Journal of Himalayan Earth Sciences Volume 49, No. 1, 2016 pp.30-40

Petrophysical analysis of the reservoir intervals in Kahi-01 well, Kohat Sub-Basin, Pakistan

Babar Saddique[1*], Nowrad Ali1[2], Irfan U. Jan[1], Muhammad Hanif[1], Syed Anjum Shah[3], Ijaz Saleem[2], Mufeed Muhammad Faizi[4] and Muhammad Yasir Arafat[4]
[1]National Centre of Excellence in Geology, University of Peshawar
[2]Department of Geology, University of Peshawar
[3]Saif Energy Limited, Pakistan
[4]Oil and Gas Development Company Limited, Islamabad Pakistan
*Corresponding author E-mail: babarsaddique@gmail.com

Abstract

This study deals with the petrophysical analysis of the Kahi-01 well in Kahi village in the Kohat Sub-Basin (Upper Indus Basin) for evaluating the reservoir potential, using different evaluation parameters in the interpretation equations. Three formations namely, Lockhart Limestone, Hangu and Lumshiwal Formations have been selected for further investigation keeping the fact that they have acceptable ranges for porosity, water saturation and shale volume. The 36 m thick Lockhart Limestone with dominant limestone content, vuggy and crystalline porosities is appreciated as a hydrocarbon bearing formation. The underlying 50 m thick Hangu Formation with dominant sandstone content shows that the grain size is coarser. There are three prospective zones identified as; A1, A2, and A3 with comparatively high hydrocarbon saturation and less shale content having the thickness of 7m, 15m and 22m respectively, in which A3 zone seems more promising. The underlying Lumshiwal Formation has 75 m thickness and is dominantly represented by fine to coarse grained sandstone. Unlike Hangu and Lockhart formations, the Lumshiwal Formation has only few probable zones for hydrocarbon accumulation, however due to the lesser effective porosity values, the formation is not very promising.

Keywords: Petrophysical analysis; Reservoir intervals; Kahi-01; Kohat Sub-Basin; Pakistan.

1. Introduction

The Kahi-01 well is located at 33^{o} 14’ 05’’ N; 71^{o} 31’ 55’’ E in Kahi Village in Kohat Sub-Basin, which is part of Upper Indus Basin, Pakistan (Fig. 1). The Upper Indus Basin known for its fascinating style of deformation, has a thick succession of sedimentary strata making it potential site for petroleum generation and entrapment (Khan et al., 1986; Paracha, 2000). Over the last two decades, a significant number of oil and gas discoveries have been made within the Kohat Sub-Basin (Sercombe et al., 1998). AMOCO Pakistan Exploration Company (APEC) drilled three wells, i.e. Tolanj-1, Kahi-1 and Sumari-1 between 1990 and 1993 in the Kohat Sub-Basin (i.e. Tal block; SPE, 2010), but they failed to establish production and abandoned the area (Paracha, 2004). However, in the last decade, discoveries of hydrocarbons in Manzalai-2002, Makori-2004, Mela-2005 and Chanda have increased the interest of exploration and production companies in the area. Exploration block TAL is covered by Eocene to Pliocene sediments at outcrop, underlain by Mesozoic-Palaeocene successions. Multiple episodes of deformation under different tectonic stress regimes have led to subsurface complexities and substantial variation in topographic relief (Sercombe et al., 1998). The Tolanj-1 well, though which is related to a complex flower type structure, indicates that it is not a thrust related structure but Kahi-1 and Sumari-1 are drilled on thrusted anticline (Sercombe et al., 1998). The Kohat Sub-Basin still awaits significant discoveries, despite of limited space available, where all the concessions are held by Oil and Gas Development Corporation Limited (OGDCL) and MOL. The abandoned Kahi-01 well, was re-drilled in 1992 up to a depth of 2067m in the North West part of Tal Block (SPE, 2010). The stratigraphic succession drilled in Kahi-01 well ranges in age from Jurassic to Early Eocene (Fig. 2). Research indicates that there is no academic work done or published data, regarding petrophysical analysis of the Kahi-01 well, thus, the present study is aimed towards the petrophysical analysis of the rock units drilled in Kahi-01 for evaluating the reservoir potential.

2. Methodology

Two important properties of reservoir rock for its characterization are porosity and permeability (Asquith and Gibson, 1997). The quantitative and qualitative analysis of these properties along with the identification of the reservoir intervals within Kahi-01 well is achieved by addressing volume of shale, water, and hydrocarbon saturation, porosities, water resistivity and gas effect by suits of

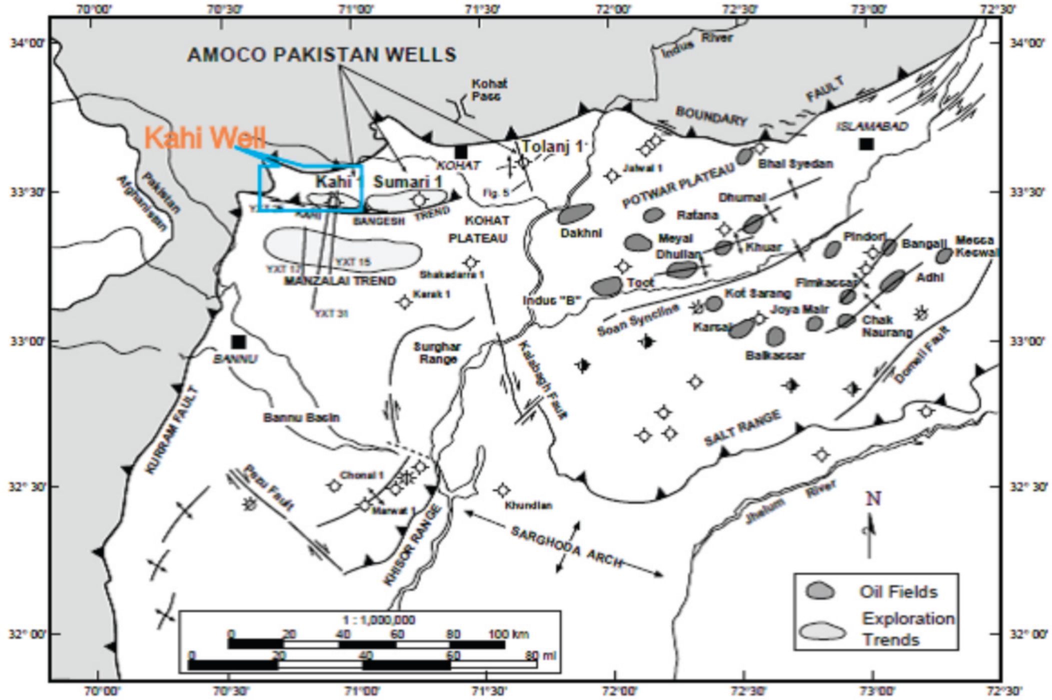

Fig.1 . Map showing the location of Kahi-01 well and the major structural features of the Kohat Sub-Basin (Pivnik and Sercombe, 1993).

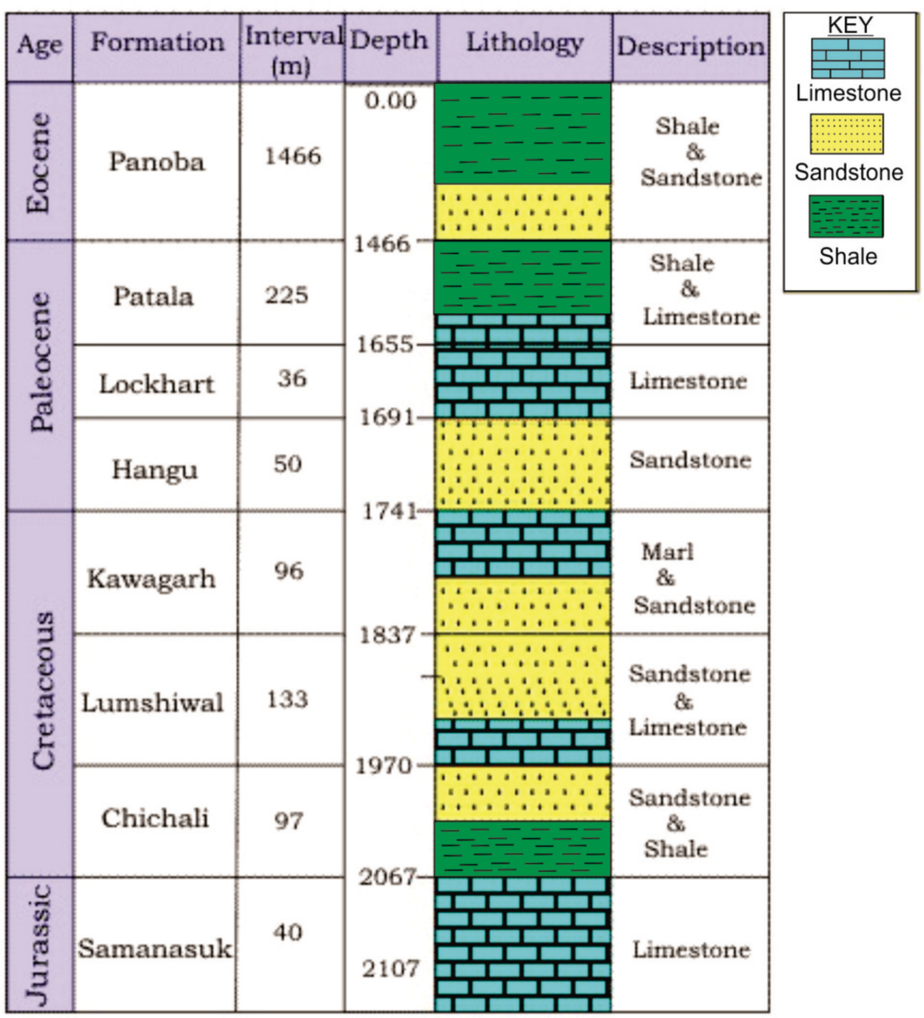

Fig.2 . The stratigraphic succession exposed within the Kahi-01 well.

wireline logs, i.e., self-potential, dual induction focused (ILD & ILM), gamma ray, neutron, density and resistivity logs for a total depth of 2067 m. The neutron porosity (ϕN), density porosity (ϕD), total porosity (ϕT) and effective porosity (PHIE / ϕE) were calculated using the following formulae (Rider, 1996; Asquith and Gibson, 1982; Crain, 1986);

$\phi N = (1.02 \times \phi N \log) + 0.0425$
ϕ density $= \rho matrix - \rho log / \rho matrix - \rho fluid$
$\phi T = (\phi D + \phi N) / 2$
$\phi E = \phi T \times (1 - Vsh)$
ρmatrix = Density of matrix,
ρlog = Density reading from the log curve
ρfluid = Density of the fluid
Vsh = Volume of shale

The volume of shale (Vsh) was calculated using gamma ray log by first calculating the gamma ray index (IGR) using the following equation (Schlumberger, 1974);

IGR= GRlog – GRmin / GRmax - GRmin
IGR= Gamma ray index
GRlog = Gamma ray reading at the depth of interest
GRmin = Minimum gamma ray reading (Usually the mean minimum through a clean sandstone or carbonate formation).
GRmax = Maximum gamma ray reading (Usually the mean maximum through a shale or clay formation).
After calculating IGR, the values can be used to calculate the volume of shale using the following formulae (Larionov, 1969);
$V_{sh} = 0.083 \times (2^{3.7 \times IGR} - 1)$ for the tertiary rocks and
$V_{sh} = 0.33 \times (2^{2 \times IGR} - 1)$ for older rocks,

The saturation for a pore fluid (S_w and Sh) was determined using Archie's (1942) equation, first by finding the saturation for water (S_w) as;

$S_w = [(a/ \phi\, m) \_\_ \times (Rw/Rt)]^{1/n}$ (Archie, 1942)
and putting water saturation in the following formula;

Sh = (100 – Sw) % (Schlumberger, 1996).

Further, the bulk volume of water was calculated as follows;

$V_{bw} = \phi\, e \times S_w$ (Asquith and Gibson, 1982; Crains, 1986).

The gas effect, in a gas bearing zone can be calculated as follows;

Gas effect = A* ϕD + (1-A)* ϕN / A (2) (Asquith and Gibson, 1982).

Rw = Water resistivity (calculated through SP method, is 0.028 for Lockhart Limestone, 0.027 for Hangu Formation and 0.025 for Lumshiwal Formation)

R_t = True resistivity,
S_w = Water saturation,
Sh = Hydrocarbon saturation,
V_{bw} = Bulk volume of water,
a = Tortousity factor,
m = Cementation exponent,
n = Saturation exponent
A= Gas correction factor.

The lithology was determined from bulk density (RHOB) and neutron porosity (NPHI) curves (Schlumberger, 1996). All the logs were analysed with the help of Geographix Software, used under the academic license of Saif Energy Limited, Pakistan. The following cut-offs were used to identify 3 intervals for more detailed petrophysical analysis;

Volume of shale (V_{sh}) < 35%;
Water saturation (S_w) < 70% and
Effective porosity (ϕ_E) > 7 %.

3. Results and discussion

3.1. Identification of reservoir intervals

The identification of a potential reservoir zone in a borehole is of prime importance and a number of criteria can be used like low GR log values, high effective porosity values and high neutron porosity values. The petrophysical parameters were determined for the formations drilled within Kahi-01 well, the Lockhart Limestone, Hangu Formation and Lumshiwal Formation were selected for detailed petrophysical analysis, as they fulfil the criteria of cut off factor (Table 1).

3.2. Petrophysical interpretation of lockhart limestone

The Lockhart Limestone is 36 m thick with a depth range 1655m-1691m (Fig. 4). Various log curve statistics were calculated in order to understand its reservoir potential (Tables 2-4). The lithology evaluated from NPHI and RHOB is dominantly limestone (Fig. 3). The average value for shale volume, density porosity and neutron porosity along with the effective porosity is not satisfactory contrary to the values for the total porosity, ILM and ILD separation and hydrocarbon saturation (Fig. 4 and Tables 2-4). The average bulk volume of water for Lockhart Limestone is 0.024 (Table 4) indicating vuggy to crystalline type porosities (Fertl and Vercellino, 1978). The overall formation can be considered as hydrocarbon wet (Table 4 and Fig. 4).

Table 1. Max and Min log curve values for the various rock units encountered in Kahi-01 well.

Formation	Vsh	V_{bw}	ϕ_N	$\phi_{density}$	ϕ_e	Sw
Lockhart Limestone	0.032-0.686	0.07-0.065	0.18-0.396	2.737-3.363	0.004-0.111	0.022-0.996
Hangu Formation	0.011-0.743	0.001-.652	0.03-0.175	2.063-3.129	0.01-.0.180	0.001-0.652
Lumshiwal Formation	0.020-0.992	0.013-.055	0.002-0.156	0.063-2.796	0.007-0.050	0.63-0.997

Table 2. The volume of shale in Lockhart Limestone at different depths.

S.No	Depth (m)	V_{sh}
1	1655	0.458
2	1662	0.194
3	1669	0.326
4	1676	0.350
5	1683	0.390
6	1690	0.672
Average volume of shale		**0.39**

Table 3. The average values for the total porosity in Lockhart Limestone.

S.No	Depth (m)	ϕ_N	ϕ_D	$\phi_D+\phi_N/2$
1	1655	0.382	0.107	0.245
2	1662	0.153	0.191	0.172
3	1669	0.250	0.118	0.184
4	1676	0.237	0.113	0.175
5	1683	0.367	0.178	0.272
6	1690	0.250	0.176	0.213
Average value				**0.21**

Table 4. Water (S_w) and hydrocarbon (Sh) saturation at different depths for Lockhart Limestone.

S.no	Depth (m)	V_{bw}	S_w	S_h
1	1655	0.016	0.352	0.648
2	1662	0.017	0.815	0.185
3	1669	0.017	0.628	0.372
4	1676	0.020	0.865	0.135
5	1683	0.036	0.078	0.922
6	1690	0.038	0.732	0.268
Average value		**0.024**	**0.42**	**0.58**

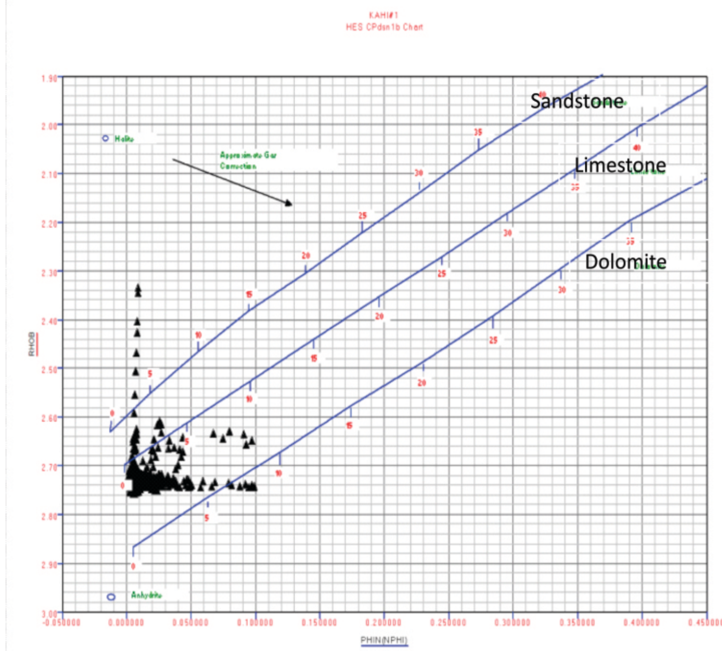

Fig. 3. NPHI and RHOB cross plot for Lockhart Limestone showing the dominant lithology (Schlumberger, 1996).

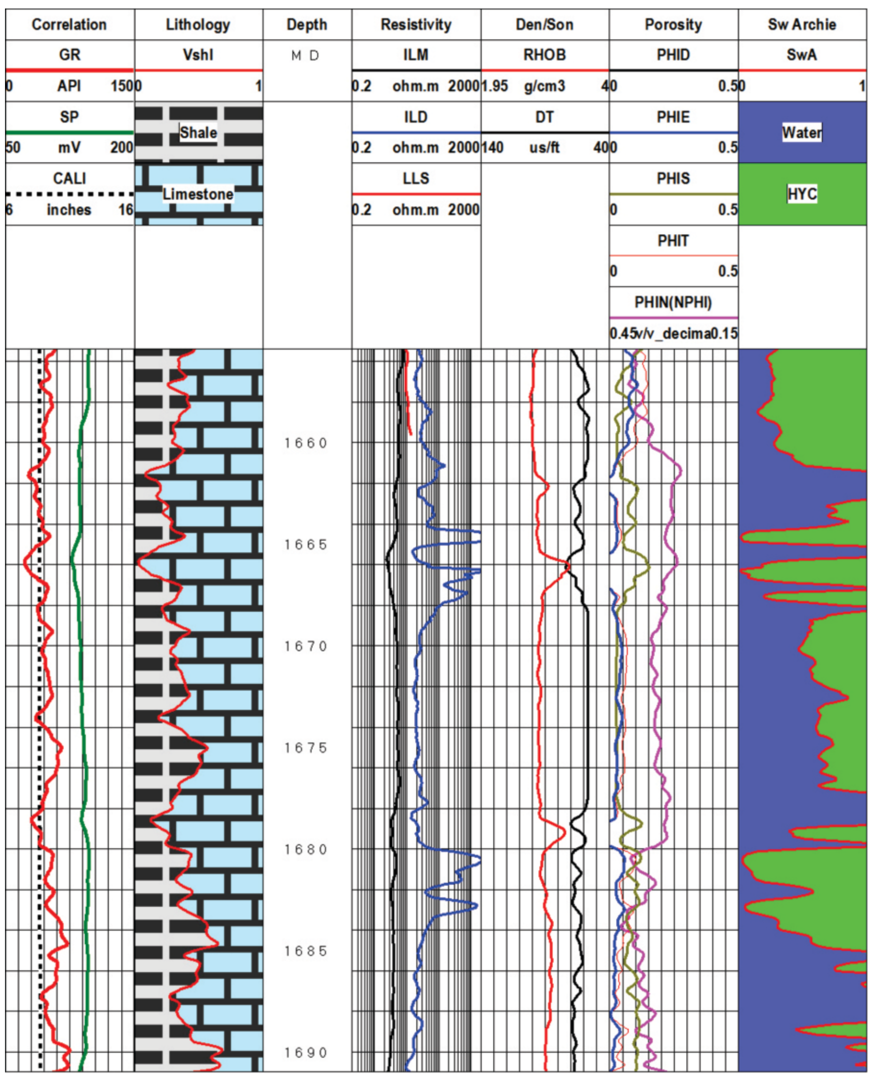

Fig. 4. Computer processed logs interpretation of the Lockhart Limestone in the Kahi-01 well.

3.1. Petrophysical interpretation of Hangu Formation

The total thickness of Hangu Formation is 50m with a depth range of 1691-1741m (Fig. 5 and Tables 5-7). The dominant lithology is sandstone based on a crossplot of the NPHI and RHOB curves (Fig. 6). There are three potential reservoir zones identified within the Hangu Formation named as: A1, A2 and A3 (Fig. 5). The thickness of interval A1 is 7m and occurs at depth from 1692-1698m for which the effective porosity (3.4 %) and total porosity (5.5 %) are not very promising, however, the average values for volume of shale is 24.4 % and the hydrocarbon saturation is 76 %. The thickness of zone A2 is 15m with depth ranging from 1701-1716m. The average values of effective porosity (5.5 %), total porosity (6.4 %), volume of shale (22.4 %) and hydrocarbon saturation (82 %) for zone A2 suggests that it is more prospective. The thickness of A3 interval is 22m and depth ranges from 1718-1740m. The average values of effective porosity (6.8%), total porosity (9%), volume of shale (8.33%) and hydrocarbon saturation (86 %) for zone A3 marks it the best among the three zones within the Hangu Formation, and the greater thickness than A1 and A2 zones further increase the importance of A3 zone as a potential reservoir. The value for the bulk volume of water in Hangu Formation ranges from 0.01 to 0.03 which indicates that the grain size within this formation is dominantly coarse sand (Fertl and Vercellino, 1978; Table 7), which may increase its reservoir potential.

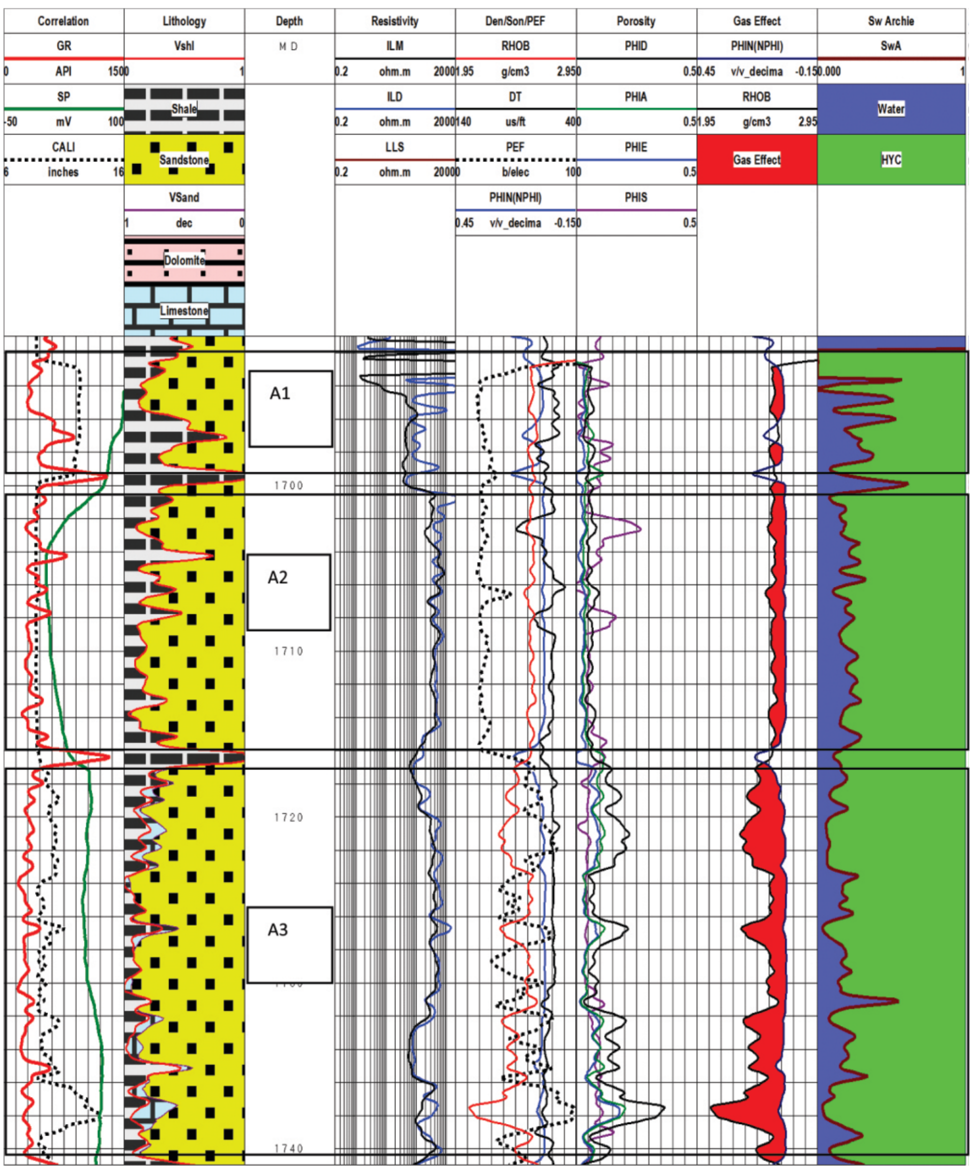

Fig. 5. Computer processed logs interpretation of the Hangu Formation in the Kahi-01 well.

Table 5. Volume of shale in Hangu Formation at different depth.

No	Depth (m)	V_{sh}
1	1691	0.17
2	1701	0.18
3	1706	0.03
4	1711	0.16
5	1716	0.15
6	1721	0.24
7	1726	0.2
8	1731	0.10
9	1736	0.17
10	1741	0.01
Average volume of shale		**0.24**

Table 6. Total Neutron and Density porosity average values for the Hangu Formation.

No	Depth (m)	ϕ_N	ϕ_D	$\phi_D+\phi_N/2$
01	1696	0.0369	0.041	0.039
02	1701	0.008	0.065	0.037
03	1706	0.013	0.092	0.050
04	1711	0.008	0.068	0.038
05	1716	0.082	0.075	0.079
06	1721	0.009	0.221	0.115
07	1726	0.009	0.085	0.047
08	1731	0.008	0.094	0.051
09	1736	0.013	0.112	0.063
10	1741	0.075	0.022	0.049
		Average value		**0.057**

Table 7. Water (S_w) & hydrocarbon (S_h) saturation and bulk volume of water values at different depths for Hangu Formation.

No	Depth (m)	V_{bw}	S_w	S_h
01	1696	0.02	0.572	0.428
02	1701	0.03	0.110	0.890
03	1706	0.02	0.215	0.785
04	1711	0.02	0.209	0.791
05	1716	0.01	0.167	0.833
06	1721	0.02	0.069	0.931
07	1726	0.02	0.212	0.788
08	1731	0.03	0.556	0.444
09	1736	0.02	0.168	0.832
10	1741	0.02	0.333	0.667
Average values		**0.021**	**0.26**	**0.74**

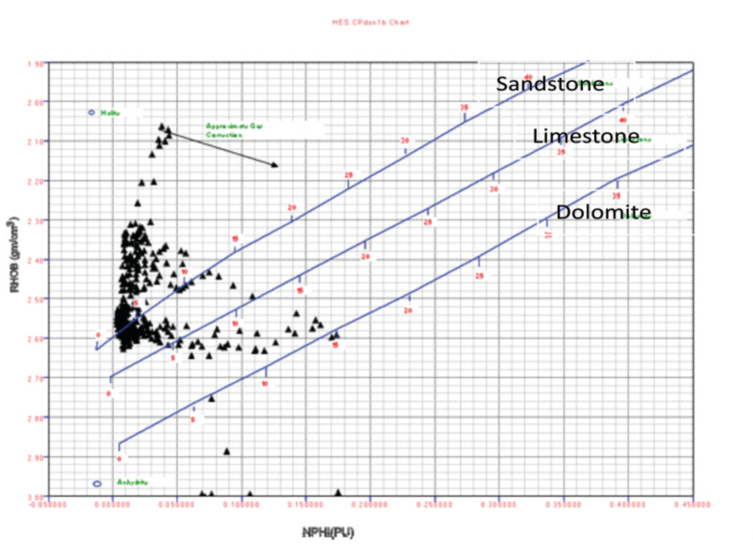

Fig. 6. NPHI and RHOB cross plot for Hangu Formation showing the dominant lithology type (Schlumberger, 1996).

3.4. Petrophysical interpretation of Lumshiwal Formation

The total thickness of Lumshiwal formation in Kahi-1 well is 133m, starting from 1837m to 1970m (Table 8). Petrophysical evaluation of the Lumshiwal Formation reveals only one reservoir zone occurring at the depth of 1885-1960m (75m thick; Fig. 7). There is sandstone and limestone present in the formation as evaluated from the NPHI and RHOB (Fig. 8). The average values of effective porosity (2.6%), total porosity (5.5 %), volume of shale (39.85 %) and hydrocarbon saturation (44 %) for this zone are not much promising. The bulk volume of water values in Lumshiwal Formation mostly ranges from 0.01 to 06, which indicates that the grain size in this formation is from fine to coarse grained (Fertl and Vercellino, 1978; Table 8).

Table 8. Volume of shale, effective porosity, bulk volume of water and water saturation values at different depths for Lumshiwal Formation.

DEPTH (m)	Vsh	ϕ_e	V_{bw}	Sw
1837	0.54	0.01	0.02	0.66
1847	0.45	0.01	0.01	0.72
1857	0.45	0.03	0.02	0.53
1867	0.60	0.02	0.03	0.35
1877	0.54	0.01	0.03	0.58
1887	0.20	0.02	0.06	0.32
1897	0.27	0.03	0.06	0.85
1907	0.41	0.02	0.06	0.88
1917	0.13	0.04	0.06	0.66
1927	0.12	0.03	0.05	0.72
1937	0.15	0.04	0.05	0.81
1947	0.41	0.01	0.04	0.65
1957	0.65	0.02	0.02	0.37
1970	0.66	0.02	0.02	0.33
Average	**0.39**	**0.022**	**0.03**	**0.60**

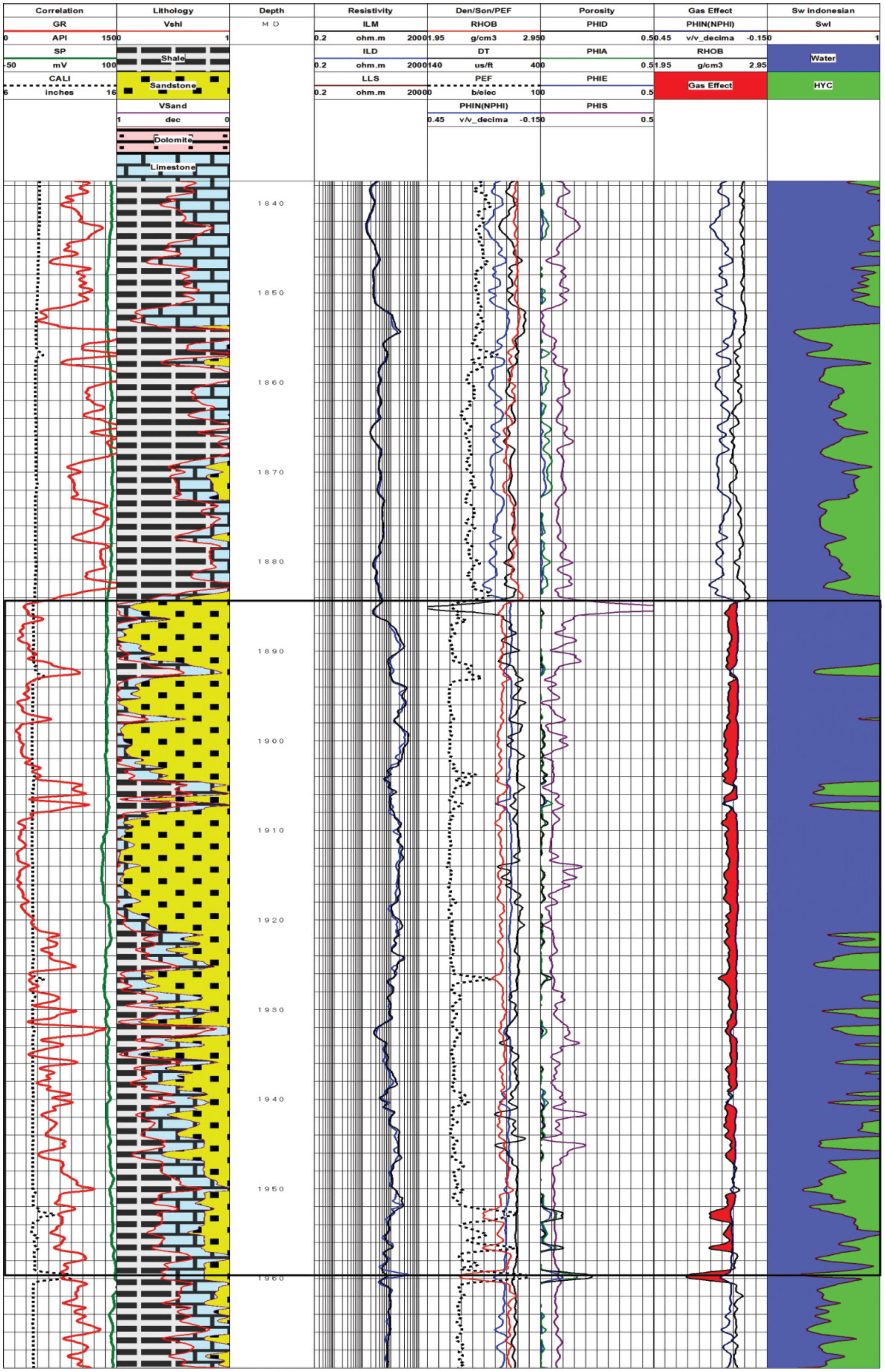

Fig. 7. Computer processed logs interpretation of the Lumshiwal Formation in the Kahi-01 well.

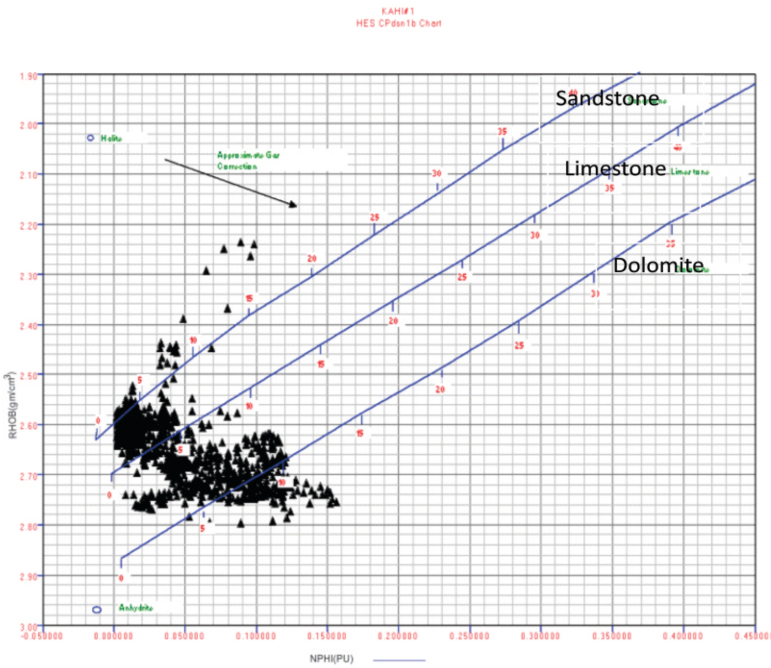

Fig. 8. NPHI and RHOB cross plot for Lumshiwal Formation showing the dominant lithology type (Schlumberger, 1993).

4. Conclusions

The Lockhart Limestone with dominant lithology of limestone with vuggy and crystalline type of porosities having 36m thickness is considered to be hydrocarbon wet. The Hangu Formation has thickness of 50m with dominant lithology of sandstone. The analysis shows that the grain size is coarse. There were three prospective zones identified as A1, A2, and A3 with high hydrocarbon saturation and less shale content having the thickness of 7m, 15m and 22m respectively, in which A3 zone is more promising than the rest. The reservoir zone in Lumshiwal Formation has a thickness of 75m, with dominant lithology of fine to coarse grained sandstone. The prospects as compared to the intervals identified within Lockhart Limestone and Hangu Formation are not much promising due to the lesser PHIE values, however, with fair amount of hydrocarbon saturation and coarseness of the grain size of the sandstone suggests it be a significant one.

5. Suggestions and recommendations

The current investigations are only focused on the petrophyscial analysis of the reservoir intervals in Kahi-01 well. In order to trace these intervals in the Kohat Sub-Basin, a detail sedimentological and petrophysical work is required in other parts of the basin to understand their spatial depositional distribution. These wells should be correlated with seismic section to find lateral variation of the formation. The intense structural complexity can be addressed using both the tools (seismic and well log). To better understand the reservoir potential of the drilled units in the study well and to calibrate the determined petrophysical parameters the core data should also be evaluated.

Acknowledgements

The authors acknowledge the Directorate General Petroleum Concession (DGPC), Islamabad, Pakistan for providing well data and the Saif Energy Limited, Pakistan for providing academic license of Geographix software.

References

Archie, G. E, 1942. The electrical log resistivity log as an aid in determining some reservoir characteristics. Petroleum Technology.

Asquith, G., Gibson, C., 1982. Basic well log for Geologists. American Association of Petroleum Geologist, Tulsa Methods in Exploration, 216.

Crain, E. R., 1986. The Log Analysis Handbook Volume 1: Quantitative Log Analysis

Methods. Penn Well, Tulsa, 44, 91-95.
Fertl, W. H., Vercellino, W. C., 1978. Predict water cut from well logs, in Practical log analysis. Oil and Gas Journal, 4.
Khan, M. A., Ahmed, R., Raza, H. A., Kemal, A., 1986. Geology of petroleum in Kohat-Potwar depression, Pakistan. American Association of Petroleum Geologist Bulletin. 70, 396- 414.
Larionov, V. V., 1969. Radiometry of boreholes (in Russian), NEDRA, Moscow.
Paracha, W., Kemal, A., Abbasi, F., 2000. Kohat Duplex in Northern Potwar Deformed Zone, Pakistan. Geological Survey of Pakistan, Geologica, 5, 99-107.
Pivnik, D. A., Sercombe, W. J., 1993. Compression and transpression related deformation in the Kohat Plateau, NW Pakistan. In: Searle M. P., Treloar, P. (Eds.), Himalayan Tectonics. Geological Society of London (Special Publication), 44, 559-580.
Rider, M. H., 1996. Geological Interpretation of Well Logs. French Consultant Ltd., Scotland.
Schlumberger, C., Schlumberger, M., Leonardon, E. G., 1996. Log Interpretation Chart Book, Houston, 201.
Sercombe, W. J., Pivnik, D. A., Wilson, W. P., Albertin, L. M., Beck, R. A., Stratton, M. A., 1998. Wrench faulting in the Northern Pakistan foreland. American Association of Petroleum Geologist Bulletin, 82 (11), 2003-2030.