



Deposited via The University of Leeds.

White Rose Research Online URL for this paper:

<https://eprints.whiterose.ac.uk/id/eprint/204752/>

Version: Accepted Version

---

**Article:**

Mohammed-Sajed, O.K., Glover, P.W.J., Al-Khatony, F.H. et al. (2024) Qualitative and quantitative diagenetic modelling in a tight carbonate reservoir in north-western Iraq. *Geoenergy Science and Engineering*, 232 (Part A). 212450. ISSN: 2949-8929

<https://doi.org/10.1016/j.geoen.2023.212450>

---

**Reuse**

This article is distributed under the terms of the Creative Commons Attribution-NonCommercial-NoDerivs (CC BY-NC-ND) licence. This licence only allows you to download this work and share it with others as long as you credit the authors, but you can't change the article in any way or use it commercially. More information and the full terms of the licence here: <https://creativecommons.org/licenses/>

**Takedown**

If you consider content in White Rose Research Online to be in breach of UK law, please notify us by emailing [eprints@whiterose.ac.uk](mailto:eprints@whiterose.ac.uk) including the URL of the record and the reason for the withdrawal request.

# 1 Qualitative and quantitative diagenetic modelling in a tight 2 carbonate reservoir in north-western Iraq

3  
4 Omar K. Mohammed-Sajed<sup>a,b</sup>, Paul W. J. Glover<sup>b</sup>, Flyah H. Al-Khatony<sup>a</sup>, Richard E. LI. Collier<sup>b</sup>

5  
6 <sup>a</sup>*Department of Geology, College of Science, University of Mosul, Iraq.*

7 <sup>b</sup>*School of Earth and Environment, University of Leeds, UK.*  
8  
9

10 **Abstract.** The diagenetic history of the Butmah Formation (Lower Jurassic) is very complex  
11 and affected by several diagenetic processes that worked effectively with fracturing control  
12 to create the final pore network. A microscopic study, core plug and well log analyses were  
13 combined in this study in order to describe, and differentiate between, the diagenetic and  
14 fracturing control that created the final pore system of the formation. The diagenetic  
15 processes of the Butmah Formation were studied in depth to describe the diagenetic stages  
16 and identify the elements that may compose a petrodiagenetic pathway illustrating its effect  
17 on the reservoir quality of the Butmah Formation. Accordingly, the Butmah Formation  
18 samples were divided into three petrophysical fields controlled mainly by fracturing and  
19 diagenesis, which were then used to develop a new method for estimating the pre-  
20 dolomitisation petrophysical properties of the dolomite samples and the post-dolomitisation  
21 petrophysical properties of the limestone samples. Consequently, the output of applying this  
22 method allows us to effectively begin to predict each of the elements that may compose a  
23 petrodiagenetic pathway for the Butmah Formation and make its reservoir characterisation  
24 integrated and more understandable. The new method provided a good prediction of matrix  
25 porosity and permeability, as well as allowing the estimation of reservoir properties of any  
26 other carbonate reservoir in petroleum development projects when there are no core samples  
27 in some formation intervals within boreholes.

28  
29 **Keywords:** Diagenetic control, carbonate reservoir, Butmah Formation, poroperm  
30 relationship, tight carbonate, petrodiagenetic pathway  
31

## 32 1. INTRODUCTION

33 It is very important to take account of diagenetic processes when considering reservoir quality  
34 during exploration studies because of their critical influence on all aspects of the rock  
35 microstructure including porosity, pore and pore throat size distributions, pore connectivity  
36 and, consequently, permeability (Nader, 2017; Worden et al., 2018; Adelinet et al., 2019;  
37 Wang et al., 2019; Baqués et al., 2020; Rashid et al., 2022).

38 Primary porosity is high in carbonate during deposition, and subsequently modified by  
39 diagenesis and fracturing controls (Longman, 1980; Moore, 1989; Ehrenberg, 2004; Scholle  
40 and Ulmer-Scholle, 2003; Ahr, 2008). Most, sometimes all, of carbonate rock pores are  
41 secondary in origin, having been formed during diagenesis. Consequently, a good  
42 understanding of the diagenesis a carbonate rock has undergone is crucial to the interpretation  
43 of their petrophysical properties (Selley, 2000; Ahr, 2008; Boggs, 2009; Esrafil-Dizaji and  
44 Rahimpour-Bonab, 2009; Tavakoli et al., 2011; Hollis, 2011; Leonide et al., 2014; Zhang et  
45 al., 2017; Nader, 2017; Mohammed Sajed and Glover, 2020). Depositional control should also  
46 be considered as a benchmark to improve understanding the role of diagenetic processes and  
47 fracturing in improving or reducing the carbonate reservoir quality (Hollis et al., 2010; Agar  
48 and Geiger, 2014; Shuja Ullah et al., 2023).

49 Diagenesis and fracturing can occur *in tandem* to improve or reduce the reservoir quality of  
50 carbonates (Moore, 2001; Ahr, 2008). Rocks are affected differently by fractures depending  
51 on their type, nature, and severity inside the rock (Caine et al., 1996; Childs et al., 1997;  
52 Maerten et al., 2002; Geraud et al., 2006; Laubach et al., 2019; Corrêa et al., 2022; Forstner  
53 and Laubach, 2022; Rysak et al., 2022; Wang and Laubach, 2023). In carbonate rocks,  
54 fractures occur to variable degrees and, if open, enhance fluid movement and the quality of  
55 the reservoir (Arosi and Wilson, 2015; Wennberg et al., 2016; Mohammed Sajed and Glover,  
56 2020; de Lima et al., 2023). If cemented, fractures can hinder fluid flow and compartmentalise  
57 reservoirs (Mohammed-Sajed and Glover, 2022).

58 The type and degree of diagenetic processes both significantly affect the distribution of pore-  
59 throat sizes, bulk, potential, and effective porosity, as well as permeability, and other  
60 petrophysical parameters through their ability to create, enhance, rework, occlude, and  
61 destroy pores in carbonate rocks (Tavakoli et al. 2011; Wang et al., 2019; Mohammed Sajed  
62 and Glover, 2020; Mohammed Sajed et al., 2021; Rashid et al., 2022).

63 Diagenesis has been investigated intensively in many studies (e.g., Bourque et al., 2001;  
64 Cerepi et al., 2003; Stenoft et al., 2003; Esrafil-Dizaji and Rahimpour-Bonab, 2009; Maliva et  
65 al., 2009; Tavakoli et al., 2011; Hollis, 2011; Leonide et al., 2014; Zhang et al., 2017; Jiang et  
66 al., 2018). These studies have all been qualitative, focussing on the use of observations of  
67 morphological changes to characterise the type, extent and conditions involved in the  
68 diagenetic processes, and their effect on the porosity of the rock. The diverse porosities and  
69 pore types of many carbonate reservoirs are caused by intricate diagenetic mechanisms.  
70 Understanding the likely products of each diagenetic process is necessary in order to  
71 comprehend the petrophysical characteristics of the resulting carbonate reservoir (Longman,  
72 1980; Tucker et al., 1990; Anselmetti and Eberli, 1993; Moore, 2001; Boggs, 2006 and 2009;  
73 Verwer et al., 2008; Brigaud et al., 2010).

74 Recently, there has been progress in understanding tight carbonate rocks better by using  
75 carbonate petrophysics to make the understanding of diagenesis more quantitative (Rashid et  
76 al., 2015a; 2015b; 2017; 2022; Al-Khalifah et al., 2020; Sabouhi et al., 2022; Glover et al.,  
77 2022). Rashid et al. (2015a; 2015b; 2017), for example, have produced methods for estimating  
78 permeability in carbonates. Integrated analysis of facies, well logs and seismic data were  
79 adopted by Sabouhi et al., (2022) as a new approach to quantitative diagenesis modelling in  
80 the Sarvak Formation in south-western Iran. Machine learning has been applied to the  
81 characterisation of tight carbonates and the recognition of facies caused by diagenetic  
82 processes (Al-Khalifah et al., 2020; Glover et al., 2022), while the concept of petrodiagenetic  
83 pathways for describing how the quantitative poroperm characteristics of a rock change as a  
84 result of concurrent and contemporaneous diagenetic processes is another recent

85 development ([Al-Khalifah et al., 2020](#); [Rashid et al., 2022](#)). This emerging field of Quantitative  
86 Diagenesis seems to have started well.

87 The reservoir quality of the Butmah Formation in this study is controlled mainly by diagenetic  
88 and fracturing factors. Accordingly, the Butmah Formation represents an exemplar for other  
89 formations that show the operation of diagenetic processes working with fracturing to result in  
90 the same current rock composition and texture, such as the Khuff, Dalan, and Kangan  
91 formations in the Middle East ([Alsharhan, 2006](#); [Ehrenberg et al., 2007](#); [Koehrer, et al., 2010](#);  
92 [Tavakoli et al., 2011](#); [Aleali et al., 2013](#); [Amel et al., 2015](#)).

93 This study shines a light on how to differentiate between diagenetic and fracturing controls  
94 using qualitative and quantitative methods in order to identify the effect of each control on the  
95 petrophysical properties of the Butmah Formation. This new method can also be applied to  
96 other carbonate formations in order to estimate of the porosity and permeability of a dolomite  
97 if the petrophysical properties of the pre-dolomitised limestone are known. Conversely, the  
98 method can be used to estimate the porosity and permeability of the pre-dolomitised limestone  
99 from knowledge of the petrophysical properties of the existing dolomite.

100 The new method represents a very useful approach for fast and effective prediction of the  
101 porosity and permeability of any carbonate reservoir consisting of both limestone and dolomite  
102 lithology, especially if there is a shortage of core samples within boreholes. Moreover, this  
103 method will help to create its petrodiagenetic pathway and make its reservoir characterisation  
104 integrated and more understandable.

## 105 **2. BACKGROUND OF THE STUDY AREA AND FORMATION**

106 This paper describes the Butmah Formation as encountered within the Ain Zalah and Butmah  
107 oilfields north-western Iraq.

108 The Ain Zalah anticline is located in the Zagros foothills zone, about 60 km north-west of Mosul  
109 city in northern Iraq. On the surface, it is represented by a long, low topographic high that is  
110 approximately 20 km long by 5 km broad and has a maximum elevation of 457 m above sea  
111 level. The Butmah anticline runs parallel to and south-east of the Ain Zalah anticline. It is a 12

112 km long and 6 km broad asymmetrical anticline made up of two domes, one eastern and one  
113 western (Dunnington, 1958; Bellen et al., 1959; Hart and Hay, 1974) (Figure 1). Oil is extracted  
114 from fractured limestones of the Shiranish Formation (Campanian-Lower Maastrichtian) in  
115 both anticlines. In addition, limited oil production occurs in some wells from the Mauddud  
116 (Albian), Butmah (Lower Jurassic), and Kurrachine Formations (Upper Triassic) (Aqrabi et al.,  
117 2010).

118 **Figure 1.** The position of the Butmah and Ain Zalah oilfields in north-western Iraq may be  
119 observed along with the tectonic division of Iraq after Fouad (2015).

120 Dunnington (1953) identified the Butmah Formation at Butmah oilfield in north-western Iraq as  
121 a 500 m thick, high heterogeneity carbonate unit (Bellen et al., 1959), while the authors of this  
122 paper (Mohammed Sajed and Glover 2020; Mohammed Sajed et al., 2021; Mohammed-Sajed  
123 and Glover, 2022) characterised the examined section (Butmah-15) as five stratigraphic units  
124 including three primary lithofacies (Figure 2). Limestone alone or associated occasionally with  
125 anhydrite nodules makes up Lithofacies 1, which is numerous times reiterated as units 1, 3,  
126 and 5 (U1, U3, and U5). Shale and a few anhydrite nodules interbedded the dolomite in  
127 Lithofacies 2. Dolomite with beds and nodules of anhydrite make up Lithofacies 3. Unit 4 is  
128 the only one that represents it.

129 **Figure 2.** Stratigraphic units, lithofacies, microfacies distribution, and environments of the  
130 Butmah Formation at well Bm-15.

131  
132 These identified stratigraphic units of the Butmah Formation were subdivided into eight  
133 microfacies, which were used to identify the palaeo-environment of the formation into; (i) tidal  
134 flats, (ii) lagoon, and (iii) shoal (Figure 2). The tidal flat environment is characterised by the  
135 presence of crystalline anhydrite (B1), nodular dolomudstone (B2), and dolomudstone with  
136 sparse anhydrite crystals (B3). The lagoon environment is characterised by dolomudstone  
137 with sparse anhydrite crystals (B3), stromatolite boundstone (B4), fossiliferous packstone  
138 (B5), and peloidal wackstone/packstone (B6). Finally, the shoal environment is represented

139 by peloid-oidal packstone (B7) and ooidal grainstone (B8) microfacies ([Mohammed-Sajed](#)  
140 [and Glover, 2022](#)).

### 141 **3. MATERIALS AND METHODS**

#### 142 **3.1 Wireline log data**

143 A limited set of wireline log data (gamma ray, density, neutron, and sonic logs) from two wells,  
144 Bm-15 and Az-29, located in the Butmah and Ain Zalah oilfields, respectively, were provided  
145 by the North Oil Company (NOC) in Iraq. The Interactive Petrophysics<sup>®</sup> software (version 4.3)  
146 from Senergy<sup>®</sup> Inc. was used to redraft and analyse these well logs after they had been  
147 digitally converted using Didger<sup>®</sup> software (version 3.5). The Butmah Formation's porosity has  
148 been determined using wireline log data, which has also been utilised to distinguish between  
149 diagenetic and fracturing controls. Furthermore, the wireline log data has been merged with  
150 core descriptions in order to identify lithofacies describing the stratigraphic units of the Butmah  
151 Formation ([Mohammed Sajed and Glover, 2020](#)).

152

#### 153 **3.2 Image analysis**

154 Microscopic description of rock microstructure using thin sections and petrological, binocular  
155 or scanning electron microscopes is one of the most important tools for the determination of  
156 the mineralogy of its components and the porosity and pore structure of its pores (micro-  
157 texture). These features are crucial for determining the rock's origin, depositional facies,  
158 deposition environment, and the type, degree, and timing of any diagenesis that has occurred.  
159 ([Flugel, 2010](#)).

160 Under the binocular microscope, 540 thin-section slides were examined to characterise the  
161 depositional facies and environments, diagenesis, and pore network of the Butmah Formation.  
162 Alizarin red (AR), potassium ferricyanide ( $K_3(FeCN)_6$ ), and hydrochloric acid (HCl) were used  
163 to stain all thin-section slides made from cores, according to [Dickson's \(1965\)](#) staining  
164 procedure. This was carried out in order to distinguish between carbonate minerals such as

165 calcite, ferroan calcite, and dolomite. Prior to the production of thin sections, an epoxy  
166 containing blue dye was injected into the rock to emphasise the pores in the thin section slides.  
167 Sixteen samples were selected from the Butmah formation for imaging at a nanometer scale  
168 size using Scanning Electron Microscopy (SEM). The SEM analysis was used to identify the  
169 sample components (grains, crystals and pores) under high magnification of up to 10,000×,  
170 allowing resolutions down to 50 nm.

171 Solvents were used to clean all of the selected samples to remove any hydrocarbon residue  
172 or dust that may have compromised the picture quality (Erdman and Bell, 2015). After drying  
173 the samples, some of them were polished, whereas others were left with a fresh broken  
174 surface to obtain three-dimensional image of the broken surface. The samples were then  
175 placed on stubs and covered with a 20 nm layer of carbon for image capturing (Erdman and  
176 Bell, 2015).

### 177 **3.3 Porosity and permeability**

178 A total of 84 core plug samples with nominal dimensions of 1.5 inches in diameter and 2.0  
179 inches in length were measured by the Wolfson laboratory at the University of Leeds. After  
180 utilizing Soxhlet extraction to clean them, the samples were dried for 48 hours in a  
181 temperature-controlled oven at 60°C (McPhee et al., 2015). Helium pycnometry was used to  
182 determine the porosity of each dry sample at a pressure of 15 psig (Spain, 1992).

183 For samples with high permeability ( $k > 1$  mD), a steady-state method was used (Ross, 2011),  
184 and for samples with lower permeability ( $k < 1$  mD), a pulse-decay permeameter was used  
185 (Jones, 1997; Jannot et al., 2007; Zhang et al., 2000; MCPhee et al., 2015). Both methods  
186 used helium as the probe gas. The Klinkenberg adjustment was applied to all the measured  
187 samples to correct for so-called gas "slippage," which occurs when the criterion for continuity  
188 in the gas fails (Klinkenberg, 1941; Rushing et al., 2004; Haines et al., 2016). A further set of  
189 data for 16 samples, that were provided from the NOC, included porosity measurements as

190 well as estimated permeabilities of fractured samples using the empirical equations of [Ross](#)  
191 [\(2011\)](#).

### 192 **3.4 Pore throat description**

193 According to their lithology, porosity, and permeability, eight samples were chosen for the  
194 mercury injection capillary pressure (MICP) test in order to describe their pore-throat size  
195 distributions using pressure up to 60,000 psig, applying the Young-Laplace equation  
196 [\(Washburn, 1921; Jennings, 1987; Kopaska-Merkel and Amthor, 1988; Katz and Thompson,](#)  
197 [1987; Glover et al., 2006\)](#). The samples were cleaned and evacuated after slicing to sizes  
198 between 15 and 10 mm. A Micromeritics Autopore IV 9250 device was then used to collect  
199 the mercury intrusion data [\(Giesche, 2006\)](#). The approach developed by [Glover and Déry](#)  
200 [\(2010\)](#) was used to calculate characteristic pore size distributions.

## 201 **4. DIAGENETIC AND FRACTURING CONTROLS**

202 Based on the petrographic study of the Butmah Formation, three diagenetic stages have been  
203 distinguished, belonging to the three diagenetic realms; marine, meteoric and burial. These  
204 stages are discussed below with details about their petrographic evidence and interpretation.

### 205 **4.1 Stage 1 (*marine and syn-depositional diagenesis*)**

206 This stage is represented by microbial micritisation, marine cementation, light mechanical  
207 compaction, and early anhydrite cementation [\(Scholle and Ulmer Scholle, 2003; Ahr, 2008;](#)  
208 [Boggs, 2009\)](#).

209 Micritisation is shown in most packstone and grainstone microfacies of the Butmah Formation.  
210 Some skeletal grains show a thin black micritic envelope coating around the grains. The  
211 micritic envelope is sometimes still discernible even after the grain has been disintegrated  
212 [\(Figure 3A\)](#).

213 In the oolitic grainstone of the Butmah Formation, isopachous calcite cement with a bladed  
214 rind can be found either directly on the ooids or in its micritic envelope [\(Figure 3B\)](#).  
215 Furthermore, the fibrous cement was found to fill some fractures [\(Figure 3C\)](#).

216 Anhydrite cementation and the formation of anhydrite nodules of the Butmah formation have  
217 occurred in confined, shallow marine settings under hypersaline circumstances (Figure 3D,  
218 and 3E). Most of the anhydrite are primary in origin. This is inferred from many features,  
219 including early dolomitisation accompanied by this anhydrite cements, the usual structure of  
220 this diagenetic realm comprises interactions between anhydrite and dolomite, cross-cutting of  
221 anhydrite with stylolites, and poikilotopic anhydrite that fills intergranular porosity (Figure 5F).

222 **Figure 3.** Observed textures associated with diagenetic processes. (A) Micritic envelopes  
223 around skeletal grains (ooids), Bm-15, (2627 m). (B) Isopachous cement, Bm-15, (2540 m).  
224 (C) Fibrous cement, Bm-15, (2480 m). (C) Blocky cement, Bm-15, (2524 m). (D) Anhydrite  
225 nodules in fine dolomite crystals, Bm-15, (2500 m). (E) Sparse anhydrite crystals in  
226 Dolomudstone microfacies, Bm-15, (2350 m). (F) Poikilotopic anhydrite cement, Bm-15, (2292  
227 m). (G) A low peak amplitude stylolite (pressure solution) within fine crystalline dolomite, Bm-  
228 15, (2391m). (H) Slightly-compacted contacts between dolomitised peloids, Bm-15, (2541 m).  
229 (I) Fine crystalline dolomite showing vuggy porosity and solution-enlarged vugs Bm-15, (2391  
230 m). (J) Drusy cement, Bm-15 (2290 m). (K) Mechanical compaction between ooids within  
231 ooids grainstone microfacies, Az-29, (3358 m). (L) A high peak amplitude stylolite (pressure  
232 solution) within fine crystalline dolomite, Bm-15, (2378m). (M) Zoning coarse dolomite crystals  
233 as late dolomitisation features, Bm-15, (2376 m). (N) Late-stage anhydrite cement occluding  
234 early porosity, Bm-15, (2390 m). (O) Compressed chicken-wire texture by compaction effect,  
235 Bm-15, (2379 m). (P) Late-stage blocky anhydrite cement fills some fractures and alongside  
236 stylolite, Bm-15, (2524 m). (Q) Burial dissolution as a few voids and solution enlarged stylolite,  
237 Bm-15, (2381 m). (R) Two generations of fractures, the old fracture is occluded by blocky  
238 anhydrite cement and the new open fracture cuts the old one, Bm-15, (2524 m).

239

240 Petrographic evidence of syndepositional dolomite were represented by fine to medium  
241 euhedral to subhedral crystals of dolomite, preservation of depositional and early diagenetic  
242 characteristics such as micritisation and marine cementation. This dolomite is associated with  
243 anhydrite fabrics and is cut by stylolites and fractures (Figure 3G). Moreover, slightly-  
244 compacted contacts between dolomitised crystals suggest that this dolomitisation occurred  
245 before significant burial (Figure 3H).

#### 246 **4.2 Stage 2 (*meteoric and mixing zone diagenesis*)**

247 In this stage, metastable grains are dissolved and generate secondary porosity according to  
248 Choquette and Pray (1970). Petrographic evidences for this realm are represented by  
249 intergranular/intercrystal dissolution pores and solution-enlarged vugs (Figure 3I).

250 Furthermore, drusy calcite cement was noted clearly in the Butmah Formation as freshwater  
251 cementation (Figure 3J), and mechanical compaction reflects shallow-burial conditions without  
252 or with only poorly developed stylolites (Figure 3K).

### 253 4.3 Stage 3 (*Burial diagenesis*)

254 Many of the characterised diagenetic processes in the Butmah Formation are related to this  
255 realm such as recrystallization, cementation, chemical compaction (stylolitization) and late  
256 dolomitisation (Tucker et al., 1990; Scholle and Ulmer Scholle, 2003; Ahr, 2008).

257 Chemical compaction is represented by stylolites lines make way for the dissolution fluids that  
258 created by the chemical compaction (Figure 3L). Other diagenetic features were also  
259 observed, such as; (i) late dolomitisation and saddle dolomite cementation, which occurred  
260 during the late burial diagenesis (Figure 3M), (ii) late stage anhydrite cement occluding early  
261 porosity and late fractures (Figure 3N), (iii) Anhydrite textures previously created were  
262 compacted into chicken-wire anhydrite after burial (Figure 3O), (iv) late-stage anhydrite forms  
263 filling some fractures and alongside stylolites in some places as a blocky or granular cement  
264 (Figure 3P), and finally (v) burial dissolution, which is usually associated with well-developed  
265 chemical compaction units. There were also noted a few cavities, solution-enhanced fractures  
266 and stylolites (Figure 3Q).

267 Fracturing is significant in the Butmah Formation and plays different roles in improving the  
268 reservoir properties of each stratigraphic unit depending on whether the presence or lack of  
269 anhydrite cement partially or completely occluding fractures (Figure 3R).

270 Taking all of the previous observations into account, we have created a possible diagenetic  
271 sequence for the Butmah Formation, which is shown in Figure 4. In this figure, we have  
272 included timing, position (diagenetic environment) of each identified diagenetic stage in this  
273 study including their diagenetic processes. Figure 4 also illustrates the effect of diagenesis as  
274 an improvement or reduction of the petrophysical properties to create the pore system of the  
275 studied formation.

276

**Figure 4.** Summaries of the qualitative diagenetic pathway include a generalised diagenetic sequence with the effect of each diagenetic process on the reservoir quality of the Butmah Formation.

## 5. PETROPHYSICAL PROPERTIES

The petrophysical investigation in this study includes describing porosity, pore throat size and distributions, permeability, and pore size and shape.

### 5.1 Porosity

The porosity of the rock unit defines its maximum storage capacity. Generally, porosity ranges from little more than 1% for some tight clastic and carbonate reservoirs to a maximum of about 40% for some high porosity carbonate reservoirs (Asquith and Krygowski, 2004; Gluyas and Swarbrick, 2004; Tiab and Donaldson, 2012; Rider, 2018; Mohammed Sajed and Glover, 2020).

In this work, we report effective porosities to helium, which approach the total porosity of the rock because the helium molecule is small enough to access most connected pores, however small. The effective porosity of the studied samples from U4 and U5 are presented in Table 1 and Figure 5. The highest porosity in the dolomite samples (U4) of the Butmah Formation was 8.6%, and the lowest 0.72%, with an arithmetic mean of 4.62%, and a mode of 3.5%. Compared to the U4 measurements, the limestone samples (U5) were shown to have lower porosities, with the highest porosity being 6.91%, and the lowest being 0.19%, with an arithmetic mean 2.72%, and a mode of 1.5%. As expected, the porosity ranges of the limestone and dolomite overlap significantly, but it is the dolomite which presents the larger porosities on average.

**Table 1.** Statistics of the effective porosity in the stratigraphic units 4 and 5.

Number of samples	Stratigraphic units	Lithofacies	Effective porosity (%)				
			Min	Max	Mean	Mode	Std Dev
36	U.4	L.3	0.72	8.6	4.62	3.5	4.64
31	U.5	L.1	0.19	6.91	2.72	1.5	3.38

**Figure 5.** The effective porosity histogram of the Butmah Formation at well Bm-15.

304

305 **Figure 5** illustrates that the Butmah Formation's porosity distribution is roughly unimodal with  
306 a wide spread (standard deviation = 4.64% in U4 and 3.38% in U5). Consequently, the  
307 effective matrix porosity of all units in the Butmah formation is less than 9%, but varies widely,  
308 from 0.19% – 6.91% for the dolomite samples (U4) and 0.72% - 8.6% for the limestone  
309 samples (U5).

## 310 **5.2 Pore throat characterisation**

311 Pore throat size is important because it is related to reservoir porosity, permeability and  
312 irreducible water saturation (Porrás and Campos, 2001). The variations in pore throat and  
313 pore size distribution in the Butmah Formation's limestone and dolomite units are due to  
314 dolomite recrystallisation, anhydrite fraction and distribution, and other diagenetic processes  
315 (Mohammed Sajed and Glover, 2020). Eight samples were selected for mercury injection  
316 capillary pressure (MICP) measurements. **Figure 6** displays the pore throat distributions from  
317 several of these samples as a result of the MICP study.

318 The limestone samples (**Figure 6A** and **6B**) exhibit a single peak, but with slightly different  
319 styles. Both limestone samples show moderate pore sorting, one with a peak at 7 nm with  
320 very few pores larger than 1  $\mu\text{m}$ , the other has a peak at about 30 nm and its largest pore is  
321 600 nm in diameter.

322 The two dolomite samples are presented in the bottom row of **Figure 6**. A wider variety of  
323 pore diameters may be seen in the dolomite samples, with poor pore sorting, and ill-defined  
324 double peaks at 30 nm and 2  $\mu\text{m}$  for Sample C, and 40 nm and 4  $\mu\text{m}$  for Sample D. It is  
325 possible that the peak at the smaller size represents relict porosity from before dolomitisation,  
326 while the larger pore sizes are all derived from the dolomitisation process.

**Figure 6.** Pore throat distributions for four samples from the Butmah Formation; top row (A and B) from the limestone lithofacies (U5, L1), and bottom row (C and D) from the dolomite lithofacies (U4, L3).

327  
328  
329

330 **5.3 Permeability**

331 The permeability of a rock describes its ability to transmit fluid and it is measured in m<sup>2</sup> in SI  
 332 units or in darcies (D) or millidarcies (mD) in industry (Tiab and Donaldson, 2012). The results  
 333 of the permeability measurements made in this work are summarised in Table 2 and Figure  
 334 7.

335 **Table 2.** Permeability measurements of the studied formations.

Units	Lithofacies & lithology	No. samples	Matrix permeability (mD)			
			Min	Max	Geometric Mean	Log-normal measure of standard deviation
U4	L.3 (dolomite)	47	$5.41 \times 10^{-5}$	$6.10 \times 10^{-2}$	$8.6 \times 10^{-3}$	$+7.14 \times 10^{-7}$ $-1.04 \times 10^{+2}$
U5	L.1 (limestone)	43	$1.30 \times 10^{-6}$	$7.69 \times 10^{-3}$	$0.42 \times 10^{-3}$	$+2.52 \times 10^{-10}$ $-7.0 \times 10^{+2}$

336  
 337 The permeability measurements are not distributed normally, but approximate to a log-normal  
 338 distribution. Consequently, we have calculated the log-normal arithmetic mean (which is the  
 339 geometric mean of the raw data) and the equivalent measure of standard deviation. The  
 340 dolomite samples of the U4 have a unimodal distribution in terms of permeability, with the  
 341 lowest value being  $5.41 \times 10^{-5}$  mD and the highest being  $6.10 \times 10^{-2}$  mD, with a geometric mean  
 342 of  $8.6 \times 10^{-3}$  mD and a log-mean standard deviation of  $+7.14 \times 10^{-7} / -1.04 \times 10^{+2}$  mD. The  
 343 limestone samples of U5 permeability measurements also show a unimodal distribution but  
 344 shifted to lower values, the lowest value being  $1.30 \times 10^{-6}$  mD and the highest being  $7.69 \times 10^{-3}$   
 345 mD, with a geometric of  $0.42 \times 10^{-3}$  mD and a log-mean standard deviation of  $+2.52 \times 10^{-10} / -$   
 346  $7.0 \times 10^{+2}$  mD.

347 Figure 7 shows that the permeability in the dolomite rocks of the U4 of the Butmah Formation  
 348 is distributed between  $1.0 \times 10^{-1}$  mD and  $1.0 \times 10^{-5}$  mD, with the highest occurrence (33.3% of  
 349 the measurements) in the range  $1.0 \times 10^{-3}$  mD –  $1.0 \times 10^{-4}$  mD. By contrast, the permeability  
 350 measurements of the limestone samples from U5 of the Butmah Formation show fewer values

351 distributed between  $1.0 \times 10^{-2}$  mD and  $1.0 \times 10^{-6}$  mD, with the highest occurrence (48.4% of the  
352 measurements) in the range  $1.0 \times 10^{-4}$  mD –  $1.0 \times 10^{-5}$  mD. As expected, the dolomite presents  
353 generally higher permeabilities than the limestones, although there is an overlap in the  
354 permeability ranges. The reasons for this are (i) dolomites commonly have larger matrix  
355 porosity than limestones, and (ii) dolomites are more brittle than limestones, and are  
356 consequently more susceptible to the development of permeability-enhancing fractures.

357 **Figure 7.** Histogram showing the permeability of the dolomite and limestone lithofacies in  
358 the Butmah Formation.

359

#### 360 **5.4 Pore description**

361 The pore network of the Butmah Formation has been characterised based on optical and SEM  
362 microscopy. Units 1, 3 and 5 consist of tight limestones, characterised by small mesopores  
363 (1-62.5  $\mu\text{m}$ ) as vugs and intergranular porosity (Figure 8A, B, and C). Some of the pores in  
364 these units (Lithofacies 1) are occluded by anhydrite and calcite cement.

365 Units 2 and 4 consist of different kinds of pores within dolomite lithofacies (Lithofacies 2 and  
366 4). These pores are dependent on the crystallisation of dolomite and the formation of anhydrite  
367 cement in the spaces between the crystals. These lithofacies have exhibits increased porosity  
368 and pore sizes when the anhydrite cement is dissolved as a late diagenetic process, providing  
369 large mesopores (62.5  $\mu\text{m}$  – 1 mm) as intercrystalline and separate and/or touching vugs  
370 (Figure 8D, E, F, G, H, and I).

371 All of the characterised stratigraphic units have significant levels of fracture intensity, but most  
372 of the fractures are occluded (filled or semi-filled) by anhydrite cement and some calcite  
373 cement. Accordingly, there are some open fractures were described especially in units 3, 4  
374 and 5. The final shape of pore network indicates that units 1, 3 and 5 the pore structure is  
375 controlled by a combination of dissolution and fracturing, whereas units 2 and 4 are more  
376 complex than the other units, with their pore structure controlled by dissolution, dolomitisation  
377 and fracturing.

378 **Figure 8.** The Butmah Formation pore structures. (A) (B) (C) Stromatolite boundstone  
379 microfacies, Bm-15, U4 (2278 m) with (A) intercrystalline porosity and (B) intercrystalline and  
380 fracture porosity (C) SEM backscatter image illustrating pore space geometry, and anhydrite  
381 cement effects. (D) Fine crystalline dolomite with intercrystalline and vuggy porosity, Bm-15,  
382 U2 (2580 m). (E) Coarse crystalline dolomite of Lithofacies 3 showing intercrystalline porosity  
383 Bm-15, U4 (2391 m). (F) SEM images showing pores shape and size in coarse crystalline  
384 dolomite, Bm-15, U4 (2391 m). (G) Fine crystalline dolomite of lithofacies 3 showing vuggy  
385 and fracture porosity, Bm-15, U4 (2450 m). (H) Coarse crystalline dolomite showing  
386 intercrystalline porosity and solution-enlarged vugs Bm-15, U4 (2391 m). (K) SEM images  
387 showing intercrystalline and vuggy porosity in medium dolomite crystals, Bm-15, U4 (2388m).

388 The separation between the neutron-density bulk porosity ( $\phi_{nd}$ ) and sonic porosity ( $\phi_s$ ) can be  
389 a good indicator of secondary porosity (Schlumberger, 1997) or of fractures in those units  
390 where there is no geochemical diagenesis apparent in the rocks. This study introduces the  
391 fracture-diagenesis indicator (FDI) as a term indicating both secondary porosity and fracturing  
392 has occurred. The FDI is the result of comparing the calculated SPI from the wireline logs and  
393 diagenesis and fracturing features that are characterised under the microscopic study.  
394 Calibration of the FDI was carried out by using a microscopic thin section study to identify  
395 whether the FDI was due to fracturing or other positive diageneses such as dissolution and  
396 dolomitisation (Figure 9).

397 **Figure 9.** Porosity distribution (bulk and effective) within the Butmah Formation at well Bm-  
398 15 with secondary porosity indicator (SPI) and fracturing-diagenesis indicator (FDI) at each  
399 depth.

## 400 6. DISCUSSION

401 This section considers three main issues; (i) integration of petrophysical properties with the  
402 qualitative description of controlling factors, (ii) using the integrated results to create a new  
403 method for calculating post- and pre-dolomitisation poroperm characteristics and its validation,  
404 (iii) identification the pore system and petrodiagenetic pathway of the Butmah Formation.

### 405 6.1 Integration of petrophysical properties and controlling factors

406 The porosity-permeability (poroperm) relationship in carbonate rocks is controlled by whether  
407 pores and vugs are inter-granular, inter-crystalline, separate or touching (Lucia, 2007). Each  
408 type has a different pore connectivity and size distribution. Hence, for the best interpretation,

409 it is important to integrate the information of the pore space type in the facies with the poroperm  
410 relationship (Ma and Morrow, 1996; Tiab and Donaldson, 2012; Hommel et al., 2018;  
411 Bohnsack et al., 2020).

412 The position of each sample within the poroperm plot depends upon the degree of fracturing  
413 exhibited by the sample as well as the cementation exponent and grain size. In this study, we  
414 have spilt each of the limestone and dolomite poroperm relationships into three fields using  
415 the modified carbonate RGPZ poroperm relationship (Glover et al., 2006; Rashid et al.,  
416 2015b). This relationship can be expressed as

$$417 \quad k = \frac{d_g^2}{4am^2\eta\phi^{-m}(\eta\phi^{-m}-1)^2} \approx \frac{d_g^2\phi^{3m}}{4am^2\eta^3} \text{ if } \phi^{-1} \gg 1, \quad (1)$$

418 where  $k$  is permeability in ( $m^2$ ),  $d_g$  is the characteristic grain size (in m),  $a=8/3$ ,  $\phi$  is the porosity  
419 (fractional),  $m$  is the cementation exponent (no units) and  $\eta$  is a factor expressing how the  
420 characteristic pore size of the rock is related to the characteristic grain size.

421 We have defined three fields within the poroperm relationship. Field D represents the  
422 poroperm characteristics of a rock which is controlled any degree of diagenesis without  
423 fracturing. Field F represents the poroperm characteristics of a rock which is controlled by  
424 fracturing with no appreciable diagenesis, while Field FD represents the poroperm  
425 characteristics of a rock partially controlled by diagenesis and partially by fracturing.

426 In Figure 10, the D/FD cut-offs are ( $\eta=1$ ,  $m=2.0$ ,  $d_g=1 \mu m$ ) and ( $\eta=1$ ,  $m=2.0$ ,  $d_g=4 \mu m$ ) for  
427 limestone and dolomite samples, respectively. For the FD/F boundary, the cut-off values are  
428 ( $\eta=1$ ,  $m=1.8$ ,  $d_g=10 \mu m$ ) and ( $\eta=1$ ,  $m=1.8$ ,  $d_g=40 \mu m$ ) for limestone and dolomite samples,  
429 respectively. The lower cementation exponent for the FD/F cut-off takes account for the lower  
430 cementation exponents associated with the decrease in pore space connectivities associated  
431 with fractures (Glover, 2015). For the D/FD cut-off, the characteristic grain sizes of  $1 \mu m$  and  
432  $4 \mu m$  are associated with characteristic pore sizes of  $0.002 \mu m$  and  $0.0086 \mu m$  using the  
433 transformation given in Glover and Walker (2009) for a porosity of 5%. This transformation is  
434 given by

435 
$$d_p^2 = \frac{8\phi^{2m}}{am^2} \cdot d_g^2, \quad (2)$$

436 where all the parameters were defined for Eq. (1) except  $d_p$ , which is the pore diameter (same  
 437 units as  $d_g$ ). For the FD/F cut-off, the characteristic grain sizes of 10  $\mu m$  and 40  $\mu m$  are  
 438 associated with characteristic pore sizes of 0.044  $\mu m$  and 0.175  $\mu m$ , also calculated from  
 439 Equation (2) for a porosity of 5%, showing in all cases that the pore dimensions are  
 440 significantly smaller than the grains that define them in both the limestones and the dolomites,  
 441 but that the dolomite grains are significantly larger than those in the pre-dolomitised limestone,  
 442 which is consistent with both our micrographical experience and those of others (Moore, 2001;  
 443 Lucia, 2004; 2007).

444 In summary, the D field consists of samples whose petrophysical properties have developed  
 445 mainly by diagenetic processes such as dolomitisation, dissolution, and cementation. The FD  
 446 field consists of samples whose petrophysical properties have developed partially by fracturing  
 447 and partially by diagenesis, and the F field contains the samples whose petrophysical  
 448 properties have been improved mainly by fracturing, without or with minor diagenetic influence.  
 449 Table 3 summarises the field and zone definitions that we have used, while Figure 10 shows  
 450 all of the experimental data in the context of the defined fields and zones.

451 **Table 3.** The poroperm zones classification applied to the Butmah Formation

Lithology	Zone	Porosity (%)	Permeability (mD)	Pore throat ( $\mu m$ )	Controlling factor
Limestone	D	1.8 – 6.5	0.000001 - 0.001	0.001 – 0.1	Diagenesis
	FD	1.0 – 4.5	0.00001 – 0.02	0.08 – 1.0	Fracturing + diagenesis
	F	0.5 – 3.5	0.003 - 8.0	0.3 - 20	Fracturing
Dolomite	D	1.8 – 8.6	0.00005 - 0.05	0.02 – 1.0	Diagenesis
	FD	1.0 – 5.0	0.001 – 8.0	0.1 – 20	Fracturing + diagenesis
	F	1.5 - 2.5	0.8 - 8.0	8.0 - 18	Fracturing

452 D= diagenesis effect field, FD= fracturing and diagenesis effect field, F= fracturing effect field.

453

454 **Figure 10.** Porosity-permeability relationships with controlling factors shown as identified  
455 petrophysical fields. (A) The poroperm relationship for the limestone samples (U.5, L.1) with  
456 pie chart shows the distribution of the identified petrophysical fields. (B) The poroperm  
457 relationship for the dolomite samples (U.4, L.3) with pie chart shows the distribution of the  
458 identified petrophysical fields. The solid lines partitioning the poroperm relationships are  
459 RGPZ contours where the grain size ( $d$ ) and cementation exponent ( $m$ ) parameters are given  
460 in the figure (Glover et al., 2006; Rashid et al., 2015b). The dashed lines are best fit RGPZ-  
461 type power laws for each field.

462

### 463 **Limestone Samples**

464 The 43 limestone samples of the Butmah Formation have, in general, smaller porosity, pore  
465 throat and pore sizes and permeabilities than the dolomite samples. They can be divided into  
466 three fields, as follows.

467 **D (Diagenetically altered samples).** This field consists of 32.6% of the limestone samples of  
468 the Butmah Formation and includes pore network consist of interparticles, intercrystalline,  
469 vugs and microfractures. Their permeability has been improved mainly by diagenetic  
470 processes, such as dissolution and cementation. These samples have porosity range between  
471 1.8% and 6.5% and a permeability range between  $1.0 \times 10^{-6}$  mD and  $1.0 \times 10^{-3}$  mD, with a pore  
472 throat range between 0.001  $\mu\text{m}$  and 0.1  $\mu\text{m}$ . **Figure 10A** shows that these samples follow an  
473 RGPZ type power law (blue dashed line) with a power law coefficient of determination  
474  $R^2=0.85$ , indicating that there is a small degree of heterogeneity. None of these samples  
475 showed any significant fracturing at microscopic or macroscopic scale.

476 **FD (Fractured and diagenetically altered samples).** This field represents 41.8% of the  
477 limestone samples of the Butmah Formation and contains samples which have a pore network  
478 consisting of interparticle and intercrystalline pores, together with microfractures. Their  
479 permeability has been improved both by fracturing and diagenetic processes such as  
480 dissolution and cementation. These samples have a porosity range between 1.0% and 4.5%  
481 and a permeability range between 10 nD and 0.02 mD with a pore throat range between 0.08  
482  $\mu\text{m}$  and 1.0  $\mu\text{m}$ . The best-fit RGPZ-type power law that is shown by a dashed green line in  
483 **Figure 10A** shows that these samples are scattered, with a low power law coefficient of

484 determination,  $R^2=0.57$ . This low value may be the result of the samples exhibiting a great  
485 deal of heterogeneity resulting from the porosity and permeability being affected by a large  
486 number of diagenetic processes and fracturing, the latter of which can amplify the degree of  
487 diagenesis locally.

488 **F (Fractured samples)**. This field represents 25.6% of the limestone samples of the Butmah  
489 Formation. These samples have pore networks consisting of macroscopic fractures together  
490 with interparticle and intercrystalline pores, and microfractures. Their permeability has been  
491 improved predominantly by fracturing. These samples have porosity ranging between 0.5%  
492 and 3.5% and permeability ranging between 0.003 mD and 8.0 mD with 'pore throats' greater  
493 than 0.3  $\mu\text{m}$ , which likely represent the apertures of fractures. The best-fit RGPZ-type power  
494 law that is shown by a dashed red line in [Figure 10A](#) shows that the fractured limestone  
495 samples are scattered, with a power law coefficient of determination  $R^2=0.25$ . The cause of  
496 the low coefficient of determination, here, is expected to be the presence of different degrees  
497 of fracturing in the data set, with the three lowest permeability points exhibiting only small  
498 degrees of fracturing.

#### 499 **Dolomite samples**

500 A total of 47 samples of the dolomite lithology were analysed to calculate their petrophysical  
501 properties in the same way as for the limestone samples. These samples can also be divided  
502 into three fields.

503 **D (Diagenetically altered samples)**. This field consists of 59.6% of the dolomite samples of  
504 the Butmah Formation and includes samples where the pore network consists of interparticle,  
505 intercrystalline, and vuggy pores, with some microfractures. Their permeability has been  
506 improved mainly by the diagenetic process of such as dissolution and cementation. These  
507 samples have a porosity range between 2.0% and 8.6%, permeability ranging between  
508  $5.0 \times 10^{-5}$  mD and  $5.0 \times 10^{-2}$  mD, and pore throat diameters between 0.02  $\mu\text{m}$  and 1.0  $\mu\text{m}$ . The  
509 best-fit RGPZ-type power law, that is shown by a dashed blue line in [Figure 10B](#), shows that  
510 these samples are scattered, with a power law coefficient of determination  $R^2=0.63$ , which is

511 a larger degree of variation than that found for the Limestone Field D samples, described  
512 above, and indicates that the dolomite exhibits a higher degree of heterogeneity than the  
513 limestone, which is caused by the development of a pore texture that is dependent on  
514 dolomitisation, dissolution and precipitation. None of these samples showed any significant  
515 fracturing at microscopic or macroscopic scale.

516 **FD (Fractured and diagenetically altered samples).** This field represents 31.9% of the  
517 dolomite samples of the Butmah Formation and has a pore network consisting of both fractures  
518 (mainly microfractures) and interparticle or intercrystalline pores. Their permeability has been  
519 improved by both diagenesis and fracturing. The fracturing may have enhanced certain  
520 diagenetic processes, such as dissolution, compaction and cementation, by allowing the  
521 access and egress of fluids. Equally, the process of dolomitisation may have promoted the  
522 formation of fractures because dolomite is more brittle than limestones and would also be  
523 hosting a higher porosity matrix.

524 These samples have a porosity range between 1.0% and 5.0%, a permeability range between  
525 0.001 mD and 8.0 mD, and have pore throat diameters between 0.1  $\mu\text{m}$  and 20  $\mu\text{m}$ . The best-  
526 fit RGPZ-type power law that is shown by a dashed green line in [Figure 10B](#) shows that these  
527 samples show a high degree of variation, with a power law coefficient of determination  
528  $R^2=0.49$ . This value is slightly lower than the Limestone FD samples, which may be due to the  
529 process of dolomitisation largely reworking the pore texture, making it more locally  
530 heterogeneous.

531 **F (Fractured samples).** This field represents 8.5% of the dolomite samples of the Butmah  
532 Formation. These samples have a pore network that consists of some interparticle and  
533 intercrystalline pores, but that is dominated by macroscopic fractures and microfractures. As  
534 a result, their permeability has been enhanced mainly by fracturing. These samples have  
535 porosity range between 1.5% and 2.5%, permeabilities between 0.8 mD and 8.0 mD, with pore  
536 throat diameters greater than 8.0  $\mu\text{m}$ . As for fractured limestones, the largest pore diameters  
537 are probably measurements of the apertures of fractures. In [Figure 10B](#) the best-fit RGPZ-

538 type power law (shown by a dashed red line) is almost meaningless because it is based on  
539 only 4 datapoints. However, it gives a power law coefficient of determination  $R^2=0.42$ , which  
540 is consistent with an RGPZ trend. This is mainly due to the fact that locally some samples  
541 were substantially fractured while others were only slightly fractured, in a small sample set  
542 where variability can be significantly changed by one unusual sample.

543

## 544 **6.2 New method for calculating post- and pre-dolomitisation poroperm characteristics**

### 545 **Relative poroperm characteristics**

546 Comparison between the difference in the petrophysical properties of each lithology  
547 (limestone and dolomite) samples of the Butmah Formation is very important for three  
548 reasons. First, in order to ascertain the petrodiagenetic pathway of carbonate rocks  
549 ([Mohammed Sajed and Glover, 2020](#)). Second, to obtain the pre-dolomitisation petrophysical  
550 properties of dolomite samples, and thirdly, to predict the post-dolomitisation petrophysical  
551 properties of limestone samples. Accordingly, a non-linear best fitting process was carried  
552 out on each of the 6 fields. In all cases the best fitting equation was a power law, and these  
553 are given in [Table 4](#) and [Figure 11](#). It was expected that a power law would represent the best-  
554 fitting equation because the generic RGPZ model ([Glover et al., 2006](#); [Rashid et al., 2015b](#))  
555 has a power law form which arises from its theoretical pedigree. Hence the fit is informed by  
556 the physics of the porous medium to which it is being applied. It follows that the RGPZ  
557 equations, when written in the generic power law form provide good fits with high values of  
558 coefficient of determination ( $R^2$ ) compared to all other *ad hoc* fitting types ([Rashid et al., 2015b](#);  
559 [Al-Khalifah et al., 2020](#)).

560 It should be noted that these equations were identified for the Butmah Formation, and any  
561 other carbonate formation needs to find its own best-fit equations. However, since the RGPZ  
562 equations present a generic form of the fitting equations and were ultimately derived  
563 theoretically rather than simply being empirical fits ([Glover et al., 2006](#)), it is more than likely  
564 that the best fitting will commonly be attained by using a power law fit.

565 **Figure 11** shows a comparison of the poroperm trends for each of the three identified fields.  
566 **Figure 11A** shows that the diagenetically-altered limestone samples increase in permeability  
567 as porosity increases with a power law coefficient of determination  $R^2=0.85$ . The increase in  
568 porosity is related mainly to dissolution and increases at a rate dependent upon the  
569 connectivity of the pores. By contrast, the diagenetic dolomite samples in **Figure 11A** show a  
570 similar increase in permeability with porosity ( $R^2=0.63$ ) but to higher porosities and  
571 permeabilities that are due to dissolution and dolomitisation. The difference in the porosity  
572 ranges of the limestone and dolomite samples is approximately 1.5 units. Whereas **Figure 11B**  
573 shows only one unit different between the porosity range of limestone and dolomite samples,  
574 with a low power law coefficient of determination ( $R^2=0.49$  and  $0.57$  respectively) as a result  
575 of the effect of diagenesis and fracturing controls. The dolomite samples were more  
576 heterogeneous due to effect of dolomitisation compared to the limestone samples.

577 **Table 4.** Permeability estimating equations for the 3 identified fields for each limestone and  
578 the dolomite samples.

Lithology	Field	Equation ( $k$ in mD and $\phi$ as a percentage)	Limits of validity
Limestone	D	$k_D = 2 \times 10^{-8} \phi^{5.2579}$	Porosity: 1.8% - 6.5% Permeability: $10^{-6} - 10^{-3}$ mD Pore throat diameter: 0.001 – 0.1 $\mu\text{m}$ Grain diameter: < 1 $\mu\text{m}$ Cementation exponent: > 2
	FD	$k_{FD} = 2 \times 10^{-5} \phi^{3.9099}$	Porosity: 1.0% - 4.5% Permeability: $10^{-5} - 2 \times 10^{-2}$ mD Pore throat diameter: 0.08 – 1.0 $\mu\text{m}$ Grain diameter: 1 - 10 $\mu\text{m}$ Cementation exponent: 1.8 - 2
	F	$k_F = 4 \times 10^{-2} \phi^{3.4569}$	Porosity: 0.5% - 3.5% Permeability: 0.003 – 8.0 mD Pore throat diameter: 0.3 – 20 $\mu\text{m}$ Grain diameter: > 10 $\mu\text{m}$ Cementation exponent: < 1.8
Dolomite	D	$k_D = 3 \times 10^{-6} \phi^{3.7444}$	Porosity: 1.8% - 8.6% Permeability: $5 \times 10^{-5} - 5 \times 10^{-2}$ mD Pore throat diameter: 0.02 – 1.0 $\mu\text{m}$ Crystal diameter: < 4 $\mu\text{m}$ Cementation exponent: > 2
	FD	$k_{FD} = 1.1 \times 10^{-3} \phi^{4.3692}$	Porosity: 1.0% - 5.0% Permeability: $10^{-3} - 8.0$ mD

		Pore throat diameter: 0.1 – 20 $\mu\text{m}$ Crystal diameter: 4 - 40 $\mu\text{m}$ Cementation exponent: 1.8 - 2
F	$k_F = 0.5877\phi^{1.7574}$	Porosity: 1.5% - 2.5% Permeability: 0.8 – 8.0 mD Pore throat diameter: 8.0 – 18 $\mu\text{m}$ Crystal diameter: > 1 $\mu\text{m}$ Cementation exponent: < 1.8

579

580 **Figure 11.** Comparison of the three identified petrophysical fields in both lithology limestone  
581 and dolomite including porosity, permeability, and the non-linear best fitting equations with a  
582 power law coefficient of determination ( $R^2$ ). (A) Diagenetically altered samples. (B) Fractured  
583 and diagenetically- altered samples. (C) Fractured samples.

584 **Figure 11C** shows that there is complete overlap between the fractured limestone and  
585 dolomite due to the degree of scatter in both datasets, with a low power law coefficient of  
586 determination ( $R^2=0.25$  and  $0.42$  respectively). This is mainly due to the fact that some  
587 samples were substantially fractured while others were only slightly fractured. This may be a  
588 result of the measurements being made on core samples, which are sufficiently small for the  
589 full expression of fracturing not to be taken into account in the data. Indeed, it is likely that only  
590 the higher permeability group in **Figure 11C** are truly caused by fracturing, while some of the  
591 smaller permeability values, though high for their individual porosity, are due to relict  
592 diagenetic processes, particularly dissolution. This same separation of the fractured samples  
593 is shown to a lesser degree for the fractured dolomite samples, probably for the same reason.

#### 594 **Predicting pre- and post-dolomitisation porosity**

595 This study applies a new method for

- 596 (i) estimating the petrophysical properties of dolomite if the petrophysical properties of  
597 the pre-dolomitised limestone are known, or
- 598 (ii) estimating the petrophysical properties of the pre-dolomitised limestone from  
599 knowledge of the petrophysical properties of the existing dolomite.

600 The methodology takes account of varying porosity values and uses a non-linear best fitting  
601 process to ensure that transformation of data for individual samples is carried out with

602 contributing canonical averages for the whole related dataset. Calculations were carried out  
603 on each of the 6 fields (limestone to dolomite and vice versa, for D, FD and F data).

604 For the process of dolomitisation (i.e., calcite becoming dolomite mineral) the methodology  
605 uses the following steps, the results of which are shown in figures 12 to 14 for each of the D,  
606 FD and F data, respectively.

- 607 1- Plot the samples on the poroperm plot (e.g., Figure 12A).
- 608 2- Apply the power law fitting equation to the limestone samples (e.g., Figure 12A).
- 609 3- Using a millimetric scale to measure the high and low of plotting sample of the best  
610 fitting line (e.g., Figure 12A).
- 611 4- Calculate the difference in the porosity ranges between the limestone and dolomite  
612 samples using Equation (3) for each identified (D, FD and F) as follows;

$$613 \quad \psi_f = \frac{(\phi_{dol\_hi} - \phi_{dol\_low})}{(\phi_{lmst\_hi} - \phi_{lmst\_low})}, \quad (3)$$

614 where  $\psi_f$  is the fractional relative variation of the dolomite samples with respect to the  
615 variation in the limestone samples in a particular field ( $f$ ), whether D, FD or F. The other  
616 parameters in Equation (3) are  $\phi_{dol\_hi}$ , which is the highest calculated porosity in the  
617 dolomite samples,  $\phi_{dol\_low}$ , which is the lowest calculated porosity in the dolomite  
618 samples,  $\phi_{lmst\_hi}$ , which is the highest calculated porosity in the limestone samples,  
619 and  $\phi_{lmst\_low}$ , which is the lowest calculated porosity in the limestone samples.

620 In this study,  $\psi_f$  was found to be 1.49 for diagenetically-altered samples, 1.05 for  
621 fractured and diagenetically-altered samples, and 0.51 for fractured samples.

- 622 5- Add the porosity percentage to each limestone sample.
- 623 6- Replot the new porosities together with the permeability calculated by applying the  
624 non-linear best fitting equation for the dolomite samples on a poroperm plot (e.g.,  
625 Figure 12B). At this stage all the predicted points fall exactly on the fitting curve. The  
626 next step restores the scatter to the data points.

627 7- Use the millimetric scale again to give the high and low of each sample according to  
628 the earlier measurements in Point 3 in this list to give the best estimated values of  
629 post-dolomitisation limestone samples including scatter (e.g., [Figure 12C](#)).

630 8- Plot the origin limestone measurements with the post-dolomitisation limestone  
631 samples to compare the result (e.g., [Figure 12D](#)).

632 It is important to note that the millimetric scale represents an arbitrary scale that measures the  
633 scatter in data points and is valid irrespective of the other relative scales and units if applied  
634 consistently. The calculation of  $\psi_f$  is consequently non-dimensional.

635 We can also apply the same processes 'in reverse' to estimate the petrophysical properties of  
636 pre-dolomitisation limestone from the dolomite samples of the Butmah Formation (e.g., [Figure](#)  
637 [12E-H](#)).

638 [Figures 13](#) and [14](#) show the same procedure that has been applied in [Figure 12](#), but for  
639 samples that are altered both by fracturing and diagenesis ([Figure 13](#)), and for samples that  
640 are only altered by fracturing ([Figure 14](#)).

641 **Figure 12.** Prediction of post-dolomitisation dolomite poroperm data and the pre-  
642 dolomitisation limestone data for the diagenetically-altered samples (Field D). (A-D) The  
643 limestone samples (U.5, L.1) are used to estimate their post-dolomitisation petrophysical  
644 properties. (E-H) The dolomite samples (U.4, L.3) are used to estimate the pre-dolomitisation  
645 petrophysical properties.

646

647 **Figure 13.** Prediction of post-dolomitisation dolomite poroperm data and the pre-  
648 dolomitisation limestone data for the fractured and diagenetically altered samples. (A-D) The  
649 limestone samples (U.5, L.1) are processes of estimating the post-dolomitisation petrophysical  
650 properties. (E-H) The dolomite samples (U.4, L.3) are processes of the pre-dolomitisation  
651 petrophysical properties.

652

653 **Figure 14.** Prediction of post-dolomitisation dolomite poroperm data and the pre-  
654 dolomitisation limestone data for the fractured samples. (A-D) The limestone samples (U.5,  
655 L.1) are processes of estimating the post-dolomitisation petrophysical properties of limestone  
656 samples. (E-H) The dolomite samples (U.4, L.3) are processes of the pre-dolomitisation  
657 petrophysical properties.

658 **Figure 15** shows comparisons between the predicted and the measured values for the post-  
659 dolomitisation and pre-dolomitisation values. There is good correspondence in all the  
660 comparisons. However, the weakest correspondence occurs for the F field, where the small  
661 number of samples has made the method more inaccurate.

662 **Table 5** summarises the results of carrying out two sample *t*-tests on the data, which is  
663 required in order to quantify the extent to which the new method is effective. Two sample *t*-  
664 tests have the capability of distinguishing whether the two samples, here predicted and  
665 associated measured values, are different, that is, they are not drawn from the same  
666 population and cannot be considered to be statistically equal within a given probability. In our  
667 case we are looking for statistical evidence that the opposite is the case. In other words, that  
668 the predicted and measured data seem to be drawn from the same population and hence are  
669 identical.

670 In our case we do this for both the porosity and the permeability separately, using Welch's  
671 unequal variances *t*-test formulation (Delacre et al., 2017). This formulation takes account of  
672 unequal variances in the two sample sets. All of the requirements of using this test are fulfilled.  
673 That is to say that (i) the data consists of two independent samples, one from each of the two  
674 populations being compared (here the measured and predicted data), (ii) the sample means  
675 are normally distributed, (iii) the sample variances are  $\chi^2$  distributed, which follows from (ii),  
676 and (iv) the sample means and sample variances are statistically independent. We have pre-  
677 tested for normality for all of our porosity data using the Kolmogorov-Smirnov test. All porosity  
678 data was found to be distributed normally. However, permeability is commonly distributed log-  
679 normally, and is so in our datasets. Consequently, we have carried out all statistical tests on  
680 the logarithm to the base 10 of permeability data. When this logged data was subjected to the  
681 Kolmogorov-Smirnov test, normality was found in all cases.

682 We have calculated a *t*-statistic, a critical *t*-value and a *P*-value using the Welch's unequal  
683 variances *t*-test formulation (Delacre et al., 2017) and taking account of the variable degrees  
684 of freedom between the D, DF and F field data, and these are shown in **Table 5**.

685 The criteria that that the predicted and measured data are drawn from the same population  
686 and hence are identical is that the  $t$ -value is as close to zero as possible, and that the  $t$ -value  
687 is less than, preferably much less than the  $t$ -critical value. This is clearly the case for all of the  
688 D and DF field data shown in the table. The evidence is weaker for the F field data because  
689 there are only 4 samples in the dolomite F dataset, which weakens the statistical power of the  
690 calculation. Consequently, on the basis of the  $t$ -test, it might be said that the predicted  
691 permeabilities agree well with the associated experimental data. Hence the new method works  
692 well, at least for the D and the DF data, and might work well for the F data if we had a  
693 sufficiently large dataset to test it more thoroughly.

694 We have also calculated the  $P$ -value from the  $t$ -value statistic. Since we are seeking the  
695 fulfilment of the null hypothesis rather than when it fails, this statistic is difficult to interpret.  
696 The  $P$ -value is normally used to recognise the probability that the null hypothesis (here that  
697 the two datasets have equal mean values, i.e.,  $H_0: \mu_1 = \mu_2$ ) is apparently broken by chance. For  
698 example, two very different, but maybe slightly overlapping datasets might have a  $P$ -value of  
699 0.02, representing a 2% chance that the data seem to be separated but are in fact from the  
700 same population. In this work we obtain values as high as 0.863 indicating that it is highly  
701 likely that the data are from the same population – 86.3% chance in fact.

702 **Table 5.** Statistical 2 sample *t*-tests on the data using Welch's unequal variances *t*-test (Delacre et al., 2017) with a level of probability of 95%  
 703 (0.05). Permeability data have been calculated on the base 10 logarithm of the data value to take account of the log-normal distribution of the  
 704 permeability data. All porosity data and log<sub>10</sub>(permeability) data passed the Kolmogorov-Smirnov test for normality.

Field	Prediction	Variable	Dataset	Sample size	Mean (%)	Standard deviation (%)	<i>t</i> -statistic		<i>t</i> -critical at $\alpha=0.05$	<i>P</i> -value
D	Post-dolomitisation	Porosity	Predicted	14	5.343	1.364	0.322	<<	2.032	0.749
			Measured	28	5.178	1.921				
D	Post-dolomitisation	log <sub>10</sub> (Permeability)	Predicted	14	-2.797	0.576	0.54	<<	2.028	0.592
			Measured	28	-2.919	0.870				
D	Pre-dolomitisation	Porosity	Predicted	28	3.687	1.921	0.322	<<	2.030	0.749
			Measured	14	3.854	1.364				
D	Pre-dolomitisation	log <sub>10</sub> (Permeability)	Predicted	28	-4.573	1.514	0.876	<<	2.026	0.386
			Measured	14	-4.237	0.953				
DF	Post-dolomitisation	Porosity	Predicted	18	3.520	1.043	0.292	<<	2.048	0.772
			Measured	15	3.407	1.170				
DF	Post-dolomitisation	log <sub>10</sub> (Permeability)	Predicted	18	-0.697	0.914	0.174	<<	2.048	0.863
			Measured	15	-0.757	1.047				
DF	Pre-dolomitisation	Porosity	Predicted	15	2.357	1.170	0.292	<<	2.048	0.772
			Measured	18	2.471	1.043				
DF	Pre-dolomitisation	log <sub>10</sub> (Permeability)	Predicted	15	-3.467	1.647	0.245	<<	2.074	0.808
			Measured	18	-3.346	1.043				
F	Post-dolomitisation	Porosity	Predicted	11	2.440	0.736	1.466	<	2.306	0.166
			Measured	4	1.950	0.500				
F	Post-dolomitisation	log <sub>10</sub> (Permeability)	Predicted	11	0.506	0.902	0.785	<	2.179	0.447
			Measured	4	0.258	0.324				
F	Pre-dolomitisation	Porosity	Predicted	4	1.440	0.500	1.466	<	2.306	0.166
			Measured	11	1.930	0.736				
F	Pre-dolomitisation	log <sub>10</sub> (Permeability)	Predicted	4	-0.891	0.642	0.851	<	2.262	0.41
			Measured	11	-0.502	1.079				

706 We hypothesize that we do not have  $P$ -values higher than 0.863, and approaching unity,  
707 because we are constrained to testing the predicted porosity and permeability after  
708 dolomitisation with the actual measured porosity and permeability after dolomitisation on  
709 closely associated units. The diversion from unity represents the natural variability between  
710 the petrophysical properties of the predicted rock from the nearby test rock, which may be  
711 different. The same effect also occurs when predicting porosity and permeability before  
712 dolomitisation. Consequently, it might be expected that a value closer to unity than 0.863  
713 would not be expected, indeed that values between 0.7 and 0.9 are very creditable. If this is  
714 the case, for a  $P$ -value of 0.863, the value 0.137 ( $=1-0.863$ ) represents some measure of the  
715 variability between the rock used for prediction and the test rock. Nonetheless, we also obtain  
716 a few lower values for the permeability predictions in the Field D as well as lower values still  
717 for the statistically weak tests carried out for Field F.

718 In summary, both [Figure 15](#) and [Table 5](#) provide strong quantitative evidence for a good  
719 correlation in most of the 16 tests. This data leads us to believe that the new method  
720 represents a useful new approach to predicting the porosity and permeability of limestone  
721 rocks post-dolomitisation, and obtaining the likely porosity and permeability of dolomitised  
722 rocks before the dolomitisation occurred. Here, this new method was applied to the Butmah  
723 Formation as an example that could be easily applied to any other carbonate formations using  
724 the same processes to cover any shortage of core samples in some formation intervals within  
725 boreholes and to obtain an integrated reservoir characterisation.

726 **Figure 15.** Comparison of the modelled post-dolomitisation and pre-dolomitisation porosity  
727 and measured permeability values with values from associated dolomite and limestones,  
728 respectively. (A) predicted and measured values for post-dolomitisation dolomite in diagenetic  
729 field samples (Field D), (B) predicted and measured values for pre-dolomitisation limestone in  
730 diagenetic field samples (Field D), (C) predicted and measured values for post-dolomitisation  
731 dolomite in fractured-diagenetic field samples (Field FD), (D) predicted and measured values  
732 for pre-dolomitisation limestone in fractured-diagenetic field samples (Field FD), (E) predicted  
733 and measured values for post-dolomitisation dolomite in fractured field samples (Field F), (F)  
734 predicted and measured values for pre-dolomitisation limestone in fractured field samples  
735 (Field F).

736

### 737 6.3 The pore system and petrodiagenetic pathway of the Butmah Formation

738 The qualitative observations of the diagenesis in the Butmah Formation were characterised  
739 by three stages (Figure 4); a syndepositional and marine diagenetic stage (Stage-1), a  
740 meteoric and mixing zone diagenetic stage (Stage-2), and a burial diagenetic stage (Stage-  
741 3).

742 The major dolomitisation phase of the Butmah Formation is either syndepositional or occurs  
743 during shallow-burial conditions associated with anhydrite cement and ends before significant  
744 burial occurs (Mohammed Sajed and Glover, 2022). Accordingly, early dolomitisation plays a  
745 significant role in improving the reservoir properties of the Butmah Formation in Stage-1.  
746 Whereas, intergranular/intercrystal, solution-enlarged vugs and selective dissolution were the  
747 main factors improving the reservoir properties in Stage-2, the main factor in Stage 3 was  
748 fracturing. Stage-3 processes have affected all the stratigraphic units of the Butmah Formation  
749 in two ways. First, reduction in matrix porosity by dolomite recrystallization, cementation, and  
750 significant compaction. Second, increased fracture intensity due to high compaction (chemical  
751 compaction) (Mohammed Sajed and Glover, 2020).

752 Consequently, the final shape of the pore network of the Butmah Formation was described in  
753 stratigraphic units 1, 3, and 5 as pores are mainly due to a combination of dissolution,  
754 cementation, and fracturing controls, whereas stratigraphic units 2 and 4 are more complicated  
755 by including dolomitisation to dissolution, cementation, and fracturing controls.

756 In general, porosity in carbonate rocks is secondary porosity caused mainly by dissolution,  
757 dolomitisation and fracturing (Ahr, 2008; Mohammed Sajed and Glover, 2020; Quan et al.,  
758 2023). The separation between the bulk porosity ( $\phi_{nd}$ ) and sonic porosity ( $\phi_s$ ) can be a good  
759 indicator of secondary porosity (Schlumberger, 1997) or of fractures in those units where there  
760 is no geochemical diagenesis apparent in the rocks and it is often used to indicate the extent  
761 of diagenetic reworking of porosity (Wyllie et al., 1956, 1958; Asquith and Gibson, 1982;  
762 Bateman, 1985; Schlumberger, 1989). Accordingly, this study used the fracture-diagenesis  
763 indicator (FDI) for comparing the calculated SPI from the wireline logs and diagenesis and

764 fracturing features that are characterised under the microscopic study to identify whether the  
765 FDI was due to fracturing (F) field or other positive diageneses such as dissolution and  
766 dolomitisation (D) field or mixture of both (FD) field (Figure 9). Only U.1 shows the effect of  
767 the three controlling factors D, DF, and F whereas, U.2 and U.4 were influenced by D and FD  
768 and U.3 and U.5 were affected by FD and F.

769 The quantitative observations of the Butmah Formation including porosity, permeability and  
770 pore throat measurements were integrated with the qualitative description of the diagenetic  
771 and fracturing controls allowed us to split the poroperm relationship of the Butmah Formation  
772 using the modified carbonate RGPZ poroperm relationship (Glover et al, 2006; Rashid et al.,  
773 2015b) into three petrophysical fields for each limestone and dolomite lithology according to  
774 their grain/crystal size, and cementation exponent that take account of whether the main  
775 control on petrophysical properties and reservoir quality is diagenesis (D), fracturing (F) of a  
776 mixture of both (FD) to illustrate clearly that the general pore system in the Butmah Formation  
777 can be described as a hybrid, diagenetic-fracturing pore system according to Ahr's  
778 classification (2008), with 32.6% diagenetic petrophysical field, 41.8% fracturing-diagenetic  
779 petrophysical field and 25.6% fracturing petrophysical field for limestone. Whereas for the  
780 dolomite the diagenetic petrophysical field represented by 59.6% and 31.9% and 8.5% for the  
781 diagenetic, fracturing-diagenetic, and fracturing petrophysical fields respectively.

782 Diagenesis and fracturing can cause increases or decreases in both porosity and permeability,  
783 fracturing generally results in smaller changes to porosity and larger changes to permeability  
784 than diagenetic processes. Consequently, diagenesis and fracturing can work together to  
785 make the pore network of carbonate reservoirs more heterogeneous resulting in a hybrid  
786 porosity system (Tuker et al., 1990; Selly, 2000; Scholle and Ulmer Scholle, 2003; Ahr, 2008;  
787 Boggs, 2009; Ross, 2011; Mohammed-Sajed and Glover, 2022). The Butmah Formation  
788 shows this tendency well, with fractured samples plotting on the poroperm plots at high  
789 permeabilities and low porosities (Field F), whereas diagenetically-altered samples show  
790 moderately high permeabilities but substantially higher porosities (Field D) (Figure 10).

791 Consequently, the integrated result of applying the qualitative description and the quantitative  
792 measurements and predictions presented in this study, the main petrodiagenetic pathways of  
793 the Butmah Formation according to the effect of dolomitisation and fracturing can be  
794 summarised in **Figure 16**. This figure illustrates that dolomitisation generally increases porosity  
795 and permeability even if the rocks are previously fractured. The effect of dolomitisation alone  
796 on the limestone samples shows notable changes in porosity and permeability (**Figure 16A**).  
797 The dolomitisation effect on the partially fractured limestone samples also shows a notable  
798 increase in both permeability and porosity, (**16B**). The dolomitisation effect on the fully  
799 fractured limestone samples shows an increase in permeability but no apparent increase or  
800 decrease in porosity (**Figure 16C**). This may be due to the small numbers of samples in the  
801 fractured set.

802 Fracturing occurring in either a limestone or a dolomite with no further dolomitisation (**Figure**  
803 **16D** and **16E**, respectively, provided significant increases in permeability despite also showing  
804 decreases in porosity. This is contrary to expectations, and it is thought that some other  
805 diagenetic process, such as matrix precipitation, is also contributing to the changes in the  
806 petrodiagenetic pathway. It is worth noting that the decrease in porosity on fracturing is larger  
807 if it happens to dolomitised rock (**Figure 16E**).

808 **Figure 16.** The petrodiagenetic pathway of the Butmah Formation according to the effect of  
809 dolomitisation and fracturing. (A) Dolomitisation of limestone. (B) Dolomitisation of partially  
810 fractured limestone. (C) Dolomitisation of fully fractured limestone. (D) Fracturing of limestone  
811 with no dolomitisation. (E) Fracturing of dolomite.  
812

813 Moreover, **Figure 17** summarises in an overall flow diagram, the qualitative and quantitative  
814 observations and inferences set out in this paper from two points of view; (i) qualitative  
815 descriptions including diagenetic stages, main controlling factors and pore types and their  
816 outcome as pore network and pore system, and (ii) quantitative descriptions and  
817 measurements, including field-based poroperm classifications as a new technique and their  
818 outcome to divided it into petrophysical fields according to the characterised main controlling

819 factors (fracturing and diagenetic), and the changes in the petrophysical properties including  
820 porosity, permeability and pore throat size.

821 **Figure 17.** Flow chart summarising the qualitative and quantitative descriptions of the  
822 petrodiagenetic pathway of the Butmah Formation ( $\phi$ , porosity;  $k$ , permeability;  $d_{th}$ ,  
823 characteristic pore throat diameter.  
824

## 825 7. CONCLUSIONS

826 The results of this study may be summed up as follows;

- 827 • The Butmah Formation has been affected by several diagenetic processes characterised  
828 by three diagenetic stages that create the final pore system of the Butmah Formation, which  
829 are; a syndepositional and marine diagenetic stage, a meteoric and mixing zone diagenetic  
830 stage, and a burial diagenetic stage. Consequently, the final shape of the pore network  
831 described in units 1, 3, and 5 as pores are mainly due to a combination of dissolution,  
832 cementation, and fracturing controls, whereas units 2 and 4 are more complicated by  
833 adding dolomitisation to dissolution, cementation, and fracturing controls.
- 834 • Three petrophysical fields have been identified according to their poroperm relationships  
835 that take account of whether the main control on petrophysical properties and reservoir  
836 quality is diagenesis, fracturing, or a mixture of both.
- 837 • A new method of estimation the petrophysical properties of limestones if they are  
838 subjected to dolomitisation and of dolomites before they were dolomitised has been  
839 developed. The method relies on the fitting of some theoretical non-linear equations to the  
840 identified petrophysical fields and controlling scatter. The new method has been validated  
841 against associated data from the Butmah Formation and found to work well. This new  
842 method can be applied easily to any other carbonate formations using the same processes  
843 to cover any shortage of core samples in some formation intervals within boreholes and to  
844 obtain an integrated reservoir characterisation.
- 845 • While this work has defined no explicit consecutive petrodiagenetic pathway for the  
846 Butmah Formation, it has helped define the size and direction of five individual diagenetic

847 and fracturing events that are the building blocks of such a pathway. These events are (i)  
848 dolomitisation, (ii) dolomitisation of partially fractured rocks, (iii) dolomitisation of fully  
849 fractured rocks, (iv) fracturing with no dolomitisation, and (v) fracturing from dolomitized  
850 rocks.

## 851 **ACKNOWLEDGEMENTS**

852 The authors are grateful to the Iraqi North Oil Company for providing the study's core samples  
853 and data, and Dr. Samuel Allshorn of the Wolfson Laboratory where many of the  
854 measurements were carried out.

## 855 **REFERENCES**

856 [Adelinet, M., Barthélémy, J.F., Bemer, E. and Hamon, Y., 2019. Effective medium modeling  
857 of diagenesis impact on the petroacoustic properties of carbonate  
858 rocks. \*Geophysics\*, 84\(4\), pp.WA43-WA57.](#)

859 [Agar, S. M., and Geiger, S., 2014. Fundamental controls on fluid flow in carbonates: current  
860 workflows to emerging technologies. The Geological Society of London, special  
861 publications, v. 406, p. 1-59.](#)

862 [Ahr, W.M., 2008. Geology of carbonate reservoirs: the identification, description, and  
863 characterization of hydrocarbon reservoirs in carbonate rocks. Canada, John Wiley &  
864 Sons, Inc., Hoboken, New Jersey, 296 p.](#)

865 [Aleali, M., Rahimpour-Bonab, H., Moussavi-Harami, R., & Jahani, D. 2013. Environmental  
866 and sequence stratigraphic implications of anhydrite textures: A case from the Lower  
867 Triassic of the Central Persian Gulf. \*Journal of Asian Earth Sciences\*, 75, p.110-125.](#)

868 [Al-Khalifah, H., Glover, P.W.J. and Lorinczi, P., 2020. Permeability prediction and diagenesis  
869 in tight carbonates using machine learning techniques. \*Marine and Petroleum Geology\*,  
870 112.](#)

871 [Alsharhan, A.S. 2006. Sedimentological character and hydrocarbon parameters of the middle  
872 Permian to Early Triassic Khuff Formation, United Arab Emirates. \*GeoArabia\*, 11, 121–  
873 158.](#)

874 Amel, H., Jafarian, A., Husinec, A., Koeshidayatullah, A., Swennen, R., 2015. Microfacies,  
875 depositional environment and diagenetic evolution controls on the reservoir quality of the  
876 Permian Upper Dalan Formation, Kish Gas Field, Zagros Basin, Marine and petroleum  
877 geology, 67, 57-71.

878 Anselmetti, F.S., Eberli, G.P., 1993. Controls on sonic velocity in carbonates. *Pure and*  
879 *Applied Geophysics*, 141, p. 287-323.

880 Aqrawi, A. A. M., Goff, J. C., Horbury, A. D., and Sadooni, F. N., 2010. The petroleum geology  
881 of Iraq. Scientific Press Ltd, Beaconsfield, Bucks, 424 p.

882 Arosi, H.A. and Wilson, M.E., 2015. Diagenesis and fracturing of a large-scale, syntectonic  
883 carbonate platform. *Sedimentary geology*, 326, pp.109-134.

884 Asquith, G.B. and Gibson, C.R., 1982. Basic well log analysis for geologists, American  
885 Association of Petroleum Geologists, Tulsa, Oklahoma, 216 p.

886 Asquith, G., and Krygowski, D., 2004. Basic well log analysis. American Association of  
887 Petroleum Geologists, Tulsa, Oklahoma, 244 p.

888 Baqués, V., Ukar, E., Laubach, S.E., Forstner, S.R. and Fall, A., 2020. Fracture, dissolution,  
889 and cementation events in ordovician carbonate reservoirs, Tarim Basin, NW  
890 China. *Geofluids*, 2020.

891 Bateman R. M., 1985. Open-hole log analysis and formation evaluation. International Human  
892 Resources Development Corporation, Boston, p 647.

893 Bellen, R. C. V., Dunnington, H., Wetzel, R. and Morton, D., 1959. Lexique stratigraphique.  
894 International, Asie, Iraq, 333 p.

895 Boggs Jr, S., 2006. Sedimentology and stratigraphy. 4th edition, Pearson Education, 662p.

896 Boggs Jr, S., 2009. Petrology of Sedimentary Rocks. 2nd edition, Cambridge University  
897 Press, New York, 600p.

898 Bohnsack, D., Potten, M., Pfrang, D., Wolpert, P. and Zosseder, K., 2020. Porosity–  
899 permeability relationship derived from Upper Jurassic carbonate rock cores to assess the  
900 regional hydraulic matrix properties of the Malm reservoir in the South German Molasse  
901 Basin. *Geothermal Energy*, 8, p.1-47.

902 Bourque, P.A., Savard, M.M., Chi, G. and Dansereau, P., 2001. Diagenesis and porosity  
903 evolution of the upper silurian-lowermost devonian west point reef limestone, eastern  
904 Gaspe Belt, Quebec Appalachians. *Bulletin of Canadian Petroleum Geology*, 49(2),  
905 p.299-326.

906 Brigaud, B., Vincent, B., Durllet, C., Deconinck, J.F., Blanc, P. and Trouiller, A., 2010.  
907 Acoustic properties of ancient shallow-marine carbonates: effects of depositional  
908 environments and diagenetic processes (Middle Jurassic, Paris Basin, France). *Journal*  
909 *of Sedimentary Research*, 80(9), p.791-807.

910 Caine, J.S., Evans, J.P. and Forster, C.B., 1996. Fault zone architecture and permeability  
911 structure. *Geology*, 24(11), pp.1025-1028.

912 Cerepi, A., Barde, J.P. and Labat, N., 2003. High-resolution characterization and integrated  
913 study of a reservoir formation: the danian carbonate platform in the Aquitaine Basin  
914 (France). *Marine and petroleum geology*, 20 (10), p.1161-1183.

915 Childs, C., Walsh, J.J., Watterson, J., 1997. Complexity in fault zone structure and  
916 implications for fault seal prediction. In: Møller-Pedersen, P., Koestler, A.G. (Eds.),  
917 *Hydrocarbon Seals: Importance for Exploration and Production*. (Elsevier) Norwegian  
918 *Petroleum Society Special Publication*, 7, p. 61–72.

919 Choquette, P. W., and Pray, L. C., 1970. Geological Nomenclature and classification of  
920 porosity in sedimentary carbonates. *American Association of Petroleum Geologists*  
921 *Bulletin*, 54, p. 819-834.

922 Corrêa, R.S., Ukar, E., Laubach, S.E., Aubert, I., Lamarche, J., Wang, Q., Stockli, D.F.,  
923 Stockli, L.D. and Larson, T.E., 2022. Episodic reactivation of carbonate fault zones with  
924 implications for permeability—An example from Provence, Southeast France. *Marine and*  
925 *Petroleum Geology*, 145, p.105905.

926 Delacre, M., Lakens, D., & Leys, C., 2017. Why Psychologists Should by Default Use Welch's  
927 t-test Instead of Student's t-test. *International Review of Social Psychology*, 30(1).  
928 <https://doi.org/10.5334/irsp.82>.

929 de Lima, A., Lopes, J.A., Medeiros, W.E., Schiozer, D.J., La Bruna, V. and Bezerra, F.H.,  
930 2023. Impact of fracture set scales and aperture enlargement due to karstic dissolution  
931 on the fluid flow behavior of carbonate reservoirs: A workflow to include sub-seismic  
932 fractures in 3D simulation models. *Geoenergy Science and Engineering*, 221, p.211374.

933 Dickson, J. A. D., 1965. A modified staining technique for carbonates in thin section: *Nature*,  
934 205, p.587-587.

935 Dunnington, H. V., 1958. Generation, Migration, Accumulation and Dissipation of Oil in  
936 Northern Iraq: Middle East, American Association of Petroleum Geologists, special  
937 volume, p. 1194-1251.

938 Ehrenberg, S.N., 2004. Factors controlling porosity in Upper Carboniferous– Lower Permian  
939 carbonate strata of the Barents Sea. *AAPG bulletin*, 88 (12), pp.1653-1676.

940 Ehrenberg, S.N., Nadeau, P.H. and Aqrawi, A.A.M., 2007. A comparison of Khuff and Arab  
941 reservoir potential throughout the Middle East. *AAPG bulletin*, 91(3), pp.275-286.

942 Erdman, N. and Bell, D.C., 2015. Scanning Electron and Ion Microscopy of Nanostructures.  
943 In *Nanocharacterisation*, Royal Society of Chemistry, p. 300-350.

944 Esrafil-Dizaji, B. and Rahimpour-Bonab, H., 2009. Effects of depositional and diagenetic  
945 characteristics on carbonate reservoir quality: a case study from the South Pars gas  
946 field in the Persian Gulf. *Petroleum Geoscience*, 15 (4), p.325344.

947 Flugel, E., 2010. *Microfacies of carbonate rocks*. Verlag Berlin Heidelberg, 984 p.

948 Forstner, S.R. and Laubach, S.E., 2022. Scale-dependent fracture networks. *Journal of*  
949 *Structural Geology*, 165, p.104748.

950 Fouad, S. F. A., 2015. Tectonic map of Iraq, scale 1: 1000 000, 3rd edition, *Iraqi Bulletin of*  
951 *Geology and Mining, Papers of the Scientific Geological Conference*, 11, p. 1-7.

952 Géraud, Y., Diraison, M. and Orellana, N., 2006. Fault zone geometry of a mature active  
953 normal fault: a potential high permeability channel (Pirgaki fault, Corinth rift, Greece).  
954 *Tectonophysics*, 426 (1), p.61-76.

955 Giesche, H., 2006. Mercury porosimetry: a general (practical) overview. *Particle & particle*  
956 *systems characterization*, 23(1), p.9-19.

957 Glover, P.W.J., Zadjali, I.I., Frew, K.A., 2006. Permeability prediction from MICP and NMR  
958 data using an electrokinetic approach. *Geophysics*, 71 (4), p.49-60.

959 Glover, P.W.J. and Walker, E., 2009. Grain-size to effective pore-size transformation derived  
960 from electrokinetic theory. *Geophysics*, 74(1), pp. E17-E29.

961 Glover, P.W.J. and Déry, N., 2010. Streaming potential coupling coefficient of quartz glass  
962 bead packs: Dependence on grain diameter, pore size, and pore throat radius.  
963 *Geophysics*, 75(6), p. F225-F241.

964 Glover, P.W.J., 2015. *Geophysical Properties of the Near Surface Earth: Electrical*  
965 *Properties. Treatise on Geophysics: Second Edition.* pp. 89-137.

966 Glover, P.W.J., Mohammed-Sajed, O.K, Cenk Akyüz, C., Lorinczi, P. and Collier, R. E. LI.,  
967 2022, Clustering of facies in tight carbonates using machine learning, *Marine and*  
968 *Petroleum Geology*, published online 105828. [10.1016/j.marpetgeo.2022.105828](https://doi.org/10.1016/j.marpetgeo.2022.105828)

969 Gluyas, J. and R. Swarbrick, 2004. *Petroleum Geoscience.* Blackwell Science Ltd, 349p.

970 Hart, E. and J.T.C. Hay, 1974, Structure of Ain Zalah Field, Northern Iraq. *AAPG Bulletin*,  
971 58(6), p.973-981.

972 Haines T.J., Michie, E.A.H., Neilson, J.E., and Healy, D. 2016. Permeability evolution across  
973 carbonate hosted normal fault zones, *Marine and Petroleum Geology*, 72, p. 62-82.

974 Hollis, C., Vahrenkamp, V., Tull, S., Mookerjee, A., Taberner, C. and Huang, Y., 2010. Pore  
975 system characterisation in heterogeneous carbonates: An alternative approach to widely-  
976 used rock-typing methodologies. *Marine and Petroleum Geology*, 27(4), pp.772-793.

977 Hollis, C., 2011. Diagenetic controls on the reservoir properties of carbonate successions  
978 within the Albian-Turonian of the Arabian plate. *Petroleum Geoscience*, 17, p. 223-241.

979 Hommel, J., Coltman, E. and Class, H., 2018. Porosity–permeability relations for evolving  
980 pore space: a review with a focus on (bio-) geochemically altered porous  
981 media. *Transport in Porous Media*, 124(2), pp.589-629.

982 Jannot, Y., Lasseux, D., Vizé, G. & Hamon, G. 2007. A detailed analysis of permeability and  
983 Klinkenberg coefficient estimation from unsteady-state pulsedecay or draw-down  
984 experiments. Paper No. SCA2007-08.

985 Jennings, J.B., 1987. Capillary pressure techniques: application to exploration and  
986 development geology. AAPG Bulletin, 71(10), p.1196-1209.

987 Jiang, L., Worden, R.H., Cai, C.F., Shen, A. and Crowley, S.F., 2018. Diagenesis of an  
988 evaporite-related carbonate reservoir in deeply buried Cambrian strata, Tarim Basin,  
989 Northwest China. AAPG Bulletin, 102(1), pp.77-102.

990 Jones, S. C. 1997. A Technique for Faster Pulse-Decay Permeability Measurements in Tight  
991 Rocks. Society of Petroleum Engineers (SPE) formation evaluation, 12 (01), p. 19-26.

992 Katz, A. J., and Thompson, A. H., 1987. Prediction of rock electrical conductivity from  
993 mercury injection measurements. Geophysical research, 92, p. 599-607.

994 Klinkenberg, L.J., 1941. The permeability of porous media to liquids and gases. Drill. Prod.  
995 Pract. 200e213.

996 Koehrer, B., Heymann, C., Prousa, F., Aigner, T., 2010. Multiple-scale facies and reservoir  
997 quality variations within a dolomite body– outcrop analog study from the Middle Triassic,  
998 SW German Basin. Marine and Petroleum Geology 27, 386– 411.

999 Kopaska-Merkel, D.C. and Amthor, J.E. 1988. Very high pressure mercury porosimetry as a  
1000 tool in reservoir characterization, Carbonate Evaporite, 3, p.53–63.

1001 Laubach, S.E., Lander, R.H., Criscenti, L.J., Anovitz, L.M., Urai, J.L., Pollyea, R.M., Hooker,  
1002 J.N., Narr, W., Evans, M.A., Kerisit, S.N. and Olson, J.E., 2019. The role of chemistry in  
1003 fracture pattern development and opportunities to advance interpretations of geological  
1004 materials. Reviews of Geophysics, 57(3), pp.1065-1111.

1005 Léonide, P., Fournier, F., Reijmer, J.J., Vonhof, H., Borgomano, J., Dijk, J., Rosenthal, M.,  
1006 van Goethem, M., Cochard, J. and Meulenaars, K., 2014. Diagenetic patterns and pore  
1007 space distribution along a platform to outer-shelf transect (Urgonian limestone,  
1008 Barremian–Aptian, SE France). Sedimentary Geology, 306, p.1-23.

- 1009 Longman, M.W., 1980. Carbonate diagenetic textures from near surface diagenetic  
1010 environments. AAPG bulletin, 64(4), p.461-487.
- 1011 Lucia, F. J., 2004. Origin and petrophysics of dolomite pore space. In: Braithwaite, C.J., Rizzi,  
1012 G. and Darke, G., 2004. The geometry and petrogenesis of dolomite hydrocarbon  
1013 reservoirs. Geological Society, London, Special Publications, 235(1), p. 141-155.
- 1014 Lucia, F. J., 2007, Carbonate reservoir characterization Springer-Verlag Berlin Heidelberg,  
1015 331 p.
- 1016 Ma, S. and Morrow, N.R., 1996. Relationships between porosity and permeability for porous  
1017 rocks. In International Symposium of the Society of Core Analysts, September (pp. 8-10).
- 1018 Maerten, L., Gillespie, P. and Pollard, D.D., 2002. Effects of local stress perturbation on  
1019 secondary fault development. Journal of Structural Geology, 24(1), p.145-153.
- 1020 Maliva, R.G., Missimer, T.M., Clayton, E.A. and Dickson, J.A.D., 2009. Diagenesis and  
1021 porosity preservation in Eocene microporous limestones, South Florida, USA.  
1022 Sedimentary Geology, 217(1), p.85-94.
- 1023 McPhee, C., Reed, J. and Zubizarreta, I., 2015. Core Analysis: A Best Practice Guide,  
1024 Elsevier, 64, 852p.
- 1025 Mohammed Sajed, O.K. and Glover, P.W.J., 2020. Dolomitisation, cementation and reservoir  
1026 quality in three Jurassic and Cretaceous carbonate reservoirs in north-western  
1027 Iraq. Marine and Petroleum Geology, p.104256.
- 1028 Mohammed Sajed, O.K., Glover, P.W. and Collier, R.E.L., 2021. Reservoir quality estimation  
1029 using a new ternary diagram approach applied to carbonate formations in north-western  
1030 Iraq. Journal of Petroleum Science and Engineering, 196, p.108024.
- 1031 Mohammed-Sajed, O.K. and Glover, P.W., 2022. Influence of anhydritisation on the reservoir  
1032 quality of the Butmah Formation in north-western Iraq. Marine and Petroleum  
1033 Geology, 135, p.105391.
- 1034 Moore, C.H., 1989. Carbonate diagenesis and porosity, Developments in Sedimentology, 46,  
1035 338 p.

- 1036 Moore, C. H., 2001. Carbonate reservoirs, porosity evaluation and diagenesis in a sequence  
1037 stratigraphic framework, *Developments in sedimentology*, Netherland, 55, 444p.
- 1038 Nader, F.H., 2017. Multi-scale quantitative diagenesis and impacts on heterogeneity of  
1039 carbonate reservoir rocks (pp. 1-132). Springer International Publishing.
- 1040 Porras, J. C., and Campos, O., 2001. Rock typing: A key approach for petrophysical  
1041 characterization and definition of flow units, Santa Barbara Field, Eastern Venezuela  
1042 Basin. Society of Petroleum Engineers, SPE-69458-MS.
- 1043 Quan, L., Wang, G., Zhang, Y., Hao, F., Xu, R., Zhou, L. and Liu, Z., 2023. Early  
1044 dolomitization and subsequent hydrothermal modification of the middle Permian Qixia  
1045 Formation carbonate in the northwest Sichuan Basin. *Geoenergy Science and  
1046 Engineering*, 221, p.211384.
- 1047 Rashid, F., Glover, P.W.J., Lorinczi, P., Collier, R. and Lawrence, J., 2015a. Porosity and  
1048 permeability of tight carbonate reservoir rocks in the north of Iraq. *Journal of Petroleum  
1049 Science and Engineering*, 133, pp. 147-161.
- 1050 Rashid, F., Glover, P.W.J., Lorinczi, P., Hussein, D., Collier, R. and Lawrence, J., 2015b.  
1051 Permeability prediction in tight carbonate rocks using capillary pressure measurements.  
1052 *Marine and Petroleum Geology*, 68, pp. 536-550.
- 1053 Rashid, F., Glover, P.W.J., Lorinczi, P., Hussein, D. and Lawrence, J.A., 2017.  
1054 Microstructural controls on reservoir quality in tight oil carbonate reservoir rocks. *Journal  
1055 of Petroleum Science and Engineering*, 156, pp. 814-826.
- 1056 Rashid, F., Hussein, D., Glover, P.W.J., Lorinczi, P. and Lawrence, J.A., 2022. Quantitative  
1057 diagenesis: Methods for studying the evolution of the physical properties of tight  
1058 carbonate reservoir rocks. *Marine and Petroleum Geology*, 139.
- 1059 Rider, M.H. and Kennedy, M., 2018. *The geological interpretation of well logs*, 3rd edition,  
1060 Rider-French Consulting Ltd, Sutherland, U.K., 440p.
- 1061 Ross, E. R., 2011. *Grain's Petrophysical handbook: online shareware petrophysics Training  
1062 and Reference manual*.

1063 Rushing, J.A., Newsham, K.E., Lasswell, P.M. I, Cox, J.C., and Blasingame, T.A. 2004.  
1064 Klinkenberg-Corrected Permeability Measurements in Tight Gas Sands: Steady-  
1065 State Versus Unsteady-State Techniques. SPE 89867.

1066 Rysak, B., Gale, J.F., Laubach, S.E. and Ferrill, D.A., 2022. Mechanisms for the generation  
1067 of complex fracture networks: Observations from slant core, analog models, and  
1068 outcrop. *Frontiers in Earth Science*, 10, p.463.

1069 Sabouhi, M., Moussavi-Harami, R., Kadkhodaie, A., Rezaee, P. and Jalali, M., 2022. A new  
1070 approach to Quantitative Diagenesis Modeling (QDM) by integrated facies, well logs and  
1071 seismic attributes from the cenomanian-early Turonian Sarvak Formation, Abadan Plain,  
1072 SW Iran. *Journal of Petroleum Science and Engineering*, 218, p.110943.

1073 Schlumberger, 1989. *Log interpretation principles/applications*, 228p.

1074 Schlumberger, 1997. *Log Interpretation Charts*, Houston, Schlumberger Wireline  
1075 and Testing. 193p.

1076 Scholle, P., A., and D. Ulmer-Scholle, S., 2003. A colour guide to the petrography of  
1077 carbonate rocks: grains, textures, porosity, diagenesis. *American Association of*  
1078 *Petroleum Geologists Bulletin*, 77, Tulsa, Oklahoma, U.S.A.

1079 Selley, R. C., 2000. *Applied Sedimentology*. 2nd edition, Academic press, 521p.

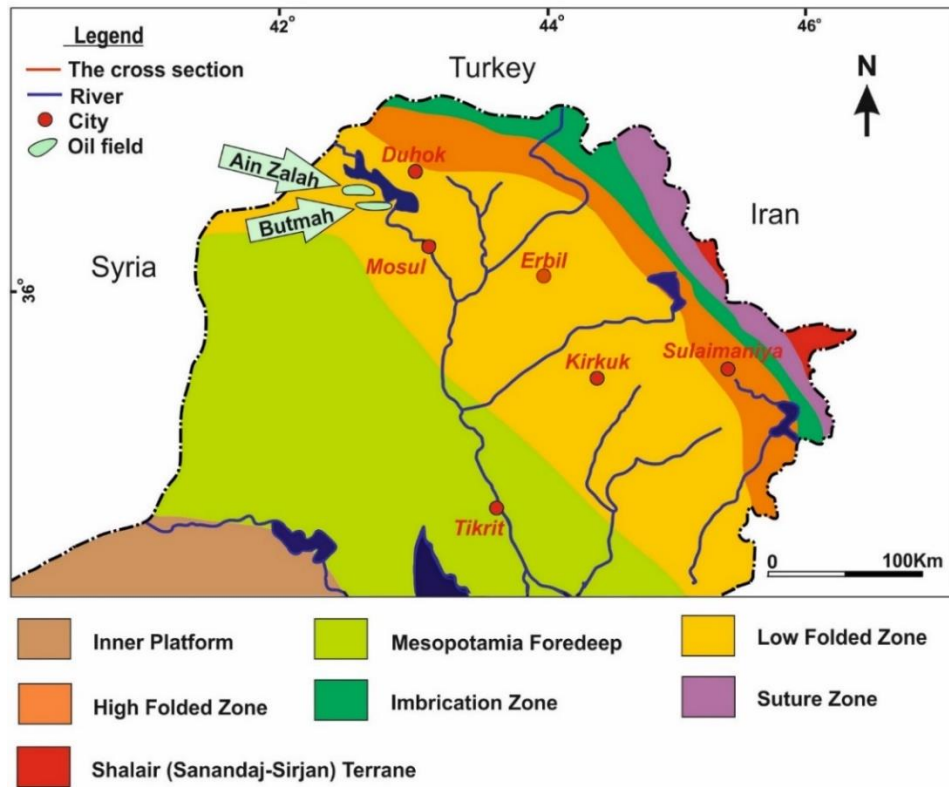
1080 Shuja Ullah, Hanif, M., Radwan, A.E., Luo, C., Rehman, N.U., Ahmad, S., Latif, K., Ali, N.,  
1081 Thanh, H.V., Asim, M. and Ashraf, U., 2023. Depositional and diagenetic modeling of the  
1082 Margala Hill Limestone, Hazara area (Pakistan): Implications for reservoir  
1083 characterization using outcrop analogues. *Geoenergy Science and Engineering*, 224,  
1084 p.211584.

1085 Spain, D.R., 1992: Petrophysical evaluation of a slope fan/ basin floor fan complex, cherry  
1086 canyon formation, Ward County, Texas, *AAPG Bulletin*, 76 (6), p. 805-827.

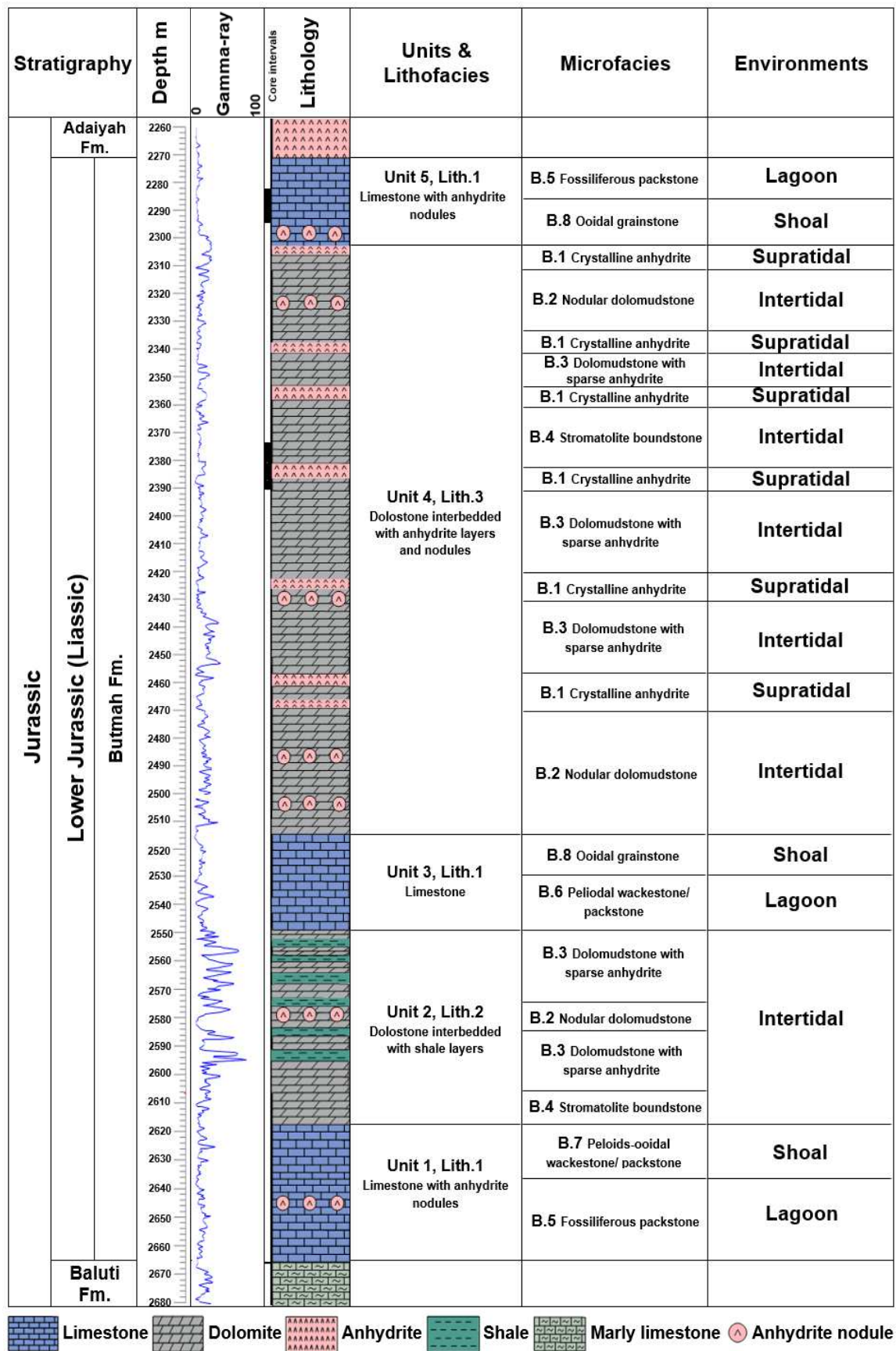
1087 Stenoft, N., Lapinskas, P. and Musteikis, P., 2003. Diagenesis of Silurian reefal carbonates,  
1088 Kudirka oilfield, Lithuania. *Journal of Petroleum Geology*, 26(4), p.381-402.

- 1089 Tavakoli, V., Rahimpour-Bonab, H. and Esrafil-Dizaji, B., 2011. Diagenetic controlled  
1090 reservoir quality of south Pars gas field, an integrated approach. *Comptes Rendus*  
1091 *Geoscience*, 343, p. 55- 71.
- 1092 Tiab, D., and E. C. Donaldson, 2012. *Petrophysics: Theory and practice of measuring*  
1093 *reservoir rock and fluid transport properties* 3rd edition. Elsevier, 950 p.
- 1094 Tucker, M. E., V. P. Wright, and J. Dickson, 1990, *Carbonate Sedimentology*. Blackwell  
1095 Science Ltd. 480p.
- 1096 Verwer, K., Braaksma, H. and Kenter, J.A., 2008. Acoustic properties of carbonates: Effects  
1097 of rock texture and implications for fluid substitution. *Geophysics*, 73(2), p.B51-B65.
- 1098 Wang, M., Yang, Z., Shui, C., Yu, Z., Wang, Z. and Cheng, Y., 2019. Diagenesis and its  
1099 influence on reservoir quality and oil-water relative permeability: A case study in the  
1100 Yanchang Formation Chang 8 tight sandstone oil reservoir, Ordos Basin, China. *Open*  
1101 *Geosciences*, 11(1), pp.37-47.
- 1102 Wang, Q., Narr, W. and Laubach, S.E., 2023. Quantitative characterization of fracture spatial  
1103 arrangement and intensity in a reservoir anticline using horizontal wellbore image logs  
1104 and an outcrop analogue. *Marine and Petroleum Geology*, p.106238.
- 1105 Washburn, E. W., 1921. Note on a method of determining the distribution of pore sizes in a  
1106 porous material. *Proceedings of the National Academy of Sciences*, 7, p. 115-116.
- 1107 Wennberg, O.P., Casini, G., Jonoud, S. and Peacock, D.C., 2016. The characteristics of  
1108 open fractures in carbonate reservoirs and their impact on fluid flow: a discussion. p. 91-  
1109 104.
- 1110 Worden, R.H., Armitage, P.J., Butcher, A.R., Churchill, J.M., Csoma, A.E., Hollis, C., Lander,  
1111 R.H. and Omma, J.E., 2018. *Petroleum reservoir quality prediction: overview and*  
1112 *contrasting approaches from sandstone and carbonate communities*. Geological Society,  
1113 London, Special Publications, 435(1), pp.1-31.
- 1114 Wyllie, M.R.J., Gregory, A.R. and Gardner, L.W., 1956. Elastic wave velocities in  
1115 heterogeneous and porous media. *Geophysics*, 21(1), pp.41-70.

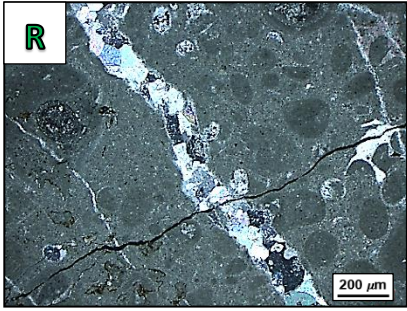
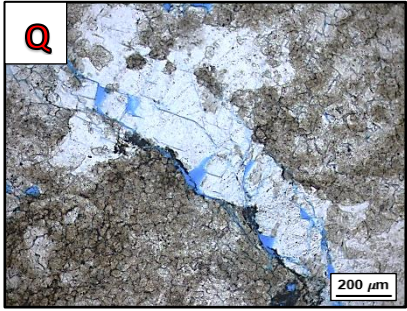
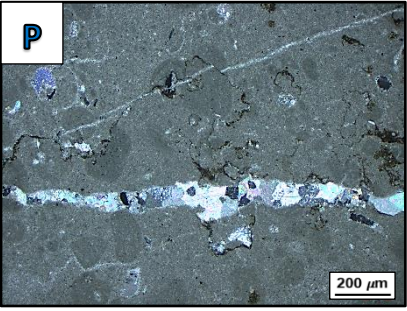
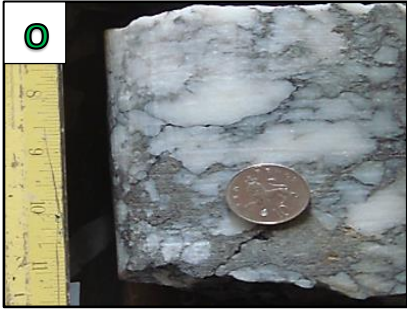
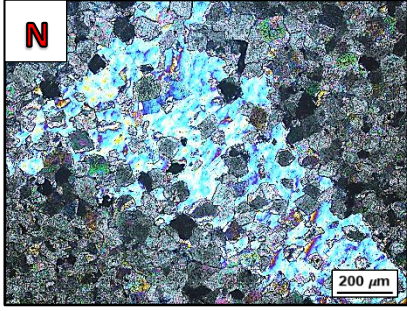
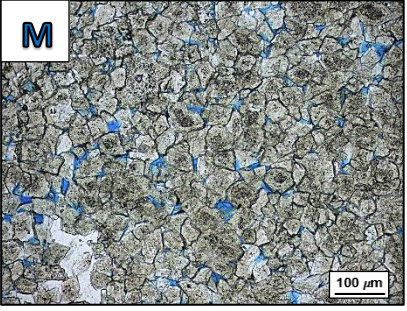
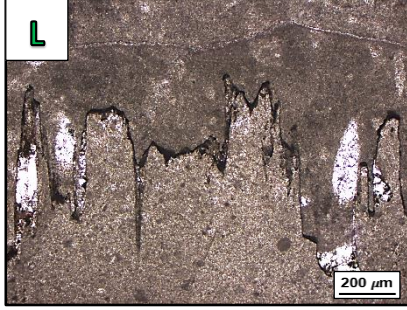
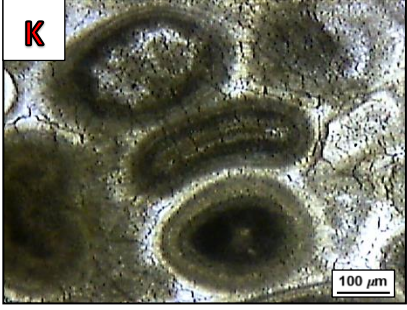
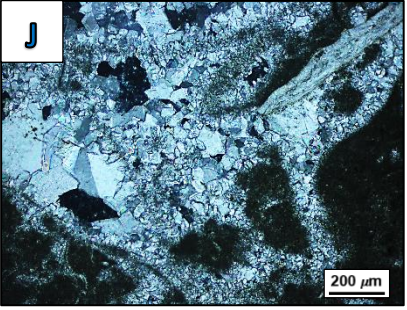
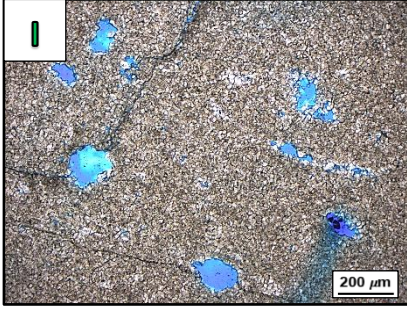
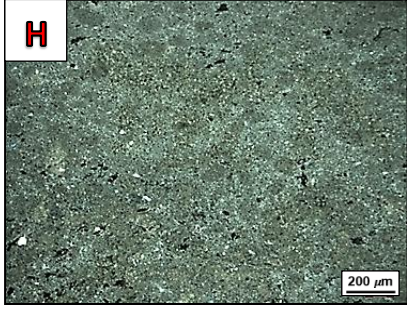
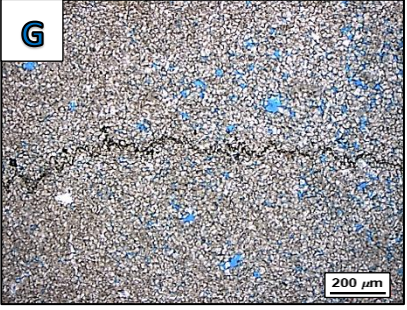
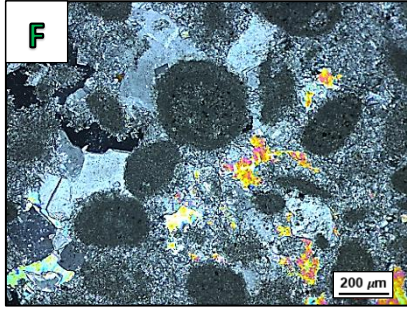
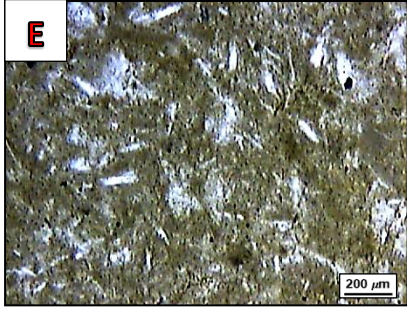
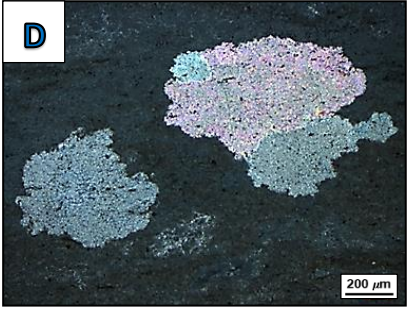
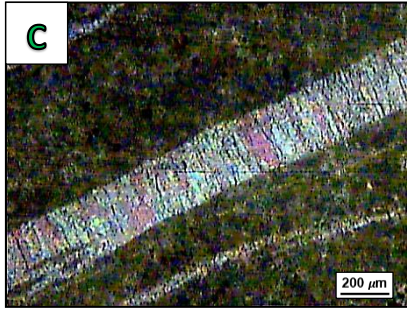
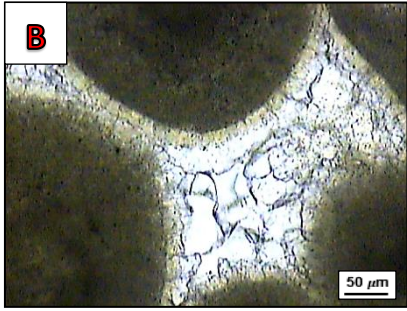
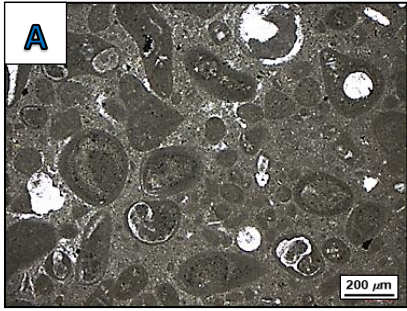
- 1116 Zhang, M., Takahashi, M., Morin, R. H. and Esaki, T. 2000. Evaluation and Application of the  
1117 Transient-Pulse Technique for Determining the Hydraulic Properties of Low-Permeability  
1118 Rocks – Part 1: Theoretical Evaluation. American Society for Testing and Materials :  
1119 Geotechnical Testing Journal, p.83-90.
- 1120 Zhang, L., Jiao, Y., Rong, H., Li, R. and Wang, R., 2017. Origins and Geochemistry of Oolitic  
1121 Dolomite of the Feixianguan Formation from the Yudongzi Outcrop, Northwest Sichuan  
1122 Basin, China. Minerals, 7(120), p.1-21.



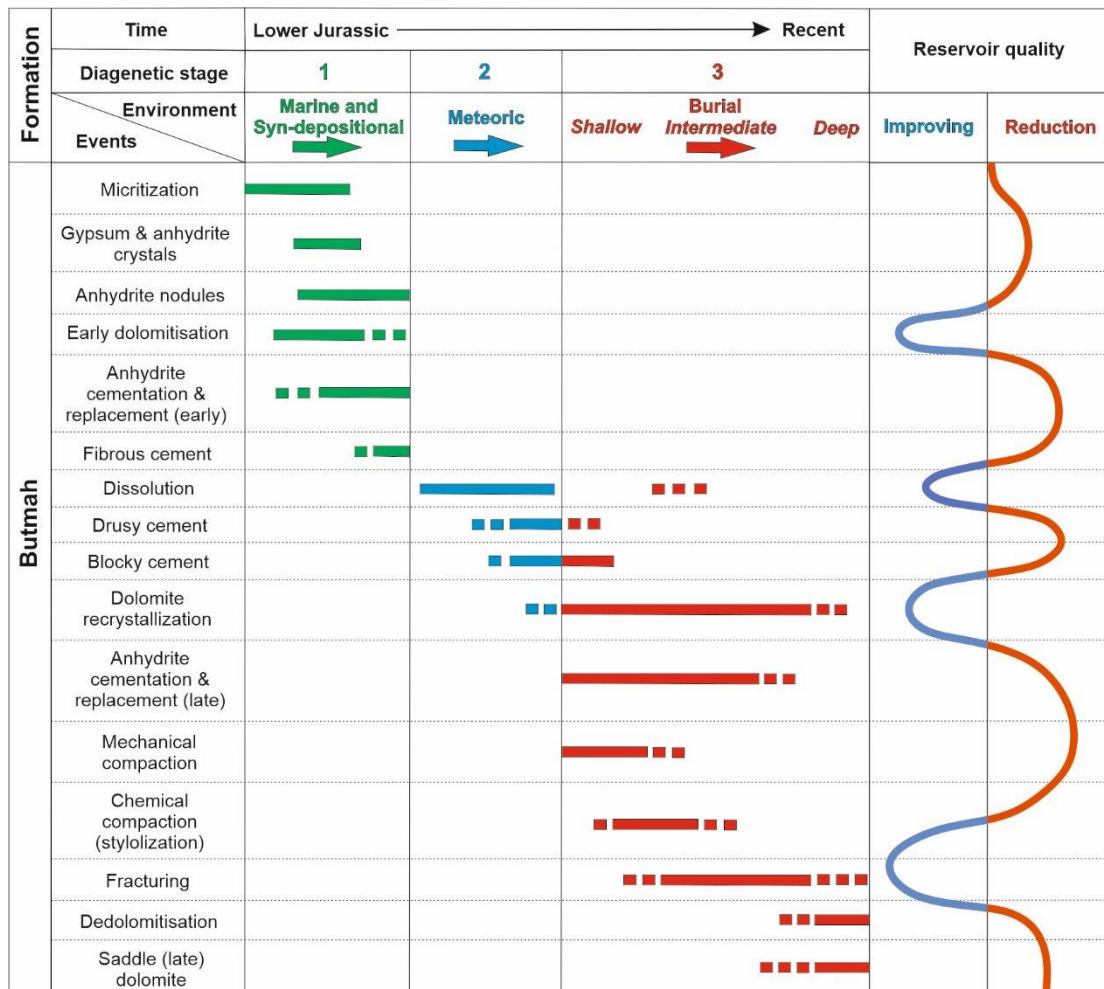
**Figure 1.** The position of the Butmah and Ain Zalah oilfields in north-western Iraq may be observed along with the tectonic division of Iraq after Fouad (2015).



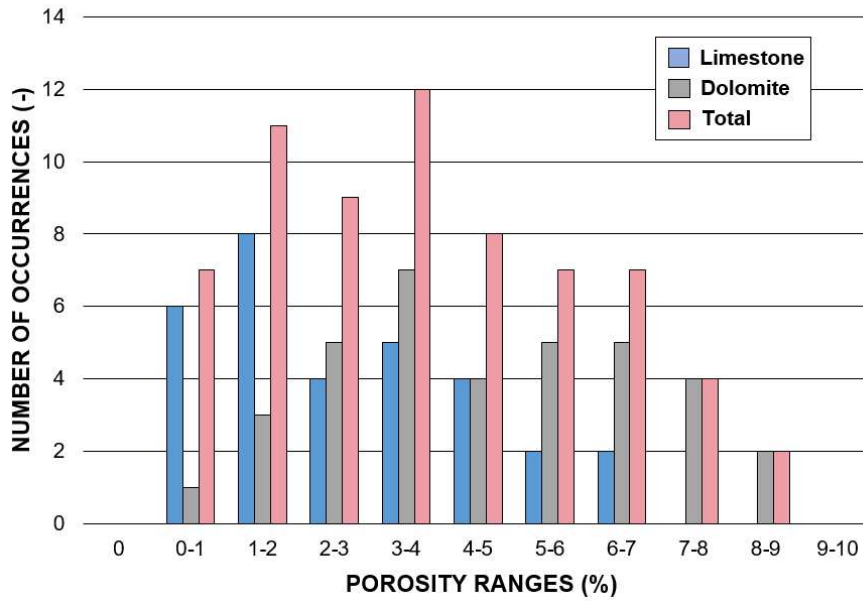
**Figure 2.** Stratigraphic units, lithofacies, microfacies distribution, and environments of the Butmah Formation at well Bm-15.



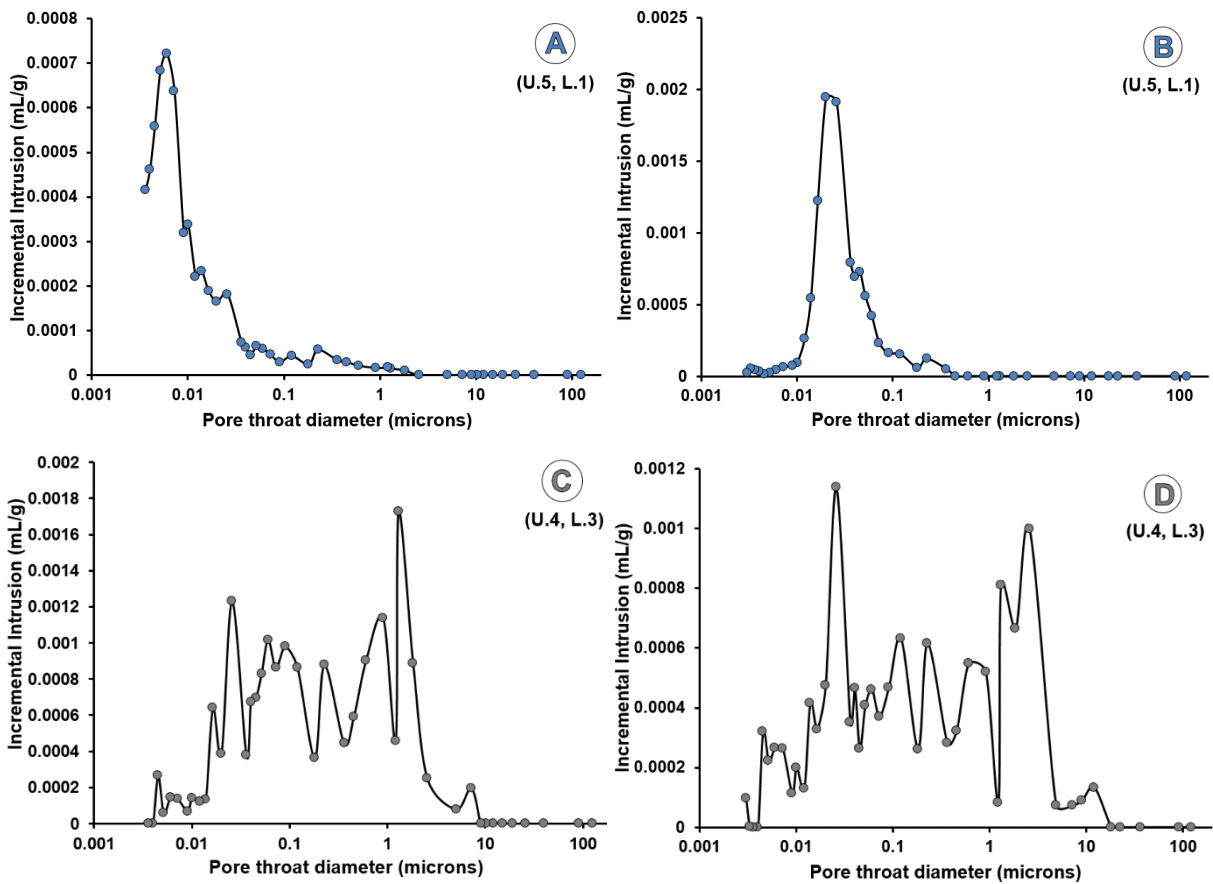
**Figure 3.** Observed textures associated with diagenetic processes. (A) Micritic envelopes around skeletal grains (oids), Bm-15, (2627 m). (B) Isopachous cement, Bm-15, (2540 m). (C) Fibrous cement, Bm-15, (2480 m). (C) Blocky cement, Bm-15, (2524 m). (D) Anhydrite nodules in fine dolomite crystals, Bm-15, (2500 m). (E) Spare anhydrite crystals in Dolomudstone microfacies, Bm-15, (2350 m). (F) Poikilotopic anhydrite cement, Bm-15, (2292 m). (G) A low peak amplitude stylolite (pressure solution) within fine crystalline dolomite, Bm-15, (2391m). (H) Slightly-compacted contacts between dolomitised peloids, Bm-15, (2541 m). (I) Fine crystalline dolomite showing vuggy porosity and solution-enlarged vugs Bm-15, (2391 m). (J) Drusy cement, Bm-15 (2290 m). (K) Mechanical compaction between ooids within ooids grainstone microfacies, Az-29, (3358 m). (L) A high peak amplitude stylolite (pressure solution) within fine crystalline dolomite, Bm-15, (2378m). (M) Zoning coarse dolomite crystals as late dolomitisation features, Bm-15, (2376 m). (N) Late-stage anhydrite cement occluding early porosity, Bm-15, (2390 m). (O) Compressed chicken-wire texture by compaction effect, Bm-15, (2379 m). (P) Late-stage blocky anhydrite cement fills some fractures and alongside stylolite, Bm-15, (2524 m). (Q) Burial dissolution as a few voids and solution enlarged stylolite, Bm-15, (2381 m). (R) Two generations of fractures, the old fracture is occluded by blocky anhydrite cement and the new open fracture cuts the old one, Bm-15, (2524 m).



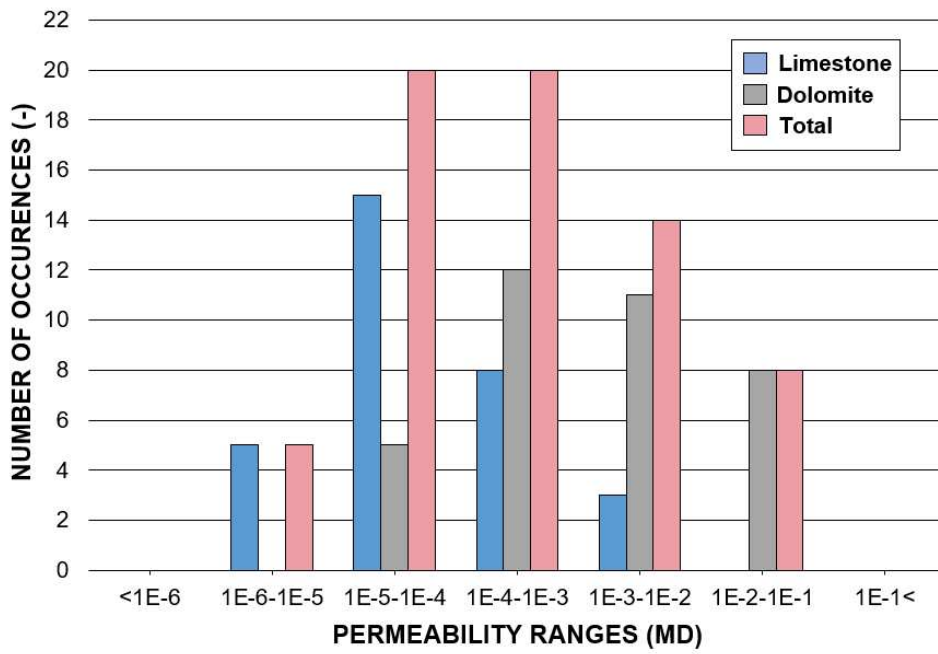
**Figure 4.** Summaries of the qualitative diagenetic pathway include a generalised diagenetic sequence with the effect of each diagenetic process on the reservoir quality of the Butmah Formation.



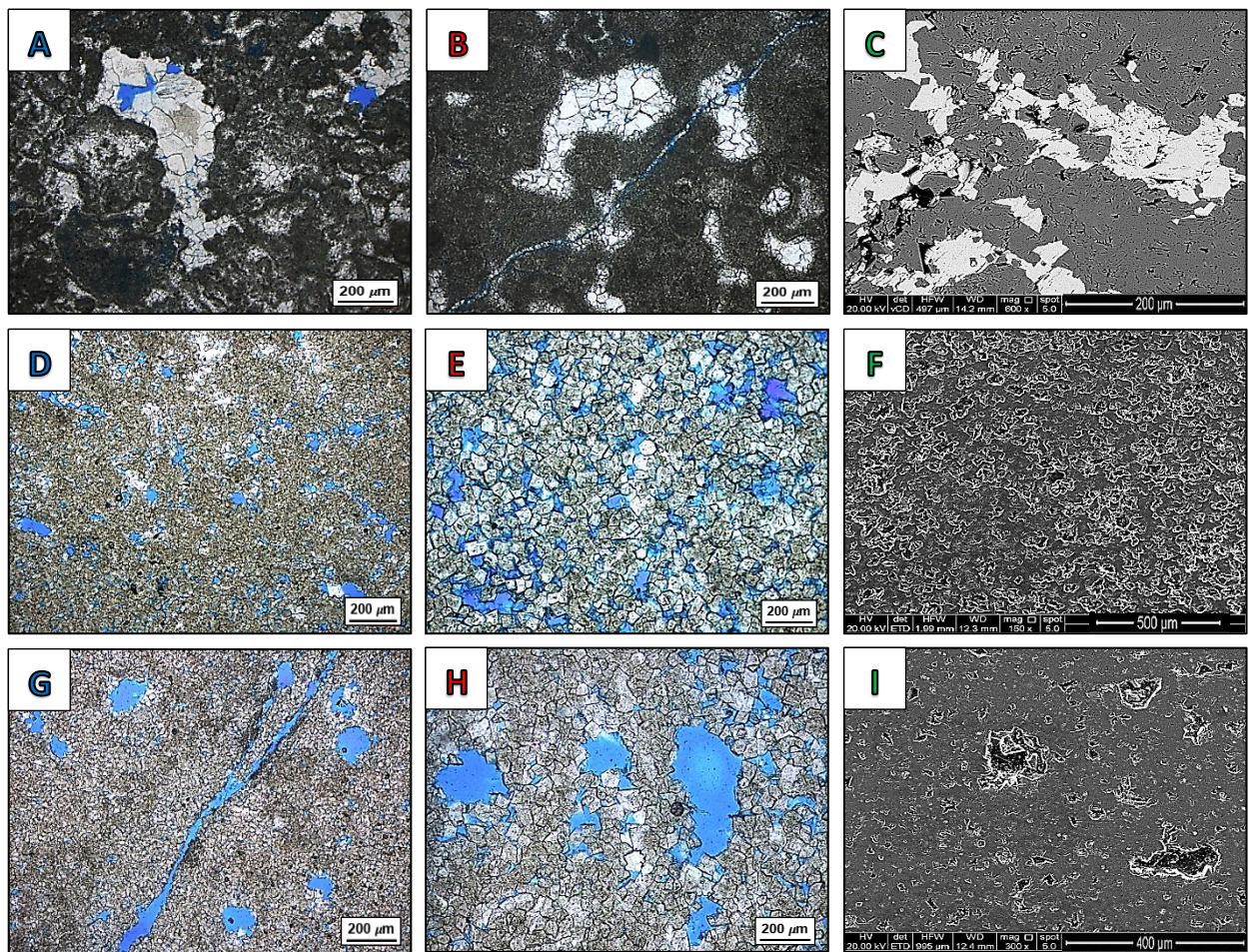
**Figure 5.** The effective porosity histogram of the Butmah Formation at well Bm-15.



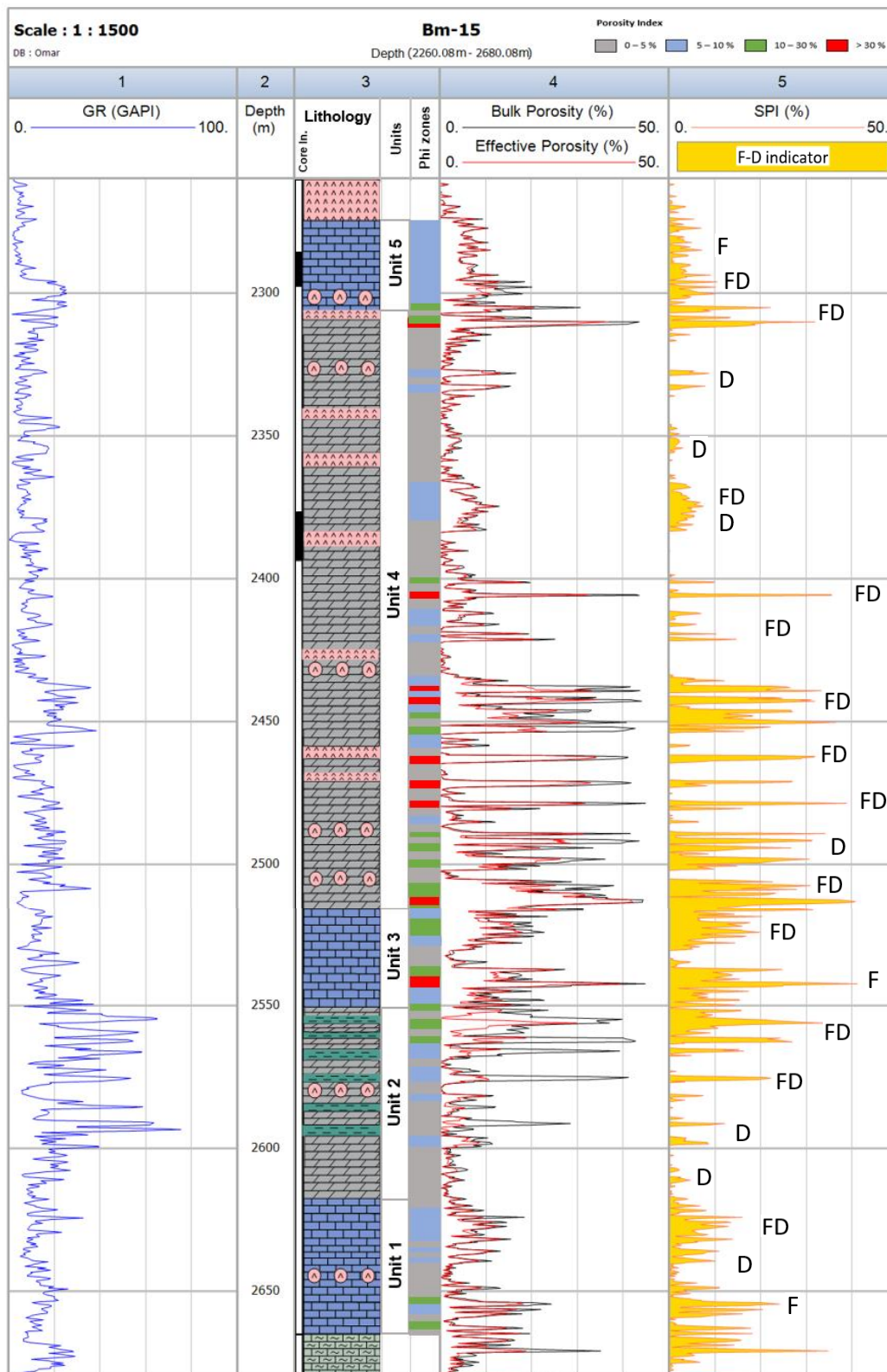
**Figure 6.** Pore throat distributions for four samples from the Butmah Formation; top row (A and B) from the limestone lithofacies (U5, L1), and bottom row (C and D) from the dolomite lithofacies (U4, L3).



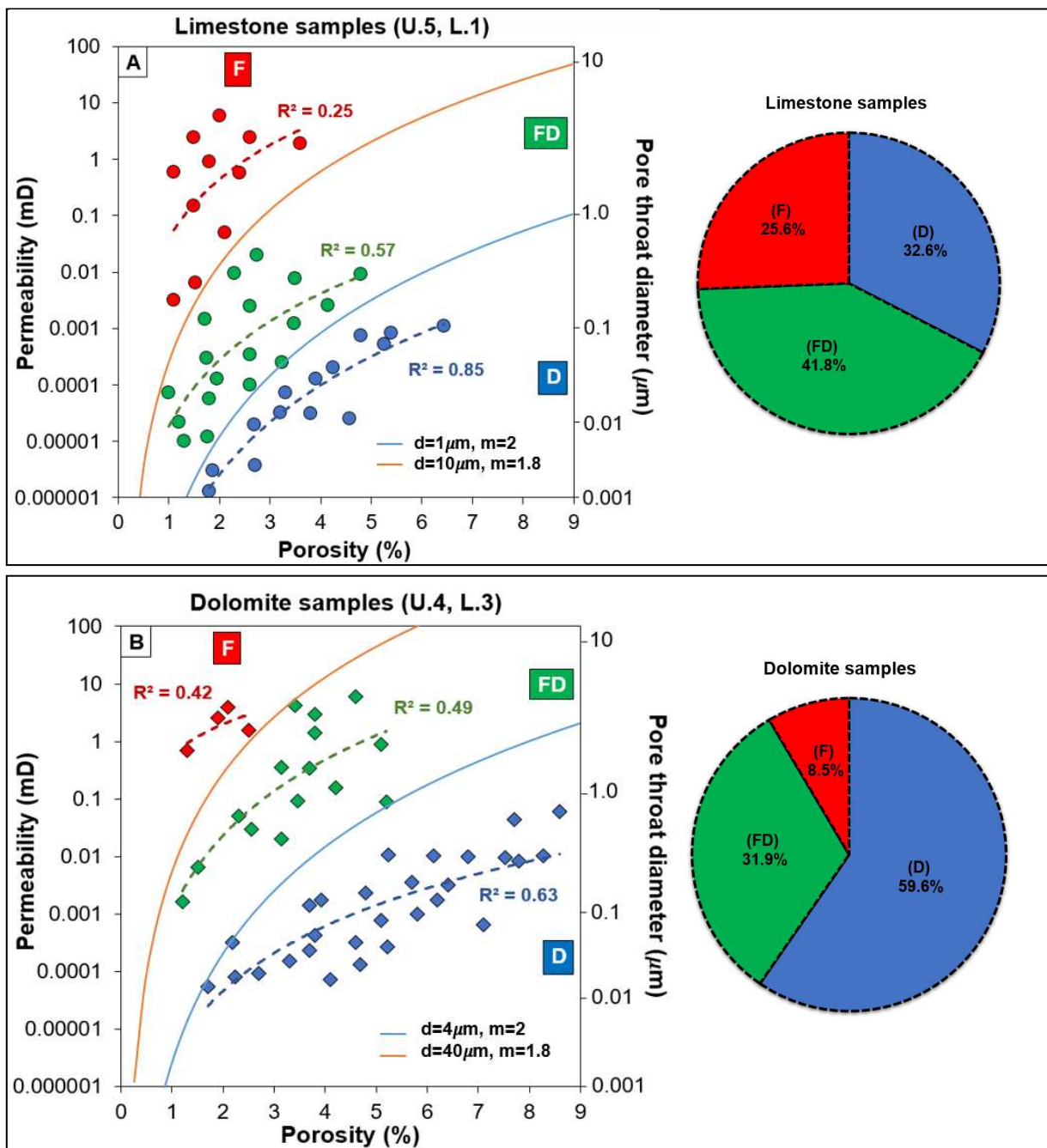
**Figure 7.** Histogram showing the permeability of the dolomite and limestone lithofacies in the Butmah Formation.



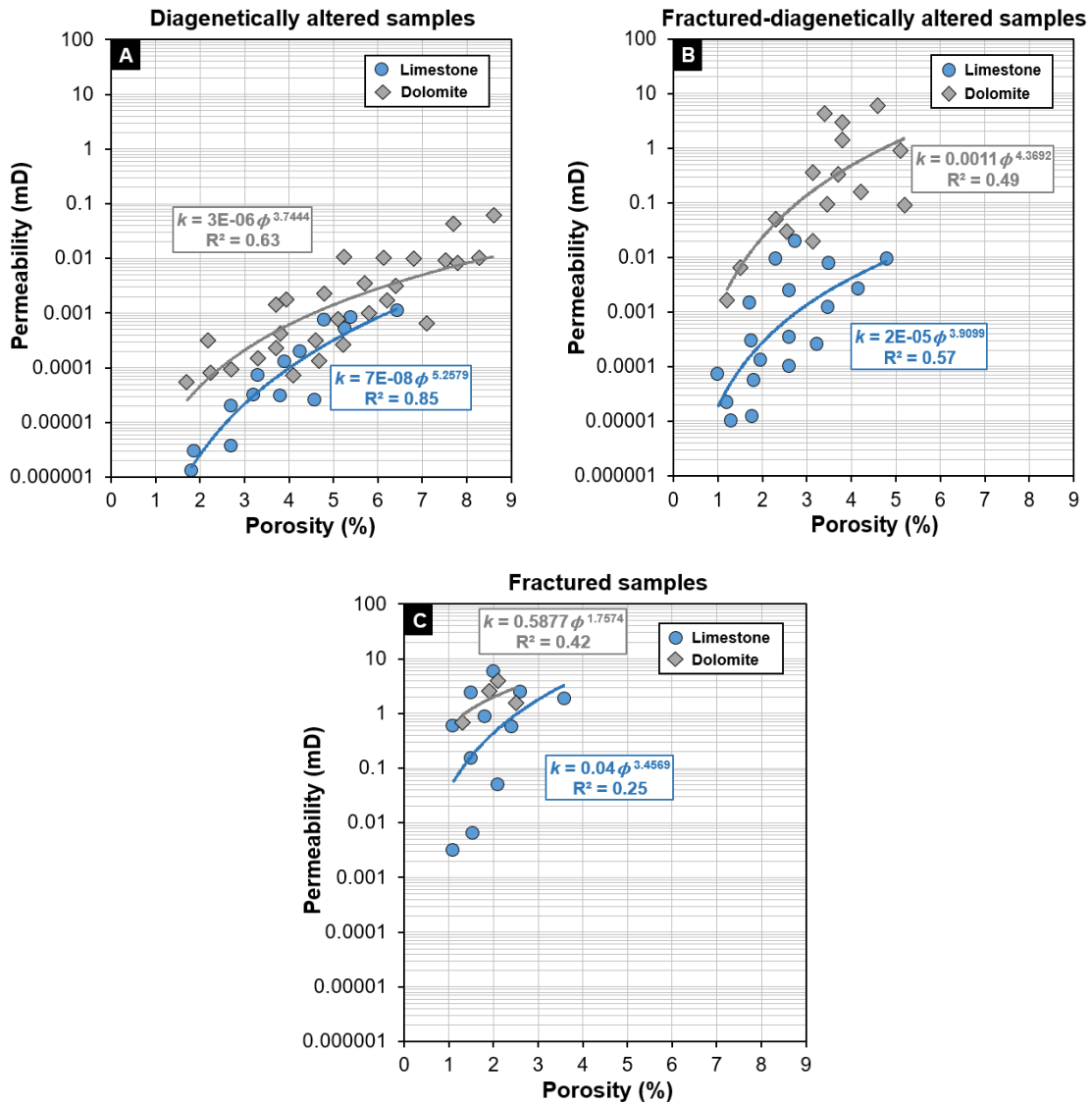
**Figure 8.** The Butmah Formation pore structures. (A) (B) (C) Stromatolite boundstone microfacies, Bm-15, U4 (2278 m) with (A) intercrystalline porosity and (B) intercrystalline and fracture porosity (C) SEM backscatter image illustrating pore space geometry, and anhydrite cement effects. (D) Fine crystalline dolomite with intercrystalline and vuggy porosity, Bm-15, U2 (2580 m). (E) Coarse crystalline dolomite of Lithofacies 3 showing intercrystalline porosity Bm-15, U4 (2391 m). (F) SEM images showing pores shape and size in coarse crystalline dolomite, Bm-15, U4 (2391 m). (G) Fine crystalline dolomite of lithofacies 3 showing vuggy and fracture porosity, Bm-15, U4 (2450 m). (H) Coarse crystalline dolomite showing intercrystalline porosity and solution-enlarged vugs Bm-15, U4 (2391 m). (K) SEM images showing intercrystalline and vuggy porosity in medium dolomite crystals, Bm-15, U4 (2388m).



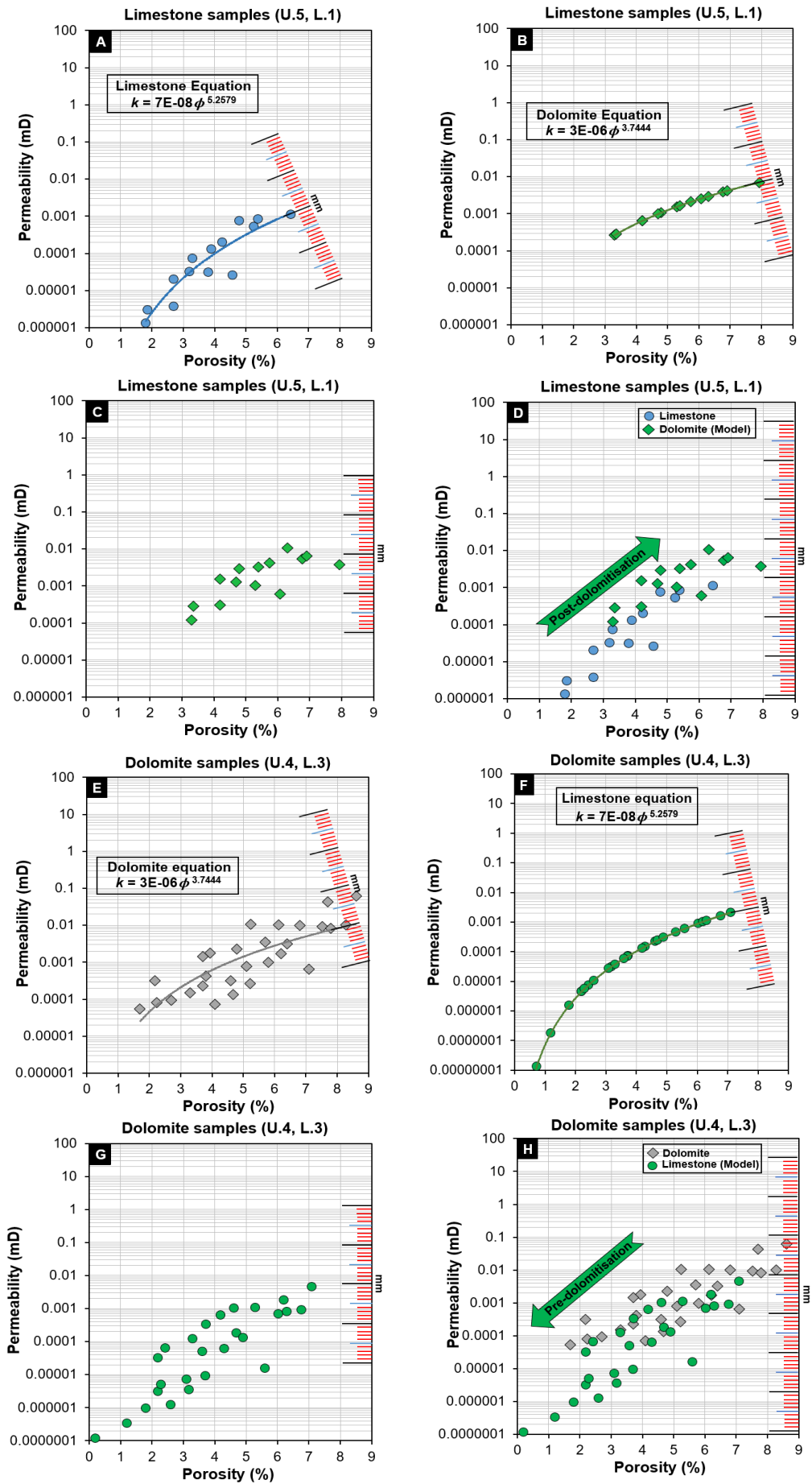
**Figure 9.** Porosity distribution (bulk and effective) within the Butmah Formation at well Bm-15 with secondary porosity indicator (SPI) and fracturing-diagenesis indicator (FDI) at each depth.



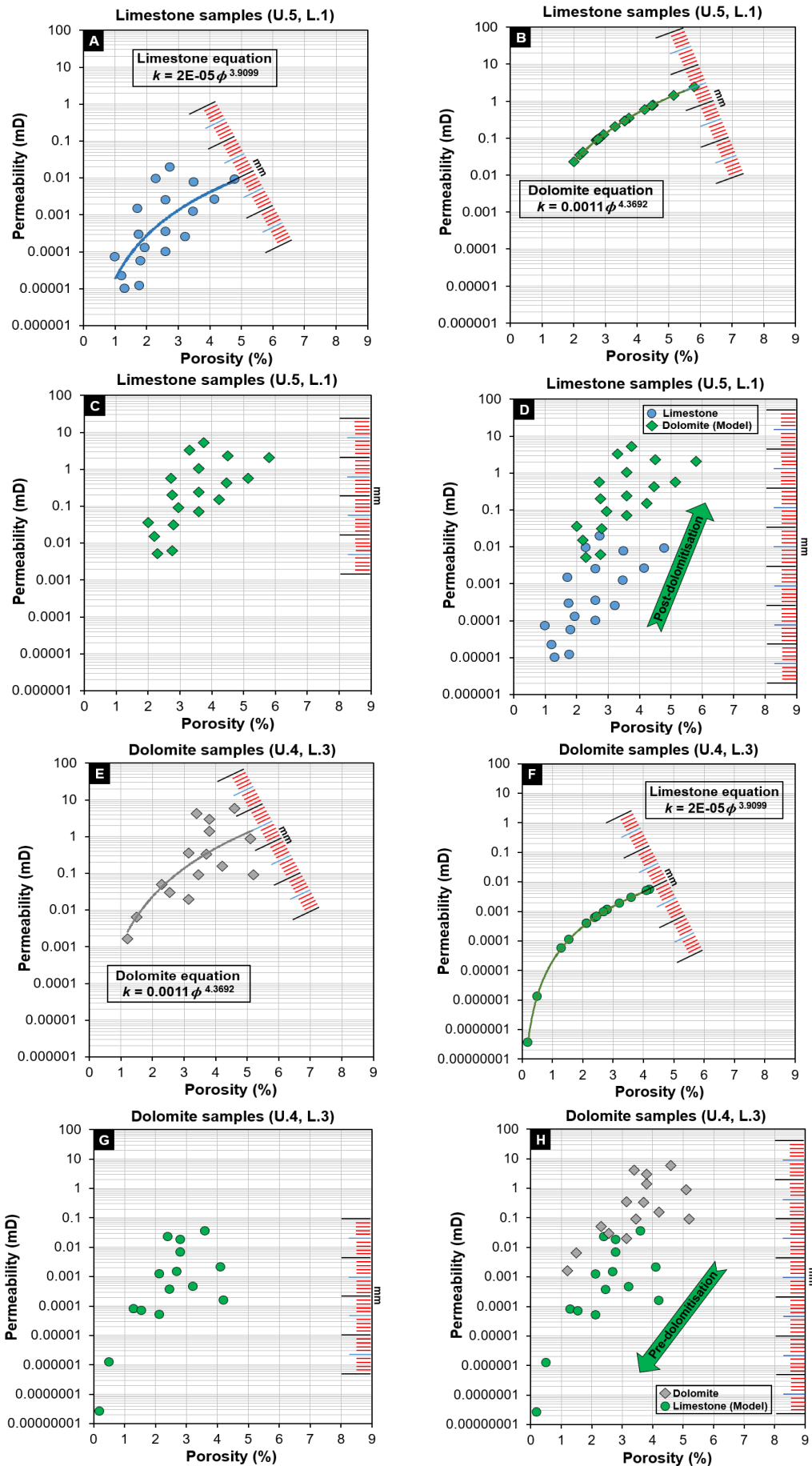
**Figure 10.** Porosity-permeability relationships with controlling factors shown as identified petrophysical fields. (A) The poroperm relationship for the limestone samples (U.5, L.1) with pie chart shows the distribution of the identified petrophysical fields. (B) The poroperm relationship for the dolomite samples (U.4, L.3) with pie chart shows the distribution of the identified petrophysical fields. The solid lines partitioning the poroperm relationships are RGPZ contours where the grain size ( $d$ ) and cementation exponent ( $m$ ) parameters are given in the figure (Glover et al., 2006; Rashid et al., 2015b). The dashed lines are best fit RGPZ-type power laws for each field.



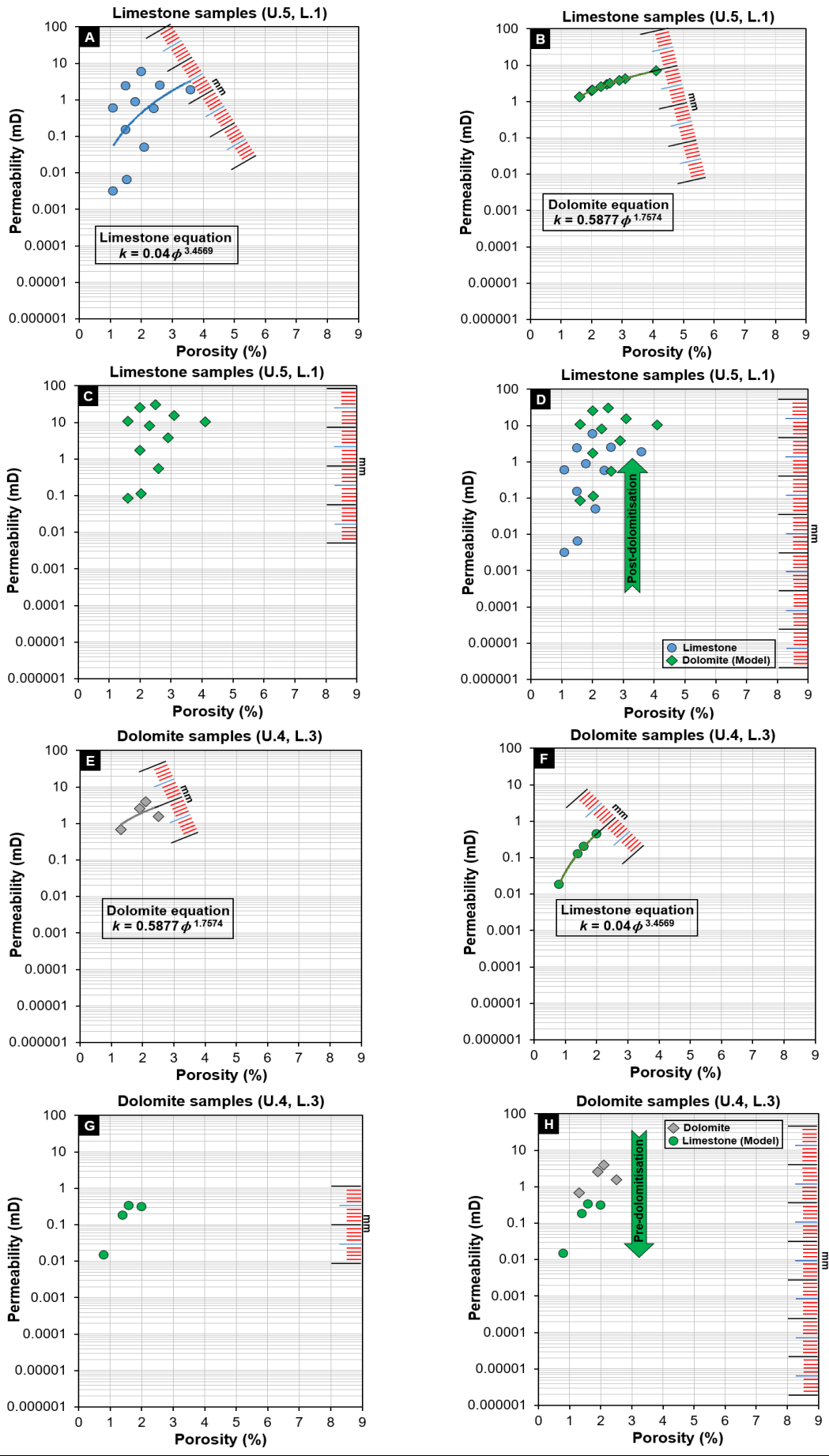
**Figure 11.** Comparison of the three identified petrophysical fields in both lithology limestone and dolomite including porosity, permeability, and the non-linear best fitting equations with a power law coefficient of determination ( $R^2$ ). (A) Diagenetically altered samples. (B) Fractured and diagenetically- altered samples. (C) Fractured samples.



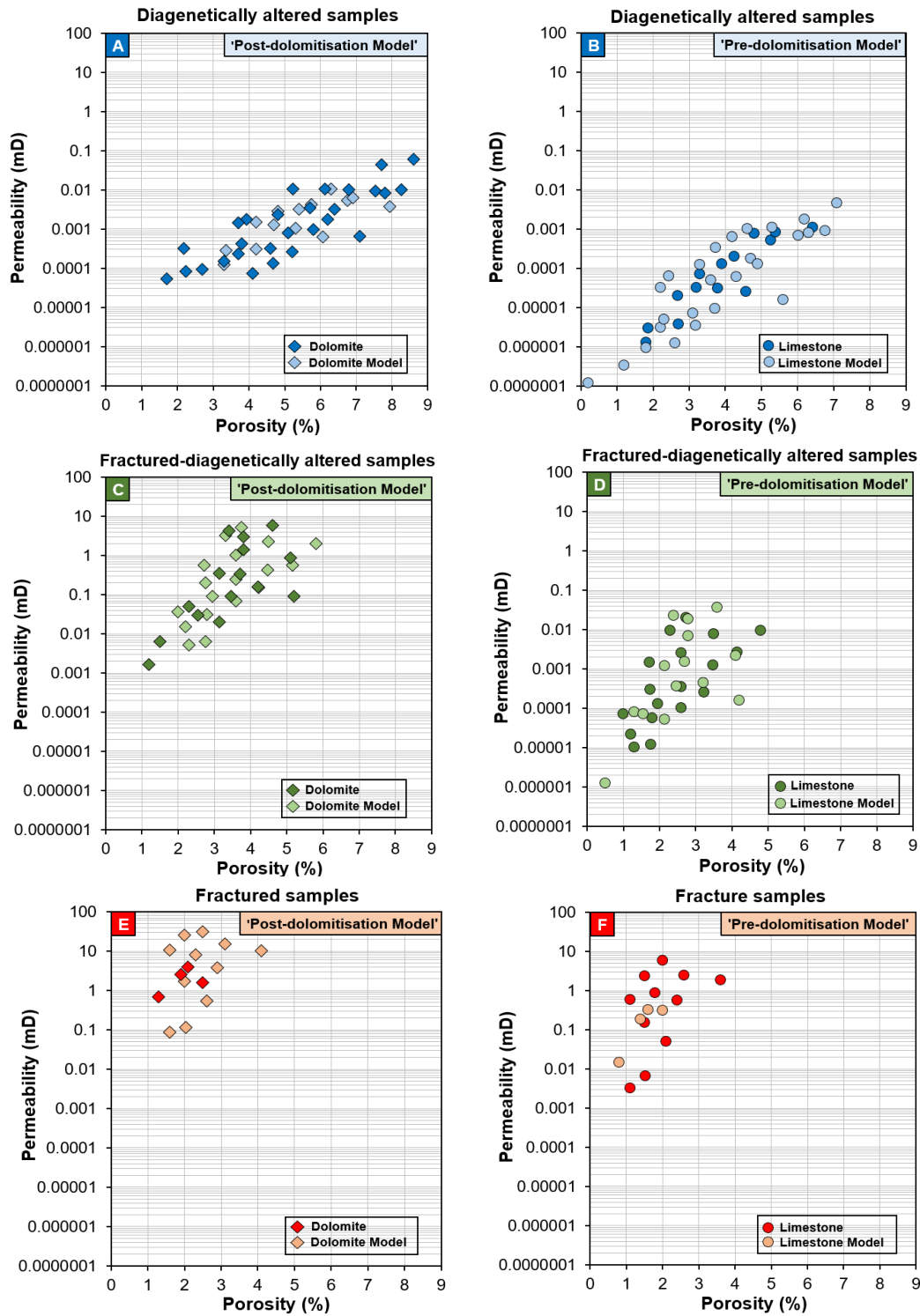
**Figure 12.** Prediction of post-dolomitisation dolomite poroperm data and the pre-dolomitisation limestone data for the diagenetic-altered samples (Field D). (A-D) The limestone samples (U.5, L.1) are used to estimate their post-dolomitisation petrophysical properties. (E-H) The dolomite samples (U.4, L.3) are used to estimate the pre-dolomitisation petrophysical properties.



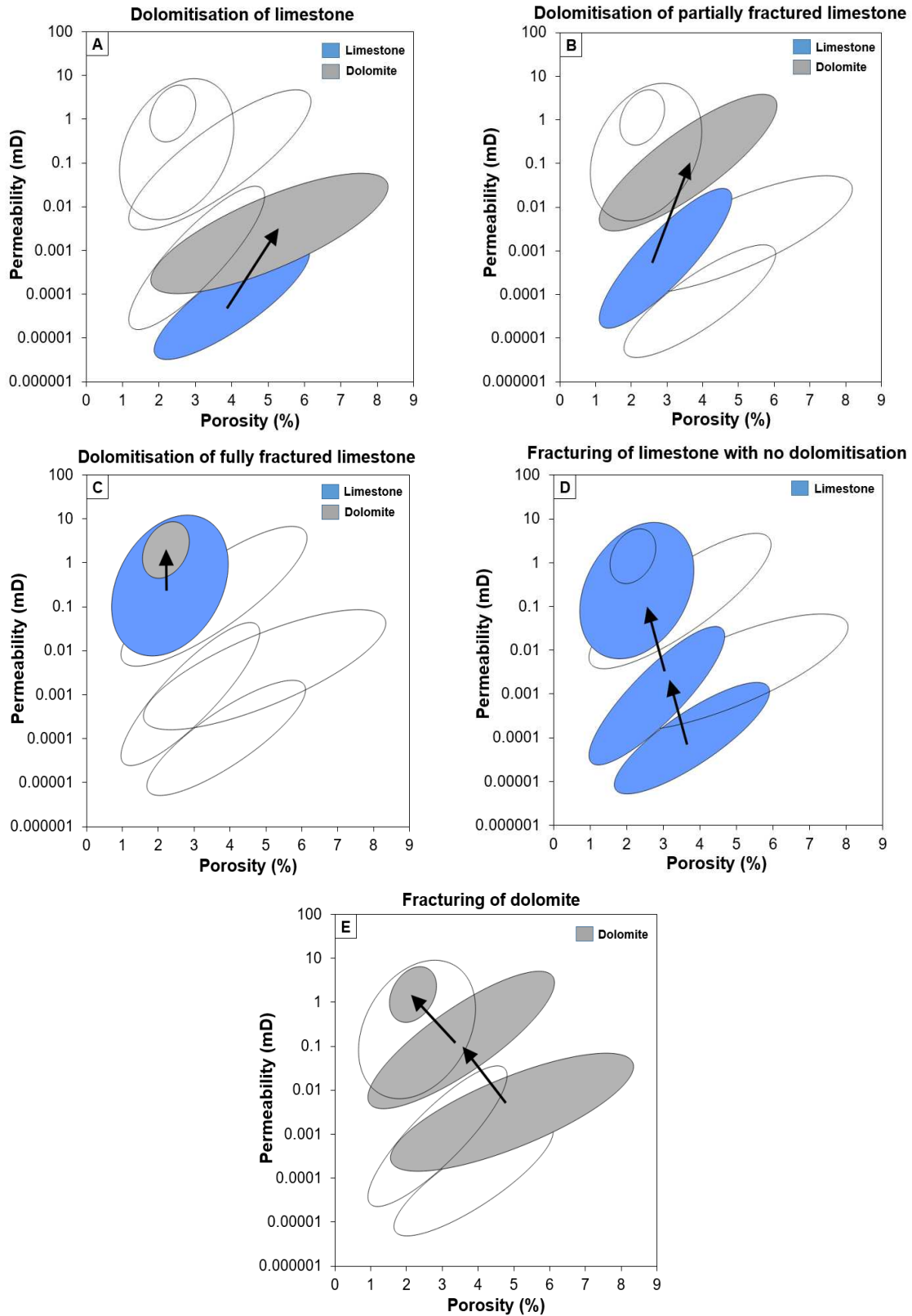
**Figure 13.** Prediction of post-dolomitisation dolomite properm data and the pre-dolomitisation limestone data for the fractured and diagenetically altered samples. (A-D) The limestone samples (U.5, L.1) are processes of estimating the post-dolomitisation petrophysical properties. (E-H) The dolomite samples (U.4, L.3) are processes of the pre-dolomitisation petrophysical properties.



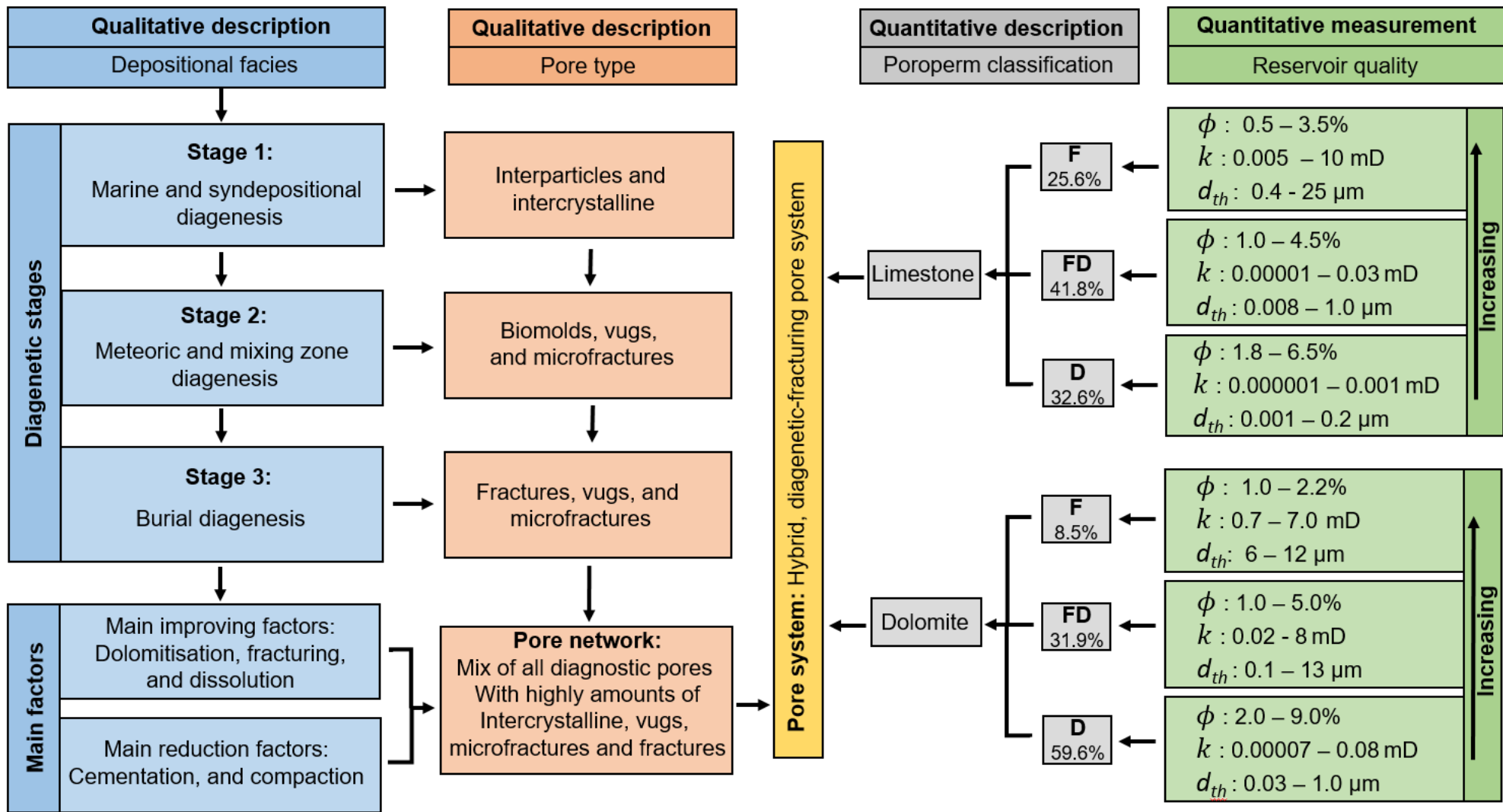
**Figure 14.** Prediction of post-dolomitisation dolomite properperm data and the pre-dolomitisation limestone data for the fractured samples. (A-D) The limestone samples (U.5, L.1) are processes of estimating the post-dolomitisation petrophysical properties of limestone samples. (E-H) The dolomite samples (U.4, L.3) are processes of the pre-dolomitisation petrophysical properties.



**Figure 15.** Comparison of the modelled post-dolomitisation and pre-dolomitisation porosity and measured permeability values with values from associated dolomite and limestones, respectively. (A) predicted and measured values for post-dolomitisation dolomite in diagenetic field samples (Field D), (B) predicted and measured values for pre-dolomitisation limestone in diagenetic field samples (Field D), (C) predicted and measured values for post-dolomitisation dolomite in fractured-diagenetic field samples (Field FD), (D) predicted and measured values for pre-dolomitisation limestone in fractured-diagenetic field samples (Field FD), (E) predicted and measured values for post-dolomitisation dolomite in fractured field samples (Field F), (F) predicted and measured values for pre-dolomitisation limestone in fractured field samples (Field F).



**Figure 16.** The petrodiagenetic pathway of the Butmah Formation according to the effect of dolomitisation and fracturing. (A) Dolomitisation of limestone. (B) Dolomitisation of partially fractured limestone. (C) Dolomitisation of fully fractured limestone. (D) Fracturing of limestone with no dolomitisation. (E) Fracturing of dolomite.



**Figure 17.** Flow chart summarising the qualitative and quantitative descriptions of the petrodiagenetic pathway of the Butmah Formation ( $\phi$ , porosity;  $k$ , permeability;  $d_{th}$ , characteristic pore throat diameter).

