Abstract

Drilling and production onshore and offshore Mexico have substantiated U. Jurassic source rocks as effective source rocks for conventional and now unconventional petroleum resources. The U. Jurassic section in the Tampico-Misantla basin has excellent source rock characteristics for oil generation based on good original TOC values and hydrogen indices indicative of oil prone marine organic matter. From a mineralogical viewpoint, these shales (or mudstones) are generally very high in carbonate content that is conducive to unconventional production potential.

Data from various source rock oil reservoir systems show that the overall petroleum composition is significantly different from juxtaposed, organic-lean, non-source rock intervals as well as produced petroleum at the wellhead or separator. Thus, it is necessary to understand the in situ petroleum composition of the source rock if that is the completion objective. Petroleum composition affects physicochemical properties such as API gravity, viscosity, and gas-to-oil ratio (GOR). For example, the amount of the polar compounds (NSOs) is inversely proportional to API gravity and saturated hydrocarbon content. It then is important to discriminate the oil type and related phase as black oil, volatile oil, condensate-NGL, and dry gas by correlative and direct indications of such composition.

At higher thermal maturities, oil quality increases rapidly as the non-hydrocarbon constituents of petroleum are cracked to hydrocarbons and refractory carbonaceous residues. There is an exponential increase in GOR in the volatile oil to the earliest gas window, albeit appearing linear in the black oil window. The key is to relate the physicochemical properties of petroleum to correlative tools, i.e., thermal maturity measurements, and direct indicators of sub-surface oil properties and phase.

A combination of visual and chemical measurements, when available, are used to risk thermal maturity assessments including vitrinite and solid hydrocarbon reflectance, Tmax, hydrogen index, gas composition, gas carbon isotopes, and aromatic hydrocarbons. These values are integrated into an interpretive thermal maturity and related to surface and subsurface API gravity and GOR values. Reasonable thermal maturity interpretation allows restoration of the petroleum generation potential for any given sample analyzed by determining the level of kerogen conversion and also taking into consideration secondary cracking. This permits computation of restored TOC, hydrogen indices, and pyrolysis (S2) yields. From these results, the total generation potential can be estimated along with expelled and retained petroleum contents. Comparing these reverse model results with forward model results using restored total oil (S1total) allow a check and a comparative estimate of expulsion as otherwise estimated. These predictions are further checked by slope factor analysis allowing PVT-like restoration of oil and gas yields.

Introduction

The Upper Jurassic source potential and its effectiveness in sourcing various petroleum pools in Mexico have been well documented by various authors (e.g., Morelos, 1996; Santamaria, 2000; Magoon et al., 2001). There are three
source rock intervals in the Upper Jurassic of Mexico: Tithonian Pimienta Shale, Kimmeridgian Taman Formation, and Oxfordian Santiago Formation. These intervals have been documented by the above-referenced authors as a Type II marine carbonate source rocks that generate petroleum of varying quality primarily depending on thermal maturity. Produced oils range in API gravity from the low tens to over 40°API. Most low maturity, low gravity oils also contain high sulfur contents. However, mature black oils and volatile oils are low in sulfur.

This paper addresses various geochemical characteristics of the U. Jurassic in the Tampico-Misantla (T-M) basin in east-central Mexico along the Gulf of Mexico (Figure 1). The onshore area of the basin is of recent interest in both its conventional and unconventional potential for additional production.

The U. Jurassic source rocks have varying thicknesses with the Pimienta Shale reaching over 200 meters in some locations. The Taman and Santiago formations also vary but reach about 60 to 90 meters in thickness. The formations are largely continuous with little present-day depth change across the basin.

Figure 1. Map of Mexico with an approximate outline of the Tampico-Misantla basin.

Results

Data from various sources illustrates not only the source potential but also the high degree of variability in the Pimienta Shale due to both organofacies and thermal maturity variation (Figure 2). The Taman and Santiago formations show less variability and are marine carbonate source rocks. Original source rock quality in the Pimienta Shale suggests good TOC values averaging about 4.50% with original hydrogen indices (HI) from 400 to over 600 mg petroleum potential per gram of rock. Interestingly one of the top unconventional shale resource plays in the USA, the Eagle Ford Shale, has very similar bulk organic properties. Indeed, these ‘shales’ are not high in siliciclastic material but are carbonate mudstones despite the common nomenclature. The range of carbonate content and TOC values shows that high TOC values are found at both high and low carbonate contents (Figure 3). In zones of high production potential carbonate contents average 52 wt.%. 


The importance of such high carbonate content within a source rock interval relates to higher storage capacity (porosity and permeability), high brittleness, enhanced primary migration and expulsion, and reduced retention by organic and clay adsorption. These are reasons, at least in part, for the high productivity of the Eagle Ford Shale in South Texas, USA. While secondary porosity enhancement by source rock acids has been discounted in conventional reservoirs (e.g., Barth and Bjørløkke, 1993), acid etching has been noted in various unconventional shale resource plays in the USA, e.g., the Eagle Ford Shale, possibly in the Middle Member of the Bakken Formation (Pitman et al., 2001), the Niobrara Formation (Budd, 2016) and the Smackover Formation (Jarvie, 2014).

Figure 2. Present-day source rock generation potential and TOC in the Upper Jurassic, Tampico-Misantla Basin, Mexico.

Figure 3. Range of carbonate carbon values per TOC for the Pimienta Shale showing high TOC values at both high and low carbonate carbon values.
Of course important in shale resource plays is the generation of mobile oil with associated gas to assist production efforts. As such the thermal maturity of the T-M U. Jurassic section is shown to cover a full range of maturation ranging from early to late black oil, volatile oil, condensate-wet gas, and wet gas. The objective for high volume production from shale oil resource systems is typically volatile oil maturity (0.90% to 1.15%Roe) with the Middle Member of the Bakken formation being an exception.

A modified Espitalie plot of kerogen type and thermal maturity from Tmax illustrates the variable thermal maturity of the Pimienta Shale (Figure 4). This plot clearly shows the change in remaining generative organic carbon in the form of HI with maturity allowing clear prediction of organic matter conversion or kerogen transformation ratio (TR). This maturity and TR values must then be related to product composition particularly for the retained product, i.e., petroleum present in the source rock. Since it is known that the U. Jurassic has expelled petroleum that charges conventional reservoirs in the Tampico-Misantla basin, knowledge of the quality of the retained petroleum is paramount to assessing the producibility of the shale resource system(s).

![Figure 4. A modified Espitalie kerogen type and thermal maturity plot using hydrogen index (HI) vs. average Tmax values from 82 wells in the U. Jurassic of Tampico-Misantla Basin. Some Tmax values are unreliable and are not used in estimating kerogen conversion.](image)

Determining Thermal Maturity on Marine Shales

The industry standard for thermal maturity assessments is vitrinite reflectance. However, one of the ongoing problems in determining the thermal maturity of marine carbonates and shales is that they are often devoid of vitrinite particles that are derived from land plants. If vitrinite particles are present, it is a subjective process for the microscopist to determine if the particles are autochthonous or allochthonous. Whole rock vitrinite reflectance assists the microscopist’s interpretation by allowing viewing of the particle in the context of the rock matrix, but typically very few readings are obtained. However, it is preferable to have correct readings rather than 20 readings of allochthonous vitrinite particles. Another approach is to measure the reflectivity of bitumen, solid hydrocarbons, or pyrobitumen, which is then corrected to a reflectivity of vitrinite particles by equations published by Jacob (1989) or Landis and Castaño (1995). However, the calibration curves for the reflectivity of bitumen or solid hydrocarbons by these two equations result in quite different values (Table 1).

Tmax is a chemical measure of thermal maturity derived from the kinetics of kerogen decomposition. Thus, Tmax values are determined by, and depend on upon, kerogen kinetics. An important distinction between marine carbonate and marine shale source rocks is that they will crack to petroleum under different thermal regimes.
depending on their composition and chemical configuration. Also, Tmax can be fraught with problems. These are usually related to the features (shape) of the pyrolysis (S2) pyrogram that can be skewed by retained oil and oil-based mud (OBM) usually to lower Tmax values. Soltex®, a sulfonated asphalt, and similar products are commonly used in either water-based mud or OBM when drilling shales. It is particularly problematic as it chemically binds to the shale. Depending on the shale maturity and kerogen yield, it can either lower or raise Tmax values. Thus, it is important to check the mud additives log to see what was added to the mud and when. Poorly shaped, indistinct, or broad peaks from samples with low S2 values will also give poor Tmax values as will spikes in the S2 peak (usually from dust particles passing through the detector). Salt ionization will also skew Tmax to unusually high values (Espitalie et al., 1984).

If a single maceral type becomes dominant either throughout or from restructuring of organic matter, Tmax will again vary. It is also affected by oxidation.

Table 1. Comparison of Jacob versus Landis and Castaño conversions of solid bitumen or solid hydrocarbons to an equivalent %Ro value including the difference (%Roe(LC) - %Roe(J)).

<table>
<thead>
<tr>
<th>%Ro</th>
<th>Jacob Conversion (%Roe(J))</th>
<th>Landis &amp; Castano Conversion (%Roe(LC))</th>
<th>Delta</th>
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<tr>
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A formulation for conversion of reliable Tmax values to equivalent vitrinite reflectance values (%Roe) for the Barnett Shale was presented by Jarvie et al. (2001), i.e., %Roe = 0.018 x Tmax - 7.16. This was done as there was little or no vitrinite present in the Barnett Shale and was utilized as another risking parameter to assess thermal maturity (Jarvie et al., 2007). The Jarvie et al. (2001) conversion equation is substantiated by comparison to reported values for vitrinite reflectance and Tmax by Teichmüller and Durand (1983). Taking the midpoint of their graphical representation of the Teichmüller and Durand data, the Jarvie et al. (2001) equation plots basically on top of this midpoint from 0.50% to 1.5%Ro (Figure 5). A more accurate representation of the Teichmüller and Durand (1983) data is given by a 5th order polynomial extending the range to 2.0 %Ro, i.e., y = 8.69E-11x^5 - 1.93E-07x^4 + 1.70E-04x^3 - 7.34E-02x^2 + 1.56E+01x - 1.31E+03 (note that the numbers must be extended to 12 places to obtain correct estimates). However, it must be noted that Tmax is seldom reliable at very high thermal maturity as it is based on the presence of a distinct pyrolysis (S2) peak, which is nearly completely exhausted at high maturity resulting in a flat, broad or indistinguishable peak.
The fit of the Jarvie et al. (2001) equation is also confirmed by the data of Espitalie et al. (1984) and also Cornford et al. (2002), the latter two of which overlay the Jarvie et al. (2001) data as well as the Teichmüller and Durand (1983) mid-point line.

Various issues with data quality and interpretation can arise from the use of both Tmax and measured vitrinite reflectance. Another approach can be utilized effectively is based on the fact that increasing thermal maturity results in increasing aromatization. Taking advantage of this by using quantitative aromatic hydrocarbon analysis allows another means of determining an equivalent vitrinite reflectance. It is difficult to establish a correlation to vitrinite reflectance to some extent but once the calibration is established it is always the same and constant based on quantitative chemical analysis. Aromatic hydrocarbon data acquired on Pimienta Shale shows the relationship between these select aromatics and an indication of vitrinite reflectance (Figure 6). The key then becomes establishing the product type and quality at a given maturity level.

An evolving thermal maturity assessment approach is to utilize quantitative aromatic hydrocarbons from GC/MS/MS (gas chromatography mass spectrometry) or triple quad (QQQ) analysis (Rocher et al., 2015). The logic behind this approach is that with increasing thermal maturity, there is increased condensation or aromatization. A relationship of methylphenanthrenes was found to provide an indication of thermal maturity (Radke et al., 1983), but has been inconsistent in providing thermal maturity values on oil prone petroleum source rocks. Pyrolysis gas chromatography experiments on rock samples by Hill et al. (1995) showed a clear relationship of select aromatic compounds to thermal maturity of rock samples. The GC/MS/MS approach detailed by Rocher et al. (2015) uses 31 different aromatic compounds in ratios providing what they refer to as VREQ, i.e., equivalent vitrinite reflectance from quantitative QQQ analysis. Their approach has been used on over 300 oil and rock extract samples with maturity values matching production results extremely well (Jarvie, unpublished data, 2015).

There are several benefits to the QQQ approach: (1) it is quantitative analysis meaning it is not a subjective process, (2) it does not depend on the presence of vitrinite particles, (3) it can be completed on rock extracts or oil samples, and (4) it is generally a very expedient analysis. It has not, to date, shown significant dependency on source rock lithofacies, although Ordovician source rocks and oils yield lower values than expected for thermal maturity.
Figure 6. One formulation for determination of an equivalent vitrinite reflectance value from quantitative aromatic hydrocarbon analysis of Pimienta Shale oils and extracts.

Nonetheless, once a value for thermal maturity is established, it must necessarily be related to the level of kerogen conversion and the quality of the generated petroleum. This relationship is illustrated in Figure 7, where at the same level of thermal maturity as determined by calculated vitrinite reflectance (EasyRo) using a constant heating rate of 3.3°C/ma for comparison purposes. This shows that the level of kerogen conversion varies by source rock, primarily by lithofacies and sulfur content (Jarvie and Lundell, 2001). At 0.90 %Ro under these arbitrary conditions, the Kimmeridge and Monterey shales are 77% converted to petroleum, whereas the Woodford, Green River Oil Shale, and Pennsylvanian coal samples are only about 44%, 35%, and 18% converted, respectively. All are at the same level of thermal maturity, but at vastly different levels of conversion of the organic matter. It then becomes a challenge to determine the quality and phase of petroleum generated for each source rock at a given thermal maturity and TR.

Figure 7. The level of kerogen conversion for given levels of vitrinite reflectance, either measured or equivalency values. Note the high level of kerogen conversion at 1.0 %Ro (blue dashed line) in the Kimmeridge Clay and Monterey Shale compared to the Woodford Shale and Pennsylvanian coal from Indiana. Assessing Retained Petroleum Quality
In order to assess petroleum quality, samples of the retained petroleum need to be assessed for various geochemical properties such as API gravity, SARA (saturates, aromatics, resins, and asphaltenes) yields, alkane (paraffin) distribution, and gas-to-oil ratios (GOR). Of obvious concern is the low API gravities of conventionally produced petroleum in the Tampico-Misantla basin. API gravities range from 10 to about 40°. It would be inherently more difficult to flow high density, highly viscous oils through tight shale with low pressure. Open-fractured shale reservoir production provides one indication of generation and storage as has been demonstrated in unstimulated horizontal wells in the U. Bakken Shales since the late 1980s (LeFever, 1991) and the Bazhenov Shale in the Western Siberian Basin (Lopatin et al., 2001).

To address petroleum quality and phase, an initial assessment of whole and extracted rocks was analyzed using the new HAWK Petroleum Assessment Methodology (PAM). A comparison of standard pyrolysis output to the HAWK PAM approach is shown in Figure 8. This provides an indication of oil quality although it is necessary to account for the presence of oil-based mud (OBM) in most samples. A solution offered by efforts at Core Laboratories is to take a center-cut core plug, the same type of plug taken for rock mechanic analysis. When these plugs are analyzed by HAWK and gas chromatographically (GC) fingerprinted they are almost always devoid of any OBM contamination. Thus, high-quality samples for analysis are obtained via this procedure.

HAWK Petroleum Assessment Method (PAM) provides a means of predicting API gravity by using the correlation of predicted API to a derivative of HAWK peaks (Figure 9). It shows a linear correlation (R^2) of 0.91.

Obtaining SARA analysis provides a direct indication of bulk petroleum composition. Petroleum is comprised of non-polar hydrocarbons (saturates and aromatics) and very polar non-hydrocarbons (resins and asphaltenes). With increasing thermal maturity, the asphaltenes and resins crack along with kerogen in the oil window and into the earliest condensate-wet gas window to form additional saturated hydrocarbons and pyrobitumen. The SARA composition of Pimienta Shale extracts was found to be favorable for production with less than 20% polars in the shale extracts at about 0.90%Roe (Figure ). This is quite different from low thermal maturity Pimienta Shale that has upwards of 50% polars and yields oil gravities of less than 10-20°API.

SARA yields of saturates are correlated to the light versus heavier oil from the HAWK PAM data showing a linear correlation (R^2) of 0.75 (Figure 10). Although this is an initial correlation, it provides an expedient means to obtain bulk compositional data.

Figure 8. HAWK pyrograms: (1) classical method of S1 and S2; (2-right) petroleum assessment method (PAM) using multiple ramp and soak for determination of increasing volatility fractions of oil or rock extract (Oil-1, -2, -3, -4), which allows assessment of the quality of the retained petroleum.
Figure 9. API gravity prediction using HAWK Petroleum Assessment Method (PAM).

Figure 10. SARA yields from Pimienta Shale extracts showing high-quality petroleum atypical of many oils sourced by the Pimienta Shale offshore.
In SARA analysis, whether an oil or rock extract, there is evaporative loss and this increases with oil volatility. The same is true of Rock-Eval® or HAWK oil (S1) analysis or in GC fingerprinting. Thus, a sizeable portion of the oil content of a rock or oil is excluded from geochemical measurements simply due to evaporation. However, estimates of evaporative loss can be made using a combination of thermal maturity, oil density, lithofacies, and sample type (cuttings, SWC, core chips, center-cut core plugs) in combination with gas chromatographic results (Michael et al., 2013; Jarvie, 2015). In addition, gas chromatographic fingerprinting yields an exponential yield of hydrocarbons and alkanes increasing in the lightest components. The yield of alkanes can be used to construct an exponential fit on oil or rock extracts. A GC of a Pimienta Shale extract is shown in Figure 12 (a-left). After normalization slope factor analysis was completed on the highly correlated normal alkanes from C$_{21}$ to C$_{40}$ (Figure 11 (b-right)).
Using these results and limited production results from unconventional wells drilled in the Pimienta Shale and oils from conventional reservoirs, the petroleum quality and phase can be predicted using the approach of Holba et al. (2013) (Figure 12). From the restored gas contents and matching light hydrocarbon GOR calculation (Mango and Jarvie, 2001; Jarvie et al., 2015), a GOR is calculated to be of about 820 scf/stb, which is consistent with a mature black oil of 38°API. This GOR is the in situ GOR value, which is generally lower than the readings at the surface, but reflective of the true reservoir conditions. It also suggests a bubble point of about 6440 psi (Jarvie et al., 2015).

![Figure 12](image_url)

**Figure 12.** Relationship of API gravity to GC slope analysis as shown by Holba et al. (2013) showing the predicted API gravity for the analyzed Pimienta Shale sample to be approximately 38°API or late black oil window.

Returning to basic geochemical measurements that are available on a large number of samples from commercially available studies, the relationship of HI to Tmax can also be used as a generalized indication of product type and phase (Figure 13). One caveat to this relationship is any variations in organofacies, some of which are obvious from geochemical analysis of the Pimienta Shale in the T-M basin (Jarvie, 2016, unpublished data).

**Core Properties**

Limited petrophysical data and core analyses are available, but porosities and permeabilities are comparable to the Eagle Ford Shale. Porosities range from about 5-8% and permeabilities are in the tenth of a millidarcy range. Brittleness of the rock fabric is likely very high based on 52% carbonate content on average and also due to interbedded organic-lean intervals within the potent source rock systems.

**Volumes of Petroleum**

Estimated volumes of expelled and retained petroleum are determined using a stochastic formulation derived from the Barnett Shale (Jarvie et al., 2007). It utilizes a forward and backward model from present-day S1 and S2 values restored to original values (Jarvie et al., 2007; Michael et al., 2013; Jarvie et al., 2015). This also utilizes an estimate of expulsion based on the data of Pepper (1992) with the difference from total petroleum generation being retained petroleum. The estimate of expelled petroleum is approximately 60% of those generated; thus, retained petroleum is about 40%.
Figure 13. Using GC slope analysis to assess product type and phase, the relationship of HI to Tmax on a larger number of samples can be estimated for an indication of oil quality and phase. Variations in lithofacies will affect these predictions.

Using estimated net thickness of the Pimienta, Taman, and Santiago formations of 650 ft, an average retained petroleum content of 54 mmboe/section ± 15 mmboe/section is estimated. At the average value for retained petroleum, just over 12,000 acres would mean over one (1) billion barrels of oil equivalent in place. Given the lithologic framework of the U. Jurassic, while 5% recovery is readily achievable in such a setting, 10% recovery is not unexpected, resulting in a potential recovery of 1 billion barrels per 100,000 acres.

When compared to source rocks related to various shale oil resource systems, the Upper Jurassic of the Tampico-Misantla basin, Mexico, is one of the premier worldwide shale oil resource systems (Figure 14). The very organic-rich Bakken Shale and Bazhenov Shale are productive, but from open-fractured shale reservoirs; the main unconventional Bakken Formation production is from the organic-lean Middle Bakken Formation. When thickness is added to the equation, the U. Jurassic of the Tampico-Misantla basin is the top-ranked system regarding potential with the Wolfcamp and Eagle Ford being the second and third ranked systems. Of course, potential is not production so for the time being, the Eagle Ford and Wolfcamp are the top two systems in organic-rich shale oil production. The potential and thickness of the U. Jurassic make it an Eagle Ford/Wolfcamp type play – Eagle Ford-type source rock with Wolfcamp thickness.

While the above counts only petroleum found in organic-rich intervals, a percentage of the expelled petroleum will likely be found in juxtaposed, interbedded organic-lean intervals of the Upper Jurassic in the Tampico-Misantla basin.

Also, EOG Resources recently announced their enhanced oil recovery (EOR) efforts in the Eagle Ford Shale that showed very promising enhanced production (EOG, 2016). Improvements in EUR (estimated ultimate recoverable) of 30-50% were suggested (EOG, 2016). While EOG does cite that this will not work with every play type, the U. Jurassic of the Tampico-Misantla basin has very similar characteristics as the Eagle Ford Shale and will be a prime candidate for such efforts in the not too distant future.

**Resource and Comparative Costs**

Well costs in Mexico are considerably higher than in the U.S.A. at this time (15-20 million USD/unconventional well). However, it has been found that well costs in the U.S.A. decline by 30-50% with time due to experience and
also critical mass of services and supplies. Furthermore, productivity generally increases with time and experience in developing such plays.

In the U.S.A. two plays that exhibit properties similar to the U. Jurassic of the Tampico-Misantla basin are the Eagle Ford Shale (EFS) in terms of a marine carbonate source rock and the Wolfcamp Shale of the Midland Basin in terms of thickness. The pursuit of EFS shale oil effectively began in 2008 and as of December 31, 2015, the well count has reached over 9000 wells. EFS wells range from 5,000 to 13,000 ft deep depending on location (EIA, 2016). In the optimum volatile oil window, wells are approximately 10,900 ft. vertically and about 5,500 ft laterally (EIA, 2016). These wells use more than 7 million pounds of proppant and 5.7 million gallons of fluid incorporated into, for example, 22 stimulation stages (EIA, 2016). EFS well costs are currently ranging from about $6.9 million to $7.6 million depending on operator and location (EIA, 2016). Of this, completion costs are over 50% of well costs. Since 2012 drilling costs have dropped from about $180/ft to $125/ft, whereas completion costs have dropped from about $1.40/lb of proppant to $0.65/lb resulting in decreased well costs of over 40% (EIA, 2016). Current production from the EFS is 1.5 million barrels of oil/day and 6 billion cubic feet of gas/day (EIA, 2016).

Midland Basin Wolfcamp wells range from $6.6 to $7.7 million although vertical Spraberry wells are about $2.5 million (EIA, 2016). Lateral lengths are typically about 7,200 ft in the Wolfcamp (EIA, 2016). An average well cost estimate is $7.5 million with a range from $5.5 to $8.6 million (EIA, 2016). Each lateral is assumed to take about 60 acres (EIA, 2016). It is also assumed that multiple wells and horizons could be drilled from a single, well thereby dramatically reducing overall well costs in the future, which is also applicable to the thick U. Jurassic of the T-M basin, Mexico. Mexico is eager to promote the development of this play and has shown considerable professionalism and willingness to promote any changes that are needed to promote the economics and related mass-scale development of this world-class unconventional shale oil resource play for the country.

![Figure 14. Total petroleum generation potentials for various source rocks associated with shale oil potential at 1.00% vitrinite reflectance.](image-url)
Conclusions

Available data is high quality and allows a good estimation of the petroleum potential, thermal maturity, and oil quality for different maturation regimes of the Upper Jurassic intervals. Matching valid thermal maturity values to product quality and phase are one of the key factors in achieving success in shale oil resource plays. Combined with rock mechanics and core properties, the basis for great success in unconventional shale oil production in the Tampico-Misantla basin is readily foreseen

The Upper Jurassic of the Tampico-Misantla basin in Mexico has very high potential for unconventional shale oil production. This is due to a variety of factors including high amounts of retained petroleum, favorable rock properties, high maturity black and volatile oil regimes, and high net thickness. It is estimated that there are about one (1) billion barrels of retained oil in the U. Jurassic per 12,000 acres. However, economic success is currently constrained by high well costs and low oil prices. Should a critical mass of activity be attained, the Upper Jurassic in the Tampico-Misantla basin will be another shale oil resource gem, potentially one of the best in the world.

References


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Cornford, C., Burgess, C., Kelly, R., 2002. Truths in large data sets - ill: secure interpretations of maturation, generation and expulsion. Combined with rock mechanics and core properties, the basis for great success in unconventional shale oil production in the Tampico-Misantla basin is readily foreseen

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Conclusions

Available data is high quality and allows a good estimation of the petroleum potential, thermal maturity, and oil quality for different maturation regimes of the Upper Jurassic intervals. Matching valid thermal maturity values to product quality and phase are one of the key factors in achieving success in shale oil resource plays. Combined with rock mechanics and core properties, the basis for great success in unconventional shale oil production in the Tampico-Misantla basin is readily foreseen

The Upper Jurassic of the Tampico-Misantla basin in Mexico has very high potential for unconventional shale oil production. This is due to a variety of factors including high amounts of retained petroleum, favorable rock properties, high maturity black and volatile oil regimes, and high net thickness. It is estimated that there are about one (1) billion barrels of retained oil in the U. Jurassic per 12,000 acres. However, economic success is currently constrained by high well costs and low oil prices. Should a critical mass of activity be attained, the Upper Jurassic in the Tampico-Misantla basin will be another shale oil resource gem, potentially one of the best in the world.


