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Technically Recoverable Shale Oil and Shale Gas Resources:

Other Western Europe

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Contents

Executive Summary

Introduction

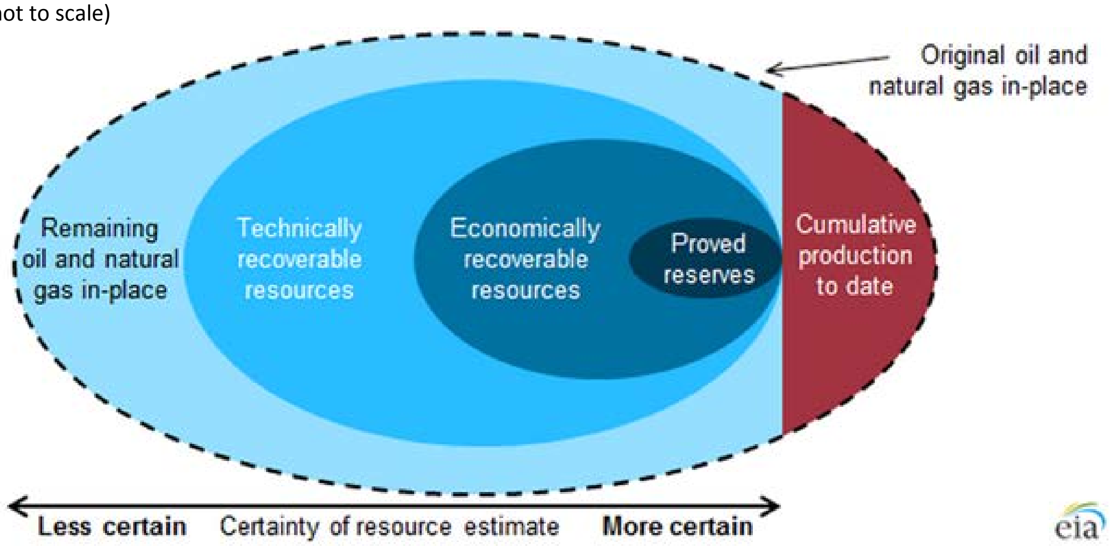
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

Resource categories

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

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

(not to scale)



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Methodology

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

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

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

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

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

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

Key exclusions

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

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

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

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

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

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

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

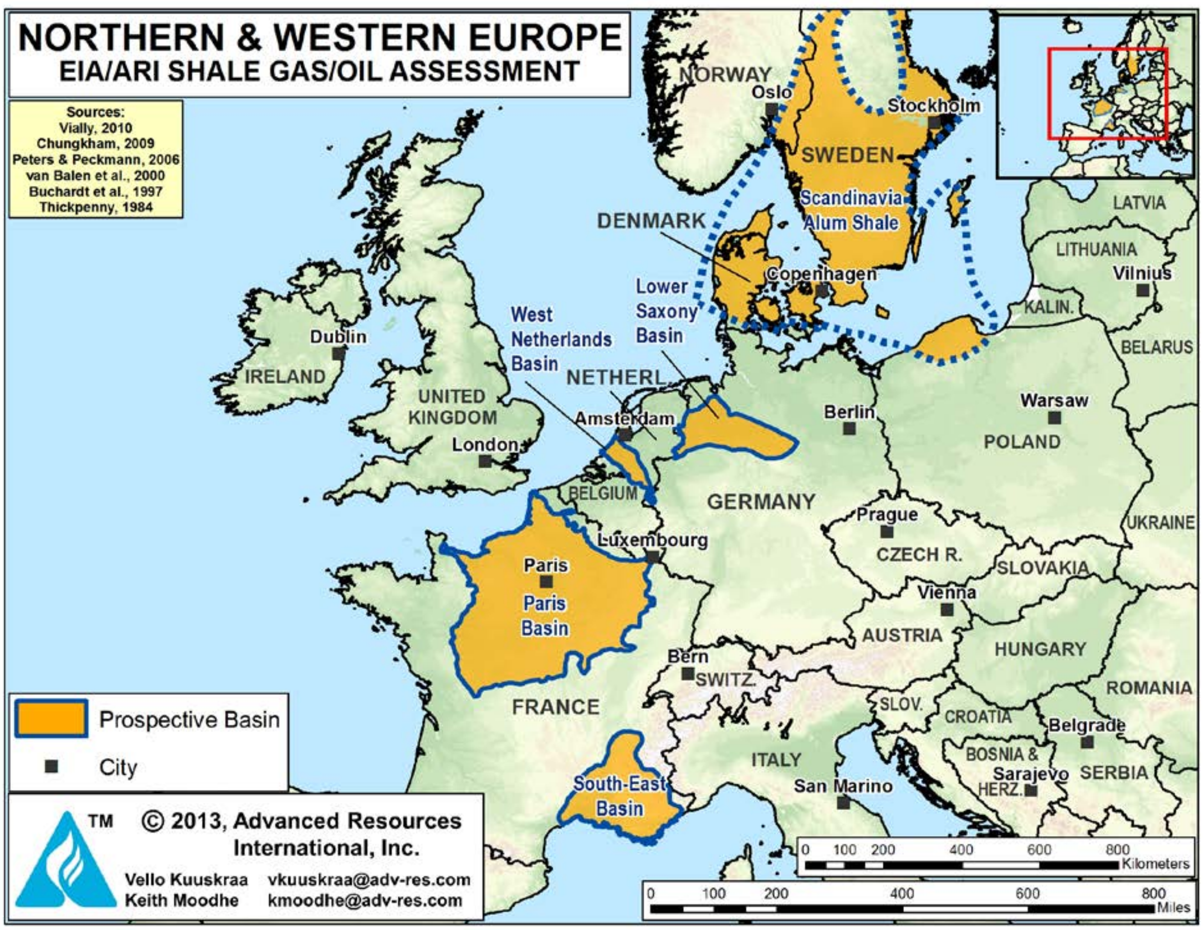
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

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

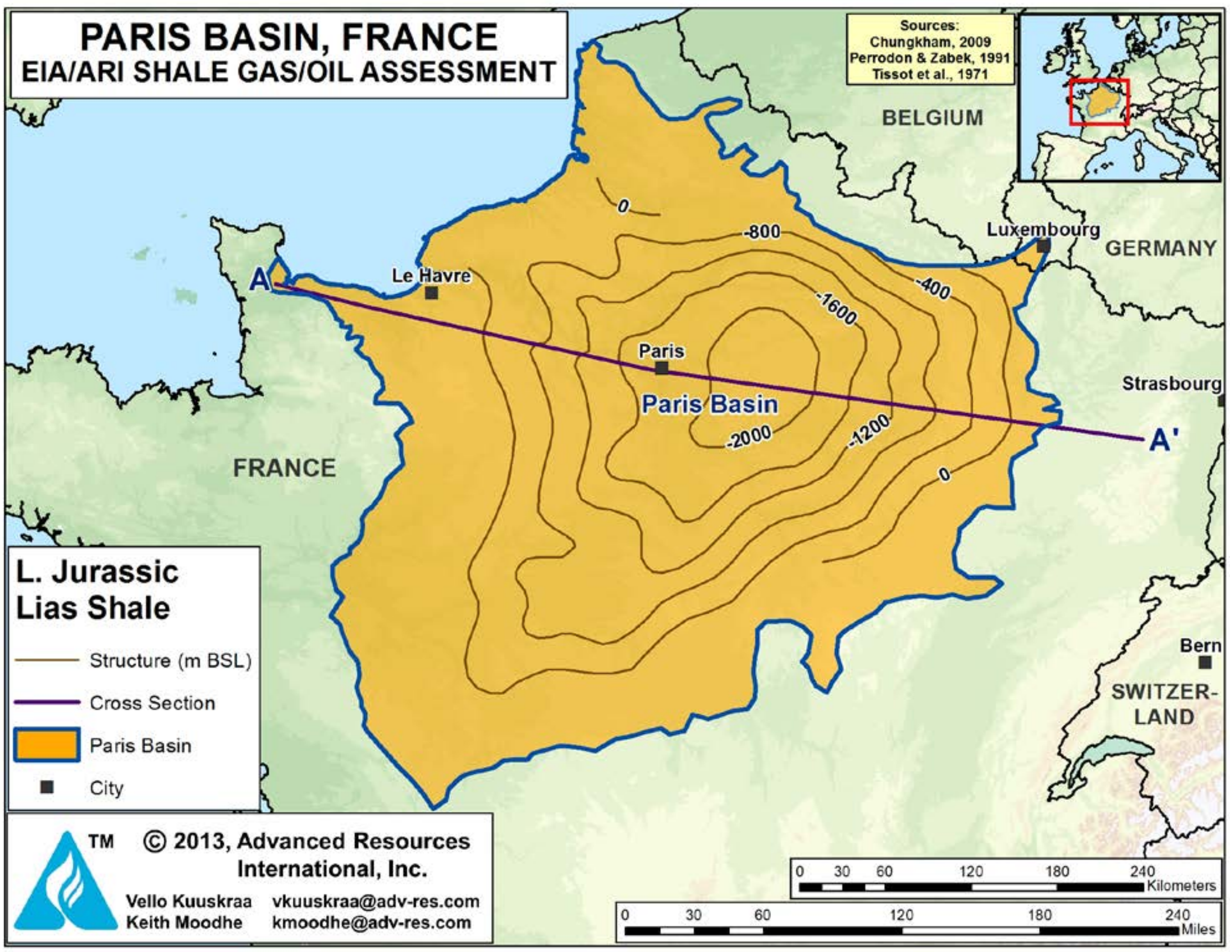
	Risked Shale Gas Resources		Risked Shale Oil Resources	
Basin/Formation	**In-Place (Tcf)**	**Technically Recoverable (Tcf)**	**In-Place (B bbl)**	**Technically Recoverable (B bbl)**
1. Paris Basin (France)				
·L. Jurassic Lias	23.8	1.9	38.0	1.52
·Permian-Carboniferous	666.1	127.3	79.5	3.18
Total	689.9	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

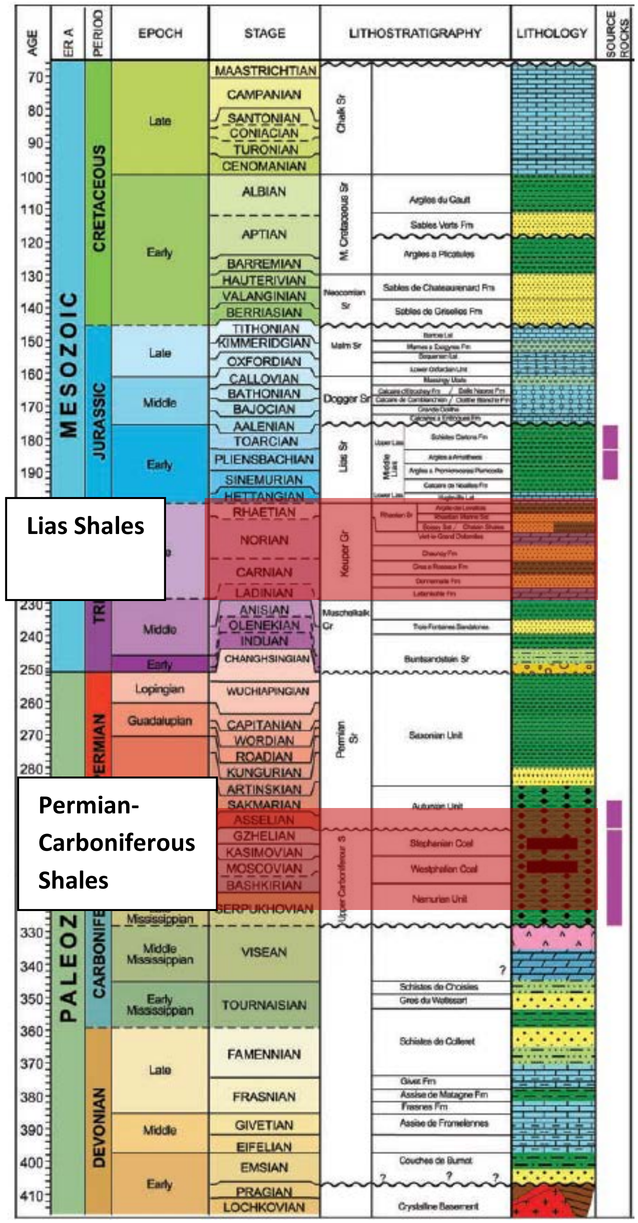
The Paris Basin contains two shale plays addressed by this resource study - - the Lower Jurassic Lias Shale and the Permian-Carboniferous Shale, Figure XIII-3[1]. The Jurassic Lias Shale is composed of three distinct organic-rich black shales - - the Hettangian-Sinemurian (Lower Lias) Shale, the Pliensbachian (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.

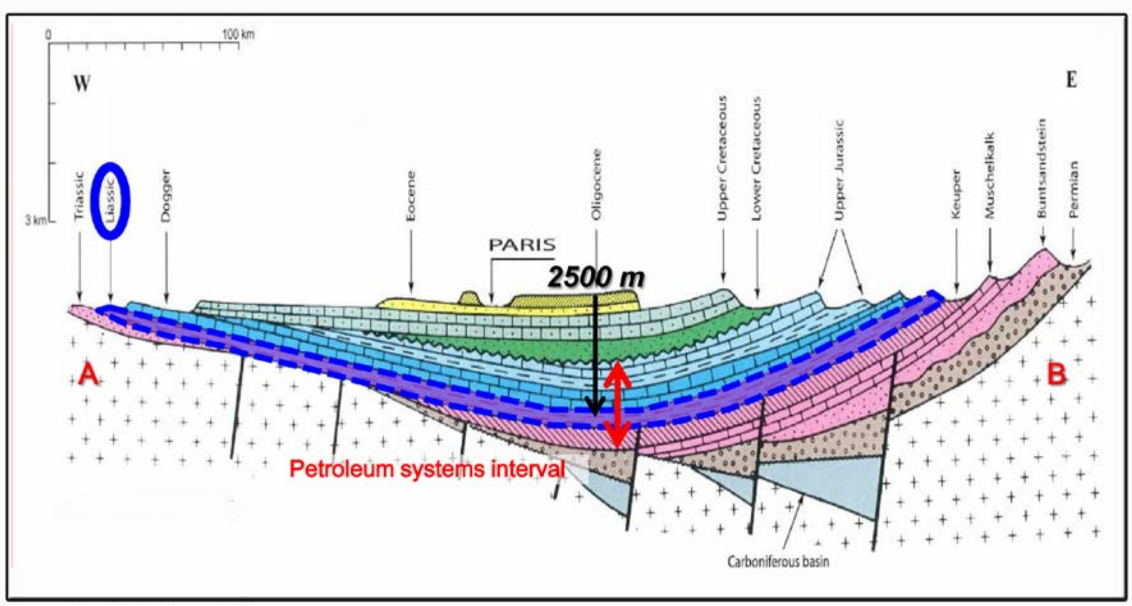
Figure XIII-5 provides an east to west cross-section across the Paris Basin, identifying the Permian-Carboniferous Shale in the eastern portion of the basin.[1] The shales have fluvial and lacustrine deposition raising concern with respect to higher clay content and less brittle reservoir rock. The kerogen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

Figure XIII-3. East Paris Basin Stratigraphic Column



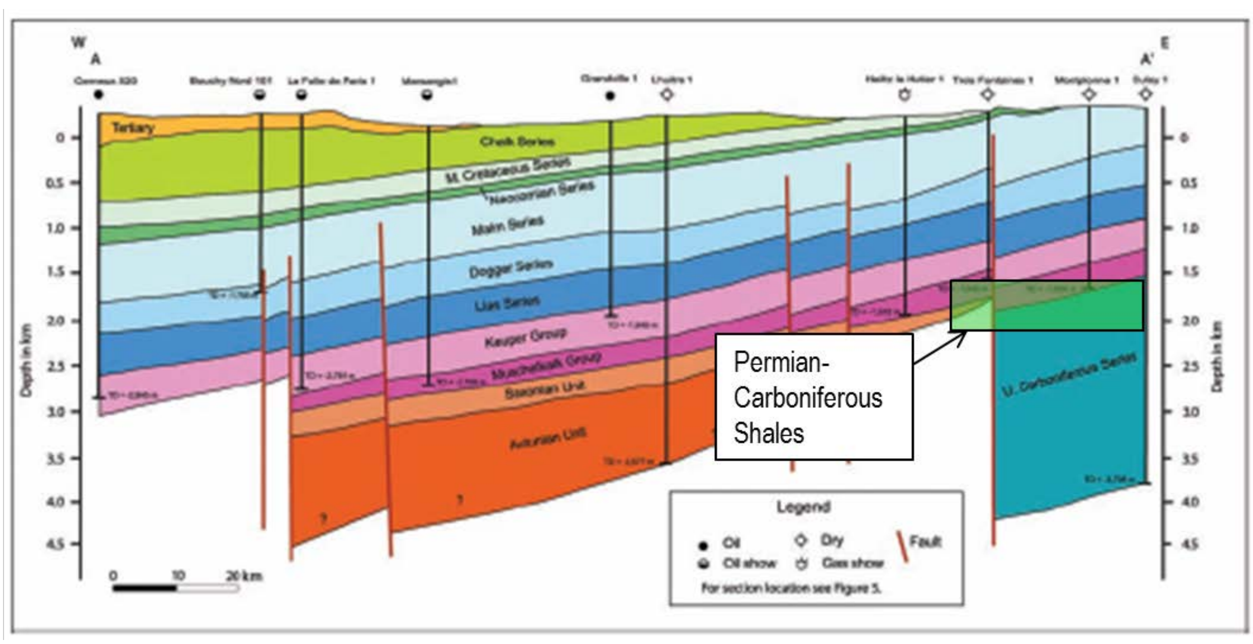
Source: Chungkham, 2009

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

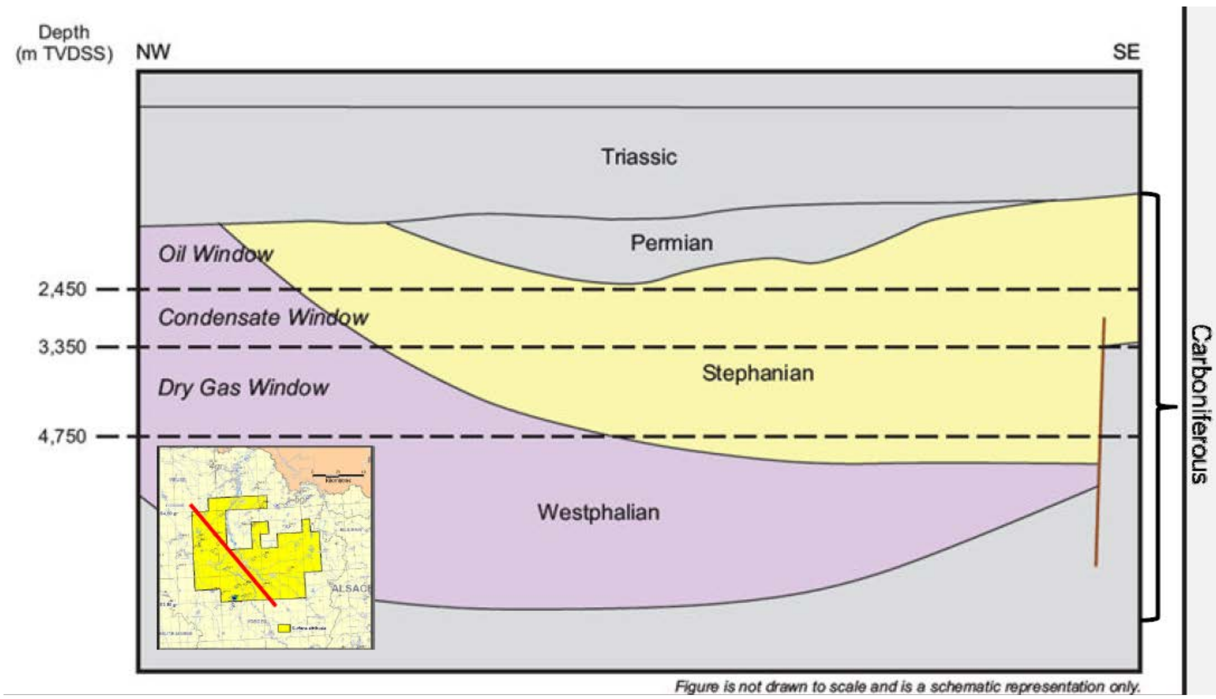


Source: Chungkham, 2009

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%.

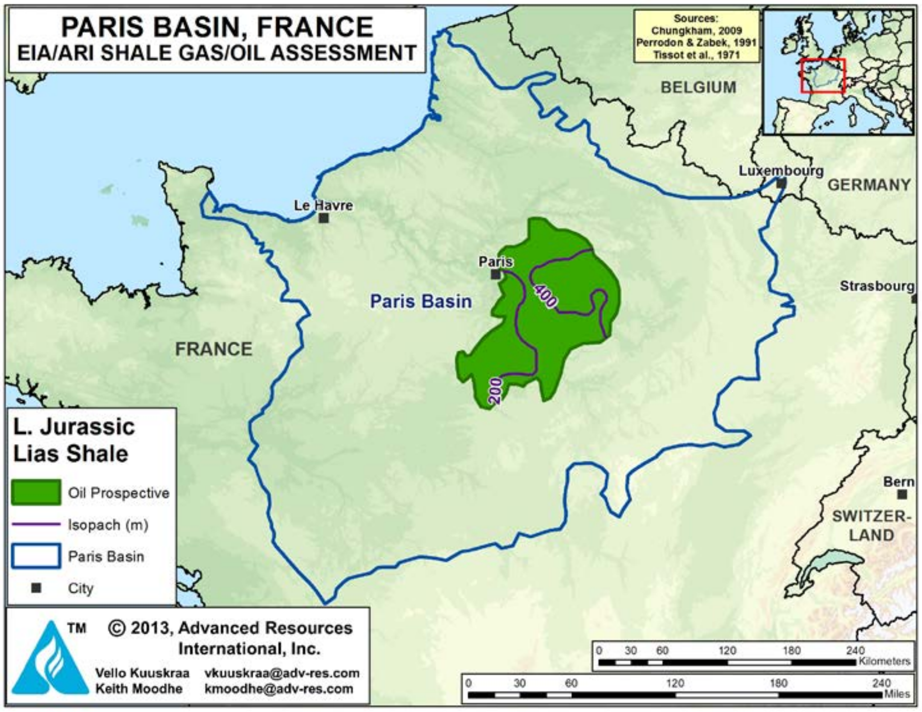
The shales are assumed to be normally pressured, given the presence of vertical fractures (and higher vertical permeability). The shale appears to be medium in clay content, lower in calcite (10% to 30%) and quartz (5% to 20%).

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.

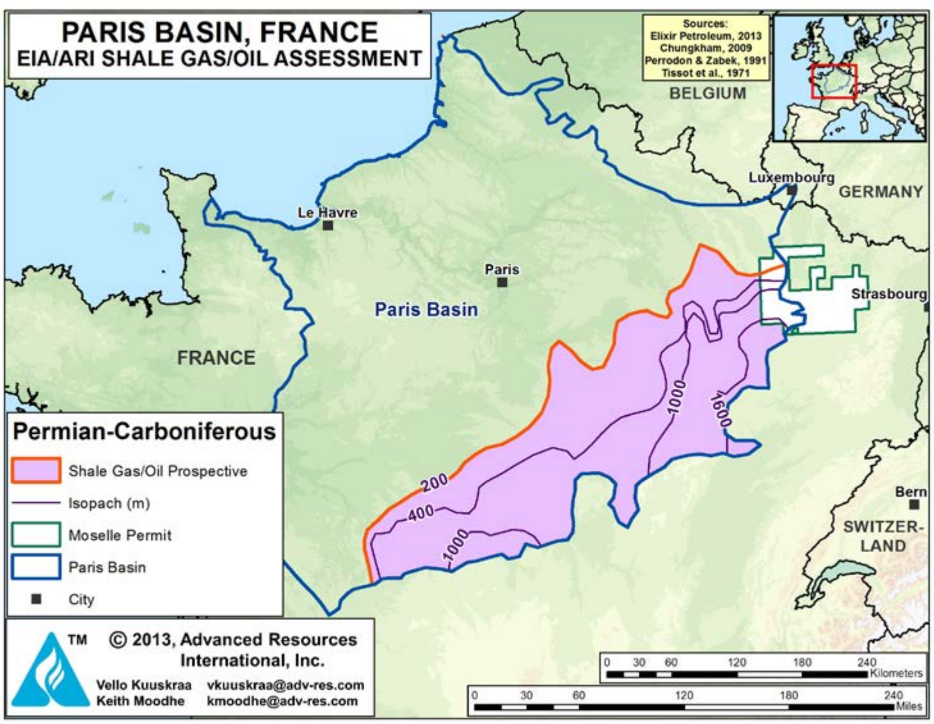
The depth of the Permian Carboniferous Shale ranges from 6,000 feet to 16,400 feet, averaging 7,000 feet in the oil window, 10,000 feet in the wet gas/condensate window, and 14,200 feet in the dry gas window. A significant portion of the Upper Carboniferous Namurian section is at depths below 5,000 m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

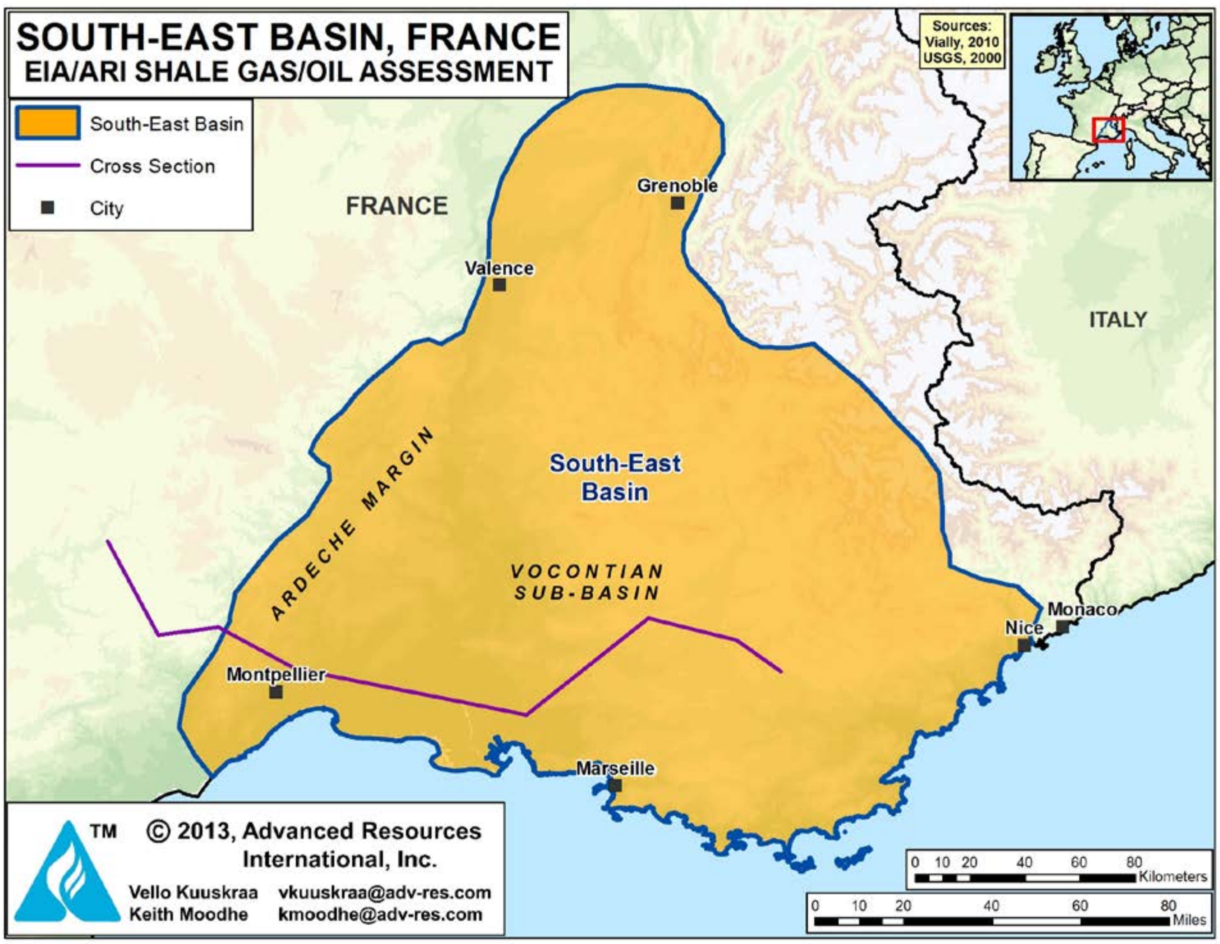
Most of the past exploration in the Paris Basin has targeted the Jurassic-age Lias Shale oil play. However, some firms are beginning to acquire acreage in the eastern portions of the Paris Basin where the Permian-Carboniferous Shale formation is the target. The 2,070 mi^2 Moselle Permit and its Permian-Carboniferous 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.

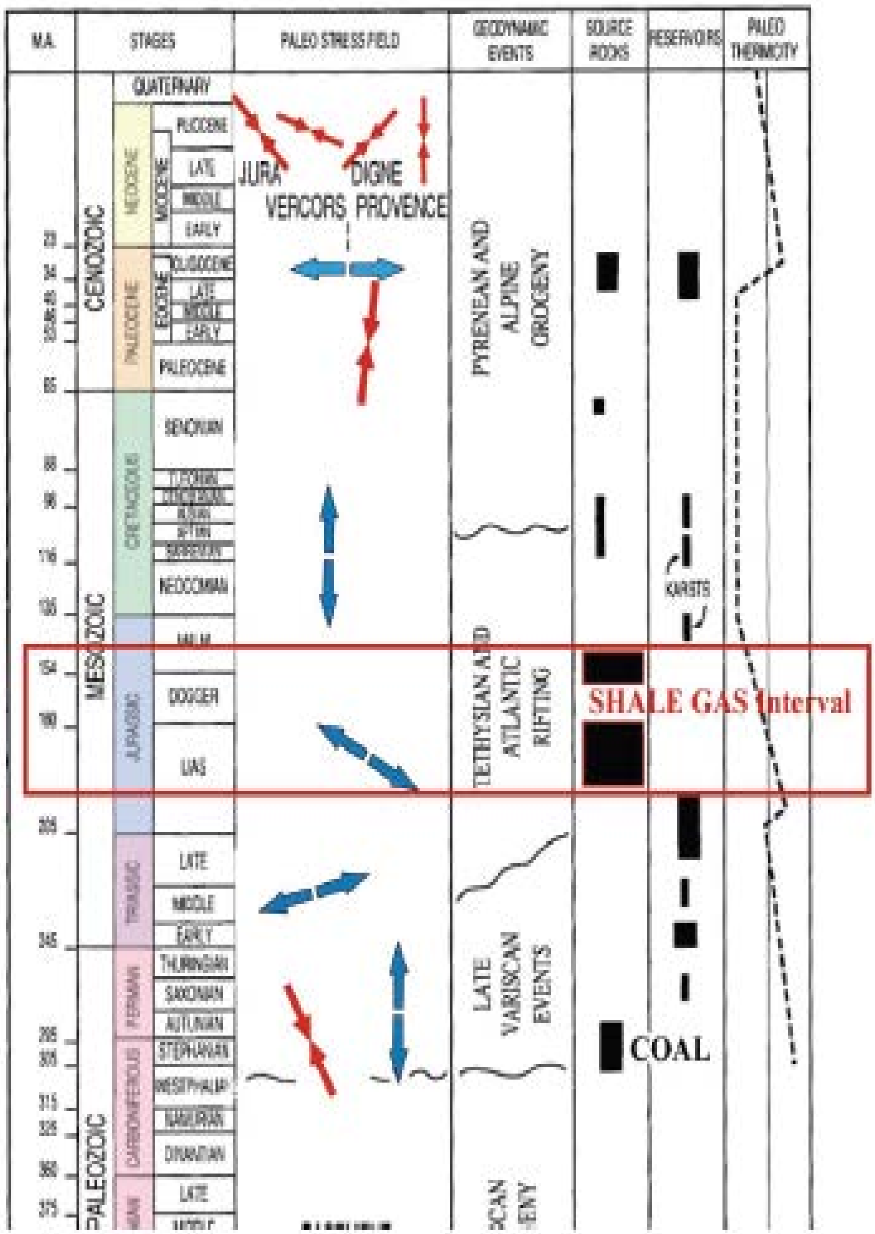
Table XIII-4. Shale Gas Reservoir Properties and Resources for the South-East Basin

Basic Data	Basin/Gross Area		South-East ($17,800 mi^2$)
	Shale Formation		Lias Shale
	Geologic Age		L. Jurassic
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		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/mi^2)		54.4
	Risked GIP (Tcf)		37.0
	Risked Recoverable (Tcf)		7.4

2.2 Geologic Setting

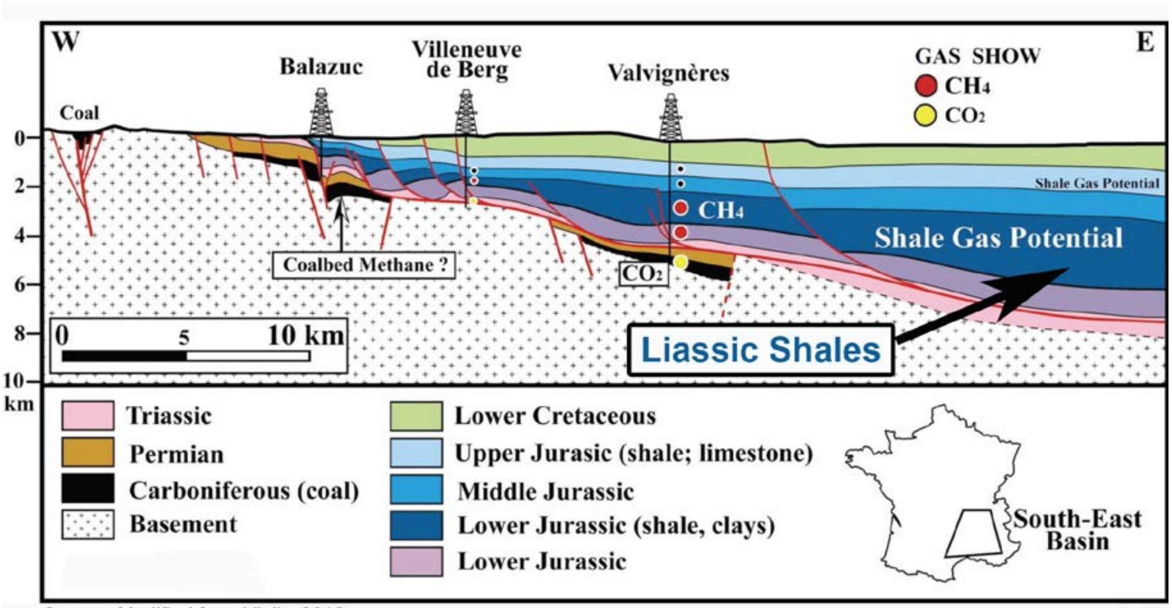
This study examined the shale gas potential of two formations in the South-East Basin, the Upper Jurassic "Terres Niores" black shale, and the Lower Jurassic Liassic black shale, Figure XIII-10. These shales are composed of Type II marine organic matter and were deposited during a time of subsidence 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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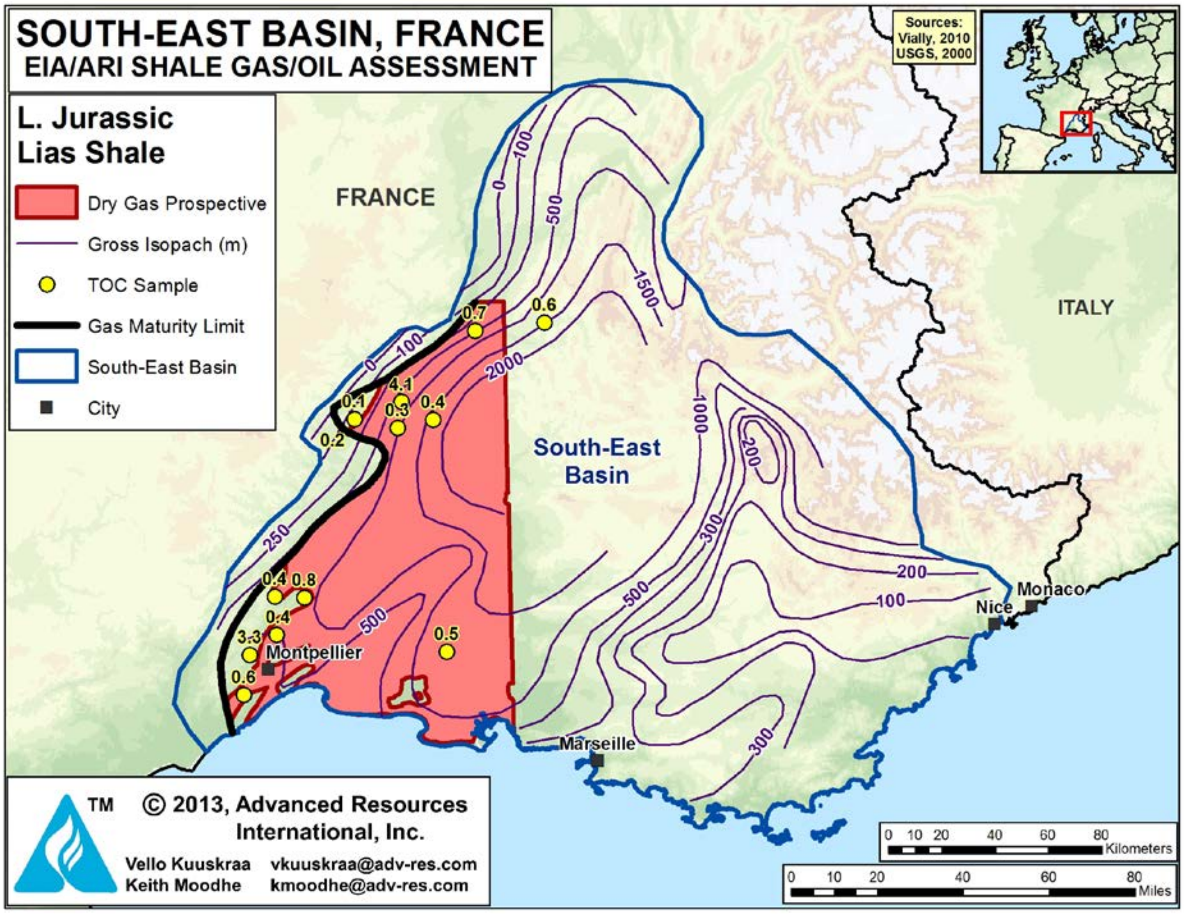
We have mapped an unrisked, 4,000-mi^2 area prospective for shale gas in the eastern portion of the South-East Basin, Figure XIII-12. The prospective area is bounded on the west by the dry gas maturity limit, on the south by the onshore portion of basin, and on the east by the available data on the TOC 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

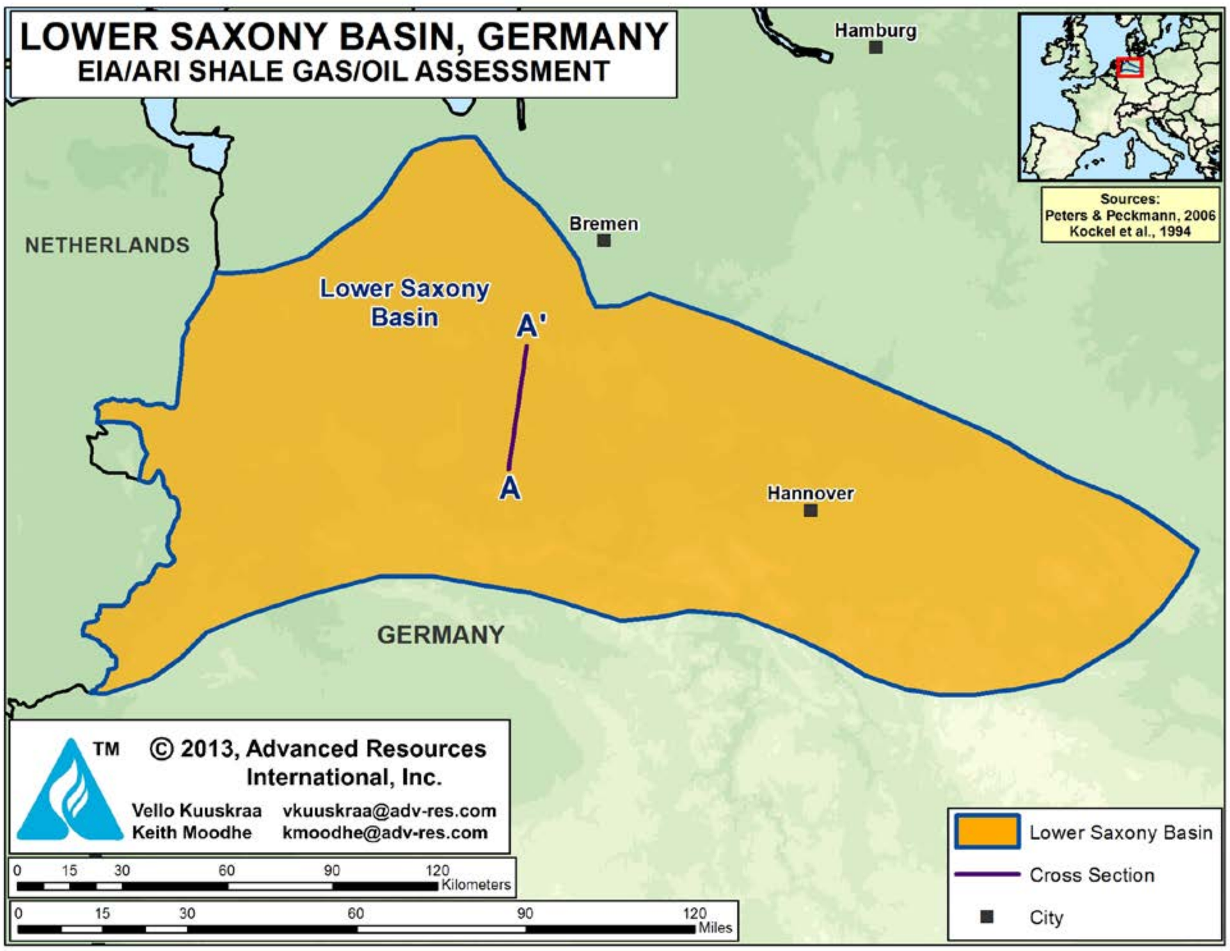
A number of firms are beginning to examine the shale gas potential of the South-East Basin; the initial permit award deadline was delayed due to the large numbers of applications. The French Ministry of Energy and the Environment awarded several exploration permits, covering over 4,000 mi^2, to companies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

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

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

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

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.

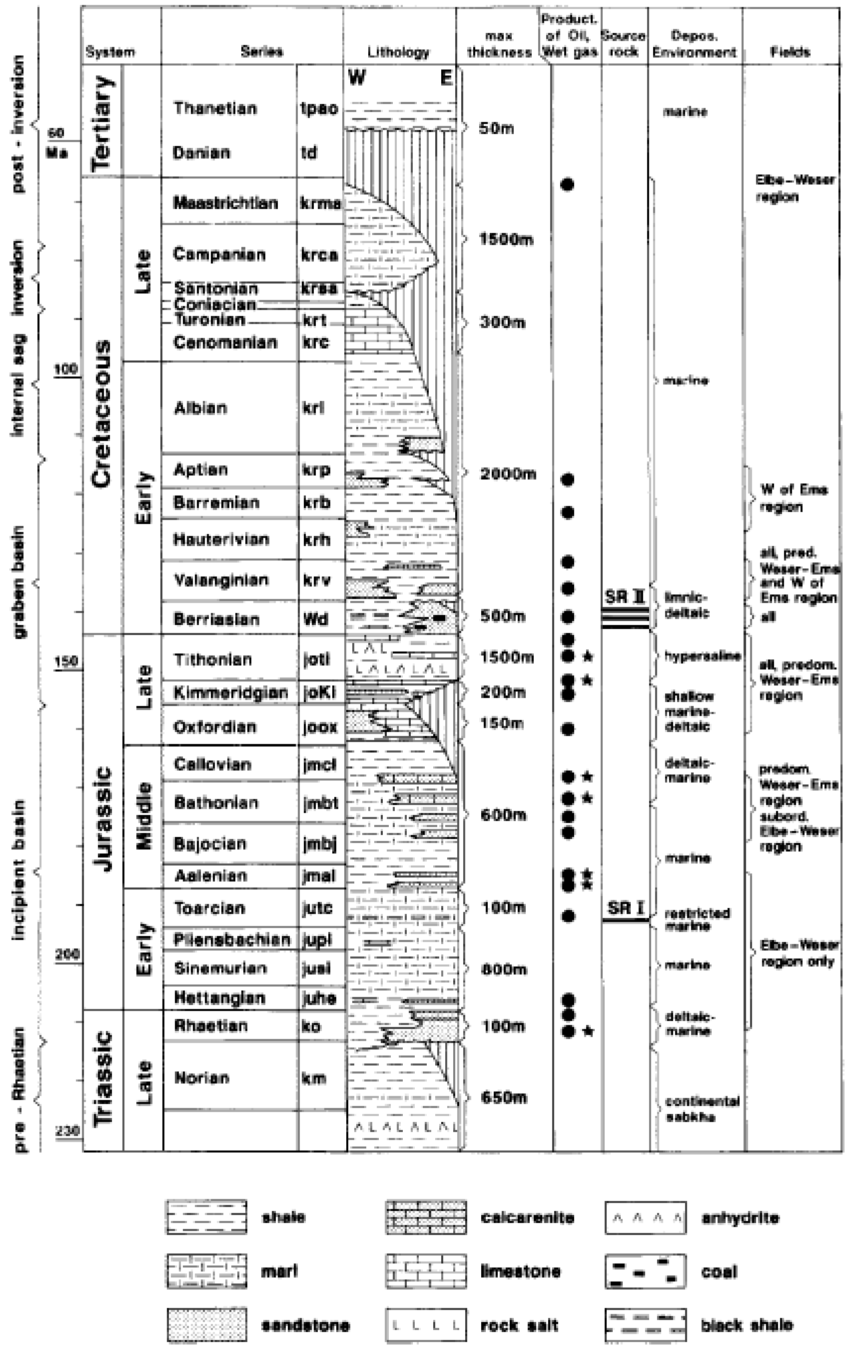
The Lower Saxony Basin contains two organic-rich shale source rocks - - the restricted marine Lower Toarcian (Jurassic) Posidonia Shale that underlies most of the basin, and the Early Cretaceous (Berriasian) lacustrine-deltaic Wealden Shale that underlies the western part of the basin (west of the Weser 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.

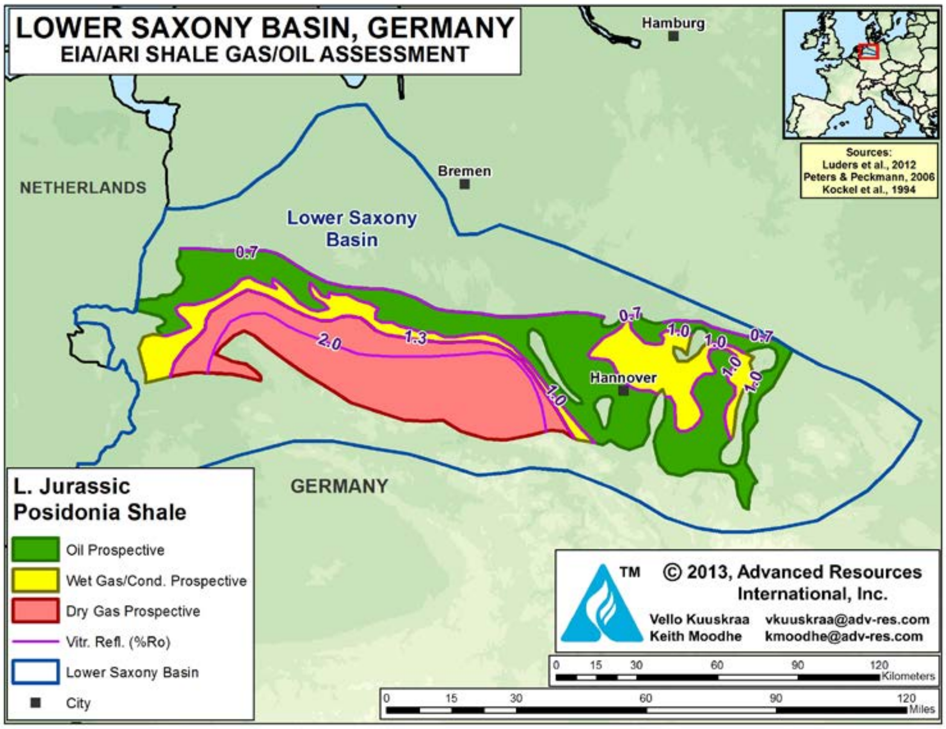
In addition, organic-rich mudstones occur in the Upper Permian Stassfurth Carbonate Formation in the eastern part of the North Sea-German Basin in southern Brandenburg. The Ca2 shale interval in this formation occurs at a depth of 3,800 to 4,000 m, has a thermal maturity of over 2% R_o, and contains 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.



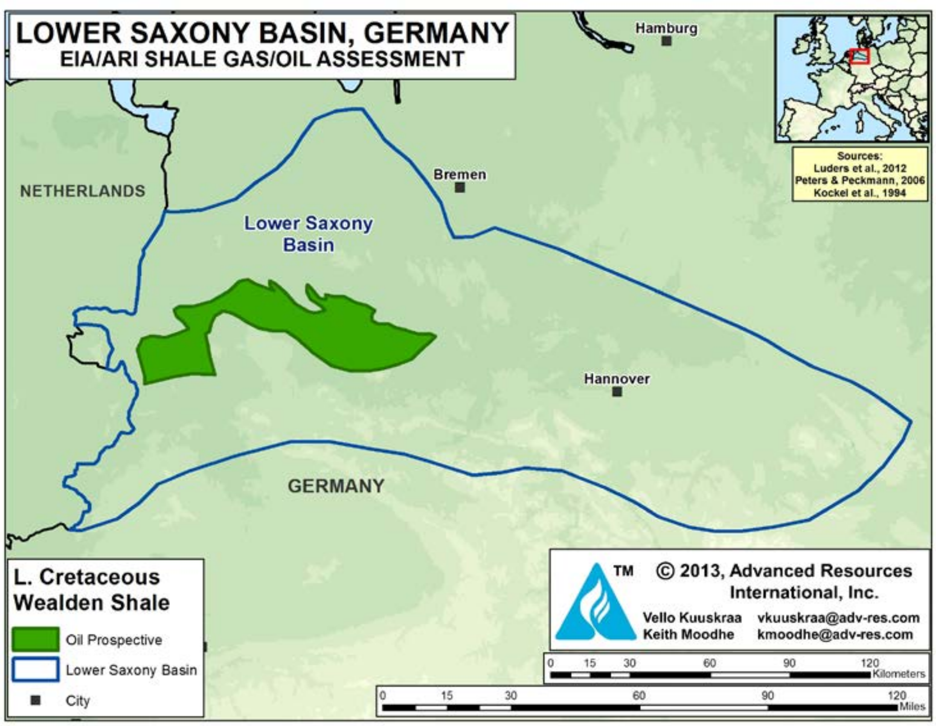
Source: Kockel, 1994.

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.

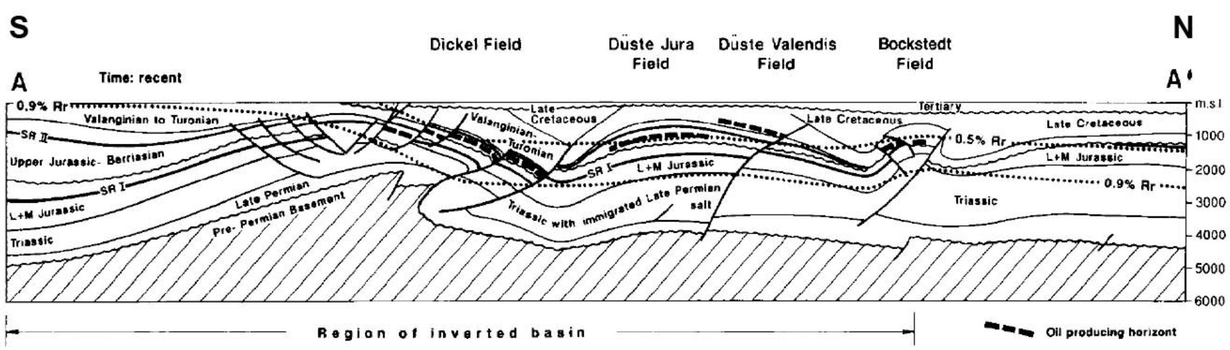


Source: ARI, 2013.

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.

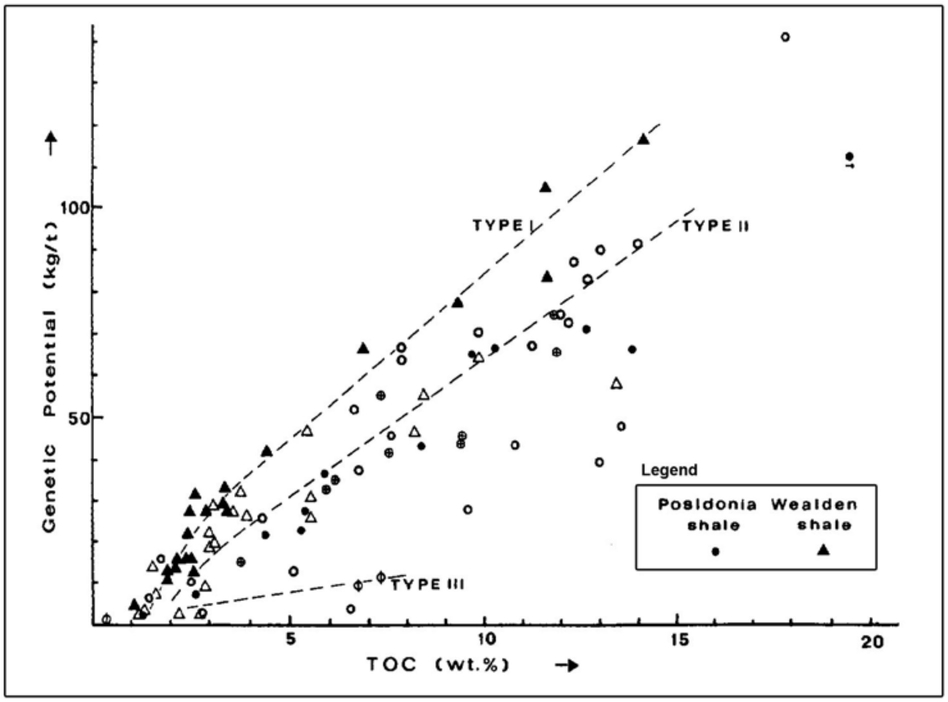
Figure XIII-17. Lower Saxony Basin North to South Cross Section, A to A'



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.

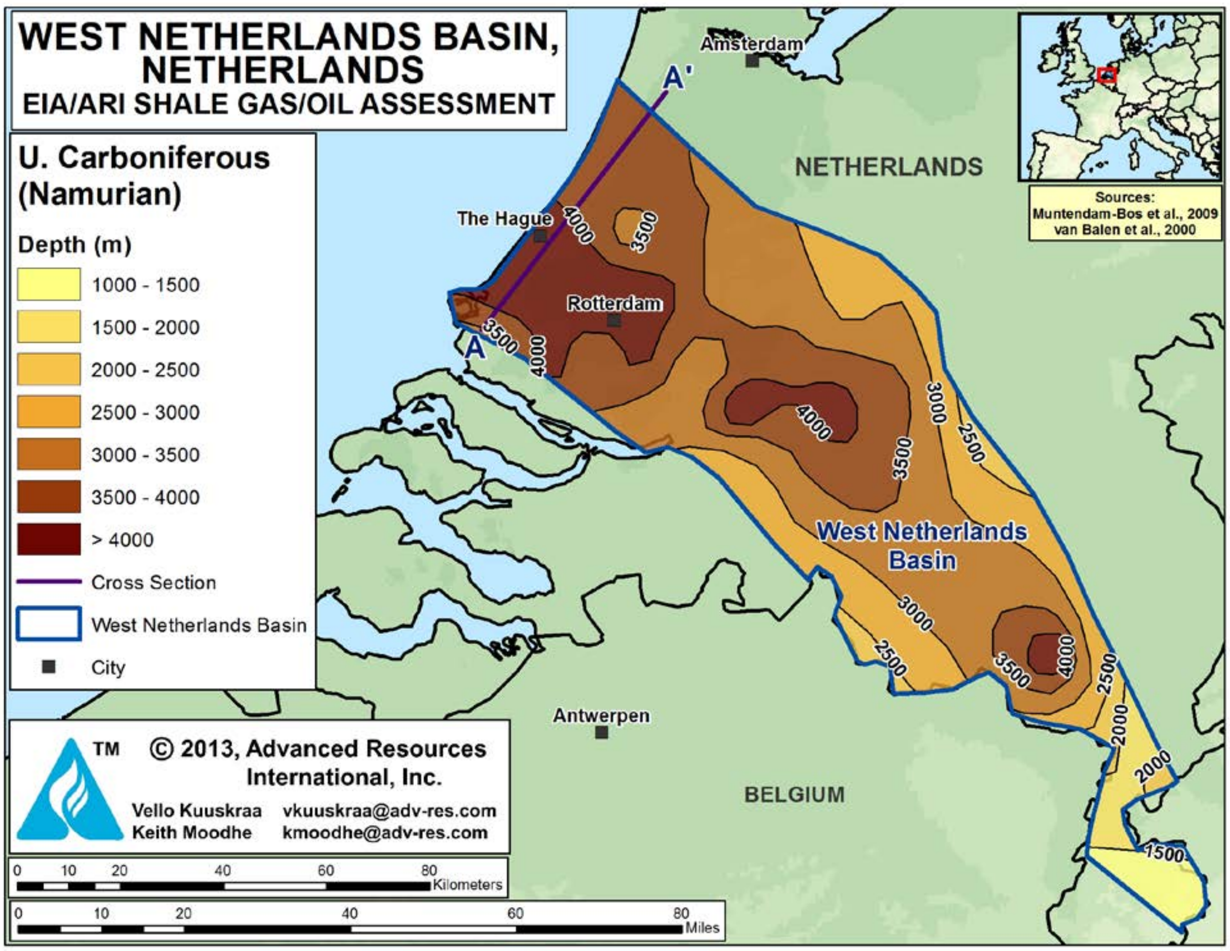
After a lengthy period of study, the German government issued, in late February 2013, draft legislation what would allow the development of shale and the use of hydraulic stimulation (fracturing) under environmental safeguards.

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

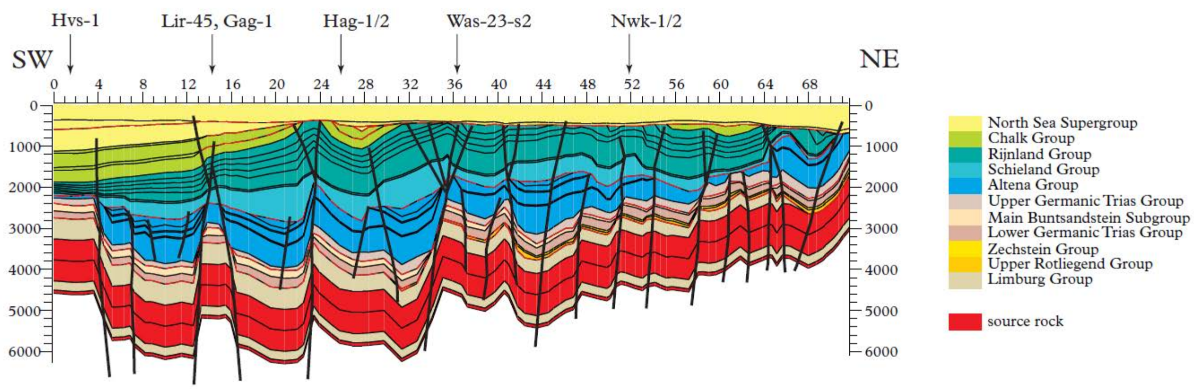
Table XIII-8. Shale Oil Reservoir Properties and Resources of West Netherland Basin, Netherlands

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.

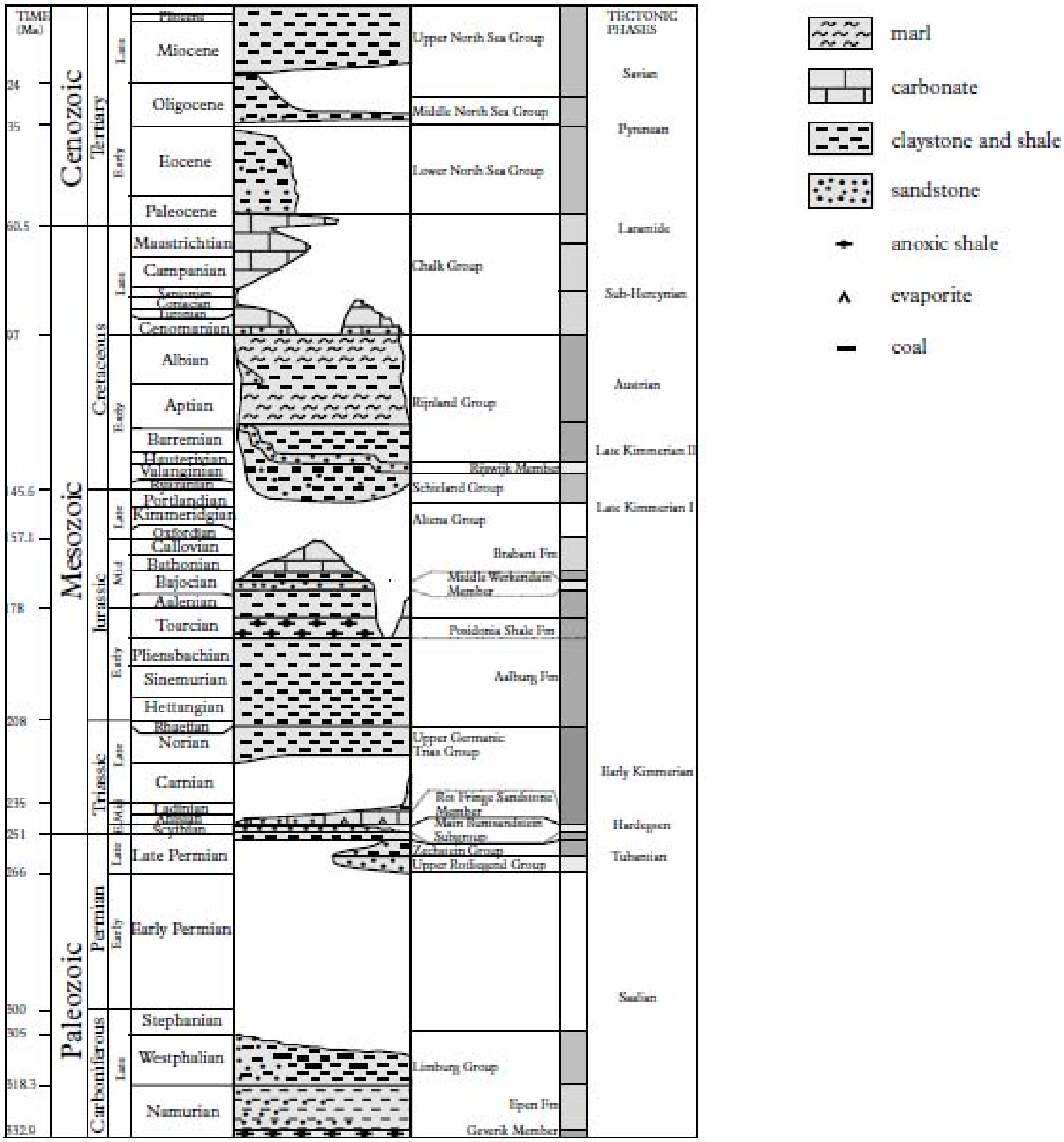


Source: van Balen, R.T. et al., 2000.

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.

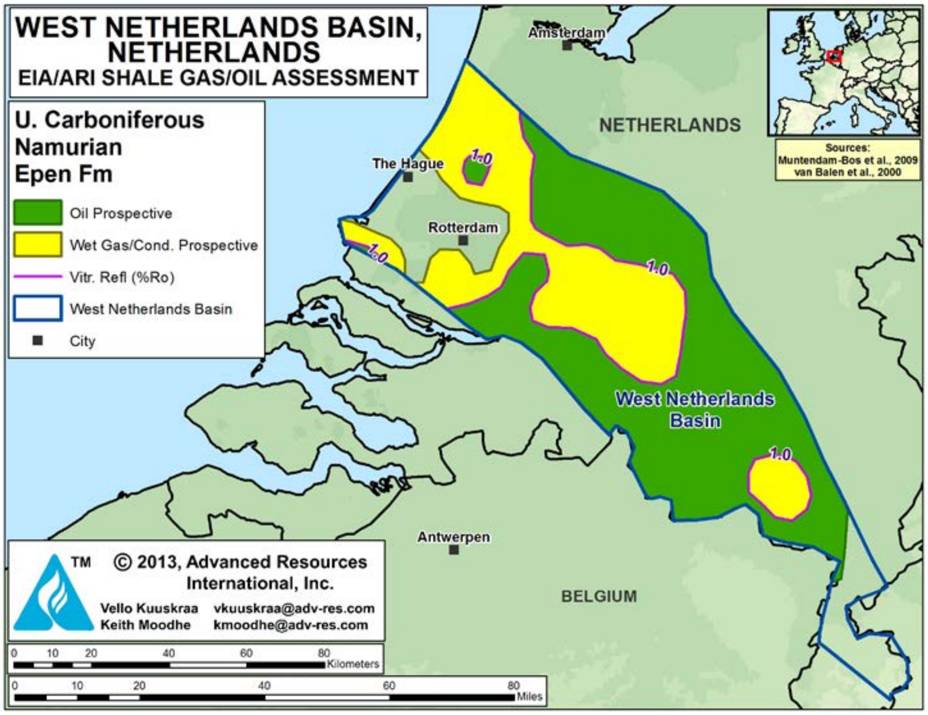
4.3 Reservoir Properties (Prospective Area)

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.

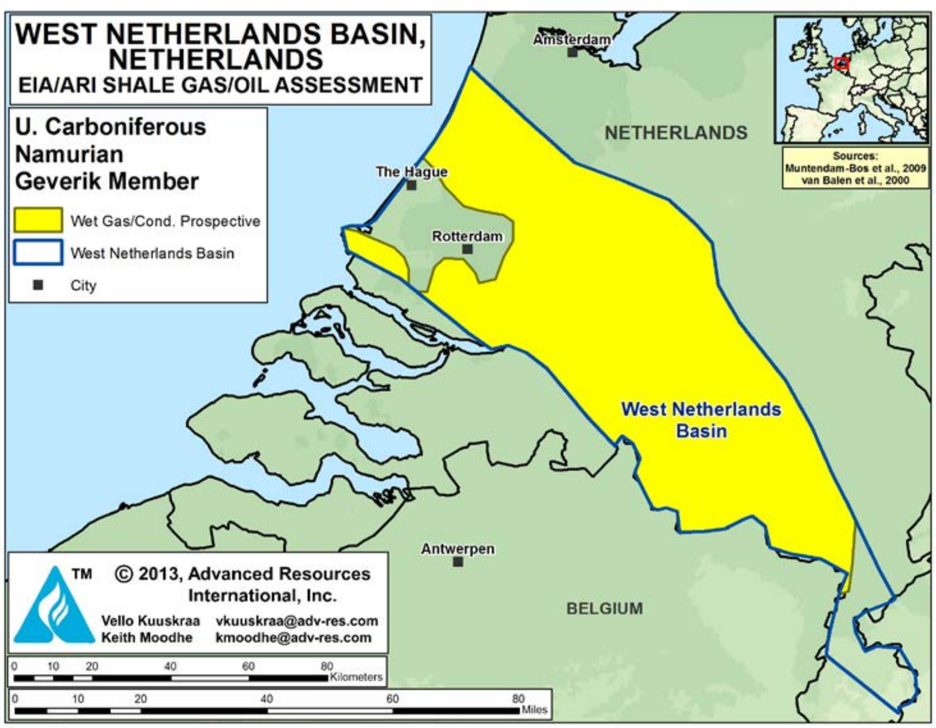
Depth to the underlying Geverik Shale ranges from 5,000 feet to 16,400 feet, averaging 11,000 feet in the wet gas/condensate prospective area. As for the Epen Shale, the deep west-central portion of the basin below 5,000 m has been excluded. The Geverik Shale has an organic-rich gross interval of 225 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.



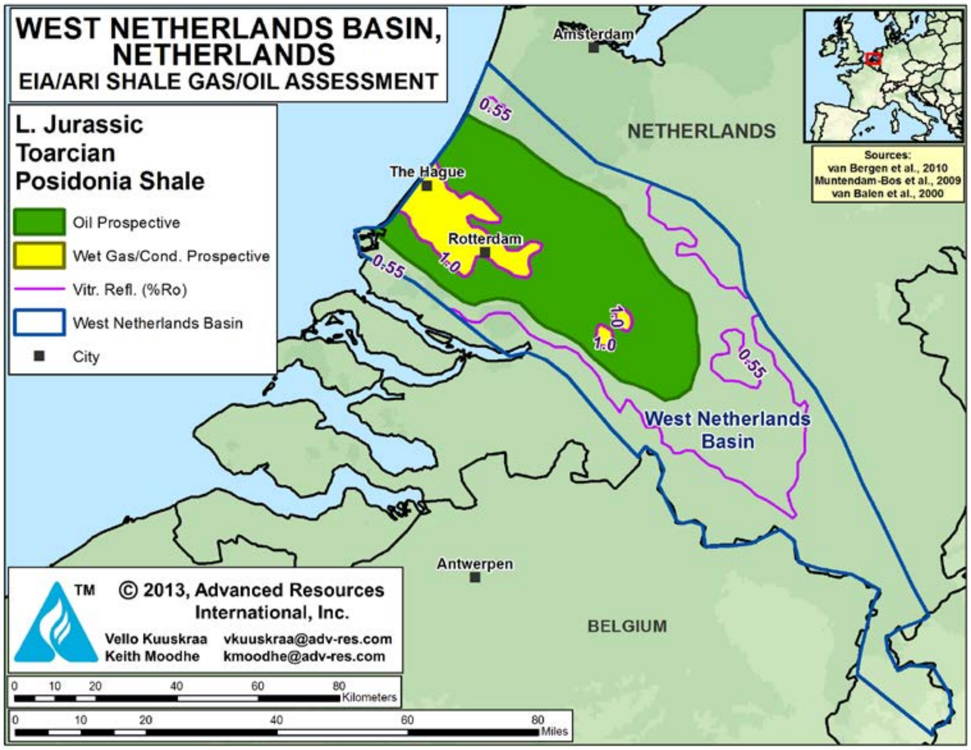
Source: ARI, 2013

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

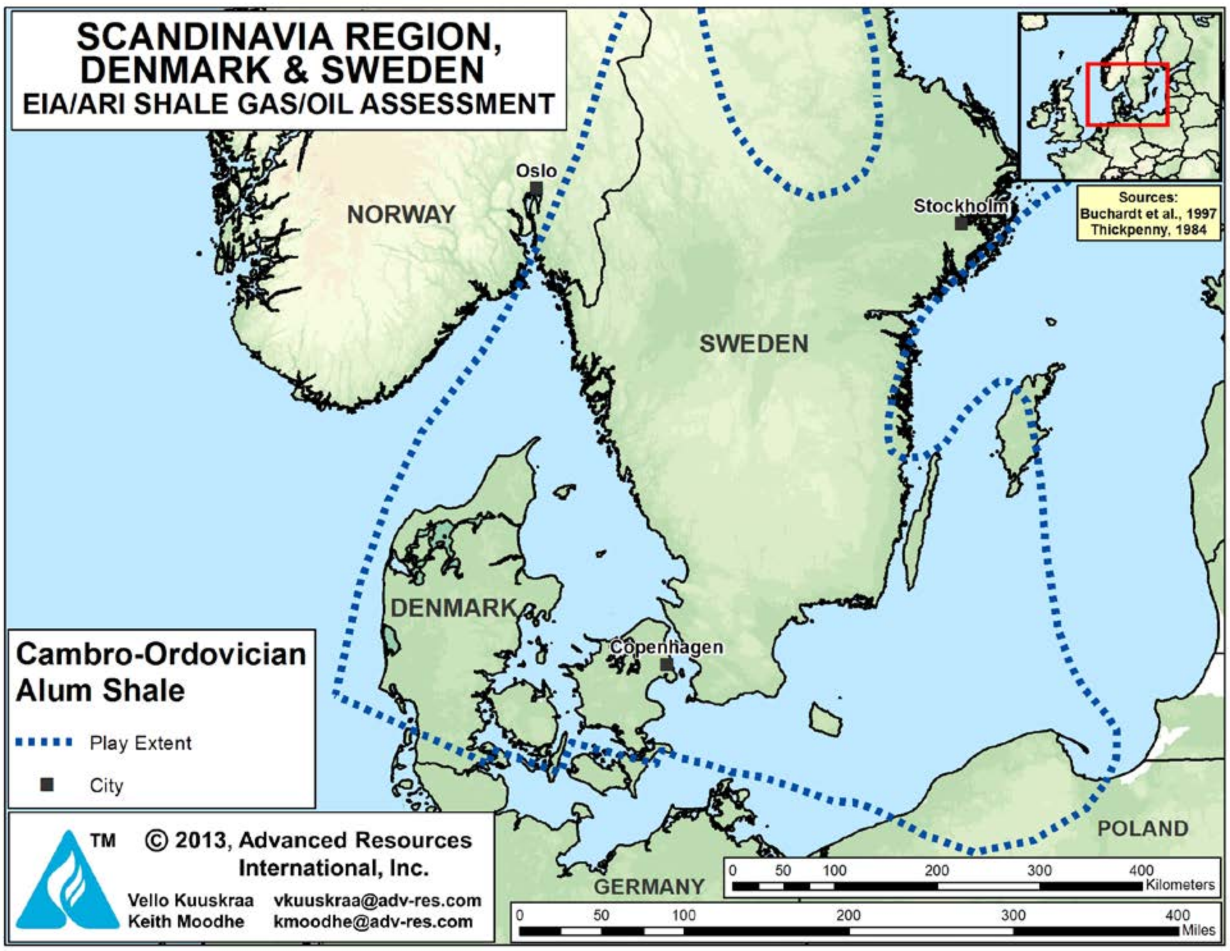
Three companies have acquired shale gas and oil leases in the Netherlands. Cuadrilla Resources and DSM Energie have leases in the West Netherland Basin while Queensland Gas Company (now part of BG Group) has leases in north-central Netherlands. Beyond the earlier exploratory wells that helped define 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.

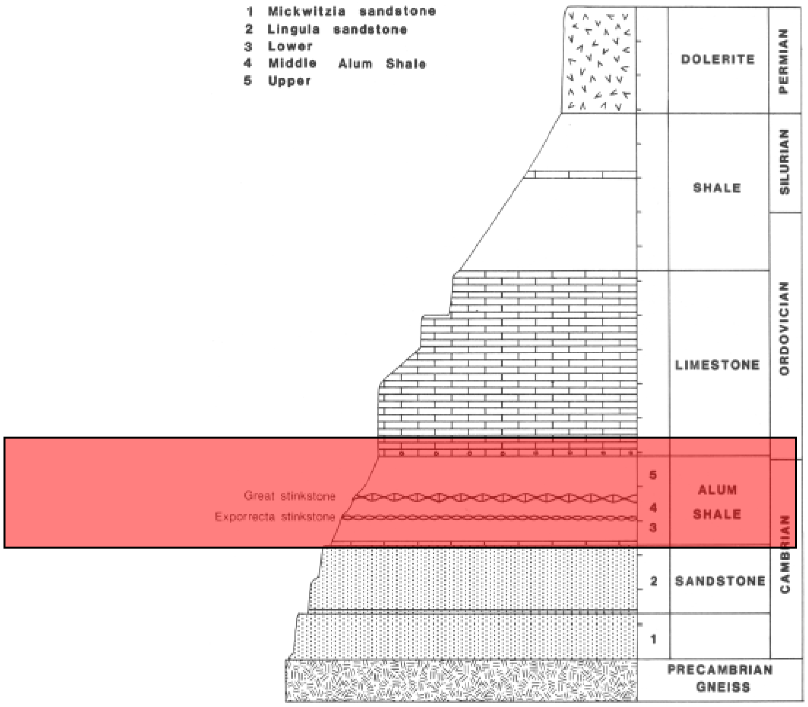
Table XIII-9. Shale Gas Reservoir Properties and Resources of Scandinavia

			Scandinavia Region	
Basic Data	Basin/Gross Area		Scandinavia Region ($90,000 mi^2$)	
	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

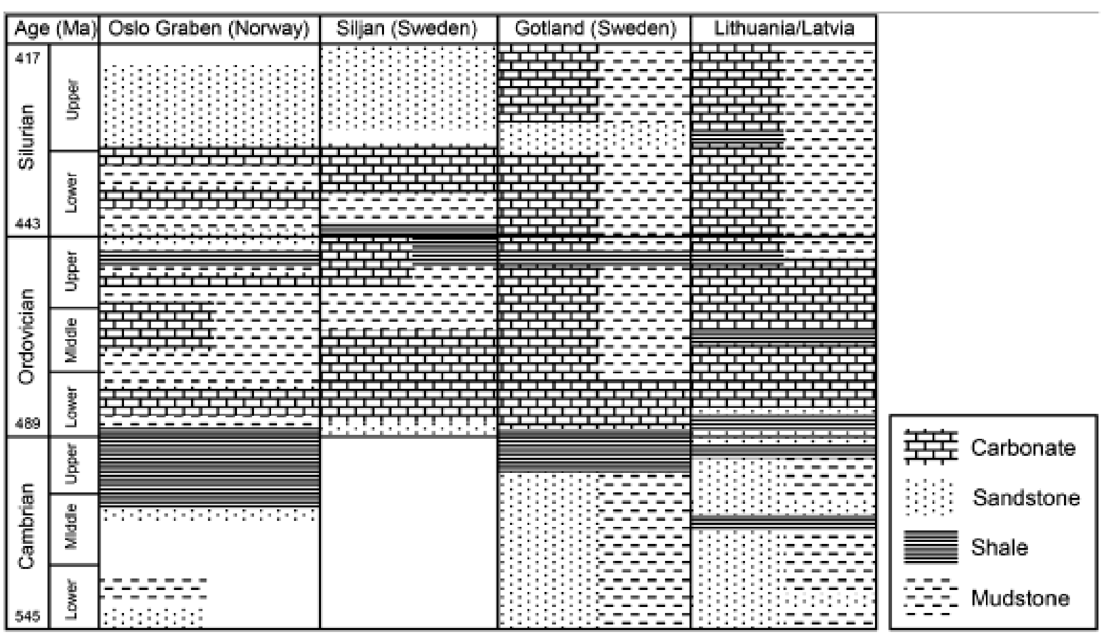
The depositional setting of the Cambrian-Ordovician Alum Shale in southern Sweden and northern Denmark has been mapped in the technical literature. Outcrops of the Alum Shale exist along the Caledonian Mountain belt along the Sweden-Norway border and in southern Sweden. Figure XIII-26 provides the stratigraphic 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.

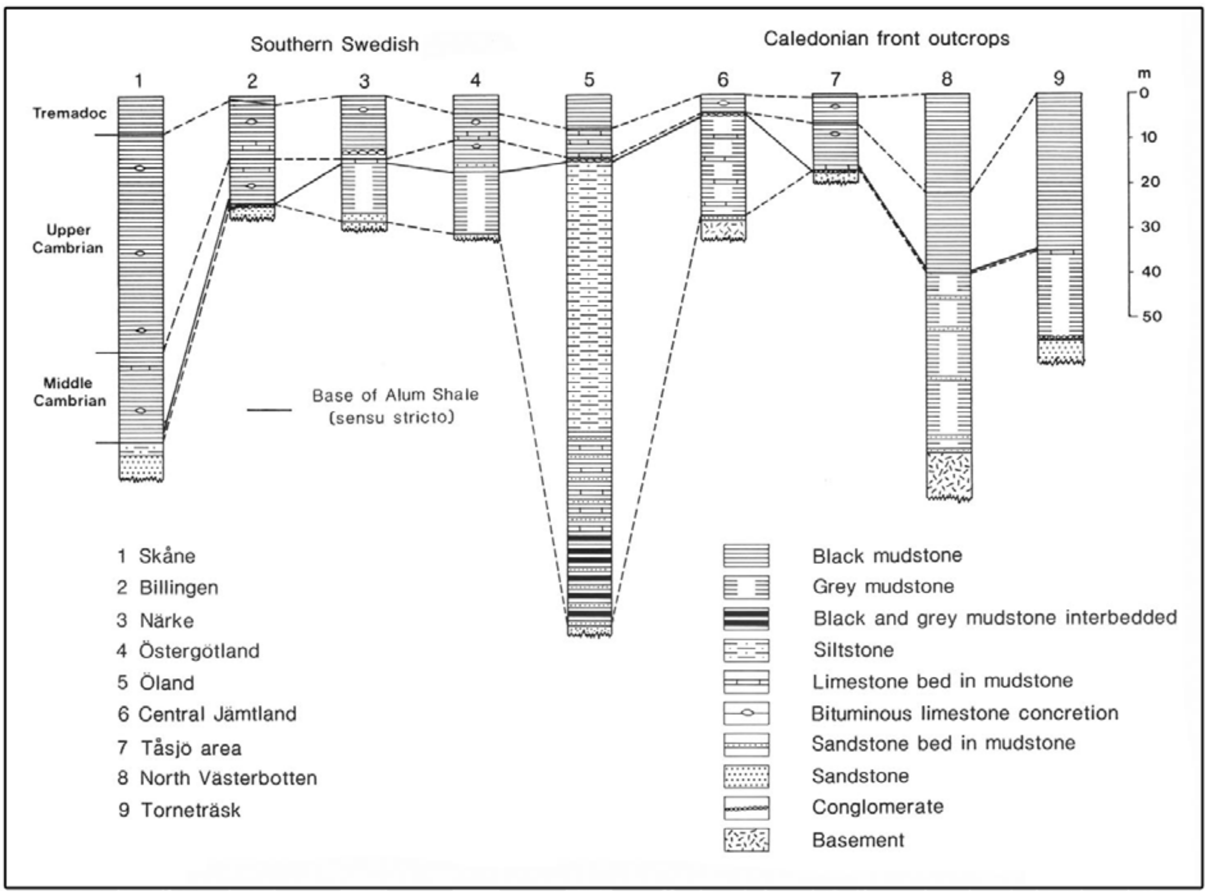
Figure XIII-27. Generalized Lower Paleozoic Stratigraphy for the Scandinavia-Baltic Region.



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.

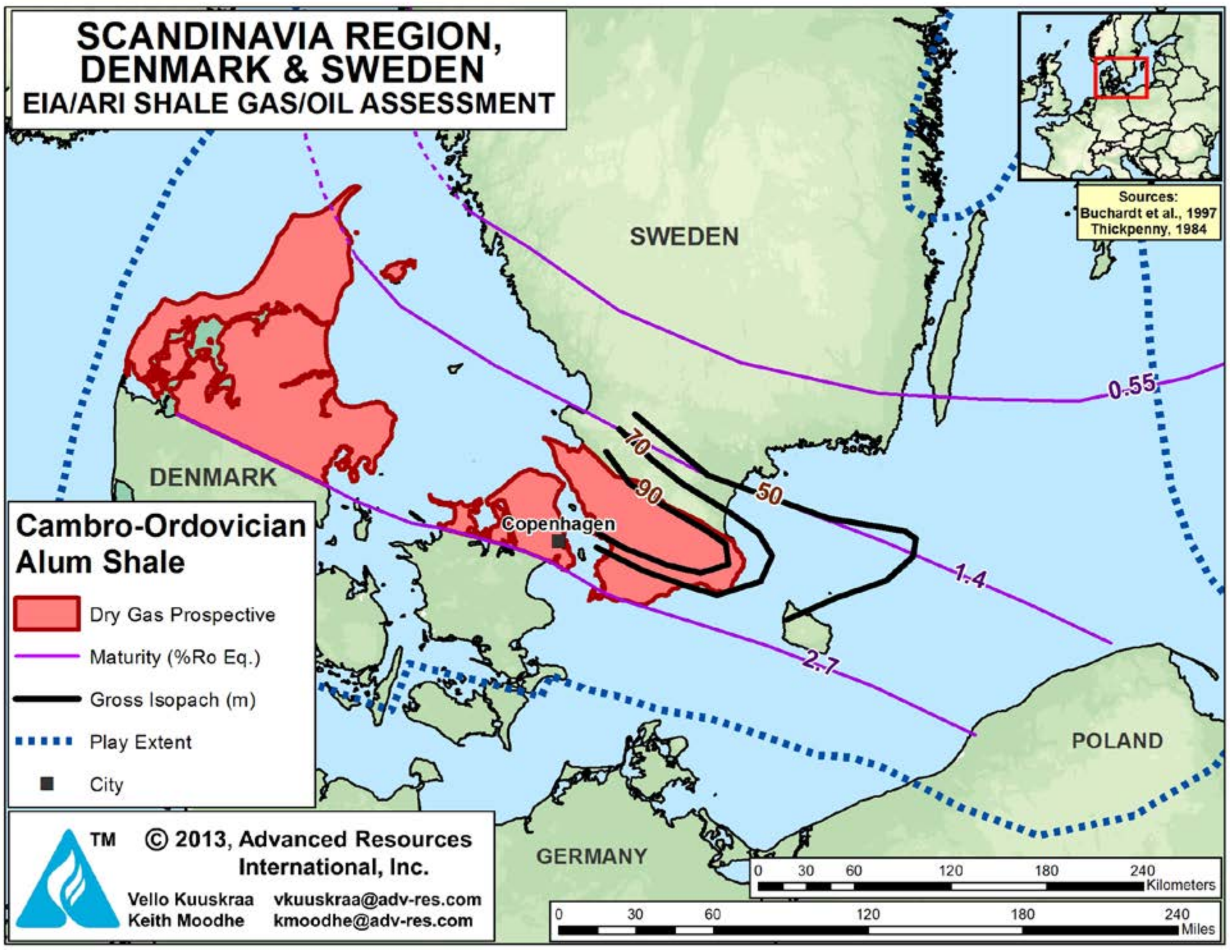
Figure XIII-28. Comparative Middle and Upper Cambrian Stratigraphic Columns for Selected Outcrop Areas in Scandinavia



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.

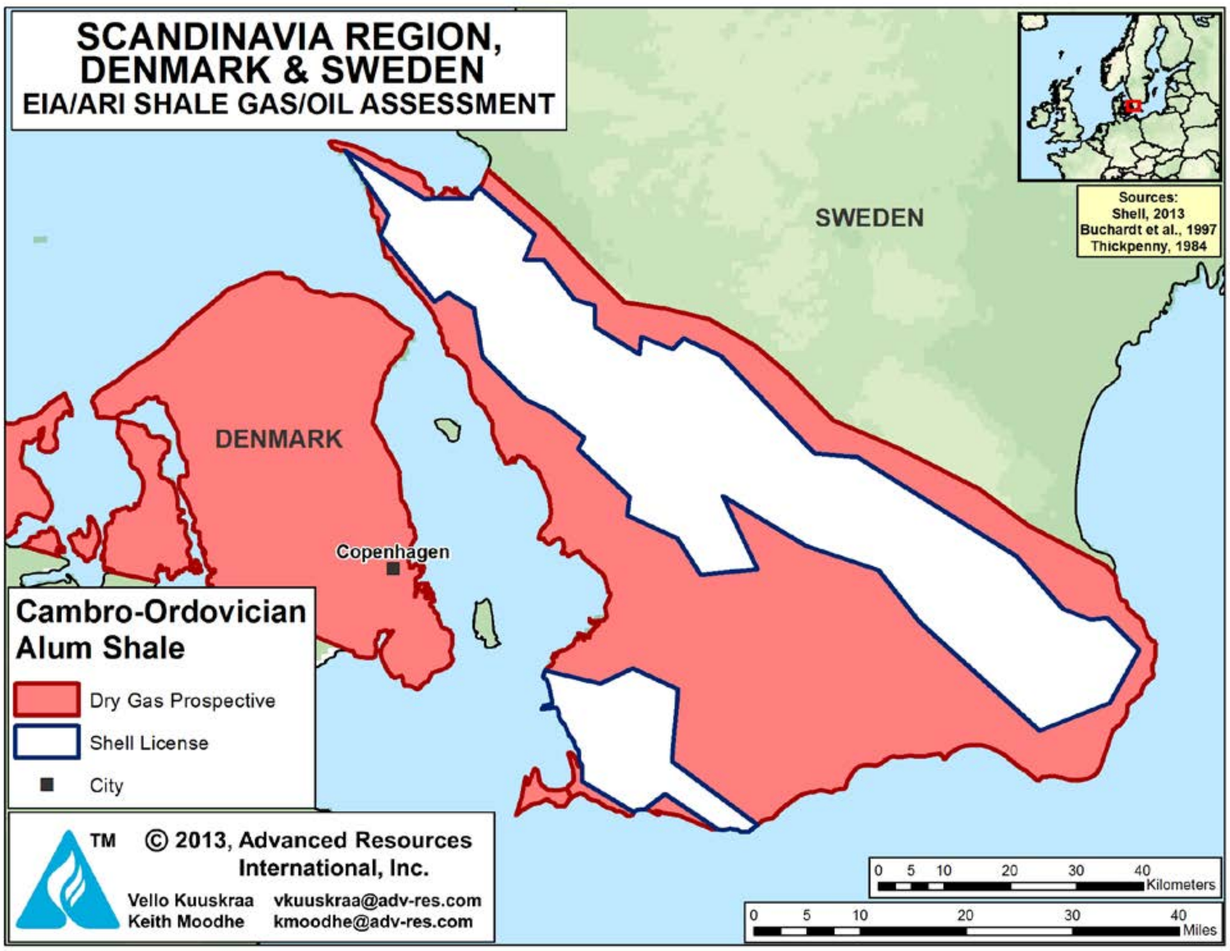
5.5 Recent Activity

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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