Independent Statistics & Analysis
U.S. Energy Information Administration

Technically Recoverable Shale Oil and Shale Gas Resources:

Argentina

September 2015

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

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Introduction

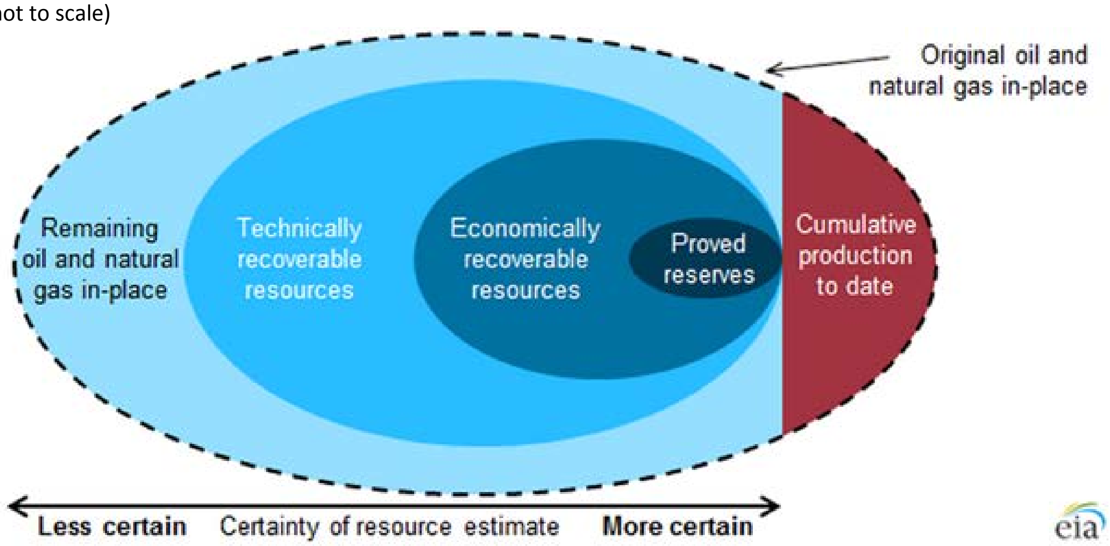
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

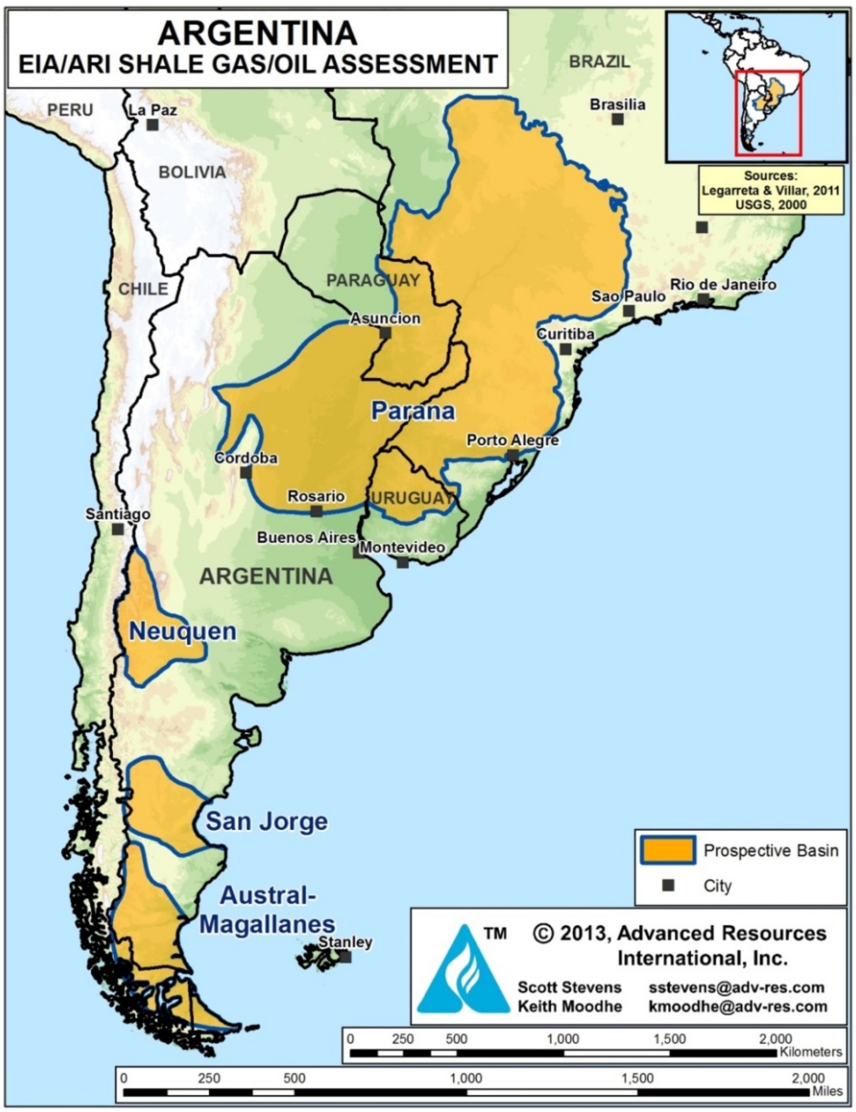
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

V. ARGENTINA

SUMMARY

Argentina has world-class shale gas and shale oil potential – possibly the most prospective outside of North America – primarily within the Neuquen Basin. Additional shale resource potential exists in three other untested sedimentary basins, Figure V-1.

Figure V-1. Prospective Shale Basins of Argentina



Source: ARI, 2013.

Significant exploration programs and early-stage commercial production are underway in the Neuquen Basin by Apache, EOG, ExxonMobil, TOTAL, YPF, and smaller companies. Thick, organic-rich, marine-deposited black shales in the Los Molles and Vaca Muerta formations have been tested by approximately 50 wells to date, with mostly good results. Vertical shale wells are producing at initial rates of 180 to 600 bbl/day following typically 5-stage fracture stimulation. Horizontal wells also are being tested although initial results have not been uniformly encouraging.

Cretaceous shales in the Golfo San Jorge and Austral basins in southern Argentina also have good potential, although higher clay content may pose a risk in these lake-formed deposits. Marine-deposited Devonian shales in the Parana Basin are prospective over a limited area of northeast Argentina. Argentina has an estimated 802 Tcf of risked, shale gas in-place out of 3,244 Tcf of risked, technically recoverable shale gas resources, Table V-1. In-place risked shale oil resources are estimated at 480 billion barrels, of which about 27 billion barrels of shale oil may be technically recoverable, Table V-2.

Table V-1A. Shale Gas Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		Neuquen (66,900 mi^2)					
	Shale Formation		Los Molles			Vaca Muerta		
	Geologic Age		M. Jurassic			U. Jurassic - L. Cretaceous		
	Depositional Environment		Marine			Marine		
Physical Extent	Prospective Area (mi^2)		2,750	2,380	8,140	4,840	3,270	3,550
	Thickness (ft)	Organically Rich	800	800	800	500	500	500
		Net	300	300	300	325	325	325
	Depth (ft)	Interval	6,500 - 9,500	9,500 - 13,000	13,000 - 16,400	3,000 - 9,000	4,500 - 9,000	5,500 - 10,000
		Average	8,000	11,500	14,500	5,000	6,500	8,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		2.0%	2.0%	2.0%	5.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	2.20%	0.85%	1.15%	1.50%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		49.3	118.0	190.1	66.1	185.9	302.9
	Risked GIP (Tcf)		67.8	140.4	773.8	192.0	364.8	645.1
	Risked Recoverable (Tcf)		8.1	35.1	232.1	23.0	91.2	193.5

Table V-2B. Shale Gas Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		San Jorge (46,000 mi²)			
	Shale Formation		Aguada Bandera	Pozo D-129		
	Geologic Age		U. Jurassic - L. Cretaceous	L. Cretaceous		
	Depositional Environment		Lacustrine	Lacustrine		
Physical Extent	Prospective Area (mi²)		8,380	920	540	4,120
	Thickness (ft)	Organically Rich	1,600	1,200	1,200	1,200
		Net	400	420	420	420
	Depth (ft)	Interval	6,500 - 16,000	6,600 - 8,000	8,000 - 10,000	10,000 - 16,400
		Average	13,000	7,300	9,000	12,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.2%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		3.00%	0.85%	1.15%	2.00%
	Clay Content		Med./High	Med./High	Med./High	Med./High
Resource	Gas Phase		Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi²)		151.7	41.2	103.4	163.3
	Risked GIP (Tcf)		254.2	9.1	13.4	161.5
	Risked Recoverable (Tcf)		50.8	0.5	2.0	32.3

Table V-3C. Shale Gas Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		Austral-Magallanes (65,000 mi²)			Parana (747,000 mi²)	
	Shale Formation		L. Inoceramus-Magnas Verdes			Ponta Grossa	
	Geologic Age		L. Cretaceous			Devonian	
	Depositional Environment		Marine			Marine	
Physical Extent	Prospective Area (mi²)		4,620	4,600	4,310	270	2,230
	Thickness (ft)	Organically Rich	800	800	800	400	400
		Net	400	400	400	200	200
	Depth (ft)	Interval	6,600 - 11,000	9,000 - 14,500	11,500 - 16,400	9,000 - 10,000	10,000 - 11,500
		Average	8,000	11,500	13,500	9,500	10,500
Reservoir Properties	Reservoir Pressure		Slightly Overpress.	Slightly Overpress.	Slightly Overpress.	Normal	Normal
	Average TOC (wt. %)		3.5%	3.5%	3.5%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.60%	1.15%	1.40%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi²)		32.5	113.8	155.9	34.9	56.9
	Risked GIP (Tcf)		67.5	235.6	302.4	1.1	15.2
	Risked Recoverable (Tcf)		6.8	47.1	75.6	0.2	3.0

Table VI-2A. Shale Oil Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		Neuquen (66,900 mi²)			
	Shale Formation		Los Molles		Vaca Muerta	
	Geologic Age		M. Jurassic		U. Jurassic - L. Cretaceous	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi²)		2,750	2,380	4,840	3,270
	Thickness (ft)	Organically Rich	800	800	500	500
		Net	300	300	325	325
	Depth (ft)	Interval	6,500 - 9,500	9,500 - 13,000	3,000 - 9,000	4,500 - 9,000
		Average	8,000	11,500	5,000	6,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		2.0%	2.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi²)		36.4	9.2	77.9	22.5
	Risked OIP (B bbl)		50.0	11.0	226.2	44.2
	Risked Recoverable (B bbl)		3.00	0.66	13.57	2.65

Table VI-2B. Shale Oil Reservoir Properties and Resources of Argentina

Basic Data	Basin/Gross Area		San Jorge (46,000 mi²)		Austral-Magallanes (65,000 mi²)		Parana (747,000 mi²)
	Shale Formation		Pozo D-129		L. Inoceramus-Magnas Verdes		Ponta Grossa
	Geologic Age		L. Cretaceous		L. Cretaceous		Devonian
	Depositional Environment		Lacustrine		Marine		Marine
Physical Extent	Prospective Area (mi²)		920	540	4,620	4,600	270
	Thickness (ft)	Organically Rich	1,200	1,200	800	800	400
		Net	420	420	400	400	200
	Depth (ft)	Interval	6,600 - 8,000	8,000 - 10,000	6,600 - 11,000	9,000 - 14,500	9,000 - 10,000
		Average	7,300	9,000	8,000	11,500	9,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Slightly Overpress.	Slightly Overpress.	Normal
	Average TOC (wt. %)		2.0%	2.0%	3.5%	3.5%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	1.20%
	Clay Content		Med./High	Med./High	Low/Medium	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Condensate
	OIP Concentration (MMbbl/mi²)		63.7	20.3	48.4	14.8	8.1
	Risked OIP (B bbl)		14.1	2.6	100.6	30.6	0.3
	Risked Recoverable (B bbl)		0.42	0.08	5.03	1.53	0.01

INTRODUCTION

Argentina has large and potentially high-quality shale gas and oil resources in four main sedimentary basins, **Figure V-1**. Basins assessed in this chapter include:

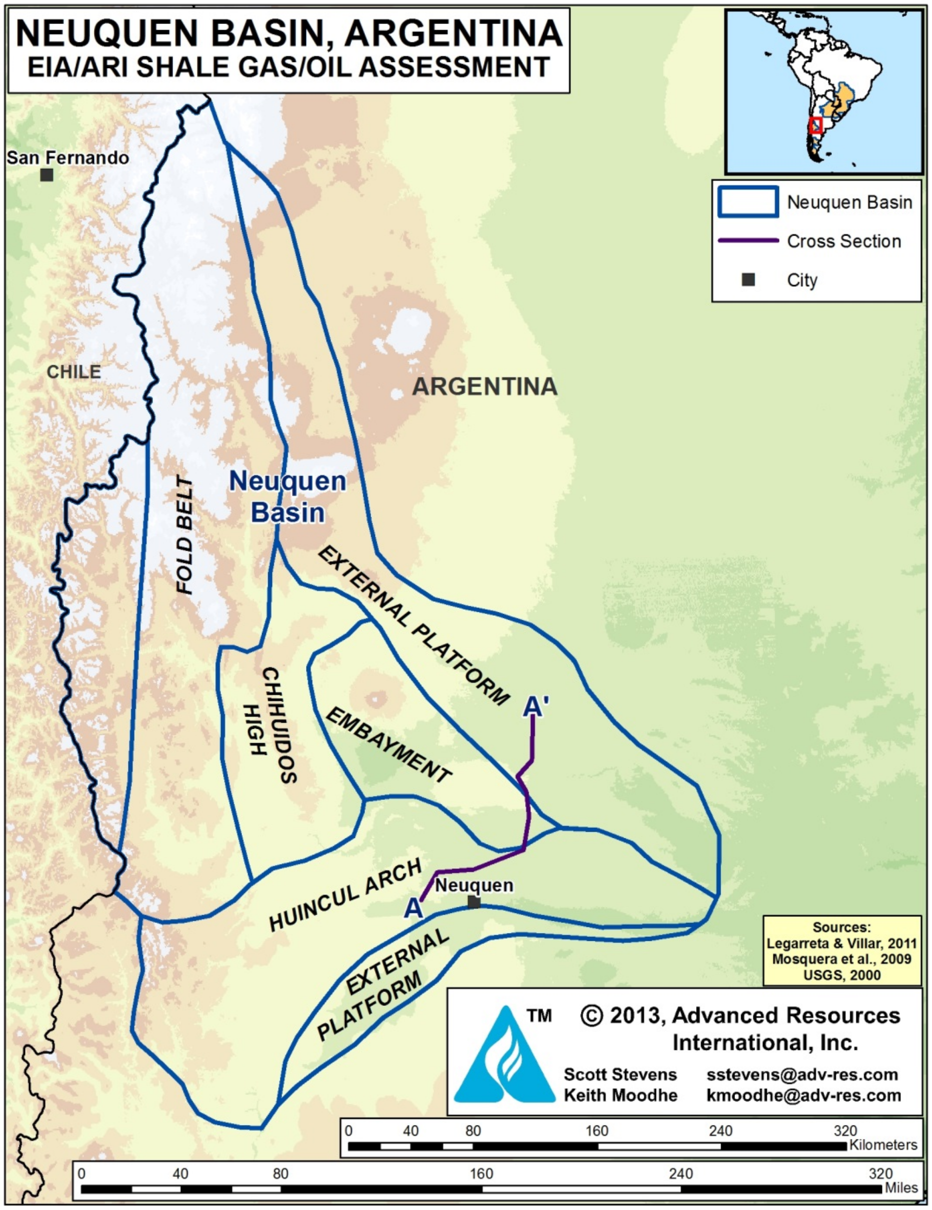
- **Neuquen Basin:** The main focus of shale exploration in Argentina, some 50 mostly vertical wells drilled since 2010 indicate good production potential in the marine-deposited Los Molles and especially Vaca Muerta shales of Jurassic age.
- **Golfo San Jorge Basin:** Containing mostly non-marine lacustrine shale source rocks of Jurassic to Cretaceous age, this basin has untested but prospective, primarily shale gas resources in a structurally simple setting.
- **Austral Basin**: Known as the Magallanes Basin in Chile, the Austral Basin of southern Argentina contains marine-deposited black shale in the Lower Cretaceous, considered a major source rock in the basin.
- **Paraná Basin**: Although more extensive in Brazil and Paraguay, Argentina has a small area of the Paraná Basin with Devonian black shale potential. The structural setting is simple but the basin is partly obscured on surface by flood basalts, although they are less prevalent in Argentina than in Brazil.

1 NEUQUEN BASIN

1.1 Introduction and Geologic Setting

Located in west-central Argentina, the Neuquen Basin contains Late Triassic to Early Cenozoic strata that were deposited in a back-arc tectonic setting.[1] Extending over a total area of 66,900 mi^2, the basin is bordered on the west by the Andes Mountains and on the east and southeast by the Colorado Basin and North Patagonian Massif, **Figure V-2**. The sedimentary sequence exceeds 22,000 ft in thickness, comprising carbonate, evaporite, and marine siliclastic rocks.[2] Compared with the thrusted western part of the basin, the central Neuquen is deep and structurally less deformed. Already a major oil and gas production area from conventional and tight sandstones, the Neuquen Basin is emerging as the premier shale gas and shale oil development area of South America.

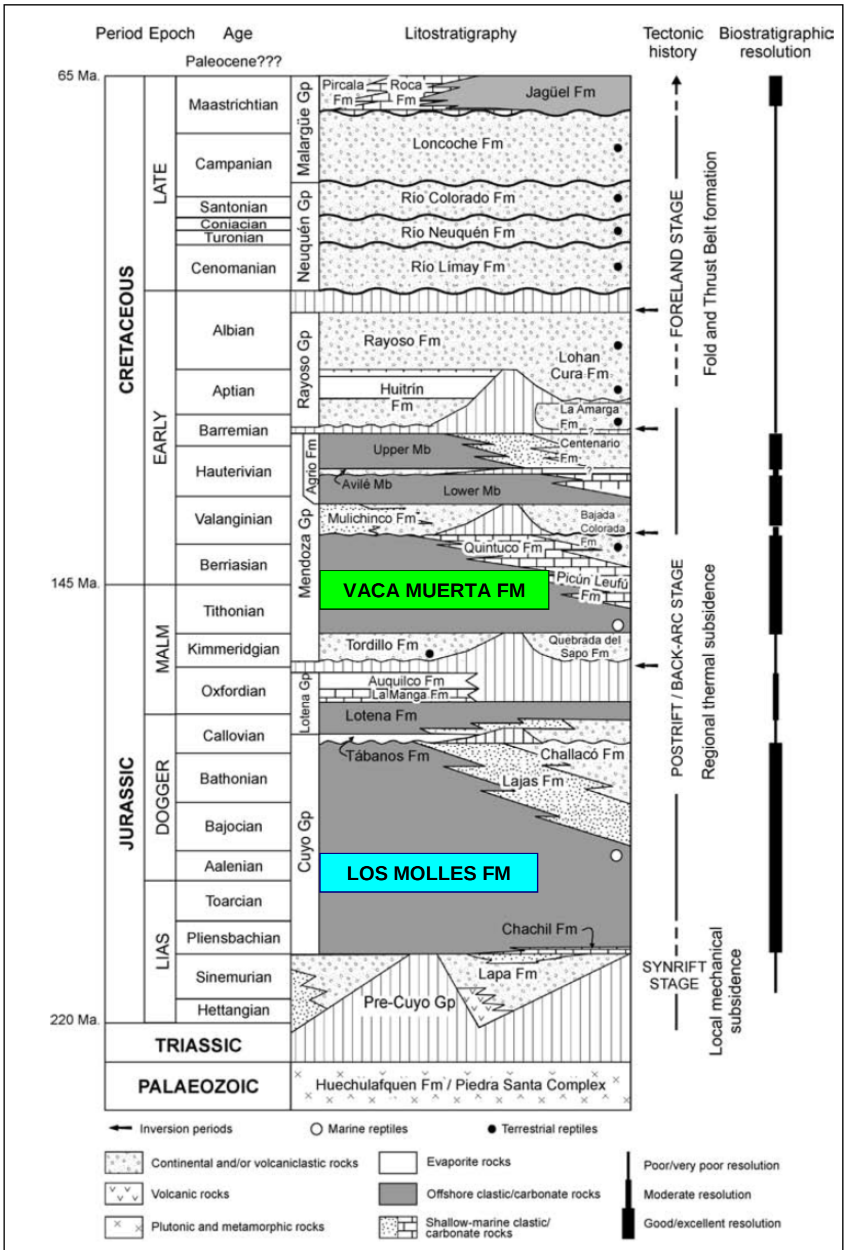
Figure V-2. Neuquen Basin Structure Map



Source: ARI, 2013.

The stratigraphy of the Neuquen Basin is shown in **Figure V-3**. Of particular exploration interest are the shales of the Middle Jurassic Los Molles and Late Jurassic-Early Cretaceous Vaca Muerta formations. These two thick deepwater marine sequences sourced most of the oil and gas fields in the basin and are considered the primary targets for shale gas development.

Figure V-3: Neuquen Basin Stratigraphy.



Modified from Howell, J., et al., 2005

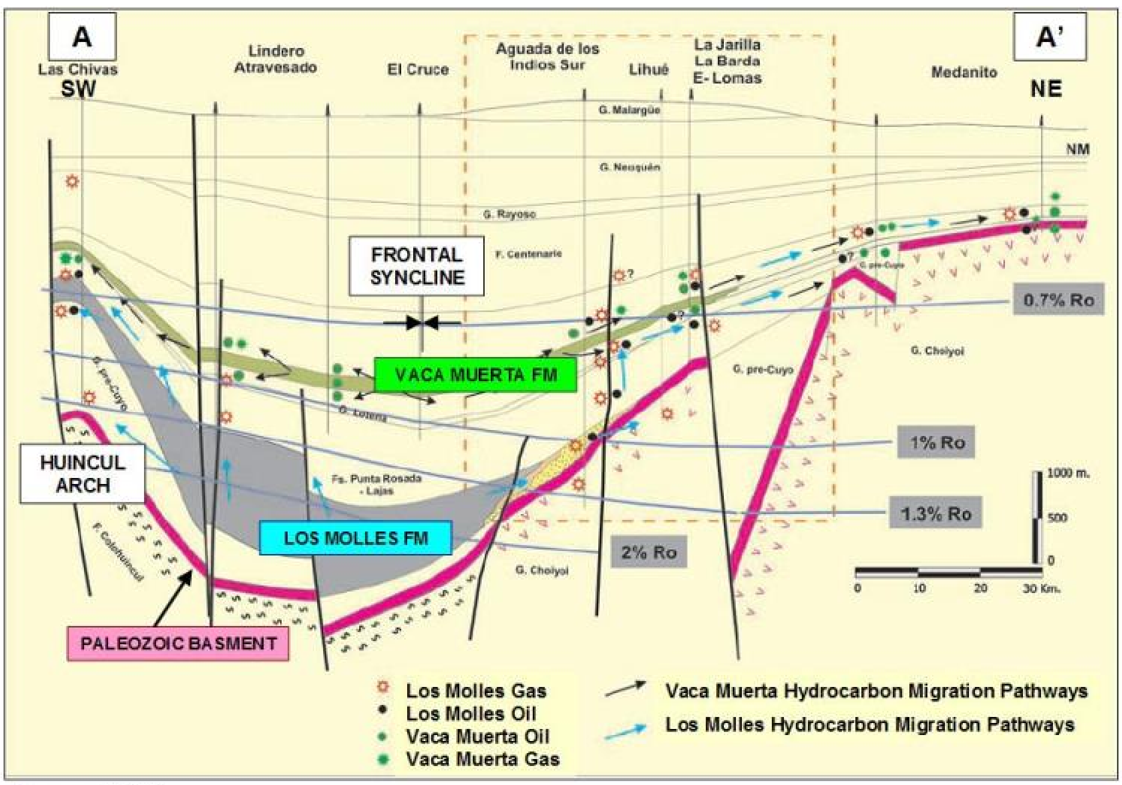
Source: Howell et al., 2005.

1.2 Reservoir Properties (Prospective Area)

Los Molles Shale. The Middle Jurassic (Toarcian-Aalenian) Los Molles Formation is considered an important source rock for conventional oil and gas deposits in the Neuquen Basin. Thermal maturity modeling indicates that hydrocarbon generation took place in the Los Molles at 50 to 150 Ma, with the shallower Lajas Formation tight sands serving as reservoirs.[3] The overlying Late Jurassic Aquilco Formation evaporites effectively seal this hydrocarbon system, resulting in overpressuring (0.60 psi/ft) in parts of the basin.

The Los Molles shale is distributed across much of the Neuquen Basin, reaching more than 3,300 ft thick in the central depocenter. Available data shows the shale thinning towards the east.[4] A southeast-northwest regional cross-section, **Figure V-4**, shows the Los Molles deposit particularly thick in the basin troughs. Well logs reveal a basal Los Molles shale about 500 feet thick.[5]

Figure V-4: Neuquen Basin SW-NE Regional Cross Section



Source: Mosquera et al., 2009.

On average, the prospective Los Molles shale occurs at depths of 8,000 to 14,500 ft, with maximum depth surpassing 16,000 ft in the basin center. In the south, the shale occurs at depths of 7,000 feet or shallower within the uplifted Huincul Arch. The Los Molles shale is at shale-prospective depth across much of the Neuquen Basin.

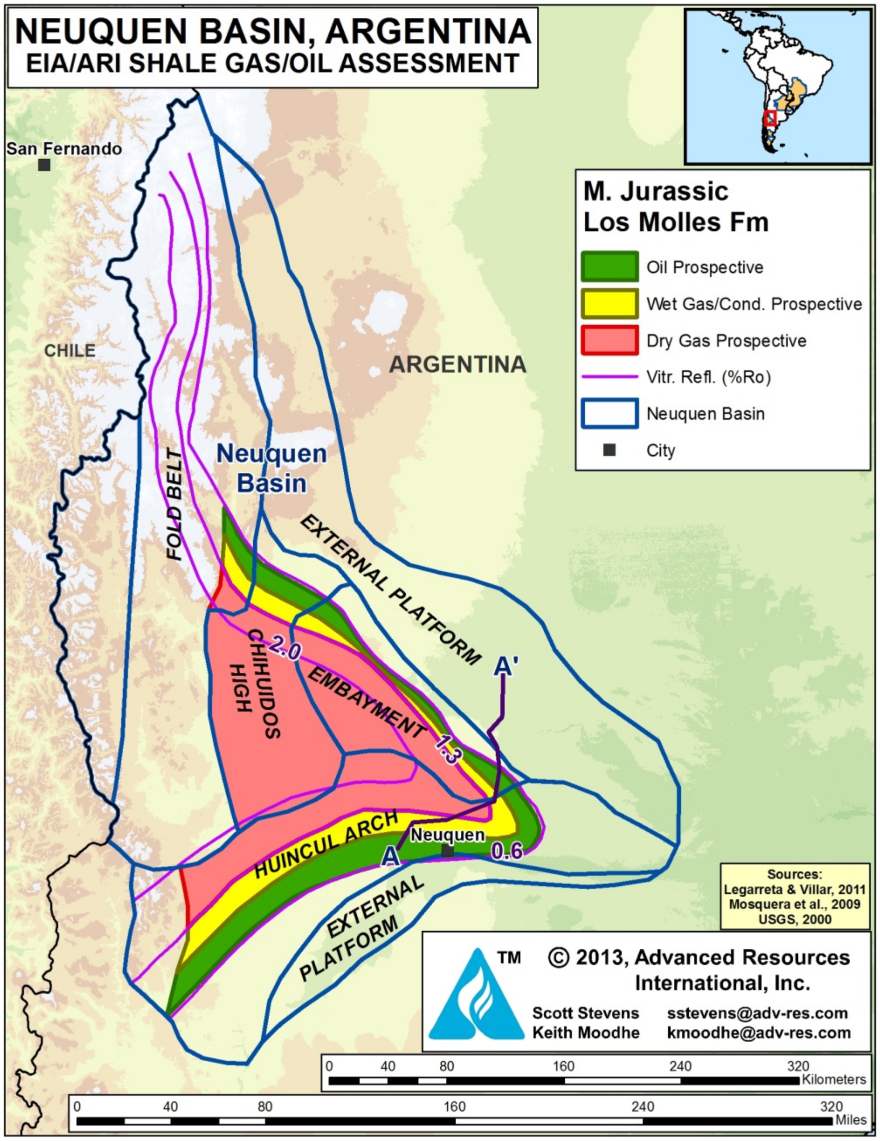
Total organic carbon for the Los Molles shale was determined from various locations across the Neuquen Basin. Samples from five outcrops in the southwestern part of the basin showed average TOC ranging from 0.55 to 5.01%.[6] In the southeast, TOC averaged 1.25% at shallower depths of 7,000 feet at one location. Further east, another interval of the Los Molles Formation, sampled from depths of 10,500 to 13,700 feet, yielded TOC's in the range of 0.5% to nearly 4.0%. The lowermost 800-ft section here recorded a mean TOC of about 2%. Limited data were available for the central and northern regions, where shale is deeper and gas potential appears highest. One well in the basin's center penetrated two several-hundred-foot thick intervals of Los Molles shale, with average 2% and 3% TOC, respectively.[7]

The thermal maturity of the Los Molles shale varies across the Neuguen Basin, from highly immature (R_o = 0.3%) in the shallow Huincul Arch region, to oil-prone (R_o = 0.7%) in the eastern and southern parts of the basin, to fully dry-gas mature (R_o > 2.0%) in the basin center.[8,9] The lower portion of the Los Molles is in the wet gas window (R_o > 1.0%) in a well located north of the Huincul Arch. Gas shows are prevalent throughout the Los Molles Formation.

The prospective area of the Los Molles, **Figure V-5**, is defined by low vitrinite reflectance cutoff in the north, thinning in the east, and complex faulting and shallow depth at the Huincul Arch in the south. The oil-prone thermal maturity window within the prospective area covers an area of 2,750 mi^2; the wet gas window 2,380 mi^2; and the dry gas window 8,140 mi^2.

ARI extended the western play edge beyond the main productive Neuquen area, where most of the conventional oil and gas fields are located, into the Agrio Fold and Thrust Belt along the foothills of the Andes Mountains. While there is some geologic risk associated with this region, the thermal maturity is favorable.

Figure V-5: Prospective Shale Gas and Shale Oil Areas, Los Molles Formation, Neuquen Basin.



Source: ARI, 2013.

Vaca Muerta Shale. The Late Jurassic to Early Cretaceous (Tithonian-Berriasian) shale of the Vaca Muerta Formation is considered the primary source rocks for conventional oil production in the Neuquen Basin. The Vaca Muerta shale consists of finely-stratified black and dark grey shale and lithographic lime-mudstone that totals 200 to 1,700 feet thick.[10] The organic-rich marine shale was deposited in reduced oxygen environment and contains Type II kerogen. Although somewhat thinner than the Los Molles Fm, the Vaca Muerta shale has higher TOC and is more widespread across the basin.

The Vaca Muerta Formation thickens from the south and east towards the north and west, ranging from absent to over 700 feet thick in the basin center.[11] Depth ranges from outcrop near the basin edges to over 9,000 feet deep in the central syncline.[12]

The Vaca Muerta Formation generally is richer in TOC than the Los Molles Formation. Sparse available TOC data were derived from wells and bitumen veins sampled from mines in the north.[13] These asphaltites are very rich in organic carbon, increasing northward to a maximum of 14.2%. In the south, mapped TOC data ranges from 2.9 to 4.0%. TOC of up to 6.5% is reported in the lower bituminous shale units of the Vaca Muerta.

While the Vaca Muerta Formation is present across much of the Neuquen Basin, its thermal maturity changes, increasing from east to west. **Figure V-4** is a cross-section for the Vaca Muerta illustrating the oil and gas regions of this formation. Thermal maturity increases from less than 0.7% R_o along the eastern border of the basin to over 1.5% R_o in the deep northwest trough.[14] Northeast of the Huincul Arch, R_o of 0.8% was measured, placing this area in the oil window.

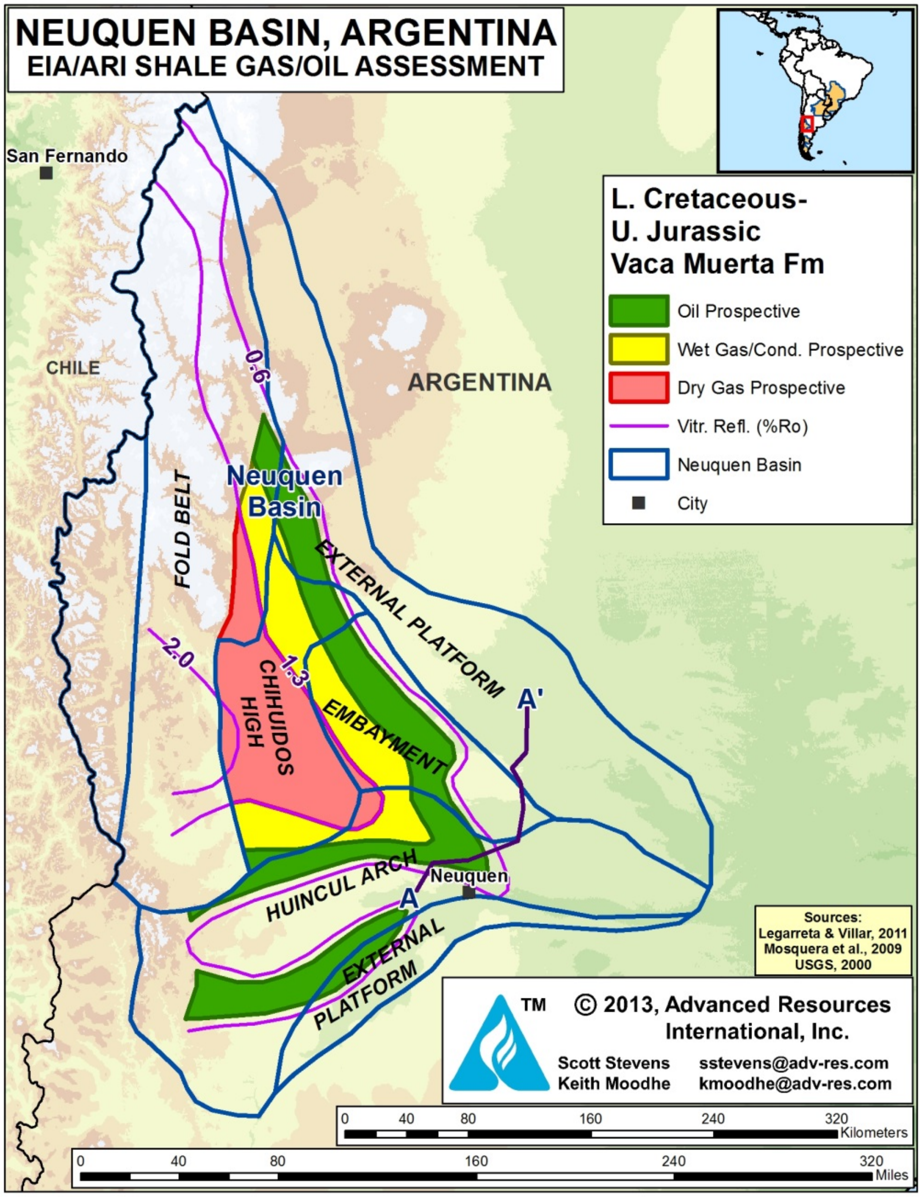
The Vaca Muerta Formation has three distinct prospective areas of hydrocarbons in the Neuquen Basin, as shown on the thermal maturity and prospective area map, Figure V-6. The oil-prone thermal maturity window within the prospective area covers an area of approximately 4,840 mi^2; the wet gas window covers 3,270 mi^2; and the dry gas window covers 3,550 mi^2.

1.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from black shale within the Los Molles Formation of the Neuquen Basin are estimated at 275 Tcf of shale gas and 3.7 billion barrels of shale oil and condensate, from 982 Tcf and 61 billion barrels of risked, in-place shale gas and shale oil resources, Tables 1 and 2. The Los Molles Formation has moderate to high resource concentrations of 49 to 190 Bcf/mi^2 for shale gas and 9 to 36 million bbl/mi^2 for shale oil, depending on the thermal maturity window.

The Vaca Muerta Formation has risked, technically recoverable shale gas and shale oil resources of 308 Tcf of gas and 16 billion barrels of oil and condensate, from 1,202 Tcf and 270 billion barrels of risked, in-place shale gas and shale oil resources. The Vaca Muerta has high to very high resource concentrations of 66 to 303 Bcf/mi^2 for shale gas and 23 to 78 million bbl/mi^2 for shale oil, depending on thermal maturity window.

Figure V-6. Prospective Shale Gas and Shale Oil Areas, Vaca Muerta Formation, Neuquen Basin.



Source: ARI, 2013.

1.4 Recent Activity

Early drilling and production testing are underway in the Neuquen Basin, evaluating the Vaca Muerta Formation mostly at depths of 6,000 to 11,000 ft. YPF reported it holds about 3 million net acres in the basin and is negotiating with Chevron, TOTAL, Statoil, Dow Chemical, and other companies to jointly develop its shale resources. Including earlier Repsol operated wells, YPF has drilled 37 Vaca Muerta wells through 2012.[15] Chevron has reportedly agreed to invest up to $1 billion to drill 100 wells with YPF in the Neuquen Basin, although the deal awaits final approval. CNOOC signed a joint venture deal with YPF to invest up to $1.5 billion to drill 130 wells in the basin.

Repsol, which previously operated YPF's position in the Neuquen Basin, drilled some 20 vertical wells targeting the Vaca Muerta Shale that produced at encouraging initial rates of 180 to 600 bbl/day on restricted 4-mm choke. In 2012, Repsol estimated that its leases held a total of 92 Tcf and 7.0 billion barrels of contingent and prospective shale gas and oil resources.[16]

Apache has 1.3 million net acres in the Neuquen Basin with Vaca Muerta Shale potential, of which the company estimates 586,000 net acres is liquids-rich. Apache estimates its net recoverable potential at 0.8 billion barrels. The company completed its first Vaca Muerta horizontal well during 2012, a relatively short 1,900-ft lateral treated with a 7-stage hydraulic stimulation, described by Apache as "very encouraging."[17] The company's earlier Los Molles horizontal, drilled into the dry gas thermal maturity window at a depth of 4,400 m, IP'd at 4.5 MMcfd from a 2100' lateral that was stimulated by a 9-stage fracture treatment. Apache plans to invest $200 MM during 2013 to drill 16 net wells focusing on the Vaca Muerte within the TDF and Rio Negro blocks.[18]

EOG Resources estimates it holds about 100,000 net acres with shale potential in the Neuquen Basin. The company reported lower-than-expected results from its first horizontal oil well in the Vaca Muerta Formation, with production similar to its nearby vertical well. EOG is evaluating the results of the two wells and plans to proceed cautiously during 2013.[19]

Calgary-based Americas Petrogas operates 15 blocks covering nearly 1.4 million net acres in the Neuquen Basin. To date the company has drilled four shale exploration wells to test the Vaca Muerta Formation. Its LTE.x1 vertical well on the Los Toldos II block, drilled with partner ExxonMobil, IP'd at 309 boe/day (30-day average rate; 82% oil) from the 343-m thick Vaca Muerta Formation following a 5-stage hydraulic stimulation. The company's second vertical shale well, drilled on the Los Toldos I block, intersected 562 m of Vaca Muerta Formation at depths of 2,570-2,929 m. This well produced up to 3.2 million ft^3/day of natural gas with 9 to 18 bbl/day of condensate following a 4-stage fracture stimulation.[20]

2 GOLFO SAN JORGE BASIN

2.1 Introduction and Geologic Setting

Located in central Patagonia, the 67,000-mi^2 Golfo San Jorge Basin accounts for about one-quarter of Argentina's conventional oil and gas production.[21] An intra-cratonic extensional basin, the San Jorge extends across the width of southern Argentina, from the Andean foothills on the west to the offshore Atlantic continental shelf in the east. Excluding its small offshore extent, the onshore Golfo San Jorge Basin covers approximately 46,000 mi^2.

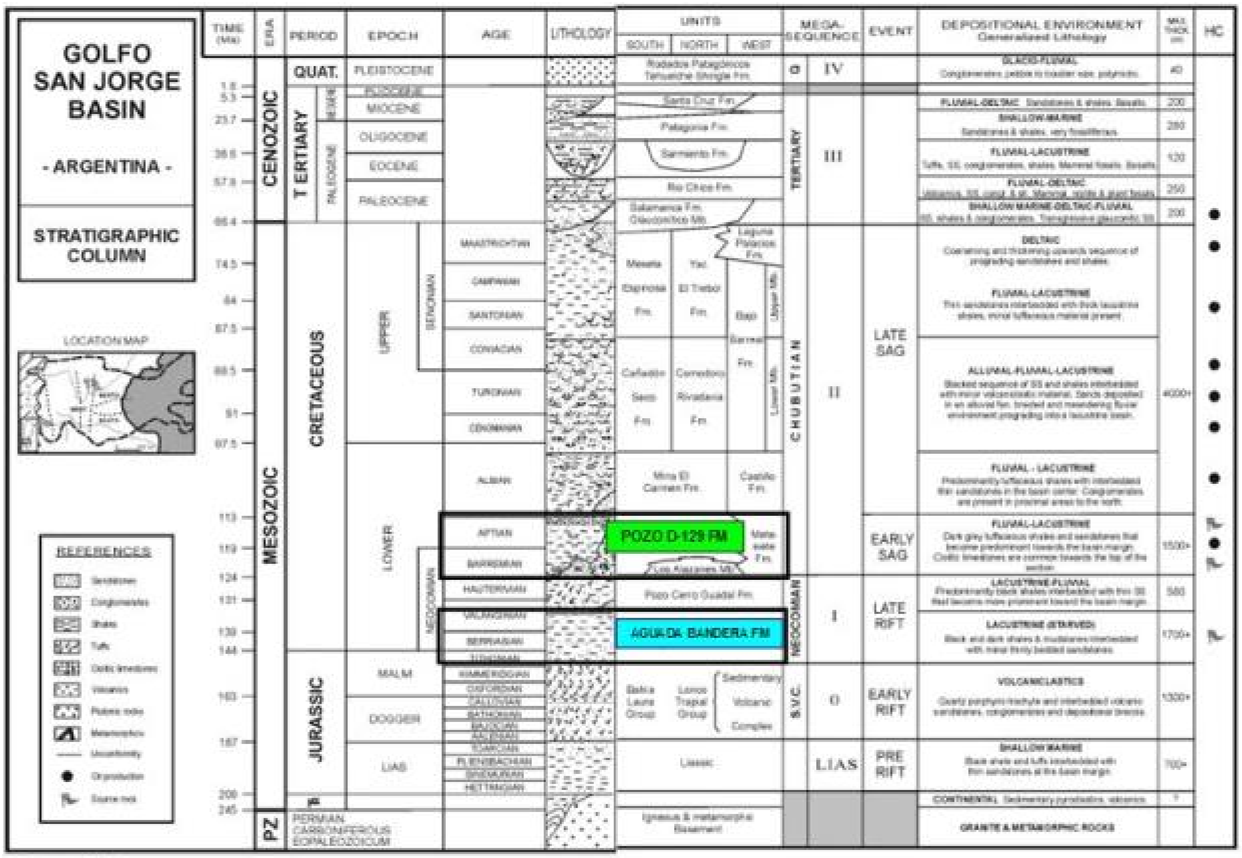
The basin is bordered by the Deseado Graben and Massif to the south, by the Somuncura Massif to the north, and the Andes Mountains in the west. Compressional structures of the San Bernardo Fold Belt transect the west-central region.[22] Extensional faults are widespread in the northeastern and southern flanks, while the northwestern edge of the basin is less faulted.[23]

Extensional events marked by the formation of grabens and half-grabens in the present-day location of the Golfo San Jorge Basin began in the Triassic to Early Jurassic as the Gondwana supercontinent began to break up.[24] A separate period of extension followed in the Middle Jurassic, as the Lonco Trapial Volcanics were deposited via northwest-striking faults. The region subsided by the end of the Jurassic and extensive, mainly lacustrine deposits formed, including the thick black shale and mudstone source rocks of the Neocomian Aguada Bandera Formation.

2.2 Reservoir Properties (Prospective Area)

Aguada Bandera Shale. The Late Jurassic-Early Cretaceous Aguada Bandera Formation comprises fine gray sandstones that grade upward into a tuffaceous matrix, with black shales and mudstones increasing towards its base, **Figure V-7**.[25] Much of the formation is lacustrine in origin, although foraminifera found in western areas suggest possible marine sources in particular beds.[26] Towards the north, other biota indicative of an outer marine platform depositional environment were observed in well samples near Lago Colhue Huapi.[27]

Figure V-7: Golfo San Jorge Basin Stratigraphy



Sylwan, 2001

Source: Sylwan, 2001.

The Aguada Bandera Formation is a heterogeneous unit comprising shale, sandstone, and occasional limestone. Total formation thickness varies widely, from more than 15,000 ft thick in the southwest to 0-2,000 ft thick about 60 miles offshore in the east. A similar thickness variation also is seen in the west. Limited data is present south of Lago Colhue Huapi to the north. The Aguada Bandara Formation generally is 1,000 to 5,000 ft thick in the central basin, probably only a fraction of which is high-quality organic shale.

Depth to the top of the Aguada Bandera Formation was mapped based on the top of the underlying Middle Jurassic Loncol Trapial volcanics. Burial depth reaches a maximum 20,000 ft along the onshore coast in the center of the basin. Depocenters in the western portion of the basin typically average a more prospective 10,000 to 12,000 ft deep. The Aguada Bandera is much shallower, 2,000 to 8,000 ft deep, along the northern and western flanks. In the eastern coastal onshore portion of the basin, the Aguada Bandera Shale is about 1,500 to 2,500 ft thick and 20,000 ft deep.

Limited geochemical data were available for analyzing the Aguada Bandera, which is considerably deeper than the conventional reservoirs and thus rarely sampled. Only two available wells have TOC and R_o data, both located in the basin's western area. Average TOC ranged from 1.44% to 3.01% at depths of 12,160 ft and 11,440 ft, respectively.[28] Organic-rich intervals reached 4.19% TOC. Vitrinite reflectance indicated a dry-gas thermal maturity of 2.4% R_o.

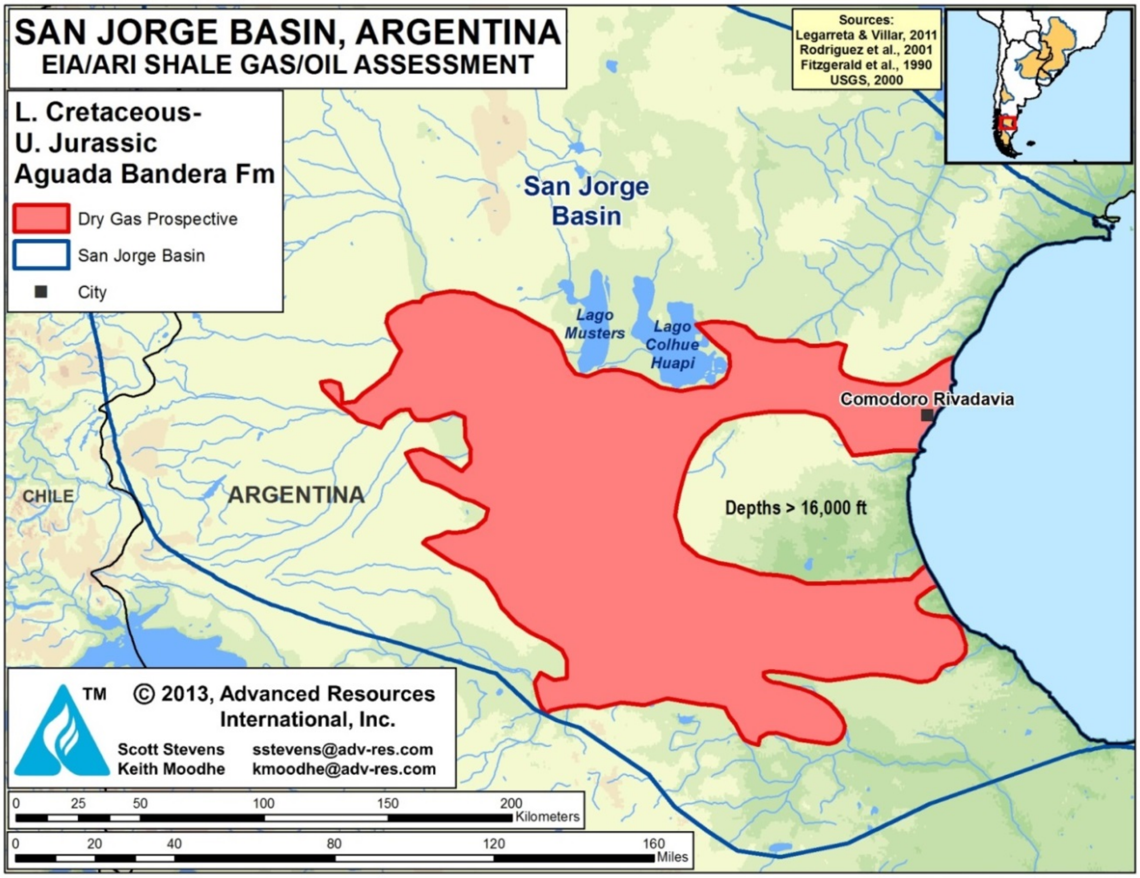
Petroleum basin modeling indicates that the minimum gas generation threshold (R_o = 1.0 to 1.3%) is typically achieved across the basin at depths below about 6,600 ft. Thus, the Aguada Bandera Formation appears to be mature for gas generation across most of the basin, **Figure V-8**. The unit is likely to be over mature in the deep basin center, where R_o is modeled to exceed 4%.

Using depth distribution and appropriate minimum and maximum R_o cutoffs, ARI's prospective area for the Aguada Bandera Shale covers approximately 8,380 mi^2 of the onshore Golfo San Jorge Basin. The central coastal basin (>16,000 ft deep) and the northern Lake region (<6,000 ft deep) were excluded as not prospective.

Pozo D-129 Shale. The Early Cretaceous Pozo D-129 Formation comprises a wide range of lithologies, with the deep lacustrine sediments -- organic black shales and mudstones – considered most prospective for hydrocarbon generation.[29] The presence of pyrite, dark laminations, and the absence of fossil burrows in the marine shale portions of this unit all point to favorably anoxic depositional conditions.[30] Siltstones, sandstones, and oolitic limestones also were deposited in the shallower water environments of the Pozo D-129.

The Pozo D-129 Shale is consistently thicker than 3,000 ft in the central basin, with local maxima exceeding 4,500 ft thick. Along the northern flank the interval is typically 1,000 to 2,000 ft thick. A locally thick deposit occurs in the western part of the basin, but thins rapidly from about 1,000 ft thick to absent.

Figure V-8: Aguada Bandera Fm Prospective Area, Golfo San Jorge Basin



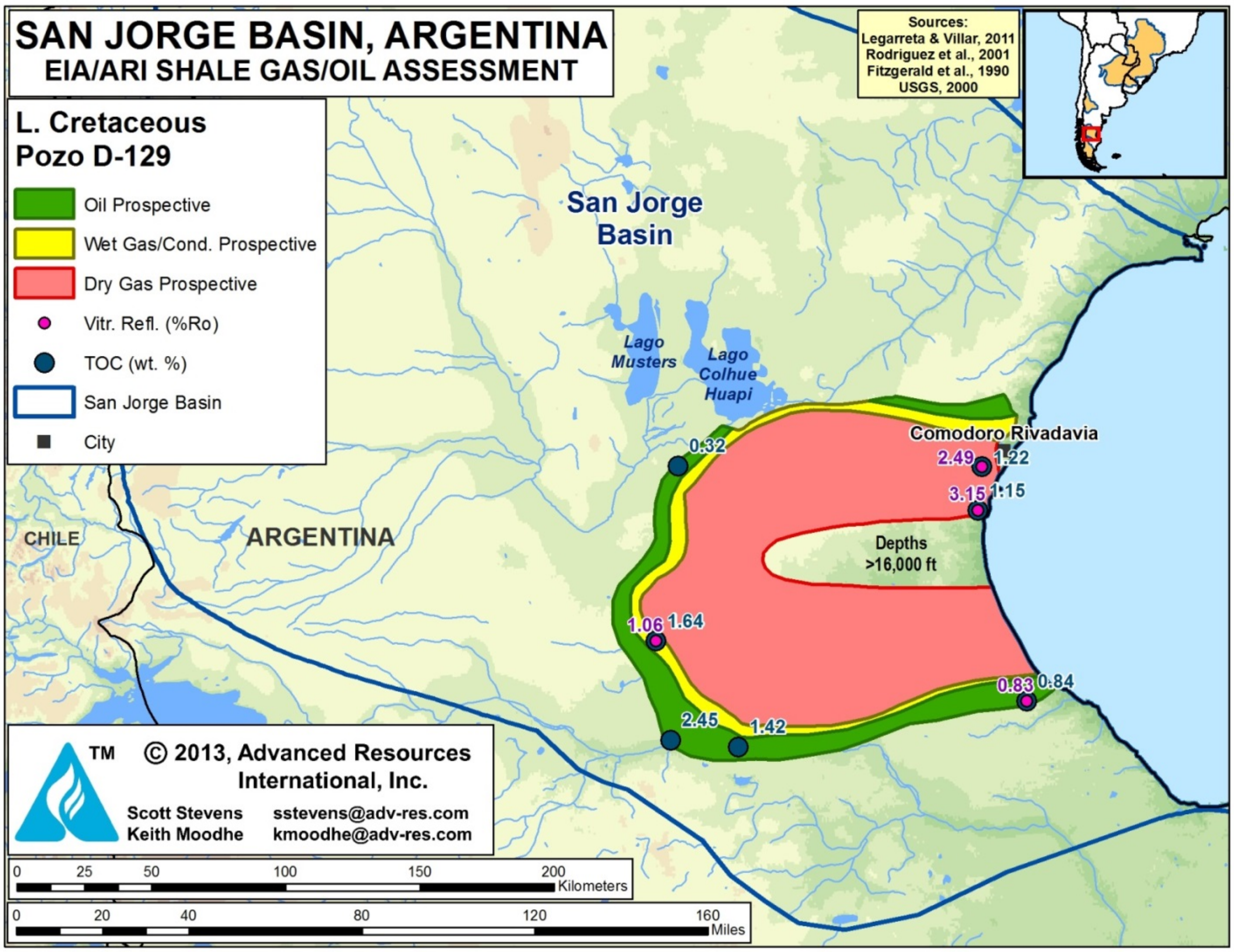
Source: ARI, 2013.

Northeast of Lago Colhue Huapi, the Pozo D-129 shoals rapidly from 6,000 ft to about 2,800 ft deep. Just southwest of the lake, depth increases from about 5,000 ft to nearly 9,500 ft. To the south, depths range from 5,000 to 6,400 ft, with similar depths in the west. The Pozo D-129 deepens along the eastern coastal flank of the basin to nearly 15,900 ft near the city of Comodoro Rivadavia.

Available data indicates organic richness in the southwest, 1.42% to 2.45% TOC, with a corresponding early gas maturity of 1.06% R_o. In the north-central region a low 0.32% TOC was recorded, with slightly higher 0.5% R_o near Lago Colhue Huapi.[31] Towards the basin center in the east, organic carbon (TOC) rises to around 1.22%. The thermal maturity in this deep setting is correspondingly high, 2.49 to 3.15% R_o. In the south, thermal maturity drops to oil-prone levels, 0.83% R_o with a measured TOC here of about 0.84%, excluding this area from the resource assessment.

ARI defined the shale prospective areas for the Pozo D-129 Formation based primarily on depth and available (but incomplete) vitrinite reflectance data, **Figure V-9**. The total prospective area for the Pozo D-129 Shale is estimated at approximately 5,580 mi^2, mainly in the dry gas window (4,120 mi^2), with much smaller wet gas (540 mi^2) and oil-prone (920 mi^2) areas.

Figure V-9: Pozo D-129 Fm, TOC, Thermal Maturity, and Prospective Area, Golfo San Jorge Basin



Source: ARI, 2013.

2.3 Resource Assessment

Aguada Bandera Formation. Risked, technically recoverable shale gas resources for the Aguada Bandera Formation in the Golfo San Jorge Basin are estimated at 51 Tcf of natural gas, from risked shale gas in-place of 254 Tcf, Table 1. The play has a high net average resource concentration of 152 Bcf/mi^2.

Pozo D-129 Formation. The Pozo D-129 Formation has risked, technically recoverable shale resources estimated at 35 Tcf of shale gas and 0.5 billion barrels of shale oil and condensate, from 184 Tcf and 17 billion barrels of risked, in-place shale gas and shale oil resources, Tables 1 and 2. The Pozo D-129 has moderate to high net resource concentrations of 41 to 163 Bcf/mi^2 of shale gas and 20 to 64 million bbl/mi^2 of shale oil and condensate, depending on the thermal maturity window.

2.4 Recent Activity

No shale activity has been reported in the Golfo San Jorge Basin.

3 AUSTRAL BASIN

3.1 Introduction and Geologic Setting

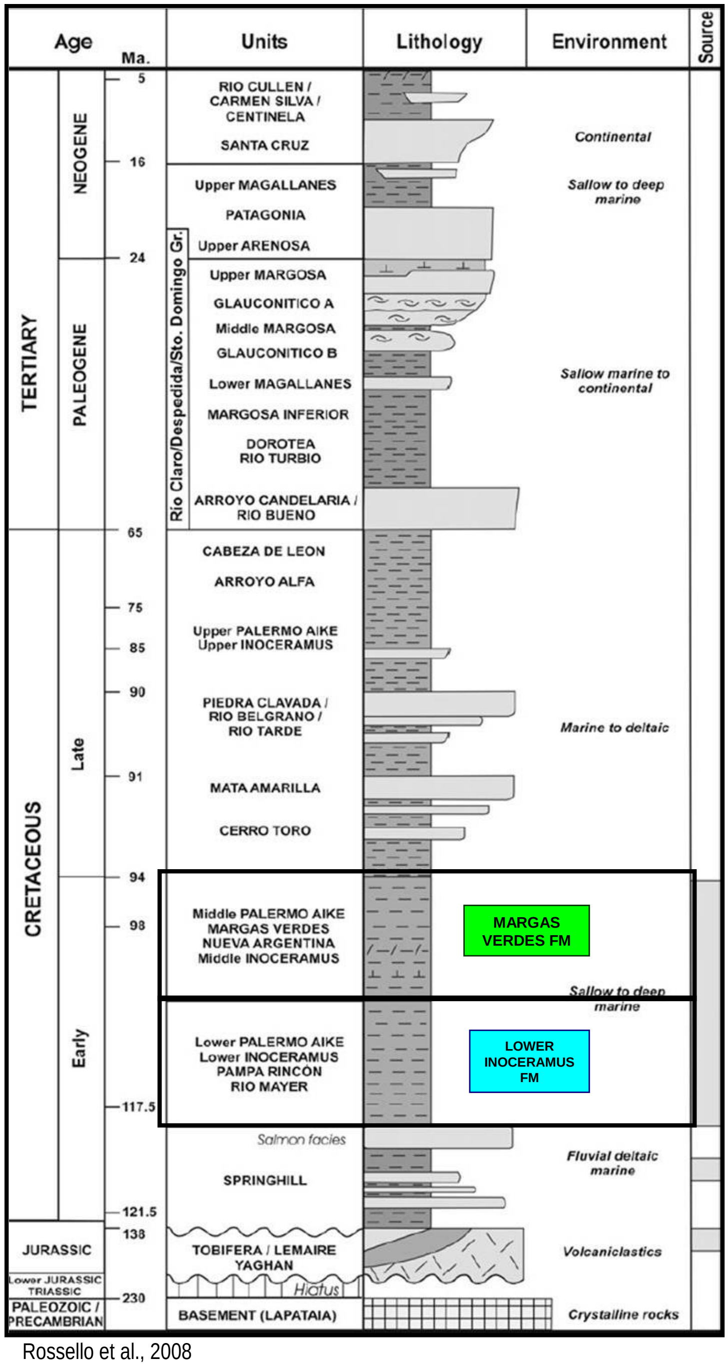
Located in southern Patagonia, the 65,000-mi^2 Austral-Magallanes Basin has promising but untested shale gas potential, **Figure V-10**. Most of the basin is in Argentina, where it is usually called the Austral Basin. A small southernmost portion of the basin is located in Chile's Tierra del Fuego region, where it is referred to as the Magallanes Basin. Oil and gas has been produced in the basin for decades from deltaic to fluvial sandstones in the Early Cretaceous Springhill Formation at depths of about 6,000 ft.

The Austral Basin comprises two main structural regions: a normal faulted eastern region and a thrust faulted western area. The basin contains a thick sequence of Upper Cretaceous and Tertiary sedimentary and volcaniclastic rocks which unconformably overlie the deformed metamorphic basement of Paleozoic age. Total sediment thickness ranges from 3,000 to 6,000 ft along the eastern coast to a maximum 25,000 ft along the basin axis. Jurassic and Lower Cretaceous petroleum source rocks are present at moderate depths of 6,000 to 10,000 ft across large areas, **Figure V-11**.[32] The overlying Cretaceous section comprises mainly deepwater turbidite clastic deposits up to 4 km thick which appear to lack shale gas and oil potential.[33]

The organic-rich shales of Jurassic and Early Cretaceous age formed under anoxic marine conditions within a Neocomian sag on the edge of the Andes margin. The basal sequence consists of Jurassic source rocks that accumulated under restricted lacustrine conditions within small half-grabens. Interbedded shale and sandstone of the Zapata and Punta Barrosa formations were deposited in a shallow-water marine environment.[34] The mid-lower

Jurassic Tobifera Formation contains 1% to 3% TOC (maximum 10% in coaly shales), consisting of Types I to III kerogen. However, carbon in this unit is mainly coaly and probably insufficiently brittle for shale exploration.

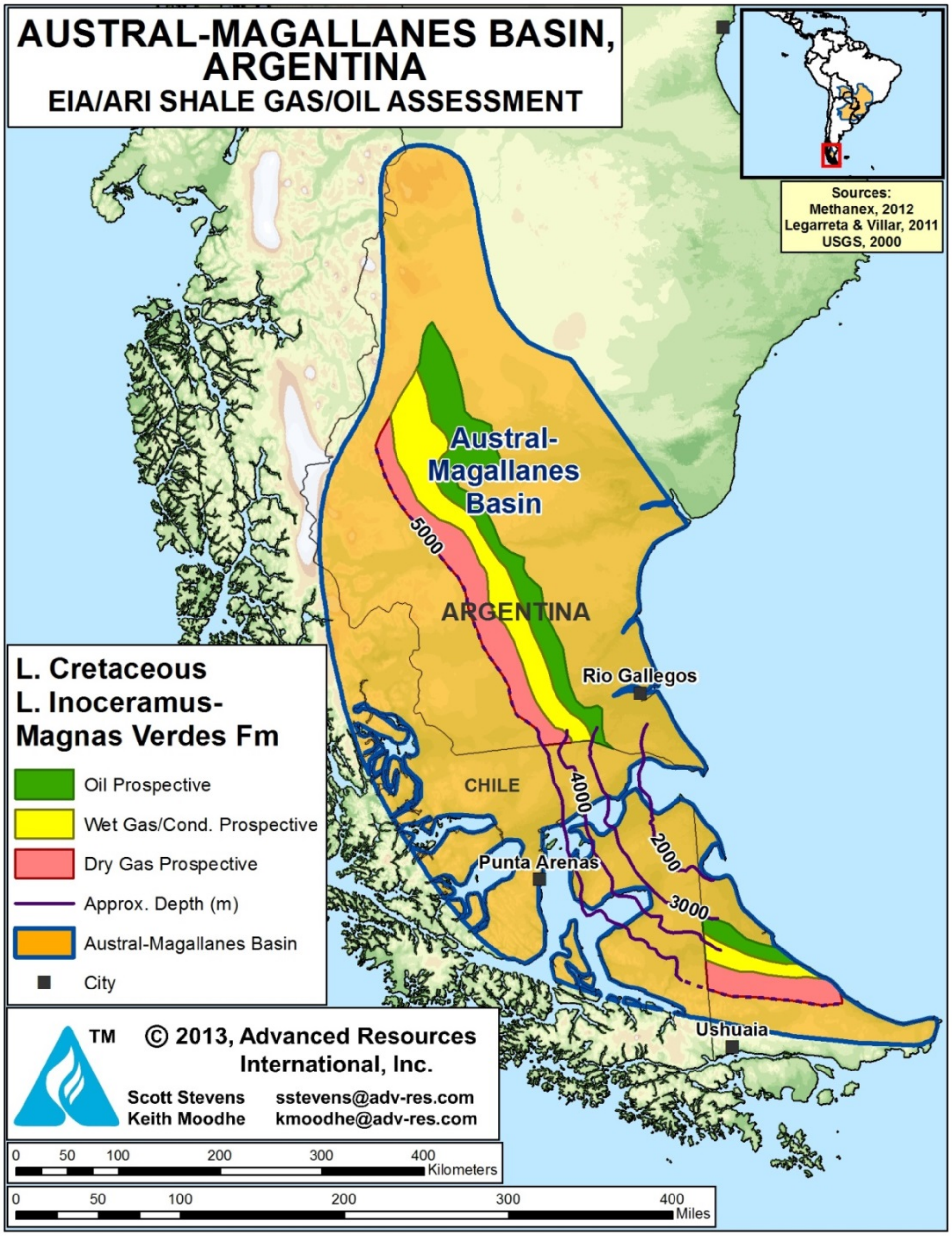
Figure V-10: Stratigraphy of the Austral-Magallanes Basin, Argentina and Chile



Source: Rossello et al., 2008

Advanced Resources International, Inc.

Figure V-11: Inoceramus Shale, Depth, TOC, and Thermal Maturity, Austral / Magallanes Basin

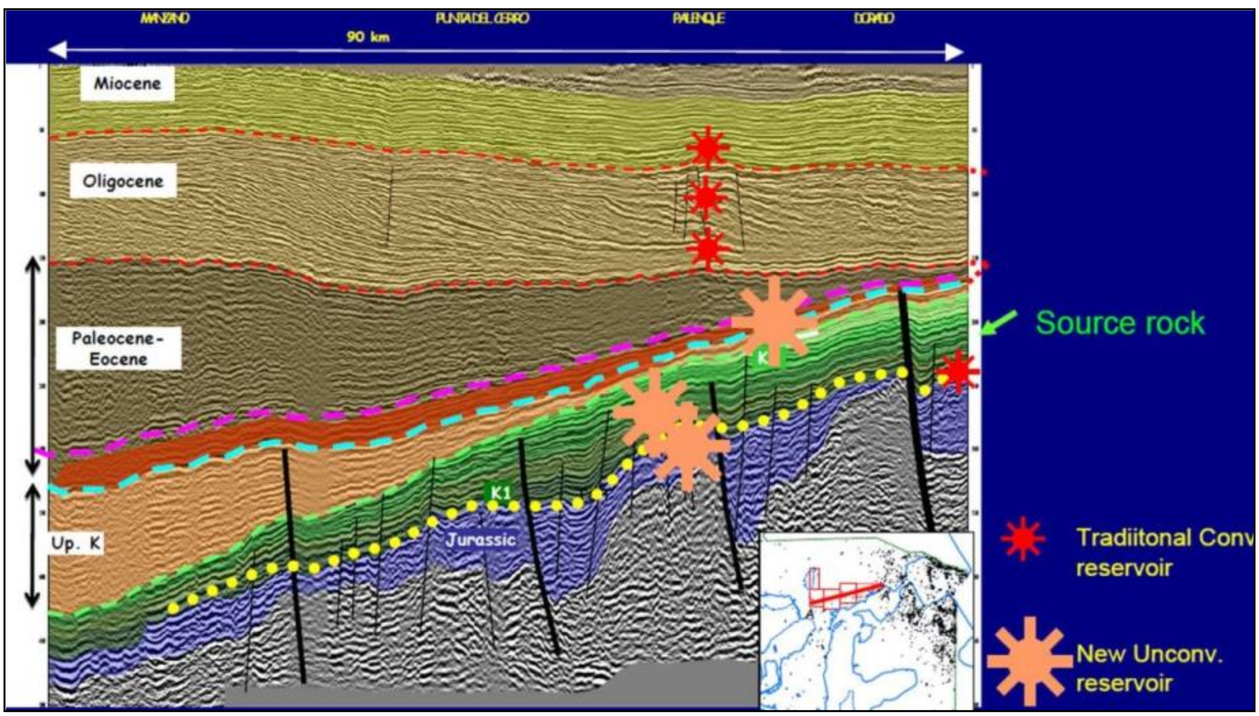


Source: ARI, 2013.

Overlying the Tobifera Formation are more prospective shales within the Early Cretaceous Lower Inoceramus or Palermo Aike formations (Estratos con Favrella Formation in Chile). The Tobifera was deposited under shallow water marine conditions. The Lower Inoceramus Formation is 50 to 400 m thick. In the Argentina portion of the basin, the total shale thickness (including the Magnas Verdes Formation) ranges from 800 ft thick in the north to 4,000 ft thick in the south, representing neritic facies deposited in a low-energy and anoxic environment.[35] Total organic content of these two main source rocks generally ranges from 1.0% to 2.0%, with hydrogen index of 150 to 550 mg/g.[36] Based on analysis in Chile reportedly conducted by Chesapeake Energy, the Lower Cretaceous Estratos con Favrella Formation contains marine-deposited shale with consistently good to excellent (up to 6%) TOC, particularly near its base.[37]

Figure V-12, a seismic time section across the basin, shows the 180-m thick Estratos con Favrella Formation dipping gently west in a relatively simple structural setting. ENAP has estimated porosity of 6% to 12%, but we assumed a more conservative estimate of 6%. Thermal maturity increases gradually with depth in a half-moon pattern, ranging from oil-prone (R_o 0.8%) to dry gas prone (R_o 2.0%). The transition from wet to dry gas (R_o 1.3%) occurs at a depth of about 3,600 m in this basin.[38]

Figure V-12: Seismic Time Section in the Magallanes Basin, Chile



Source: Methanex, September 27, 2012.

3.2 Reservoir Properties (Prospective Area)

Argentina's portion of the Austral Basin has an estimated 13,530-mi^2 prospective area with organic-rich shale in Lower Cretaceous formations. Of this total prospective area, approximately 4,620 mi^2 is in the oil window; 4,600 mi^2 is in the wet gas/condensate thermal maturity window; and 4,310 mi^2 is in the dry gas window. These shales average about 800 ft thick (organic-rich), 8,000 to 13,500 ft deep, and have estimated 3.5% average TOC. Thermal maturity (R_o) ranges from 0.7% to 2.0% depending mainly on depth. Porosity is estimated at about 5%. The Estancia Los Lagunas gas condensate field in southeast Argentina measured a 0.46 psi/ft pressure gradient with elevated temperature gradients in the Serie Tobifera Formation, immediately underlying the Lower Inoceramus equivalent.[39]

3.3 Resource Assessment

Risked, technically recoverable shale gas and oil resources from the Lower Cretaceous formations in the Argentina portion of the Austral Basin are estimated at 130 Tcf of shale gas and 6.6 billion barrels of shale oil and condensate, Tables V-1 and V-2. Risked shale gas and oil in-place is estimated at 606 Tcf and 131 billion barrels. The play has moderate to high resource concentrations of 33 to 156 Bcf/mi^2 of shale gas and 15 to 48 million bbl/mi^2 of shale oil and condensate, depending on the thermal maturity window.

3.4 Recent Activity

No shale leasing or exploration activity has been reported in the Austral Basin. In Chile, Methanex had partnered with ENAP in conventional oil and gas exploration in the Magallanes basin and also had expressed interest in shale gas exploration during 2011-12. However, recently the company decided to relocate about half of its methanol capacity in Chile to Louisiana, USA.[40]

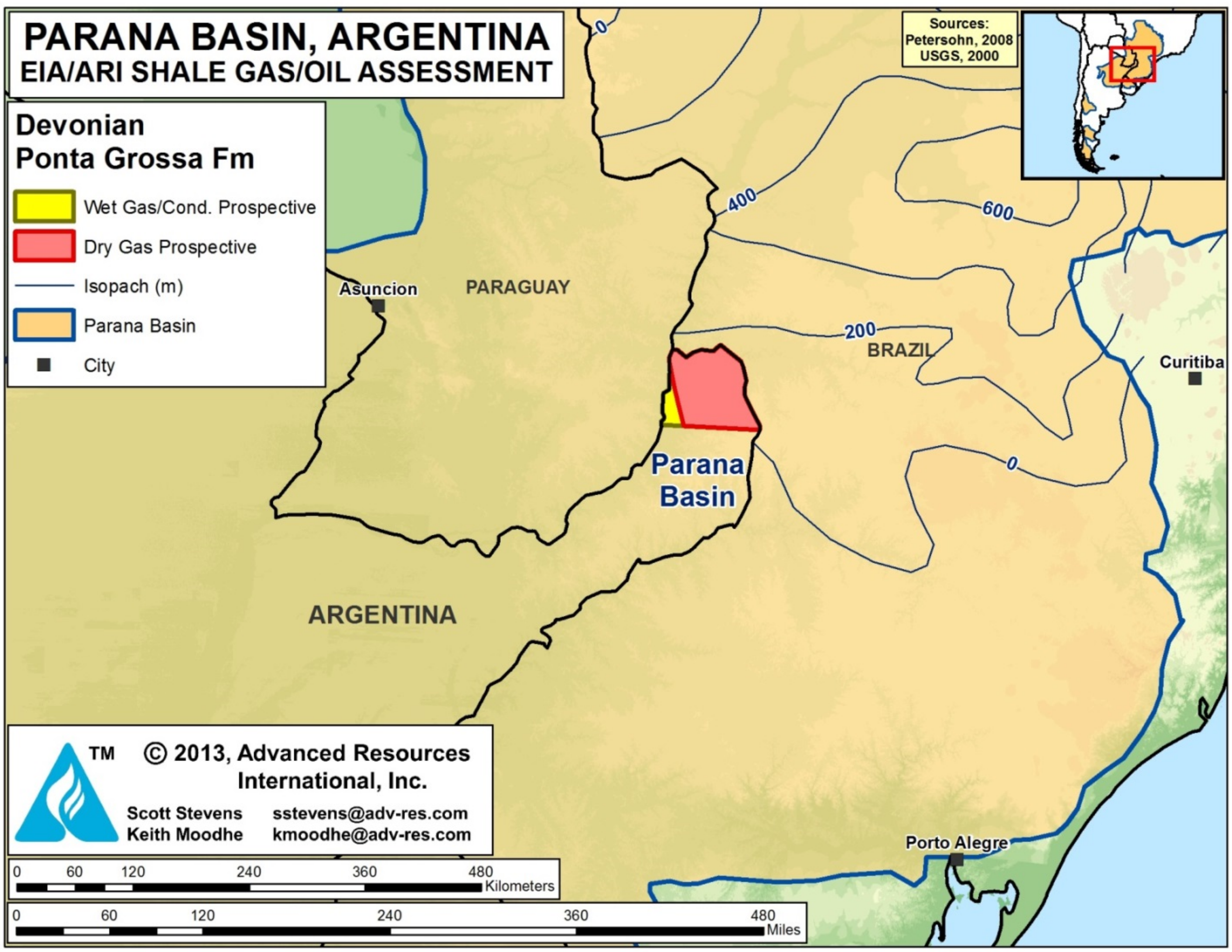
UK-based GeoPark holds conventional petroleum leases in the Magallanes Basin of Chile, which the company notes contains shales in the Estratos con Favrella Formation which previously have produced oil. In 2012, GeoPark conducted diagnostic fracture injection tests on eight wells on the Fell Block to determine reservoir properties of the shale.[41]

4 PARANÁ BASIN

4.1 Introduction and Geologic Setting

The Paraná Basin is a large (747,000 mi^2) depositional feature that covers areas of Brazil, Paraguay, and Uruguay, as well as a small area of northeastern Argentina, **Figure V-13**. The basin contains up to 5 km (locally 7 km) of Paleozoic and Mesozoic sedimentary rocks that range from Late Ordovician to Cretaceous. The basin's western border is defined by the Asuncion Arch, related to Andean thrusting, while the east is truncated by the South Atlantic tectonic margin.[42] Much of the Brazilian portion of the basin is covered by flood basalts, partly obscuring the underlying geology from seismic and increasing the cost of drilling, but the Argentina portion is largely free of basalt.

Figure V-13: Prospective Shale Area in the Parana Basin, Argentina



Source: ARI, 2013.

The main petroleum source rock in the Paraná Basin is the Devonian (Emsian/Frasnian) black shale of the Ponta Grossa Formation. The entire formation ranges up to 600 m thick in the center of the basin, averaging about 300 m thick. TOC of the Ponta Grossa Fm reaches up to 4.6% but more typically is 1.5% to 2.5%. The mostly Type II kerogen sourced natural gas that migrated into conventional sandstone reservoirs.[43]

Figure V-14, a cross-section of the Paraná Basin, illustrates the thick and gently dipping Devonian source rocks that pass through the oil window into the gas window.[44] A conventional well log in the Paraguay portion of the basin penetrated Devonian source rocks and interbedded sandstones with oil and gas shows.[45] In outcrop, the Devonian Cordobes Formation ranges up to 160 m thick, including up to 60 m of organic-rich shale. TOC ranges from 0.7 to 3.6%, consisting mainly of Type II marine kerogen. Based on the low thermal maturity at outcrop (R_o 0.6%), ANCAP has estimated the boundary between dry and wet gas to occur at a depth of about 3,200 m.[46]

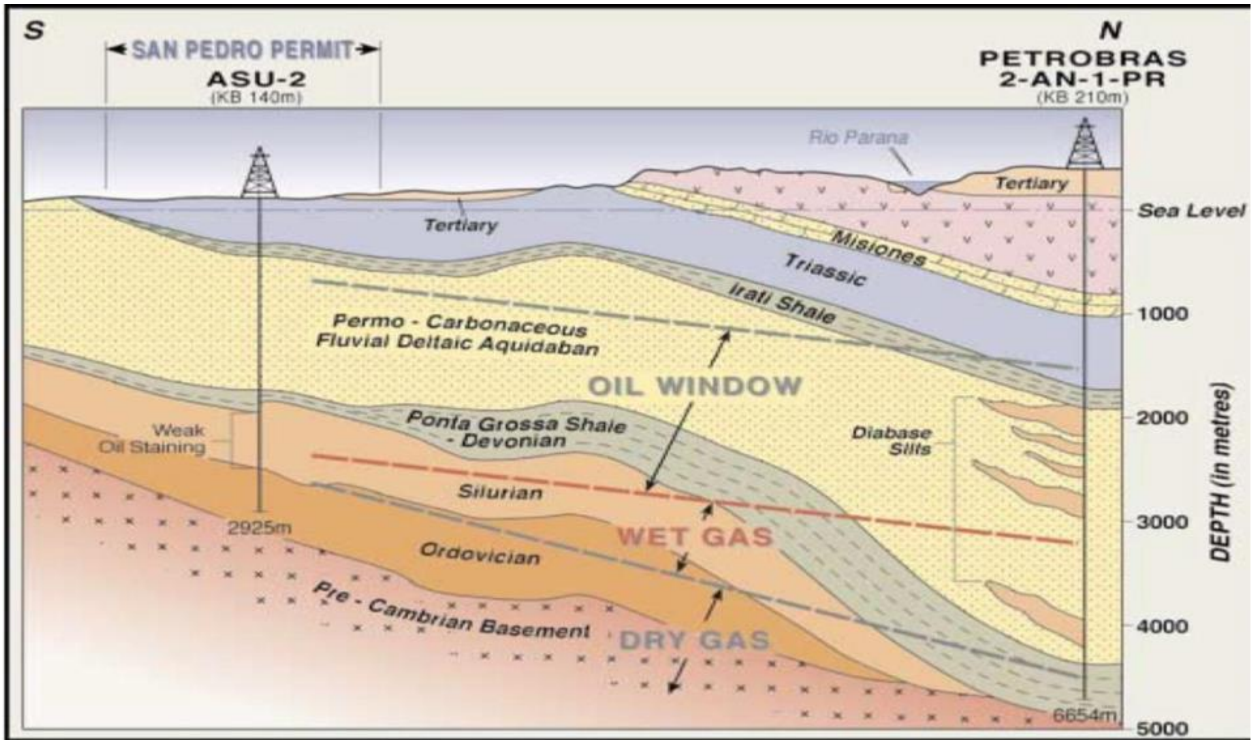
The Paraná Basin has remained at moderate burial depth throughout its history. Consequently, the bulk of thermal maturation took place during the late Jurassic to early Cretaceous igneous episode. Most of the basin remains thermally immature (R_o <0.5%), but there are sizeable concentric windows of oil-, wet-gas-, and dry-gas maturity in the central deep portion of the basin.

4.2 Reservoir Properties (Prospective Area)

Depth and thermal maturity of the Devonian Ponta Grossa Formation are moderately constrained by data in the Argentina portion of the Paraná Basin. The total prospective area in Argentina is estimated at 2,500 mi^2, of which 270 mi^2 is in the wet gas/condensate thermal maturity window, and 2,230 mi^2 is in the dry gas window (the oil window is negligible in this basin). Devonian Ponta Grossa shale averages about 300 m thick (net), 11,000 to 14,000 ft deep, and has estimated 2.0% average TOC. Thermal maturity (R_o) ranges from 0.85% to 1.5% depending mainly on depth.

For example, Amerisur reported that the Devonian Lima Formation has good (2-3%) TOC and is oil-prone (R_o 0.87%) at their conventional exploration block in Paraguay. Porosity is estimated at about 4% and the pressure gradient is assumed to be hydrostatic.

Figure V-14: Cross-Section of the Paraná Basin of Paraguay, Showing Thick and Gently Dipping Devonian Source Rocks Passing Through the Oil and Gas Windows.



Source: Chaco Resources PLC, 2004.

4.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from black shale in the Devonian Ponta Grossa Formation in the Argentina portion of the Paraná Basin are estimated at 3.2 Tcf of natural gas and minimal (0.01 billion barrels) shale oil and condensate, Tables V-1 and V-2. Risked shale gas and shale oil in-place is estimated at 16 Tcf and 0.3 billion barrels. The play has low to moderate net resource concentrations of 35 to 57 Bcf/mi^2 of shale gas and 8 million bbl/mi^2 of shale oil and condensate, depending on the thermal maturity window.

4.4 Recent Activity

No shale leasing or exploration activity has been reported in the Argentina portion of the Paraná Basin. In Uruguay TOTAL, YPF, and small Australia-based Petrel Energy hold large exploration licenses with Devonian shale potential but have not drilled.

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