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Technically Recoverable Shale Oil and Shale Gas Resources:

Spain

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Executive Summary

Introduction

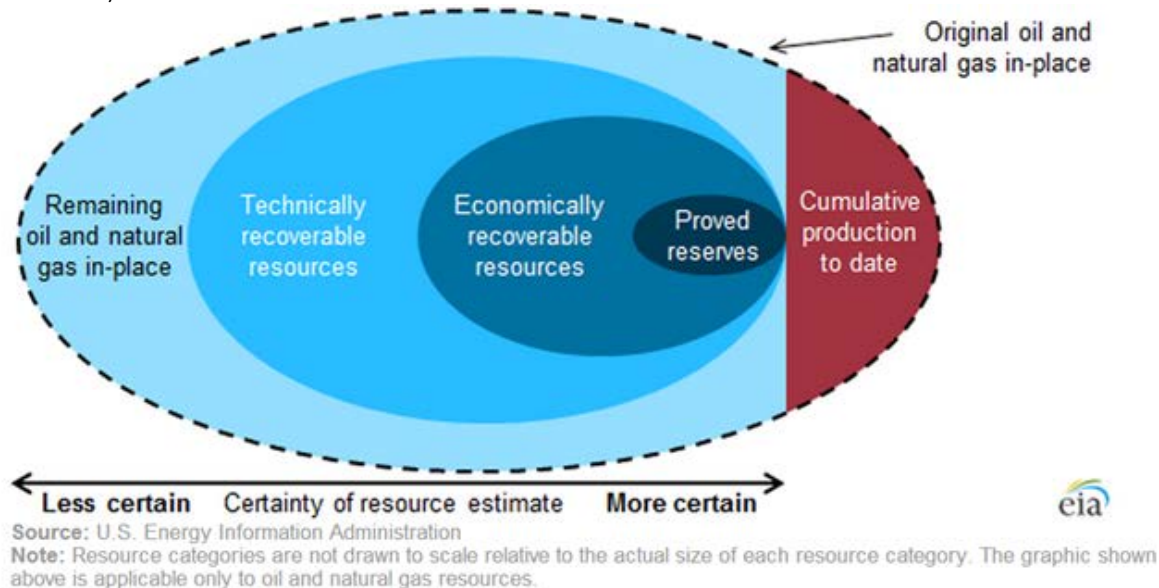
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

Resource categories

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

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

(not to scale)



Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known

ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

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

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

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

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

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

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

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

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

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

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

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

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

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

Methodology

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

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

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

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

2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*¹ and *adsorbed gas*² that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.³ For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources⁴ represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

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

Key exclusions

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

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

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

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

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

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

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

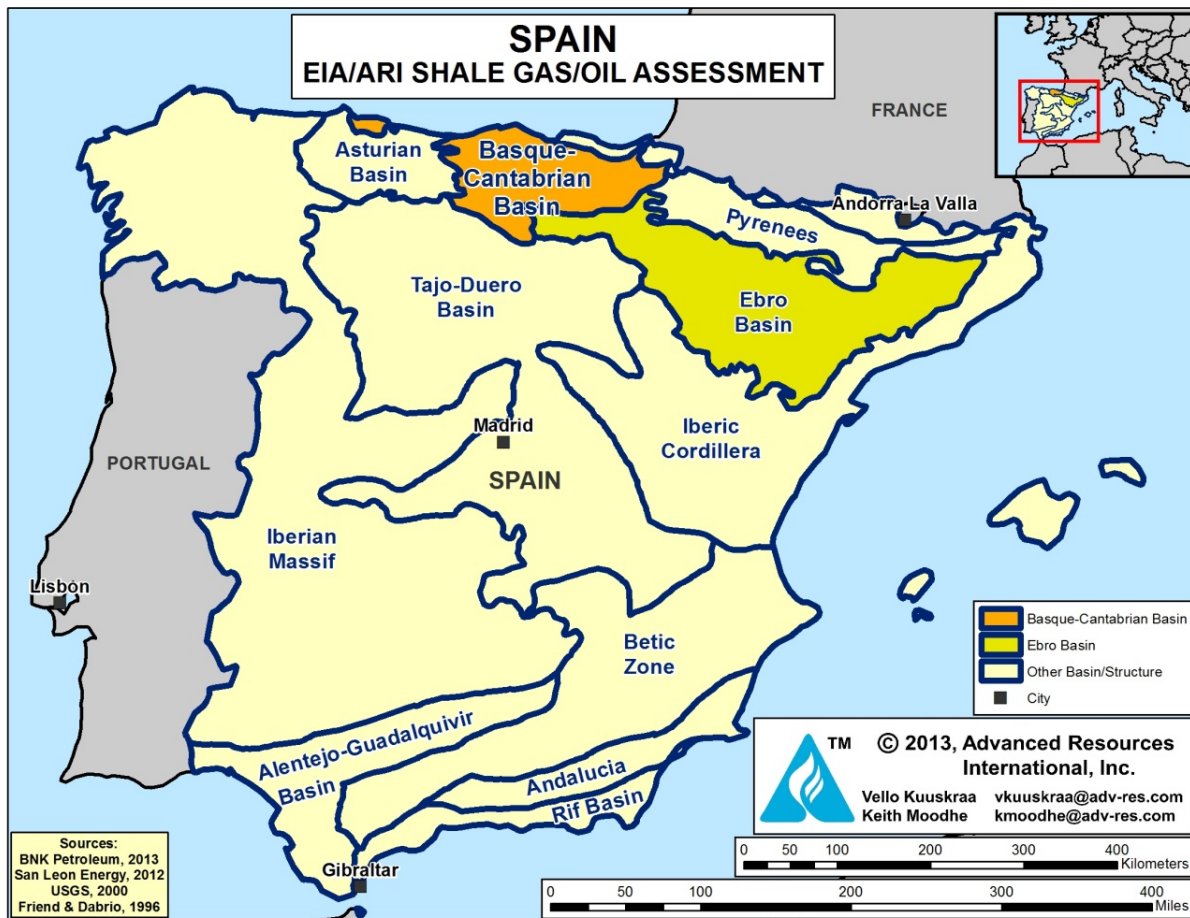
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

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 mi ²)
	Shale Formation		Jurassic
	Geologic Age		L. - M. Jurassic
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi ²)		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/mi ²)		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 mi ²)
	Shale Formation		Jurassic
	Geologic Age		L. - M. Jurassic
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi ²)		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/mi ²)		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 expelled from the maturing shales.^{1,2}

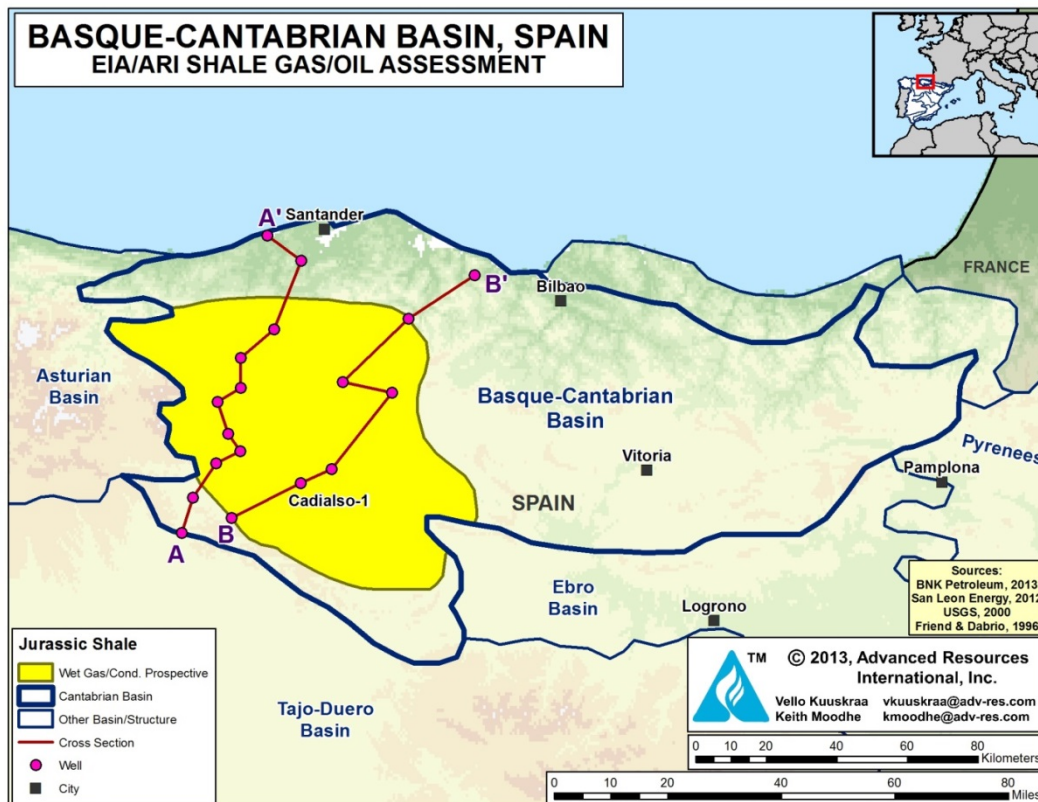
1. BASQUE-CANTABRIAN BASIN

The Basque-Cantabrian Basin covers a large 6,620-mi² 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-mi² 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

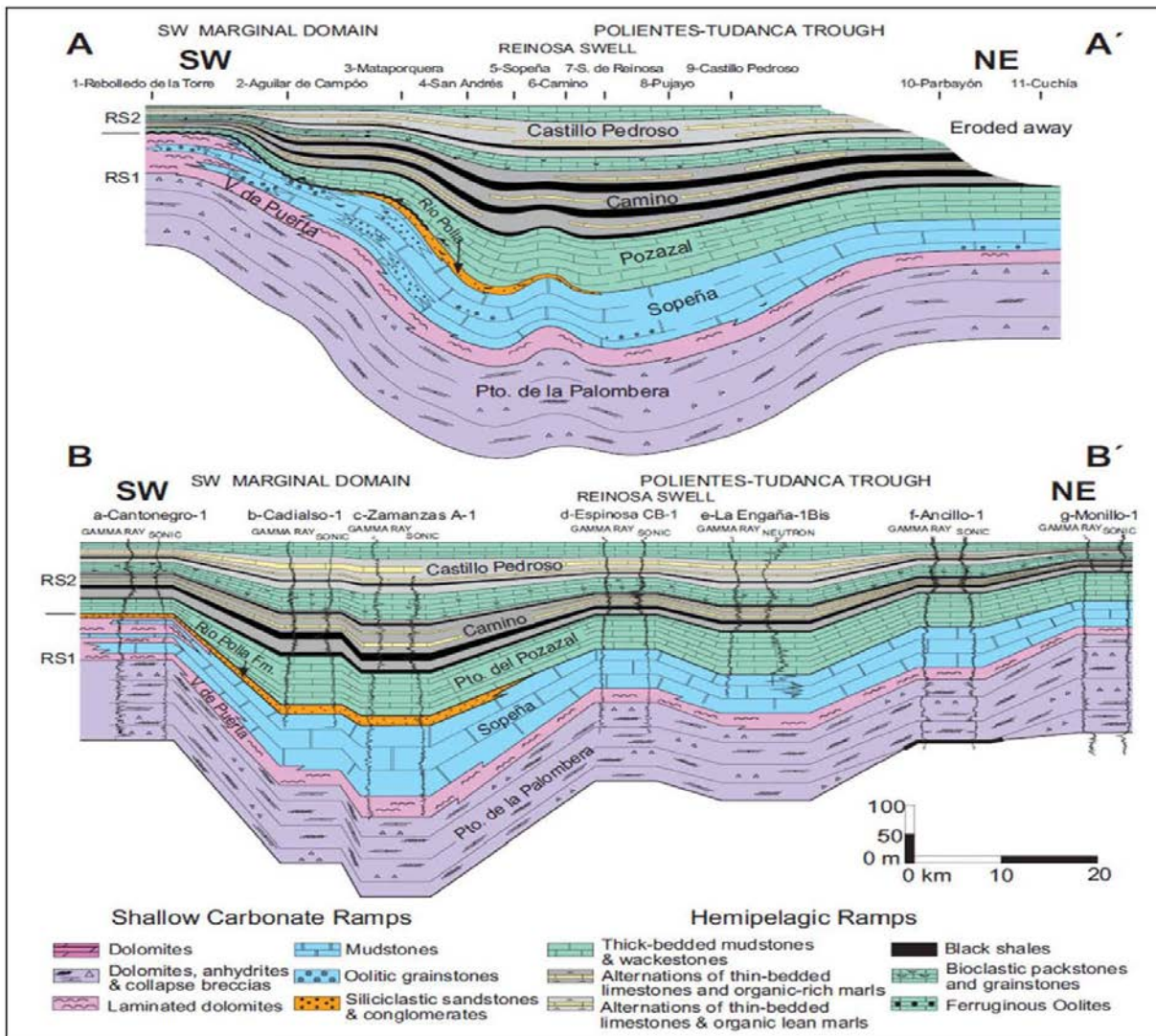
Figure XII-2. Prospective Area of Jurassic Shale, Basque-Cantabrian Basin



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



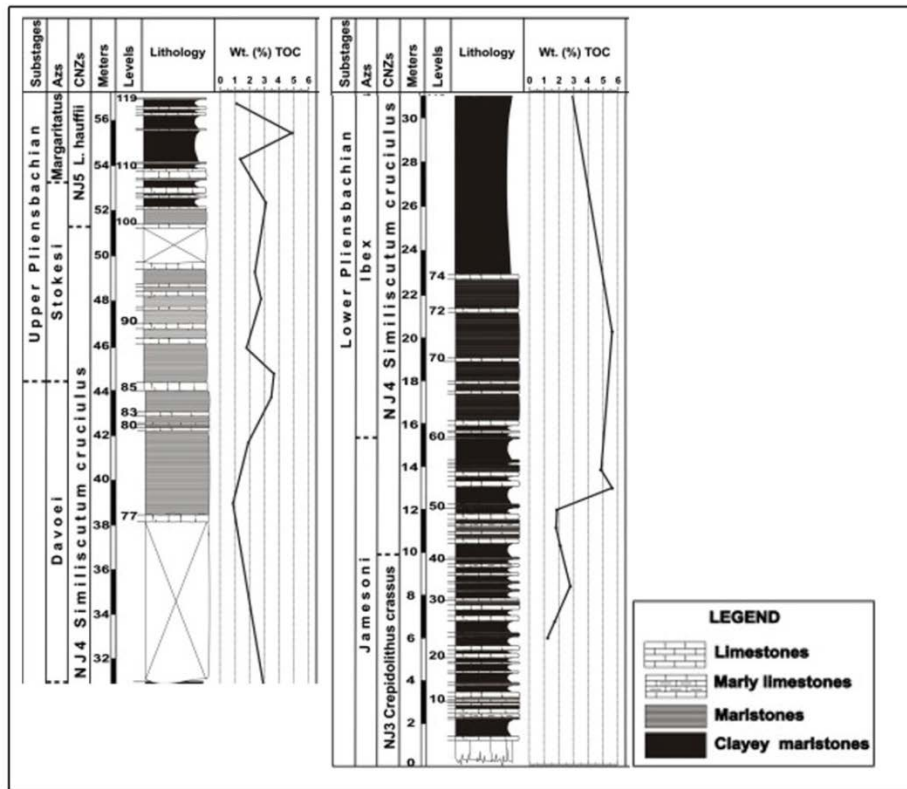
Source: Quesada, S., 2005.

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%.

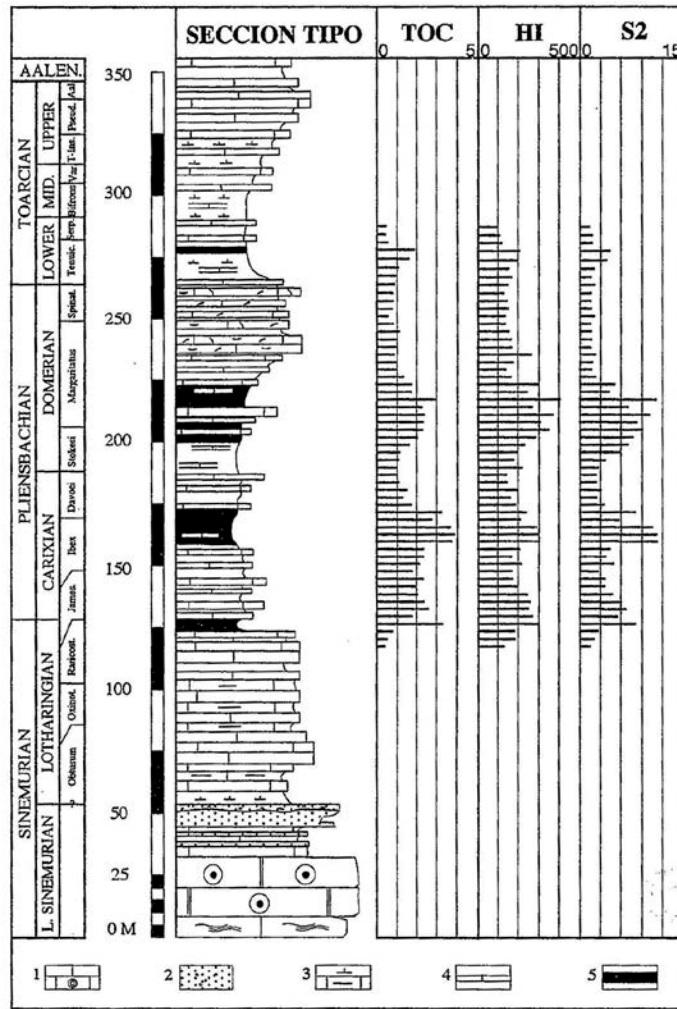
Figures XII-4 and XII-5 provide additional information on the TOC and thermal maturity values for the Jurassic (Pliensbachian) Lias Shale in the northern portion of the prospective area near the Poliente-Tudanca Trough.^{4,5,6}

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



Source: Modified from Fraguas et al., 2008

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



Source: Quesada, S., 1996.

1.3 Resource Assessment

The entire package of Jurassic shales, including the Lias Shale, within the 2,100-mi² prospective area of the Basque-Cantabrian Basin has a resource concentration of about 50 Bcf/mi² of wet shale gas and 3 million barrels/mi² 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 Bm³ (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

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