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New Methodology for Fracture Attributes Determination Based on Petrographic Analyses, and Its Application in Two Naturally Fractured Carbonate Reservoirs of Southeastern Mexico*

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Abstract

Characterization studies of naturally fractured reservoirs (NFR) generally omit the impact of diagenetic processes that affect fracture systems, giving as a result fracture models not fully calibrated with hard data. This work presents the results of the application of the SDPS (Structural-Diagenetic Petrographic Study) methodology, for calculation of fracture attributes. The main objective is to identify and to characterize fracture sets, where the hydrocarbons flow, based on the relationship between fracturing and diagenesis, and the rock properties alteration during the tectonic and sedimentary evolution of the area. To demonstrate the application of this methodology, two oil and gas carbonated reservoirs from the southeastern México were selected: the first in limestones with porosity (Φ) exclusively due to fractures (Φmatrix <2%) and the second in dolostones with dual porosity (Φmatrix = 4-5%). Thirty-eight oriented thin sections form cores and nine hundred and twenty cutting samples from ten wells were analyzed.

In both reservoirs were identified five fracture sets. In the first, four fracture sets are conductive, with high connectivity: Set1 (105°/83°), Set3 (55°/77°), Set4 (03°/79°), and Set5 (140°/80°). In the second reservoir, two sets are conductive: Set4 (48°/88°) and Set5 (86°/87°), with good connectivity between matrix-fractures. The first reservoir presents a better fracture attributes (density, porosity, connectivity, and conductive quality) than the second one. These differences are reflected in the productivity in both reservoirs.

The application of the SDPS allowed differentiates conductive fracture systems in the reservoirs, main fluid flow directions were corroborated with reservoir dynamic information.

Introduction

In the oil industry fracture models are being developed using software with the objective of controlling their distribution and attributes, these models will serve to construct reservoir simulation models. However, these models, generally omit the knowledge of the diagenetic processes that directly control the mechanical properties of the rock and fracture attributes. In this paper, we show the impact of the diagenesis in the control of quality, porosity, and permeability in fractures, applying the methodology named Structural Diagenetic Petrographic Study (SDPS) (Monroy, 2009), using two fractured reservoirs with different matrix porosities. The methodology focuses in the determination of families or "sets" of conductive fractures and the quantification of fracture attributes such as orientation, opening, degree of cement, porosity, geometry, connectivity between fractures and connectivity matrix-fractures, using diagenetic and structural techniques. These attributes are hard data to calibrate any other fracture study at other scales.

Objectives

The main objective of this work is to analyze the impact of diagenetic processes in the fracture systems proprieties, in two carbonated reservoirs with different petrophysical properties, by measurement and calculation of fracture attributes, e.g. conductive fracturing direction, minimum conductive aperture, density, and connectivity. The study is focused in the fracture system characterization by fracture families (or sets) of the same diagenetic structural origin, using oriented thin sections from well cores. Results will improve reservoir fracture models.

Methodology

Measurement of structural data of fracture planes from thirty-eight oriented thin sections from ten cores of 8 wells are the base of this study. Core selection was based on number of sets identified according to Monroy´s methodology (Monroy, 2009). In addition 920 thin sections from cutting samples were reviewed in the wells intervals of interest (Middle and Upper Cretaceous) of both reservoirs (named Y1 and Y2). For petrographic study we used a conventional microscope, Olympus BX61.

The SDPS consists in the determination, in core oriented thin sections, of main fractures attributes characteristics, to separate them in families or sets, and to classify them in conductive, partially conductive and non conductive or cemented sets (Figure 1). In addition, the methodology includes apertures measurements of conductive fractures sets, to determine parameters like remaining porosity, minimum conductive aperture, fracture density, and connectivity (Monroy et al., 2001). The results must to be calibrated with engineering data of the reservoir, mainly cumulative productions and interference tests, to confirm preferential flow directions (Figure 1).

One of the most important steps to applying a SDPS is to differentiate sets with different temporary origin, even if they share the same direction, since the direction is not criterion sufficient to group fracture sets (Marrett, 1996). To understand, this is very important because we faced this situation commonly in fracture characterization studies. These types of differences are difficult to observe in another scale of study. The petrographic study permits analysis of the optical properties of the mineral presents in fractures. Each fracture set is differentiated by its diagenetic-structural origin, occurred during the geological evolution of rocks and the structures that conforms the reservoirs. The results of this methodology allowed modeling in 3D these attributes especially from conductive sets of fluids flow. The main impacts to take two different set as a one, is in calculation of fracture density, fracture distribution and the minimum conductive apertures. We can generate calculations not representative for a reservoir and use it in the final fracture model.

Study Area

The study area is located in the south-east of Mexico (Figure 2). The Mesozoic in this area is characterized by carbonated marine sediments of low matrix porosity (<2%), where the fracture systems play an important role in the hydrocarbon production. These characteristics are representative of the Y1 reservoir, in a structural trap of 12 km², which produce light oil of 43° API. The production rate per day varies from 4 to 6 times greater than the Y2 reservoir. Some intervals of the Middle Cretaceous rocks are dolomitized, and that increase matrix porosity interacts with the fractured systems. This is the case of the Y2 reservoir, constituted by an anticline trap of 21 km^2, producer of gas and condensate of 47.6°API.

Results

Next section describes the main results from the SDPS performed in both reservoirs; including conductive fracture sets attributes and other diagenetic processes that affected rocks in these reservoirs.

Structural-diagenetic petrographic analysis

A petrographic characterization to group structural diagenetic families, was performed for each conductive fracture set. In both reservoirs, five fracture sets were identify and named from the oldest to the youngest, set1, set2, set3, set4, and set5. In the Y1 reservoir, four sets are conductive: Set1 (E-W) 105°/83°, Set3 (NE-SW) 55°/77°, Set4 (N-S) 03°/79°, and Set5 (NW-SE) 140°/80°. While in the Y2 reservoir only two sets are conductive: Set4 (NE-SW) 48°/88°, and Set5 (E-W) 86°/87°.

Y1 Reservoir Characterization

The Y1 Cretaceous reservoir is constituted by wackestone with planktonic organisms, dark in color, partially recrystallized and fractured. Intercalation of argillaceous mudstone beds and chert bands are present. The reservoir has one well with a core from 4899 to 4906 m depth. Matrix porosity in average is less that 2%, and fracture sets 1, 3, 4, and 5 have remaining porosity and they are classified as conductive. Set 2 is non conductive cemented set, but it shares the same structural direction (NE-SW) that Set 3, which has good porosity. Based on cut relationships, we interpreted that sets 2 and 3 were generated in different times, probably during the deformation that created the structure. The fracture sets characteristics are as follow:

Family 1 (Set1) E-W (105°/83°). Fracture set 1 is characterized by discontinuous and rectilinear geometry, partially open with synkinematic blocky calcite cement forming blade type bridges, and postkinematic calcite. Postkinematic calcite crystals are deformed, possible as a consequence of shear right lateral movement during formation. Fractures from this set have remaining porosity and apertures ranks from 0.01 to 3.4 mm, with a minimum conductive aperture of 0.02 mm, evidences of oil migration, and good connectivity with sets 3, 4, and 5 (Figure 3A).

Family 2 (Set2) NE-SW (44°/84°). Set 2 presents sinuous geometry with crack seal structures, cemented by synkinematic twining blocky calcite and amorphous quartz. This set does not present any porosity and its kinematics aperture varies from 0.025 to 1.8 mm (Figure 3B).

Family 3 (Set3) NE-SW (55°/77°). Fractures from set 3 have continuous rectilinear geometry, are partially open with presence of synkinematic and postkinematics calcite both blocky type, kinematics aperture varies from 0,02 to 1.9 mm, minimum conductive aperture is about 0.1 mm, and connects to sets 1, 4, and 5. Fractures of this set have remaining porosity with hydrocarbon stain (Figure 3C). The characteristics of this set such as cement crystallography, the kinematics of cements, fracture geometry and cement deformation are diagenetic-structural differences that allow separate it from Set 2, which shares the same direction (Figure 3C).

Family 4 (Set4) N-S (03°/79°). Set 4 are fractures with rectilinear geometry, partially open, with presence of synkinematic twining calcite bridges, with kinematics aperture that varies from 0.0035 to 1.2 mm. Fracture porosity is very low, but with evidences of hydrocarbon migration. Minimum conductive aperture is 1.2 mm, and fractures are connected with sets 1, 3, and 5, (Figure 3D).

Family 5 (Set5) NW-SE (140°/80°). Fractures from this set have rectilinear geometry, and are partially open, with synkinematic blocky calcite cement, aperture ranks between 0.01 to 0.34 mm, and the minimum conductive aperture is about 0.01 mm. This fracture set is the one of smaller conductive aperture of the system and connects sets 1, 3, and 4. Remaining porosity is impregnated of hydrocarbon (Figure 3E).

Y2 Reservoir Characterization

The Y2 reservoir was penetrated by 8 wells corresponding to the Middle Cretaceous rocks, and is constituted by dolostones, in parts with a brecciaed texture due to probable tectonics. Reservoir rocks present matrix inter-crystalline porosity (average of 4-5%), and hydrocarbon stains. The cored interval analyzed is found between 5957 to 5966 m. Fractures from sets 1, 2, and 3 are cemented. The most important fracture sets are 4 and 5, because are those that present remaining porosity.

Family 4 (Set4) NE-SW (217°/48°). It is constitutes by fractures with rectilinear geometry to sinuous, partially open and impregnated with hydrocarbon, with presence of synkinematic and postkinematic dolomite. Kinematics aperture varies from 0.2 to 3.8mm, and the minimum conductive aperture is about 0.02mm. Fractures from this set connect Set 5 fractures (Figure 4A).

Family 5 (Set5) E-W (86°/87°). Fractures from this set have rectilinear geometry, and are partially conductive, with synkinematic and postkinematic calcite cements. Fractures are connected to Set 4 fractures, and they present also good connectivity with matrix. The kinematics aperture average varies from 0.4 to 1.1 mm, with a minimum conductive aperture of 0.01 mm (Figure 4B).

Structural-paragenetic sequence (paragenesis)

The structural paragenetic sequences of both reservoirs were performed according to the diagenetic process and fracture sets identified. To perform a structural-paragenetic sequence is necessary to identify fracture attributes and types of cements precipitated in fractures walls, and to interpret timing relationships among fractures and temporary ordering. The SDPS considers the fracturing as a diagenetic process that affects the rock (Monroy, 2009). The methodology focuses in the determination of conductive fractures families or "sets", and the quantification of fracture attributes in oil and gas fields. The structural paragenetic sequence can be used as guide to explore new areas near to the fields studied, to found new targets by drilling exploratory wells. If the paragenesis is similar in the new areas than the fields studied, we will have the possibility to found fractures sharing the same characteristic of conductive sets. However, diagenetic processes can change even in a short distance, and we have the risk that fractures attributes can also change.

The following section describes the paragenesis found in each reservoir. The main diagenetic process linked to fracturing will be described and numbered in order to the oldest to the youngest (named by the first letter of the process name follow by a number 1, 2, etc, starting with the number 1). In the case of fracture event we follow similar rule and the orientation will be note in parenthesis.

Paragenesis of Y1 reservoir

After deposition of the reservoir rocks the main diagenetic events linked to fracturing are as a follow: One fracturing event F1 (E-W), C2 calcite precipitation, F2 fracturing (NE-SW), C2 calcite precipitation, quartz precipitation, F3 fracturing (NE-SW), pressure-solution 1 (high angle stylolites), fracturing F4 (N-S), fracturing F 5(NW-SE), precipitation C3 calcite, and hydrocarbons migration into the reservoir (Figure 5A).

Paragenesis of Y2 reservoir

Rocks of the reservoir in the whole field present dolomitization by replacement (D1) and this is a main semi-regional diagenetic process. Dolomitization affected the stratigraphic column of Middle Cretaceous and some parts of the Upper Cretaceous rocks. D1 dolomitization served as reference for other processes. One fracture set (F1) was identified as a pre-dolomitization event and four fracture sets (F2 to F5) as post-dolomitization events. The paragenesis in the Y2 reservoir is as follow: F1 fracturing, F2 fracturing (NW-SE), D1 dolomitization, F3 fracturing (N-S), D2 dolomite precipitation, F4 fracturing (NE-SW), D3 dolomite precipitation, F5 fracturing (E-W), C1 calcite cementation, C2 calcite cementation, PS 1 pressure-solution, and oil migration. The main diagenetic process that controls the petrophysical properties of rocks from Y2 reservoir is the D1 dolomitization which generated inter-crystalline porosity, and changed the rock rheology to become more brittle (Figure 5B).

Fracture aperture and density analysis.

Fracture apertures and fracture density were calculated for both reservoirs. Fracture apertures and fracture spacing were directly measured on thin sections using the scanlines (measurement lines) method, according to Marrett et al. (1999) criteria. All scanlines were taken perpendicular to the fracture set under study.

Fracture apertures for a set are plotted in a logarithmic-logarithmic scale, where a phenomenon that follows a power law, is represented by a straight line. To make it, plot the apertures against its cumulative frequency, identifying the minimum and maximum aperture values, as well as the observed minimum conductive aperture size. Cumulative frequencies are normalized according to the scan line length, and fracture intensity or density calculated (number of fractures/meter). In the log-log plot, fracture intensity calculated is the number of fractures by length unit of a specific value of aperture size or higher. Because fracture density calculation depends of the size of the attribute (aperture size in this case), in this study we used for this calculation, the minimum conductive aperture (mca) size, which is determined by visual inspection under the microscope of those smaller fractures with remaining porosity and hydrocarbon migrations evidences (Monroy, 2009). This fracture attribute is important because it can establish the interval of apertures which it can begin to consider the calculation of fracture intensity.

Fracture density calculated by this method in thin sections, allow us to compare from one set to another, and to decide which one has higher density; and also allow us to compare sets from a flow unit to other, sets from one part of the reservoir to another, or sets from one field to another. The average spacing between fractures was also calculated, using the scan line length, to distribute all fractures in regular spacing (Gale et al., 2004; Gomez and Laubach, 2006; and Ortega et al., 2006). The calculation of both fracture aperture and spacing were performed for all conductive fracture sets in both reservoirs.

Y1 reservoir

Fracture sets 3 and 5 in the Y1 reservoir were classified previously as conductive based on the SDPS. Both sets were considered for fracture aperture and fracture density calculation. Figure 6 shows the log-log distribution of fracture apertures and fracture intensity calculated, and compares scan lines measured in sets 3 and 5. For set 3 the mca size, determinate in thin sections, is 0.1 mm, while for set 5 is 0.009 mm. Considering these values in Figure 6A, for example we expect 300 for set 5, and 35 fractures/m of 0.1 mm or higher for set 3. So, Set 3 has higher conductive aperture size but lower density than set 5.

Y2 reservoir

Fracture aperture and fracture intensity were measurement and calculated for conductive fracture sets 4 and 5 (Figure 6 B). Set 4 has a minimum conductive aperture size of 0.05 mm, and set 5 has 0.01 mm. Considering these values in Figure 6 B, for example, we expect 40 fractures/m of 0.05 mm wide or higher for fracture set 4, and 180 fractures/m of 0.01mm wide or higher for set 5. Green color indicates fractures with higher values that the minimum conductive aperture size, and in red color lower values indicating closed fractures. By comparing both sets, the set number 4 presents a minimum aperture conductive value higher than set 5, but lower fracture density. Set 5 presents the smaller conductive minimum aperture but greater density than set 4.

However, to compare fracture abundance (number of fractures identified/meter), determined from images logs or cores, with the calculation from thin sections, is more complicated. The resolution and the scale from logs and cores are different, and therefore the aperture sizes visualized are also different. Figure 7 shows an example of a fracture abundance calculation and the comparison of observed and measured fractures for all directions. 11 fractures were identified in image logs, 44 in the core, and 418 in thin sections. The big different among these three calculation is scale and we have to take this in account when we made the static and dynamic models in naturally fractured reservoirs.

Connectivity

The connectivity, according to Robinson (1983), is the number of fracture intersections divided by the number of fractures. However, the connectivity of a fracture system (one or several sets) can vary from a static point of view to dynamic for fluids flow. Fractures in a system can be open or partially open but little connected, or connected but sealed. In practical terms, if the fractures in analysis, are partially, or fully open, we can establish a classification, using the Robinson´s equation for core and thin section scale, to define the connectivity of fractures in high (>1), medium (0.5-1.0) and low (<0.5) (Monroy, 2009). Those criteria can be extrapolated for a system where several sets interact in a reservoir. For both reservoirs we estimated a quantitative connectivity fracture sets to compare the differences.

Y1 Reservoir

Conductive fracture sets 1, 3, 4, and 5 were analyzed for Y1 reservoir. The number of fractures was obtained from the density calculation and the numbers of intersections were determined by visual inspection under the microscope. The results indicate that set 5 has high conductivity, diminishing the connectivity degree consecutively for set 4 until set 1 that has low conductivity.

Y2 Reservoir

Conductive fracture sets 4 and 5 were analyzed for Y2 reservoir. The number of fractures and intersections number were obtained in similar way for Y1 reservoir. The results indicate that set 5 has better conductivity than set 4. However, both fracture sets are good connected with the inter-crystalline porosity resulted from dolomitization of the matrix.

Ranking fracture attributes

Ranking fracture attributes is generated from the comparison of all fracture attributes of sets in a reservoir (Prieto-Ubaldo et. al., 2010 and Monroy, 2010). This allows identification of the main attributes for each fracture set, and identifies which set has better permeability conditions for the fluids flow, especially in the oil reservoir development. All considerations for ranking are very important for a reservoir that produces completely by fractures, especially when matrix porosity is very low (lower than 2%), as several oil and gas fields in Mexico, where the production depends exclusively from the permeability of conductive fractures.

Figure 8A and Figure 8B, show the fracture set ranking by order of importance in the Y1 and Y2 reservoirs, according to apertures, minimum conductive aperture, fracture density, connectivity, fracture remaining porosity, and the general porosity in the system.

Y1 reservoir ranking

Set3 is the better set, followed by sets 5, 1, and 4. Set 2 is a sealed set. Fracture set3 is the most important, its rank of aperture varies from 0.02 to 1.9 mm, the conductive minimum aperture is 0.1 mm, with low fracture density, but remaining fracture porosity about 36%, that in terms of the whole reservoir is equivalent to 0.72%. Fracture set number 5 is the most abundant, its rank of aperture varies from 0.001 to 0.34 mm, with a minimum aperture conductive of 0.009 mm, fracture remaining porosity is about 13%, that in the whole reservoir is equivalent to the 0.26% approximately. Fracture set number 1 with orientation 105°/83°, has a rank of apertures between 0.01 and 3.4 mm, the minimum conductive aperture is 0.02 mm, with 5.5% fracture remaining porosity, equivalent to the 0.11% in the reservoir. Fracture set 4 with orientation 03°/79°, has an aperture rank from 0.004 to 1.2 mm, minimum conductive aperture of 0.04, and is almost sealed, with just 4% of fracture porosity, equivalent in the reservoir to the 0.08%. Fracture set2 is sealed by cement and is not a conductive set.

Y2 reservoir ranking

Conductive fracture sets corresponds to set 5 (NE-SW) and set 4 (E-W). Fracture set 5 is the most important, its rank of aperture varies from 0.02 to 0.4 mm, and its minimum conductive aperture is about 0.01 mm. This set presents the lowest fracture density, with remaining porosity of 40% that represents the 1.2% of the reservoir. Fracture set number 4 has apertures that vary from 0.01 to 3.8 mm, and a minimum conductive aperture of 0.05 mm, with remaining porosity of 25%, that in the reservoir is equivalent to the 0.76%. Fracture sets 3, 2, and 1 are sealed.

Last step to have a full characterization, is the integration of the results from the methodology SDPS (Figure 1) with other disciplines. The diagenetic-structural study and the fracture attributes calculated are values to calibrate other fracture study at bigger scale to have a better fracture model. In fact, once we have all wells ranked in a reservoir the risks can be reduced, and a better oil and gas field development program can be preformed.

Conclusions

The results of the SDPS application, along the fracture attributes calculation, permitted identification of main conductive and partially conductive fracture sets for two reservoirs in the southern part of Mexico. For naturally carbonated fractured reservoirs, of very low matrix porosities (of the order of 2% or lower) this analysis is extremely important, because it permits us to interpret the directions of conductive fractures and the main direction of fluids flow. In addition, it allows us to extrapolate the information, and to predict the quality in other zones of interest, as well as to calculate the hydrocarbons volume that is storage in fractures. In dolomitized carbonates, fractures play a secondary role, because matrix porosity can be high (more than 5%), however, connectivity between matrix and conductive fractures can addresses the preferential direction of the fluids flow.

The SDPS study also allowed the ranking from the highest conductive fracture sets to sealed sets, which is very important for reservoir simulation and fields' development. Once main conductive fracture sets are identify in a reservoir, fracture orientation and their attributes of the most conductive sets can be used to design well trajectories and to reduce risk for drilling wells in better locations, increasing well productivity and reducing reservoir exploitation costs.

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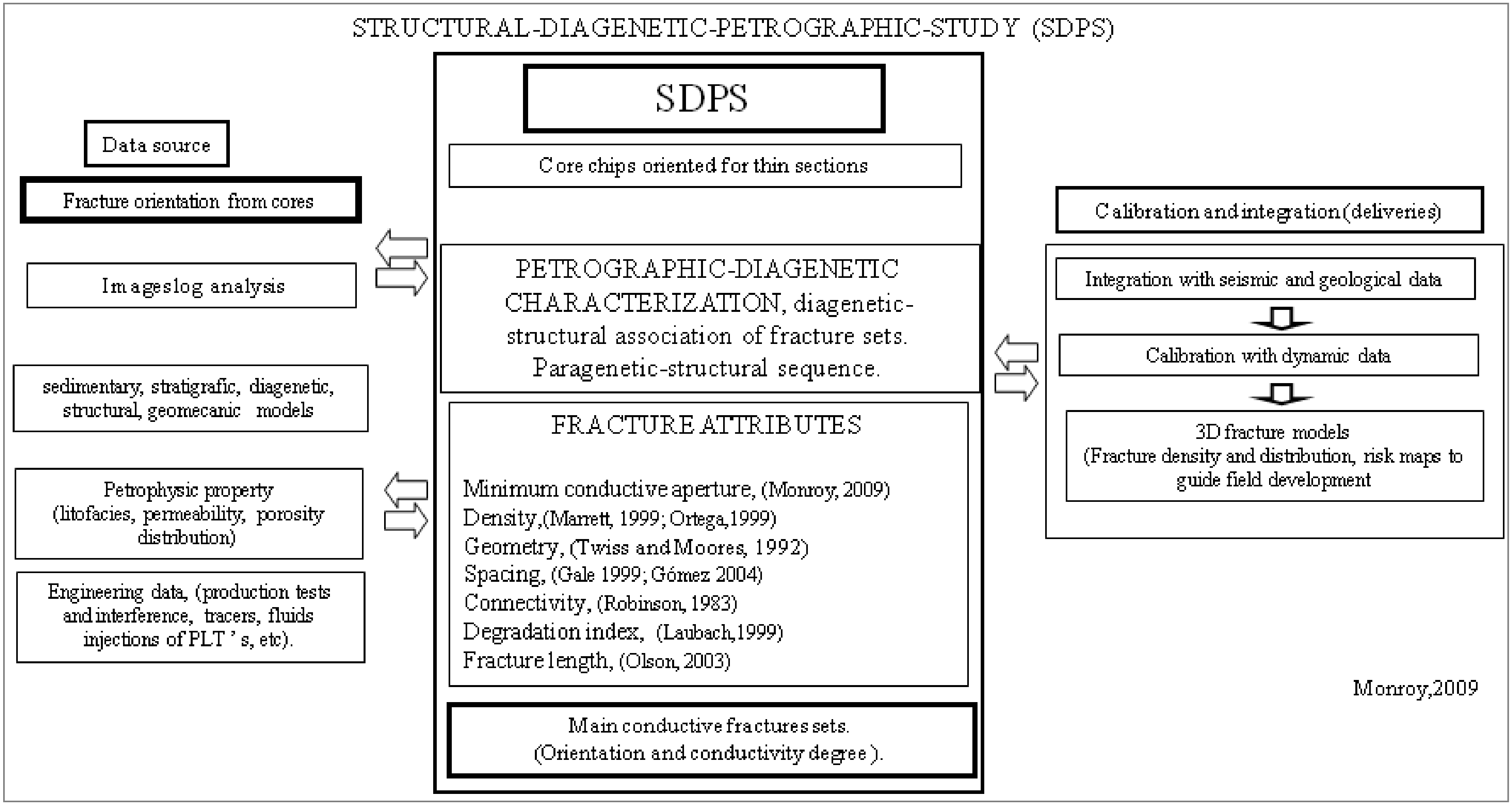

Figure 1. Workflow for a diagenetic-structural petrographic study (SDPS) showing the inputs necessary, as well as the integration with other disciplines and deliverables. Integration of the SDPS results with other disciplines and the calibration with engineering data (production, PLTs, tracer, tests of interference, history of production, etc.) is necessary. The end product is a 3D fracture model to delimit areas most likely to find greater density of conductive open fractures, as well as addresses, to guide the development of the field study.

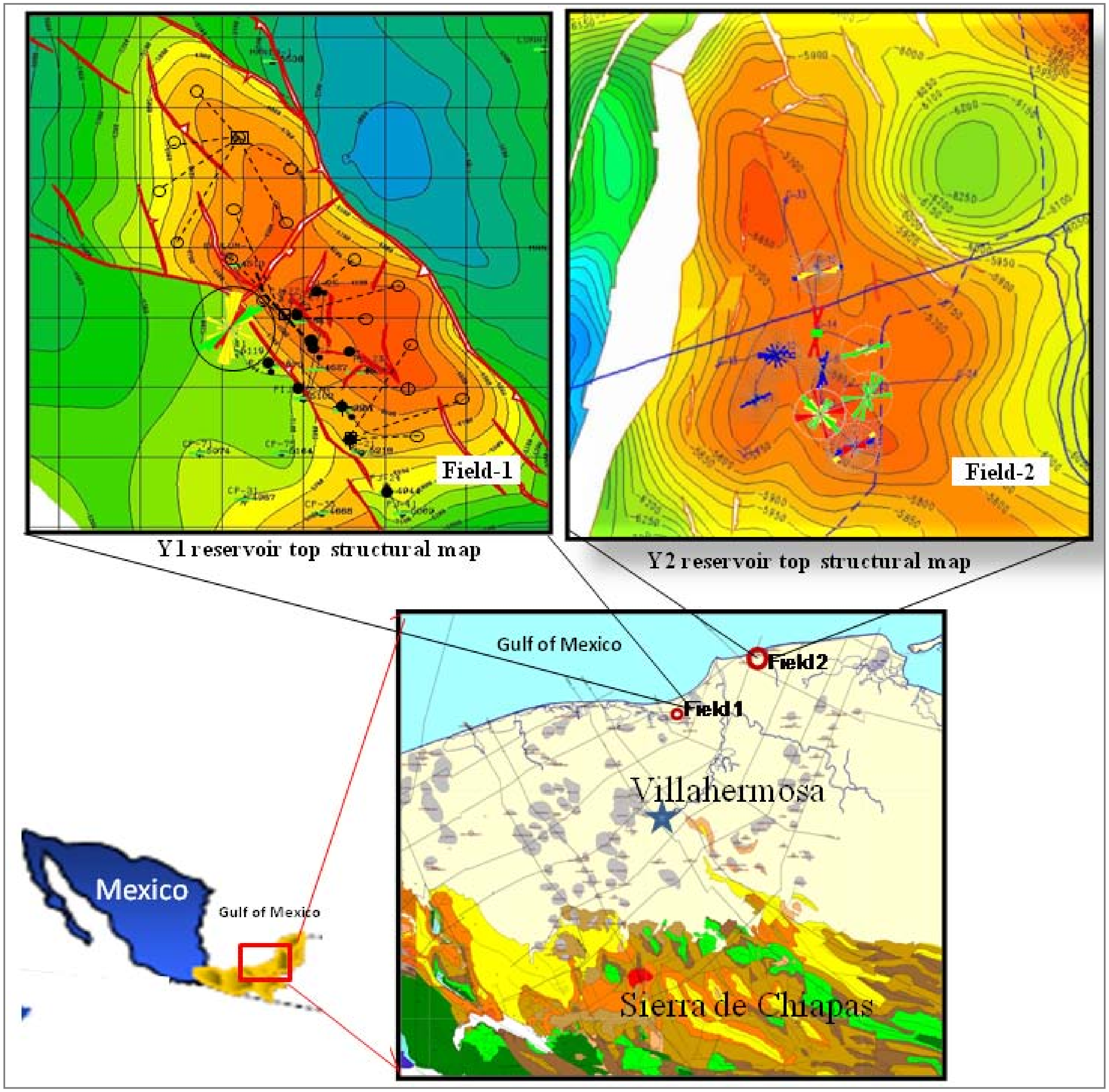

Figure 2. Location map of the study area. The southeast part of Mexico is a prolific oil and gas geological province where main reservoirs are naturally fracture carbonates from Cretaceous. Y1 reservoir (Field 1) is an anticline structure oriented NW-SE, while Y2 reservoir (Field 2) is an anticline almost N_S.

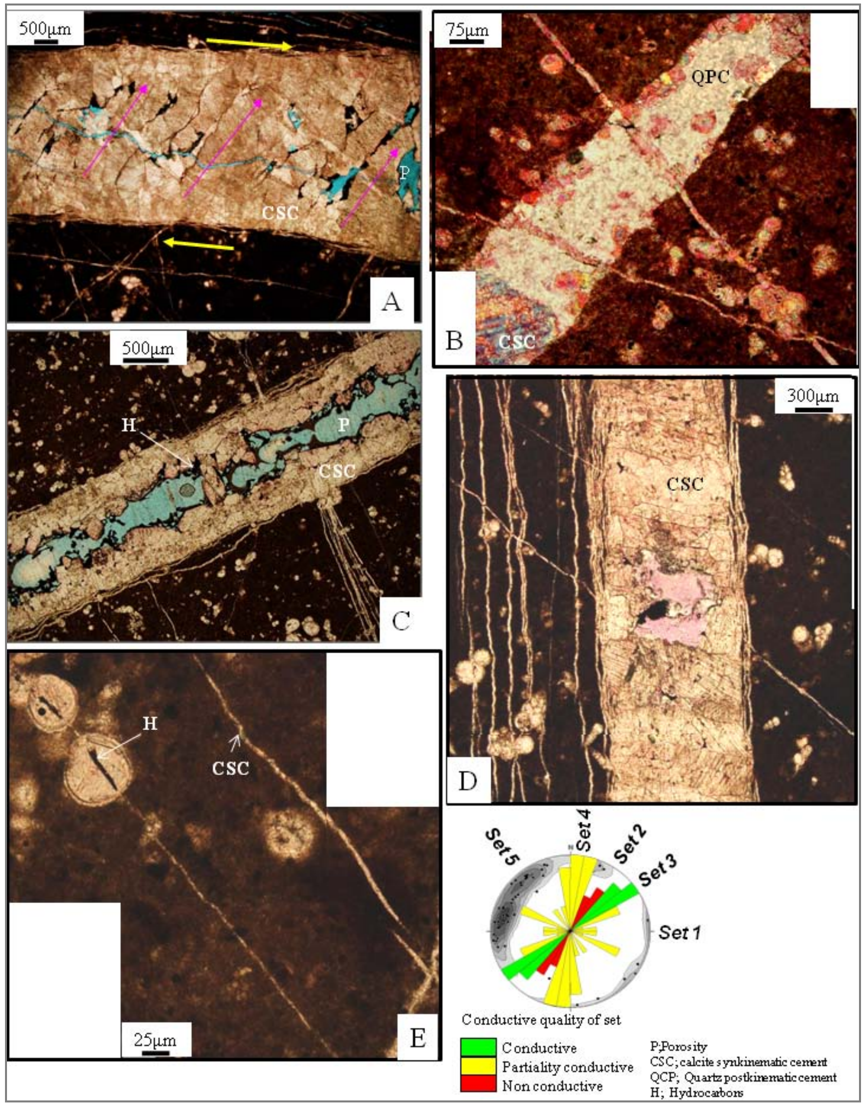

Figure 3. Photomicrographs showing Y1 reservoir fracture sets attributes. A) Fracture set 1 has an orientation E-W, characterized by linear walls, partially open, and twining calcite curved bridges indicating probably left strike slip movement during its precipitation. Fractures from this set present remaining porosity with evidences of hydrocarbons migration (oil stains). B) Fractures from set 2, with NE-SW trend, are cemented by twining calcite cement, and have no visible porosity. C) Fracture set 3 with similar orientation that set 2, but with remaining porosity and hydrocarbon stains, indicating high conductivity. Notice calcite bridges from wall to wall. D) Set 4 showing a big N-S sealed fracture, twining calcite cement is almost sealed the whole porosity. Notice also microfractures next to the big one. E) Fractures from set 5 have calcite synkinematic cement and remaining porosity, notice fracture segment inside of a fossil with oil stains, indicating partially conductivity for this set. CSC, Calcite synkinematic cement; P, Porosity; QCP, Quartz postkinematic cement; H, Hydrocarbons.

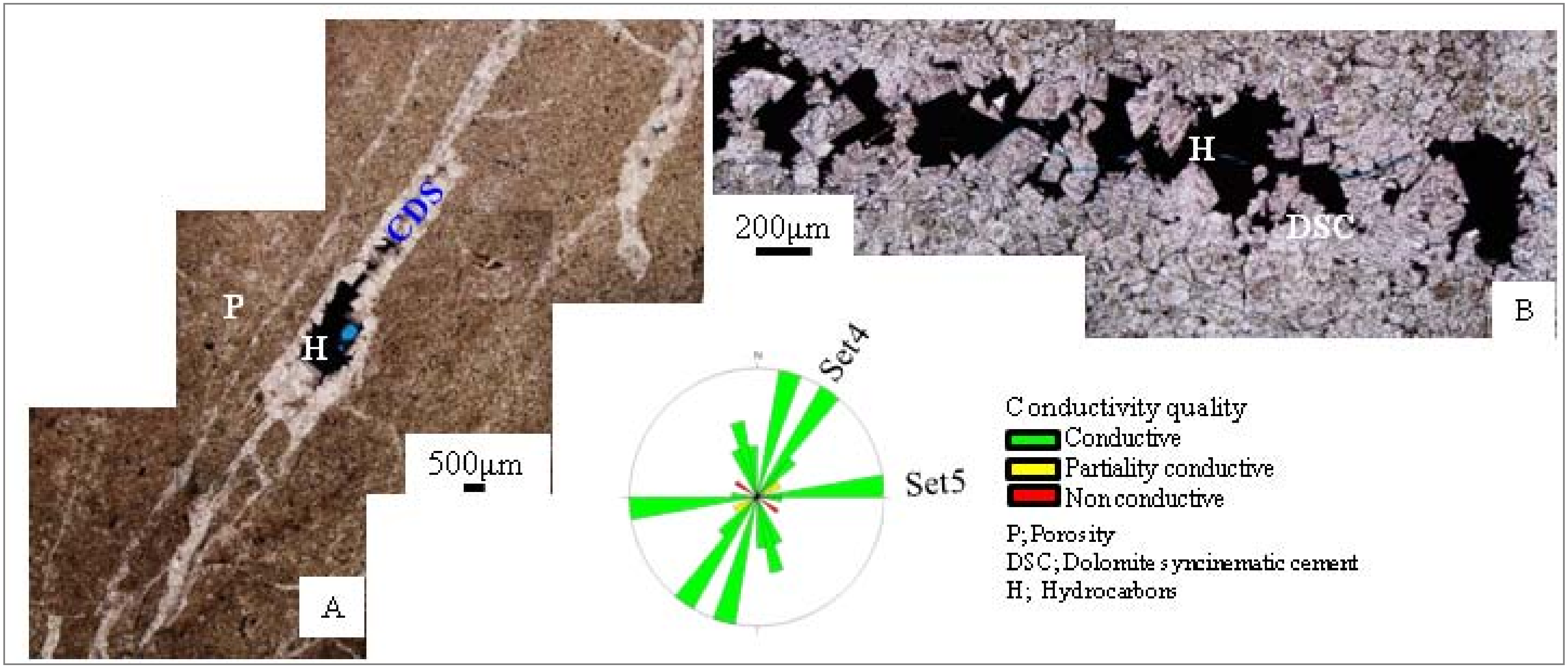

Figure 4. Photomicrographs from Y2 reservoir, showing diagenetic and structural characteristics. A) Fracture set 4 with NE-SW orientation, is characterized by irregular walls, partially open, and dolomite synkinematic cement, and hydrocarbon migration evidences (oil stains). B) Fracture set 5 with an almost E-W trend, is cemented by synkinematic dolomite, with good remaining porosity and oil stains. Fracture set 5 is the higher conductivity set in the reservoir. DSC, dolomite synkinematic cement; P, porosity; H, hydrocarbons.

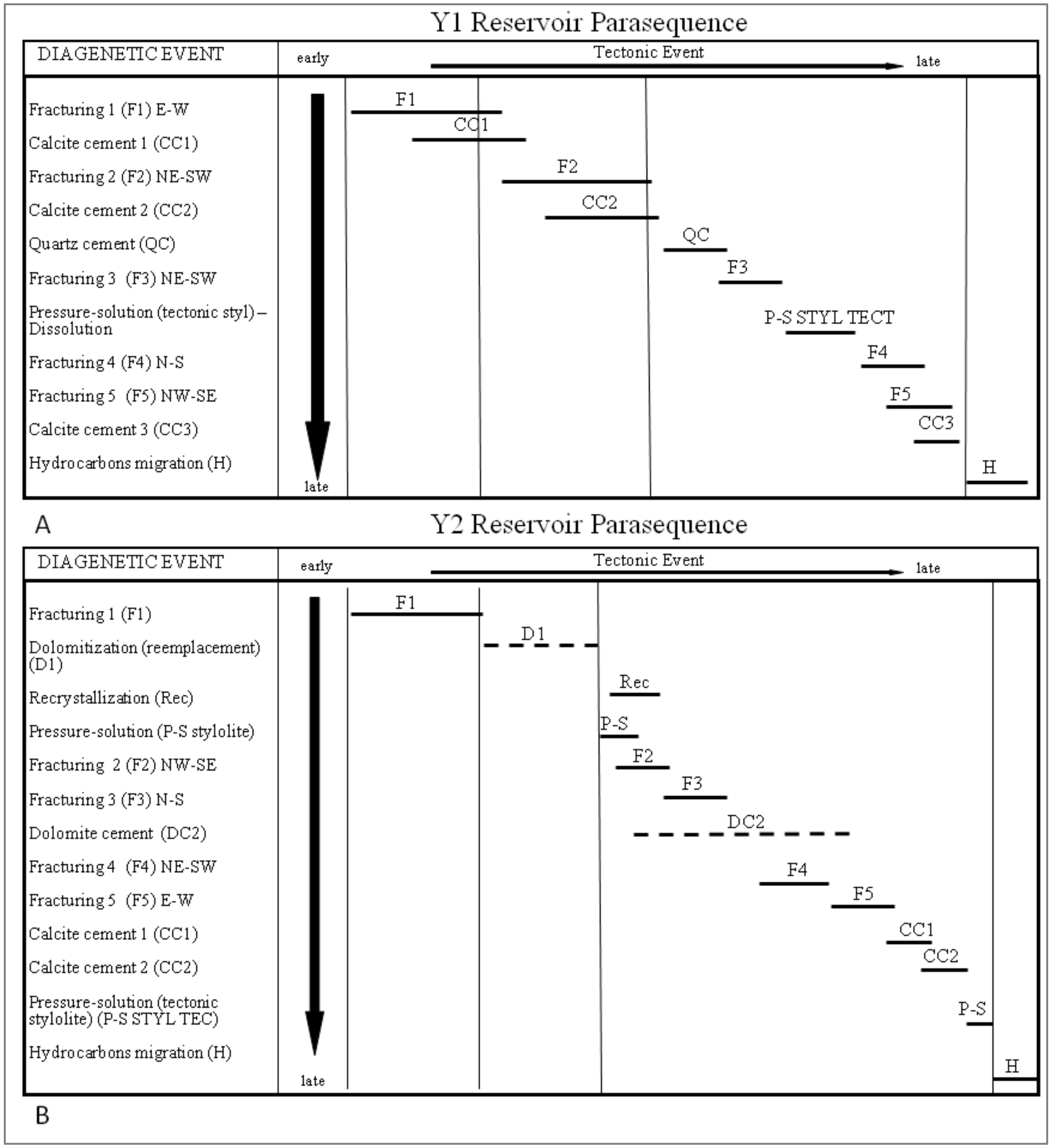

Figure 5. Plot showing the parasequences in both reservoirs. A) Y1 reservoir. Fractures set 1, 3, and 5 are the main conductive sets, calcite cement plugged much of the fracture porosity as postkinematic cement. B) Y2 Reservoir. Fractures from sets 4 and 5 are main conductive fractures. Notice, that dolomite cement is present in these two sets as synkinematic cement.

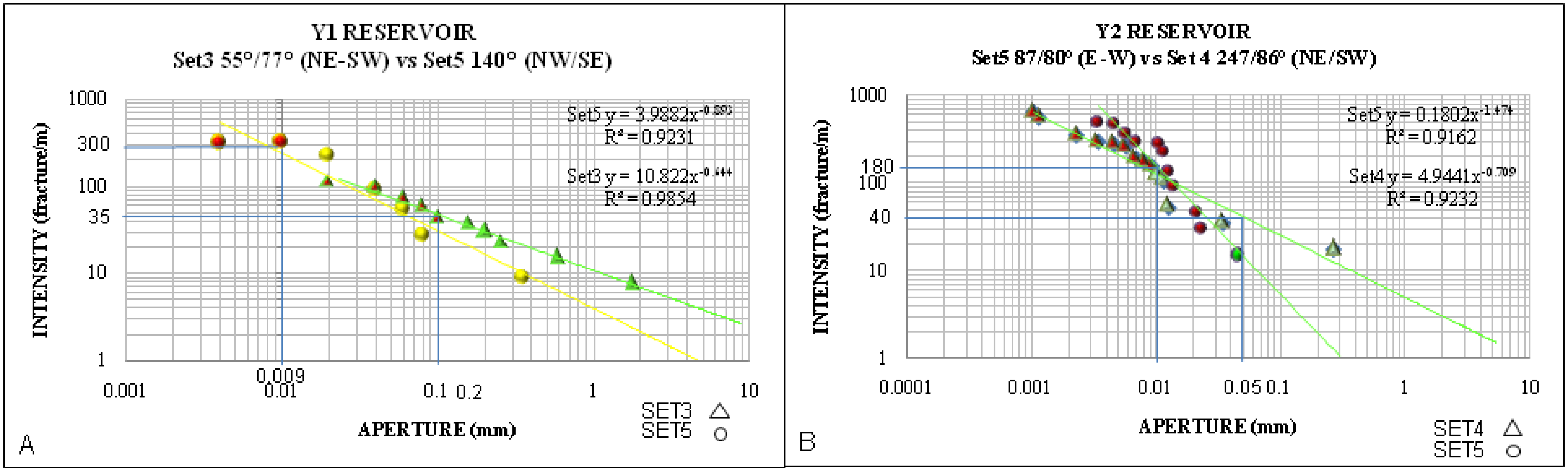

Figure 6. Log-log plots of aperture vs. intensity for higher conductive fracture for both reservoirs. A) Fracture sets 3 and 5 in Y1 reservoir have good conductivity however fracture set number 3 has higher intensity than fracture set 5. B) Fracture sets 4 and 5 in Y2 reservoir have good conductivity however fracture set number 4 has little more intensity than fracture set 5. These plots are power tools to compare fracture density from one reservoir to other, in this case if we take a minimum conductive aperture of 0.01 mm, fracture intensity from reservoir Y1 is about 300 fractures by meter, while Y2 reservoir fracture density is about 180 fractures by meter, indicating that fracture density in much higher in Y1 reservoir. Well production corroborates this calculation. In fact, currently one well from Y1 reservoir produces 4.5 times approximately more oil and gas barrels per day than Y2 reservoir where exist 6 producer wells. Red color dots means closed fracture of this set, green means open fracture, and yellow, partially open.

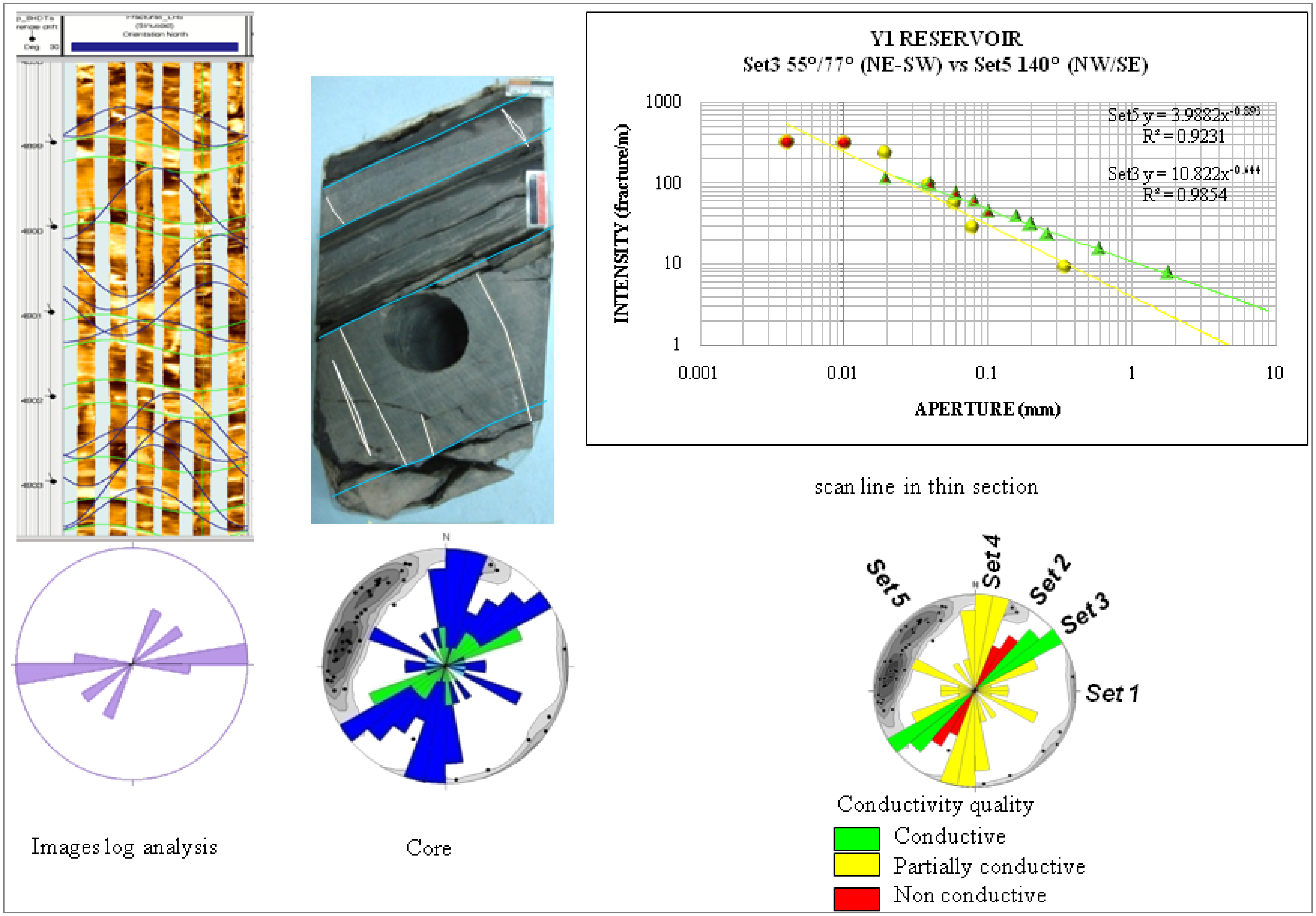

Figure 7. Comparative of fracture density and abundance, in three different scales, from image logs, core, and thin sections from Y1 reservoir. All orientation fracture sets are included, 11 from images logs, 48 in cores, and 518 in thin sections. Number of fractures in thin sections includes only conductive fractures. Notice that fracture density is scale depended. For this reason, measurement of minimum conductive fracture aperture is very important to estimate fracture density for those fractures that impact in the fluids flow in a reservoir.

Y1 reservoir, fracture sets ranking

Set	Strike	Conductivity	Cements		Apertures (mm)	Minimum conductive aperture	Density (>conductive aperture)	Total remaining porosity (%)	Equivalent total porosity in the reservoir
			Synkinematic	Postkinematic					
3	NE-SW	Conductive	Calcite	Calcite	0.02-1.9	0.1	35	36	0.72
5	NW-SE	Partially conducive	Calcite	-	0.001-0.34	0.009	300	13	0.26
1	E-W	Partially conducive	Calcite	Calcite	0.01-3.4	0.02	70	5.55	0.11
4	N-S	Partially conducive	Calcite	Calcite	0.004-1.2	0.01	190	4	0.08
2	NE-SW	Not conductive	Calcite	Calcite, quartz	0.02-1.8	0	0	0	0

Y2 reservoir, fracture sets ranking

Set	Strike	Conductivity	Cements		Apertures (mm)	Minimum conductive aperture	Density (>conductive aperture)	Total remaining porosity (%)	Equivalent total porosity in the reservoir
			Synkinematic	Postkinematic					
5	E-W	Conductive	Calcite	Calcite	0.02-0.4	0.01	180	40	1.2
4	NE-SW	Conductive	Dolomite	Calcite	0.01-3.8	0.05	40	25	0.76
3	N-S	Partially conducive	Dolomite	Dolomita,calcite, quartz	0	0	0	0	-
2	NW-SE	Partially conducive	Dolomite	Dolomite	0	0	0	0	-
1	NE-SW	Partially conducive	Dolomite	Dolomite	0	0	0	0	-

Figure 8. Fracture sets ranking for both reservoirs. Fracture attributes for all sets permitted ranking from the better conductive sets to the sealed fractures. Notice that in the Y1 reservoir fractures with better characteristics of conductivity are sets 3 and 5, while in Y2 reservoir is 5 and 4. Notice that fracture sets with the same number are different form one reservoir to another. For example, fracture 5 in Y1 reservoir trends NW.SE, while in Y2 reservoir fracture set 5 has E-W direction.