

KASDI MERBAH UNIVERSITY – OUARGLA

**FACULTY OF HYDROCARBONS, RENEWABLE ENERGIES AND EARTH AND
UNIVERSE SCIENCES**

DEPARTMENT OF EARTH AND UNIVERSE SCIENCES



Academic Master's Dissertation

Field: Geology

Option: Petroleum Geology

Subject

**Carbonate Reservoir Characterization and Acid
Fracturing Optimization – Case Study of the LD2
Reservoir, Hassi R'mel Field**

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On:15/06/2026

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Academic Year: 2025/2026

Dedication

First and foremost, I dedicate this achievement to myself for believing in my dreams, overcoming challenges, and never giving up despite the obstacles along the way. This diploma is the result of perseverance, dedication, and countless efforts.

To my beloved father, whose wisdom, strength, and unwavering belief in me have always been my greatest source of motivation. Your sacrifices and hard work have given me the opportunity to pursue my ambitions, and for that, I will always be deeply grateful.

To my beloved mother, whose unconditional love, endless patience, and sincere prayers have filled my life with comfort and hope. Your kindness and encouragement have been my constant source of strength.

To my only brother, Abdelhak, my pillar of strength and my constant support in life. Thank you for always believing in me, encouraging me, and standing by my side through every challenge and every success.

To my family, friends, and teachers, thank you for your guidance, trust, and unwavering support throughout this journey.

This achievement is a reflection of everyone who believed in me and stood by my side, and I dedicate it to all of you with love and gratitude.

Acknowledgement

I would like to express my deepest gratitude to Almighty God for granting me the strength, patience, and determination to complete this work.

My heartfelt thanks go to my family for their unconditional love, endless support, and constant encouragement throughout every step of this journey.

A very special thank you goes to my dear friends, Radia and Hadil, whose unwavering moral support, encouragement, and belief in me gave me the strength to keep moving forward during difficult times. I am truly grateful to have had you by my side.

My sincere appreciation and deepest gratitude go to my supervisor, Professor Belksier Mohamed Salah, for his continuous support, guidance, and encouragement throughout this period. His valuable advice and trust have been invaluable in the completion of this work.

I would also like to express my profound gratitude to the PE Technical Team - Halliburton Algeria for their invaluable assistance, support, and encouragement.

Finally, I extend my sincere thanks to everyone who contributed in one way or another, to the completion of this dissertation, even through a simple word of kindness or encouragement. Your support and generosity will always be deeply appreciated.

يتناول هذا العمل التوصيف الجيولوجي والبتروفيزيائي للخران الكربوناتي منخفض النفاذية (LD2) بحقل حاسي الرمل في الجزائر، مع تقييم تقنية التكسير الحمضي باعتبارها إحدى أهم وسائل التحفيز لتطويره واستغلاله تجارياً. ويعتمد البحث على مقارنة متكاملة تجمع بين الدراسة الجيولوجية والتركيبية للحقل، والتوصيف البتروفيزيائي والجيوميكانيكي لصخور الخزان، إضافة إلى استعراض الأسس العلمية لتقنية التكسير الحمضي وتحليل تطبيقاتها الميدانية من خلال دراسة ثلاث آبار تختلف في خصائصها الجيولوجية وهندسة مسارها.

وتُظهر نتائج الدراسة أن التاريخ الدياجيني متعدد المراحل للخران يمثل العامل الرئيس المتحكم في خصائصه البتروفيزيائية واستجابته لعمليات التحفيز الحمضي، كما أن التركيب المعدني للصخور الكربوناتية والكفاءة الهيدروليكية المقاسة أثناء اختبارات الحقن يشكلان العاملين الأساسيين في نجاح المعالجة وتحقيق تحسين ملموس في إنتاجية الآبار. وتؤكد الدراسة أهمية الدمج بين التوصيف الجيولوجي والبتروفيزيائي والجيوميكانيكي من أجل تصميم عمليات تكسير حمضي أكثر كفاءة وملاءمة لخصائص الخزانات الكربوناتية منخفضة النفاذية.

الكلمات المفتاحية: حاسي الرمل، الخزان الكربوناتي منخفض النفاذية، LD2، التكسير الحمضي، التاريخ الدياجيني، عدم التجانس، تحسين الإنتاج

Résumé

Ce travail porte sur la caractérisation géologique et pétrophysique du réservoir carbonaté serré LD2 du champ de Hassi R'mel (Algérie) ainsi que sur l'évaluation de la fracturation acide en tant que principale technique de stimulation pour son développement commercial. L'étude adopte une approche intégrée combinant l'analyse géologique et structurale du champ, la caractérisation pétrophysique et géomécanique des roches carbonatées, les fondements scientifiques de la fracturation acide, ainsi qu'une étude de cas appliquée à trois puits présentant des caractéristiques géologiques et des géométries de trajectoire différentes.

Les résultats démontrent que l'histoire diagénétique complexe du réservoir constitue le principal facteur contrôlant les performances des traitements de fracturation acide. Ils montrent également que la minéralogie carbonatée et l'efficacité hydraulique mesurée lors des essais d'injection représentent les paramètres déterminants du succès des opérations et de l'amélioration de la productivité des puits. Cette étude met ainsi en évidence l'importance d'une intégration rigoureuse des données géologiques, pétrophysiques et géomécaniques pour optimiser la conception et l'efficacité des traitements de fracturation acide dans les réservoirs carbonatés serrés.

Mots-clés : Hassi R'mel, réservoir carbonaté serré, LD2, fracturation acide, histoire diagénétique, hétérogénéité, optimization de la production.

Abstract

This dissertation addresses the geological and petrophysical characterization of the LD2 tight carbonate reservoir at the Hassi R'mel field, Algeria, and the evaluation of acid fracturing as the primary stimulation technique for its commercial development. The work integrates the structural and geological analysis of the field, the petrophysical and geomechanical characterization of carbonate rocks, the scientific principles of acid fracturing, and a field case study on three wells of contrasting geological character and completion geometry.

The study establishes that the multiphase diagenetic history of the LD2 reservoir is the fundamental determinant of treatment performance, and that carbonate mineralogy and field-measured hydraulic fluid efficiency are the two parameters governing treatment success.

Keywords: Hassi R'mel, tight carbonate reservoir, LD2, acid fracturing, diagenesis, heterogeneity, production optimization.

Summary

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General Introduction

General Introduction

The central challenge addressed in this dissertation is not resource scarcity but reservoir access: the LD2 carbonate, despite its considerable in-place volume, requires a stimulation technique capable of restoring economic productivity in a formation shaped by a long, heterogeneous diagenetic history. Acid fracturing is the method most widely applied to such tight carbonates, but its success depends on a chain of interlinked decisions from geological characterization and acid system selection through model calibration to treatment execution. A gap in any link compromises performance, and the LD2's documented heterogeneity makes generic design assumptions unreliable.

This dissertation addresses that gap by integrating the geological characterization of the LD2 reservoir with the engineering principles of acid fracturing design, and by validating the resulting framework against field data from three wells of contrasting completion geometry and mineralogical character. The specific objectives are: to establish the geological and petroleum-system context of the Hassi R'mel field and the structural position of the LD2 within it; to build a petrophysical and geomechanical characterization framework linking mineralogy, diagenesis, and rock mechanics to stimulation behavior; to develop the theoretical basis of acid fracturing in carbonates, from the differential etching mechanism to the acid systems and treatment design workflow used in field practice; and to apply this integrated framework to a three-well case study and derive field-validated conclusions on the parameters governing acid fracturing performance in the LD2.

Chapter 1:

Geological Settings
and Petroleum System
of Hassi R'mel Field

Field Discovery, Development and Current Status

The Hassi R'mel field was discovered in October 1956 by the HR-1 well, which encountered a rich gas-condensate accumulation in the Triassic sandstones at initial reservoir conditions of approximately 310 atm and 90°C (Magloire, 1970). Commercial production commenced in 1961 and the field rapidly became the centerpiece of Algeria's gas export infrastructure. Initial recoverable reserves were estimated at approximately 2.415 trillion cubic metres of natural gas. After more than six decades of production, approximately 80% of originally recoverable gas has been extracted through two prior development phases completed in 2004 and 2009, and the field currently contributes approximately 26% of Algeria's daily gas output (Energynews.pro, 2024).

I. Geological Settings

Hassi R'mel is located in Laghouat Province, central Algeria, approximately 550 km south of Algiers, centered near 32.95°N and 3.17°E. The field extends approximately 70 km in the north–south direction and 50 km east–west, with a structural closure at the level of the Triassic reservoir estimated at 2,600 km², one of the largest structural traps in North Africa (Magloire, 1970). Figure 1.1 shows the location of the field on the Saharan Platform and its relationship to the principal intracratonic basins of Algeria.

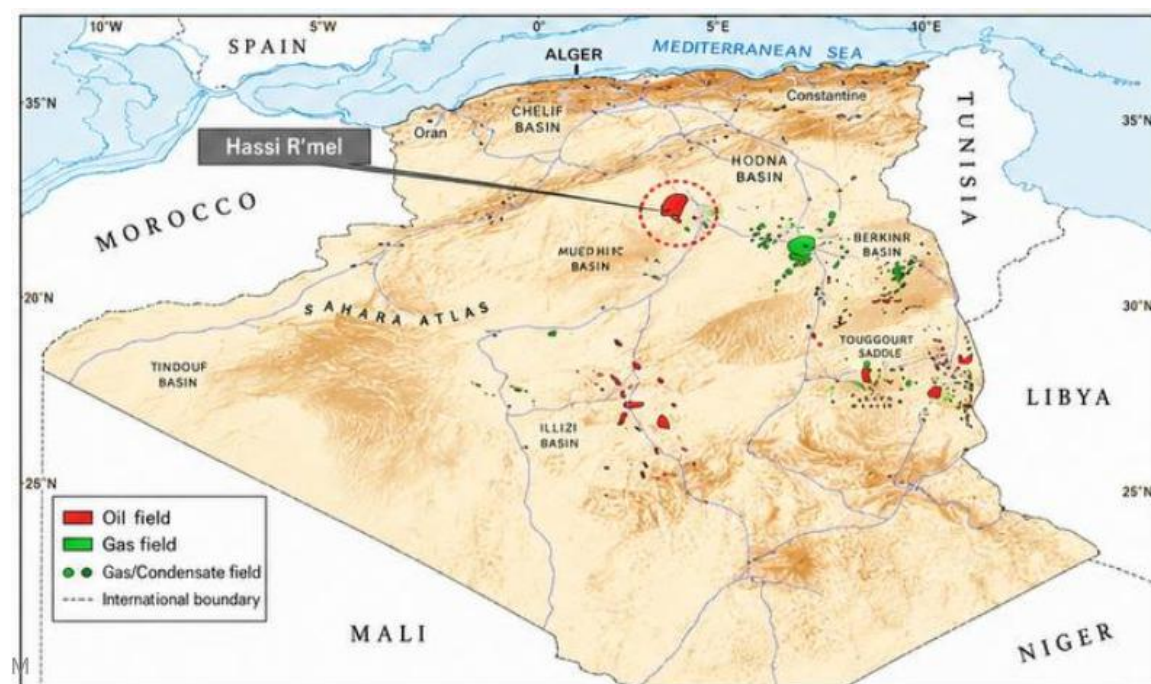


Figure 1. Geographical setting of the Hassi R'mel field (SONATRACH)

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At the regional scale, Hassi R'mel sits on the M'zab dorsal, also referred to as the Tirlhemt–Talemzane uplift, a long-lived positive structural feature of the Saharan Platform. The broader Saharan Platform is a mosaic of intracratonic basins and intervening arches of Proterozoic crystalline basement. The principal sub-basins relevant to the northern Algerian petroleum province include the Tindouf, Reggane, Ahnet, and Timimoun basins to the west; the Illizi and Berkine (Ghadames) basins to the east; and the Oued Mya Basin in the north-center. Hassi R'mel and the adjacent Hassi Messaoud oil field together form the two supergiant nodes of the so-called Triassic Province, a USGS-defined petroleum assessment unit (Province 2054) whose combined resources account for a dominant share of Algeria's proven hydrocarbon reserves (USGS, 2000).

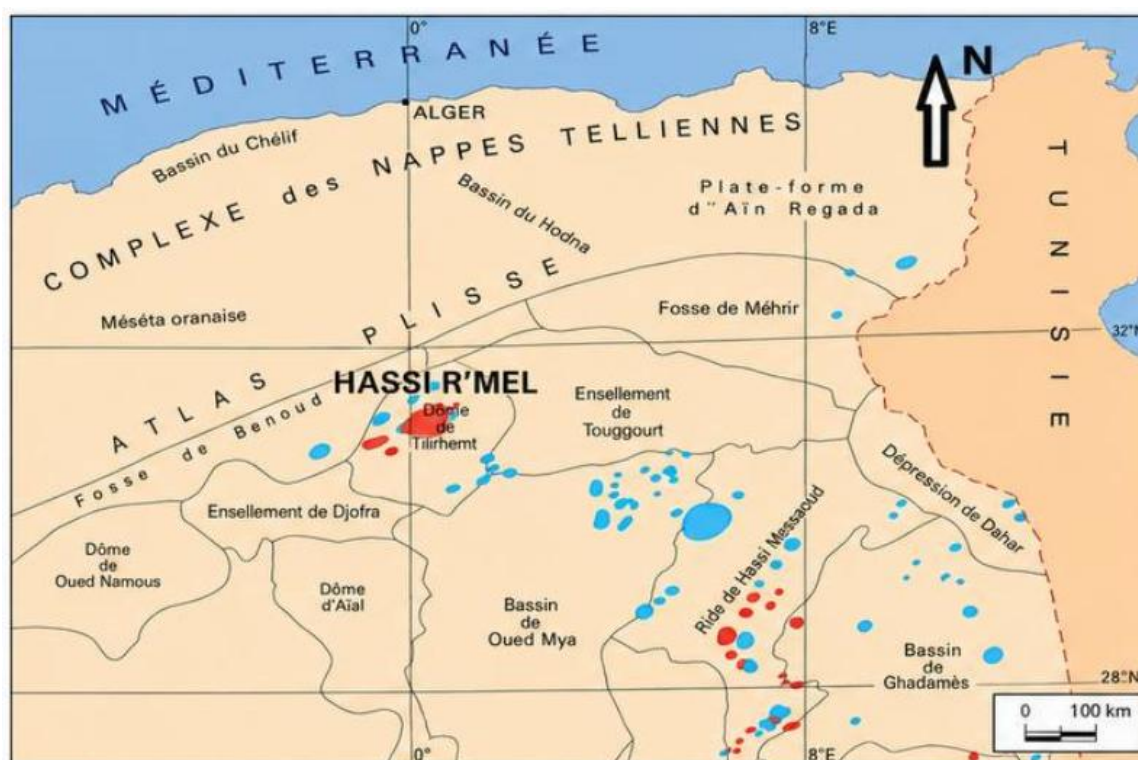


Figure 2. Regional location of the Hassi R'mel field on the Saharan Platform, (SONATRACH)

II. Stratigraphy and Lithostratigraphy

The sedimentary cover of the Hassi R'mel field is essentially Meso-Cenozoic in age, with a thickness varying between 2,000 and 2,300 m. The stratigraphic column, from base to top, is described as follows.

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Sys	EP moy (m)		ETAGES		STRAT	DESCRIPTION LITHOLOGIQUE
TERTIAIRE	100		MIO-PLIOCENE Discordance Alpine			Croûte calcaire et série argilo-gréseuse
CRETACE	40		SENONIEN			Calcaire à silex
	40		TURONIEN			Dolomie vacuolaire
	100		CENOMANIEN			Calcaire et argile
	460			ALBIEN		Grès fins, friables, à passées d'argile
				APTEN		Marnes et grès
				BARREMIEN		Grès fins à grossiers, à ciment carbonaté
				NEOCOMIEN		Grès à passées d'argile, de calcaire et de lignite
	JURASSIQUE	600		MALM		
220		100	DOGGER	ARGILEUX		Calcaire dolomitique et argile
		120		LAGUNAIRE		Calcaire dolomitique et argile
510		130	LIAS	MARNEUX		Marnes et calcaire
				CARBONATE		Calcaire à passées d'argile et d'anhydrite
				ANHYDRITIQUE		Anhydrite massive à passées d'argile
		80		SALIFERE I		Sel massif avec une passée dolomitique "D1"
				150	SALIFERE II & III	
		15			ARGILEUX SUPERIEUR	
TRIAS		50	TRIAS	ARGILEUX INFERIEUR		
	120	ARGILO-GRESEUX		A		Grès fin à moyen, à ciment plus ou moins argileux, anhydritique, à intercalations d'argile brune
				B		
				C		
30	SERIE INFERIEURE (Disc Hercynienne)			Andésite, argile et passées de grès argileux		
PALEO-ZOIQUE	22	DEVONIEN			Argile à passées de grès	
	100	SILURIEN			Argile noire à graptolites	
	128	CAMBRO-ORDOVICIEN			Quartzite-Grès à grès quartzite, grès fin à moyen, arkosandesite à lits d'argile Grès fin, argilo-dolomitique et brèches tectoniques	
SOCLE PRE-CAMBRIEN						Granites, éléments de grande fracture, rose, granite, terranes ancêtres

Figure 3. lithostratigraphic column of the Hassi R'mel field (SONATRACH)

1. Precambrian Basement

The basement consists of large fractured granitic elements of pink and orange color, associated with volcanic rock components.

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2. Paleozoic

2.1. Cambrian:

rests directly on the crystalline basement. It is composed of quartzitic sandstones, white to fine-medium grained, with abundant siliceous cement and numerous layers of green micaceous clay. The upper part presents a transition zone between the Cambrian and the Ordovician, characterized by an alternation of fine, partially quartzified sandstones and black silty-micaceous clays, with abundant Tigillites. The Cambrian is subdivided into four lithological zones: zone R3 (very coarse to conglomeratic, highly argillaceous sandstones, with no petroleum interest), zone R2 (anisometric argillaceous sandstones, approximately 100 m thick, considered a secondary reservoir), zone Ra (anisometric quartzite sandstones, 0 to 120 m thick, subdivided into lower coarse, middle fine, and upper coarse sub-units), and zone Ri (isometric quartzite sandstones, generally massive, fine to medium grained, well sorted, with argillaceous-siliceous cement and abundant Tigillites).

2.2. Ordovician:

is developed principally in the western part of the field. It is entirely detrital and reaches approximately 500 m in thickness. It comprises, from top to base, an alternating zone of fine quartzite and indurated clay (approximately 20 m), the El Gassi clays (fine to very fine argillaceous sandstones, dark grey, approximately 20 m), the Hamra quartzites (fine to medium grey quartzitic sandstones, approximately 75 m), and the Ouargla sandstones (fine silico-quartzitic sandstones with silt and clay intercalations, approximately 50 m).

2.3 Silurian:

where present at the northwestern edge of the field, is argillo-arenaceous. The Devonian is essentially argillaceous and has been eroded across most of the study area. The Carboniferous, present only in the northwestern part of the field, consists of fossiliferous limestones at the top and sandstones at the base.

3. Mesozoic

3.1. Triassic:

the Triassic deposits rest in angular unconformity on the Paleozoic formations the Hercynian unconformity and have an average thickness of approximately 200 m in the

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north and 75 m in the south. From base to top, the Triassic of Hassi R'mel comprises the following units.

3.1.1. The Triassic Argilo-Gréseux Inférieur (TAGI), also called the Lower Series, is represented by an alternation of indurated green and sometimes brown clays with fine, well-sorted sandstones; it is characterized by the presence of volcanic flows (andesites) and rests unconformably on the Palaeozoic formations.

3.1.2. The Triassic Argilo-Gréseux Supérieur (TAGS) groups the three productive reservoir levels of the Hassi R'mel field, levels A, B, and C extending from the base of level C to the top of level A.

- **Level C** consists of fine to medium sandstones, locally coarse, poorly cemented, with conglomerate, quartz pebbles, and carbonaceous debris.
- **Level B** consists of highly argillaceous, anhydritic sandstones, more developed in the central zone of the field.
- **Level A** consists of fine to very fine, locally argillaceous sandstones with strong anhydritic cementation.

3.1.3. The Triassic Argileux (lower argillaceous unit) is formed of indurated chocolate-brown clays traversed by anhydrite and salt veinlets; it is subdivided in its median part by a dolomitic bed called D2, which marks the Triassic–Lias boundary.

3.1.4. The Triassic Salifère (S4 or infra-D2) consists of a thick series of massive crystalline salt and argillaceous layers; this unit is absent in the north-west and central parts of the field but is well developed in the southern zone of Hassi R'mel.

3.2. Jurassic:

The Jurassic has an average thickness of approximately 1,100 m and is subdivided into three units.

3.2.1. Lias: is composed of three lithological assemblages: the saliferous Lias (comprising massive salt and plastic brown-red-grey clays with a compact dolomite marker bed at the base), the anhydritic Lias, and the carbonated Lias (Lias Carbonaté the LD2 reservoir targeted in this dissertation).

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3.2.2. Dogger: is characterized at its top by beige or grey crystalline dolomites with oolites, and at its base by oolitic limestones overlain by green plastic clays that are often dolomitic.

3.2.3. Malm: is detrital in the center of the field, represented by plastic brown clays, crystalline limestones (sometimes argillaceous), and grey argillaceous dolomite; in the north, the carbonate facies predominate and is characterized by abundant fossils.

3.3. Cretaceous:

The Cretaceous has an average thickness of approximately 640 m.

3.3.1. Neocomian: consists of an argillaceous-arenaceous alternation.

3.3.2. Barremian: comprises fine to coarse sandstones with argillaceous or carbonate cement, and multicolored sandy plastic clays; it is entirely absent in the northern part of the field.

3.3.3. Aptian consists of sandy marls and argillaceous sandstone intercalations in the south, becoming beige-to-pinkish dolomitic with clay northward.

3.3.4. Albian is essentially arenaceous, subdivided into an upper series of red, pink, or beige fine sandstones with argillaceous-dolomitic cement, and a lower series of fine sandstones becoming more argillaceous and gypsiferous toward the base.

3.3.5. Cenomanian consists of crystalline dolomite with multicolored clay intercalations and dolomitic limestones.

3.3.6. Turonian is composed of white or beige crystalline dolomites, vacuolar and locally fissured. The Senonian is represented essentially by dolomitic limestones with a few meters of fissured dolomite with siliceous levels at the base.

4. Cenozoic

The Cenozoic formations were affected by intense erosion and are only represented by the Eocene and the Mio-Pliocene.

4.1. Eocene:

has an average thickness of approximately 50 m, consisting of plastic white marls at the base and white to yellow limestones or marly limestones at the top.

4.2. Mio-Pliocene:

encountered principally in the northwest of the field with an average thickness of approximately 100 m, is formed of argillaceous sandstone overlain by medium to coarse sand with carbonate cement and a few red clay intercalations.

III. Sedimentology and Depositional Environment of HRM reservoirs

III-1 TAGI

sandstones were deposited in a continental fluvial environment following the emergence and peneplanation of the Hercynian unconformity. Detailed sedimentological analysis of Hassi R'mel wells identifies a transition from dominantly braided fluvial facies in the southern part of the field to meandering fluvial facies toward the north, creating a laterally variable reservoir architecture that controls connectivity between producing zones. The sandstone reservoir facies are dominated by braided fluvial channel deposits poorly to moderately sorted, medium- to coarse-grained sands with cross-bedded and trough cross-stratified structures that formed as part of a proximal alluvial fan to distal braided river system sourced from the Hercynian uplands.

III-2 The Liassic LD2 carbonate

was deposited on a shallow marine carbonate platform that developed across the Saharan Platform during the Early Jurassic marine transgression. The depositional environment was characterized by periodically restricted, evaporitic conditions, as evidenced by the interbedding of the dolomitic LD horizons with the halite- and anhydrite-bearing LS units (Hafsi, 2015). The dolomitic facies of the LD2 represent deposition in a shallow subtidal to intertidal setting, with periodic emergence or restriction producing the sabkha-type conditions favorable for early syn-depositional dolomitization. The lateral variability of the LD2 across the platform thinning and locally absent in certain areas reflects the inherent heterogeneity of shallow carbonate platform sedimentation controlled by syn-sedimentary tectonics and sea-level fluctuations.

IV. Tectonic evolution

The tectonic evolution of the Saharan Platform can be divided into five broadly defined phases, each of which left a measurable imprint on the stratigraphic record at Hassi R'mel

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The first phase: Precambrian and earliest Cambrian involved the Pan-African orogenic cycle that consolidated the West African Craton and produced the crystalline basement principally granites and rhyolites that forms the deepest penetrated interval at Hassi R'mel ([Magloire, 1970](#)). Post-orogenic east–west extension accompanied the initiation of continental rifting, and the resulting Cambrian basins received the first marine and transitional sedimentary sequences.

The second phase: extending through the Ordovician, Silurian and Devonian, was characterized by progressive marine transgression over the Gondwana margin. During the Ordovician, periglacial and shallow marine sandstones of the Tassili group were deposited across the platform; the Hirnantian glaciation at the end of the Ordovician left a prominent erosion surface and tillite deposits that are traceable across North Africa. The Silurian transgression that followed deposited the critical Tanezzuft Formation, including the organic-rich basal 'hot shale' horizon that constitutes the primary source rock of the Hassi R'mel petroleum system ([Lüning et al., 2000](#)). Devonian shales and carbonates complete the Paleozoic marine succession.

The third phase: and most structurally significant phase was the Hercynian orogeny, which affected the platform during the late Carboniferous and Permian. North–south to northwest–southeast compressive stresses caused regional uplift, tilting and intense erosion of the pre-existing Paleozoic section, producing the composite Hercynian unconformity. This surface is one of the most important stratigraphic features of the Hassi R'mel section: the productive Triassic reservoirs rest in Hercynian unconformity directly on the Silurian (Gothlandian) shales where the intervening Devonian and Carboniferous section has been eroded away ([Magloire, 1970](#)). The Hercynian surface thus places the source rock in direct stratigraphic adjacency to the reservoir, significantly shortening the migration pathway.

The fourth phase: encompassed Triassic–Liassic extension associated with the opening of the central Atlantic Ocean and the Neo-Tethys. Northeast–southwest tensional faulting created accommodation space for the thick continental and transitional sequences of the Triassic, which include not only the principal reservoir sandstones but also interbedded andesitic volcanic flows related to the Central Atlantic Magmatic Province (CAMP). Thick Triassic and Liassic evaporites salts, anhydrites and dolomitic marls were deposited

in the restricted, sabkha-dominated conditions that prevailed across the platform as sea-level and subsidence fluctuated (Talamali et al., 2016).

The fifth phase: and final phase was Cenozoic Alpine compression, driven by the convergence of the African and Eurasian plates. Northwest–southeast shortening imparted the final structural geometry to the Hassi R'mel anticline and is responsible for the present-day in-situ stress. A mid-Cretaceous 'Austrian' phase of vertical tectonic movements also contributed to the current structural configuration (Boote et al., 1998).

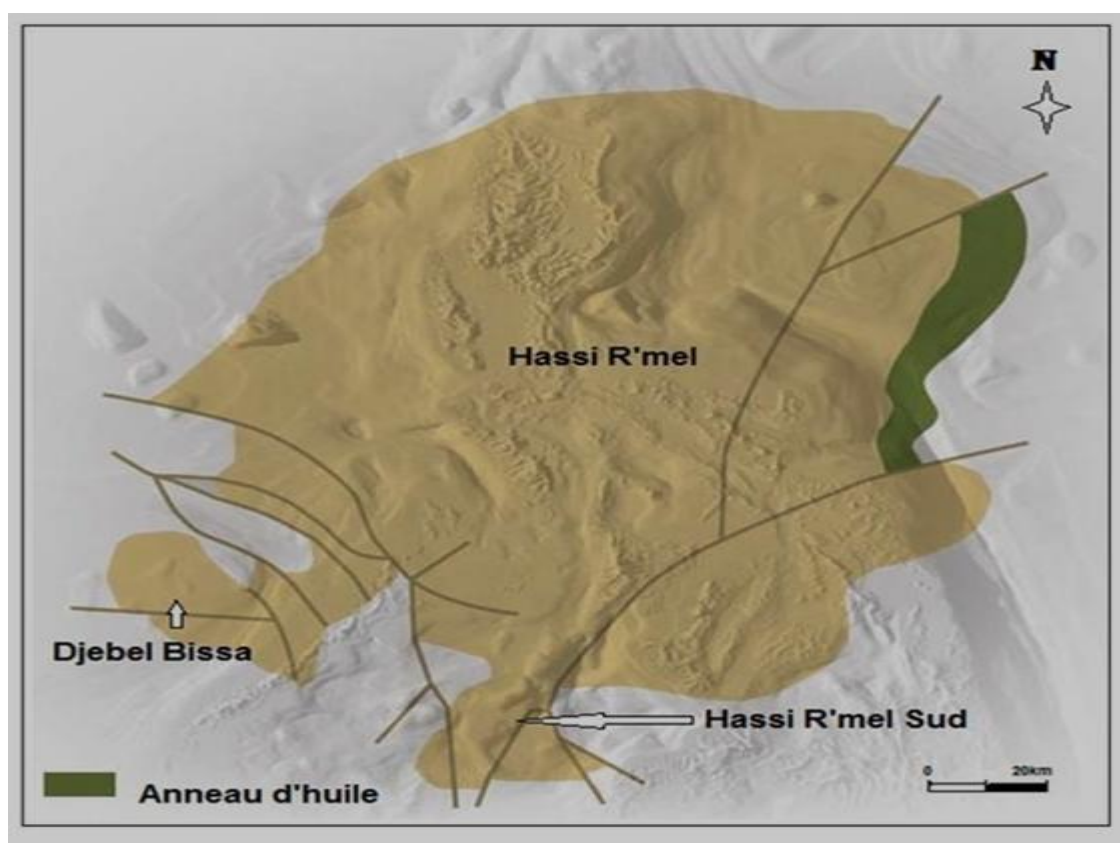


Figure 4. Hassi R'mel Anticlinal Structure, Southern Algeria (WEC 2007)

V. Structural Geology of the Hassi R'mel Field

The Hassi R'mel structure is a broad, gently dipping anticlinal dome with a NNE–SSW trending axis, reflecting the long-term tectonic stability of the M'zab dorsal rather than the product of strong compressional folding (Magloire, 1970). The structural closure at the top of the Triassic reservoir defines a trapping area of approximately 2,600 km², making it one of the largest structural traps in North Africa. The principal fault families trend N–S and NE–SW, mirroring the regional structural grain of the Oued Mya Basin. These faults were initiated by basement reactivation during Cambrian rifting and were periodically

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reactivated through subsequent tectonic phases, serving as migration conduits for hydrocarbons sourced from the Silurian shales (Boote et al., 1998).

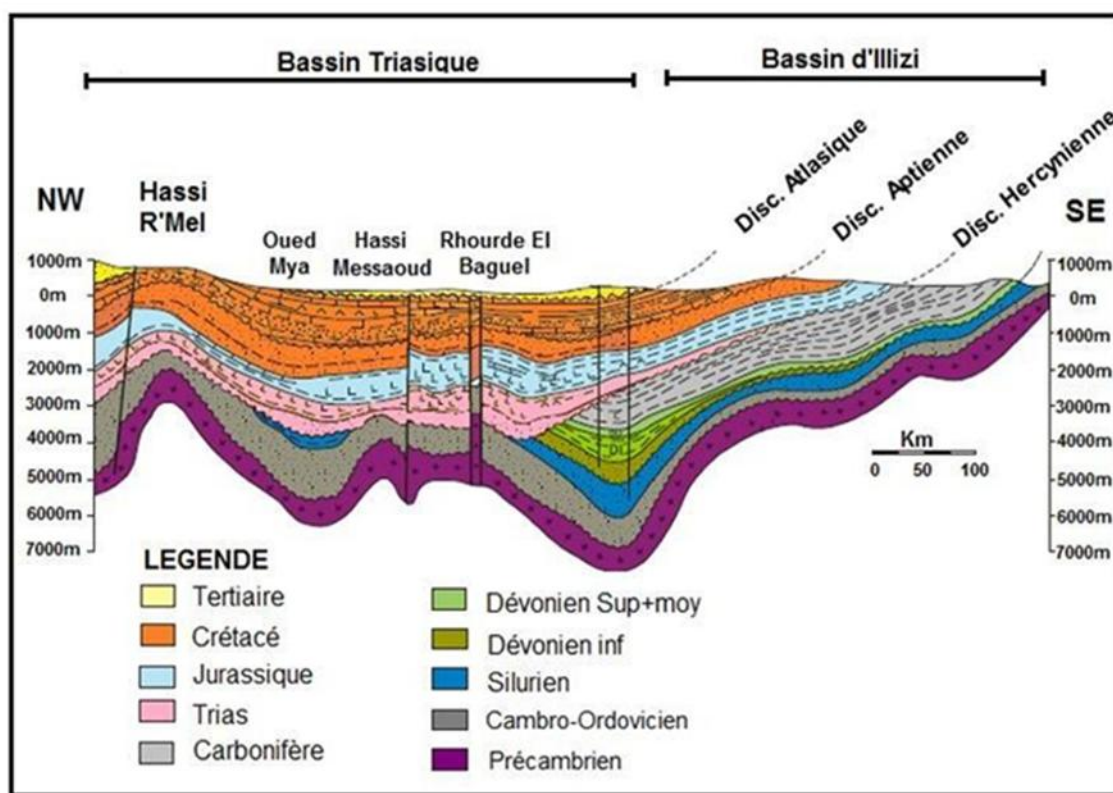


Figure 5. Geological cross-section of the Hassi R'mel. (Sonatrach 1991)

The present-day in-situ stress state is a strike-slip regime — $SH_{max} > S_v > SH_{min}$ — with the maximum horizontal stress (SH_{max}) oriented NW–SE at $N125^{\circ}E$ to $N147^{\circ}E$ throughout the Oued Mya Basin, consistent with the regional direction of Africa–Eurasia plate convergence (Baouche et al., 2021). Published stress gradients for the basin are: pore pressure 13.58–13.77 MPa/km, SH_{min} 17.3–19.2 MPa/km, and SH_{max} 23.8–26.5 MPa/km, giving a stress ratio SH_{max}/SH_{min} of approximately 1.4–1.65. This stress configuration directly governs the orientation and geometry of acid-induced fractures in the LD2 reservoir: hydraulic fractures propagate vertically in a NW–SE striking plane aligned with SH_{max} , and the high horizontal stress contrast favors planar, well-confined fractures that are ideal for sustained acid etching.

VI. Petroleum System of Hassi R'mel

The Hassi R'mel petroleum system is a large intracratonic gas system controlled by the interaction of mature Paleozoic source rocks, Mesozoic reservoirs, regional evaporitic seals, and a complex structural framework. While the Triassic sandstones constitute the

main producing interval, the Lower Jurassic carbonate reservoir (LD2) represents a significant secondary target and is the main focus of this study.

VI.1. Source Rock

The primary source rock for the Hassi R'mel gas-condensate accumulation is the Lower Silurian Tanezzuft Formation, specifically its basal organic-rich interval the 'hot shale'. This horizon is recognized as the origin of 80 to 90% of Paleozoic-sourced hydrocarbons in North Africa, with total organic carbon (TOC) values reaching up to 17% and a predominantly Type I–II kerogen (Lüning et al., 2000). In the Oued Mya Basin specifically, the Lower Silurian source averages approximately 50 m in thickness with a mean TOC of approximately 6%, locally up to 14%, and lies within the gas-generative portion of the thermal maturity window (Benamrane et al., 1993). The Upper Devonian Frasnian shales constitute a secondary source contributing an additional approximately 10% of regional hydrocarbon charge (Boote et al., 1998).

The system is therefore characterized mainly by dry gas with associated condensates, reflecting the high thermal maturity of the Silurian source interval. Devonian clay-rich formations may also contribute locally to the hydrocarbon charge, but their role is considered secondary relative to the dominant Silurian source.

VI.2. Migration

Hydrocarbon migration from the Tanezzuft source to the Triassic and Liassic reservoirs followed two principal pathways: vertical migration along deep-seated basement faults and through the Hercynian unconformity surface which places the source rock in direct or near-direct contact with the base of the Triassic sandstones and lateral migration within the TAGI sandstones along the flanks of the M'zab dorsal toward the structural crest. Magloire (1970) concluded that, although the Hassi R'mel anticlinal structure was initiated at an early date, the definitive trapping of gas took place during the Early Cretaceous, coinciding with maximum generation from the deeply buried Silurian source. Vertical migration is principally controlled by deep faults related to basement tectonics, while lateral migration is enhanced by regional stratigraphic discontinuities. The Hercynian unconformity plays a particularly important role as a migration pathway, facilitating fluid movement from Paleozoic source rocks toward Mesozoic reservoirs, including both the Triassic and Lower Jurassic intervals.

VI.3. Reservoir Systems

VI.3.1. Triassic Reservoir (Main Reservoir)

The primary reservoir is the Upper Triassic Argilo-Gréseux Supérieur (TAGS), composed of three main sandstone units (levels A, B, and C). These reservoirs are characterized by porosity values between 12% and 18%, high permeability reaching several Darcies locally, and good lateral continuity across the field. They contain the majority of gas reserves at Hassi R'mel and represent the main producing interval throughout the field's production history.

VI.3.2. Lower Jurassic Carbonate Reservoir (LD2 – Study Focus)

The LD2 reservoir corresponds to a carbonate unit within the Lower Jurassic sequence, composed mainly of dolomite and limestone deposited in shallow marine environments on a periodically restricted, evaporitic carbonate platform. Unlike the Triassic sandstones, the LD2 reservoir is highly heterogeneous, and its reservoir quality is principally controlled by secondary diagenetic processes: fracturing, which enhances permeability; dolomitization, which can improve pore development; and dissolution and diagenetic alteration, which create secondary porosity. Overall, the LD2 generally has lower and more variable petrophysical properties than the Triassic reservoirs; however, where fracture networks and diagenetic enhancement are well developed, it can form effective hydrocarbon-bearing zones capable of commercial production with appropriate stimulation.

VI.4. Seal

The sealing system is provided by thick evaporitic and clay-rich formations within the Triassic and Lower Jurassic sequences, including claystones and evaporites composed mainly of anhydrite and salt. Two principal reservoir–seal pairs operate: the TAGI sandstones sealed by the Saliferous Trias, and the LD2 carbonates sealed by the LS1 and LS2 evaporite units. These formations are highly effective seals owing to their very low permeability, plastic mechanical behavior, and significant thickness, collectively ensuring long-term hydrocarbon retention in both reservoir systems.

VI.5. Trap Mechanisms

Chapter 1

Hydrocarbon accumulation is principally controlled by structural traps associated with the large anticlinal dome of the Hassi R'mel structure, trending NNE–SSW. The trap is a broad, four-way dip-closed anticline with a structural closure at the top of the Triassic reservoir estimated at 2,600 km², making it one of the largest structural traps in North Africa. This structure is affected by faulting and folding along N–S and NE–SW fault families, creating multiple closures. In addition to structural traps, stratigraphic and lithological variations contribute locally, particularly within the LD2 carbonate reservoir where facies changes and fracture distribution play an important role in controlling hydrocarbon distribution and production potential.

VI.6. Role of the Hercynian Unconformity

The Hercynian unconformity represents a key regional geological surface that strongly influences the Hassi R'mel petroleum system. It acts simultaneously as a major migration pathway, a structural and stratigraphic discontinuity, and a control on reservoir distribution and connectivity. This surface is one of the most important stratigraphic features of the field section: the productive Triassic reservoirs rest in angular unconformity directly on the Silurian (Gothlandian) shales where the intervening Devonian and Carboniferous section has been eroded away, placing the source rock in direct stratigraphic adjacency to the reservoir and significantly shortening the migration pathway. The Hercynian surface thus played a major role in linking Paleozoic source rocks with overlying Mesozoic reservoirs throughout the Saharan Platform.

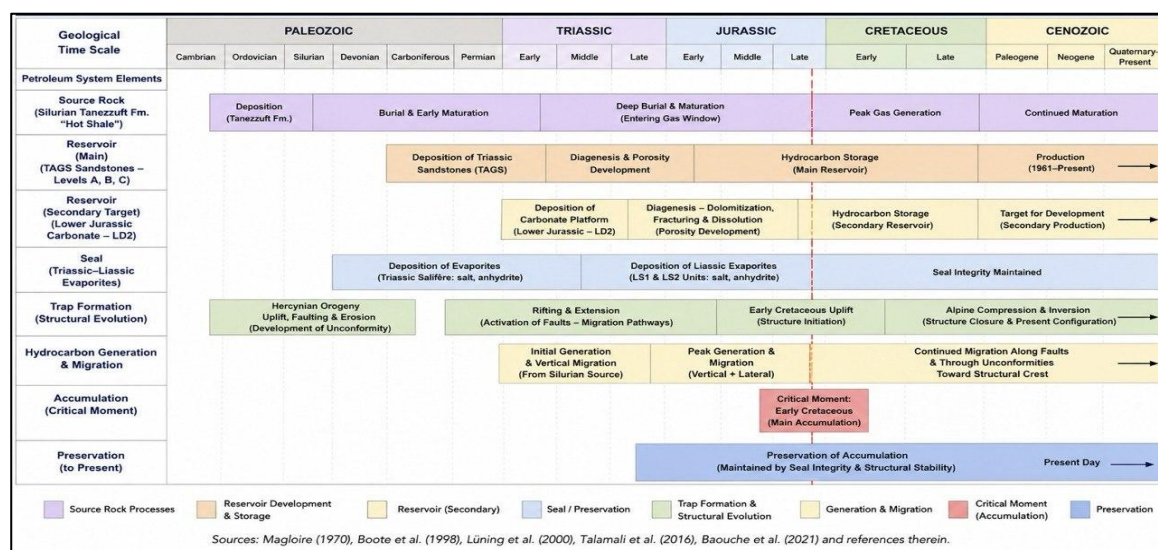


Figure 6. Petroleum System Events of Hassi R'mel. (Sonatrach 1991)

Chapter 2:

Carbonate Reservoir
Characterization,
Formation Damage and
Stimulation Mechanisms

I. Introduction

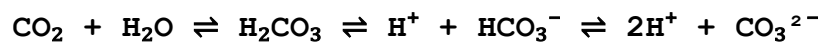
Carbonate rocks limestones and dolomites host an estimated 60% of global proven oil reserves, yet their geological complexity makes them among the most technically demanding reservoir types to characterize. Unlike sandstones, whose quality is set largely by depositional grain size, carbonates undergo extensive post-depositional modification through diagenesis dolomitization, cementation, dissolution, and compaction that produces orders-of-magnitude variation in porosity and permeability at the centimeter scale, combining matrix, vuggy, and fracture porosity in arrangements that cannot be predicted from depositional texture alone.

Characterizing a carbonate reservoir for stimulation design requires an integrated approach: mineralogy governs acid reactivity; petrophysical parameters quantify storage and deliverability; geomechanical properties control fracture behavior; and diagenetic history explains present-day reservoir quality. Formation damage assessment, through the skin factor, then quantifies the deficit between actual and theoretical productivity, justifying stimulation.

II. Generalities on Carbonate Rocks

II.1. Geological Formation of Carbonate Rocks

Carbonate precipitation in marine and lacustrine environments is governed by the inorganic carbonate equilibrium system. When dissolved CO_2 decreases through photosynthesis, warming, or physical degassing the equilibrium shifts toward higher carbonate ion activity, promoting spontaneous CaCO_3 precipitation [4]:



Decreasing dissolved CO_2 shifts the equilibrium to the right, increasing CO_3^{2-} activity and promoting CaCO_3 supersaturation.



CaCO_3 precipitates initially as aragonite in the marine environment, converting to calcite during early diagenesis through neomorphism.

A large proportion of marine carbonate sediment is also produced biogenically, through the extraction of calcium carbonate from seawater by foraminifera, molluscs, echinoderms, and corals to build shells and skeletons. The resulting grain composition and sorting are determined by the organisms present and the hydrodynamic energy of the depositional environment variables preserved in the Dunham textural classification.

Chapter 2

II.2. Mineralogy of Carbonate Rocks

Carbonate rocks are sedimentary formations in which carbonate minerals constitute at least 50% of the total composition. In petroleum reservoirs, three minerals are of primary importance: calcite, aragonite, and dolomite.

II.2.1. Calcite (CaCO_3)

Calcite is the most stable carbonate mineral under near-surface and burial conditions. It crystallizes in the rhombohedral system, ranging from the primary rhombohedron through vein cements to prismatic burial cements that frequently occlude fracture porosity. Its key property is high reactivity with HCl at concentrations as low as 1% at ambient temperature, producing a rapid, exothermic, fully soluble reaction:



Reaction rate increases exponentially with temperature. All products are fully soluble — no secondary precipitate risk from the reaction itself.

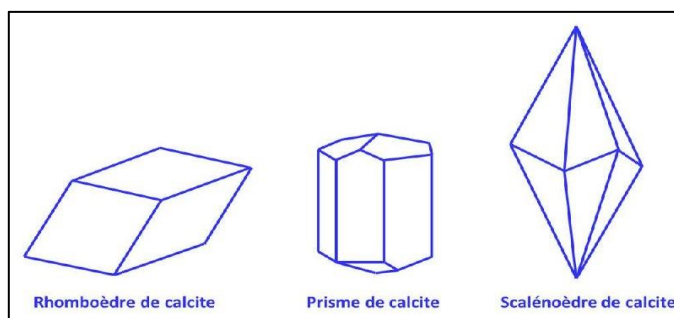


Figure 7. Principal crystal forms of calcite (CaCO_3): rhombohedron (primary depositional habit), scalenohedron (open vein and fracture cement), and prismatic calcite (late-stage burial fracture cement). (Tucker & Wright, 1990)

II.2.2. Aragonite

Aragonite is a polymorph of calcite with an orthorhombic structure that is thermodynamically metastable under burial conditions, and is the primary precipitate from supersaturated seawater. During burial, it dissolves and reprecipitates as calcite through neomorphism, often creating secondary moldic porosity later occluded by calcite cement.

II.2.3. Dolomite ($\text{CaMg}(\text{CO}_3)_2$)

Dolomite differs from calcite through the ordered substitution of half the calcium sites by magnesium, producing a tighter, more rigid lattice and significantly lower solubility: meaningful HCl dissolution requires higher concentrations (10–15%+), elevated temperature, or retarded systems:



Reaction rate is 10–100 times slower than for calcite at equivalent HCl concentration and temperature — a property exploited in acid system design to achieve deeper fracture penetration.

Three dolomite crystal types reflect their timing of crystallization:

- Planar-euhedral: early near-surface replacement.
- Planar-subhedral: deeper burial replacement.
- Saddle/baroque: curved faces, sweeping extinction, late hydrothermal crystallization; commonly lines or fills fractures and vugs a diagnostic indicator of late-stage occlusion of secondary porosity.

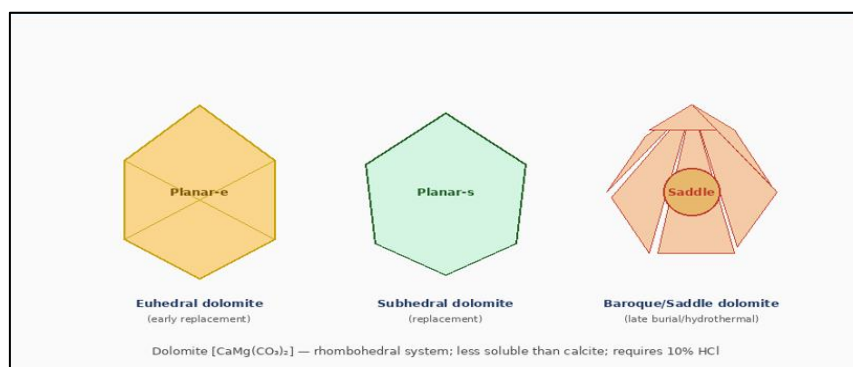


Figure 8. Principal crystal forms of dolomite (Tucker & Wright, 1990)

II.3. Classification of Carbonate Rocks

Several classification systems capture different aspects of carbonate composition and texture. The mineralogical classification ranks carbonates from pure limestone (100% calcite) to pure dolostone (100% dolomite), with intermediate compositions named by the dominant mineral.

Folk's (1959) classification distinguishes allochems (ooids, peloids, bioclasts) by their binding phase: sparite (high-energy) or micrite (low-energy). Dunham's (1962) textural classification is more directly applicable to reservoir quality, ranking fabric from mudstone (lowest energy, poorest porosity) through wackestone, packstone, and grainstone to boundstone, giving a first-order estimate of original reservoir quality before diagenetic modification.

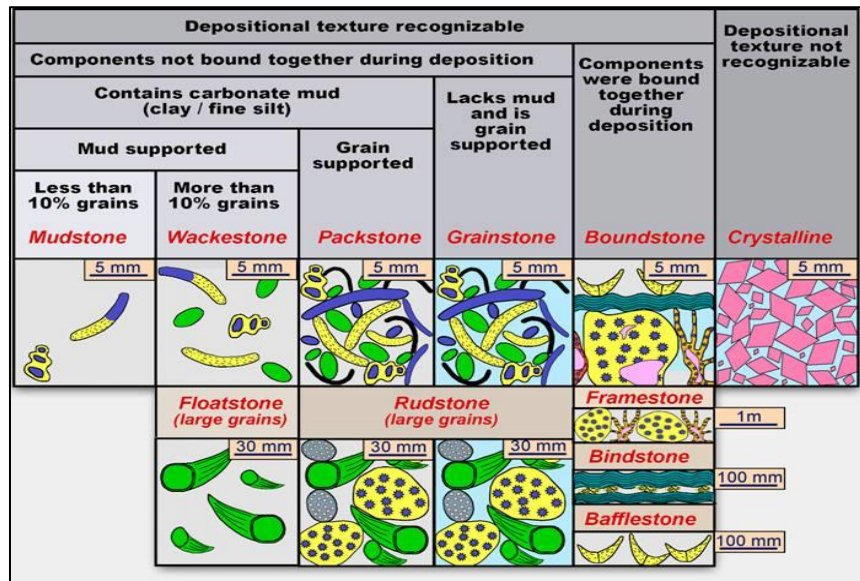


Figure 9. Dunham textural classification of carbonate rocks. (Dunham, 1962)

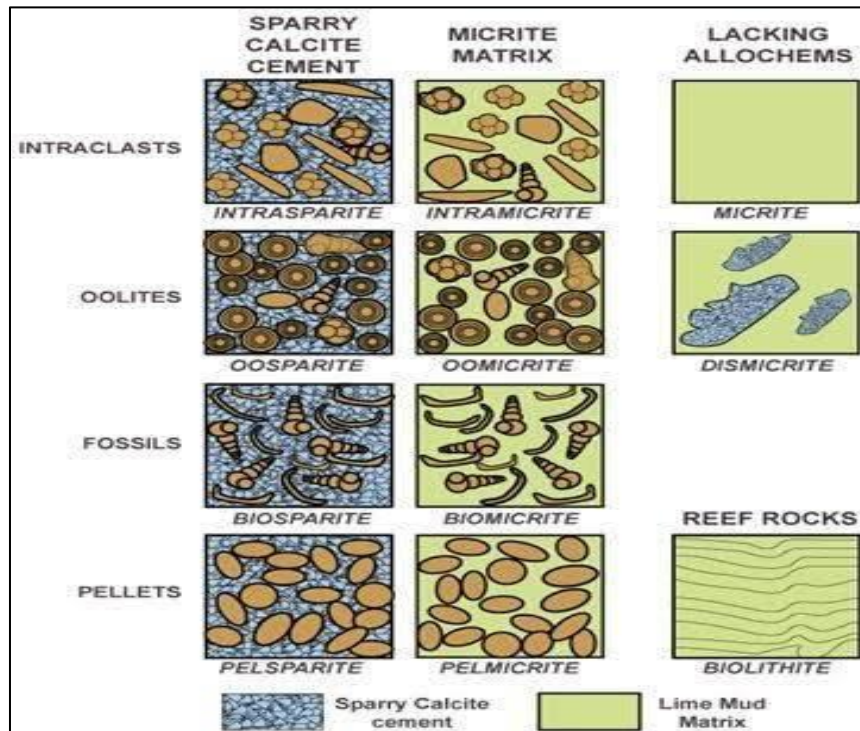


Figure 10. Folk compositional classification of carbonate rocks. (Folk, 1959)

II.4. Diagenesis of Carbonate Rocks

Diagenesis all physical and chemical change after deposition is the most consequential process controlling present-day carbonate reservoir quality, since it can both create and destroy porosity and permeability throughout burial history. The principal processes are dolomitization, cementation, dissolution, and compaction.

Chapter 2

II.4.1. Dolomitization

Dolomitization is the diagenetic replacement of calcite or aragonite by dolomite through the exchange of Ca^{2+} for Mg^{2+} in the carbonate lattice:



The reaction produces a theoretical 13% volume reduction relative to the calcite precursor. In practice, this porosity gain is commonly offset or eliminated by subsequent cementation.

Three mechanisms are recognized. Seepage-reflux dolomitization occurs when hypersaline brines from evaporation in restricted lagoons sink through the platform, replacing calcite with microcrystalline dolomite the dominant model for Triassic-Liassic sequences in North Africa. Burial dolomitization occurs when Mg-rich waters interact with limestone at depth, producing coarser textures that typically occlude secondary porosity. Hydrothermal dolomitization, driven by hot fluids rising along faults, produces irregular fracture-controlled dolomite bodies with baroque habits.

II.4.2. Cementation

Cementation precipitates minerals in pore spaces during burial. Calcite cementation is the most damaging process, occluding both matrix pores and natural fractures simultaneously late-stage prismatic calcite along pre-existing fractures is directly responsible for sealing natural fracture networks in many tight carbonates. Anhydrite cementation, common in evaporite-interbedded carbonates, is particularly damaging since it is insoluble in HCl-based stimulation fluids.

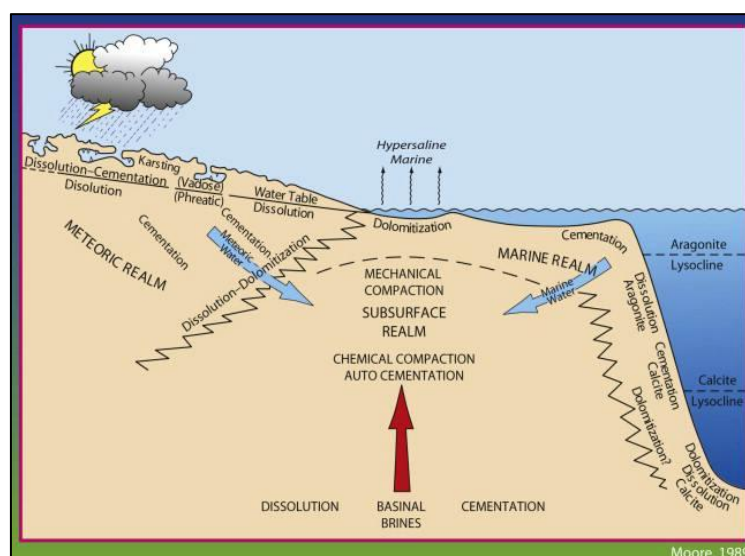


Figure 11. Diagenesis processes on carbonate shelf. (Moore 1989)

II.4.3. Dissolution

Dissolution removes soluble phases by undersaturated fluids, creating moldic pores or vugs. The most important events occur at unconformities, where meteoric water creates karst-related porosity that can be highly productive when preserved. Burial dissolution by organic-derived acidic fluids also creates secondary porosity, though more localized and harder to predict.

II.4.4. Compaction and Stylolitization

Compaction reduces porosity through mechanical grain rearrangement at shallow depth, where grain contacts deform and pores collapse, and chemical pressure solution at greater depths, where minerals dissolve at stressed contacts and reprecipitate as overgrowth cement. The clearest evidence is stylolites sutured dissolution seams concentrating insoluble residues that act as permeability baffles, capable of compartmentalizing reservoirs at bed scale.

II.5. Heterogeneity in Carbonate Reservoirs

Carbonate heterogeneity operates across multiple scales simultaneously, from crystal-scale pore throats to field-scale facies and diagenetic zones distinguishing carbonate behavior from sandstones and requiring a multi-disciplinary characterization approach.

At microscopic scale, a uniformly fine-crystalline dolomite has high porosity but low permeability since pore throats are very small; stylolites add centimeter-scale permeability barriers. At meter scale, alternating high-energy grainstone shoals and low-energy lagoon mudstones can produce a permeability contrast exceeding four orders of magnitude. At field scale, dolomitization fronts, dissolution zones, and cementation events follow their own spatial patterns governed by faults, unconformities, and permeable layer boundaries that guided diagenetic fluid migration.

II.6. Geomechanical Properties

Geomechanical properties govern the pressure required to initiate and propagate a fracture and the resulting fracture geometry. The principal parameters relevant to carbonate stimulation are described below.

Chapter 2

II.6.1. Young's Modulus (E)

Young's modulus defines rock stiffness and controls fracture width for a given net treating pressure:

$$E = \sigma / \varepsilon \quad [\text{GPa}]$$

σ = axial stress (MPa); ε = axial strain. Tight dolomites: $E = 40\text{--}80$ GPa stiffer rock yields narrower, longer fractures.

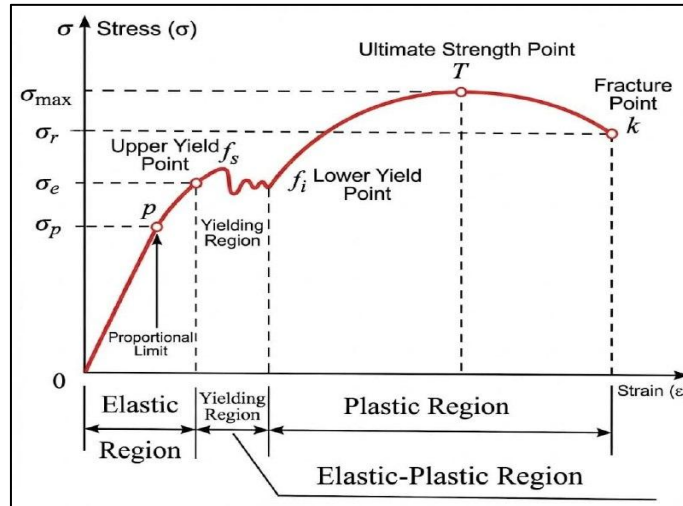


Figure 12. Stress-strain diagram

II.6.2. Poisson's Ratio (ν)

Poisson's ratio relates lateral to axial strain and is used to calculate minimum horizontal stress from the overburden gradient:

$$\nu = \varepsilon_{\text{lateral}} / \varepsilon_{\text{axial}}$$

Dolomite: $\nu = 0.25\text{--}0.30$; used with E and overburden stress to compute closure pressure.

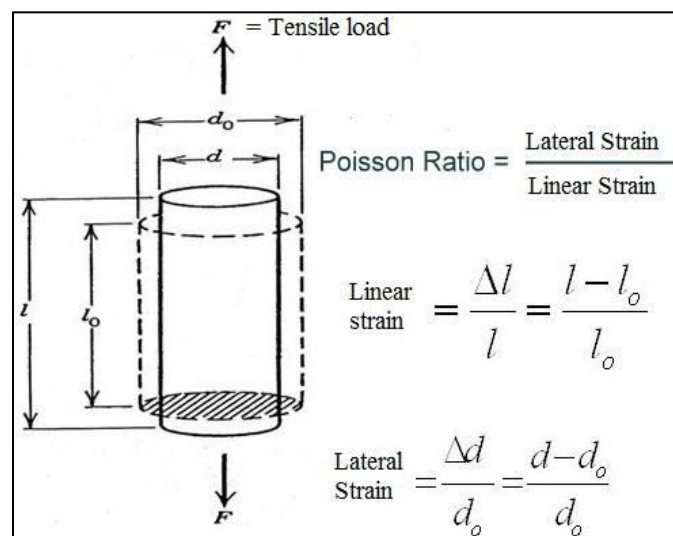


Figure 13. Poisson Ratio Principle

Chapter 2

II.6.3. Unconfined Compressive Strength (UCS)

UCS is the maximum axial stress before failure at zero confining pressure, providing the baseline for fracture initiation pressure. Tight dolomites range from 100–200 MPa substantially higher than sandstones (20–100 MPa) reflecting rigid crystal interlocking and minimal plastic deformation before brittle failure.

II.6.4. Tensile Strength (T_0)

Tensile strength, roughly one order of magnitude below UCS, is the critical parameter governing hydraulic fracture initiation. The breakdown pressure for a vertical well is:

$$P_b = 3 S_{hmin} - S_{Hmax} + T_0 - P_p$$

S_{hmin} , S_{Hmax} = horizontal stresses; T_0 = tensile strength; P_p = pore pressure. Tight carbonates: $T_0 \approx 5\text{--}20$ MPa.

II.6.5. Shear Strength, Cohesion and Friction Angle

Shear strength governs failure along a shear plane rather than a tensile fracture, described by the Mohr-Coulomb criterion:

$$\tau = C + \sigma_n \times \tan(\phi)$$

C = cohesion (MPa); ϕ = friction angle ($^\circ$). Dolomite: $C = 20\text{--}60$ MPa; $\phi = 30\text{--}45^\circ$.

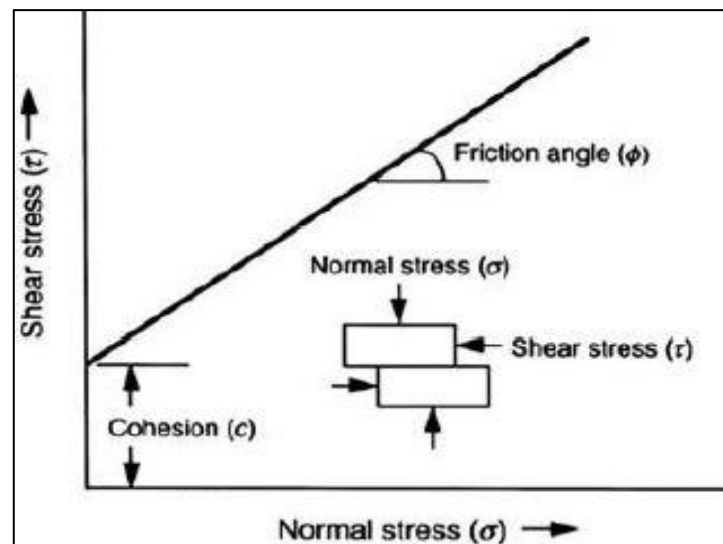


Figure 14. Mohr-Coulomb failure criterion Diagram

These parameters predict whether a hydraulic fracture propagates in tensile mode or reactivates pre-existing natural fractures in shear mode, with direct implications for fracture geometry and conductivity distribution.

Chapter 2

II.6.6. In-Situ Stresses

Three principal stresses define the in-situ stress state. Vertical stress S_v (overburden) is computed by integrating bulk density logs:

$$S_v = \int \rho_b(z) \times g \times dz$$

$\rho_b(z)$ = depth-dependent bulk density; g = gravitational acceleration. Typical S_v gradient: 22–25 MPa/km.

S_{hmin} (fracture closure pressure) and S_{Hmax} are derived from leak-off tests, mini-fracture tests, and breakout inversion. Their relative magnitudes define the stress regime: normal faulting ($S_v > S_{Hmax} > S_{hmin}$), strike-slip ($S_{Hmax} > S_v > S_{hmin}$), or reverse ($S_{Hmax} > S_{hmin} > S_v$) and together with S_{Hmax} orientation determine that a hydraulic fracture always propagates perpendicular to S_{hmin} .

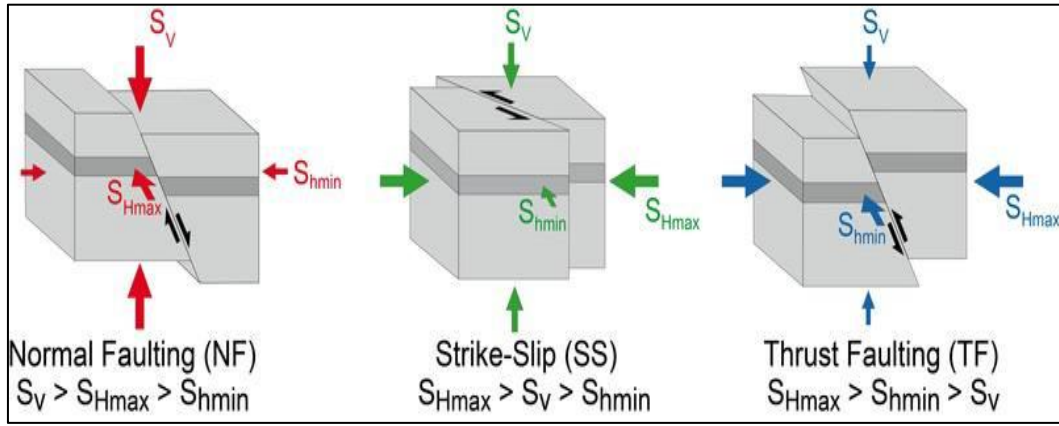


Figure 15. Main fault regimes as per Anderson's classification (Heidbach et al., 2016)

II.6.7. Pore Pressure (P_p)

Pore pressure acts as an internal support force partially counteracting applied confining stresses, entering all effective stress calculations:

$$\sigma'_{eff} = \sigma_{total} - \alpha \times P_p$$

α = Biot's coefficient; σ_{total} = total stress; P_p = pore pressure. Governs fracture closure, compaction, and shear failure.

II.6.8. Biot's Coefficient (α)

Biot's coefficient quantifies how efficiently pore pressure counteracts total stress, ranging from 0 (rigid skeleton) to 1 (fully compressible). Tight, well-cemented dolomites typically fall between 0.5–0.8:

$$\alpha = 1 - (K_{dr} / K_{grain})$$

K_{dr} = drained bulk modulus; K_{grain} = grain bulk modulus. Dolomite: $K_{grain} \approx 94$ GPa.

III. Petrophysical Characterization of Carbonate Reservoirs

Petrophysical characterization of a carbonate reservoir provides the quantitative measurements describing storage capacity, fluid distribution, and flow potential. Unlike sandstones, where simple empirical correlations often suffice, carbonates require parameter-by-parameter assessment accounting for the multi-scale heterogeneity and complex pore geometry described in Section II.4.

III.1. Porosity

Porosity (ϕ) is the ratio of void volume to total bulk volume and is the primary measure of a reservoir's fluid storage capacity. It is defined as:

$$\phi = V_v / V_o$$

V_v = void volume; V_o = total bulk volume. Expressed as a fraction or percentage.

Carbonate porosity must be disaggregated into component types of differing productivity significance.

Intercrystalline matrix porosity, between individual crystals, ranges from <1% in tightly cemented dolomites to ~20% in well-preserved grainstones. Moldic and vuggy porosity, from selective dissolution, contribute significantly to storage but may be poorly connected. Fracture porosity, though typically <1% of rock volume, provides the dominant permeability pathway when open; the critical factor is cementation degree open fractures give permeability orders of magnitude above the matrix, while calcite-cemented fractures contribute nothing to flow.

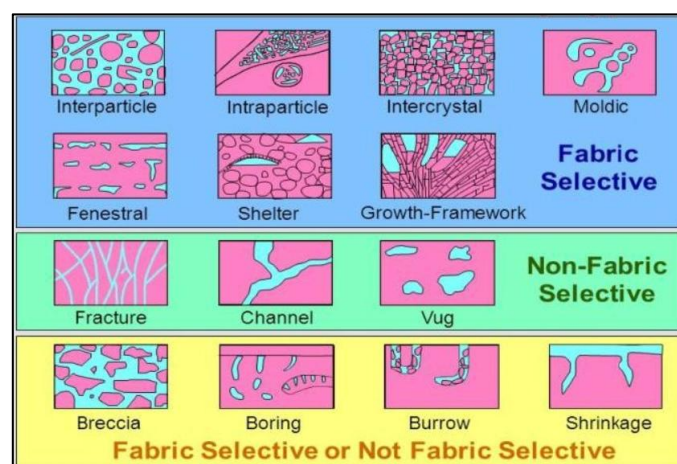


Figure 16. Porosity classification system for carbonate rocks (Choquette and Pray 1970)

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The dual-porosity concept (Warren & Root, 1963) quantifies matrix and fracture system contributions through the inter-porosity transfer coefficient λ and storativity ratio ω , both identifiable from pressure transient analysis.

III.2. Permeability

Permeability quantifies the capacity of the rock to transmit fluid under an applied pressure gradient. It is formally defined through Darcy's Law:

$$q = - (k \times A / \mu) \times (\Delta P / \Delta L)$$

q = flow rate; k = permeability (mD); A = cross-section; μ = viscosity; $\Delta P / \Delta L$ = pressure gradient.

The porosity-permeability relationship is far less predictable than in sandstones, since permeability depends on pore throat size, shape, and connectivity, not just pore volume: an 8%-porosity dolomite with isolated micropores may have permeability below 0.01 mD, while a 5%-porosity limestone with connected vugs may reach tens of mD. Open fracture permeability is estimated from the cubic law:

$$k_f = w^2 / 12$$

k_f = fracture permeability; w = aperture. A 0.1 mm aperture gives $k_f \approx 8.3 \times 10^{-10} \text{ m}^2$ orders of magnitude above matrix permeability.

III.3. Fluid Saturation

Fluid saturation quantifies the fraction of the pore volume occupied by each fluid phase. Water saturation (S_w) is the most important saturation parameter for reservoir evaluation because it directly determines hydrocarbon pore volume. It is calculated from the Archie equation, adapted for the variable cementation exponent m characteristic of carbonate rocks:

$$S_w = [(a \times R_w) / (\phi^m \times R_t)]^{(1/n)}$$

R_w, R_t = water/formation resistivity; a = tortuosity factor; m = cementation exponent (1.8–2.5 for dolomites); n $\approx$ 2.0.

The cementation exponent m is particularly variable in dolomites, reaching 2.5 in tight microcrystalline types versus 1.8–2.0 for limestones; an incorrect m can produce 15–25% errors in estimated hydrocarbon pore volume. Where core data exist, SCAL measurements calibrate m and n directly for the specific lithology.

III.4. Density

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The bulk density (ρ_b) of a porous rock is a composite of the solid matrix and fluid contributions:

$$\rho_b = (1 - \phi) \times \rho_{ma} + \phi \times \rho_{fl}$$

ρ_{ma} = matrix grain density; ρ_{fl} = fluid density. Dolomite $\rho_{ma} \approx 2.87$; calcite $\rho_{ma} \approx 2.71$ g/cm³.

The distinct grain densities of calcite and dolomite (2.71 vs 2.87 g/cm³), combined with the PEF log, allow unambiguous mineralogical discrimination in the subsurface.

Minerals	Bulk modulus (GPa)	Shear modulus (GPa)	Density (g/cm ³)
Calcite	68.30	28.40	2.71
Dolomite	94.90	45.00	2.87
Clay	25.00	9.00	2.55
Anhydrite	56.10	29.10	2.98
Quartz	37.00	44.00	2.65
Oil	1.02	0.00	0.80

Figure 17. Elastic proprieties of some dominant minerals in carbonate formation.

III.5. Electrical Resistivity

Electrical resistivity the fundamental basis for fluid identification, since hydrocarbons are resistive while saline water is conductive relates the fully water-saturated resistivity (R_0) to formation water resistivity (R_w):

$$F = R_0 / R_w = a / \phi^m$$

a = tortuosity factor; m = cementation exponent, quantifying pore network tortuosity to current flow.

Resistivity interpretation is complicated by the variable m : vuggy porosity yields higher m than intercrystalline porosity at the same total porosity, since current follows a more tortuous path around vugs. Ignoring this typically overestimates S_w in vuggy intervals.

III.6. Wettability

Wettability describes a rock surface's preference for one fluid phase over another, expressed as the contact angle θ between the water phase and rock surface. A water-wet surface ($\theta < 90^\circ$) lets oil or gas occupy the central pore space; an oil-wet surface ($\theta > 90^\circ$) confines water to the pore centers.

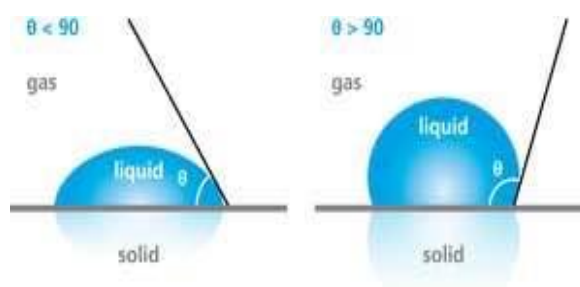


Figure 18. Concept of contact angle θ .

Wettability governs relative permeability and ultimate recovery. Most carbonates are naturally water-wet at migration time, but adsorption of polar crude oil compounds can progressively shift wettability toward oil-wet, reducing oil relative permeability and increasing residual oil saturation hence the relevance of surfactant-based wettability modification in carbonate EOR. It is measured via contact angle or the Amott-Harvey imbibition/drainage index.

III.7. Capillary Pressure

Capillary pressure (P_c), the pressure difference across a curved fluid interface in a pore throat, balances interfacial tension against pore throat geometry via the Young-Laplace equation:

$$P_c = (2 \times \gamma \times \cos \theta) / r$$

γ = interfacial tension; θ = contact angle; r = pore throat radius. Smaller throats give higher entry pressure and irreducible S_w .

MICP or centrifuge capillary pressure curves give the most detailed pore throat characterization: a flat, low-entry plateau indicates a well-connected unimodal system (grainstone), while a steep curve with multiple inflections indicates a heterogeneous multi-pore-size system (tight dolomite). Reservoirs with matrix, vuggy, and fracture porosity may show distinct plateaus for each, and integrating this with log-derived porosity is essential to correctly partition hydrocarbon saturation between pore types.

III.8. Well Log Analysis in Carbonate Reservoirs

Well logs provide the primary dataset for carbonate characterization without full core coverage. Table 1 summarizes the principal log types, measurements, applications, and limitations.

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Log	Tool	Measurement	Carbonate Application	Principal Limitation
Gamma Ray	GR	Natural radioactivity (API)	Shale volume; clay content estimation	Cannot distinguish carbonate mineral types
Neutron-Density	CN-FDC	Porosity (ϕ_N , ϕ_D)	Total porosity; lithology crossplot	Vuggy porosity overestimated by neutron tool
Photoelectric Factor	PEF	Photoelectric absorption index	Direct mineralogy: calcite 5.1, dolomite 3.1	Sensitive to borehole rugosity and mudcake
Resistivity	LLD/LLS	Formation resistivity ($\Omega \cdot m$)	Fluid identification; water saturation	Variable cementation exponent m in dolomites
Sonic	DT	Compressional travel time ($\mu s/ft$)	Porosity; Young's modulus and Poisson's ratio	Cycle-skipping in vuggy or fractured carbonates
Borehole Image	FMI/UBI	Borehole wall microresistivity	Fracture identification, orientation and fill	High cost; open hole conditions required

Table 1. Principal well logs used in carbonate reservoir characterization, with their measurements, applications, and limitations. (Schlumberger, 1991; Rider, 2002)

The PEF log deserves particular emphasis as the only conventional log responding directly to mineral atomic number (calcite 5.08, dolomite 3.14, quartz 1.81 barns/electron), allowing limestone-dolomite discrimination and, via density crossplot, quantification of mixed compositions information directly required for acid system selection in stimulation planning.

IV. Well Log Evaluation, Diagenesis and Petrophysical Impact

IV.1. Well Log Evaluation Workflow in Carbonate Reservoirs

Well log evaluation begins with lithology identification from the density-neutron combination. The PEF log is the primary discriminator (5.1 = limestone, 3.1 = dolomite, intermediate = mixed/clay); the density-neutron crossplot complements it, since dolomite's higher matrix density (2.87 g/cm³) versus calcite (2.71 g/cm³) produces a characteristic rightward shift.

Porosity is then computed from the density log, the most reliable total porosity measure since it responds uniformly to all pore types; neutron porosity should be used cautiously in vuggy carbonates, where gas-filled vugs cause overestimation. The density-neutron

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crossover is a reliable gas indicator even where gas-water resistivity contrast is ambiguous.

The gamma ray log identifies argillaceous intervals that reduce net pay and supports clay volume corrections. The sonic log, combined with density, provides the elastic moduli (E , ν) needed for fracture propagation models. The FMI image log, where available, provides fracture orientation, density, and fill data essential for natural fracture modelling and predicting hydraulic fracture azimuth.

IV.2. Diagenetic Processes and Their Petrophysical Consequences

Each diagenetic process described in Section II.4 produces a characteristic combination of effects on the petrophysical parameters and on the well log response. Table 2 summarizes these relationships systematically, providing the interpretive framework for linking observed log signatures to their diagenetic origin and predicting the associated petrophysical behavior.

Diagenetic Process	Crystal / Texture	Porosity Effect	Permeability Effect	Log Signature
Early dolomitization	Planar-euhedral fine rhombs	Preserves or slight increase (13% vol. reduction)	Remains low, pores poorly connected	Density decreases; PEF shifts toward 3.1
Burial dolomitization	Planar-subhedral coarser	Variable, may create intercrystalline porosity	May improve if connected	Density lower than limestone; PEF ~3.1–3.4
Calcite cementation	Prismatic / blocky cement	Reduces, occludes matrix pores and fractures	Strongly reduced, pore throats blocked	Density increases toward 2.71 g/cm ³ ; DT decreases
Dissolution	Vuggy / moldic pores	Increases, secondary porosity created	Variable, depends on vug connectivity	Neutron overestimates ϕ ; density-neutron crossover
Compaction / stylolites	Stylolite seams	Reduces, pore collapse along seams	Reduces perpendicular to seam; baffle created	No direct log signature; inferred from core
Fracture filling	Calcite vein fill	Negligible effect on matrix	Eliminates fracture permeability	FMI shows filled fracture traces; DT unchanged

Table 2. Diagenetic processes and their characteristic effects on porosity, permeability, and well log response in carbonate reservoirs. (compiled from Flügel, 2010; Schlumberger, 1991; Nelson, 1985)

Early seepage-reflux dolomitization slightly increases porosity via the 13% calcite-to-dolomite volume reduction, but the resulting intercrystalline pores are small and poorly

connected, keeping matrix permeability low. On logs, this appears as decreasing density (toward 2.87 g/cm^3) and PEF shifting from 5.1 toward 3.1 a diagnostic signature for dolomitized intervals. Late-stage calcite cementation instead increases density back toward 2.71 g/cm^3 (as calcite cement fills the pores), decreases sonic travel time as the rock stiffens, and increases resistivity as pore space is occluded. FMI provides the most direct evidence of cemented fractures, appearing as high-resistivity traces versus low-resistivity traces for open fractures.

Dissolution-related vuggy porosity is identified by density-neutron divergence and anomalously high resistivity in gas-bearing vuggy intervals. Compaction stylolites produce no direct log signature and are identified from core; their permeability-baffle impact is inferred from pressure transient compartmentalization.

IV.3. Integration of Diagenesis and Petrophysics for Reservoir Quality Assessment

Integrating diagenetic interpretation with petrophysical measurement is the most powerful approach to carbonate reservoir quality assessment, connecting log signatures to geological origin and predicting quality beyond individual wells. A PEF/density-based dolomitization index can map dolomitization fronts across the field, distinguishing early seepage-reflux zones (better porosity, lower permeability) from late cementation zones (near-zero permeability) and dissolution-enhanced zones. This also rationalizes spatial variation in stimulation response: wells in heavily cemented zones require higher acid volumes, and the optimal acid system may vary with the residual calcite-versus-dolomite ratio along the fracture.

V. Formation Damage

V.1. Definition and General Concept

Formation damage is any alteration of near-wellbore properties most critically permeability causing actual productivity or injectivity to fall below the undamaged theoretical potential (Frick & Taylor, 1962). Quantified through the skin factor, its correct identification is the essential prerequisite for selecting stimulation technique and treatment parameters.

V.2. Principal Types and Mechanisms of Formation Damage

Formation damage mechanisms are classified into four broad categories based on their physical or chemical origin.

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-Mechanical damage results from solid particle invasion in pore throats: fines migration, particle plugging from drilling mud solids, and perforation damage (the compacted low-permeability annulus around each perforation tunnel).

-Chemical damage encompasses fluid-mineral incompatibilities: clay swelling from low-salinity filtrate; scale precipitation from mineral salt supersaturation; emulsion blockage at the fluid interface; and wettability alteration from surfactant adsorption, reducing relative permeability to hydrocarbons.

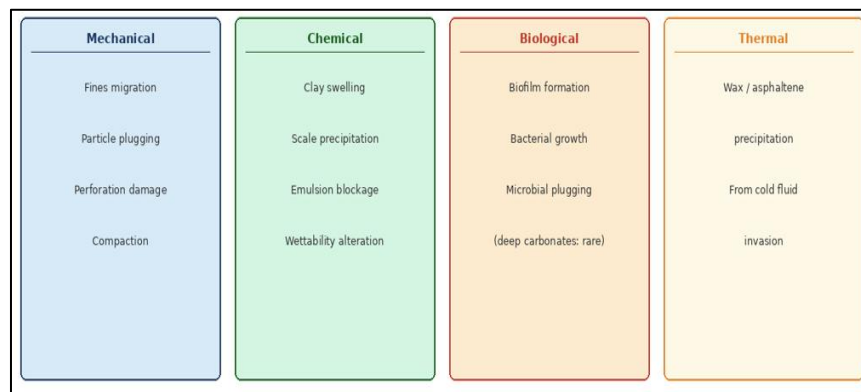


Figure 19. Classification of formation damage mechanisms. (compiled from Economides & Nolte, 2000; Frick & Taylor, 1962)

-Biological damage involves the formation of biofilm by bacteria introduced with injection water.

-Thermal damage results from the invasion of cold fluids that precipitate wax or asphaltene deposits near the wellbore.

V.3. Formation Damage Specific to Carbonate Reservoirs

While all four damage categories apply broadly, some mechanisms are particularly significant in carbonate reservoirs. Calcite scale precipitation is the most prevalent damage in carbonate gas-condensate systems: as gas expands, brine progressively supersaturates with CaCO_3 , since formation water is already near-equilibrium with the carbonate matrix. Acid sensitivity is a second carbonate-specific mechanism uncontrolled acid contact can generate migrating fines or release Fe^{3+} that precipitates as iron hydroxide gel at the pH neutralization front. Fine-grained dolomitic reservoirs amplify all damage mechanisms, since any permeability reduction in already-marginal rock disproportionately affects productivity.

V.4. The Skin Factor as a Quantitative Measure of Damage

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The skin factor (S) is the dimensionless measure of productivity departure from the undamaged theoretical baseline. Formulated by Hawkins (1956), it expresses the additional pressure drop across the damaged zone:

$$S = (k / k_s - 1) \times \ln(rs / rw)$$

k = undamaged permeability; k_s = damaged zone permeability; r_s = damage radius; r_w = wellbore radius. Positive S = damage; negative S = stimulation beyond baseline.

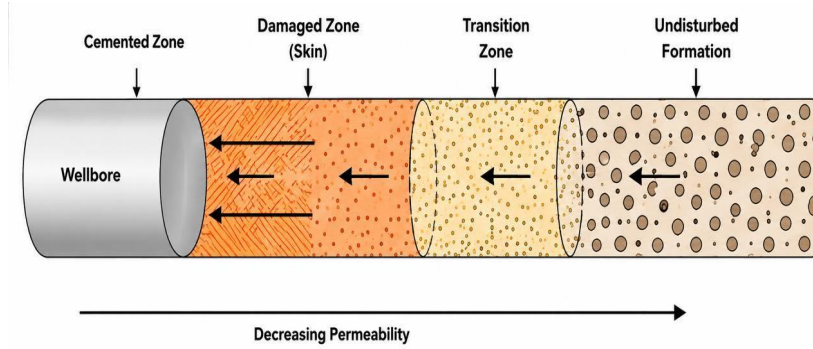


Figure 20. Skin zone schematic

The total skin measured from a pressure transient well test decomposes into its component contributions:

$$S_{\text{total}} = S_e + S_p + S_c$$

Where: S_e = true matrix damage skin; S_p = perforation skin; S_c = partial penetration skin from the limited perforated interval relative to total formation thickness.

Each component demands a different remediation: S_e (true damage) is the target of chemical stimulation; S_p (perforation skin) is addressed by perforating optimization or acid wash; S_c (partial penetration) is geometric, cannot be reduced by stimulation, but must be accounted for when establishing true formation permeability.

VI. Well Stimulation: Concepts, Techniques and Candidate Selection

VI.1. Definition and Objectives of Well Stimulation

Well stimulation is any engineering intervention applied to a well to improve deliverability beyond the level achievable from the natural reservoir and completion state alone (Economides & Nolte, 2000). Two productivity problems motivate stimulation. Damage-limited production underperforms due to reduced near-wellbore permeability; the objective is damage removal. Permeability-limited production lacks sufficient natural permeability regardless of wellbore condition; the objective is permeability bypass an artificial high-conductivity path letting hydrocarbons drain across a much larger contact

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area than the tight matrix can naturally provide. Correctly identifying which problem limits a given well is the first and most critical step in stimulation design.

VI.2. Overview of Stimulation Techniques

Well stimulation methods range from simple wellbore cleanup to more intensive fracturing treatments. Wellbore cleanup removes mud cake and debris near the wellbore but does not improve deeper formation damage or low permeability. Matrix acidizing injects acid below fracture pressure to create wormholes and reduce formation damage, though it is ineffective in very low-permeability reservoirs. Acid fracturing injects acid above fracture pressure, creating conductive fractures that extend deep into the formation and remain productive after closure due to acid etching, making it the preferred technique for tight carbonate reservoirs. Propped hydraulic fracturing is commonly used in sandstones and shales but is generally less effective in deep carbonates because high closure stresses can crush proppants and restrict fracture conductivity.

VI.3. Candidate Well Selection Criteria for Stimulation

Selecting a stimulation candidate requires evaluating four key areas. Reservoir quality must demonstrate hydrocarbon presence, adequate net pay, and permeability below commercial production thresholds. Damage assessment should indicate formation impairment through a positive skin factor or lower-than-expected productivity. Rock properties must confirm suitable mineralogy, acid reactivity, and sufficient mechanical strength. Finally, well geometry must be appropriate, including adequate casing integrity, proper perforation placement, and a well trajectory that is understood relative to the in-situ stress field. All criteria should be satisfied before proceeding with stimulation.

Reservoir Quality	Damage Indicators	Rock Properties	Well Geometry
• Sufficient porosity ($\phi > 4\%$) • Hydrocarbon saturation ($S_w < 50\%$) • Net pay thickness defined • Below commercial permeability threshold without stimulation	• Positive skin factor ($S > 0$) • PI below theoretical potential • Mud filtrate invasion evidence • Scale or clay damage on logs • Fines migration history	• Carbonate mineralogy confirmed • Acid reactivity test positive • Sufficient mechanical strength • Brittle rock behaviour (favours fracture creation)	• Perforation interval in pay • Casing integrity verified • Wellbore trajectory known • Stress orientation relative to well azimuth assessed

Figure 21. Candidate well selection criteria for stimulation in carbonate reservoirs.

VI.4. Justification for Acid Fracturing as the Selected Technique

The candidate well selection analysis indicates that acid fracturing is the most suitable stimulation technique for this tight dolomitic carbonate reservoir with sealed natural fractures. This choice is supported by four key factors:

1. **Extremely low matrix permeability** makes matrix acidizing ineffective, as wormholes provide only limited penetration (typically 1–3 m) and may require injection rates high enough to initiate fracturing.
2. **Dolomitic mineralogy** reacts much more slowly with acid than calcite, requiring emulsified or retarded acid systems to achieve sufficient penetration and effective fracture etching.
3. **Sealed natural fractures** can be reactivated and etched during acid fracturing, while the hydraulic fracture simultaneously creates new flow pathways extending beyond the existing fracture network.
4. **Bounding evaporite layers** above and below the reservoir act as natural barriers to fracture height growth, helping confine the treatment to the productive interval and improving stimulation efficiency.

Chapter 3:

Acid Fracturing in Carbonate Reservoirs

I. Introduction

Acid fracturing is a stimulation method used in carbonate reservoirs where hydrochloric acid is injected at pressures high enough to create a hydraulic fracture while simultaneously dissolving the carbonate rock along the fracture walls. Unlike conventional hydraulic fracturing, which uses proppants to keep fractures open, acid fracturing creates rough, etched surfaces that prevent complete fracture closure under reservoir stress. The remaining open channels provide a highly conductive pathway for hydrocarbons to flow to the wellbore.

The success of acid fracturing depends on balancing two key processes: fracture creation, controlled by reservoir stresses, rock properties, and injection conditions; and fracture-wall etching, controlled by acid type, temperature, carbonate composition, and reaction kinetics. Optimizing this interaction is the main challenge in acid fracturing design.

II. From Hydraulic Fracturing to Acid Fracturing

II.1. Why Propped Fracturing Is Unsuitable for Carbonates

Hydraulic propped fracturing was originally developed for low-permeability sandstone reservoirs, where the formation does not react chemically with the fracturing fluid and where the fracture must be physically kept open by solid proppant after treatment. When applied to deep carbonate reservoirs, propped fracturing encounters two fundamental limitations that progressively reduce its effectiveness. The first is proppant embedment: carbonate rocks particularly tight dolomites have high Young's moduli (40–80 GPa) that generate narrow fracture widths, making proppant transport difficult, while the localized stress concentrations at proppant-to-wall contact points can cause the softer calcite or dolomite surface to yield plastically, embedding the proppant grain and progressively reducing the fracture aperture over the production lifetime of the well. The second limitation is proppant crushing: at the high effective closure stresses typical of deep carbonate reservoirs, conventional sand proppant grains are mechanically crushed, generating fines that migrate and plug the proppant pack, destroying the conductivity that the treatment was designed to create.

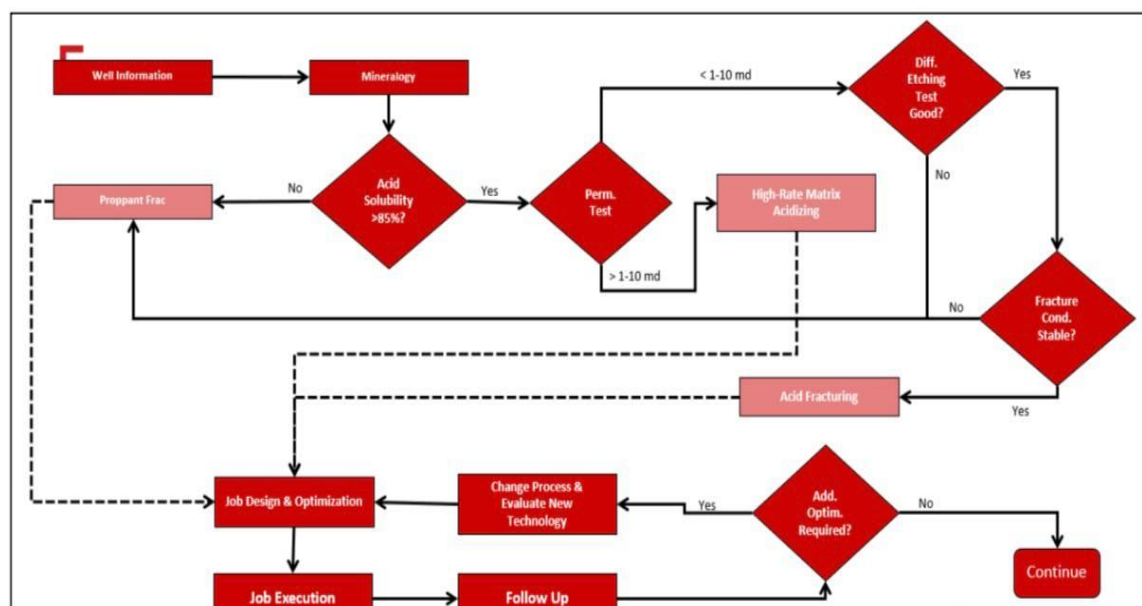


Figure 22. Typical Decision Tree for Oil-Gas Producer Carbonate Formations Stimulation

Criterion	Hydraulic (Propped) Fracturing	Acid Fracturing
Applicable lithology	Sandstone, tight rock (any type)	Carbonates only, limestone, dolomite, chalk
Conductivity mechanism	Proppant pack (sand, ceramic beads)	Differential etching of carbonate fracture walls
Fracturing fluid	Viscous gel or slickwater carrier	HCl-based acid system
Proppant required	Yes, essential	No, etched topography maintains aperture
High closure stress behavior	Proppant crushes → conductivity loss over time	Etched carbonate asperities resist crushing; durable conductivity
Carbonate suitability	Less suitable, proppant embedment risk	Preferred technique for all carbonate reservoirs

Table 3. Comparison between hydraulic fracturing and acid fracturing across key geological and operational criteria.

II.2. The Acid Fracturing Concept and Its Geological Basis

Acid fracturing emerged from the recognition that carbonate rocks react chemically with the injected fluid, and that this reaction can be exploited to create permanent conductivity without any solid proppant. First, carbonate minerals (calcite and dolomite) are soluble in hydrochloric acid at concentrations and temperatures readily achievable in field

operations, producing fully soluble reaction products with no secondary precipitate risk. Second, the diagenetic heterogeneity of carbonate reservoirs the variation in crystal size, mineralogy, cementation intensity, and local porosity at the millimeter to centimeter scale ensures that when acid contacts the fracture wall, dissolution is inherently non-uniform: some zones dissolve rapidly while others dissolve slowly, creating the irregular surface geometry that constitutes the conductivity of the treated fracture. Third, the brittle mechanical character of tight dolomites their high Young's modulus and rapid transition from elastic to brittle failure favors the creation of discrete, planar hydraulic fractures rather than diffuse crushed zones, concentrating acid flow along a defined pathway and maximizing etching efficiency.

II.3. How Carbonate Mineralogy Makes Acid Fracturing Possible

The feasibility and design of an acid fracturing treatment is fundamentally determined by the carbonate mineralogy of the target formation. Calcite (CaCO_3) reacts rapidly with HCl at concentrations as low as 5% at ambient temperature, making it highly responsive to acid fracturing but also prone to rapid acid spending near the wellbore, which limits effective penetration depth. Dolomite ($\text{CaMg}(\text{CO}_3)_2$) reacts 10–100 times more slowly than calcite at equivalent acid concentrations and temperatures, which is initially a disadvantage requiring stronger acid or higher temperatures to achieve useful dissolution but becomes an advantage for deep fracture penetration because the acid travels further along the fracture before being spent. This kinetic difference between calcite and dolomite is the primary criterion governing acid system selection: a treatment designed for a limestone formation may fail completely in a dolomitic formation if the same acid type and concentration are used without adaptation. The carbonate mineralogy therefore functions as the geological input that defines the entire acid system design concentration, type, retardation, and volume making the petrographic and log-based mineralogical characterization a direct prerequisite for effective stimulation design.

III. The Etching Mechanism

III.1. What Is Differential Etching and Why It Happens

Differential etching is not a designed or controlled process in the conventional stimulation sense; it arises spontaneously from the heterogeneous character of the carbonate rock itself and from the spatial gradients of acid concentration and flow velocity that develop naturally within the fracture during injection.

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Three geological factors drive differential etching. The first is mineralogical heterogeneity: in a carbonate rock that contains both calcite cement and dolomite matrix, the calcite phases dissolve far more rapidly than the dolomite phases under the same acid contact conditions, creating dissolution relief that directly reflects the mineral distribution in the original rock. The second factor is textural heterogeneity: in a microcrystalline dolomite, zones with slightly larger crystal size and better-connected intercrystalline pores allow acid to penetrate more rapidly into the matrix behind the fracture face, producing deeper and more irregular dissolution than zones of finer, more tightly packed crystal texture. The third factor is the flow field within the fracture itself: acid is neither uniformly distributed across the fracture width nor uniformly concentrated from inlet to tip. The highest H^+ concentration is at the fracture inlet, where fresh acid first contacts the wall; the lowest is at the tip, where acid has been progressively neutralized. Within any cross-section of the fracture, the acid flows faster in the center and more slowly near the walls, creating a shear-driven concentration gradient that causes the wall to dissolve faster in regions of higher local velocity and acid concentration.

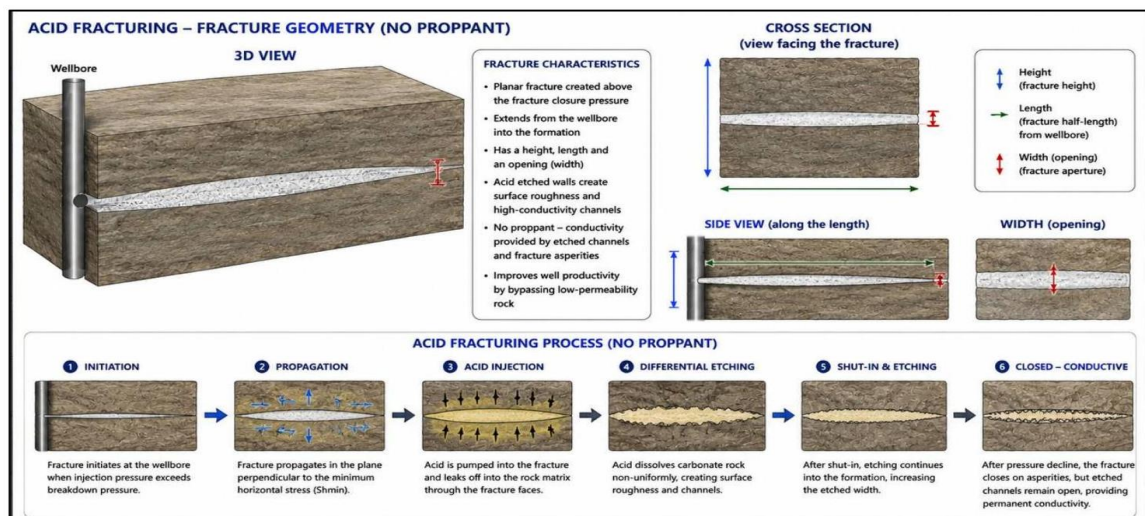


Figure 23. Acid Effects on Carbonate Reservoirs

III.2. The Role of Rock Heterogeneity in Creating Conductivity

The geological heterogeneity of the carbonate reservoir its diagenetic variability, mineralogical contrasts, and textural irregularity is not a complication to be minimized in acid fracturing design, it is the fundamental mechanism through which useful fracture conductivity is created. A perfectly homogeneous, uniform carbonate rock would dissolve uniformly along the entire fracture face, producing a smooth surface that would close

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completely under the in-situ effective stress with essentially zero residual aperture. Only a rock that dissolves non-uniformly produces the peaks and valleys asperities and channels that prevent complete closure and maintain an open flow pathway.

This means that the degree of geological heterogeneity in the target carbonate directly controls the potential conductivity achievable from acid fracturing. Rocks with strong diagenetic contrasts for example, a dolomite with alternating bands of calcite-cemented and dolomite-dominated intervals will produce pronounced differential etching and high residual conductivity. Rocks with very uniform mineralogy and texture for example, a finely crystalline, homogeneous chalk may produce only modest etching relief despite consuming the same acid volume. The petrographic characterization of the target carbonate through thin sections, core photographs, and PEF log analysis therefore serves a dual purpose, it identifies the acid system required, and it provides a qualitative prediction of the degree of differential etching and therefore the expected fracture conductivity achievable from the planned treatment.

III.3. Etching Patterns: Uniform, Channeled and Face Dissolution

The spatial pattern of dissolution on the acid fracture wall is not random but follows one of three characteristic regimes depending on the injection rate, the acid diffusivity, and the reactivity of the rock surface. Understanding which regime dominates in a given formation is essential for predicting the fracture conductivity achievable from a planned treatment.

Conventional Acid Fracturing	Multiple Alternating Fluid (MAFA)	Closed-Fracture Acidising (CFA)	Emulsified / Retarded Acid
Pad → Acid → Flush	Pad→Acid→Pad→Acid	Applied below P _c	HCl dispersed in oil
Single acid stage	Multiple alternating stages	After fracture closes	Slows reaction rate
Simplest approach	Maximises etched area	Improves near-wellbore	Deeper penetration
Moderate T, limestone	High leakoff formations	conductivity	High T / dolomite

Figure 24. Four principal types of acid fracturing systems and their associated etching behavior.

Uniform face dissolution occurs when the acid reaction rate is so high relative to the transport rate that H^+ ions are consumed almost instantaneously at the fracture face before any significant lateral variation in dissolution depth can develop. The result is a smooth, uniformly dissolved surface that, when the fracture closes, provides little resistance to complete closure and essentially zero residual conductivity. This regime is most likely with highly reactive 28% HCl in contact with a calcite-rich limestone at elevated temperature conditions that are deliberately avoided in acid fracturing design. Channeled etching the optimal regime for acid fracturing occurs at intermediate reaction rates where dissolution is fast enough to create significant relief but slow enough for lateral contrasts in dissolution depth to develop before the acid is spent. Deep, narrow channels separated by undissolved or less-dissolved asperities characterize this regime, and it produces the maximum residual conductivity for a given acid volume. Channeled etching is promoted by high-viscosity acid systems (emulsified or gelled acid), which slow the diffusion of H^+ to the rock surface and allow lateral concentration gradients to develop. Wormhole-dominated etching at the fracture face occurs when the treating pressure is close to the closure pressure and the acid partially invades the matrix behind the fracture wall, creating a zone of dissolved matrix porosity rather than a clean surface channel. This regime reduces the mechanical strength of the asperities and may cause them to collapse under closure stress, limiting the durability of the achieved conductivity.

III.4. Wormhole Dissolution

Wormhole dissolution is a distinct acid-rock interaction regime that occurs when acid is injected below the fracture closure pressure and flows through the existing pore network of the formation rather than along an open hydraulic fracture. At the optimal injection rate characterized by the Damköhler number, which expresses the ratio of acid reaction rate to acid transport rate a single dominant wormhole propagates efficiently through the formation, achieving maximum penetration depth per unit acid volume. The resulting dissolution geometry is three-dimensional and branching, extending radially 1–3 m from the wellbore through the most permeable pathways in the pore network.

Wormhole dissolution and fracture etching are not mutually exclusive, in a treatment where injection rate is ramped from below to above closure pressure, wormhole dissolution occurs first in the near-wellbore region before the fracture opens, and fracture etching dominates once the fracture is fully propagating. In tight carbonate reservoirs with matrix permeability below 1 mD however, the injection rate required to reach the

optimal wormhole propagation regime approaches or exceeds the fracture initiation pressure before efficient wormhole development occurs, rendering standalone matrix acidizing ineffective and making fracture-based acid injection the only viable stimulation approach.

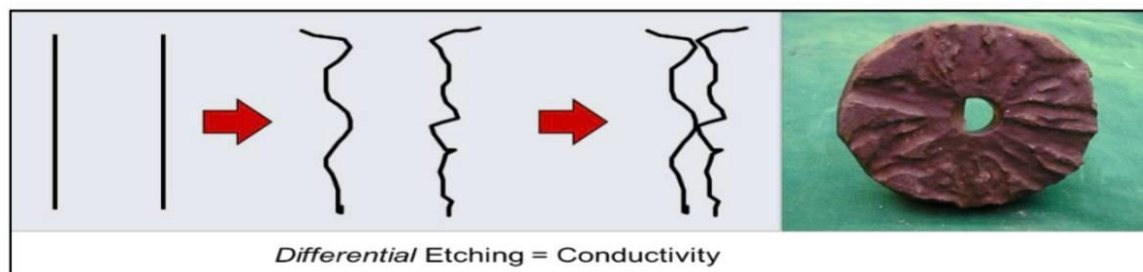


Figure 25. The Conductivity in Carbonate Reservoirs

IV. Channeling

Channeling is the development of preferential dissolution pathways along discrete zones of the fracture wall, driven by the positive feedback between local acid concentration, flow velocity, and mineral reactivity. Where dissolution begins preferentially at a calcite cement patch, a coarser crystal zone, or a local flow velocity maximum the dissolving zone widens slightly, attracting more acid flow, accelerating further dissolution, and progressively deepening into a channel. The resulting fracture wall geometry is a network of deep narrow dissolution channels separated by load-bearing carbonate ridges whose spacing and depth are controlled by the diagenetic fabric of the rock.

The geometry of channels their width, depth, and spacing are governed primarily by the carbonate heterogeneity at the fracture face scale. In a rock with strongly banded diagenetic fabric alternating calcite-cemented and dolomite-dominated layers channels form preferentially in the calcite-rich bands, producing elongated dissolution features aligned with the bedding. In a rock with random diagenetic heterogeneity scattered calcite cement patches in dolomite matrix channels are more irregularly distributed but produce a higher density of short, deep features per unit fracture area. In a very uniform, homogeneous carbonate, channel development is suppressed and dissolution tends toward the less productive uniform face dissolution regime.

V. Fracture Conductivity

The permanent conductivity of an acid-fractured carbonate derives entirely from the channel-and-asperity surface relief created by differential etching and channeling. When injection ends and the fracture closes, the walls make first contact at the highest asperity points. As effective closure stress increases, load concentrates progressively on the asperity contacts, which deform elastically then plastically as local stress exceeds the compressive strength of the carbonate. The channels remain open, sustained by the mechanical resistance of the flanking asperities. The residual aperture of these open channels the effective fracture permeability after treatment depends on two geological factors: the depth contrast between channels and asperities, which is a direct function of differential etching intensity, and the embedment strength of the asperity rock, which governs how much the contact zones compact under sustained closure load.

V.1. The Nierode-Kruk Conductivity Concept

The relationship between acid volume, rock embedment strength, closure stress, and the resulting fracture conductivity was systematically quantified by Nierode and Kruk (1973) in the first comprehensive experimental study of acid fracture conductivity. Their work established that the conductivity of an acid-etched fracture decreases exponentially with increasing effective closure stress a relationship that reflects the progressive compression of the asperities and the narrowing of the open channels as the net stress on the fracture walls increases. The key geological insight from their study was that the rock embedment strength the resistance of the carbonate surface to permanent deformation under point contact load from an asperity is the single most important rock property governing conductivity durability. Rocks with high embedment strength (corresponding to high UCS and tight crystal packing) maintain substantially higher conductivity at elevated closure stresses than rocks with low embedment strength, for the same etching geometry and the same acid volume. Dolomite, with its more rigid crystal lattice and higher typical UCS compared with limestone, generally exhibits higher embedment strength and therefore more durable acid fracture conductivity under the high closure stresses of deep formations a geological advantage that contributes to the effectiveness of acid fracturing in dolomitic reservoirs.

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V.2. Factors That Destroy Conductivity: Embedment, Fines and Scale

Several geological and operational mechanisms act to reduce or eliminate acid fracture conductivity after treatment. Asperity embedment the plastic deformation of asperity contact zones under sustained closure stress is the most fundamental and irreversible mechanism. It is most severe in soft carbonates (chalks, argillaceous limestones) at high closure stresses and cannot be reversed by any post-treatment intervention. Fines migration occurs when the dissolution of calcite cement or dolomite matrix releases fine carbonate particles that are not fully displaced by the flush stage; these particles settle into the channel apertures during flow-back, progressively plugging the conductivity pathways. The risk of fines migration is highest in mechanically weak carbonates and in treatments where the flush stage volume is insufficient to displace all reaction products from the fracture before closure.

VI. Acid Types and Systems

The selection of the appropriate acid system is one of the most consequential decisions in acid fracturing design because the acid system directly determines the etching regime, the effective penetration distance, and the channel geometry that will develop in the treated fracture. In field practice as experienced during oilfield service operations at companies such as Halliburton the acid system is selected from a menu of options whose properties span a wide range of viscosity, reactivity, and retardation mechanism, each optimized for a specific set of formation conditions. Table 4 presents the principal acid systems used in carbonate fracturing treatments worldwide.

Acid System	Base Fluid	Viscosity	Retardation Mechanism	Best Application
Regular HCl	15–28% HCl	~1 cP	None, fast reaction	Limestone, moderate temperature, near-wellbore
Emulsified Acid	HCl in oil emulsion	50–200 cP	Oil film limits H ⁺ diffusion to rock surface	Deep dolomite stages; high temperature formations
Retarded HCl	HCl + chemical retarder	~1–5 cP	Retarder adsorbs on carbonate surface	High-T formations; extended penetration

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				needed
Gelled Acid	HCl + polymer gel	20–100 cP	Viscosity reduces H ⁺ transport to surface	High leakoff formations; wide fracture needed
Viscoelastic Acid	HCl + VES surfactant	Medium	VES micelles retard diffusion; self-diverting	Heterogeneous intervals; natural fracture diversion
Foamed Acid	HCl + N ₂ or CO ₂	Very low	Foam structure reduces fluid contact	Low-pressure wells; excellent cleanup; thin pay

Table 4. Principal acid systems used in carbonate fracturing treatments. (Economides & Nolte, 2000; Schechter, 1992); Halliburton Technical Manual)

The selection of the acid system is governed by three geological parameters carbonate mineralogy, formation temperature, and desired penetration depth and determines directly which dissolution regime will dominate in the treated fracture.

V.1. Regular HCl (15–28%)

is the baseline system. It reacts rapidly with calcite, spending within 3–8 m of the wellbore at temperatures above 80°C in limestone, making it suitable only for near-wellbore stages or moderate-temperature formations. In dolomite, the inherently slower reaction rate extends spending distance to 20–40 m under the same conditions.

V.2. Emulsified acid

such as Halliburton's HalED system disperses HCl as the internal phase within a continuous oil phase, achieving viscosities of 50–200 cP. The surrounding oil film imposes a physical mass-transfer barrier that reduces H⁺ diffusivity to the fracture wall by a factor of 10–100, extending effective etching distances to 80–150 m in hot dolomitic formations. It remains the primary deep-penetration system for high-temperature carbonate reservoirs.

V.3. Chemically retarded acid

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achieves slower reaction rates through adsorption of a retarding agent onto the carbonate surface, forming a protective film between the acid and the mineral. It is most effective at moderate temperatures (60–100°C) where intermediate penetration distances of 20–60 m are sufficient.

V.4 Gelled

acid uses polymer thickeners (guar, HEC) to achieve viscosities of 20–100 cP, improving leakoff control and fracture width. It is less effective as a retarder than emulsified acid because the polymer network does not prevent H^+ diffusion to the fracture wall and degrades rapidly at elevated temperatures.

V.5. Viscoelastic surfactant (VES)

acid forms worm-like micelles that increase viscosity as spent acid pH rises, creating a self-diverting mechanism that redirects fresh acid toward less-etched or lower-permeability intervals. The system is self-breaking at reservoir temperature, requiring no breaker additives and facilitating post-treatment cleanup.

V.6. Foamed acid

co-injects HCl with N_2 or CO_2 at 50–70% gas quality, producing very low matrix leakoff and excellent cleanup through gas expansion during flow-back. It is the preferred system for low-pressure, depleted reservoirs where minimizing total liquid volume is critical.

Acid system selection follows a mineralogy-temperature matrix: regular HCl for calcite at moderate temperature, emulsified or retarded acid for dolomite or any carbonate above 90°C, and a staged multi-system approach for mixed calcite-dolomite formations.

VI. Acid Additives

No acid fracturing treatment is performed with acid alone. A carefully formulated package of chemical additives is required alongside the base acid system to address the simultaneous operational challenges of equipment protection, reservoir compatibility, fluid loss control, and post-treatment cleanup. The composition of the additive package is tailored to the specific conditions of each treatment formation temperature, acid concentration, reservoir fluid composition, and well completion design and is a critical part of the overall treatment design.

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Additive	Primary Function	Geological and Operational Significance
HCl Raw Acid	Base dissolving agent for carbonate minerals (calcite and dolomite)	15–28% concentration selected based on mineralogy and temperature; higher concentration increases dissolving capacity but accelerates acid spending in the near-wellbore region
Surfactant	Prevents stable emulsions between acid and crude oil; reduces interfacial tension; improves post-treatment cleanup	Ensures spent acid and reaction products are efficiently displaced during the flush stage; critical in gas-condensate reservoirs where condensate contacts the treating acid
Gelling Agent	Increases acid viscosity (20–100 cP); controls fluid loss from fracture face; widens fracture geometry	Polymer thickener (guar, HEC, or synthetic acid-stable polymer); improves fluid efficiency but degrades at elevated temperatures and is not a reliable retarder above 100°C
Iron Reducer	Reduces Fe^{3+} to Fe^{2+} before acid contacts the formation, preventing iron hydroxide precipitation at the pH neutralisation front	Applied when formation minerals or tubular corrosion contribute high Fe^{3+} to the acid; prevents gelatinous $\text{Fe}(\text{OH})_3$ precipitation that plugs etched channels and destroys fracture conductivity
Iron Chelating Agent	Forms stable soluble complexes with Fe^{3+} across the full pH range, maintaining iron in solution throughout the treatment cycle	EDTA or citric acid-based; complements the iron reducer by preventing re-precipitation as spent acid pH rises during carbonate neutralisation; essential in iron-rich formations
Acid Retardant	Adsorbs onto the carbonate surface to reduce the H^+ contact rate and extend the acid spending distance along the fracture	Critical for deep-penetration stages in dolomitic or high-temperature formations; extends effective etching distance from 3–8 m (regular HCl) to 20–60 m; used in combination with emulsified systems at extreme temperatures
Fluid Loss Control	Reduces acid leakoff through the fracture face and reopened natural fractures; deposits a thin filter cake on fracture walls	Preserves acid volume for deep fracture etching rather than matrix invasion; particularly important in formations with a sealed natural fracture network that may partially reopen under treating pressure
Mutual Solvent	Maintains compatibility between the acid and reservoir fluids; prevents sludge and asphaltic deposit formation	Prevents asphaltic or wax precipitation when acid contacts crude oil components in the near-wellbore region; improves wettability of fracture walls and facilitates efficient post-treatment cleanup

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Corrosion Inhibitor	Protects tubing, casing and wellhead from HCl attack by forming a protective molecular film on the metal surface	Mandatory for all HCl concentrations above 5%; required concentration increases with temperature — high-temperature formulations with intensifiers (e.g. copper salts) required above 120°C
Diverter	Temporarily blocks the most conductive zones of the fracture to redirect subsequent acid cycles toward less-etched, lower-permeability intervals	Pumped between acid cycles (HCl and CSA stages) to improve uniformity of etching along the fracture length; can be mechanical or chemical, selected based on perforation geometry, fracture complexity, and formation temperature

Table 5. Chemical additives used in acid fracturing treatments. (Economides & Nolte, 2000; Halliburton Technical Manual, 2010)

VII. Treatment Design Principles

VII.1. Injection Test and MiniFrac: Purpose and Stages

The injection test is performed before any acid fracturing treatment to replace preliminary design estimates with direct field measurements of the actual formation response, and to confirm wellbore integrity before the acid stages are committed.

Loading the well: usually Treated water is injected at a low controlled rate to displace residual completion fluid, confirm wellbore acceptance of fluid, and establish the hydrostatic reference pressure for converting surface pressures to bottomhole values throughout the test.

Breakdown: usually by Linear gel is injected at the planned treating rate above the fracture closure pressure to initiate and propagate a hydraulic fracture. Linear gel is selected for its moderate viscosity, which creates sufficient fracture width for meaningful pressure decline analysis while minimizing friction-related uncertainties in the bottomhole pressure calculation.

Displacement: Treated water displaces the linear gel from the tubing into the fracture before shut-in, ensuring that the bottomhole pressure gauge records the true formation response rather than fluid standing in the tubing. The well is then shut in and the pressure decline recorded for data frac monitoring.

Data frac monitoring: Bottomhole pressure is continuously recorded during shut-in and analyzed in real time using G-function and square root of time methods to extract the key fracture and formation parameters.

- **Bottomhole Instantaneous Shut-In Pressure (BH ISIP)**

The BH ISIP is the bottomhole pressure recorded at the exact moment pumping stops, before any pressure decline occurs. It is calculated from the surface shut-in pressure by adding the hydrostatic head and subtracting tubing friction at shut-in. It represents the sum of the fracture closure pressure and the residual net pressure in the fracture at shut-in, and serves as the upper reference point for the entire pressure decline analysis.

- **G-Function**

The G-function, developed by Nolte (1979), is a dimensionless time function that linearizes the post-shut-in pressure decline for ideal Carter leak-off. On the $G \times dP/dG$ versus G diagnostic plot, ideal leak-off produces a straight line through the origin. The fracture closure pressure is identified at the point where this derivative departs from linearity. Deviations from the straight line indicate complex leak-off behavior pressure-dependent leak-off from natural fractures or fracture height recession requiring design adjustment.

- **Square Root of Time Plot**

The square root of time plot graphs bottomhole pressure against the square root of shut-in time. For ideal leak-off, the relationship is linear and the closure pressure is identified at the departure from the straight line. It complements the G-function analysis and is particularly sensitive to early-time behavior and fracture height recession events.

- **Closure Pressure (P_c)**

The closure pressure is the in-situ minimum horizontal stress S_{hmin} the pressure at which the fracture transitions from hydraulically open to mechanically closed as bottomhole pressure declines after shut-in. It is the most critical parameter from the injection test: it defines the minimum treating pressure required to keep the fracture open during acid injection, determines the effective closure stress on the etched fracture walls after treatment, and is the reference for all net pressure calculations.

- Fluid Efficiency (η)

Fluid efficiency is the ratio of fracture volume created at end of injection to total fluid volume injected: $\eta = V_{\text{fracture}} / V_{\text{total injected}}$

It quantifies the fraction of injected fluid that contributes to fracture extension rather than leak-off. High η is typical in tight carbonate matrices; low η indicates significant leak-off through natural fractures and requires larger pad volumes to achieve the target fracture geometry.

- Net Pressure (P_{net})

Net pressure is the excess of bottomhole treating pressure over the fracture closure pressure: $P_{\text{net}} = \text{BHP} - P_c$

It represents the hydraulic force driving fracture opening and propagation.

Monitored in real time during injection, it is the primary diagnostic of fracture behavior: increasing P_{net} confirms confined PKN propagation; a steeper slope indicates height growth; declining P_{net} during injection signals natural fracture opening or transition to unconfined geometry.

Temperature log: After shut-in, a temperature log is run along the treated interval to identify the main cooling anomaly the zone of maximum temperature reduction that marks where the fracture opened and where the greatest fluid volume was placed. It confirms fracture placement within the target carbonate interval and provides fracture height information that pressure decline analysis alone cannot resolve.

Model calibration and redesign: The pressure decline data and temperature log results are used to match and recalibrate the fracture propagation model adjusting the leak-off coefficient, fracture height, and fracture compliance until the model reproduces both the observed pressure decline and the temperature-derived fracture geometry. The matched model is then used to redesign the main acid treatment with volumes, rates, and stage sequence recalculated from real formation parameters.

VII.3. Acid Treatment Stages

The main acid fracturing treatment is executed as a defined sequence of stages, each serving a specific chemical or mechanical function within the overall treatment program.

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The sequence is designed on the basis of the recalibrated model from the injection test, with volumes, rates, and fluid systems adjusted to the real formation parameters.

Pre-flush with Mutual Solvent: The treatment opens with a pre-flush of mutual solvent ahead of the acid. Its purpose is to displace residual hydrocarbons from the perforation tunnels and the near-wellbore fracture face, wet the carbonate surface with a water-compatible film, and prevent stable emulsions from forming when the subsequent acid contacts crude oil or condensate components. This stage is particularly important in gas-condensate reservoirs where condensate saturation near the wellbore is elevated.

Pad Stage: A viscous pad typically cross-linked gel or linear gel is injected above the closure pressure to extend the fracture to a preliminary width and half-length before any acid contacts the formation. The pad establishes sufficient fracture width typically 3–8 mm at the wellbore so that subsequent acid stages enter the fracture as a flowing film in full contact with both walls rather than spending immediately at the perforations. Without an adequate pad, acid would be consumed in the near-wellbore region without creating any deep fracture etching.

Acid Stages: The acid stages are injected in alternating cycles within the open fracture — a pumping strategy designed to maximize the total etched fracture area and extend effective acid penetration beyond what a single continuous acid stage would achieve. Each cycle consists of two acid systems pumped in sequence, 15% HCl, which reacts rapidly with the most accessible carbonate phases and initiates etching of the near-fracture surface, followed by Carbonate Stimulation Acid (CSA), a viscous gelled acid system whose elevated viscosity reduces fluid loss from the fracture face, widens the fracture geometry, and improves acid distribution along the fracture length. Between each cycle, a diverter is pumped to redistribute the subsequent acid away from the already-etched and higher-conductivity zones toward the less-etched, lower-permeability sections of the fracture, improving the uniformity of etching across the entire treated interval. The alternating sequence (Pad, HCl, CSA, Spacer, diverter) is repeated typically two to four times depending on the target fracture half-length, the formation temperature, and the fluid efficiency measured from the injection test. The number of cycles and the volume of each stage are determined from the recalibrated fracture propagation model to deliver the planned acid penetration depth under real formation conditions

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Displacement: After the final acid stage, treated water is injected in a volume equal to the tubing capacity below the perforations to displace all residual acid and reaction products from the tubing and perforations into the fracture body before closure. Spent acid left standing in the perforation tunnels will precipitate secondary damage iron hydroxide gel, calcite scale, or asphaltic deposits as its pH rises during neutralization, permanently blocking the entry points to the fracture and negating the conductivity improvement achieved by the treatment.

Closed-Fracture Acidizing (CFA): After the fracture has fully closed, a final acid volume is injected below the closure pressure. The acid enters the closed fracture through the residual aperture between asperities and etches the fracture face from the inside, specifically targeting the near-wellbore section where flow velocities and pressure drops are highest during production. CFA improves near-wellbore fracture conductivity, addresses tortuosity in the fracture geometry near the wellbore, and ensures that the section of the fracture carrying the highest production rates has the highest possible conductivity for long-term well deliverability.

Chapter 4:

Case Study

I. Introduction

Acid fracturing in tight carbonate reservoirs represents one of the most technically demanding challenges in petroleum engineering requiring the simultaneous optimization of fracture mechanics, acid-rock chemistry, and completion design to unlock hydrocarbons from formations that would otherwise remain unproductive. The Hassi R'mel LD2 reservoir, with its sub-millidarcy matrix permeability, sealed natural fracture network, and diagenetically complex dolomitic carbonates, is precisely this type of reservoir. The case study presented here analyses acid fracturing operations performed on three wells a deviated calcite-dominated well, a vertical dolomite-dominated well, and a horizontal well each treated using the engineering framework developed in the preceding chapters. The three-well dataset provides a controlled comparison of the two variables that most strongly govern treatment outcome in the LD2: carbonate mineralogy and well orientation. By following a consistent analytical workflow across all three wells from log-based geological characterization through injection test calibration, treatment design, and real-time execution analysis, this study derives field-validated conclusions about the parameters controlling acid fracturing performance in tight carbonate reservoirs and translates them into actionable recommendations for the continued development of the LD2 play at Hassi R'mel.

II. Acid Fracturing Surface Equipment Layout

The acid fracturing operation requires a set of surface equipment deployed and configured at the wellsite prior to treatment execution. The equipment spread includes high-pressure pumping units responsible for delivering fluid at the planned injection rates, blending and mixing systems ensuring accurate fluid formulation and additive set points, fluid storage and supply units, and a wellhead isolation tool protecting the surface installation during high-pressure injection. Real-time monitoring and treatment control are performed from a dedicated command center, allowing continuous supervision of treating pressure, injection rate, and fluid properties throughout all treatment stages.

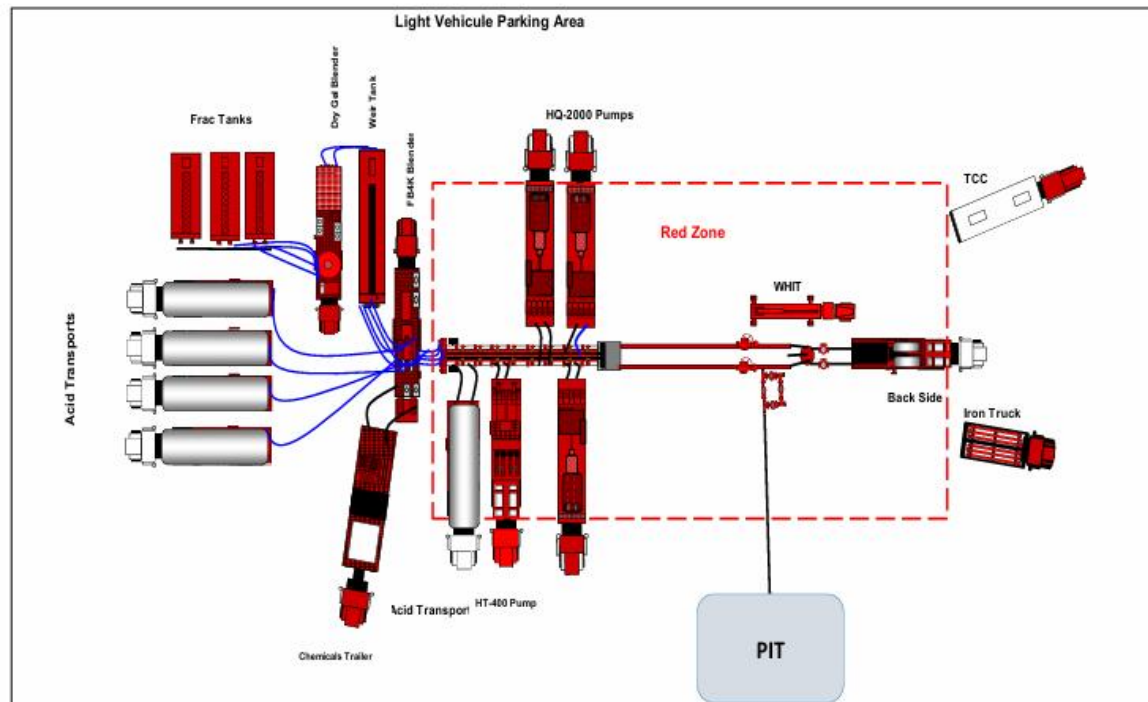


Figure 26. Surface Equipment Layout used for Acid Fracturing Operation (HALLIBURTON)

Chapter 4

III. Presentation of the Three Study Wells

III.1. HRX-1 Well: Deviated Well, Calcite-Dominated Interval

III.1.1. Log Interpretation and Lithological Characterization

HRX-1 is a deviated gas well targeting the LD-2 carbonate reservoir completed with cemented production liner. The well was selected for an acid frac treatment to increase flow capacity and transmissibility of the reservoir. The stratigraphy log shows that the LD-2 section is mainly dominated by calcite. The GOHFER 3D mechanical earth model indicates that the minimum horizontal stress within this interval is lower than in the bounding layers, confirming natural fracture height containment and favorable conditions for acid fracture initiation and propagation.

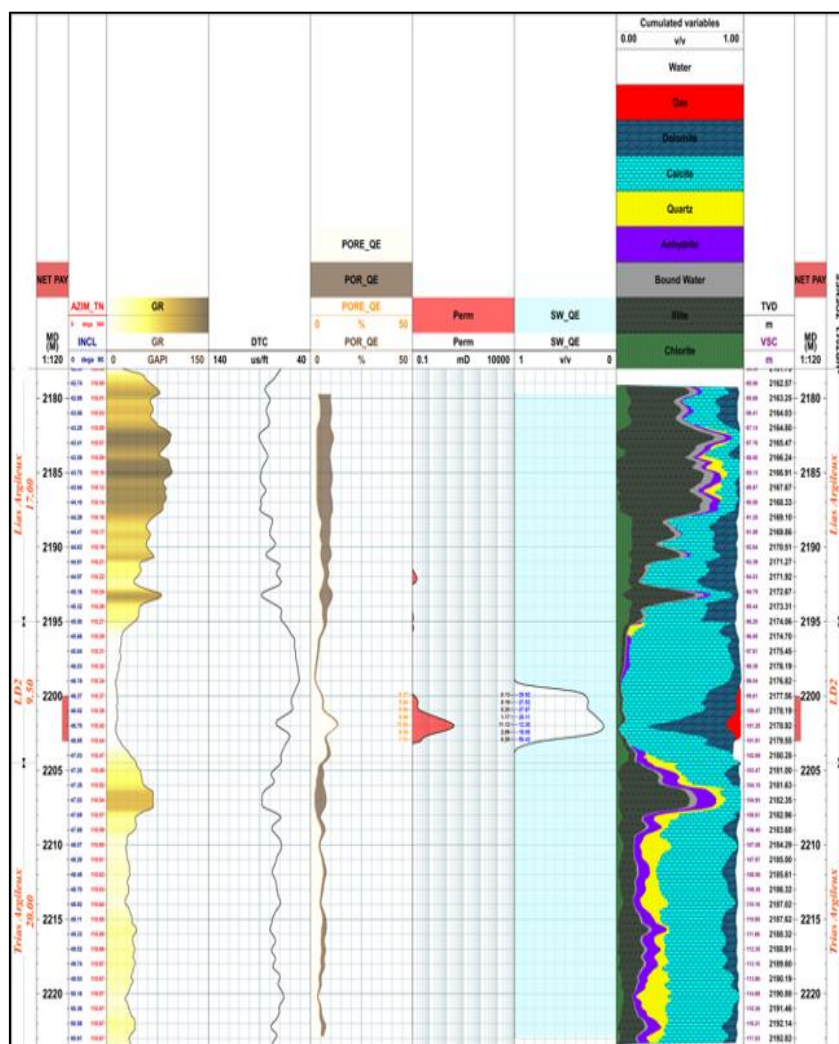


Figure 27. Stratigraphy Log — HRX-1.

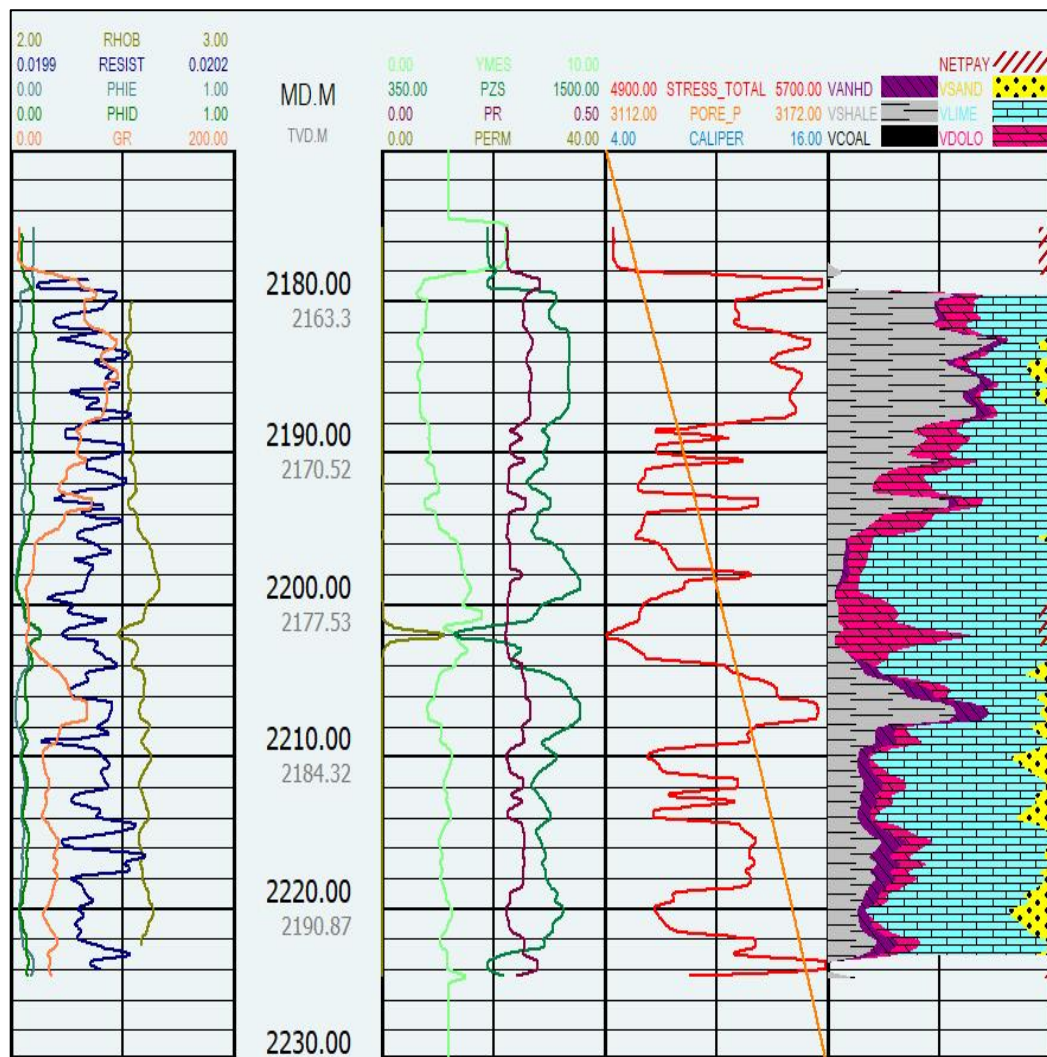


Figure 28. GOHFER 3D Log Interpretation (Geomechanics) — HRX-1.

III.1.2. Injection Test Analysis

The injection test started by filling the well with treated water, reaching a breakdown pressure of approximately 7,200 psi, confirming fracture initiation in the target interval. The treating pressure then stabilized at approximately 4,000 psi during stable fracture propagation at 15 bpm using linear gel, then displaced with treated water. At the final stage the pumps were shut down and the ISIP was recorded at approximately 6,500 psi at surface, providing the reference pressure for the subsequent G-function and square root of time pressure decline analysis.

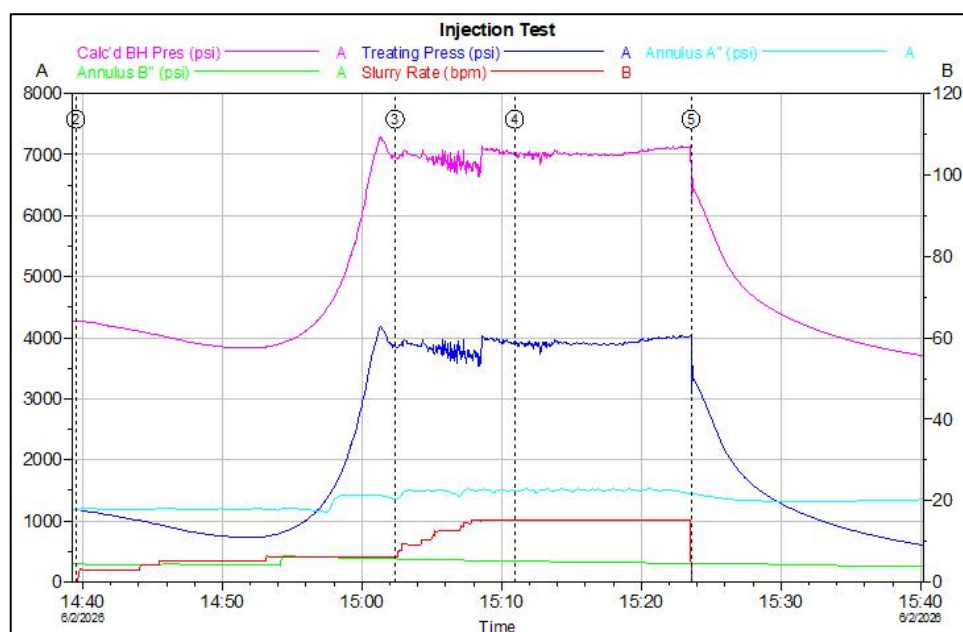


Figure 29. Injection Test — HRX-1.

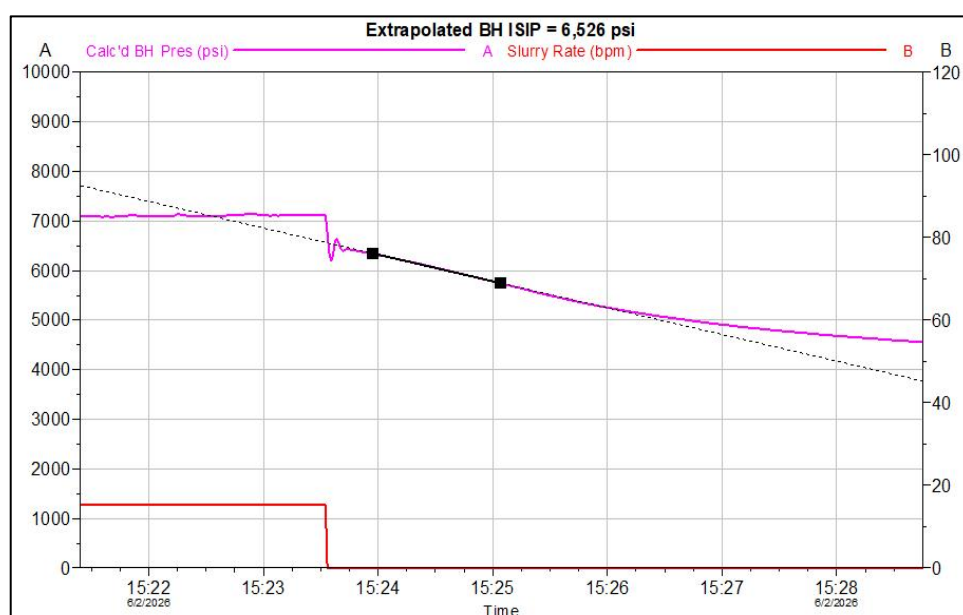


Figure 30. Extrapolated Bottom Hole ISIP — HRX-1.

III.1.3. Injection Test Analysis Summary

After pressure monitoring, the G-function analysis identified fracture closure at a bottomhole pressure of 5,521 psi, with the derivative following a straight line through the origin confirming ideal Carter-type leakoff behavior. The square root of time plot confirmed closure at the same pressure, with no secondary inflections indicating complex leakoff behavior. The key parameters extracted are: closure pressure 5,521 psi, net pressure 1,000 psi, and fluid efficiency 10.73%. These values were used to recalibrate the fracture propagation model for the main acid treatment design.

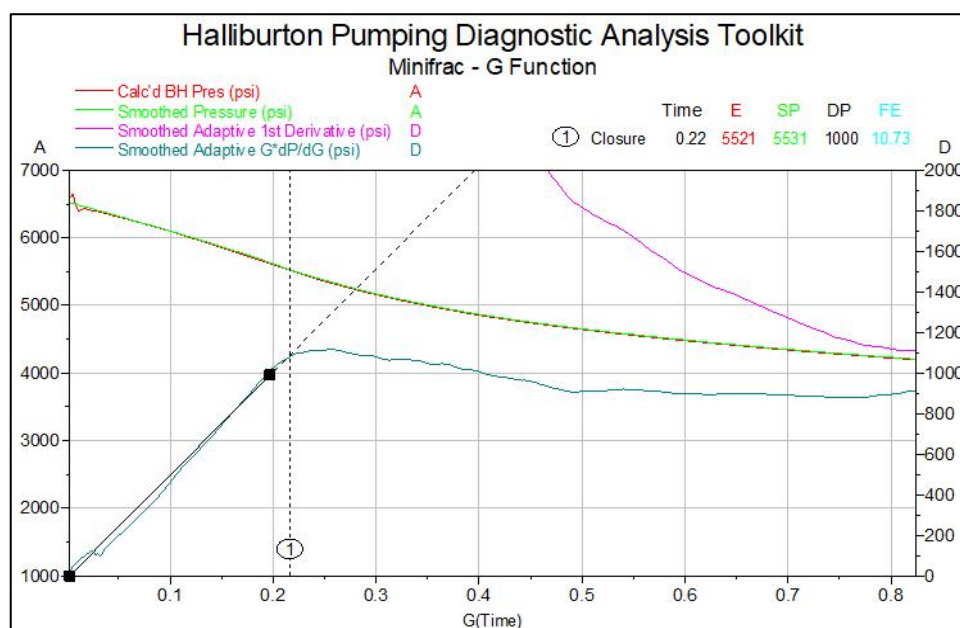


Figure 31. G-Function Plot — HRX-1.

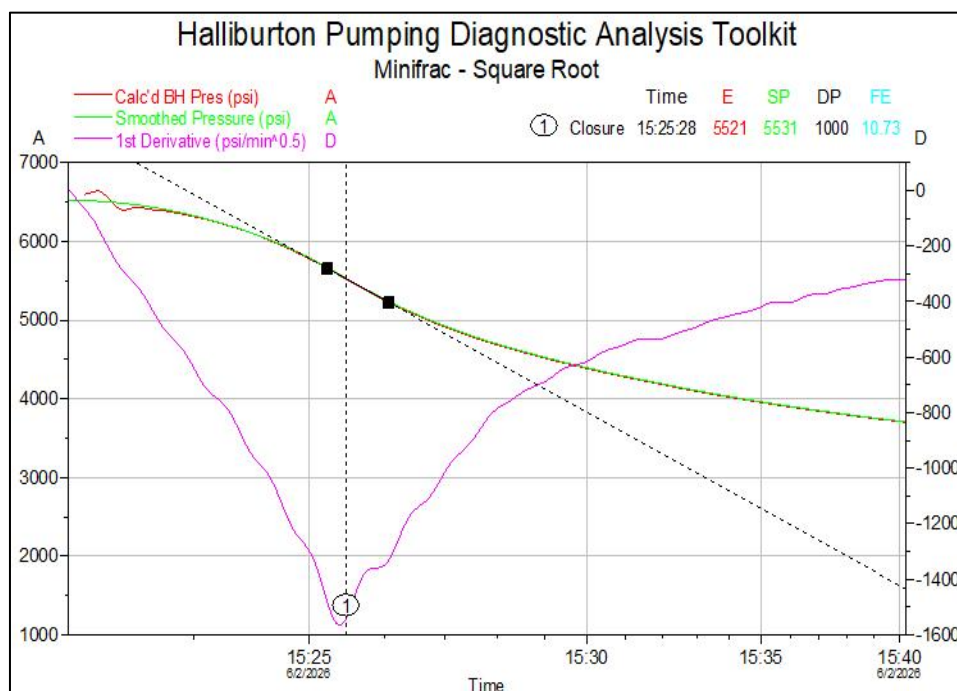


Figure 32. Square Root Plot — HRX-1.

III.1.4. Temperature Log and Model Calibration

The temperature log run after the injection test confirmed fluid placement within the target interval. The main cooling anomaly was observed directly in the lower part of the perforated interval, confirming that the fracture initiated and the fluid was placed within the LD2 productive zone.

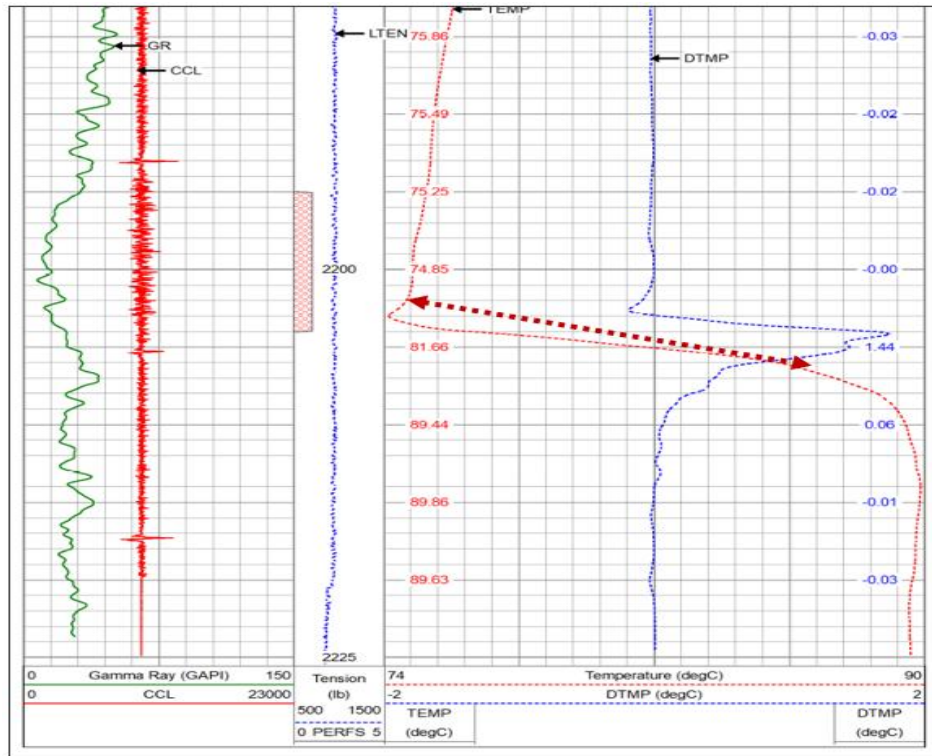


Figure 33. Post Injection Test Temperature Log — HRX-1.

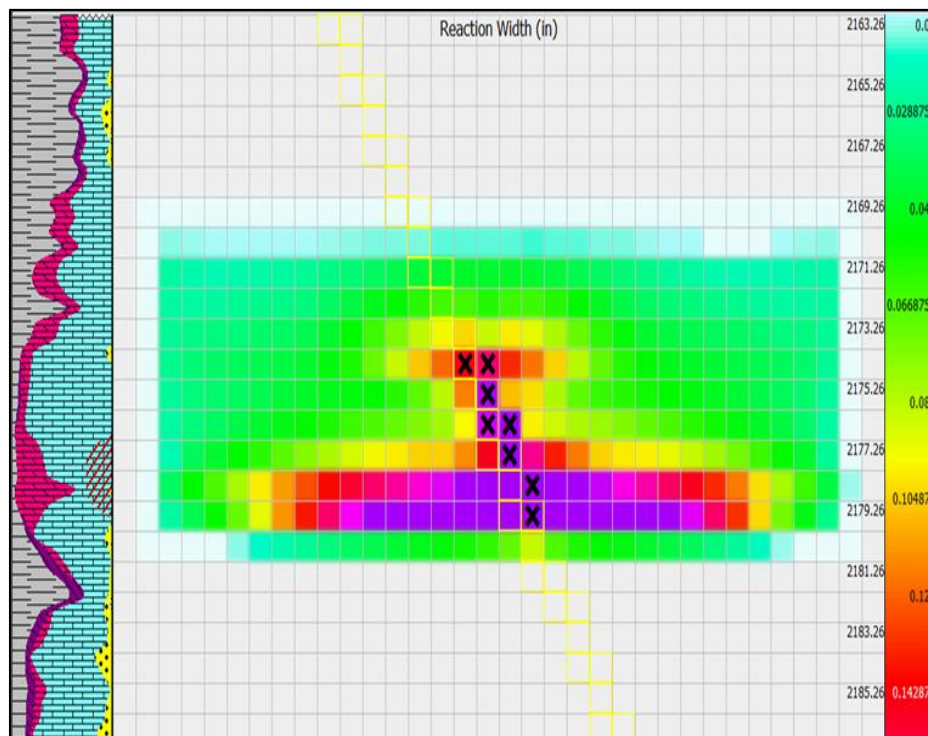


Figure 34. Geometry Matching and Model Calibration — HRX-1.

III.1.5. Acid Treatment Design and Pumping Schedule

The acid fracturing treatment was designed based on the recalibrated fracture propagation model, with a total fluid volume of 49,000 gallons at 15 bpm.

Stage Description	Fluid Description	Clean Volume (gal)	Slurry Rate (bbl/min)
Pre-Flush	Mutual Solvent	3,000	2 - 8
Displacement	Treated Water	6,000	8
Shut In	-	-	-
Pre-Pad	Linear Gel 25#	1,000	2 - 15
Pad	Linear Gel 25#	2,000	15
Retardant Acid	Acid 15% HCL X-Tend 180F	4,500	15
Carbonate Stimulation Acid	CSA 15% 180F	4,500	15
Pad	Linear Gel 25#	2,000	15
Retardant Acid	Acid 15% HCL X-Tend 180F	4,500	15
Carbonate Stimulation Acid	CSA 15% 180F	4,500	15
Displacement	Treated Water	6,500	15
Shut-In	Shut-In for closure time	-	-
Closed Fracture Acid	X-Tend CFA 28% HCL 180F	3,000	2 - 5
Over- Displacement	Treated Water	7,500	5
Shut-In	-	-	-
Total		49,000	

Figure 35 Acid Frac Pumping Schedule — HRX-1.

III.1.6. Acid Treatment Plots and Real-Time Analysis

The acid fracturing treatment of HRX-1 Well was executed successfully across all planned stages. The pre-flush, two acid cycles, and CFA stage were pumped at the designed rates and volumes without anomalies, confirming stable fracture propagation and effective acid placement within the target LD2 interval throughout the treatment.

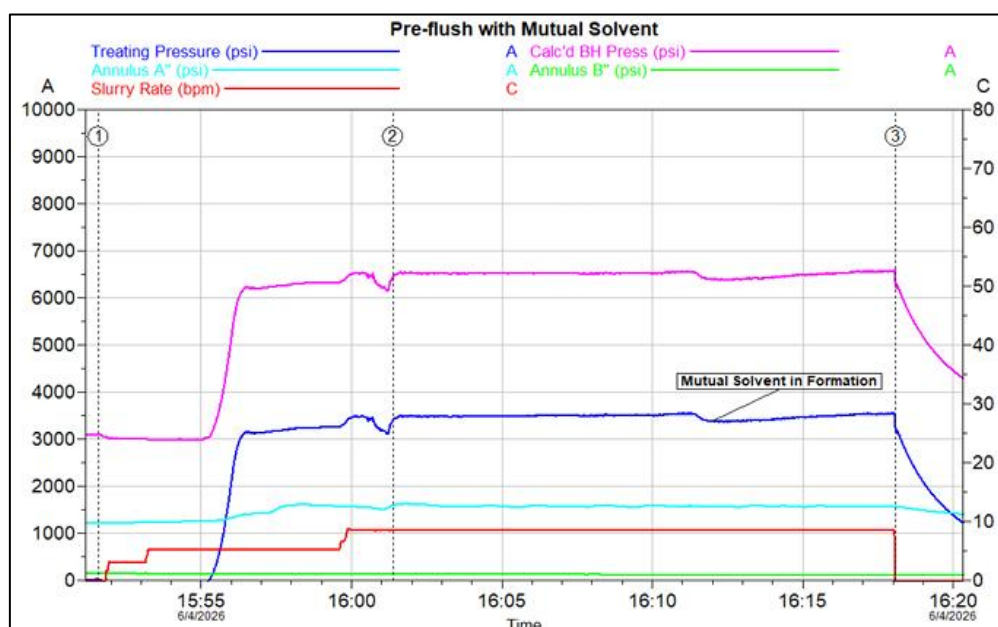


Figure 36. Pre-flush with Mutual Solvent — HRX-1.

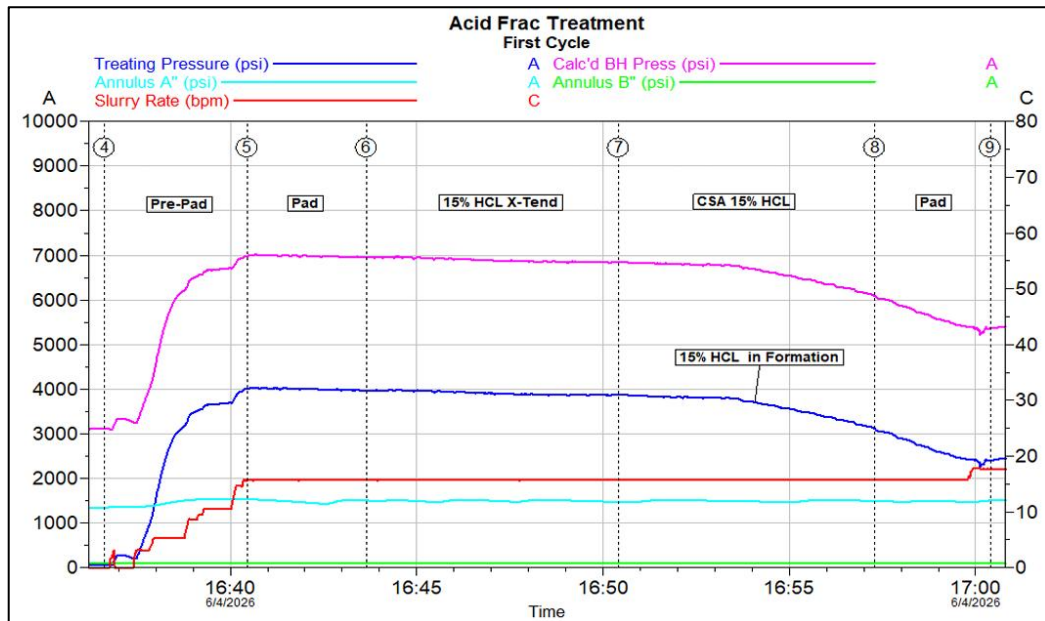


Figure 37. Acid Frac Treatment — First Cycle — HRX-1.

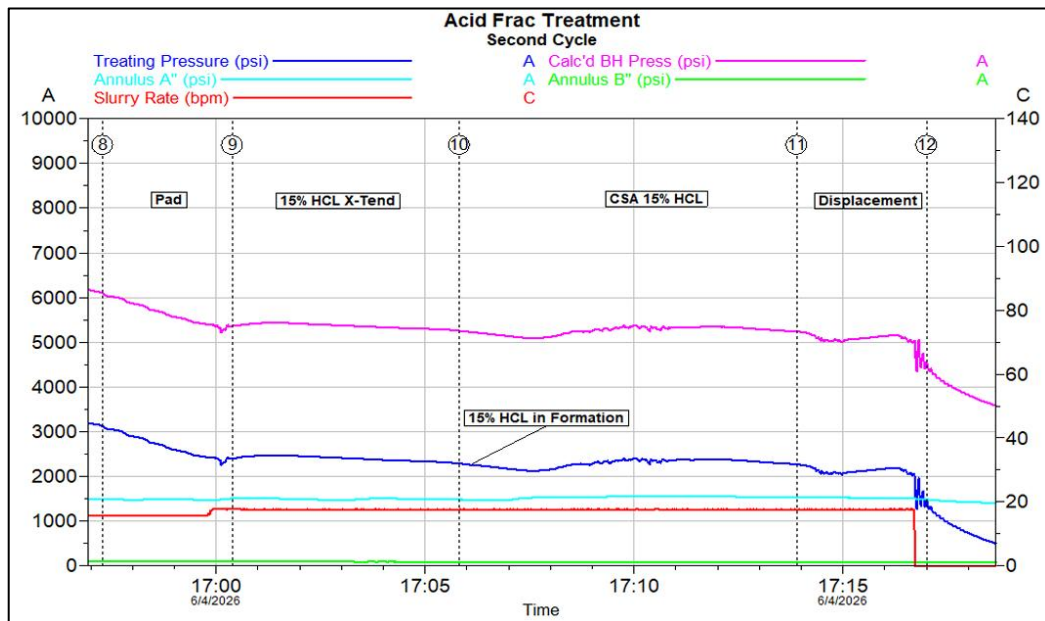


Figure 38. Acid Frac Treatment — Second Cycle — HRX-1.

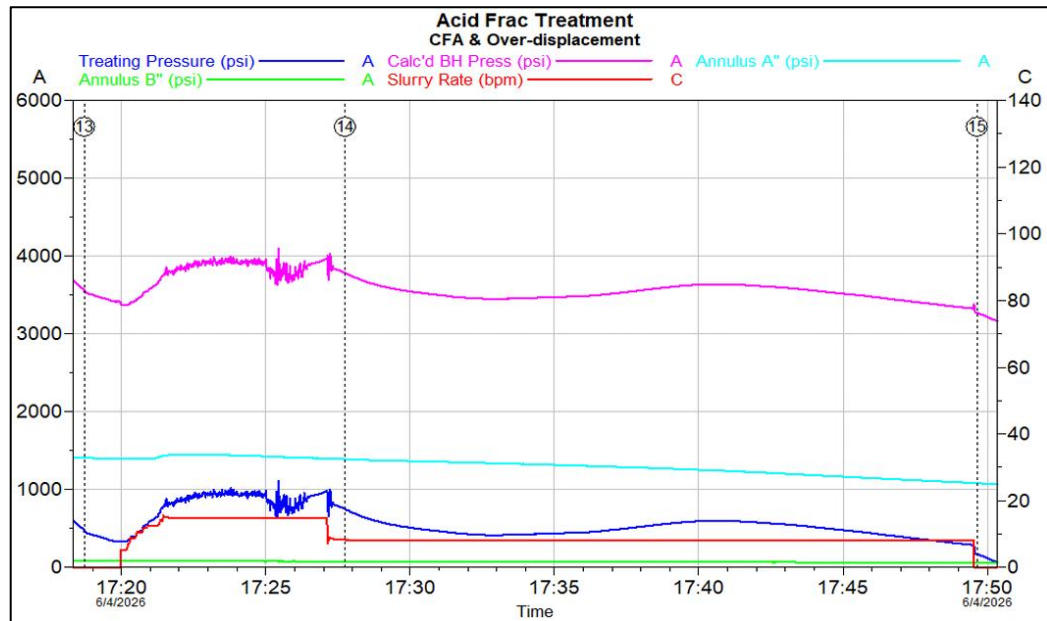
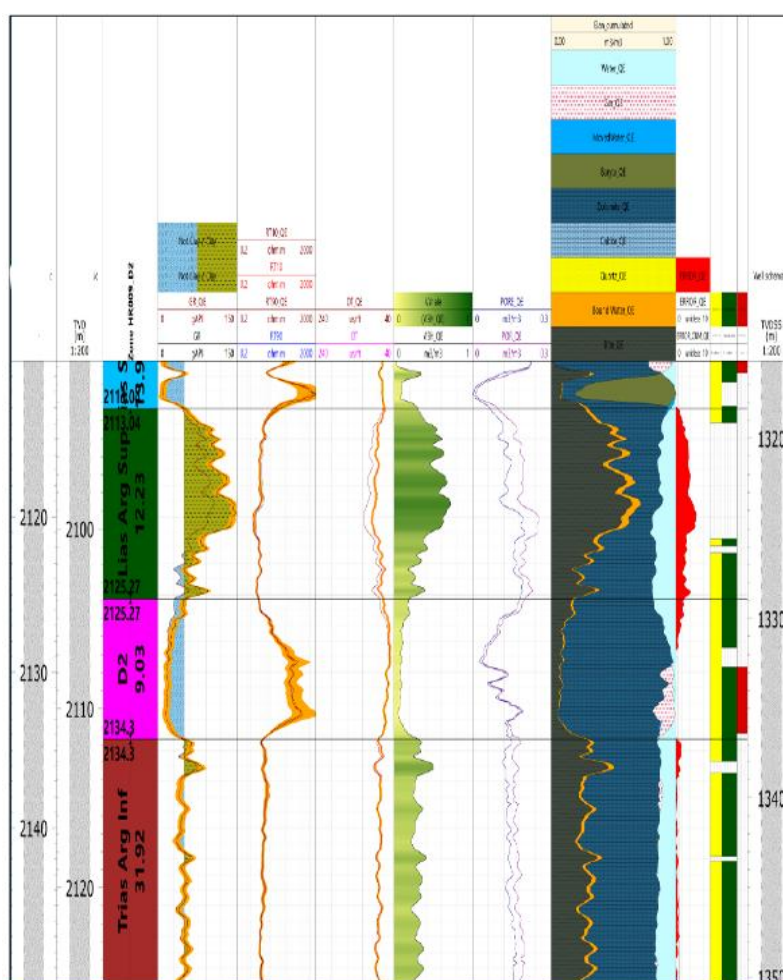


Figure 39. Acid Frac Treatment — Closed Fracture Acidizing — HRX-1.



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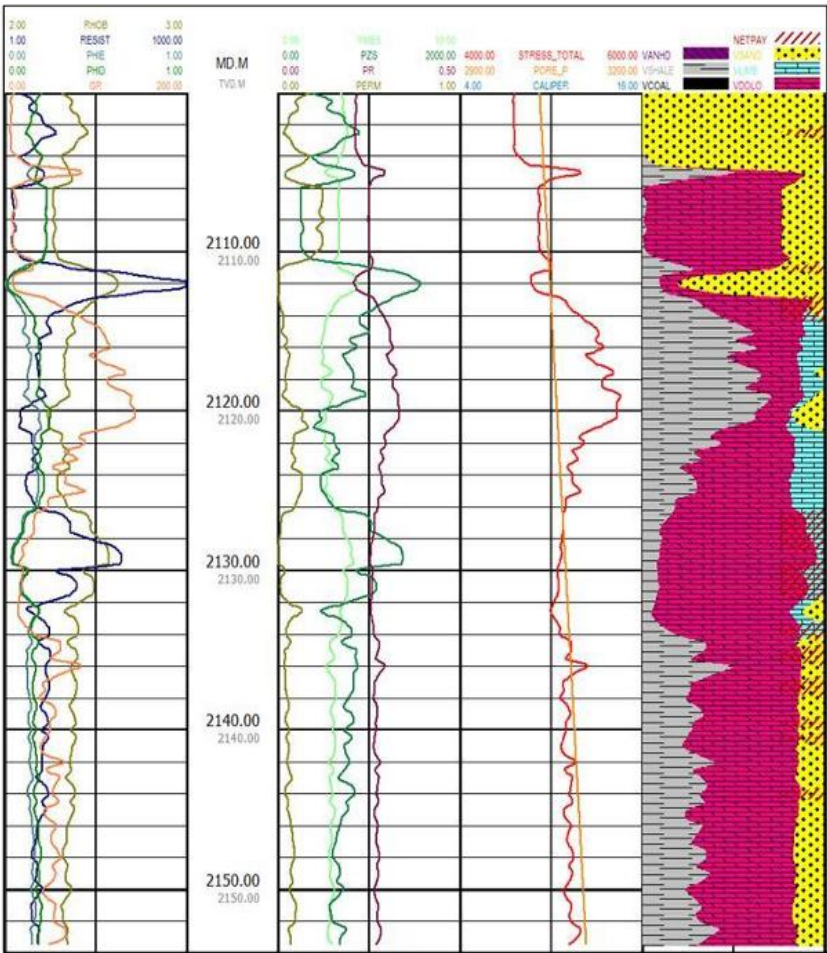


Figure 41. GOHFER 3D Log Interpretation (Geomechanics) — HRXX-2 Well.

III.2.2. Injection Test Analysis

The injection test started by filling the well with treated water, reaching a breakdown pressure of approximately 8,200 psi, confirming fracture initiation in the target interval. The treating pressure then stabilized during stable fracture propagation using linear gel, then displaced with treated water. At the final stage the pumps were shut down and the ISIP was recorded at approximately 7,181 psi at surface, providing the reference pressure for the subsequent G-function and square root of time pressure decline analysis.

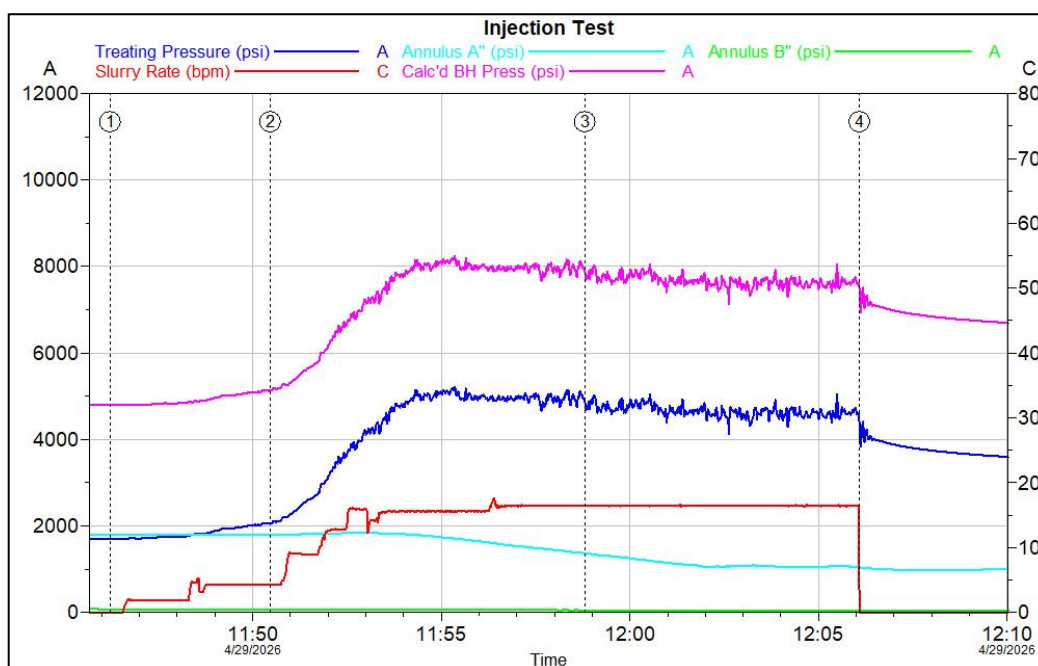


Figure 42. Injection Test — HRXX-2 Well.

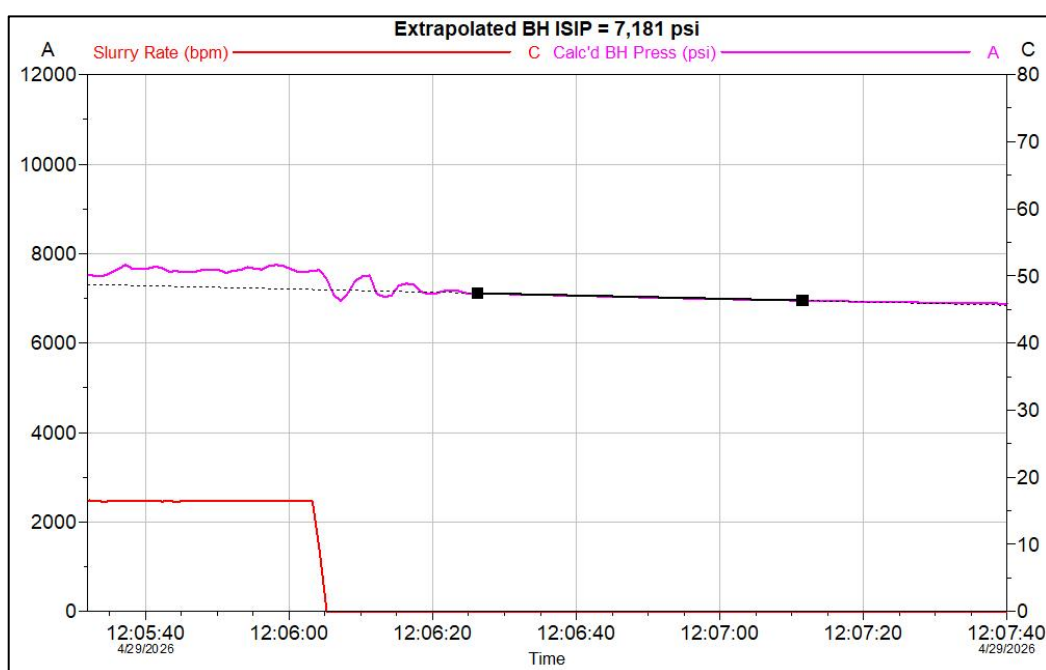


Figure 43. Extrapolated Bottom Hole ISIP — HRXX-2 Well.

III.2.3. Injection Test Analysis Summary

The G-function analysis identified fracture closure at a bottomhole pressure of 6,485 psi, with the derivative following a straight line through the origin confirming ideal Carter-type leakoff behavior. The square root of time plot confirmed closure at the same pressure with no secondary inflections. The key parameters extracted are summarized in Table 6.

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III.2.4. Temperature Log and Model Calibration

The temperature log confirmed that the main cooling anomaly was observed within the zone of interest, validating acid placement within the LD2 productive interval and confirming fracture height containment by the bounding layers.

III.2.5. Acid Treatment Design and Pumping Schedule

The acid fracturing treatment was designed based on the recalibrated fracture propagation model. Standard HCl was used for the first stage of each cycle the inherently slower dolomite reaction rate providing sufficient natural retardation followed by CSA for deeper penetration and leakoff control.

III.2.6. Acid Treatment Plots and Real-Time Analysis

The real-time treatment plots confirm execution of both acid cycles within the designed pressure envelope. The net pressure response during acid injection in the dolomite interval is lower than observed for Well 1, consistent with the higher fluid efficiency and wider fracture geometry expected in the stiffer dolomite formation.

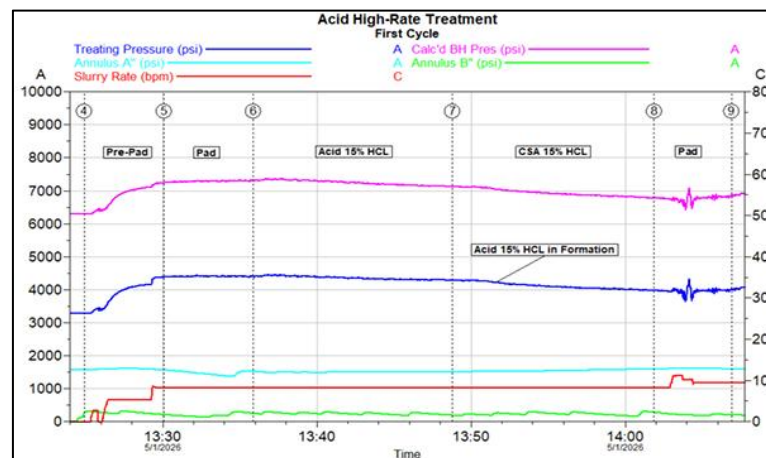


Figure 44. Acid Frac Treatment — First Cycle — HRXX-2 Well.

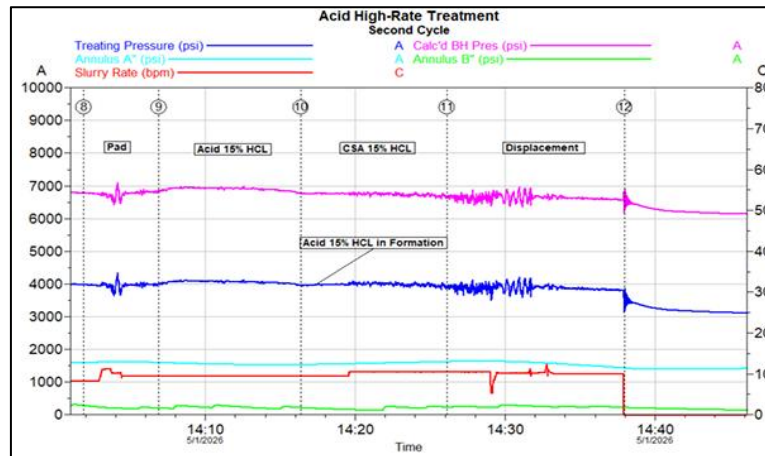


Figure 45. Acid Frac Treatment — Second Cycle — HRXX-2 Well.

III.3. HRXX-3 Well: Horizontal Well

III.3.1. Log Interpretation and Lithological Characterization

HRXX-3 is a horizontal well completed in the LD2 reservoir with a slotted liner. Log analysis confirms a dolomite-dominated interval. The GOHFER 3D mechanical earth model reveals a clear stress contrast between the LD2 interval and its bounding layers, confirming favorable conditions for fracture height containment and acid fracture initiation.

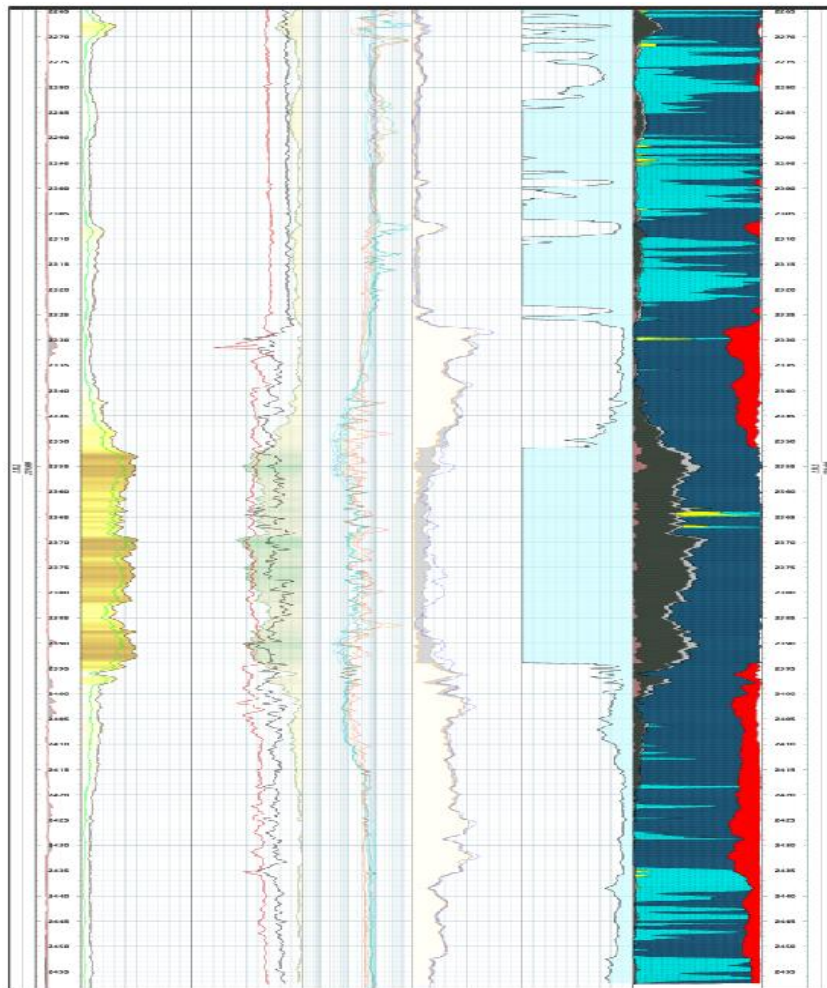


Figure 46. Stratigraphy Log Interpretation — HRXX-3 Well.

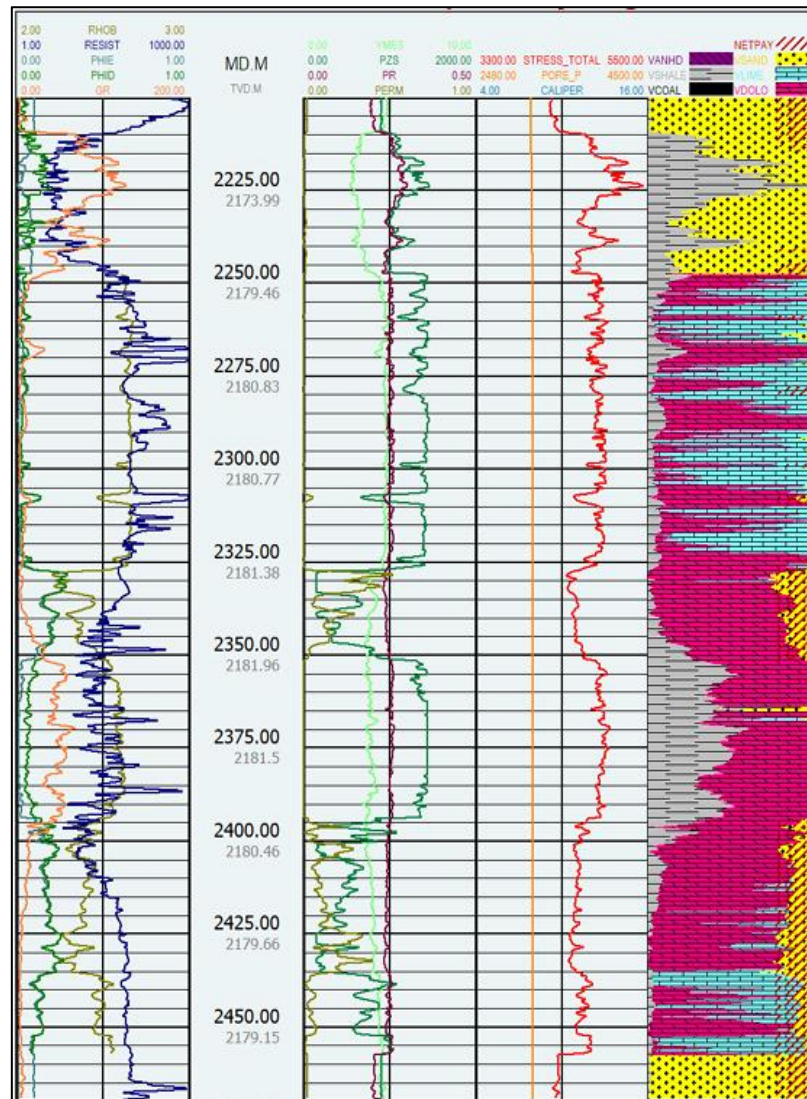


Figure 47. GOHFER 3D Log Interpretation (Geomechanics) — HRXX-3 Well.

III.3.2. Injection Test Analysis

Following the injection test, the data frac parameters were recorded and used to calibrate the fracture propagation model. The key results: closure pressure, net pressure, and fluid efficiency are summarized in Table 6.

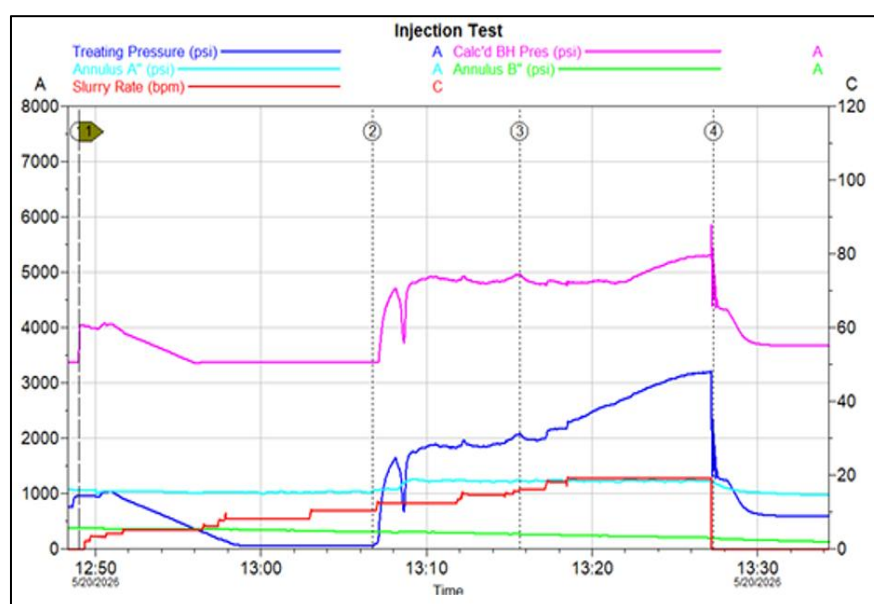


Figure 48. Injection Test — HRXX-3 Well.

III.3.5. Acid Treatment Design and Pumping Schedule

The treatment was designed as a high-rate acid fracturing treatment adapted for the horizontal completion. Three acid cycles were pumped with diverters placed between each cycle to ensure uniform acid coverage along the full length of the horizontal section.

III.3.6. Acid Treatment Plots and Real-Time Analysis

The real-time treatment plots confirm execution of the three acid cycles. The diverter placement between cycles is visible as brief pressure increases, confirming successful acid redirection along the horizontal section.

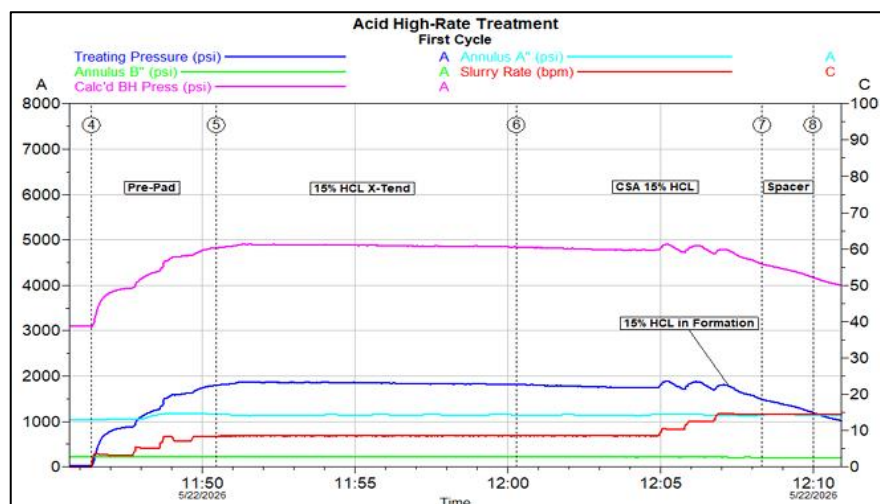


Figure 49. Acid Frac Treatment — First Cycle — HRXX-3 Well.

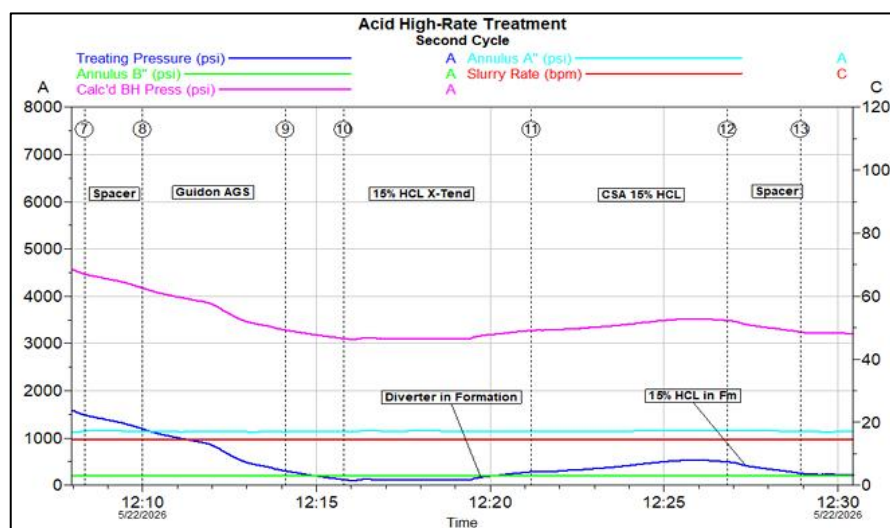


Figure 50. Acid Frac Treatment — Second Cycle — HRXX-3 Well.

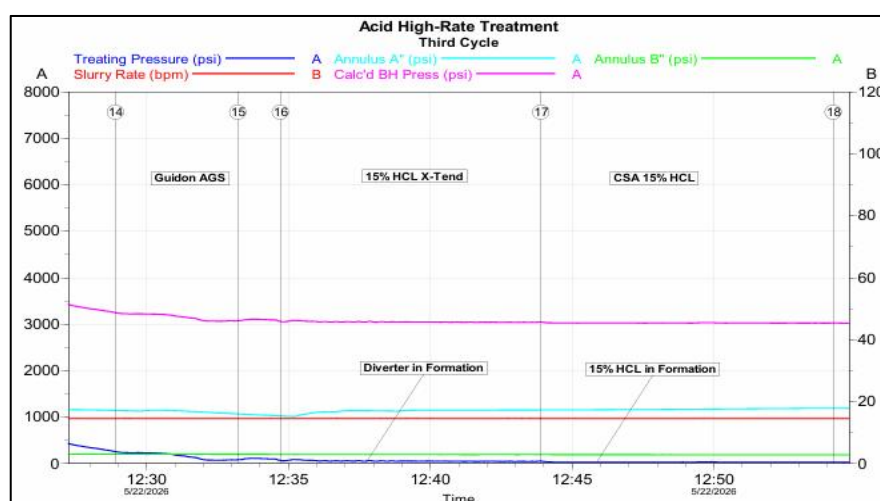


Figure 51. Acid Frac Treatment — Third Cycle — HRXX-3 Well.

IV. Comparative Analysis

IV.1. Summary of Key Treatment Parameters: Three-Well Comparison

Parameter	HRX-1 Deviated Well	HRXX-2 Vertical Well	HRXX-3 Horizontal Well
Dominant mineralogy	Calcite	Dolomite	Dolomite
Net pay (m)	6	8.3	8
ISIP (psi)	6,526	7,181	4,800
Closure pressure (psi)	5,521	6,485	3,981
Fluid efficiency η (%)	10.73	38.93	7.5
Net pressure (psi)	1,000	613	816
Acid system — Stage 1	Retarded Acid	Standard Acid	Retarded Acid
Acid system — Stage 2	Carbonate Stimulation Acid	Carbonate Stimulation Acid	Carbonate Stimulation Acid
Number of acid cycles	2	2	3
Total acid volume (gal)	21,000	21,000	24,000
Temperature log	Zone of interest	Zone of interest	Not recorded

Table 6. Summary of injection test and acid treatment parameters for the three study wells, LD2 reservoir, Hassi R'mel field.

IV.2. Effect of Mineralogy: Calcite versus Dolomite Response

The comparison between Well 1 (calcite) and Well 2 (dolomite) demonstrates the direct influence of carbonate mineralogy on acid fracturing behavior within the same LD2 reservoir. The most significant difference is the fluid efficiency: Well 2 achieved 38.93% compared to only 10.73% for Well 1, indicating that the dolomite interval retained a substantially higher fraction of injected fluid in the fracture, producing more efficient fracture extension for the same injected volume. This is consistent with the lower matrix leakoff coefficient characteristic of tight dolomitic carbonates relative to calcite-cemented intervals.

The net pressure contrast 1,000 psi for Well 1 versus 613 psi for Well 2 reflects the different geomechanical response of the two mineralogies. The higher net pressure in the calcite interval indicates a narrower fracture geometry for the same injection rate, consistent with the lower Young's modulus of calcite-dominated rock compared with dolomite. The acid system selection confirmed this mineralogical difference: Well 1 required chemically retarded X-Tend acid to prevent near-wellbore spending in the fast-reacting calcite interval, while Well 2 performed effectively with standard acid given the

natural kinetic retardation of dolomite. Both wells used CSA for the deeper penetration stages, confirming the robustness of the two-cycle across each carbonate mineralogizes.

IV.3. Effect of Well Orientation: Vertical versus Horizontal

The comparison between the two vertical wells and the horizontal Well 3 highlights the specific challenges introduced by well orientation in the LD2 reservoir. The ISIP and closure pressure of Well 3 are significantly lower than those of the two vertical wells, reflecting the shallower depth of the horizontal section and the corresponding lower in-situ minimum horizontal stress at that level. The fluid efficiency of Well 3 at 7.5% was the lowest of the three wells, reflecting the larger fracture face area exposed during injection along the horizontal section, which substantially increases the total leakoff rate and reduces the fraction of injected fluid contributing to fracture extension.

These differences directly influenced the treatment design. Three acid cycles were required for Well 3 versus two for each vertical well, and systematic diverter placement between cycles was critical to redistribute acid from the most conductive entry points toward less-stimulated sections of the horizontal interval. The absence of a temperature log for Well 3 prevented direct verification of acid placement uniformity along the horizontal section.

VI. Conclusion

This case study has evaluated acid fracturing performance on three LD2 wells at Hassi R'mel: a deviated calcite-dominated well, a vertical dolomite-dominated well, and a horizontal dolomite well applying a consistent analytical workflow to each. The three-well comparison has produced three principal conclusions.

First, carbonate mineralogy is the primary geological control on acid system selection and treatment behavior in the LD2. The calcite-dominated Well 1 required chemically retarded acid to prevent near-wellbore spending, while the dolomite-dominated Well 2 achieved equivalent performance with standard acid, exploiting the inherently slower dolomite reaction rate. The fluid efficiency contrast between the two vertical wells 10.73% for calcite versus 38.93% for dolomite confirms that mineralogy also significantly influences leakoff behavior and therefore pad volume requirements.

Second, well orientation introduces a fundamentally different set of design requirements. The horizontal well required more than two acid cycles, systematic diverter placement, and a larger total fluid volume, reflecting the greater complexity of achieving uniform acid coverage along a horizontal slotted liner compared with a vertical perforated interval. The absence of a post-treatment temperature log for Well 3 is a limitation that should be addressed in future horizontal well treatments.

Third, the injection test is the single most important pre-treatment operation in the LD2 acid fracturing workflow. The large variability in fluid efficiency across the three wells confirms that model recalibration from injection test data is essential and that no default design assumption can replace direct field measurement in a reservoir as heterogeneous as the LD2.

General Conclusion

General Conclusion

General Conclusion

This work has addressed the geological characterization and stimulation optimization of the LD2 tight carbonate reservoir at Hassi R'mel, Algeria, progressing from the regional geological framework through reservoir characterization, acid fracturing theory, and a three-well field case study.

The geological analysis established that the LD2's tight character results from a multiphase diagenetic history dolomitization, compaction, and late calcite cementation that sealed its natural fractures and reduced matrix permeability below 0.1 mD, placing it outside the range of commercial production without stimulation. The NW–SE stress orientation was shown to directly govern acid fracture geometry.

Chapters 2 and 3 connected carbonate mineralogy to acid reactivity and established that fracture conductivity arises from differential etching driven by the rock's own diagenetic heterogeneity not despite it. The complete treatment design workflow, from injection test calibration to multi-cycle acid staging, was developed as the framework linking geological understanding to operational decisions.

The three-well case study confirmed three key findings: carbonate mineralogy governs acid system selection and leakoff behavior (fluid efficiency: 10.73% for calcite versus 38.93% for dolomite); well orientation determines treatment complexity, with the horizontal well requiring three acid cycles and systematic diverter placement; and the injection test is the indispensable pre-treatment operation, as inter-well variability confirms that no default design assumption can replace direct field calibration.

These findings confirm that commercial development of the LD2 play is achievable only through acid fracturing guided by rigorous geological characterization and field-calibrated design a conclusion reinforced by Sonatrach's 2022 revaluation of LD2 resources to 100–340 billion cubic meters.

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