Improved Formation Evaluation of Organic-Rich Shale Formations by Integrating Digital Rock Analysis with Core Data and Well Logs

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Abstract

To reliably evaluate the petrophysical, geochemical, and geomechanical properties of an organic-rich shale formation in China, we integrated digital rock analysis (DRA) with conventional core data and well log interpretation. The objectives of this paper included (a) to create a complete and accurate formation evaluation model for Wufeng-Longmaxi shale gas formation by combining pore-scale (digital rock), core-scale, and log-scale data; (b) to accurately characterize the micro-scale pore space, rock matrix, and organic matters in this formation, and create 3D pore network models from core samples; and (c) to identify the geological and engineering sweet-spot along vertical wellbore.

For well log interpretation, we obtained Gamma Ray (GR), spectral GR, neutron, density, resistivity, sonic logs, and elemental spectroscopy logs in the wells. For core measurements, we performed static and dynamic geomechanical experiments on core samples. For DRA, we obtained multi-scale images of the organic-rich shale samples, using three-dimensional (3D) micro-Computed Tomography (CT), 3D Focused-Ion-Beam Scanning Electron Microscope (FIB-SEM), and high-resolution Back-scattered Electron (BSE) imaging. Mineralogical and elemental analysis was also obtained by QEMSCAN. We then quantified various petrophysical properties from the digital rocks, including organic/inorganic porosity, Total Organic Carbon (TOC), elemental concentration and mineralogy. Most of the obtained properties were cross-validated with log data. Furthermore, we extracted pore network models from the digital rocks to quantify pore connectivity, pore throat size distribution, organic pore radius distribution, … etc, to provide more micro-scale information within the rock. Next, we determined the origin of quartz and the cause of high natural gamma-ray sections in the formation, based on point-by-point elemental analysis on SEM images and geochemical analysis. At last, we investigated various geomechanical properties using digital rock, core and log data. We compared geomechanical properties from core experiments and logs, then performed sensitivity study by DRA.

Two vertical wells in Wufeng-Longmaxi shale formation were studied by the introduced workflow. The DRA, core, and log data were mostly in good agreement, confirming the reliability of these methods. When multiple logs showed discrepancies in TOC, DRA provided additional key information for judgment. Based on the obtained petrophysical, geochemical, and geomechanical properties, we accurately characterized
the Wufeng-Longmaxi formation, predicted the shale gas sweet-spot along the wellbore, and provided suggestions for future operations of horizontal drilling and fracking in this formation.

The exploration and development of shale gas formations in China attracted extensive interests among Chinese national oil companies and international operators. However, it was extremely challenging due to the complex geological features of organic-rich shale formations in China. Furthermore, conventional methods of core analysis and well log interpretation were usually unreliable in these complex formations, and unable to illustrate micro-scale information in shale. The integration of DRA with conventional core and log analysis significantly improved formation evaluation in organic-rich shale formations in China, and can provide basis for future development decisions.

Introduction

The organic-rich shale play under study is located in the south of the Sichuan basin. Two vertical wells named Y3 and Y5 were drilled in Zhaotong City, Yunnan Province, which targeted the Wufeng-Longmaxi group. Figure 1 showed the locations of the two wells in the map.

![Figure 1—The locations of two vertical wells in Yunnan Provice, China.](image)

The major shale gas formation was the Upper Ordovician and Lower Silurian Wufeng-Longmaxi, which was a prolific shale gas reservoir in Sichuan basin (Xie et al., 2017). The Upper Ordovician Wufeng formation was interpreted as containing two members, WF1 and WF2; while the Lower Silurian Longmaxi formation contained two members, Long1 and Long2. The Long1 member was divided to Long1_1 and Long1_2 members, and Long1_1 was further divided into 4 sub-members, named Long1_1^1, Long1_1^2, Long1_1^3, and Long1_1^4, respectively. Figure 2 illustrated the stratigraphy of the seven (sub-)members and correlated the two wells Y3 and Y5. The seven shale (sub-) members spanned 131.7 m (2350.9 – 2219.2 m) in Well Y3, and 139.2 m (2261.7 – 2122.5) in well Y5, respectively. In both wells the (sub-)members from Long1_1^4 to WF1 were the favorable shale gas section.
Figure 2—Comparison of DRA vs. log interpretation results: TOC and total porosity in two wells Y3 and Y5. The two wells are correlated by log interpretation. Track 1: natural GR; Track 2: depths and sample number; Track 3: electrical resistivity logs; Track 4: neutron/density logs; Track 5: spectral GR (Uranium); Track 6: mineralogy results from ELAN; Track 7: DRA and log results for TOC; Track 8: DRA and log results for porosity; Track 9: zones. In Track 7 the log TOC curve was produced by elemental spectroscopy log. In Track 8 the log porosity curve was effective porosity (PIGN) interpreted from ELAN.

The TOC, thermal maturity, porosity, and permeability of Wufeng-Longmaxi formation were similar to those of commercial shale gas formations in US (Xie et al., 2017). But the initial development in this block was very challenging due to the tectonically complex setting. We met difficulties in determining geological and engineering sweet-spot, and designing future plans for fracturing and horizontal drilling. In this paper we integrated DRA, core, and log data to comprehensively evaluate the Wufeng-Longmaxi organic-rich shale formation, provided insight on the micro-structures, petrophysical, geochemical and geomechanical properties, and suggested sweet-spot for fracturing and future development.

Methods
This section described the methods used in this paper, including well log interpretation, core sample description, core experiments, and DRA methods (multi-scale imaging, image processing, mineralogy analysis and BSE imaging, pore network extraction, and numerical simulations). The following subsections described the methods in detail.
Well Log Processing and Interpretation
We obtained Gamma Ray (GR), spectral GR, resistivity, neutron, density, sonic logs, and elemental spectroscopy log in both wells. ELAN analysis was performed to interpret mineralogy from neutron, density, and sonic logs. Elemental spectroscopy log provided mineralogy and element dryweight concentrations in the wells, and a stand-alone TOC measurement.

Core Samples
We obtained 9 organic-rich shale cores from Well Y3, and 11 cores from Well Y5. Among these cores, we performed DRA on 6 cores from Well Y3, and 9 from Well Y5. Figure 2 illustrates the coring locations in two wells (the second track), and Table 1 provides the coring depths for DRA samples.

<table>
<thead>
<tr>
<th>Well</th>
<th>Sub-Member</th>
<th>Sample Number</th>
<th>Sample Depth, m</th>
<th>Organic Porosity, %</th>
<th>Inorganic Porosity, %</th>
<th>Total Porosity, %</th>
<th>TOC, %</th>
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Core Measurements: Geomechanical Experiments
The static and dynamic geomechanical experiments on shale cores were performed by a research lab in Beijing, China. The triaxial testing machine provided both static and dynamic mechanical properties of core samples. The static measurements generated breaking load, yield stress, Young's Modulus, Poisson Ratio, Bulk Modulus and Shear Modulus; and the dynamic measurements generated compressional wave velocity, shear wave velocity, Young's Modulus, Poisson Ratio, Bulk Modulus and Shear Modulus.

DRA: Multi-Scale Imaging
We obtained and imaged total 41.37 m of core plugs in well Y3, and 41.33 m core plugs in well Y5. Because at resolution above 250 nm we cannot see any pores, we did not perform whole-core CT imaging. We used 3D micro-CT to characterize fractures in core plugs, then used 2D BSE-SEM and 3D FIB-SEM for microscopic studies on shale cores. For 3D micro-CT coarse imaging, we used image resolution of 26.87 μm/pixel on plug samples with diameter of 25mm and length of about 30 mm; for 2D BSE imaging, we used 250 nm/pixel on a large area of 17×17 mm² (coarse imaging) and 10 nm/pixel on a small area of 0.8×0.8 mm² (fine imaging), respectively; for 3D FIB-SEM, we used 5 nm/pixel on subsamples of core plugs.
X-ray micro-CT imaging was performed with a Micro XCT 200, manufactured by Xradia. SEM imaging was performed with a Helios 650, manufactured by FEI.

**DRA: Image Processing**

All 3D rock images obtained by micro-CT and FIB-SEM are processed and segmented before running any numerical simulations. First, we perform noise reduction using SUSAN smoothing algorithm (Smith and Brady, 1997), which removes noises from each rock phase (e.g. pores or grains), while leaving the phase boundaries untouched. Next, we segment the grey-scale images into different phases, including solid, pores, and microporosity volume. The microporosity volume is the area containing micro-scale pores visible in higher-resolution imaging. The segmentation process is performed using the gray-scale histogram that includes local gradient information.

**DRA: Mineralogy/Element Analysis and BSE Imaging**

Mineralogy was determined on the plug scale using Quantitative Evaluation of Minerals by SCANning electron microscopy (QEMSCAN) analysis. QEMSCAN produces quantitative mineralogy and 2D distribution maps of minerals from the sample surfaces at the same time as generating a BSE image. Note that QEMSCAN provided element or mineral weight fractions relative to the weight of all inorganic minerals, which was defined as the "dry weight element/mineral fractions".

We performed QEMSCAN on a large area (17×17 mm²) with a resolution of 25μm, and then on a small area (0.8×0.8 mm²) with a resolution of 1 μm. We performed BSE imaging on a large area (17×17 mm²) with a resolution of 250 nm, and then on a small area (0.8×0.8 mm²) with a resolution of 10 nm. Mineralogy was investigated with a QEMSCAN 650 F, and BSE images were acquired on a Helios NanoLab 650, both manufactured by FEI.

**DRA: Pore Network Extraction**

The topology of the pore space is determined using a revised maximal ball algorithm pioneered by Dong and Blunt (2009). For each voxel in the image, the largest sphere that fits within the pore space centered on that voxel is found. The largest spheres define pores, while a chain of such spheres define the connections between them, i.e. the throats. This provides a robust characterization of the pore space as a network of pores connected by throats.

**DRA: Numerical Simulations of Rock Physics Parameters**

For conventional permeability calculation, we simulated a single-phase fluid flow in porous media, assuming very slow and incompressible, by numerically solving Stokes equations with Finite Difference Methods (FDM). We then calculated the absolute permeability by Darcy's law. Our simulated permeability results were verified by lab-measured permeability data on other rock samples (Roth et al., 2017), confirming the reliability and accuracy of our simulations.

The geomechanical properties were simulated by solving the linear elastic equations (Hooke's law) on an energy representation of the 3D digital rock, using a finite element method (FEM) assuming isotropic behavior. We applied FEM by representing each individual voxel in a 3D image as an elastic element connecting each other. Iterative algorithm was employed to find the solutions by sufficient convergence. The solved global stress and strain were used to derive the effective elastic moduli such as Young's modulus and Poisson’s ratio.

**Results**

This section provided the log interpretation, core analysis, and DRA results in the two wells under study, including (a) quantification of TOC and organic/inorganic porosity, (b) microscopic characterization of organic pores, and (c) mineralogy and elemental analysis. We also discussed (d) the origin of quartz, (e) the
cause of high-natural-gamma-ray sections, and (f) geomechanical properties in Wufeng-Longmaxi shale formation, based on the log, core and DRA results. The following seven sub-sections show these results in detail.

**Quantification of TOC and Organic/Inorganic Porosity by DRA and Well Logs**

The 2D BSE images were used to quantify TOC and organic/inorganic porosity in DRA. First, we segmented pores, organic matters, and solid minerals on BSE image, using the image segmentation method described in Methods. Specifically, the organic pores were delineated within the organic matters, and inorganic pores and fractures delineated in the mineral phase. Next, we calculated the percentage of organic matters in the imaging area to represent TOC (vol%), and the percentage of organic pores in the imaging area to represent organic porosity. The TOC volume fraction was then divided by 2 to convert to TOC weight fraction. We calculated the inorganic porosity by the equation below:

\[
\text{Inorganic Porosity} = \text{Sum} \left( \text{mineral fraction} \times \text{mineral porosity} \right) + \text{Fracture porosity},
\]

where mineral fraction was determined by BSE imaging and QEMSCAN on 2D images, the porosity for each mineral was determined by image analysis and averaging mineral porosity at different representative locations, and fracture porosity was determined by image segmentation on 3D micro-CT images. Then the DRA total porosity was calculated as the sum of organic and inorganic porosity.

**Table 1** lists the DRA-calculated organic/inorganic porosity, total porosity, and TOC of shale samples from wells Y3 and Y5. **Figure 2** shows the comparison between DRA and log interpretation results for TOC and porosity in Tracks 7 and 8, in both Y3 and Y5 wells. We compared DRA total porosity with log-interpreted effective porosity (Track 8), because SEM cannot capture the clay-bound-water (CBW) porosity in shale, which is below the SEM imaging resolution (Perry et al., 2017). Results in Track 8 show good agreement between DRA total porosity and log-interpreted effective porosity.

In Track 7 we compared DRA TOC data with log TOC curve from elemental spectroscopy log, but the results show discrepancies in multiple locations, esp. in well Y5. Therefore, we used another two log interpretation methods to estimate TOC, and compared DRA TOC with three different log TOC curves to determine which result is more reliable.

One of the new TOC log curves was estimated from Uranium by an empirical relationship for hot shales as reported in literature (Clennell et al., 2017), named TOC_U; the other one was estimated from sonic and density logs by the following empirical equation (Xu et al., 2017), named TOC_empiri:

\[
\text{TOC}_{\text{empiri}} = 0.0197 \times \text{DTCO} - 17.3 \times \text{ZDEN} + 42.78,
\]

where DTCO is the compressional wave curve, and ZDEN is the density log curve. This equation is obtained by a regional empirical multi-regression method for Wufeng-Longmaxi formation in a near-by shale play (Xu et al., 2017).

**Figure 3** showed the comparison between DRA TOC and three different TOC log curves in Track 6. Note that the scale for TOC_empiri was shifted to match other curves and point data. Results showed that the DRA TOC data match the two empirical TOC curves (TOC_U and TOC_empiri) much better than the elemental-spectroscopy TOC curve (DWTOC_INCP). Thus, we concluded that the elemental-spectroscopy TOC was not reliable in this formation, compared to empirical TOC relationships and DRA TOC results. This might be caused by elemental spectroscopy mistakenly estimating calcite content in the formation (shown later in **Figure 5**, Track 15). Because the elemental spectroscopy log calculated TIC (total inorganic carbon) as carbon in calcite and dolomite, and then calculated TOC by TC (total carbon) minus TIC, so its mis-interpretation of calcite content led to errors in TOC.
Figure 3—Comparison of DRA TOC data and log TOC curves in well Y5. Track 1 shows natural GR, Track 2 shows depths and sample number, Track 3 shows neutron/density logs, Track 4 shows electrical resistivity logs, Track 5 shows sonic logs, Track 6 shows comparison of DRA TOC data and three log-interpreted TOC curves, and Track 7 shows the zones. In Track 7 the black curve represents the elemental spectroscopy log TOC (DWTOC_INCP), the blue curve represents TOC estimated from U content (TOC_U), and the red curve represents TOC estimated from empirical relationship (TOC_empiri).

It must be noted that in Wufeng-Longmaxi shale formation, the ΔlogR method for TOC estimation by Passey (1990) or its revised version (Sondergeld et al., 2010), was not applicable, because the log separation in ΔlogR method had a poor correlation with TOC content. This might be due to low resistivity caused by high pyrite content in this formation (Xu et al., 2017). Therefore, we did not apply Passey's ΔlogR method to estimate TOC in this formation; instead, we used the two empirical methods to estimate TOC as mentioned above, to compare with the elemental spectroscopy TOC and DRA TOC.

Microscopic Characterization of Organic Pores by DRA

To further study the microscopic properties of shale cores, we performed image processing and segmentation on 3D FIB-SEM images to illustrate the micro-structure of organic matters. Figure 4 showed the 3D FIB-SEM images and segmentation for 3 shale samples, No. 4 and No. 6 from well Y3, and No. 4 from well Y5. This illustrated the methodology we used to process all 3D FIB-SEM images.

In 2D BSE SEM images, we observed two distinct types of organic pore morphology, named Organic Pore Type 1 and Type 2. Figure 5a showed the two types of organic pores in a BSE image obtained on No. 6 shale sample from well Y5, located in Long1_1^1 sub-member. We analyzed the two types of organic pores by 3D FIB-SEM image segmentation and pore network extraction. Figure 5b showed the 3D FIB-SEM image for each type of organic pore and the extracted pore networks, in No. 6 sample from well Y5.

We believed that the spongy round pores in Organic Pore Type 1 were developed within migrated organic matter (OM), which migrated into mineral pores after formation of mineral crystals and then became solid.
bitumen, as described by Loucks and Reed (2014). And the "narrow-crack" pores in Organic Pore Type 2, lying between the clay minerals and bitumen, were devolatilization cracks in solid bitumen or pyrobitumen (Loucks and Reed, 2014). These devolatilization cracks might be caused by coring, but still indicated that surrounding OM was solid bitumen and pyrobitumen rather than kerogen. This observation further confirmed the over-maturity of Wufeng-Longmaxi gas shale.

To quantitatively study the two organic pore types, we calculated their connected and total organic porosity, permeability, and pore/throat parameters. Table 2 listed the organic porosity, permeability, and pore/throat parameters for the two organic pore types, respectively. Results showed that the organic pores in migrated OM were well connected, as mentioned by Loucks and Reed (2014). Organic Pore Type 1 had a better connectivity than Model 2, but Type 1 permeability was lower than Model 2 permeability by one order of magnitude. This was because the pore sizes and throat sizes of Model 1 were smaller than those of Model 2.

![3D FIB-SEM images and segmentation for 3 shale samples: No. 4 and No. 6 from well Y3, and No. 4 sample from well Y5. The volume fractions of organic pores, organic matters, and other minerals were listed for each sample.](image-url)
Figure 5—Analysis of organic pores in Sample No. 6, Well Y5. (a) BSE image showing two distinct types of organic pore morphology, Organic Pores Type 1 and Type 2; (b) Pore network models extracted from 3D FIB-SEM images for Organic Pores Type 1 and Type 2, respectively.
Table 2—The calculated parameters for Organic Pore Types 1 and 2 in Sample No. 6, Well Y5.

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<thead>
<tr>
<th>Parameters</th>
<th>Type 1</th>
<th>Type 2</th>
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It must be noted that in conventional DRA, we can simulate fluid flow in pore networks and calculate absolute and relative permeability of rocks reliably. But in these shale core samples the permeability simulations might not be reliable, because the fluid flow becomes non-newtonian in this length scale, thus the Navier-Stokes equations cannot apply. We listed the simulated permeability in Table 2 as a reference value, to show their differences in the order of magnitude.

In addition to migrated OM, we also observed depositional OM in the shale cores by SEM imaging. The 3D OM network formed by both migrated and depositional OM had an excellent 3D connectivity, and the organic pores within OM were also well connected. This observation confirmed the high reservoir quality of Long1_1^1 sub-member.

**Mineralogical and Elemental Analysis by DRA and Elemental Spectroscopy Log**

We performed mineralogical and elemental analysis in Wufeng-Longmaxi formation by both elemental spectroscopy log and DRA method (QEMSCAN). Figure 6 showed the comparison between log curve and DRA data for mineralogy and element dry weight fractions in well Y5. Note that QEMSCAN provided dry weight fractions of elements/minerals, so did the spectroscopy log (named DWXX_INCP), so we can compare these two measurements directly.
The two measurements showed very good agreement in most minerals and elements, confirming the reliability of both methods. But the spectroscopy log tended to underestimate quartz content, and over estimate K-feldspar. It also mistakenly estimated calcite weight fraction in certain depths, thus misinterpreted TIC and TOC, as mentioned earlier. Note that in the last track the QEMSCAN carbon content matched well with the TIC log curve, because QEMSCAN only reported carbon in inorganic minerals. So we calculated total carbon (TC) fraction by adding QEMSCAN carbon and DRA TOC, the calculated TC matched well with the spectroscopy TC curve (DWTC_INCP), confirming the reliability of TC measurement in both methods.

In general, the DRA data confirmed the reliability of mineralogy and elemental analysis by elemental spectroscopy log, except quartz, calcite, and K-feldspar measurements. We believed that the log-measured quartz, calcite, K-feldspar, and TOC/TIC was not reliable in this formation.

**Origin of Quartz in Wufeng-Longmaxi Organic Shale Formation**

This section investigated the origin of excess quartz observed in Wufeng-Longmaxi formation. The excess quartz or excess Si content referred to the Si content higher than that in the normal shale rocks, which was given by

\[
Si_{excess} = Si_{sample} - \left( \frac{Si}{Al} \right)_{background} \times Al_{sample}^* 
\]

where \(Si_{excess}\) is excess Si content, \(Si_{sample}\) and \(Al_{sample}\) is Si and Al content in rock samples, and \((Si/Al)_{background}\) is the ratio of Si/Al in background. We adopted the average value for shale, 3.11, for \((Si/Al)_{background}\). Figure 7 listed the excess Si content in each shale sample from two wells. The excess Si content in the samples varied from 8.36% to 31.51%, with an average of 19.59%.
Regarding the origin of quartz, biogenic quartz was considered more favorable for hydrocarbon production than terrestrial quartz. In literature, the Zr element concentration in rocks has been used to differentiate biogenic quartz from detrital quartz (Wright et al., 2010; Dong et al., 2017). In Wufeng-Longmaxi shale formation, we combined Al, Ti, Zr element concentrations to determine the origin of quartz, because Al and Ti are closely associated with clay. The element concentrations were all determined by QEMSCAN on shale samples. Figure 8 showed a plot of quartz content vs. Al+Ti+Zr content (normalized), and clearly showed two trends. Group A is dominated by terrigeneous quartz, and Group B dominated by biogenic quartz. Figure 9 showed the two types of quartz origin in two wells along the wellbore. Results showed that Long1_1^1 and Long1_1^2 submembers were dominated by biogenic quartz in both wells.
High content of biogenic quartz not only suggested good fracability of rocks, but also indicated better OM development and higher potential for hydrocarbon production. In addition to high biogenic quartz content, Long1_1^1 submember showed high TOC content and high OM connectivity, so we determined that Long1_1^1 should be the target for fracturing and future development.

**Cause of High-Natural-Gamma-Ray Zones in Wufeng-Longmaxi Formation**

This section investigated the cause of high natural GR in certain depths in Wufeng-Longmaxi organic shale formation. Figure 10 showed the locations of high-GR zones in the two wells. The sub-members from WF1 to Long1_1^3 showed total GR higher than 150 gAPI. And in certain depths the total GR was even higher than 200 gAPI, as highlighted in Figure 10.
It was well known that natural GR was often related to clay minerals, which absorb radioactive elements more easily than other minerals. However, we observed a negative correlation between GR and clay content in core samples from Y3 and Y5 wells. Figure 11 showed the negative correlation between GR and clay content in the two wells, obtained by DRA. Instead, we observed a moderate positive correlation between GR and TOC.
We used the ratio of Tu/U to study the depositional environment of Wufeng-Longmaxi formation (Kimura and Watanabe, 2001; Whignall and Myers, 1988). Statistics showed that Th/U > 7 indicates terrestrial depositional formations with oxidizing conditions, Th/U < 7 indicates marine depositional formations with reducing conditions, and Th/U < 2 usually indicates marine black shale. In Wufeng-Longmaxi shale formation, we observed a low Th/U ratio at high-GR zones, indicating marine deposition with reducing condition (Track 8, Figure 10). This was because in reducing conditions, esp. when clay contains OM and H₂S, U⁶⁺ was reduced to U⁴⁺ by H₂S, which makes U elements in water easily deposit. Besides, OM can absorb U element, and decomposition of OM can reduce U⁶⁺ to U⁴⁺ too. These factors led to the high content of U and low Th/U ratio in these organic-rich zones. The richness of OM played a key role in formation of high U content in the formation.

Based on the geochemical analysis, we concluded that high-GR was caused by the richness of OM in certain depths, instead of clay content. For future development, we suggested using OM, organic porosity, and biogenic quartz as indicators of favorable zones, rather than GR or clay content.

**Geomechanical Study by Log Interpretation, Core Analysis, and DRA**

This section investigated the geomechanical properties of Wufeng-Longmaxi organic shale formation by core measurements, log interpretation, and DRA. We performed dynamic and static geomechanical experiments on core samples, to compare with the log interpretation results. Figure 12 compared the dynamic and static geomechanical properties measured by log and core analysis. Most of the data showed good agreement between log and core analysis, except the yield stress (Break) in static properties showing significant discrepancies.
Figure 12—Comparison of geomechanical properties from log and core analysis in Well Y5. (a) Dynamic geomechanical properties, and (b) static properties. Track 1: GR; Track 2: depths and coring locations; Track 3: resistivity logs; Track 4: neutron and density logs; Track 5: spectral GR; Track 6: mineralogy content from ELAN. Track 7-10 in (a): log and core dynamic geomechanical properties, including Shear Wave Delay Time (DTSM), Compressional Wave Delay Time (DTCO), Poisson Ratio (PR), and P/S ratio. Track 7-10 in (b): log and core static geomechanical properties, including PR, yield stress (Break), Young’s Moduli, and Friction Angle (FANG).
Furthermore, we performed sensitivity study on geomechanical properties by numerical simulations on synthetic digital rock samples. We made synthetic digital rock samples by varying their OM content and porosity, then simulated their shear and bulk moduli by FEM, as described in Methods Section. Figure 13a and 13b showed the change of shear and bulk moduli as a function of OM content, and Figure 14a and 14b showed the change of shear and bulk moduli as a function of porosity. Results showed that both shear and bulk moduli decreased exponentially with increases of OM content or porosity, which explained the trend we observed in core data and log interpretation results.

![Shear Modulus vs. OM Content](image1)

![Bulk Modulus vs. OM Content](image2)

Figure 13—Variation of shear/bulk moduli as a function of OM content. (a) Shear Modulus and (b) Bulk Modulus as a function of OM content.

![Shear Modulus vs. Porosity](image3)

![Bulk Modulus vs. Porosity](image4)

Figure 14—Variation of shear/bulk moduli as a function of porosity. (a) Shear Modulus and (b) Bulk Modulus as a function of porosity. The fitting equations and corresponding $R^2$ are shown in each graph.

**Integrated Formation Evaluation and Suggestions for Future Development**

To sum up, we studied two wells in Wufeng-Longmaxi organic shale formation in multi-scales by integrating DRA, core analysis, and log interpretation. We obtained thorough understanding of micro-structures, petrophysical, geochemical, and geomechanical properties of this shale formation. We determined that Long1_1 sub-member should be the sweet spot and the target for fracking in the future.
Before this study, we fracked Long1_1^2 sub-member, simply because of high GR in adjacent Long1_1^1 and Long1_1^3 sub-members, and we supposed that fracking Long1_1^2 could cover both 1 and 3 sub-members. However, this strategy did not generate favorable results for us. After this study, we decided to focus on Long1_1^1 sub-member for fracking and future exploration in this area. We obtained satisfactory results using the new strategy in our block in Sichuan basin.

Conclusions
We studied two vertical wells in Wufeng-Longmaxi organic shale formation by integrating DRA, core measurements, and log interpretation. The DRA, core, and log data were mostly in good agreement, confirming the reliability of these methods. When multiple logs showed discrepancies in TOC, DRA provided additional key information for judgment. Specifically, we quantified TOC and organic/inorganic porosity, characterized OM and organic pores in micro-scale, analyzed mineralogy and element concentrations, determined the origin of quartz, investigated the cause of high GR zones, and studied geomechanical properties, by combining DRA, core, and log analysis. Based on the obtained petrophysical, geochemical, and geomechanical properties, we accurately characterized the Wufeng-Longmaxi organic shale formation, predicted the shale gas sweet-spot along the wellbore, and provided suggestions for future operations of horizontal drilling and fracking in this formation.

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Acronyms

2D Two-Dimensional
3D Three-Dimensional
CBW Clay Bound Water
CT Computed Tomography
DRA Digital Rock Analysis
FEM Finite Element Method
FIB-SEM Focused Ion Beam Scanning Electron Microscope
GR Gamma Ray
OM Organic Matter
TC Total Carbon
TIC Total Inorganic Carbon
TOC Total Organic Carbon

References


