Diagnostic Fracture Injection Test (DFIT) Recommendations

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August 2020

Revised July 2023

The original text for this document was included in the report by Enlighten Geoscience Ltd.:

Pressure, Stress and Fault Slip Risk Mapping in the

Kiskatinaw Seismic Monitoring and Mitigation Area,

British Columbia

for the BC Oil and Gas Research and Innovation Society

ER-Seismic-2020-01

Introduction

The Diagnostic Fracture Injection Test (DFIT, or more generically as a mini-frac test) is a versatile, cost-effective, and informative test for any sub-surface energy development evaluation. It is a critical first step for any completion optimization process. DFITs have become the preferred data type for geomechanical and reservoir property information in low permeability formations (a.k.a. resource plays) where conventional well tests are impractical. They provide a convenient option for both appraisal of new exploration/step-out wells and testing of properties in development wells to understand pressure and stress changes in the reservoir.

The purpose of this document is to establish a set of recommendations for DFIT design, execution interpretation, data submission and quality ranking.

Test Types

Conventional DFITs utilize a small volume injection of fluid into a formation at sufficient rate and pressure to create and sustain a relatively small opening mode fracture. Once injection is stopped, fall-off pressures are monitored for an extended period. This test provides the most reliable and widest range of parameters when conducted successfully.

Variations on the conventional DFIT include repeat injection and flow-back cycles (most common in oil sands applications for caprock evaluation), step-up/step-down tests and accelerated flow-back tests. These are not the focus of this document.

Recommended Test Procedures

The most important requirements for successful execution of a conventional DFIT are advance planning, communication with operations personnel, and providing sufficient time for the pressure fall-off period before proceeding with full-scale completions operations.

<u>Surface versus Bottom-hole Data</u>

In general, surface data collection is recommended for a DFIT. Surface data is suitable when reservoir pressure is greater than the wellbore hydrostatic pressure. If reservoir pressure is lower than hydrostatic (9.8 kPa/m for fresh water) consideration should be given to using downhole gauges and a downhole shut-in tool upon termination of the injection phase. This procedure is more expensive and inherently more complicated, which may increase the risk of a misrun (e.g., leaking isolation device).

If the wellhead gauge pressure drops below zero (well goes on vacuum), both surface pressure and downhole pressure are affected due to large fluid compressibility changes that occur.

If surface pressure is used, the density of the wellbore fluid must be known (or measured just prior to, or during, injection) to provide the information necessary to calculate the bottom-hole pressure from the fluid gradient. Alternatively, a slickline- or wireline-conveyed static gradient pressure survey may be conducted <u>after the end of the pressure fall-off period</u> to calibrate surface to downhole pressure calculations. To mitigate thermal expansion effects, delay the DFIT for at least 24 hours after filling the wellbore with fluid and insulate the wellhead to minimize the impact of fluctuations in pressure due to ambient temperature changes.

Bottom-hole gauges can be pre-installed to estimate reservoir pressure from static conditions in cases of sufficiently high permeability. This can assist in finding a unique interpretation for the data collected.

Recommended Conventional DFIT Design and Execution Procedures – Surface Pressure Data Recording

1. Install wellhead pressure data recorders (1 second sampling frequency) on wellhead in a location that will not interfere with bottom-hole injection point pressure measurement for the entire test duration.
2. Rig in pump truck, pump manifold injection fluid supply.
3. Thoroughly pressure-test entire system. Even extremely small leaks will be detrimental to, or even preclude successful analyses.
4. Pump-in 70/30 water/methanol mix (cold weather locations) to open toe-stage burst port and achieve pressure leak-off.
5. Shut-in the well and monitor initial leak-off for 1-hour (pre-DFIT Leak-Off Test, LOT).
6. Pump at 0.5 m^3/min until formation breakdown is established.
7. Once breakdown is achieved, increase pump rate to 1-1.5 m^3/min for the desired pump time. Typically DFITs are pumped between 5 and 15 minutes.
8. Once maximum rate is achieved, hold rate steady until end of injection period. Sequential rate reduction for step-down testing is not recommended for most tests looking for fracture extension pressure, closure pressure, formation pore pressure and permeability.
9. Shut down as fast as possible. Wait at least 30 minutes.
10. Ensure pressure on wellhead/pump manifold system remains undisturbed and pressure monitoring system is isolated and undisturbed.
11. Rig out pump truck.
12. Monitor pressures for 7-10 days. Terminate test when one of the following occurs:
    a) Surface pressure drops to 0 gauge (well goes on vacuum).
    b) Pressure reaches a static level (no further drop in 24 hrs). A rule of thumb of 2.0 kPa/hr can be used to rig off pressure recorders if analysis cannot be completed prior to the end of testing.
    c) Pressure Transient Analysis (PTA) shows sufficient after-closure data to confidently identify linear or radial (radial less commonly observed) flow regimes that may be used to extrapolate to reservoir (pore) pressure.

Ideal Pressure Gauge Specifications

Pressure gauges should be:

- recently calibrated
- temperature-compensated
- capable of 0.02% full scale accuracy and 0.07 kPa (0.01 psi) resolution

One-second sampling frequency is normally sufficient. Live data transmission of pressure and temperature data helps the DFIT analyst determine when sufficient data has been collected to terminate the test.

Injection Fluids

Water

Water is the most commonly used injection fluid for DFITs due to availability, low cost, low compressibility and safety of handling compared to other fluids. In rare cases the formation damaging effects of water (clay swelling, imbibition, etc.) may be considered, however these issues are usually manageable with clay stabilization chemicals such as Potassium Chloride (KCl).

Acid Solutions

Acid solutions are not normally recommended unless near well damage must be overcome to allow for injection at high enough rate to achieve breakdown (tensile fracture). Acid may affect pressure fall-off behavior as reactive fluids create permeability and heat both of which will affect fluid leak-off behavior and the interpretation. If acid must be used to achieve breakdown, it may be beneficial to pump a larger 'flush' volume of water after the acid to minimize reactive and thermal effects.

Avoiding Freezing

The largest drawback to water-based injection fluids in colder locations is freezing. With a typical DFIT, the pressure fall-off period will last tens to hundreds of hours, during which time a static wellhead will freeze with ambient temperatures below zero °C (32 °F). Antifreeze chemicals must be used in these situations to ensure a successful test. A 70/30 mix of water and methanol or glycol solves this problem. Ensure that the antifreeze mix is circulated into all parts of the wellhead, especially where gauges are located. Ice expands in volume which will increase pressure and adversely affect the DFIT interpretation or render the test a misrun.

Interval Selection, Rate and Volume

It is generally preferred to perform a DFIT in a single lithological interval to reduce uncertainty in the test height and the risk of communicating into multiple intervals with significantly differing geomechanical or reservoir properties.

DFIT injection rate and fluid volume should be sufficient to achieve fracture growth over a considerable portion of the test interval thickness and away from the wellbore stress concentration effects. Out-of-zone height growth or excessive fracture length should be avoided. The latter will extend the duration of flow periods and required shut in time. Similarly, injection volumes that are too small may reduce the quality of test results and may not shorten the required fall-off time. Rates of 1.0 to 1.5 m^3/min for 5 to 10 minutes are usually acceptable. Detailed recommendations may be found in Hawkes et al (2018).

Pressure Fall-off Time

Pressure fall-off time depends on test objectives. Identification of fracture closure is normally achievable within several hours. Late-time flow periods that are used to extrapolate for reservoir pressure and transmissibility may take many days or even weeks to develop. Comparing analogue tests prior to execution may help in the design of the current test.

Misruns and Testing Multiple Wells

In situations where a new area is being evaluated, it is recommended that DFITs be performed in more than one well. Multiple tests will minimize the effects of any possible misruns. Misruns are defined as tests where the objective measurements (usually fracture closure pressure or reservoir pressure) cannot be determined from the analysis. Results from several tests increase statistical relevance and may illuminate information that is difficult to gather from a single test.

Troubleshooting

Table 1 presents some common DFIT execution problems and suggested solutions. Refer to Figure 1.

	Problem	Solution
1	Air trapped in wellbore increases compressibility and wellbore storage	Circulate DFIT fluid to remove gas bubbles if possible. If circulation is not possible, repeatedly fill well with DFIT fluid to a pressure safely below breakdown or toe-stage activation pressure and bleed back until gas head is removed. Confirm DFIT fluid column is free of gas by observing the linear relationship (surface chart recorder) of pressure vs. time while pressuring up toe-stage port to activation pressure or, if the toe port is open, pressuring up to breakdown pressure. This compression phase is also often the first phase of a pre-DFIT Leak-Off-Test (LOT).
2	Pressure testing does not detect wellbore or wellhead leaks	DFIT analysis relies on the interpretation of subtle changes in pressure. Any leaks in the well casing, packers, tubing or wellhead equipment will likely render a test useless. Typical oilfield pressure testing is done to a surface pressure of 7 MPa (1,000 psi) for 10 minutes using a surface dead-weight pressure gauge. This test is often insufficient to detect very small leaks. It is recommended that pressure testing be performed to as high a pressure as safely possible (considering well equipment pressure ratings and toe-stage activation pressure) and for up to 30 minutes to improve chances of detecting very small leaks prior to testing.
3	Wellhead freezes and over-pressures or isolates gauges from fall-off pressure.	In cold weather operations, the last fluid pumped into the wellhead should include anti-freeze chemicals such as methanol, glycol or a non-volatile, incompressible hydrocarbon (such as diesel fuel). Note that dead spaces in the wellhead (e.g., gauge locations) may not get exposed to anti-freeze during pumping so a small quantity injected into these spaces prior to installation may also help prevent freezing.
4	Rig out of DFIT pumping equipment compromises early-time DFIT data (surface data).	Install wellhead valves to allow for removal of pump equipment without any de-pressuring of DFIT gauges. If there is no choice but to disconnect data recorders during a portion of the rig-out (e.g., vibration due to hammering may damage gauges, cables may be severed, etc.) it is recommended that data be recorded concurrently between the pump truck and the DFIT gauges during pumping and for a minimum of 60 minutes after pump shut-down. This early time data collection redundancy can be useful to synchronize pumping time measurement while providing back-up for the early falloff data. If prior DFITs have been recorded and analyzed in the area, care should be taken to rig-off at a time that is not critical to the test objectives (e.g., avoid rigging down pumping equipment and lines around closure time).
5	Inconclusive Breakdown Pressure	Achieving formation breakdown pressure in the toe port of a horizontal well is not as clear a signature as the textbooks and technical papers depict. This is generally due to the large wellbore volume and the compressibility of the system. Even though the toe port may open, due to volume restraints (smaller and shorter tests) put on the pumping company, the fracture initiation and formation breakdown is inadequate to meet the tests objectives. This oversight is normally not picked up until well after pressure gauges are rigged off and data are in the hands of the interpretation engineer. A simple but cost-effective procedure is to perform a pre-DFIT Leak-Off-Test (LOT). This is accomplished by pressuring up the wellbore until a toe port opens or an observed "apparent" breakdown pressure has occurred and then shutting down the pump and securing the wellbore to monitor the leak-off for a minimum of 60 minutes. Typically, pressure will

		fall-off confirming wellbore to formation communication. After this step, the main DFIT test can be pumped as programmed. This procedure satisfies both conditioning of the wellbore and provides a cleaner formation breakdown signature for the main DFIT.

Table 1. Common DFIT execution problems and suggested solutions.

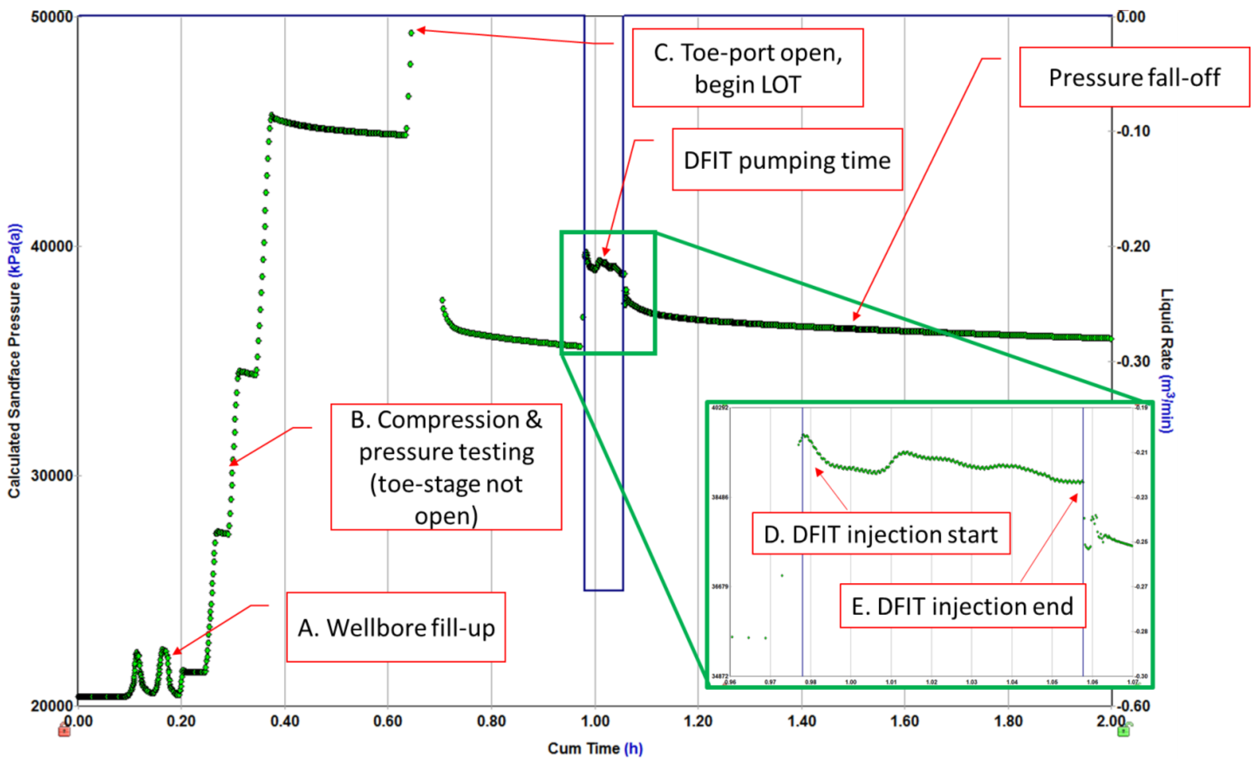

Figure 1. Conventional DFIT Pump Chart – Identification of Phases

DFIT Analysis

Evolution of DFIT Analysis Methodology

The analysis of DFIT data has evolved over time and continues to do so. The authors are aware of more than eight approaches to DFIT interpretation currently in use or under development. Table 2 summarizes some of important publications and the key advancements they introduced from 1957 to present day.

Reference	Key Contribution
Carter, 1957	Introduced simple hydraulic fracture fluid leak-off behavior based on the square-root of time.
Nolte, 1979	Pioneered DFIT analysis techniques, introducing the concept of the G-function.
Barree et al., 2007	Refinement of Nolte's G-function approach. Incorporated four different leak-off mechanisms ('Normal', 'Transverse Storage/Height Recession', 'Pressure-Dependent Leak-off', and 'Tip Extension'). These leak-off mechanisms are identified using a combination of specialized diagnostic plots centered around the G-function plot. Fracture closure pressure, Pc, is picked from the G-function plot at the point created at the intersection of a line from the origin to the tangent of the semi-log G*dP/DG plot. This technique is often referred to as the "Tangent Method". Although still widely practiced by industry, the authors believe these techniques have been superseded by newer interpretations of the physics of fracture closure and the benefits of more modern techniques some of which are referenced below.
Bachman et al., 2012 and 2015; Bachman, 2016	Used well testing Pressure Transient Analysis (PTA) theory with the Bourdet Derivative (Bourdet et al., 1983) and Primary Pressure Derivative (PPD, Mattar and Zaoral, 1992) to show that DFIT leak-off creates unique flow regimes. These flow regimes are identifiable on a log-log plot and define fracture and reservoir behavior before and after fracture closure. This technique is called the "PTA method." Combining this method with observation of pressure gradients (pressure divided by true vertical depth, TVD) can help identify complex behavior resulting from fracture, reservoir and wellbore effects. Special cases have been more clearly identified from their flow regimes, including composite permeability, horizontal-plane fractures and large changes in wellbore compressibility due to surface pressure falling below zero-gauge pressure (vacuum). Several examples highlighting the benefits of this method are outlined in Hawkes et al., 2013, 2018. Currently the PTA analysis method is the only approach being used to describe horizontal-plane fractures observed in DFITs (Hawkes et al., 2013; Nicholson et al., 2017).
Craig et al., 2014	Uses type curve matching ("Type Curve Method") to interpret closure and after-closure reservoir parameters. This technique is based on the idea that fracture closure is a storage phenomenon which consists of both wellbore and hydraulic fracture components.
Liu and Ehlig-Economides, 2015	Utilize analytical and semi-analytical models to pressure-history match "abnormal" before-closure leak-off behaviors such as tip extension, pressure dependent leak-off, transverse storage and multiple (vertical) closures ("Multiple Closure Method").
McClure et al., 2016	Re-interprets the G-function closure plot and picks closure at a higher pressure where fracture disparities first make contact and fracture compliance is changing most rapidly. This interpretation is known as the "Compliance or Contact Method." This technique tends to provide a closure pressure interpretation more consistent with PTA theory, but it still lacks the ability to illustrate the various before and after-closure flow regimes.

Hoek, 2016	Uses an analytical solution based on 3-D fracture simulation for water injector leak-off tests that computes leak-off signatures given input geometry conditions. Storage-dominated (mini-frac) & leak-off dominated (water injection well pressure fall-off) bounding cases are presented ("Storage/Leak-off Bounded Method"). Also claims superior results in the 'mid-leak-off' cases using this technique.
Zanganeh et al., 2017	Uses numerical simulation to interpret pressure fall-off behavior as a combination of leak-off and geometry changes including after-flow effects that simultaneously narrow and extend the length of the fracture. This method is known as "Moving Hinge Closure." The authors believe elements of this interpretation occur during a DFIT. These have been included (in simplified form) in the model presented in Nicholson et al. (2019a). This approach requires a numerical simulation that is not readily available for most engineers.

Table 2. Brief history of DFIT analysis techniques.

Recommended Analysis Technique

Nicholson et al. (2019a, 2019b) use PTA and Pressure Gradient Analysis ("PTA & PGA Analysis") to analyze DFITs with a focus on Early-Time Flow Regime (ETFR) identification which helps characterize and quantify complex hydraulic fracture geometry (see example in Figure 2). Additional rules are introduced to identify Fracture Extension Pressure away from the near wellbore using PTA. This Far-field Fracture Extension Pressure (FFEP) has excellent correlation with closure pressure compared with ISIP values (SPE 204183 App. B). ISIP picks tend to vary widely due to inconsistent and subjective methodologies.

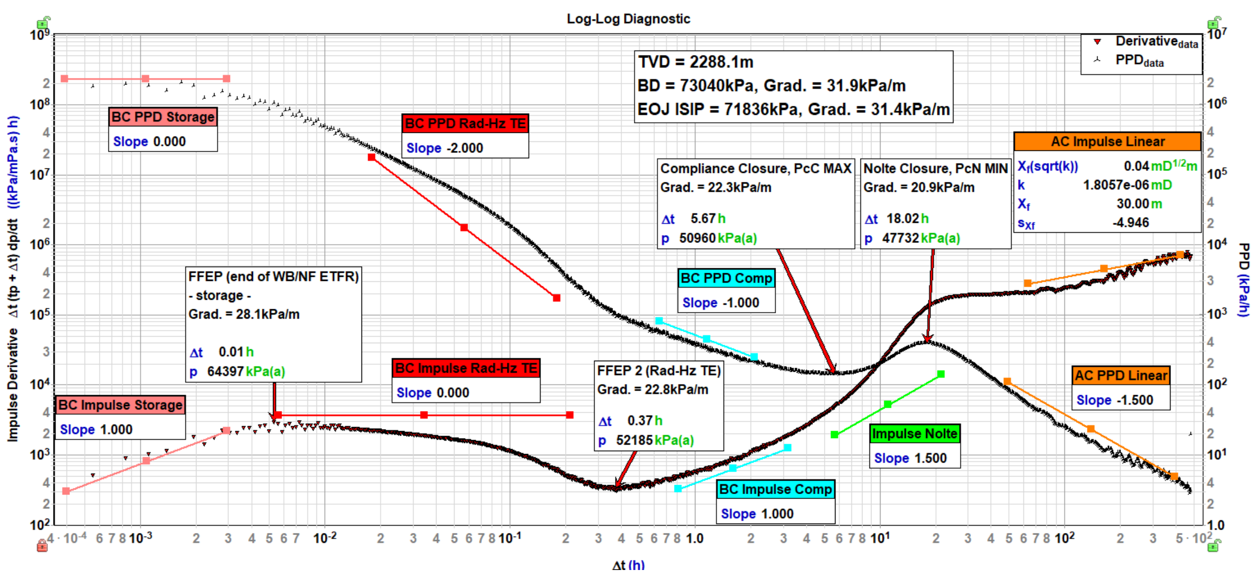

Figure 2. Combined PTA & PGA for a DFIT exhibiting complex fracture behavior with two FFEPs identified.

Analyzing a DFIT usually requires specialized software, however the calculations and plots are possible in a spreadsheet with the correct formulae and data manipulation skills. The following list summarizes the steps normally undertaken to analyse a Conventional DFIT using well test analysis software.

Summary of Analyses Step by Step:

1. Pressure and temperature data should be loaded into the software. Endpoint gauge data that is not representative of the well pressures (e.g., from before the gauge was installed or after it is removed at the end of the test) should be deleted.
2. Injection data should be loaded, or entered, into the software. Rate data may need to be synchronized with pressure data as often the clock time setting on pressure gauges differs from the pumping service truck. It is important to have the beginning rate start at break-down pressure. Rate and volume used to fill the wellbore or pressure up to open a port is not technically contributing to the creation of a fracture so it should be excluded from the analysis.
3. Often the full pressure file has tens or hundreds of thousands of data points. This will create very large file size and can be cumbersome. Therefore, filtering of the data is an important step. However too much filtering can be detrimental to the analysis. Usually a total of 5000 data points is adequate provided both injection and falloff data are captured.
4. Reservoir and PVT data must be entered for the analysis. This is most important for after-closure transmissibility (permeability) measurements. If the reservoir fluid properties are unknown a safe approach is to use water properties which normalize the analyses between wells for comparison purposes.
5. Surface pressure data must be converted to Bottom Hole (BH) data at the injection point. To have the software perform this calculation the true vertical depth (TVD) of the injection point, the wellbore fluid and injection fluid density must be known. Then Bottom Hole Pressure (BHP) can be calculated using the expression:

   $$\text{BHP} = \text{Surface Gauge Pressure} + (\text{Injection Point Depth TVD} - \text{Gauge Location TVD}) \times \text{fluid density gradient}$$

   Note: Fluid density gradient is assumed to be 9.8 kPa/m for fresh water.

6. Create Log-Log Diagnostic Plots for flow regime identification (see below) – Bourdet (Bourdet et al., 1983) or Impulse (Bartko et al., 2005) Derivative & PPD.
7. Select all Flow Regimes. A Flow Regime can be confidently identified if it lasts for more than one half of a log-cycle and if it is consistently represented by both the Bourdet/Impulse Derivative & PPD. See Table 3.
8. A late-time, after-fracture closure Linear Flow Regime may be used to compute reservoir pressure, P* and transmissibility.

NOTE: Be aware of the potential for a “false” radial flow signature occurring quickly after closure (Table 4, No. 6).

Log-Log	Wellbore Storage		Bilinear		Linear		Pseudo-Radial		Nolte	
	Early	Late	Early	Late	Early	Late	Early	Late	Early	Late
Log dP vs Log Δt	1/1	1/1	1/4	~0	1/2	~0	~x kPa per log(t_{er}) cycle		1/1	1/2
Log dP/dt vs Log Δt (PPD)	0	0	−3/4	−7/4	−1/2	−3/2	−1/1	−2/1	0	−1/2
Log Δt(dP/dt) vs Log Δt (DT Log-Log Derivative)	1/1	1/1	1/4	−3/4	1/2	−1/2	0	−1/1	1/1	1/2
Log $\Delta t^{1/4}$ (dP/dt_{eb}) vs Log Δt (Bilinear Equiv. Time)	1/1	2/1	1/4	1/4	1/2	1/2	0	0	1/1	3/2
Log $\Delta t^{1/2}$(dP/dt_{el}) vs Log Δt (Linear Equiv. Time)	1/1	2/1	1/4	1/4	1/2	1/2	0	0	1/1	3/2
Log Δt_{er}(dP/dt_{er}) vs Log Δt (Radial Equiv. Time)	1/1	2/1	1/4	1/4	1/2	1/2	0	0	1/1	3/2
Log Δt(dP/dt_{en}) vs Log Δt (Nolte Equiv. Time)	1/1	3/2	1/4	−1/4	1/2	0	0	−1/2	1/1	1/1
Log $\Delta t^{3/2}$(dP/dt_{en}) vs Log Δt (Nolte Equiv. Time)	3/2	2/1	3/4	1/4	1/1	1/2	1/2	0	3/2	3/2

Note: Above slopes are also applicable when plotting vs Log t_d

Table 3. Expected slopes for flow regimes on log-log plots. (Source: Thang Ung, CNRL, personal communication)

Potential Analysis Issues and Solutions

Table 4 outlines some common issues encountered and the proper solutions to ensure analysis results are most accurate.

	Technique	Description
1	Synchronize start and end of pump rates with pressure response	DFIT injection begins with formation break-down (BD) (Figure 1 Pt. D.). In Figure 1, there are several pressure responses prior to BD which are not fracture related and therefore should not be used as part of the DFIT. If a clear BD signature is not evident, a point should be taken immediately after the pressure departs from the straight-line compression present during pressure-up. This departure indicates the formation is taking fluid. End of injection should similarly coincide with the last pressure prior to the pressure drop indicating pumps are off.
2	Pick End of Pumping (EOP) instead of ISIP	ISIP is often not a well-defined feature of pressure-time readings and is one of the most inconsistently picked values in fracture stimulation. Although there are multiple techniques to pick ISIP, to overcome this ambiguity, pick the last pressure just before pump shut-down or End of Pumping (EOP). This value is easily picked and eliminates the inconsistency of picking ISIP. It is recommended that PTA techniques be used to determine FFEP in place of ISIP as previously discussed.
3	Time Functions for Log-Log Diagnostic Plots	If step-rate testing or if multiple injection rates occur due to equipment failure, high pressure shut-down, leaks, etc., then superposition-time is recommended.
4	Pressure Gradients	One simple plot often missing from the analysis is the BHP versus time plot for the whole test including three reference pressure gradient lines corresponding to:

		- lithostatic (overburden) gradient (or use 22.6 kPa/m…1.0 psi/ft) - expected horizontal fracture pressure gradient - water hydrostatic gradient (9.8 kPa/m or 0.433 psi/ft) This plot will enable the analyst to quickly make an assessment of the likelihood of complex fracture development (e.g., Pressure > lithostatic…possible horizontal plane fractures) or whether late-time flow regimes are affected by fluid compressibility changes (e.g., Pressure <= hydrostatic…well on vacuum).
5	Data Smoothing	Some well testing software by default applies too much smoothing to data. The authors recommend reducing or turning off smoothing functions to ensure diagnostic features are not lost or erroneously represented in the analysis. If no identifiable flow regimes are observed, then the test cannot be interpreted and should be reported as such.
6	Late-time After-Closure Behavior	It is the authors' experience that late time behavior should first be monitored to determine if fracture closure has occurred. The onset of early radial flow after closure should only be considered valid for high permeability reservoirs. Generally, formation linear or bi-linear flow is to be expected and in very tight formations a composite permeability response is common.

Table 4. Common Issues Occurring During Analysis of DFITs

Recommended Data Submission Guidelines

Diagnostic Fracture Injection Tests (DFITs) fall under the BC Oil and Gas Commission Well Testing and Reporting Requirements Guide VERSION 2.3: June 2020. The Pressure ASCII Standard (TRG.PAS) has been updated to include the pressure test type (PRSTY) 50 (DFIT) and additional data fields specifically related to DFITs, including before-closure and after-closure analysis.

As of June 1, 2020, a DFIT submission must comprise of one TRG.PAS file and one or more PDF file(s).

The updated PAS file specifications can be found at:

https://www.aer.ca/documents/dds/PASFileFormats.pdf

DFIT Quality Ranking Schedule

A DFIT quality ranking schedule with examples is provided in Appendix 1.

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