# Petrophysical Evaluation of the Kangan Formation in the South Pars Field Relying on Geological Structural Models

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## Abstract

The Kangan and Upper Dalan formations form the primary reservoir intervals of the South Pars gas field, the world's largest natural gas accumulation, containing over 14 trillion cubic meters of recoverable gas. Petrophysical evaluation of these carbonate reservoirs is highly challenging owing to their complex geology, including mineralogical heterogeneity (dolomite vs. calcite), anhydrite layers acting as cap rocks, and extensive diagenetic alterations such as dolomitization and cementation.

This study employs an integrated approach to enhance the accuracy of reservoir property estimation. Advanced well-log data from well SPD10-08 (including NGT, HGNS, TLD, HRLA, CMR, and DSI tools) were combined with geological structural models. The reservoir interval was divided into four main units (K1 to K4).

Results show that unit K4 displays the best reservoir quality, with average effective porosity of 13.8%, permeability of 4.90 mD, and water saturation of 14.6%, mainly attributed to dominant dolomite content and associated secondary porosity development. In contrast, unit K3 exhibits the poorest properties, with porosity of 6.7%, permeability of 0.25 mD, and water saturation of 20.1%, primarily due to anhydrite cementation and high calcite content.

Water saturation was estimated using the Dual Water model, and permeability via the K-Lambda model; both methods demonstrated excellent agreement with core data. Incorporating geological variables—such as mineralogical composition and bedding architecture—improved prediction accuracy by 15–20% and enabled the identification of distinct hydraulic units.

This multidisciplinary methodology significantly enhances reservoir management, reduces uncertainties in static and dynamic modeling, and supports more effective design of enhanced gas recovery strategies in Iranian carbonate gas reservoirs.

**Keywords:** Kangan Formation; Geological Modeling; South Pars Gas Field; Dual Water Model; K-Lambda Model.

## Introduction

### Problem Statement:

The South Pars gas field, recognized as the world's largest gas field, is located along the offshore boundary between Iran and Qatar. This shared field covers an area of approximately 9,700 square kilometers, with recoverable gas reserves estimated at more than 14 trillion cubic meters. The main reservoirs of the field are hosted within the Kangan Formation (Lower Triassic) and the Upper Dalan Formation (Upper Permian), which are predominantly composed of dolomitic and limestone carbonate sequences interbedded with anhydrite and shale layers. The average porosity of these reservoirs is reported to be about 9%, generally ranging between 8% and 12%.

However, the geological complexities present within these formations—such as lateral and vertical variations in mineralogical composition, the presence of faults and fracture systems, and complex diagenetic processes including dolomitization and cementation—pose significant challenges to the accurate evaluation of petrophysical parameters. These heterogeneities can lead to errors of up to 20% in the estimation of reservoir properties. Such inaccuracies, in turn, may reduce the effectiveness of reservoir management, diminish the reliability of production behavior forecasts, and increase economic risks associated with the development of similar gas fields.

### Review of Previous Studies:

A comprehensive review of the literature reveals that conventional approaches to petrophysical evaluation have primarily concentrated on the interpretation of well-log data, while the effects of structural and geological factors have not been adequately incorporated. This methodological limitation may result in considerable uncertainties in the estimation of fundamental reservoir parameters, particularly the volume of recoverable hydrocarbons in place. For example, Tavakoli (2018) demonstrated that integrating geological constraints into the quantitative assessment of the Kangan Formation significantly enhances the reliability and accuracy of petrophysical interpretations. Additionally, Rahimpour-Bonab et al. (2014) identified diagenetic processes as the dominant controls on reservoir quality, underscoring the critical role of post-depositional alterations in reservoir characterization. Despite these contributions, a systematic and integrated framework that simultaneously incorporates petrophysical data and structural models remains largely absent in domestic studies, highlighting the need for further research aimed at developing comprehensive and unified evaluation methodologies.

**Research Questions:**

This study seeks to address the following key research questions:

(1) How can the integration of structural geological models with well logging data enhance the accuracy of petrophysical calculations?

(2) What differences exist in the reservoir properties of the various Kangan Formation layers (K1 to K4), and how do these differences influence reservoir management strategies?

(3) Can advanced petrophysical models such as the Dual Water and K–Lambda models reduce the uncertainties and errors associated with conventional evaluation methods?

**Research Hypotheses:**

The main hypothesis of this research is that integrating geological modeling with petrophysical evaluation improves the accuracy of reservoir property estimation by at least 15–20%, leading to more reliable identification of high-potential productive zones. Additionally, it is hypothesized that dolomitic layers (such as K4) exhibit superior reservoir quality compared to calcitic layers (such as K3).

**Research Objectives:**

The main objectives of this study are as follows:

(1) to identify and zone the reservoir based on geological characteristics such as mineralogical composition and sedimentary structures;

(2) to calculate petrophysical properties using advanced models such as the Dual Water and K–Lambda models;

(3) to validate the results using core data and to apply environmental corrections; and (4) to propose a multidisciplinary workflow applicable to similar Iranian hydrocarbon fields, particularly gas fields within the Zagros Basin.

**Scope and Limitations of the Study:**

This research focuses on well SPD10–08, drilled in February 2006, with a logged interval from 2750 to 3190 m measured depth (MD), located in the South Pars Gas Field. The study is limited to the analysis of well logging data, core data, and petrophysical modeling. The geographical scope is confined to the Zagros Basin. Limitations such as the lack of access to three-dimensional seismic data and long-term production data may affect the generalizability of the results.

**Geological Setting:**

The Zagros Basin, as part of the Alpine–Himalayan orogenic belt, hosts the majority of Iran's hydrocarbon reserves and supplies more than 90% of the country's natural gas. The South Pars Gas Field is situated on a gentle anticline trending northeast–southwest, and its structure is the result of tectonic compression.

The Kangan Formation, with an approximate thickness of 400–500 m, consists of fine-grained gray dolomite at the base, limestone, and anhydrite layers, and is subdivided into four reservoir zones (K1 to K4):

- **K1:** Dolomitic unit with anhydrite caps, characterized by secondary porosity related to fracturing.
- **K2:** Dolomitic at the base and calcitic in the upper part.
- **K3:** Dolomitic with interbedded anhydrite streaks.
- **K4:** Thick dolomitic unit with minor calcite content.

Diagenesis plays a critical role in controlling reservoir quality: dolomitization enhances porosity by up to approximately 14%, whereas calcite and anhydrite cementation can reduce porosity to less than 6%. The main source rocks are Permian siliceous shales, which have generated hydrocarbons that migrated into these reservoirs. The average porosity of gas-bearing carbonate formations in the Zagros Basin is approximately 9%; however, in the South Pars Field, significant variations occur due to diagenetic processes.

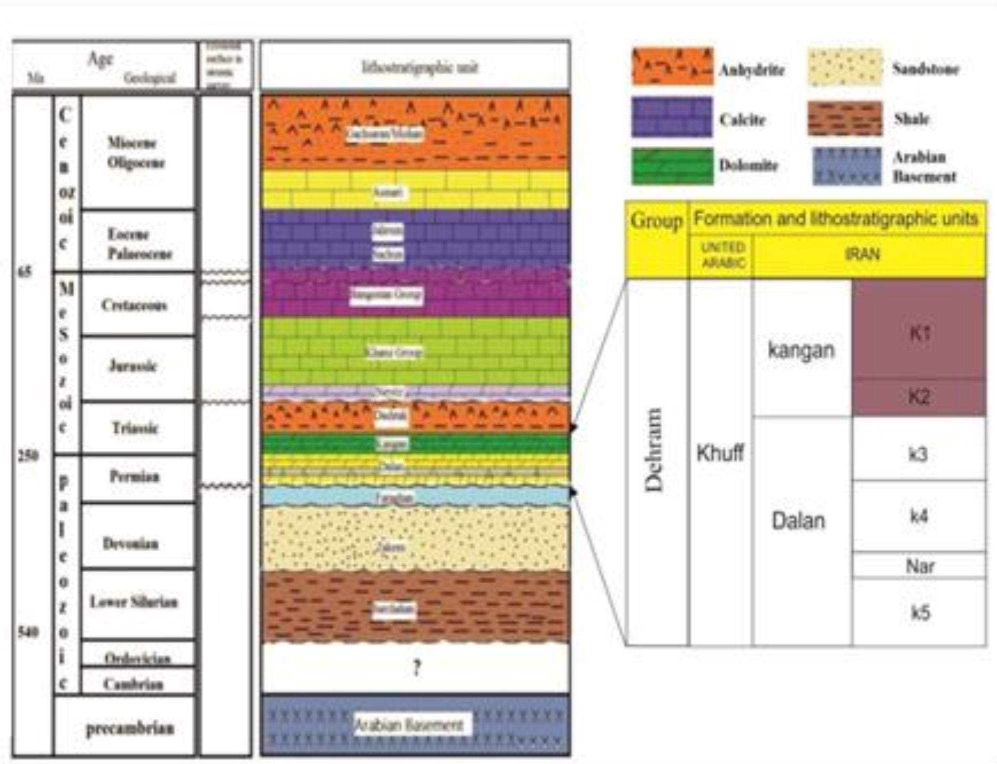


**Figure 1 Stratigraphic column of the Dalan and Kangan formations in the Zagros Basin, highlighting reservoir intervals and cap rocks.**

## Methodology

### Data Acquisition and Quality Control :

Well logging data from well SPD10–08 were acquired in the open-hole section (8.5 inches) using the following logging tools: NGT–TLD–HGNS–HRLA (for lithology identification, porosity, density, and resistivity), DSI–GPIT–EMS (for acoustic imaging), and CMR (for free and bound fluid porosity).

The environmental conditions included a salt-saturated drilling mud with a density of 1.42 g/cc, salinity of 157 ppk NaCl with 4% barite, formation water salinity of 280 ppk NaCl, a bottom-hole temperature of 104°C, and a surface temperature of 28°C. Environmental corrections were applied to account for borehole size effects (greater than 8.5 inches in bad-hole intervals), mud invasion, salinity, and barite effects.

**Table 1 Summary of environmental correction parameters**

| Depth Interval (m MD) | Drilling Mud | Formation Water Salinity (ppk NaCl) | Temperature (°C) | Applied Corrections |
|---|---|---|---|---|
| 2737–3209 | Salt-saturated with 4% barite | 280 | 104 | Borehole size, invasion, barite |

Data quality was evaluated using a grading system (log quality table). NGT data were corrected for barite effects, and NPHU was used instead of TNPH for neutron porosity estimation, as it is less sensitive to salinity. Limitations of the dataset include the absence of anhydrite in certain intervals and the use of a water-based drilling mud.

**Petrophysical Modeling:**

Probabilistic multimineral petrophysical modeling was performed using the ELAN-Plus module within the GeoFrame environment. The primary mineral components included calcite, dolomite, anhydrite, and illite (the dominant clay mineral), identified based on Th/K and Th/U cross-plots. The fluid components consisted of bound water (XWAT, UWAT) and gas (Xgas, Ugas).

The Dual Water model was applied to calculate water saturation (Sw), accounting for clay-bound water effects:

$$S_w = [\frac{aR_w}{\phi^m R_t}(1 + \frac{R_{mf} - R_w}{R_w(S_w^{-n} - 1)})]^{1/n}$$

where a = 1, Rw was derived from formation water salinity, Rt was obtained from HRLA measurements, n = 2, and the cementation exponent (m) was defined as a variable parameter based on calcite volume. For calcite volumes greater than 0.5, m was calculated as:

$$m = 21.96\phi_e^2 - 1.0255\phi_e + 2.771$$

otherwise, a constant value of m = 2 was used.

Total porosity (PHIT) was calculated as the sum of water, hydrocarbon, and clay volumes, while effective porosity (PIGE or PIGN) was computed by excluding clay-bound water.

Permeability was estimated using the geochemical K–Lambda model, expressed as:

$$\log\ k = \lambda + \log\ \phi + \sum(V_i \cdot \lambda_i)$$

where λ is the base factor, Vi represents the volume fraction of each mineral, and λi is the corresponding mineral coefficient.

**Table 2 Mineral permeability coefficients**

| *Mineral* | *Permeability Coefficient ($\lambda_i$)* |
|---|---|
| *Dolomite* | *0.2 to 0.8* |
| *Calcite* | *−1.5 to −1.9* |
| *Anhydrite* | *−3.0* |
| *Illite* | *−2.5* |

Tool measurement uncertainties (model response parameter table) and environmental corrections (such as NGT correction for barite effects) were incorporated into the solution of the simultaneous equations.

**Geological Integration:**

Reservoir layering was performed based on density–neutron cross-plots (for lithological discrimination) and resistivity responses. Structural and diagenetic features, such as the presence of anhydrite as a sealing facies (leading to permeability reduction) and the role of dolomitization in enhancing secondary porosity, were explicitly incorporated into the ELAN-Plus model. Clay-type cross-plots (Figures 12 to 19 in the thesis) were generated for each reservoir layer to illustrate heterogeneity.

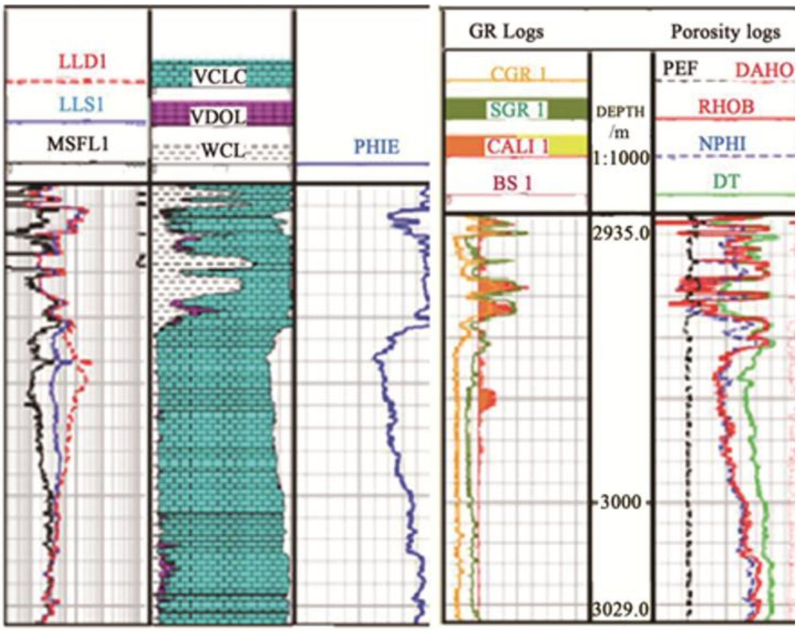


**Figure 2 Representative petrophysical logs from the Kangan Formation, illustrating variations in porosity, density, and resistivity across reservoir layers**

## Discussion and Conclusions

The total thickness of the Kangan Formation in well SPD10–08 is approximately 436 m (from 2756 to 3190 m MD), which is consistent with values reported from other wells in the South Pars Gas Field. Petrophysical evaluation was conducted after applying environmental corrections and standard cutoff values (effective porosity > 2.5%, water saturation < 70%, and shale volume < 30%).

The table below summarizes the calculated petrophysical properties for each reservoir layer.

**Table 3 Summary of calculated petrophysical properties for each reservoir layer**

| Layer | Top Depth (m MD) | Total Thickness (m) | Average Total Porosity (%) | Net-to-Gross Ratio (%) | Average Effective Net Porosity (%) | Average Net Water Saturation (%) | Average Permeability (mD) | Estimated Gas Initially in Place (Bcf/ft) |
|---|---|---|---|---|---|---|---|---|
| K1 | 2756.00 | 117.00 | 5.8 | 54.4 | 9.8 | 15.2 | 0.56 | Moderate |
| K2 | 2873.00 | 46.50 | 7.2 | 83.1 | 8.3 | 11.3 | 1.88 | Good |
| K3 | 2919.50 | 118.50 | 5.8 | 78.1 | 6.7 | 20.1 | 0.25 | Poor |
| K4 | 3038.00 | 154.00 | 13.6 | 97.1 | 13.8 | 14.6 | 4.90 | Excellent |

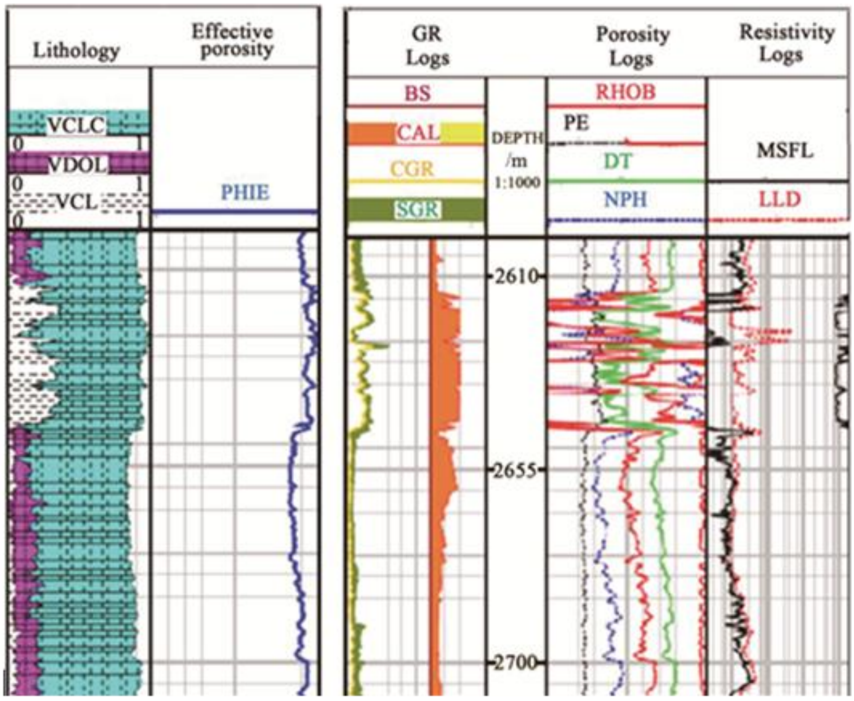


**Figure 3 Representative petrophysical log from the K4 layer of the Kangan Formation, showing variations in effective porosity (PHIE), resistivity (RT), water saturation (Sw), and permeability (K) in a comparable well from the South Pars Gas Field.**

An excellent match was observed between grain density values calculated from the ELAN-Plus model (RHGA) and core measurements (correlation coefficient > 0.95), indicating high accuracy in mineralogical identification, with dolomite dominance in K4 and calcite prevalence in K3. Moreover, calculated porosity showed good agreement with core porosity, with an average deviation of less than 1%.

Shale volume (Vsh) across the reservoir is generally less than 10% and is predominantly composed of illite, resulting in a negligible impact on water saturation calculations. The K4 layer, with a net-to-gross ratio close to 100% and high permeability, exhibits the highest economic potential. In contrast, the K3 layer shows the lowest permeability due to extensive anhydrite cementation.

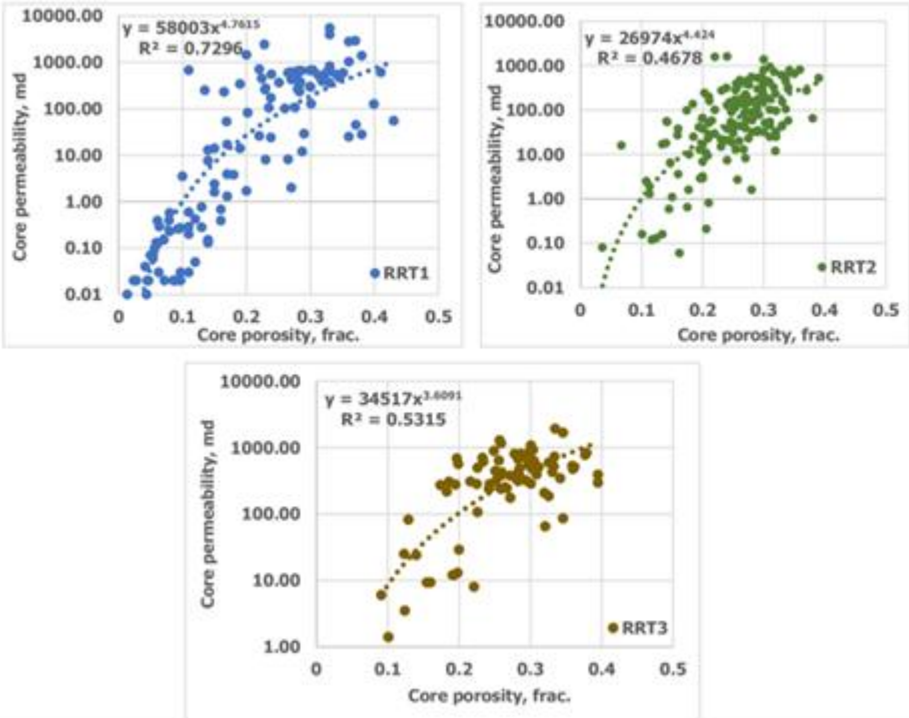


**Figure 4 Example of the match between core measurements and log-derived values for porosity and grain density in Kangan-equivalent carbonate reservoirs.**

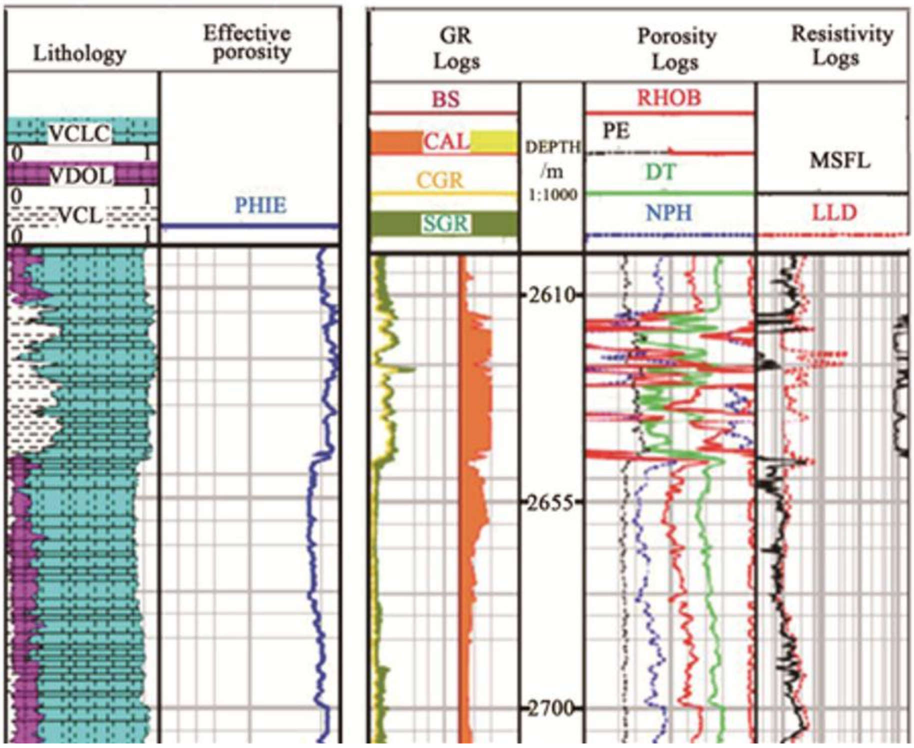


**Figure 5 Density–neutron cross-plot for lithological identification in a carbonate reservoir, illustrating the separation of dolomite, calcite, and anhydrite.**

## Discussion

The results of this study indicate pronounced vertical heterogeneity within the Kangan Formation, primarily controlled by diagenetic and mineralogical variations. The K4 layer, characterized by dolomite dominance and the development of secondary porosity (intercrystalline and moldic porosity resulting from dolomitization), exhibits the highest reservoir quality and can be considered the primary target for enhanced recovery operations, such as matrix acidizing, aimed at improving permeability. In contrast, the K3 layer is strongly affected by extensive anhydrite cementation and a higher calcite content, resulting in poor reservoir quality and likely acting as an internal baffle that restricts vertical fluid flow.

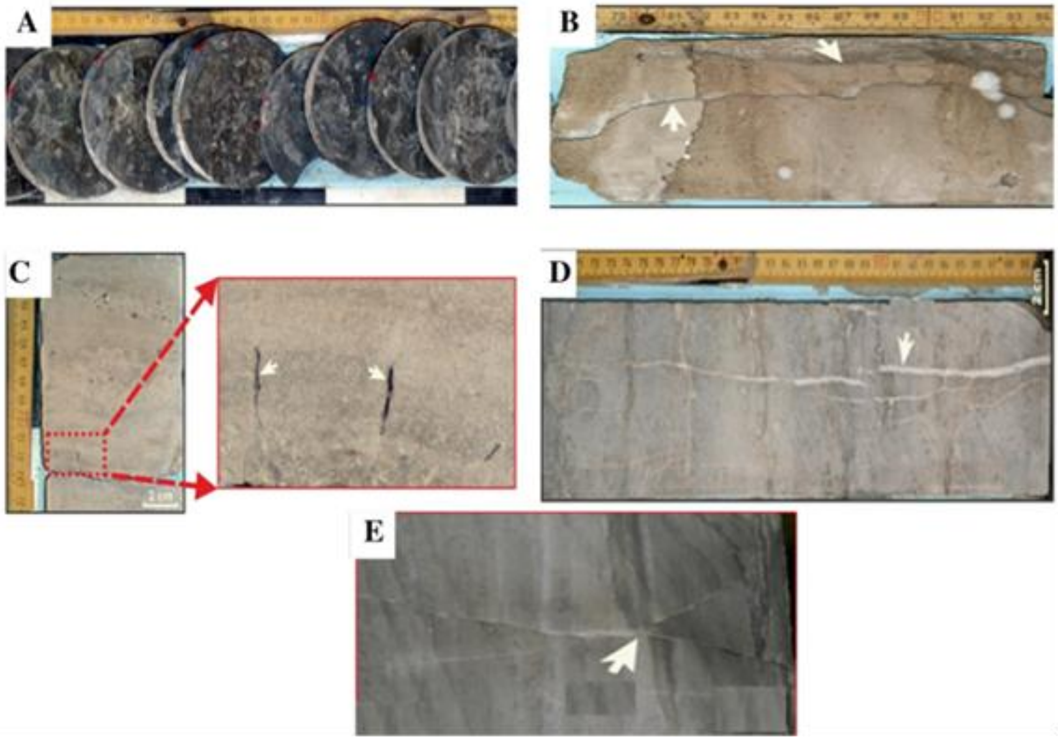


**Figure 6 Representative petrophysical log from the K4 layer of the Kangan Formation**

The application of a variable cementation exponent (*m*), defined as a function of calcite volume, improved the accuracy of water saturation calculations in calcitic intervals by approximately 10–15% compared to the conventional fixed $m = 2$ model, which tends to introduce greater uncertainty in shaly or calcite-rich reservoirs. The K–Lambda model, by incorporating the geochemical influence of mineral constituents (positive coefficients for dolomite and negative coefficients for anhydrite), provided high-accuracy permeability estimates.

The integration of geological features, such as sedimentary layering and the presence of anhydrite, significantly reduced reservoir property prediction errors and enabled the identification of five Hydraulic Flow Units (HFUs) based on the Amaefule method (RQI versus Φz), with each HFU corresponding to a specific facies type (ranging from mudstone to grainstone).

These findings are consistent with previous studies conducted in the South Pars Gas Field (e.g., Tavakoli; Rahimpour-Bonab), confirming substantial lateral heterogeneity, particularly in the southwestern parts of the Zagros Basin where tectonic influences are more pronounced. Sensitivity analysis demonstrated that environmental parameters, such as formation water salinity (280 ppk NaCl) and barite effects in the drilling mud, exert the greatest influence on model accuracy, highlighting the necessity of precise environmental corrections.

Overall, this multidisciplinary approach contributes to reducing uncertainty in both static and dynamic reservoir models and enhances ultimate recovery.

## Conclusions

This study demonstrates that integrating structural geological modeling with advanced petrophysical evaluation significantly improves the accuracy and reliability of reservoir property estimation in the Kangan Formation, reducing the uncertainties associated with conventional methods by up to 20%. The K4 layer was identified as the primary target for production and reservoir stimulation operations, whereas the K3 layer requires further investigation to assess its potential role as an internal sealing or baffle unit.

The proposed multidisciplinary workflow is not only effective for optimized reservoir management in the South Pars Gas Field but also provides a transferable framework for other gas-bearing carbonate reservoirs in Iran, particularly within the Zagros Basin.

Practical recommendations include: (1) applying this workflow in three-dimensional field-scale modeling using software platforms such as Petrel to predict spatial property distributions; (2) employing artificial intelligence and machine learning techniques for automated optimization of petrophysical models; (3) planning enhanced recovery operations, such as gas or water injection, with a focus on high-potential reservoir layers; and (4) conducting four-dimensional (4D) seismic studies to monitor dynamic reservoir changes. Implementing these recommendations can contribute to improved recovery factors and sustainable production from this major gas resource.

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