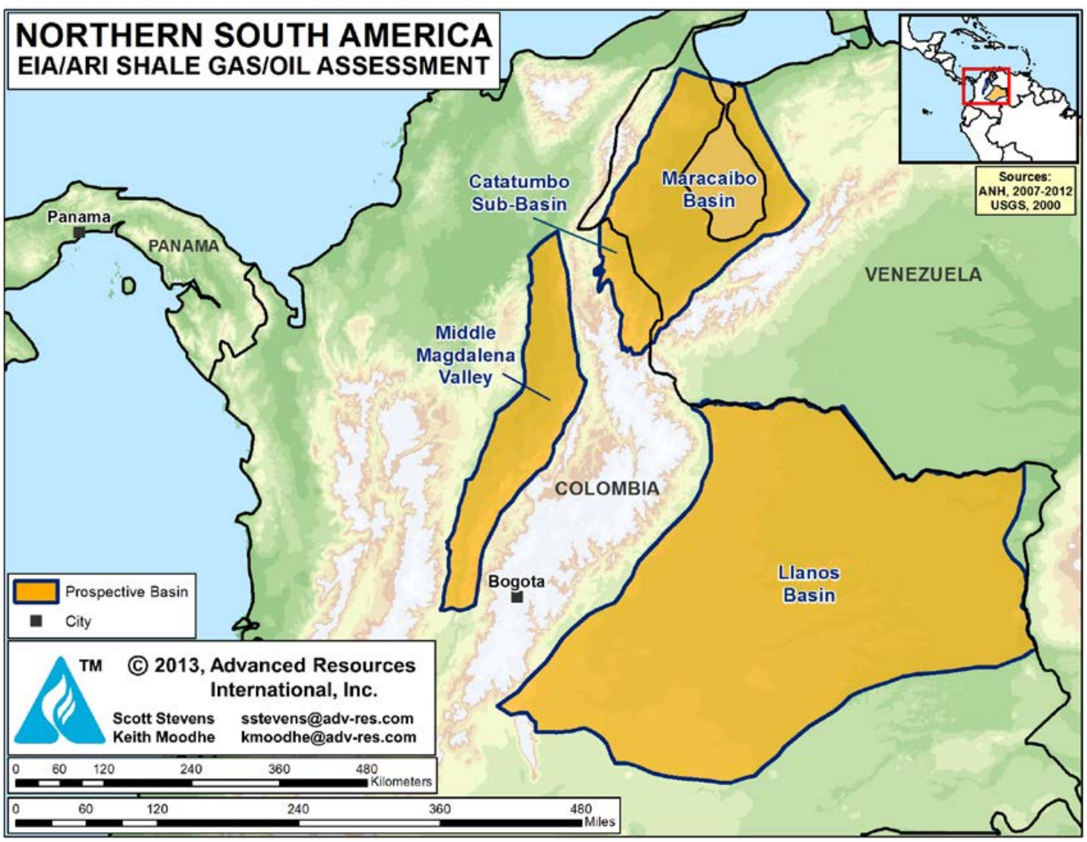
IV. NORTHERN SOUTH AMERICA

SUMMARY

Northern South America has prospective shale gas and shale oil potential within marine-deposited Cretaceous shale formations in three main basins: the Middle Magdalena Valley and Llanos basins of Colombia, and the Maracaibo/Catatumbo basins of Venezuela and Colombia, **Figure IV-1**. The organic-rich Cretaceous shales (La Luna, Capacho, and Gacheta) sourced much of the conventional gas and oil produced in Colombia and western Venezuela, and are similar in age to the Eagle Ford and Niobrara shale plays in the USA. Ecopetrol, ConocoPhillips, ExxonMobil, Shell, and others have initiated shale exploration in Colombia. Colombia's petroleum fiscal regime is considered attractive to foreign investment.

Figure IV-1: Prospective Shale Basins of Northern South America



Source: ARI 2013

For the current EIA/ARI assessment, the Maracaibo-Catatumbo Basin was re-evaluated while new shale resource assessments were undertaken on the Middle Magdalena Valley and Llanos basins. Technically recoverable resources (TRR) of shale gas and shale oil in northern South America are estimated at approximately 222 Tcf and 20.2 billion bbl, **Tables IV-1 and IV-2**. Colombia accounts for 6.8 billion barrels and 55 Tcf of risked TRR, while western Venezuela has 13.4 billion barrels and 167 Tcf. Eastern Venezuela may have additional potential but was not assessed due to lack of data.

Colombia's first publicly disclosed shale well logged 230 ft of over-pressured La Luna shale with average 14% porosity. More typically, the black shales within the La Luna and Capacho formations total about 500 ft thick, 10,000 ft deep, calcareous, and average 2-5% TOC. Thermal maturity comprises oil, wet-gas, and dry-gas windows (R_o 0.7-1.5%). Shale formations in the Llanos and Maracaibo/Catatumbo basins have not yet been tested but also have good shale oil and gas potential.

INTRODUCTION

As first highlighted in EIA/ARI's 2011 assessment, Colombia and Venezuela both have excellent potential for shale oil and gas.. In particular, Colombia's shale potential appears considerably brighter today based on the results of initial shale drilling as well as the entry of major oil companies (ConocoPhillips, ExxonMobil, and Shell) as well as several smaller companies.

Colombia's Agencia Nacional de Hidrocarburos (ANH) regulates oil and gas exploration and development. The country's model contract for unconventional gas includes 8-year exploration and 24-year production terms. Preferential terms are in place for shale gas investment, including a 40% reduction in royalties and higher oil prices. In 2011 the National University of Colombia conducted a shale gas resource evaluation for ANH, estimating a total 33 Tcf of potential in the Eastern Cordillera, Eastern Llanos and Caguan-Putumayo regions. The study and methodology have not been disclosed; apparently shale oil resources were not assessed. ANH conducted Colombia's first auction of shale gas blocks in 2012.

Table IV-1: Northern South America Shale Gas Reservoir Properties and Resources.

Basic Data	Basin/Gross Area		Middle Magdalena Valley (13,000 mi^2)		Llanos (84,000 mi^2)	Maracaibo/Catatumbo (23,000 mi^2)		
	Shale Formation		La Luna/Tablazo		Gacheta	La Luna/Capacho		
	Geologic Age		U. Cretaceous		U. Cretaceous	U. Cretaceous		
	Depositional Environment		Marine		Marine	Marine		
Physical Extent	Prospective Area (mi^2)		2,390	200	1,820	7,280	4,290	5,840
	Thickness (ft)	Organically Rich	1,000	1,000	600	1,000	1,000	1,000
		Net	300	300	210	500	500	500
	Depth (ft)	Interval	3,300 - 16,400	3,300 - 10,000	13,000 - 16,400	5,000 - 15,000	5,500 - 15,000	6,000 - 15,000
		Average	10,000	8,000	14,500	10,000	11,000	12,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Mod. Overpress.	Normal	Normal	Normal
	Average TOC (wt. %)		5.0%	5.0%	2.0%	5.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	0.85%	1.15%	1.60%
	Clay Content		Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Assoc. Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		88.0	150.3	40.4	71.8	176.1	255.7
	Risked GIP (Tcf)		117.8	16.8	18.2	183.0	264.4	522.6
	Risked Recoverable (Tcf)		14.1	4.2	1.8	18.3	52.9	130.7

Table IV-2: Northern South America Shale Oil Reservoir Properties and Resources.

Basic Data	Basin/Gross Area		Middle Magdalena Valley (13,000 mi^2)		Llanos (84,000 mi^2)	Maracaibo/Catatumbo (23,000 mi^2)	
	Shale Formation		La Luna/Tablazo		Gacheta	La Luna/Capacho	
	Geologic Age		U. Cretaceous		U. Cretaceous	U. Cretaceous	
	Depositional Environment		Marine		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		2,390	200	1,820	7,280	4,290
	Thickness (ft)	Organically Rich	1,000	1,000	600	1,000	1,000
		Net	300	300	210	500	500
	Depth (ft)	Interval	3,300 - 16,400	3,300 - 10,000	13,000 - 16,400	5,000 - 15,000	5,500 - 15,000
		Average	10,000	8,000	14,500	10,000	11,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Mod. Overpress.	Normal	Normal
	Average TOC (wt. %)		5.0%	5.0%	2.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	0.85%	1.15%
	Clay Content		Low	Low	Low	Low	Low
Resource	Oil Phase		Oil	Condensate	Oil	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		57.0	26.1	28.0	92.3	41.0
	Risked OIP (B bbl)		76.3	2.9	12.6	235.1	61.6
	Risked Recoverable (B bbl)		4.58	0.18	0.63	11.75	3.08

Venezuela's government and oil companies have not disclosed shale oil or shale gas exploration activities, although the potential in western Venezuela appears to be large and of high quality. Overall, three main basins are present in northern South America that contain prospective marine-deposited shales and were assessed in this report, Figure IV-2. These basins include:

- **Middle Magdalena Valley Basin (Colombia):** The focus of shale exploration leasing and drilling activity in the region thus far, the MMVB near Bogota also is Colombia's main conventional onshore production area. It contains thick deposits of the organic-rich Cretaceous La Luna Formation, mostly in the oil to wet gas windows.
- **Llanos Basin (Colombia):** This large basin in eastern Colombia has prospective Gacheta Formation source rock shales of Cretaceous age that are equivalent to the La Luna Fm. TOC and R_o generally appear low, but the western foothills region may be richer and more thermally mature.
- **Maracaibo/Catatumbo Basin (Venezuela and Colombia):** One of South America's richest petroleum basins, the Maracaibo (Venezuela) and Catatumbo (Colombia) basins have extensive oil and gas potential in thick, widespread Cretaceous La Luna Shale.
- A fourth basin, the **Putamayo Basin** in southern Colombia, also may contain shale potential but was not assessed due to lack of data. The Putamayo contains organic-rich Cretaceous shales in the Macarena Group.[1] While relatively shallow (3,000 ft) in this up-thrusted basin-edge location, the Macarena shales deepen towards the center of the basin where they may become less faulted. Hydraulic fracturing already is being used in the Putamayo Basin for conventional reservoirs.[2]

Figure IV-2: Stratigraphic Chart Showing Source Rocks And Conventional Reservoirs In Northern South America.

			COLOMBIA & VENEZUELA BASINS		
	BASIN		MID MAGDALENA VALLEY	MARACAIBO-CATATUMBO	LLANOS
ERA	PERIOD	EPOCH	FORMATION		
CENOZOIC	QUATERNARY	Pleistocene	Alluvium	Alluvium	Necesidad
CENOZOIC	TERTIARY	Pliocene	Mesa	Guayabo	Guayabo
CENOZOIC	TERTIARY	Miocene	Real; *Colorado*	Guayabo; Leon; *Carbonera*	Guayabo; Leon; *Carbonera*
CENOZOIC	TERTIARY	Oligocene	*Mugrosa*; *Esmeraldas*	*Carbonera*	*Carbonera*
CENOZOIC	TERTIARY	Eocene	*Esmeraldas*; *La Paz*	*Carbonera*; *Mirador*	*Carbonera*; *Mirador*
CENOZOIC	TERTIARY	Paleocene	Lisama	Los Cuervos; *Barco Catatumbo*	Los Cuervos; Barco
MESOZOIC	CRETACEOUS	Upper	Umir; La Luna; Simiti	Mito Juan; Colon; La Luna; Capacho	Guadalupe; Gacheta; *Une*
MESOZOIC	CRETACEOUS	Lower	Simiti; *Tablazo*; Paja; Rosablanca; Cumbre; Arcabuco/ Giron	*Aguardiente*; *Apon*; Rio Negro	
MESOZOIC	JURASSIC		Arcabuco/ Giron	Giron	
MESOZOIC	TRIASSIC				

Source Rock	*Conventional Reservoir*	Absent/Unknown

Source: ARI 2013

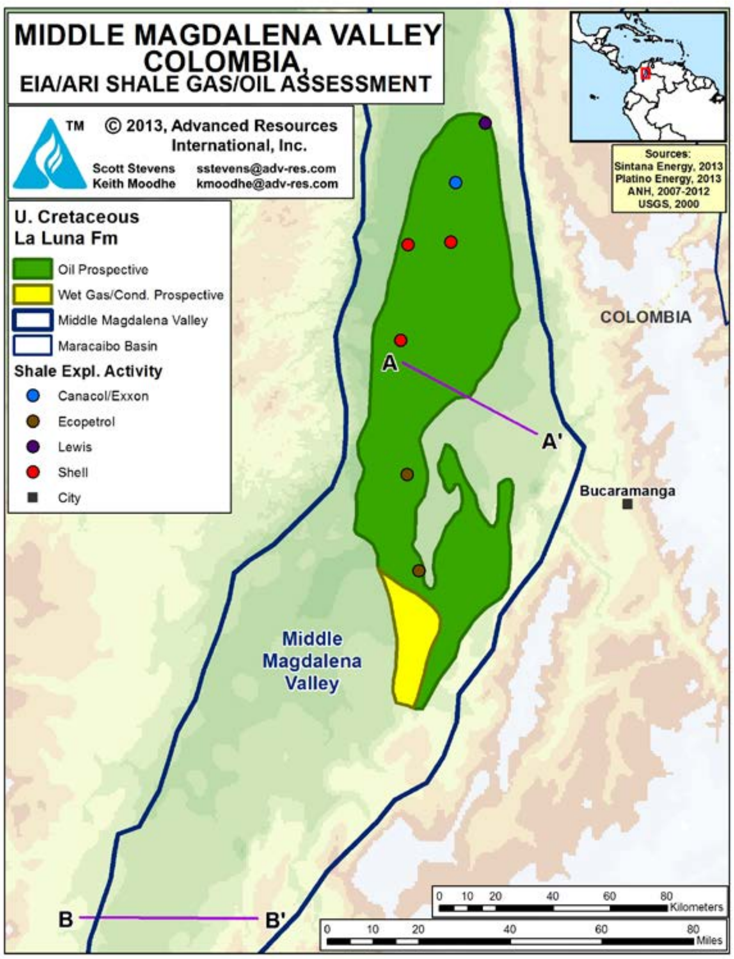
Advanced Resources International, Inc.

1. MIDDLE MAGDALENA VALLEY BASIN (COLOMBIA)

1.1 Introduction and Geologic Setting

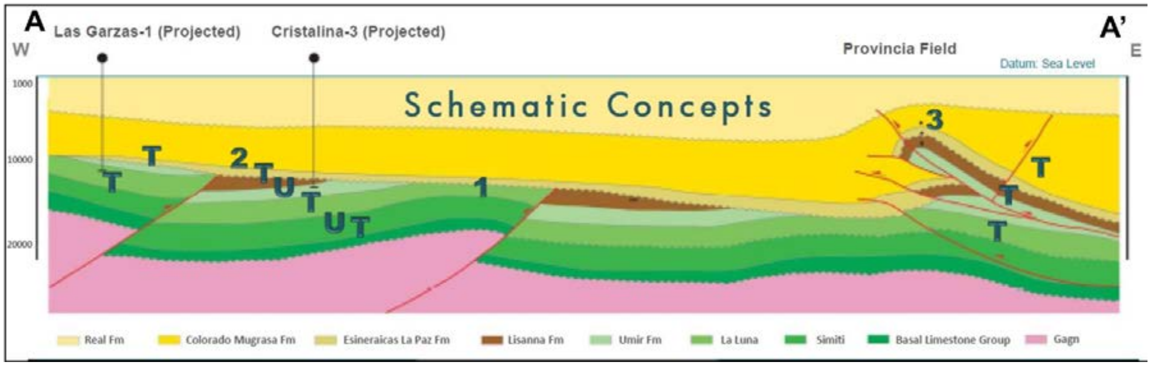
The 13,000-mi^2 Middle Magdalena Valley Basin (MMVB) is a north-south trending inter-montane basin in central Colombia, situated between the Eastern and Central cordilleras and located 150 miles north of Bogota, **Figure IV-3**. The MMVB is Colombia's most explored conventional oil and gas producing basin, with over 40 discovered oil fields that produce mainly from Tertiary sandstone reservoirs. Although within the Andes Mountains region, with its complex tectonics including numerous thrust and extensional faults, the interior of the MMVB has simpler structure with relatively flat surface topography, **Figure IV-4**.[3] The western side of the basin is structurally more complex and overthrusted, **Figure IV-5**.[4]

Figure IV-3: Middle Magdalena Valley Basin, Shale-Prospective Areas and Shale Exploration



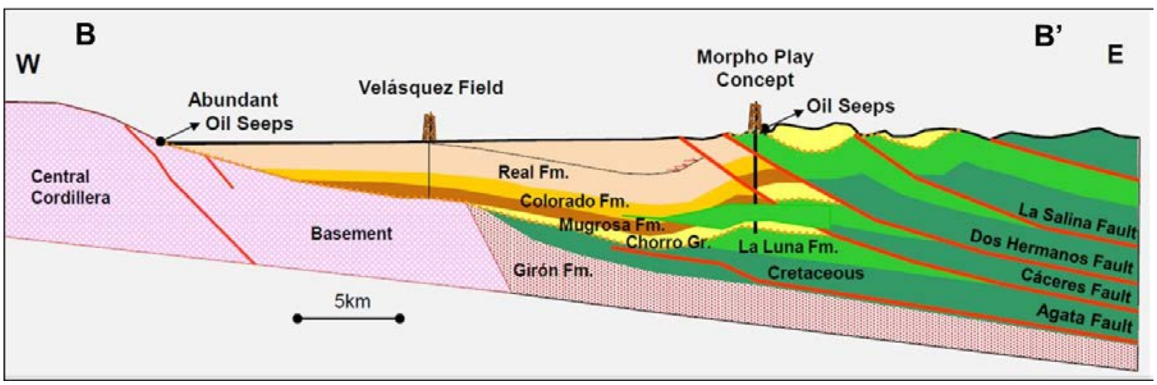
Source: ARI 2013

Figure IV-4: Schematic Cross-Section of the Middle Magdalena Valley Basin Showing U. Cretaceous Umir and La Luna And L. Cretaceous Simiti Shales Totaling 750-1,000 Ft Thick (Correlate With Eagle Ford Shale).



Source: Sintana Energy, Q3 2012

Figure IV-5: Schematic Cross-Section of Western Margin of the Middle Magdalena Valley Basin in Central Colombia, Showing Thrusted Fault Blocks with La Luna Shale.



Source: Platino Energy, 2013

The Cretaceous La Luna Formation is the principal source rock in the MMVB. A marine-deposited black shale, the organic-rich La Luna was formed in a widespread epicontinental sea and is time-equivalent (Santonian) with the Niobrara Shale in the USA.[5] However, sedimentation and facies distribution of the La Luna Fm were strongly controlled by the paleo-topography, while post-depositional tectonics caused erosional events that truncated its thickness in places. For example, much of the Campanian and lower Maastrichtian sections were eroded in the southern Upper Magdalena Valley and Putumayo Basins.[6]

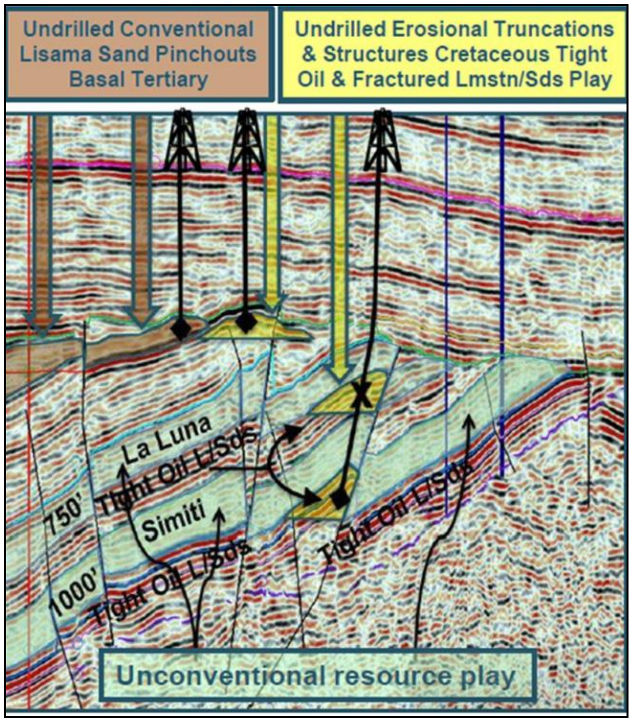
The La Luna Formation comprises three members: the Salada, Pujamana, and Galembo.[7] The most organic-rich (3-12% TOC) is the 150-m thick Salada Member, which consists of hard, black, thinly bedded and finely laminated limy shales (40% $CaCO_3$), along with thin interbeds of black fine-grained limestone. Pyrite veins and concretions are common, as are planktonic (but not benthonic) foraminifera and radiolaria. The lower-TOC Pujamana Member consists of gray to black, thinly bedded and calcareous shale (43% $CaCO_3$). The 220-m thick Galembo Member has moderate TOC (1-4%) and also consists of black, thinly bedded, calcareous shale, but with only thin argillaceous limestone interbeds. The Galembo also has abundant blue to black chert beds.[8] The underlying Cretaceous Tablazo/Rosablanca Fm, about 480-920 ft thick, also contains high TOC (2-8%) that is in the oil to wet gas windows (R_o 0.6% to 1.2%).

1.2 Reservoir Properties (Prospective Area)

The 1,000-ft thick Cretaceous La Luna Formation ranges from 3,000 ft to slightly over 15,000 ft deep across the Middle Magdalena Valley Basin. However, the La Luna is truncated in places by an erosional unconformity, which juxtaposes Paleogene La Paz Fm on top, **Figure IV-6**. The La Luna shale is organic rich (average 5%) with mainly Type II kerogen.[9] We mapped a larger (2,390-mi^2) oil-prone prospective window for the La Luna shale, with a much smaller (200 mi^2) wet gas window to the south (R_o 0.7% to 1.2%).

Calgary-based Canacol Energy Ltd. has noted that the La Luna and Tablazo/ Rosablanca shales are 4,000 to 12,000 ft deep across its blocks in the MMVB . The La Luna ranges from 1,200 to 1,800 ft thick while the underlying Tablazo/Rosablanca is 480 to 920 ft thick. TOC of the two units ranges from 2% to 8% and is mostly at oil-prone thermal maturity (R_o 0.6% to 1.2%). Shale porosity is estimated by Canacol to be 3% to 14%.[10] In 2012 Canacol drilled the Mono Arana-1 well on its VMM 2 block, where it is partnered with ExxonMobil. The well tested shallow conventional targets as well as deeper shale and carbonate potential in the La Luna and Tablazo oil source rocks. Heavy mud, up to 16.5 pounds per gallon, was required to safely drill across these over-pressured shales, indicating they are at nearly twice the normal hydrostatic pressure. The well encountered the top of the La Luna Formation at a depth of 9,180 ft and penetrated 760 ft into the formation, logging oil and gas shows across the entire shale interval. Logs run across the La Luna reportedly indicated 230 ft of potential high-quality net oil pay with 14% average porosity.

Figure IV-6: Seismic Line in the Middle Magdalena Valley Basin Showing Cretaceous La Luna and Simiti Shales Truncated by Erosional Unconformity.



Source: Sintana Energy, Q3 2012

According to Texas-based Sintana Energy the La Luna Formation averages about 1,500 ft thick (gross), has 950-1,900 ft of net pay, 5-10% TOC, 15% effective porosity, and favorably low 17% clay content (should be quite brittle) on the company's blocks in the western MMVB. The underlying Tablazo Formation averages about 600 ft thick (gross), has 150-450 ft of net pay, 5.5-7.0% TOC, 8% effective porosity, and higher 30% clay content. The La Luna in Sintana's area is in the oil window (R_o 0.7-1.0%), while the Tablazo is in the oil to wet gas windows (R_o 1.1%). The pressure gradient ranges from 0.55-0.80 psi/ft in the La Luna to 0.65 psi/ft in the Tablazo.[11]

1.3 Resource Assessment

The risked, technically recoverable shale gas and shale oil resources in the combined Cretaceous La Luna and Tablazo shales of the Middle Magdalena Valley Basin are estimated to be 18 Tcf and 4.6 billion barrels, out of risked shale gas and shale oil in-place of 135 Tcf and 79 billion barrels. By comparison Ecopetrol has estimated the MMV Basin has 29 Tcf of shale gas potential (methodology not disclosed, nor was oil potential noted).

1.4 Recent Activity

A number of companies -- including Ecopetrol, ConocoPhillips, ExxonMobil, Nexen, and Shell -- have initiated shale oil and gas exploration programs at existing conventional oil and gas lease positions in Colombia during the past two years. Activity has been concentrated in the Middle Magdalena Valley Basin, close to the Bogota market. More than 12 vertical and horizontal shale exploration wells were planned for 2012, including several re-entries.

State-owned Ecopetrol S.A., which controls about one-third of the oil and gas licenses in Colombia, first announced its shale exploration program in early 2011 and drilled the La Luna-1 stratigraphic test in the MMVB later that year (results not disclosed). Ecopetrol already has been drilling horizontal wells in the MMVB for non-shale targets during the past several years, providing a good foundation for future horizontal shale development in the basin.[12]

Canacol holds three conventional exploration licenses in Colombia, which the company estimates have a total 260,000 gross acres with shale oil potential. The company has disclosed a Mean Estimate of 2.9 billion barrels of recoverable resource potential within their lease position. In recent months Canacol has signed separate joint-venture agreements with ConocoPhillips, ExxonMobil, and Shell to conduct shale exploration within Canacol's acreage. These companies plan to drill a total of 19 shale exploration wells at an estimated cost of $123 million. ConocoPhillips expects to drill its first exploration well to test the La Luna Shale in the second quarter of 2013.[13] Canacol continues to review the shale potential of two of its other blocks.

Nexen was one of the first companies to report exploring for shale gas in Colombia. The company reports it holds several shale blocks in Colombia for a total 1.5 million acres with shale gas potential.[14] In late 2011 Nexen began drilling the first of four planned shale gas wells. These wells, located in Sueva and Chiquinquira blocks in the Sabana de Bogota high savannah plateau of the Eastern Cordillera mountain range, reportedly target the La Luna Formation. No further details are available.

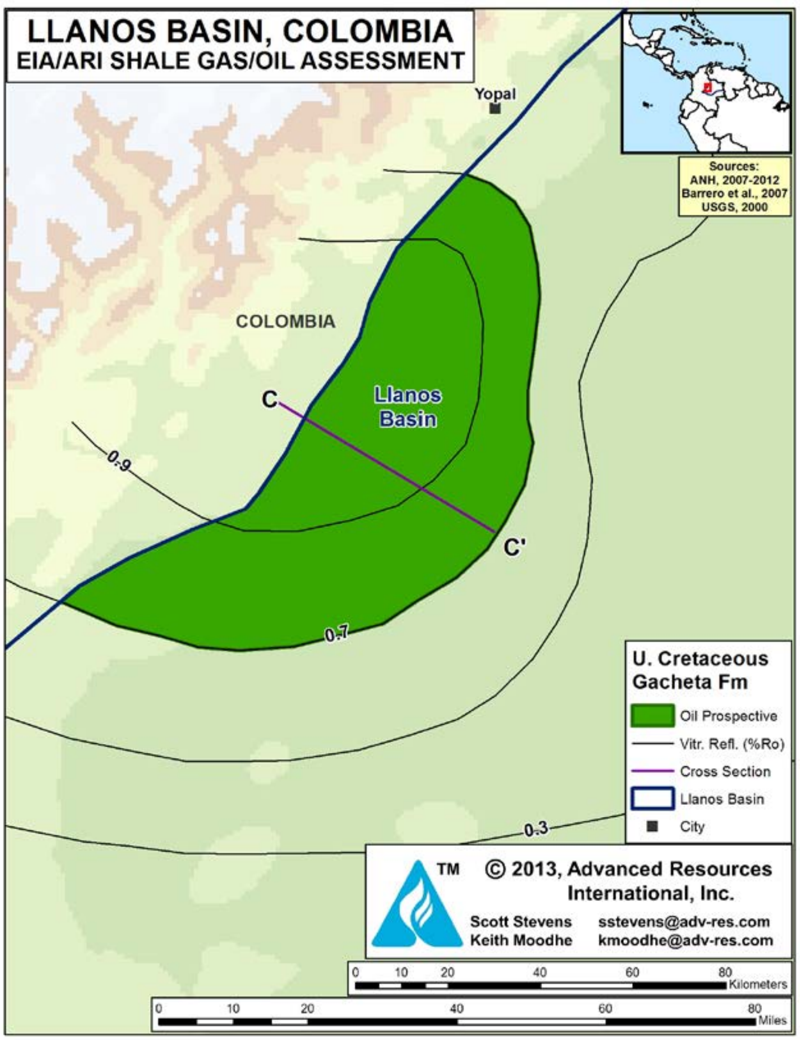
Sintana Energy has reported that its third-party consultant estimated 210 million bbl of prospective recoverable resources in shale formations at the company's VMM-37 block in the MMVB, which cover 44,000 acres (Mean Estimate). Sintana estimated initial horizontal well costs at about $13 million.

2. LLANOS BASIN (COLOMBIA)

2.1 Introduction and Geologic Setting

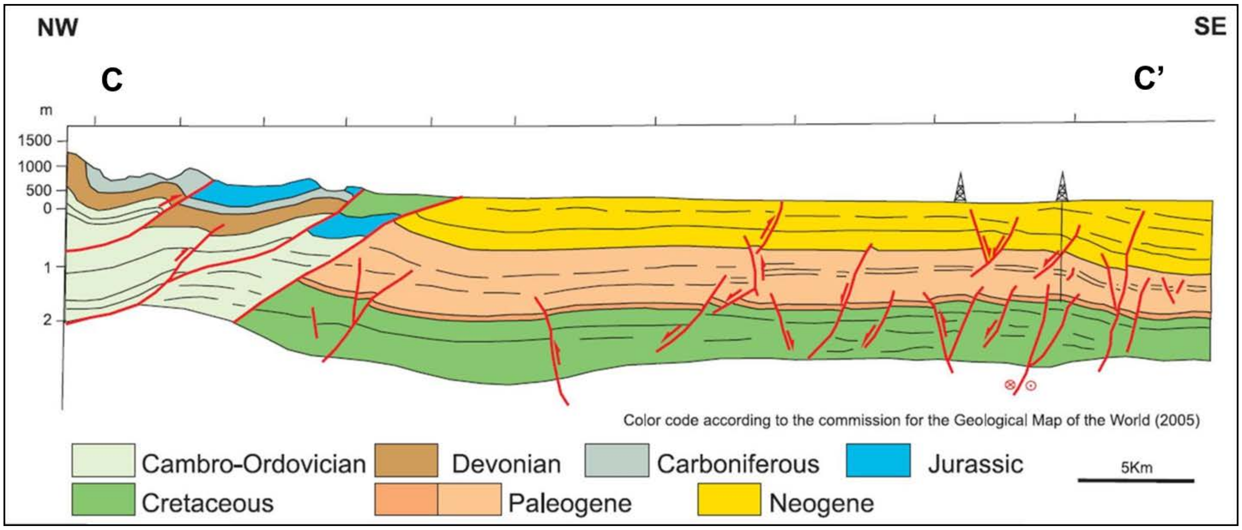
The large (84,000-mi^2) Llanos Basin, located in eastern Colombia, has only recently become a focus of shale exploration and thus is less well understood than the Middle Magdalena Valley Basin, **Figure IV-7**. The Gacheta Fm shale source rocks are equivalent to the La Luna Fm in the MMV and Maracaibo/Catatumbo basins. The northeast-trending Llanos Basin represents the northern extent of the Sub-Andean Mountain Belt. **Figure IV-8** shows the generally simple geologic structure in the interior of the Llanos Basin, as well as the overthrusting on the western margin.

Figure IV-7: Llanos Basin Showing Shale-Prospective Area.



Source: ARI 2013

Figure IV-8: Schematic Cross Section of the Llanos Basin in Colombia



Source : ANH, 2007

Up to 30,000 ft of Cambrian to Ordovician strata are unconformably overlain by thick Cretaceous marine shale deposits. These in turn were partially eroded by uplift during the early Tertiary. Other potential source rocks in the Llanos Basin include the Cretaceous Los Cuervos Fm and Tertiary shales (Carbonera and Leon formations).[15] Conventional reservoirs are found in the Paleogene Carbonera and Mirador sandstones as well as Cretaceous sandstones.

2.2 Reservoir Properties (Prospective Area)

The Cretaceous Gacheta Fm, time-equivalent to the La Luna Fm and averaging 600 ft thick, is the principal source rock in the Llanos Basin. The Gacheta reaches a depth of more than 15,000 ft along the basin's western margin, shoaling to only 2,000 feet in the east. The central axis has the Gacheta shale ranging from 4,000 to over 10,000 ft deep.

The 1,820-mi^2 depth-prospective area is entirely in the oil window. The effective source rock thickness of the Gacheta shale ranges from 150 to 300 ft (average 210 ft net), with TOC of 1% to 3% consisting of Type II and III kerogen.[16] Thermal maturity of the Gacheta ranges from the oil to wet gas windows, with R_o ranging from 0.3% in the shallow east to 1.1% in the deeper western foothills region where the shale oil potential is greatest.[17] Porosity is uncertain but assumed to be relatively high (7%) based on initial data on the correlative La Luna Shale in the MMVB. The basin is slightly over-pressured, averaging about 0.5 psi/ft gradient.

2.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources in the Llanos Basin are estimated to be 2 Tcf of associated shale gas and 0.6 billion barrels of shale oil and condensate, out of risked shale gas and shale oil in-place of about 18 Tcf and 13 billion barrels, **Tables IV-1 and IV-2**. Within the prospective area, the play has a moderate resource concentrations of about 40 Bcf/mi^2 and 28 million bbl/mi^2.

2.4 Recent Activity

No shale exploration leasing or drilling has been reported in the Llanos Basin. Sintana Energy previously mentioned the shale potential of its leases in the Llanos Basin in the company's 2011 investor presentation.

3. MARACAIBO-CATATUMBO BASIN (VENEZUELA, COLOMBIA)

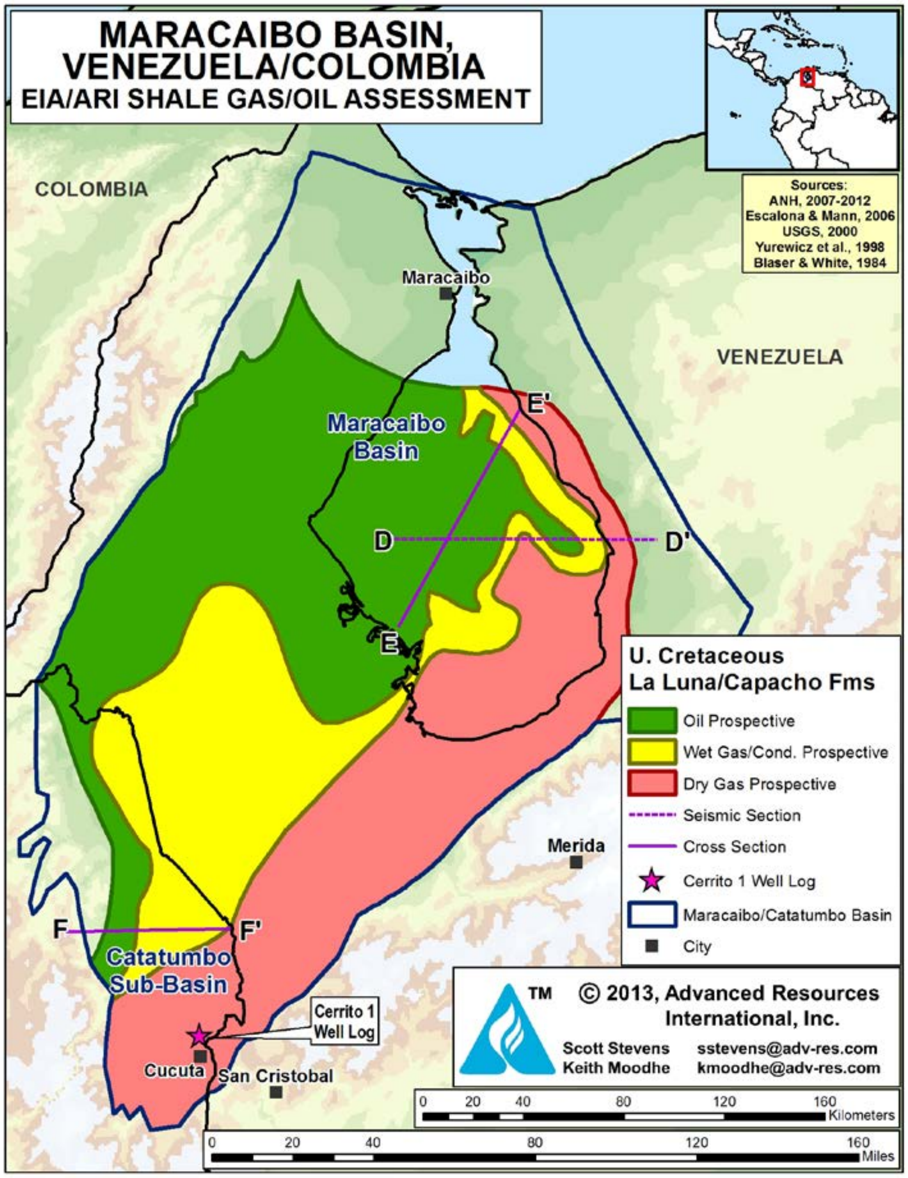
3.1 Introduction and Geologic Setting

The Maracaibo Basin extends over 23,000 mi^2 in western Venezuela and eastern Colombia, the latter area known locally as the Catatumbo Sub-basin, **Figure IV-9**.[18] The Maracaibo/Catatumbo Basin contains a rich sequence of organic-rich marine-deposited Cretaceous shales that are the principal source rocks for prolific conventional fields.[19] These Cretaceous shales, especially the La Luna and Gapacho, appear to be prospective targets for shale oil and gas exploration.

Depth to the Precambrian-Jurassic basement in the Maracaibo Basin reaches over 20,000 feet in southern Lake Maracaibo and its onshore eastern edge, **Figure IV-10**. On the west side of the basin, basement and Cretaceous shale deposits become shallower again, **Figure IV-11**. Depth to the La Luna Fm ranges from less than 5,000 to over 15,000 feet, generally deepening from northeast to southwest. The eastern edge of the shale play is limited by maximum 15,000-ft depth, inferred from the structure of the Late Jurassic basement.[20]

The Catatumbo Sub-basin, located on the rugged east flank of the Andes in eastern Colombia, has similar shale targets but is structurally more complex than the rest of the Maracaibo Basin, with thrust faulting in the west and less severe wrench-faulting in the east, **Figure IV-12**.[21] Much like the northern Maracaibo Basin, the Catatumbo Sub-basin has numerous conventional oil fields.

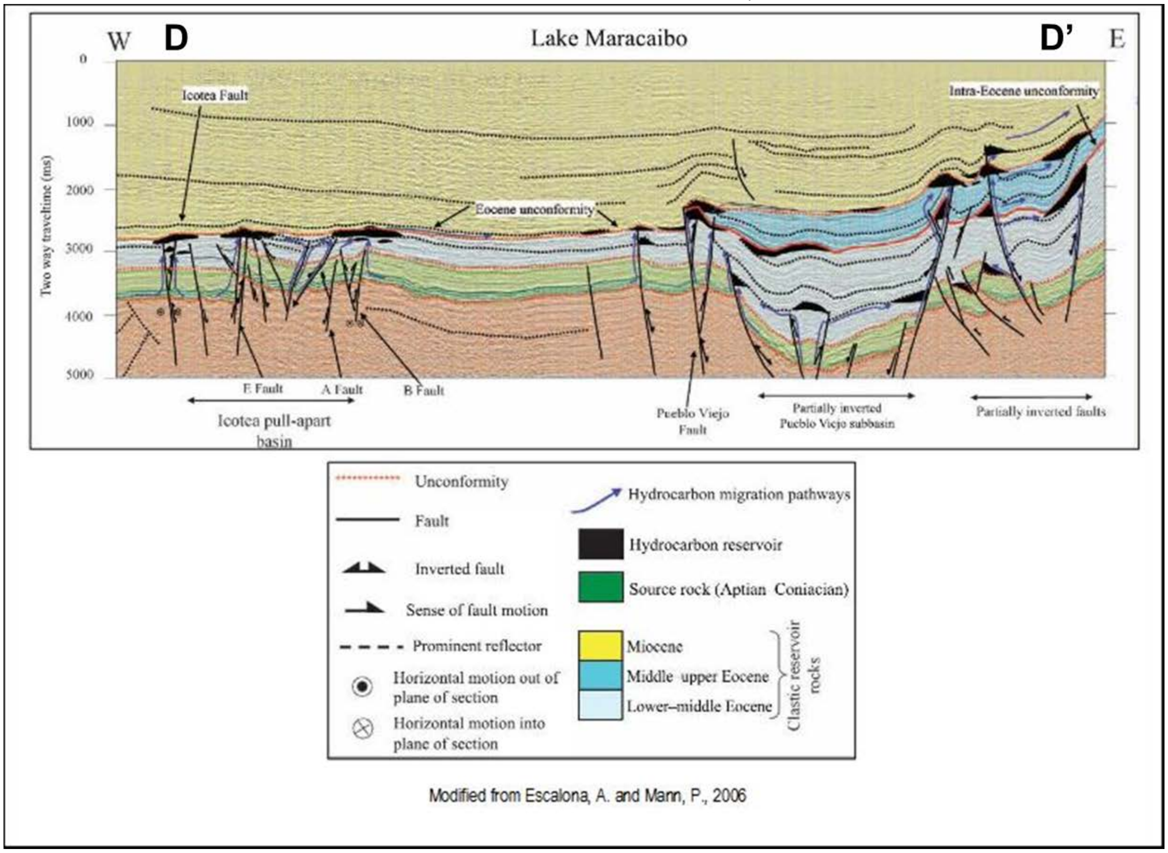
Figure IV-9: Prospective Area for Shale Exploration in the Maracaibo/Catatumbo Basin.



Source : ARI, 2013

Figure IV-10: Seismic Time Section of the Maracaibo Basin in Western Venezuela.

Modified from Escalona and Mann, 2006



Source : ARI, 2013

Figure IV-10: Schematic Cross-Section Showing Depth to Cretaceous Source Rocks in the Maracaibo Basin, Western Venezuela.

Modified from Escalona and Mann, 2006

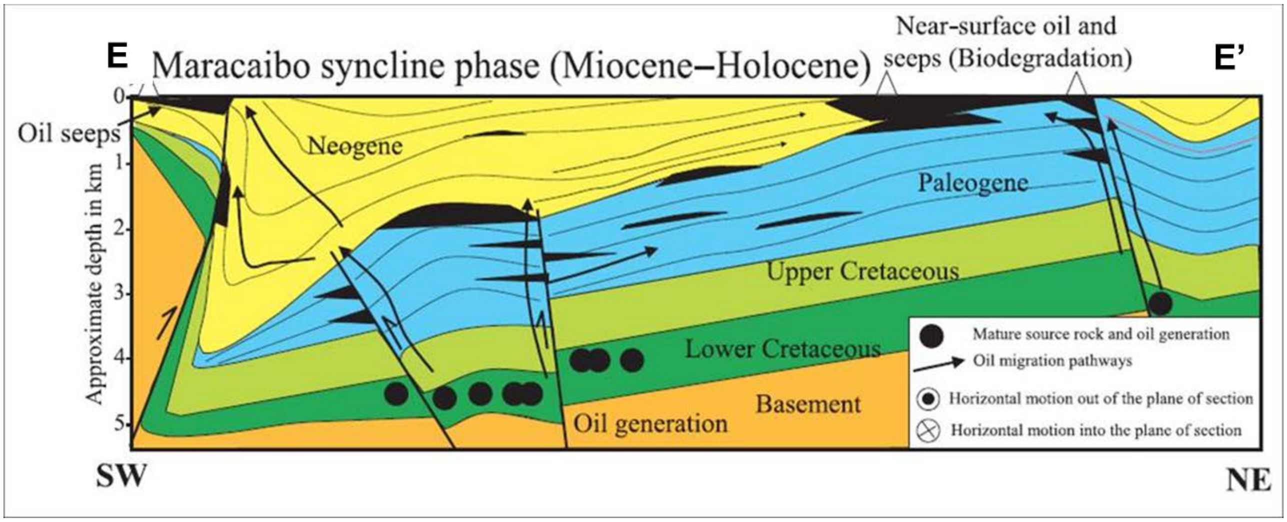
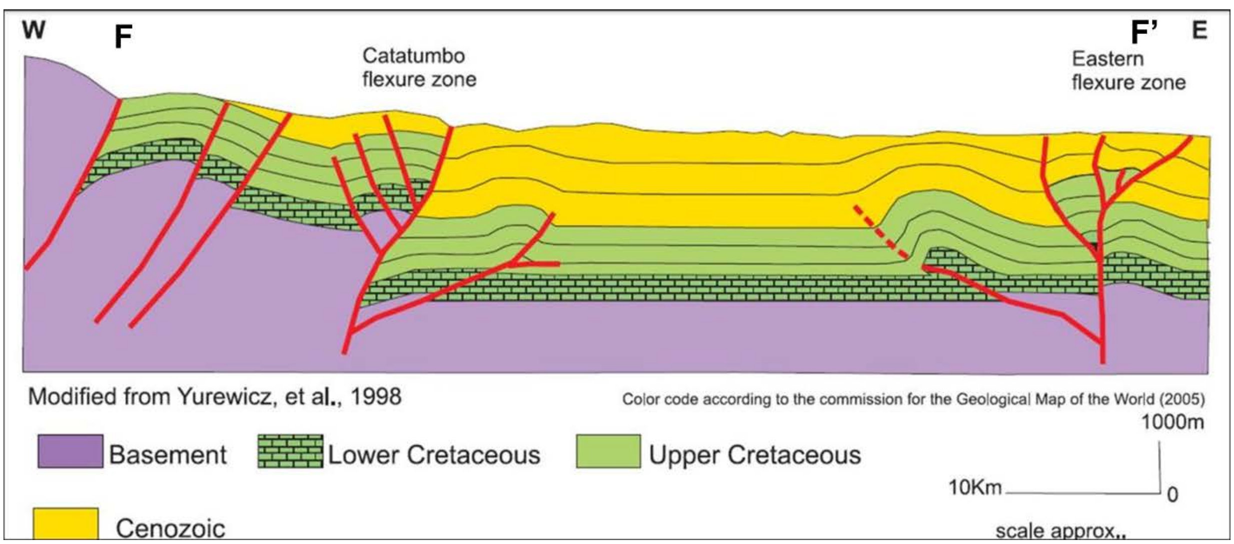


Figure IV-12: Schematic Cross-Section of the Catatumbo Sub-Basin in Eastern Colombia.

Modified from Yurewicz et al., 1998



La Luna Formation. The Maracaibo-Catatumbo Basin hosts some of the world's richest source rocks and conventional oil and gas reservoirs. The Late Cretaceous (Cenomanian-Santonian) shale of the La Luna Formation, the primary source rock in the basin[22] and time-equivalent with the Eagle Ford Shale in Texas, appears to be the most prospective target for shale oil and gas exploration. The black calcareous La Luna Shale ranges from 100 to over 400 feet thick across the basin, thinning towards the south and east. [23,24]

Total organic carbon (TOC) varies across the basin, with values ranging from 3.7% to 5.7% in the northwest to 1.7% to 2% in the south and east. Maximum TOC values can reach 16.7%. A large portion of this shale-gas-prospective area includes part of Lake Maracaibo itself. ARI chose to include this submerged area because water depths are shallow (less than 100 feet) and there are numerous conventional production platforms that could provide access to shale drilling and development.

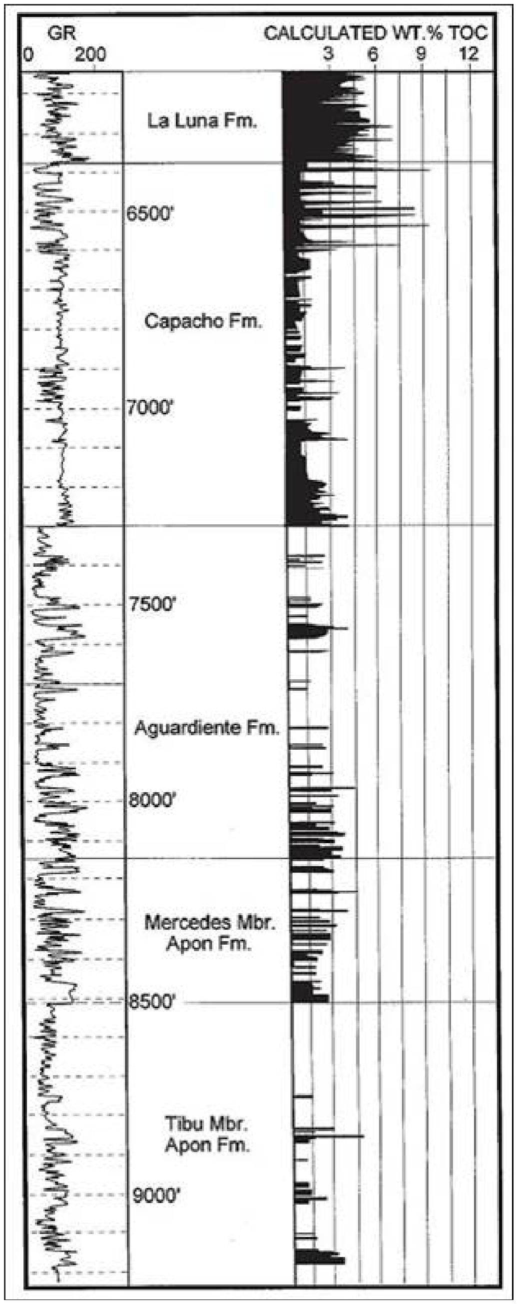
Thermal maturity of the La Luna Fm increases with burial depth from west to east across the Maracaibo Basin, from less than 0.7% R_o to over 1.7% R_o southeast of Lake Maracaibo.[25] Vitrinite reflectance data indicate the unit is mainly in the oil generation window, with a narrow sliver of dry-gas maturity in the east. Note that no significant free gas accumulations have been discovered in the Maracaibo Basin; all natural gas production has been associated gas.

In the much smaller Catatumbo Sub-Basin of Colombia, the La Luna Fm is about 200 ft thick, comprising dark-gray, laminated, limey mudstones and shales with high TOC averaging 4.5% (maximum 11%), mainly Type II with some Type III kerogen.[26] Total organic carbon in core samples reaches a maximum of 11.2% in the La Luna, but more typically averages a still rich 4 to 5% TOC. **Figure IV-13** shows a slight increase in TOC concentration towards the base of the La Luna Fm in the Cerrito 1 well, southeastern Catatumbo Sub-basin.

The La Luna is at relatively shallow depth in the Catatumbo Sub-basin, ranging from 6,000 to 7,600 feet.[27] Based on available vitrinite samples, thermal maturity ranges from 0.85 to 1.21% R_o, with generally higher reflectance in the central and northern areas of the basin. Samples from the Cerro Gordo 3 well in the southeast portion of the Catatumbo Sub-basin averaged 0.85% R_o, indicating that this area is oil prone.

Figure IV-13: Calculated TOC Profile from Well Log in the Catatumbo Sub-Basin.

Modified from Yurewicz et al., 1998



Capacho Formation. The Capacho Formation (Cenomanian-Coniacian) is a distinct unit from the overlying La Luna, although its upper portion is fairly similar. In the Maracaibo basin the Capacho Fm consists of dark-gray to black shales and limestones and is much thicker than the La Luna, ranging from 590 to nearly 1,400 feet in total thickness. However, less data are available on the Capacho. Thus, for this assessment we combined the 200-ft thick, TOC-rich upper portion of the Capacho with the stratigraphically adjacent La Luna for analysis.

Depth to the Capacho ranges from 6,500 feet to 8,500 feet in the Catatumbo Sub-basin, with greater measured depth in the north and east at 8,275 feet in the Socuavo 1 well. TOC reaches 5% in the Socuavo 1 well, northeastern Catatumbo Sub-basin, but more typically is about 1.5%. Kerogen is Type II and III. Vitrinite reflectance ranges from 0.96% R_o in the northern Rio de Oro 14 well to 1.22-1.24% R_o in southeastern well samples.

3.2 Reservoir Properties (Prospective Area)

Three thermal maturity windows were mapped in the Maracaibo/ Catatumbo Basin: dry-gas, wet-gas, and oil. Geologic modeling shows that the present-day temperature gradient in the area ranges from 1.7 and 2.0° F per 100 feet of depth.

Dry Gas Window. Within the 5,840-mi^2 depth-screened, dry-gas thermal maturity window (average 1.6% R_o) of the Maracaibo/Catatumbo Basin, the Cretaceous La Luna Fm and the adjoining upper portion of the Capacho Fm averages about 500 ft thick net, about 12,000 ft deep, and is estimated to have average 5% TOC. Reservoir pressure is uncertain thus assumed to be normal (hydrostatic).

Wet Gas Window. Within the 4,290-mi^2 depth-screened, wet-gas thermal maturity window (average 1.15% R_o), the La Luna and upper Capacho formations average about 11,000 ft deep. Other parameters are similar to the dry gas window.

Oil Window. The La Luna and upper Capacho shales in the thermally less mature portion of the Maracaibo/Catatumbo basin are oil-prone, with average 0.85% R_o. The oil window extends over an area of about 7,280 mi^2 and averages about 10,000 ft deep.

3.3 Resource Assessment

Total risked, technically recoverable shale gas and shale oil resources in the La Luna and Capacho formations of the Maracaibo and Catatumbo basins are estimated to be 202 Tcf and 14.8 billion barrels, out of risked shale gas and shale oil in-place of 970 Tcf and 297 billion barrels, **Tables IV-1 and IV-2**. The play has high a resource concentration of up to 256 Bcf/mi^2 within the dry gas prospective area.

Dry Gas Window. Risked, technically recoverable shale gas resources in the dry-gas window of the Maracaibo/Catatumbo Basin are estimated at 131 Tcf, from a risked shale gas in-place of 523 Tcf. Resource concentration is high (average 256 Bcf/mi^2) due in part to favorable shale thickness and porosity.

Wet Gas Window. The slightly shallower and less thermally mature wet gas window of the Maracaibo/Catatumbo Basin has risked, technically recoverable resources of approximately 53 Tcf of shale gas and 3.1 billion barrels of shale condensate. Risked in-place resources are estimated at 264 Tcf of wet shale gas and 62 billion barrels of shale condensate.

Oil Window. The still shallower and oil-prone window of the La Luna formation and upper Capacho formation in the Maracaibo/Catatumbo basins has an estimated risked, technically recoverable resource of 11.8 billion barrels of shale oil and 18 Tcf of associated shale gas. Risked in-place shale resources are about 235 billion barrels of shale oil and 183 Tcf of shale gas.

3.4 Recent Activity

Junior Canadian E&P Alange Energy Corporation is evaluating the prospectivity of the eastern area of the Catatumbo Sub-basin. However, this exploration activity appears to be focused on conventional reservoirs within the La Luna Shale interval. No shale exploration leasing or drilling has been reported in the Maracaibo Basin.

REFERENCES

[1] PetroNova, Inc., Investor Presentation, November 2012, 26 p.

[2] Torres, F., Reinoso, W., Chapman, M., Han, X., and Campo, P., 2012. "Field Application of New Proppant Detection Technology - A Case History of the Putumayo Basin of Colombia." Society of Petroleum Engineers, SPE Paper #152251, Latin America and Caribbean Petroleum Engineering Conference, 16-18 April 2012, Mexico City, Mexico.

[3] Cooper, M.A., Addison, F.T., Alvarez, R., Coral, M., Graham, R.H., Hayward, A.B., Howe, S., Martinez, J., Naar, J., Peñas, R., Pulham, A.J., and Taborda, A., 1995. "Basin Development and Tectonic History of the Llanos Basin, Eastern Cordillera, and Middle Magdalena Valley, Colombia." American Association of Petroleum Geologists, vol. 79, no. 10, p. 1421-1443.

[4] Platino Energy, Investor Presentation, March 2013, 22 p.

[5] Mann, U. and Stein, R., 1997. "Organic Facies Variations, Source Rock Potential, and Sea Level Changes in Cretaceous Black Shales of the Quebrada Ocal, Upper Magdalena Valley, Colombia." American Association of Petroleum Geologists, Bulletin, vol. 81, p. 556-576.

[6] Mora, A., Mantilla, M., and de Freitas, M., 2010. "Cretaceous Paleogeography and Sedimentation in the Upper Magdalena and Putumayo Basins, Southwestern Colombia." American Association of Petroleum Geologists, Search and Discovery Article #50246.

[7] Torres, E., Slatt, R.M., O'Brien, N., Phip, R.P., and Rodrigues, H.L., 2012. "Characterization of the Cretaceous La Luna Formation as a Shale Gas System, Middle Magdalena Basin, Colombia." Houston Geological Society Conference on Unconventional Resource Shales, poster.

8 Ramon, J.C. and Dzou, L.I., 1999. "Petroleum Geochemistry of Middle Magdalena Valley, Colombia." Organic Geochemistry, vol. 30, p. 249-266.

9 Agencia Nacional de Hidrocarburos, Republic of Colombia, 2005. "Middle Magdalena Valley, MMV Basin." 8 p.

10 Canacol Energy Ltd., Investor Presentation, March 2013, 22 p.

11 Sintana Energy, Investor Presentation, Q1 2013, 35 p.

12 Ecopetrol S.A., Investor Presentation, March 2013, 72 p.

13 ConocoPhillips, News Release, April 25, 2013, 5 p.

14 Nexen Energy, Colombia: "Nexen Explores for Shale Gas in Colombia." June 2012, 4 p.

15 Moretti, I, Mora, C., Zamora, W., Valendia, M., Rodriguez, G., and Mayorga, M., 2009. "Llanos N-S Petroleum System Variation (Columbia)." American Association of Petroleum Geologists, Search and Discovery Article #10208.

16 Agencia Nacional de Hidrocarburos (ANH), 2007. "Colombian Sedimentary Basins: Nomenclature, Boundaries, and Petroleum Geology, a New Proposal." Bogota, Colombia, 91 p.

17 Bachu, S., Ramon, J.C., Villegas, M.E., and Underschultz, J.R., 1995. "Geothermal Regime and Thermal History of the Llanos Basin, Colombia." American Association of Petroleum Geologists, Bulletin, vol. 79, p. 116-129.

18 Escalona, A. and Mann, P., 2006. "An Overview of the Petroleum System Of Maracaibo Basin." American Association of Petroleum Geologists, vol. 90, p. 657-678.

19 Erlich, R. N., Macostay, O., Nederbragt, A.J., and Lorente, M.A., 1999. "Palaeoecology, Palaeogeography and Depositional Environments Of Upper Cretaceous Rocks Of Western Venezuela." Palaeogeography, Palaeoclimatology, Palaeoecology, vol. 153, p. 203-238.

20 Castillo, M.V. and Mann, P., 2006. "Deeply Buried, Early Cretaceous Paleokarst Terrane, Southern Maracaibo Basin, Venezuela." American Association of Petroleum Geologists, vol. 90, no. 4, p. 567-579.

21 Rangel, A. and Hernandez, R., 2007. "Thermal Maturity History and Implications for Hydrocarbon Exploration in the Catatumbo Basin, Colombia." Ecopetrol, CT&F Ciencia, Tecnologia y Futuro, vol. 3, p. 7-24.

22 Goddard, D.A. and Talukdar, S.C., 2002. "Cretaceous Fine-Grained Mudstones Of The Maracaibo Basin, Venezuela." Gulf Coast Association of Geological Societies Transactions, Volume 52, p. 1093-1101.

23 Goddard, D.A., 2006. "Venezuela Sedimentary Basins: Principal Reservoirs & Completion Practices." Venezuela Society of Petroleum Engineers, 60 pages.

24 Lugo, J. and Mann, P., 1995. "Jurassic-Eocene Tectonic Evolution of Maracaibo Basin, Venezuela." in A.J. Tankard, R. S. Soruco, and H.J. Welsink, eds., Petroleum Basins of South America. American Association of Petroleum Geologists, Memoir 62, p. 699–725.

25 Blaser, R. and White, C., 1984. "Source-Rock and Carbonization Study, Maracaibo Basin, Venezuela." in American Association of Petroleum Geologists Memoir 35, p. 229-252.

26 Yurewicz, D.A., Advocate, D.M., Lo, H. B., and Hernandez, E.A., 1998. "Source Rocks and Oil Families, Southwest Maracaibo Basin (Catatumbo Subbasin), Colombia." American Association of Petroleum Geologists, Bulletin, vol. 82, p. 1329-1352.

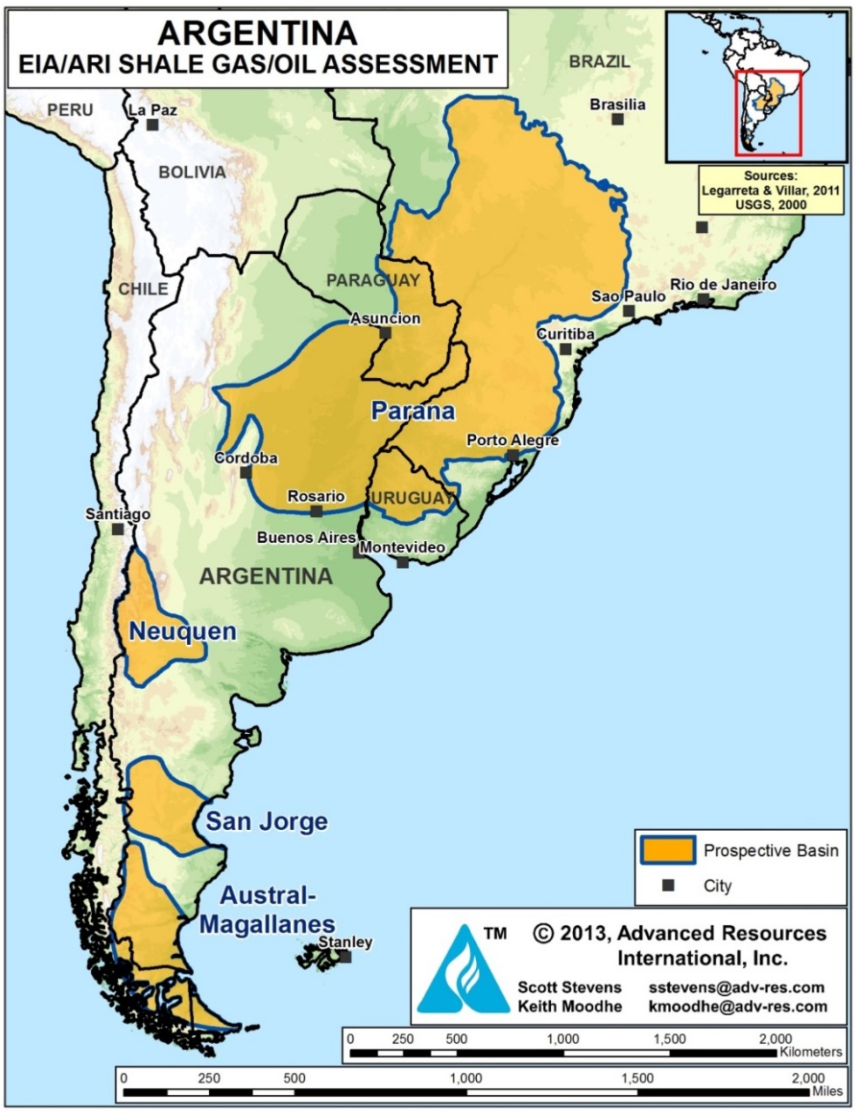
27 Yurewicz, D.A. et al.,1998.

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 mi^2)			
	Shale Formation		Aguada Bandera	Pozo D-129		
	Geologic Age		U. Jurassic - L. Cretaceous	L. Cretaceous		
	Depositional Environment		Lacustrine	Lacustrine		
Physical Extent	Prospective Area (mi^2)		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/mi^2)		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 mi^2)			Parana (747,000 mi^2)	
	Shale Formation		L. Inoceramus-Magnas Verdes			Ponta Grossa	
	Geologic Age		L. Cretaceous			Devonian	
	Depositional Environment		Marine			Marine	
Physical Extent	Prospective Area (mi^2)		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/mi^2)		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 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	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/mi^2)		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 mi^2)		Austral-Magallanes (65,000 mi^2)		Parana (747,000 mi^2)
	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 (mi^2)		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/mi^2)		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:

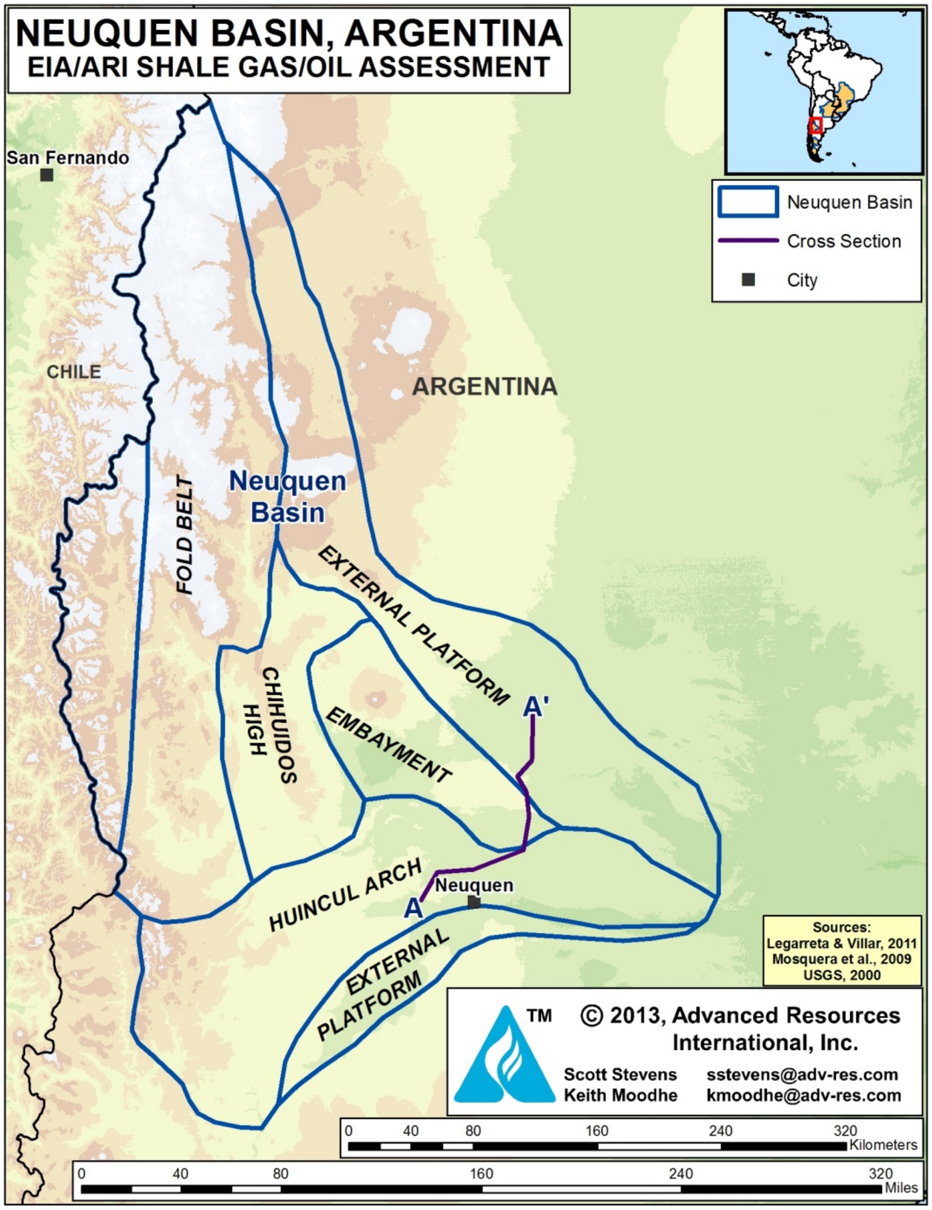
- **Neuquen Basin:** The main focus of shale exploration in Argentina, some 50 mostly vertical wells drilled since 2010 indicate good production potential in the marine-deposited Los Molles and especially Vaca Muerta shales of Jurassic age.
- **Golfo San Jorge Basin:** Containing mostly non-marine lacustrine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

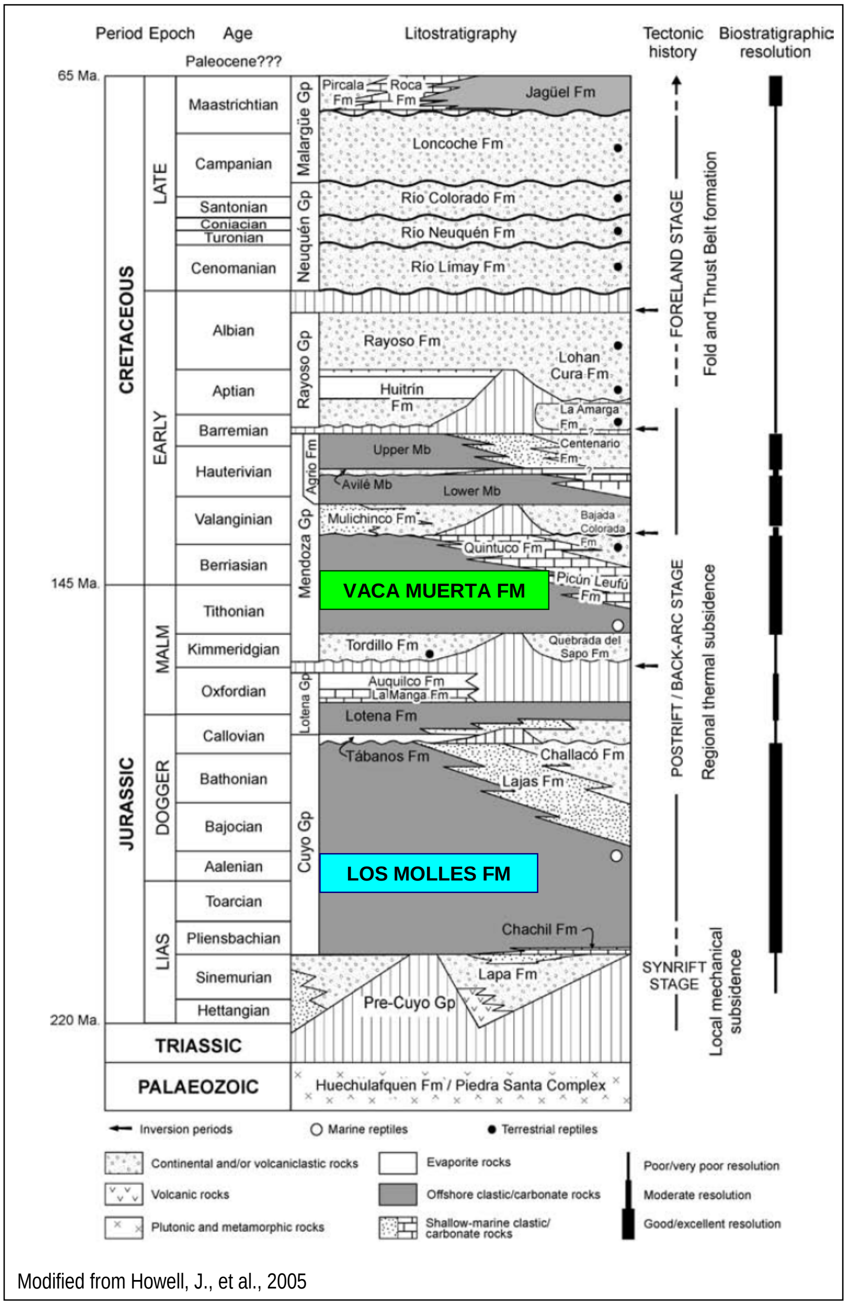
Figure V-2. Neuquen Basin Structure Map



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.



Source: Howell et al., 2005.

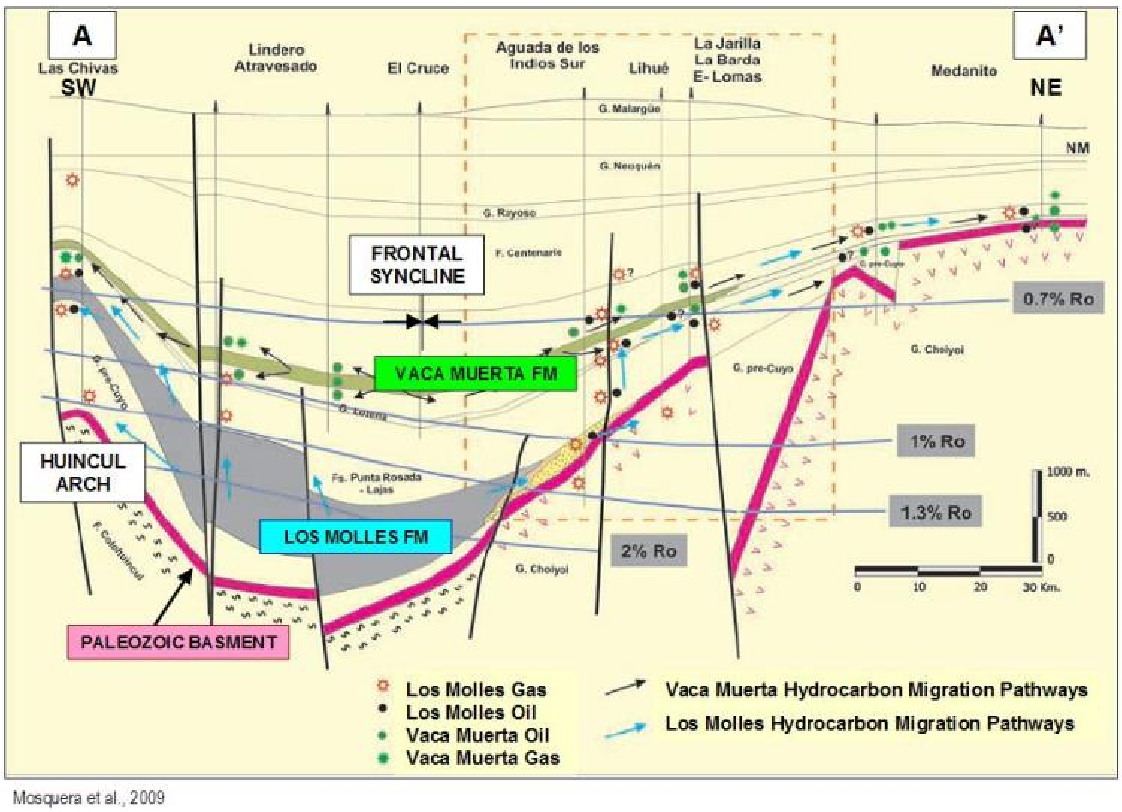
Advanced Resources International, Inc.

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.

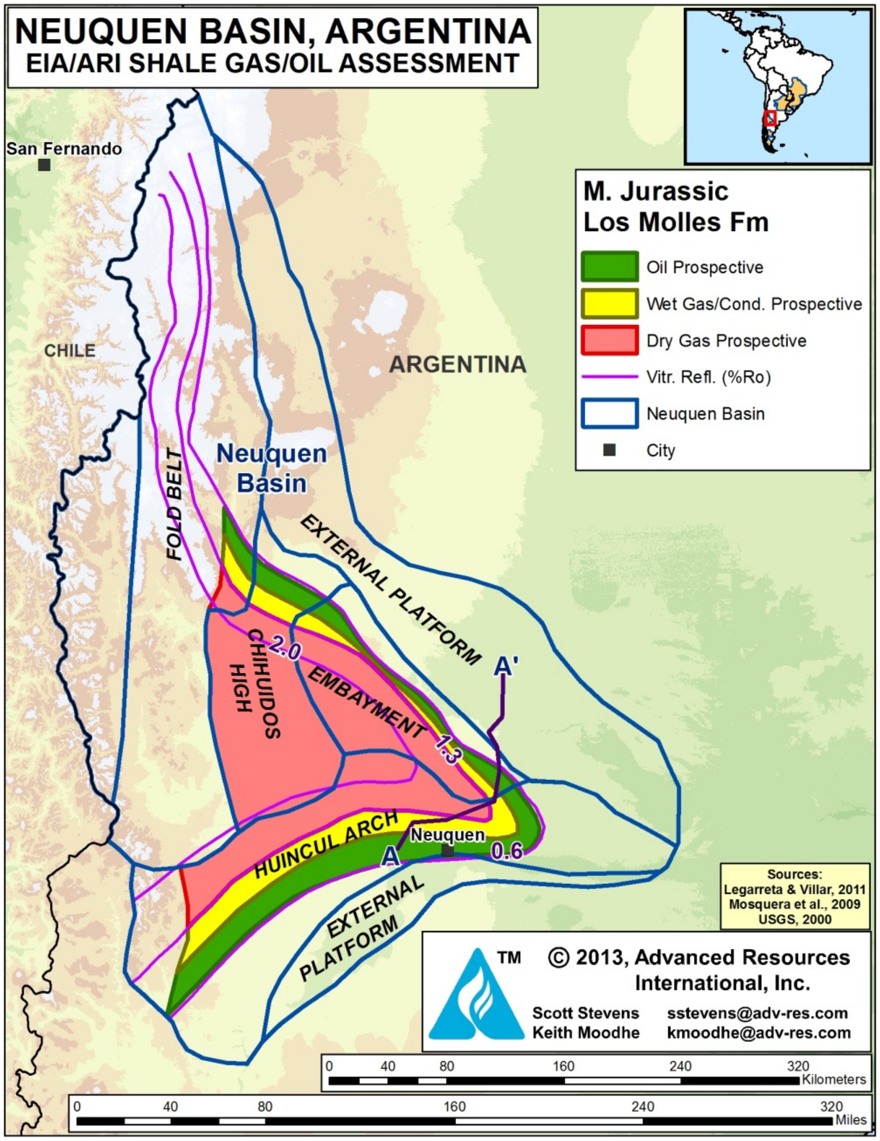
Total organic carbon for the Los Molles shale was determined from various locations across the Neuquen Basin. Samples from five outcrops in the southwestern part of the basin showed average TOC ranging from 0.55 to 5.01%.[6] In the southeast, TOC averaged 1.25% at shallower depths of 7,000 feet at one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

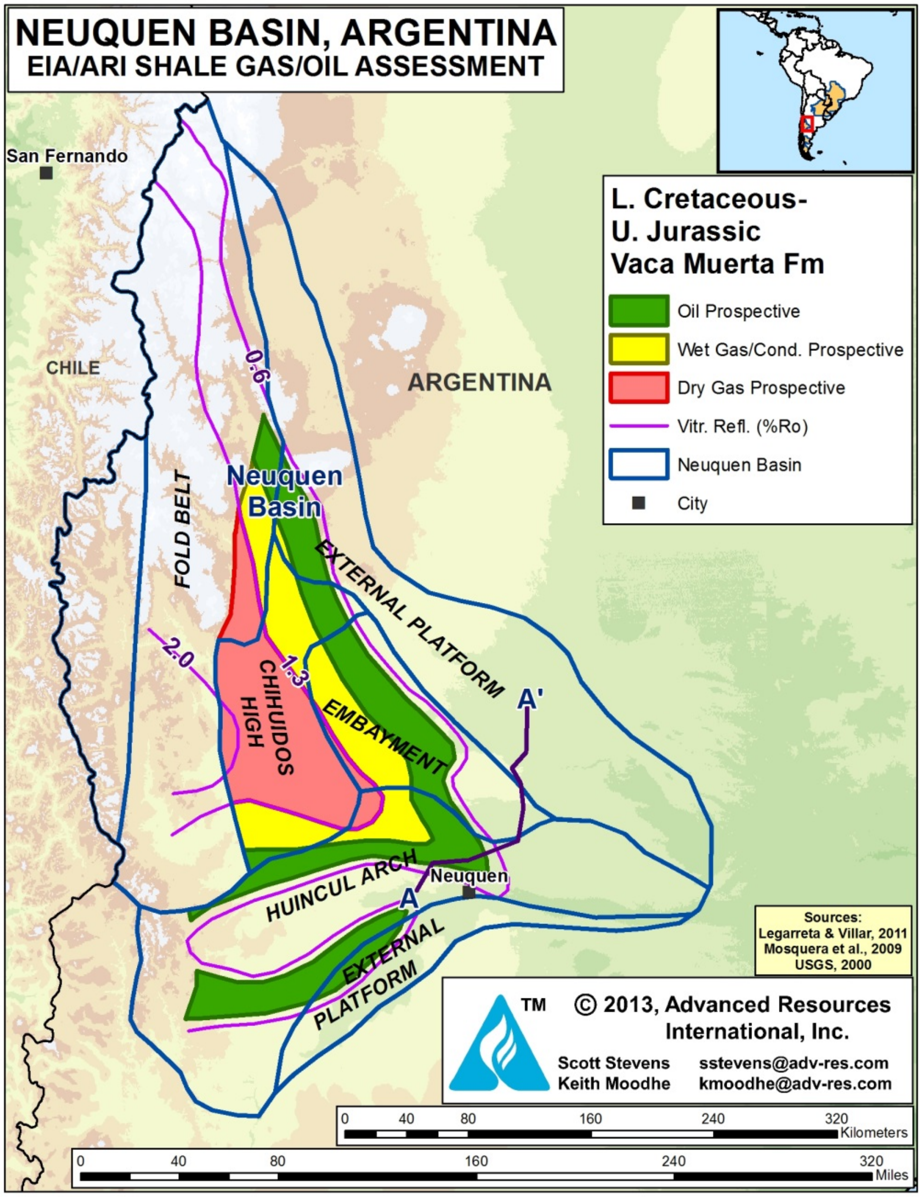
The Vaca Muerta Formation has three distinct prospective areas of hydrocarbons in the Neuquen Basin, as shown on the thermal maturity and prospective area map, Figure V-6. The oil-prone thermal maturity window within the prospective area covers an area of approximately 4,840 mi^2; the wet gas window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

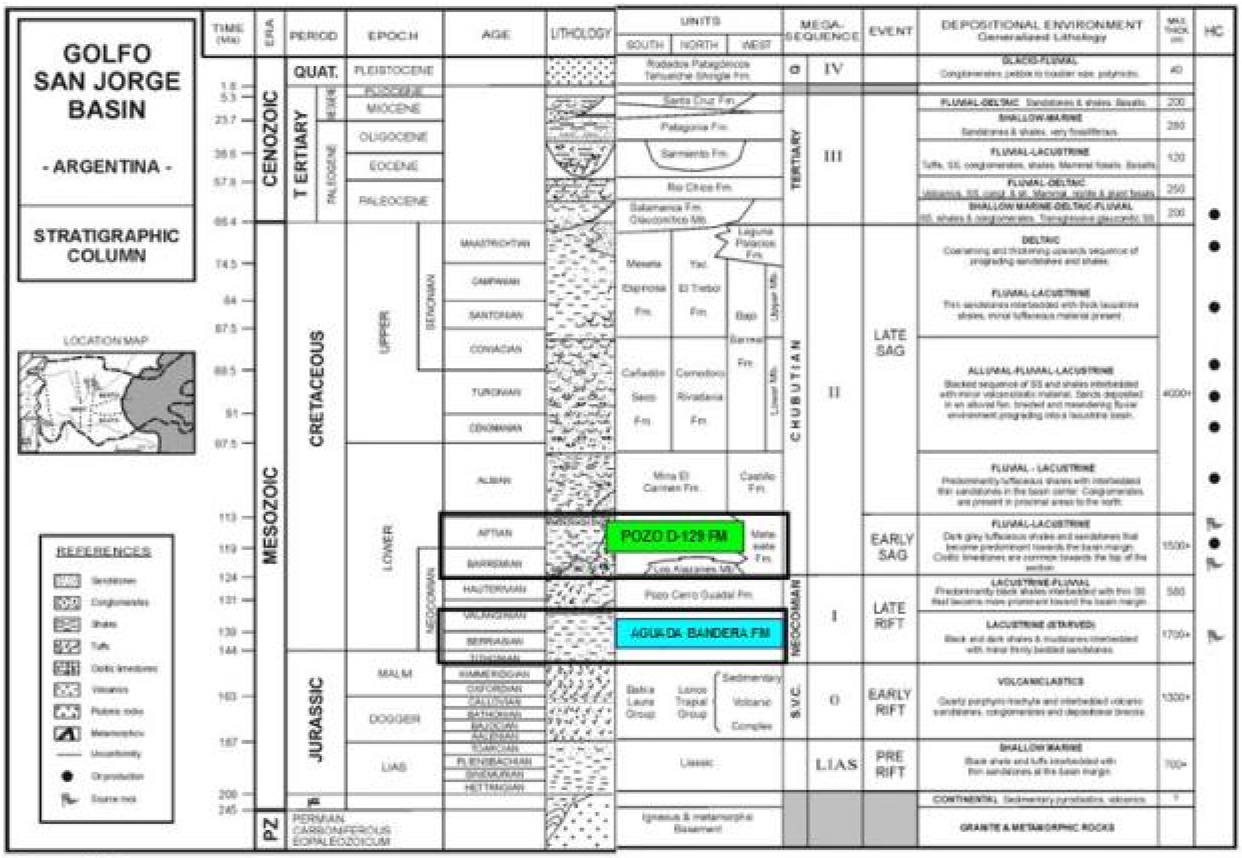
The basin is bordered by the Deseado Graben and Massif to the south, by the Somuncura Massif to the north, and the Andes Mountains in the west. Compressional structures of the San Bernardo Fold Belt transect the west-central region.[22] Extensional faults are widespread in the northeastern and southern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

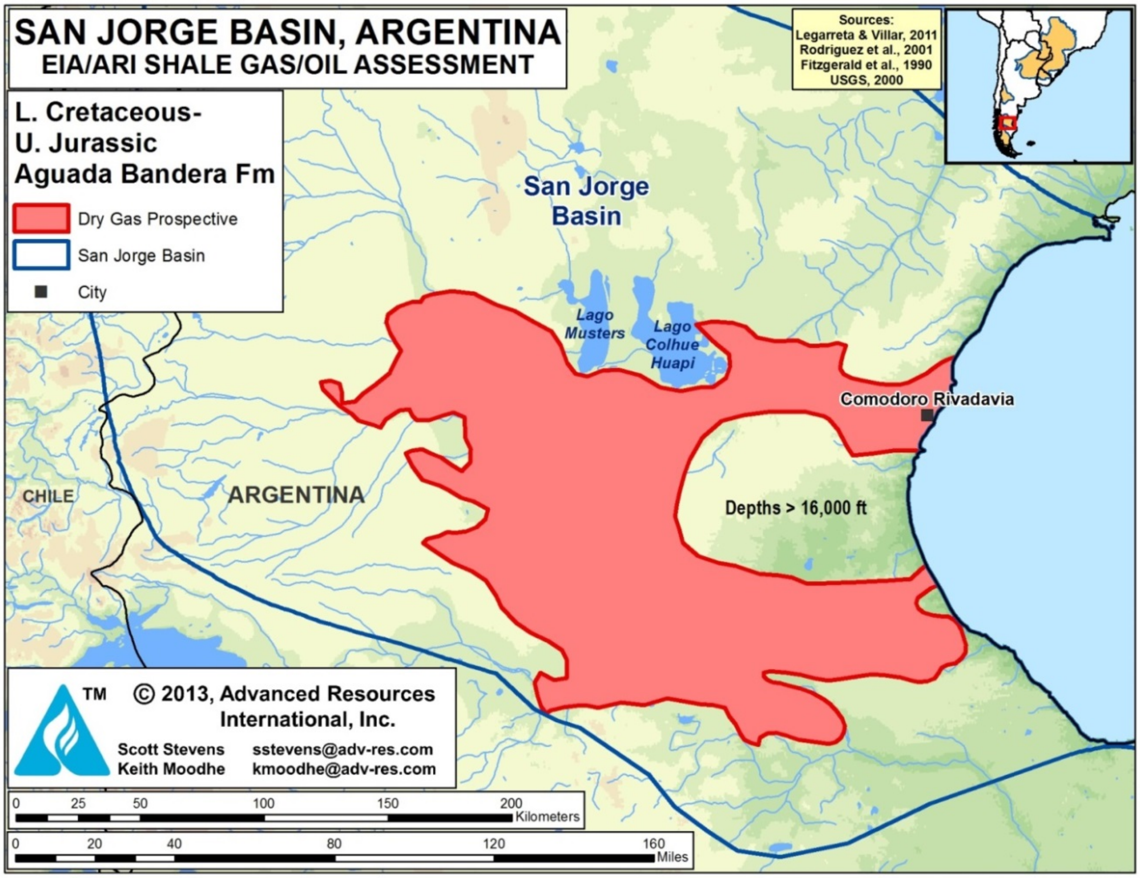
Petroleum basin modeling indicates that the minimum gas generation threshold (R_o = 1.0 to 1.3%) is typically achieved across the basin at depths below about 6,600 ft. Thus, the Aguada Bandera Formation appears to be mature for gas generation across most of the basin, **Figure V-8**. The unit is likely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



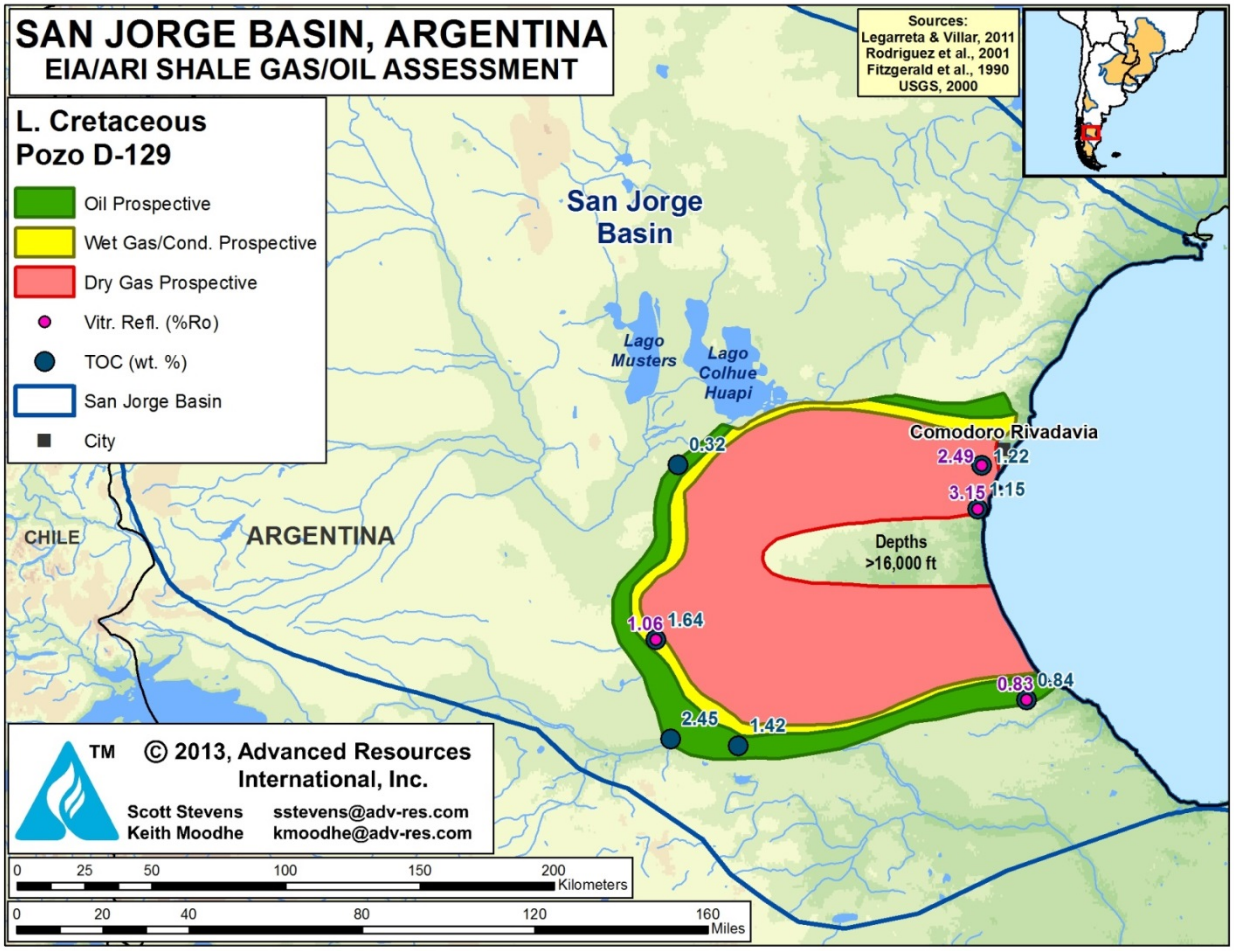
Source: ARI, 2013.

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

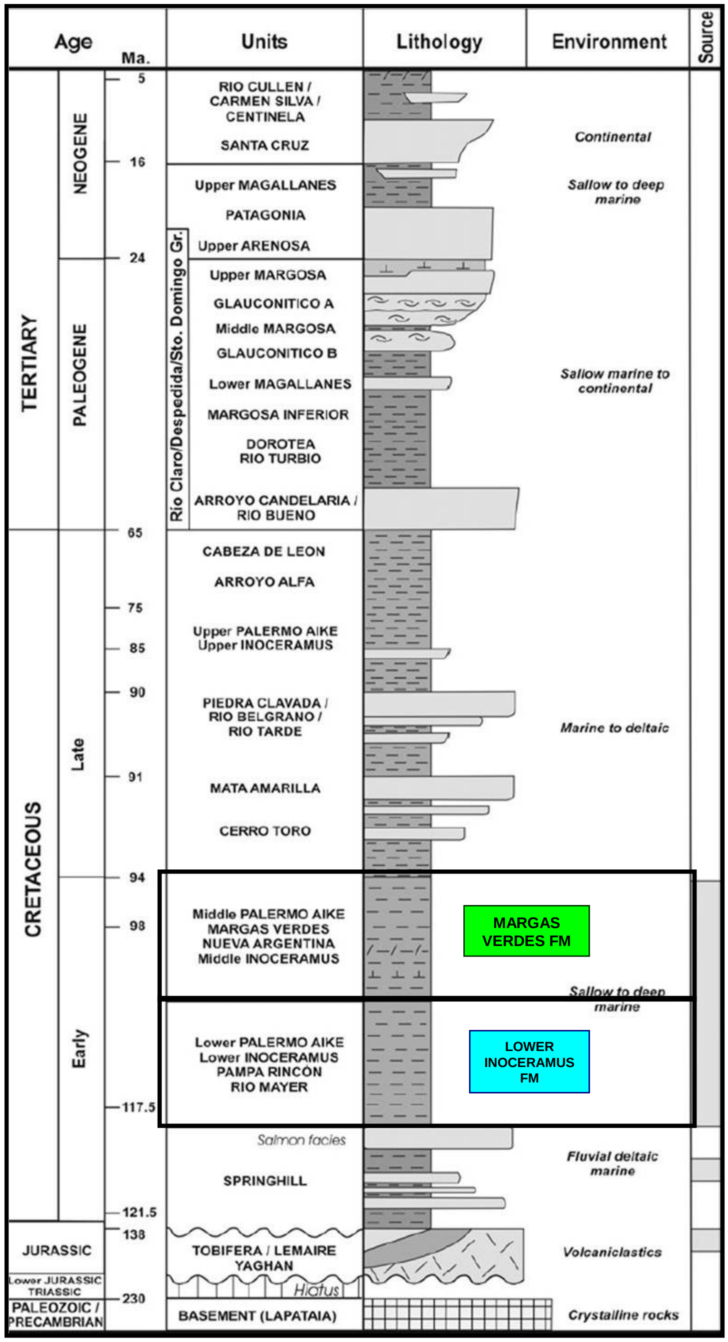
Located in southern Patagonia, the 65,000-mi^2 Austral-Magallanes Basin has promising but untested shale gas potential, **Figure V-10**. Most of the basin is in Argentina, where it is usually called the Austral Basin. A small southernmost portion of the basin is located in Chile's Tierra del Fuego region,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

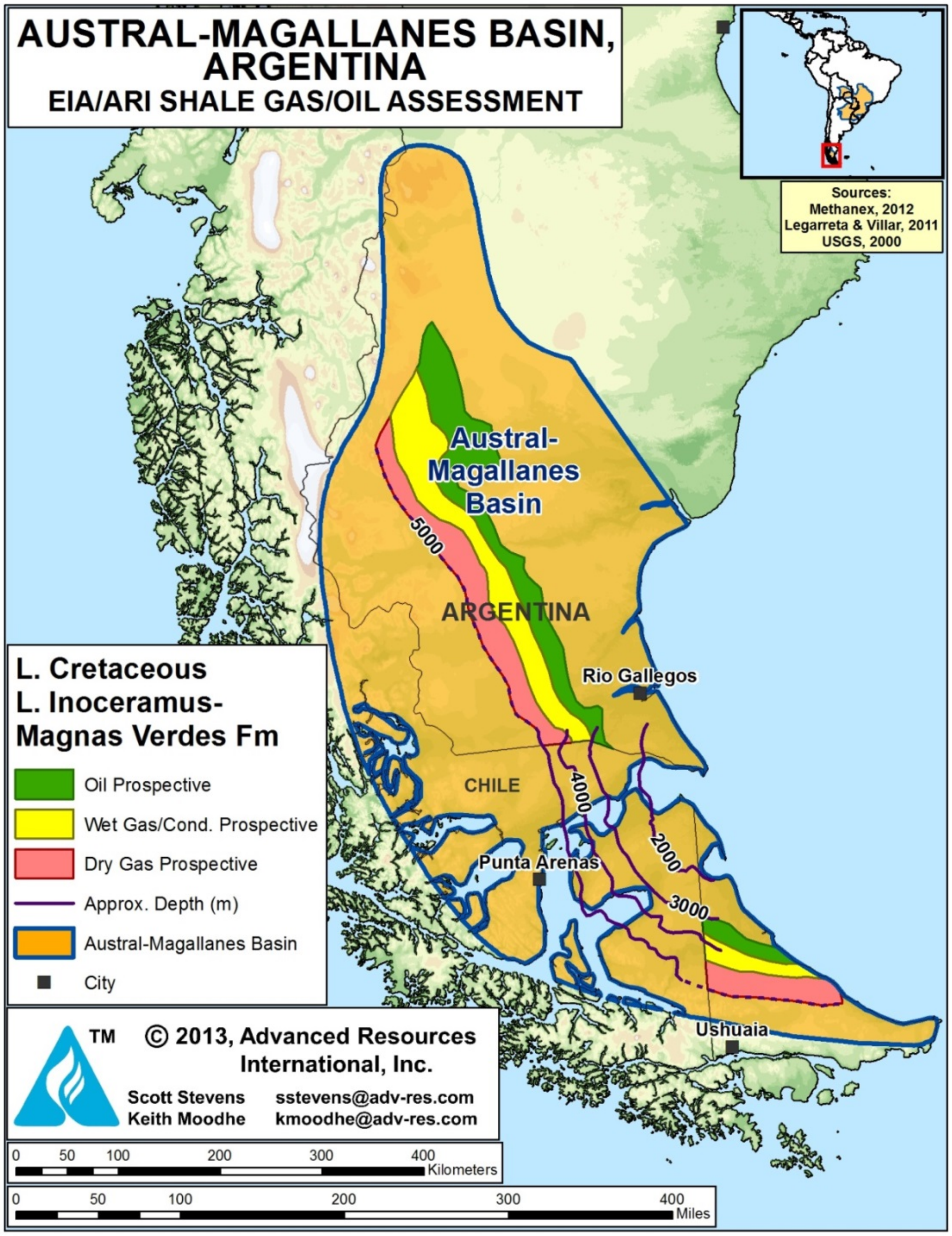
Figure V-10: Stratigraphy of the Austral-Magallanes Basin, Argentina and Chile



Rossello et al., 2008

Source: Rossello et al., 2008

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

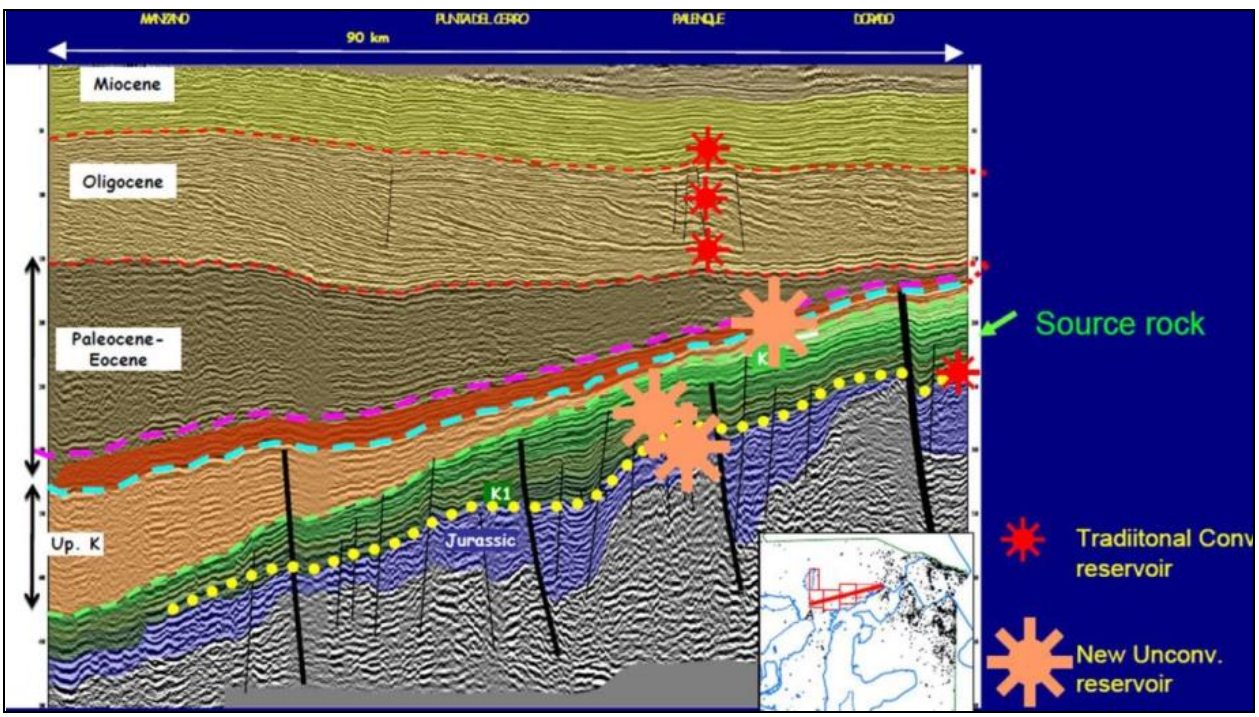


Source: ARI, 2013.

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]

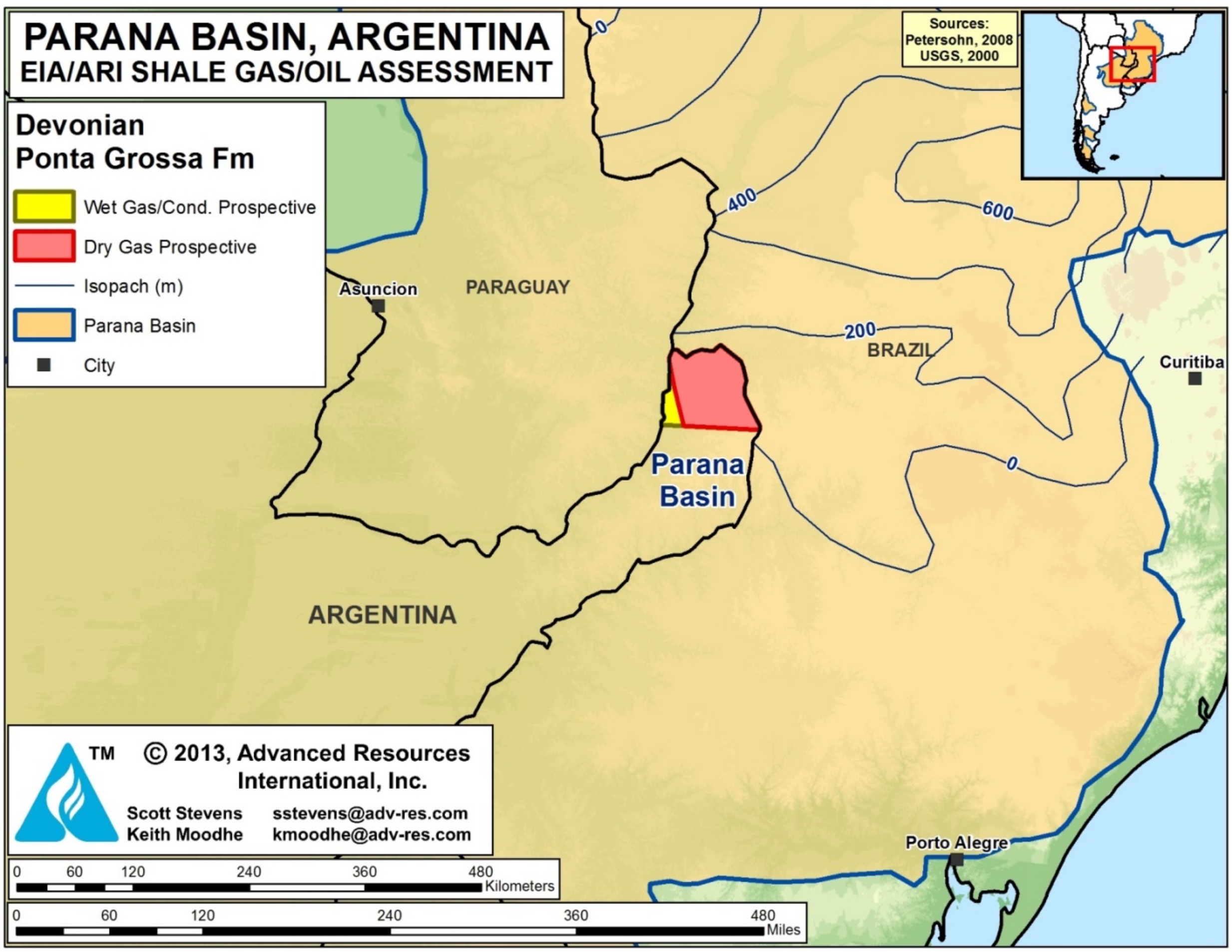
UK-based GeoPark holds conventional petroleum leases in the Magallanes Basin of Chile, which the company notes contains shales in the Estratos con Favrella Formation which previously have produced oil. In 2012, GeoPark conducted diagnostic fracture injection tests on eight wells on the Fell Block to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

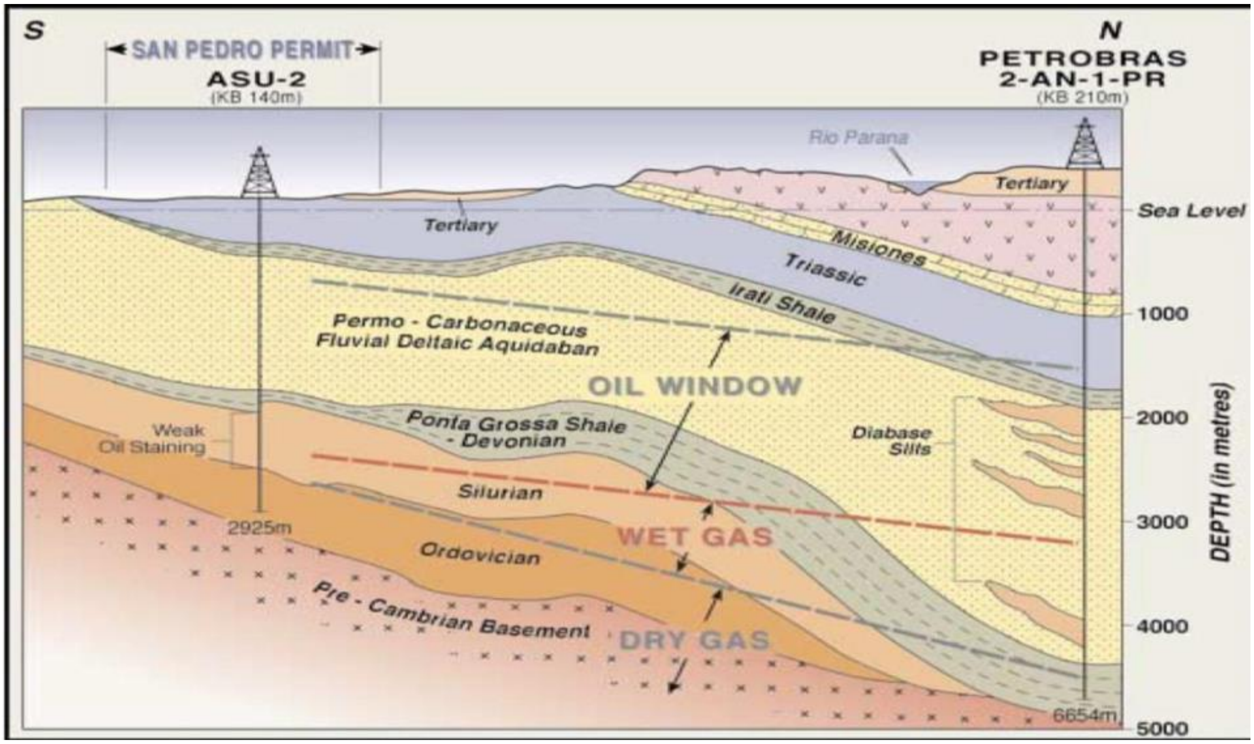
The Paraná Basin has remained at moderate burial depth throughout its history. Consequently, the bulk of thermal maturation took place during the late Jurassic to early Cretaceous igneous episode. Most of the basin remains thermally immature (R_o <0.5%), but there are sizeable concentric windows of oil-,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

REFERENCES

[1] Howell, J.A., Schwarz, E., Spalletti, L.A., and Veiga, G.D., 2005. "The Neuquén Basin: An Overview." In G.D. Viega, L.A. Spalletti, J.A. Howell, and E. Schwarz, eds., The Neuquén Basin, Argentina: A Case Study in Sequence Stratigraphy and Basin Dynamics. Geologic Society, London, Special Publications, 252, p. 1-14.

[2] Manceda, R. and Figueroa, D., 1995. "Inversion of the Mesozoic Neuquén Rift in the Malargue Fold and Thrust Belt, Mendoza, Argentina." in A.J. Tankard, R.S. Soruco, and H.J. Welsink, eds., Petroleum Basins of South America. American Association of Petroleum Geologists, Memoir 62, p. 369–382.

[3] Rodriguez, F., Olea, G., Delpino, D., Baudino, R., and Suarez, M., 2008. "Overpressured Gas Systems Modeling in the Neuquen Basin Center." American Association of Petroleum Geologists Annual Convention and Exhibition, April 20-23, 2008, 4 pages.

[4] Cruz, C.E., Boll, A., Omil, R.G., Martínez, E.A., Arregui, C., Gulisano, C., Laffitte, G.A., and Villar, H.J., 2002. "Hábitat de Hidrocarburos y Sistemas de Carga Los Molles y Vaca Muerta en el Sector Central de la Cuenca Neuquina, Argentina." IAPG, V Congreso de Exploración y Desarrollo de Hidrocarburos, Mar del Plata, November 2002, 20 pages.

[5] Stinco, L.P., 2010. "Wireline Logs and Core Data Integration in Los Molles Formation, Neuquen Basin, Argentina." Society of Petroleum Engineers, SPE 107774, 2007 SPE Latin America and Caribbean Petroleum Engineering Conference, Buenos Aires, Argentina, 15-18 April, 7 p.

[6] Martinez, M.A., Prámparo, M.B., Quattrocchio, M.E., and Zavala, C.A., 2008. "Depositional Environments and Hydrocarbon Potential of the Middle Jurassic Los Molles Formation, Neuquén Basin Argentina: Palynofacies and Organic Geochemical Data." Revista Geológica de Chile, 35 (2), p. 279-305.

[7] Kugler, R.L., 1985. "Soure Rock Charcateristics, Los Molles and Vaca Muerta Shales, Neuquen Basin, West-Central Argentina." American Association of Petroleum Geologists, Bulletin, vol. 69, no. 2, p. 276.

[8] Sounders-Smith, A., 2001. "Neuquen Province Offers Areas With Exploration Potential." Oil & Gas Journal, September 24, 2001.

[9] Villar, H.J., Legarreta, L., Cruz, C.E., Laffitte, G.A., and Vergani, G., 2005. "Los Cinco Sistemas Petroleros Coexistentes en el Sector Sudeste de La Cuenca Neuquina: Definición Geoquímica y Comparación a lo Largo de una Transecta de 150 Km." IAPG, VI Congreso de Exploración y Desarrollo de Hidrocarburos, Mar del Plata, November 2005, 17 pages.

[10] Aguirre-Urreta, M.B., Price, G.D., Ruffell, A.H., Lazo, D.G., Kalin, R.M., Ogle, N., and Rawson, P.F, 2008. "Southern Hemisphere Early Cretaceous (Valanginian-Early Barremian) Carbon and Oxygen Isotope Curves from the Neuquen Basin, Argentina." Cretaceous Research, vol. 29, p. 87-99.

[11] Hurley, N.F., Tanner, H.C., and Barcat, C., 1995. "Unconformity-Related Porosity Development in the Quintuco Formation (Lower Cretaceous), Neuquén Basin, Argentina." in D.A. Budd, A.H. Saller, and P.M. Harris, eds., Unconformities and Porosity in Carbonate Strata. American Association of Petroleum Geologists, Memoir 63, p. 159-176.

[12] Mosquera, A., Alonso, J., Boll, A., Alarcón, Zavala, C., Arcuri, M., and Villar, H.J., 2009. "Migración Lateral y Evidencias de Hidrocarburos Cuyanos en Yacimientos de la Plataforma de Catriel, Cuenca Neuquina." In M. Schiuma, ed., IAPG, VII Congreso de Exploración y Desarrollo de Hidrocarburos, p. 491-526.

[13] Parnell, J., and Carey, P.F., 1995. "Emplacement of Bitumen (Asphaltite) Veins in the Neuquén Basin, Argentina." American Association of Petroleum Geologists, Bulletin, vol. 79, no. 12, p. 1798-1816.

[14] Cobbold, P.R., Diraison, M., Rossello, E.A., 1999. "Bitumen Veins and Eocene Transpression, Neuquén Basin, Argentina." Tectonophysics, 314, p. 423-442.

[15] YPF, 2013. "Vaca Muerta Shale Oil." Corporate Presentation, 28 p.

[16] Repsol, Fourth Quarter and Full-Year 2011 Results, Corporate Presentation, February 29, 2012, 26 p.

[17] Apache Corporation, 3Q-2012 Earnings Call, November 16, 2012.

[18] Apache Corporation, Investor Presentation, April 10, 2013, 38 p.

[19] EOG Resources, 3Q-2012 Earnings Call, November 6, 2012.

[20] Americas Petrogas, Investor Presentation, January 14, 2013, 36 p.

[21] Torres-Verdín, C., Chunduru, R.G., and Mezzatesta, A.G., 2000. "Integrated Interpretation of 3D Seismic and Wireline Data to Delineate Thin Oil-Producing Sands in San Jorge Basin, Argentina." Society of Petroleum Engineers 62910, presented at the 2000 SPE Annual Technical Conference and Exhibition, 10 pages.

[22] Peroni, G.O., Hegedus, A.G., Cerdan, J., Legarreta, L., Uliana, M.A., and Laffitte, G., 1995. "Hydrocarbon Accumulation in an Inverted Segment of the Andean Foreland: San Bernardo Belt, Central Patagonia." in A.J. Tankard, R.S. Soruco, and H.J. Welsink, eds., Petroleum Basins of South America. American Association of Petroleum Geologists, Memoir 62, p. 403-419.

[23] Hirschfeldt, M., Martinez, P., and Distel, F., 2007. "Artificial-Lift Systems Overview and Evolution in a Mature Basin: Case Study of Golfo San Jorge." Society of Petroleum Engineers 108054, presented at the 2007 SPE Latin American and Caribbean Petroleum Engineering Conference, 13 pages.

[24] Fitzgerald, M.G., Mitchum, R.M. Jr., Uliana, M.A., and Biddle, K.T., 1990. "Evolution of the San Jorge Basin, Argentina." American Association of Petroleum Geologists, Bulletin, vol. 74, no. 6, p. 879-920.

[25] Sylwan, C.A., 2001. "Geology of the Golfo San Jorge Basin, Argentina." Journal of Iberian Geology, 27, p. 123-157.

[26] Laffitte, G.A., and Villar, H.J., 1982. "Poder Reflector de la Vitrinita y Madurez Térmica: Aplicaión en el Sector NO. de la Cuenca del Golfo San Jorge." I Congreso Nacional de Hidrocarburos, Petróleo y Gas. Exploración, p. 171-182.

[27] Seiler, J.O., and Viña, F., 1997. "Estudio Estratigráfico, Palinofacial y Potencial Oleogenético Pozo: OXY.Ch.RChN.x-1. Area: CGSJ-5 Colhué Huapi. Pcia del Chubut. Rep. Argentina. Pan American Energy. Unpublished.

[28] Rodriguez, J.F.R, and Littke, R., 2001. "Petroleum Generation and Accumulation in the Golfo San Jorge Basin, Argentina: A Basin Modeling Study." Marine and Petroleum Geology, 18, p. 995-1028.

[29] Figari, E.G., Strelkov, E., Laffitte, G., Cid de la Paz, M.S., Courtade, S.F., Celaya, J., Vottero, A., Lafourcade, P., Martínez, R., and Villar, H., 1999. "Los Sistemas Petroleros de la Cuenca del Golfo San Jorge: Sintesis Estructural, Estratigrafía y Geoquímica. Actas IV Congreso de Exploración y Desarollo de Hidrocarburos, Mar del Plata, I, p. 197-237.

[30] Paredes, J.M., Foix, N., Piñol, F.C., Nillni, A., Allard, J.O., and Marquillas, R.A., 2008. "Volcanic and Climatic Controls on Fluvial Style in a High-Energy System: The Lower Cretaceous Matasiete Formation, Golfo San Jorge Basin, Argentina." Sedimentary Geology, 202, p. 96-123.

[31] Bellosi, E.S., Villar, H.J., and Laffitte, G.A., 2002. "Un Nuevo Sistema Petrolero en el Flanco Norte de la Cuenca del Golfo San Jorge: Revelación de Áreas Marginales y Exploratorias." IAPG, V Congreso de Exploración y Desarrollo de Hidrocarburos, Mar del Plata, November 2002, 16 pages.

[32] Rodriquez, J. and Cagnolatti, M.J., 2008. "Source Rocks and Paleogeography, Austral Basin, Argentina." American Association of Petroleum Geologists, Search and Discovery Article #10173, 24 p.

[33] Romans, B.W., Fildani, A., Hubbard, S.M., Covault, J.A., Fosdick, J.C., and Graham, S.A., 2011. "Evolution of Deep-water Stratigraphic Architecture, Magallanes Basin, Chile." Marine and Petroleum Geology, vol. 28, p. 612-628.

[34] Fildani, A. and Hessler, A.M., 2005. "Stratigraphic Record Across a Retroarc Basin Inversion: Rocas Verdes–Magallanes Basin, Patagonian Andes, Chile." Geological Society of America, vol. 117, p. 1596-1614.

[35] Ramos, V.A., 1989. "Andean Foothills Structures in Northern Magallanes Basin, Argentina." American Association of Petroleum Geologists, Bulletin, vol. 73, no. 7, p. 887-903.

[36] Pittion, J.L. and Arbe, H.A., 1999. "Sistemes Petroleros de la Cuenca Austral." IV Congreso Exploracion y Desarrollo de Hidrocarburos, Mar del Plata, Argentina, Actas I, p. 239-262.

[37] Methanex, Investor Presentation, September 27, 2012, 129 p.

[38] Legarreta, L. and Villar, H.J., 2011. "Geological and Geochemical Keys of the Potential Shale Resources, Argentina Basins." American Association of Petroleum Geologists, Search and Discovery Article, Adapted from AAPG Geoscience Technology Workshop, "Unconventional Resources: Basics, Challenges, and Opportunities for New Frontier Plays," Buenos Aires, Argentina, June 26-28, 2011.

[39] Venara, L., Chambi, G.B., Cremonini, A., Limeres, M., and Dos Lagunas, E., 2009. "Producing Gas And Condensate From a Volcanic Rock In The Argentinean Austral Basin." 24th World Gas Congress, 5-9 October, Buenos Aires, Argentina.

[40] Methanex, news release, April 2013.

[41] GeoPark Holdings Limited, "Second Quarter 2012 Operations Update," July 23, 2012, 6 p.

[42] Milani, E.J. and Zalán, P.V., 1999. "An Outline of the Geology and Petroleum Systems of the Paleozoic Interior Basins of South America." Episodes, vol. 22, p. 199-205.

[43] Vesely, F.F., Rostirolla, S.P., Appi, C.J., Kraft, E.P., 2007. "Late Paleozoic Glacially Related Sandstone Reservoirs in the Parana Basin, Brazil. American Association of Petroleum Geologists, Bulletin, vol. 91, p. 151-160.

[44] Chaco Resources PLC, 2004. "Proposed Acquisition of Amerisur S.A. and Bohemia S.A., Notice of Extraordinary General Meeting." 83 p.

[45] Guapex S.A., 2012. "Unconventional Gas in Paraguay." 21 p.

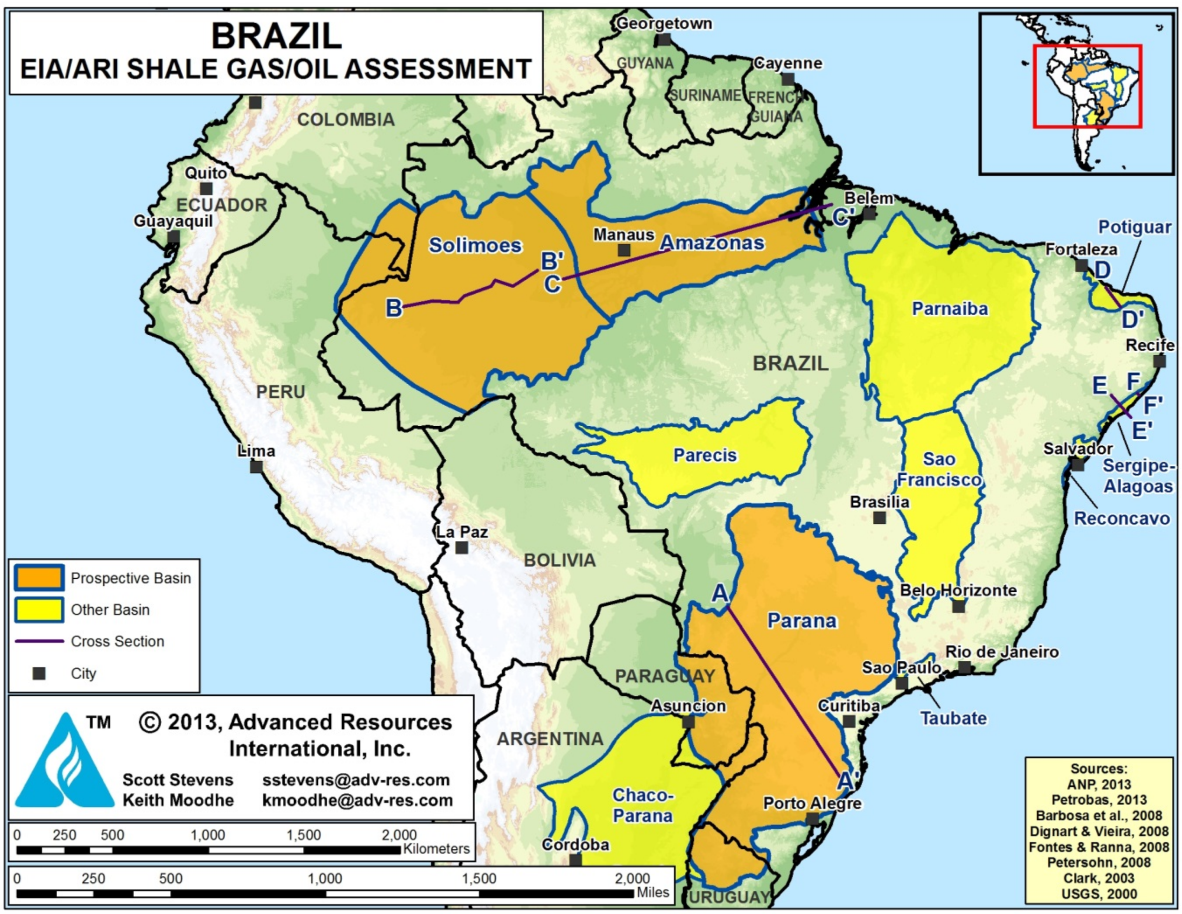
[46] US Geological Survey, 2011. "Assessment of Potential Shale Gas and Shale Oil Resources of the Norte Basin, Uruguay, 2011." 2 p.

VI. BRAZIL

SUMMARY

While Brazil's most prolific petroleum basins lie offshore, the country has 18 mostly undeveloped and lightly explored sedimentary basins onshore, **Figure VI-1**. Three of these basins -- the Paraná in the south and the Solimões and Amazonas in the north – produce significant conventional oil and gas from demonstrated source rock systems. These three basins also have sufficient geologic data to be assessed for shale gas and shale oil potential.

Figure VI-1: Prospective Shale Basins of Brazil



Source: ARI, 2013

The main shale target is the Devonian (Frasnian) marine black shale, which is extensively developed in the three structurally simple basins but has relatively modest TOC (2-2.5%). Several other basins in Brazil may have shale gas and oil potential but lack proven source rock systems, are thermally immature, and/or lack sufficient public data for assessment.

Brazil's risked, technically recoverable shale gas and shale oil resources in the Paraná, Solimões and Amazonas basins are estimated at 245 Tcf and 5.4 billion barrels, Tables VI-1 and VI-2. Risked, in-place shale resources are estimated to be 1,279 Tcf of shale gas and 134 billion barrels of shale oil. No shale-focused exploration leasing or drilling has been announced to date in Brazil.

Table VI-1. Shale Gas Reservoir Properties and Resources of Brazil

Basic Data	Basin/Gross Area		Parana ($747,000 mi^2$)			Solimoes ($350,000 mi^2$)		Amazonas ($230,000 mi^2$)		
	Shale Formation		Ponta Grossa			Jandiatuba		Barreirinha		
	Geologic Age		Devonian			Devonian		Devonian		
	Depositional Environment		Marine			Marine		Marine		
Physical Extent	Prospective Area (mi^2)		25,600	18,050	22,840	8,560	54,750	5,520	3,260	44,890
	Thickness (ft)	Organically Rich	1,000	1,000	1,000	160	160	260	300	300
		Net	300	300	300	120	120	195	225	225
	Depth (ft)	Interval	9,500 - 13,000	10,000 - 14,000	12,000 - 16,400	3,300 - 10,000	10,000 - 16,400	6,500 - 13,000	8,000 - 14,000	3,300 - 16,400
		Average	11,000	12,000	14,000	7,500	12,000	9,500	11,500	12,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	2.2%	2.2%	2.5%	2.5%	2.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	1.15%	1.60%	0.85%	1.15%	1.60%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		25.5	55.7	91.3	20.1	36.1	15.2	45.4	70.2
	Risked GIP (Tcf)		78.5	120.7	250.4	25.8	296.8	12.6	22.2	472.4
	Risked Recoverable (Tcf)		6.3	24.1	50.1	5.2	59.4	1.0	4.4	94.5

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

Basic Data	Basin/Gross Area		Parana ($747,000 mi^2$)		Solimoes ($350,000 mi^2$)	Amazonas ($230,000 mi^2$)	
	Shale Formation		Ponta Grossa		Jandiatuba	Barreirinha	
	Geologic Age		Devonian		Devonian	Devonian	
	Depositional Environment		Marine		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		25,600	18,050	8,560	5,520	3,260
	Thickness (ft)	Organically Rich	1,000	1,000	160	260	300
		Net	300	300	120	195	225
	Depth (ft)	Interval	9,500 - 13,000	10,000 - 14,000	3,300 - 10,000	6,500 - 13,000	8,000 - 14,000
		Average	11,000	12,000	7,500	9,500	11,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.2%	2.5%	2.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.15%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Condensate	Oil	Condensate
	OIP Concentration ($MMbbl/mi^2$)		26.8	11.4	5.5	18.3	8.7
	Risked OIP (B bbl)		82.4	24.7	7.1	15.1	4.3
	Risked Recoverable (B bbl)		3.30	0.99	0.28	0.61	0.17

INTRODUCTION AND GEOLOGIC OVERVIEW

Brazil has 18 onshore sedimentary basins, of which 14 basins may have petroleum source rocks. However, since the 1980s Brazil has focused mainly on its offshore oil and gas resources, while the onshore basins have seen less activity. Only two onshore basins have significant oil and gas output (Amazonas and Paraná). Relatively few conventional oil and gas wells have been drilled to the deep source rock intervals in these basins. Shale exploration drilling has not yet occurred. As a result, geologic data on the shale source rocks in Brazil are relatively scant.

Brazil's National Oil and Gas Agency (ANP) has conducted exploration surveys, mostly gravity and magnetics with minimal drilling, on four onshore basins: the Amazonas, Parana, Parnaiba, and part of the Sao Francisco.[1] Recently ANP estimated that Brazil may have 208 Tcf of shale gas resources, based on a rough analogy of three onshore Brazilian basins (Parnaiba, Parecis, Recôncavo) with the Barnett Shale in the Fort Worth Basin of Texas.[2] Petrobras, the national oil company, recently drilled its first shale oil well in Argentina but has not announced plans for shale drilling in Brazil.

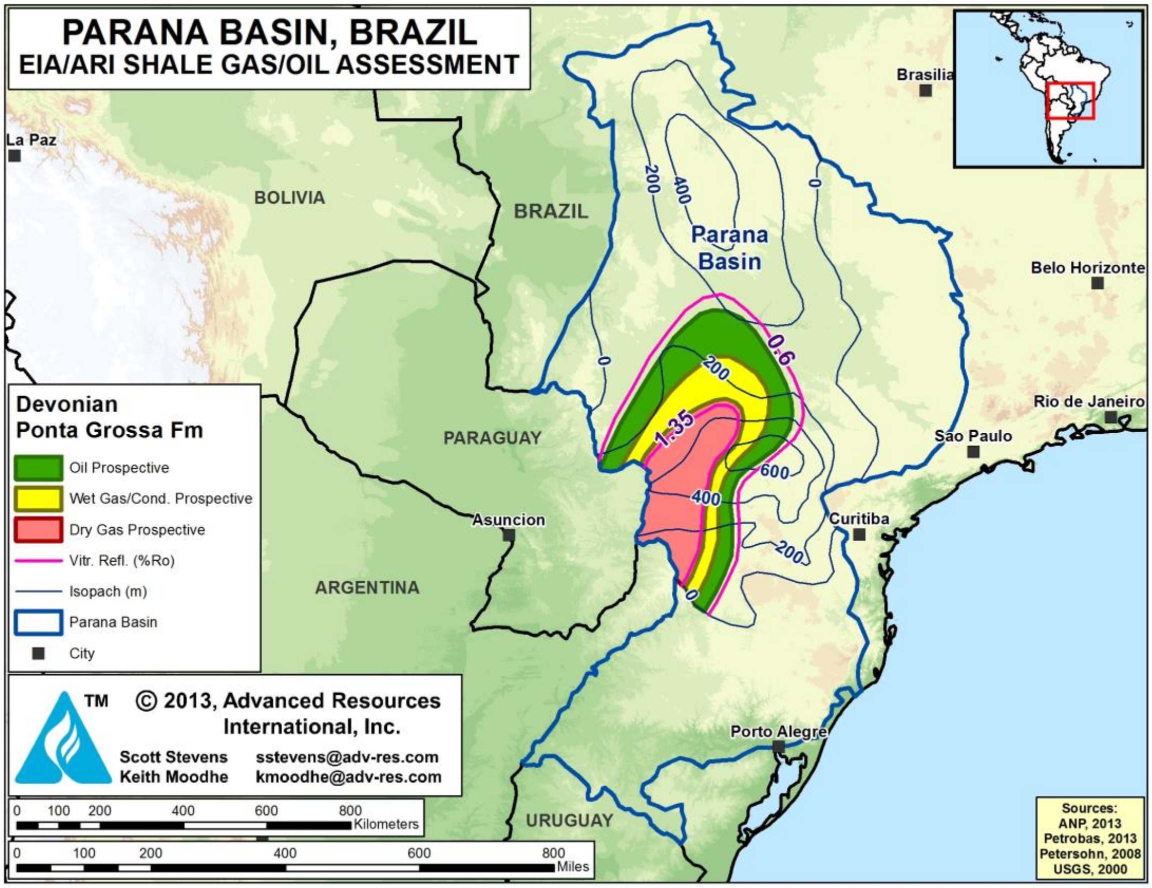
EIA/ARI has assessed the shale resource potential of three of Brazil's onshore basins (Paraná, Solimões, and Amazonas). These basins have prospective shales that sourced commercially productive conventional oil and gas fields as well as sufficient available geologic data for resource analysis. In addition, Brazil has a half-dozen other basins which may have shale potential, but their source rock systems are less proven and/or they lack sufficient available geologic data. These six other basins -- which were reviewed but not formally assessed in this study -- include the Potiguar, Parnaiba, Parecis, Recôncavo, Sergipe-Alagoas, Sao Francisco, Taubaté, and Chaco- Paraná.

1. PARANÁ BASIN

1.1 Introduction and Geologic Setting

Located in Brazil's economically most developed southern region, the Paraná Basin is a large (1.5 million km^2) depositional feature that covers 747,000 mi^2 within Brazil, with additional area in Paraguay, Uruguay, and northern Argentina, **Figure VI-2**. Major infrastructure in the region includes the Brazil-Bolivia and Uruguaiana-Porto Alegre pipelines.

Figure VI-2: Prospective Shale Gas and Shale Oil Areas in the Paraná Basin



Source: ARI, 2013

Conventional petroleum exploration began in the Paraná Basin during the 1890's, but the first (and thus far only) commercial discovery came in 1996, with the low-permeability Barra Bonita gas field of limited output (36 Bcf total through 2009).[3] Approximately 124 petroleum wells have been drilled in the Brazil portion of the Paraná Basin, a low drilling density of 1 well per 10,000 km^2. In addition, some 30,000 km of 2D seismic have been acquired.[4] Only a fraction of this data set has been published and made available for our study.

The Paraná Basin contains up to 5 km (locally 7 km) of Paleozoic and Mesozoic sedimentary rocks that range from Late Ordovician to Cretaceous. Its western border is defined by the Asuncion Arch, related to Andean thrusting, while the east is truncated by the South Atlantic tectonic margin.[5] On the north the basin onlaps Precambrian basement. Some two-thirds of the basin is covered by flood basalts, partly obscuring the underlying geology from seismic and increasing the cost of drilling.

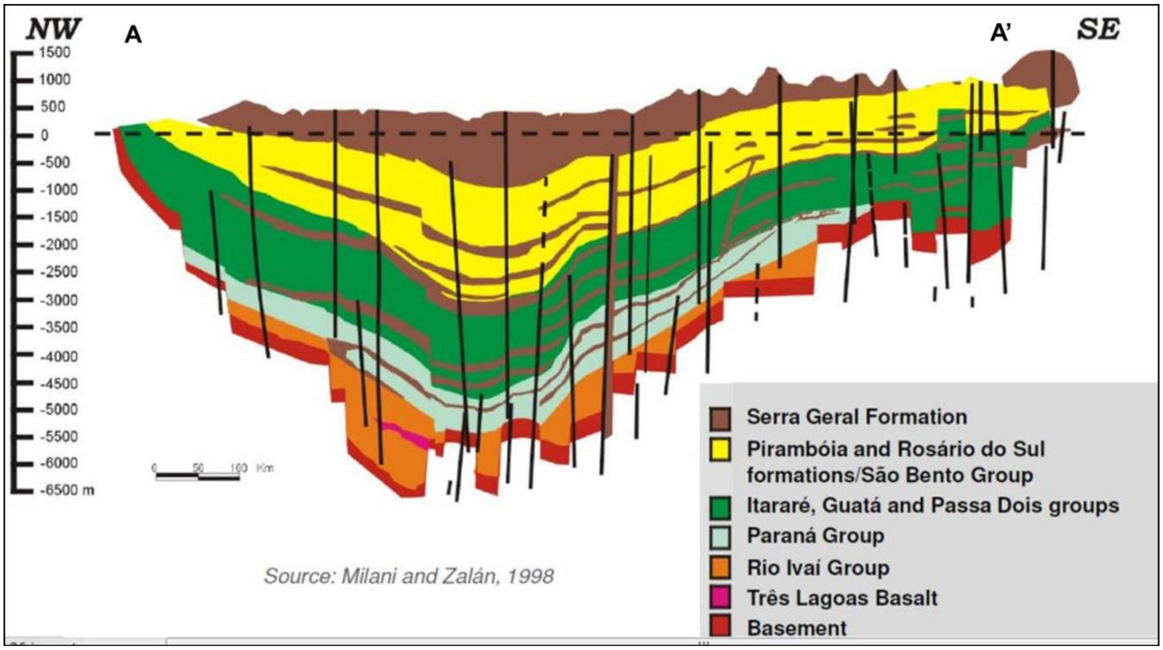
The structure of the Paraná Basin appears to be moderately simple, at least based on available data, consisting of a gentle syncline with minor faulting and secondary folding, **Figure VI-3**. Faults, predominately normal in orientation, are controlled by older basement faults (aulocogens) which separate large undeformed tracts of the basin interior. However, numerous igneous sills and dikes, related to emplacement of the flood basalts during the Early Cretaceous, intrude the sedimentary sequence. More detailed seismic reveals the presence of numerous smaller faults, **Figures VI-4 and VI-5**.

The main petroleum source rock in the Paraná Basin is the Devonian black shale of the Ponta Grossa Formation (Emsian/Frasnian), **Figure VI-6**. This 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 of the Late Carboniferous to Early Permian Itararé Group.[6]

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 deep central basin area.

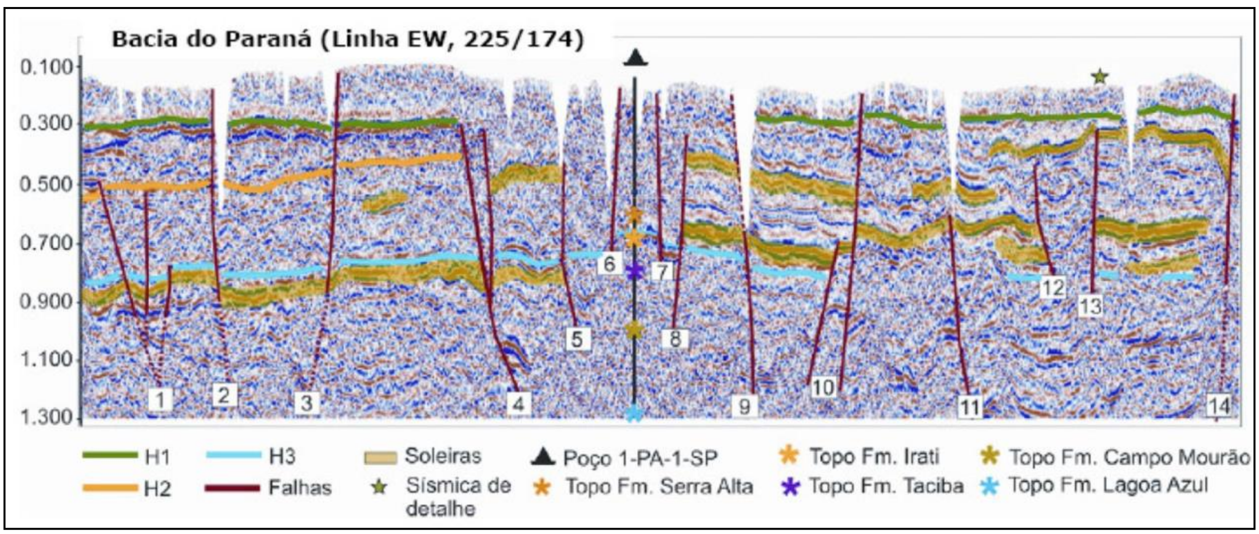
A second less prolific source rock in the Paraná Basin is the Permo-Triassic Irati Formation. This non-marine bituminous unit sourced oil trapped in biodegraded conventional sandstones (tar sands) of the Permian and Triassic Rio Bonito and Pirambóia formations.[7] The Irati Formation is widespread and can be organic-rich, averaging 8-13% TOC of Type I kerogen with peaks to 24%, but the shales are quite thin and thermally immature (R_o <0.5%). Petrobras is mining Irati oil shale from the surface at São Mateus do Sul and processing it using rock pyrolysis. Although the Irati Fm may be thermally mature in the deep Paraguay portion of the Paraná Basin,[8] its Brazil extension was not assessed due to low thermal maturity.

Figure VI-3. Cross-Section of the Paraná Basin, Brazil



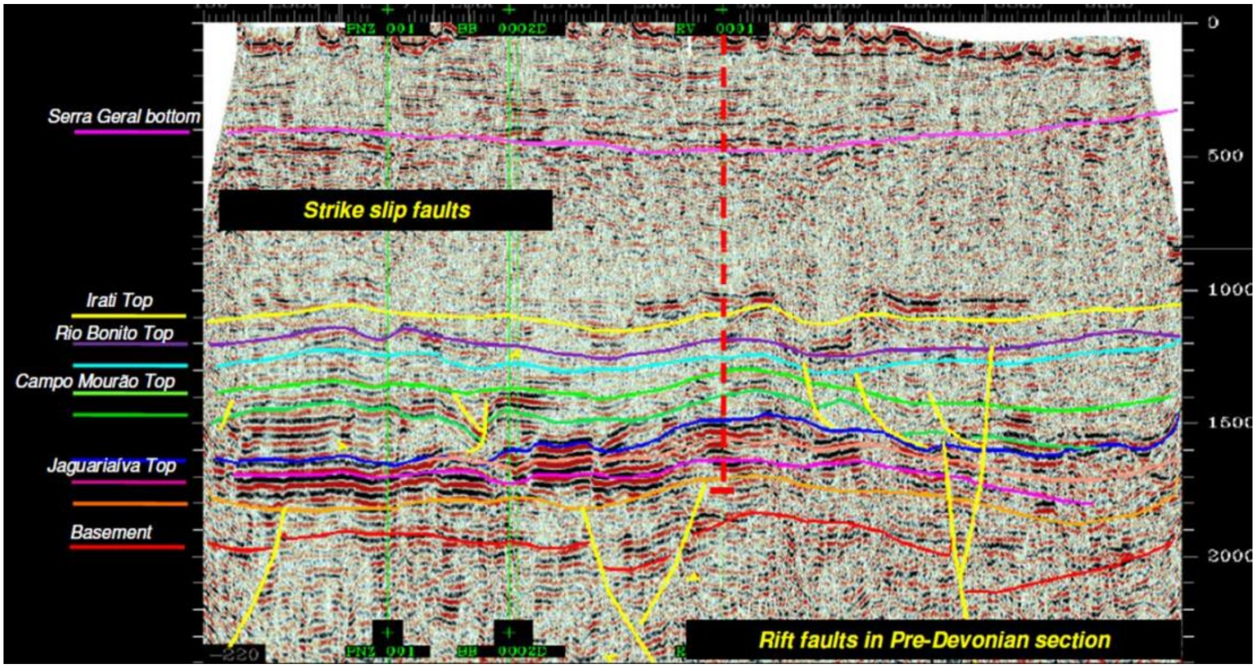
Source: ANP, 2012

Figure VI-4: Seismic Time Section Showing Regional Moderate Block Faulting of the Paraná Basin, Brazil



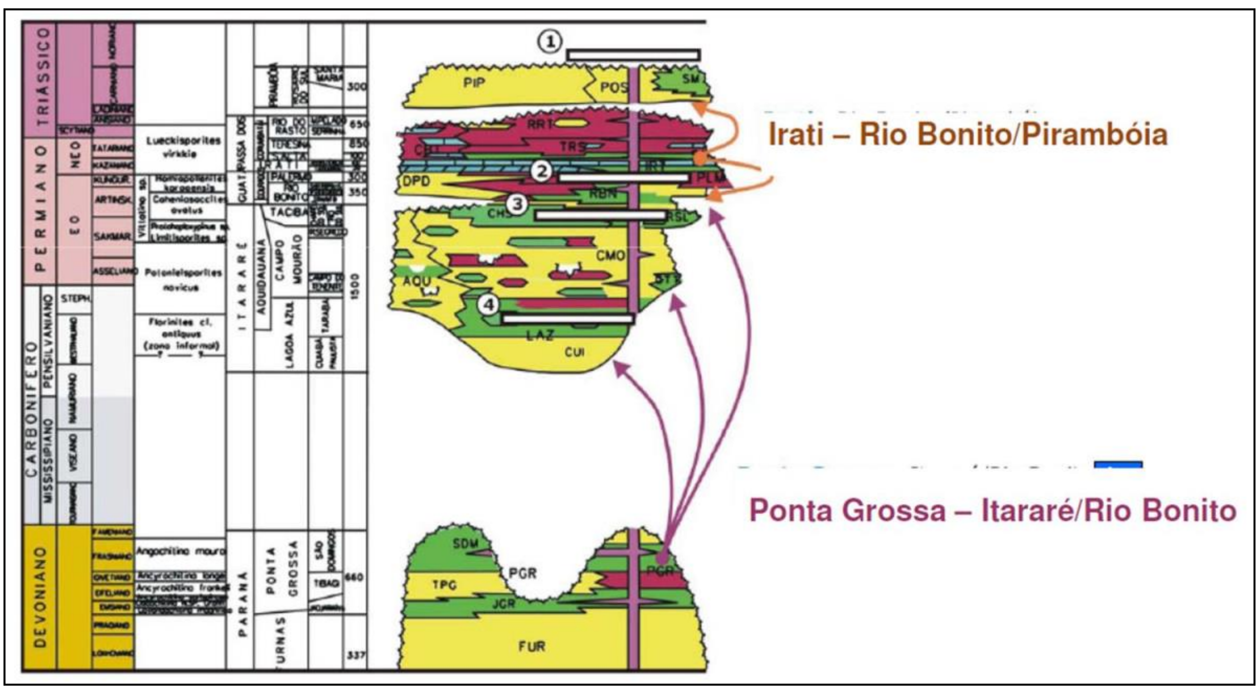
Source: Petersohn, 2003

Figure VI-5: Seismic Time Section of the Paraná Basin Showing Small Faults.



Source: Petersohn, 2003

Figure VI-6: Stratigraphy of Paraná Basin Showing Source Rock Shales, Devonian Ponta Grossa Formation



Source: Petersohn, 2003

1.2 Reservoir Properties (Prospective Area)

The prospective area of organic-rich shale in the Devonian Ponta Grossa Formation of the Paraná Basin is estimated at approximately 66,500 mi^2, of which 25,600 mi^2 is in the oil window; 18,050 mi^2 is in the wet gas/condensate thermal maturity window; and 22,840 mi^2 is in the dry gas window. The Devonian 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. Porosity is estimated at about 4% and the pressure gradient is assumed to be hydrostatic.

1.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from Devonian Ponta Grossa (Frasnian) black shale in the Paraná Basin are estimated at 81 Tcf of shale gas and 4.3 billion barrels of shale oil and condensate, Tables VI-1 and VI-2. Risked shale gas and shale oil in-place is estimated at 450 Tcf and 107 billion barrels. The play has moderate net resource concentrations of 26 to 91 Bcf/mi^2 for shale gas and 11 to 27 million bbl/mi^2 for shale oil depending on thermal maturity window.

1.4 Recent Activity

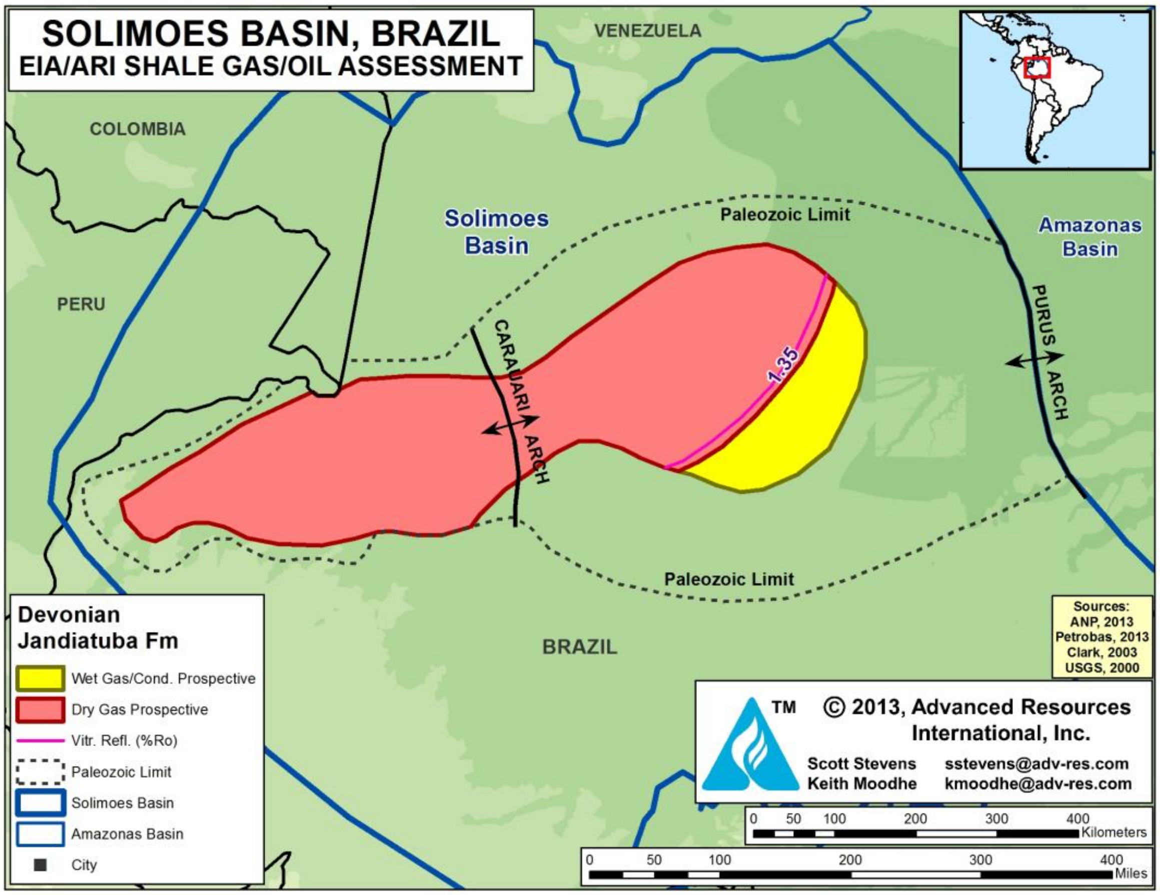
No shale gas/oil exploration activity has been reported in the Brazil portion of the Paraná Basin, although Amerisur Energy has discussed the shale potential of the Cretaceous Irati Fm in the Paraguay portion of the basin.

2. SOLIMÕES BASIN

2.1 Introduction and Geologic Setting

Located in northern Brazil, the Solimões Basin extends over 350,000 mi^2 of Amazon jungle, **Figure VI-7**. While less prolific than Brazil's offshore fields, the Solimões is the country's most productive onshore basin, with output of about 50,000 bbl/d of oil and 12 million m^3/d of natural gas from the Carboniferous Juruá Formation sandstone.[9]

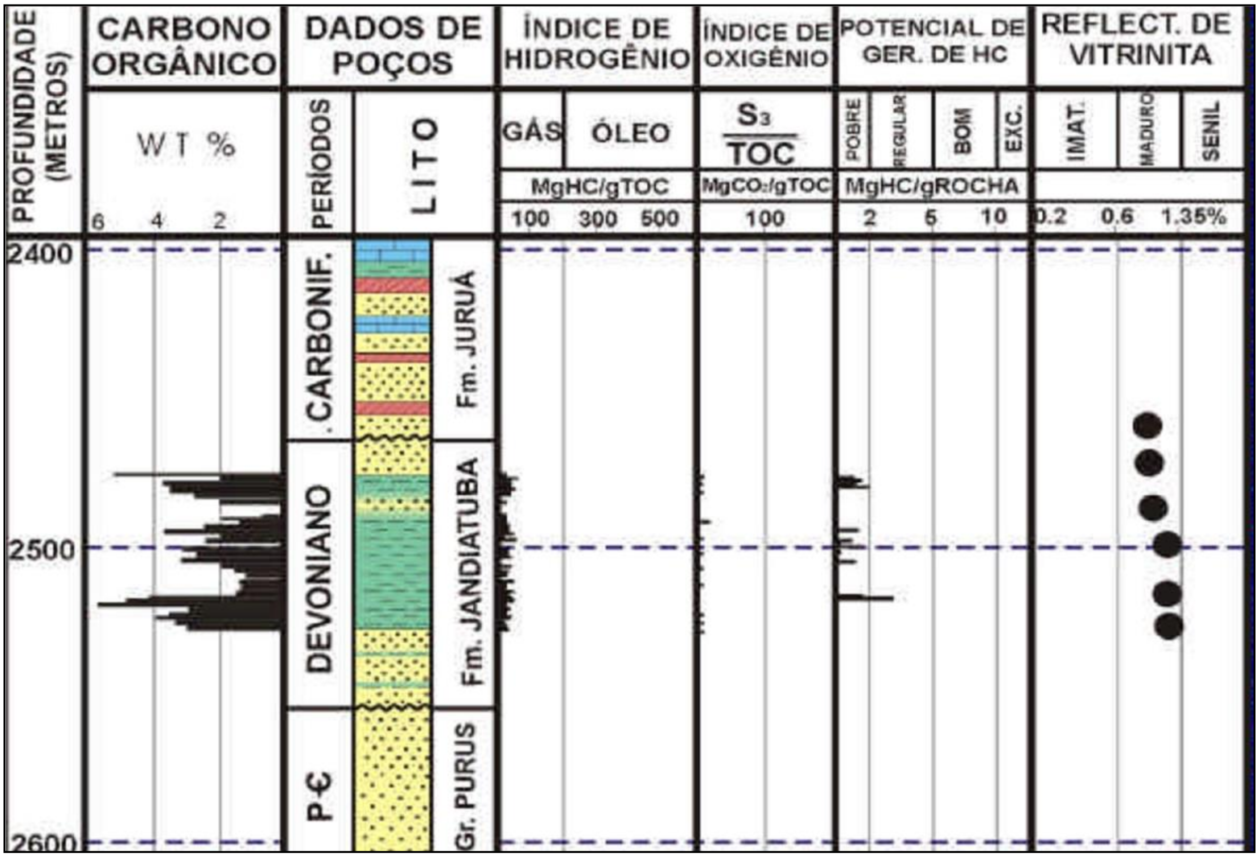
Figure VI-7: Prospective Shale Gas and Shale Oil Areas in the Solimões Basin



Source: ARI, 2013

These conventional reservoirs directly overlie and were sourced by marine-deposited source rocks within the Devonian Jandiatuba (mostly), Jaraqui and Ueré formations. The Jandiatuba Fm (Frasnian) contains a 50-m thick section of radioactive ("hot") black shale, with TOC ranging from 1% to 4% (average 2.2%; maximum 8.25%), **Figure VI-8**. Thermal maturity is mostly in the dry gas window (R_o >1.35%), apart from a small area in the east that is wet-gas prone (R_o 1.0% to 1.3%).[10]

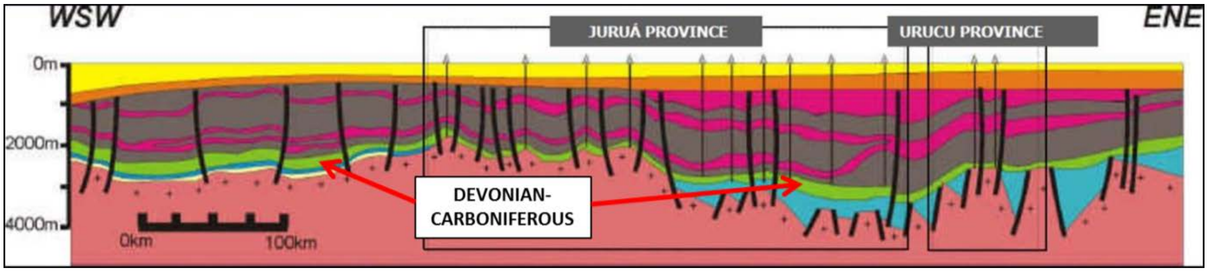
Figure VI-8: Black Shale in the Devonian Jandiatuba Formation of the Solimões Basin is about 40 m Thick with 1% to 4% TOC at this Location



Source: Clark, 2003

Figure VI-9, a regional cross-section oriented in the basin's strike direction, shows the mostly flat-lying but still moderately faulted Devonian shale at depths of 2 to 3 km. Note that a dip-oriented cross-section would reveal the steeper dips. Structural uplifts define several sub-basins. The easternmost Juruá Sub-basin, with up to 3.8 km of sedimentary rocks, accounts for most of the conventional oil and gas found in the Solimões Basin, indeed in the entire Paleozoic sequence of South America. The shale's thermal history is controlled more by proximity to igneous intrusions rather than simple burial depth.

Figure VI-9: Cross-Section (Strike Direction) of the Solimões Basin, Showing Flat-lying but Moderately Faulted Devonian Shale (Green) at Depths of 2 to 3 km.



Source: Clark, 2003

2.2 Reservoir Properties (Prospective Area)

The total estimated prospective area of organic-rich shale in the Devonian Jandiatuba Formation of the Solimões Basin is estimated at 63,000 mi^2, of which 8,560 mi^2 is in the wet gas thermal maturity window and 54,750 mi^2 is in the dry gas window. The Jandiatuba shale averages about 120 ft thick (net), 7,500 to 12,000 ft deep, and has estimated 2.2% average TOC. Porosity is estimated at 4% and the pressure gradient is assumed to be hydrostatic.

2.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from Devonian Jandiatuba black shale in the Solimões Basin are estimated at 65 Tcf of shale gas and 0.3 billion barrels of shale oil, out of risked shale gas and shale oil in-place of 323 Tcf and 7.1 billion barrels, Tables VI-1 and VI-2. The play has a moderate net resource concentration of 20 to 36 Bcf/mi^2 for shale gas and 5.5 million bbl/mi^2 for shale oil.

2.4 Recent Activity

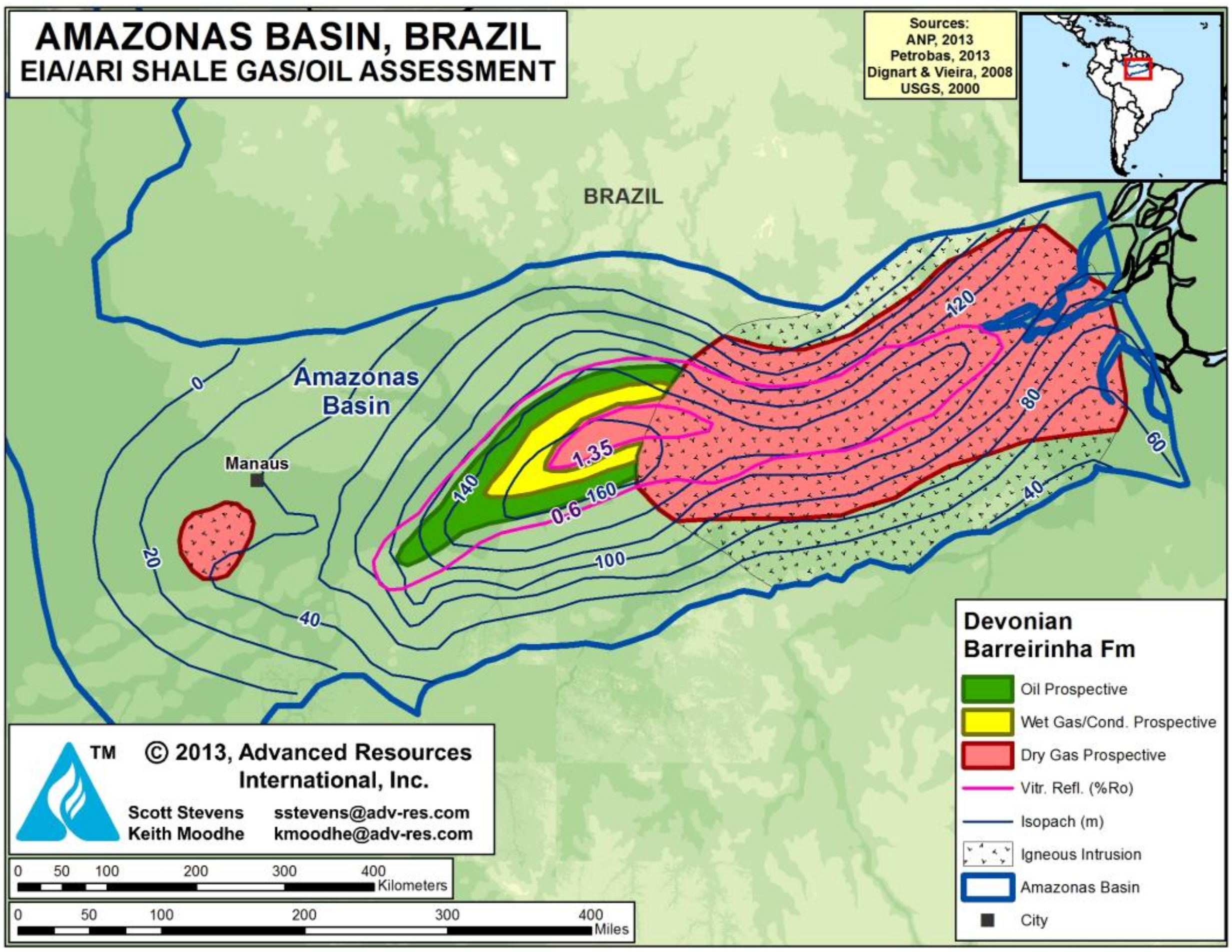
No shale gas/oil exploration activity has been reported in the Solimões Basin.

3. AMAZONAS BASIN

3.1 Introduction and Geologic Setting

Extending over more than 230,000 mi^2 of Amazon forest in remote northern Brazil, the Amazonas Basin is an ENE-WSW trending structural trough bounded by the Purus and Garupa arches, **Figure VI-10**. The first conventional petroleum fields were discovered in 1999 and commercialized starting in 2009, when the Urucu-Coari-Manaus gas and LPG pipeline system was commissioned. By late 2010, this pipeline was transporting about 0.2 Bcfd, mainly from the nearby Solimões Basin, along with smaller volumes from the Amazonas Basin.

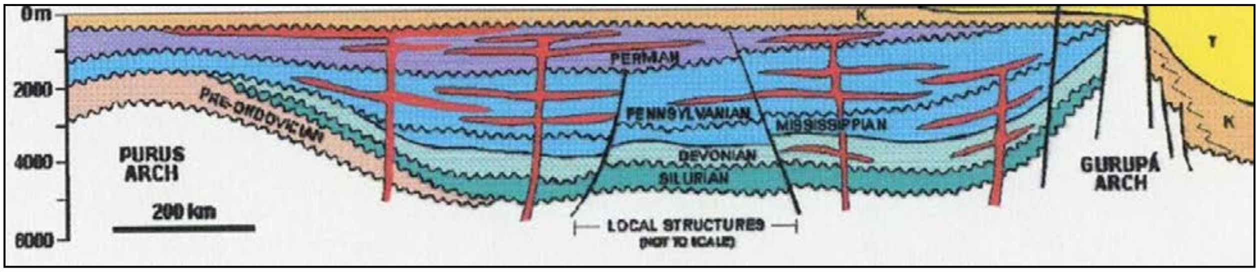
Figure VI-10: Prospective Shale Gas and Shale Oil Areas in the Amazonas Basin



Source: ARI, 2013

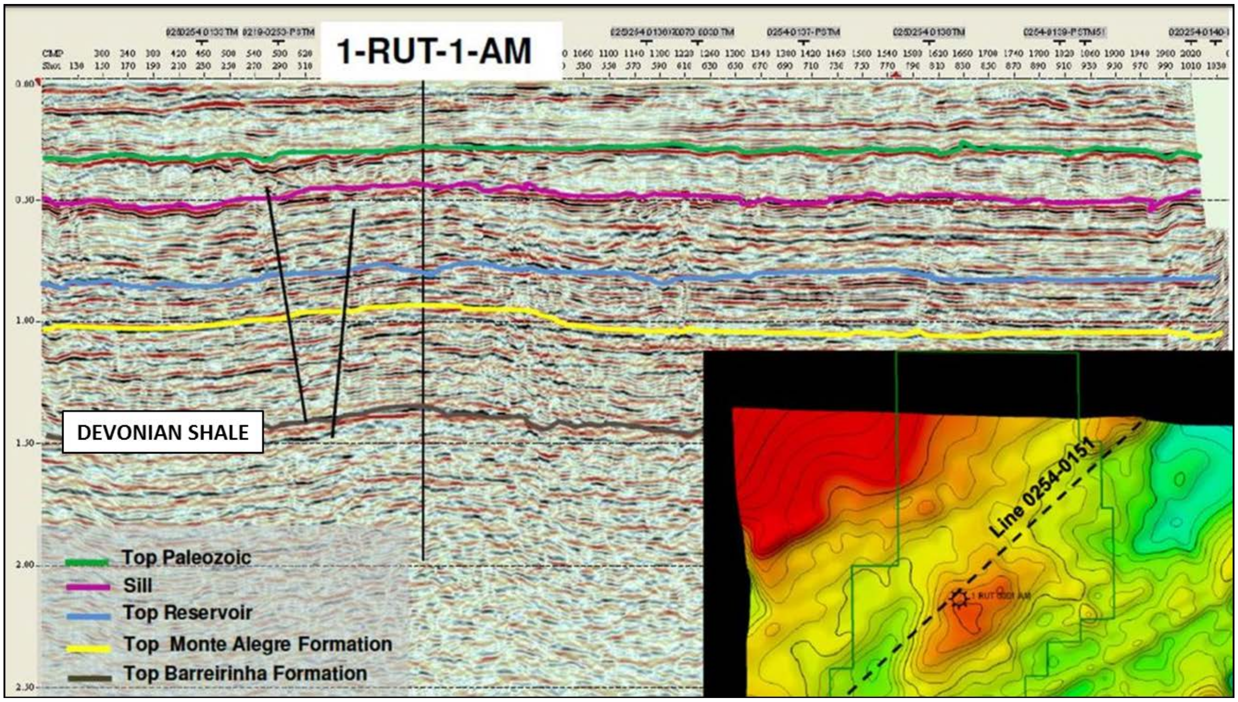
The Amazonas Basin contains up to 5 km of mostly Paleozoic sedimentary rock that are covered by Mesozoic and Cenozoic strata, **Figure VI-11**. While not structurally complex, the Amazonas Basin was extensively intruded by igneous activity during the Early Jurassic, particularly in the eastern half of the basin. This was followed by Cenozoic structural deformation that included extensional block and strike-slip faulting and salt tectonics. **Figure VI-12** illustrates the relatively simple local structure in one portion of the basin.

Figure VI-11: Devonian (Frasnian) Marine Black Shale Ranges from 2 to 4 Km Deep in the Amazonas Basin. Faults Appear to be Widely Spaced but Igneous Intrusions are Common.



Source: Dignart and Vieira, 2007

Figure VI-12: Seismic Time Section in the Amazonas Basin Showing Simple Structure of the Devonian Marine Black Shale.



Source: Dignart and Vieira, 2007

Advanced Resources International, Inc.

The petroleum system in the Amazonas Basin is broadly similar to that in the Solimões Basin. Up to 160 m (average 80 m) of laminated marine-deposited black shales are present in the Devonian Barreirinha Formation (Frasnian), which was the source rock for conventional sandstones of the overlying Nova Olinda Formation.[11] Ranging from 2 to 4 km deep, the Devonian shale has 2% to 5% TOC that consists of Type II kerogen. The Devonian is thermally immature (R_o < 0.5%) in the shallow and western portions of the basin, increasing to wet gas prone in the deeper center and dry gas prone in the more heavily intruded east. Additional marine black shales occur in the Silurian Pitinga Formation, but these contain less than 2% TOC and thus were not assessed.

3.2 Reservoir Properties (Prospective Area)

Based on the limited geologic control available for the Amazonas Basin, the total estimated prospective area of organic-rich shale in the Devonian Barreirinha Formation is estimated at about 54,000 mi^2, of which 5,520 mi^2 is in the oil window; 3,260 mi^2 is in the wet gas and condensate window; and 44,890 mi^2 is in the dry gas window. The Devonian shale averages 195-225 ft thick (net), 9,500-12,000 ft deep, and has estimated 2.5% average TOC. Porosity is estimated at 4% and the pressure gradient is assumed to be hydrostatic.

3.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from the Devonian Barreirinha Formation (Frasnian) black shale in the Amazonas Basin are estimated at 100 Tcf of shale gas and 0.8 billion barrels of shale oil and condensate, out of risked shale gas and shale oil in-place of 507 Tcf and 19 billion barrels, Tables VI-1 and VI-2. The play has a moderate net resource concentrations of approximately 15 to 70 Bcf/mi^2 for shale gas and 9 to 18 million bbl/mi^2 for shale oil.

3.4 Recent Activity

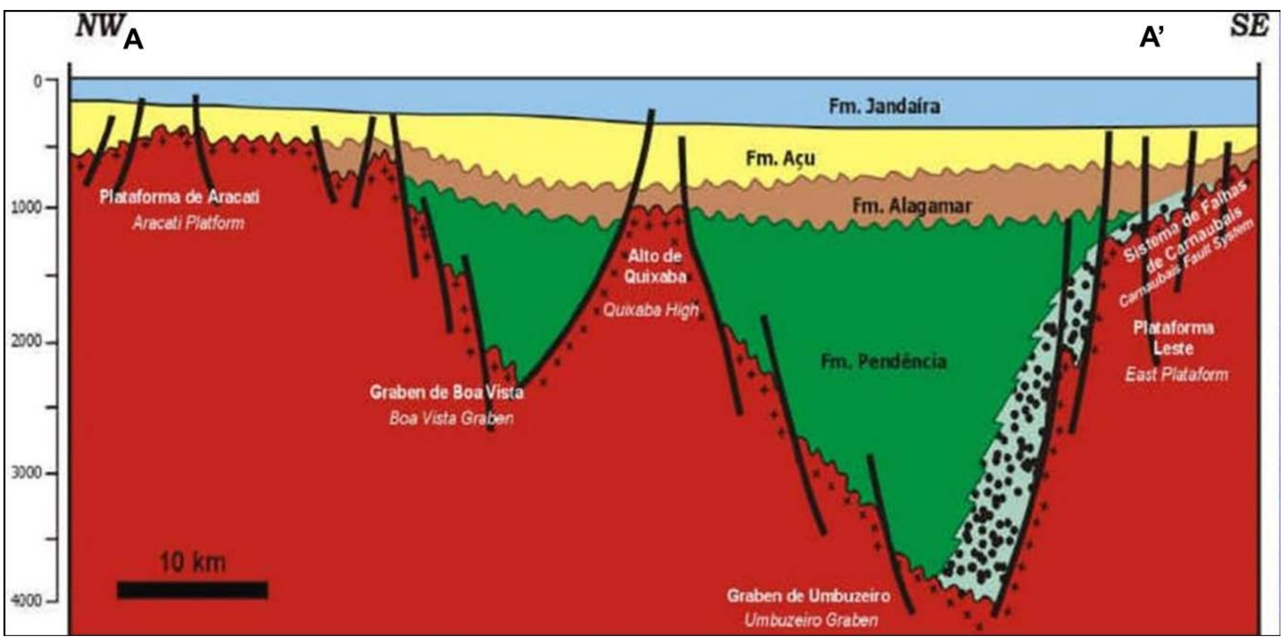
No shale gas/oil exploration leasing or drilling activity has been reported in the Amazonas Basin.

4. OTHER BASINS

More than a dozen other sedimentary basins occur in onshore Brazil. Most have no commercial oil and gas production and some lack identified petroleum generation and maturation systems. Some of these basins may have shale potential but public data are not currently sufficient for detailed characterization and assessment by EIA/ARI. However, these basins could be prospective for shale exploration and should be assessed once additional geologic data become available. Six of the more promising basins include:

- **Potiguar Basin.** This Neocomian rift basin in northeastern Brazil extends over an onshore area of about 33,000 km^2 plus a much larger area offshore. The onshore portion of the basin contains up to 4 km of mostly Cretaceous deposits. The basin comprises a number of smaller fault blocks, with major structures trending northeast-southwest, **Figure VI-13**. Oil production currently averages 125,000 bbl/day, making the Potiguar Basin Brazil's second largest production area after the offshore Campos Basin. The 5,000 mostly onshore wells have recovered a total of 0.5 billion barrels of oil and 0.5 Tcf of natural gas.[12]

Figure VI-13: Cross-Section of the Potiguar Basin, Showing the Pendência and Alagamar Formations.



Source: ANP, 2003

The Upper Cretaceous (Barremenian) to Paleocene Pendência Formation, a rift sequence, is considered the main petroleum source rock in the Potiguar Basin, containing about 4% TOC of Type I kerogen. The Alagamar Formation contains up to 6% TOC of Types I and II kerogen, but is shallow (<1 km) in the onshore.[13] However, shale resources were not assessed in the Potiguar Basin due to its apparent structural complexity and the lack of available data control on source rock depth, thickness, and thermal maturity.

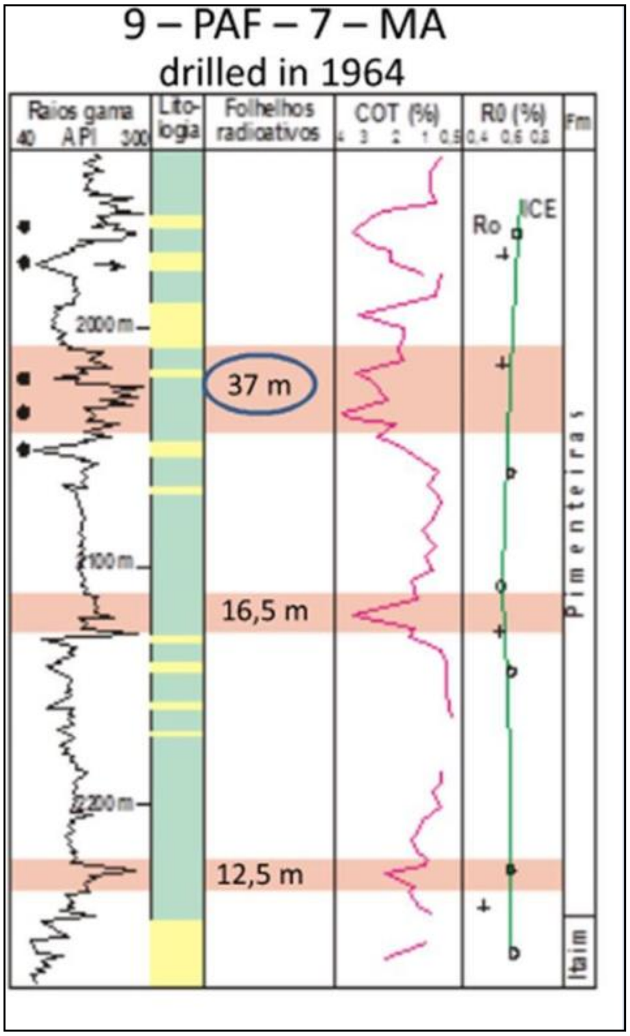
- **Parnaiba Basin.** Also located in northeastern Brazil, this large (600,000-km^2) circular basin contains up to 3.5 km of sedimentary rocks within a relatively simple -- albeit heavily intruded -- structural setting. The Devonian Pimenteiras Formation contains marine black shale up to 300 m thick with 2.0-2.5% TOC. Local independent operator MPX Energia S.A. has reported the company logged gas shows while drilling through a 23-m thick "naturally fractured" Devonian shale interval.[14]

  Figure VI-14 shows the distribution of thickness, depth, TOC, and thermal maturity of the Pimenteiras at a conventional exploration well in an undisclosed portion of the basin. Organic-rich shale in this well totals about 50 m thick at a depth of 2,000 to 2,200 m. The TOC ranges up to 4%, averaging 2.5%, but is thermally immature (R_o ~0.5%) at this location. ANP has projected that thermal maturity reaches oil- and eventually gas-prone levels in the deeper parts of the basin (1,600 to 2,500 m), and estimated 64 Tcf of recoverable shale gas resources, based on analogy with the Barnett Shale play in the Fort Worth Basin.[15]

  However, as just noted available data suggests the Pimenteiras Fm is thermally immature (R_o 0.5%) at a depth of 2,200 m and may only just be entering the oil window at 2,500 m. Other researchers have reported this unit to be thermally immature, apart from local contact zones near the abundant igneous intrusions. Note also that the basin lacks commercial oil and gas production. Given the sparse data available for this study, EIA/ARI did not assess the shale potential of the Parnaiba Basin.

- **Parecis Basin.** A frontier non-productive sedimentary basin in northern Brazil. ANP has noted that radioactive dark shale averages some 50 m thick in the deep basin grabens. As much as 106 m was logged at a depth of 4 km in one conventional petroleum well. ANP recently estimated that 124 Tcf of shale gas may be recoverable based on the Barnett Shale comparison. However, data available to EIA/ARI were not sufficient for assessing the shale potential of the Parecis Basin, which does not produce oil and gas.

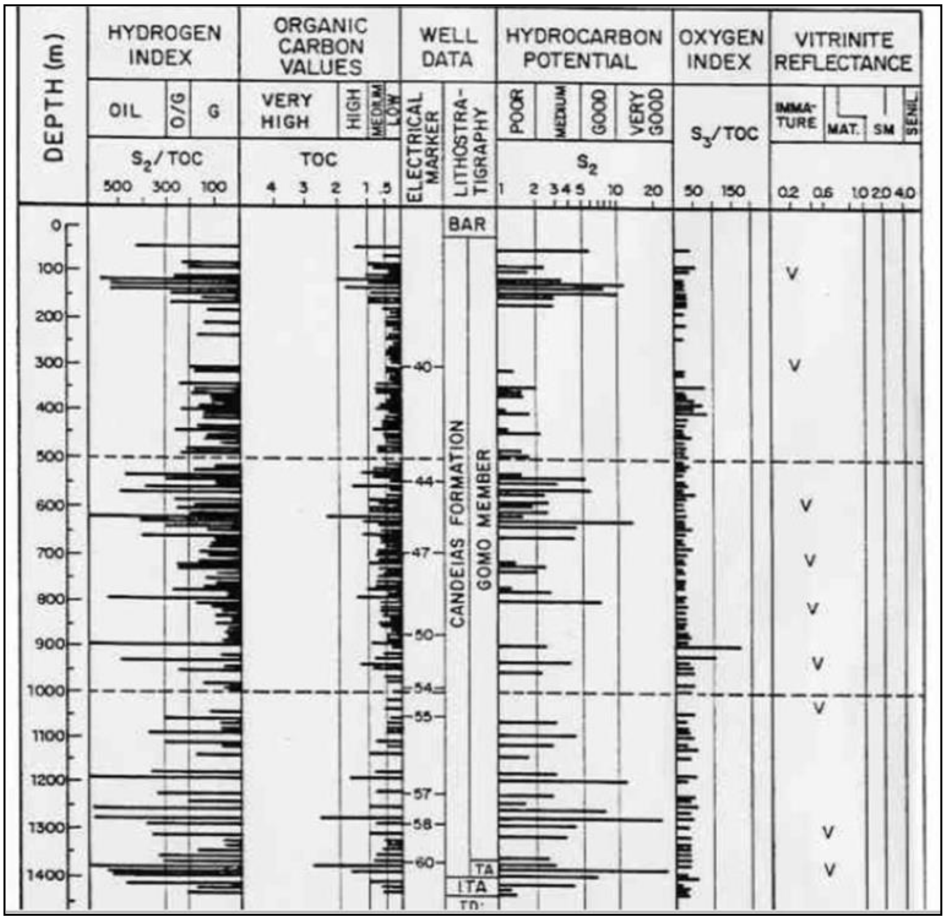
Figure VI-14: Source Rock Thickness, Depth, TOC, and Thermal Maturity of the Pimienta Shale in the Parnaiba Basin



Source: ANP, 2003

- **Recôncavo Basin.** One of many failed rift basins in eastern Brazil, the Recôncavo Basin was the country's first productive petroleum basin. Over 6,000 wells have drilled, of which some 1,800 extent producing wells make 50,000 bbl/day of oil. The Gomo Member of the Lower Cretaceous Candeias Formation, deposited in a lacustrine environment during early rifting, is considered the main source rock.[16] Although quite thick (200-1,000 m), the Gomo Member has relatively low TOC, mostly ranging from 1% to 2%, **Figure VI-15**. ANP recently estimated recoverable shale gas resources in the Recôncavo Basin to be 20 Tcf. However, based on EIA/ARI's screening criteria, the Gomo Member appears to be below the 2% average TOC cutoff and its shale potential was not assessed.

Figure VI-15: The Gomo Member of the Lower Cretaceous Candeias Formation in the Recôncavo Basin can be Thick (>1 km) but is Low in TOC (<2%) and Mostly Thermally Immature (R_o < 0.6%)



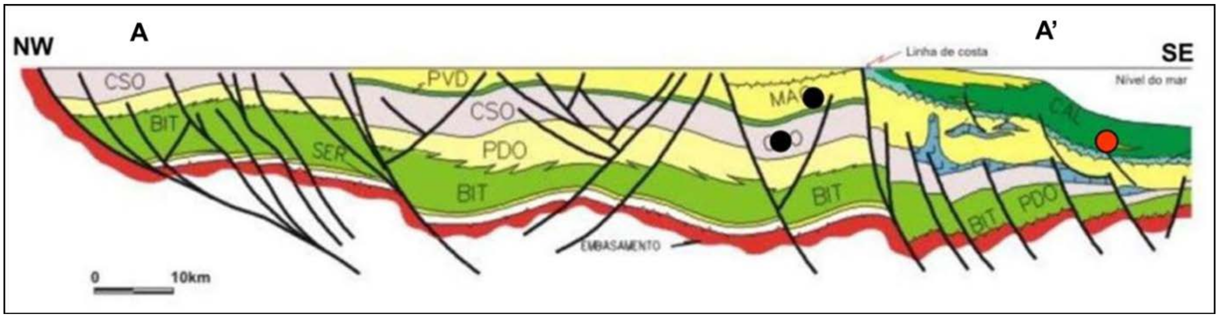
Source: ANP, 2003

- **Sergipe-Alagoas Basin.** Another Neocomian rift basin in northeastern Brazil, the Sergipe-Alagoas Basin extends over an onshore area of 12,600 km^2 as well as a considerably larger area offshore. The basin comprises a number of relatively small, isolated and tilted fault blocks, with major structures trending northeast-southwest, **Figure VI-16**.[17] To date some 57 conventional oil and gas fields have been discovered in the basin, with nearly 5,000 wells drilled, primarily in the onshore portion of the basin. **Figure VI-17** shows a detailed cross-section of the Campo de Pilar Field, showing the numerous closely spaced faults.

The Cretaceous Maceió Formation (Neoaptian) is the main source rock in the Sergipe-Alagoas Basin. The Maceió Fm contains organic-rich black shales, marls and calcilutites that were deposited in a lacustrine, non-marine setting which may exhibit ductile behavior during hydraulic stimulation. The higher-quality source rock shales within the Maceió Fm average about 200 m thick (maximum 700 m) and average 3.5% TOC (maximum 12%; Type II kerogen).[18] However, this basin was not assessed due to its structural complexity and lack of available geologic data.

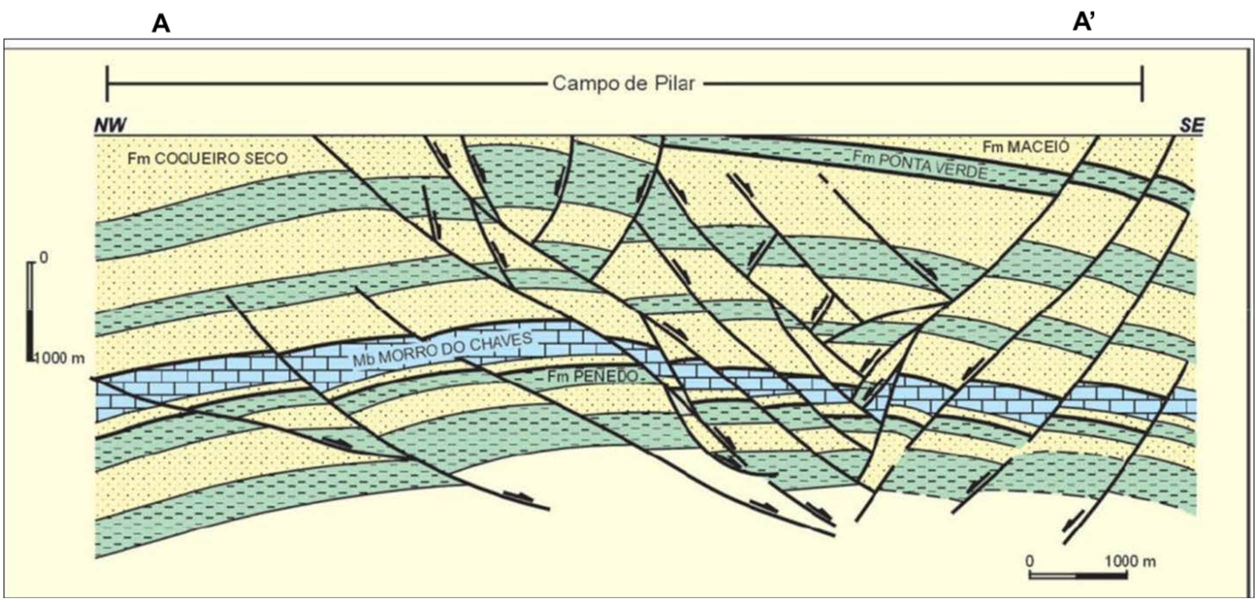
- **São Francisco Basin.** Very little conventional exploration has occurred in this frontier basin in Minas Gerais and there is no significant commercial oil and gas production.[19] Potential source rocks are of Proterozoic age, much older than the productive shales of North America, which are about 400 m thick within a moderately faulted structural setting at depths of 2 to 5 km. Shell reportedly plans to drill its first Brazilian exploration well for unconventional gas in the São Francisco Basin, although this effort appears to be targeting tight sandstone and carbonate formations rather than shale.[20] The São Francisco basin was not assessed by EIA/ARI due to the lack of an established hydrocarbon generation system and the paucity of available geologic data.
- **Taubaté Basin.** Located in southeast Brazil, the Taubaté Basin is a northeast-southwest trending trough related to the Atlantic Ocean continental breakup. The Oligocene Tremembé Formation contains up to 500 m of organic-rich deposits that were deposited within a non-marine lacustrine environment. Within this interval there is a 50-m thick section of laminated black shale with average 10% TOC.[21] However, this deposit is thermally immature oil shale[22] and is not considered prospective for shale gas and oil exploration.
- **Chaco-Paraná Basin.** Not to be confused with the Paraná Basin, the Chaco-Paraná Basin is a large (500,000-km^2) elliptical-shaped depositional feature mainly in northern Argentina, Paraguay and Uruguay. However, only a very small area lies within southern Brazil. The basin contains up to 5 km of early Paleozoic (Ordovician to Devonian) sedimentary and igneous rocks, overlain in the northeast particularly by Cretaceous basalt flows. About 1.2 km of Devonian marine-deposited sandstones (Cabure Formation) and black shales (Rincon Fm) is present. These are overlain by up to 2.3 km of Perm-Carboniferous sandstones and black shales (Sachayoj Fm). The Chaco-Paraná Basin was not assessed due to its small extent and lack of data control within Brazil.

Figure VI-16: Cross-section of the Alagoas Sub-basin, Showing Faulted Pendência and Alagamar Source Rock Shales.



Source: ANP, 2007 (no vertical scale)

Figure VI-17: Detailed Cross-section of the Campo de Pilar Field in the Sergipe-Alagoas Basin, Showing Numerous Closely Spaced Faults.



Source: ANP, 2007

REFERENCES

[1] Neves, A., De Sordi, D., and Egorov, V.I., 2010. "Frontier Basins Onshore Brazil." AAPG Search and Discovery Article #10237, Adapted from oral presentation at American Association of Petroleum Geologists, International Conference and Exhibition, Rio de Janeiro, Brazil, November 15-18, 2009, 16 p.

[2] National Oil and Gas Agency (ANP), "Reservas Brasileiras de Gás Convencional e Potencial Para Gás Não Convencional," undated presentation accessed April 14, 2013.

[3] Amerisur Resources PLC, Investor Presentation, December 2009, 36 p.

[4] Petersohn, E., 2008. "Bid Round 10: Parana Basin." National Oil and Gas Agency (ANP), 59 p.

[5] Milani, E.J. and Zalán, P.V., 1999. "An Outline of the Geology and Petroleum Systems of the Paleozoic Interior Basins of South America." Episodes, vol. 22, p. 199-205.

[6] Vesely, F.F., Rostirolla, S.P., Appi, C.J., Kraft, E.P., 2007. "Late Paleozoic Glacially Related Sandstone Reservoirs in the Parana Basin, Brazil. American Association of Petroleum Geologists, Bulletin, vol. 91, p. 151-160.

[7] Araújo, C.C., Yamamoto, J.K., Rostirolla, S.P., Malagutti, W., Dourado, J.C. and Ferreira, F.J.F., 2003. "An Integrated Analysis of Tar Sand Occurrences in Paraná Basin, Brazil." 8th International Congress of the Brazilian Geophysical Society, Rio de Janeiro, Brazil, 14-18 September 2003.

[8] Amerisur, Investor Presentation, March, 2013, 30 p.

[9] Garcia, G., Araújo, L.M., and Wanderley Filho, J.R., 2013. "Basin Modeling Uncertainties Related to the Hybrid Devonian Petroleum System (Conventional Plus Atypical) of the Solimões Basin (Brazil)." AAPG Search and Discovery Article #120106, Adapted from AAPG Hedberg Conference, Petroleum Systems: Modeling The Past, Planning The Future, 1-5 October 2012, Nice, France, 5 p.

[10] Clark, J., 2003. "Brazil Round 4: Solimões Basin." National Oil and Gas Agency (ANP), 38 p.

[11] Dignart, A. and Vieira, J.R., 2008. "Round 10: Amazonas Basin." National Oil and Gas Agency (ANP), 52 p.

[12] Lovatini, A., Myers, K., Watterson, P., and Campbell, T., 2010. "An Integrated Approach to Exploration Data in the Potiguar Basin, Offshore Brazil." First Break, May, p. 55-59.

[13] de Tarso Araripe, P. 2003. "Brazil Round 4: Potiguar Basin." National Oil and Gas Agency (ANP), 38 p.

[14] MPX Energia S.A., News release, September 2, 2010.

[15] National Oil and Gas Agency (ANP), "Unconventional Hydrocarbons," undated presentation accessed April 13, 2013.

[16] De Tarso Araripe, P., 2003. "Brasil Round 4: Recôncavo Basin." ANP, 54 p.

[17] Fontes, C. and Ranna, R., 20087. "Brazil Round 10: Sergipe-Alagoas Basin." ANP, 70 p.

[18] PGS Reservoirs, 2007. "Competent Person's Report on the Petroleum Interests of Mercury Brazil Ltd, a Wholly Owned Subsidiary of Eromanga Hydrocarbons NL." Prepared for Mercury Brazil Ltd., 51 p.

[19] Clark, J., 2003. "Brazil Round 4: São Francisco Basin." ANP, 38 p.

[20] Orihuela, R., 2013. "Brazil Prepares to Surprise Drillers this Time with Gas." Bloomberg, February 8.

[21] Bergamaschi, S., Rodrigues, R., and Pereira, E., 2010. "Shale from the Tremembé Formation, Taubaté Basin, Brazil." AAPG Search and Discovery Article #80080, Adapted from oral presentation at American Association of Petroleum Geologists, International Conference and Exhibition, Rio de Janeiro, Brazil, November 15-18, 10 p.

[22] Mendonça Filho, J.G., Chagas, R.B.A., Menezes, T.R., Mendonça, J.O., da Silva, F.S., Sabadini-Santos, E., 2010. "Organic Facies of the Oligocene Lacustrine System in the Cenozoic Taubaté Basin, Southern Brazil." International Journal of Coal Geology, vol. 84, p. 166-178.

VII. OTHER SOUTH AMERICA

SUMMARY

Four other countries in South America (Bolivia, Chile, Paraguay, and Uruguay) have prospective shale gas and shale oil potential within marine-deposited Cretaceous and Devonian shale formations in three large basins: the Paraná Basin of Paraguay and Uruguay; the Chaco Basin of Bolivia and Paraguay; and the Magallanes Basin of Chile, Figure VII-1. (Extensions of these basins within neighboring Argentina and Brazil were assessed in separate chapters.)

Figure VII-1: Prospective Shale Gas and Shale Oil Resources in Bolivia, Chile, Paraguay, and Uruguay.

Source: ARI, 2013

Risked, technically recoverable shale gas and shale oil resources in these four other South American countries are estimated at 162 Tcf and 7.2 billion barrels, Tables VII-1 and VII-2. The geologic setting of this region generally is favorably simple, with mostly gentle structural dip and relatively few faults or igneous intrusions (apart from surface basalt flows). Technically recoverable shale resources by country are: Bolivia (36 Tcf; 0.6 billion barrels); Chile (49 Tcf; 2.4 billion barrels); Paraguay (75 Tcf; 3.7 billion barrels); and Uruguay (2 Tcf; 0.6 billion barrels). Initial shale-related leasing and evaluation has been reported in Paraguay and Uruguay within existing conventional petroleum license areas.

Table VII-1A. Shale Gas Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Parana (747,000 mi^2)				
	Shale Formation		Ponta Grossa			Cordobes	
	Geologic Age		Devonian			Devonian	
	Depositional Environment		Marine			Marine	
Physical Extent	Prospective Area (mi^2)		3,830	3,260	2,350	2,690	1,230
	Thickness (ft)	Organically Rich	800	800	800	800	800
		Net	240	240	240	240	240
	Depth (ft)	Interval	10,000 - 11,000	11,000 - 12,000	12,000 - 13,000	3,300 - 5,000	5,000 - 7,000
		Average	10,500	11,500	12,500	4,000	6,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	3.6%	3.6%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas
	GIP Concentration (Bcf/mi^2)		19.9	44.1	71.2	9.7	46.3
	Risked GIP (Tcf)		9.1	17.3	20.1	4.2	9.1
	Risked Recoverable (Tcf)		0.7	3.5	4.0	0.3	1.8

Table VII-1B. Shale Gas Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Chaco (157,000 mi^2)			Austral-Magallanes (65,000 mi^2)		
	Shale Formation		Los Monos			Estratos con Favrella		
	Geologic Age		Devonian			L. Cretaceous		
	Depositional Environment		Marine			Marine		
Physical Extent	Prospective Area (mi^2)		6,870	9,890	14,210	1,580	1,920	1,500
	Thickness (ft)	Organically Rich	1,500	1,500	1,500	800	800	800
		Net	450	450	450	400	400	400
	Depth (ft)	Interval	3,300 - 9,000	7,000 - 12,000	10,000 - 16,400	6,600 - 10,000	10,000 - 14,500	11,500 - 16,400
		Average	7,000	10,000	13,000	8,000	12,000	13,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		2.5%	2.5%	2.5%	3.5%	3.5%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	0.85%	1.15%	1.60%
	Clay Content		Low	Low	Low	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)		27.8	86.8	140.5	32.5	114.8	155.9
	Risked GIP (Tcf)		28.7	128.7	299.5	23.1	99.2	105.2
	Risked Recoverable (Tcf)		2.9	25.7	74.9	2.3	19.8	26.3

Table VII-2A. Shale Oil Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Parana (747,000 mi^2)			
	Shale Formation		Ponta Grossa		Cordobes	
	Geologic Age		Devonian		Devonian	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		3,830	3,260	2,690	1,230
	Thickness (ft)	Organically Rich	800	800	800	800
		Net	240	240	240	240
	Depth (ft)	Interval	10,000 - 11,000	11,000 - 12,000	3,300 - 5,000	5,000 - 7,000
		Average	10,500	11,500	4,000	6,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	3.6%	3.6%
	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/mi^2)		21.8	9.3	27.7	12.0
	Risked OIP (B bbl)		10.0	3.6	11.9	2.4
	Risked Recoverable (B bbl)		0.40	0.15	0.48	0.09

Table VII-2B. Shale Oil Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Chaco (157,000 mi^2)		Austral-Magallanes (65,000 mi^2)	
	Shale Formation		Los Monos		Estratos con Favrella	
	Geologic Age		Devonian		L. Cretaceous	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		6,870	9,890	1,580	1,920
	Thickness (ft)	Organically Rich	1,500	1,500	800	800
		Net	450	450	400	400
	Depth (ft)	Interval	3,300 - 9,000	7,000 - 12,000	6,600 - 10,000	10,000 - 14,500
		Average	7,000	10,000	8,000	12,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		2.5%	2.5%	3.5%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Low	Low	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		46.0	18.7	48.4	14.5
	Risked OIP (B bbl)		47.4	27.7	34.4	12.6
	Risked Recoverable (B bbl)		2.37	1.39	1.72	0.63

INTRODUCTION

This chapter discusses the shale potential of the other countries in South America (Argentina, Brazil, and Colombia-Venezuela are assessed in separate chapters). As first highlighted in EIA/ARI's 2011 assessment, these other South American countries (Bolivia, Chile, Paraguay, and Uruguay) have significant shale gas and oil resource potential in favorable structural settings. Exploration shale drilling has not yet begun in the region although initial shale leasing and evaluation are underway.

Bolivia. A significant natural gas exporter to Argentina and Brazil, Bolivia produces natural gas from conventional reservoirs, mainly in the Chaco Basin in the southeast part of the country. Following 2006 nationalization, YPFB administers investment and production in Bolivia's oil and gas sector, while the Ministry of Hydrocarbons and Energy (MHE) and the National Hydrocarbons Agency establish overall policy. Shale exploration or leasing have not been reported in Bolivia.

Chile. ENAP, the national oil company of Chile, produces about 5,000 bbl/day mainly from conventional reservoirs in the Magallanes basin.[1] In March 2011 ENAP announced that it will require companies bidding for conventional oil and gas exploration blocks to also explore for shale gas. While exploration is underway for tight gas sandstone reservoirs in the basin, no shale-specific exploration has been reported in Chile.

Paraguay. Paraguay does not produce oil and gas, although extensions of its sedimentary basins are productive in both Argentina and Bolivia. Only two conventional petroleum wells have been drilled in Paraguay during the past 25 years. Shale drilling has not occurred in the country but President Energy is investigating the shale potential at its conventional petroleum licenses in the Chaco Basin.

Uruguay. Uruguay also does not produce oil and gas, although extensions of its sedimentary basins are productive in neighboring Brazil and Argentina. ANCAP (Administración Nacional de Combustibles, Alcoholes y Portland), the state-owned oil company in Uruguay, administers the country's petroleum licensing. TOTAL, YPF, and others hold leases in the onshore Paraná Basin and are evaluating the shale potential.

Three major sedimentary basins with prospective organic-rich and marine-deposited black shales are present in Bolivia, Chile, Paraguay, and Uruguay, Figure VII-1. These basins, which were assessed in this chapter, are:

- **Paraná Basin** (Paraguay, Uruguay): The Paraná Basin contains black shale within the Devonian Ponta Grossa Formation. The structural setting is simple but the basin is partly obscured at surface by flood basalts, although this igneous cap is less prevalent here than in the Brazil portion of the basin.
- **Chaco Basin** (Paraguay, Bolivia): Black shale in the Devonian Los Monos Formation is present within a relatively simple structural setting in northwest Paraguay. The shale becomes increasingly deep and thrust faulted in southeast Bolivia, where they source that country's prolific conventional reservoirs.
- **Magallanes Basin** (Chile): Known as the Austral Basin in Argentina, the Magallanes Basin of southern Chile contains marine-deposited black shale in the Lower Cretaceous Estratos con Favrella Formation, considered a major source rock in the basin.

1 PARANÁ BASIN (PARAGUAY, URUGUAY)

1.1 Introduction and Geologic Setting

The Paraná Basin is a large depositional feature in south-central South America. Most of the basin is located in southern Brazil, but there are significant extensions into Paraguay, Uruguay, and northern Argentina, **Figure VII-2**. This section focuses on the Paraguay and Uruguay portions of the basin. The Paraná Basin contains up to 5 km (locally 7 km) of Paleozoic and Mesozoic sedimentary rocks that range from Late Ordovician to Cretaceous. Its western border is defined by the Asuncion Arch, related to Andean thrusting, while the east is truncated by the South Atlantic tectonic margin.[2] 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 Paraguay portion is largely free of basalt.

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.[3]

Figure VII-2: Prospective Shale Gas and Shale Oil Areas in the Paraná Basin of Paraguay and Uruguay

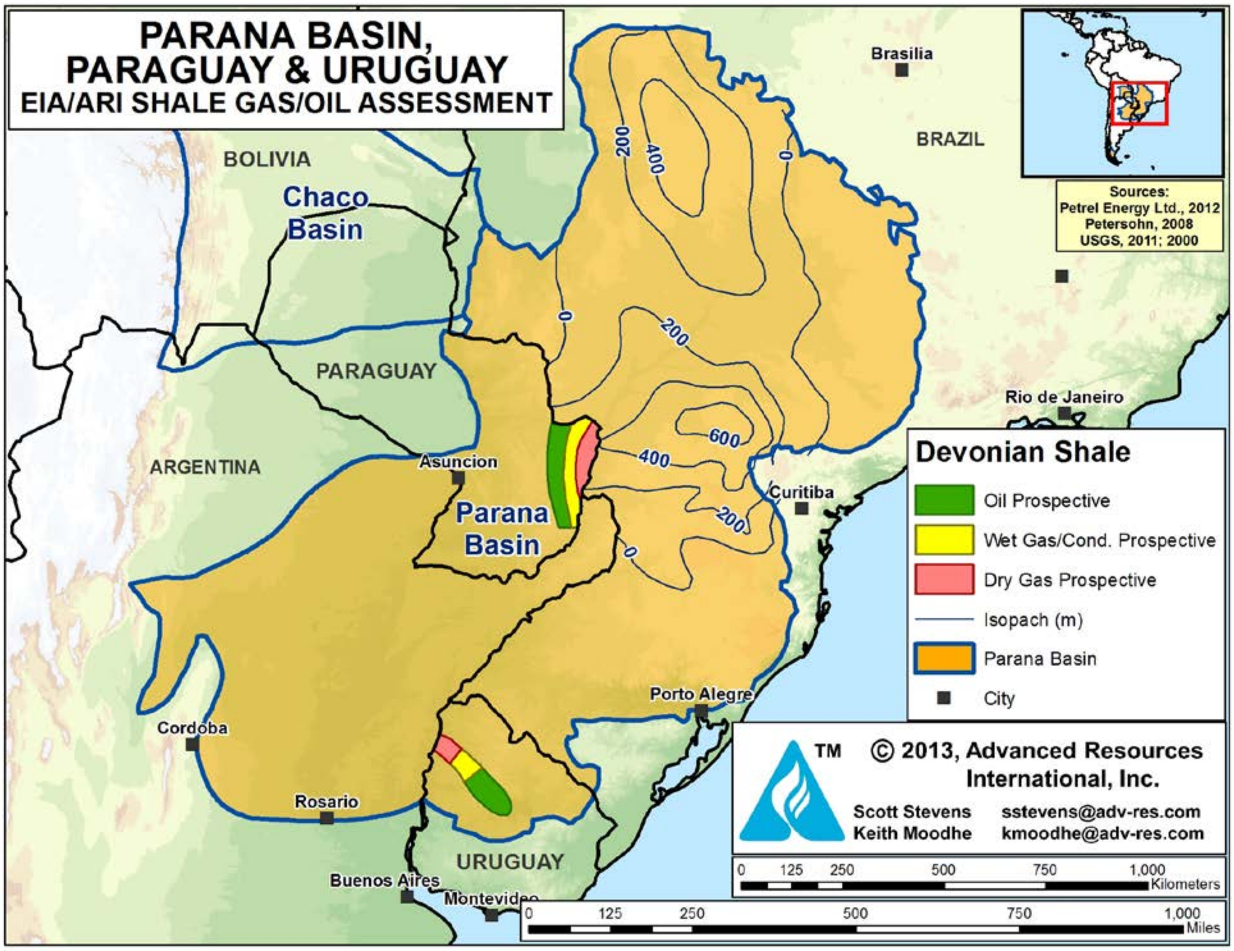
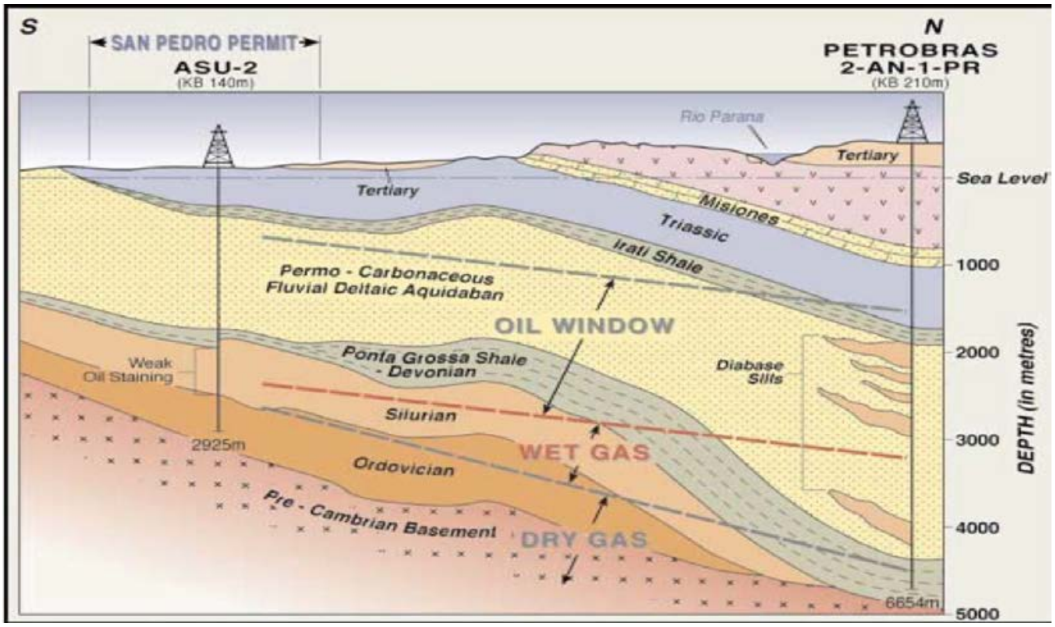


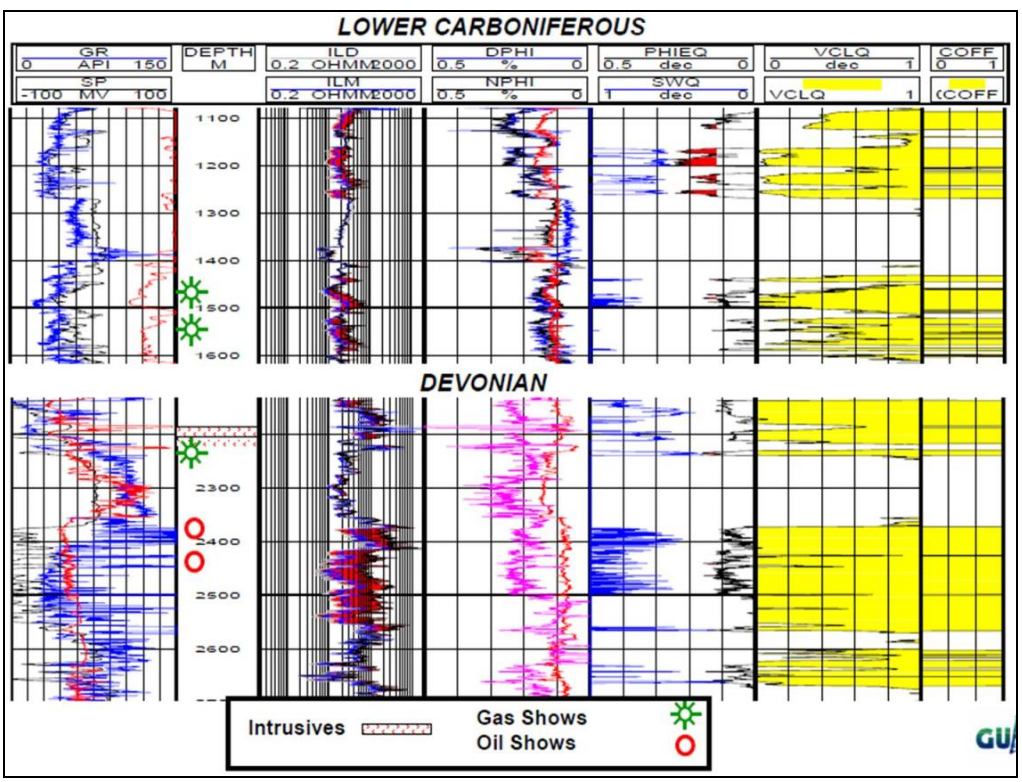
Figure VII-3, a cross-section of the Paraná Basin, illustrates the thick and gently dipping Devonian source rocks that pass through the oil window into the gas window.[4] **Figure VII-4**, a conventional well log in the Paraguay portion of the basin, shows Devonian source rocks and interbedded sandstones with oil and gas shows.[5] 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.[6]

Figure VII-3: 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

Figure VII-4: Asuncion-1 Well Log from the Paraná Basin of Paraguay, Showing Devonian Source Rocks and Interbedded Sandstones with Oil and Gas Shows.



Source: Guapex S.A., 2012

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 deep central portion of the basin.

1.2 Reservoir Properties (Prospective Area)

Depth and thermal maturity of the Devonian Ponta Grossa Formation are relatively well constrained in the Paraguay portion of the Paraná Basin. The prospective area in Paraguay is estimated at 9,440 mi^2, of which 3,830 mi^2 is in the oil window; 3,260 mi^2 is in the wet gas/condensate thermal maturity window; and 2,350 mi^2 is in the dry gas window.

However, Devonian depth and thermal maturity are much less certain in Uruguay. Uruguay's shale-prospective area is estimated at 3,920 mi^2, of which 2,690 mi^2 is in the oil window and 1,230 mi^2 is in the wet gas/condensate thermal maturity window (no evidence the Devonian attains dry-gas thermal maturity in Uruguay). The Ponta Grossa shale averages about 240 m thick (net), 10,500 to 12,500 ft deep in Paraguay but only 4,000 to 6,000 ft deep in Uruguay, and averages 2.0% to 3.6% TOC.

Thermal maturity (R_o) ranges from 0.85% to 1.5% depending mainly on depth. For example, Amerisur reported that the Devonian Lima Fm has good (2-3%) TOC and is oil-prone (R_o 0.87%) at their conventional exploration block. Porosity is estimated at about 4% and the pressure gradient is assumed to be hydrostatic.

1.3 Resource Assessment

Risked, technically recoverable shale gas and oil resources from the Devonian Ponta Grossa Shale in the Paraguay portion of the Paraná Basin are estimated at 8 Tcf of shale gas and 0.6 billion barrels of shale oil and condensate, Tables VII-1 and VII-2. Uruguay has further estimated resources of 2 Tcf of shale gas and 0.6 billion barrels of shale oil and condensate in this play. Risked shale gas and shale oil in-place in Paraguay and Uruguay are estimated at 60 Tcf and 28 billion barrels. The play has low-moderate net resource concentrations of 10 to 71 Bcf/mi^2 for shale gas and 9 to 28 million bbl/mi^2 for shale oil, depending on thermal maturity window.

The USGS recently estimated that Uruguay's portion of the Paraná Basin (Norte Basin) has 13.4 Tcf of shale gas and 0.5 billion barrels of shale oil resources in the Devonian Cordobes Formation. They noted that the sub-basalt extent of inferred deep grabens for their study was imaged by ANCAP using geophysical methods, with no well control.[7] Petrel Energy recently noted that new data indicates the Devonian is less thermally mature than mapped by the USGS.[8] The EIA/ARI thermal windows were adjusted accordingly.

1.4 Recent Activity

TOTAL, YPF, and small Australia-based Petrel Energy hold large exploration licenses with Devonian shale potential in the Uruguay portion of the Paraná Basin (Norte Basin). No shale-focused drilling has occurred in Uruguay, nor has shale leasing or drilling activity been reported in the Paraguay portion of the Paraná Basin.

2 CHACO BASIN (BOLIVIA, PARAGUAY)

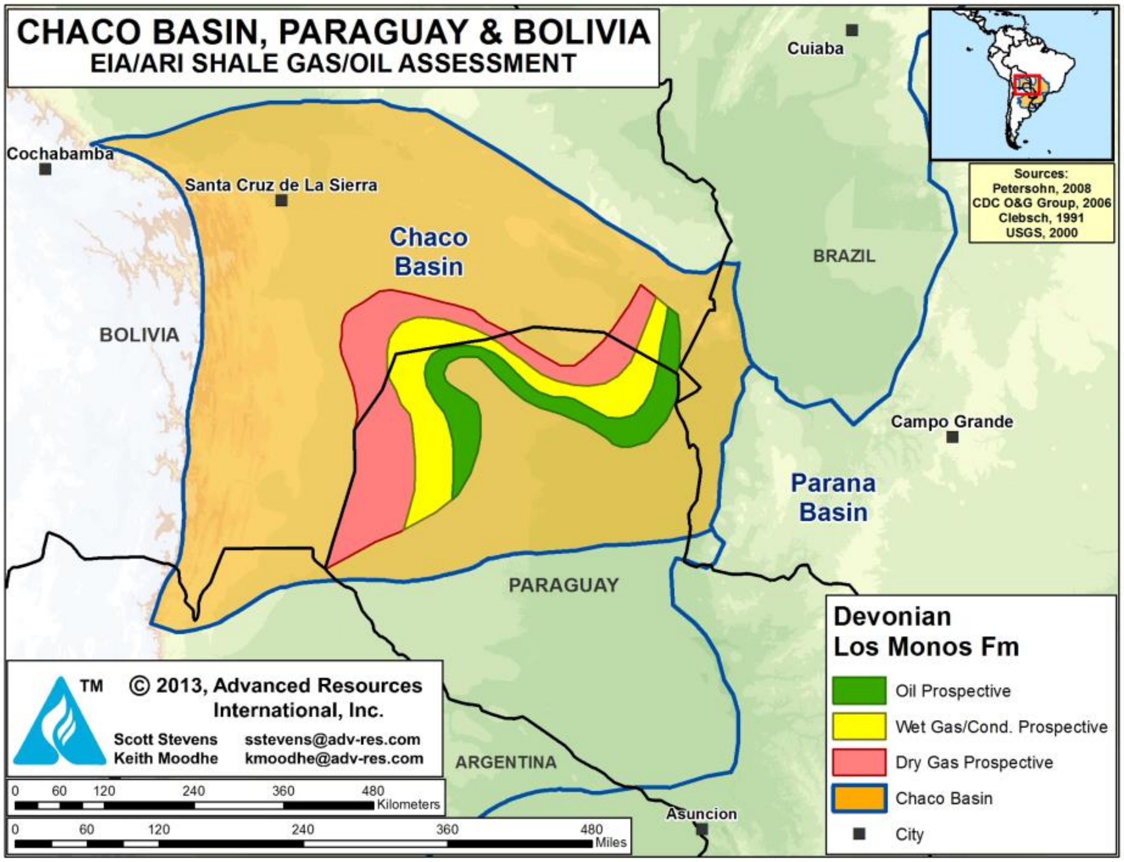
2.1 Introduction and Geologic Setting

The large (157,000-mi^2) Chaco Basin is an intra-cratonic foreland basin broadly similar in origin to the Neuquen and other South American basins east of the Andes Mountains, **Figure VII-5**. The Chaco Basin extends across southeast Bolivia and northwest Paraguay, as well as southern Brazil and northern Argentina (please see separate chapters for these countries). Structural highs (Ascuncion Arch) separate the Chaco Basin from the Parana Basin to the southeast. Structure is relatively simple, with scattered mainly vertical normal faults and none of the thrusting typical of Andean tectonics further to the west.

Sub-basins include the Pirity, Carandayty, and Curupayty troughs. Oil and gas production occurs in Bolivia and Argentina but not in Paraguay, which has experienced much less drilling. Fewer than 10 petroleum wells have been drilled in the Pirity Sub-basin of Paraguay, all pre-1987, where no commercial production has occurred. However, the Argentina portion of the Basin (Olmedo Sub-basin) has produced over 110 million bbls of oil from the Upper Cretaceous Yacoraite and Palmer Largo formations and that basin continues to be productive.[9] Apart from the international border, no geologic discontinuity separates the two sub-basins.

Advanced Resources International, Inc.

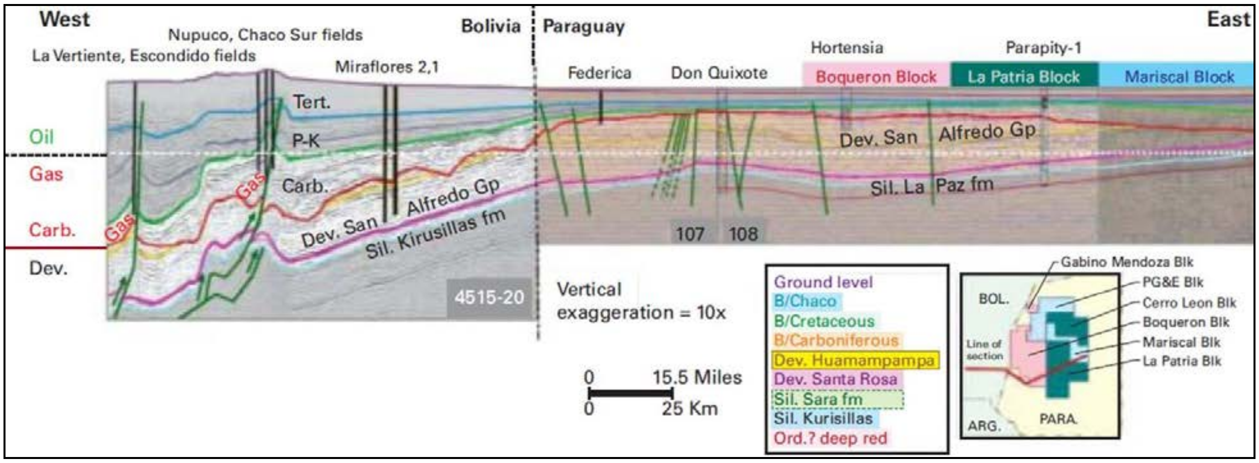
Figure VII-5: Prospective Area of the Devonian Los Monos Formation, Chaco Basin, Paraguay and Bolivia



The main source rocks include the Silurian Kirusillas Formation and the Devonian Los Monos and Icla formations.[10] The Devonian, considered the main source rock for the world-class conventional gas fields in the Tarija Basin foothills of southeast Bolivia, appears to have shale gas potential in northwest Paraguay where structure is considerably simpler, **Figure VII-6**. The gas window in this basin reportedly is at about 2 km depth.

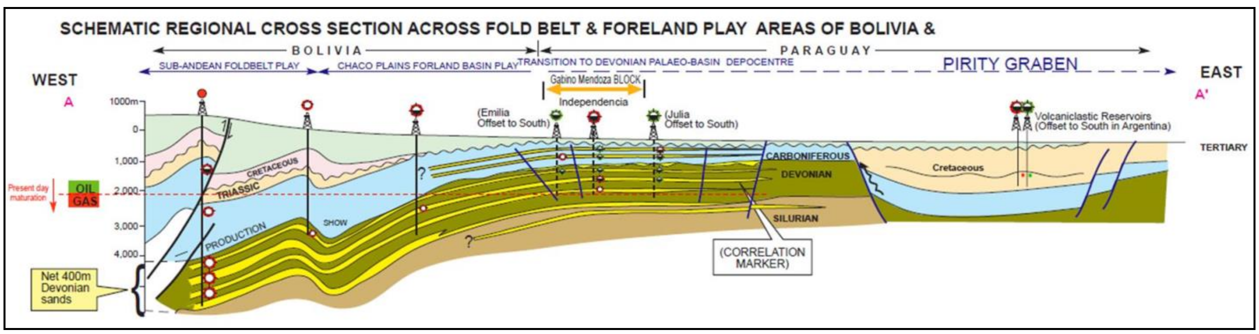
Significant shale gas potential exists within the 8,000- to 12,000-foot thick Devonian Los Monos Formation in the Carandaity and Curupaity sub-basins of Paraguay. The Devonian is exceptionally thick in southern Bolivia but consists mainly of coarse-grained sandstones there. The Devonian is also deeper and structurally more complex in much of Bolivia, **Figure VII-7**. Within the Los Monos, the San Alfredo Shales appear to be most prospective, comprising a lower sandy unit and an upper thick, monotonous black shale that formed under shallow marine conditions.[11] The thickest Devonian section (8,339 feet) penetrated in the Chaco Basin was in the Pure Oil Co. Mendoza-1 well. The Los Monos marine shale accounted for about 8,200 feet of this section.[12]

Figure VII-6: Regional Seismic Time Section Across the Chaco Basin of Bolivia and Paraguay, Showing Thick and Mostly Flat-Lying Silurian and Devonian Source Rocks.



Source: Wade, 2009

Figure VII-7: Regional Cross-Section Across the Chaco Basin of Bolivia and Paraguay, Showing Thick and Mostly Flat-Lying Silurian and Devonian Source Rocks.



Source: CDS Oil and Gas Group, PLC, 2006

Scarce geochemical data suggest 2.5% overall average TOC for the entire Los Monos, but richer zones are likely to be present within this thick and poorly documented unit. An exploration well in the Curupaity sub-basin measured up to 2.1% TOC in the Los Monos. Independent E&P Amerisur reports TOC of 1.44% to 1.86% in the Devonian Los Monos Fm in the Curupaity sub-basin.[13] Depth to the Los Monos Shale can exceed 10,000 feet (3,000 m) in deep synclines such as the San Pedro Trough.[14,15] Structural uplifts within the Chaco Basin have high geothermal gradients and are gas-prone.

Another potential source rock is the Puesto Guardian Member in the lower portion of the U. Cretaceous Yacoraite Formation. The Puesto Guardian reportedly contains about 78 m of black shale within a 6,000-km^2 area of the Pirity Sub-basin of the Cretaceous Basin.[16] TOC is up to 12%, consisting of Type II / III amorphous and algal kerogen that was deposited in lacustrine to restricted marine environments. Peak hydrocarbon maturation and charge is estimated to have occurred 34-40 million years ago, with current maturity in the oil window. However, the potential of the Cretaceous shale was not assessed due to insufficient geologic control.

2.2 Reservoir Properties (Prospective Area)

The Devonian Los Monos Formation is exceptionally thick (as much as 12,000 feet) in the Chaco Basin, of which 2,000 feet (San Alfredo Shales) was conservatively assumed to be organic-rich. Faulting is not extensive, thus relatively little area is sterilized due to structural complexity.

The shale matrix reportedly consists primarily of brittle minerals such as calcite, dolomite, albite feldspar, ankerite, quartz as well as significant rutile and pyrite. Some clay is present -- mainly illite, kaolinite and chlorite – but is considered “less common.”[17] Temperature gradients range from elevated 1.9°F/100 feet on structural highs to 1.0°F/100 feet in the Carandaity sub-basin.

Depth and thermal maturity of the Devonian Los Monos Formation are relatively well constrained in the Paraguay portion of the Chaco Basin. The prospective area in Paraguay is estimated at 22,210 mi^2, of which 6,200 mi^2 is in the oil window; 7,450 mi^2 is in the wet gas/condensate thermal maturity window; and 8,560 mi^2 is in the dry gas window. An additional 8,760 mi^2 is prospective in Bolivia, of which 670 mi^2 is in the oil window; 2,440 mi^2 is in the wet gas/condensate thermal maturity window; and 5,650 mi^2 is in the dry gas window.

2.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from the Devonian Los Monos black shale in the Paraguay portion of the Chaco Basin are estimated at 67 Tcf of shale gas and 3.2 billion barrels of shale oil and condensate, Tables VII-1 and VII-2. Bolivia has further estimated resources of 37 Tcf of shale gas and 0.6 billion barrels of shale oil and condensate. Risked shale gas and shale oil in-place are estimated at 457 Tcf of shale gas and 75 billion barrels of shale oil for the two countries. The play has moderate to high net resource concentrations of 28 to 141 Bcf/mi^2 for shale gas and 19 to 46 million bbl/mi^2 for shale oil, depending on thermal maturity window.

2.4 Recent Activity

Initial shale evaluation is occurring on existing conventional petroleum exploration leases in the Chaco Basin, but no shale-specific drilling or testing has occurred yet. President Energy PLC (UK) holds eight conventional petroleum exploration licenses which it considers to have shale gas/oil potential.

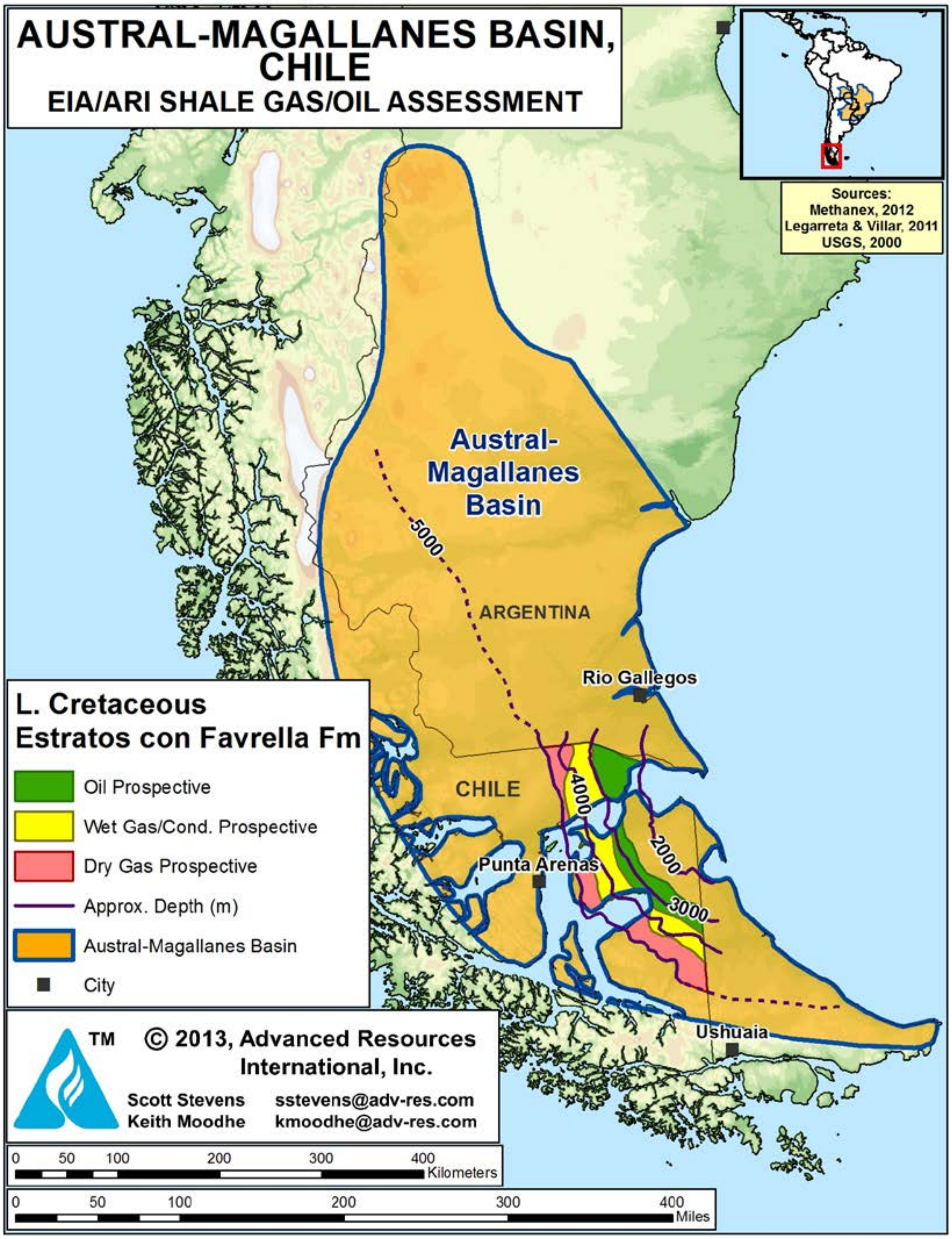
3 MAGALLANES BASIN (CHILE)

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 VII-8**. While most of the basin is in Argentina, where it is called the Austral Basin, a portion of the basin is located in Chile's Tierra del Fuego region, where it is referred to as the Magallanes Basin. The Chile portion of the basin, which started producing conventional natural gas over 60 years ago, currently accounts for most of that country's oil and gas output, produced primarily from deltaic to fluvial sandstones in the Early Cretaceous Springhill Formation at depths of about 6,000 feet.

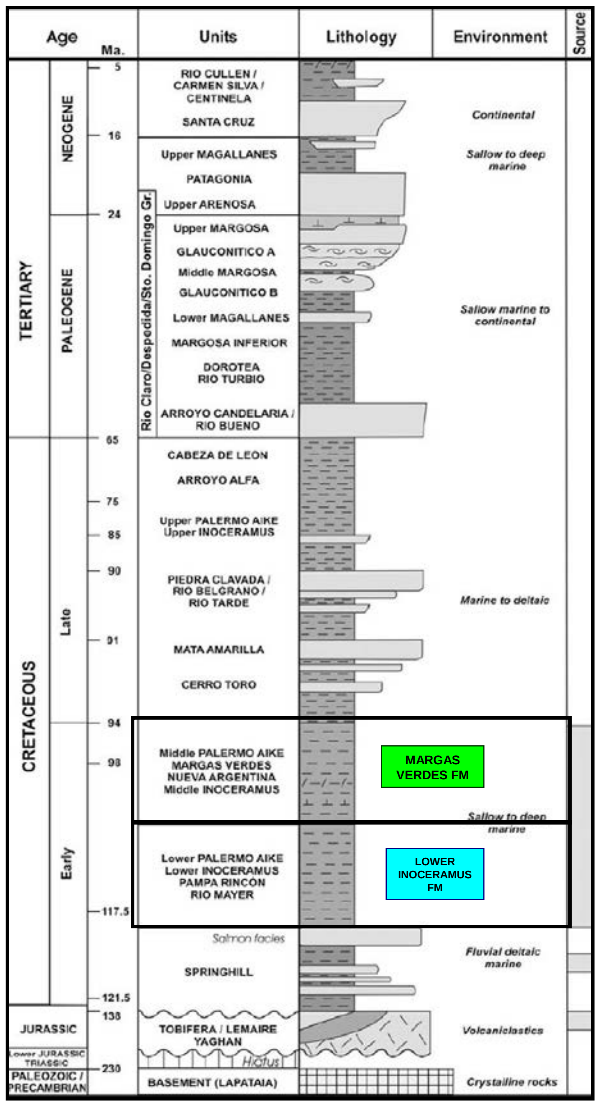
The Magallanes Basin comprises two main structural regions: a normal faulted eastern region and a thrust faulted western area. The basin contains a thick sequence of Upper Cretaceous and Tertiary sedimentary and volcaniclastic rocks which unconformably overlie deformed metamorphic basement of Paleozoic age. Total sediment thickness ranges from 3,000 to 6,000 feet along the eastern coast to a maximum 25,000 feet along the basin axis. Jurassic and Lower Cretaceous petroleum source rocks are present at moderate depths of 6,000 to 10,000 feet across large areas.[18] The overlying Cretaceous section comprises mainly deepwater turbidite clastic deposits up to 4 km thick, which appear to lack shale gas and oil potential.[19]

Figure VII-8: Prospective Area of the L. Cretaceous Estratos con Favrella Formation, Magallanes Basin, Chile



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, Figure VII-9. 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.[20] The mid-lower Jurassic Tobifera Formation contains 1% to 3% TOC (maximum 10% in coaly shales), consisting of Types I to III kerogen. However, this unit is mainly coaly and probably insufficiently brittle for shale exploration.

Figure VII-9: Stratigraphy of the Austral-Magallanes Basin, Argentina and Chile



Source: Rossello et al., 2008

Advanced Resources International, Inc.

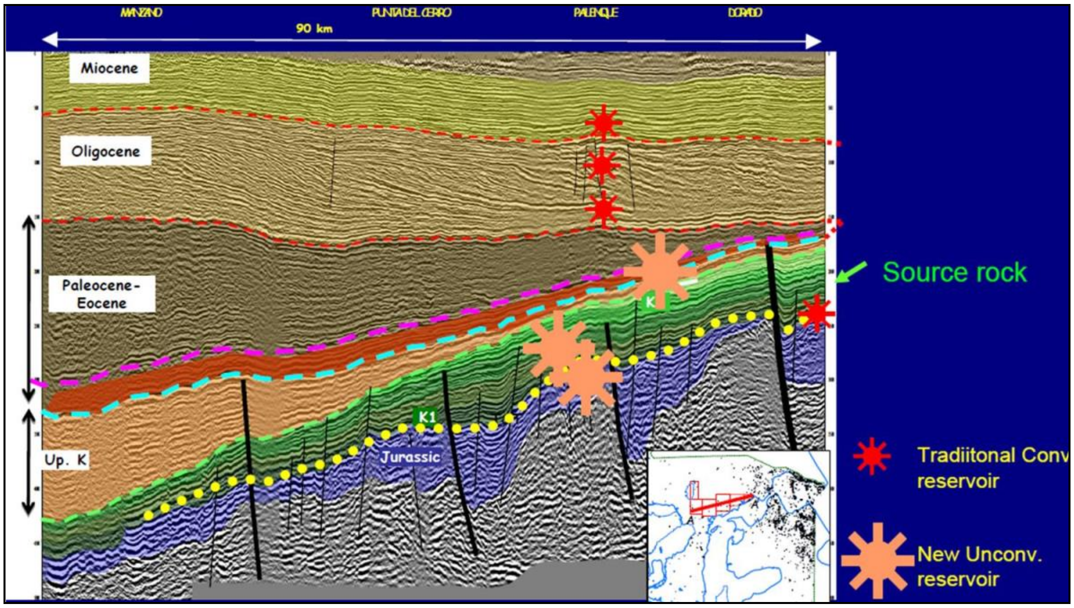
Overlying the Tobifera Fm are more prospective shales within the Early Cretaceous Estratos con Favrella Formation (or Lower Inoceramus or Palermo Aike in Argentina), deposited under shallow water marine conditions. The Lower Inoceramus Formation is 50 to 400 m thick. In the Argentina portion of the basin, the total shale thickness (including the Magnas Verdes Formation) ranges from 800 feet thick in the north to 4,000 feet thick in the south, representing neritic facies deposited in a low-energy and anoxic environment.[21] Total organic content of these two main source rocks have been reported to range from 1.0% to 2.0%, with hydrogen index of 150 to 550 mg/g.[22] More recent analysis conducted by Chesapeake Energy of the Lower Cretaceous Estratos con Favrella Formation in Chile indicates this unit contains marine-deposited shale with consistently good to excellent (up to 6%) TOC, particularly near its base.[23]

Figure VII-10, 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. Net organic-rich shale thickness was estimated by ENAP to be only 40 to 120 ft, although this appears conservative and we assumed 280 net ft. ENAP also 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.[24]

3.2 Reservoir Properties (Prospective Area)

Chile's portion of the Magallanes Basin has an estimated 5,000-mi^2 prospective area with organic-rich shale in the Estratos con Favrella and adjoining Lower Cretaceous formations. Of this total prospective area, about 1,580 mi^2 is in the oil window; 1,920 mi^2 is in the wet gas/condensate thermal maturity window; and 1,500 mi^2 is in the dry gas window. The Estratos con Favrella and adjoining 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 Fm, immediately underlying the Lower Inoceramus equivalent.[25]

Figure VII- 10: Seismic Time Section Across the Magallanes Basin, Showing Marine Source Rock Shales in the 180-m Thick L. Cretaceous Estratos con Favrella Formation within a Relatively Simple Structural Setting.



Source: Methanex, September 27, 2012

3.3 Resource Assessment

Risked, technically recoverable shale gas and oil resources from the Estratos con Favrella and adjoining Lower Cretaceous formations in the Chile portion of the Magallanes Basin are estimated at 48 Tcf of shale gas and 2.4 billion barrels of shale oil and condensate, Tables VII-1 and VII-2. Risked shale gas and shale oil in-place are estimated at 228 Tcf and 47 billion barrels, respectively. The play has moderate to high net resource concentrations of 33 to 156 Bcf/mi^2 for shale gas and 15 to 48 million bbl/mi^2 for shale oil, depending on thermal maturity window.

3.4 Recent Activity

No shale leasing or exploration activity has been reported in the Magallanes Basin. Methanex operates a methanol manufacturing plant in the basin which is running at about 10% of its 2 million t/year capacity due to local shortages of natural gas supply.[26] During 2011-2, Methanex had partnered with ENAP on conventional oil and gas exploration in the Magallanes Basin and also had expressed interest in shale gas exploration. However, recently the company decided to relocate about half of its methanol production capacity in Chile to Louisiana, USA.[27]

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.[28]

REFERENCES

[1] ENAP (Empresa Nacional del Petróleo), 4Q 2012 Results, April 2013, Santiago, Chile, 28 p.

[2] Milani, E.J. and Zalán, P.V., 1999. "An Outline of the Geology and Petroleum Systems of the Paleozoic Interior Basins of South America." Episodes, vol. 22, p. 199-205.

[3] Vesely, F.F., Rostirolla, S.P., Appi, C.J., Kraft, E.P., 2007. "Late Paleozoic Glacially Related Sandstone Reservoirs in the Parana Basin, Brazil. American Association of Petroleum Geologists, Bulletin, vol. 91, p. 151-160.

[4] Chaco Resources PLC, 2004. "Proposed Acquisition of Amerisur S.A. and Bohemia S.A., Notice of Extraordinary General Meeting." 83 p.

[5] Guapex S.A., 2012. "Unconventional Gas in Paraguay." 21 p.

[6] US Geological Survey, 2011. "Assessment of Potential Shale Gas and Shale Oil Resources of the Norte Basin, Uruguay, 2011." 2 p.

[7] US Geological Survey, 2011. "Assessment of Potential Shale Gas and Shale Oil Resources of the Norte Basin, Uruguay, 2011." 2 p.

[8] Petrel Energy Limited, Investor Presentation, November 2012, 22 p.

[9] President Energy PLC, Resource Evaluation prepared by DeGoyler and MacNaughton, December 15, 2012, 27 p.

[10] Wade, J., 2009. "Nonproducing Paraguay's Potential Conventional and Unconventional." Oil and Gas Journal, April 6, p. 39-42.

[11] Petzet, A., 1997. "Nonproducing Paraguay to get Rare Wildcats." Oil and Gas Journal, April 21.

[12] Wiens, F., 1995. "Phanerozoic Tectonics and Sedimentation in the Chaco Basin of Paraguay, with Comments on Hydrocarbon Potential." In A. J. Tankard, R. Suarez S., and H. J. Welsink, eds., Petroleum Basins of South America. American Association of Petroleum Geologists Memoir 62, p. 185-205.

[13] Amerisur Resources PLC, 2009. Interim Results Presentation, December, 36 p.

[14] Kuhn, C.A.C., 1991. "The Geological Evolution of the Paraguayan Chaco." Ph.D. dissertation, Texas Tech.

[15] Grupo Montecristo, 2012. "Unconventional Gas in Paraguay." 21 p.

[16] President Energy PLC, Investor Presentation, January 2013, 32 p.

[17] Kern, M., Machado, G., Franco, N., Mexias, A., Vargas T., Costa, J., and Kalkreuth, W. 2004. "Source Rock Characterization of Paraná Basin, Brazil: Sem and XRD Study of Irati and Ponta Grossa Formations Samples." 3° Congresso Brasileiro de P&D em Petróleo e Gás, 2 a 5 de outubro de 2005, Salvador, Brasil.

[18] Rodriquez, J. and Cagnolatti, M.J., 2008. "Source Rocks and Paleogeography, Austral Basin, Argentina." American Association of Petroleum Geologists, Search and Discovery Article #10173, 24 p.

[19] Romans, B.W., Fildani, A., Hubbard, S.M., Covault, J.A., Fosdick, J.C., and Graham, S.A., 2011. "Evolution of Deep-water Stratigraphic Architecture, Magallanes Basin, Chile." Marine and Petroleum Geology, vol. 28, p. 612-628.

[20] Fildani, A. and Hessler, A.M., 2005. "Stratigraphic Record Across a Retroarc Basin Inversion: Rocas Verdes–Magallanes Basin, Patagonian Andes, Chile." Geological Society of America, vol. 117, p. 1596-1614.

[21] Ramos, V.A., 1989. "Andean Foothills Structures in Northern Magallanes Basin, Argentina." American Association of Petroleum Geologists, Bulletin, vol. 73, no. 7, p. 887-903.

[22] Pittion, J.L. and Arbe, H.A., 1999. "Sistemes Petroleros de la Cuenca Austral." IV Congreso Exploracion y Desarrollo de Hidrocarburos, Mar del Plata, Argentina, Actas I, p. 239-262.

[23] Methanex, Investor Presentation, September 27, 2012, 129 p.

[24] Legarreta, L. and Villar, H.J., 2011. "Geological and Geochemical Keys of the Potential Shale Resources, Argentina Basins." American Association of Petroleum Geologists, Search and Discovery Article, Adapted from AAPG Geoscience Technology Workshop, "Unconventional Resources: Basics, Challenges, and Opportunities for New Frontier Plays," Buenos Aires, Argentina, June 26-28, 2011.

[25] Venara, L., Chambi, G.B., Cremonini, A., Limeres, M., and Dos Lagunas, E., 2009. "Producing Gas And Condensate From a Volcanic Rock In The Argentinean Austral Basin." 24th World Gas Congress, 5-9 October, Buenos Aires, Argentina.

[26] Methanex, Investor Presentation, March 2013, 37 p.

[27] Methanex, news release, April 2013.

[28] GeoPark Holdings Limited, "Second Quarter 2012 Operations Update," July 23, 2012, 6 p.