Organic geochemical characteristics of Jurassic petroleum system in Abadan Plain and north Dezful zones of the Zagros basin, southwest Iran

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Jurassic succession has resulted in prolific oil and gas reservoirs in southwest Iran. In order to geochemically investigate the Jurassic petroleum system and assess the source rock of these hydrocarbons, 32 source rock samples (from well cutting and surface section) and 4 condensate samples were analysed using geochemical approaches. Rock-Eval pyrolysis and vitrinite reflectance measurement were done on rock samples. Then, condensate samples and source rock extracts were subjected to gas chromatography, gas chromatography–mass spectrometry and isotopic analyses in order to establish oil–oil and oil–source rock correlation. The hydrocarbon generation prediction was then confirmed by petroleum system modelling. The results indicated that the middle Jurassic Sargelu Formation with average total organic carbon (TOC) and hydrogen index values of 3.8% and 600 mg HC/g TOC, respectively, can be classified as good to excellent source rock with kerogen of type II. The maturity indicators revealed late oil to wet gas generation window for the Jurassic Sargelu Formation. Biomarker parameters showed marine carbonate source rock with advanced level of thermal maturity for the source rock of the condensates. Furthermore, there were good correlations between Jurassic Sargelu Formation and the studied oil and condensate samples which proved the Sargelu Formation as the main source rock of the Jurassic petroleum system in the study area. The basin modelling results also confirmed late oil to wet gas window maturity for the Sargelu Formation enabling it as a source rock for generating gas condensate accumulation in southwest Iran. The hydrocarbon generation from Sargelu Formation began in the late Cretaceous and its peak expulsion occurred in the Miocene time.

Keywords. Source rock; Jurassic reservoir; condensate; Abadan Plain; Iran.

1. Introduction

Most of Iran's explored oil and gas is believed to have been sourced from Jurassic (Sargelu Formation) and Cretaceous (Garau and Kazhdumi formations) intervals and trapped in Cretaceous and Cenozoic reservoirs in the Dezful Embayment and Abadan Plain area.

The Middle Jurassic succession includes very significant source rocks over southwest of Iran through eastern Iraq in the Zagros basin owing to the high total organic carbon (TOC) content of the Sargelu Formation that was deposited throughout the Jurassic basin in these areas (Jassim and Goff 2006). There is no published paper on geochemical characteristics of Jurassic petroleum system in

southwest of Iran while several studies document the stratigraphy and sedimentology of Jurassic strata (Sadooni 1997; Alsharhan and Nairn 2003; Sherkati and Letouzey 2004; Rabbani and Kamali 2005; Alizadeh *et al.* 2007).

Pitman *et al.* (2004) reported that Jurassic Sargelu Formation exhibits good to excellent petroleum generation potential and the kerogen prevalent in the formation is of type II-S. The thermal modelling conducted by the researchers indicated that in most parts encompassed by the Abadan Plain and Iraqi parts of Zagros basin, the formation has reached and passed the oil generation window (Pitman *et al.* 2004; Zeinalzadeh *et al.* 2015).

In the southwest of Iran a few wells have penetrated Jurassic succession and proved the occurrence of hydrocarbon as condensate to wet gas. Due to deep burial of Jurassic sediments in the Zagros basin and difficulty of access to samples, there are limitations to geochemical study of source rock and hydrocarbon generation, migration and entrapment in the Jurassic petroleum system.

The aim of this study was to address the characteristics of middle Jurassic source rocks in the study area (figure 1). To characterise the quantity, quality and maturity of organic matter in the studied formation, Rock-Eval pyrolysis and vitrinite reflectance measurements were carried out, and a one-dimensional (1D) burial history was created and evaluated to derive additional information on source rock maturity stages and hydrocarbon generation in southwest Iran. Also, the present study presents a detailed geochemical description of hydrocarbon discovered in the Jurassic reservoir in the region. The first step was to characterise geochemical parameters in the Jurassic condensate. Then, the biomarker composition in the studied samples was classified and finally, using oil–oil and oil–source correlation, the oil family and respective source rocks were identified.

This study integrated detailed analytical work on outcrop, well cuttings and oil (condensates) samples to explain the above-mentioned issues. In addition, thermal modelling was done in the key localities to assess the maturity level and timing of hydrocarbon generation in the source rock. In this regard, PetroMod 1D software has been undertaken for two representative well locations.

2. Geological background

In the Late Permian–Early Triassic, the southern Tethys Ocean bordered the Arabian platform in

the northeast. This marine environment existed between the time of opening of the Tethys and the collision of the Arabian Plate with the Eurasian margin (including the Iran block) in the Early Miocene (Stocklin 1968; Berberian and King 1981). As a result of this collision, the northern margin of the Arabian Platform was subducted northward beneath Eurasia and extensively folded and thrust in the present Zagros region, particularly during the Styrian orogenic phase in Middle Miocene and Atikan phase in Late Miocene–Pliocene time. In addition to Palaeogene orogenic folding and thrusting, some regional structural features in the region persisted from the beginning of the Middle Jurassic until the Early Miocene (Sepehr and Cosgrove 2004).

Wide, shallow intracratonic seas or basins covered the eastern and northeastern parts of the Arabian Platform during most of its geological history (Muris 1980). As a result of relative sea level changes, the basin shore fluctuated widely and underwent a low-amplitude differential subsidence. This is confirmed by seismic observations of meandering channel systems in the upper part of the Sarvak Formation. Sedimentation consisted predominantly of calcareous deposition that was temporarily interrupted either by evaporite deposition or by clastic influxes (Stöcklin 1974). High TOC source rocks were developed when the environment became anoxic because of a combination of sea level rise or increasing subsidence, a humid climate and the occurrence of upwelling currents in the Tethys Ocean (Bordenave and Huc 1995). The main reservoirs in southwest of Iran occur in the Asmari Formation (Fars Group) and Bangeshtan, Khami and Deh Ram Groups of the Zagros Foredeep, as shown in figure 2.

The Zagros basin is divided into three zones: the Zagros Thrust Zone (ZTZ), which forms the eastern margin; the Imbricated Zone, which is about 80 km wide and lies to the west of the ZTZ; and the Folded Belt, which is farther west and in which the intensity of folding decreases towards the southwest (Ala 1974).

Development of the Zagros basin started in the Late Cretaceous as a result of foredeep subsidence that preceded the continental closure along the Zagros suture. The area previously had been a stable shelf margin of the Afro-Arabian continental plate (Muris 1980).

In the permo-Triassic episode, the Zagros basin was divided into two main basins. In the northwestern part the Lurestan and the Fars basin to

Figure 1. Location map of the studied area and oil fields in the Zagros basin with main tectonic boundaries (modified after NIOCEXP 2010; Zeinalzadeh *et al.* 2015).

the southeast in which sedimentary successions are quite different (Setudehnia 1978). The Jurassic–Cretaceous in the Lurestan and northwestern part of the Dezful Embayment contain deeper water sediments (Sepehr and Cosgrove 2004).

Middle Jurassic sediments in the Zagros basin are represented by contrasting facies in the study area (figure 2). In the west, basinal organic-rich carbonate source rock facies of the Sargelu Formation were deposited in a deep basin which has been proven in deep wells in MIS-306 and Bangestan-1. In the eastern parts, time equivalent platform carbonates of the Surmeh Formation were deposited as can be seen at outcrop on the Mungasht and Khami anticlines (see figure 1 for location). Facies relationships between the basinal Jurassic source rocks (Sargelu Formation) and its time equivalent dolomitised carbonate platform have not yet been observed due to lack of outcrop and well control.

The Dezful Embayment is a tectonic feature in the southwestern edge of the Zagros basin. The embayment contains Iran's major oil fields;

it is the centre of the southwestern Iranian oil province, which geologically belongs to the northern part of the Arabian plate. The name 'Dezful Embayment' was assigned to that part of the Zagros basin where there is no evidence of the Asmari Formation (Oligo–Miocene) in outcrop (Motiei 1995). The Dezful Embayment is bound by three main tectonic elements. There is an E–W trending flexure zone (Balaroud fault) and a 'mountain front' flexure with a NW–SE trend in the northern part. To the east and southeast the Dezful Embayment is bound by a complex zone of faults and flexures having an N–S trend (Kazeroun–Qatar fault). The structural and stratigraphic features of the Dezful Embayment have been well documented since the middle of the last century (Falcon 1967; Motiei 1995; Alavi 2007).

The Abadan Plain is a structural unit located in southwest of Iran. The boundaries of this plain include the Zagros Fold Belt in the northeast and the Persian Gulf in the south (figure 1). The generally N–S trending anticlines

Figure 2. Stratigraphic chart of the studied area in southwest Iran. The main sources are indicated by two stars and the marginal ones by one star (after Bordenave and Hegre 2010).

of the Abadan Plain are not exposed in outcrop but occur in the subsurface. The most important structures in this area contain oil, including the Juffair, Darquin, Azadegan and Hendijan oil fields.

Geologically, the Abadan Plain is the continuation of the northeastern part of the Arabian plate and as such the main structural trends correspond to those of Kuwait, southern Iraq,

the northern Persian Gulf and northeastern Saudi Arabia.

3. Materials and methods

Only a few wells in southwest of Iran have reached Jurassic petroleum system in which four condensate samples (taken during drill stem test)

Table 1. Rock-Eval pyrolysis data are tabulated for the Middle Jurassic Sargelu Formation in the studied wells, southwest Iran.

Well	Formation	Depth (m)	S1 (mgHC/ g rock)	S2 (mgHC/ g rock)	$T_{\max}$ (°C)	S3 (mgHC/ g rock)	TOC (%)	HI (mgHC/ g TOC)	OI (mgHC/ g TOC)	PI	PP
A-2	Dezful	3425	0.3	3.47	460	0	7.13	49	0	0.1	3.77
A-2	Dezful	3430	0.37	5.21	442	0.5	5.55	94	8	0.1	5.58
A-2	Dezful	3595	0.44	4.31	440	0.6	10.46	41	6	0.1	4.75
A-2	Dezful	3600	0.66	6.19	439	0.6	11.55	54	5	0.1	6.85
A-2	Dezful	3604	0.86	3.86	439	0.6	9.51	41	7	0.2	4.72
A-2	Dezful	3740	0.73	5.25	443	0.5	10.74	49	5	0.1	5.98
A-2	Dezful	3760	0.08	0.18	435	0.5	0.13	138	408	0.3	0.26
A-2	Dezful	3780	0.18	1.14	430	1.1	0.48	238	240	0.1	1.32
A-2	Dezful	3840	0.31	0.24	436	0.9	0.13	185	685	0.3	0.55
A-2	Dezful	3860	0.2	0.99	437	1	0.44	225	236	0.2	1.19
A-2	Dezful	3936	5.73	6.59	453	0	9.82	67	0	0.4	12.32
A-4	Abadan Plain	5230	1.75	5.22	440	0.8	1.58	330	22	0.25	6.97
A-4	Abadan Plain	5300	1.7	6.24	439	1.01	1.94	322	26	0.21	7.94
A-5	Abadan Plain	4985	1.3	3.32	449	1.98	4.61	72	43	0.28	4.62
A-5	Abadan Plain	4995	0.82	1.24	445	1.96	1.48	84	132	0.4	2.06
A-5	Abadan Plain	5236	0.23	0.5	450	1.05	0.56	89	188	0.32	0.73
A-5	Abadan Plain	5274	0.15	0.39	449	0.75	0.73	53	103	0.27	0.54
A-5	Abadan Plain	5009	0.22	0.54	446	0.93	0.53	102	174	0.29	0.76
A-5	Abadan Plain	5025	0.09	0.21	440	0.47	0.27	78	174	0.29	0.30
A-5	Abadan Plain	5037	0.18	0.25	438	0.39	0.18	139	217	0.42	0.43
A-5	Abadan Plain	5050	0.16	2.07	428	1.09	0.75	276	145	0.07	2.23
A-6	Abadan Plain	5180	0.23	5.41	457	0.7	9.91	55	7	0.04	5.64
A-6	Abadan Plain	5210	0.12	2.55	432	0.38	0.84	304	45	0.04	2.67
A-6	Abadan Plain	5490	3.98	1.56	442	0.63	1.42	110	44	0.72	5.54
Surface section	Dezful	Surface	0.05	0.06	507	0.23	0.06	100	382	0.45	0.11
Surface section	Dezful	Surface	0.03	0.07	465	0.15	2.14	3	7	0.3	0.1
Surface section	Dezful	Surface	0.02	0.03	445	0.34	1.42	2	24	0.4	0.05
Surface section	Dezful	Surface	0.01	0.02	425	0.09	2.2	1	4	0.33	0.03
Surface section	Dezful	Surface	0.01	0.01	446	0.08	1.08	1	8	0.5	0.02
Surface section	Dezful	Surface	0.03	0.02	475	1.75	1.11	2	158	0.6	0.05
Surface section	Dezful	Surface	0.06	0.07	485	1.63	0.8	8	204	0.46	0.13
Surface section	Dezful	Surface	0.01	0.01	499	0.19	2.7	0	7	0.5	0.02

Abbreviations: HI: hydrogen index ($S2/TOC$); OI: oxygen index ($S3/TOC$); PI: potential index ($S1/(S1 + S2)$).

were collected for this study. In addition, 24 cutting samples were collected from four oil wells in different fields in southern part of the Dezful Embayment and Abadan Plain align with eight samples from two surface sections in the Lurestan area to characterise source potential of Jurassic Sargelu Formation (see figure 1 for localities). The samples were selected on the basis of their lithology and dark colour and correlated with Gamma Ray log, which may point to high organic matter content.

3.1 Source rock geochemistry

To evaluate generation potential and thermal maturity of organic matter in different source rocks, the most widely used method is Rock-Eval pyrolysis (Espitalié *et al.* 1977). After decontaminating the samples from mud additives (such as

mica and iron filings) using a binocular microscope, in order to have a uniform and comparable size of sediments for geochemical analysis, they were ground to $<180\text{ }\mu\text{m}$.

Pyrolysis analyses have been done using a Rock-Eval 6 apparatus manufactured by Vinci Technologies (Tissot and Welte 1978). Rock-Eval analysis results show several geochemical parameters including $S1$, $S2$, $S3$, TOC and T_{max} (table 1). Some additional calculated parameters from measurements such as HI (hydrogen index), OI (oxygen index) and PI (production index) also are listed. After preliminary experiments, four rock samples were selected for complementary analyses which are explained in the following.

Nine samples have been selected for measuring vitrinite reflectance considering results of Rock-Eval pyrolysis. Reflectance was measured using a Zeiss Axipolan II microscope in oil immersion following the method described by Taylor *et al.* (1998)

Table 2. Vitrinite reflectance measurement results of studied samples.

Well	Depth (m)	Mean (%)	Min (%)	Max (%)	No. of measures
A-2	3720	0.9	0.79	0.95	27
	3735	0.86	0.81	0.9	23
	3750	0.92	0.8	1	38
A-5	5036	0.75	0.73	0.95	12
	5000	0.73	0.71	0.89	21
	4980	0.83	0.76	0.79	33
Surface section		0.8	0.75	0.86	32
Surface section		1	0.92	1.1	42
Surface section		0.9	0.68	1.1	18

Figure 3. Plot of PP *vs.* TOC showing good to excellent source potential of Sargelu Formation (Peters and Cassa 1994).

and Alizadeh *et al.* (2012). The results can be seen in table 2.

Regarding the Rock-Eval pyrolysis results, four rock samples were selected for extraction and other complementary analyses which are explained in the next section. The organic matter extraction was done by Soxhlet using dichloromethane (DCM) overnight and then the solvent was removed by centrifuge evaporator. To fractionate the extract, a liquid column of silica gel activated by alumina was employed.

3.2 Oil geochemistry

In this study, oil (condensate) samples from two wells were subjected to preliminary experiments such as oil gravity, API (American Petroleum

Institute) measurements, asphaltene precipitation and column chromatography. Column separation is basically a system which will separate the extracted material into saturated hydrocarbons, aromatic hydrocarbons and resins. Asphaltenes can either be separated from the extract before separation or they remain a part of the resin fraction. The asphaltene fraction was precipitated by the addition of *n*-hexane. The remaining fractions were then separated into saturate, aromatic and resins by column chromatography, using alumina/silica gel (2/1 ratio) columns. These fractions were eluted with *n*-hexane, benzene and methanol, respectively. Then complementary stages such as gas chromatography (GC), GC-mass spectrometry (GC-MS) and stable isotope analysis were performed.

Figure 4. Plots of HI vs. OI detecting kerogen type (A) and T_{max} yielding maturity of source rock (B) and plot of PI vs. T_{max} yielding maturity of source rock (C) (Hunt 1996).

After fractionating the oil samples, saturates and aromatic fractions were analysed on a gas chromatograph. GC apparatus which has been used in this study is of type 'chrompakcp9000' equipped with Flame Ionization Detector (FID) and capillary column of type 'CP-Sil-5' with 30 m length and 0.25 mm inner diameter and coupled to a Finnigan MAT GCQ ion trap mass spectrometer. Oven's initial temperature was 70°C and was programmed to increase at the rate of 4°C/min to 300°C. Carrier gas was helium and compressed air and hydrogen were used as the flame of the detector. The sample was injected in split-less mode while the injector temperature was set at 275°C. For processing data a Finnigan system was used. Relative percentages and absolute concentrations of different compound families of saturates and aromatics such as normal alkane, pristane, phytane, terpanes, steranes and DBT (dibenzothiophenes) were detected and related parameters were calculated.

Oil and rock extracts contain components whose ^{13}C isotopic composition is related to the origin of the organic matter and thermal history as well as any post-accumulation changes such

as biodegradation or migration. These data are used in geochemical assessments for source rock evaluation and correlation. The analysis of their composition is made by stable carbon isotope mass spectrometry, using a VG Sira10 Mass Spectrometer. This method describes the measurement of the relative amounts of ^{13}C to ^{12}C of oil and sediment extracts.

The measurement is made relative to an international standard, PDB (a belemnite from the Upper Cretaceous Peedee Formation, USA) via a secondary standard NBS22 (a lube oil).

For stable carbon isotopic analysis (i) sediment samples must have their inorganic carbon (carbonate) removed and (ii) oil and sediment extracts must have the volatile material (below $n\text{-C}_{10}$) removed, as variable evaporation of this material will cause data scatter.

4. Results and discussion

4.1 Source rock geochemistry

The quantity of organic matter in a rock sample usually is expressed as TOC (Hunt 1996). In the

Figure 5. GC-SAT chromatogram of the A-5 Jurassic oil-1 sample indicating n -alkanes as well as Pr and Ph.

Sargelu Formation, TOC content is variable and changes from 0.13% up to 11.55% in the cutting samples. Average TOC in well cutting samples is about 3.8% while in the samples from surface sections, TOC values are much lower and average TOC is 1.4% (table 1). According to Peters and Cassa (1994), TOC values of Sargelu Formation are consistent with very good source rocks. The highest TOC values can be seen in the northern part of Dezful embayment in the range of 7–11 wt%.

In some other studies on the Sargelu Formation in Zagros basin (Pitman *et al.* 2004), it has been shown that the TOC is variable from 2% to more than 6% in well cutting and less than 2% in the surface section. Hence, it appears that variability in organic matter content in the Sargelu Formation is a regional phenomenon and a result of basin sedimentary environmental conditions.

Other important pyrolysis provided parameters are S_2 and HI which are the remaining hydrocarbon potential or amount of hydrocarbon obtained by heating during pyrolysis (Hunt 1996). S_2 yield of Sargelu Formation changes from 0.2 to more than 6.59 mg HC/g rock in the well samples and is less than 0.07 mg HC/g rock in the surface sections. The present HI value of Sargelu Formation in the studied area is quite variable and ranges between 40 and more than 330 mg HC/g TOC. Initial HI value of this Formation is calculated as 620 mg HC/g TOC in a joint study between NIOC (National Iranian Oil Company) and BP (British Petroleum; NIOC 2003, unpublished report). In another basin modelling study in the Mesopotamian basin in Iraq, the initial HI value for Sargelu and Naokelekan Formations was considered as 600 mg HC/g TOC (Pitman *et al.* 2004).

$T_{\max}$ is a temperature at which there is a maximum in S_2 curve during pyrolysis. The level of thermal maturity for different types of organic matter may be estimated from the $T_{\max}$ data. In this study, average $T_{\max}$ values in well samples is about 445°C (without considering samples which have unusually low or high $T_{\max}$) and in the surface section average $T_{\max}$ is 468°C which shows late oil to wet gas generation window (Hunt 1996).

Plot of production potential (PP) *vs.* TOC in figure 3 shows good to excellent source potential of Sargelu Formation in all the studied areas. TOC and PP measurement can be influenced by contamination in samples. S_1 /TOC ratio for most of studied samples is lower than one which shows there was no contamination (such as

Table 3. Result of liquid chromatography and GC-FID for Jurassic oils and Sargelu Formation.

Well	Formation	Sat%	Aro%	Pol%	Pr/Ph	Pr/ nC_{17}	Ph/ nC_{18}	CPI	$nC_{17}/(nC_{17} + nC_{27})$	$nC_{18}/(nC_{18} + nC_{28})$	TAR	API gravity	H ₂ S (%)
A-2-Jurassic Oil	Jurassic	68.9	23.1	8	1.03	0.45	0.55	1	0.95	0.95	0.05	42	4
A-5-Jurassic Oil-1	Jurassic	52.5	31.5	16	1.32	0.43	0.39	1.03	0.82	0.8	0.19	40	19
A-5-Jurassic Oil-2	Jurassic	78.9	9.3	11.8	0.83	0.10	0.22	0.99	0.88	0.84	0.13	41	18
A-5-Jurassic Oil-3	Jurassic	61.83	19.18	19.17	1.33	0.12	0.20	1.01	0.88	0.87	0.1	43.2	25
A-2-Sargelu Fm-1	Jurassic	57.7	32.5	9.8	1	0.53	0.59	1.02	0.88	0.54	0.13	—	—
A-2-Sargelu Fm-2	Jurassic	66	25	9	0.97	0.64	0.73	0.94	0.82	0.53	0.13	—	—
A-6-Sargelu Fm	Jurassic	51.85	16.14	32.01	0.82	0.33	0.43	1.01	0.96	0.97	0.05	—	—
A-5-Sargelu Fm	Jurassic	20.44	10.22	69.34	0.88	0.20	0.28	0.97	0.75	0.78	0.3	—	—

Sat = saturates; Aro = aromatics; Pol = polars; Pr = pristane; Ph = phytane; CPI = $2(nC_{23} + C_{25} + C_{27} + C_{29})/[C_{22} + 2(nC_{24} + C_{26} + C_{28}) + nC_{30}]$; TAR = $(nC_{27} + C_{29} + C_{31})/(nC_{15} + C_{17} + C_{19})$.

Figure 6. Typical saturate GC-MS fragmentograms of the A-5 Jurassic oil-1 sample.

drilling mud, migrated hydrocarbons, etc.) in the studied samples and all organic matter are indigenous (table 1).

Maximum hydrocarbon which can be produced by a specific source rock is turned to SPI (source potential index) if no expulsion occurred (Demaison and Huizinga 1991). In the Sargelu Formation considering there has been expulsion, remaining SPI can be calculated as follows:

$$SPI_r = h \times [(S1 + S2)/1000] \times \rho,$$

where h is the thickness of source rock in metre, $S1$ and $S2$ are in mg HC/g rock or kg HC/t rock and ρ is the source rock density in t/m³. The average thickness of Sargelu Formation in the studied area is about 170 m, the average remaining production potential (PP = $S1 + S2$) is 3.66 mg HC/g rock and density of Sargelu Formation is considered as 2.68 t/m³ based on mixed limestone and shale lithology. Remaining SPI of Sargelu Formation is about 1.6 t HC/m² which classifies it as high potential source rock. It should be considered that initial potential of this formation had been much higher.

Determining the type of kerogen in Sargelu Formation, HI is plotted *vs.* OI in figure 4(A) (Hunt 1996). Regarding this plot, kerogen of Sargelu Formation can therefore be classified as type II or II/III. As it was mentioned, initial hydrogen index had been much higher and therefore in HI *vs.* OI plot, moving to higher hydrogen index, the kerogen type will be type II.

Source rock maturity was assessed on the basis of Rock-Eval T_{max} and PI values. T_{max} for Sargelu Formation in the studied area varies between 426

and 460°C and the average is 442°C which indicates thermal maturity in the oil window. Plots of HI and PI *vs.* T_{max} also show oil window level of maturity in the kerogen (figure 4).

Another important and reliable parameter for indicating maturity is vitrinite reflectance measurement. Vitrinite reflectance in the studied samples ranges between 0.75% and 1% with average of 0.85% which indicates oil window maturity in the source rock (table 2).

4.2 Oil geochemistry and correlation

In this study, four oil (condensate) samples from Jurassic reservoir (Sargelu and Neyriz formations) of two fields (Asmari and Azadegan) in the Zagros basin were analysed. The oils have API gravity in the range of 40–43 and amount of H₂S gas in the oil samples ranges between 4% and 27% which place them in the light and sour oil classification. Short-chain *n*-alkanes predominance can be detected in the oil (figure 5), carbon preference index is close to 1 and pristane/phytane ratio ranges 0.8–1.3 for all oil samples (table 3).

Regarding gas chromatograms envelope and lack of 25-norhopane in the GC–MS fragmentograms (Peters and Moldowan 1993), there is no evidence of alteration process such as biodegradation in the studied oil (figure 6).

Indicating thermal maturity of oil samples a set of biomarker and diagrams can be used according to different references. Very low values of Pr/C₁₇ and Ph/nC₁₈ (0.1–0.45) in the plot of figure 7, CPI (carbon preference index) close to unity and high values of C₂₉ααS/(S + R) and ββ/(ββ + αα) ethylcholestane ratios (table 4) show

Figure 7. Plot of Pr/*n*-C₁₇ *vs.* Ph/*n*-C₁₈ ratios for Jurassic oil and source rocks in southwest of Iran (after Hunt 1996).

advanced maturity of Jurassic oil and cutting samples. Aromatic biomarkers which are more resistive to thermal cracking, also show high maturity for studied oil and source rock samples, as it is shown in figure 8, and using methylphenanthrene index (MPI)-1 index, amount of vitrinite reflectance is calculated for oil samples between 0.7% and 1.1% (Radke and Welte 1983). There is an acceptable correlation between studied oil and Jurassic source samples in the mentioned figures.

Geochemical biomarkers can be used to investigate the nature and depositional environment of suspected source rock of the oil. In the studied oil samples, higher predominance of low chain *n*-alkanes align with Pr/*n*-C₁₇ and Ph/*n*-C₁₈ (figure 5) indicates marine organic matter (Peters and Moldowan 1993). Plot of C₂₇-C₂₈-C₂₉ sterane relative distribution shows low amount of C₂₉ steranes which indicate little contribution of higher plants. As it is shown in ternary diagram of figure 9, in most studied samples there is a shifting towards C₂₇ indicating marine carbonate source rock (Moldowan *et al.* 1985). In addition, ratio of C₂₉-C₃₀ hopane and higher values of 17 α (H)trisorhopane (Tm) relative to 18 α (H)trisorhopane (Ts) indicate marine carbonate source for the studied samples (Peters and Moldowan 1993).

Using statistical processing on the isotope analysis results, a parameter called canonical variable (CV) can be calculated (Sofer 1984). CV value lower than -2 in table 5 indicates no contribution of lacustrine and paralic shale while all of studied oil originate from marine carbonate and shale environment. According to plot of figure 9, there is good correlation in the studied oil and Jurassic source rock samples.

In addition to geochemical biomarker for source rock environment, DBT/Phen ratio is dependent on environment of source rock. In the studied samples, DBT/Phen ratio changes between 1.5 and 4.5 which confirms marine environment of source rock.

Peters *et al.* (1999) used biomarker ratio oleanane/(oleanane + hopane) for recognition of oil younger than Cretaceous, and for all studied oil this ratio is zero which means Cretaceous and older sources. Plot of Pr/Ph ratio *vs.* $^{13}\delta\text{C}$ saturates in figure 10 shows source age of studied samples; early Mesozoic age has been derived for the studied oil samples (Chung *et al.* 1992). Bjorøy *et al.* (1992) believed that with advance increase in maturity

Table 4. Result of GC-MS analysis for Jurassic oils and Sargelu Formation.

Well	Formation	Ts/(Ts+Tm)	C ₂₉ /C ₃₀ hopane	Oleanane index	20S/(20S+20R)	Str 29 $\beta\beta/(\beta\beta+\alpha\alpha)$	C ₂₇ %	C ₂₈ %	C ₂₉ %	DBT/Phen	MPI-1	C ₂₉ /C ₂₇ Str
A-2-Jurassic Oil	Jurassic	0.4	1.23	0	0.57	0.57	51.9	24.7	23.4	2.71	0.84	0.64
A-5-Jurassic Oil-1	Jurassic	0.41	1.26	0	0.52	0.53	51.9	28.59	19.6	4.5	1.26	0.37
A-5-Jurassic Oil-2	Jurassic	0.49	1.31	0	0.49	0.66	41	22	37	2.23	1.06	0.92
A-5-Jurassic Oil-3	Jurassic	0.51	1.28	0	0.51	0.61	47	22	31	3.5	1.1	0.67
A-2-Sargelu Fm-1	Jurassic	0.41	1.34	0	0.49	0.57	40.5	29.3	30.2	1.5	0.78	0.8
A-2-Sargelu Fm-2	Jurassic	0.41	1.49	0	0.58	0.55	41.2	29.2	29.6	1.54	0.89	0.83
A-6-Sargelu Fm	Jurassic	0.42	1.09	0	0.5	0.56	40	29	30	2.38	0.77	0.8
A-5-Sargelu Fm	Jurassic	0.56	1.39	0	0.49	0.54	38	26	36	0.65	0.55	0.94

Ts/(Ts + Tm) = C₂₇18 α (H) trisorhopane/(C₂₇ 18 α (H)trisorhopane); C₂₉/C₃₀H = C₂₉ 30-norhopane/hopane; oleanane index = oleanane/(oleanane + C₃₀ hopane); %C₂₇ = %C₂₇ steranes/(%C₂₇-C₂₉ steranes); %C₂₈ = %C₂₈ steranes/(%C₂₇-C₂₉ steranes); %C₂₉ = %C₂₉ steranes/(%C₂₇-C₂₉ steranes); DBT/P = dibenzothiophenes/phenanthrene; MPI-1 (methylphenanthrene index) = 1.5(2MP+3MP)/(PHEN+1MP+9MP).

Figure 8. Plot of MPI-1 *vs.* calculated vitrinite reflectance for studied oil and source rock samples (Radke and Welte 1983).

Figure 9. Ternary diagram of C₂₇–C₂₈–C₂₉ steranes for studied oil and rock samples (after Moldowan *et al.* 1985).

Table 5. Result of isotope analysis in the studied samples.

Well	Formation	Saturated HC	Aromatic HC	CV
		$\delta^{13}\text{C}$ (PDB)	$\delta^{13}\text{C}$ (PDB)	
A-2-Jurassic Oil	Jurassic	−26.6	−25.7	−2.691
A-5-Jurassic Oil-1	Jurassic	−27.2	−26.8	−3.67
A-5-Jurassic Oil-2	Jurassic	−27.6	−27.1	−3.339
A-5-Jurassic Oil-3	Jurassic	−27.8	−27.2	−3.06
A-2-Sargelu Fm-1	Jurassic	−27.1	−27	−4.377
A-2-Sargelu Fm-2	Jurassic	−29.1	−27.8	−1.133
A-6-Sargelu Fm	Jurassic	−25.6	−24.3	−2.043
A-5-Sargelu Fm	Jurassic	−27.3	−26.8	−3.417

CV = canonical variable = $-2.53 \delta^{13}\text{C}$ saturates + $2.27 \delta^{13}\text{C}$ aromatics − 11.6.

of oil samples, the isotope values (especially in lighter fractions) will be heavier (more positive). As mentioned in the previous paragraphs, biomarker

parameters show high maturity in the studied samples. Regarding these comments, in the plot of figure 10, the isotope values of saturate should be

Figure 10. Plot of Pr/Ph vs. $\delta^{13}C$ Saturated indicating source rock age (Chung *et al.* 1992).

Figure 11. Plot of star diagrams using GC and GC-MS parameters for oil-oil and oil-source correlation.

Figure 12. Plot of correlation between calculated and measured parameters in studied oil field.

shifted more leftward in which there will be good correlation between Jurassic condensate and source rock samples.

All GC and GC-MS parameters have been used in order to do oil-oil and oil-source rock correlation in the studied Jurassic petroleum system. As it

Figure 13. Plot of burial history and temperature in two Jurassic drilled oil wells (A-5 and A-2).

Figure 14. Plot of temperature and transformation ratio *vs.* time in the Jurassic Sargelu Formation in the wells A-5 and A-2.

is shown in the star diagrams of figure 11, there is very good correlation among all the studied oil samples (solid lines) in which they can be put in the same oil family. In addition the correlation between oil and source rock samples is acceptable which means condensates in the Jurassic reservoirs have been generated by the Jurassic Sargelu Formation.

4.3 Modelling hydrocarbon generation

Petroleum system modelling is a tool most often used to describe the modelling of the series of processes that include generation, expulsion, migration, trapping and preservation of the hydrocarbons within a specific system. Modelling of petroleum systems is a compromise between what one would like to do and what our limited knowledge permits. As a result, most workers in the field of system modelling are sceptical about the quantitative potential of such models and prefer to

use them comparatively or semi-quantitatively at most (Barker 1996).

1D basin modelling was applied to describe the hydrocarbon generation in Jurassic petroleum system in two key wells in Zagros basin using Petro-Mod software.

Formation tops, ages and lithologies for drilled strata were taken from palaeogeology which was prepared based on geological and palaeontological studies of the oil fields.

The Sargelu Formation was considered as a source rock in the modelling process. Initial geochemical properties of the Sargelu Formation have been used from a joint study between NIOC and BP (unpublished report 2001) and initial TOC and HI are 5–8% and 600–650 mg/g TOC, respectively.

Corrected bottom-hole temperatures were applied to define the present-day heat flow that was considered constant in the model to test the fit of calculated vitrinite reflectance against observed data from drilled wells. Plots of figure 12 show

there is a good correlation between measured and calculated vitrinite reflectance and temperature.

In modelling of Asmari oil field which is located in Dezful embayment a 1000 m erosion was considered using near geological surface sections along with correlation to adjacent drilled wells. Heat flow as most important boundary condition factor for source rock maturity and hydrocarbon generation has been considered constant as 45–48 mW/m².

Plot of figure 13 shows the burial history and temperature evolution in the studied oil fields. The Jurassic Sargelu Formation has entered oil window in middle Cretaceous and the main expulsion (transformation ratio more than 25%) from this formation occurred in the Miocene and Eocene time in the Abadan Plain and north of Dezful embayment, respectively. The highest temperature in this formation had been 145°C. Transformation ratio in the Sargelu Formation reaches 90–100% which means almost all PP has been generated (figure 14). Models show Jurassic strata in recent time are in condensate window which are in good correlation with reality of having condensate in the Drill Stem Test of drilled wells.

5. Conclusions

During this study, Jurassic petroleum system in the Zagros basin was characterised geochemically. The most important Jurassic source interval, the Sargelu Formation with average TOC value of 3.8% and initial HI value of 600 mg HC/g TOC can be classified as a very good to excellent source rock. Kerogen type of this formation was considered to be type II. Rock-Eval pyrolysis and vitrinite reflectance measurements indicated that the maturity in the Sargelu Formation is in late oil to wet gas all over the studied area.

In the oil geochemistry study, four condensate and four source rock extract samples from three oil fields in the Zagros basin were analysed. Geochemical parameters such as CPI, Pr/nC₁₇ and Ph/nC₁₈ as well as maturity indicating biomarkers showed advanced level of maturity for the studied samples. C₂₇, C₂₈ and C₂₉ steranes distribution as well as DBT/Phen ratio and canonical variable showed marine carbonate and shale source environment for condensates. Lack of oleanane biomarker and isotopic values suggested early Mesozoic age for source of the studied samples.

Finally regarding all the GC and GC–MS parameters of the samples, there is a very good similarity

among oil samples which put them in the same family. In addition, correlation between oil and source rock samples revealed that the entire Jurassic hydrocarbon is generated by Jurassic Sargelu Formation.

Thermal history reconstruction by PetroMod 1D basin modeller was carried out for two key wells which have penetrated the Jurassic succession. Initial TOC and HI values were considered to be 5–8% and 600 mg HC/g TOC, respectively. Models showed that Sargelu Formation is in condensate window at present time and had entered oil generation window at middle Cretaceous. The maximum temperature reached for this formation has been 145°C and almost all its oil PP has been generated.

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