Hydraulic fracturing in a penny-shaped crack. Part II: Testing the frackability of methane hydrate-bearing sand

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A R T I C L E   I N F O

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Apparent fracture toughness
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A B S T R A C T

This work examines the susceptibility of methane hydrate in sand to fracture. The task is made difficult because of two challenges: (1) the means to conduct hydraulic fracturing experiments under high pressure and low temperature conditions, and (2) the formation of high saturation hydrate-bearing sand. The apparent fracture toughness ($K_Q$) of a material is usually determined via conducting standard tests such as three-point bend on notched beams or pull test on compact specimens. In Part I, Too et al. (2018), hydraulic fracturing in a penny-shaped crack was found able to determine $K_Q$ and estimate the tensile strength of frozen sand. As such, experiments were conducted using the similar approach on the synthesized high saturation methane hydrate-bearing sand specimens (approximately 50–75%) with sample size of 80 mm in diameter and 150 mm in length. The range of $K_Q$ determined is between 0.3 and 1.4 MPa$\sqrt{m}$ while the tensile strength estimated ranges between 6 and 12.5 MPa for the hydrate saturation range. The possibility of creating artificial fractures in synthetic methane hydrate-bearing sand may present an opportunity to improve the gas production from natural occurring hydrate-bearing sand.

1. Introduction

Methane hydrate is a non-stoichiometric crystalline solid compound consisting of water and methane gas under high pressure and low temperature conditions (Englezos, 1993; Sloan and Koh, 2007). They are a potential new source of energy found under the permafrost and in deep ocean sediments (Beaudoin et al., 2014; Collett, 2014; Kvenvolden, 1988; Milkov, 2004; Klauda and Sandler, 2005). The gas hydrate in sand layers have better reservoir properties such as high hydrate saturation in the layer and permeability of intrinsic sand layers (Collett, 2014). The depressurization method is deemed the easiest approach to produce gas from hydrate-bearing sand (Moridis and Collett, 2003; Moridis et al., 2010; Rutqvist et al., 2009; Yamamoto, 2014; Chong et al., 2016a). It would dissociate hydrates close to the wellbore (or depressurization point/area) before moving deeper into the layer radially (dissociation front) (Kneafsey et al., 2007). In addition, the thermal-assist dissociation in the depressurization method has been investigated in the laboratory, and shown to improve the gas production because it minimizes the endothermic (cooling) effect in the hydrate dissociation, and prevents temporary hydrate reformation (Chong et al., 2016b; Loh et al., 2015; Tang et al., 2007).

Besides the depressurization method, the CO$_2$-CH$_4$ gas exchange method is another promising approach in producing methane gas from hydrates (Schoderbek et al., 2013; Lee et al., 2003, 2015; Baldwin et al., 2009; Schicks et al., 2011). It is an attractive option because carbon dioxide can be sequestrated (thereby lowering the greenhouse gas) while producing methane gas for energy consumption. In the experiments, methane gas recovery using pure CO$_2$ or CO$_2$/N$_2$ mixture at 2:1 mol fractions have reached 64 % and 85 % methane gas, respectively (Koh et al., 2012; Park et al., 2006). Moreover, this gas recovery method may mitigate potential geohazards in dissociating hydrates in sand. The conversion of CH$_4$ hydrate to CO$_2$ hydrate may not change the hydrate-bearing sand matrix, in which subsidence will not occur (Ersland et al., 2010). A field gas hydrate production test was con-
ducted in 2012 at the North Slope of Alaska using this method (Ignik Sikumi test well) by injecting liquid N$_2$-CO$_2$ (Schoderbek et al., 2013). The field test had reported success in producing methane gas from the CO$_2$-CH$_4$ exchange process after the injection of N$_2$-CO$_2$ liquid was left in the hydrate sand layer for a period of time. However, the field test had highlighted some challenges in utilizing this approach, such as concerns over the loss of injectivity of the liquid due to the secondary CO$_2$ hydrate formation with the excess water in the pore space. Moreover, the permeability of fluid decreases with the increasing hydrate saturation in the sediments, which would prevent the penetrability of N$_2$-CO$_2$ liquid deeper into the layer (Kleinberg et al., 2003).

The effectiveness of hydrate dissociation or gas exchange is governed by the contact area. If an artificial fracture is created in the hydrate-bearing sand layer, larger surface contact area between the pores and solid hydrates will allow for more dissociation, and provide a pathway for the dissociated water and gas to flow to the wellbore (Moridis et al., 2010; Ito et al., 2008). The CO$_2$-CH$_4$ gas exchange benefits from having artificial fractures by increasing the gas exchange area and alleviating the injectivity of CO$_2$ liquid mixture. The idea of creating artificial fractures in hydrate-bearing sand has been proposed before, but to date, experimental studies investigating this aspect have been very limited. Although fracturing the layers above or below the hydrate-bearing layer is not desirable, potential gas seepage, uncontrolled dissociation or blowout may not be a concern because hydrate is a self-preserving material (Johnson, 2017). As long as the hydrates are within the stable thermodynamic and unperturbed, the transient endothermic dissociation of hydrate into gas would be halted. In fact, the stable hydrate mounts found on the seafloor is a good evidence of this self-limiting condition (Hester and Brewer, 2009).

There are some experimental studies conducted on examining the hydraulic fracture characteristics of hydrate in sediment systems. Hydraulic fracturing experiment had been conducted on kaolinite mixed sand interlaid in mud layers without the formation of methane hydrate under vertical and lateral stresses (Ito et al., 2008). It was observed that fracture occurred at the interface between the layers when machine oil was used as the fracturing fluid. It should be noted that such approach yields pseudo-fracture characteristics but do not possess strong tensile characteristics, similar to the experiment on hydraulic fracturing in consolidated sand under confining stresses (Khodaverdian and McElfresh, 2000). In a more recent effort, a high saturation methane hydrate in sand (SH = 72%) specimen was formed in a triaxial cell and hydraulically fractured (50 mm in diameter and 70 mm long) (Konno et al., 2016). Fracture cracks were observed to develop in the specimen when it was examined under X-ray tomography. The experiment was conducted by injecting distilled water at the centre of the top surface through a 3 mm injection hole. The study suggested that a net hydraulic pressure of 2.9–3.9 MPa was related to the tensile strength of the laboratory hydrate-bearing sand specimen, and noting that the experiment was limited to a maximum injection pressure of 9 MPa under a 5.1 MPa confining stress. Such approach indicates a tensile characteristic in the material because of the distinct fracture crack appearance when non-viscous liquid is used as a fracturing liquid. Moreover, Jung and Santamarina (2011) experiments have demonstrated that hydrates possess adhesive and tensile strength when they are formed between two mica or calcite substrates.

Following a recent study conducted on frozen sand as found in (Too et al., 2015, 2018), the apparent fracture toughness can be determined from hydraulic fracturing in a penny crack. This study will investigate the susceptibility of synthetic hydrate-bearing sand to fracture via the similar approach, and to determine the apparent fracture toughness, tensile strength and characteristic length across high saturation hydrate-bearing sand. The synthetic specimens have hydrate saturation in sand between 50 and 75%, which is similar to the in-situ maximum or average hydrate saturation (Medioli et al., 2005; Winters et al., 2011). It should be noted that such experiments are challenging due to the difficulties (i) in forming or obtaining preserved high saturation hydrate-bearing sand samples and (ii) available means to conduct fracture tests at high pressure and low temperature conditions. The majority of hydraulic fracturing of rocks or standard three-point bend on notched specimen (to determine the fracture toughness) will require the material to be handled or tested at standard pressure and temperature at some point. Other than the two references described (Ito et al., 2008; Konno et al., 2016), this work provides a closer examination of the fracture properties of hydrate-bearing sand which is not available in the published literature.

2. Methodology

2.1. Hydraulic fracturing in a penny-shaped crack

The detailed investigation and validation of the hydraulic fracturing approach is given in the Part I (Too et al., 2018), and not repeated here. A penny crack is illustrated in Fig. 1 and the corresponding stress-intensity factor (SIF) is given by (Sneddon and Sih, 1973; Valko and Economides, 1995):

$$K_0 = \frac{2}{\pi} n_i p \sqrt{R}$$  \hspace{1cm} (1)

where $R$ is the crack radius dimension, $p$ is the hydraulic pressure, and $n_i$ is a factor to account for the semi-infinite solution in a penny crack (Sneddon and Sih, 1973; Sneddon and Tait, 1963). In this text, the geometrical crack radius is normalized by the height (or length) of the boundary, $W$, which is the geometrical dimension with respect to the crack plane or axis. For the three crack-height ratios conducted in this study, $R/W = 0.3, 0.5,$ and 0.7, the corresponding $n_i$ is 1.0, 1.02, and 1.165 respectively. The maximum hydraulic pressure attained at failure is known as the breakdown pressure ($p = p_b$).

In another method, the brittleness approach involves the stress analysis in the uncracked ligament. The stress-intensity generated from the hydraulic pressure in the crack can be represented by a nominal stress in the uncracked ligament, which is given in the following:

$$\sigma_N = \frac{p (\pi R^2)}{\pi (W^2 - R^2)} = \frac{p \alpha^2}{(1 - \alpha^2)}$$  \hspace{1cm} (2)

where $\alpha = R/W$ or known as crack-height ratio. The brittleness number ($\beta$) introduced by Carpinteri (1982), is a dimensionless number that relates the apparent fracture toughness, tensile strength of the material and the geometrical height ($W$), which is given in the following:
\[ \beta = \frac{K_0}{\sigma \sqrt{W}} = \frac{l_{ch}}{\sqrt{W}} \]  
(3)

where \( \sigma \) is the tensile strength and \( l_{ch} \) is the characteristic length, defined by Hillerborg et al. (1976), given as

\[ l_{ch} = \left( \frac{K_0}{\sigma} \right) \]  
(4)

The breakdown pressure \( p_b = p_i \) is related to \( \sigma, \beta \) and \( \alpha \) through Equations (1) and (3) by:

\[ p_b = \sigma \frac{\pi}{2n_l \sqrt{\alpha W}} \]  
(5)

Curves derived from a combination of \( \sigma \) and \( \sqrt{l_{ch}/W} \) can be plotted for the breakdown pressure \( (p_b, y\text{-axis}) \) versus the crack-height ratio \( (\sigma \text{ or } R/W, x\text{-axis}) \). The experimental results provide the breakdown pressure over the known crack-height ratio. They are overlaid onto the plot to estimate the tensile strength and characteristic length from the brittle ness curves.

2.2. Quantifying hydrate-bearing sand saturation

The excess water method is utilized to synthesize methane hydrate in the sand for this study, whereby the amount of unreacted water (in moles) is more than the free gas (in moles) at the end of the formation. However, it differs from the convention by not realizing a full conversion of gas into methane hydrate, as defined by the various references on the excess gas versus excess water method (Linga et al., 2009; Priest et al., 2009; Spangenberg et al., 2005; Waite et al., 2009). Fig. 2 illustrates the initial and end formation of hydrate in the sand column for a fixed volume reactor. The hydrate saturation, \( S_H \), in pores of sand is given by (Priest et al., 2009):

\[ S_H = \frac{n_{net} M_H}{V_{H}} \times 100 \% \]  
(6)

where \( n_{net} \) is the net gas moles converted into hydrate (initial minus final gas moles in the voids), \( M_H \) is the molar mass of methane hydrate (0.1196 kg/mol), \( V_H \) is the void volume of the sand column (in m^3), \( \rho_H \) is the density of methane hydrate (913 kg/m^3). The initial and final gas moles in voids are calculated using the Virial equation of state (EOS):

\[ n_G = \frac{p V_G}{R T} \]  
(7)

where \( p, T, R, \) and \( V_G \) are pressure, temperature (Kelvin), ideal gas constant (8314.5 kPa/K/mol), and gas void volume, respectively. The \( z \) is the Pitzer’s correlation to account for real gas compressibility that is commonly used in hydrate formation experiments (Linga et al., 2007; Smith et al., 2005), is given by:

\[ z = 1 + \frac{\beta_p P_i}{T_i} + \frac{\omega \beta^2 P_i}{T_i^4} \]  
(8)

where

\[ \beta_p = 0.083 - \frac{0.422}{(T_i)^{1.6}} \]  
(9)

\[ \beta^2 = 0.139 - \frac{0.172}{(T_i)^{4.2}} \]  
(10)

\[ T_i = \frac{T}{T_c} \]  
(11)

\[ P_i = \frac{P}{P_c} \]  
(12)

Here, \( p_c \) is the critical pressure point for methane gas (4656 kPa), \( T_c \) is the critical temperature point for methane gas (190.6 K), and \( \omega \) is the acentric factor for methane gas (0.0108) (Chapoy et al., 2004).

Since the gas volume in voids \( (V_G) \) changes throughout the formation, the gas moles in equation (7) is numerically solved using Equation (13):

\[ V_G = V_{W} + V_G + V_H \]  
(13)

where \( V_{W}, V_G \), and \( V_H \) are the volume of water, and hydrate in the voids of sand column. The void volume \( (V_{W}) \) is fixed at the beginning of each test. The measured pressure and temperature are used to estimate the gas volume \( (V_G) \) and to determine the gas moles \( (n_G) \) in Equation (7). The difference between initial and current (or final) gas moles will hence provide the amount of hydrates formed. The corresponding volume of water required for hydrate to form is calculated using hydration number of 6.1, which is based on the values measured from laboratory and in-situ hydrate (Sloan and Koh, 2007; Kida et al., 2015; Lu et al., 2011; Ripmeester et al., 2005; Ripmeester and Ratcliffe, 1988; Uchida et al., 1999). The estimated unreacted water of methane \( (V_{W}) \) and gas \( (V_G) \), and hydrate volume \( (V_H) \) are then summed up in Equation (13). This process is iterated until the summed volume is equal to the fixed void volume, in which the volume of unreacted water and gas, and hydrate formed in the voids of sand are determined. The details of this approach can be found in Too (2017).

3. Experimental setup

3.1. Apparatus setup

A new stainless steel high pressure reactor was constructed for this study. The synthetic hydrate-bearing sand is formed inside the reactor with dimensions of 80 mm in diameter and 150 mm in height. The reactor consists of a cylindrical body and two flanges securing at both ends with rubber gasket lined at the connecting faces. The reactor has two acrylic windows along the cylindrical section, 30 mm in diameter, which are used
to observe the activity at the boundary of the specimen. A water bath jacket is welded to the cylindrical body that keeps the experiment at low temperatures. The reactor was hydro-tested to ensure the safe operation of the experiment whereby a pressure of 23 MPa was sustained for 48 h. Hence, the maximum operating pressure of the reactor was set at 20 MPa for the hydrate formation.

The pressure reactor design, dimensions of the sand column, and instrumentations are illustrated in Fig. 3. The two flanges securing the reactor's body have three inlets each (two 1/8″ NPT and one 1/4″ NPT) for various functions: (1) gas supply, venting and pressure-relief valve inlet, (2) water injection inlets, (3) thermocouple measurement inlets, (4) pressure transducers inlets and (5) liquid injection inlet for the hydraulic fracturing process. Three pressure transducers are used to measure the specimen's pressure in the reactor, which are located at the top and bottom of the reactor, and at the injection pipe (hydraulic fracturing). Two thermocouples, which measures temperature at its tip, are installed at the top flange and in the middle of the reactor. The reactor does not have any provision for external confining stresses.

The schematic of the hydraulic fracturing setup is given in Fig. 4. A syringe pump (Teledyne Isco 500D) and piston pump (Eldex Optos) are utilized for the hydraulic fracturing and water injection purposes. The setup is connected to a data collector NI-DAQ (National Instruments) hardware and a computer to record the experimental data. An external refrigerator is utilized to circulate the cold liquid (glycol mixed with water) in and out of the pressure reactor's jacket. It is able to maintain the temperature in the sand column approximately 2.5 °C at T2 and 6.5 °C at T1 (see Fig. 3 (b)).

3.2. Specimen preparation

Sand, which was procured from River Sands Pty Ltd (RiverSands, 2010), was filled from the bottom to the top of the reactor column. The average sand grain size, $d_{50}$, is 0.25 mm, which is comparable to some of the in-situ hydrate-bearing sand (Medioli et al., 2005; Winters et al., 2011). An injection pipe was installed at the centre of the column and filled with non-viscous red-dye water up to the tip of the pipe, and

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Fig. 3. Pressure reactor constructed with observation window in (a). The various instrumentations for the setup in the reactor in (b).

Fig. 4. Schematic of the hydraulic fracturing of hydrate-bearing sand setup.
isolated using a thin plastic film and elastic band to form a small bulb. This was done to prevent water and methane gas at high pressure inside the reactor from entering the pipe, but it could still be easily punctured to allow the red-dye water to flow into the specimen during the injection. It prevented the hydrate from forming inside the pipe which may clog the pipe. A thin circular plastic sheet was placed at the tip centre of the pipe. The circular plastic sheet acted as an initial penny-shaped crack where liquid from the tip of injection pipe could flow into this plastic sheet to form an ellipsoid volume mimicking a penny crack. The described hydraulic fracturing setup is shown in Fig. 5.

The solid volume in the sand column can be calculated using the weight of sand and specific gravity of the sand (2.63 g cm$^{-3}$). With the total volume of the reactor known, the void volume of the sand column was determined to be approximately 38–42% for all of the tests. The porosity of the laboratory specimens were comparable to the in-situ hydrate-bearing sand specimens (Medioli et al., 2005; Winters et al., 2011). The atmospheric gas in the sand column reactor was removed by undergoing 4–5 rounds of pressurizing (up to 1–2 MPa) and depressurizing the reactor with methane gas (Linga et al., 2009).

The hydrate formation in sand column began by injecting the targeted methane gas pressure where the hydrate saturation of 50–75% would require approximately 9–12 MPa. Then, 0.05–0.1% (by weight) of sodium dodecyl sulphate (SDS) mixed in de-ionised water was injected into the reactor where it would increase the reactor’s pressure up to 19 MPa. The amount of de-ionised solution injected into the sand column would make up the water content of 17–20%, which was comparable to the water content of in-situ hydrate-bearing sand (Medioli et al., 2005; Winters et al., 2011). The pressure reactor was then cooled down to the temperature of 2.5–6.5°C. The water and methane gas under high pressure and low temperature formed methane hydrate in the sand column, which was observed from the temperature spikes and pressure drop in the exothermic hydrate formation process. For hydrate saturation above 60%, it would require a second water solution injection since it is not able to reach the targeted water content below the reactor’s operating pressure during the first injection. The hydrate formation would take up to 120 hours depending on the target saturation. It would mark the end of formation when pressure drop measured at the top and bottom of the reactor was less than 200 kPa for 12 hours. We note that at the end of the formation experiment, not all of the methane gas gets converted into hydrate for the experimental time scale used in this study. This aspect has been discussed in detail in our recent work on excess water formation method (Chong et al., 2016b). Besides, to ensure the safe operation of the setup, it was intended to have unreacted gas in voids. If all of the voids in sand column were filled with incompressible water and solid hydrates, further injection of red-dye water during hydraulic fracturing process would cause mechanical failure to the fixed volume reactor.

### 3.3. Hydraulic fracturing of hydrate-bearing sand specimens

At the end of hydrate formation, the hydraulic fracturing commences. A typical hydraulic fracturing process is given in Fig. 6 for two separate tests with similar saturation but at different crack-height ratios. The syringe pump was pressurized up to the higher of the pressure in the sample (P1 or P2 in Fig. 3(b)), as indicated by a→b in Fig. 6. Then, the valve connecting the syringe pump to the injection pipe was released, and the pressure would drop slightly (b→c), which indicated the true pressure inside the specimen. Once the pressure was stabilized in the pipe, red-dye water was injected at a fixed flow-rate of 10 mL/ min and it would reach a peak pressure (d→e). Subsequently, the pressure would drop from the peak to a lower pressure or close to P1 or P2. Pressure would gradually increase with the continuous injection into a fixed void until the injection stopped (f→g). The majority of the test did not record any propagation pressure after the peak pressure.

The net breakdown pressure, which is defined as peak pressure minus the pore pressure, is used to calculate the apparent fracture toughness and nominal stress in Equations (1), (2) and (5). In calculating $K_f$ from SIF approach, the radius of crack is known from the embedded plastic sheet. For example, $R/W = 0.5$ corresponds to $R = 20$ mm with $W = 40$ mm.

### 4. Results and discussion

Hydrate-bearing sand may form a cementing structure at higher saturations, which could be due to the interconnected network of hydrates in pores or hydrates on sand grains. The core samples collected from in-situ had shown that hydrate in conglomerate or sand were intact, suggesting a cementitious structure exist (Dallimore et al., 2005). Moreover, the experimental investigation conducted by Konno et al. (2016) concluded that tensile property was present in high saturation samples. Thus, it is necessary to quantify the cementing property that describe the structure across the higher saturation hydrate-bearing sand, which is indicated by the apparent fracture toughness ($K_f$) and tensile strength ($\sigma_t$). It should be noted that there is no available (published) information from the literature for possible comparison for the fracture characteristics while no quantification of permeability.
improvements are made on these artificially fractured specimens. The observed results should be seen in the context of the method employed in this study. In addition, the time-dependent strength changes are not examined in this study, in which the results in this paper may be representative of laboratory time-scale only.

4.1. Hydrate saturation in sand

A total of 37 specimens were formed in which 34 of them had hydrate saturation above 50% while 3 specimens were at 36.6, 47.6 and 48.9%. Table S1 summarizes the results for all the tests conducted which are available in the Supporting Information. More detailed pressure-temperature recordings can be found in Too (2017).

Fig. 7 shows the hydrate saturation cross-plot, in which the saturation at the end formation (S_{h,\text{Experimental}}, y-axis) is compared to the target saturation that each test can form based on the amount of gas injected (S_{h,\text{Target}}, x-axis). With the limited formation time in laboratory (up to 120 h for high saturation specimens), it was noted that the maximum hydrate saturation achieved was 76.2% even though the total gas pressure injected could form up to 80–83%. The majority of tests with hydrate saturation of less than 70% achieved their target saturation, whereby the results lie on the linear line of the saturation cross plot. However, for hydrate saturation above 70%, it was difficult for hydrate to reach the target saturation. This implicitly indicates that the fluid movement could be limited possibly due to the reduction in permeability when hydrate saturation is increased in the porous media (Schoderbek et al., 2013; Liang et al., 2012).

4.2. Visual observation of crack appearing at the boundary of the specimen

All of the 37 tests were hydraulically fractured at three crack-height ratios, R/W = 0.3, 0.5 and 0.7. In some of the tests, visual crack at specimen boundary was observed when the hydraulic fracturing attained the peak pressure, as shown in Fig. 8. A video is made available in the Supporting Information (SI Video) to show the crack appearing at the boundary of the crack plane during the red-dye injection, which was observed from the acrylic window on the pressure reactor. The cracks may not occur at the crack plane, with some tests showing the crack appearing above the plane. These cracks occurred in a short length, which could be due to the non-uniformity of hydrate formed in the sand column. Some areas may have high hydrate concentrations, leaving other area with a lower concentration and unreacted methane gas or water isolated. Such event has been reported as patchy hydrate (Dai et al., 2012). These areas would form a weaker section in the hydrate-bearing sand column, which would be developed as the fracture initiation path.

Supplementary video related to this article can be found at http://dx.doi.org/10.1016/j.jngse.2018.01.046.

Fig. 8. A hydrate saturation cross-plot whereby the hydrate saturation at the end of the formation in the experiment (y-axis) versus the target hydrate saturation (x-axis) based on amount of gas pressure injected in each test.
4.3. The apparent fracture toughness, tensile strength, and characteristic length of hydrate-bearing sand

The $K_Q$ calculated using Equation (1) (refer to Table S1) were analyzed via a linear regression analysis, as shown in Table 1. The coefficient of determination, $R^2$, given in the table represents the scatter of the data in relation to the linear regression. Higher $R^2$ (maximum value of 1.0) means that the linear regression has a better fit to the experiment data. Fig. 10 compiles the results from the linear regression and experimental data from the three groups of crack-height ratios. Based on the regressions, hydrate-bearing sand begins to exhibit a cementitious property when the hydrate saturation is above 40–44 % ($K_Q \geq 0$). The maximum apparent fracture toughness when the hydrate saturation is 100 % in the voids of the sand column is estimated at 1.95–2.10 MPa√m. For the experiments conducted ($S_H \approx 50$–75%), the apparent fracture toughness determined is found to be between 0.27 and 1.43 MPa√m.

The tensile strength and characteristic length can be estimated from the brittleness approach. Using Equation (5), a plot of breakdown pressure curves ($p_b$, y-axis) versus the crack-height ratio ($a/q$ or $R/W_q$, x-axis) was established. The longitudinal net breakdown pressure served as the limit for the prescribed crack-plane fracture. Three groups of hydrate saturations were assembled from the results, in which the hydrate saturation groups were: (A) $S_H \geq 70 \%$ (13 tests), (B) $60 < S_H < 70 \%$ (8 tests) and (C) $S_H \leq 60 \%$ (10 tests). The estimation of tensile strength for each of the groups was taken to be higher than the nominal stress in the uncracked ligament from Equation (2). The maximum nominal stress produced from the experiments for $R/W = 0.7$, was approximately 10.8, 5.6 and 5.2 MPa for the three hydrate saturation groups, respectively. The estimation was made by fixing the range of $W/l_h$ since it was the same material while the tensile strength increased with the increase of hydrate saturation in the sand. In doing so, the range of $W/l_h$ and tensile strength were estimated as shown in Fig. 11.

<table>
<thead>
<tr>
<th>Table 1</th>
<th>The relationship of the apparent fracture toughness, $K_Q$, with the hydrate saturation in sand, $S_H$, analyzed using a linear regression.</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R/W$</td>
<td>Linear Regression</td>
</tr>
<tr>
<td>0.3</td>
<td>$K_Q \approx 3.50 S_H - 1.40$</td>
</tr>
<tr>
<td>0.5</td>
<td>$K_Q \approx 3.50 S_H - 1.55$</td>
</tr>
<tr>
<td>0.7</td>
<td>$K_Q \approx 3.50 S_H - 1.48$</td>
</tr>
</tbody>
</table>

Fig. 8. Crack-line fractures captured at the boundary of the specimens during the hydraulic fracturing process. The crack-line is shown by the arrows while puncture hole with a dashed box. The crack plane is oriented horizontally near the middle of the acrylic window of the pressure reactor.

Fig. 9. A vertical crack along the injection pipe axis observed at the boundary of the specimen for test T3-07 and T3-10, with a much higher net breakdown pressure recorded.

Table 2 compiles the results from the brittleness approach for the estimated tensile strength, characteristic length derived from the known specimen radius, $W = 40$ mm, and the apparent fracture toughness range determined using Equation (4). The estimated tensile strength indicated that hydrate-bearing sand would exhibit cementing property when the saturation was above 40 %, as shown in Fig. 12. At full hydrate saturation in the sand column ($S_H = 100$ %), the tensile strength was estimated at 23.5 MPa based on the linear regression.

### Table 2

<table>
<thead>
<tr>
<th>Hydrate Saturation (%)</th>
<th>Characteristic Length, $l_{ch}$ (mm)</th>
<th>Tensile Strength, $\sigma_t$ (MPa)</th>
<th>Apparent Fracture Toughness, $K_Q$ (MPa$\sqrt{m}$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$S_H \geq 70$</td>
<td>72.0</td>
<td>$2 &lt; l_{ch} &lt; 13.3$</td>
<td>$12.5 &lt; K_Q &lt; 1.44$</td>
</tr>
<tr>
<td>$60 &lt; S_H &lt; 70$</td>
<td>66.8</td>
<td>$2 &lt; l_{ch} &lt; 13.3$</td>
<td>$10.5 &lt; K_Q &lt; 1.21$</td>
</tr>
<tr>
<td>$S_H \leq 60$</td>
<td>55.4</td>
<td>$2 &lt; l_{ch} &lt; 13.3$</td>
<td>$6.0 &lt; K_Q &lt; 0.69$</td>
</tr>
</tbody>
</table>

Note.

* The characteristic length is calculated using the estimated range of $W/l_{ch}$ and the specimen radius, $W$, of 40 mm, as described in the experimental setup.

* The apparent fracture toughness is determined from equation (4).

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![Fig. 10. The apparent fracture toughness, $K_Q$, determined using the SIF with the linear regression (dash-dot lines) for the three crack-height ratios, $R/W = 0.3$, 0.5, and 0.7.](image)

![Fig. 11. Net breakdown pressure plot for the hydraulic fracturing of hydrate bearing sand. The estimation of tensile strength was separated into three hydrate saturation groups; (A) $S_H \geq 70$ %, (B) $60 < S_H < 70$ % and (C) $S_H \leq 60$ % using the same range of characteristic length.](image)

![Fig. 12. The estimated tensile strength versus hydrate saturation in sand column.](image)

### 4.4. Effect of lower flow rates in the hydraulic fracturing of hydrate-bearing sand

Three tests with comparable saturations (70.2, 69.8, and 68.6%) were examined using the lower flow rates of 2, 0.5, and 0.1 mL/min at $R/W = 0.3$. The tests were conducted to examine if fracture propagation pressure was present, as shown in Fig. 13. The hydraulic fracturing process is more complex when there is leak-off during injection due to a permeable system. Both 2 and 0.5 mL/min tests yielded a similar net breakdown pressure of approximately 10 MPa, while test using 0.1 mL/min did not record any pressure build-up. The pressure build-up was linear until it was close to the peak pressure whereby a declining pressure-gradient was observed. A short flattening pressure indicated that a minute propagation pressure may have occurred before it dropped. The apparent fracture toughness calculated using these flow rates are compiled in Fig. 14. The lower flow rates tend to produce slightly lower $K_Q$ than the higher flow rates, consistent to the previous finding in Part I (Too et al., 2018). Nonetheless, they are still comparable to the test conducted at 10 mL/min.

### 5. Conclusion

Laboratory synthesized hydrate-bearing sand with saturation of 50–75% can be artificially fractured using hydraulic fracturing in a penny-shaped crack. The cracks appeared at the crack-plane of the specimen’s boundary, and recorded a net breakdown pressure. The corresponding apparent fracture toughness was determined ranging from 0.27 to 1.43 MPa$\sqrt{m}$, while the tensile strength and characteristic length was estimated ranging from 6-12.5 MPa and 2–13.3 mm, respectively.
Though the results in this work could serve as a reference in conducting hydraulic fracturing of hydrate-bearing sand for gas production, it is noted that the results obtained in the work could be condition, reactor and approach specific. The actual quantification in terms of the improvements (or increase) in the gas production from an artificially fractured hydrate-bearing sediment, if any, needs to be further investigated. This requires innovative experimental integrations that decouples and measures the gas and water dissociated from hydrates, as well as the excess gas and water from the system that was not converted into hydrates. It should be noted that the various formation methods, homogeneity of hydrate in sand column, and the exclusion of external stresses, may affect the fracture properties and gas production behavior in a fractured hydrate-bearing system. Thus, some of the potential future work relating to the frackability of hydrate-bearing sand may include examining the: (1) effect of confining and effective stresses, (2) different fracture geometries or setups (such as a vertical wellbore) to simulate closely to the real application, (3) flow permeability improvements in a fractured specimen, and (4) scalability of the system.

Fig. 13. Hydraulic fracturing of hydrate-bearing sand with saturations of approximately between 69 and 70% at different flow rates: 2.0 mL/min in (A), 0.5 mL/min in (B), and 0.1 mL/min in (C).

Fig. 14. The apparent fracture toughness of hydrate-bearing sands examined at varying flow rates.

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Appendix A. Supplementary data

Supplementary data related to this article can be found at http://dx.doi.org/10.1016/j.jngse.2018.01.046.

References
