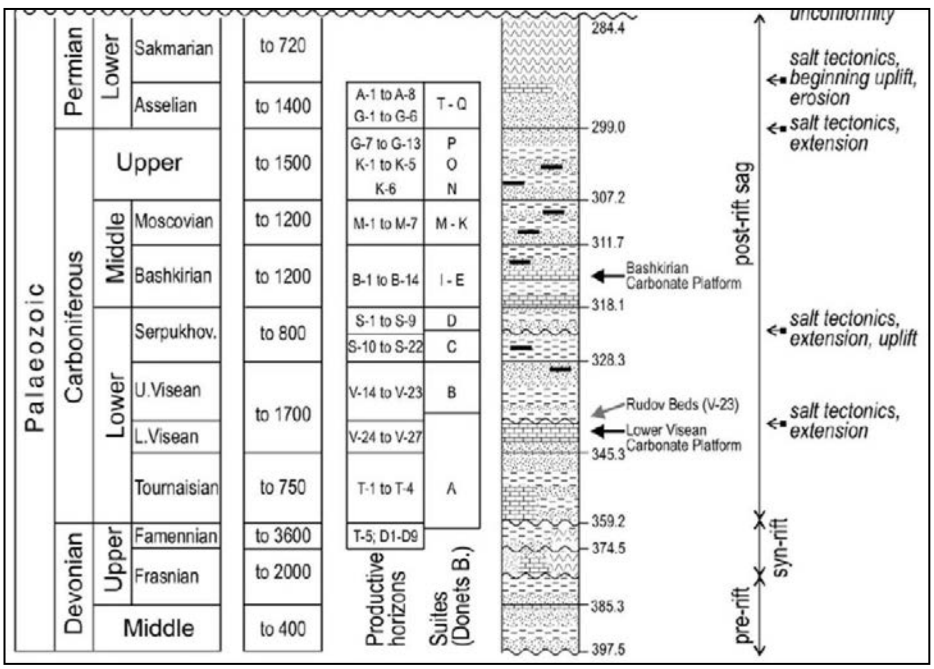
Figure X-7: Cross-Section of Dneipr-Donets Basin Showing Depth to the L. Carboniferous (L. Visian) Black Shale




Source: Stovba et al., 1996

Several black shale targets occur within the L. Carboniferous sequence, Figure 8.[13] The Upper Visean Rudov Beds are considered the best quality source rock and shale gas target. These black shales are up to 70 m thick, but more typically 30-40 m, and particularly well developed in the Srebnen and Zhdanivske depressions where they are quite deep and dry gas prone. The Rudov Beds are rich in siliceous radiolaria, making them potentially brittle, while the lower part of the formation is high in calcite as well as clay. The organic-rich middle section of the Rudov Beds has 3.0% to 10.7% TOC (average 5%), mostly Type III with some Type II kerogen. Additional slightly leaner (TOC of 3.0% to 3.5%) but still quite prospective source rocks occur in the Upper Visean above the Rudov Beds, while the lower Serpukhovian contains black shales with up to 5% TOC.

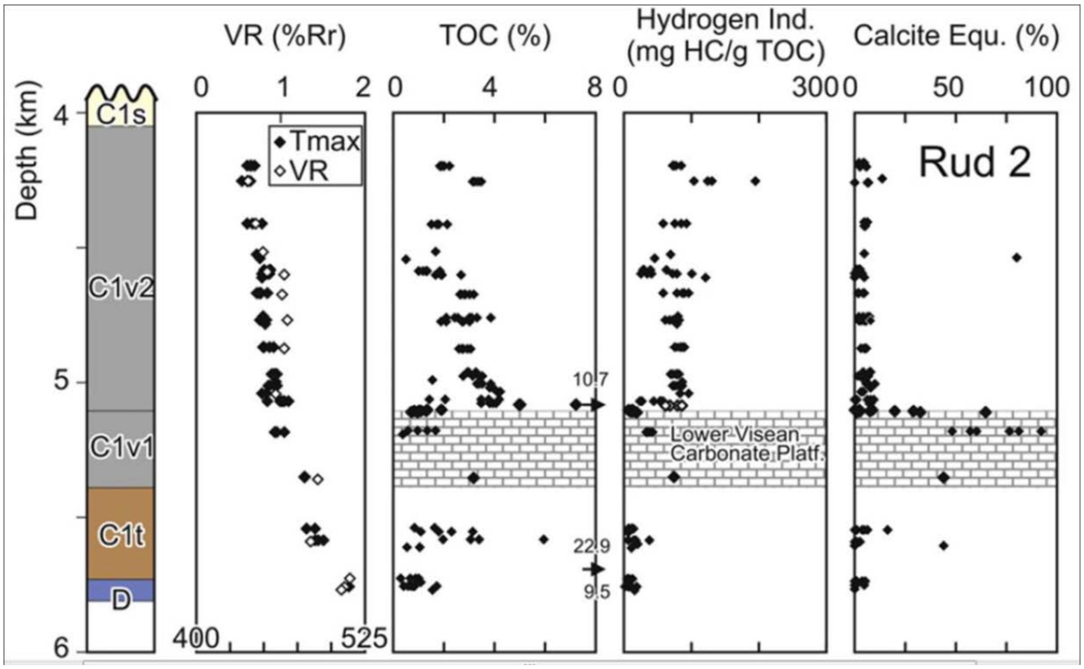
Figure X-8: Stratigraphy of Dniepr-Donets Basin. Black shales Occur in L. Carboniferous Rudov and U. Visean.




Source: modified from Sachsenhofer et al., 2010

Thermal maturity of the Rudov Beds and the overlying Upper Visean is mainly in the oil window ($R_o$ 0.8-1.0%) in the central and northwestern DDB, increasing to dry gas maturity ($R_o$ 1.3-3.0%) in the southeast. For example, the Rud-2 petroleum well in the Dniepr-Donets Basin penetrated a nearly 1-km thick Carboniferous Upper Visean shale interval at a depth of 4 to 5 km, **Figure X-9**. TOC of up to 4% in this interval is within the oil thermal maturity window ($R_o$ 0.8-1.0%). The oil window in this basin appears to be normally to under-pressured, while the dry gas window is likely to be over-pressured due to ongoing gas generation, although pressure data control is poor.[14]

Figure X-9: Rud-2 Well in the Dniepr-Donets Basin, Showing the Carboniferous Upper Visean Shale (C1v2) with TOC up to 4% in the Oil Window (Ro 0.8 to 1.0%).




Source: Sachsenhofer et al., 2012

The southwest flank of the Dneipr-Donets Basin is characterized by a structurally simple dip slope, where thick L. Carboniferous black shale tilts gently to the NNE towards the basin axis. The L. Carboniferous is at ideal depth for shale development (1-5 km) over a broad belt. The northeast flank of the DDB has thinner L. Carboniferous that is structurally more complex. Lacking a detailed depth map on the Carboniferous, we constrained the depth-prospective area using basement contours and multiple published cross-sections, yielding good control on the prospective area. Note that salt intrusions up to 15 km thick may negatively impact shale potential along various parts of the slope.

## 2.2 Reservoir Properties (Prospective Area)

Lower Carboniferous black shales (Rudov Beds, Lower Visean, and Lower Serpukhovian) are prospective within a 10,150-mi$^2$ depth-controlled belt that surrounds the axis of the Dneipr-Donets Basin. These shales are estimated to total about 1 km in thickness but are relatively deep (3-5 km). They largely consist of siliceous or calcareous lithologies rich in radiolarian and thus are expected to be brittle with high porosity (6%). Gas recovery rates also should be favorable (30%) due to the inferred frackability of the shale. TOC appears favorable, averaging about 4.5%. Thermal maturity ranges from oil to dry gas. On the negative side, salt intrusions may sterilize some of the mapped prospective area (10%).

## 2.3 Resource Assessment

***Dry Gas Window.*** The mapped prospective area for the dry shale gas window in southeastern Dniepr-Donets Basin is estimated at 6,010 $mi^2$. Lower Carboniferous shale (comprising the Rudov Beds and portions of the overlying Upper Visean) has a highly favorable resource concentration of approximately 195 Bcf/$mi^2$. Risked, technically recoverable shale gas resources are estimated to be 59 Tcf, out of a risked shale gas in-place of 235 Tcf.

***Wet Gas Window.*** The wet gas prospective area of the DDB extends over about 2,680 $mi^2$. Risked, technically recoverable resources are estimated at 16 Tcf of shale gas and 0.5 billion barrels of condensate from in-place shale gas and shale oil resources of 63 Tcf and 10 billion barrels.

***Oil Window.*** The smaller oil window in the northwestern Dniepr-Donets Basin covers a prospective area of about 1,460 $mi^2$. Risked technically recoverable resources are estimated to be about 0.7 billion barrels of shale oil and condensate and 1 Tcf of associated shale gas, out of risked in-place shale oil resources of 13 billion barrels.

Ukraine's State Commission on Mineral Resources has estimated that the Yuzovska shale gas license in the eastern Dniepr-Donets Basin has 2-3 $Tm^3$ (71-107 Tcf) of shale gas and tight gas resources. Whether this estimate reflects in-place or recoverable resources was not specified.

## 2.4 Recent Activity

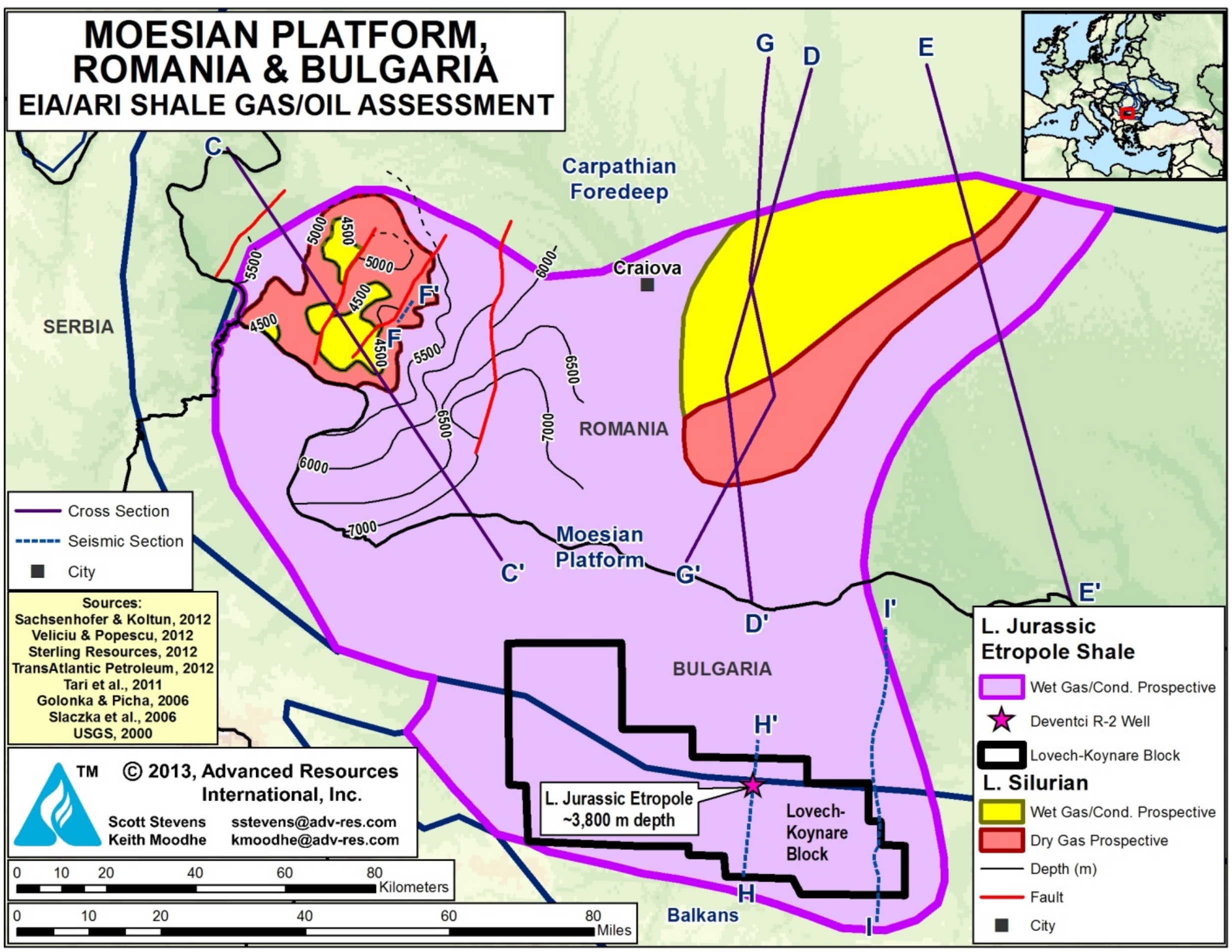
In early 2013 Shell was awarded Ukraine's first formal shale gas exploration license, the 7,800-$km^2$ Yuzovska PSA located on the south flank of the Dniepr-Donets Basin. Shell's first-stage investment commitment is $200 million. Previously in 2011, ENI acquired from Cadogan Petroleum portions of the Zagoryanska and Pokroskoe conventional licenses in the DDB, which may include shale potential.

# 3. MOESIAN PLATFORM (ROMANIA, BULGARIA)

## 3.1 Introduction and Geologic Setting

The Moesian Platform is a comparatively simple (for Europe) foreland basin that stretches across southern Romania and north-central Bulgaria, Figure X-10. The Platform is overthrusted by the Balkan thrust system to the south, while the Carpathian thrust system forms the northern boundary; both are Cenozoic features related to Alpine tectonics. To the east, the Moesian Platform is separated from the Carpathian Foreland Basin and on the north by the North Dobrogea Orogen. The adjacent Getic Basin of Romania, the foreland of the South Carpathians, contains similar source rocks but is more deformed by Tertiary tectonic events and considered less prospective.

Figure X-10: Moesian Platform Region Showing Shale-Prospective Areas.




Source: ARI 2013

Up to 12 km of mostly flat-lying, carbonate-rich Paleozoic and Mesozoic sedimentary rocks are present on the Moesian Platform, Figure X-11. The relatively few conventional oil and gas fields that have been discovered in this region produce mainly from mid-Triassic dolomite and occasionally from basal Jurassic sandstone. [15,16]

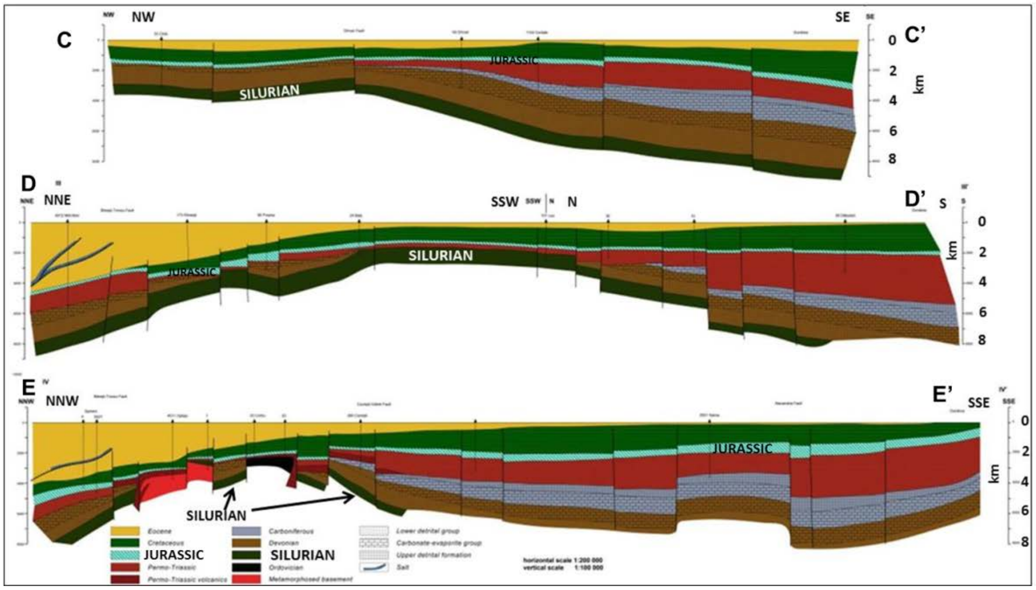
The Moesian Platform contains multiple organic-rich source rock shales that are prospective for shale gas development, Figure X-12. These include the Ordovician to Upper Carboniferous Tandarei, Vlasin, and Calarasi formations, including Silurian shales; the Jurassic Etropole Shale; the Bathonian (Dogger) shales (Bals Formation); and Mid-Miocene marls and shales (Badenian to Sarmatian). The main targets for shale gas exploration are the Silurian shale and Jurassic Etropole Shale.

The Silurian shale in the Moesian Platform is broadly similar to that targeted in Poland and the Carpathian Foreland Basin further to the north. Regional cross-sections show the Silurian ranges from 2 to over 5 km deep across the Moesian Platform. At the South Craiova Block in southwest Romania, the Silurian Llandovery Shale is at least 160 m thick, 4,050 to 4,200 m deep, and has about 3% TOC, Figures X-13 and X-14.[17] At the Bulgarian Arch in eastern Bulgaria, thick (650-m), organic-rich Silurian shales reportedly are at prospective depths of 1 to 5 km, but data were not sufficient to map this portion of the play.

The other main target in the Moesian Platform is the Jurassic Etropole Shale, considered the main petroleum source rock in northwest Bulgaria, Figure X-15. In particular its organic-rich lower portion, the Stefanetz Member, contains thick, carbonate-rich (40-50%) black shale with interbeds of marl and limestone that was deposited in a marine environment, not dissimilar to the Upper Jurassic Haynesville Shale.[18] TOC ranges from 1.0% to 4.6%,[19] with Type II kerogen predominating.[20] The Etropole Shale generally ranges from 2.5 to >5 km deep[21] and is over-pressured in much of the region, with an elevated pressure gradient of 0.78 psi/ft. Thermal maturity falls in the oil window in the north, increasing to wet and dry gas in the south near the Balkan thrust belt ($R_o$ 1.0% to 1.5%).[22]

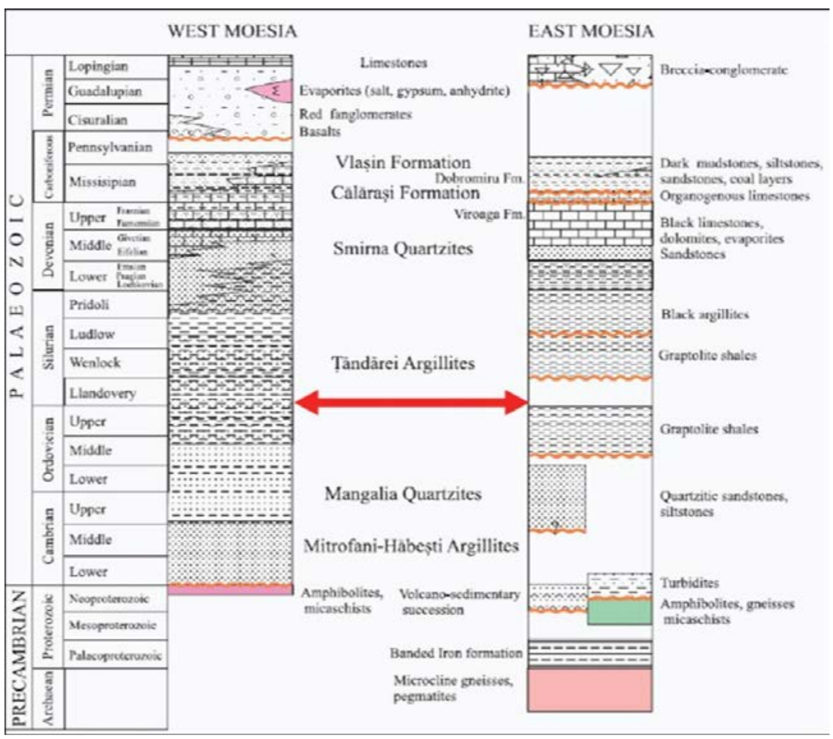
Oil and gas has been produced from conventional silty, sandy, and carbonate intervals within the Etropole Formation, such as the Peshtene R-5 well which reportedly flowed gas at an unstimulated rate of 530,000 $ft^3$/d. In addition, oil produced from the Jurassic Dolni Lukovit and Mid-Triassic Dolni Dabnik fields has been chemically linked back to the Etropole Shale.

Figure X-11: Regional Cross-Sections in of the Moesian Platform In Romania Showing Jurassic and Paleozoic Shale at Mostly Moderate Depth with Relatively Simple Structure.




Source: Veliciu and Popescu, 2012

Figure X-12: Stratigraphic Column Showing L. Silurian Llandovery Shales in Southwest Romania.

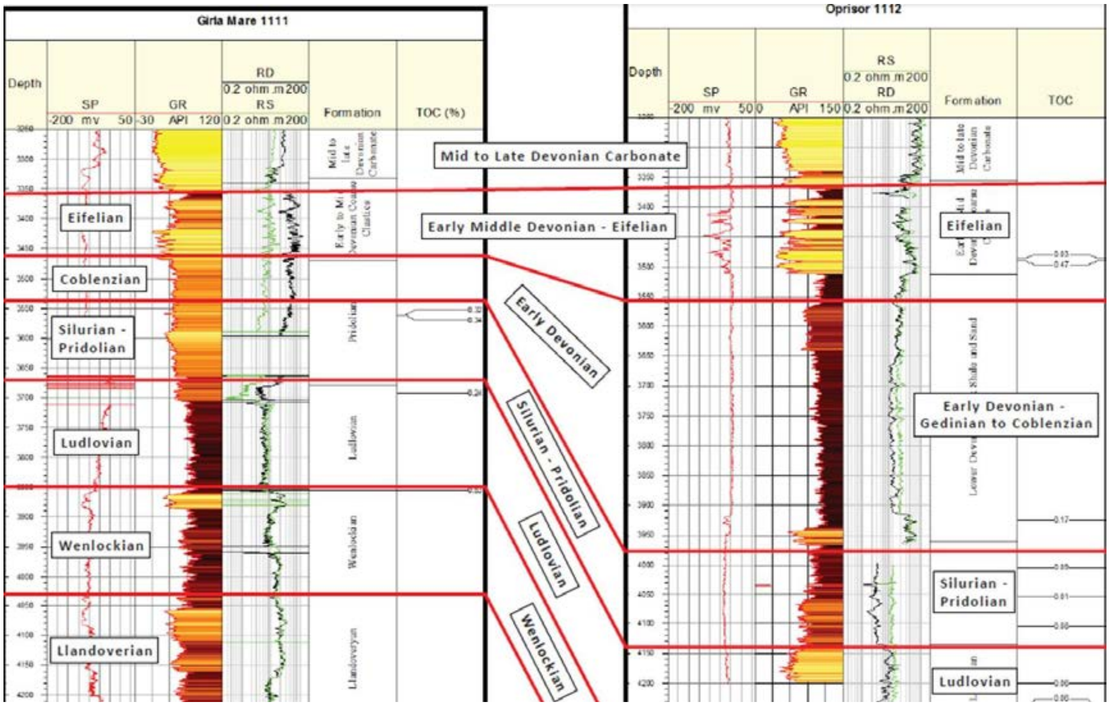



Source: Sterling Resources, 2013



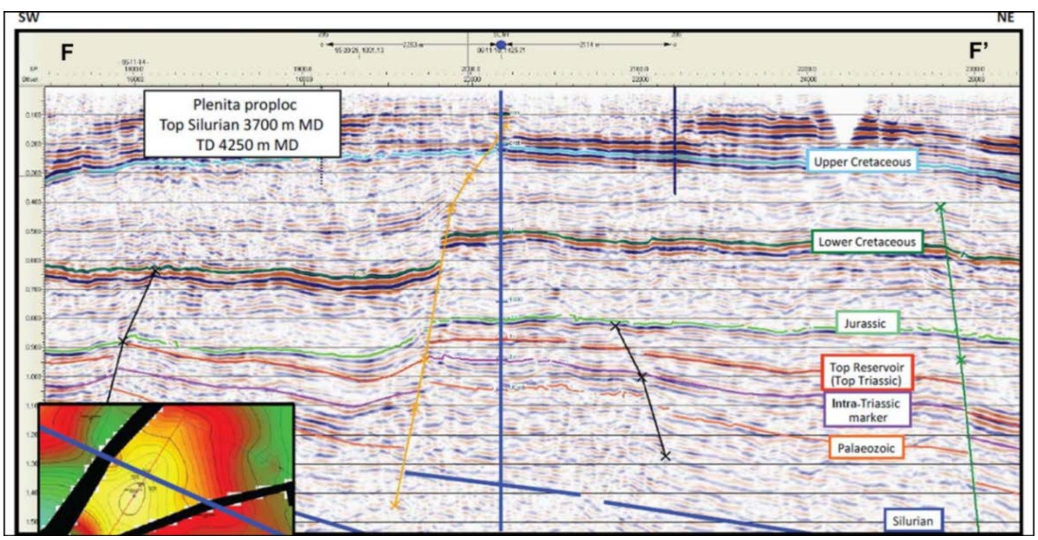
Advanced Resources International, Inc.

Figure X-13: Well Logs Showing Paleozoic Section Including L. Silurian Llandovery Shales at the South Craiova Block (EIII-7) in Southwest Romania.



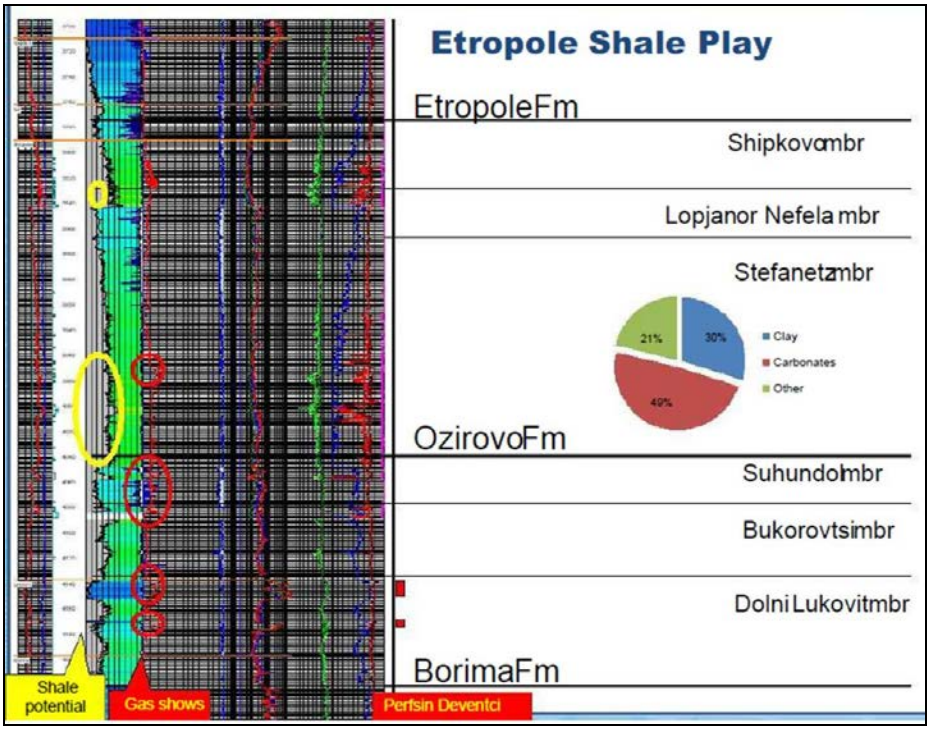

Source: Sterling Resources, 2013

Figure X-14: SW-NE Trending Seismic Line Showing Paleozoic Section Including L. Silurian Llandovery Shales at the South Craiova Block in Southwest Romania. Structure is Relatively Simple But Faults are Present.




Source: Sterling Resources, 2013

Figure X-15: Well log across the Jurassic Etropole Shale in Bulgaria

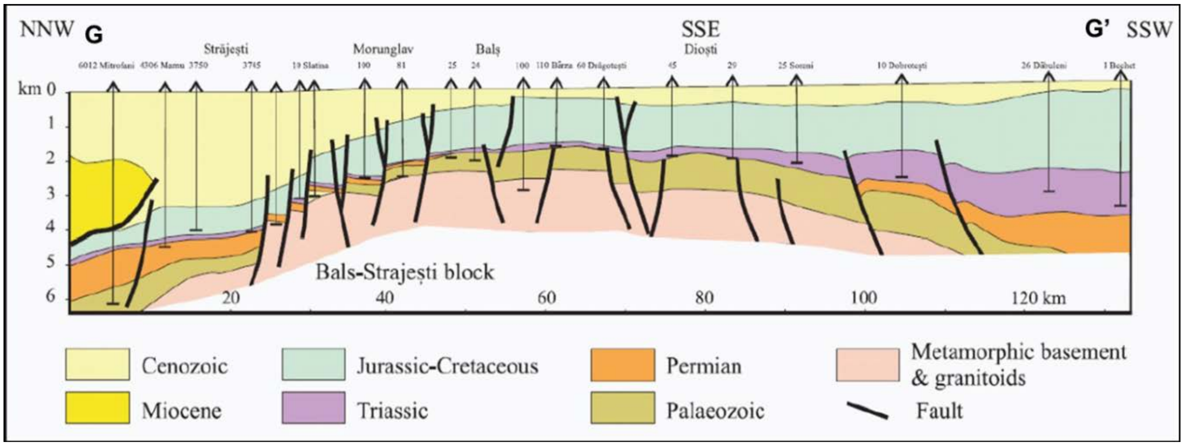



Source: TransAtlantic Petroleum Ltd, February 2011

At the Sud Craiova license in southwest Romania, operated by Sterling and TransAtlantic, the Etropole Shale ranges from 115 to over 700 m thick and 3,700 to 4,500 m deep across the block, Figure X-16. At the Lovech block in northwest Bulgaria the Etropole Shale is about 3,800 m deep, Figure X-17. Structure is fairly simple in this region, with flat lying dips cut by several faults. Other portions of the Moesian Platform lacking data control also were assumed to have relatively similar structure.

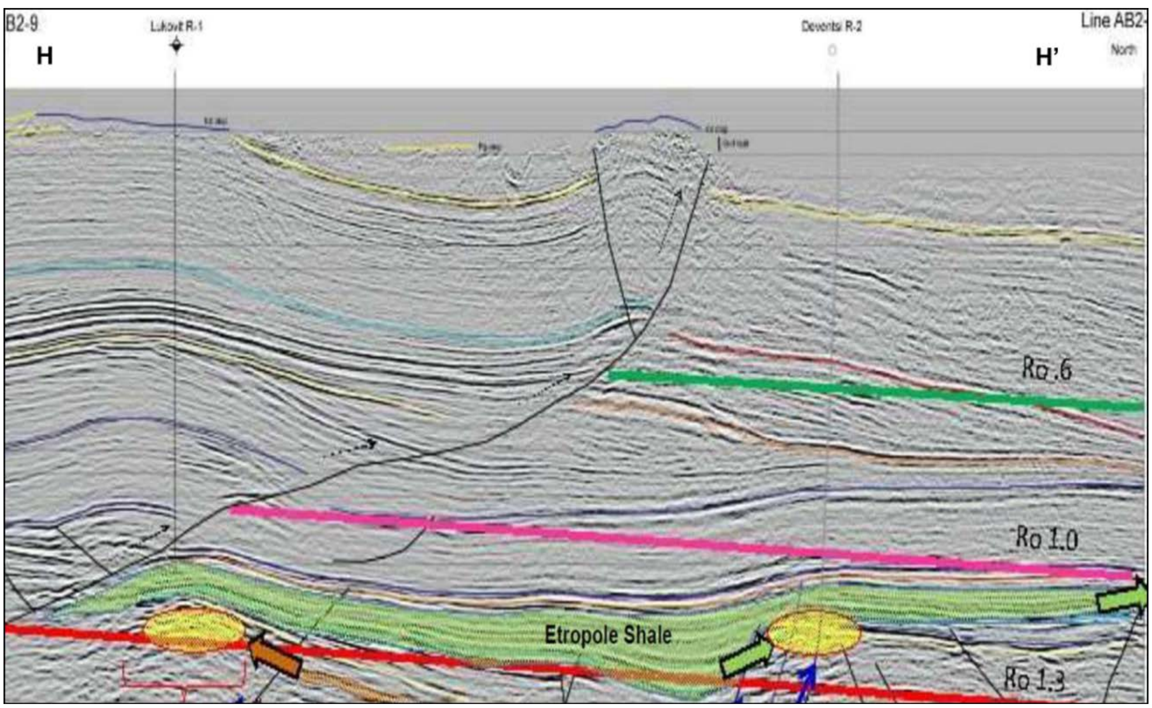
The eastern continuation of the Jurassic Etropole Shale is unclear and could not be rigorously mapped. Two time-structure transects suggest the Etropole may be present in eastern onshore Bulgaria at two-way seismic times of 0.5 to 3.0 seconds, deepening to the east into the Black Sea, Figure X-18. The Central Dobrogea Green Schist Zone, comprising uplifted blocks of Proterozoic basement blocks north of the Palazu Fault, has only a thin or no Jurassic sequence. On the other hand, the North Bulgarian Arch -- where Chevron initially was awarded a shale gas license – holds preserved Jurassic to Tertiary sedimentary sequences.[23]

Figure X-16: Regional Seismic Section Showing Jurassic and L. Silurian Llandovery Shales at the South Craiova Block in Southwest Romania. The Structural Dip is Relatively Gentle but Numerous Faults are Present.



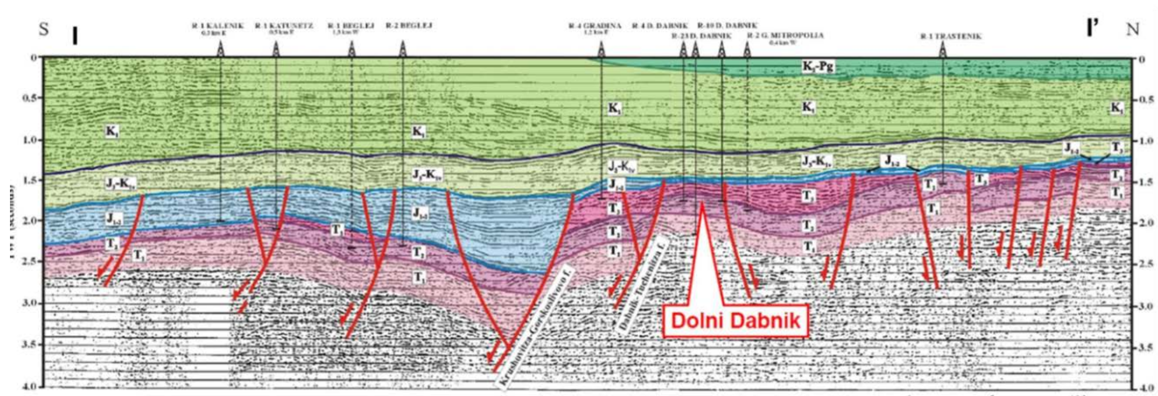

Source: Sterling Resources, 2013

Figure X-17: Jurassic Etropole Shale is about 3,800 m Deep with 1.0% to 1.3% Ro at TransAtlantic Petroleum's Lovech Block in Northwest Bulgaria.




Source: TransAtlantic Petroleum, 2011

Figure X-18: Regional Cross-Section Showing Thick Jurassic Lias and Dogger Shale Deposits in Northern Bulgaria Which Thin Markedly to the North into Romania.




Source: Tari et al., 2011

## 3.2 Reservoir Properties (Prospective Area)

***L. Silurian Shale***. The mapped prospective area for black shales in the L. Silurian totals 1,600 $mi^2$, all of which is located in Romania. No prospective area was identified in Bulgaria due to data limitations, although there could be prospective Silurian areas in northeast Bulgaria. Depth ranges from 2 to 5 km. Organic-rich thickness averages about 600 ft (gross). Thermal maturity ranges from wet to dry gas. TOC is estimated at 3%, porosity at about 4%.

***Jurassic Etropole Shale.*** Black shales in the Mid-Jurassic Etropole Shale are prospective within an estimated 7,940-$mi^2$ area of the Moesian Platform, in northwest Bulgaria and southwest Romania. The most organic-rich shales are estimated to total about 250 m thick (gross) at moderate depth of about 10,000 ft. Porosity is assumed to be moderately high (5%). Gas recovery rates also could be favorable based on the inferred brittle lithology. TOC appears moderate, averaging about 3% in the more prospective intervals. Thermal maturity is wet gas ($R_o$ 1.0% to 1.3%). The pressure gradient is estimated at 0.7 psi/ft.

## 3.3 Resource Assessment

Risked, technically recoverable shale resources in the Moesian Platform region of Romania and Bulgaria are estimated to be 47 Tcf of shale gas and 0.5 billion barrels of shale condensate, out of a risked shale gas and shale oil in-place of 196 Tcf and 10 billion barrels, respectively. Romania's share is approximately 30 Tcf and 0.3 billion barrels while Bulgaria's share is estimated at 16 Tcf and 0.2 billion barrels.

***Silurian Llandovery Shale***. Risked, technically recoverable shale gas resources in the Silurian shale of the Moesian Platform of Romania and Bulgaria are estimated to be 10 Tcf, out of a risked shale gas in-place of 48 Tcf.

***Jurassic Etropole Shale.*** Risked, technically recoverable shale resource in the Jurassic Etropole Shale within the Moesian Platform of Romania and Bulgaria are estimated to be 37 Tcf out of a risked shale gas in-place of 148 Tcf, while shale oil/condensate resources are estimated at 0.4 billion barrels of condensate out of 7.9 billion barrels of risked oil in-place.

Separately, in northeastern Bulgaria, the government has estimated the 4,400-mi$^2$ Novi Pazar block has 0.3 to 1.0 Tm$^3$ (11 to 35 Tcf) of shale gas resource potential in the Devonian-Silurian silty shale. The Devonian-Silurian was reported in the study to be up to 2 km thick, 800 to 2,800 m deep, and have 3.5% sapropelic organic matter with TAI from 2 to 5.[24] However, it was not possible to map this play due to lack of data.

At the 1,500-mi$^2$ Sud Craiova license in southwest Romania, Sterling and TransAtlantic have estimated that the Silurian shale has gross recoverable prospective resources of approximately 3 Tcf (Best Estimate). Including the Jurassic Etropole, TransAtlantic has estimated its blocks hold a total of 0.3 Tm$^3$ (11 Tcf) of unrisked, recoverable shale gas prospective resources (gross; Best Estimate).[25]

Independent researchers in Romania recently estimated the technically recoverable resources in the Silurian shale of the southern Romanian portion of the Moesian Platform to be 26 Tcf, out of 1,295 Tcf of OGIP (Mean Estimate). The Jurassic was not assessed, nor was the Silurian potential in Bulgaria.[26]

## 3.4 Recent Activity

Several companies have pursued shale gas leasing in Bulgaria but only one shale test well has been drilled. In June 2011, Chevron received a 5-year shale gas exploration permit for the 4,400-km$^2$ Novi Pazar block of northeastern Bulgaria. However, since the shale ban of January 2012 Chevron can only pursue conventional targets in the block without hydraulic fracturing.

US-based TransAtlantic Petroleum, through its subsidiary Direct Petroleum Bulgaria, holds a shale gas exploration license at the 2,300-$km^2$ Lovech block, located in the southern Moesian Platform north of the Balkan forelands in northwest Bulgaria. TransAtlantic recently was also awarded the adjacent 648-$km^2$ Koynare block.

In November 2011 TransAtlantic and Canada-based partner LNG Energy drilled the 3,190-m deep Goljamo Peshtene R-11 exploration well at Lovech to core and test the Mid-Jurassic Etropole Shale. The R-11 well was drilled in 56 days and cost $7.5 million. It was located near the Peshtene R-5 well, which had flowed 530,000 $ft^3$/d from a conventional interval in the Jurassic Etropole. The R-11 well penetrated 354 m of Etropole argillite with numerous gas shows (C1-C3) and cored 289 m of the Jurassic Etropole and Ozirovo formations. LNG described rock properties as similar to those of productive US shale plays. The well was not fracture stimulated as Bulgaria has a ban in place. TransAtlantic plans to test the Etropole Shale elsewhere on the Lovech block where it is about 3,800-m deep.[27]

Canada's Park Place Energy received an exploration permit in northwest Bulgaria's Dobruja province (blocks Vranino 1 to 11). In June 2011 Chevron won a tender to explore for shale gas at the Novi Pazar field, also located in Dobruja, but the permit was cancelled in January 2012 when the shale gas ban came into effect. Bulgaria's state gas company Bulgargaz has not disclosed any shale-related activity.

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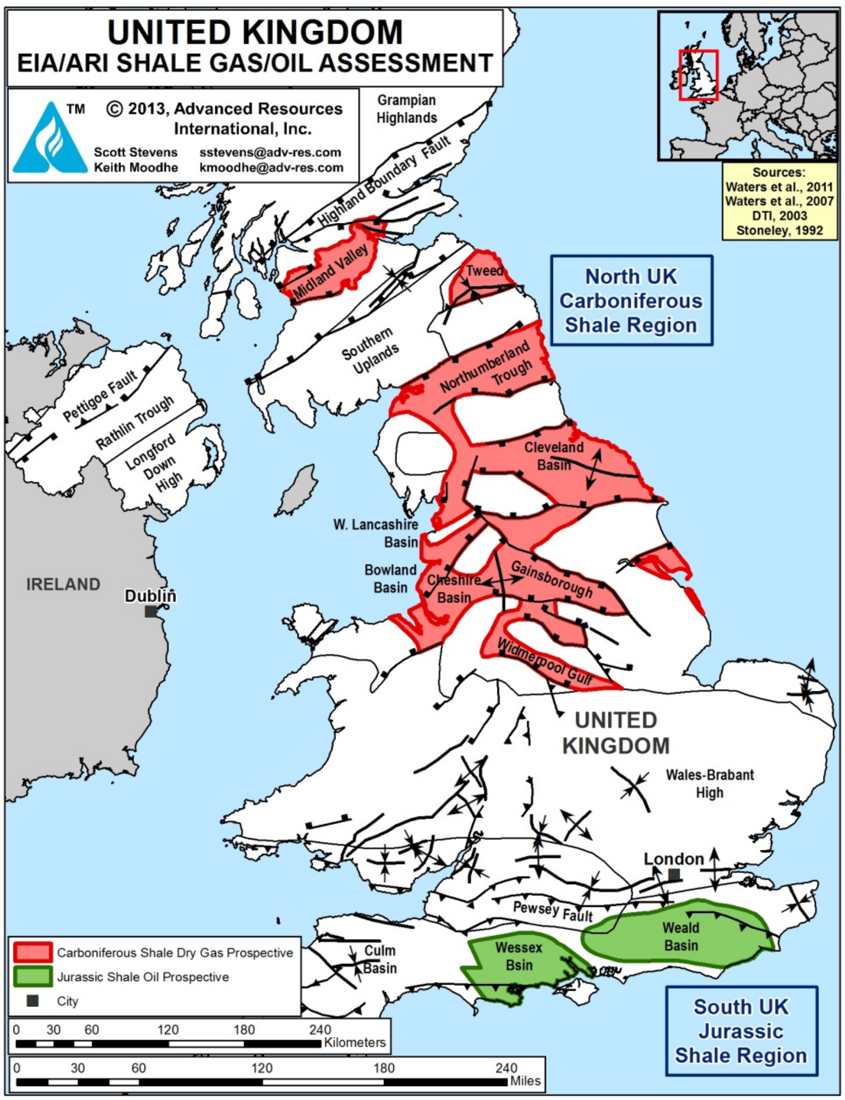
# XI. UNITED KINGDOM

## SUMMARY

The United Kingdom has substantial volumes of prospective shale gas and shale oil resources within Carboniferous- and Jurassic-age shale formations distributed broadly in the northern, central and southern portions of the country.

Figure XI-1 : Shale Basins in the United Kingdom




Source: ARI 2013.

The risked, technically recoverable shale resources of the U.K. are estimated at 26 Tcf of shale gas and 0.7 billion barrels of shale oil and condensate in two assessed regions, Tables XI-1 and XI-2. This is based on the much larger unrisked estimates of 623 Tcf of shale gas in-place (134 Tcf, risked) and 54 Bbbl of shale oil in-place (17 billion barrels, risked). These estimates reflect only the higher-TOC portions of the Carboniferous and Jurassic shale intervals.

Table XI-1. Shale Gas Reservoir Properties and Resources of the United Kingdom

| | | | | |
|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | North UK Carboniferous Shale Region (10,200 mi$^2$) | South UK Jurassic Shale Region (3,470 mi$^2$) |
| | Shale Formation | | Carboniferous Shale | Lias Shale |
| | Geologic Age | | Carboniferous | L. Jurassic |
| | Depositional Environment | | Marine | Marine |
| Physical Extent | Prospective Area (mi$^2$) | | 5,100 | 1,735 |
| | Thickness (ft) | Organically Rich | 820 | 165 |
| | | Net | 410 | 149 |
| | Depth (ft) | Interval | 5,000 - 13,000 | 4,000 - 6,000 |
| | | Average | 8,500 | 5,000 |
| Reservoir Properties | Reservoir Pressure | | Normal | Normal |
| | Average TOC (wt. %) | | 3.0% | 3.0% |
| | Thermal Maturity (% Ro) | | 1.30% | 0.85% |
| | Clay Content | | Medium | Medium |
| Resource | Gas Phase | | Dry Gas | Assoc. Gas |
| | GIP Concentration (Bcf/mi$^2$) | | 117.3 | 14.5 |
| | Risked GIP (Tcf) | | 125.6 | 8.0 |
| | Risked Recoverable (Tcf) | | 25.1 | 0.6 |

Source: ARI, 2013

Table XI-2. Shale Oil Reservoir Properties and Resources of the United Kingdom

| | | | |
|---|---|---|---|
| Basic Data | Basin/Gross Area | | South UK Jurassic Shale Region (3,470 mi$^2$) |
| | Shale Formation | | Lias Shale |
| | Geologic Age | | L. Jurassic |
| | Depositional Environment | | Marine |
| Physical Extent | Prospective Area (mi$^2$) | | 1,735 |
| | Thickness (ft) | Organically Rich | 165 |
| | | Net | 149 |
| | Depth (ft) | Interval | 4,000 - 6,000 |
| | | Average | 5,000 |
| Reservoir Properties | Reservoir Pressure | | Normal |
| | Average TOC (wt. %) | | 3.0% |
| | Thermal Maturity (% Ro) | | 0.85% |
| | Clay Content | | Medium |
| Resource | Oil Phase | | Oil |
| | OIP Concentration (MMbbl/mi$^2$) | | 30.9 |
| | Risked OIP (B bbl) | | 17.1 |
| | Risked Recoverable (B bbl) | | 0.69 |

Source: ARI, 2013

Initial exploration drilling has confirmed the presence of thick, gas-bearing shale deposits in the Bowland Sub-basin in the west portion of the Pennine Basin of northwest England. However, production testing has not yet occurred and the other shale regions remain undrilled. EIA/ARI's current estimate of the UK's shale gas resources is about 10% higher than our initial 2011 assessment, while new shale oil potential has been added.

Compared with North America, the shale geology of the UK is considerably more complex, while drilling and completion costs for shale wells are substantially higher. The Pennine Basin, one of the country's most prospective areas, has been tested with five vertical wells which cored the Carboniferous Bowland Shale. Other prospective areas include the rest of the North UK Carboniferous Shale region and the liquids-rich Jurassic Shale region of southern England in the Wessex and Weald basins, Figure XI-1.

Shale testing is still at an early phase in the UK – flow testing and horizontal shale drilling have not even been attempted. In a temporary setback, the first shale well to be hydraulically stimulated triggered a series of minor earthquakes related to a nearby fault. Following an 18-month moratorium, the government concluded that the environmental risks of shale exploration are small and manageable. Shale drilling was allowed to resume in December 2012, albeit with stricter monitoring controls. Current shale operators include Cuadrilla Resources, IGAS, Dart Energy, and others.

## INTRODUCTION

Within Europe, the United Kingdom stands next after Poland in pursuing its shale gas and shale oil potential. However, with a small existing onshore conventional oil and gas industry, the UK has limited domestic service sector capability for shale exploration. Natural gas prices are high (~$9/MMBtu) in the UK compared with North America, but geologic conditions are much more complex. Faults are numerous, geologic data control is weak, and shale wells are more costly to drill. While the UK's shale resource base appears substantial, commercial levels of shale production are yet to be established.

Political opposition to shale development is greater in the UK than in Poland but less than in France or Germany. Hydraulic fracturing got off to an abysmal start. The UK's first shale production test well triggered small local earthquakes during fracture stimulation and the vertical wellbore was deformed. This is perhaps unsurprising given the highly faulted nature of shale deposits in the UK (and generally in Europe). The government banned onshore hydraulic fracturing for a period of eighteen months to better evaluate the risks.

In January 2012 the British Geological Survey noted that the risks of shale development to groundwater and earthquakes had been exaggerated. Minor earthquakes caused by the Preese Hall-1 well were “comparable in size to the frequent minor quakes caused by coal mining. What's more, they originate much deeper in the crust so have all but dissipated by the time they reach the surface.”[1] In December 2012 the UK government finally granted conditional approval for shale exploration, albeit with strict monitoring conditions. Cuadrilla recently delayed its plan to resume fracture stimulation until 2014 at the earliest.

Companies which have been granted a Petroleum Exploration and Development license (PEDL) by the UK government are permitted to explore and develop shale gas, as well as other types of petroleum resources (conventional, coalbed methane, tight gas, etc.). Field development is subject to necessary national and local consent and planning permission. Currently there are about 334 onshore PEDLs, of which several dozen have recognized shale potential. Proprietary shale data typically are kept confidential for a four-year period from the date of well completion.

At least six oil and gas companies are targeting shale gas exploration in the UK but only two have actually drilled shale wells. All wells have been vertical. UK-based Cuadrilla Resources, partly (43%) owned by Australian drilling company AJ Lucas, is the most active, drilling and coring four shale exploration wells in the West Bowland Sub-basin that confirmed the presence of up to 2-km of gas-bearing organic-rich shale. However, at least one well encountered active faults and high-stress conditions. IGAS Energy has drilled a shale well nearby, coring the 1,600-ft thick Bowland Shale. Horizontal shale wells have not yet been attempted in the UK, nor have flow tests been reported. Coastal Oil and Gas Ltd., Celtique Energie, Dart Energy, and Eden Energy also are evaluating their UK shale resource potential but haven’t yet drilled.

## GEOLOGIC OVERVIEW

As early as the late 1980s researchers at Imperial College, London had identified the main stratigraphic targets for shale gas exploration in the UK, the marine-deposited black shales of Carboniferous and Jurassic age.[2,3] More recently in 2003, a study conducted by the British Geological Survey (BGS) and published by the UK Department of Trade and Industry (DTI) presented an integrated review of the geology of Britain's onshore conventional oil and gas fields and source rock shales, although it was not asked to consider shale as a productive reservoir.[4] In 2010 BGS published a compilation of shale-specific geologic data collected from outcrops and conventional petroleum wells.[5]

BGS published its preliminary evaluation of UK shale gas resources later in 2010, conducted on behalf of the Department of Energy and Climate Change (DECC).[6] BGS' initial estimate was 5.3 Tcf (150 Bcm) of recoverable shale gas resources. BGS, in association with DECC, plans to release an updated evaluation of shale gas potential of northwest England later in 2013, followed eventually by a more complete national estimate.[7]

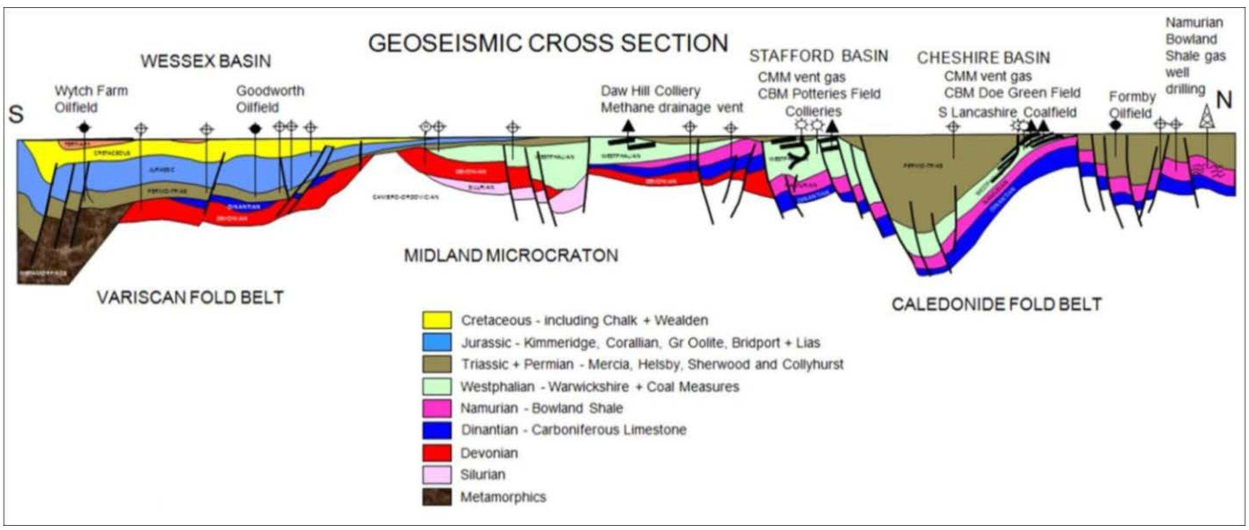
The main onshore sedimentary basins in the UK that produce oil and gas or have conventional or shale exploration potential are shown in Figure XI-1. The current EIA/ARI resource assessment groups these numerous, typically fault-bounded basins into two main shale exploration regions:

- **North UK Carboniferous Shale Region.** A complex assemblage of isolated structural basins and troughs is present across northern England and southern Scotland. These contain prospective organic-rich shales of Carboniferous age, including notably the Bowland Shale. Within the greater Pennine Basin, individual sub-basins include the Bowland, Cleveland, Cheshire, West Lancashire, Northumberland, East Midlands, Gainsborough, Midland Valley, as well as others. The Bowland Sub-basin is the only area to undergo shale exploration drilling to date.

- **South UK Jurassic Shale Region.** In southern England the Wessex and Weald basins extend offshore into the English Channel. They contain Jurassic-age shales that are oil-prone. While no shale drilling has occurred here yet, the region includes Britain's largest onshore oil field and appears highly prospective for shale oil development.

It is important to note that the UK shale basins generally are not simple continuous structures, such as found in many North America shale regions, but rather typically comprise a series of small fault-bounded sub-basins. Figure XI-2 shows a regional cross-section from the Wessex Basin in the south to the Bowland Sub-basin in the north, highlighting the Carboniferous-Namurian and Jurassic shale targets. Even the interior of the sub-basins may be significantly faulted, to an extent generally not displayed on schematic cross-sections. The structural complexity, coupled with the relatively small data base of onshore petroleum wells in the UK (particularly in the troughs), makes resource assessment more difficult. It also could slow the pace of shale exploration, de-risking, and commercial development in the UK.

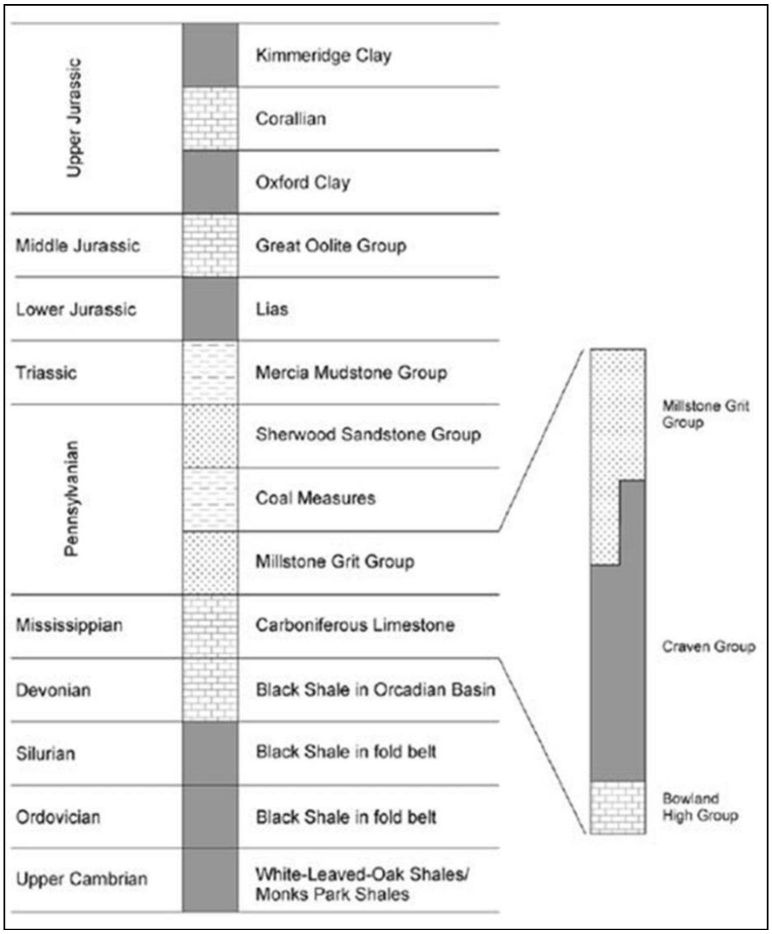
Figure XI-2 : Regional Cross-Section from Wessex Basin Through Bowland Sub-basin Highlighting Carboniferous-Namurian and Jurassic Shale Targets




Source: British Geological Survey, 2012

The main stratigraphic targets for shale exploration in the UK are the Carboniferous Mississippian (Lower Namurian)[8] and the Lower Jurassic Lias formations, both of which contain organic-rich, marine-deposited shales, Figure XI-3. Other potential shale targets include the U. Cambrian and the U. Jurassic Oxford and Kimmeridge Clays, but these were excluded from our study due to their low thermal maturity, lower organic content, and/or extreme structural complexity. In particular, organic-rich shales found within the Carboniferous Coal Measures were excluded because these non-marine shales are coaly, high in clay, and unlikely to be sufficiently brittle. However, further data collection and mapping may reveal these or other shale formations to be prospective in places.

Figure XI-3: Stratigraphic Column Showing UK Formations That Contain Organic-Rich Shales. The Lower Jurassic Lias And Carboniferous Shales Appear Most Prospective.




Source: Smith et al., 2010

The BGS has cited the Middle Cambrian Conasauga Shale in Alabama as the closest North American geologic analog for Cambrian shale deposits in the UK, given their similar age and degree of structural complexity. However, shale gas development in the Conasauga Shale has not been successful to date. The Cambrian-age shale deposits in the UK were not assessed in the EIA/ARI study due to their structural complexity and lack of geologic data.

## SEISMIC HAZARDS

The UK shale industry experienced a serious setback in 2011, when the first hydraulic fracturing operation of a shale well unexpectedly generated a series of very small earthquakes. However, it is noteworthy that none of the approximately 50,000 horizontal shale wells drilled in North America during the past decade have generated significant earthquakes, although a few suspected seismic events are under review.

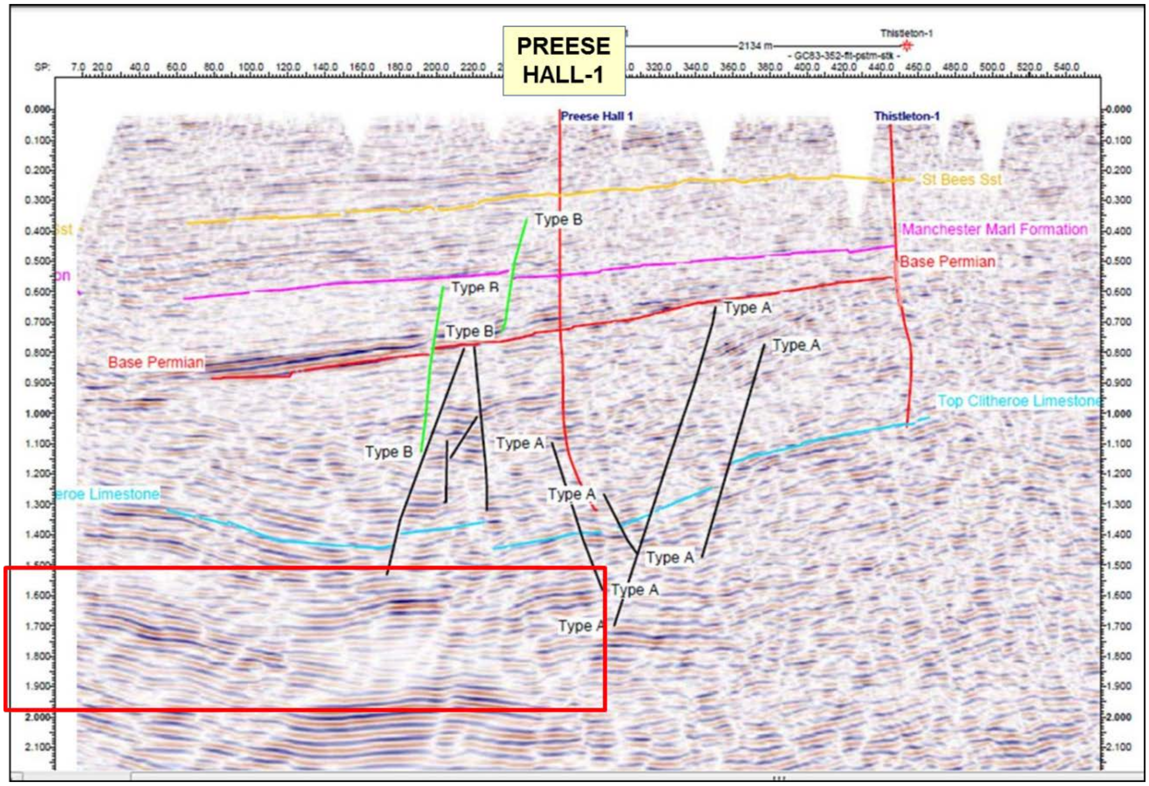
In August 2010 Cuadrilla drilled the UK's first shale gas exploration well, spudding the **Preese Hall-1** vertical well in the Bowland Sub-basin near Blackpool, Lancashire. The well was fracture stimulated during early 2011, inducing several dozen small earthquakes close to the downhole injection zone. The timing of the earthquakes corresponded with fluid injection and continued for several hours after injection ceased. Fortunately, the largest earthquakes were relatively small, measuring magnitudes of 2.3 and 1.5 on the Richter scale. No surface damage was reported. However, the UK government shut down shale testing in the country for 18 months to determine the cause of the seismic events and to develop mitigation rules.

An evaluation of seismicity from these earthquakes generated by the Preese Hall-1 well and the fault geometry of the basin indicated that movement was strike-slip along a sub-vertical fault plane. The suspected fault was located on the well's image log as well as on detailed seismic, Figure XI-4.[9] Separately, bedding plane slip -- already noted in core cut prior to running casing in the well -- induced wellbore damage, with oval deformation noted across several hundred feet of the 5.5-inch casing.

The maximum horizontal stress gradient, based on mini-frac and borehole breakout data, was determined to be relatively high at 1.25 psi/ft. The stress differential within the Bowland Shale -- about 4,000 psi -- was found to be an order of magnitude higher than in North American shale plays, which typically have stress differentials of only several hundred psi. It is unclear whether the high stress differential is local or widely prevalent across the UK.

Cuadrilla's consultants concluded that excess fluid pressure exerted on the fault during the hydraulic stimulation overcame the rock friction containing this stress, which enabled the fault to slip and generate small earthquakes. Simultaneously, bedding plane slip up the hole caused the well's casing string to deform. Based on fault size and geometry, the maximum earthquake in the Bowland Sub-basin was estimated to be approximately magnitude 3.0, still considered too small to cause significant damage to surface structures in this region.

Figure XI-4: Seismic Reflection Line Showing Suspected Active Faults
Near The Preese Hall-1 Well In The Bowland Sub-basin




Source: de Pater and Baisch, 2011

The consultants also inferred that the injected frac fluid remained contained within the induced fracture system and did not leak into the shallow freshwater aquifer system, because of the thick and impermeable Bowland Shale and overlying Permian anhydrites. A subsequent report recommended monitoring during hydraulic fracturing operations to help mitigate induced seismicity.[10]

As a result of the earthquakes the government halted shale operations in the UK from May 2011 until December 2012. The Royal Society and Royal Academy of Engineering conducted a review of the risks, recommending the following three primary steps for ensuring health and safety during shale development:[11]

- ***Groundwater Monitoring***. The BGS should conduct regional baseline surveys of groundwater ahead of shale development, while operators conduct site-specific surveys to identify possible natural methane concentrations in groundwater. Abandoned wells should be monitored and remediated to prevent fracture fluids from entering freshwater aquifers.

- ***Well Integrity***. Well design, construction, and integrity testing should ensure that multiple layers of steel and cement are present to preclude leakage of fluids into freshwater aquifers.

- ***Mitigating Seismicity.*** The BGS should survey the regional distribution of faults, stresses, and seismic hazards ahead of shale development, while operators conduct site-specific surveys. Seismicity should be monitored before, during, and after hydraulic stimulation, which should be shut down if seismic risks become unacceptable.

After considering these and other views, DECC put in place a new regulatory regime for shale development starting December 2012. The regime requires operators to evaluate potential seismic hazards posed by hydraulic fracturing, implement seismic monitoring of each individual well site area, and propose mitigation steps to minimize the chance of future earthquakes due to hydraulic fracturing. A real-time trigger is to be installed to cut off injection should significant earthquake risks arise. These rules are expected to add significant cost and time to drill shale wells in the UK. Cuadrilla's Anna's Road-1 well is the first to be spud under the new shale rules. Hydraulic stimulation of this well -- which Cuadrilla recently announced would be delayed until 2014 at the soonest -- would require further specific approvals.

## 1. NORTH UK CARBONIFEROUS SHALE REGION

### 1.1 Introduction and Geologic Setting

Northern England and southern Scotland are characterized by a complex assemblage of isolated basins and troughs which contain thick, organic-rich Carboniferous shales, Figure XI-1. These shale-prospective lows are separated by structural highs where Carboniferous was not deposited or has been eroded. Based on mapping of Carboniferous basins conducted by the BGS, these troughs cover a total area of approximately 10,000 mi$^2$.

The Bowland Sub-basin of Lancashire, where shale drilling has been concentrated thus far, is one such trough, representing the onshore margin of the petroliferous East Irish Sea Basin. Further to the east the Cleveland Basin is considered the onshore extension of the Southern North Sea gas basin. In between lay the Cheshire, West Lancashire, Northumberland, East Midlands, Pennine, Gainsborough, Midland Valley, and other basins and troughs containing Carboniferous-age shales. Our study grouped these isolated basins into a single region for shale resource assessment.

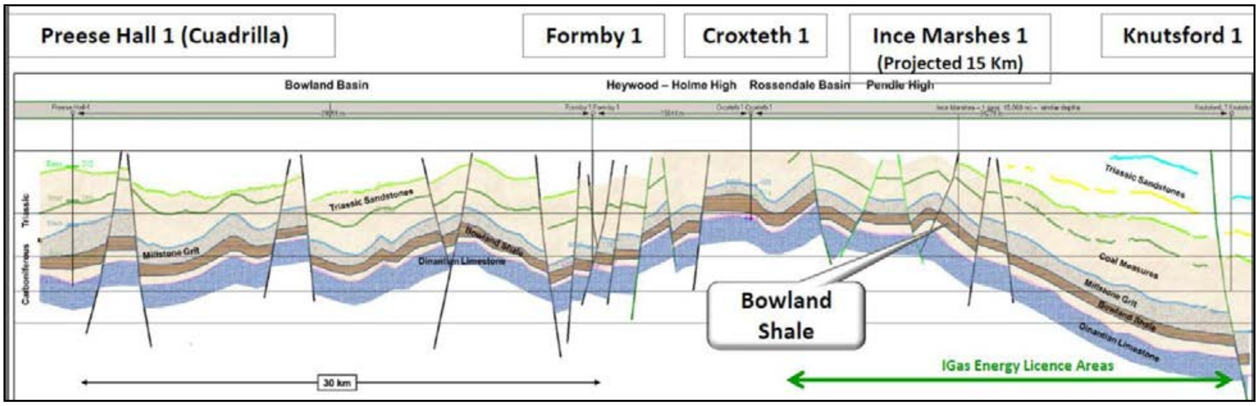
The western portion of the Bowland Sub-basin has been the site of all UK shale exploration drilling to date. The Carboniferous Bowland Shale is the main target, ranging from about 2.0 to 2.5 km deep across the moderately faulted Bowland Sub-basin, Figures XI-5 and XI-6. Cuadrilla's Preese Hall-1 well encountered the top of the target Lower Carboniferous Bowland Shale at a measured depth of 6,854 ft and penetrated a total 2,411 ft of organic-rich shale, Figure XI-**7**. The BGS has mapped the thickness of the Upper Bowland Shale Formation, as well as its organic-rich (high-gamma) section, across northern England, Figure XI-8. The organic-rich shale ranges up to 120 m thick but more typically is recorded as 20 to 40 m thick. Note, however, that petroleum wells are preferentially drilled on structural highs, where shale tends to be thinner than in the troughs.

The eastern Bowland Shale play extension in the Gainsborough Basin has less geologic control than the west. Here the shale ranges up to 300 m thick in the Dinantian half-graben basins, Figure XI-9. Dart Energy reported that the most organic-rich portion defined by high-gamma shales ranges up to 110 m thick. In the Cheshire Basin the Carboniferous (Namurian) Bowland and Holywell shales with TOC up to 5% occur at depths of 1 to 5 km, Figure XI-10.

Elsewhere in the region, the Namurian Holywell Shale, source rock for conventional oil fields in the southern East Irish Sea as well as the Formby oil field, is reported to have an overall average TOC of 2.1% (range 0.7% to 5%) and averages 3.0% TOC in its lower, more organic-rich portion. Clay content is uncertain, although public data indicate that Carboniferous mudstones in the UK generally average around 25% $Al_2O_3$ (range 12-38%), mostly from clay.

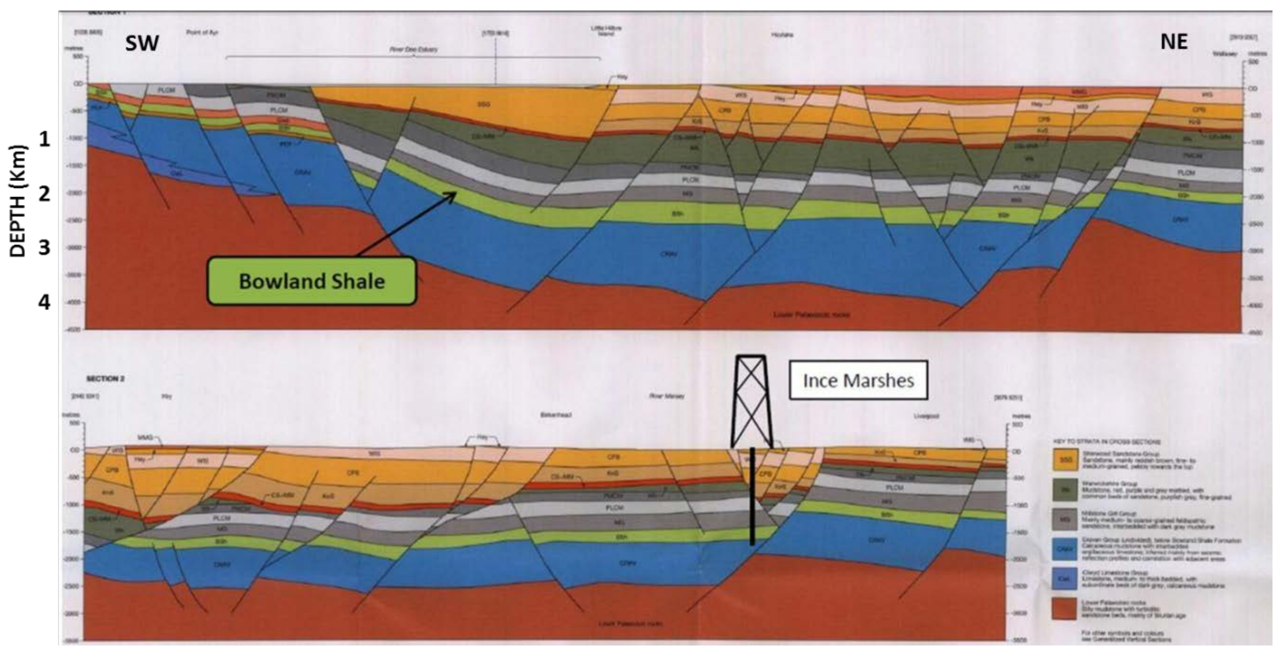
The Pennine Basin has relatively good geologic control from past petroleum exploration. The Craven Group (Mississippian) ranges from about 1.5 km thick in the Craven sub-basin to over 5 km thick in the Widmerpool Gulf. These mudstones were deposited in distal slope turbidite and hemipelagic environments in relatively narrow, deep depocenters. The early Namurian shale units (local names Bowland, Edale, Holywell shales, top part of Craven Group) of the Pennine Basin have high TOC and are known to have sourced hydrocarbons. These Namurian marine shales generally have rich TOC in excess of 4%.

Figure XI-5: Structural Cross-Section in the Bowland Sub-basin Region, Northwest UK Showing Numerous Faults Across the Cuadrilla and IGas Energy Licenses.



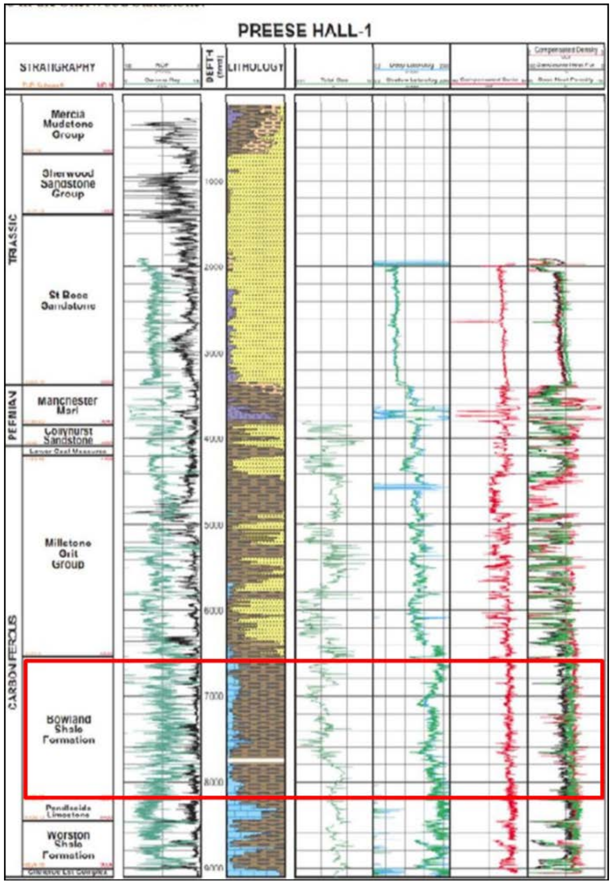

Source: Source: IGAS Energy, 2012

Figure XI-6: Structural Cross-Section In The Bowland Sub-basin Region Showing The Highly Faulted Bowland Shale At 2 To 3 Km Depth. Additional Faults Penetrated By The Ince Marshes Well Suggest That Many Additional Faults Are Present But Unrecognized.



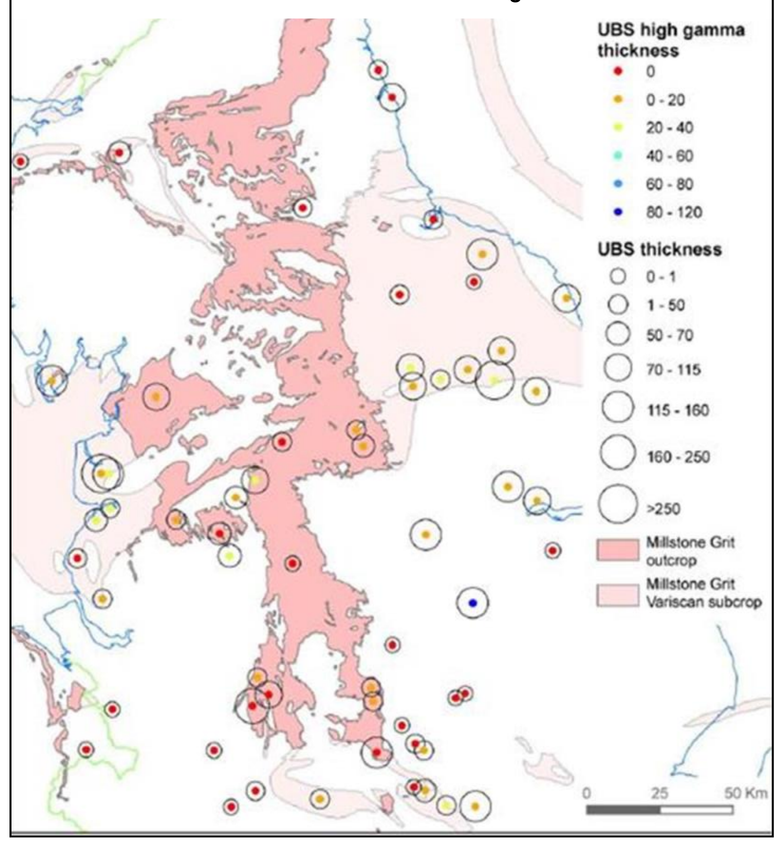

Source: IGAS Energy, 2012; modified from BGS Map 96_Liverpool

Figure XI-7: Stratigraphic Column and Composite Log for the Cuadrilla Preese Hall-1 well in the Bowland Sub-Basin



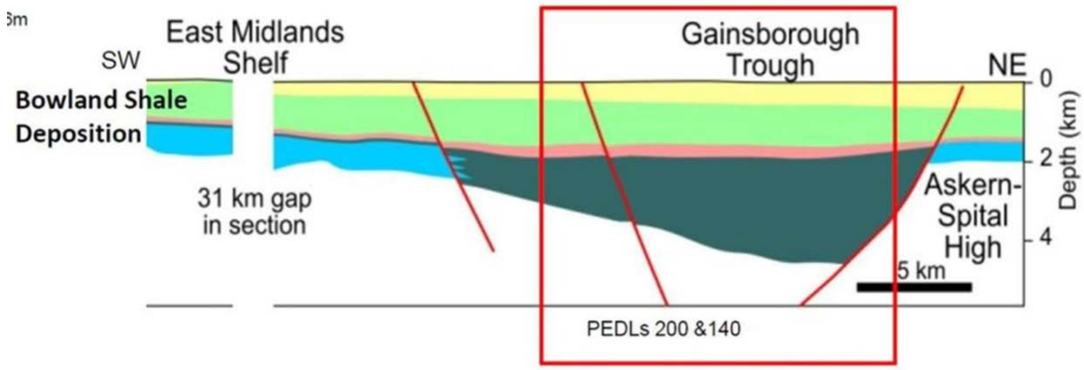

Source: de Pater and Baisch, 2011

Figure XI-8: Thickness of the Upper Bowland Shale Formation in Northern England, as Well as the High-Gamma Thickness. Note That Petroleum Wells Tend to be Drilled on Structural Highs Where the Shale May be Thinner Than in the Troughs.



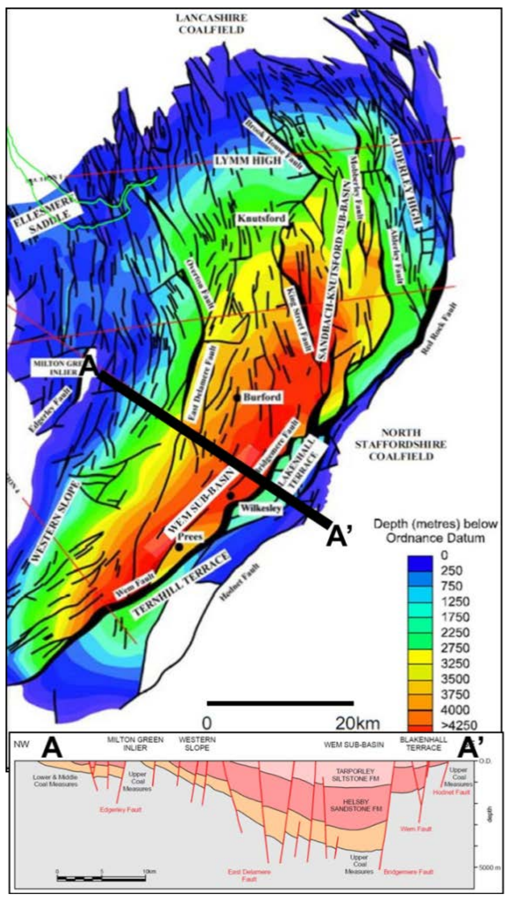

Source: Smith et al., 2010

Figure XI-9: Schematic Cross-Section Across The Gainsborough Trough Showing Thick Bowland Shale. Additional Faults Are Likely To Be Present But Not Shown.




Source: Dart Energy, 2013

Figure XI-10: Geologic Map and Generalized Structural Cross-Section of the Cheshire Basin. Carboniferous (Namurian) Bowland and Holywell Shales with TOC Up to 5% Occur at Depths of 1 to 5 km.




Source: DECC, 2012

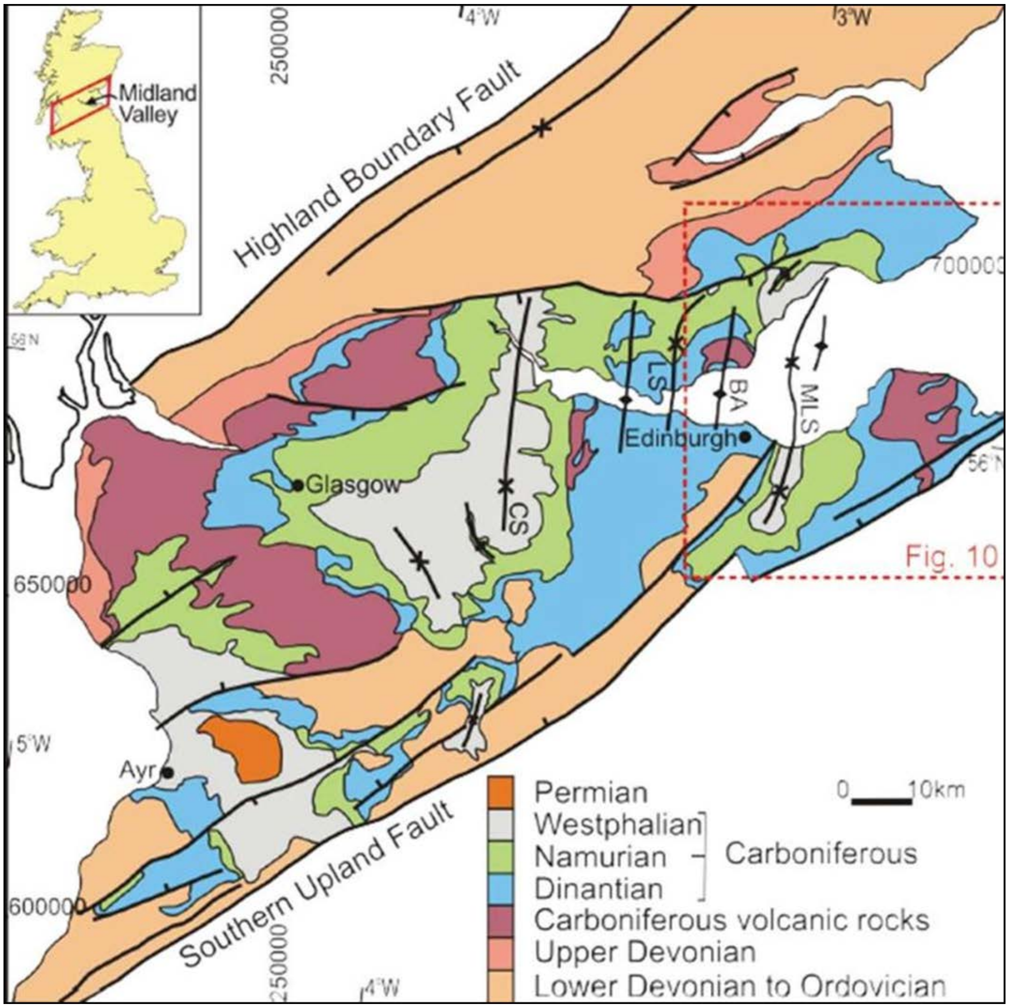
The North UK Carboniferous Shale region is mainly in the dry gas window. For example, the Normanby-1 and Grove-3 conventional petroleum wells reportedly recorded high-gamma sections within the Bowland Shale, while the Scaftworth-B2 well measured 2.07% to 3.63% TOC with 1.26% $R_o$ at a depth of 2,246 m.[12] In addition, most of the Cleveland Basin is known to be within the dry gas window. Oil and wet gas thermal maturity windows may be present locally but could not be defined with the limited data available.

No porosity data are available for Namurian shales in the Pennine Basin. Based on boreholes drilled by the BGS in the southern Midlands, relatively shallow (900 m deep) Upper Paleozoic shales retained high porosities (5-10%). However, porosity is likely to be considerably lower (perhaps 3-5%) at typical target shale depth of 2-4 km.

The Midland Valley Basin (MVB), a large east-northeast trending graben complex that stretches across southern Scotland, is bounded by the Highland Boundary Fault to the northwest and the Southern Upland Fault to the southeast. The MVB comprises a complex series of small faulted sub-basins, such as the Kinkardine Basin where Dart Energy is evaluating shale gas resources. This structural complexity was over-printed by extensive igneous intrusion during late Carboniferous to early Permian time.

The MVB contains a relatively complete sequence of Carboniferous deposits up to 6 km thick, Figure XI-11.[13] Namurian strata range from 450 m to 1,400 m thick at outcrop. The depositional sequence reflects mixed marine shelf carbonate and deltaic successions, comprising upward-coarsening cycles of marine limestone, mudstone, siltstone and sandstone.[14] Lower Carboniferous (Dinantian) oil-shale source rocks, such as the Mid-Lothian Oil shale, buried deeply in the Midlothian-Leven Syncline generated waxy crude oil that sourced clastic reservoirs of similar age in the adjacent anticlines.

Figure XI-11: Geologic Map of the Midland Valley Basin. Carboniferous (Namurian) Shales Crop Out at the Surface but May Reach Prospective Depth.




Source: Underhill et al., 2009

## 1.2 Reservoir Properties (Prospective Area)

The total mapped deep Carboniferous area in the North UK Carboniferous Shale region is approximately 10,200 mi$^2$. Because of structural complexity and poor depth control was poor, only half of the total area was assumed to be in the prospective depth window and relatively unfaulted (4,635 mi$^2$). The target lower organic-rich portion of the Bowland and Holywell shales (and local equivalents) averages about 300 ft thick and 8,000 ft deep in the Bowland Sub-basin region, with 3.0% average TOC. Porosity is estimated to be about 4% at target depths of 3 km, much lower than the 5-10% measured at shallow <1 km depth. Thermal maturity is mainly in the dry gas window ($R_o$ 1.3%), although less mature pockets in the wet gas window may exist.

## 1.3 Resource Assessment

Risked, technically recoverable shale gas resources in the North UK Carboniferous Shale region are estimated to be 25 Tcf, out of a risked shale gas in-place of 126 Tcf, Table XI-1. The play has a favorable net resource concentration of about 117 Bcf/mi$^2$, reflecting the significant thickness of organic-rich shale.

For comparison, in September 2011 Cuadrilla Resources estimated the total shale gas in-place within its Bowland Sub-basin licenses to be approximately 200 Tcf, based on logs and core from two shale and three conventional petroleum wells.[15] The company has estimated the total shale gas resource-in-place concentration at its Preese Hall-1 well to be 539 Bcf/mi$^2$. Cuadrilla's estimate is that 10% or about 20 Tcf may be recoverable. It appears that Cuadrilla's estimate is based on the entire shale section, whereas EIA/ARI considers only the lower, most organic-rich section as the prospective interval.

Separately, IGAS Energy's independent consultant identified a 1,195-km$^2$ prospective area within an average 250-m thick organic-rich interval, constrained by geophysical logs from eight conventional petroleum wells that penetrated the Bowland Shale. After drilling its first shale appraisal well last year, IGAS estimated the shale gas in-place (GIP) resources within its licenses to be about 9.2 Tcf.

Dart Energy's third-party consultant NSAI has estimated that Dart's licenses have some 32.46 Tcf of GIP in unspecified shale formations in the Gainsborough Trough of East Midlands, as well as 30.55 Tcf of shale gas GIP in the Cheshire Basin (gross, Best Estimate). No recovery estimate was reported.[16] Finally, in Scotland's Midland Valley Basin, Dart Energy reported that the company's PEDL 133 license has an estimated 2.5 Tcf of shale gas GIP based on a third-party consultant report. Recoverable prospective shale gas resources were estimated at 115 Bcf in the Carboniferous Black Metal Shale and 255 Bcf in the Lothian-Broxburn Shale (Best Estimates; net to Dart).

## 1.4 Recent Activity

The Bowland Sub-basin, the only active shale drilling region in the UK, has had five shale exploration wells drilled to date. The main operators are Cuadrilla Resources (4 licenses totaling 1185 km$^2$; 4 wells), IGAS Resources (14 licenses; 1363 km$^2$; 1 well), and Dart Energy (11 licenses; 1041 km$^2$).

In August 2010 Cuadrilla drilled the first shale gas exploration well in the UK, spudding the **Preese Hall-1** vertical well in the Bowland Sub-basin near Blackpool, Lancashire. The top of the target Lower Carboniferous Bowland Shale was encountered at a measured depth of 6,854 ft. The well penetrated a total 2,411 ft of organic-rich shale. Naturally fractured, the Bowland is within the dry gas thermal maturity window.

After drilling was completed on the Preese Hall-1, Cuadrilla completed and fracture stimulated the well in early 2011. This operation represented the UK's first and only concerted attempt to produce shale gas. As previously discussed, small earthquakes were induced near the well by the hydraulic fracture stimulation. Operations at the well were halted in May 2011 with no gas production reported.

In completing the well, Cuadrilla perforated shale formations within the Bowland Shale, Worston Shale, and Hodder Mudstone at depths ranging from 7,670 to 8,949 ft. Five shale zones, out of 12 originally planned, were individually stimulated with a sand/water slurry, separated by bridge plugs. The total stimulation size, over 50,000 bbl of water and 400 t of sand proppant, was relatively large for a vertical shale well but still considerably smaller than the typical stimulation of a horizontal shale well in North America (about half the water volume and 10% of the sand volume).

Cuadrilla drilled and cored two other vertical wells in the Bowland Basin. During 2H 2010 the nearby **Grange Hill-1** vertical well logged over 2 km of Carboniferous shale across the depth interval of 1,200 m to 3,300 m, the total depth of the well. In 2011 the **Becconshall-1** well logged shale from depths of 2,450 m to 3,100 m, the total depth of the well.

Cuadrilla's most recent shale well in the Bowland Sub-basin, the **Anna's Road-1**, was abandoned at a depth of 2,000 ft due to drilling problems. The well was expected to be re-spud in January 2013 and completed in about four weeks, with the top Bowland Shale predicted at a depth of about 3100 m.

**IGAS Energy Plc**, 24.5% owned by Nexen and the UK's largest onshore operator of oil and gas fields, is evaluating the shale gas potential of its blocks. IGAS had acquired Nexen's portfolio of UK coalbed methane licenses in March 2011. The company reported that at its Point of Ayr acreage has shale extending over the entire block with an expected average thickness of more than 800 ft. IGAS Energy noted that a significant proportion of its acreage in the northwest England—from Ellesmere Port in the west in PEDL 190 to the Trafford Centre in the east within PEDL 193—is considered to have shale potential.

In 2011-12 IGAS drilled the **Ince Marshes-1** well to a total depth of 5,714 ft in the Bowland Sub-basin. Originally intended as a shallow coalbed methane test, the well was deepened and encountered the upper two-thirds of the Bowland Shale at depths of 4,200 to 5,200 ft. The Bowland Shale, estimated at 1,600-ft total thickness, had gas shows and TOC ranging from 1.2% to 6.9% (average 2.7%). Thermal maturity appeared to be in the wet gas window ($R_o$ 1.0-1.1%).[17]

**Dart Energy**, based in Australia and Singapore, holds a significant shale position in the UK, including the western Pennine Basin, but has not yet drilled for shale there or elsewhere in the country. Dart's 14 PEDL's with shale potential, part of its acquisitions of coalbed methane operators Composite and Greenpark Energy, total about 3,700 km$^2$ in gross area. Third-party consultant NSAI has estimated these blocks hold approximately 65 Tcf of total shale GIP, of which approximately 30.5 Tcf is located in the western Pennine Basin (gross, Best Estimate).

No shale drilling has occurred yet on the eastern side of the Bowland Shale Region. Dart Energy holds the largest land position, a total of 13 licenses covering about 1,235 km$^2$. NSAI has estimated that Dart's blocks hold about 47.6 Tcf of shale GIP (gross, Best Estimate). Houston-based eCORP International, LLC has committed to drilling and coring a horizontal well by 2014 to farm into one of Dart's blocks. Separately, IGAS estimates it holds 388 km$^2$ of shale-prospective area in 9 licenses in this region.

Dart Energy, the only active shale operator in the Midland Valley Basin, has not announced firm plans for shale drilling. BG Group remains a joint-venture partner on Dart's Lothian Shale interval in this region.

Much further to the south, Australia-based **Eden Energy** and UK-based **Coastal Oil and Gas Ltd.** jointly control 2100 km$^2$ of shale gas and coalbed methane potential in South Wales, Bristol, and Kent. Prospective recoverable shale gas resources were estimated by Eden's third-party consultant to be 18.3 Tcf out of a total 49.8 Tcf of GIP (gross; Best Estimate). This includes 806 km$^2$ within 7 PEDLs in South Wales with potential in the Namurian Measures. However, this region was not assessed by EIA/ARI because of limited publicly available data.

## 2. SOUTH UK JURASSIC SHALE REGION

### 2.1 Introduction and Geologic Setting

The Wessex and Weald basins region of southern England is the UK's principal onshore oil-producing area. Both basins produce oil and some natural gas from conventional Jurassic and Triassic clastic and carbonate reservoirs which were sourced by Jurassic marine shales. The Wessex Basin hosts the 500 million bbl Wytch Farm oil field, by far the country's largest onshore field, whereas the Weald Basin has several much smaller oil fields.

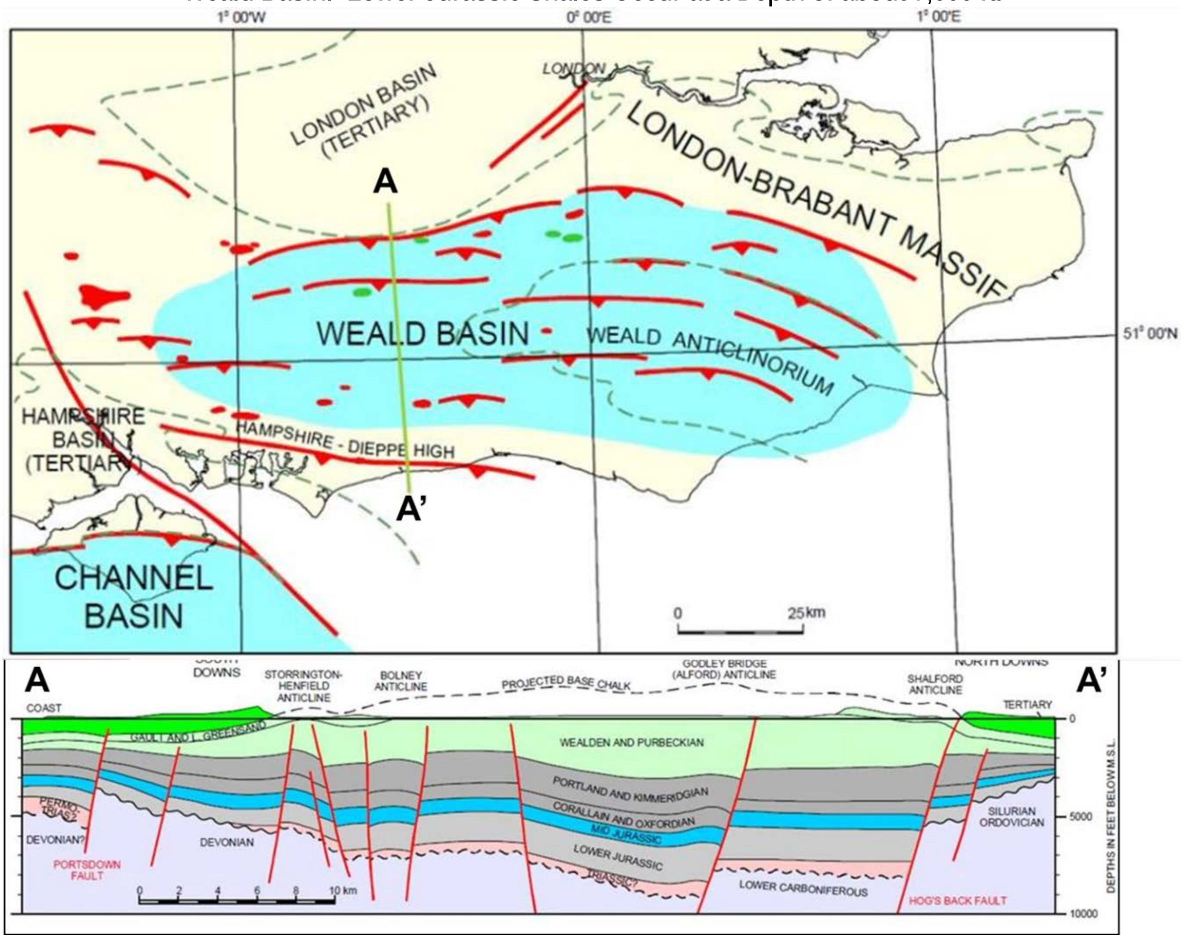
The Wessex Basin comprises a series of post-Variscan extensional sedimentary troughs and intra-basinal highs, located mainly in Hampshire and Dorset and extending into adjacent offshore areas. The Weald Basin is a better defined and structurally simpler syncline located in Sussex, Surrey, and Kent. The basins are separated by the Hampshire-Dieppe High, but the boundary is indistinct and the two basins were intermittently connected during Mesozoic deposition. They contain repeating cycles of Jurassic shallow-water marine mudrocks, sandstones, and limestones which are overlain by largely non-marine sediments of the Lower Cretaceous Wealden Group.

For the purpose of this study, the Wessex and Weald basins are considered a single Jurassic oil-prone shale resource region. Additional Jurassic shale areas with affinity to the Wessex Basin may exist further to the west (e.g., Bristol Channel Basin), but these were not assessed.[18]

The structural geology of the Wessex and Weald basins is somewhat simpler than most other UK shale regions, although still more complex and faulted than North American shale plays. While not intensively deformed, these basins comprise a series of individual sub-basins separated by normal faults. For example, the Wessex Basin comprises four smaller half-grabens (Pewsey, Mere-Portsdown, Dorset and Channel).

Figure XI-12 shows that roughly 10,000-ft thick of Lower Carboniferous to Tertiary sedimentary rocks is present in the Weald Basin. Lower Jurassic organic-rich shales reach depths of about 7,000 ft or more along the basin axis. Interior faults appear to be relatively few, spaced about 5 to 10 km apart, and seemingly allow ample room for shale development. The strata dip quite gently, only a few degrees.

Figure XI-12: Geologic Map and Generalized Structural Cross-Section of the Weald Basin. Lower Jurassic Shales Occur at a Depth of about 7,000 ft.

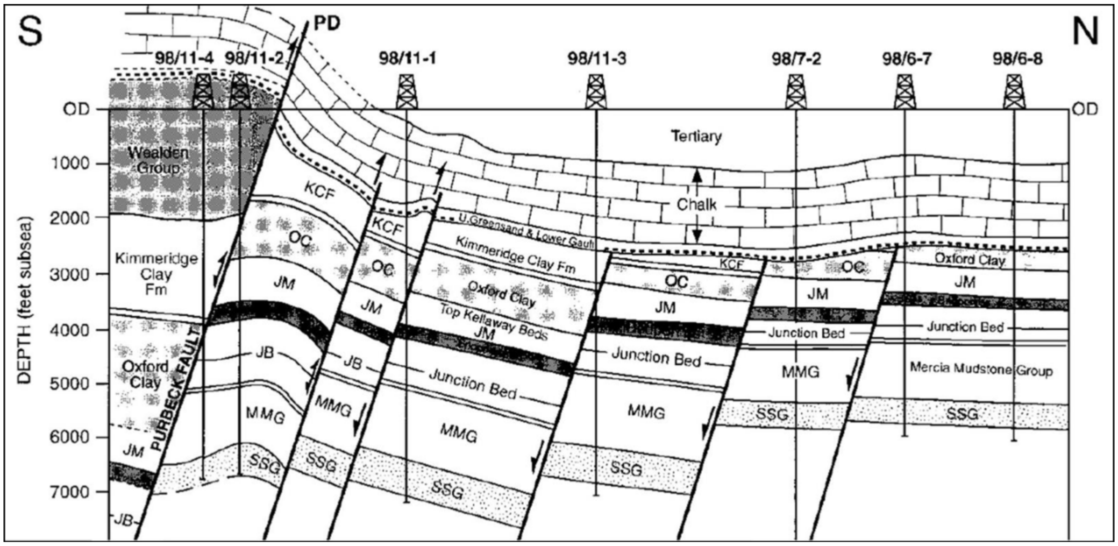



Source: DTI, 2003

However, close-spaced drilling often reveals the presence of additional faults. Indeed, a detailed cross-section of the southern portion of the Wessex Basin, constrained by multiple wells, shows a series of closely spaced faults, Figure XI-13. The depth to the Lias (JB) in this offshore setting south of Wytch oil field ranges from 4,000 to 5,000 ft. Note how each well is located in a separate fault block. Further drilling is likely to discover additional faults.

The Jurassic section comprises an alternating sequence of organic-rich mudstones and carbonates with subordinate sandstones. The main source rocks and potential shale targets in this region are several Jurassic-age shale formations, which are mainly oil-prone in deeper settings (immature elsewhere), in contrast with the mostly dry-gas prone Carboniferous shales of northern England and Scotland.

Figure XI-13: Structural Cross-Section of a 9-Mile Long Portion of the Wessex Basin, Located Offshore Just South of Wytch Oil Field, Showing Depth to the Lias (JB) Ranging from 4,000 to 5,000 ft. Note How Each Well is Located in a Separate Fault Block and Further Drilling is Likely to Discover Additional Faults.




Source: Underhill and Paterson, 1998

The Lias, Kimmeridge, and Oxford clays contain Types II (algal sapropelic), III (terrestrial plant), and II/III (mixed or degraded) kerogen sources. Thermal maturity is highly variable, dependent upon the complex structural evolution of the basins. In general, thermal maturity increases towards the centers of the Wessex and Weald basins, where it reaches adequate rank for shale oil exploration.

The Lower Lias Clays (L. Jurassic), the most important source rock in the region as well as the main shale target, consists of interbedded shales, mudstones, marls and micritic limestones. Lower Lias shales contain 0.5% to 2.1% TOC, reaching as high as 7%. The isotopic character of conventional oils in the Weald Basin (35-42° API gravity) matches with that of the Lower Liassic, indicating close source rock genesis. Organic matter is predominantly sapropelic oil-prone kerogen derived from marine plankton.[19] While vertical TOC variation is considerable, the eastern Weald Basin appears to have lower TOC.

The Arreton 2 well, a key data point located south of the Isle of Wight monocline, recorded oil-prone thermal maturity of 0.8% to 0.9% $R_o$ in the Lias. Similar oil-prone maturity was noted at Penshurst in the central Weald Basin. Thermal maturity modeling indicates that the Lias is within the oil window across much of the Wessex-Channel Basin, perhaps becoming marginally gas-prone in the Pewsey Sub-Basin.

Secondary potential exists in the Oxford (up to 12% TOC) and Kimmeridge clays (up to 20% TOC) in the Upper Jurassic. The Upper Jurassic Kimmeridge Clay consists of alternating shales (including oil shales), calcareous mudstones, interbedded micritic limestones, and thin sandstones and siltstones. The TOC of some thin black shales frequently reaches 10%, occasionally even 20%. Britain's first natural gas well, drilled in 1895 at Heathfield in Sussex, produced 1,000 $ft^3$/d from an unstimulated Kimmeridge Clay section. However, the Kimmeridge Clay is considered thermally immature in the Wessex-Weald region, apart possibly from the northernmost axial part of the Wessex-Channel Basin. The Upper Jurassic Oxford Clay is organic-rich, reaching 10% TOC, but likewise is thermally immature. Consequently, the Kimmeridge and Oxford clays were excluded from our evaluation.

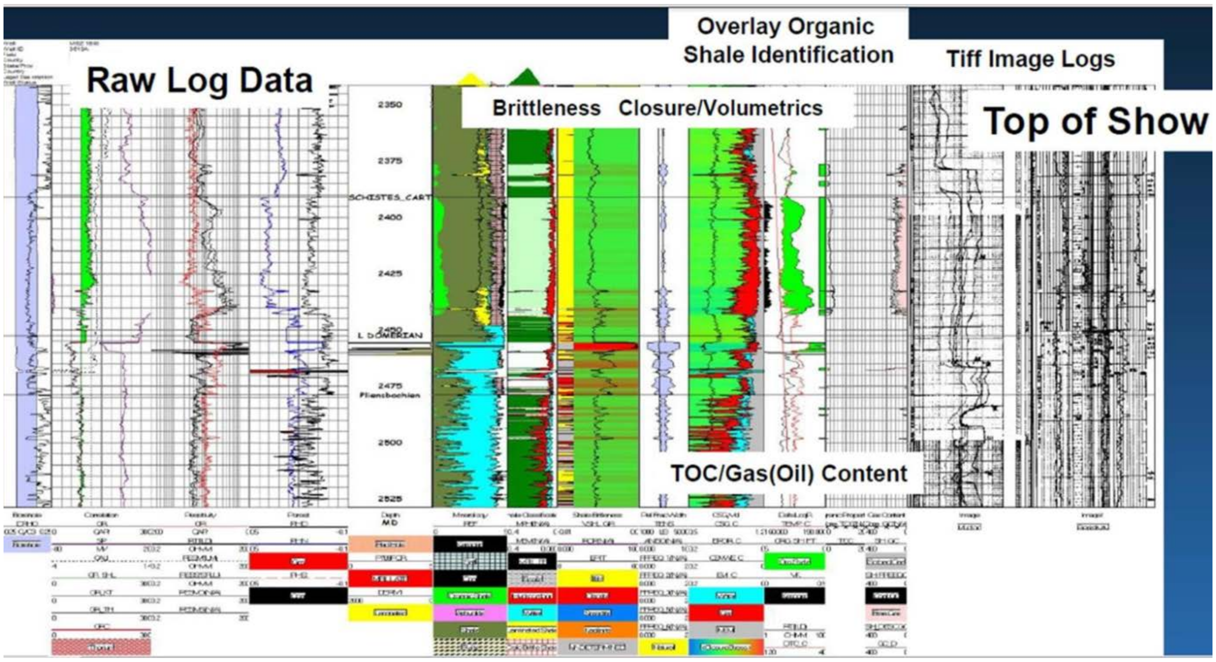
Porosity and permeability of the Jurassic shales are likely to be higher than in the Carboniferous because they have not been subject to as much compaction. Jurassic mudstones encountered in shallow (<30 m) engineering boreholes have porosities in the range 30-40%. However, Jurassic shales buried at depths of 1-5 km are likely to have much lower porosity, perhaps 7%.

## 2.2 Reservoir Properties (Prospective Area)

The Lias shales average about 600 thick (gross) in the Wessex and Weald basins. Organic-rich thickness of the most oil-saturated and brittle zones, based on analysis of the Lias in the Paris Basin,[20] is estimated at approximately 165 ft, Figure XI-14. Depth to the Lias reaches 6,000 ft in the Weald Basin, averaging about 5,000 ft deep. TOC of the prospective zone is estimated to average 3% but could be considerably higher. Porosity, estimated at 7%, is likely to be higher than older Carboniferous shales, but lower than the 30-40% porosity measured at shallow locations near outcrop.[21] The current average geothermal gradient is 33°C/km.

Although not assessed, the Jurassic Kimmeridge Clay, another potential source rock in the Wessex and Weald basins, is notable for containing thin limestone stringers. These include coccolithic carbonates which are somewhat similar to the lithology of the carbonate-rich Mid-Bakken Shale in North Dakota.

Figure XI-14: Log Suite Showing the Jurassic Lias In the Paris Basin, as a Proxy for the Wessex-Weald Shale Region in the UK




Source: M. Mullen, Realm Energy, 2011

## 2.3 Resource Assessment

The Wessex and Weald basins extend over an onshore area of approximately 3,500 mi$^2$. The prospective area was estimated to be half of total area (1,740 mi$^2$), with the remaining area excluded due to potential faulting, shallow depth, erosion of the Lias, and surface access issues. Out of a risked shale oil in-place of 17 Bbbl and risked shale gas in-place of 8 Tcf, the risked, technically recoverable resources are estimated to be 0.7 billion barrels of shale oil and 0.6 Tcf of associated shale gas, Tables XI-1 and XI-2.

Celtique Energie has reported that the Liassic Shale at their Weald Basin licenses ranges from 9,000 to 13,000 ft deep within a 467-km$^2$ prospective area. The company estimated that the Liassic could have mean recoverable shale oil and shale gas resources of 125 million barrels of oil and 10 Tcf of shale gas.

## 2.4 Recent Activity

Privately held **Celtique Energie** holds licenses in three areas of the UK: the Cheshire Basin, East Midlands, and the Weald Basin. In the Weald Basin, Celtique has a 50% share in licenses covering 1,000 sq km. The company claims to have unconventional oil and gas potential in the Jurassic Liassic shales, as well as conventional potential in the Triassic. No shale drilling has been reported.

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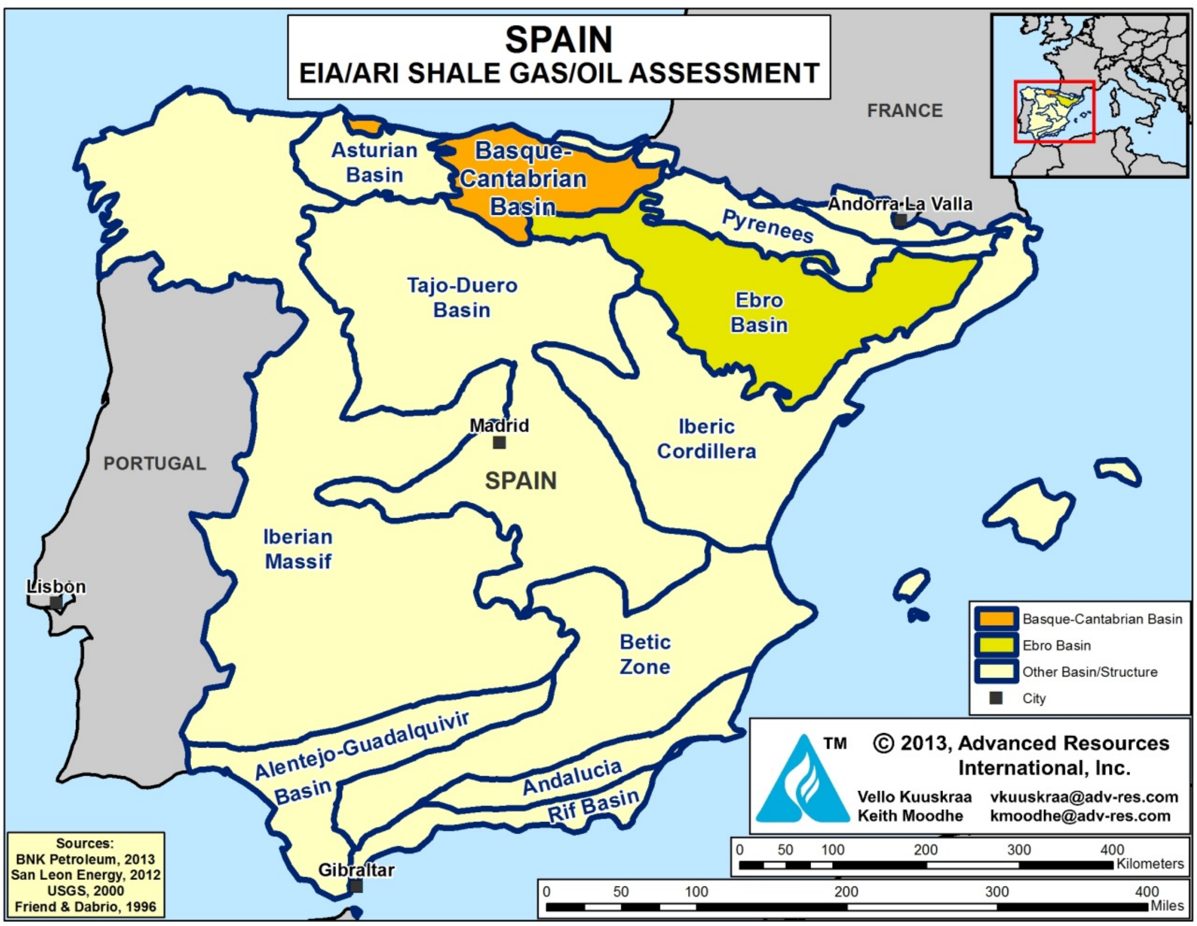
# XII. SPAIN

## SUMMARY

The Basque-Cantabrian Basin, located in northern Spain, contains a series of organic-rich Jurassic-age shales with potential for wet gas and condensate, Figure XII-1. In addition, the Ebro (Solsona) Basin, located to the south and east of the Basque-Cantabrian Basin, may also have local potential for shale gas and oil. However, the shale in the Ebro Basin has TOC below the 2% cut-off used in this study and thus was not quantitatively assessed.

Figure XII-1. Selected Shale Gas and Oil Basins of Spain




Source: ARI, 2013

The Jurassic-age (Liassic) marine shale in the Basque-Cantabrian Basin contains an estimated 42 Tcf of risked shale gas resource in-place, with about 8 Tcf as the risked, technically recoverable shale gas resource, Table XII-1. In addition, the Jurassic Lias Shale contains nearly 3 billion barrels of risked oil/condensate in-place, with about 0.1 billion barrels as the risked, technically recoverable shale oil resource, Table XII-2.

Table XII-1. Shale Gas Reservoir Properties and Resources of Spain

| | | | |
|---|---|---|---|
| Basic Data | Basin/Gross Area | | Basque-Cantabrian (6,620 mi²) |
| | Shale Formation | | Jurassic |
| | Geologic Age | | L. - M. Jurassic |
| | Depositional Environment | | Marine |
| Physical Extent | Prospective Area (mi²) | | 2,100 |
| | Thickness (ft) | Organically Rich | 600 |
| | | Net | 150 |
| | Depth (ft) | Interval | 8,000 - 14,500 |
| | | Average | 11,000 |
| Reservoir Properties | Reservoir Pressure | | Slightly Overpress. |
| | Average TOC (wt. %) | | 3.0% |
| | Thermal Maturity (% Ro) | | 1.15% |
| | Clay Content | | Medium |
| Resource | Gas Phase | | Wet Gas |
| | GIP Concentration (Bcf/mi²) | | 49.8 |
| | Risked GIP (Tcf) | | 41.8 |
| | Risked Recoverable (Tcf) | | 8.4 |

Source: ARI, 2013

Table XII-2. Shale Oil Reservoir Properties and Resources of Spain

| | | | |
|---|---|---|---|
| Basic Data | Basin/Gross Area | | Basque-Cantabrian (6,620 mi²) |
| | Shale Formation | | Jurassic |
| | Geologic Age | | L. - M. Jurassic |
| | Depositional Environment | | Marine |
| Physical Extent | Prospective Area (mi²) | | 2,100 |
| | Thickness (ft) | Organically Rich | 600 |
| | | Net | 150 |
| | Depth (ft) | Interval | 8,000 - 14,500 |
| | | Average | 11,000 |
| Reservoir Properties | Reservoir Pressure | | Slightly Overpress. |
| | Average TOC (wt. %) | | 3.0% |
| | Thermal Maturity (% Ro) | | 1.15% |
| | Clay Content | | Medium |
| Resource | Oil Phase | | Condensate |
| | OIP Concentration (MMbbl/mi²) | | 3.4 |
| | Risked OIP (B bbl) | | 2.9 |
| | Risked Recoverable (B bbl) | | 0.14 |

Source: ARI, 2013

## INTRODUCTION

The Jurassic-age rocks of the Basque-Cantabrian Basin crop out in the eastern and western portion of the basin, providing access to valuable information on the geologic setting and reservoir properties of these shales. Analysis of rock samples indicates Type I/II organic matter with TOC values (in immature samples) of up to 25%.[1]

The shales in the Lower Jurassic Comino and Castillo Pedroso formations (Toarcian- and Pliensbachian-age) were deposited under deep marine conditions following tectonic extension. The shales are interbedded within limestones and marls which, much like in the Bakken Shale of the Williston Basin (USA), may provide additional flow and storage capacity for oil and gas expulsed from the maturing shales.[1,2]

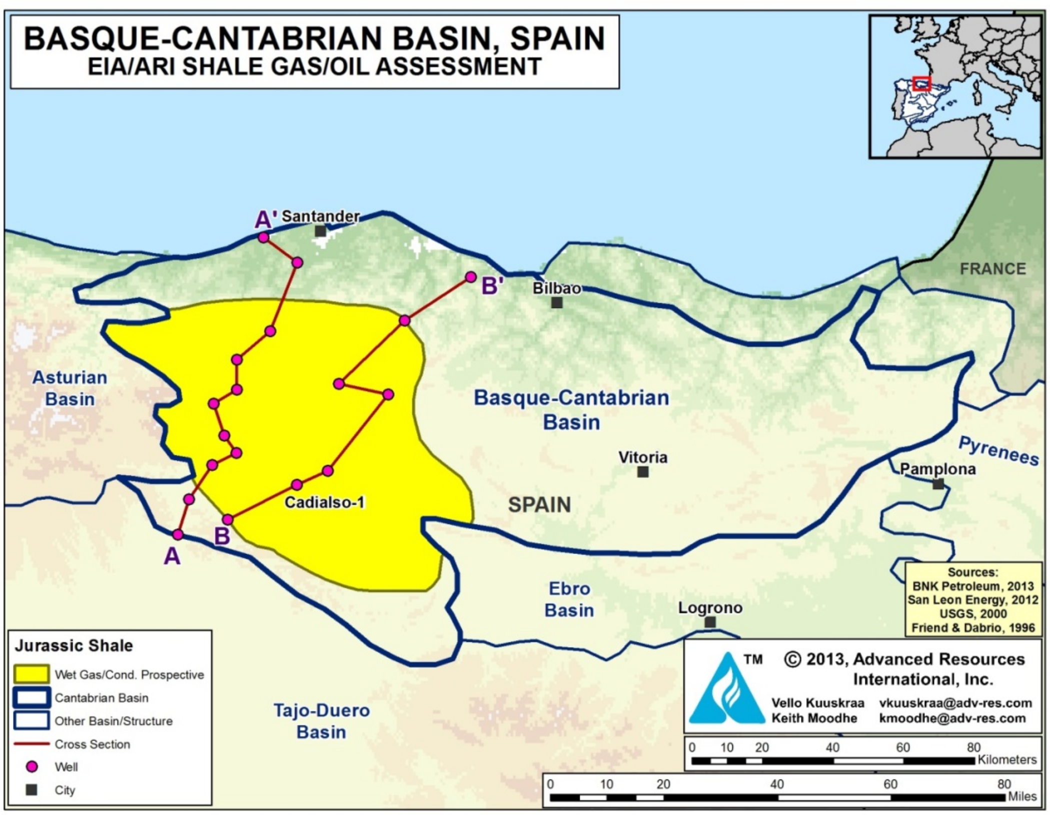
## 1. BASQUE-CANTABRIAN BASIN

The Basque-Cantabrian Basin covers a large 6,620-mi$^2$ area along the northern border of Spain. The basin is bounded by faults and thrusts on the east, west and south and by the Cantabrian Sea on the north. The Basque-Cantabrian Basin contains a sequence of formations that hold organic-rich shales of Silurian-Ordovician, Jurassic and Cretaceous age. Of these, the Jurassic (Liassic) shales appear to offer the most potential.

### 1.1 Geologic Setting

***Jurassic Shales.*** The Basque-Cantabrian Basin contains a series of regionally significant, thick black shales of Jurassic-age, including the Lias Shale at the base of the Lower Jurassic. We have mapped a 2,100-mi$^2$ higher quality prospective area for the Lias Shale in the western portion of this geologically complex basin. We used information on the erosion of the Lias Shale on the north and south and the 400-m gross Jurassic interval to establish our prospective area, Figure XII-2.[3]

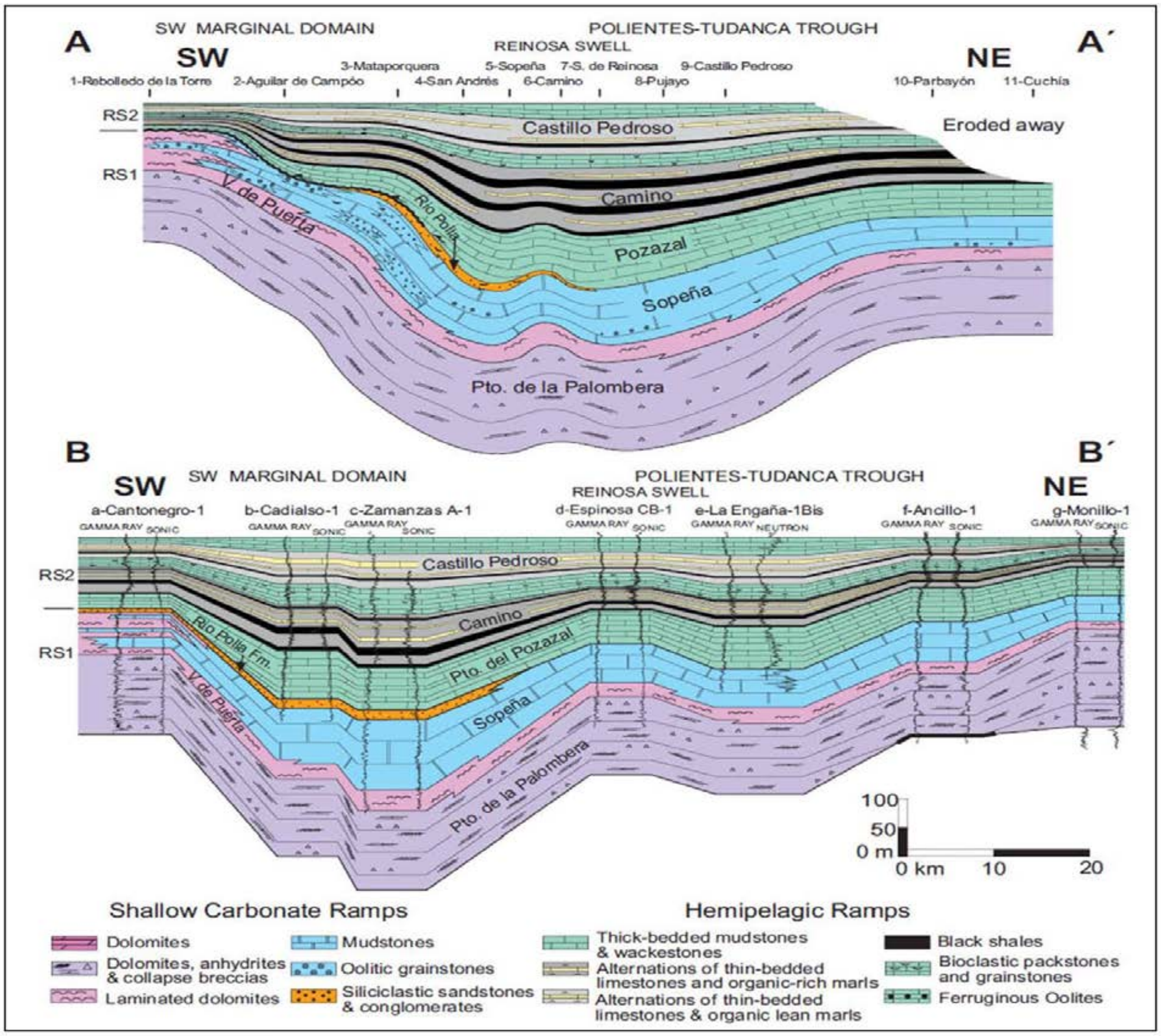
Figure XII-2. Prospective Area of Jurassic Shale, Basque-Cantabrian Basin




Source: ARI, 2013

A series of interbedded black shales and carbonates exists within the Jurassic interval. Figure XII-3 provides two regional cross-sections, A to A' and B to B', identifying the sequence of Jurassic black shales in the prospective area of the basin. Figure XII-2, shown previously, provides the location of these two cross-sections and identifies the key Cadialso-1 well near the south-western end of cross-section B to B'.

Figure XII-3. Cross-Sections Through Prospective Area of Basque-Cantabrian Basin



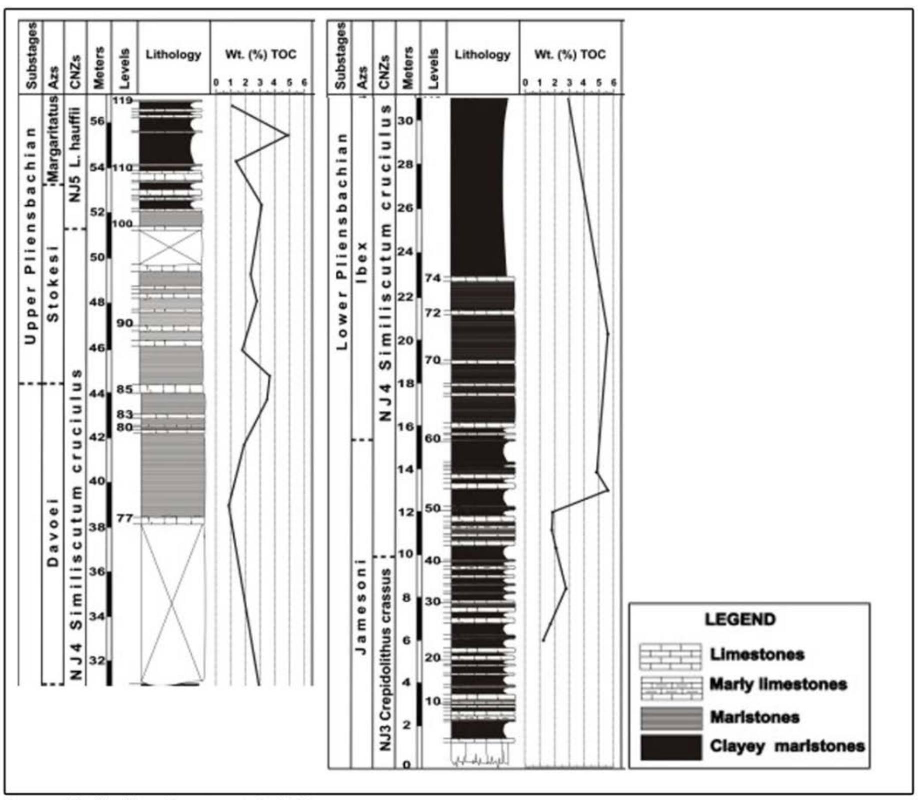

Source: Quesada, S., 2005.

## 1.2 Reservoir Properties (Prospective Area)

***Jurassic (Liassic) Shales.*** The Cadialos-1 well (shown on Cross-Section B-B'), drilled to 12,000 ft, provided valuable information on the organic-rich Lias Shale. The shale has a gross thickness of 280 ft with a net thickness of 30 to 50 ft, TOC values of 2% to 4% and a thermal maturity ($R_o$) of 1.2%. The well also intersected a shallower Jurassic Shale at about 9,500 ft with a gross thickness of 400 ft and a net thickness of about 100 ft. This shallower Jurassic Shale has a TOC of about 2% and a thermal maturity ($R_o$) of 1.1%.

Figures XII-4 and XII-5 provide additional information on the TOC and thermal maturity values for the Jurassic (Pliensbachian) Lias Shale in the northern portion of the prospective area near the Poliente-Tudanca Trough.[4,5,6]

Figure XII-4. TOC Values in the Pliensbachian Interval of the Jurassic

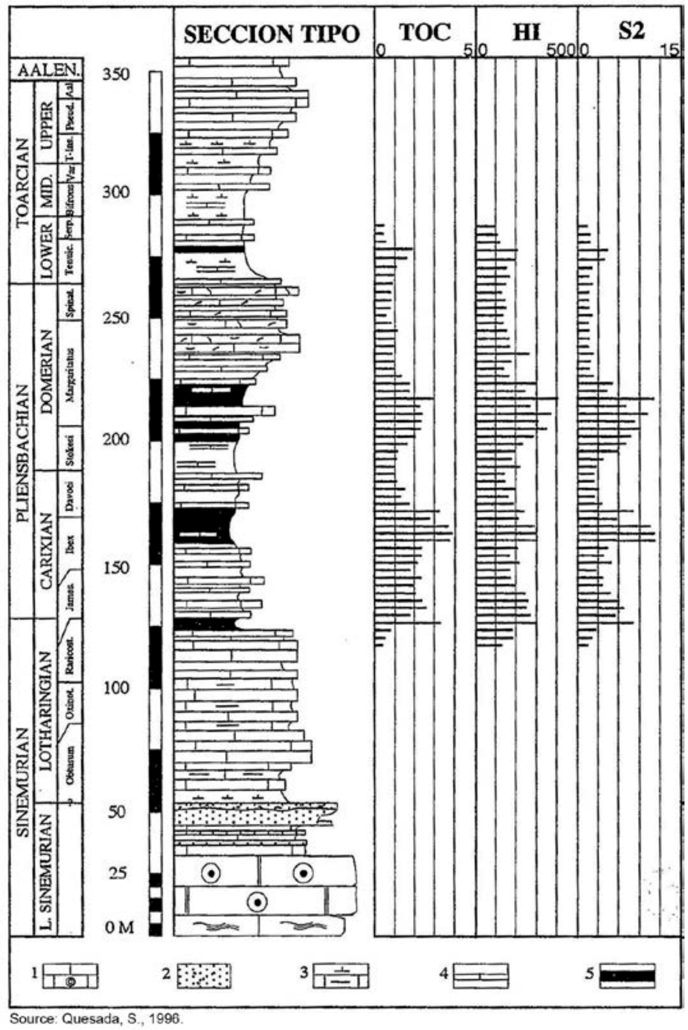



Source: Modified from Fraguas at al., 2008



Advanced Resources International, Inc.

Figure XII-5. TOC Values in the Pliensbachian Interval of the Jurassic




## 1.3 Resource Assessment

The entire package of Jurassic shales, including the Lias Shale, within the 2,100-mi$^2$ prospective area of the Basque-Cantabrian Basin has a resource concentration of about 50 Bcf/mi$^2$ of wet shale gas and 3 million barrels/mi$^2$ of shale condensate.

The risked resource in-place within the prospective area is estimated at 42 Tcf of wet shale gas and 3 billion barrels of shale condensate. Based on moderate reservoir properties, we estimate risked, technically recoverable resources from these Jurassic shales of 8 Tcf of wet shale gas and 0.1 billion barrels of shale condensate.

### 1.4 Recent Activity

Several companies hold leases and are actively exploring the Jurassic Shales in the Basque-Cantabrian Basin. For example, San Leon Energy (who acquired Realm Energy and its oil and gas concessions in Spain) has two concession areas, totaling over 210,000 acres in the basin. In addition, BNK Petroleum has a 380,000-acre Jurassic Shale concession in Castillo y Leon and hopes to spud an exploration well in this area during 1Q 2013, pending approval.[7]

HEYCO Energy and Cambria Europe, along with the Basque Energy Board, announced a USD $138 million exploration program in 2011.[8] No further information is available on the activities or results of this exploration program.

## 2. OTHER SHALES OF THE BASQUE-CANTABRIAN BASIN

***Ordovician and Silurian Shales.*** The presence of the Ordovician and Silurian shale interval, a major source rock in the Middle East and North Africa, has been well established in Spain in outcrops and boreholes. To further assess the resource potential of these shales, a total of 24 new samples of the Lower Silurian Formigoso Formation and Middle Ordovician Sueve Formation was gathered from twelve different outcrop locations in the provinces of Asturias and Leon during May 2010. [9]

Nineteen of the twenty-four samples had TOC values less than 1% and no sample recorded a TOC above 2%. In addition, the remaining kerogen type was mostly inertinite.[9] Based on the results of this geochemical work, the investigators concluded that the Lower Paleozoic (Ordovician and Silurian) shales in this part of the basin have poor potential for shale gas and oil. As such, these shales were excluded from further assessment.[9]

***Cretaceous Shales.*** The thick Cretaceous-age (Albian-Cenomanian) Valmaseda Formation contains the Enara Shale, which hold an estimated 185 $Bm^3$ (6.5 Tcf) of shale gas based on a study of 13 wells in the Gran Enara field in northern Spain. A shale gas exploration program has been proposed.[10] However, no details in the TOC or other properties accompanied this initial shale gas assessment. San Leon Energy's separate characterization of the Valmaseda Formation and the Enara Shale indicates that the TOC, while up to 3.6% locally, averages only about 1%. As such, these shales were excluded from further assessment.

## 3. EBRO BASIN

The Ebro (Solson) Basin is located to the south and east of the Basque-Cantabrian Basin in the northeast portion of Spain. The shale potential in this basin has been evaluated based on 30 older petroleum wells, twelve of which penetrated the Paleozoic section. The wells identified a shale sequence at 1,650 to 4,000 m depth, with a thickness of 50 to 100 m and a thermal maturity ranging from 1% to 2% $R_o$, placing these shales in the wet to dry gas window. However, because the TOC of these shales averages only about 1%, the Paleozoic shales in the Ebro Basin were excluded from further assessment.[4]

A series of younger Eocene-age reservoir intervals also contain thermally mature shales. These mostly Middle Eocene shales are deposited as thin layers of shale interbedded within low-porosity sandstones. Again, however, the TOC values in these Eocene shales averaged less than 1%, therefore these shales were excluded from further assessment.[4]

## REFERENCES


[1] Gibbons, W. and Moreno, T., 2002. "The Geology of Spain." The Geological Society of London, ISBN 1-86239-110-6.

[2] Suárez-Ruiz, I. and Prado, J.G., 1995. "Characterization of Jurassic Black Shales from Asturias (Northern Spain): Evolution and Petroleum Potential." Composition, Geochemistry and Conversion of Oil Shales, NATO ASI Series Volume 455, 1995, pp 387-393.

[3] Quesada, S., Robles, S. and Rosales, I., 2005. "Depositional Architecture and Transgressive–Regressive Cycles within Liassic Backstepping Carbonate Ramps in the Basque–Cantabrian Basin, Northern Spain." Journal of the Geological Society, London, vol. 162.

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[7] BNK Petroleum Investors presentation, 2011.

[8] Oil & Gas Journal, 2011. "Thick Shale Gas Play Emerging in Spain's Cantabrian Basin", May 12.

[9] Maio, F., Aramburu, C. and Underwood, J., 2011. "Geochemistry of Ordovician and Silurian Black Shales, Cantabrian Zone, Asturias and Leon Provinces, Northwest." AAPG Search and Discovery Article #50529, posted December 19, 2011, adapted from poster presentation at AAPG International Conference and Exhibition, Milan, Italy, October 23-26, 2011.

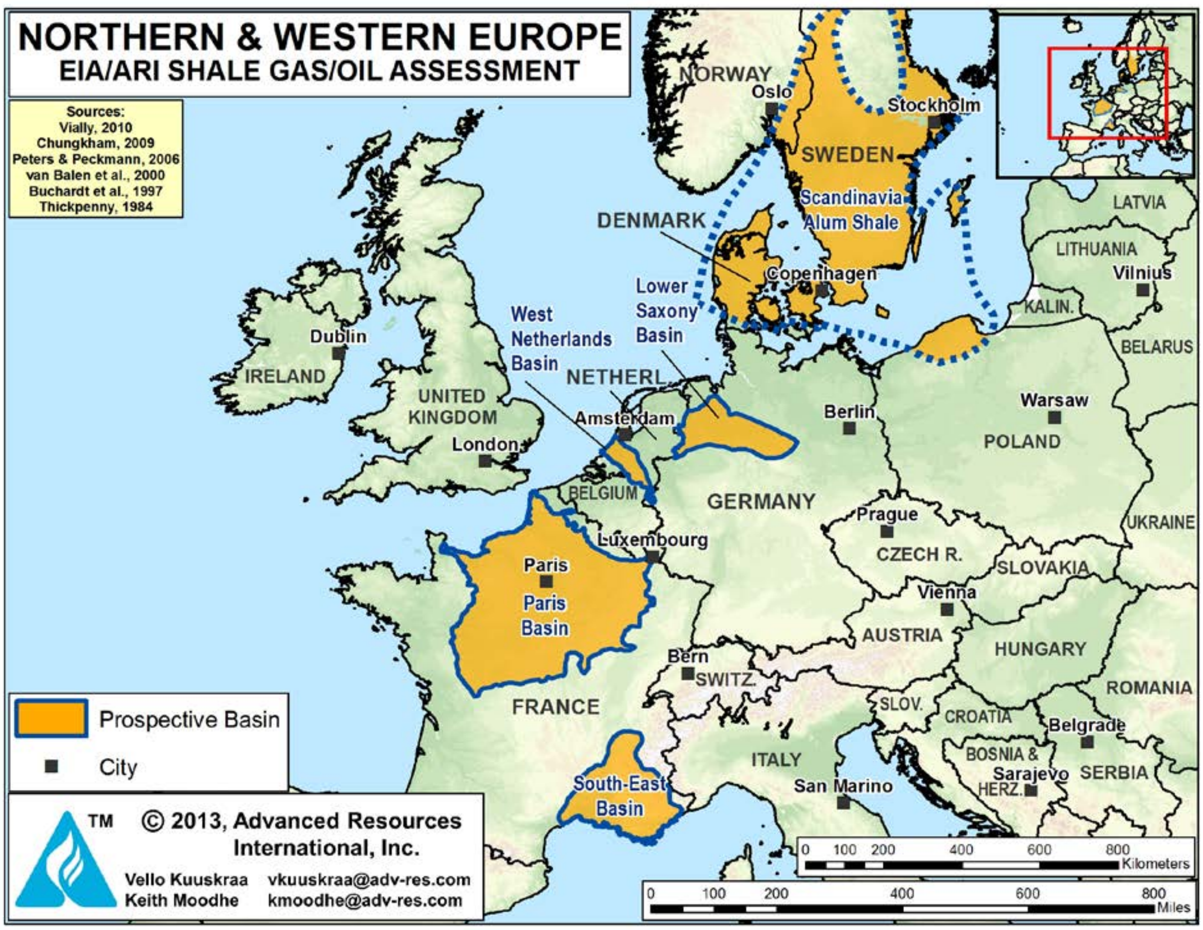
[10] Platts, 2011. "Spanish Basque Region Reports 185 Bcm of Shale Gas Finds in Alava." 17Oct2011/919 am EDT/1319 GMT, www.platts.com accessed March 7, 2013.

# XIII. NORTHERN AND WESTERN EUROPE

## SUMMARY

Numerous shale gas basins and formations exist in Northern and Western Europe. This Chapter discusses five of the more prominent of these shale basins and formations, namely: the Paris and South-East basins of France, the Lower Saxony Basin of Germany, the West Netherland Basin of the Netherlands, and the Alum Shales underlying Scandinavia, Figure XIII-1. Please see individual Chapters for United Kingdom (Chapter XI) and Spain (Chapter VII) for discussion of the other shale basins of Northern and Western Europe.

Figure XIII-1. Prospective Shale Basins of Northern and Western Europe




Source: ARI, 2013.

We estimate risked shale gas in-place for the five Northern and Western European shale basins addressed by this study of 1,165 Tcf, with 221 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate that these five shale basins contain 190 billion barrels of risked shale oil in-place, with 8.3 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-1.

Table XIII-1. Shale Gas and Shale Oil Resources of Northern and Western Europe

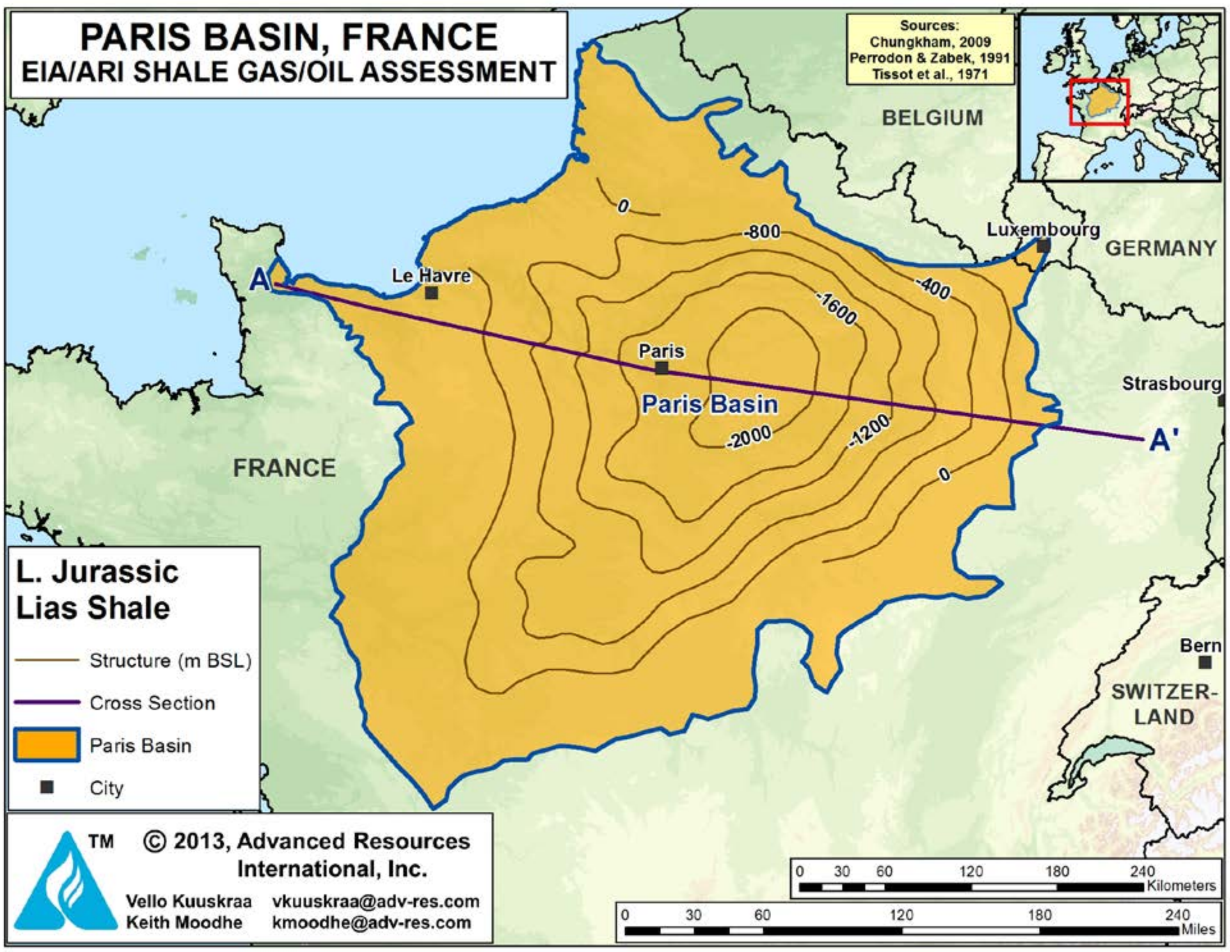
| | Risked Shale Gas Resources | | Risked Shale Oil Resources | |
|---|---|---|---|---|
| **Basin/Formation** | **In-Place (Tcf)** | **Technically Recoverable (Tcf)** | **In-Place (B bbl)** | **Technically Recoverable (B bbl)** |
| **1. Paris Basin (France)** | | | | |
| ·L. Jurassic Lias | 23.8 | 1.9 | 38.0 | 1.52 |
| ·Permian-Carboniferous | 666.1 | 127.3 | 79.5 | 3.18 |
| Total | 689.9 | 129.3 | 117.5 | 4.70 |
| **2. South-East Basin (France)** | | | | |
| ·L. Jurassic Lias | 37.0 | 7.4 | 0.0 | 0.00 |
| Total | 37.0 | 7.4 | 0.0 | 0.00 |
| **3. Lower Saxony Basin (Germany)** | | | | |
| ·Toarcian Posidonia | 77.7 | 16.9 | 10.6 | 0.53 |
| ·Wealden | 1.8 | 0.1 | 3.2 | 0.13 |
| Total | 79.5 | 17.0 | 13.8 | 0.66 |
| **4. West Netherlands Basin (Netherlands)** | | | | |
| ·Namurian Epen | 93.7 | 14.8 | 47.1 | 2.35 |
| ·Namurian Geverik | 50.6 | 10.1 | 6.3 | 0.32 |
| ·Toarcian Posidonia | 6.8 | 1.0 | 5.4 | 0.27 |
| Total | 151.1 | 25.9 | 58.8 | 2.94 |
| **5. Alum Shale** | | | | |
| ·Denmark | 158.6 | 31.7 | 0.0 | 0.00 |
| ·Sweden | 48.9 | 9.8 | 0.0 | 0.00 |
| Total | 207.5 | 41.5 | 0.0 | 0.00 |
| **Total** | **1,165.1** | **221.0** | **190.0** | **8.29** |

# 1. PARIS BASIN

## 1.1 Introduction

The Paris Basin of France is a large 65,000-mi$^2$ intra-cratonic basin that encompasses most of the northern half of the country, Figure XIII-2. The basin is bounded on the east by the Vosges Mountains, on the south by the Central Massif, on the west by the Armorican Massif and, for the purposes of this study, by the English Channel on the north. The Paris Basin is filled mostly with Mesozoic and Paleozoic rocks which reach 10,000 feet of thickness in the center of the basin but are exposed along its margins.

Figure XIII-2. Outline and Structure of Paris Basin




Source: ARI, 2013

The Paris Basin and its two distinct shale gas and oil formations - - the Lias Shale and the Permian-Carboniferous Shale - - hold 690 Tcf of risked shale gas in-place, with 129 Tcf as the risked, technically recoverable shale gas resource, Table XIII-2. In addition, the Paris Basin and its two shale formations hold 118 billion barrels of risked shale oil in-place, with 4.7 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-3.

Table XIII-2. Shale Gas Reservoir Properties and Resources of the Paris Basin

| | | | | | | |
|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Paris ($61,000 mi^2$) | | | |
| | Shale Formation | | Lias Shale | Permian-Carboniferous | | |
| | Geologic Age | | L. Jurassic | Permian-Carboniferous | | |
| | Depositional Environment | | Marine | Lacustrine | | |
| Physical Extent | Prospective Area ($mi^2$) | | 5,670 | 11,960 | 17,940 | 17,940 |
| | Thickness (ft) | Organically Rich | 350 | 400 | 250 | 500 |
| | | Net | 105 | 160 | 83 | 100 |
| | Depth (ft) | Interval | 4,000 - 10,000 | 6,000 - 8,000 | 9,000 - 11,000 | 12,000 - 16,400 |
| | | Average | 7,000 | 7,000 | 10,000 | 14,000 |
| Reservoir Properties | Reservoir Pressure | | Normal | Normal | Normal | Normal |
| | Average TOC (wt. %) | | 4.5% | 9.0% | 9.0% | 9.0% |
| | Thermal Maturity (% Ro) | | 0.85% | 0.85% | 1.15% | 1.60% |
| | Clay Content | | Medium | Medium | Medium | Medium |
| Resource | Gas Phase | | Assoc. Gas | Assoc. Gas | Wet Gas | Dry Gas |
| | GIP Concentration ($Bcf/mi^2$) | | 8.4 | 12.8 | 46.2 | 61.3 |
| | Risked GIP (Tcf) | | 23.8 | 48.9 | 265.1 | 352.0 |
| | Risked Recoverable (Tcf) | | 1.9 | 3.9 | 53.0 | 70.4 |

Table XIII-3. Shale Oil Reservoir Properties and Resources of the Paris Basin

| | | | | | |
|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | Paris ($61,000 mi^2$) | | |
| | Shale Formation | | Lias Shale | Permian-Carboniferous | |
| | Geologic Age | | L. Jurassic | Permian-Carboniferous | |
| | Depositional Environment | | Marine | Lacustrine | |
| Physical Extent | Prospective Area ($mi^2$) | | 5,670 | 11,960 | 17,940 |
| | Thickness (ft) | Organically Rich | 350 | 400 | 250 |
| | | Net | 105 | 160 | 83 |
| | Depth (ft) | Interval | 4,000 - 10,000 | 6,000 - 8,000 | 9,000 - 11,000 |
| | | Average | 7,000 | 7,000 | 10,000 |
| Reservoir Properties | Reservoir Pressure | | Normal | Normal | Normal |
| | Average TOC (wt. %) | | 4.5% | 9.0% | 9.0% |
| | Thermal Maturity (% Ro) | | 0.85% | 0.85% | 1.15% |
| | Clay Content | | Medium | Medium | Medium |
| Resource | Oil Phase | | Oil | Oil | Condensate |
| | OIP Concentration ($MMbbl/mi^2$) | | 13.4 | 20.4 | 0.2 |
| | Risked OIP (B bbl) | | 38.0 | 78.3 | 1.2 |
| | Risked Recoverable (B bbl) | | 1.52 | 3.13 | 0.05 |

## 1.2 Geologic Setting

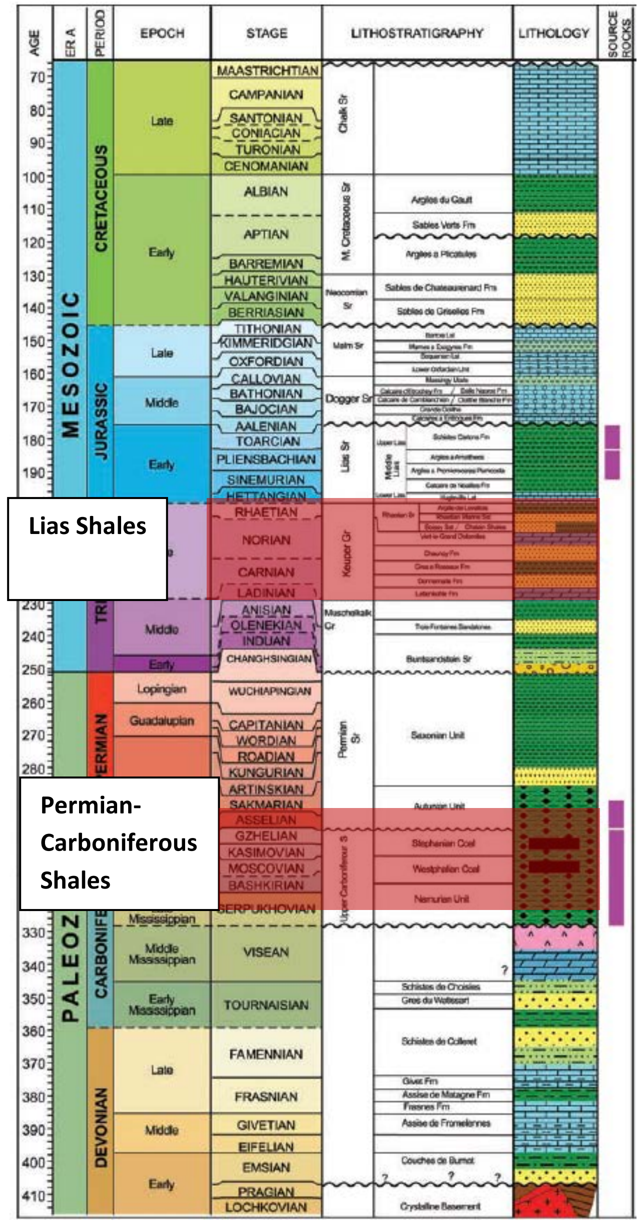
The Paris Basin contains two shale plays addressed by this resource study - - the Lower Jurassic Lias Shale and the Permian-Carboniferous Shale, Figure XIII-3[1]. The Jurassic Lias Shale is composed of three distinct organic-rich black shales - - the Hettangian-Sinemurian (Lower Lias) Shale, the Pliensbachian (Middle Lias) Shale, and the younger Toarcian ("Schistes Carton") Shale which is equivalent to the Posidonia Shale in Germany and the Netherlands. Together these three shales are as much as 650 feet thick in the central part of the Paris Basin.[2] For the purpose of this shale resource assessment, we have grouped these three shales into a single shale assessment interval called the Lias (Liassic) Shale.

Figure XIII-4 provides an east to west cross-section for the Lias Shale across the Paris Basin.[2] (The location of the cross-section is provided on Figure XIII-2). Basin modeling of the Lias Shale, in a smaller 3,640-$mi^2$ study area of the Paris Basin, indicated that this composite shale interval, primarily the Toarcian ("Schistes Carton") Shale, has generated 81 billion barrels of hydrocarbons.[3] Extrapolating the smaller basin modeling study area to the full Lias Shale prospective area in the Paris Basin of 5,670 $mi^2$ and assuming that 30% of the generated hydrocarbon still remains in the source rock, we estimate that 38 billion barrels of hydrocarbons remain in the Lias Shale.

The deeper Permian-Carboniferous unconventional gas play is located in the eastern and southern portions of the Paris Basin, particularly in the Lorraine Sub-basin. This area contains a thick package of tight sands, shales and methane-charged coals. This resource assessment will address the organic-rich shales of the Permian-Carboniferous interval, including the Lower Permian Autunian Unit, the Upper Carboniferous (Late Mississippian and Early Pennsylvanian) Namurian Unit, as well as the Upper Carboniferous (Middle and Pennsylvanian) inter-bedded bituminous shales in the Stephanian and Westphalian sections.

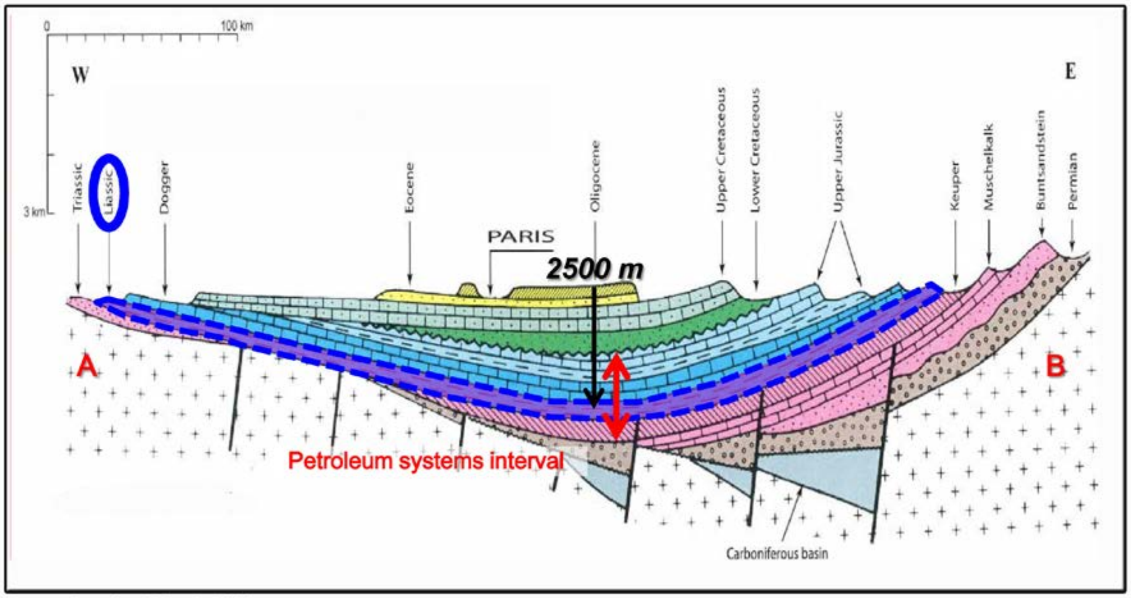
Figure XIII-5 provides an east to west cross-section across the Paris Basin, identifying the Permian-Carboniferous Shale in the eastern portion of the basin.[1] The shales have fluvial and lacustrine deposition raising concern with respect to higher clay content and less brittle reservoir rock. The kerogen in the shales is a mixed Type II/III.

Figure XIII-3. East Paris Basin Stratigraphic Column



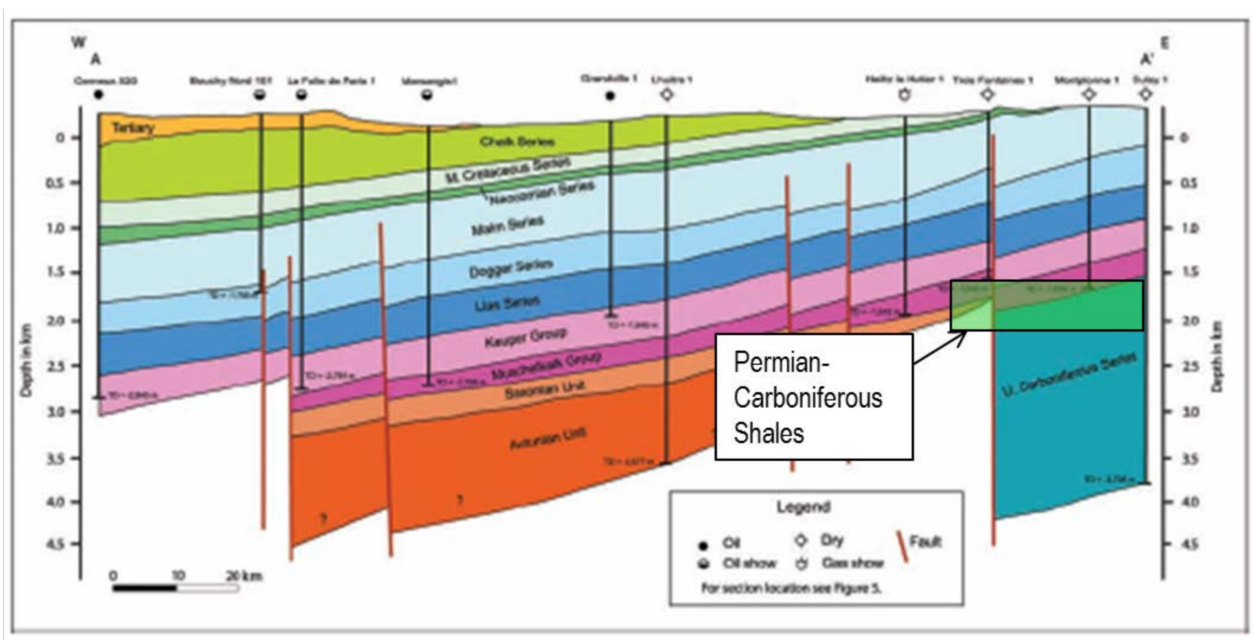

Source: Chungkham, 2009

Figure XIII-4. East-West Cross-Section of Paris Basin Highlighting Lias (Liassic) Shales




Source: Perrodon, Zabeck, 1990

Figure XIII-5. East-West Cross-Section of Paris Basin Highlighting Permian-Carboniferous Shales

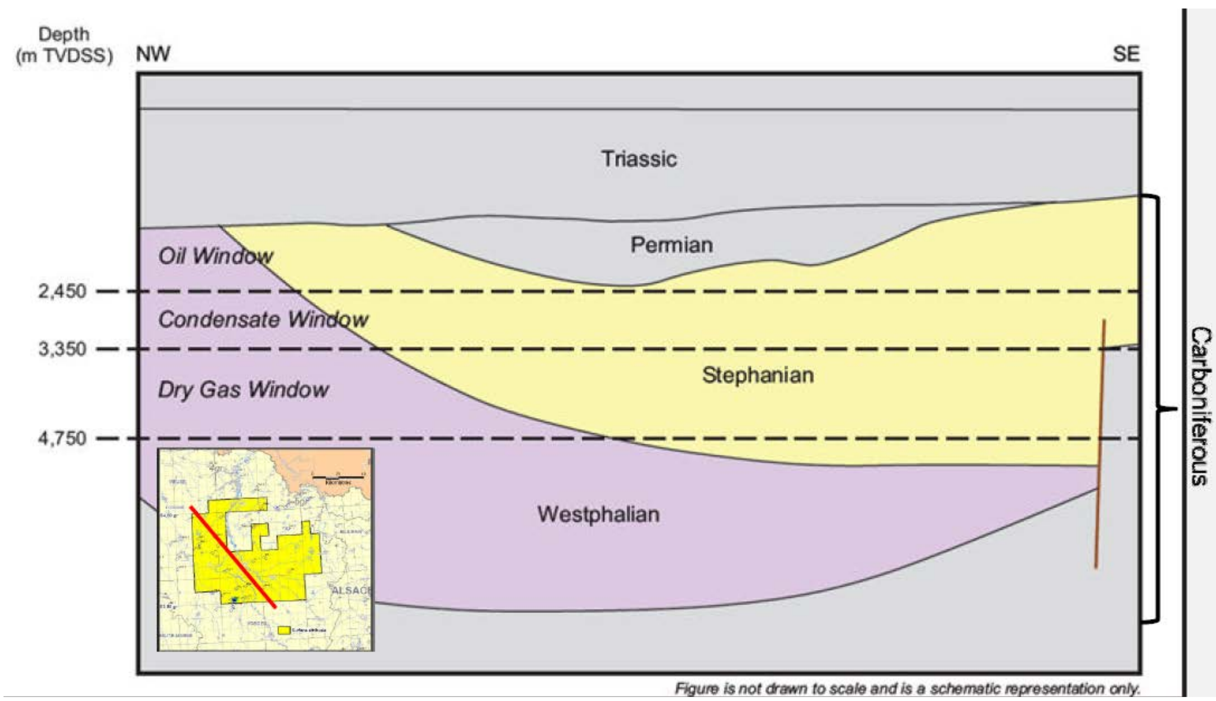



Source: Chungkham, 2009

We have concentrated our assessment on the Lower Permian Autunian and Upper Carboniferous Namurian shales. The substantial presence of less brittle coals in the Upper Carboniferous Westphalian and Stephanian may hinder successful application of hydraulic stimulation in these shales. In addition, the organic content (TOC) of the inter-bedded shales in the Westphalian and Stephanian is reported to range from 0.5 to 1.4%, below the minimum TOC criterion used in this study.[4]

Based on information in the technical literature, we have used depth as a proxy for thermal maturity ($R_o$) for establishing the dry, wet gas/condensate and oil windows for this shale play. The dry gas window is represented by burial depth between 3,350 m and 4,750 m; the wet gas/condensate window is represented by burial depth between 2,450 m and 3,350 m, and the oil window is represented by burial depth between 1,200 m and 2,450 m, Figure XIII-6.[5]

Figure XIII-6. Relationship of Thermal Maturity and Burial Depth, Paris Basin




Source: Elixir, 2011

## 1.3 Reservoir Properties (Prospective Area)

**Lias Shale.** We have mapped a 5,670-mi$^2$ oil prospective area for the Lias Shale based on the 435$^o$ C Tmax contour area for the higher organic content Toarcian ("Schistes Carton") Shale. The 435$^o$ C Tmax contour (oil window) for the deeper Hettangian-Sinemurian Shale underlies the 435$^o$C Tmax contour of the Toarcian ("Schistes Carton") Shale, Figure XIII-7.

The depth of the Lias Shale ranges from 4,000 feet to 10,000 feet in the basin center, averaging 7,000 feet. The gross thickness of the shale ranges from 300 to 400 feet, with 105 feet of net organic-rich shale over the prospective area. The thermal maturity of the shale in the prospective area (bounded by the 435$^o$ C Tmax contour) ranges from 0.7% to 1.0%, placing the Lias Shale in the oil window.[1] The TOC of the shale, while highest in the Toarcian and lowest in the Sinemurian, averages 4.5%.

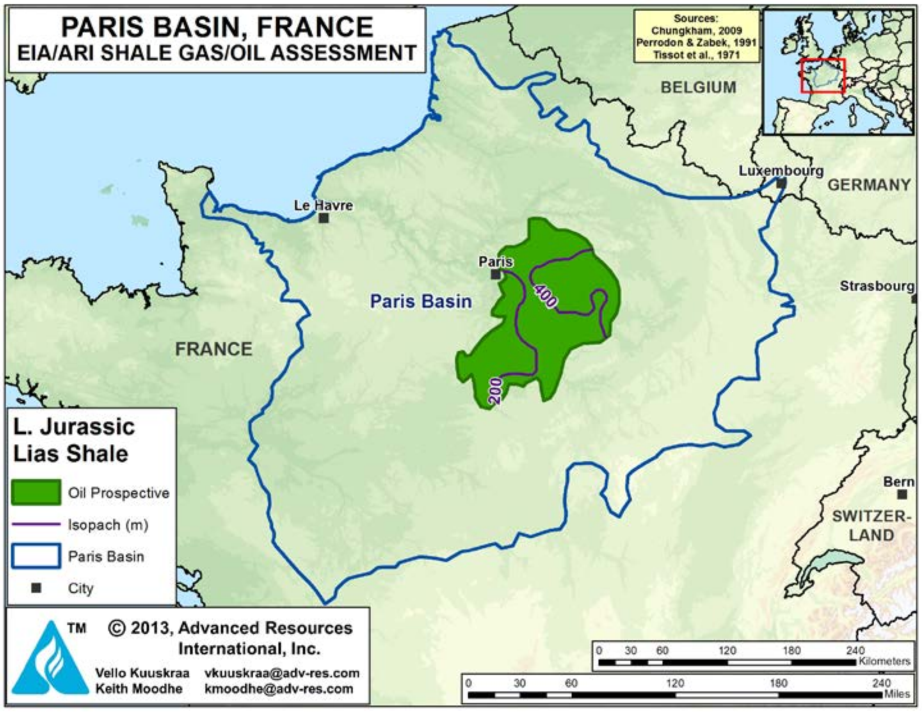
The shales are assumed to be normally pressured, given the presence of vertical fractures (and higher vertical permeability). The shale appears to be medium in clay content, lower in calcite (10% to 30%) and quartz (5% to 20%).

**Permian-Carboniferous Shale.** We have mapped a 17,940-mi$^2$ prospective area for dry gas and wet gas/condensate for the Permian-Carboniferous Shale and a more limited 11,960-mi$^2$ prospective area for oil. For this, we used the 200 m gross isopach on the north and west and the boundaries of the Paris Basin on the south and east, Figure XIII-8.[1] Approximately 50 wells provide control for this gross isopach. We assumed that the shallower oil interval extended across two-thirds of the larger prospective area.

Until recently, information on the Permian Carboniferous Shale was limited. Fortunately, Elixir Petroleum has undertaken an exploration program on their Moselle Permit in the Paris Basin and has provided information on their program. We have combined this data with information from the technical literature for the reservoir properties of the Permian-Carboniferous Shales.

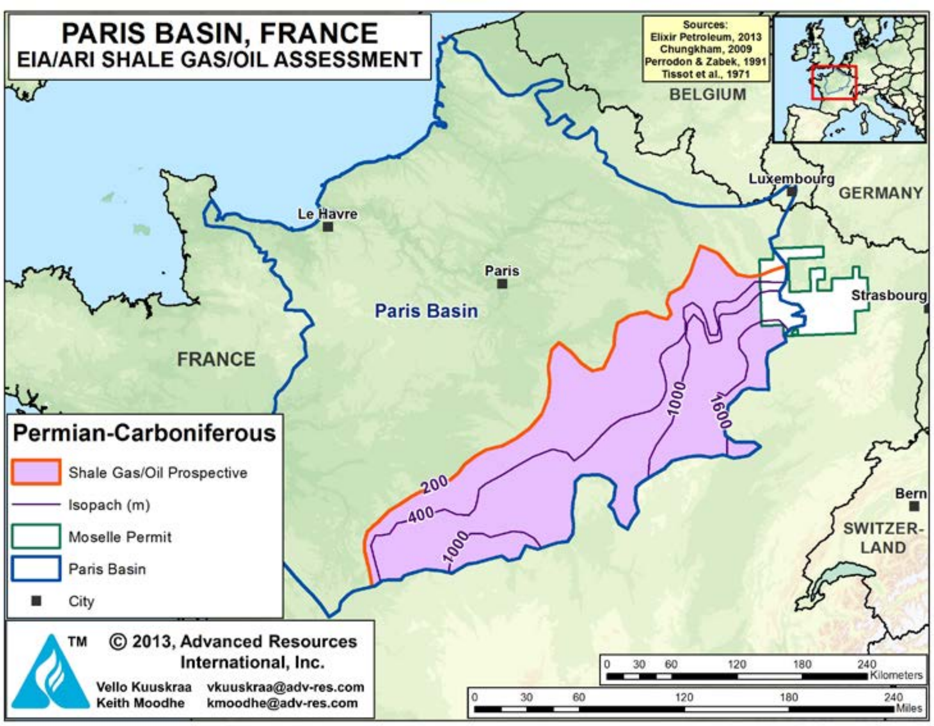
The depth of the Permian Carboniferous Shale ranges from 6,000 feet to 16,400 feet, averaging 7,000 feet in the oil window, 10,000 feet in the wet gas/condensate window, and 14,200 feet in the dry gas window. A significant portion of the Upper Carboniferous Namurian section is at depths below 5,000 m and thus excluded from this resource assessment.

Figure XIII-7. Prospective Area for Lower Jurassic Lias Shale, Paris Basin




Source: ARI, 2013

Figure XIII-8. Prospective Area for Permian-Carboniferous Shale, Paris Basin




Source: ARI, 2013

While the gross interval in the prospective area is quite thick, much of this interval contains lower TOC rocks. We estimate an average organic-rich net shale pay for the Permian Carboniferous Shale of 83 to 160 feet, using low to moderate net to gross ratios. The TOC of the shales ranges from 2% to 15%, averaging 9%. The reservoir is normally pressured.

## 1.4 Resource Assessment

**Lias Shale.** The Lias Shale of the Paris Basin contains a resource concentration of 13 million barrels/mi$^2$ of oil plus associated gas. We estimate risked oil in-place for the Lias Shale of 38 billion barrels, with 1.9 billion barrels as the risked, technically recoverable shale oil resource. In addition, we estimate risked associated shale gas in-place of 24 Tcf, with 2 Tcf as the risked, technically recoverable shale gas resource, Tables XIII-2 and XIII-3.

**Permian-Carboniferous Shale.** Given the limited data on the extent and distribution of the individual shale units within the prospective area, we view the resource assessment of the Permian-Carboniferous Shale as preliminary. The Permian-Carboniferous Shale of the Paris Basin contains resource concentrations of 61 Bcf/mi$^2$ in the dry gas window, 46 Bcf/mi$^2$ in the wet gas/condensate window, and 20 million barrels/mi$^2$ in the oil window. We estimate risked gas in-place for the Permian-Carboniferous Shale of 666 Tcf, with a risked, technically recoverable shale gas resource of 127 Tcf (including associated gas). In addition, we estimate risked shale oil/condensate in-place of 80 billion barrels, with 3.2 billion barrels as the risked, technically recoverable shale oil resource, Tables XIII-2 and XIII-3.

## 1.5 Recent Activity

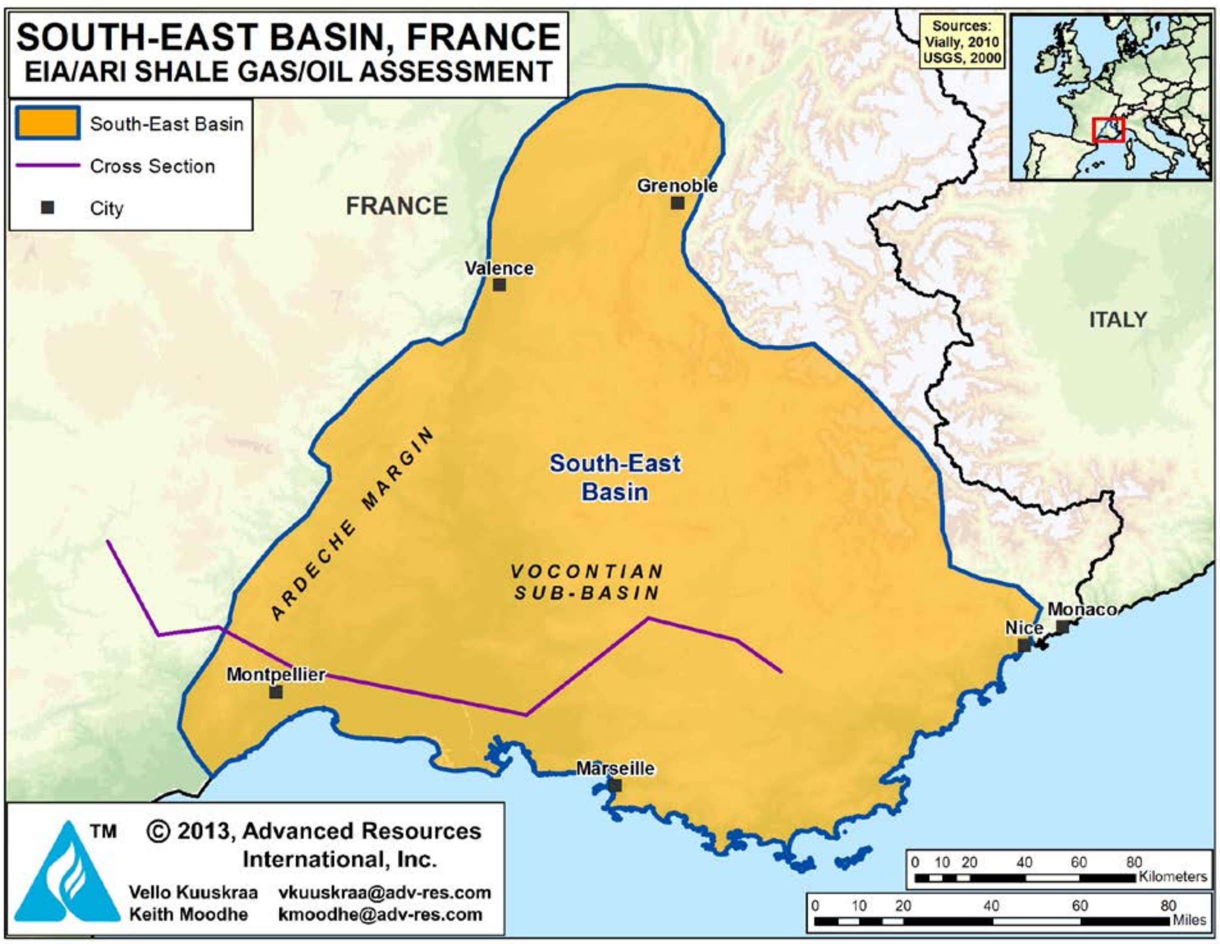
Most of the past exploration in the Paris Basin has targeted the Jurassic-age Lias Shale oil play. However, some firms are beginning to acquire acreage in the eastern portions of the Paris Basin where the Permian-Carboniferous Shale formation is the target. The 2,070 mi$^2$ Moselle Permit and its Permian-Carboniferous resource interval, first granted to East Paris Petroleum Development Corp, has been acquired by Elixir Petroleum. While the terms of the lease do not require the company to drill any wells, Elixir has publically stated that it intends to investigate the unconventional gas potential (tight gas, CBM and shale gas) on its lease.[5]

## 2. SOUTH-EAST BASIN

### 2.1 Introduction

The South-East Basin is the thickest sedimentary basin in France, containing up to 10 km of Mesozoic to Cenozoic sediments. The basin is bounded on the east and south by the Alpine thrust belt and on the west by the Massif Central, an uplifted section of the Paleozoic basement, Figure XIII-9. Local oil and gas seeps discovered in the 1940's encouraged hydrocarbon exploration in the South-East Basin. However, despite the drilling of 150 wells in the onshore and offshore portions of the basin, no significant oil and gas deposits have been found. Recent re-evaluations of the basin's potential have stimulated a further look at this complex basin and its shale formations.

Figure XIII-9. Outline of South-East Basin of France




Source: ARI, 2013

We estimate that the South-East Basin contains 37 Tcf of risked shale gas in-place, with 7 Tcf as the risked, technically recoverable shale gas resource, Table XIII-4. We have limited our shale resource assessment to the western portion of the basin and its deep dry gas potential area. In addition, given considerable uncertainty as to the location of the higher TOC (>2%) portions of the basin, we have assumed that only 30% of the overall dry gas prospective area will meet the 2% TOC criterion used by the study.

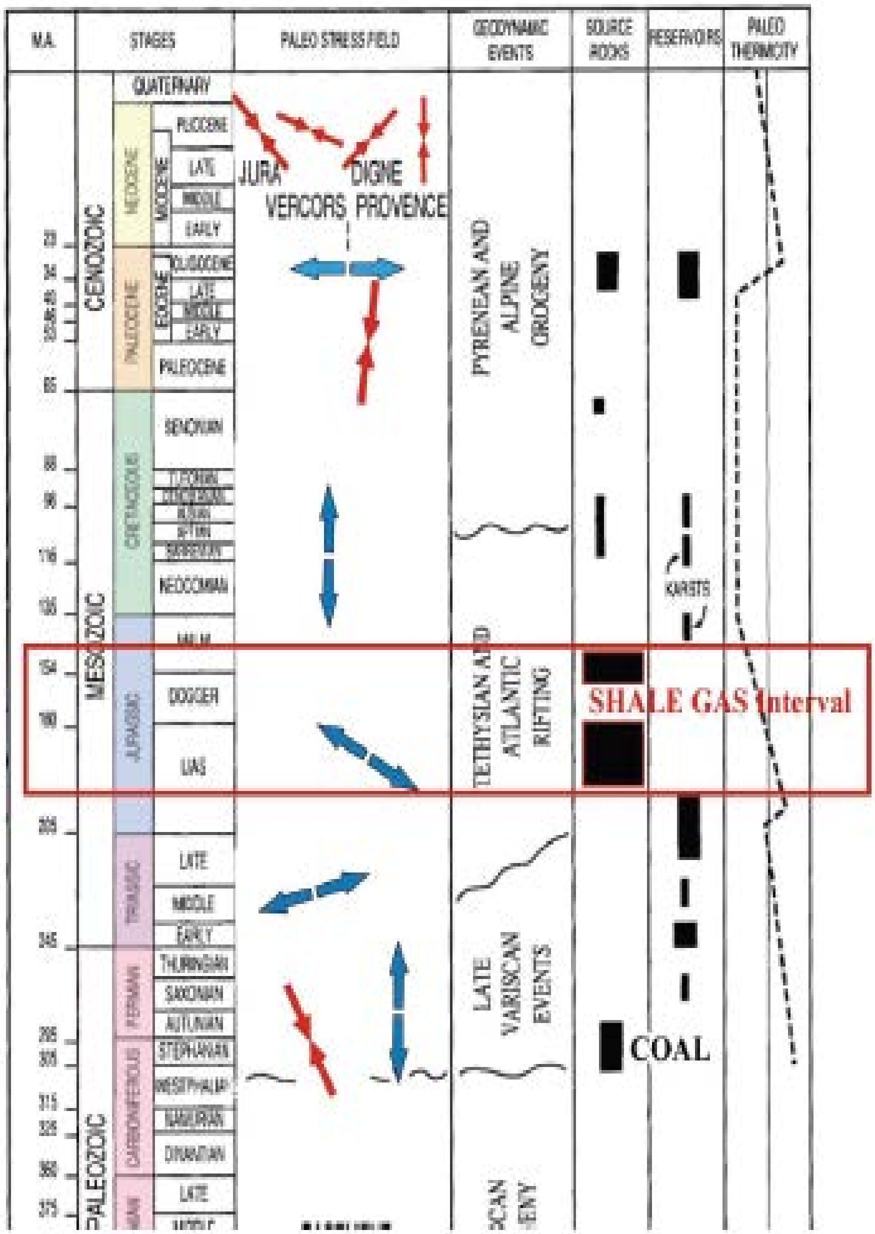
Table XIII-4. Shale Gas Reservoir Properties and Resources for the South-East Basin

| | | | |
|---|---|---|---|
| Basic Data | Basin/Gross Area | | South-East (17,800 mi²) |
| | Shale Formation | | Lias Shale |
| | Geologic Age | | L. Jurassic |
| | Depositional Environment | | Marine |
| Physical Extent | Prospective Area (mi²) | | 3,780 |
| | Thickness (ft) | Organically Rich | 525 |
| | | Net | 158 |
| | Depth (ft) | Interval | 8,200 - 16,400 |
| | | Average | 12,300 |
| Reservoir Properties | Reservoir Pressure | | Normal |
| | Average TOC (wt. %) | | 2.0% |
| | Thermal Maturity (% Ro) | | 1.50% |
| | Clay Content | | Medium |
| Resource | Gas Phase | | Dry Gas |
| | GIP Concentration (Bcf/mi²) | | 54.4 |
| | Risked GIP (Tcf) | | 37.0 |
| | Risked Recoverable (Tcf) | | 7.4 |

## 2.2 Geologic Setting

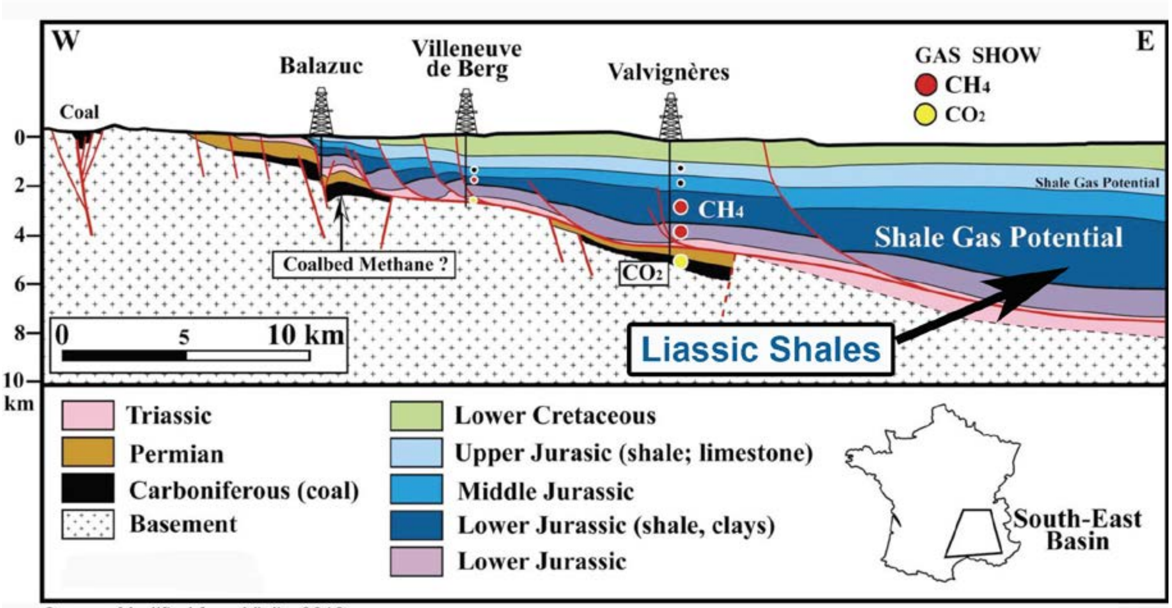
This study examined the shale gas potential of two formations in the South-East Basin, the Upper Jurassic “Terres Niores” black shale, and the Lower Jurassic Liassic black shale, Figure XIII-10. These shales are composed of Type II marine organic matter and were deposited during a time of subsidence and rifting, when the “Liguro-Piemontais” ocean covered portions of what is now southern France[6]. However, the Upper Jurassic “Terres Niores” black shale has low TOC, not exceeding 1%.[6] As such, this shale was excluded from further assessment. The Lower Jurassic Lias Shale, while thermally mature and present in much of the South-East Basin contains a wide spectrum of TOC values, ranging from 0.4% to 4.1%, Figure XIII-11.[7] Because of the presence of some higher TOC values, we have included the Lias Shale in our resource assessment but have highly risked this shale play.

Figure XIII-10. South-East Basin Stratigraphic Column




Source: Vially, R., 2010.

Figure XIII-11. Generalized South-East Basin Cross Section




Source: Modified from Vially, 2010

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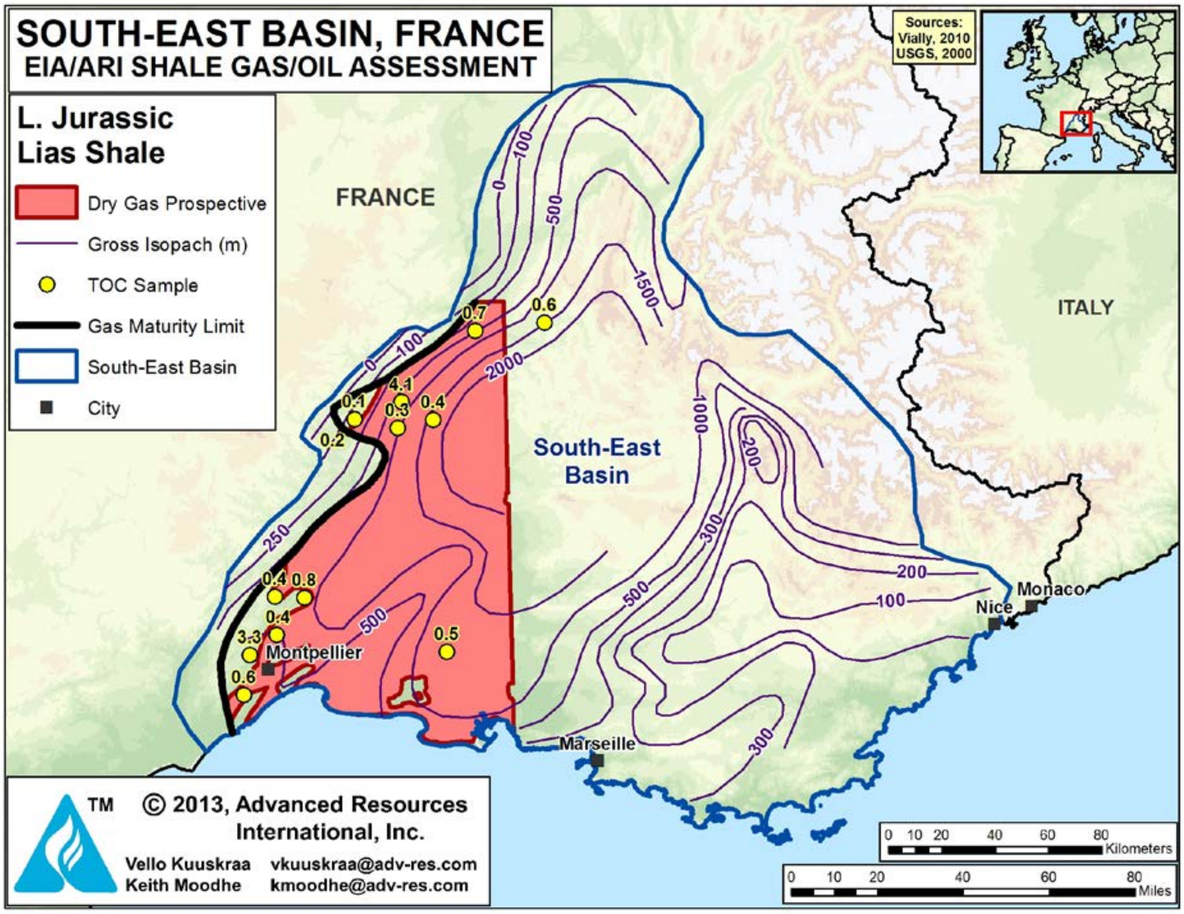
We have mapped an unrisked, 4,000-mi$^2$ area prospective for shale gas in the eastern portion of the South-East Basin, Figure XIII-12. The prospective area is bounded on the west by the dry gas maturity limit, on the south by the onshore portion of basin, and on the east by the available data on the TOC of the Lias Shale.

## 2.3 Reservoir Properties (Prospective Area)

Uplifting along the western margin of the South-East Basin has brought the Lias Shale to a more favorable depth for exploration. Depth to the Lias Shale ranges from 3,300 feet to 16,300 feet deep over the basin, with most of the shale in the prospective area at an average depth of 12,300 feet, Figure XIII-12. The organic-rich gross interval of the shale is estimated at 525 feet with 158 feet of net shale. Total organic content (TOC) in the risked prospective area averages 2%. Thermal maturity in the Lias Shale increases with depth, ranging from 1.3% $R_o$ in the shallower western areas to over 1.7% $R_o$ in the deeper central area. Average vitrinite reflectance ($R_o$) over the prospective area is 1.5%.

Figure XIII-12. Prospective Area for the Lias Shale, South-East Basin of France




Source: ARI, 2013

## 2.4 Resource Assessment

We estimate a moderate resource concentration in the dry gas prospective area of the Lias Shale, South-East Basin of 54 Bcf/mi$^2$. The risked shale gas in-place is estimated at 37 Tcf, with 7 Tcf as the risked, technically recoverable shale gas resource.

## 2.5 Recent Activity

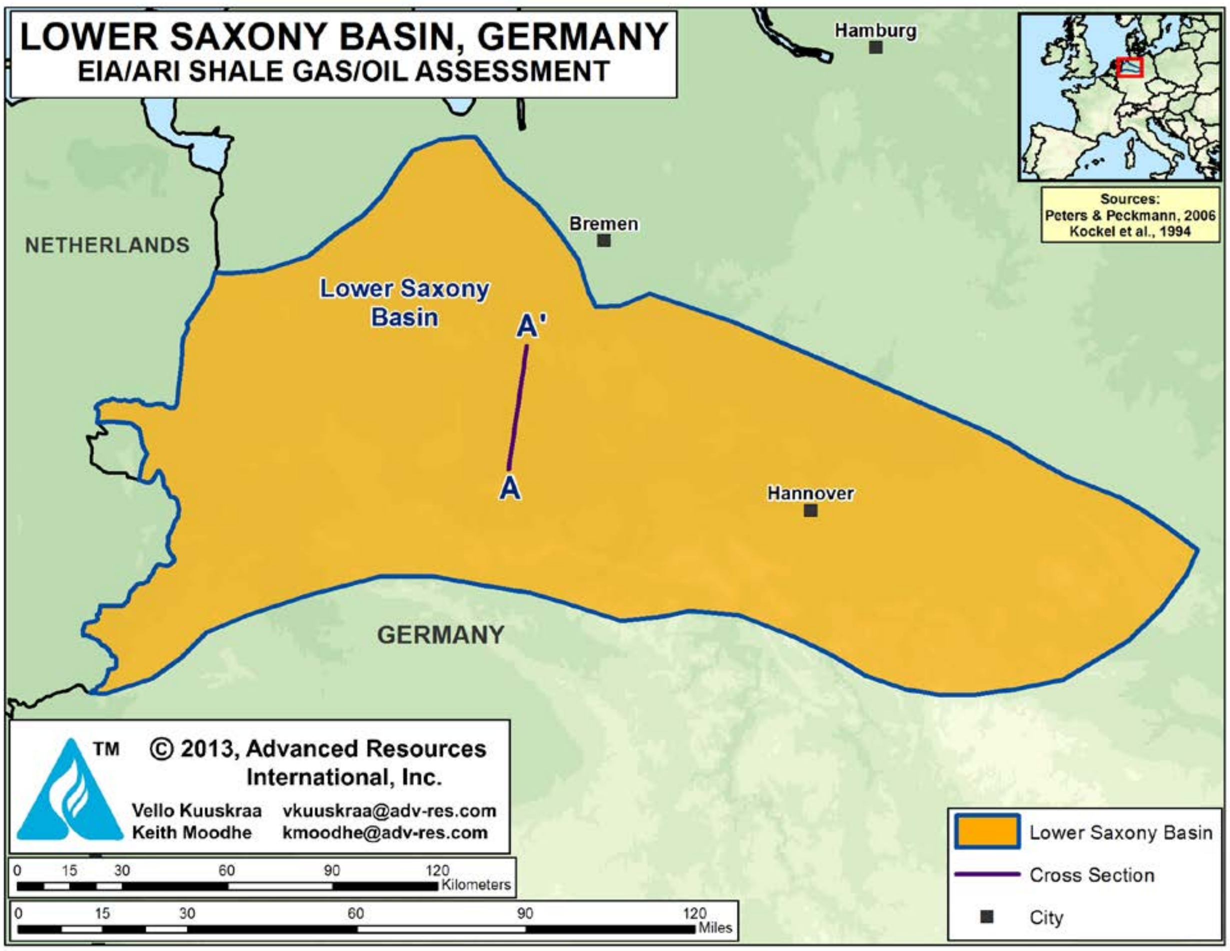
A number of firms are beginning to examine the shale gas potential of the South-East Basin; the initial permit award deadline was delayed due to the large numbers of applications. The French Ministry of Energy and the Environment awarded several exploration permits, covering over 4,000 mi$^2$, to companies interested in investing in the drilling and exploration of shale formations in the South-East Basin of France.

# 3. LOWER SAXONY BASIN: GERMANY

## 3.1 Introduction

The Lower Saxony Basin, covering an area of 10,000 mi$^2$ and located in northwestern Germany, is filled with Jurassic- to Cretaceous-age marine and lacustrine rocks, Figure XIII-13. The basin contains two petroleum systems, the Jurassic and its Posidonia (Toarcian) Shale source rock and the Lower Cretaceous and its Wealden (Berriasian) Shale source rock. The Posidonia Shale is present throughout the Lower Saxony Basin while the Wealden Shale exists primarily in its western portion of the basin.

Figure XIII-13. Outline Map for Lower Saxony Basin, Germany.




Source: ARI, 2013

For the Lower Saxony Basin of Germany, we estimate risked in-place shale gas of 80 Tcf, with 17 Tcf as the risked, technically recoverable shale gas resource, Table XIII-5. In addition, we estimate risked in-place shale oil of 14 billion barrels, with 0.7 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-6.

Table XIII-5. Shale Gas Reservoir Properties and Resources of the Saxony Basin, Germany

<table>
<tr><td rowspan="4">Basic Data</td><td colspan="2">Basin/Gross Area</td><td colspan="4">Lower Saxony<br>(10,000 mi$^2$)</td></tr>
<tr><td colspan="2">Shale Formation</td><td colspan="3">Posidonia</td><td>Wealden</td></tr>
<tr><td colspan="2">Geologic Age</td><td colspan="3">L. Jurassic</td><td>L. Cretaceous</td></tr>
<tr><td colspan="2">Depositional Environment</td><td colspan="3">Marine</td><td>Lacustrine</td></tr>
<tr><td rowspan="5">Physical Extent</td><td colspan="2">Prospective Area (mi$^2$)</td><td>1,590</td><td>770</td><td>1,390</td><td>720</td></tr>
<tr><td rowspan="2">Thickness (ft)</td><td>Organically Rich</td><td>100</td><td>100</td><td>100</td><td>112</td></tr>
<tr><td>Net</td><td>90</td><td>90</td><td>90</td><td>75</td></tr>
<tr><td rowspan="2">Depth (ft)</td><td>Interval</td><td>6,000 - 10,000</td><td>10,000 - 13,000</td><td>13,000 - 16,400</td><td>3,300 - 10,000</td></tr>
<tr><td>Average</td><td>8,000</td><td>11,500</td><td>14,500</td><td>6,000</td></tr>
<tr><td rowspan="4">Reservoir Properties</td><td colspan="2">Reservoir Pressure</td><td>Mod. Overpress.</td><td>Mod. Overpress.</td><td>Mod. Overpress.</td><td>Slightly Overpress.</td></tr>
<tr><td colspan="2">Average TOC (wt. %)</td><td>8.0%</td><td>8.0%</td><td>8.0%</td><td>4.5%</td></tr>
<tr><td colspan="2">Thermal Maturity (% Ro)</td><td>0.85%</td><td>1.15%</td><td>2.00%</td><td>0.85%</td></tr>
<tr><td colspan="2">Clay Content</td><td>Low/Medium</td><td>Low/Medium</td><td>Low/Medium</td><td>Medium</td></tr>
<tr><td rowspan="4">Resource</td><td colspan="2">Gas Phase</td><td>Assoc. Gas</td><td>Wet Gas</td><td>Dry Gas</td><td>Assoc. Gas</td></tr>
<tr><td colspan="2">GIP Concentration (Bcf/mi$^2$)</td><td>10.8</td><td>44.0</td><td>56.5</td><td>5.5</td></tr>
<tr><td colspan="2">Risked GIP (Tcf)</td><td>10.3</td><td>20.3</td><td>47.1</td><td>1.8</td></tr>
<tr><td colspan="2">Risked Recoverable (Tcf)</td><td>1.0</td><td>4.1</td><td>11.8</td><td>0.1</td></tr>
</table>

Table XIII-6. Shale Oil Reservoir Properties and Resources of the Saxony Basin, Germany

<table>
<tr><td rowspan="4">Basic Data</td><td colspan="2">Basin/Gross Area</td><td colspan="3">Lower Saxony<br>(10,000 mi$^2$)</td></tr>
<tr><td colspan="2">Shale Formation</td><td colspan="2">Posidonia</td><td>Wealden</td></tr>
<tr><td colspan="2">Geologic Age</td><td colspan="2">L. Jurassic</td><td>L. Cretaceous</td></tr>
<tr><td colspan="2">Depositional Environment</td><td colspan="2">Marine</td><td>Lacustrine</td></tr>
<tr><td rowspan="5">Physical Extent</td><td colspan="2">Prospective Area (mi$^2$)</td><td>1,590</td><td>770</td><td>720</td></tr>
<tr><td rowspan="2">Thickness (ft)</td><td>Organically Rich</td><td>100</td><td>100</td><td>112</td></tr>
<tr><td>Net</td><td>90</td><td>90</td><td>75</td></tr>
<tr><td rowspan="2">Depth (ft)</td><td>Interval</td><td>6,000 - 10,000</td><td>10,000 - 13,000</td><td>3,300 - 10,000</td></tr>
<tr><td>Average</td><td>8,000</td><td>11,500</td><td>6,000</td></tr>
<tr><td rowspan="4">Reservoir Properties</td><td colspan="2">Reservoir Pressure</td><td>Mod. Overpress.</td><td>Mod. Overpress.</td><td>Slightly Overpress.</td></tr>
<tr><td colspan="2">Average TOC (wt. %)</td><td>8.0%</td><td>8.0%</td><td>4.5%</td></tr>
<tr><td colspan="2">Thermal Maturity (% Ro)</td><td>0.85%</td><td>1.15%</td><td>0.85%</td></tr>
<tr><td colspan="2">Clay Content</td><td>Low/Medium</td><td>Low/Medium</td><td>Medium</td></tr>
<tr><td rowspan="4">Resource</td><td colspan="2">Oil Phase</td><td>Oil</td><td>Condensate</td><td>Oil</td></tr>
<tr><td colspan="2">OIP Concentration (MMbbl/mi$^2$)</td><td>12.7</td><td>4.2</td><td>9.9</td></tr>
<tr><td colspan="2">Risked OIP (B bbl)</td><td>9.1</td><td>1.5</td><td>3.2</td></tr>
<tr><td colspan="2">Risked Recoverable (B bbl)</td><td>0.46</td><td>0.07</td><td>0.13</td></tr>
</table>

## 3.2 Geologic Setting

The Lower Saxony Basin is a distinct sub-basin within the greater North Sea-German Basin. The Lower Saxony Basin is a graben that subsided and filled during Late Jurassic and Early Cretaceous. The graben is bounded on the south by the Hanz Mountains, on the north by the Pompecky Block, on the west by the Central Netherland High and on the east by Hercynian Uplifts. During the Late Cretaceous, the Lower Saxony Basin was subject to complex tectonics that transformed the basin's normal boundary faults into reverse or overthrust faults. These events facilitated volcanic intrusions causing intense metamorphism of the organics.

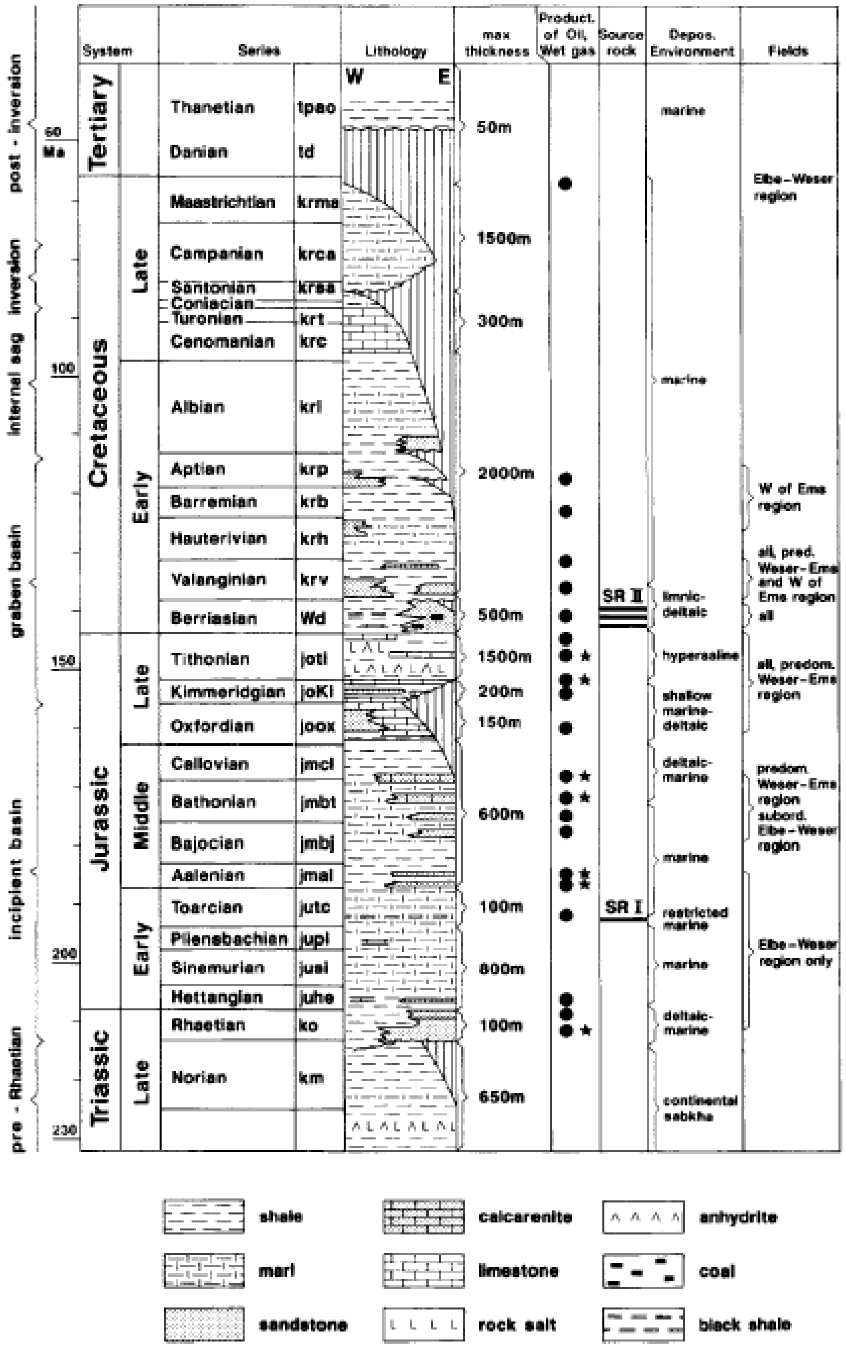
The Lower Saxony Basin contains two organic-rich shale source rocks - - the restricted marine Lower Toarcian (Jurassic) Posidonia Shale that underlies most of the basin, and the Early Cretaceous (Berriasian) lacustrine-deltaic Wealden Shale that underlies the western part of the basin (west of the Weser River). The generalized stratigraphic column for the Triassic to Tertiary interval in the Lower Saxony Basin is provided on Figure XIII-14.[8]

We mapped a 3,750-$mi^2$ prospective area for the Posidonia Shale in the Lower Saxony Basin, containing: (1) a 1,590-$mi^2$ oil prospective area ($R_o$ of 0.7% to 1%) along the north eastern border of the basin; (2) an adjoining 770-$mi^2$ wet gas/condensate prospective area ($R_o$ 1% to 1.3%); and (3) a 1,390-$mi^2$ dry gas prospective area ($R_o$ >1.3%) in the deeper southwestern portion of the basin, Figure XIII-15. We also mapped a smaller 720-$mi^2$ oil prospective area for the shallower Wealden Shale in the Lower Saxony Basin, Figure XIII-16.

In addition to the two shale formations addressed in this resource assessment, a series of other shale gas formations exist in Germany, particularly the Lower Carboniferous Visean and Westphalian coaly shales. However, these shales, while thick, thermally mature for gas and buried at acceptable depths of 1,000 to 5,000 m, have TOC values of less than 2%.[9] Thus, these shale formations have not been included in our resource assessment.

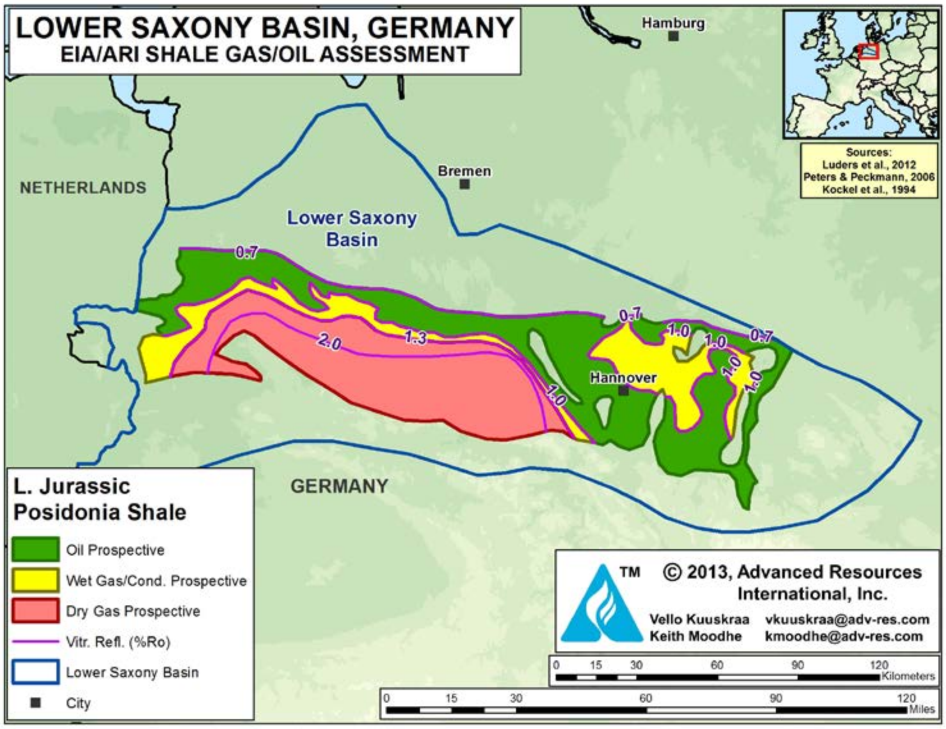
In addition, organic-rich mudstones occur in the Upper Permian Stassfurth Carbonate Formation in the eastern part of the North Sea-German Basin in southern Brandenburg. The Ca2 shale interval in this formation occurs at a depth of 3,800 to 4,000 m, has a thermal maturity of over 2% $R_o$, and contains a mixed Type II/III kerogen. However the shale formation is thin (6m) and has a low TOC content of 0.2% to 0.8%.[9] As such, this shale has also not been included in our resource assessment.

Figure XIII-14. Generalized Stratigraphic Column for the Lower Saxony Basin.



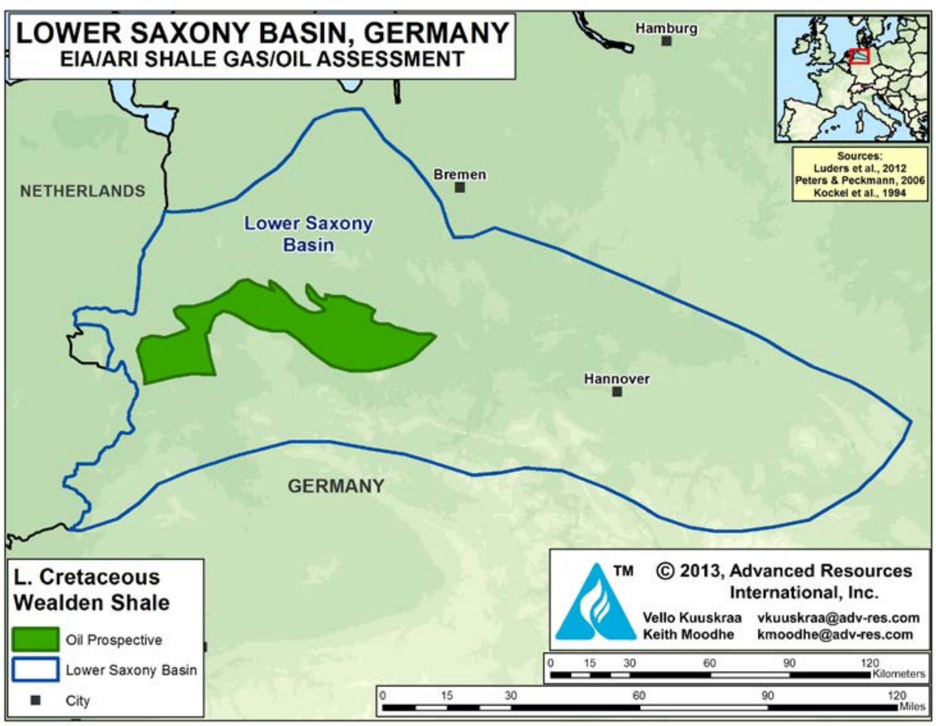

Source: Kockel, 1994.

Figure XIII-15. Prospective Area of the Posidonia Shale, Lower Saxony Basin, Germany.




Source: ARI, 2013.

Figure XIII-16. Prospective Area of the Wealden Shale, Lower Saxony Basin, Germany.

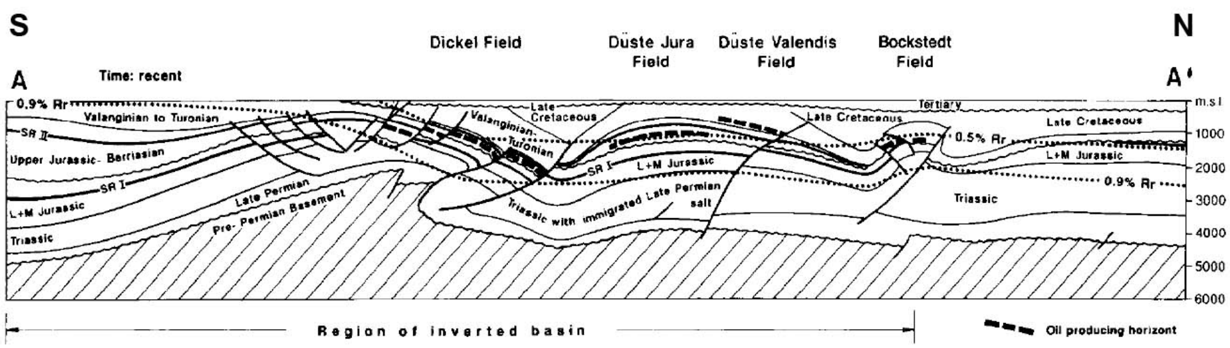



Source: ARI, 2013.

## 3.3 Reservoir Properties (Prospective Area)

**Jurassic (Toarcian) Posidonia Shale.** The depth to the Posidonia Shale ranges from 3,300 feet to 16,400 feet, with an average depth in the oil prospective area of 8,000 feet, an average depth in the wet gas/condensate prospective area of 11,500 feet, and an average depth in the dry gas prospective area of 14,500 feet. Figure XIII-17 provides a north to south cross-section through the center of the Lower Saxony Basin, illustrating the sequence of complex faults and the thrust features common to the Posidonia Shale. (The location of the north to south cross-section, A to A’, is provided in Figure XIII-10.) The shale interval in the prospective area is moderate in thickness, with an organic-rich gross thickness of 100 feet and a net shale thickness of 90 feet. Organic matter in the Posidonia Shale is Type II marine kerogen with a TOC that averages 8%, Figure XIII-18. The outer portion of the basin area is in the oil window, with the central, deeper areas of the Posidonia Shale in the wet gas/ condensate and dry gas windows, Figure XIII-15.

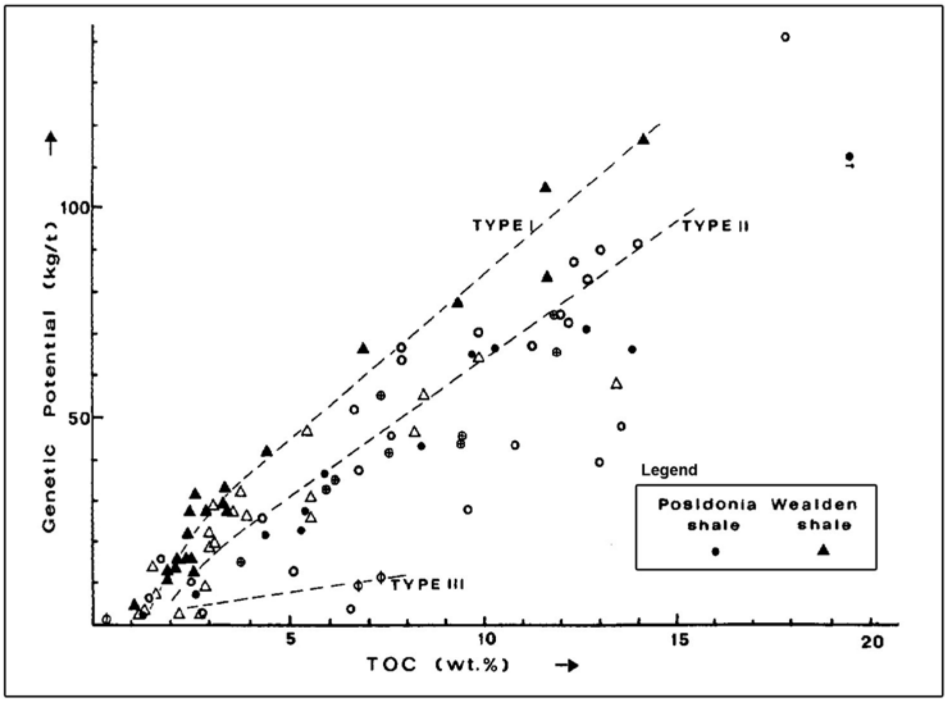
Figure XIII-17. Lower Saxony Basin North to South Cross Section, A to A’




Source: Kockel, 1994.

**Cretaceous (Berriasian) Wealden Shale.** The prospective area for the Wealden Shale is thermally mature for oil generation. The prospective area was defined by the depositional and depth limits of the Wealden Shale within the Lower Saxony Basin. In the prospective area, the depth of the Wealden Shale ranges from 3,300 feet to 10,000 feet, averaging 6,000 feet. The Wealden Shale has a gross organic-rich shale interval of 112 feet and 75 feet of net shale thickness[8]. The TOC in the Wealden Shale is highly variable, ranging from 1% to 14%, averaging 4.5% in the prospective area, Figure XIII-18. Thermal maturity ranges from 0.7% to 1.0% Ro, placing the Wealden Shale in the oil window.[8]

Figure XIII-18. Total Organic Content, Posidonia and Wealden Shales, Lower Saxony Basin




Source: Kockel, F., 1994.

## 3.4 Resource Assessment

**Jurassic Posidonia Shale.** We calculate that the prospective area of the Posidonia Shale in the Lower Saxony Basin has resource concentrations of 56 Bcf/mi$^2$ in the dry gas window, 44 Bcf/mi$^2$ of wet gas and 4 million barrels/mi$^2$ of condensate in the wet gas and condensate window, and 13 million barrels/mi$^2$ of oil in the oil window. Within the prospective area, the Posidonia Shale contains 78 Tcf of risked gas in-place, with 17 Tcf as the risked, technically recoverable shale gas resource (including associated gas), Table XIII-5. In addition, the Posidonia Shale contains 11 billion barrels of risked shale oil in-place, with 0.5 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-6.

**Cretaceous Wealden Shale**. The 720-mi$^2$ prospective area of the Wealden Shale in the Lower Saxony Basin has an oil resource concentration of 10 million barrels/mi$^2$. The risked oil in-place is 3 billion barrels, with 0.1 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-6. The oil prospective area of the Wealden Shale also contains in-place and risked, technically recoverable associated shale gas of 2 Tcf and 0.1 Tcf respectively.

### 3.5 Recent Activity

ExxonMobil has been the lead company active in the Lower Saxony Basin of Germany. The company has drilled a series of test wells on its exploration leases, at least three of which are reported to be testing shale gas potential. Starting in 2008, the company drilled the Damme 2/2A and Damme 3 test wells on its Munsterland concession and the Oppenwehe 1 exploration well on its Minden concession. In late 2010, the company spudded the Niederzwehren test well on its Schaumberg permit. After drilling these test wells, ExxonMobil halted operations in the province following the passage of a moratorium on hydraulic fracturing.

Realm Energy obtained a small, 25-square mile shale gas exploration permit in West Germany. The company plans to explore the oil and gas potential in the Posidonia and Wealden shales underneath its acreage. Realm's concession is valid for three years and does not require well drilling, but does provide the company with data from the 21 wells drilled on its acreage in past years.

BNK Petroleum has leased approximately 3,745 square miles for shale, CBM and tight gas sand exploration in West and Central Germany. The company has yet to drill on any of its properties, but reports "targeting shale formations," most likely the Posidonia and Wealden shales. Most of its concessions are not near areas with previously defined shale gas potential, suggesting the company is pursuing a wildcatting approach in Germany. To date, the company has not provided details of its drilling plans.

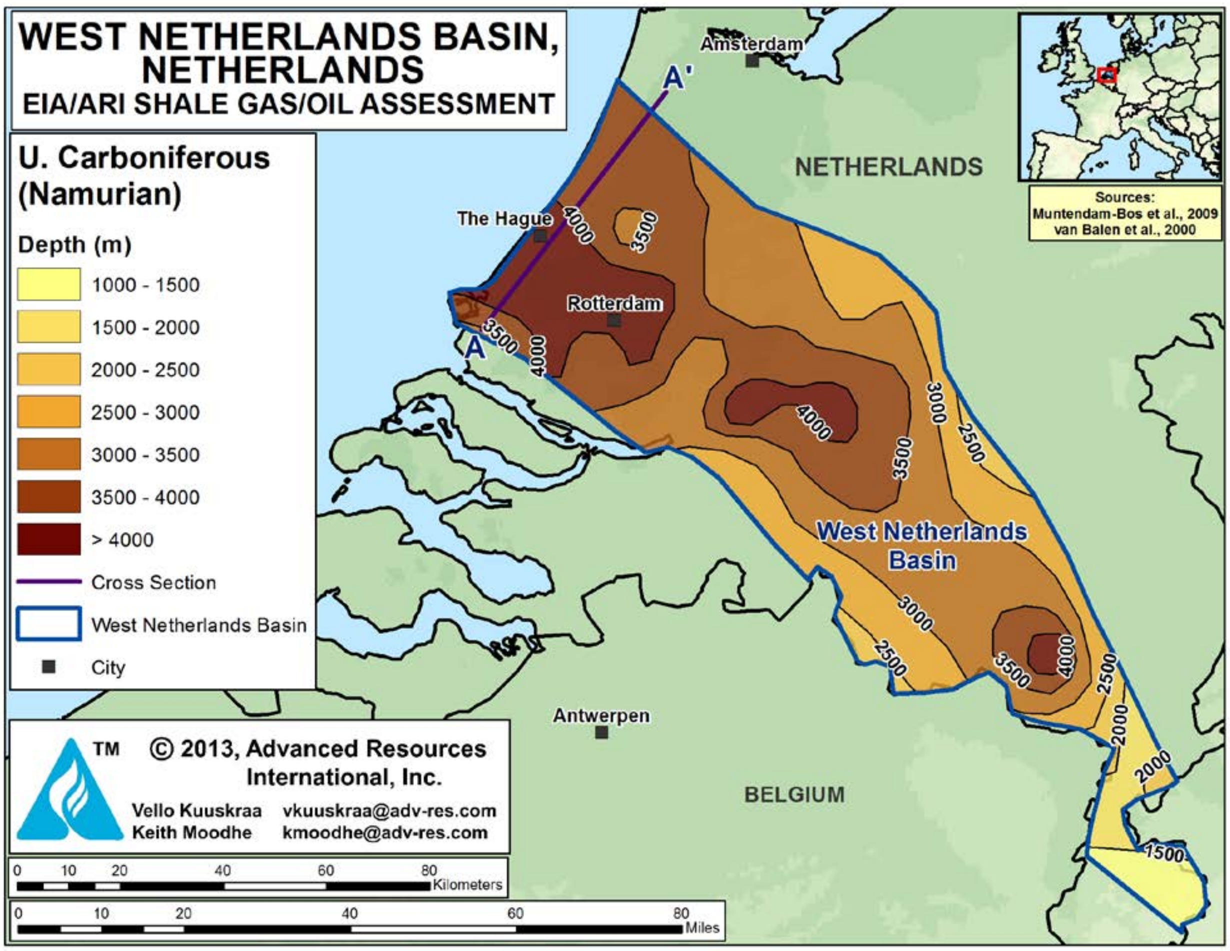
After a lengthy period of study, the German government issued, in late February 2013, draft legislation what would allow the development of shale and the use of hydraulic stimulation (fracturing) under environmental safeguards.

## 4. WEST NETHERLAND BASIN: NETHERLANDS

### 4.1 Introduction

The West Netherland Basin (WNB) is located in the southwestern portion of the Netherlands, extending into the offshore, Figure XIII-19. The basin is bounded in the south by the London-Brabant Massif and on the north by the Zandvoort Ridge. In the south-east, the WNB merges with the Ruhr Valley Graben. The West Netherlands Basin is part of a series of Late Jurassic to Early Cretaceous trans-tensional basins of Western Europe.

Figure XIII-19. Outline and Depth Map for West Netherland Basin, Netherlands




Source: ARI, 2013

For the West Netherland Basin, we estimate risked in-place shale gas of 151 Tcf, with 26 Tcf as the risked, technically recoverable shale gas resource, Table XIII-7. In addition, we estimate risked in-place shale oil of 59 billion barrels, with 2.9 billion barrels as the risked, technically recoverable shale oil resource, Table XIII-8.

Table XIII-7. Shale Gas Reservoir Properties and Resources of West Netherland Basin, Netherlands

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | West Netherlands ($2,750 mi^2$) | | | | |
| | Shale Formation | | Epen | | Geverik Member | Posidonia | |
| | Geologic Age | | U. Carboniferous | | U. Carboniferous | L. Jurassic | |
| | Depositional Environment | | Lacustrine | | Marine | Marine | |
| Physical Extent | Prospective Area ($mi^2$) | | 1,460 | 860 | 2,320 | 850 | 170 |
| | Thickness (ft) | Organically Rich | 1,500 | 1,500 | 225 | 100 | 100 |
| | | Net | 450 | 450 | 135 | 90 | 90 |
| | Depth (ft) | Interval | 3,300 - 10,000 | 10,000 - 15,500 | 5,000 - 16,400 | 3,300 - 9,000 | 9,000 - 12,500 |
| | | Average | 8,500 | 12,500 | 11,000 | 6,500 | 10,500 |
| Reservoir Properties | Reservoir Pressure | | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. |
| | Average TOC (wt. %) | | 2.4% | 2.4% | 4.0% | 6.0% | 6.0% |
| | Thermal Maturity (% Ro) | | 0.85% | 1.15% | 1.15% | 0.85% | 1.15% |
| | Clay Content | | Medium | Medium | Low/Medium | Low/Medium | Low/Medium |
| Resource | Gas Phase | | Assoc. Gas | Wet Gas | Wet Gas | Assoc. Gas | Wet Gas |
| | GIP Concentration ($Bcf/mi^2$) | | 60.6 | 139.2 | 48.5 | 10.2 | 38.5 |
| | Risked GIP (Tcf) | | 39.8 | 53.9 | 50.6 | 3.9 | 2.9 |
| | Risked Recoverable (Tcf) | | 4.0 | 10.8 | 10.1 | 0.4 | 0.6 |

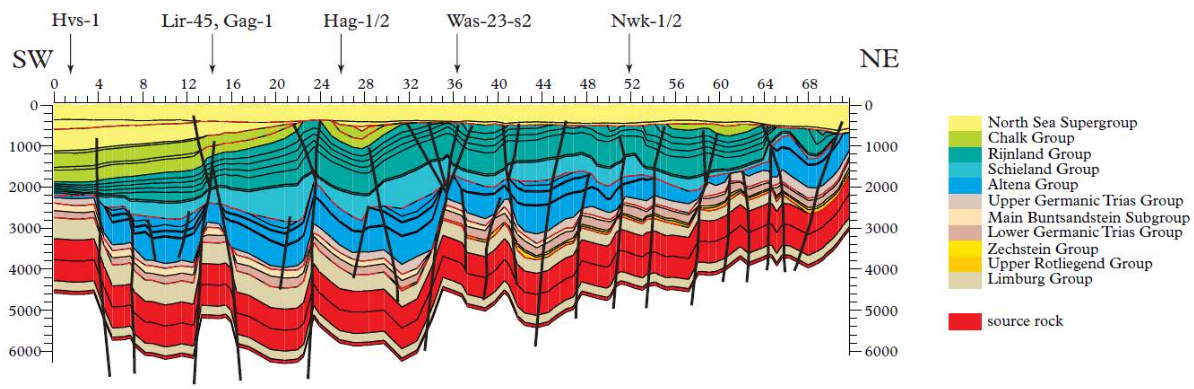
Table XIII-8. Shale Oil Reservoir Properties and Resources of West Netherland Basin, Netherlands

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | West Netherlands ($2,750 mi^2$) | | | | |
| | Shale Formation | | Epen | | Geverik Member | Posidonia | |
| | Geologic Age | | U. Carboniferous | | U. Carboniferous | L. Jurassic | |
| | Depositional Environment | | Lacustrine | | Marine | Marine | |
| Physical Extent | Prospective Area ($mi^2$) | | 1,460 | 860 | 2,320 | 850 | 170 |
| | Thickness (ft) | Organically Rich | 1,500 | 1,500 | 225 | 100 | 100 |
| | | Net | 450 | 450 | 135 | 90 | 90 |
| | Depth (ft) | Interval | 3,300 - 10,000 | 10,000 - 15,500 | 5,000 - 16,400 | 3,300 - 9,000 | 9,000 - 12,500 |
| | | Average | 8,500 | 12,500 | 11,000 | 6,500 | 10,500 |
| Reservoir Properties | Reservoir Pressure | | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. | Mod. Overpress. |
| | Average TOC (wt. %) | | 2.4% | 2.4% | 4.0% | 6.0% | 6.0% |
| | Thermal Maturity (% Ro) | | 0.85% | 1.15% | 1.15% | 0.85% | 1.15% |
| | Clay Content | | Medium | Medium | Low/Medium | Low/Medium | Low/Medium |
| Resource | Oil Phase | | Oil | Condensate | Condensate | Oil | Condensate |
| | OIP Concentration ($MMbbl/mi^2$) | | 60.4 | 19.0 | 6.1 | 13.2 | 4.1 |
| | Risked OIP (B bbl) | | 39.7 | 7.4 | 6.3 | 5.0 | 0.3 |
| | Risked Recoverable (B bbl) | | 1.98 | 0.37 | 0.32 | 0.25 | 0.02 |

## 4.2 Geologic Setting

The West Netherland Basin (WNB), while commonly described as a single structural entity, contains a series of smaller structural elements bounded by long, northwest-trending faults. The complex tectonic features present in this basin are illustrated by the northeast to southwest cross-section (A-A') located on the far western portion of the basin, Figure XIII-20.[10] (The location of the cross-section is shown on Figure XIII-19.)

Figure XIII-20. Cross-Section A to A', Western Portion of West Netherland Basin.

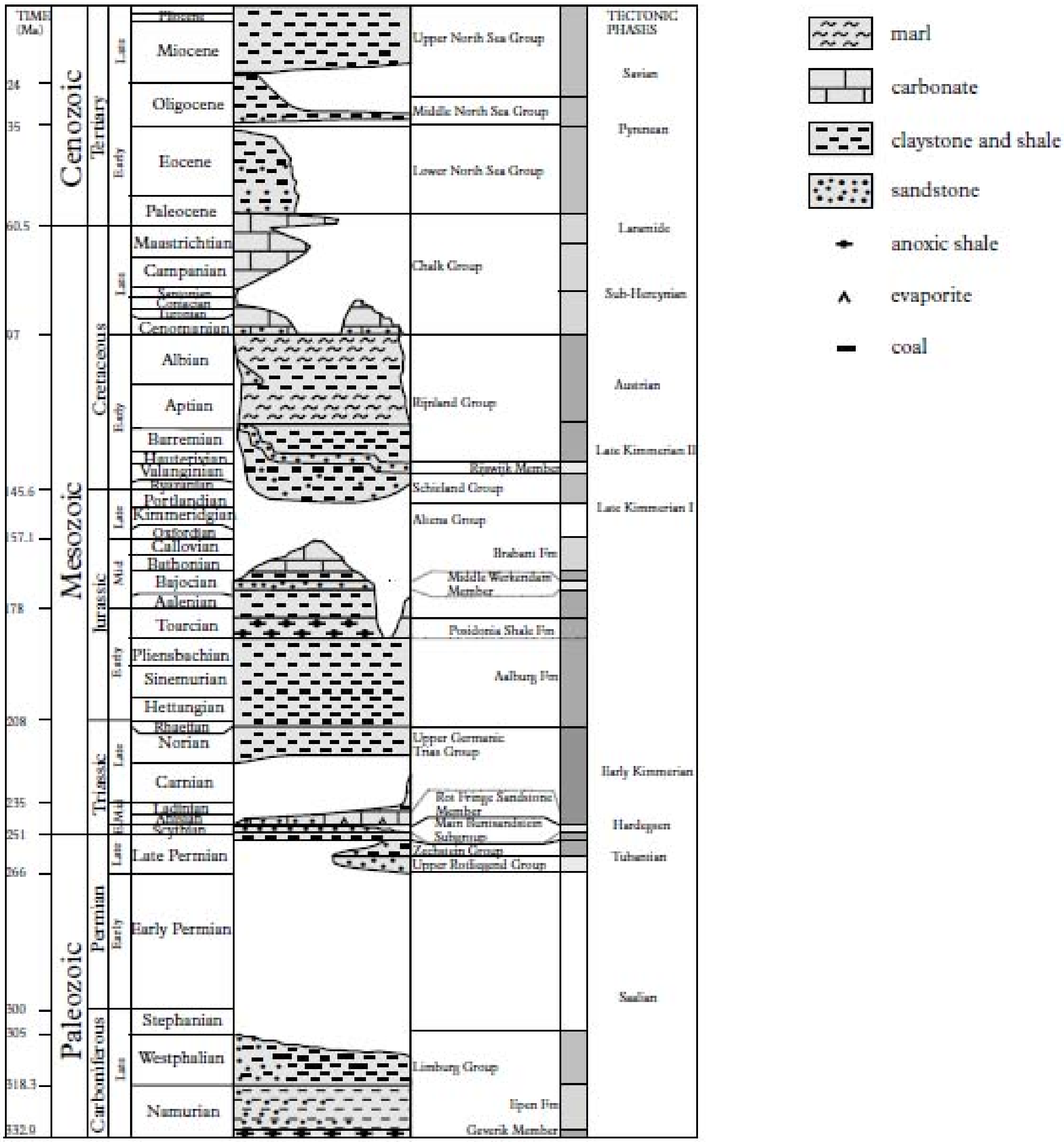



Source: van Balen, R.T. et al., 2000.

The WNB contains a series of prospective shale formations, including two Carboniferous (Namurian) shale formations, the Epen Formation and the Geverik Member, plus the Lower Jurassic (Toarcian) Posidonia Shale, Figure XIII-21.[10] Based on analysis of core and cutting samples from the deep Geverik-1 exploration well, located in the southeastern part of the basin, the Epen Shale contains Type III kerogen, with lacustrine-deltaic deposition, while the Geverik Shale contains Type II kerogen, with open-marine deposition. The Posidonia Shale contains Type II marine kerogen.

Additional shale source rocks exist in the WNB, particularly in Late Jurassic and Late Carboniferous intervals. However, these shales are considered of minor importance or contain significant inter-beds of coal.[10] Thus, these shales have been excluded from the quantitative resource assessment. An excellent, comprehensive review of the shale formations of the Netherlands is provided in the TNO report entitled, "Inventory Non-Conventional Gas" by A.G. Muntendam-Bos et al., 2009.[11]

Figure XIII-21. Stratigraphic Section for West Netherland Basin.




Numerical ages in the Namurian and Jurassic to Tertiary are after Harland et al. (1990), in the Triassic and Permian after Menning (1995), and in the Westphalian and Stephanian after Lippolt et al. (1984).
Source: van Balen, R.T. et al., 2000.

For the Epen Shale, we have mapped a 1,460-mi$^2$ area prospective for oil and associated gas and a smaller 860-mi$^2$ area prospective for wet gas and condensate, Figure XIII-22. For the Geverik Shale, we have mapped a 2,320-mi$^2$ area prospective for wet gas and condensate, Figure XIII-23. For the Posidonia Shale, we have mapped a 850-mi$^2$ area prospective for oil and a smaller 170-mi$^2$ area prospective for wet gas and condensate, Figure XIII-24.

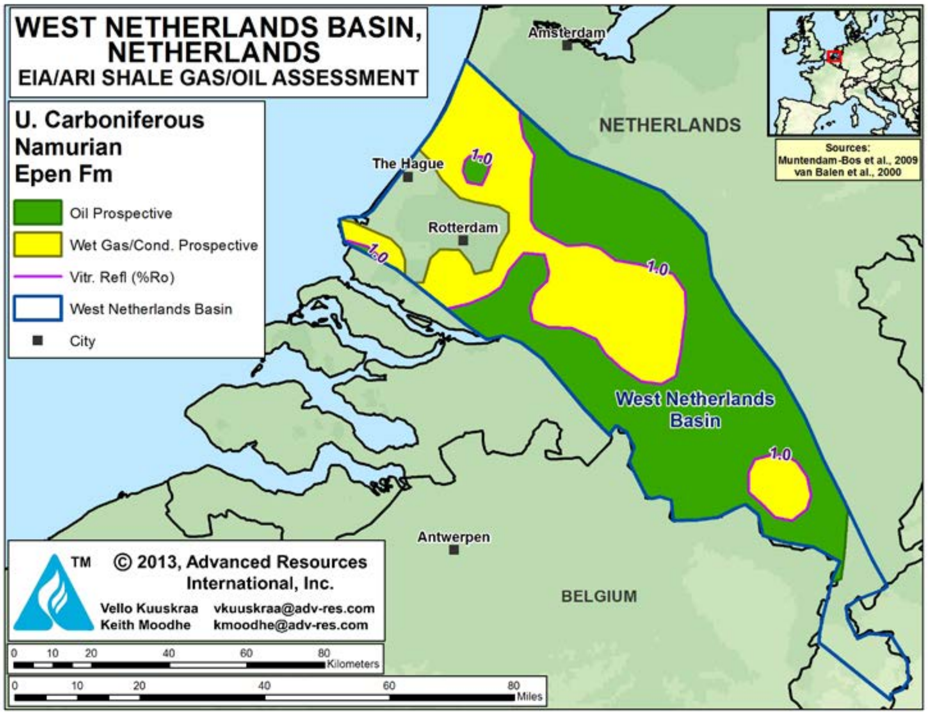
## 4.3 Reservoir Properties (Prospective Area)

**Carboniferous (Namurian) Epen and Geverik Shales**. As discussed above, the Carboniferous (Namurian) sequence in the Netherlands contains two prospective shale formations, the Epen and Geverik. The key technical paper by R. T. van Balen, et al. (2000)[10] and data provided in the more recent TNO report (Muntendam-Bos, A.G., et al., 2009)[11] were used to establish prospective areas including information on depth, thermal maturity and thickness for these two shale gas formations.

Depth to the Epen Shale ranges from 3,300 feet to 16,400 feet, averaging 8,500 feet in the oil prospective area and averaging 12,500 feet in the wet gas/condensate prospective area. In the west-central portion of the WNB, the depth of the Epen Shale is below 5,000 m. As such, this portion of the basin has been excluded from the prospective area. The Epen Shale's oil prospective area has a thermal maturity of 0.7% to 1.0% $R_o$ in the southern portion of the basin and along the shallower basin edges. In the center of the basin, the thermal maturity of the shale ranges from 1.0% to 1.3% Ro, placing the shale in the wet gas/condensate window. The Epen Shale is very thick, with a gross organic-rich thickness of 1,500 feet and a net thickness of 450 feet, based on an estimated 30% net to gross ratio. Total organic content ranges from 1% to 15%, averaging 2.4%. The shale is over-pressured and because of its lacustrine deposition has medium assumed clay content.

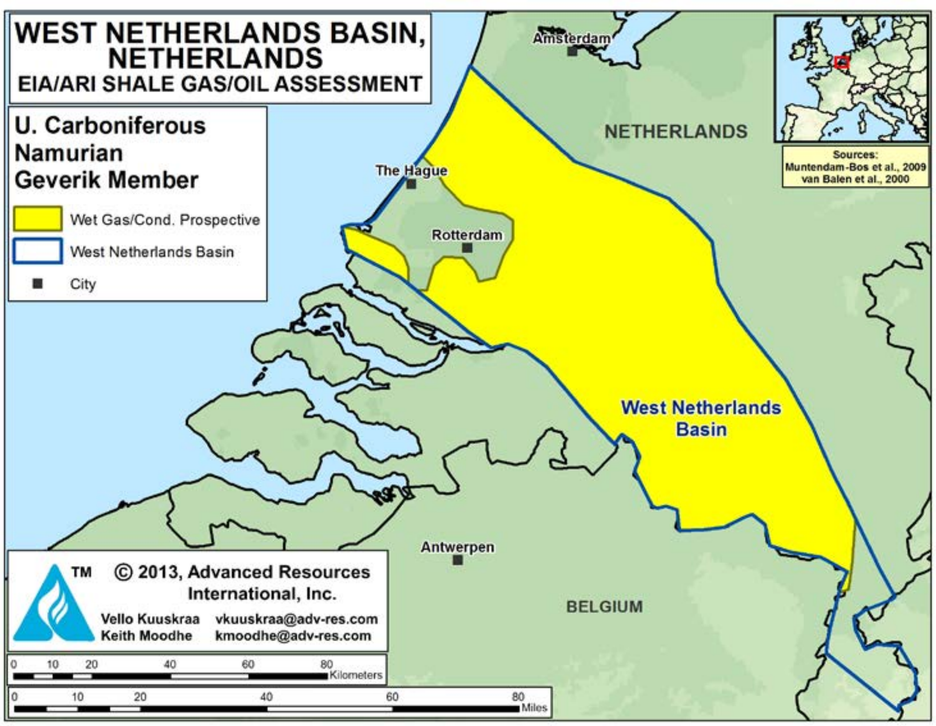
Depth to the underlying Geverik Shale ranges from 5,000 feet to 16,400 feet, averaging 11,000 feet in the wet gas/condensate prospective area. As for the Epen Shale, the deep west-central portion of the basin below 5,000 m has been excluded. The Geverik Shale has an organic-rich gross interval of 225 feet, with an estimated 135 feet of net pay, based on an estimated 60% net to gross ratio. The thermal maturity of this deeper shale ranges from 1.0% to 1.3%, placing the Geverik Shale in the wet gas and condensate window. Total organic content of the shale ranges from 2% to 7%, averaging 4%. The shale is over-pressured and due to its marine deposition has low to medium assumed clay content.

Figure XIII-22. Prospective Areas for Epen Shale, West Netherland Basin.



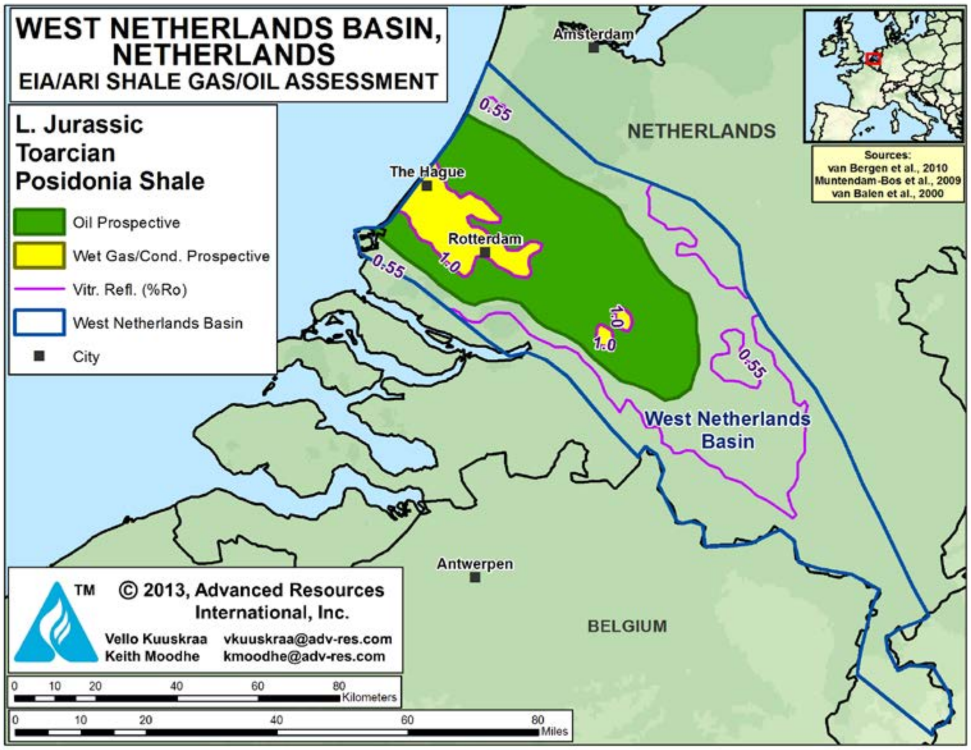

Source: ARI, 2013

Figure XIII-23. Prospective Areas for Geverik Shale, West Netherland Basin.




Source: ARI, 2013

Figure XIII-24. Prospective Area for Posidonia Shale, West Netherland Basin.




Source: ARI, 2013

**Jurassic (Toarcian) Posidonia Shale.** The shallower Posidonia Shale overlies the Carboniferous Epen and Geverik shales in the West Netherland Basin. The shale has reservoir properties similar to the Posidonia Shale in the Lower Saxony Basin of Germany, discussed previously. A total of 140 wells have been drilled through the Posidonia Shale, providing valuable data and control for this resource assessment.

The depth of the Posidonia Shale ranges from 3,300 feet on the margins of the prospective area to 12,500 feet in the basin center, averaging 6,500 feet in the oil prospective area and 10,500 feet in the wet gas/condensate prospective area. In the shallower portions of the prospective area, the Posidonia Shale has a thermal maturity of 0.7% to 1.0% $R_o$ (oil window). In the deeper basin center, Posidonia Shale has a thermal maturity of 1.0% to 1.3% $R_o$ (wet gas/condensate window). The gross organic-rich shale interval is 100 feet, with 90 feet of net pay. The shale contains Type II marine kerogen with a TOC that ranges from less than 1% to a maximum of 16%, averaging 6%. The formation is slightly over-pressured with low to medium clay content.

## 4.4 Resource Assessment

**Carboniferous (Namurian) Epen Shale.** We estimate that the prospective area of the Epen Shale in the West Netherland Basin contains risked shale gas in-place of 94 Tcf, with 15 Tcf as the risked, technically recoverable shale gas resource (including both wet shale gas and associated shale gas). In addition, we estimate that the Epen Shale in this basin has risked in-place shale oil/condensate of 47 billion barrels, with 2.4 billion barrels as the risked, technically recoverable shale oil resource.

**Carboniferous (Namurian) Geverik Shale.** We estimate that the prospective area of the Geverik Shale in the West Netherland Basin contains risked shale gas in-place of 51 Tcf, with 10 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate that the Geverik Shale in this basin has risked in-place shale oil/condensate of 6 billion barrels, with 0.3 billion barrels as the risked, technically recoverable shale oil resource.

**Jurassic (Toarcian) Posidonia Shale.** We estimate that the prospective area of the Posidonia Shale in the West Netherland Basin contains risked shale gas in-place of 7 Tcf, with 1 Tcf as the risked, technically recoverable shale gas resource (including both wet shale gas and associated shale gas). In addition, we estimate that the Posidonia Shale in this basin has risked in-place shale oil/condensate of 5 billion barrels, with 0.3 billion barrels as the risked, technically recoverable shale oil resource.

## 4.5 Recent Activity

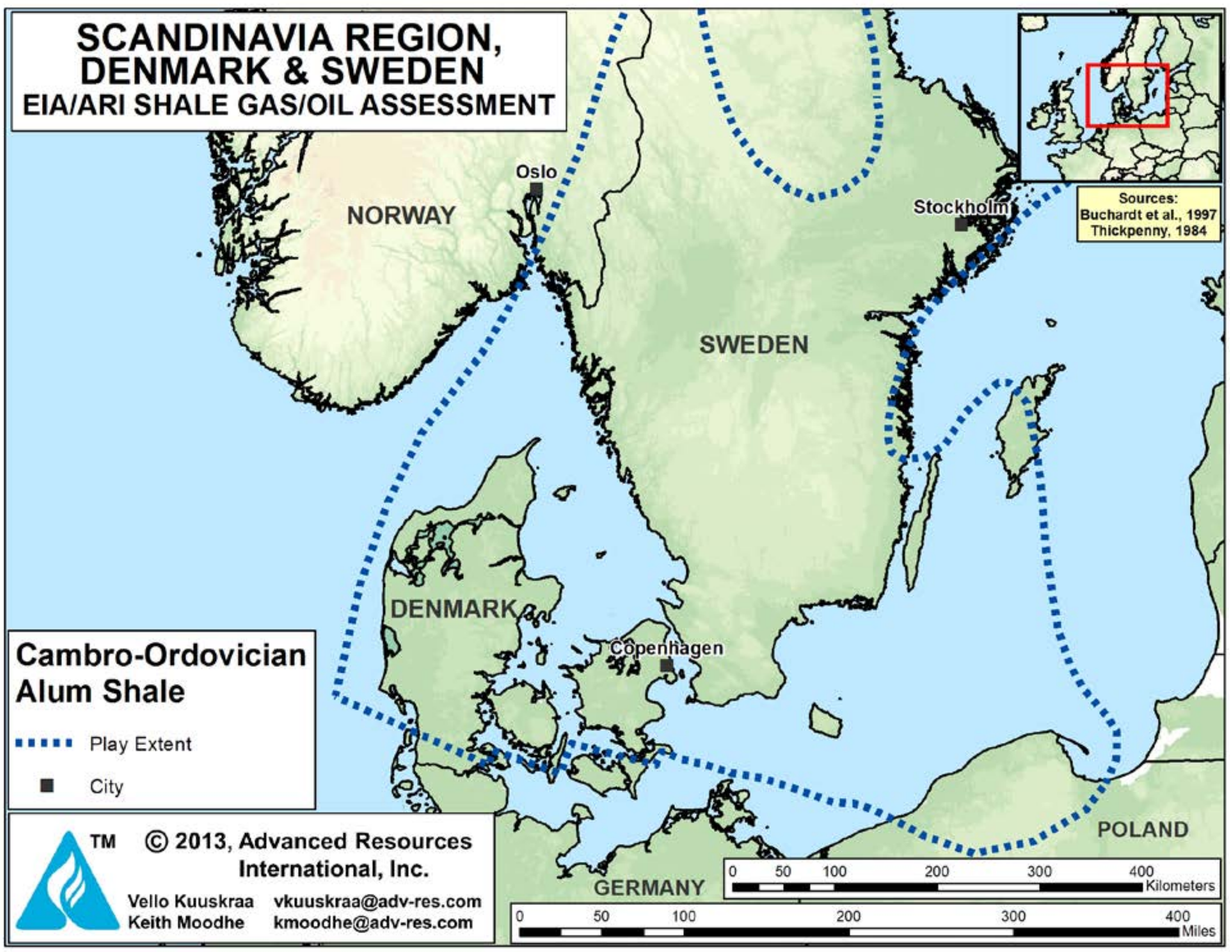
Three companies have acquired shale gas and oil leases in the Netherlands. Cuadrilla Resources and DSM Energie have leases in the West Netherland Basin while Queensland Gas Company (now part of BG Group) has leases in north-central Netherlands. Beyond the earlier exploratory wells that helped define the shale resources in the West Netherland Basin, we are not aware of any recent shale gas or oil development in the Netherlands.

# 5. SCANDINAVIA

## 5.1 Introduction

The Cambrian-Ordovician (Lower Paleozoic) Alum Shale underlies significant portions of Scandinavia, including Sweden, Denmark and potentially Norway, Figure XIII-25. However, in much of this area the Alum Shale is shallow, thin and immature. The outline of the Alum Shale depositional area examined by this shale resource assessment is bounded on the west by the Caledonia Deformation Front and outcrops of the Alum Shale. The basin is bounded on the east by the inferred depositional limits of the Lower Paleozoic and on the south by the 2.7% ($R_o$) thermal maturity contour.

Figure XIII-25. Outline Map for Alum Shale of Scandinavia




Source: ARI, 2013

For the Alum Shale in Sweden, we estimate risked in-place shale gas of 49 Tcf, with 10 Tcf as the risked, technically recoverable shale gas resource. For the Alum Shale in Denmark, we estimate risked in-place shale gas of 159 Tcf, with 32 Tcf as the risked, technically recoverable shale gas resource, Table XIII-9. A modest volume of shale gas may exist in the Oslo Graben of Norway. However, there is not sufficient data to reliably estimate the size of Norway's shale resource. Our shale gas resource estimates are preliminary and have been highly risked, awaiting more definite information from industry's planned exploration efforts, particularly in Denmark.

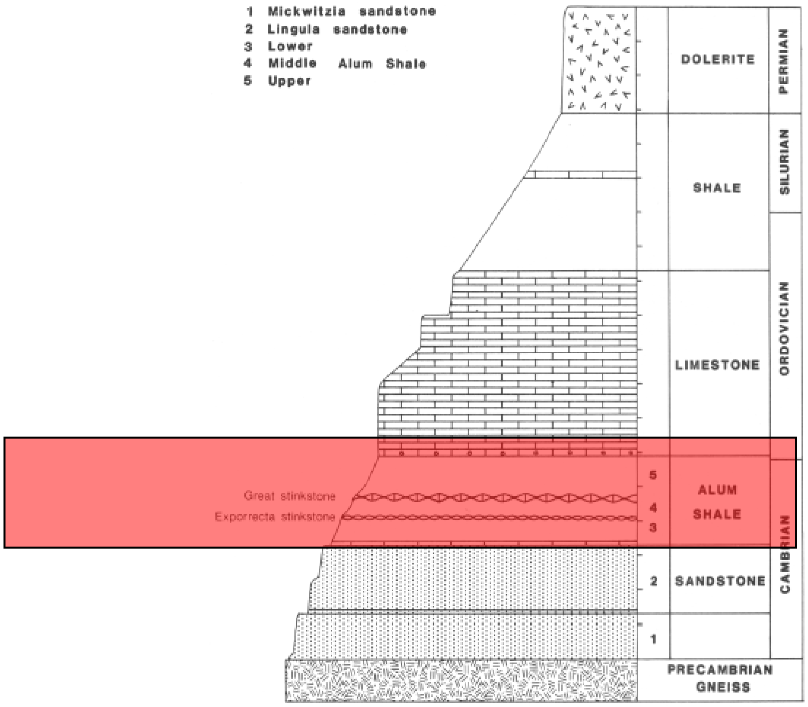
Table XIII-9. Shale Gas Reservoir Properties and Resources of Scandinavia

| | Basin/Gross Area | | Scandinavia Region (90,000 mi$^2$) | |
|---|---|---|---|---|
| Basic Data | Shale Formation | | Alum Shale - Sweden | Alum Shale - Denmark |
| | Geologic Age | | Cambro-Ordovician | Cambro-Ordovician |
| | Depositional Environment | | Marine | Marine |
| Physical Extent | Prospective Area (mi$^2$) | | 2,120 | 5,980 |
| | Thickness (ft) | Organically Rich | 250 | 250 |
| | | Net | 200 | 200 |
| | Depth (ft) | Interval | 3,300 - 7,000 | 11,000 - 15,000 |
| | | Average | 5,000 | 13,500 |
| Reservoir Properties | Reservoir Pressure | | Normal | Normal |
| | Average TOC (wt. %) | | 7.5% | 7.5% |
| | Thermal Maturity (% Ro) | | 2.00% | 2.00% |
| | Clay Content | | Low | Low |
| Resource | Gas Phase | | Dry Gas | Dry Gas |
| | GIP Concentration (Bcf/mi$^2$) | | 76.8 | 110.5 |
| | Risked GIP (Tcf) | | 48.9 | 158.6 |
| | Risked Recoverable (Tcf) | | 9.8 | 31.7 |

## 5.2 Geologic Setting

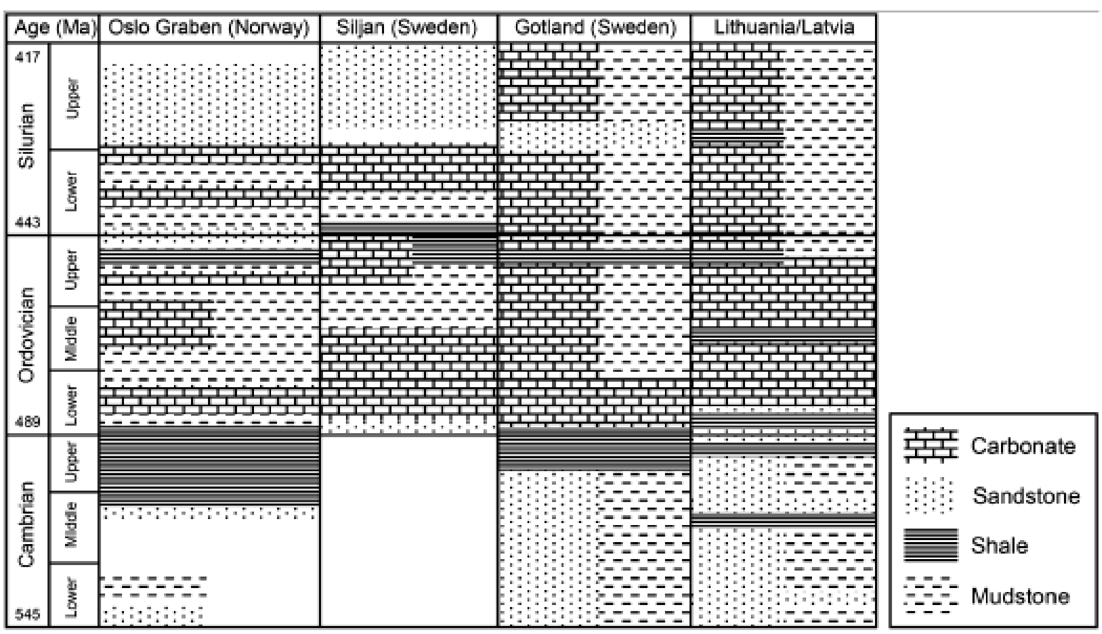
The depositional setting of the Cambrian-Ordovician Alum Shale in southern Sweden and northern Denmark has been mapped in the technical literature. Outcrops of the Alum Shale exist along the Caledonian Mountain belt along the Sweden-Norway border and in southern Sweden. Figure XIII-26 provides the stratigraphic position of the Alum Shale in Sweden. Figure XIII-27, compiled from a variety of sources, indicates the presence of the Alum Shale in the Oslo Graben of Norway and on Gotland in Sweden. While the stratigraphy of the Alum Shale has only moderate variation in central Sweden, the structural setting becomes complex along the Caledonian Front in Norway, western Sweden and northern Denmark.

Figure XIII-26. Stratigraphic Column for Cambrian Through Permian, Sweden




Source: Thickpenny, A, 1984.

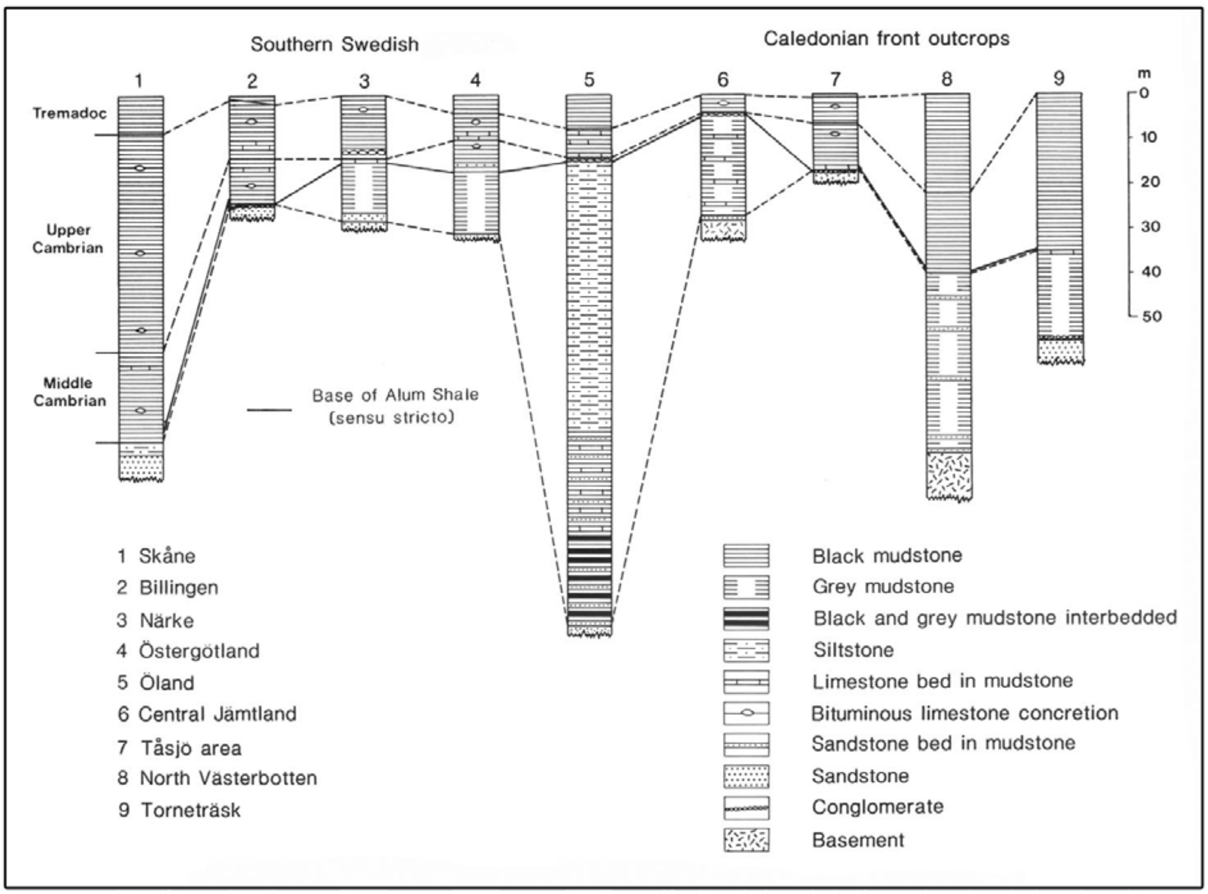
Figure XIII-27. Generalized Lower Paleozoic Stratigraphy for the Scandinavia-Baltic Region.




Modified from Bjørlykke (1974), Vlierboom et al. (1986), Thickpenny and Leggett (1987), Brangulis et al. (1993), Zdanaviciute and Bojesen-Kofoed (1997), Bondar et al. (1998), Sivhed et al. (2004).
Source: Pedersen, J.H., 2007

The Alum Shale contains a series of distinct lithotypes, as shown by the cross-section of data from selected outcrop areas in southern Sweden and the Caledonian Front, Figure XIII-28. Two of these lithotypes are important shale source rocks. The first is the black organic-rich mudstone with TOC of 5% to 7% in the Middle Cambrian, reaching up to 20% in the Upper Cambrian.[12] This interval contains 30% to 40% illite clay, and ±25% quartz, plus pyrite and K-feldspar. The second is the black and gray (dark brown) inter-bedded mudstone, with TOC of about 5%. Grey mudstone, bituminous limestone and thin sandstone, siltstone lamina constitute the remaining lithotypes. The Alum Shale was deposited in a relatively shallow, anoxic marine environment.

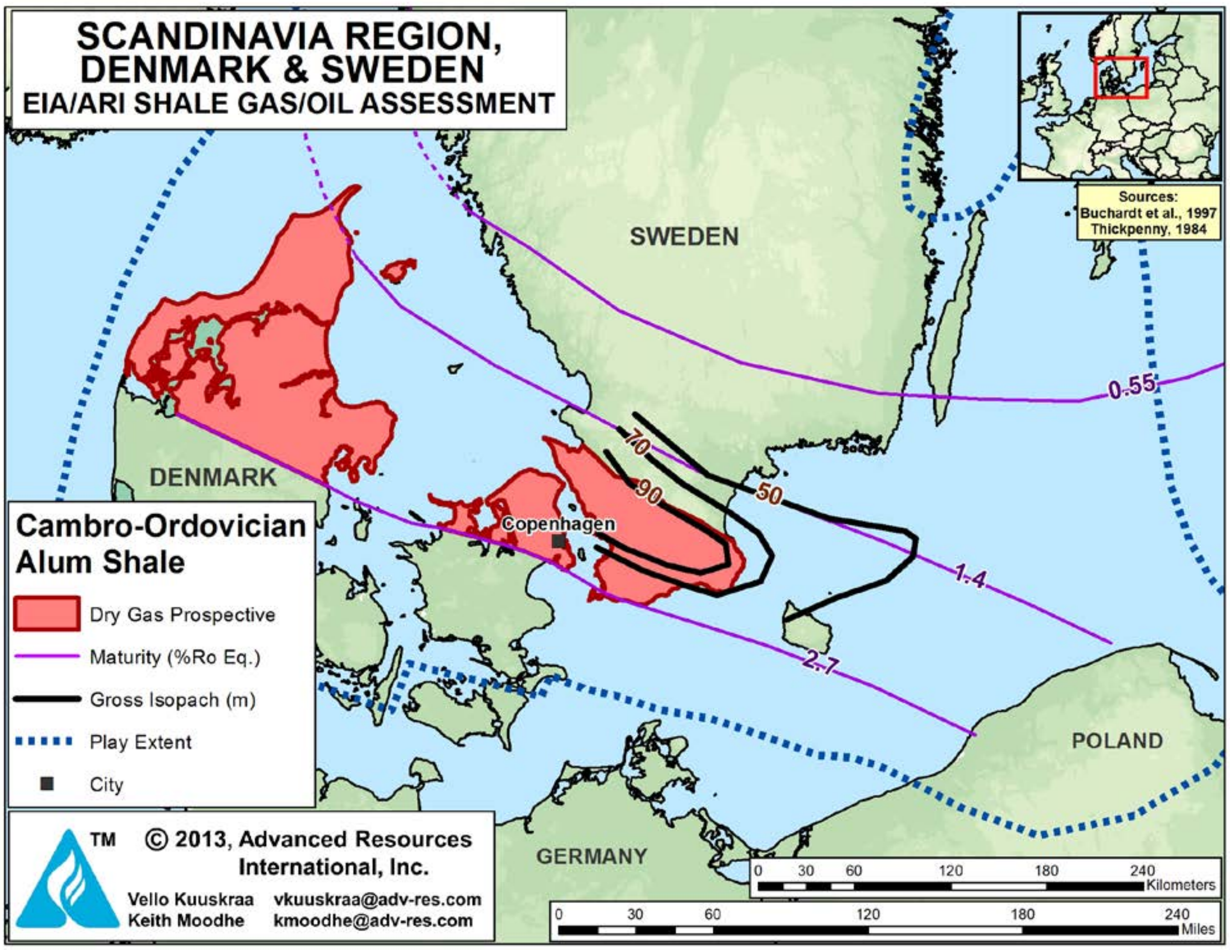
Figure XIII-28. Comparative Middle and Upper Cambrian Stratigraphic Columns for Selected Outcrop Areas in Scandinavia




Source: Thickpenny, 1984

Except for outcroppings and data from shallower wells, rigorous data on the properties of the Alum Shale are scarce. ARI has identified an 8,100-mi$^2$ prospective area where the shale is deposited below 3,300 feet at depth and where the thermal maturity data indicate the shale is inside the gas window, Figure XIII-29. The bulk of the Alum Shale prospective area is in northern Denmark, encompassing 5,680 mi$^2$. The remaining 2,120-mi$^2$ prospective area for the Alum Shale is in southern Sweden.

Figure XIII-29. Prospective Areas for Alum Shale in Denmark and Sweden.




Source: ARI, 2013.

The outlines of the Alum Shale prospective area are based on thermal maturity of 2.7% $R_o$ on the south and the 3,300-foot depth limit (plus outcrops of the shale in the Skane area) on the north. Data from well drilling by Shell provided information on the depth of the Alum Shale in southern Sweden.

## 5.3 Reservoir Properties (Prospective Area)

The depth of the Alum Shale ranges from 3,300 feet in southern Sweden to 15,000 feet in northern Denmark. We have assumed a depth of 5,000 feet for the dry gas prospective area in Sweden and a depth of 13,500 feet for the two dry gas prospective areas in Denmark.

The thickness of the Alum Shale generally ranges from 20 to 60 m, but can reach 80 to 100 m in the Skane area and 200 m or more in repeated sequences due to multiple thrust faults along the Caledonian Front.[13,14] The Alum Shale gross thickness is relatively constant, ranging from 250 to 300 feet in the prospective area, Figure XIII-29. We have assumed a relatively high net to gross ratio of 80%, giving a net shale thickness of 200 feet. Since we include both the high TOC black shale and the lower TOC dark brown shale in our net pay, we use an average TOC of 7.5%. The Alum Shale formation is normally pressured, has moderately high clay content and is structurally complex, making the shale a high risk play.

## 5.4 Resource Assessment

For the Alum Shale in Sweden, we calculate a resource concentration of 77 Bcf/mi$^2$. Based on this and a 2,120-mi$^2$ prospective area, we estimate risked shale gas in-place of 49 Tcf, with 10 Tcf as the risked, technically recoverable shale gas resource, Table XIII-9.

For the Alum Shale in Denmark, we calculate a resource concentration of 110 Bcf/mi$^2$. Based on this and a 5,980-mi$^2$ prospective area, we estimate risked shale gas in-place of 159 Tcf, with 32 Tcf as the risked, technically recoverable shale gas resource, Table XIII-9.

Additional investigation and data are required to establish the shale resources of Norway, particularly in the deeper Oslo Graben.

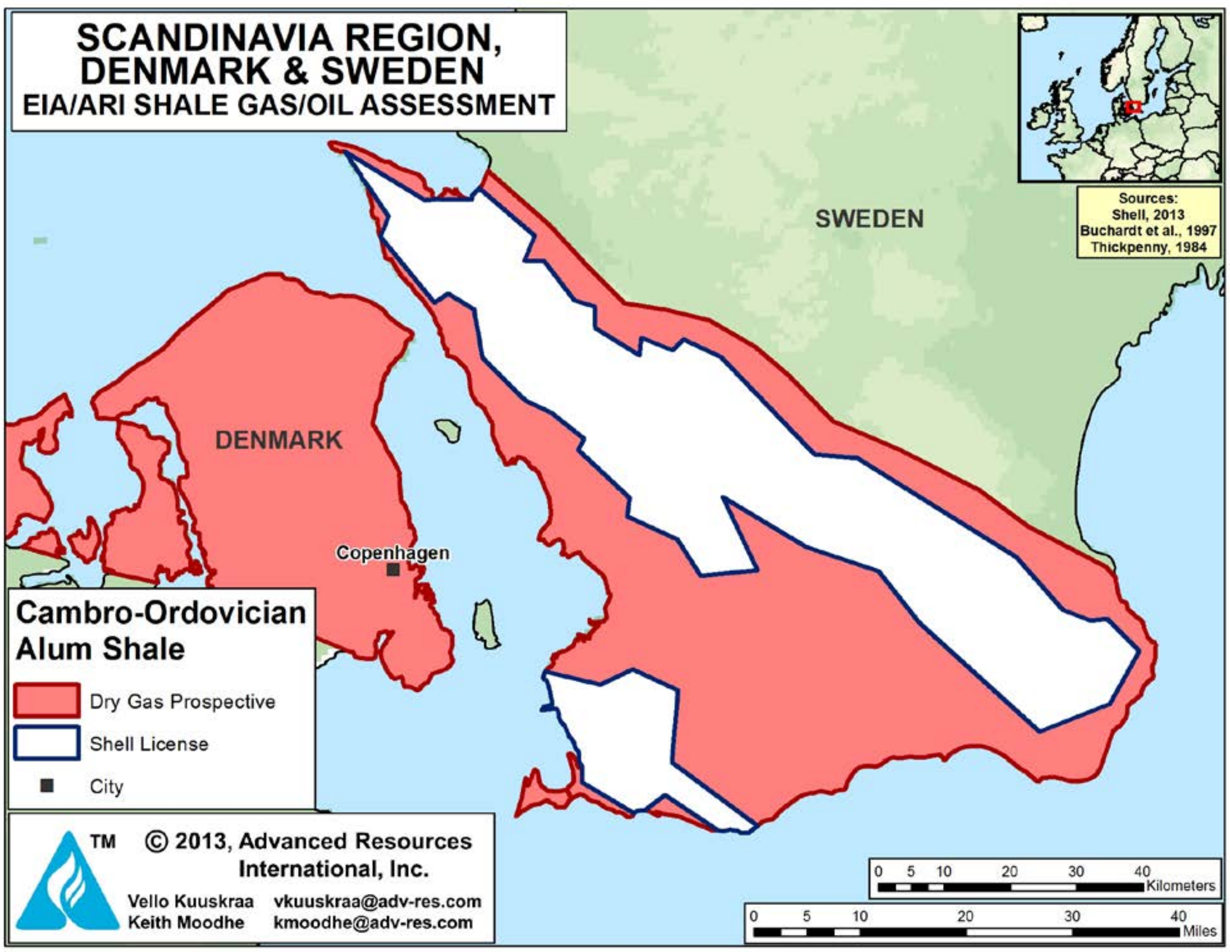
## 5.5 Recent Activity

The Alum Shale has a rich exploration history that dates back to the 1600s with the extraction of alum salt. Subsequently, the Alum Shale was mined for oil shale in 1930 to 1950 and later as a source for uranium. [15]

Of the numerous companies that have applied for exploration licenses in Sweden, Shell Oil has been the most active. Shell drilled three wells on their 400-mi$^2$ lease area in the Skane Region of Southern Sweden between 2008 to 2011, Figure XIII-30. However, according to information from the Geologic Survey of Denmark and Greenland, “They drilled three wells, but found it uneconomic."[15] Other companies with Alum Shale exploration licenses in Sweden are Gripen Gas and Energigas, with twelve licenses in south-central Sweden. However, Gripen Gas is pursuing biogenic source gas with a series of exploration wells in the shallow portion of the Alum Shale.

In Denmark, Total E&P Denmark B.V. is exploring for deep shale gas in two license areas in northern Denmark. Total submitted the work program for the first exploration well, Vendsyssel-1, in late 2012 and plans a six year exploration program to determine whether their lease areas contain sufficient shale gas resources to warrant further development.

Figure XIII-30. Shell Oil License Areas, Alum Shale, Sweden




Source: ARI, 2013.

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