



*Independent Statistics & Analysis*  
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# Technically Recoverable Shale Oil and Shale Gas Resources: Thailand

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## Executive Summary

### Introduction

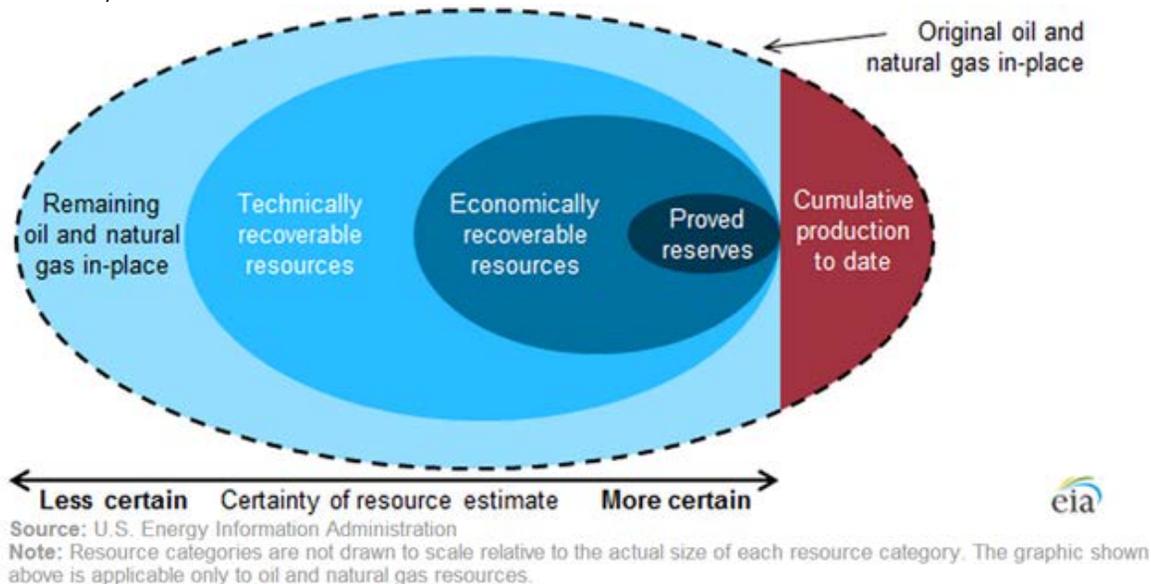
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

### Resource categories

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

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

(not to scale)



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## Methodology

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

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

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

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

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

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

## Key exclusions

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

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

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

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

<sup>4</sup> Referred to as risked recoverable resources in the consultant report.

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

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

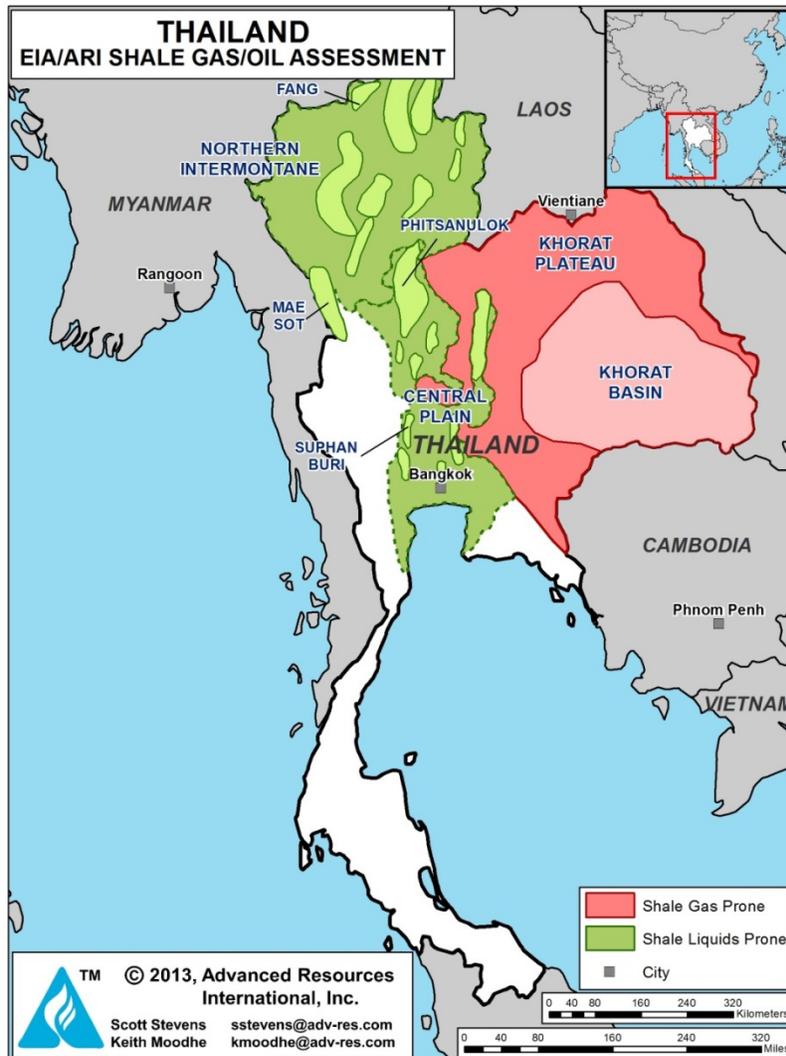
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

# XXII. THAILAND

## SUMMARY

While no shale gas/oil exploration activity has been reported to date in Thailand, this large Southeast Asian country has significant prospective shale gas and shale oil potential, in the Khorat, Northern Intermontane and Central Plains basins, Figure XXII-1.

Figure XXII-1. Prospective Shale Gas and Shale Oil Basins of Thailand.



Source: ARI, 2013

The Khorat Basin in northeast Thailand has an estimated 5 Tcf of risked technically recoverable shale gas resources, Table XXII-1. In addition, shale oil potential in the Northern Intermontane and Central Plains basins could be substantial but was not quantified due to the paucity of available public data. Block faulting has disrupted Thailand's onshore shale basins and may complicate future shale drilling and development. Overall, Thailand's shale gas/oil potential is promising but needs to be better defined by further data gathering and analysis.

Table XXII-1. Shale Gas Reservoir Properties and Resources of Thailand.

<b>Basic Data</b>	Basin/Gross Area		Khorat (32,400 mi <sup>2</sup> )
	Shale Formation		Nam Duk Fm
	Geologic Age		Permian
	Depositional Environment		Marine
<b>Physical Extent</b>	Prospective Area (mi <sup>2</sup> )		1,750
	Thickness (ft)	Organically Rich	400
		Net	200
	Depth (ft)	Interval	6,000 - 12,000
Average		9,000	
<b>Reservoir Properties</b>	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		3.0%
	Thermal Maturity (% Ro)		2.50%
	Clay Content		Low
<b>Resource</b>	Gas Phase		Dry Gas
	GIP Concentration (Bcf/mi <sup>2</sup> )		83.0
	Risked GIP (Tcf)		21.8
	Risked Recoverable (Tcf)		5.4

Thailand's greatest potential appears to be shale gas deposits contained in Permian and Triassic shale source rocks in the Khorat, the country's largest onshore sedimentary basin. These shales can be locally thick, organic-rich, dry gas prone, deeply buried, and over-pressured. Deposited under shallow marine conditions, they are likely to mineralogically brittle and suitable for hydraulic fracturing. The Khorat Basin has an existing gas pipeline network, local drilling rigs, and active independent oil and gas producers which could facilitate shale gas development.

Thailand's shale oil potential appears to be more limited. Small isolated sub-basins within the Northern Intermontane and Central Plains basins contain organic-rich shales of Oligocene to Early Miocene age. These units sourced the basin's conventional oil deposits, including the 30,000-b/d Sirikit-1 oil field. Thermally immature oil shale deposits that are locally

mined at the surface may contain mobile hydrocarbons at depth. However, these low-rank Tertiary shales were deposited under lacustrine sedimentary conditions and may be high in clay content with low “frackability”.

## INTRODUCTION

During the past three decades Thailand has built up a substantial oil and natural gas production industry. The country produced 393,000 b/d of crude oil and liquids in 2011 and 3.6 Bcfd of natural gas in 2011.<sup>1</sup> Nearly 90% of its current petroleum output comes from offshore fields in the Gulf of Thailand, with only limited production from small onshore fields. Approximately 40% of Thailand’s primary energy consumption is supplied by natural gas, including most of the country’s power generation and growing vehicle fuel usage.

Essentially all of the oil and gas currently produced in Thailand comes from conventional sandstone and carbonate reservoirs. While a handful of coalbed methane exploration wells were drilled in Thailand during 2004-6, without commercial success, and some low-permeability carbonates are being targeted in conventional anticlinal traps in the Khorat, there have been no reports of unconventional shale/tight oil or gas exploration & development to date. The only tangible sign of activity for Thailand’s unconventional resources was an MOU signed between Statoil and PTTEP in January 2011 covering potential joint studies of conventional and unconventional resources in Thailand and other countries.<sup>2</sup>

ARI’s review of published geologic literature indicates that Thailand has three main onshore sedimentary basins which may have unconventional oil and gas potential, Figure XXII-1. These include the large Khorat Basin in the northeast; a series of smaller, isolated pull-apart basins (such as Mae Sot) in the Northern Intermontane Basin, where shale oil deposits are being mined; and the similarly complex Central Plains Basin, which hosts the 30,000-b/d Sirikit-1 oil field.

Permo-Triassic shale source rocks in the Khorat Basin, thought to have sourced the overlying Permian carbonate conventional reservoirs, may offer Thailand’s best shale gas resource potential. These marine-deposited shales are thick, organic-rich, within the dry gas thermal maturity window, often over-pressured, and may be mineralogically brittle. The Khorat Basin hosts an existing gas pipeline network, a local supply of suitable drilling rigs, and a small group of active independent oil and gas producers.

Oil-prone shale/tight resources in Thailand appear to be less prospective, although available geologic information is scater. The most obvious oil-prone shale potential is the downdip extension of lacustrine oil shale (solid mineral) deposits which are mined on a small scale in the northern inter-montane basins. Similar shale/tight oil deposits also may be present in the Central Plains Basin. These oil-prone shales appear less prospective due to their lacustrine origin, low apparent thermal maturity, as well as the general paucity of publicly available subsurface geologic data.

## 1. KHORAT BASIN

### 1.1 Introduction and Geologic Setting

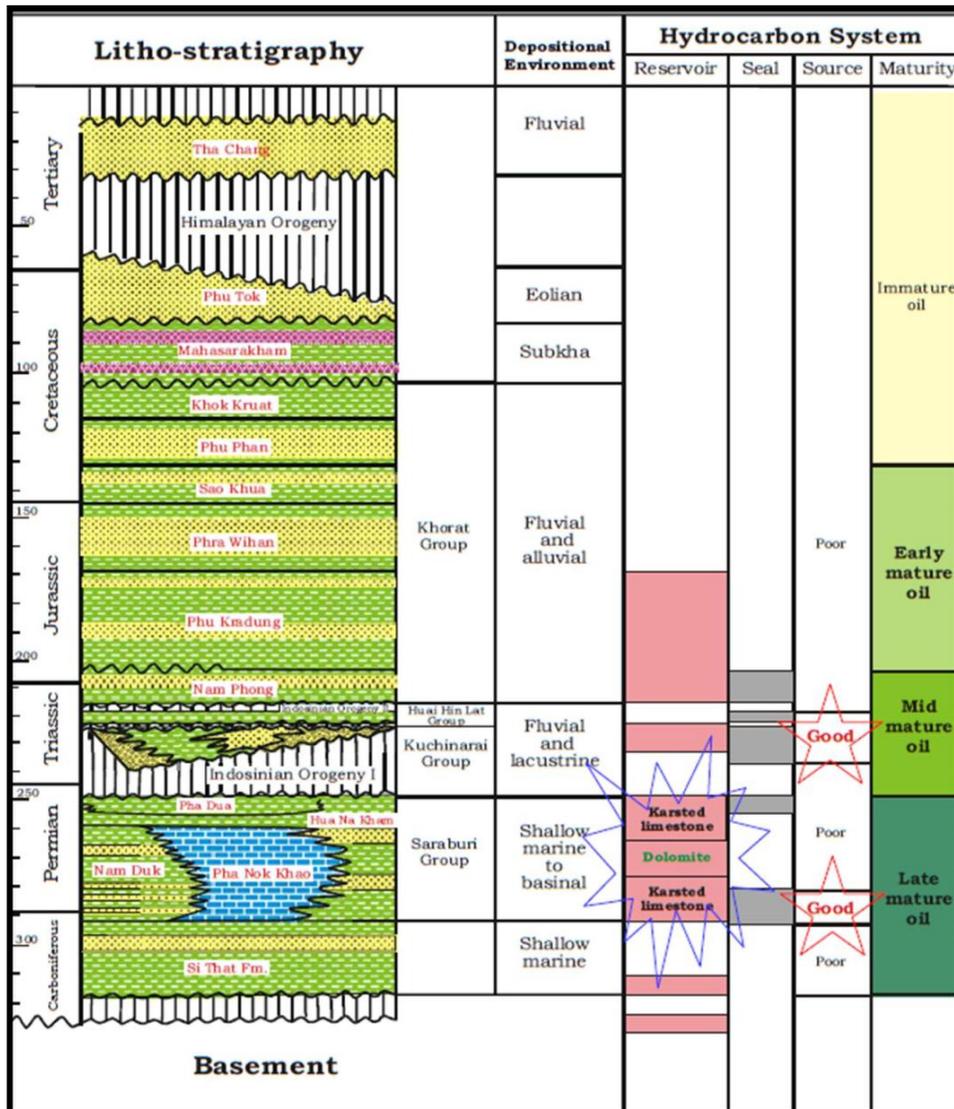
The Khorat Basin in northeast Thailand appears to have the country's best shale gas potential. Thailand's largest onshore sedimentary basin, the 35,000-mi<sup>2</sup> petroliferous Khorat lies within the southern half of the Khorat Plateau, a large roughly circular physiographic province. Ringed by mountain ranges, the Plateau itself is relatively flat with 200-m average elevation. Drained by the Moin and Chi Rivers, the Khorat Plateau receives less rainfall than central Thailand, with more extreme dry and wet seasonality. The local economy of this rural area is mainly agricultural based, with few large cities or industrial centers.

The Khorat Basin is separated from the Sakon Nakhon Basin to the north by the Phu Phan anticline. The Khorat rests on the Indochina tectonic microplate, which is bordered by the Shan Thai and South China plates to the west and north, respectively. Its sedimentary sequence comprises a series of Late Cambrian through Recent strata, which are interrupted by numerous unconformities and dominated by Permo-Carboniferous, Triassic/Mesozoic, and Tertiary/ Quaternary deposits. Figure XXII-2 illustrates the stratigraphy and petroleum systems of the Khorat Basin.<sup>3</sup> The shallow marine to basinal Permian Saraburi Group is considered the primary source rock, while the fluvial to lacustrine Triassic Kuchinarai and Huai Hin Lat Groups offer additional source rock potential. Permian dolomite and karsted limestones form the main conventional petroleum reservoirs.

The structural Khorat Basin depression was initiated during the Middle Paleozoic, with widespread deposition of clastic and carbonate sedimentary rocks, beginning with the Carboniferous Si That Formation.<sup>4</sup> Tectonic extension during the Early Permian broke the basin apart into numerous horst and graben blocks separated by high-angle normal faults. Carbonate reef deposits of the Pha Nok Khao Formation formed on regional highs, while clastic and shale

deposits of the Nam Duk Formation were deposited in the troughs, with some areas approaching 20,000 feet thick. Mixed sediments of the Hua Na Kham Formation were then deposited during the Middle to Upper Permian. Later basin-scale compression and inversion caused regional uplift and thrusting. Seismic and thermal maturity data indicate that uplift and erosion removed 3,000 to 9,000 feet of sedimentary cover during this event.

Figure XXII-2. Stratigraphy and Petroleum Systems of the Khorat Basin. Shallow Marine Permian Saraburi Group is the Primary Source Rock. The Fluvial to Lacustrine Triassic Kuchinarai and Huai Hin Lat Groups Also Have Potential. Permian Dolomite and Karsted Limestones are the Main Conventional Petroleum Reservoirs.



Source: Thailand Ministry of Energy, 2007.

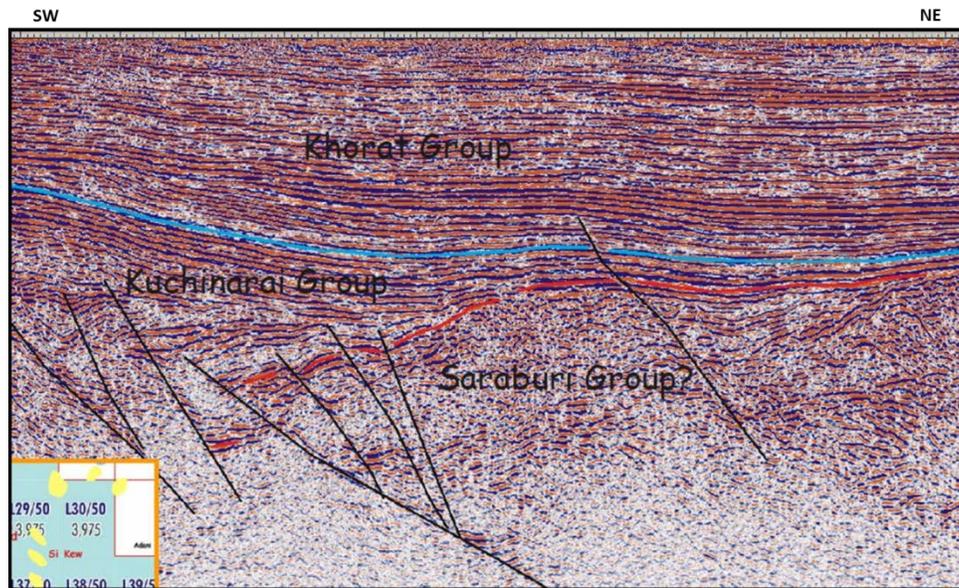
Following the Indosinian orogeny, Early Triassic continental and lacustrine sediments of the Kuchinarai Group began to unconformably fill the extensional grabens of the Khorat Basin. A second orogenic collision marked by volcanics followed, after which Late Triassic fluvial clastics were deposited. A further erosional or non-depositional hiatus occurred until the Middle to Late Jurassic, after which non-marine clastics and shales of the Khorat Group were deposited. After a Middle Cretaceous period of deformation and volcanic events, evaporites and clastics of the Mahasarakham Formation were deposited. Finally, the Tertiary Himalayan orogeny brought about regional uplift and erosion, removing up to 6,000 feet of rock.

Figure XXII-3 shows a southwest-northeast oriented seismic time section from the western Khorat Basin. It highlights possible Permian Saraburi Group and Triassic Kuchinarai Group source rock shales and carbonates, which may be prospective for shale gas exploration. These strata are overlain by fluvial and alluvial clastic rocks of the Jurassic Khorat Group; these are not considered prospective due to their low TOC content. Note significant faulting of the Saraburi Group and, to a lesser extent, Kuchinarai Group rocks.

Figure XXII-4 is a south-north oriented seismic time section from the eastern Khorat Basin. Here, the low-TOC Carboniferous Si That Formation is overlain by possible conventional reservoirs of the Permian Pha Nok Khao Formation. The primary Saraburi Formation source rock does not appear to be present in this part of the basin, while the Huai Hin Lat Formation source rock is relatively thin. These Carboniferous, Permian, and Triassic rocks were block faulted and overlain by fluvial and alluvial clastic rocks of the Jurassic Khorat Group. This preliminary information suggests that the western Khorat Basin may be more prospective for shale gas exploration than the east.

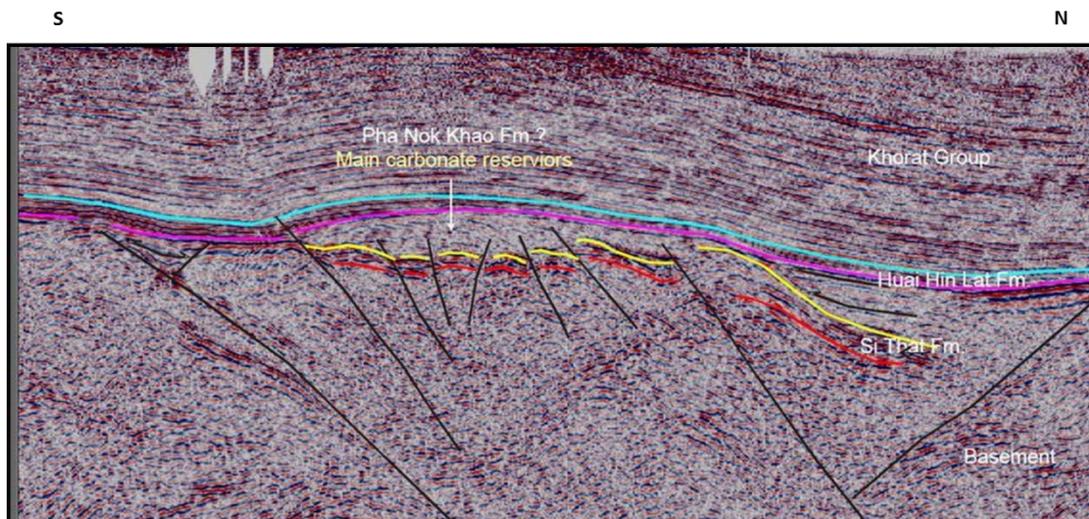
Figure XXII-5 is a schematic, non-directional cross-section of the Khorat Basin illustrating conventional petroleum play concepts. Note the Permo-Triassic source rock shales - the primary targets -- are quite discontinuous, block faulted, and eroded in many portions of the basin. The patchy shale distribution and structural and erosional complexity are likely to complicate shale gas exploration in the Khorat Basin.

Figure XXII-3. Southwest-Northeast Seismic Time Section in Western Khorat Basin, Shows Permian Saraburi Group and Triassic Kuchinarai Group Source Rock Shales and Carbonates, Overlain by Fluvial and Alluvial Clastic Rocks of the Jurassic Khorat Group.



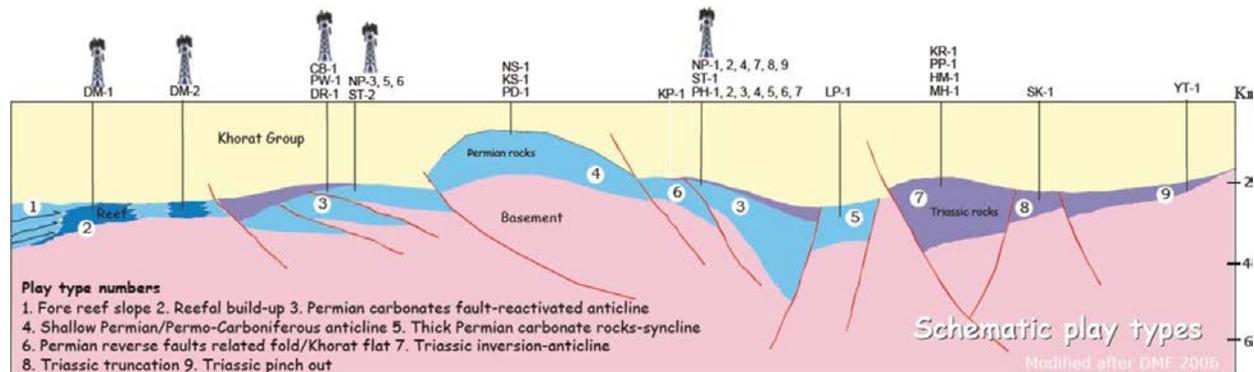
Source: Thailand Ministry of Energy, 2007.

Figure XXII-4. South-North Seismic Time Section from Eastern Khorat Basin, Showing Low-TOC Carboniferous Si That Formation Overlain by Conventional Reservoirs of the Permian Pha Nok Khao Formation. The Saraburi Formation Source Rock Does Not Appear to be Present in this Part of the Basin, While the Huai Hin Lat Formation Source Rock is Relatively Thin. Note Significant Faulting of the Permo-Carboniferous Sequence.



Source: Thailand Ministry of Energy, 2007.

Figure XXII-5. Schematic Non-directional Cross-section of the Khorat Basin, Showing Conventional Petroleum Play Concepts. Note the Primary Permo-Triassic Source Rock Shales are Discontinuous, Block Faulted, and Partly Eroded across the Basin. This Structural Complexity may Complicate Shale Gas Exploration.



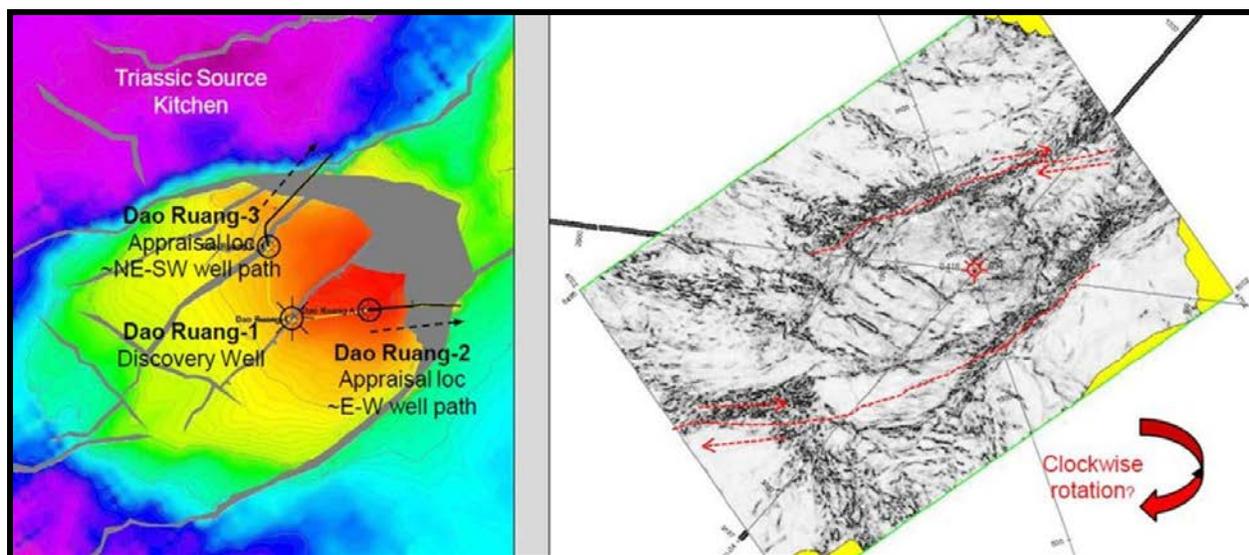
Source: Thailand Ministry of Energy, 2007.

Although the Khorat Basin is overmature for oil, a small number of conventional natural gas discoveries have been made. These fields target Permian carbonate and Triassic clastic reservoirs within anticlines and stratigraphic traps. Natural gas likely was sourced by older organic-rich Permo-Triassic shales, with gas being generated during the Early Tertiary following Cretaceous burial, and then possibly migrating along fractures and faults caused by extensional rifting.<sup>5</sup>

Figure XXII-6 illustrates a detailed seismic structure time map and structural interpretation of a small gas field in the central Khorat Basin. Note the deep Triassic source rock “kitchen”, the uplifted anticlinal fold that formed a conventional gas trap, and the interpreted clockwise rotation along strike-slip faults that created this local structure.

UK-based independent Salamander Energy holds several license blocks in the Khorat Basin. At last report, Salamander was acquiring 3D seismic, conducting basin modeling, and planning its first exploration well in 2012-13 to test conventional Permian carbonate targets.<sup>6</sup> Earlier this year Yanchang Petroleum, China’s fourth largest state-owned petroleum company, reportedly entered into a contract with Thailand’s Ministry of Energy to explore natural gas opportunities in the Khorat. Coastal Energy and Hess also have interests in Khorat Basin blocks but have not reported activity in the past two years.<sup>7,8</sup>

Figure XXII-6. Seismic Structure Time Map and Interpretation of Small Gas Field in the Khorat Basin. Note Deep Triassic Source Rock "Kitchen", Anticlinal Fold, and Interpreted Clockwise Rotation along Strike-Slip Faults.



Source: Salamander Energy PLC.

## 1.2 Reservoir Properties (Prospective Area)

Thick, organic-rich source rock shales and carbonates of Permian and Triassic age occur at prospective depth in the Khorat Basin, although mapping the location and size of depth-screened areas is not possible with current data. These shales are thermally dry-gas-prone to over-mature, with little or no liquids potential. Deposited under shallow marine to basinal sedimentary conditions, these shales are thought to have sourced the conventional Permian carbonate and Triassic clastic reservoirs of this region, including two significant producing gas fields.

Shallow marine shales also occur in the Carboniferous Si That Formation, typically at depths below 13,000 feet.<sup>9</sup> However, basin maturity modeling estimates that this unit is thermally over-mature and not prospective for shale gas development ( $R_o$  of 3 to 4%). The Early Permian Nam Duk Formation contains several thousand feet of continental to shallow marine sediments, including some organic-rich shale. TOC reportedly can exceed 3%, while depth ranges from 8,000 to more than 10,000 feet and the formation often is over-pressured. The calculated vitrinite reflectance is over 2.5%, thus the Nam Duk Fm is a potential dry gas shale target that is unlikely to be prospective for liquids.

Fluvial and lacustrine deposits of the Triassic Kuchinarai Group also have been identified as petroleum source rocks in the Khorat Basin, with high-TOC intervals of unreported thickness. The Kuchinarai Group reportedly averages a prospective 6,500 to 7,000 feet deep within the basin. Thermal maturity modeling suggests it reaches the dry gas window, with no liquids potential ( $R_o > 2.0\%$ ).

### 1.3 Resource Assessment

As discussed above, the Permian Nam Duk Formation contains organic-rich shales with suitable depth and thermal maturity and appears to be the most prospective target for shale gas development. Additional shale gas potential may exist in other organic-rich shales, such as the Triassic Kuchinarai Fm, but these were not assessed due to lack of data. The limited publicly available data on the Khorat Basin is not sufficient to constrain the regional distribution of suitable thickness, depth, TOC, thermal maturity, and prospective area. Average values for these parameters were estimated and augmented by analogs with commercial North American shale plays that have been more thoroughly studied.

A good North American analog for the Nam Duk Fm could be the Wolfcamp Shale in the Permian Basin, West Texas.<sup>10</sup> These formations share similar age (Lower Permian), depositional setting (shallow marine), thickness (>1,000 ft), lithology (high in carbonate, low in clay), TOC content (average 3%), over-pressuring (uncertain in the Khorat but assumed to be 0.6 vs 0.7 psi/ft for the Wolfcamp). The Khorat Basin appears to be structurally more deformed and faulted than the Permian Basin but the difference is not extreme. Furthermore, the Permian Basin Wolfcamp is less thermally maturity, ranging from the black oil to wet gas windows, thus the analogy is imperfect.

The Nam Duk Fm is well over 1,000 ft thick, with reported average 9,000 ft depth, 3% average TOC, and falls within the dry-gas thermal maturity window ( $R_o > 2.5\%$ ). The Nam Duk is discontinuously present within the basin due to uplift and erosion. Prospective area could not be rigorously mapped due to lack of data but is assumed to be 5% of the Khorat Basin area (~1,750 mi<sup>2</sup>). Net organic-rich shale thickness also is uncertain but is assumed to be 200 feet, much less than 20% of formation thickness. Known to be over-pressured but not known to what extent, the pressure gradient was assumed to be 0.6 psi/ft, slightly below the Wolfcamp analog. ARI assumed 6% porosity based on the Wolfcamp analog.

Based on these data and assumptions, the Nam Duk Formation in the Khorat Basin was estimated to have 22 Tcf of risked shale gas in-place, with 5 Tcf of risked, technically recoverable shale gas resources, Table XXII-1. More detailed study is recommended to define and map these parameters and estimate the full shale gas resource potential of the Khorat Basin.

#### **1.4 Recent Activity**

No shale gas activity has been reported in Thailand's Khorat Plateau.

## **2. CENTRAL PLAINS BASIN**

### **2.1 Introduction and Geologic Setting**

Thailand's Central Plains Basin is located in the south-central portion of the country, including the Bangkok region and the highly productive rice-growing regions of the lower Chao Praya River. Covering a 25,000-mi<sup>2</sup> area, the Central Plains Basin is not a continuous deposit like the Khorat but rather comprises a number of small, deep, north-south trending and discontinuous half-grabens of Tertiary age, formed due to transpressional pull-apart tectonics. The province includes the prominent Phitsanulok, Suphan Buri, Kamphaeng Saen, and Petchabun petroliferous sub-basins, among others.

The Central Plains Basin is oil-prone and currently produces oil from conventional Miocene sandstone reservoirs as well as pre-Tertiary fractured granites. Miocene lacustrine-deposited shales, which are organic-rich and considered the primary source rocks in this basin, appear to have Thailand's best potential for shale oil exploration. However, shale oil prospects which may be identified by future work are likely to be limited in size, reflecting the small discontinuous nature of the sub-basins.

Similar to most of Thailand's basins, the structural history of the Central Plain is punctuated by periods of extension and subsequent erosion. Lacustrine shales and sediments were deposited during Oligocene to Early Miocene time.<sup>11</sup> An active margin developed in the Middle Miocene, depositing interbedded fluvial sandstones and mudstones. Alluvial-fluvial sediments were then deposited towards the end of the Tertiary and into the Quaternary. In some areas, up to 26,000 feet of Cenozoic strata have been preserved.

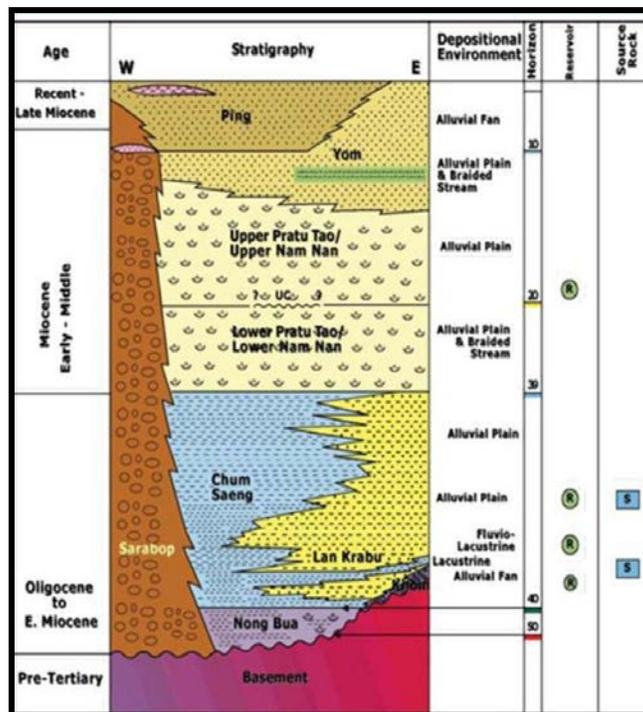
Middle Miocene sandstones (and more recently pre-Tertiary granites) are the primary conventional target in the various Central Plains sub-basins, such as at Sirikit field within the Phitsanulok Basin. Thailand's largest onshore oil field, the Sirikit (now called S-1) commenced production in the early 1980's, with over 250 wells drilled and 170 MMBO produced to date. The oil is inferred to have been sourced from the underlying lacustrine shales. PTTEP acquired the S1 field from Thai Shell in 2003 and plans to extract an additional 40 to 50 MMbbls over the next 10 years. During Q3-2012 PTTEP produced an average 30,000 b/d of oil from Sirikit-1, while continuing to drill new development wells there. PTTEP's onshore focus has been on advanced drilling and exploration techniques.<sup>12</sup>

In the Phitsanulok Basin, the main organic-rich lacustrine shales comprise the Early Miocene Chumsaeng Fm, which was deposited in a deep lake environment. Stratigraphically equivalent sediments are also noted in the Suphan Buri and other sub-basins, usually unnamed. These type I/II source rocks display high to variable TOC (average >2.0%<sup>13</sup>), with high hydrogen indices reaching over 700 mg HC/g.<sup>14</sup> Gross thickness averages 1,300 feet, with a net organic-rich shale interval of at least 600 feet. In the deeper parts of Central Plain basins, the Chumsaeng and Early Miocene lacustrine shales may reach maximum depths of nearly 15,000 feet. Oil generation depths in the smaller Suphan Buri Basin average 7,000 feet, suggesting a large range in thermally mature depths for liquids production.

Figure XXII-7 illustrates the stratigraphy and conventional petroleum systems of the Central Basin. Oligocene Nong Bua and Sarabop formations, the oldest sedimentary rocks in the Central Basin, rest unconformably on pre-Tertiary basement. Fluvial to lacustrine shales within the Oligocene to Early Miocene Chum Saeng Group act as the main source rocks. Clastic rocks of the Oligocene Lan Krabur and Miocene Pratu Nam Nan formations, deposited under alluvial plains settings, are the conventional reservoir targets. These in turn are overlain by Late Miocene to Recent alluvial fan deposits sourced by regional uplift associated with the Himalayan Orogeny.

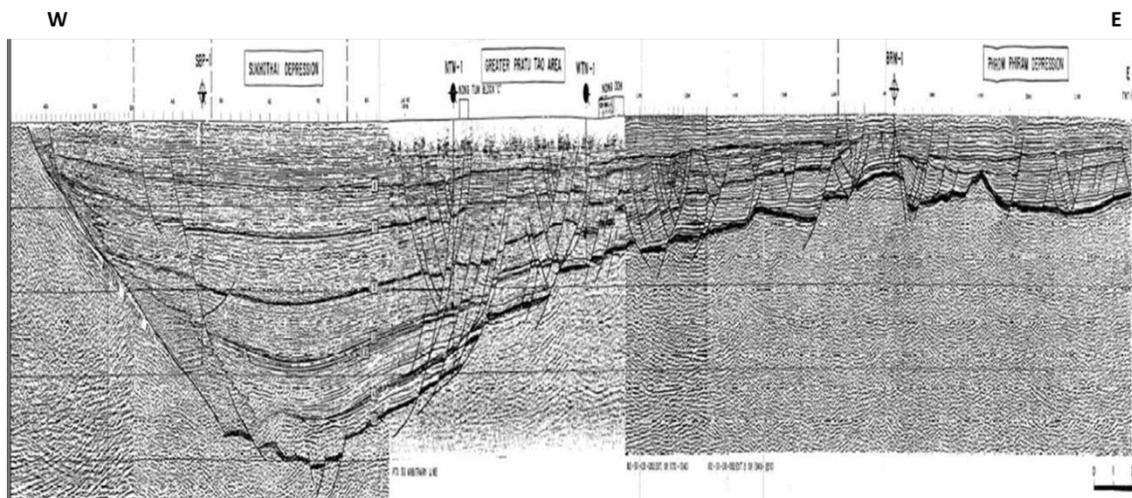
Figure XXII-8 shows a west-east oriented, uninterpreted seismic time section from the Phitsanulok Basin, one of numerous sub-basins within the overall Central Plains Basin. The main source rocks are fluvial to lacustrine shales within the Oligocene to Early Miocene Chum Saeng Group, which appear to be discontinuously present on top of pre-Miocene basement. Significant normal faulting may hinder shale oil development in this basin.

Figure XXII-7. Stratigraphy and Petroleum Systems of Thailand’s Central Basin. Fluvial to Lacustrine Shales within the Oligocene to Early Miocene Chum Saeng Group are the Main Source Rocks, while Alluvial Plain Clastics of the Oligocene Lan Krabur and Miocene Pratu Nam Nan Formations are Conventional Targets.



Source: Thailand Ministry of Energy, 2007

Figure XXII-8. West-East Seismic Time Section in the Phitsanulok Sub-basin within the Central Plains Basin. The Main Source Rocks are Fluvial to Lacustrine Shales within the Oligocene to Early Miocene Chum Saeng Group, Discontinuously Present on Top of Pre-Miocene Basement. Note Significant Normal Faulting.



Source: Thailand Ministry of Energy, 2007

### 3. NORTHERN INTERMONTANE BASIN

#### 3.1 Introduction and Geologic Setting

Thailand's Northern Intermontane Basin is a large loosely defined area covering the north-central and northwestern portions of the country. Similar to the Central Plains Basin and quite unlike the relatively continuous Khorat Basin, the Northern Intermontane Basin comprises numerous small and completely isolated structural troughs that are separated by uplifts. Several of these pull-apart basins, such as the Fang Basin, produce oil in anticlinal traps from conventional sandstone reservoirs that were sourced by organic-rich Miocene lacustrine shales. In addition, solid oil shale mineral resources near the surface in the Mae Sot Basin are under small-scale mining development. These organic-rich lacustrine-deposited shales may become thermally more mature and contain mobile oil in the deeper troughs, although ARI could not map this due to very sparse data control.

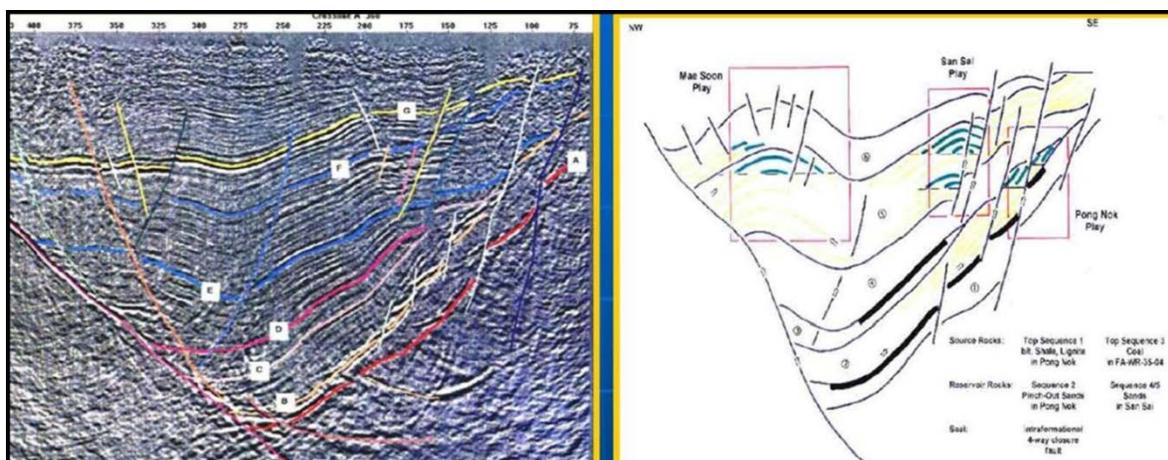
**Mae Sot Sub-Basin.** The Mae Sot Sub-basin of northwestern Thailand is one of the more prominent intermontane basins in this topographically mostly rugged Northern Intermontane region. This north-south trending basin extends over an area of approximately 900 mi<sup>2</sup>, with one-third of the area extending across the Moei River into Myanmar on the west.<sup>15</sup> Gently undulating hills and alluvial plains comprise the topography of the basin itself, which averages about 650 feet above sea level.

The Mae Sot Basin is divided into north and south sub-basins, with the southern region having the thickest sedimentary section. It contains mainly non-marine Cenozoic sedimentary units overlying Permian to Jurassic carbonate and clastic rocks that were deposited in pull-apart basins and half grabens. These units include the Mae Ramat, Mae Pa, and Mae Sot formations, the latter recognized for its oil shale deposits.

Hydrocarbon exploration of the Mae Sot Basin began with Swiss and Japanese geologists in the late 1930's. In 1947 Thailand's Department of Mineral Resources conducted an oil shale reserve evaluation. During the 1980's, the German and Japanese governments conducted feasibility analyses of the oil shale potential. Since 2000 Thailand's Mineral Fuels Division has renewed its research on Thailand's oil shale deposits.

**Fang Sub-Basin.** The crescent-shaped Fang Sub-basin in the far north of Thailand, located about 150 km north of Chiang Mai, is a fault-bounded intermontane depocenter containing Cenozoic sediments, Figure XXII-9. The 220-mi<sup>2</sup> trough trends NW-SE and borders a steep mountain range to the east. The Fang Basin is generally flat with slightly rolling hills and an average elevation of 1,500 feet above sea level.<sup>16</sup> A high geothermal gradient exists throughout the half-graben, evidenced by hot springs in the northern region. Site of Thailand's first commercial oil field, over 240 wells have been drilled to date in the Fang Sub-Basin.

Figure XXII-9. Stratigraphy and Petroleum Systems of Thailand's Central Basin. Fluvial to Lacustrine Shales within the Oligocene to Early Miocene Chum Saeng Group are the Main Source Rocks, while Alluvial Plain Clastics of Oligocene Lan Krabur and Miocene Pratu Nam Nan Formations are Conventional Targets.



Source: Thailand Ministry of Energy, 2007

During the early Tertiary, extensional faults and rifting associated with the Indian and Himalayan collision opened up the basin. Syn-rift sequences of alluvial-fluvial and lacustrine sediments were deposited during the Eocene to Miocene, followed by post-rift sequences of younger alluvium and marked by a significant unconformity. Overlying these rocks are undifferentiated gravels, sands, soils, and clays of Quaternary to Recent age. Total thickness of the sedimentary sequence reaches 10,000 ft.

The stratigraphy of the Tertiary rocks generally can be divided into two units, the Mae Fang and underlying Mae Sot formations. Interbedded coarse sandstone and red to yellow claystone occur in the Late Miocene to Pleistocene Mae Fang Formation; these were deposited in an alluvial-fluvial environment and average 1,400 feet thick. Below this unit, fluvial sandstone layers within the Mae Sot Formation have been the principle reservoirs for conventional oil field

production in the basin, beginning in the 1920's. As the Northern Intermontane region's most productive locale, the Fang Basin has yielded six oil fields, although the Pong Nok and Chaiprakarn were abandoned in the mid 1980's. These reservoirs apparently were sourced by lacustrine mudstones and shales within the Mae Sot Formation itself, most likely the main shale oil exploration target within the Fang Basin.

### 3.2 Reservoir Properties (Prospective Area)

**Mae Sot Sub-Basin.** The Paleocene Mae Ramat Formation contains mostly alluvial conglomerate, sandstone, limestone, and mudstone units that unconformably overlie pre-Tertiary strata.<sup>17</sup> The Mae Ramat Fm is up to 700 feet thick and deeper than 3,300 feet (the maximum total depth of available well data). Overlying the Mae Ramat Fm is the Upper Oligocene Mae Pa Formation, which contains lacustrine and fluvial deposits, including shales and marls, along with prevalent limestone lenses in the southern sub-basin. Minor oil shale deposits can occur within the 300-ft thick Mae Pa Fm, albeit interbedded with large amounts of low-TOC strata. The Mae Pa Fm averages about 3,000 ft deep. Overall, the Mae Ramat and Mae Pa formations are not considered viable source rocks due to lack of organic richness, undetermined shale thickness and low thermal maturity.

The most organically rich shale in the Mae Sot Basin is the Miocene Mae Sot Formation, which is dominated by shale with minor clastics. One interval within the Mae Sot Fm contains relatively thin (10 to 15 feet) oil shales beds within sandy shale assemblages, although maximum thickness can exceed 33 feet. Rock mineralogy is dominated by quartz, feldspar, calcite, dolomite, and clay (proportions not reported). In the northern sub-basin, these lacustrine oil shale deposits are grey to green and nearly 100 feet thick. Kerogen consists mainly of exinite, with immobile oil content ranging from 2.5 to 62 gallons per ton (1% to 26% by weight). Oil shale grade is highest in the middle-lower section of the unit. This formation is typically about 2,000 feet deep across much of the Mae Sot Basin. Overall, the Mae Sot Formation appears too shallow and immature for shale oil development, with  $R_o$  well below the 0.7% threshold.

**Fang Sub-Basin.** The Mae Sot Formation of Miocene to Pliocene age can be divided into three units: a lower section of brown to reddish sandstone; a middle zone of organic-rich lacustrine claystone, shale, and coal with interbedded sandstone; and an upper layer of gray claystone, mudstone, and sandstone along with fossil inclusions. The conventional sandstone

reservoirs have 25% porosity and 0.2 to 2.0 Darcies of permeability. The crude oil ranges from 16 to 38 degrees API gravity.<sup>18</sup>

The rich bituminous shales of the middle unit are the recognized source rock, with calculated total organic carbon averaging 15% (Type I or II).<sup>19</sup> Gross formation thickness can be up to 2,100 feet, while high-TOC shale intervals interbedded with sandstone average 300 feet thick (net). The formation was penetrated in conventional wells at depths of 3,000 to 3,500 feet, but these likely were drilled on structural highs. Absent vitrinite reflectance data burial history modeling suggests an  $R_o$  of 0.5% is not reached until about 4,000-ft depth. The minimum depth for mobile oil generation (0.7%  $R_o$ ) may be about 6,000 ft. Only a small portion of the Fang Basin appears to meet these screening criteria. ARI is unable to quantify such a prospective area given limited available data.

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