Research Square

Preprints are preliminary reports that have not undergone peer review.
They should not be considered conclusive, used to inform clinical practice,
or referenced by the media as validated information.

Integrated Petrophysical Workflow and Recovery Factor Index for Unconventional Resource Assessment of the Lower Napo Shale, Oriente Basin, Ecuador

Hector Santiago Moran Otoya

hsmoranotoya1@mail.austral.edu.ar

Austral University

Luis Stinco

Austral University

Research Article

Keywords: Oriente Basin, shale oil, unconventional resources, petrophysics, recovery factor index, resource assessment.

Posted Date: November 9th, 2026

DOI: https://doi.org/10.21203/rs.3.rs-11414359/v1

License: This work is licensed under a Creative Commons Attribution 4.0 International License.
Read Full License

Additional Declarations:
No competing interests reported.

Tables 16 is not available with this version

Manuscript ID:

Integrated Petrophysical Workflow and Recovery Factor Index for Unconventional Resource Assessment of the Lower Napo Shale, Oriente Basin, Ecuador

Héctor Morán[1]*, Luis Stinco[2], Silvia Barredo[3], Jorge Bravo[4]

[1] ingeniería, Universidad Austral, Buenos Aires, Pilar, Argentina.
[2] Instituto de Energía, Universidad Austral, Buenos Aires, Pilar, Argentina.
[3] Universidad de Buenos Aires, Buenos Aires, CABA, Argentina. Instituto de Energía, Universidad Austral, Buenos Aires, Pilar, Argentina.
4 Empresa Pública Petroecuador, Gerencia de Optimización. Petrophysical, Quito, Ecuador.
*Corresponding author; email: hsmoranotoya1@mail.austral.edu.ar

Supplementary Material is available in support of this paper.

ABSTRACT

The progressive decline of conventional hydrocarbon reserves and the increasing importance of unconventional resources have intensified interest in shale oil assessment worldwide. Ecuador's Oriente Basin, historically recognized as the country's principal conventional oil-producing province, contains several organic-rich intervals with potential for unconventional hydrocarbon development. This study presents an integrated geological and petrophysical evaluation of the Lower Napo Shale within the central structural domain of the Oriente Basin with the objective of identifying prospective unconventional fairways, estimating shale oil resources, and reducing uncertainty associated with recovery-factor selection. The study area focuses on the Sacha–Shushufindi corridor, which represents the principal hydrocarbon generation kitchen of the basin and is characterized by favorable thermal maturity conditions and the occurrence of Type II kerogen. More than 27 wells were evaluated using wireline logs processed with Interactive Petrophysics (IP) software, integrating stratigraphic interpretation, thermal maturity analysis, geochemical analogs, and quantitative petrophysical characterization. Geological screening included gamma-ray response, resistivity, total organic carbon (TOC), vitrinite reflectance (Ro), shale thickness, porosity, and hydrocarbon saturation.

Results indicate that the Lower Napo Shale exhibits gamma-ray values between 150 and 190 API, suggesting TOC values greater than 2%, while resistivity values exceeding 15 ohm-m indicate favorable hydrocarbon retention. Thermal maturity analysis demonstrates that the central domain lies within the oil generation window, with Ro values ranging from 0.7% to 1.0%, burial temperatures near 128 °C, and heat-flow values exceeding 58 mW/m². Detailed petrophysical evaluation of four representative wells from the Sacha Field yielded average effective porosity of 15.9%, hydrocarbon saturation of 54.3%, and net shale thickness of approximately 60 ft. The prospective area was delineated over approximately 4,000 km² within the central domain of the basin.

Volumetric calculations yielded an estimated Original Oil in Place (OOIP) of 33.89 × 10^9 bbl. Applying the Petroleum Resources Management System (PRMS) methodology and recovery factors derived from analog shale developments, technically recoverable prospective resources were estimated at 2.37 × 10^9 bbl under the P50 scenario. To address uncertainty associated with recovery-factor selection in the absence of representative PVT data and production history, a Recovery Factor Index (RFI) was developed integrating geological quality, petrophysical properties, drilling efficiency, and hydraulic-fracturing effectiveness. Application of the proposed methodology resulted in a Recovery Factor Risk Index (RFRI) of 0.845, corresponding to an estimated recovery factor of 8.45% and technically recoverable resources of 2.86 × 10^9 bbl.

The results indicate that the Lower Napo Shale constitutes one of the most promising unconventional oil opportunities identified in Ecuador. Furthermore, the proposed RFI framework provides a transparent and reproducible methodology for estimating recovery efficiency in frontier unconventional plays where production history and representative fluid-property data are unavailable. The approach therefore represents a practical contribution to unconventional resource assessment and offers a complementary tool for reducing uncertainty during the early stages of shale resource evaluation

*Shale volumes correspond to technically recoverable resources, while conventional volumes represent proven reserves.

Keywords

Oriente Basin; shale oil; unconventional resources; petrophysics; recovery factor index; resource assessment.

1. Introduction

Fossil hydrocarbons account for approximately 82% of global primary energy consumption (Energy Institute, 2023). However, most conventional reservoirs are currently in a mature stage, which increases production costs due to produced-water management, as well as multiple workovers aimed at maintaining the production rates. In this context, the search for hydrocarbons to meet global energy demand has become a critical task for petroleum engineers.

Thanks to advances in technology through the application of geosciences and engineering, it has been possible to produce from unconventional reservoirs, which has helped meet global oil and gas demand. According to multiple global assessments (EIA, 2013; SPE, 2018), unconventional resources are estimated to exceed conventional hydrocarbon reserves.

Estimation of hydrocarbon resources by reservoir type		
Types of Reservoirs	**Reserve Estimation**	**Unit of Measure**
Shale Gas	2 775 862	MMboe*
Proven gas reserves	32 241	MMboe
Shale Oil	2 800 000	MMboe
Proven oil reserves	1 383 000	MMboe

Table 1—Comparison between resource and reserve volumes (averaged values from various sources).

*MMboe: Million barrels of oil equivalent.

(EIA,2012; SPE,2018)

Given this background, it is necessary to sustain exploration and production of new prospects to meet the global energy demand. Hydrocarbons are essential for supporting several sectors of the economy such as transportation, industry, power generation, and as feedstock for petrochemicals. Natural gas is also considered a vital resource for the energy transition and to produce clean fuels such as hydrogen.

Ecuador, a country with approximately 17 million inhabitants, currently maintains a daily oil production of 500,000 barrels per day. Its main source of foreign exchange is the export of crude oil. The country's primary energy matrix depends heavily on crude, accounting for more than 90%. For this reason, exploring potential hydrocarbons represents a priority for the nation's energy security, where unconventional reservoirs may provide an opportunity to contribute to the national economy, strengthen energy management, and even generate resources for investment in new types of energy.

As shown in Table 1, shale-type hydrocarbon reserves surpass conventional reserves. However, producing them represents significant economic, technological, and engineering challenges. The latter involves the application of multiple geoscientific and mechanical disciplines, which requires a thorough analysis of the petrophysical properties of the rocks to determine the most effective development strategy.

Shale reservoirs are characterized by low permeability and high heterogeneity, which makes reservoir modeling difficult. The production of this type of resource requires hydraulic fracturing to generate a fracture network at multiple scales. This process involves injecting large volumes of water, which may cause formation damage by affecting the relative permeability to hydrocarbons.

2. Methodology

The shale resource assessment was performed following the workflow proposed by the U.S. Energy Information Administration (EIA 2013). The evaluation consisted of seven sequential stages designed to identify, characterize, and quantify unconventional hydrocarbon resources within the Oriente Basin.

Step 1. Data compilation and integration

Available geological, geophysical, petrophysical, geochemical, and engineering information was compiled and integrated. The dataset included well logs, core descriptions, laboratory analyses, seismic interpretation, published geological studies, and regional structural information.

Step 2. Shale interval identification and characterization

Potential shale formations were identified and characterized using source-rock and reservoir parameters. The evaluation included:

- Total Organic Carbon (TOC);
- Kerogen type;
- Thermal maturity indicators (Ro and Tmax);
- Net reservoir thickness;
- Burial depth;
- Mineralogical composition;
- Reservoir quality indicators.
- Only formations exhibiting favorable conditions for hydrocarbon generation and storage were selected for subsequent analysis.

Step 3. Delineation of prospective areas

Prospective areas were delineated through the integration of geological, geochemical, and petrophysical information. The screening process considered organic richness, maturity level, reservoir continuity, thickness distribution, and depth intervals suitable for unconventional development.

The resulting prospective areas represent sectors with the highest potential for shale oil and shale gas accumulation.

Step 4. Estimation of hydrocarbons in place

Hydrocarbons in place were estimated to be using standard volumetric procedures adapted for unconventional reservoirs. For shale oil formations, the assessment incorporated prospective area, effective reservoir thickness, porosity, and hydrocarbon saturation. For shale gas formations, both free gas contained within pore spaces and fractures, and adsorbed gas associated with organic matter, were considered.

Input parameters were derived from subsurface data, laboratory measurements, and analog reservoirs when direct information was unavailable.

Step 5. Technical feasibility assessment

Prospective areas were subjected to technical screening to evaluate development feasibility. The assessment included:

- Reservoir heterogeneity;
- Structural complexity;
- Geomechanical properties.
- Brittleness characteristics.
- Infrastructure availability.
- Accessibility and operational constraints.

Areas exhibiting unfavorable technical conditions were excluded from the final resource assessment.

Step 6. Recovery factor assignment and resource estimation

Recovery factors were assigned based on reservoir characteristics and analog shale developments with comparable geological conditions. Published recovery efficiencies from developed unconventional plays were used as reference values.

Technically recoverable resources were subsequently estimated by applying the selected recovery factors to the hydrocarbons initially in place.

Step 7. Uncertainty analysis

Uncertainty associated with the resource estimates was evaluated through sensitivity analyses of the principal geological and reservoir parameters. Alternative low, base, and high scenarios were generated to quantify the range of possible outcomes and to assess the impact of parameter variability on the final resource estimates.

2.1. Conducting Preliminary Geologic and Reservoir Characterization of Shale Basins and Formation(s).

The resource assessment begins with the analysis of the basin based on available studies related to unconventional resources in the Oriente Basin because this basin currently produces only conventional oil; therefore, information on unconventional resources is limited, all studies: logs, cores are relationship with conventional production.

Preliminary geological and reservoir data are systematically compiled for each major shale basin and formation in order to support probabilistic evaluation. This process involves the integration of multidisciplinary information that allows for the characterization of the resource potential and associated uncertainties. Key data elements include stratigraphic framework:

- Depositional environment of shale (marine vs non-marine)
- Depth (to top and base of shale interval)
- Gross shale interval
- Organically rich gross and net shale thickness
- Total organic content (TOC, by wt.)
- Thermal maturity (Ro)

These geologic and reservoir properties are used to provide a first order overview of the geologic characteristics of the major shale gas and shale oil formations and to help select the shale gas and shale oil basins and formations deemed worthy of more intensive assessment.

In Fig. 1, the most mature areas can be observed, with equivalent vitrinite reflectance (Roeq) values of approximately 1% in the central domain. This domain includes the Auca, Sacha, and Libertador fields, indicating rocks with favorable maturity conditions for hydrocarbon generation in the shaly facies of the Napo Group. Therefore, the challenge lies in evaluating this group to identify the stratigraphic interval with the probability of economically producing hydrocarbons

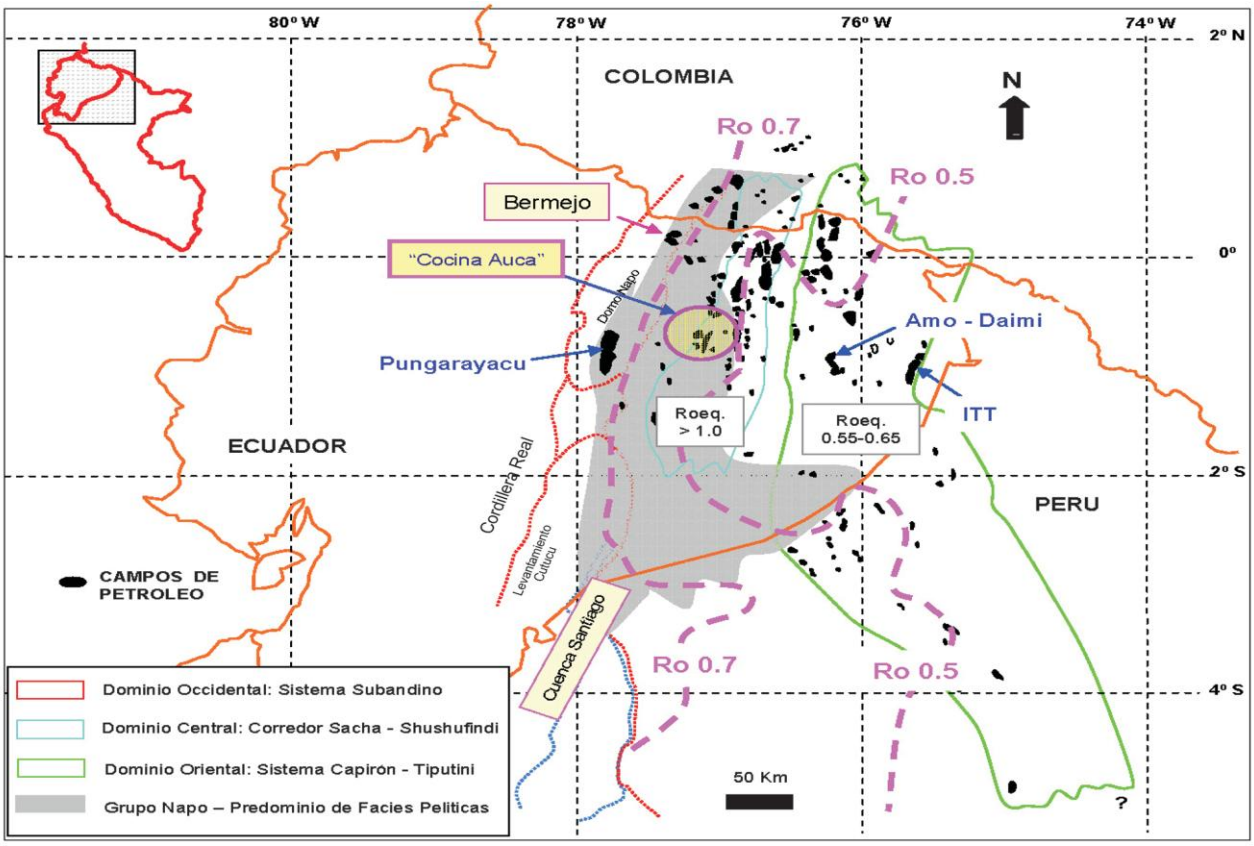


Fig. 1—Shale facies in the Napo Group, hypothetical hydrocarbon generation zones (after Mancilla et al. 2008).

Fig. 2 shows the stratigraphic column of the Oriente Basin. It is estimated that there are possible source rocks for the mudstones of the Napo Formation and the Santiago Formation. Regarding the Napo Formation: the mudstones are divided into Upper, Middle, and Lower. According to the well logs analyzed, it is evident that the Lower Napo shale have a higher probability of being an unconventional target because they show gamma ray values greater than 150 API. This shows that this formation has a significant shale content greater low water saturation.

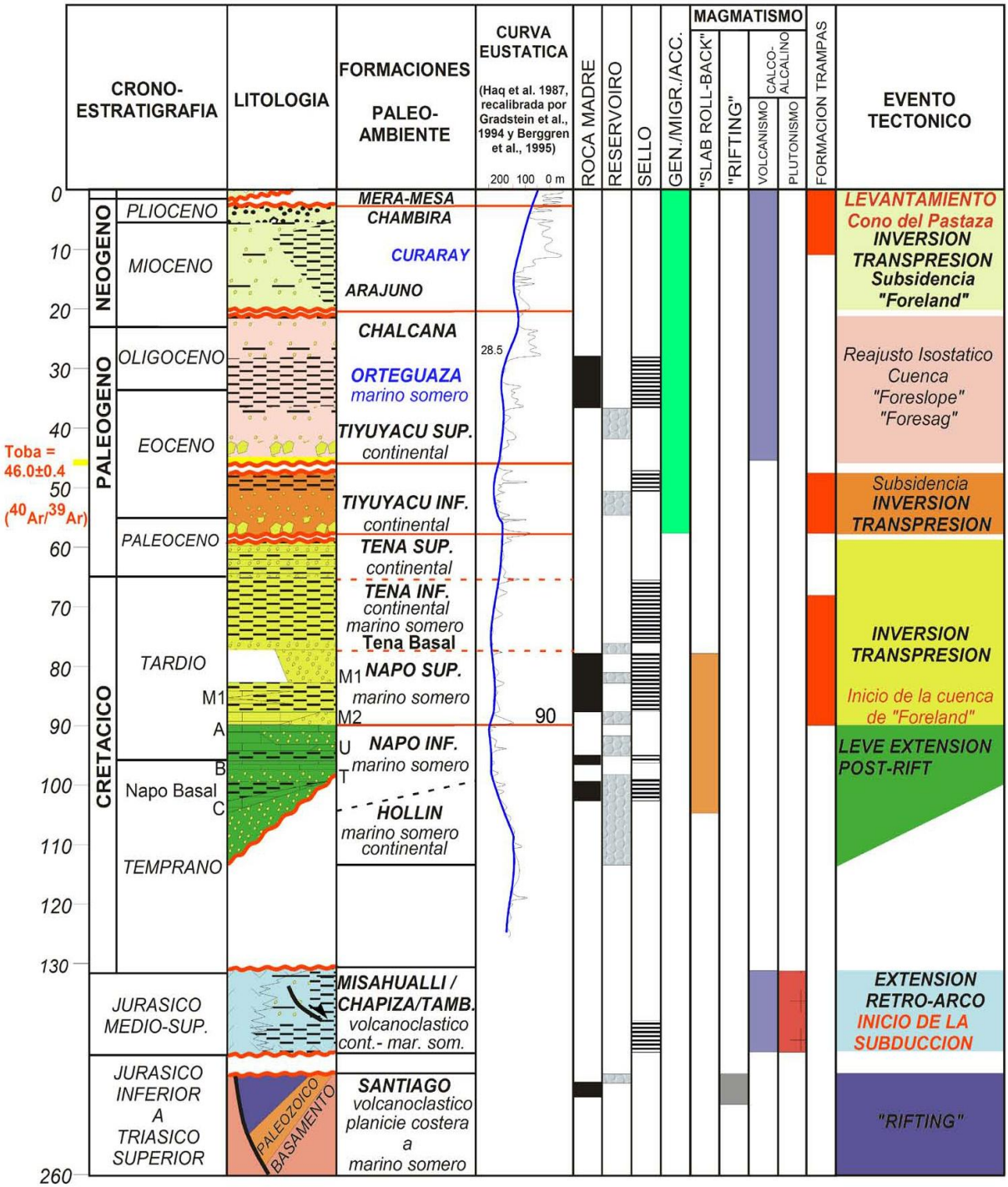


Fig. 2—Stratigraphic column of the Oriente Basin, with its respective ages and sedimentation environments with its respective tectonic event.

2.2. Establishing the areal extent of major shale gas and shale oil formations:

Having identified the major shale gas and shale oil formations, the next step is to undertake more intensive study to define the areal extent; for each of these formations.

Fig. 3, the Cretaceous formations and members are observed: with their respective sedimentation cycles. The Upper, Middle, and Lower Napo Shale formations are found in the three structural domains of the Oriente Basin; however, due to their thickness, the targets to be evaluated are the Upper and Lower Napo Shales. One of the keys of the study is to determine the structural domain with the highest probability of producing hydrocarbons from shale-type resources, based on geochemical and petrophysical data from the basin.

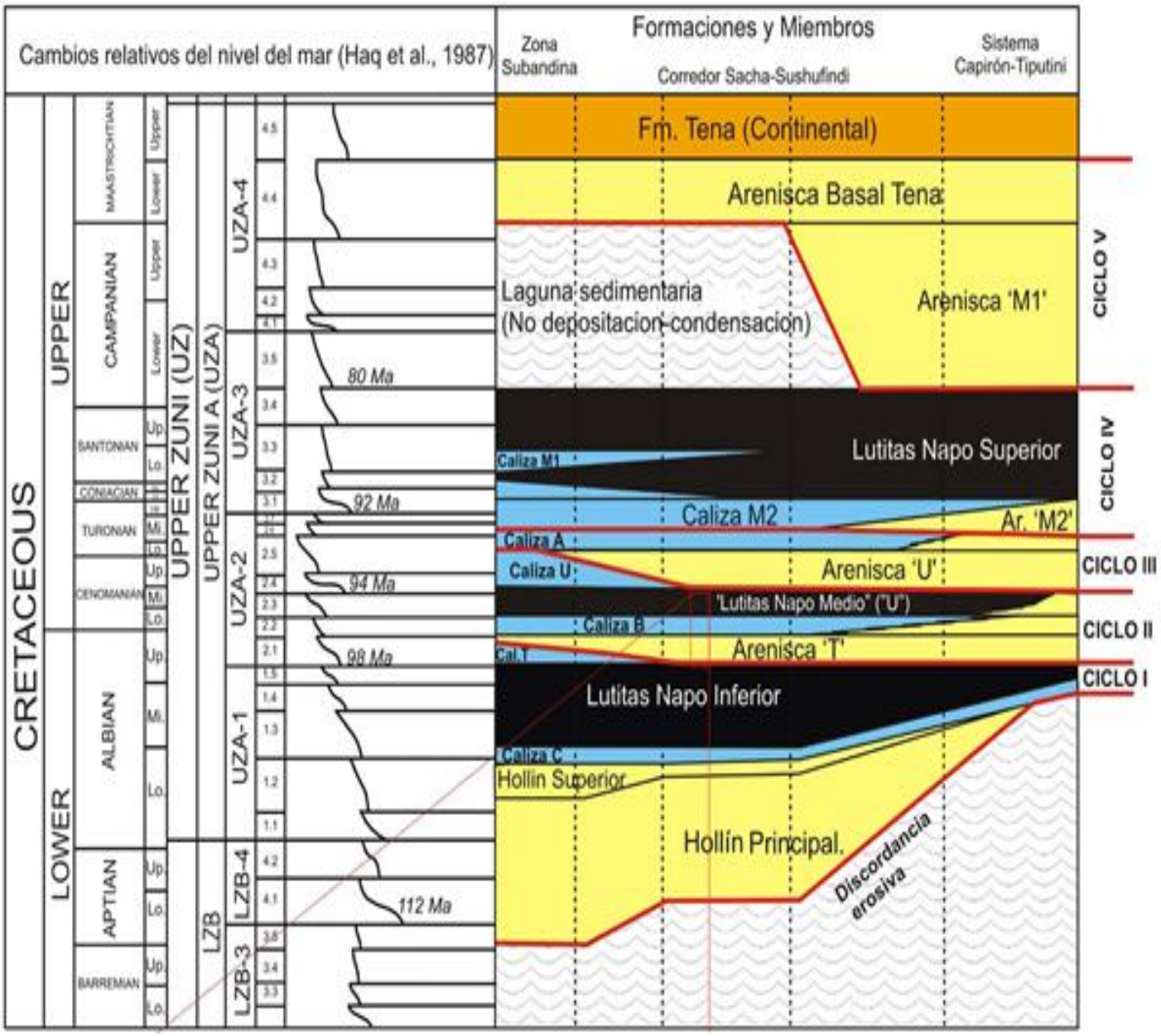


Fig. 3—Sedimentary Cycles of the Oriente Basin

2.3. Defining the Prospective Area for Each Shale Gas and Shale Oil Formation.

An important and challenging resource assessment step is to establish the portions of the basin that, in our view, are deemed prospective for development of shale gas and shale oil. The criteria used for establishing the prospective area include:

- Depositional environment of shale (marine vs non-marine)

The Oriente Basin is a morpho-structural unit known as the upper part of the Amazon Basin; it is bound to the west by the Andes Cordillera and to the east by the Guiana Shield. The Oriente Basin covers 100.000 km²; the formation of interest in this study is 700 meters thick and was deposited during the Cretaceous in the Oriente Basin of Ecuador. The Napo Formation overlies the Hollín Formation and is underlain by the Tena Formation; it comprises several stratigraphic units, one of which is the "U" sandstone. To the east it presents a thickness greater than 70 meters, thinning toward the east of the basin; this basal sandstone in the eastern part of the basin corresponds in its sedimentation to a fluvial fan and/or delta-fan system derived from the mountains, from the eastern Guiana Shield. The western part is represented by marine facies.

The relative influence of sea-level fall and rise is evident in each of the sedimentation sequences within the Napo Formation. Sea-level changes are manifested by shoreline migration, playing an important role in sedimentation in incised valleys and shallow marine settings in the central and western parts of the Oriente Basin. The sedimentation cycle begins with the channeling of sandstones transported from the eastern part; once the estuaries have been filled, successive inputs reflect transgression of marine facies occurring toward the east of the basin. In the interval of the "U" sandstone, sandstones can be found interbedded with thick shale intervals and thin limestone layers. The base of the "U" sandstone prograde over shales and platform limestones of the middle Napo. (Estupiñan & PermMayer, Diagenesis and sequence stratigraphy of the "U" sandstone of the Napo Fm, 2006).

Depth:

The Napo Formation has three significant pelitic intercalations—upper, middle, and lower—due to their thicknesses greater than 100 feet (30.48 meters); the upper and lower Mudstones are considered a target within this study as a possible shale-type reservoir. Another target to be evaluated, where several authors mention a possible source rock, is the Mudstones of the Santiago Formation of Lower Jurassic age (Institut français d'études andines, 2005). Latter is beyond the scope of this study because little information is available for this area; therefore, evaluating the Mudstones of the Santiago Formation represents an interesting unconventional prospect soon.

The Napo Mudstones are found at estimated depths of 9,500 feet to 10,000 feet, which requires hydraulic stimulation to seek economically viable production over time.

Total Organic Content (TOC).

Organic materials such as microfossil sand plant matter provide the requisite carbon, oxygen, and hydrogen atoms needed to create natural gas and oil.

As such, TOC and carbon type (Types I and II) are important measures of the oil-generation potential of shale formation.

The Van Krevelen diagram is proposed, according to data obtained from the Central and Eastern Domain of the Basin. Based on the hydrogen index and oxygen index, using unconventional basins of the region as analogs in this case Argentina—since it is the nation that has achieved successful unconventional production; studies carried out by researchers (Stinco & Barredo, 2014) have been taken as references for analogies with other basins in the region.

The supporting illustration is shown in Fig. 4.

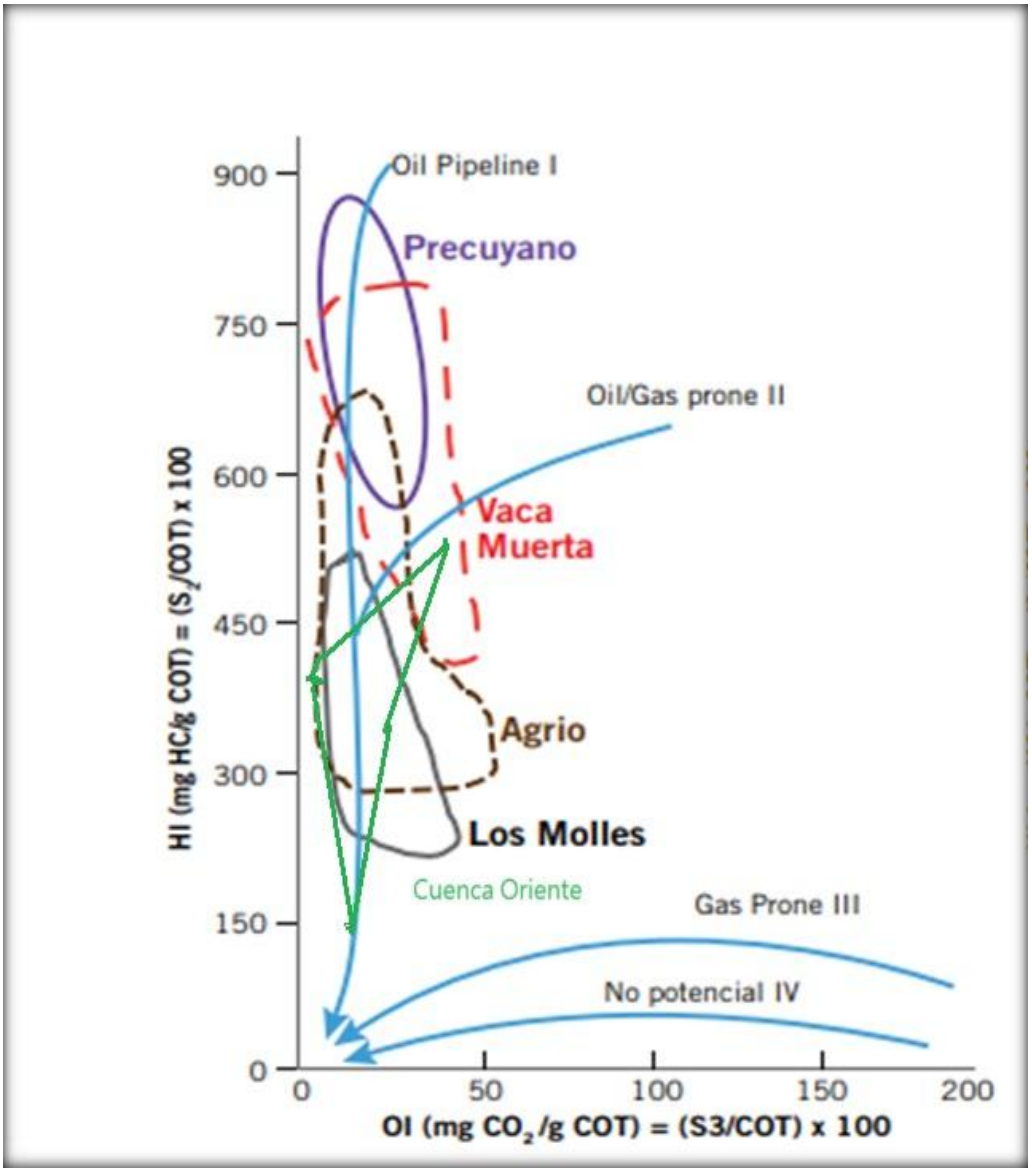


Fig. 4—Kerogen type analogies based on shale cores from Sedimentary Basins of the South America region.

(Stinco & Barredo, 2014), Modified.

Fig. 5 provides an example of using a gamma ray log to identify the TOC content for the Marcellus Shale in the New York (Chenango Co.) portion of the Appalachian Basin.

Fig. 5 shows that content gamma ray response in shales is commonly associated with TOC content, which is an indicator of organic matter and the presence of hydrocarbons retained in the rock; this is an indirect measure of oil and gas saturation, which can be used to detect source rocks in a basin.

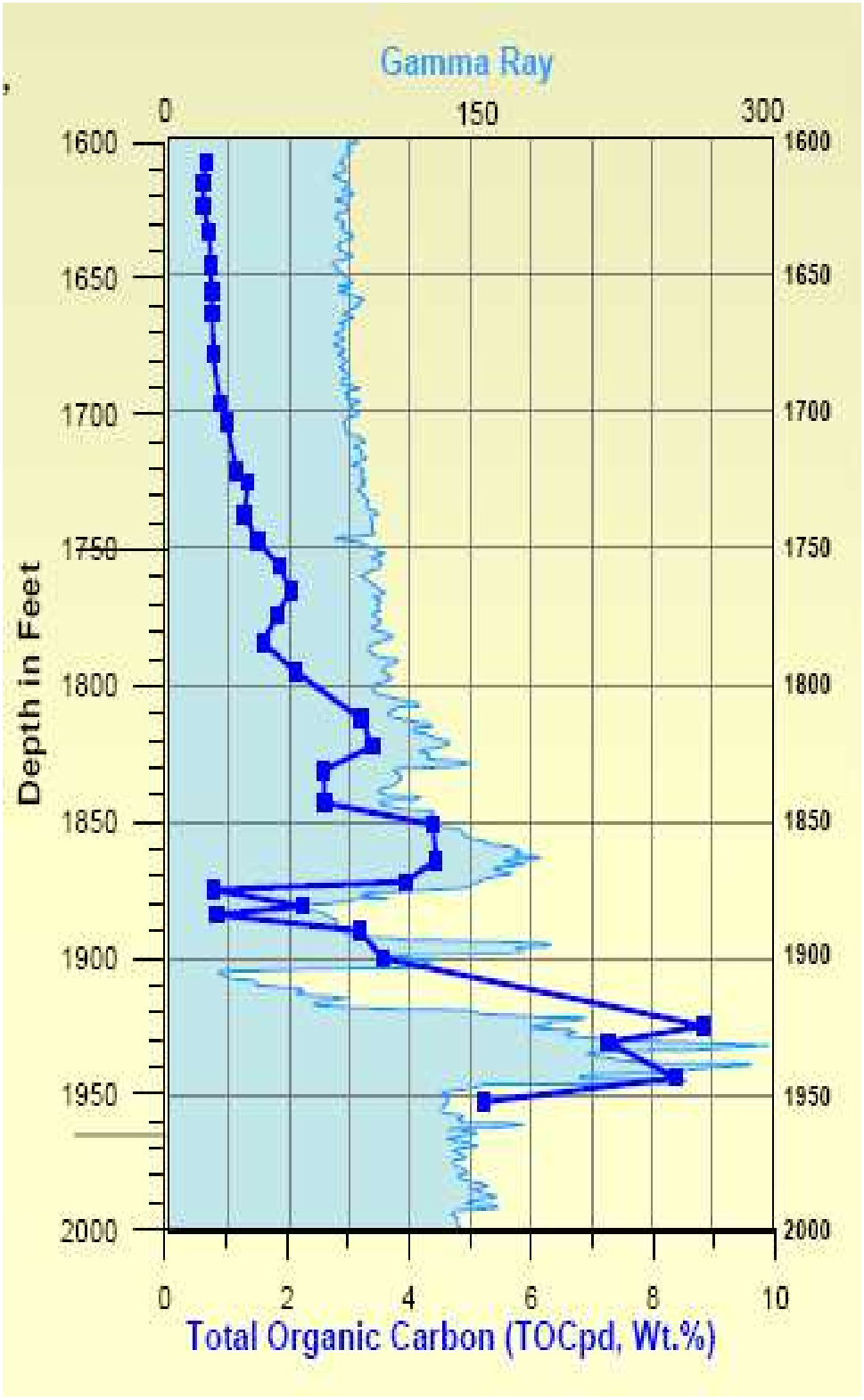


Fig. 5—Relationship TOC vs Gamma Ray for the Marcellus Shale

(EIA 2013)

In Fig. 6, radioactivity is analyzed through the Gamma Ray log; the Mudstones of the Napo Formation are analyzed. It is observed that the Mudstones of the Lower Napo Formation reach radioactivity values from 150 to 190 API, which has relationship with the TOC content. Taking the analogy from Fig. 5, we can say that the Mudstones of the Lower Napo exceed 2% TOC, which makes them a *"shale"* type target.

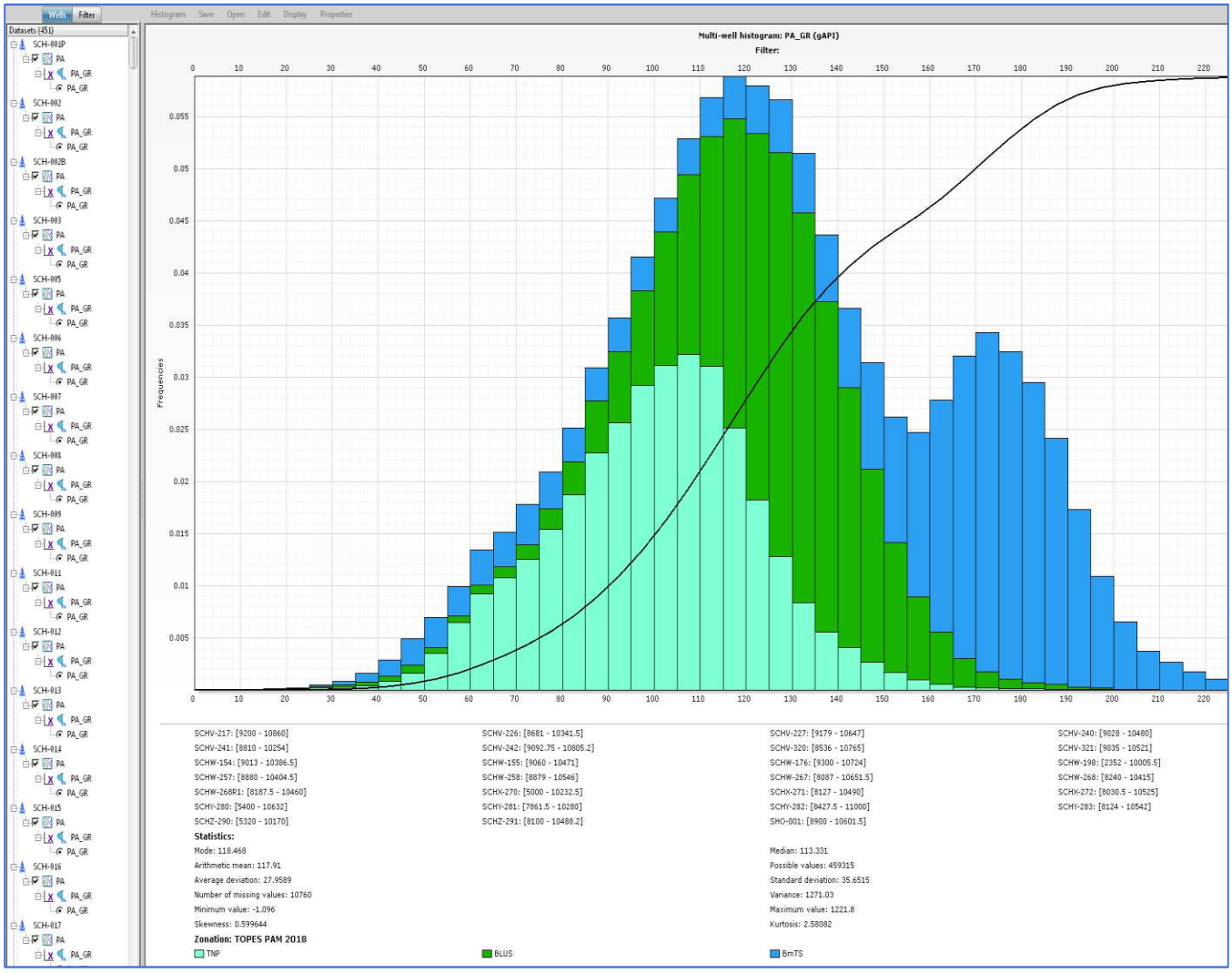


Fig. 6—Analysis of at least twenty-seven wells of the central structural domain of the Sacha Field, determination of radioactivity in the shales of the Napo Formation.

Thermal Maturity.

Thermal maturity measures the degree to which a formation has been exposed to elevated temperatures required to transform organic matte into hydrocarbons.

The reflectance of certain types of minerals (Ro%) is used as an indication of Thermal Maturity, Figure 7. The thermal maturity of the oil prone prospective area has a Ro greater than 0.7% but less than 1.0%. The wet gas and condensate prospective area has a Ro between 1.0% and 1.3%. Dry gas areas typically have a Ro greater than 1.3%. Where possible, we have identified these three hydrocarbons' "windows"

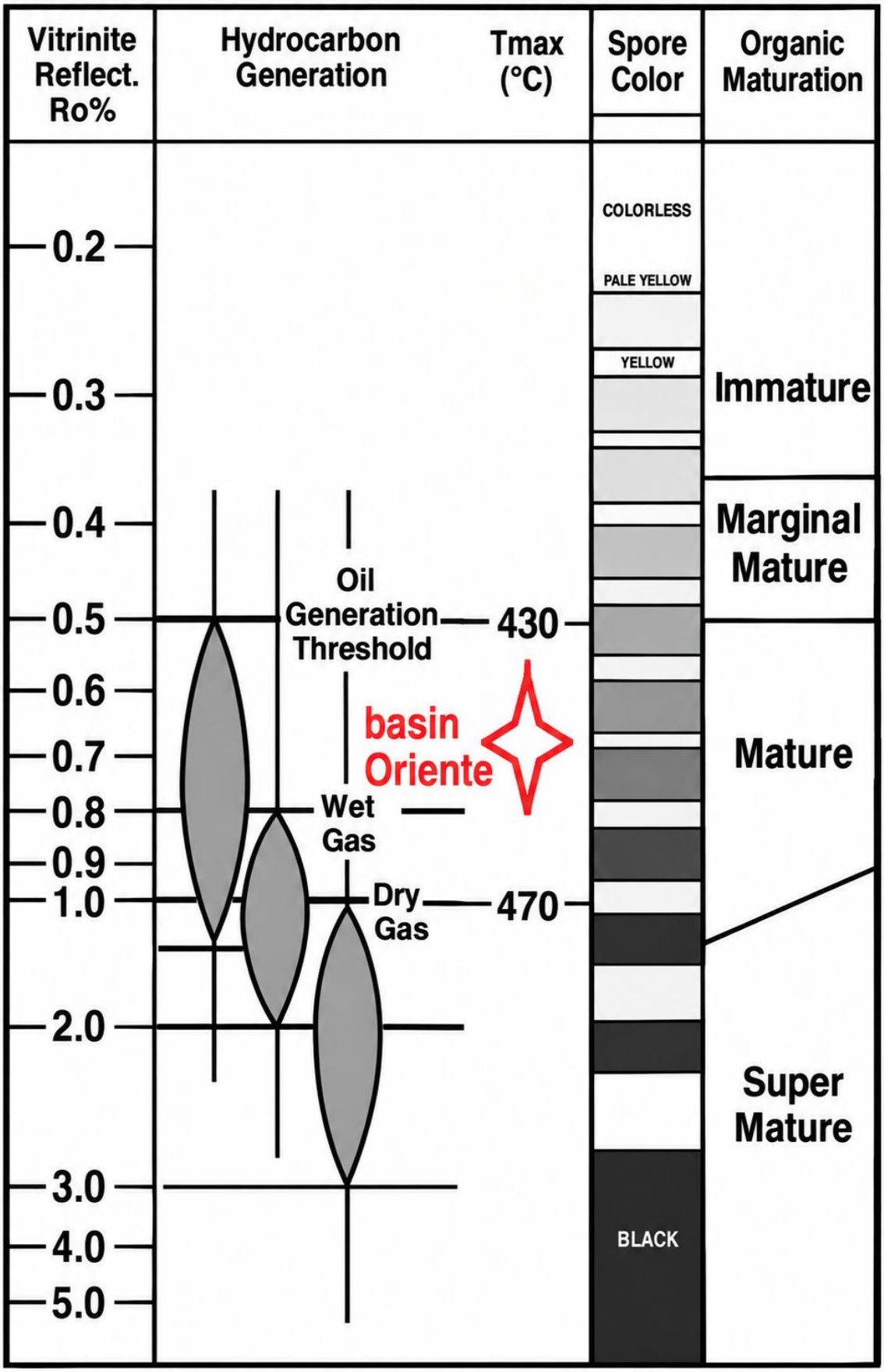


Fig. 7—Vitrinite Reflectance vs Tmax, to determine hydrocarbon generation potential.

According to doctoral studies (Estupiñan, 2005), thermal models are proposed with the purpose of determining the maturity of the source rocks in the basin; however, it is observed that there is a scarcity of sampling of Mudstones from the Napo Formation. Although the researcher concludes that in most of the Oriente Basin the Mudstones of the Formation are immature, based on Rock Eval and Pyrolysis analyses, the central zone shows a hydrocarbon generation window; therefore, this zone would be the hydrocarbon generation "kitchen", showing burial temperatures of 128 °C and thermal fluxes above 58: mW/m² or milliwatts per square meter

In Table 2 the wells with samples of Mudstones from the Napo Formation show a vitrinite reflectance index of 0.9%, together with a significant presence of thermal flux, which is an indicator of good rock maturity for generating hydrocarbons.

Well	**Sample**	**Depth (ft)**	**Depth of Temperature basement** (well logs)	**Tmax (°C)**	**Ro Eq (%)**	**T basement* (°C)**	**Thermal flow m mW/m2**
Jivino-3	B-782	10000	9491	445	0,9	128	59
Limoncocha-9	B-806(C)	9830	9477	445	0,9	128	58

Table 2—Calculation of Paleotemperatures and Heat Flow in the central zone of the Oriente Basin, of the Napo Formation.

*Método Barker & Pawlewicz (1986).

(Estupiñan, Diagenetic control on the quality of the U and T sandstones reservoirs of the Cretaceous Napo Formation of the Oriente Basin, Ecuador., 2005).

Geographic Location

The prospective area is limited to the onshore portion of the shale gas and shale oil basin.

The Oriente Basin is marked by three structural domains. The Napo Formation is composed of three shale intervals: Upper, Middle, and Lower, according to the analysis of charts 5 & 6 of TOC and radioactivity measurements; the unconventional target is found in the shales of the lower stratum because they maintain radioactivity greater than 170 API. The area of interest is the Central domain "Sacha–Shushufindi Corridor" because it presents Vitrinite Reflectance from 0.7 to 1% with Type II kerogen.

For the present study, wells from the North Central Basin were analyzed, because the public company has electric log data; the South-Central Basin is also of conventional interest. Based on the literature review, this area is presumed to be prone to gas production because it is a mature zone, according to the bibliographic review.

In the Oriente Basin, there are unconventional targets in the central domain in the lower shales of Napo, in the northern zone and in the southern zone. The objective of this study is the domain central zone of the Basin, because no well-log information is available for the southern zone, while the northern zone contains limited proprietary unconventional data about overview potential unconventional by private companies; therefore, the resources of the central zone of the shales of the Lower Napo Formation will be estimated through electric log estimations using Interactive Petrophysics.

4. Estimating the Risked Shale Gas and Shale Oil In-Place (OIP/GIP).

The Figure 8 presents the interpretation of the electric logs for the Lower Napo Formation. The analysis indicates a potential hydrocarbon-bearing interval within a predominantly shaly section. The interval is estimated to be approximately 65 ft thick, with calculated oil saturations exceeding 50% and indications of movable hydrocarbons. However, the reservoir interval contains a significant shale volume, which may adversely affect reservoir quality and production performance.

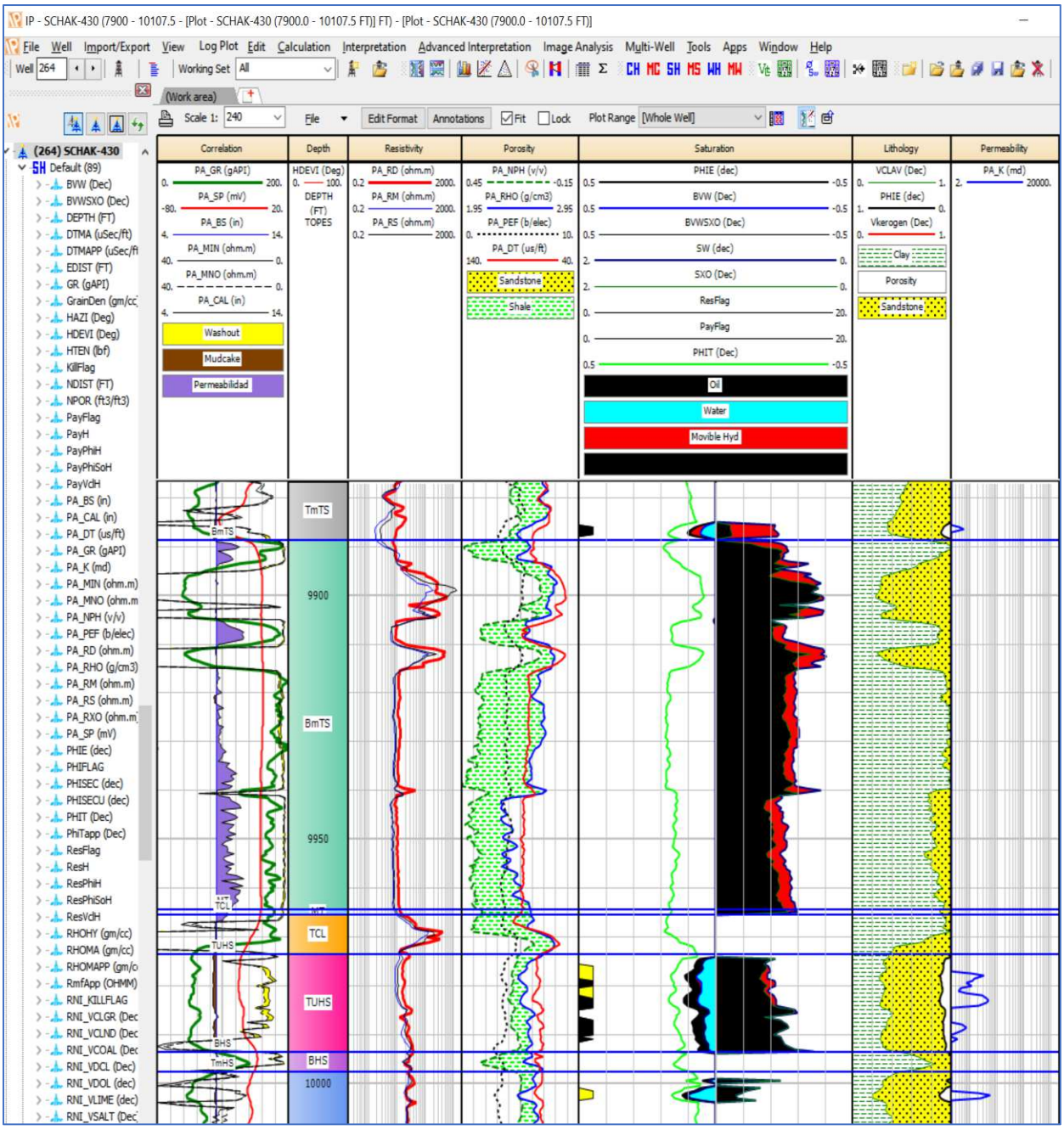


Fig. 8—Resistivity measurement in Lower Napo mudstones.

Once the potential of the central zone—lower Napo shales—was established, this study of the Oriente Basin focused on the resources present in the lower Napo shales, based on petrophysical analyses conducted on four wells in the central part of the basin, Block 60 (Sacha Field), The supporting information is shown in table 3&4.

No	Well	Location	Coordinates (UTM) ZONA 18
1	Sacha 157	Central domain of the basin.	-9954134,3 / 281748,8
2	Sacha 400	Central domain of the basin.	-9954134,3 / 281748,8
3	Sacha 440	Central domain of the basin.	-9954134,3 / 281748,8
4	Sacha 454	Central domain of the basin.	-9954134,3 / 281748,8



Project PAM_ECUADOR Well SCHAH-400

Well Header		Data Counts	
ID	14250	Documents	0 add
UWI	ECSCH7035800	Key Facts	0 add
Common Well Name	SCHAH-400	Picks	19
Lat	-.3583271	Curves	44
Lon	-76.86073789	Time Depths	3
Orig X/Lon	292905.684	Dir Surveys	1
Orig Y/Lat	9960372.549	Posn Logs	1
X	292905.684	Synthetics	1
Y	9960372.549	Lithology	0
Status	ACTIVE	Casing	0
Field	SACHA	Cores	0
Operator	RIO_NAPO	Shows	0
Lease Name	AH400	Tests	15
Well Number	AH400	Dipmeter	0
Spud Date		Paleo	0
Completion Date		Zone Attributes	4
Elevation Type	KB	Plugging	0
Elevation (feet)	902.29	DST RFTs	0
TD (feet)	10070	Interests	0
Formation at TD	UNKNOWN	Dates	0
Orig CRS	Ecuador UTM18 PSAD56	Alt UWIs	0
Data Source	SYRZ	Well Study	0
Created	sanchemo 2016-08-03	Note Pad	0
Updated	sanchemo 2018-06-19	Remarks	0 add
Remark			



Project PAM_ECUADOR Well SCH-157

Well Header		Data Counts	
ID	14174	Documents	0 add
UWI	ECSCH7016500	Key Facts	0 add
Common Well Name	SCH-157	Picks	25
Lat	-.38878203	Curves	63
Lon	-76.88230482	Time Depths	3
Orig X/Lon	290505.2083	Dir Surveys	0
Orig Y/Lat	9957004.0735	Posn Logs	0
X	290505.2083	Synthetics	1
Y	9957004.0735	Lithology	0
Status	INACTIVE	Casing	0
Field	SACHA	Cores	0
Operator	PETROPRODUCCION	Shows	0
Lease Name	157	Tests	0
Well Number	157	Dipmeter	0
Spud Date		Paleo	0
Completion Date		Zone Attributes	3
Elevation Type	KB	Plugging	0
Elevation (feet)	859.07	DST RFTs	0
TD (feet)	10028	Interests	0
Formation at TD	UNKNOWN	Dates	0
Orig CRS	Ecuador UTM18 PSAD56	Alt UWIs	0
Data Source	ORN	Well Study	0
Created	sanchemo 2016-08-03	Note Pad	0
Updated	vierae 2019-04-17	Remarks	0 add
Remark			



Project PAM_ECUADOR Well SCHAM-454

Well Header		Data Counts	
ID	14286	Documents	0 add
UWI	ECSCH7039400	Key Facts	0 add
Common Well Name	SCHAM-454	Picks	18
Lat	-.2291215	Curves	43
Lon	-76.82949518	Time Depths	2
Orig X/Lon	296381.76	Dir Surveys	1
Orig Y/Lat	9974661.91	Posn Logs	1
X	296381.76	Synthetics	1
Y	9974661.91	Lithology	0
Status	ACTIVE	Casing	0
Field	SACHA	Cores	0
Operator	RIO_NAPO	Shows	0
Lease Name	AM454	Tests	15
Well Number	AM454	Dipmeter	0
Spud Date		Paleo	0
Completion Date		Zone Attributes	3
Elevation Type	KB	Plugging	0
Elevation (feet)	918.4	DST RFTs	0
TD (feet)	11088	Interests	0
Formation at TD	UNKNOWN	Dates	0
Orig CRS	Ecuador UTM18 PSAD56	Alt UWIs	0
Data Source	ORN	Well Study	0
Created	sanchemo 2016-08-03	Note Pad	0
Updated	vierae 2022-10-27	Remarks	0 add
Remark			



Project PAM_ECUADOR Well SCHAL-440

Well Header		Data Counts	
ID	14273	Documents	0 add
UWI	ECSCH7038100	Key Facts	0 add
Common Well Name	SCHAL-440	Picks	23
Lat	-.19849683	Curves	69
Lon	-76.82800803	Time Depths	3
Orig X/Lon	296546.93	Dir Surveys	1
Orig Y/Lat	9978048.65	Posn Logs	1
X	296546.93	Synthetics	1
Y	9978048.65	Lithology	0
Status	ACTIVE	Casing	0
Field	SACHA	Cores	0
Operator	RIO_NAPO	Shows	0
Lease Name	AL440	Tests	21
Well Number	AL440	Dipmeter	0
Spud Date		Paleo	0
Completion Date		Zone Attributes	3
Elevation Type	KB	Plugging	0
Elevation (feet)	951.19	DST RFTs	0
TD (feet)	10089.98	Interests	0
Formation at TD	UNKNOWN	Dates	0
Orig CRS	Ecuador UTM18 PSAD56	Alt UWIs	0
Data Source	SYRZ	Well Study	0
Created	sanchemo 2016-08-03	Note Pad	0
Updated	vierae 2022-05-11	Remarks	0 add
Remark			

Table 3—Well Analysis, Sacha Field.

Parameter	Coordinates
Latitude	00°11′00″ S to 00°24′40″ S
Longitude	77°49′40″ W to 76°54′16″ W

Table 4—Geographic coordinates of Sacha Field.

Block 60 has an estimated monthly production of 77,000 barrels per day by 2025, according to EP Petroecuador daily production reports. It is known as the "crown jewel," being the highest-producing field in Ecuador, contributing approximately 30% of the country's refining feedstock.

Using petrophysical data calculated from electric logs with Interactive Petrophysics software, the following parameters were obtained from a well from Sacha Field:

Zn	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H	Vcl*H
14	BmTS	9888.76	9964.50	75.74	54.24	0.716						
		9888.55	9964.04	75.73	54.24	0.716	0.159	0.457	0.861	8.65	4.70	46.68
15	MT	9964.50	9965.58	1.08	0.75	0.694						
		9964.04	9965.04	1.08	0.75	0.694	0.163	0.412	0.886	0.12	0.07	0.66
16	TCL	9965.58	9973.63	8.05	0.00	0.000						
		9965.04	9973.04	8.05	0.00	0.000	---	---	---	---	---	---
17	TUHS	9973.63	9993.60	19.97	19.35	0.969						
		9973.04	9993.04	19.97	19.35	0.969	0.145	0.548	0.319	2.80	1.26	6.16
18	BHS	9993.60	9997.70	4.10	0.15	0.037						
		9993.04	9997.04	4.10	0.15	0.037	0.146	0.282	0.431	0.02	0.02	0.06
19	TmHS	9997.70	10107.50	109.80	5.00	0.046						
		9997.04	10107.03	109.79	5.00	0.046	0.122	0.622	0.300	0.61	0.23	1.50
	All Zones	8850.40	10107.50	1257.10	218.50	0.174						
		8850.07	10107.03	1257.06	218.49	0.174	0.154	0.471	0.543	33.55	17.75	118.60

Table 5—Calculated values based on Electrical Records data.

To estimate the area of interest, a screening of the three structural domains of the Oriente Basin was conducted, analyzing radioactivity and resistivity to identify the shales' zone of interest. The results showed that the Lower Napo shales in the central domain—spanning at least twenty-seven wells represent an unconventional development zone. This area was delineated as a trapezoid based on the geographic coordinates of producing fields within the central domain, covering an extent of 4,000 km² of the Oriente Basin. Resource calculations were performed using electrical logs processed with IP (Interactive Petrophysics) software. For the petrophysical data, the 'Sacha Field,' one of Ecuador's flagship fields, was analyzed; four reference wells were selected to extrapolate petrophysical parameters and obtain an estimated resource value.

The supporting illustration is shown on Fig. 9.

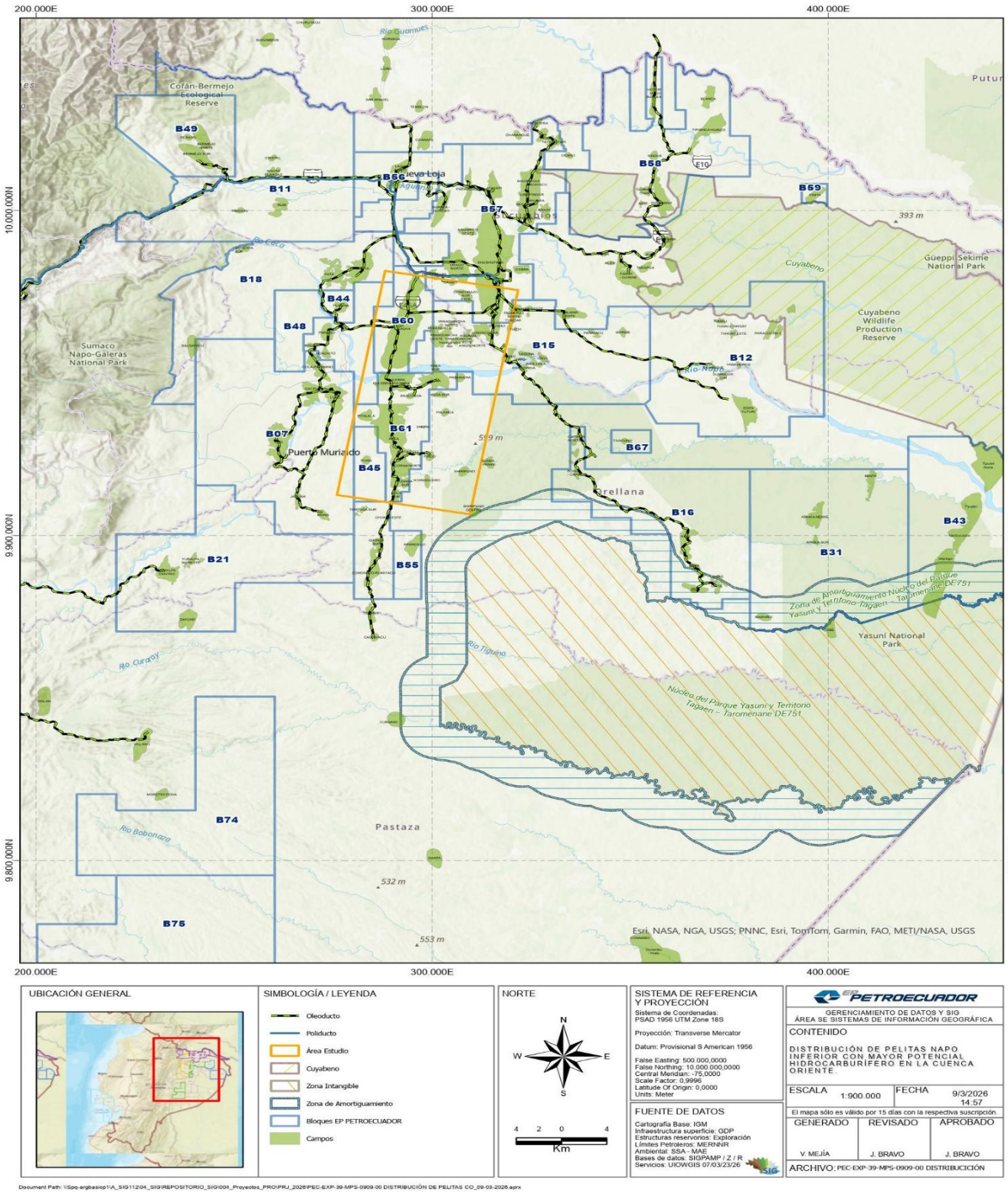


Fig. 9—Distribution zones of Lower Napo Shale taking the central domain of the Oriente Basin as the unconventional target of this evaluation.

Using Interactive Petrophysics Software: electric log data were obtained for the calculation of petrophysical properties of the Lower Napo Mudstones, taking as reference an estimate of a “non-conventional” reservoir.

To estimate unconventional hydrocarbon resources, three development scenarios were defined to provide a probabilistic assessment of the resources that could potentially be developed:

For the P10 scenario, a prospective area of 2,386 km² is considered, corresponding to the central zone of the Oriente Basin, which is interpreted as the principal hydrocarbon generation kitchen of the petroleum system. The primary unconventional exploration target is the Sacha Field, the largest conventional oil-producing field in the Oriente Basin. Accordingly, this scenario represents a conservative The supporting illustration is shown on Fig. 10. Approach for the estimation of unconventional resources, if drilling activities will target the organic-rich shales of the Lower Napo Member of the Napo Formation (Cretaceous), deposited during the post-rift stage of basin evolution.

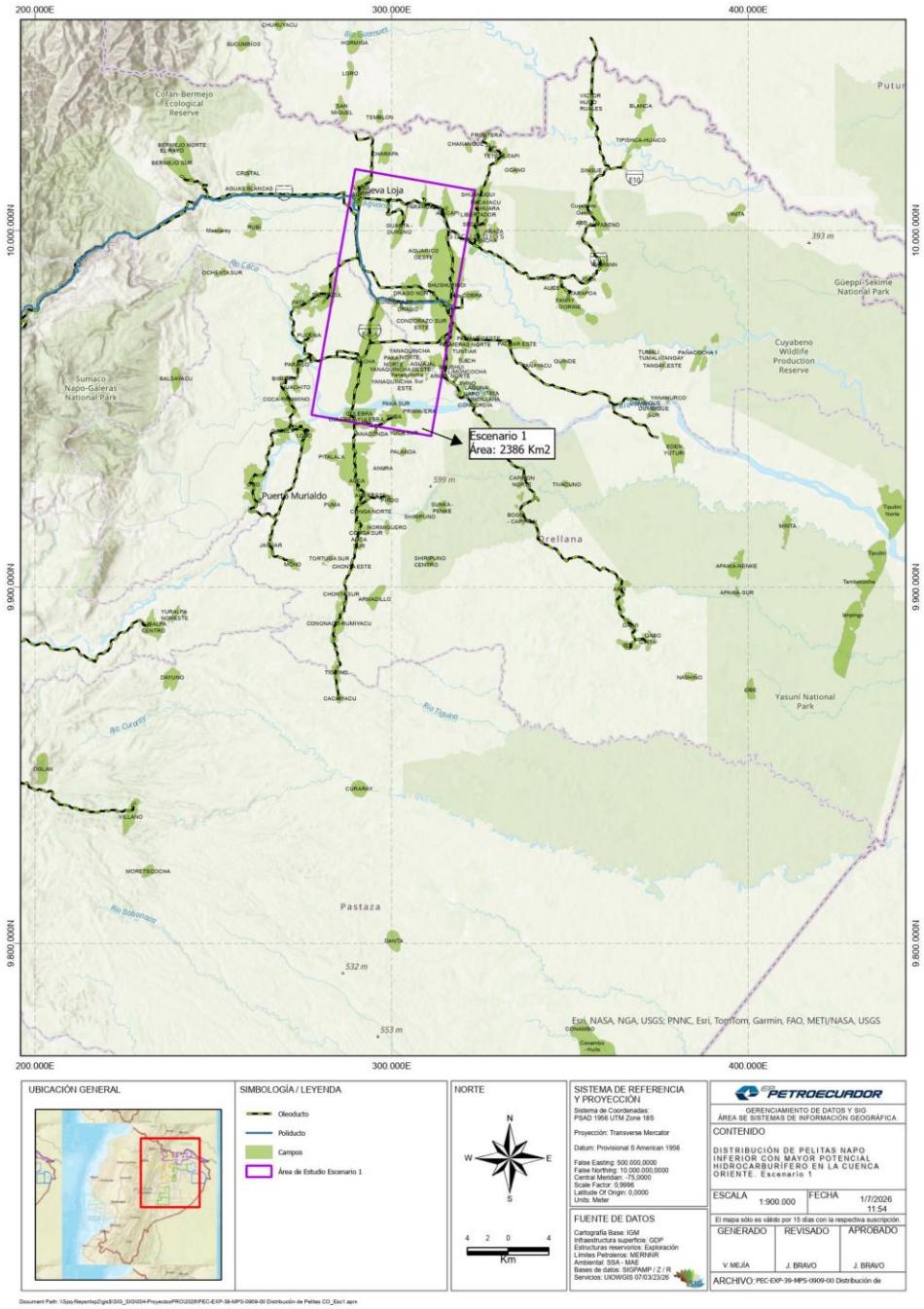


Fig. 10—Estimated Area of the Central Zone, P10 Scenario.

The primary unconventional development targets include the Sacha, Auca, and Shushufindi fields, which are the largest producing conventional oil fields in the Oriente Basin and are widely recognized as the "crown jewels" of Ecuador's petroleum industry. These assets currently produce approximately 200,000 barrels of conventional oil per day (bpd). Accordingly, the P50 scenario represents a realistic estimate of the unconventional resources that could potentially be developed within the Oriente Basin.

The supporting illustration is shown in Fig. 11.

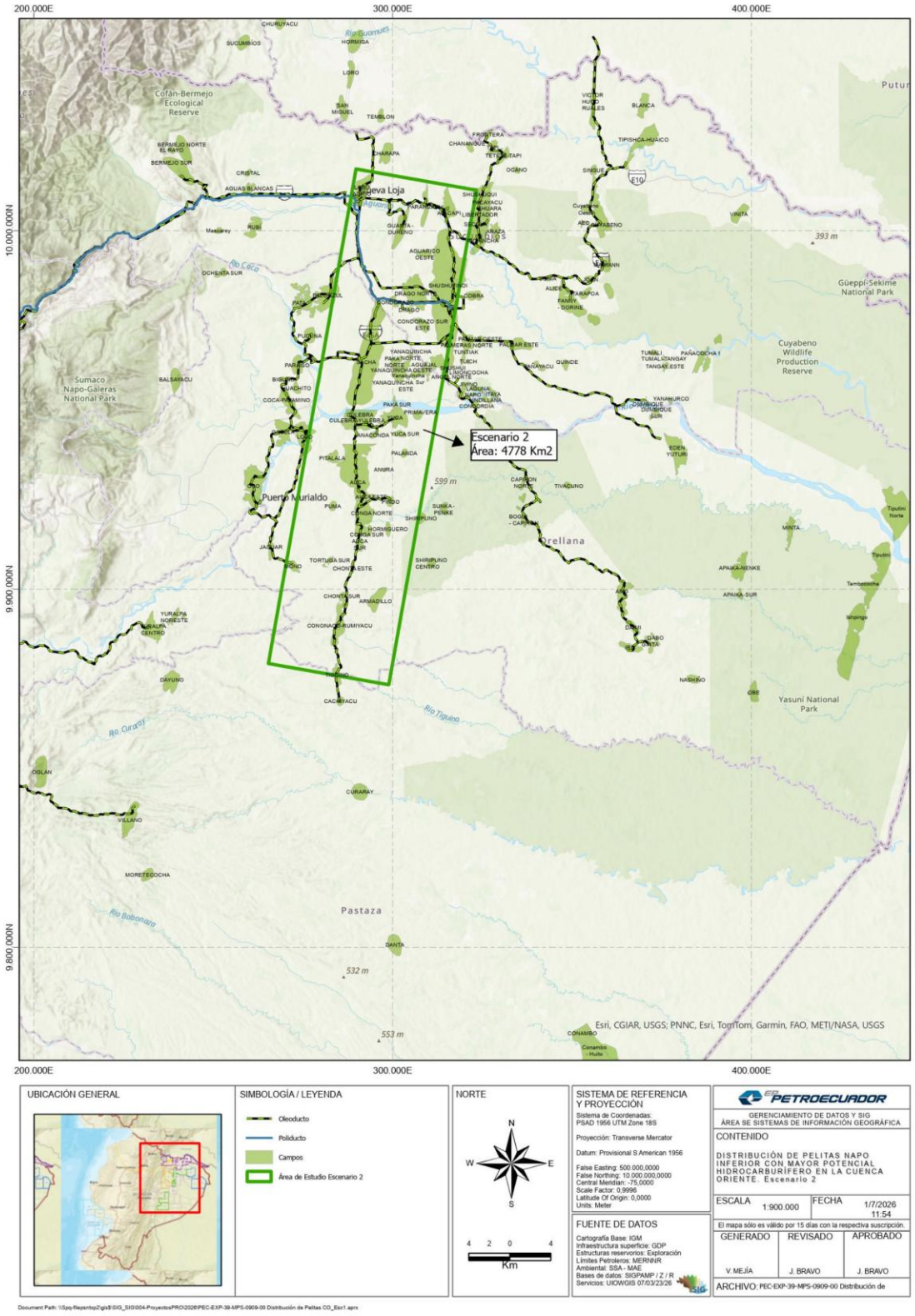


Fig. 11—Estimated Area of the Central Zone, P50 Scenario.

For the P50 scenario, the prospective area encompasses the central region of the Oriente Basin, based on the assumption that the organic-rich shales of the Napo Formation are laterally continuous throughout the central corridor

The supporting illustration is shown in Fig. 12.

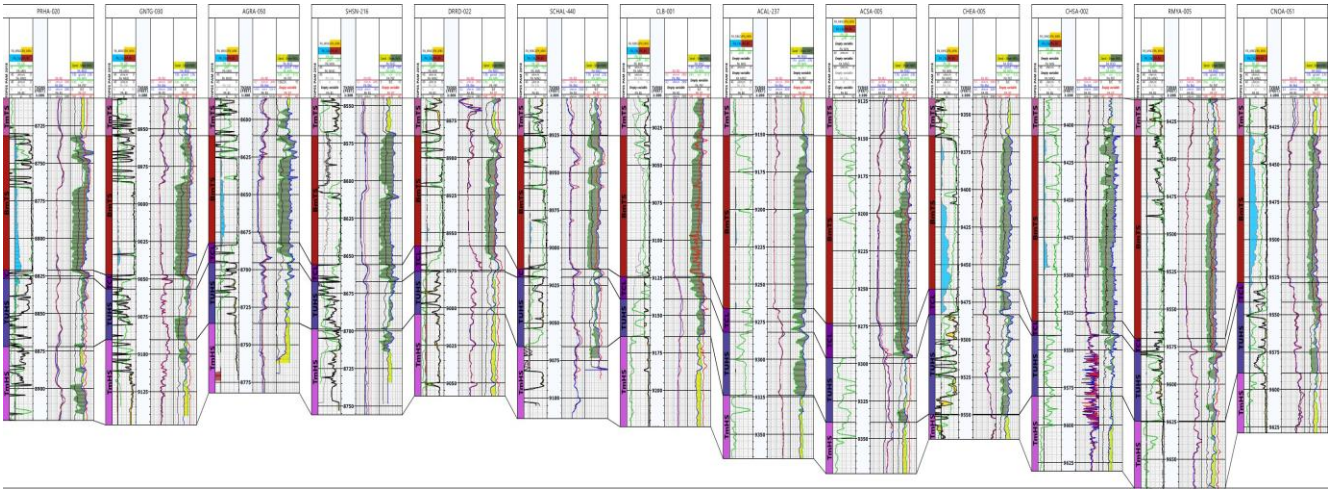


Fig. 12—Regional structural correlation flattened at the top of the BmTS horizon (Lower Napo Shale), Central Oriente Basin.

The P90 scenario assumes that the prospective area includes the central region of the Oriente Basin together with the marginal fields of the Sub-Andean zone, where the Lower Napo shale of Cretaceous age is interpreted to be laterally continuous. This represents an optimistic development scenario. Although these are marginal fields, they exhibit vitrinite reflectance values indicative of significant organic matter richness and favorable source rock characteristics. The Pungarayacu Field, located near the Sub-Andean zone, was not included in this assessment. This field contains shale intervals exceeding 200 ft in thickness and is therefore recommended as a priority target for future unconventional resource evaluation and detailed geological investigations.

The supporting illustration is shown in Fig. 13.

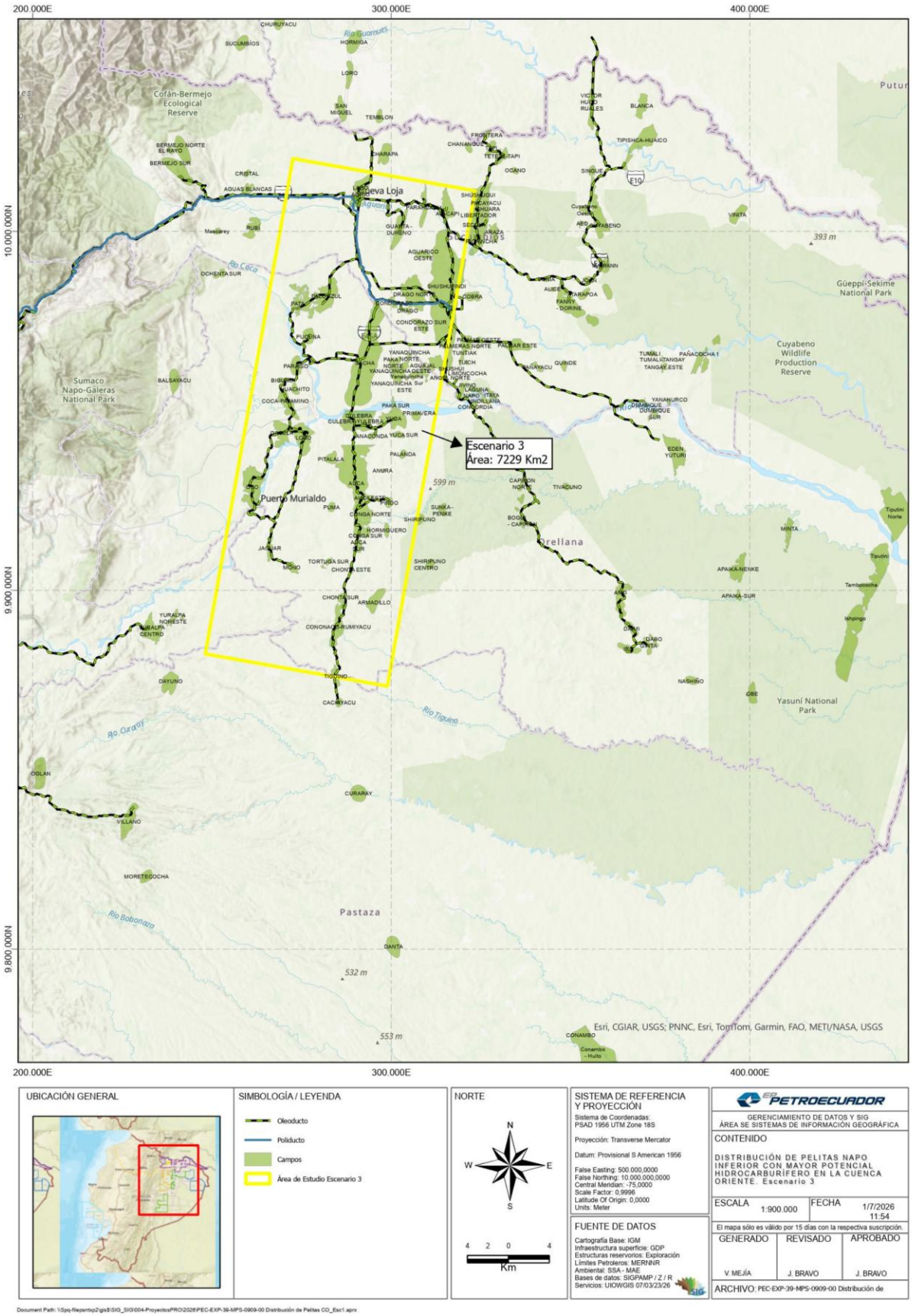


Fig. 13—Estimated Area of the Central Zone, P90 Scenario.

Table 6 presents the estimated petrophysical properties of the Lower Napo Formation shales. For the assessment of resource potential, probabilistic scenarios for the drainage area and net pay thickness were considered in accordance with PMRS guidelines. Three evaluation cases were defined: P10 (conservative scenario), P50 (most likely scenario), and P90 (optimistic scenario), representing different levels of uncertainty associated with the geological parameters. This approach allows the sensitivity of the results to be evaluated and provides a probabilistic range for the estimation of potential resources.

Variables	Values	Units of measurement	P10 / P50 / P90
Area	4046,86	acre	589346.3 / 1180670 / 1786325
thickness	54,26	ft	54,26 / 60 / 75
Oil Saturation	0,543	%	0,543
Porosity	0,159	%	0,159
Bo	1,4	(RB/STB)	1,4

Table 6—Petrophysical values of Lower Napo Shale mudstones.

Once the petrophysical data have been obtained, the Volumetric Calculation formulation is applied to obtain shale-type resources:

..... *Equation 1*

OOIP = Original oil in place volume (barrels).

7758 = Conversion factor from cubic feet to barrels.

A = Reservoir area (acres).

h = Net productive thickness (feet).

φ = Porosity (decimal, for example 0.20).

Sw = Water saturation (decimal).

Bo = Oil formation volume factor (RB/STB)

Resources ≈ 33×10^9 bbl.

Estimated Shale Oil resources, central domain of the Oriente Basin (P50)

Prospective Resources = 2,37 x 10^9 bbl.

Estimated prospective resources, central domain of the Oriente Basin (P50)

Table 7 presents the volumetric resource estimates for the Lower Napo Formation shales. The assessment integrates the petrophysical properties obtained from well-log interpretation with probabilistic ranges for drainage area and net pay thickness, in accordance with PMRS guidelines. The resulting in-place resource estimates are reported as P10, P50, and P90 scenarios, representing conservative, most-likely, and optimistic cases, respectively. This probabilistic framework quantifies the uncertainty inherent in the geological model and provides a robust basis for resource evaluation.

Sceneries			
No	P10	P50	P90
Risked Oil In-Place (B bbl)	15.299.211.351,02	33.892.099.453,66	64.097.402.911,66
Risked Technically Recoverable (B bbl)	1.070.944.794,57	2.372.446.961,76	4.486.818.203,82

Table 7—Petrophysical values of Lower Napo Shale mudstones.

Special considerations

A recovery factor between 5–7% was assumed based on shale oil analogs from mature North American plays, applying hydraulic fracturing technique, stimulation and drilling horizontal.

For the volumetric factor (Bo), since fluids have not yet been extracted from the Napo shales, "offset" reservoir data were used as analogs for the volumetric factor obtained from the "U" Formation of the Napo Group, which overlies the "lower" Napo shales.

For the present calculation of technically recoverable resources, in accordance with the Society of Petroleum Engineers classification, Prospective Resources are considered, which indicates that these are the quantities of oil estimated, as of a given date, to be potentially recoverable from undiscovered accumulations through the application of future projects.

The supporting illustration is shown in Fig. 14.

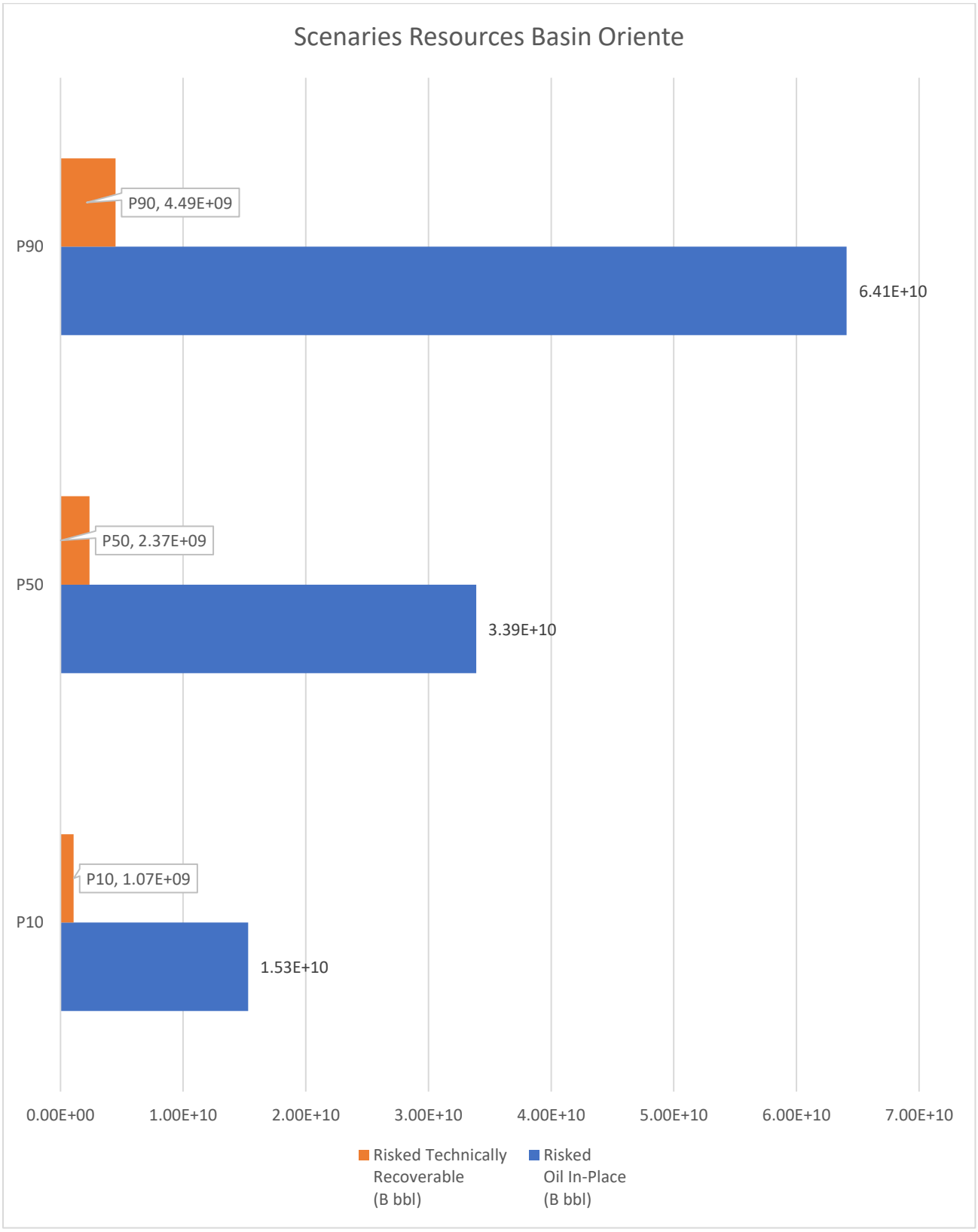


Fig. 14—Estimated Area of the Central Zone, Scenario.

5. Sensitivity Analysis of the Oil Formation Volume Factor (B_o)

The oil formation volume factor (B_o) is a key PVT parameter in volumetric resource assessments because it directly governs the conversion of hydrocarbon volumes from reservoir conditions to standard surface conditions. Since $B_o$appears in the denominator of the volumetric equation used to estimate original oil in place (OOIP) and ultimately technically recoverable resources, uncertainties associated with this parameter can significantly impact the final resource estimates. In emerging unconventional plays such as the Lower Napo Shale, where production history and detailed PVT data are limited or unavailable, evaluating the sensitivity of resource estimates to variations in $B_o$provides an effective method for quantifying volumetric uncertainty.

A sensitivity analysis was therefore performed using $B_o$values ranging from 1.05 to 1.40 rb/stb, representing a reasonable range for shale oil systems under reservoir conditions. The results indicate a clear inverse relationship between $B_o$and risked technically recoverable resources. For the most likely case (P50), estimated recoverable resources decrease from 2.82 B bbl at $B_o = 1.05$rb/stb to 2.12 B bbl at $B_o = 1.40$rb/stb, corresponding to a reduction of approximately 25%. Similar trends were observed in the P90 and P10 scenarios, confirming that fluid volumetric properties constitute one of the principal sources of uncertainty in the evaluation of unconventional resources.

The sensitivity results demonstrate that relatively small changes in the assumed $B_o$value can generate differences of several hundred million barrels in estimated recoverable resources. In the P50 case alone, the variation between the minimum and maximum $B_o$scenarios reaches approximately 706 MMbbl. This range highlights the importance of acquiring representative fluid samples and conducting detailed PVT analyses during future appraisal and pilot-development programs. Until such data become available, sensitivity-based approaches provide a practical framework for capturing uncertainty and improving confidence in early-stage resource assessments

In the Figure X. Sensitivity of risked technically recoverable resources to variations in the oil formation volume factor (B_o). Resource estimates decrease systematically with increasing B_o, reflecting the inverse relationship between fluid volumetric expansion and hydrocarbon volumes expressed at standard surface conditions. The analysis demonstrates the importance of PVT uncertainty in the evaluation of the Lower Napo Shale unconventional resource potential.

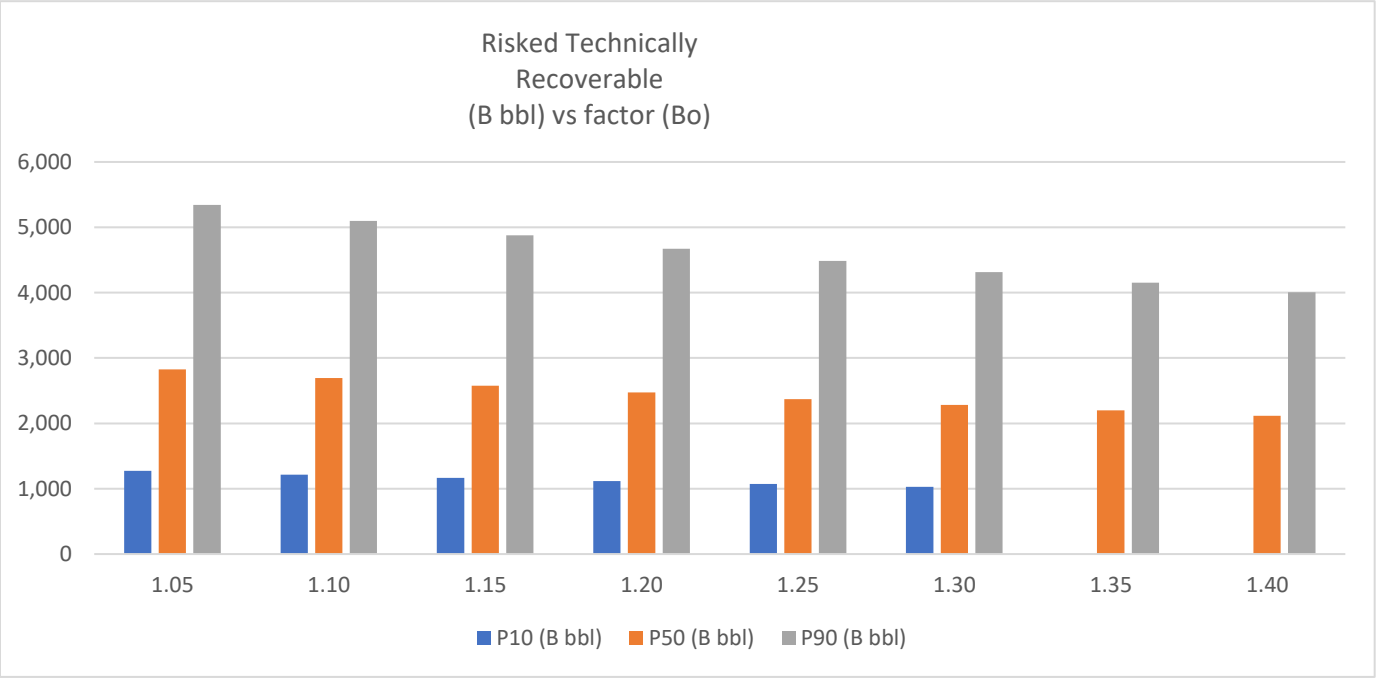


Fig. 15— Risked technically recoverable (B bbl) vs oil formation volume factor (Bo).

6. Comparison with Regional Shale Resource Assessments

The probabilistic assessment conducted in this study resulted in a P50 risked technically recoverable resource estimate of approximately 2.37 billion barrels of oil for the Lower Napo Shale. Although this volume is substantially lower than published estimates for the Vaca Muerta shale play, which range from 16.2 billion barrels according to the U.S. Energy Information Administration (EIA) to approximately 30.17 billion barrels according to a recent reassessment coordinated by the Instituto Argentino del Petróleo y del Gas (IAPG), the estimated resource magnitude remains significant within the context of emerging unconventional opportunities in South America.

Direct comparison between the Lower Napo Shale and Vaca Muerta should be approached cautiously because both plays are at markedly different stages of appraisal and development. Vaca Muerta has benefited from extensive drilling activity, hydraulic fracturing campaigns, pilot developments, production history, and continuous reservoir characterization over more than a decade, which have substantially reduced geological and engineering uncertainties. In contrast, the Lower Napo Shale remains in an early evaluation stage, with limited subsurface calibration and no commercial unconventional production available to constrain recovery efficiencies and long-term production performance.

Despite these limitations, the estimated P50 technically recoverable resource of 2.37 B bbl indicates that the Lower Napo Shale may constitute a meaningful unconventional oil accumulation within the Oriente Basin. Relative to published estimates for Vaca Muerta, the Lower Napo resource represents approximately 15% of the original EIA estimate and approximately 8% of the most recent IAPG assessment. These values suggest that the Lower Napo Shale represents a potentially significant unconventional oil resource within the Andean region. Although additional appraisal and field validation are required, the estimated resource base demonstrates a scale that warrants further geological, petrophysical, and production-oriented investigations. The results support the interpretation that the Oriente Basin may constitute an attractive opportunity for future unconventional resource development and could emerge as an important contributor to the regional energy portfolio.

Furthermore, the resource estimates presented in this work should be considered preliminary and subject to revision as additional, geomechanical, and production-related data become available. Future pilot projects, fluid characterization studies, and production testing programs will be essential for reducing uncertainty associated with recovery factors, reservoir quality distribution, and fluid behavior. Consequently, the comparison with Vaca Muerta is intended primarily as a regional benchmark to place the Lower Napo Shale in a broader South American unconventional resource context rather than to imply direct equivalence in technical maturity or commercial development potential.

Table 16 summarizes the principal geological, petrophysical, and resource-related characteristics of the Lower Napo Shale and compares them with two well-established unconventional oil plays, Vaca Muerta in Argentina and Eagle Ford in the United States. The comparison indicates that, despite its smaller net thickness, prospective area, and technically recoverable resource estimates, the Lower Napo Shale exhibits several favorable reservoir attributes, including Type II kerogen, thermal maturity within the oil window (Ro $\approx$ 1.0%), hydrocarbon saturation exceeding 50%, and porosity values that compare favorably with those reported for productive shale reservoirs. Furthermore, the estimated P50 technically recoverable resource of 2.37 B bbl places the Lower Napo Shale among the most promising emerging unconventional resource opportunities currently identified in Ecuador. Published assessments report technically recoverable oil resources of approximately 8.5 B bbl for Eagle Ford and between 16.2 and 30.17 B bbl for Vaca Muerta, providing a useful regional and international context for evaluating the scale of the Lower Napo resource. However, these comparisons should be interpreted cautiously because significant differences exist in appraisal maturity, drilling density, production history, reservoir calibration, and development status among the analyzed plays.

Parameter	Lower Napo Shale (P50)	Vaca Muerta	Eagle Ford
Basin	Oriente Basin, Ecuador	Neuquén Basin, Argentina	South Texas, USA
Development Stage	Appraisal	Commercial Development	Mature Commercial Development
Depth (ft)	10	8,000–13,000	4,000–14,000
Gross Thickness (ft)	120	600–1,500	50–300
Net Pay (ft)	60-75	200–600	50–250
TOC (%)	2.0	2–8	2–7
Kerogen Type	Type II	Type II/II-S	Type II
Thermal Maturity (Ro %)	1.0	0.7–1.5	0.7–1.6
Porosity (%)	15.9	4–12	6–15
Hydrocarbon Saturation (%)	54.3	50–80	50–85
Prospective Area (acres)	1,180,670	>7 million	Several million acres
Risked Technically Recover (B bbl)	**2.37**	**16.2–30.17**	**8.5**
Production History	No commercial shale production	Extensive commercial production	Extensive commercial production

Fig. 16—Comparison Between the Lower Napo Shale and the Vaca Muerta Shale Play

Whidden et al. (2018) for Eagle Ford; EIA (2024) and IAPG (2026) for Vaca Muerta; this study for the Lower Napo Shale

6.1. Recovery Factor Risk Index (RFRI): A Risk-Based Framework for Recovery Factor Estimation in the Lower Napo Shale

One of the major uncertainties associated with unconventional resource assessments is the estimation of the recovery factor (RF). In frontier shale plays, production history is unavailable and recovery factors are commonly derived from analog developments or expert judgment. In the present study, technically recoverable resources were estimated using recovery factors ranging from 5% to 7%, consistent with mature unconventional developments and the recommendations of the Petroleum Resources Management System (PRMS).

To provide an independent evaluation of recovery efficiency, a Recovery Factor Risk Index (RFRI) was developed. The proposed framework assumes that recovery performance is controlled by geological quality, reservoir quality, drilling efficiency, and hydraulic fracturing effectiveness. The methodology provides a transparent and reproducible approach for estimating recovery factors in unconventional plays where production data are unavailable.

The Recovery Factor Risk Index is defined as: …… Equation 2

$$RFRI = 0.35G + 0.35P + 0.15D + 0.15F$$

where:

GGG = Geological Quality Factor

PPP = Petrophysical Quality Factor

DDD = Drilling Efficiency Factor

FFF = Hydraulic Fracturing Efficiency Factor

The weighting coefficients were selected to emphasize reservoir quality while recognizing the influence of development technology. These coefficients should be considered preliminary and subject to future calibration using production datasets from mature unconventional developments.

Geological Quality Factor

The geological component integrates organic richness and thermal maturity**:** …… Equation 3

$$G = 0.5\left(\frac{TOC}{TOC_{ref}}\right) + 0.5\left(\frac{Ro}{Ro_{ref}}\right)$$

The Lower Napo Shale exhibits TOC values greater than 2% and thermal maturity values close to Ro=1.0%, corresponding to the oil generation window.

Using:

$$\text{TOC}=2.0\%$$

$$Ro = 1.0$$

and reference values:

$$TOC_{ref} = 4.0\%$$
$$Ro_{ref} = 1.1$$

the resulting geological factor is:

$$G = 0.705$$

This value indicates moderate source-rock quality compared with highly productive unconventional oil systems.

Petrophysical Quality Factor

Reservoir quality was evaluated using effective porosity and hydrocarbon saturation:

$$P = 0.5\left(\frac{\phi}{\phi_{ref}}\right) + 0.5\left(\frac{S_o}{S_{o,ref}}\right)$$

Average petrophysical properties obtained from the analysis of four representative wells include an effective porosity of 15.9% and hydrocarbon saturation of 54.3%.

verage petrophysical properties obtained from the analysis of four representative wells include an effective porosity of 15.9% and hydrocarbon saturation of 54.3%.

Substituting:

$$\phi = 15.9\%$$
$$S_o = 54.3\%$$

and:

$$\phi_{ref} = 12\%$$
$$S_{o,ref} = 75\%$$

results in a value slightly greater than unity. Therefore:

$$P = 1.0$$

The result suggests favorable reservoir quality characteristics relative to the selected shale analogs.

Development Efficiency Factors

Because no commercial unconventional development currently exists in the Lower Napo Shale, a future development scenario based on horizontal drilling and multi-stage hydraulic fracturing was assumed.

For drilling efficiency:

$$D = 0.80$$

For hydraulic fracturing effectiveness:

$$F = 0.85$$

These values are representative of modern unconventional development practices employed in mature shale oil plays.

Recovery Factor Estimation

Substituting the calculated values into the RFRI equation:

$$RFRI = 0.35(0.705) + 0.35(1.00) + 0.15(0.80) + 0.15(0.85)$$
$$RFRI = 0.845$$

The recovery factor is then estimated as:

$$RF = RF_{max} \times RFRI$$

Assuming:

$$RF_{max} = 10\%$$

the resulting recovery factor becomes:

$$RF = 8.45\%$$

Resource Implications

Using the P50 Oil-In-Place estimate obtained in this study:

$$OOIP = 33.89 \times 10^9 \ bbl$$

the resulting technically recoverable resources are:

$$TRR = OOIP \times RF$$
$$TRR = 33.89 \times 0.0845$$
$$TRR = 2.86 \times 10^9 \ bbl$$

The RFRI-derived estimate is moderately higher than the 2.37 × 10^9 bbl obtained using the conventional analog-based recovery-factor approach adopted in the base-case assessment.

6.2 Preliminary Validation Using Vaca Muerta and Eagle Ford

To provide an initial validation of the proposed resource assessment methodology, the results obtained for the Lower Napo Shale were compared with two internationally recognized unconventional oil plays: the Vaca Muerta Formation in Argentina and the Eagle Ford Formation in the United States. Both plays have undergone extensive appraisal and commercial development and therefore provide useful analogs for evaluating the plausibility of the geological and petrophysical parameters estimated in this study.

The comparison indicates that the Lower Napo Shale exhibits several characteristics commonly associated with productive unconventional oil systems. The formation contains predominantly Type II kerogen, thermal maturity values within the oil window (Ro ≈ 1.0%), average porosity of approximately 15.9%, and hydrocarbon saturation exceeding 50%. These values are comparable to, and in some cases exceed, the ranges reported for Vaca Muerta and Eagle Ford, suggesting that the Lower Napo Shale possesses favorable conditions for hydrocarbon generation and retention.

The principal differences between the Lower Napo Shale and the reference plays are related to scale and development maturity. The Lower Napo interval exhibits a gross thickness of approximately 120 ft and net pay thickness ranging from 60 to 75 ft, whereas Vaca Muerta commonly reaches gross thicknesses between 600 and 1,500 ft and Eagle Ford between 50 and 300 ft. Similarly, the prospective area evaluated in this study is approximately 1.18 million acres, considerably smaller than the areal extent of Vaca Muerta and major Eagle Ford development corridors. These differences partially explain the lower estimated technically recoverable resource volume of approximately 2.37 B bbl (P50) obtained for the Lower Napo Shale.

Nevertheless, the estimated P50 technically recoverable resource of 2.37 B bbl remains significant within the South American context. This volume corresponds to approximately 15% of the original U.S. Energy Information Administration estimate for Vaca Muerta and approximately 8% of the most recent reassessment reported by the Instituto Argentino del Petróleo y del Gas (IAPG). Although substantially smaller than the resource base of mature unconventional developments, the estimated volume places the Lower Napo Shale among the most prospective unconventional petroleum opportunities currently identified in Ecuador.

It is important to emphasize that this comparison constitutes a preliminary validation rather than a direct equivalency assessment. Vaca Muerta and Eagle Ford benefit from thousands of horizontal wells, extensive hydraulic fracturing programs, production history, geomechanical characterization, and detailed reservoir calibration. In contrast, the Lower Napo Shale remains at an early appraisal stage and lacks production data capable of constraining recovery factors and long-term performance forecasts. Consequently, the comparison should be interpreted as evidence that the geological and petrophysical characteristics estimated in this study are consistent with those observed in successful unconventional oil plays, while recognizing that substantial uncertainty remains regarding commercial productivity and ultimate recovery.

Overall, the analog-based comparison supports the validity of the volumetric assessment and suggests that the Lower Napo Shale represents a technically credible unconventional oil target that warrants additional petrophysical, geomechanical, and pilot-production studies to further reduce uncertainty and refine resource estimates.

7. Conclusions

1. This study introduces a Recovery Factor Index (RFI) designed to address one of the principal uncertainties in unconventional resource evaluation: the estimation of recovery factors in the absence of PVT data, production history, and pilot-development information. Unlike conventional approaches that depend primarily on analog reservoirs, the proposed framework quantifies recovery potential through the integration of measurable geological, petrophysical, and technological variables. Consequently, the methodology transforms recovery-factor selection from a largely subjective assumption into a structured and reproducible evaluation process. The RFI therefore constitutes a novel methodological contribution for the assessment of technically recoverable resources in frontier unconventional plays and provides a foundation for future calibration and validation using field-production datasets

2. The sensitivity analysis demonstrated that the oil formation volume factor (Bo) constitutes one of the most influential fluid-property parameters in the volumetric assessment of the Lower Napo Shale. Variations in Bo from 1.05 to 1.40 rb/stb resulted in significant changes in estimated risked technically recoverable resources, with the P50 case ranging from 2.82 to 2.12 B bbl. These results highlight the importance of future PVT characterization and fluid-property studies to reduce uncertainty and improve confidence in unconventional resource estimates within the Oriente Basin.

3. Comparison with representative unconventional plays such as Vaca Muerta and Eagle Ford indicates that, although the Lower Napo Shale exhibits smaller technically recoverable resource volumes, it shares several favorable geological and petrophysical attributes, including Type II kerogen, thermal maturity within the oil window (Ro ≈ 1.0%), hydrocarbon saturation exceeding 50%, and porosity values comparable to those reported in productive shale systems. These characteristics support the interpretation that the Oriente Basin possesses a technically attractive unconventional petroleum system that warrants continued appraisal and detailed reservoir characterization.

4. Further studies of the Pre-Cretaceous succession are recommended because the Santiago Formation represents a promising shale resource play and has been identified by several authors as a potential source rock. In addition, a comprehensive evaluation of the Pungarayacu Field, located near the Sub-Andean zone, is recommended. Although this field is currently classified as a conventional heavy-oil accumulation, it contains shale intervals exceeding 2000 ft in thickness in the well Pungarayacu 17S1 drilled by the company Ivanhoe. Furthermore, the available well logs exhibit favorable petrophysical characteristics, including elevated natural gamma-ray, high resistivities responses and hydrocarbon saturation indicators, suggesting that the field may have potential for unconventional resource assessment.

5. The Lower Napo Shale contains an estimated 2.37×10^9 bbl of prospective shale oil resources under the P50 scenario according to the PRMS framework. Furthermore, the proposed Recovery Factor Risk Index (RFRI) produced a recovery-risk score of 0.845, indicating favorable recovery potential when compared with mature unconventional plays such as Eagle Ford and Vaca Muerta. The results demonstrate that recovery efficiency can be evaluated through an integrated assessment of geological quality, reservoir quality, drilling architecture, and hydraulic fracturing effectiveness. Consequently, the RFRI constitutes a practical screening tool for recovery-factor estimation in frontier shale plays where production history is unavailable, providing a methodological contribution that complements conventional analog-based resource assessments.

The integration of the Petroleum Resources Management System (PRMS) methodology and the proposed Recovery Factor Index (RFI) provides two complementary approaches for estimating technically recoverable resources in frontier unconventional reservoirs. Using conventional PRMS assumptions and recovery factors derived from analog shale developments, the Lower Napo Shale is estimated to contain approximately 2.37×10^9 bbl of prospective technically recoverable resources under the P50 scenario. In contrast, application of the proposed RFI methodology yielded an estimated recovery factor of approximately 8.45%, resulting in a recoverable resource estimate of approximately 2.86×10^9 bbl.

The difference between both estimates demonstrates the sensitivity of unconventional resource assessments to recovery-factor selection and highlights the importance of developing alternative methodologies for frontier basins where production history and representative PVT data are unavailable. By integrating geological quality, thermal maturity, reservoir properties, and development-related parameters into a single framework, the RFI provides a transparent and reproducible approach for reducing uncertainty in recovery-factor estimation.

Using a reference WTI oil price of USD 70/bbl, the PRMS-based estimate corresponds to a gross theoretical recoverable resource value of approximately USD 166 billion, whereas the RFI-based estimate corresponds to approximately USD 200 billion. These values represent theoretical gross recoverable resource values and should not be interpreted as reserves, project revenues, or economic recoveries. Nevertheless, the results indicate that the Lower Napo Shale may represent a strategically significant unconventional resource opportunity capable of contributing to the long-term sustainability of hydrocarbon production within the Oriente Basin.

The conventional reserves of the Oriente Basin are currently estimated at approximately 1.3×10^9 bbl, representing an estimated production life of about 12 years under current production rates. In contrast, the P50 scenario estimates approximately 2.37×10^9 bbl of prospective unconventional shale oil resources in the Lower Napo Formation. If technically and economically developed, these resources could potentially extend the productive life of the Oriente Basin by at least 24 additional years, potentially beyond 2050. This project is subject to further appraisal, technical feasibility, economic viability, environmental constraints, and regulatory considerations

Additional regional structural correlations are provided in Appendix A, Figs. A-1 and A-2.

No funding was received for conducting this study.

References

Energy Information Administration (EIA). 2013. Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. Washington, DC: U.S. Department of Energy.

Energy Institute. 2023. Statistical Review of World Energy 2023. London, UK: Energy Institute.

Estupiñán, J. 2005. Diagenetic Control on the Quality of the U and T Sandstone Reservoirs of the Cretaceous Napo Formation, Oriente Basin, Ecuador. PhD Dissertation, Institut Français d'Études Andines, Quito, Ecuador.

**Estupiñán, J. and PermMayer, H. 2006. Diagenesis and Sequence Stratigraphy of the "U" Sandstone of the Napo Formation, Oriente Basin, Ecuador. Journal of South American Earth Sciences 21 (3): 215-228.

Institut Français d'Études Andines. 2005. Oriente Basin Stratigraphic and Structural Framework. Quito, Ecuador: IFEA Publications.

Instituto Argentino del Petróleo y del Gas (IAPG). 2026. Updated Assessment of Technically Recoverable Resources in the Vaca Muerta Formation. Buenos Aires, Argentina. Reports approximately 30.17 billion barrels of technically recoverable oil resources.

**Mancilla, G., Barragán, R., and Rosero, G. 2008. Petroleum Systems of the Oriente Basin, Ecuador. Paper SPE-115432-MS presented at the Latin American and Caribbean Petroleum Engineering Conference, Rio de Janeiro, Brazil, 15-18 June.

Society of Petroleum Engineers (SPE). 2018. Petroleum Resources Management System (PRMS). Richardson, Texas: Society of Petroleum Engineers.

Stinco, L. 2013. Unconventional Reservoirs in Argentina: Geological and Petrophysical Characterization. Buenos Aires, Argentina: Universidad de Buenos Aires Press.

**Stinco, L. and Barredo, S. 2014. Kerogen Characterization and Unconventional Reservoir Analogs in South American Sedimentary Basins. Presented at the AAPG International Conference and Exhibition, Cartagena, Colombia.

U.S. Energy Information Administration (EIA). 2024. Argentina's Crude Oil and Natural Gas Production Near Record Highs. Washington, DC, USA. Reports approximately 16 billion barrels of technically recoverable shale oil resources in the Vaca Muerta Formation.

Whidden, K.J., Pitman, J.K., Pearson, O.N., Paxton, S.A., Kinney, S.C., Gianoutsos, N., et al. 2018. Assessment of Undiscovered Oil and Gas Resources in the Eagle Ford Group and Associated Cenomanian-Turonian Strata, U.S. Gulf Coast, Texas, 2018. U.S. Geological Survey Fact Sheet 2018-3033. Estimated undiscovered technically recoverable resources of 8.5 billion barrels of oil.

Zhang, Y. 2017. Shale Gas Resource Assessment in the Oriente Basin, Ecuador. Journal of Petroleum Exploration and Production Technology 7 (4): 1045-1058.

Appendix A Regional Structural Correlations

Fig. A-1 presents the regional correlation along the Parahuacu–Cononaco section.

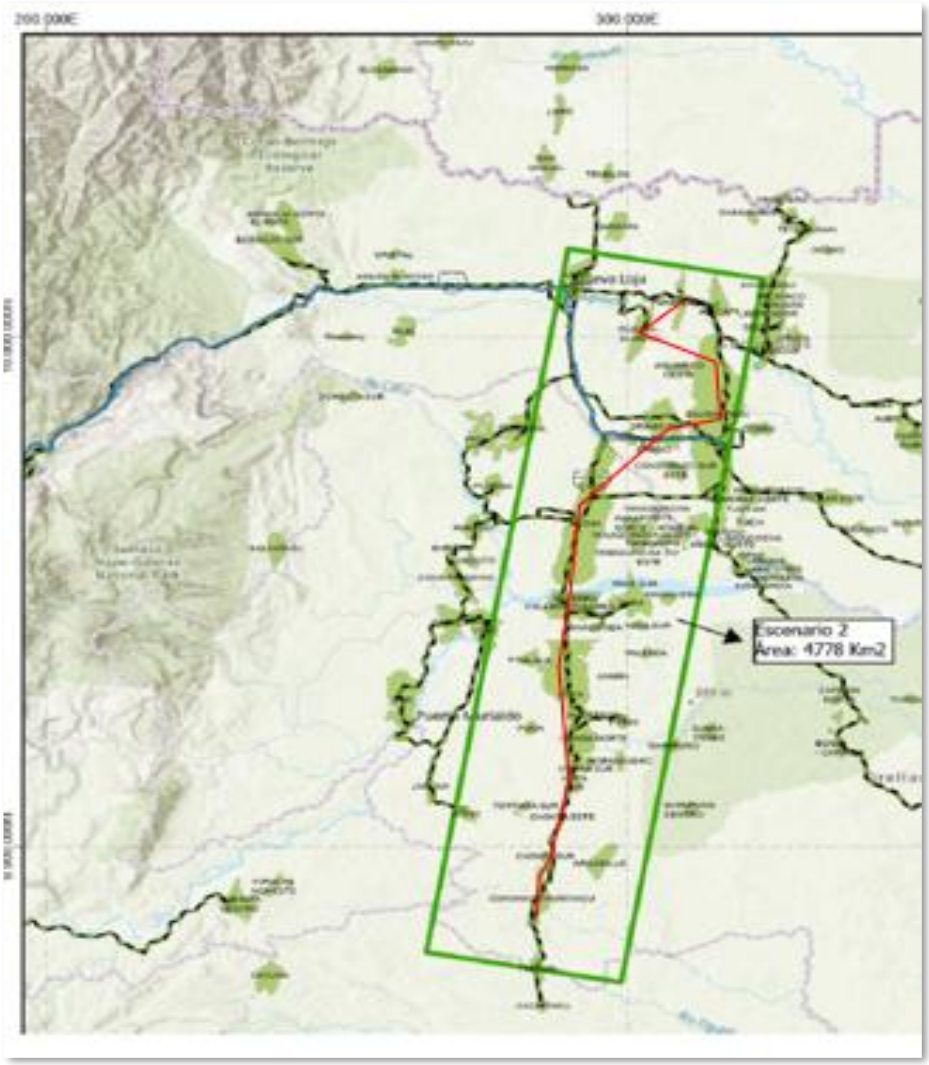


Fig. A-1—Map of the central Oriente Basin showing the regional cross-section line from Parahuacu to Cononaco.

Fig. A-2 presents the correlation flattened at the top of the BmTS horizon.

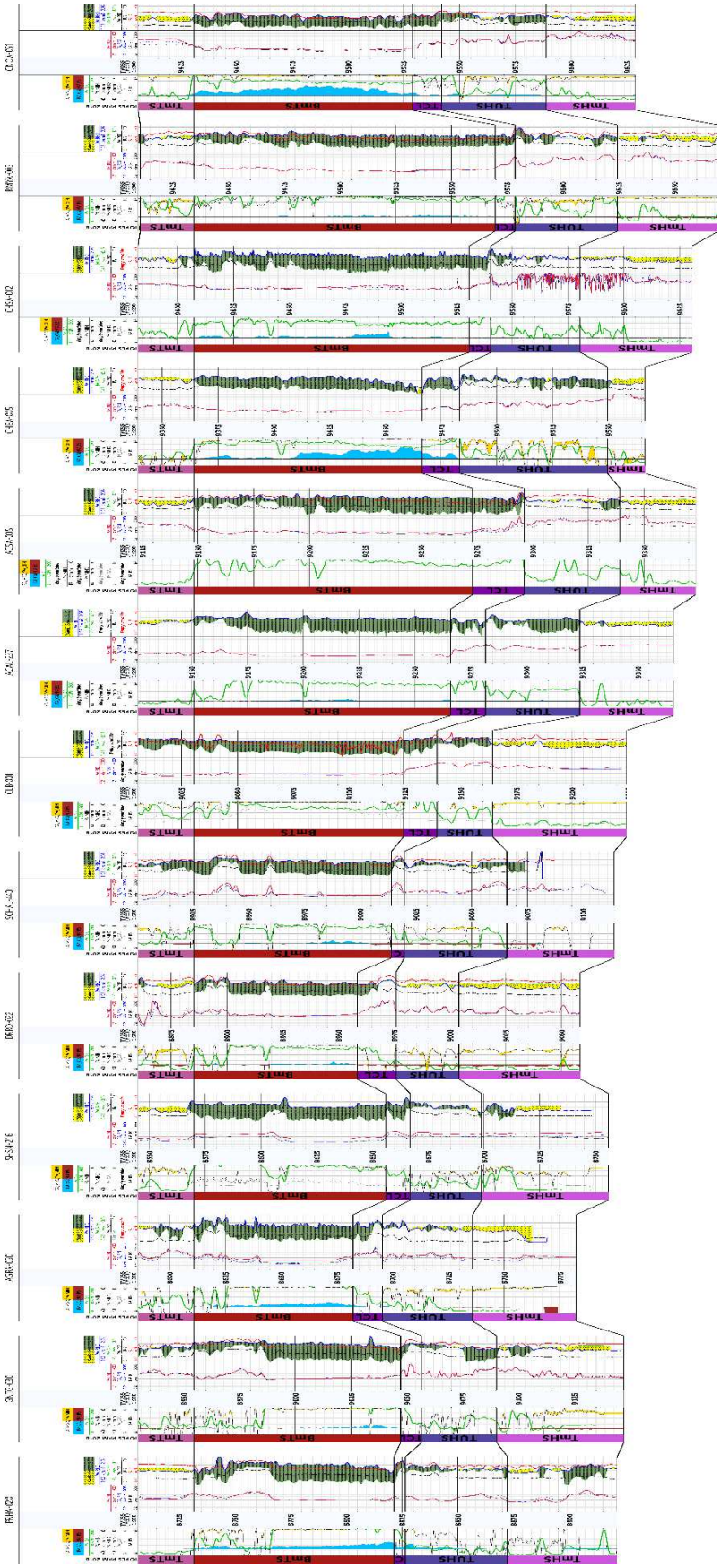


Fig. A-2—Regional structural correlation flattened at the top of the BmTS horizon (Lower Napo Shale), Central Oriente Basin.