Unconventional Shale Reservoir Characterization Through Integration Between Geophysics and Geomechanics – A Case Study in the Chumsaeng Formation, Phitsanulok Basin, Thailand*

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Abstract

The Phitsanulok Basin is the largest onshore basin in Thailand. Located within the basin is the biggest oil field in Thailand, the Sirikit Field. As the conventional oil production has surpassed the plateau, unconventional play has emerged as a promising alternative to prolong the production and add up the resource. Source rock in the basin is the Oligocene lacustrine claystone or the Chumsaeng Formation (CS). The formation is mostly matured and widely extends throughout the basin. Recent study by the USGS suggests the Chumsaeng Formation has a potential to be a new unconventional shale gas/oil reservoir with an estimated undiscovered resource of about 50 MMbbl of oil and 310 bcf of gas.

This study aims to quantify and characterize shale gas/oil reservoir potential in the Chumsaeng Formation using rock physics analysis, seismic inversion, and reservoir characterization techniques. The study started with rock physics analysis to determine the relationship between geophysical, lithological, and geomechanical properties of rocks, with an objective of transforming geophysical information into key shale gas/oil resource properties. Total Organic Carbon (TOC) values from rock sample analysis were compared to resistivity, sonic log (Delta-logR), and acoustic impedance (AI) log data to verify whether a relationship between AI and TOC could be determined. Results of geomechanical tests on core samples were used to calibrate calculated dynamic elastic moduli to static elastic moduli. Simultaneous seismic inversion was later performed using three seismic angle stacks as input. The seismic inversion results provided spatial variation of geophysical properties, i.e. P-impedance, S-impedance, and density.

With results from rock physics analysis and from seismic inversion, the reservoir was characterized by applying analyses from wells to the inverted seismic data. A 3D lithofacies cube was generated based on the relationship between Vp/Vs and AI using the Bayesian classification method. TOC was calculated from inverted P-impedance. Elastic moduli, e.g. Young's modulus and Poisson's ratio, were calculated from inverted impedances. A seismic derived brittleness cube was later calculated from Poisson's ratio and Young's modulus cubes. Finally, all the

derived properties were interpreted and analyzed. The final result from reservoir characterization provided a spatial variation in rock facies and shale reservoir properties, including TOC, rock proximate brittleness or fracability, and elastic moduli.

From the analysis, the most suitable location for shale gas/oil pilot exploration and development was identified. The southern area of the survey, with an approximate depth of 650-850 m, showed the best potential for shale to be an unconventional reservoir in this area. The shale formation is thick, with intermediate brittleness and high TOC. The structure within the area is not complex, and considering the promising properties make it a potential sweet spot for future exploration of this shale reservoir. This study has demonstrated how seismic data can be implemented to characterize an unconventional reservoir, both with respect to lithology and geomechanical properties. The study also shows a practical shale reservoir analysis methodology that can be applied during exploration or initial stages of development. However, there are still unknown factors that has not been accounted for in this work, and additional geochemical and basin modeling studies are required to support these results, especially related to the maturation and depositional setting of this unconventional resource.

Discussion

The Sirikit Oilfield has been producing for over 40 years. As the conventional oil production has plateaued, an unconventional play has emerged as a promising alternative to prolong the production in the basin. The Sirikit Field is sourced by the Oligocene lacustrine claystone or the Chumsaeng Formation. The study by the US Geological Survey (USGS) in 2014 suggested that the formation has a potential to be a new unconventional shale gas/oil reservoir with an estimated undiscovered resource potential of about 50 MMbbl of oil and 310 bcf of gas. Two areas were chosen as a test area for unconventional shale gas/oil production in a shallow, rich and mature organic claystone of the Chumsaeng Formation. To further determine the feasibility of unconventional shale gas/oil development in the basin, an analysis on shale gas/oil properties and their extension in the basin were required. The objectives of this study were to characterize key shale gas/oil reservoir parameters and to evaluate the extension of potential unconventional shale gas/oil in the Phitsanulok Basin. This integrated study included rock physics analysis, seismic inversion, and reservoir characterization to achieve these objectives. One of the main challenges was the data availability. Since the field was originally producing from a conventional reservoir, only limited data had been acquired for the purpose of unconventional resource exploration.

The Phitsanulok Basin, located onshore Thailand, is a half-graben Cenozoic basin. The basin lies along a North-South extensional trend from onshore Thailand into the Gulf of Thailand. The opening of the basin resulted from a complex regional strike-slip fault system. A western boundary fault (Figure 1) is the main structural feature of the basin where the basin center and thick formations are located next to the fault (Flint et al., 1989). The Chumsaeng Formation was deposited simultaneously to the Lan Krabu Formation (Oligocene and Miocene) and its depositional environment is lacustrine. This formation acts as both source rock and seal in the Sirikit Oilfield. The main lithology is mud or claystone, and the formation thickness can be up to 400 m with an average thickness of about 200 m. Reservoir properties within this formation are poor, usually below 5% porosity and less than 0.01 md permeability (Pinyo, 2011). Kerogen is mainly type I and II with a TOC value ranging from 5-20%.

Rock Physics Analysis

A rock physics analysis was carried out using available well data. Well information was considered as hard data, yielding the most reliable information. Well logs were the main data considered at this stage. However, additional core data was used to determine geomechanical properties of the formation within the area. Results of the rock physics and geomechanical data analysis was used to aid the seismic inversion and reservoir characterization processes. The main objective of this analysis was to find a relationship between resulting seismic inversion properties, i.e. P-impedance, S-impedance, and density, to unconventional reservoir properties.

Simultaneous Seismic Inversion

3D seismic data provides spatially varying data (P-impedance, S-impedance, and density) of a study area and can be used to quantitatively define the shale gas/oil reservoir properties between existing wells. A simultaneous deterministic inversion technique was applied, using the seismic angle stacks, interpreted horizons and available wells as input. The inversion process inverted for three properties, P-impedance, S-impedance, and density.

Reservoir Characterization

Unlike conventional reservoir exploration, which focus on the presence of sandstone and its reservoir properties, an unconventional shale reservoir focusses more on shale organic richness, maturation, and geomechanical properties such as brittleness. This is because the shale oil/gas play is produced directly from a mature, organic rich shale, which acts as both source and reservoir rock at the same time. Furthermore, as hydraulic fracturing is used to improve the recovery from unconventional reservoirs, it is usually considered critical to have a good understanding of the geomechanical properties and any lateral variation in the area.

1. **TOC:** One of the key parameters, determining organic richness is the Total Organic Carbon (TOC) value. In order to spatially determine TOC from inverted seismic data, a cross plot between P-impedance and TOC was made. The plot shows a good correlation where high TOC shows low P-impedance and vice versa. The relation between TOC and P-impedance is expressed in equation 1.

$$\mathrm{TOC}=28.93(0.995^{\mathrm{AI}}) \tag{1}$$

2. **Fracability and Brittleness:** Brittleness is another key factor for hydraulic fracturing of shale gas/oil reservoirs. Shale brittleness may refer to likeliness of shale to fracture, which can remain open or close. Fracturing of brittle rock is likely to remain open while fracture of ductile rock is likely to heal (Bandyopadhyay et al., 2012). The most common and widely use of brittleness definition is the "seismic derived brittleness" by Rickman *et al*. (2008). The brittleness is calculated from Young's modulus and Poisson's ratio as expressed in equation 2.

$$\text{Brittleness (\%)} = \frac{1}{2}\left(\frac{E_{min} - E}{E_{min} - E_{max}} + \frac{\nu_{max} - \nu}{\nu_{max} - \nu_{min}}\right) \tag{2}$$

A rock with low Poisson's ratio and high Young's modulus is relatively hard and rigid. Thus, it is less ductile and is potentially brittle. Poisson's ratio and Young's modulus are readily available outputs from seismic inversion that can be used to provide a spatially varying dataset within an area of interest.

After performing seismic inversion, inverted seismic data (P-impedance, S-impedance, and density) were converted into TOC, elastic moduli, and brittleness cubes (Figure 2). The final reservoir property cubes were later interpreted and used to identify the best locations for unconventional shale gas/oil exploration.

From elastic moduli, TOC, and brittleness, the study area can be characterized into zones. The northwestern part of the survey showed relatively poor shale reservoir quality, as both Brittleness and TOC values were low. The complex fault structure also confirmed this to be an unfavorable area for further shale reservoir exploration. The southern part of this survey showed intermediate brittleness and high Poisson's ratio. The unconventional shale reservoir was also shallower and thickening in this area. The northeastern part of the survey showed increasing amounts of sandstone, leading to a more brittle rock type. However, the increasing amount of sandstone had replaced organic rich shale, which reduced the TOC. The formation in this part of survey was also deeper, and further unfavorable as a potential unconventional reservoir.

A target location or an area within a reservoir that represents the best production or potential production is often referred to as a "sweet spot". This study defined a sweet spot to be an area with favorable shale reservoir parameters, i.e. high TOC and brittleness. Figure 3 shows an arbitrary section and the extracted attribute map, highlighting sweet spot locations in bright warm color. The analysis chose the cut offs of brittleness > 30%, and TOC > 4%. Considering these parameters, the best exploration and development area (or sweet spot) was considered to be the southern section of survey (highlighted by the red polygon in Figure 3). This area has featured the following favorable parameters for an unconventional shale oil/gas reservoir: High TOC, intermediate to high brittleness, shallow (approximately from 650 to 850 mTVDSS), and non-complex structure.

Summary

To summarize, petrophysics, geophysics, and geomechanics disciplines are the key for reservoir characterization in the Chumsaeng Formation. The result and methodology have successfully proven itself as a very useful tool for further exploration of unconventional resources in this area. The Chumsaeng Formation was evaluated within a selected area, having well data and 3D seismic data available. The study demonstrates how seismic data can be implemented to characterize the reservoir and provides the first insight to the Chumsaeng Formation in terms of shale reservoir potential as the formation that can be quantitatively determined. From the reservoir characterization, the best unconventional shale exploration area was identified. The following conclusions and recommendations are drawn from this study:

- Elastic moduli, TOC, and brittleness are all related and can be explained petrophysically and geomechanically. The Chumsaeng Formation has a potential as an unconventional shale reservoir. From elastic moduli, brittleness, TOC, and co-rendered attributes, the sweet spot for an unconventional shale exploration in the Chumsaeng Formation is in the southern part of the selected study area.

- Since the work is a preliminary, additional geochemical and basin studies are required to support the reservoir characterization, such as source rock maturation and depositional modeling.

- Based on the identified sweet spot or the best location for exploration, an additional exploration well is recommended. This well should be focused as a shale reservoir exploration where core samples are collected for useful analyses such as geomechanical and geochemical analysis, image logs for fracture determination and stress direction, and di-pole shear sonic for rock physics analysis. An additional mirco-seismic monitoring is also recommended during the hydraulic fracturing process.

- Outputs from reservoir characterization can be further used to calibrate with the available hydraulic fracturing. Results of strain and tectonic are used for in-situ stress calculation and mechanical earth model (MEM) building. This model is useful for hydraulic fracturing operations as it determines how much pressure is required, and what type of fracture will occur

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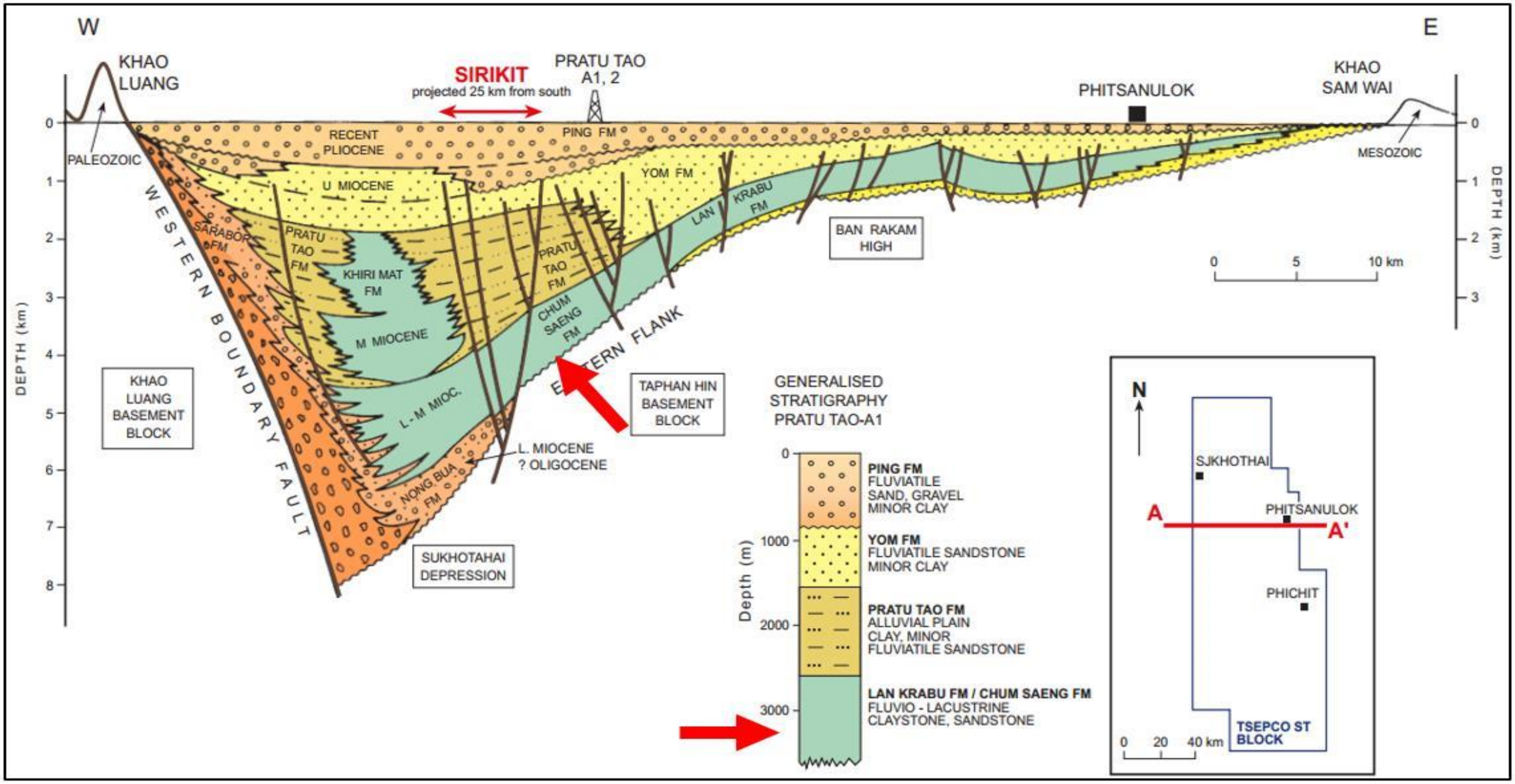

Figure 1. West-East cross section of the Phitsanulok Basin with the western boundary fault and half graben structural feature (Flint et al., 1989).

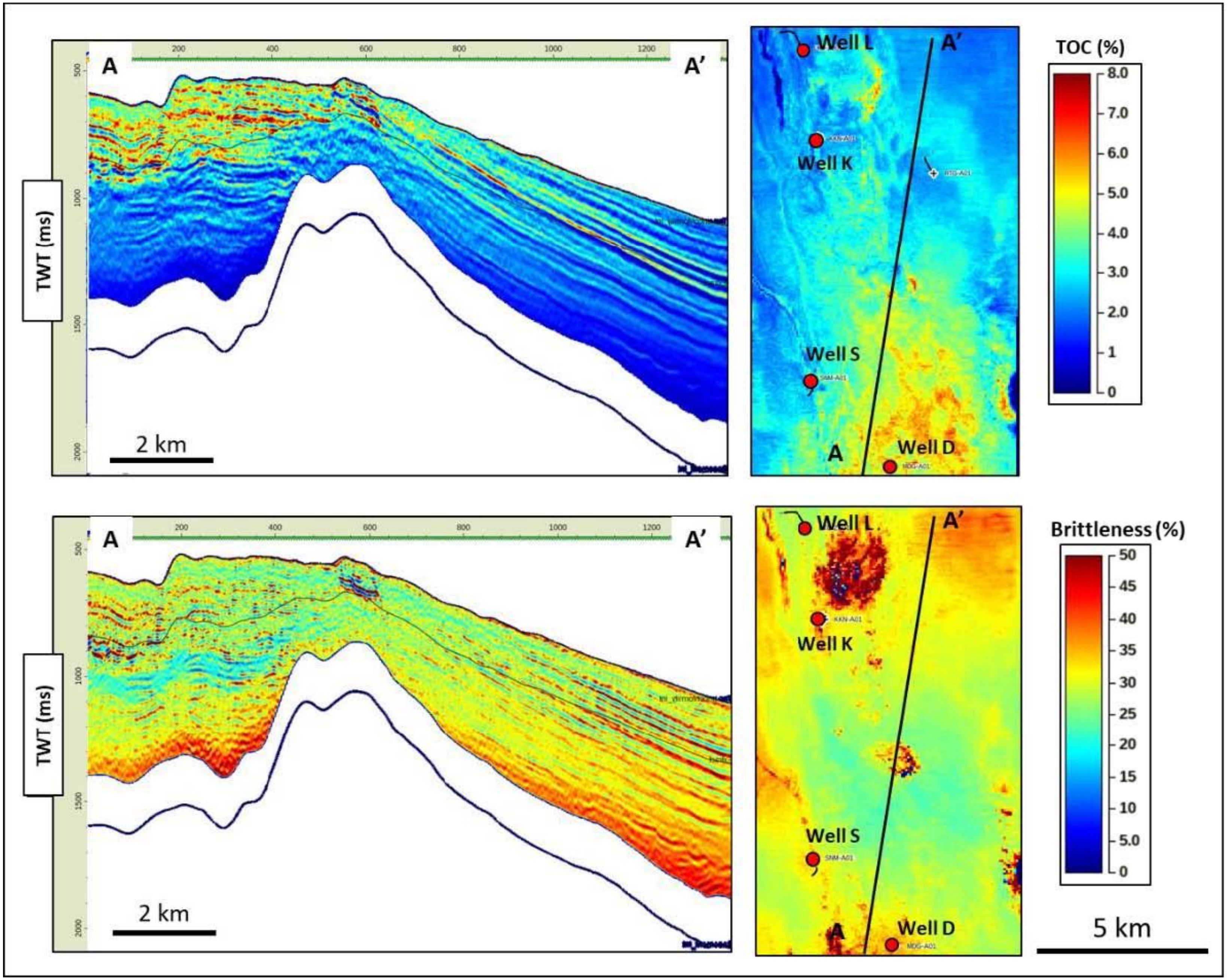

Figure 2. Arbitrary section and extracted map of averaged TOC and brittleness (50 ms window of Gaussian average) along intermediate horizon between top seal and basement. The southern part of the survey has relatively high TOC and intermediate brittleness.

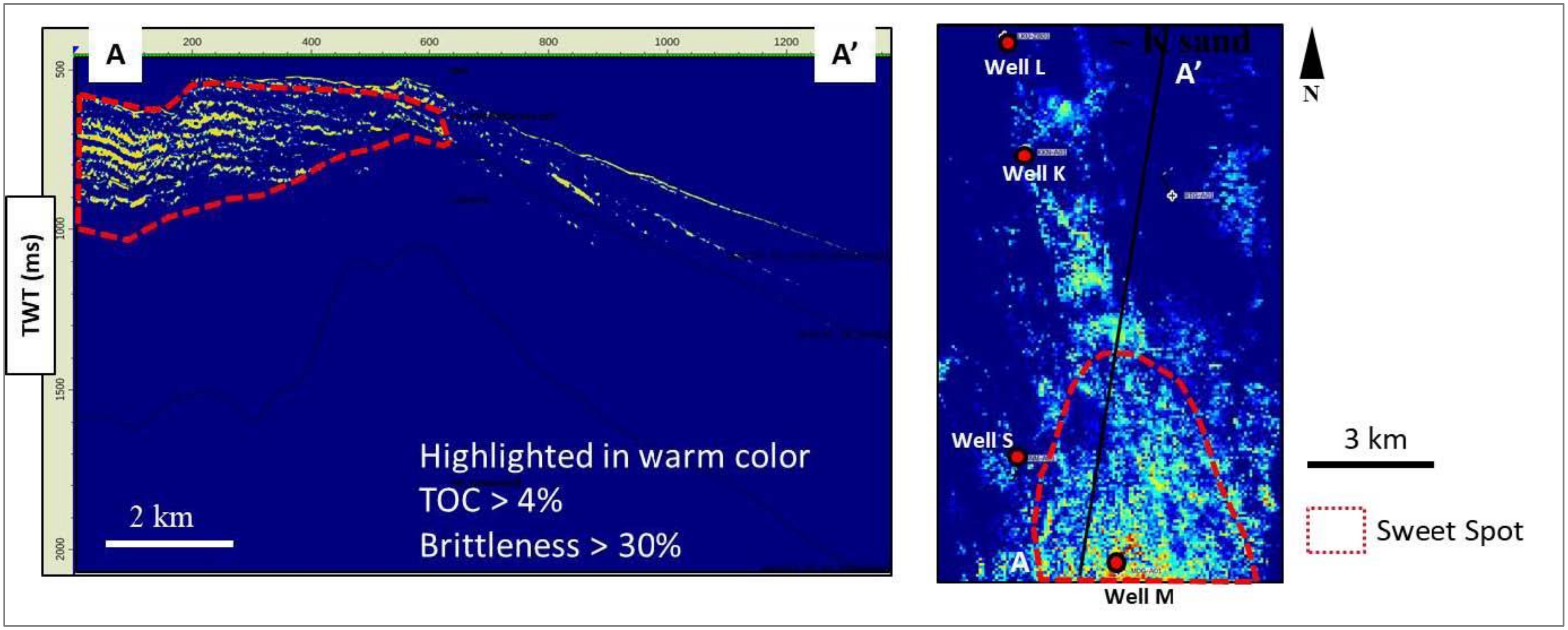

Figure 3. Proposed location for shale reservoir exploration in the RTS area overlay (red polygon) on TOC and brittleness co-rendered attribute. Sweet spot is identified in the shallow southern part of the survey.