# 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:

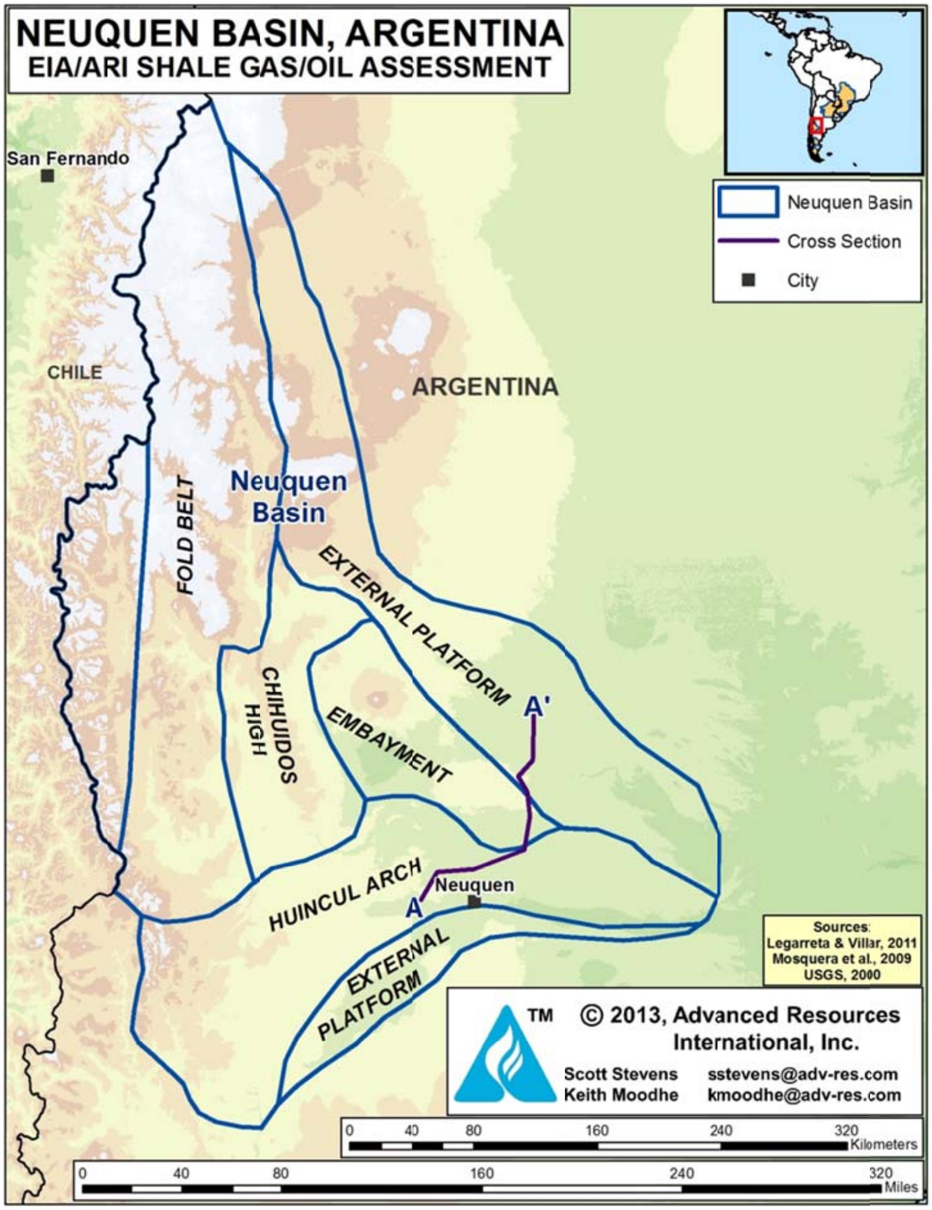
- **Neuquen Basin:** The main focus of shale exploration in Argentina, some 50 mostly vertical wells drilled since 2010 indicate good production potential in the marine-deposited Los Molles and especially Vaca Muerta shales of Jurassic age.
- **Golfo San Jorge Basin:** Containing mostly non-marine lacustrine 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.

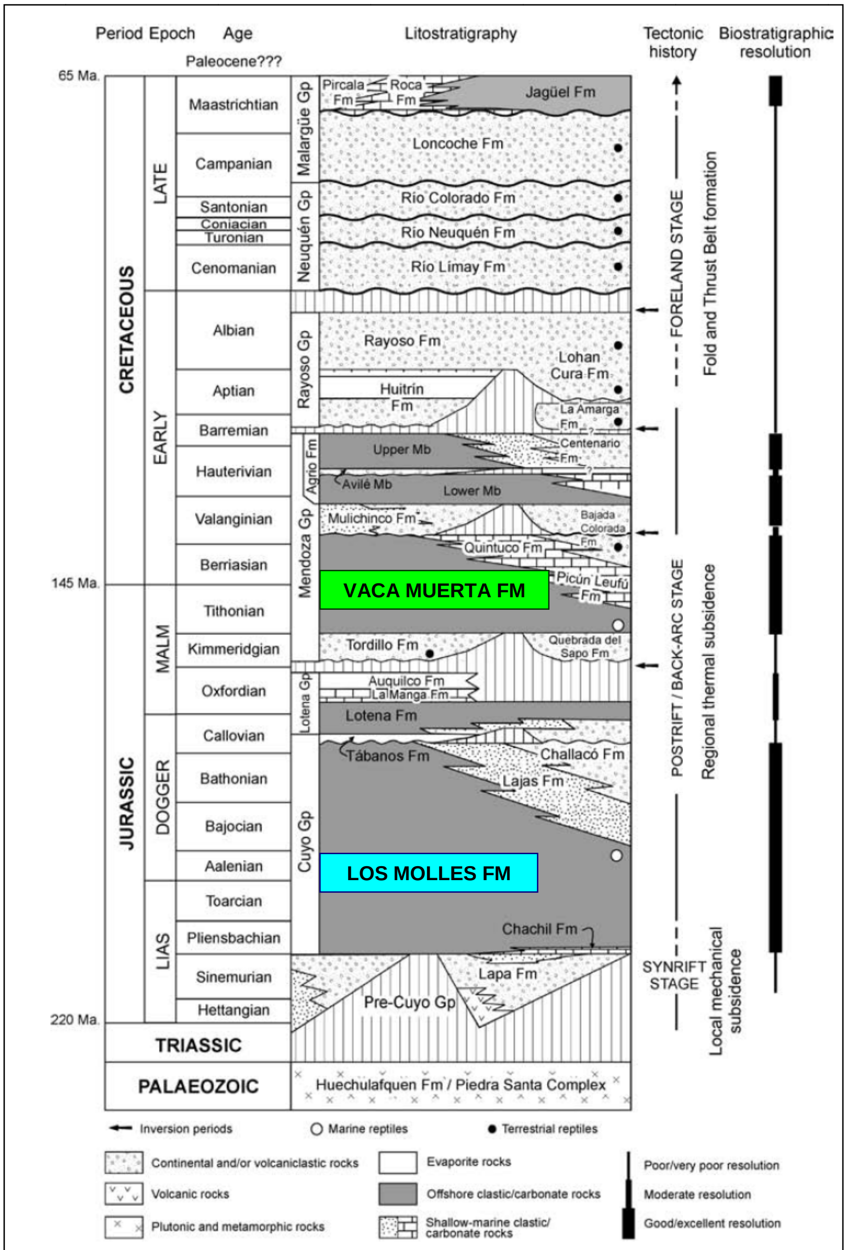
Figure V-2. Neuquen Basin Structure Map




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

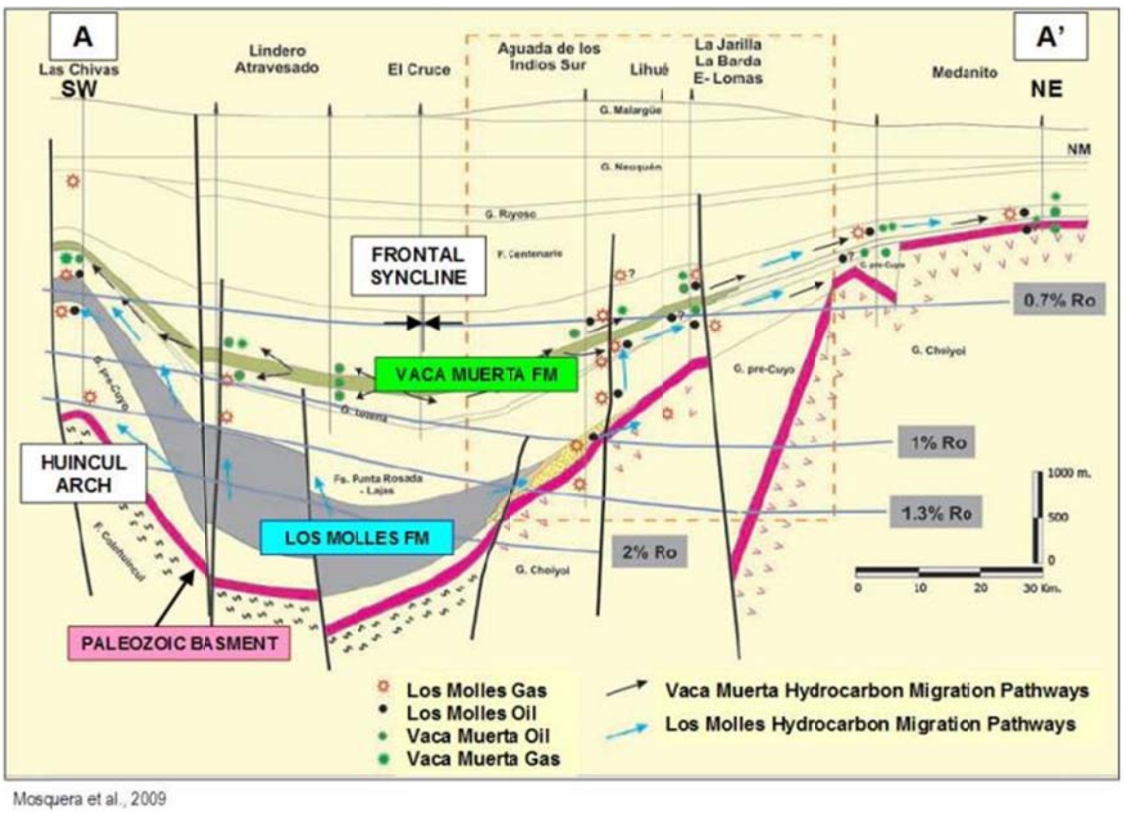
Source: Howell et al., 2005.

## 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.

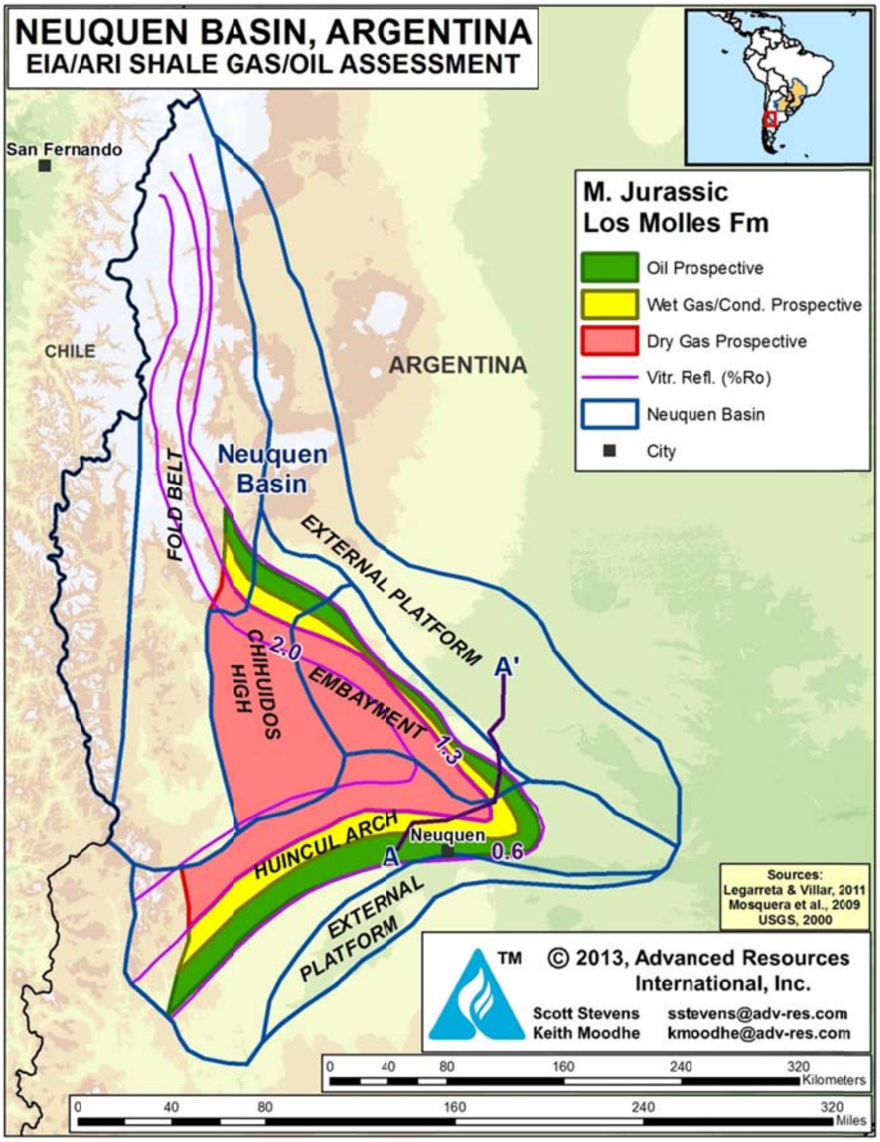
Total organic carbon for the Los Molles shale was determined from various locations across the Neuquen Basin. Samples from five outcrops in the southwestern part of the basin showed average TOC ranging from 0.55 to 5.01%.[6] In the southeast, TOC averaged 1.25% at shallower depths of 7,000 feet at one 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.

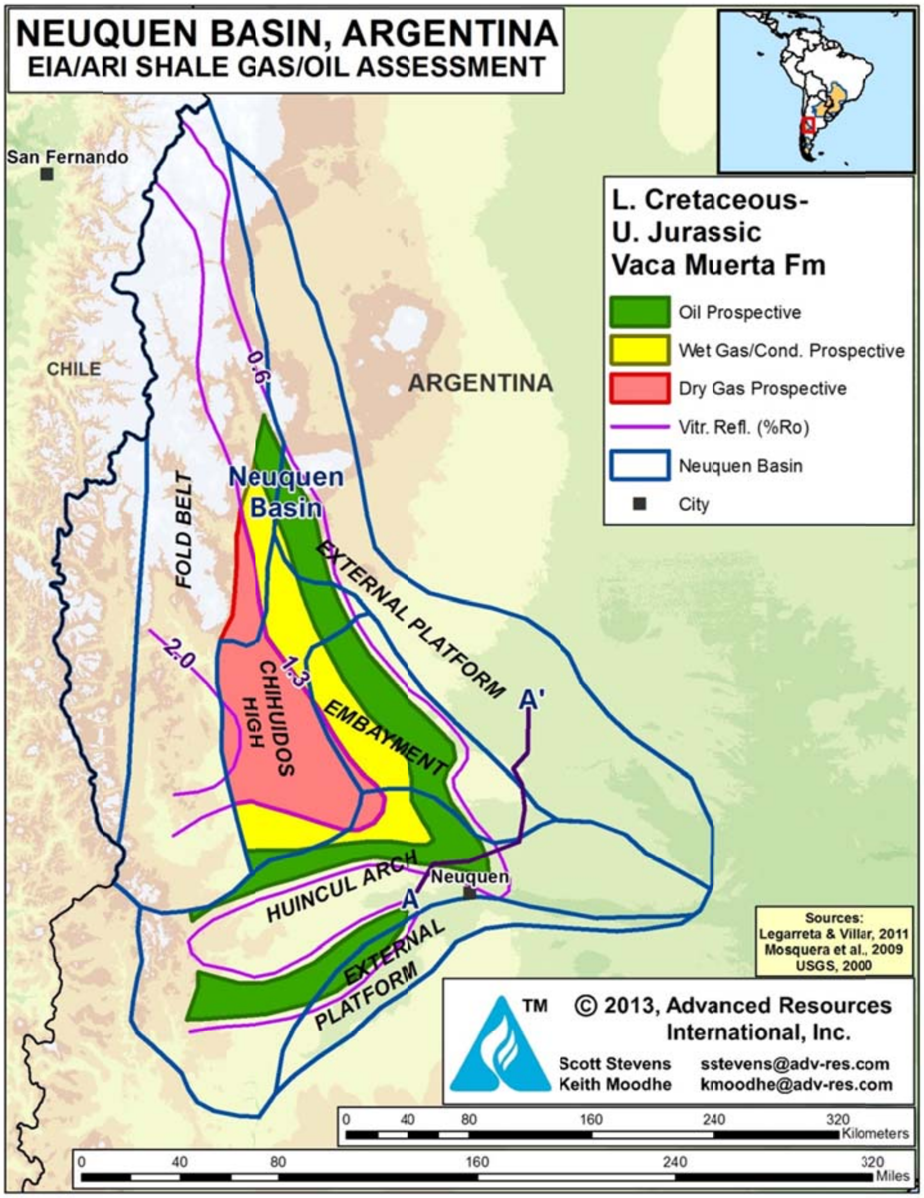
The Vaca Muerta Formation has three distinct prospective areas of hydrocarbons in the Neuquen Basin, as shown on the thermal maturity and prospective area map, Figure V-6. The oil-prone thermal maturity window within the prospective area covers an area of approximately 4,840 mi$^2$; the wet gas window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

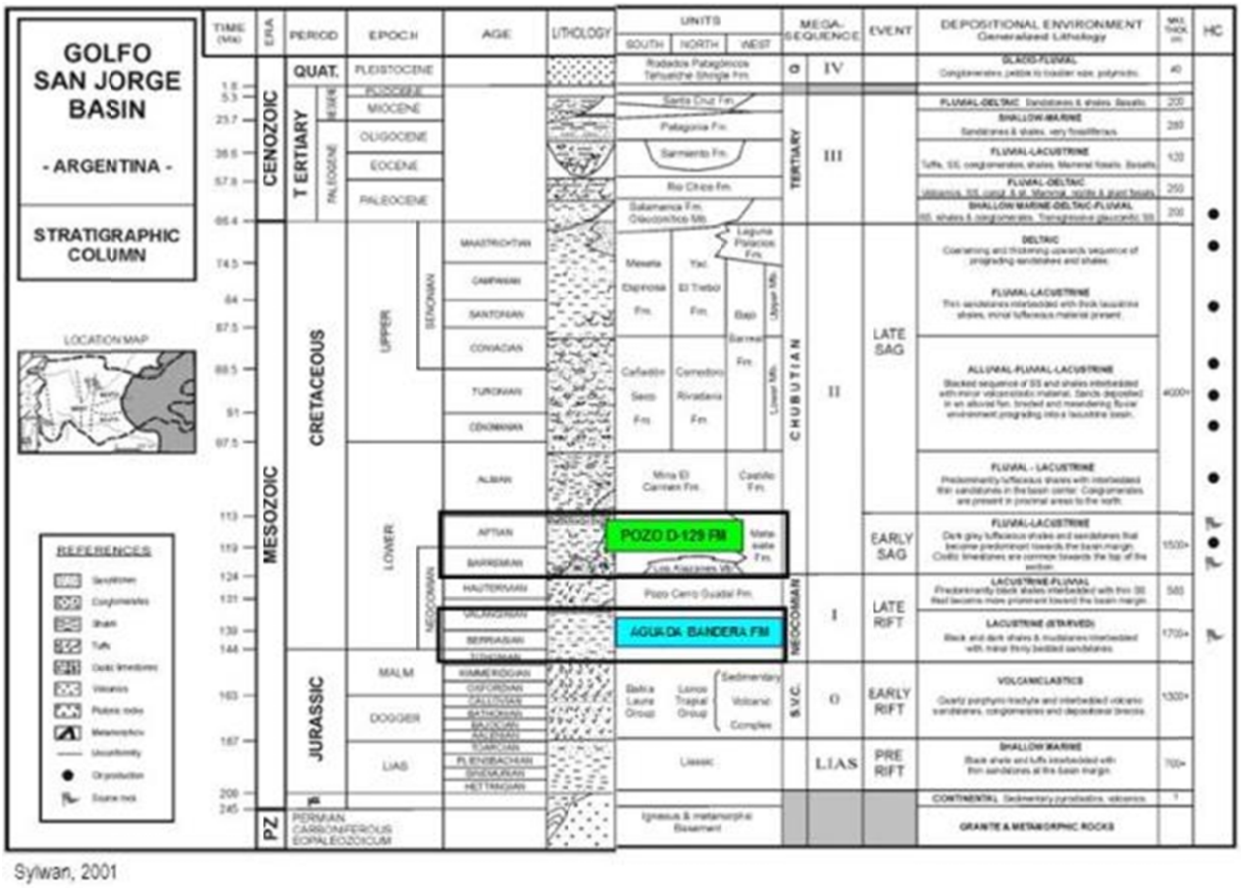
The basin is bordered by the Deseado Graben and Massif to the south, by the Somuncura Massif to the north, and the Andes Mountains in the west. Compressional structures of the San Bernardo Fold Belt transect the west-central region.[22] Extensional faults are widespread in the northeastern and southern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




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% $R_o$.

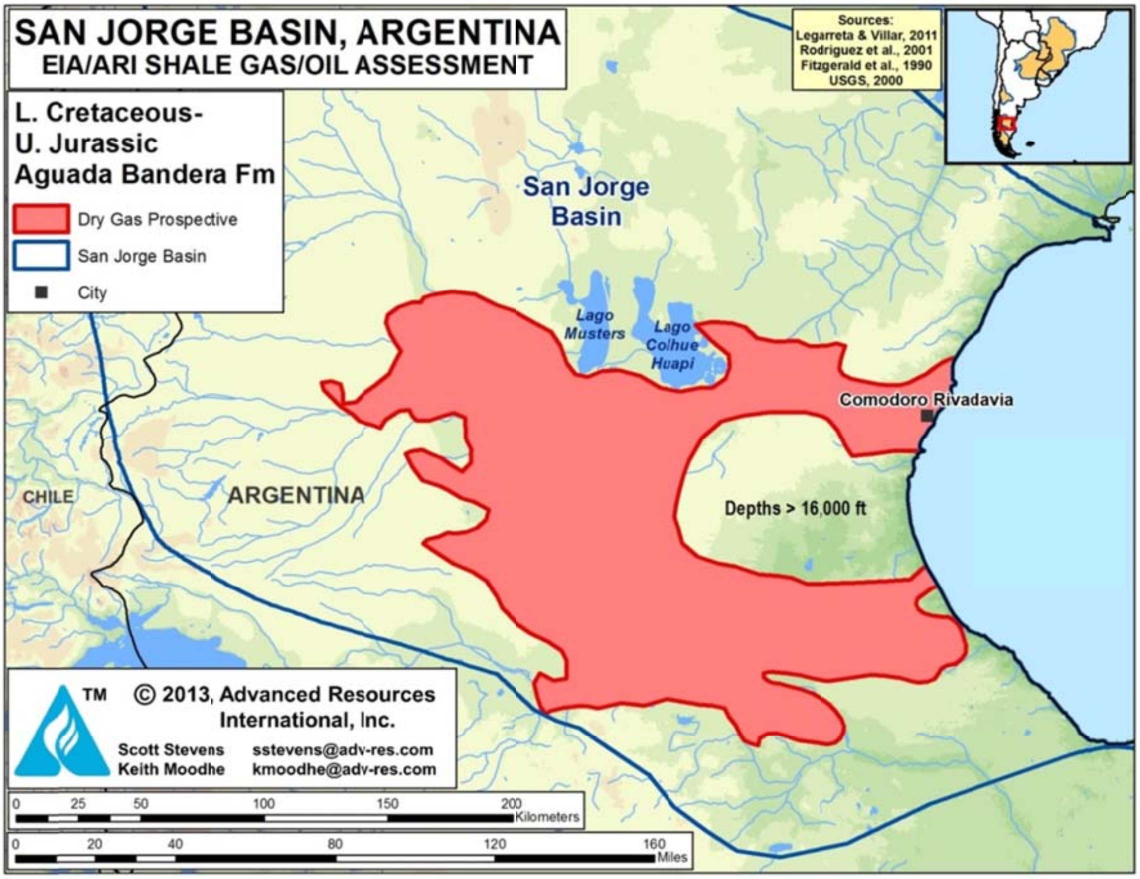
Petroleum basin modeling indicates that the minimum gas generation threshold ($R_o$ = 1.0 to 1.3%) is typically achieved across the basin at depths below about 6,600 ft. Thus, the Aguada Bandera Formation appears to be mature for gas generation across most of the basin, **Figure V-8**. The unit is likely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



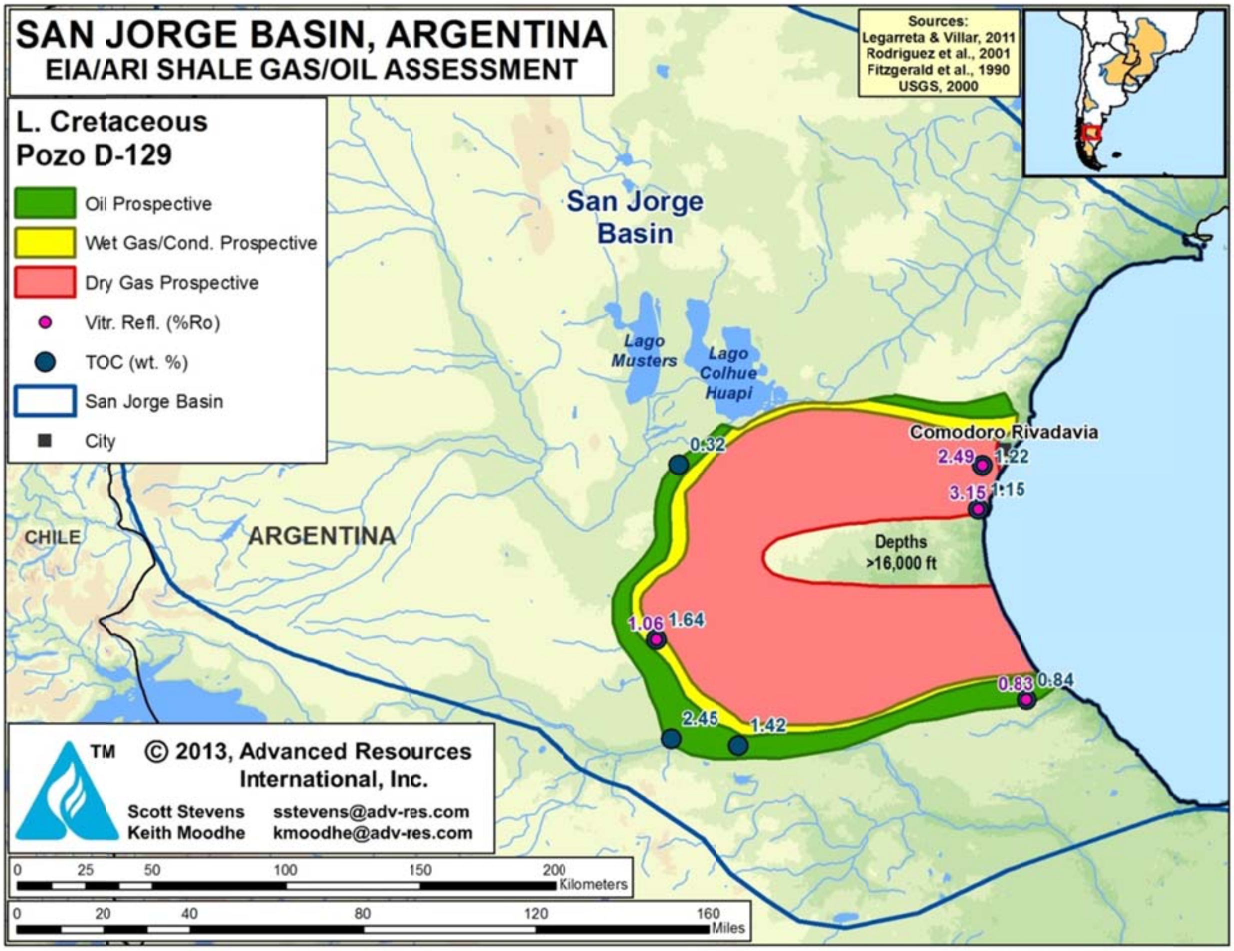

Source: ARI, 2013.

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

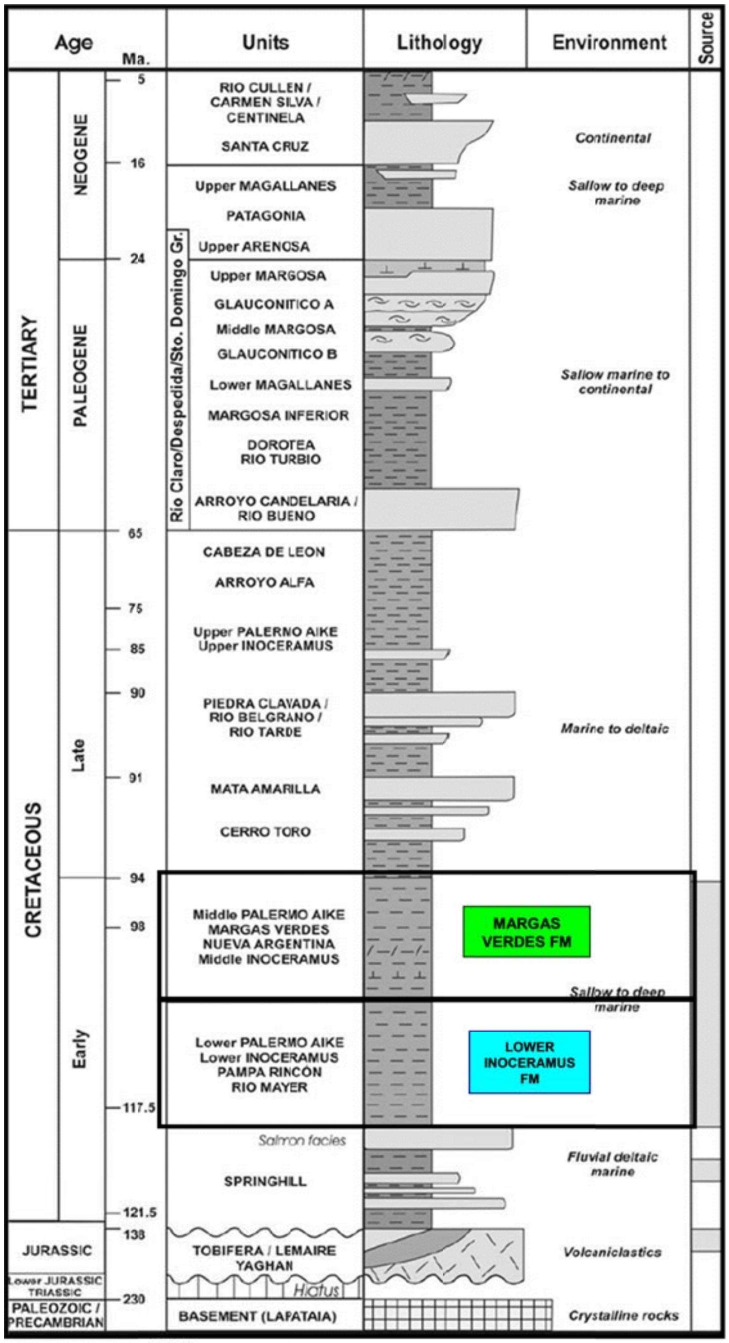
Located in southern Patagonia, the 65,000-mi$^2$ Austral-Magallanes Basin has promising but untested shale gas potential, **Figure V-10**. Most of the basin is in Argentina, where it is usually called the Austral Basin. A small southernmost portion of the basin is located in Chile's Tierra del Fuego 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

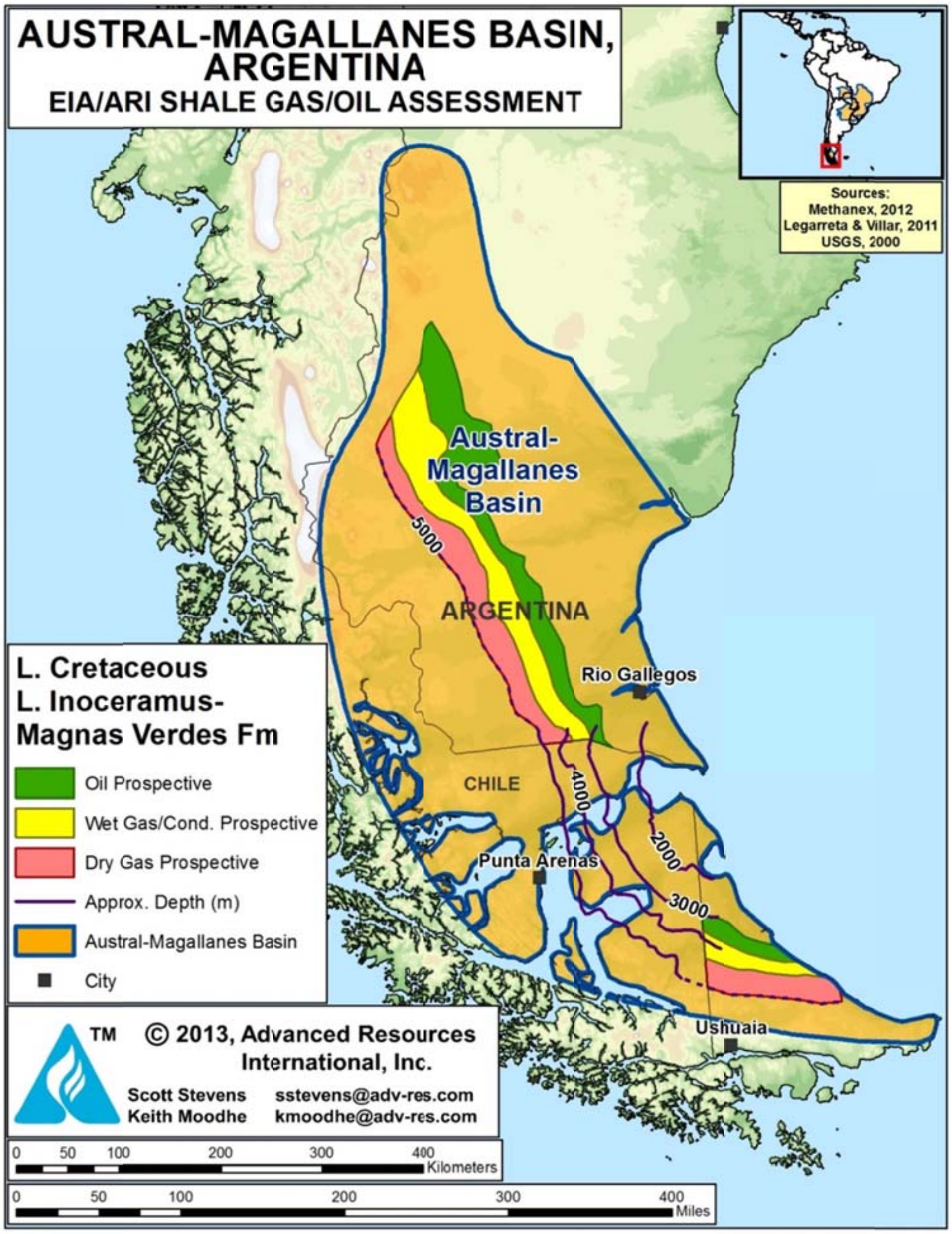
Jurassic Tobifera Formation contains 1% to 3% TOC (maximum 10% in coaly shales), consisting of Types I to III kerogen. However, carbon in this unit is mainly coaly and probably insufficiently brittle for shale exploration.

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




Source: Rossello et al., 2008

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

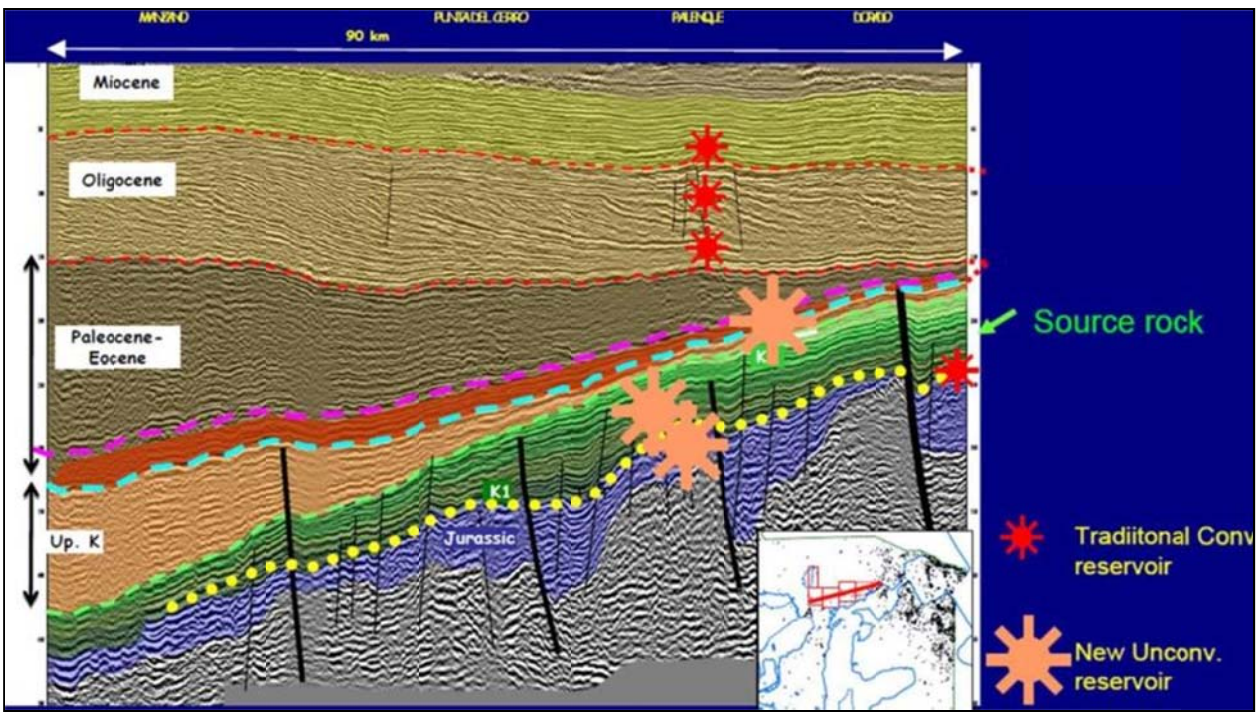



Source: ARI, 2013.

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]

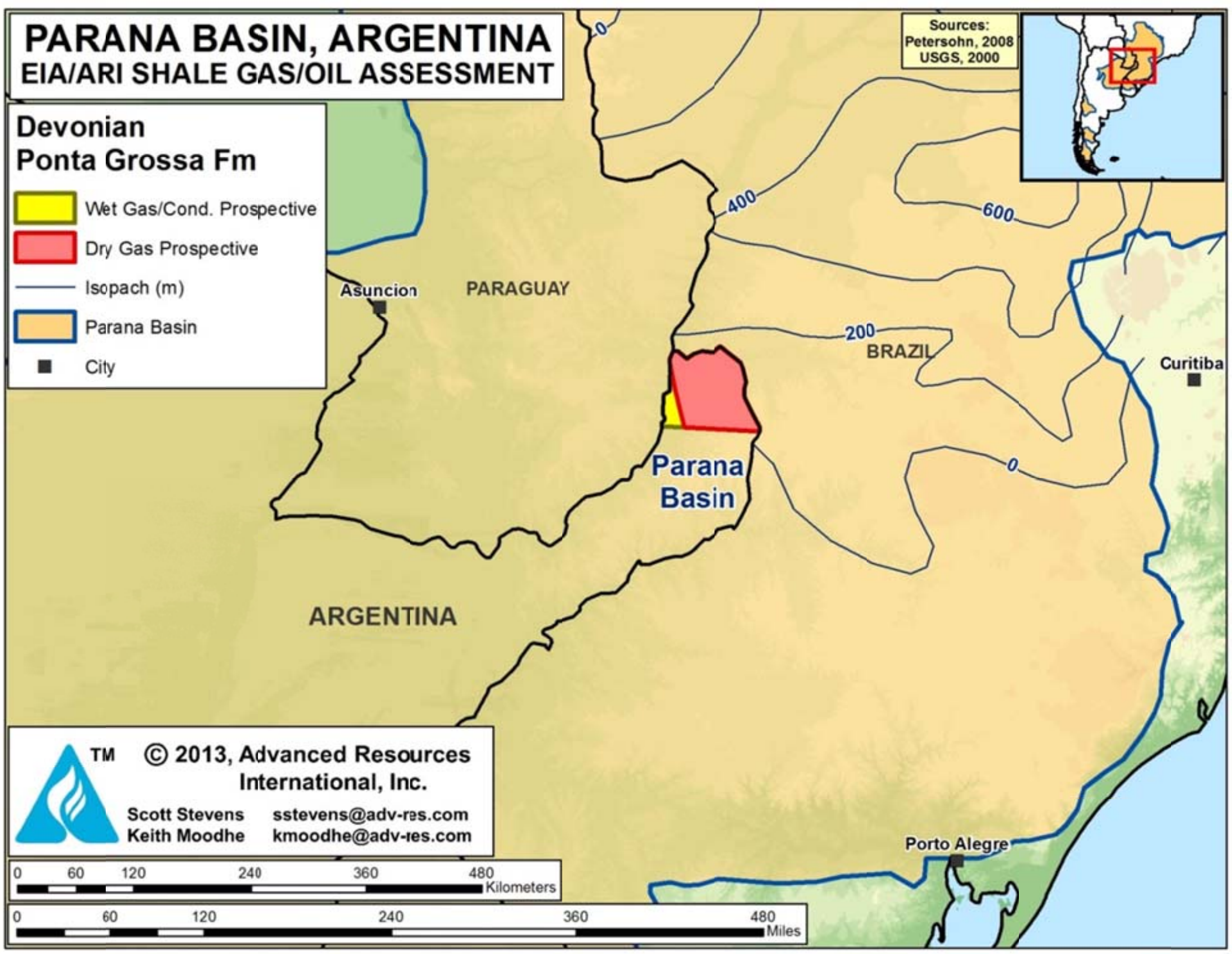
UK-based GeoPark holds conventional petroleum leases in the Magallanes Basin of Chile, which the company notes contains shales in the Estratos con Favrella Formation which previously have produced oil. In 2012, GeoPark conducted diagnostic fracture injection tests on eight wells on the Fell Block to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

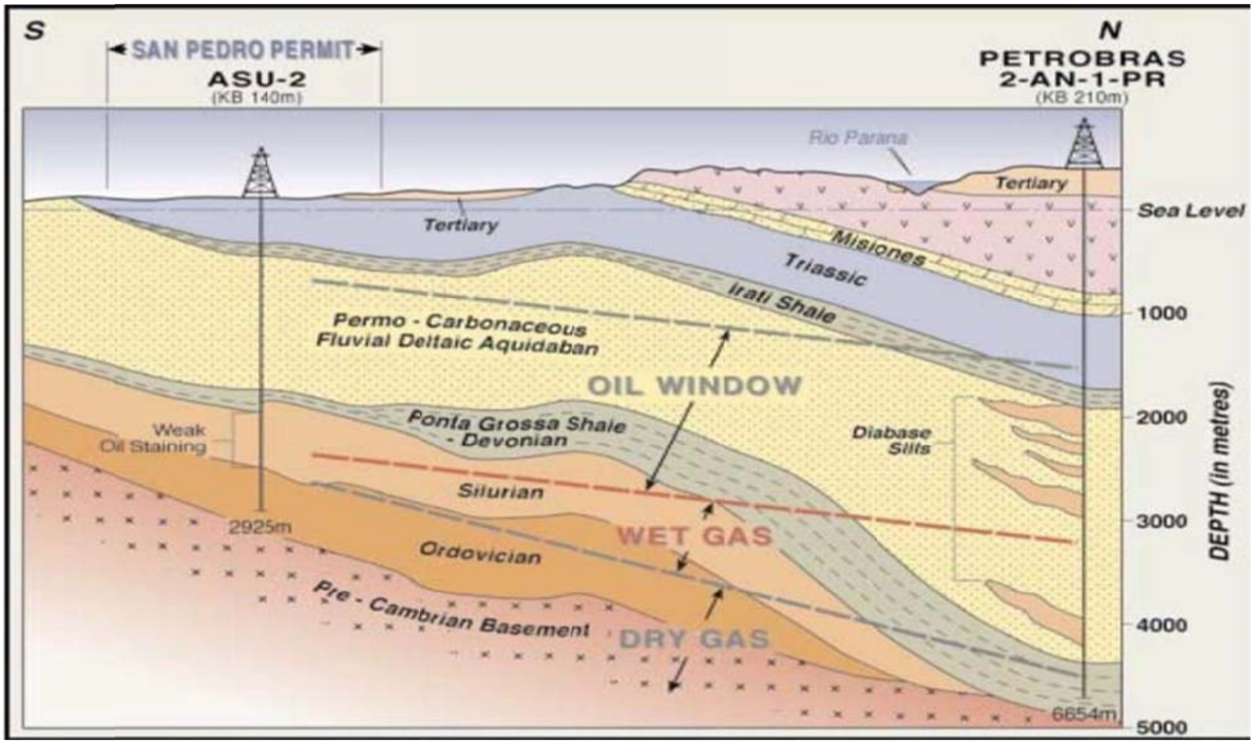
The Paraná Basin has remained at moderate burial depth throughout its history. Consequently, the bulk of thermal maturation took place during the late Jurassic to early Cretaceous igneous episode. Most of the basin remains thermally immature ($R_o$ <0.5%), but there are sizeable concentric windows of 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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