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Research Article

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Pressure transient analysis for detecting leakages along active and abandoned wells

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ABSTRACT

Leakage out of the target formation is a major risk associated with subsurface wellbores. This study explores feasibility of leakage detection with Pressure Transient Analysis (PTA) in multiple potential leakage scenarios, including induced fractures and casing failures in active and legacy wells, which may become conductive from injection-induced pressure buildup.

A mechanistic well-reservoir model based on a representative offshore Norwegian sandstone reservoir was used in the study. The fluid flow simulation study for a single-phase, isothermal, low-compressible fluid (water) has two parts. The first addresses the mechanisms of induced fracturing and fracture propagation through caprocks, creating out-of-zone leakage risks. Then, it proposes an approach to model fracture propagation into cap-rocks and explores feasibility of early detection of the fracture leakage into cap-rocks with PTA of step-rate tests. The second part examines casing-cement-rock integrity failure mechanisms with focus on behind-casing leakage or crossflow detection with PTA. A dedicated modeling approach for behind-casing leakage resulted in revealing pressure derivative signatures associated with the leakage from the flow simulations, confirming feasibility of the leakage detection from PTA of shut-ins responses of active and abandoned wells.

The monitoring approach considered in the study relies on real-time pressure data from Permanent Downhole Gauges (PDGs) installed in active wells or wireless PDGs in abandoned wells, interpreted with the PTA methods evaluated. Results from the simulated cases have demonstrated the feasibility of the PTA methods to detect leakage with a possibility to approximately assess leakage rates in some cases, with the assessment accuracy decreasing with declining leakage rate. The feasibility study results are valid for the cases considered and the assumptions taken, and further testing and validation of the PTA methods using field data is a necessary next step in maturation of the interpretation methodology presented.

Keywords: Leakage Detection, Well Monitoring, Pressure Transient Analysis, Permanent Downhole Gauges, Plug-and-Abandonment, Induced Fracturing, Casing Leakage

1 Introduction

Injection wells are now facing increased demand in well safety and cost- and energy-efficiency to comply with environmental regulations (Gupta et al., 2022). Ensuring safe operations in active wells, and particularly those located near legacy or Plug & Abandonment (P&A) wells, require careful attention to potential risks of leakage from the target formation. Also, energy- and cost-effective well operations whereby optimal well completion and monitoring designs are required to capture most of the risks at minimum investments. Thus, new feasible solutions are needed to ensure effective well operations to maintain high performance, minimizing well shut-ins and leakage risks.

Large scale geological injection projects are hindered by serious challenges of leakage through casing-cement-formation integrity failures in active or legacy wells and through reservoir features such as faults and fractures (Gasda et al., 2004; Skadsem, 2022; Alberdi-Pagola & Fischer, 2023). Figure 1 presents a diagrammatic representation of potential leakage pathways.

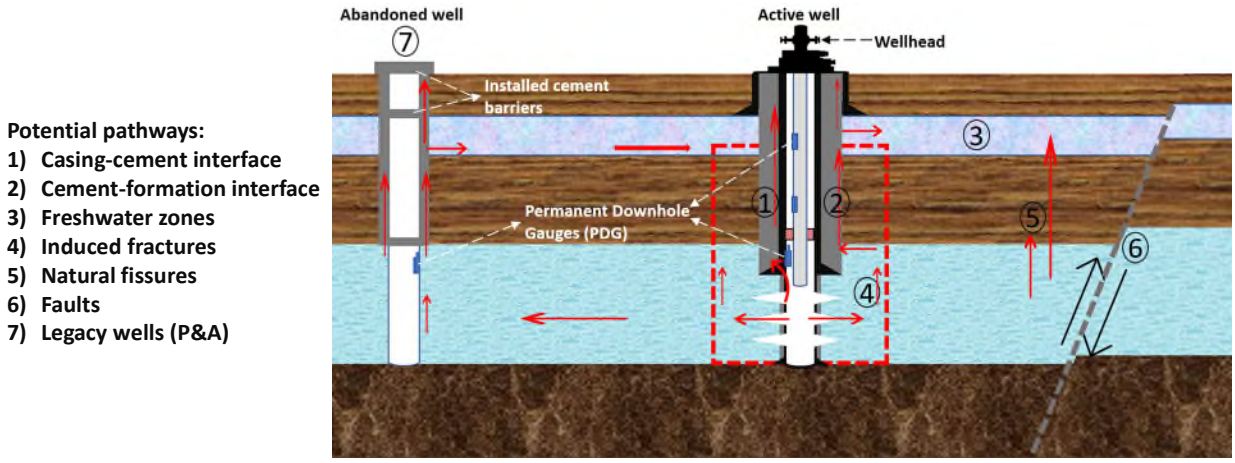


Figure 1. A diagrammatic illustration (not to scale) of general potential leakage pathways (bold arrows) across wellbore and geomechanical constraints

Leakage poses environmental risks and can impact shallow subsurface zones (Lions et al., 2011). In-situ fluids may migrate through fractures or faults, contaminating freshwater aquifers with saline water, hydrocarbons, or CO_2. Reinjected brine containing dissolved hydrocarbons or CO_2 also presents a risk to groundwater quality. High CO_2 concentrations near the surface can harm vegetation. Additionally, compromised well integrity can lead to CO_2 leakage to the atmosphere, increasing overall greenhouse gas emissions (Huo & Gong, 2010).

Well-reservoir integrity issues are always examined prior to water or brine injection although maximum risk control and management are imposed during CO_2 storage (Zhang et al., 2020). In terms of well operations, leakage around the wellbore (casing-cement or cement-formation) or within reservoir features could lessen geothermal well efficiency. This could cause temperature loss, reservoir pressure drops, and decline in flow rates (Philippacopoulos & Berndt, 2001; Santos et al., 2022). Therefore, it is essential to implement best practices in permanent well monitoring of caprock and well integrity (Braim et al., 2023).

Modern wells often use downhole sensors and fiber-optic technologies for real-time monitoring of pressure, temperature, strain, and flow behavior, although these capabilities come with added deployment costs (Johannessen et al., 2012; Soroush et al., 2022). While fiber-optic and micro-seismic methods are standard for leakage monitoring, they may face some limitations. Tubing-deployed fiber optics couple poorly to the reservoir (Soroush et al., 2022), annulus-deployed fibers are not feasible for long-term use and are noise-sensitive (Soroush et al., 2022). Casing-integrated fiber optics are technically strongest option but may still miss micro-leaks like those in P&A scenarios, occupy more wellbore space, and may increase the risk of creating additional leakage pathways (Soroush et al., 2022; Schneider et al., 2024). Micro-seismicity surveys (monitoring of seismic events) provides indirect evidence of leakage and must be supported by additional downhole measurements (Martínez-Garzón et al., 2013).

Further, complementary monitoring options, such as widely deployed Permanent Downhole Gauges (PDG), offer a promising and affordable option for industrial projects involving water injection, geothermal, and CCS, where resource allocation may be limited for wide-scale use and permanent monitoring like fiber-optics. Permanent downhole gauges seem to be a suitable permanent monitoring solution, as both U.S. (USEPA, 2008) and European directives (EU Directive, 2018) regulations mandate continuous surveillance at injection wells.

Effective leakage monitoring may be possible in conjunction with PDG and flowmeters that are able to accurately monitor well operational variables in real-time. Modern permanent downhole gauges are built for long-term use, operating at ultra HPHT, e.g., 172 MPa and 180 °C (von Flatern, 2016). Recently, new studies have shown feasibility of permanent well monitoring beyond P&A utilizing wireless downhole pressure/temperature data acquisition (Champion, 2016; Bouldin et al., 2021; Mimoun et al., 2023; Schneider et al., 2024). These data acquisition tools pave

the way to continuous monitoring by leveraging real-time data of pressure/temperature. Hence, dynamic data analysis/interpretation approaches are needed for various leakage scenarios.

Interpreting pressure measurements using Pressure Transient Analysis (PTA) methods have evolved over time, providing useful information on near wellbore effects, reservoir behavior, and boundary effects (Horne, 2007; Gringarten, 2008). The common time-lapse PTA framework is described in Shchipanov et al. (2014) and Step-Rate Tests (SRTs) commonly used by operators to monitor injection-induced fractures and assess reservoir behavior over time (Shchipanov et al., 2017). However, pressure data may be affected by noise from measurement inaccuracies or rate fluctuations, complicating interpretation (Cobanoglu & Shukri, 2020). Noise is an inherent feature of pressure data from permanent downhole gauges (PDGs) and often addressed before PTA interpretations (Horne, 2007). Noise refers to data points that scatter around the true trend while remaining within its neighborhood (Athichanagorn et al., 2002). Sources include intrinsic gauge issues such as component inaccuracies, mechanical degradation, and gauge temperament (Kikani et al., 1997), as well as environmental disturbances and wellbore pressure fluctuations (Ennaifer & Kuchuk, 2018). These factors generate noisy signals, which Bourdet derivatives further amplify (Ennaifer & Kuchuk, 2018), increasing scattering and complicating reservoir interpretation.

Consequently, defining an uncertainty envelope, typically around the pressure derivative (Ambrus et al., 2024; Mugisha, Shchipanov, et al., 2025), can enhance interpretation reliability by helping to differentiate between true signals and noise. Recently, studies have also explored PTA-based methods for wellbore monitoring of behind-casing leakage (Kremenetskiy & Kokurina, 2008; Rahman et al., 2015; Nooruddin & Rahman, 2021). Aforementioned studies on PTA-based leakage detection have primarily focused on an individual leakage scenario, however, a comprehensive monitoring approach is required to concurrently evaluate multiple potential leakage pathways.

Notably, the previous study (Mugisha, Shchipanov, et al., 2025) proposed a PTA-SRT interpretation method for detecting induced fracture opening within the target formation. The current study aims to extend this method into a monitoring approach that integrates Permanent Downhole Gauges/Pressure Transient Analysis (PDG/PTA)-based methods, to explore diagnosis of multiple leakage scenarios, specifically, fracture propagation through caprock and leakage along the casing-cement-formation interface. However, non-uniqueness of pressure derivative features is one of the known challenges in PTA interpretations whereby different well-reservoir flow conditions may yield similar PTA behaviors. This challenge may be minimized in practice by extra information about the field or wellbore using geological data, geophysical surveys, production or injection history (Gringarten, 2008; Cobanoglu & Shukri, 2020).

Exploring PDG/PTA-based approach for leakage detection is a relatively new area addressed in this study, therefore, establishing baseline thresholds through simulated scenarios is a necessary first step. This study uses approximate representations of leakage pathways and simulated pressure-induced leakage scenarios assuming single-phase, low-compressible fluid (water). Such simplification allows us to establish a feasibility and conceptual basis for applying PTA/PDG methods to the leakage detection. The modeling assumptions and simulations are used to verify that leakage signatures can be identified and interpreted from pressure data, and to assess the accuracy and applicability of the proposed PTA-based leakage detection approaches. More complex conditions of coupled thermal and multiphase effects are beyond the scope of the present work.

Next sections of this feasibility study are organized in the following sequence:

- Induced fracturing mechanisms: Analysis of fracture initiation and propagation through caprock, potentially causing out-of-zone leakage.
- Initiated leakage detection into shallow formation: Presentation of a modeling workflow and PTA method for early identification of fluid migration into overlying formations through induced fracture growth.
- Casing-cement-rock integrity failures: Examination of mechanisms leading to behind-casing leakage and crossflow.
- Leakage monitoring behind casing: Development of a tailored modeling and PTA approach for detecting and evaluating leakage behind casing.

2 Induced fracture growth through caprock

This section focuses on modeling pressure-induced fracture opening as a central aspect of developing a proper detection method. First, consider fracture mechanics and a proxy model to be used in flow simulations, fitting PTA-based interpretation to identify induced fractures and leakage into shallow formation layers.

2.1 Mechanics of induced fracturing and modeling approaches

Large-scale injection of fluids into geological formations can elevate reservoir pressures and potentially change the local stress state at the wellbore wall, within the reservoir, and may lead to caprock tensile failure (Fjær et al., 2008; Gillioz et al., 2024). One of the riskiest scenario at injection and primary leakage mechanisms is induced fracturing (Nermoen et al., 2024), where tensile failure propagates fractures vertically into the sealing layers, compromising containment as explained hereafter.

Borehole failure and fracture initiation pressure

Borehole failure refers to the mechanical breakdown of the rock surrounding a borehole when the local stress exceeds a critical threshold. Changes in loading conditions, such as reductions or increases in bottomhole pressure, can trigger various failure modes, including tensile fracturing or shear breakouts. Tensile failures such as induced fracturing usually occur when well pressure is suddenly increased, but compressive failures such as breakouts or collapse occur when the pressure within the wellbore is too low leading to compressive or shear failure. The first indications of these events often appear during drilling as mud losses (in the case of fracturing) or as cavings, where large rock fragments are circulated to the surface. Detailed assessment using borehole logs, imaging tools, and caliper measurements generally takes place afterward, once the drill string is pulled out. Figure 2 provides an idealized illustration of the two failure modes and the orientation of the principal horizontal stresses for a vertical well.

In this study, the failure condition for tensile failure is explored further due to the interest in the leakage occurring through induced fracturing. Fracturing pressure at the borehole wall can be estimated using well testing methods such as Formation Integrity Tests (FIT), Leak-Off Tests (LOT), and Extended Leak-Off Tests (XLOT) (White et al., 2002), typically performed below the casing shoe during drilling. Also, fracturing pressure maybe estimated from step-rate testing in the target reservoir when well is completed. Further, fracture initiation pressure also can be predicted analytically by applying borehole failure criteria, where the problem is approached forward by deriving explicit relationships between in-situ stresses and failure conditions. The analytical solution of fracturing pressure at the wellbore wall requires data from well log and compressive strength tests, including rock strength, Poisson ratio, and static Young's modulus (Fjær et al., 2008). However, this study only focuses on simplified case of the vertical wellbore whereby proxy modeling approach is used.

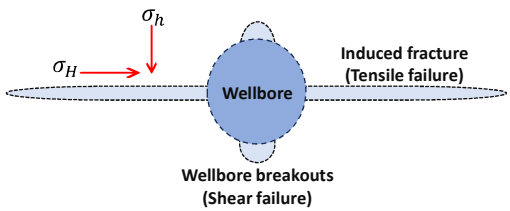


Figure 2. A top view of vertical hole showing two wellbore failure types: tensile failure and shear failure, typically occurring at different borehole locations unless pressure varies significantly (Fjær et al., 2008).

2.2 Applied modeling and simulation approach

This study employs the industry-standard reservoir simulator Rubis (Houzé et al., 2022) with a pseudo-coupling workflow (Samier et al., 2008) that bypasses explicit stress calculations.

(Mugisha, Shchipanov, et al., 2025) outlined the pressure-dependent fracture permeability function, $k_f(p)$, that was used in numerical simulations that matched the real field case. Figure 4 depicts the $k_f(p)$ curve used to define the onset of fracture opening, where k_m defines permeability in the matrix grid blocks while k_f represents the permeability of the fracture grid blocks. Initially, $k_f = k_m$ until fracture opening pressure p_f is reached and the fracture permeability increases exponentially to maximum value to maintain simulation control.

Building on the prior work (Mugisha, Shchipanov, et al., 2025) which examined fracture opening within the target formation, this study extends the same workflow to simulate fracture growth through the caprock. To assess this behavior, synthetic well tests (SRTs) were generated and analyzed using Saphir (Houzé et al., 2022), the industry standard software for pressure transient analysis. The main focus was to detect induced fracturing early through analysis of Bourdet derivative (Bourdet, 2002), thereby linking simulation outputs with interpretable diagnostic features.

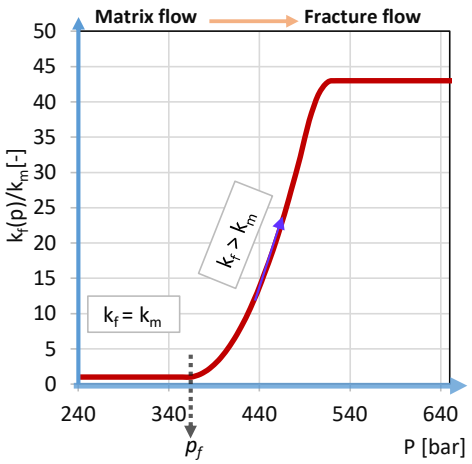


Figure 3. Illustrating induced fracture opening through proxy modelling using $k_f(p)/k_m$ function.

The flow simulations are based on the following assumptions:

- **Reservoir, wellbore, and induced fracture:**
  - vertical well in infinite-acting reservoir of homogeneous, isotropic, and constant pay thickness (h),
  - the near wellbore has two interacting domains: an induced fracture and porous matrix rock,
  - flow occurs from the wellbore into the fracture, and then into the matrix, neglecting cement zone behind casing,
  - the fracture has finite conductivity (F_C), fracture half-length (x_f), and width (w_f),
  - refined non-structural gridding is applied near the wellbore to improve simulation accuracy,
  - $k_f(p)$ is applied only within fracture grids defining fracture length, with flow rate varying per grid block based on local pressure and permeability,
  - fracturing pressure p_f is assumed to be known as 360 bar,
  - three-layered system Figure 5 where fracture grows vertically, from the target formation, through caprock, then into shallow layer,
  - well and reservoir parameters of an actual field case (Table 1) were used in the simulations.
- **Fluid flow:**
  - single-phase, isothermal flow of a slightly compressible fluid, such as water injection into an aquifer or post-oil displacement by water injection where water phase dominates near wellbore area,
  - water PVT data from a real field case (Table 1) was used in the simulations.

The geological setting of a North Sea sandstone reservoir using the field data previously reported by Mugisha et al. (2025) served in this paper as the test simulation case. Table 1 summarizes main input parameters used in the simulations.

Table 1. Input data used in simulations (modified from Mugisha et al., 2025). Water compressibility and viscosity were taken at 250 bar and 93 °C.

Parameter		Value	Units
Wellbore and fracture	Well radius	0.08	m
	Wellbore storage	0.025	m^3/bar
	Fracture half-length	10	m
	Fracture height	40	m
	Fracture conductivity	30	md.m
	Fracture width	0.05	m
	Fracture porosity	0.5	dimensionless
	Fracture skin	0	-
Rock properties are same in target and shallow formation	Initial pressure	250	bar
	Reservoir top	2400	m
	Thickness	15	m
	Permeability	75	md
	Porosity	0.3	dimensionless
	Compressibility	8.30E-06	1/bar
Caprock	Thickness	15	m
	Permeability	1.0E-06	md
	Porosity	0.2	dimensionless
	Compressibility	8.30E-06	1/bar
Water	Formation volume factor	1.025	m^3/stm^3
	Compressibility	4.35E-05	1/bar
	Viscosity	0.32	cp

This study adopts the stepwise induced fracture modeling approach illustrated in Figure 4a and detailed in (Mugisha, Shchipanov, et al., 2025) to model vertical fracture growth through the caprock. The workflow ensures the simulations clearly differentiate fracture-driven flow from the initial matrix-dominated flow. It begins with a vertical injector into a homogeneous reservoir, adds a bi-wing fracture with matrix-like permeability, then increases fracture permeability to simulate peak flow, and finally introduces a pressure-dependent permeability function within the fracture grids to capture dynamic fracture behavior. Further, the stepwise fracture growth approach is applied to the SRT simulating fracture opening into the shallow layer formation (i.e., fracture grids extend from the target formation to shallow formation which is the main case in focus).

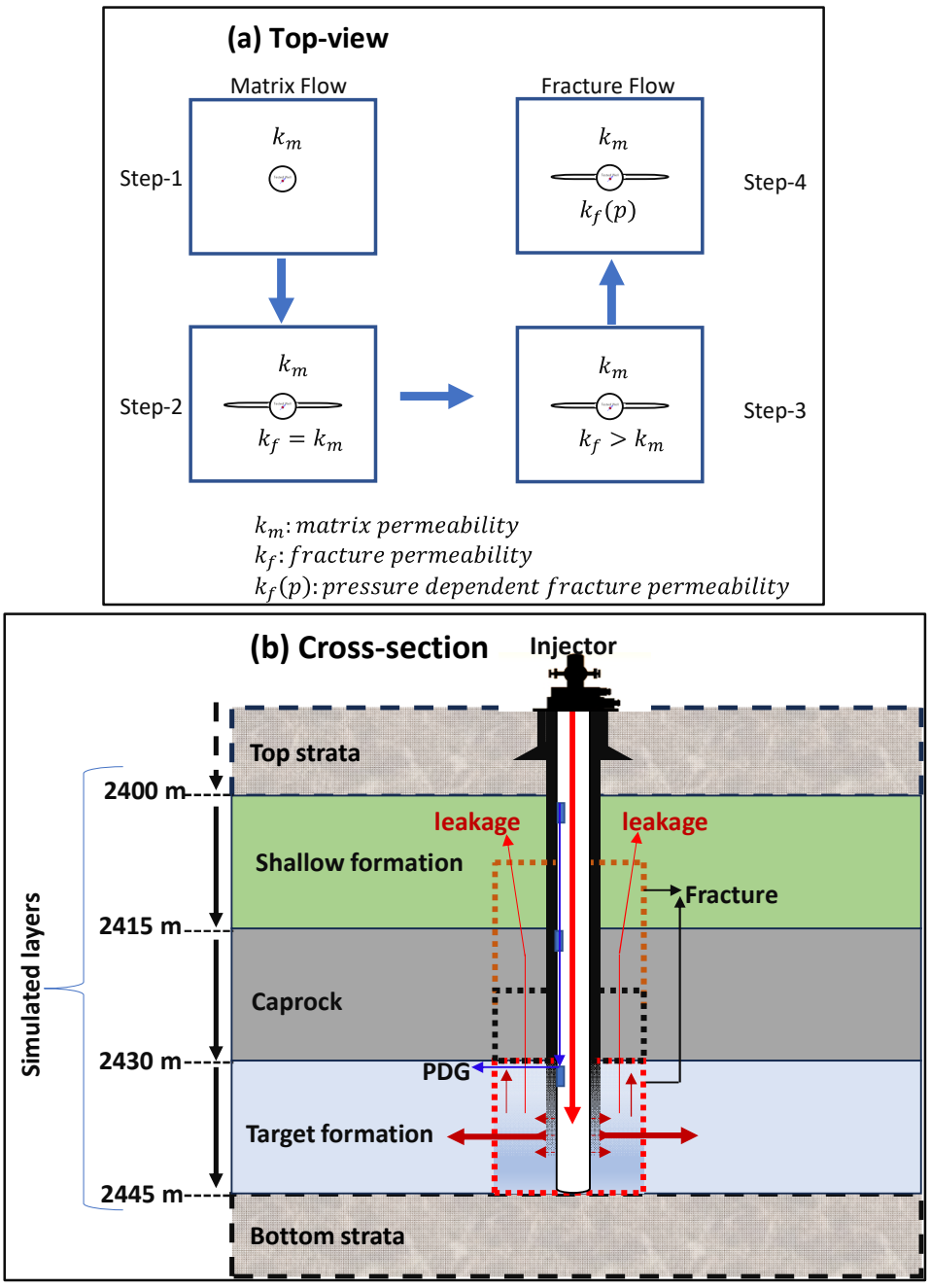


Figure 4. (a): A stepwise induced fracture modelling approach (Mugisha, Shchipanov, et al., 2025) starting from a baseline of matrix flow (reference case) to the fracture opening; (b): sketch, not to scale, for simulation approach of active injector with growing induced fracturing during step-rate test. No crossflow between layers, only through fracture. Cement behind casing is neglected in this case.

205

206 Overall, the approach used in this study enables modelling of induced fracturing into shallow formations and accurate
207 interpretation of pressure responses, enabling early detection of induced fracturing by capturing the transition from
208 matrix- to fracture-dominated flow during step-rate testing.

2.3 Proposed PTA-based leakage detection technique

PTA-SRT approach, also known as step-by-step PTA (Shchipanov et al., 2017), was recently enhanced by integrating Uncertainty Envelope (UE) concept (Mugisha, Shchipanov, et al., 2025) improving its accuracy in detecting induced fracture opening within the target formation.

PTA-SRT

PTA-SRT is a pressure transient analysis (PTA) method designed for step-rate tests (SRT), where each step is individually interpreted to track changes in key parameters like skin and permeability. By overlaying transients on a single log-log plot, it enables detection of subtle shifts in near-wellbore conditions, reservoir behavior, and boundaries (if observed). In this study, the combined PTA-SRT and UE approach (Mugisha, Shchipanov, et al., 2025) is applied to synthetic simulations (Figure 4) to demonstrate its effectiveness in identifying early signs of induced fracturing, fracture propagation through caprock, and the onset of leakage into shallow formations.

Uncertainty Envelope (UE)

The UE concept further aids in distinguishing true fracture flow signatures from noise in pressure derivative curves, enabling real-time detection and monitoring of induced fracturing. UE concept was discussed in Mugisha et al. (2025) through numerical simulations and history matching of real field SRT data. The uncertainty envelope could be estimated using the model that matched the reference transient to fit the maximum noise in the pressure derivatives. In the absence of a model, UE limits may be defined by adding or subtracting a percentage error that represents noise until the data fluctuations remain within these bounds. The UE concept has been demonstrated using a manual approach that relies on visual verification of noise; however, integrating the UE concept into automated interpretations (Mugisha et al., 2026) could leverage a statistical approach (discussed in the Appendix A in the Supplementary Material) using standard deviation metrics (Smith, 2003). Further, Moi et al. (2017) demonstrated an automated technique combining low-pass filtering and regression to effectively analyze noisy pressure measurements.

Because PTA-SRT workflow relies on Bourdet derivative behavior to delineate flow regimes, a brief description is provided on how measured pressure and rate data are converted into derivative curves for diagnostic plotting.

Calculation of Bourdet derivative for pressure transient analysis

In the context of a Step-Rate Test (SRT), a pressure transient may be considered as the response to stable flow rate during injection or production (a step). This part explains analytical formulas in calculating pressure derivatives which are essential parts of transient analysis (Bourdet derivative algorithm (Bourdet et al., 1989; Bourdet, 2002)). The Bourdet derivative calculation algorithm is the basis of PTA providing a robust, smooth, and reliable derivative of pressure data with respect to time, which is essential for identifying flow regimes and interpreting reservoir behavior. It is commonly computed using a three-point central difference method on a logarithmic time scale, where left and right slopes are estimated and their weighted average is assigned to the central point, producing a smooth and accurate derivative (Bourdet, 2002). In case of stepped variation of flow rate, principle of superposition is utilized to combine pressure responses from multiple flow rate changes over time, ensuring that the calculated derivative accurately reflects true reservoir behavior.

The algorithm in combination with the UE concept (Mugisha, Shchipanov, et al., 2025) may be described as follows:

- Normalize each pressure transient to the injection rate using Equation (7).
- Compute the Bourdet derivative of the normalized transients with Equation (9), incorporating superposition from earlier steps as defined in Equation (8) (Bourdet, 2002).

$$\Delta\bar{p}_{i,k} = \left|\frac{Q_{ref}}{Q_k - Q_{k-1}}\left(p_{i,k} - p_{0,k}\right)\right|, k = 1,2,..,K. \tag{7}$$

$$Ts_{i,k} = \frac{1}{Q_k}\sum_{k=1}^{K}(Q_k - Q_{k-1})\log\,(t_{i,k} - t_{0,k}) \tag{8}$$

$$\Delta p'_{i,k} = \left(\frac{\frac{\Delta\bar{p}_{i,k} - \Delta\bar{p}_{i-1,k}}{Ts_{i,k} - Ts_{i-1,k}}(Ts_{i+1,k} - Ts_{i,k}) + \frac{\Delta\bar{p}_{i+1,k} - \Delta\bar{p}_{i,k}}{Ts_{i+1,k} - Ts_{i,k}}(Ts_{i,k} - Ts_{i-1,k})}{\log\left[(Ts_{i,k} - Ts_{i-1,k}) + (Ts_{i+1,k} - Ts_{i,k})\right]}\right)\left(\frac{Q_{ref}}{Q_k}\right) \tag{9}$$

Where the subscripts i refer to the data index, k is step index, and K specifies the total number of steps in the SRT. $p_{0,k}$ pressure at the beginning of step, $p_{i,k}$ pressure data point, Δp denotes the pressure change relative to the start of a step, $\Delta\bar{p}$ indicates normalized pressure difference, $\Delta p'$ is the pressure derivative, Q_{ref} represents the reference injection rate Q, $Ts_{i,k}$ superposition time, $t_{0,k}$ time at the beginning of step, $t_{i,k}$ time at data point, respectively.

- To estimate the uncertainty envelope (UE): the lower and upper limit may be set (Equations 10-11) guided by observed noise surrounding the pressure derivative. The numerical element (α as e.g., 10, 20, 30, …) representing noise % was used to show how reference derivative ($\Delta p'_{ref}$) maybe shifted to make UE limits.
- In the simulated, noise-free case, UE limits were illustrated by selecting a reference derivative ($\Delta p'_{ref}$) before the fracture-opening. Using Equations (10–11), pressure derivative points defining this reference were shifted downward and upward the numerical element (α) to construct the lower and upper UE bounds. This is a synthetic demonstration of the UE concept to show its application, but in practice, UE construction could be done using statistical approach adapted to the natural trend and noise characteristics of field data, as outlined in Appendix A in the Supplementary Material.

$$\text{UE lower limit} = \Delta p'_{ref} * \frac{(100-\alpha)}{100} \tag{10}$$

$$\text{UE Upper limit} = \Delta p'_{ref} * \frac{(100+\alpha)}{100} \tag{11}$$

Where ($\Delta p'_{ref}$) is the reference derivative and α is the numerical element used to shift the reference derivative up or down (e.g., 10, 20, 30).

Bourdet derivative is commonly used in PTA in-house tools and commercial PTA software such as Saphir, which is also used in this study. The practical use of the Bourdet derivative is demonstrated in the PTA-SRT interpretation method in Figure 6.

Detection of out-of-zone leakage through induced fracture using PTA-SRT approach

The interpretation approach is illustrated on the simulated SRT, which models fracture growth from the target reservoir through the caprock into shallow formations (see Figure 4). The pressure responses simulated using the modelling approach described above (Figure 4) from successive SRT steps are interpreted using the PTA-SRT approach (Mugisha, Shchipanov, et al., 2025) as follows:

- Acquiring pressure transients for each SRT step (Figure 5).
- Overlay the pressure transients and their Bourdet derivatives (Equations 7-9) on a log-log (Figure 6).
- Establishing the UE equivalent to reference pressure derivative ± noise in derivative (e.g., 20% deviation from the reference derivative due to noise in real data (Mugisha, Shchipanov, et al., 2025)) (Figure 6).
- Examine the plots to determine which step's derivative falls outside the UE bounds (Figure 6).

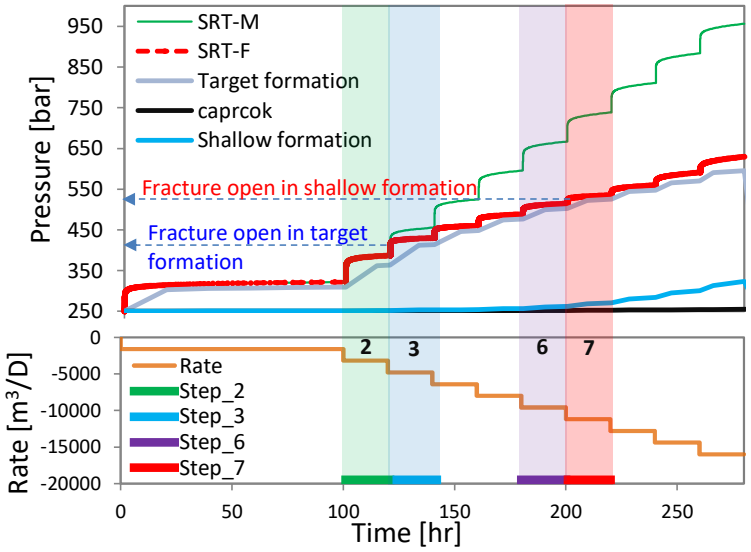


Figure 5. Simulated pressure and rate during Step-rate test (SRT) of vertical well with induced fracturing (SRT-F) and for matrix (no fracture) flow (SRT-M), comparing the SRT-M and SRT-F shows a clear departure at nearly 400 bar where the fracture opens in the target formation. Eventually, induced fracture extends from the target to shallow formation. Highlighted steps 2,3,6,7 are shown in Figure 7.

Figure 5 shows the history of SRT in linear plot, comparing the case of induced fracturing (SRT-F, i.e., SRT resulted in 'fracture' flow) to the 'reference case' with no-fracture (SRT-M, i.e. SRT with 'matrix' flow only). The fracture opening events within the target and shallow formations are highlighted, where the pressure drop at each step continually decreases from step to step. The first fracture opening event is detected within the target formation at about 400 bar in step-3 followed by the event of crossflow between the target and shallow formations caused by fracture penetration of the shallow formation detected at nearly 500 bar in step-7. The increasing leakage rate is illustrated by the corresponding fluid pressures in the target and shallow formations. The SRT-F is further interpreted in log-log plot (Figure 6).

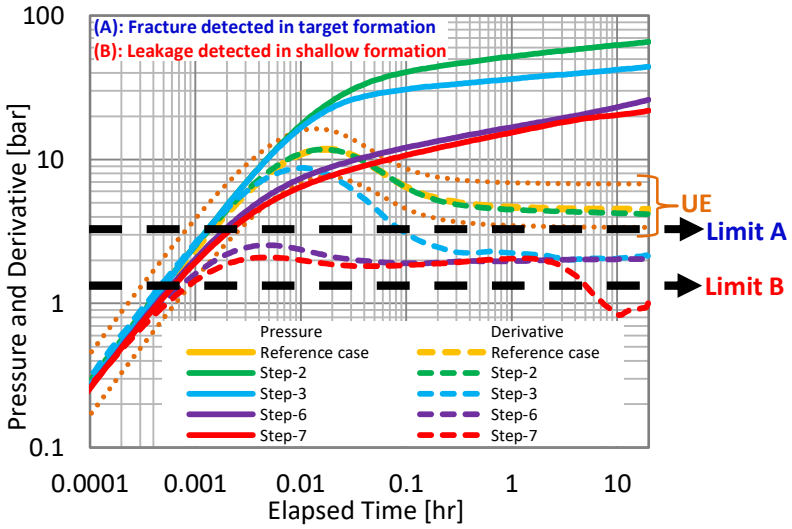


Figure 6. Pressure and derivatives compared at sequential injection steps (SRT-F compared to reference case): fracture opening in target formation is detected at step-3 as the derivative deviated from the UE in downward shifting at lower limit A and cross-flow due to fracture opening in shallow formation is detected by the derivative dip through limit B at step-7. Note that all steps for the reference 'matrix' case overlay on top of each other if there is no fracture flow.

The fracture detection method is based on the induced fracture signature reflected in the Bourdet derivatives. Figure 6 demonstrates that when the fracture opens, flow capacity increases, typically shown by a downward shift in the pressure derivative. Further, visualization of pressure diffusion in the simulated model (Figure 7) allowed to confirm the fracture upward growth and penetration of the shallow formation with fluid cross-flow between the target and shallow formations.

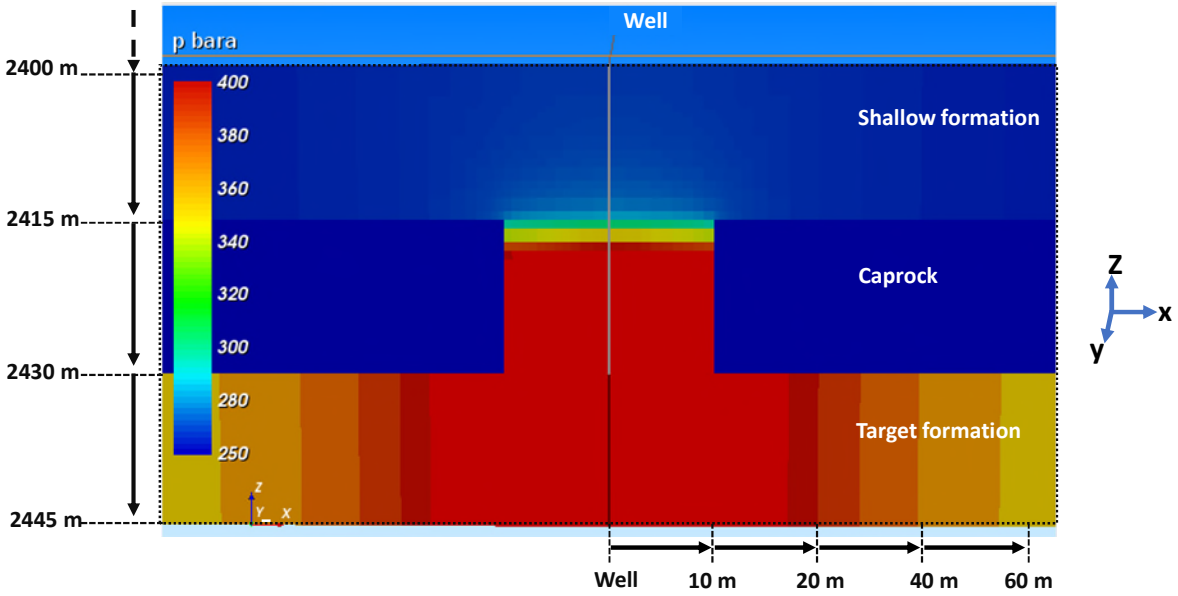


Figure 7. Zoomed cross section near wellbore area for visualizing pressure distribution at the end of injection at 220 hours timestep.

The numerical simulations showed that approximately 98% of the total injected volumes remained within the target formation and nearly 2% escaped into the shallow formation (Figure 8), confirming the cross-flow due to fracture opening in shallow formation diagnosed in Figure 6. Figure 8 shows percentage of the dynamics of fluid that remained injected in the target formation and percentage of the fluid that leaked into the shallow formation during step-rate testing period. The semi-log plot centered in Figure 8 shows that leakage below 2% is likely to be missed, whereas rates above 2% are reliably detected by the proposed method for this particular simulated case.

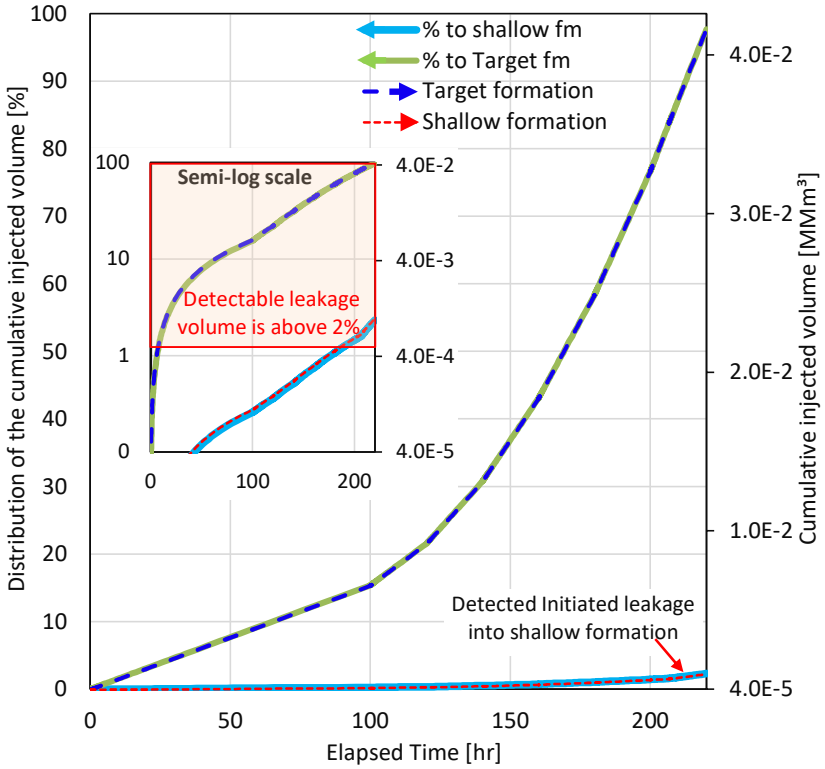


Figure 8. The initiated leakage to shallow formation was detected when reached ~2 % of the total injection (0.68E-3 MMm³) at step-7. The semi-log scale figure in the middle to clarify the escalated leakage into the shallow formation.

In summary, based on the simulated case, PTA-SRT method with an uncertainty envelope is applied to assess whether leakage out of the target formation can be detected and at what rates, as follows:

- Methodology developed in (Mugisha, Shchipanov, et al., 2025) has been extended for a growing fracture into overburden. The pressure signature with double dips/declining derivative reveals fracturing into and outside target formation, if out-of-zone injection takes place. Detection method relies on the fundamental concept in PTA that any sudden increase in flow capacity results in downward shifting of Bourdet derivative.
- The observed downward shift aligns with previous findings that it signifies changes in fracture conductivity or leakage into adjacent layers (Osman, 1993; Kremenetskiy & Kokurina, 2008; Li et al., 2022).
- The UE defines the bounds of expected noise in the pressure derivative: if it's set too narrow, normal variability may be misclassified as leakage; if too broad, small leaks will be overlooked. In practice, calibrating the UE against baseline (no-leakage well data) and quantifying measurement noise are essential to ensure that the UE reflects genuine leakage rather than artifacts.
- The applied PTA-SRT with UE method to the simulated SRT seems to accurately capture leakage levels approximately 2% of the injected volume. The validity of these estimates is limited to the specific simulation case examined in this study. The PTA-based method detected leakage rates at higher volumes, though its accuracy may diminish for micro-rate leaks. Also, this study applied proxy modeling approach employing pressure-dependent permeability that activates fracture opening once grid pressures exceed a defined fracturing pressure. Since fracture grids are predefined (with initial permeability set to matrix values), small early-stage leakage may go undetected. This limitation does not necessarily undermine the proposed method's validity; assuming that zero leakage is unrealistic and monitoring may establish acceptable leakage rate (Nassan & Amro, 2025).

The next section examines wellbore leakage resulting from compromised zonal isolation at both the casing-cement and cement-formation interfaces.

3 Casing-cement-rock integrity failure (leakage behind casing)

This section explores failure mechanisms of casing–cement–rock leading to behind-casing leakage and crossflow, then presents a framework for modeling and detecting such leaks.

3.1 Mechanisms governing casing-cement-rock integrity failure and behind-casing leakage

Behind-casing leakage arises from interfacial debonding/microannuli due to poor cement placement, thermo-mechanical cycling, and chemical alteration; CO_2-rich brine and casing corrosion exacerbate pathway development (Duguid & Scherer, 2010; Duguid et al., 2011). Experiments confirm cement degradations and preferential flow along casing–cement interfaces (Klose et al., 2021). Several studies (Celia et al., 2005; Skadsem, 2022; Alberdi-Pagola & Fischer, 2023) examining behind-casing leakage have highlighted key wellbore-cement properties, as summarized in Table 2.

Table 2. Estimates for wellbore cement properties (Celia et al., 2005; Skadsem, 2022; Alberdi-Pagola & Fischer, 2023)

Property	Value
Competent cement permeability	less than 0.1 mD
Permeability damaged cement	0.1 – 1000 mD
Crack width	1 μm – 1 mm

SCP/SCVF serve as practical indicators and, combined with bleed-off/build-up testing and pressure-transient modeling, enable detection and quantification of behind-casing crossflow (Lackey & Rajaram, 2019). Recent studies (Rahman et al., 2015; Nooruddin & Rahman, 2021) used pressure transient analysis to characterize crossflow behind casing based on build-up test data.

Building on pressure transient analysis approach, the following section will present an approximate approach for modelling and simulating cross-flows through the pathways and detecting behind-casing leakage during flowing period of active wells and shut-in period for P&A wells.

3.2 Modeling and PTA-based detection of behind-casing leakage for active wells

The first case examines an active injector well with behind-casing leakage. The simulation setup and PTA-based interpretation of downhole pressure data are both presented.

3.2.1 Modeling leakage pathways and simulation of leakage for active wells

Numerical simulations were carried out in the Rubis software to study the issue of behind-casing leakage, inheriting the well-reservoir model established in the preceding section. The model was modified to describe more details of the well completion and casing, necessary to study behind-casing leakage. The well fully penetrates three main formations: the target formation, caprock, and shallow formation, each having 15 meters thickness and same initial pressure condition. It is assumed that the vertical well has been tested, and initial reservoir parameters are known including the flow capacities of the target and shallow formations.

A modeling approach representing the wellbore as a composite system was applied, with a cement sheath separating the casing from the surrounding rock as illustrated in top view (Figure 9a) and cross-section view (Figure 9b). The composite reservoir model enabled assigning cement zone distinct permeability, thereby capturing the pressure losses and flow behavior within the cement area. This analysis assumes that the cement zone intended to isolate the target and shallow formations was compromised due to debonding of cement sheath from casing or formation interface. Consequently, this compromised cement zone acquires effective permeability (k_c) enabling fluid migration from the deeper reservoir into the shallow layer, as depicted in Figure 9b. The rate of leakage from the target to shallow formation depends on the cement permeability and pressure difference between the layers. There is no induced fracture in this case, and the cement is assumed to acquire a constant permeability.

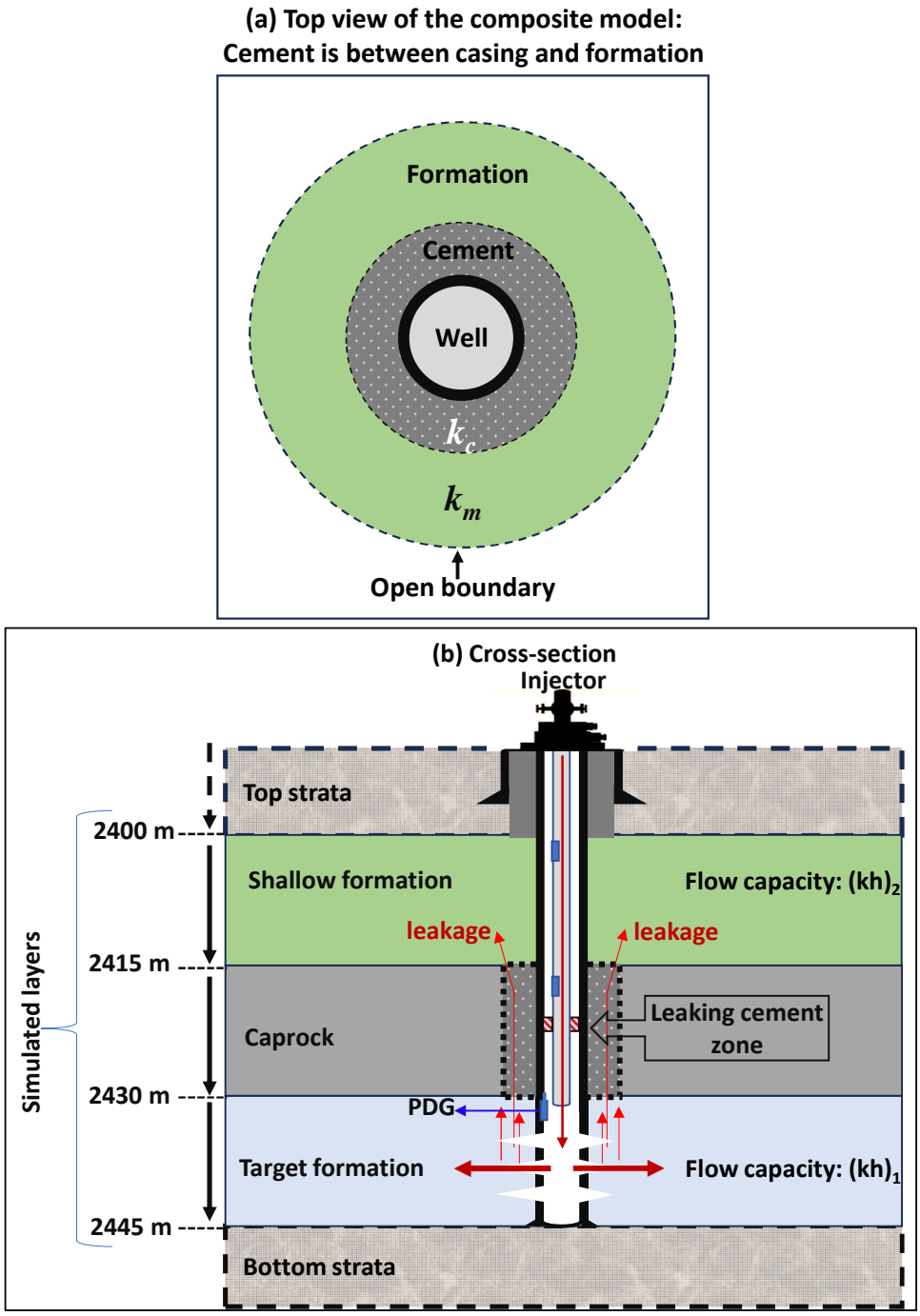


Figure 9. (a): Applied modelling approach utilizing a composite reservoir model consisting of formation with matrix permeability (k_m) and cement behind casing characterized by cement permeability (k_c) (illustration, not to scale); (b): simulated reservoir system considering two neighbouring formations separated by impermeable caprock (leakage is assumed to occur only behind the casing through the highlighted leaking cement zone)

364

365 ***3.2.2 PTA-based method to detect behind-casing leakage in active wells***

366 Based on the model setup described above, a well test is designed injecting water at constant rate of 10 m^3/D for 1000
367 hours followed by well shut-in. Simulated pressure history data representing a permanent downhole gauge (PDG)
368 measurements is presented in Figure 10a. The pressure responses are presented for different flowing scenarios. First,

pressure response for testing single (target) formation was simulated, which gives a reference pressure behavior for extreme limit where there is no leakage or communication with the shallow formation. Then, pressure response testing flow capacities of two (target and shallow) formations was simulated, which gives the second extreme limit, reflecting the wellbore pressure response if both formations are penetrated. Then, a sensitivity analysis of the pressure response is carried out considering variation of effective cement permeability from lower values to higher values, represented by k_c/k_m with values of 0.01, 0.1, 1, and 10.

The PTA interpretation method described in previous section for fracture leakage detection was further tested for active well with behind casing leakage and simplified flow sequence (one-step injection) including the following steps:

- Using the simulated well test data in Figure 10a, pressure and derivatives for the flowing period are calculated and plotted in the log-log plot in Figure 10b.
- Two extreme limits are set as 'no-leakage' and 'two-layer flow' based on single and two formations' flow capacities, respectively (Figure 10b). The limits allow to stipulate the scenario that may occur if the neighboring layer if fully contributing to the total flow (Nooruddin & Rahman, 2021; Rahman et al., 2015).
- Pressure and derivatives illustrate the impact of increasing effective cement permeability (k_c) in the log-log plot (Figure 10b), starting from k_c as smaller fraction of reservoir matrix permeability (k_m) to higher values.
- The diagnostic log-log plot shows that pressure derivatives tend to attain a declining trend as the effective permeability of cement increases. Thus, the simulated case shows that leakage was detected in log-log plot for all k_c/k_m>0.01 with improved detection capability with increasing k_c.

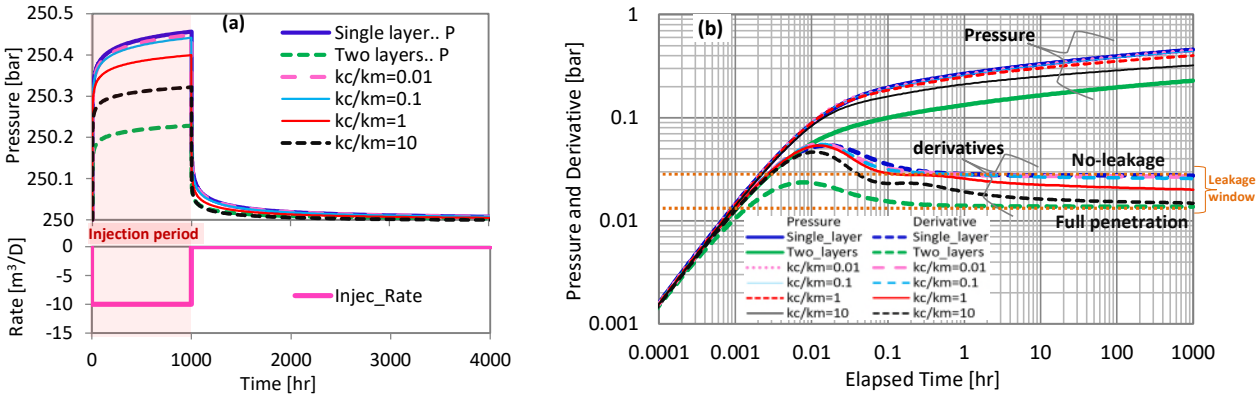


Figure 10. (a): History plot showing flow rate and simulated pressure during test injection to evaluate sensitivity of the effective permeability of cement k_c relative to reservoir permeability k_m; (b): Standard diagnostic log-log plot with pressure and Bourdet derivatives for the flowing period (greater k_c values result in a more inclined derivative)

The log-log plot is zoomed in (Figure 11a) to focus on the behavior of interpreted Bourdet derivatives. Starting from the reference transient of a single formation flow, the impact of the crossflow behind the casing is detected through the negative-slope behavior of the derivative signature. The downward slope derivative is primarily governed by the cement permeability and pressure difference between two formations. Such detection approach uses analysis of flowing pressure data while accounting for pressure losses in the cemented zone, supporting real-time monitoring and on-the-fly well-test interpretation.

Further, the ratio of the cumulative injected volume into the shallow formation to the cumulative injected volume is analyzed to estimate the relative leakage during injection. The leakage is proportional to the effective cement permeability as shown in Figure 11b. Noting that since it was assumed that both formations have the same initial pressure (i.e. initial equilibrium state) the escalating leakage from the target formation into the shallow formation increases with time due to influence of the increasing pressure differential between the formations during injection.

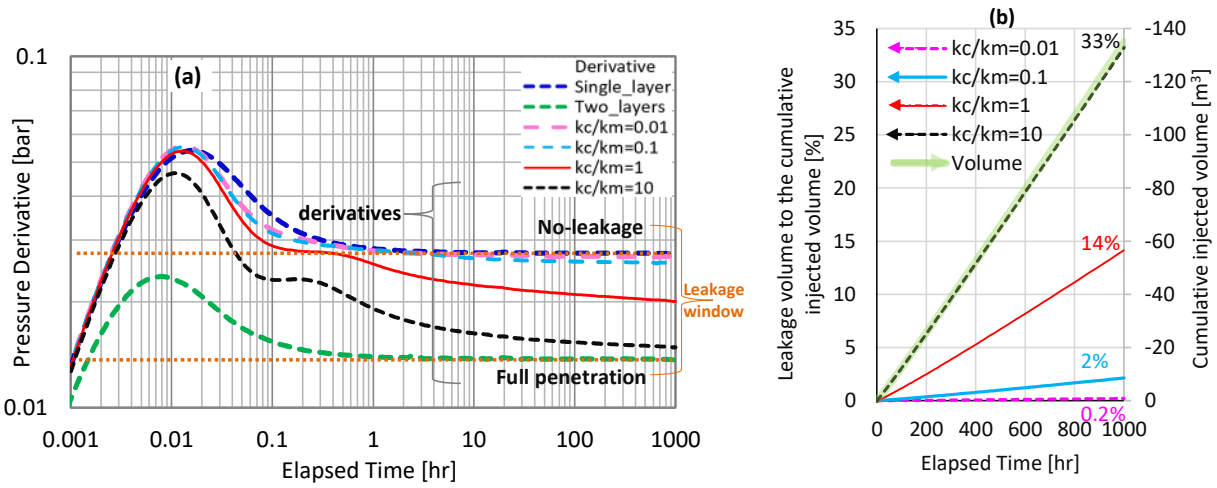


Figure 11. (a): Pressure derivative behavior dependent on the effective permeability of cement k_c relative to reservoir permeability k_m; (b): Leakage volumes in absolute values and as a percentage of the cumulative injected volumes

Figure 11a and b reveal that 0.2% leakage corresponding to relative cement permeability of 0.01 is not easily detectable. However, the PTA-based method detected leakage above 2% (based on the simulated case study) when relative cement permeability (k_c/k_m) approaches 0.1. Note that max leakage from the target to shallow formation through crossflow behind-casing is less than the 'full penetration' injection limit due to the pressure losses in cement sheath and its limited volume available for flow. The results suggest that pressure measurements from permanent downhole gauges can support real-time leak detection in active wells, but only above a certain minimum leakage rate and only for the case studies examined. Although surface SCP and SCVF tests at the wellhead remain standard practice, the downhole gauges installed at one or more intervals deliver continuous, high-resolution, depth-specific pressure measurements, enabling leakage detection precisely where they occur.

3.3 Modeling and PTA-based detection of behind-casing leakage for abandoned wells

The second simulation case examines an inactive, abandoned well (after Plug-and-Abandonment (P&A)) situated near an active injector. The composite modeling and interpretation method from the previous section was then applied to detect leakage through the compromised zonal isolation, assuming the abandoned well's cement sheath has degraded.

3.3.1 Modeling leakage pathways and simulation of leakage for abandoned wells

Consider the case where previously active well has recently been abandoned (P&A) and a newly drilled injector starts operating in the vicinity of the abandoned well (Figure 12). It is assumed that modern data-acquisition technologies may be used for monitoring of the abandoned well, such as wireless downhole gauges employing casing as a signal conduit (Champion, 2016; Bouldin et al., 2021; Mimoun et al., 2023; Schneider et al., 2024). This section explores how such downhole measurements below the plug can be used for leakage detection. Champion, (2016) details the use of wireless gauges in abandoned exploration well at the Norvarg field (Barents Sea) to extend exploration area around the abandoned well and map distant flow barriers. Recently, Schneider et al., (2024) introduced an acoustic waveguide system that powers sensors and transmits data through steel casing without additional cabling. Thus, with such prevalent data acquisition tools, the goal here is to evaluate whether the PTA methods can help in interpreting the downhole pressure readings to identify leakage in abandoned wells.

The same composite reservoir model as in the section above is applied to simulate behind-casing leakage in a abandoned well while accounting for a nearby injection (Figure 12a, b). Although the well is plugged to restore caprock integrity and prevent fluid migration, debonding at the cement–formation or cement–casing interfaces may have compromised zonal isolation. This leaking zone is highlighted in Figure 12b. With the injector located 1 km away, pressure in the abandoned well may reflect both leakage into the shallow formation and pressurization from the

injector. Since the caprock between layers is impermeable, any upward migration from the reservoir to the shallow formation can occur only through this damaged cement sheath. The permeability of the degraded cement sheath and the pressure gradient between the target and shallow formations are the primary controls on the fluid migration. When cement permeability is negligible (zero), no leakage occurs, and the pressure transient in the abandoned well should reflect flow exclusively within the target reservoir. In contrast, if cement permeability is sufficiently high, fluids may migrate into the shallow formation, and the pressure transient will exhibit flow signatures characteristic of a commingled two-layer system (Rahman et al., 2015). Thus, flow capacities of single and two formations provide reference pressure transients in detection of possible leakage behind casing.

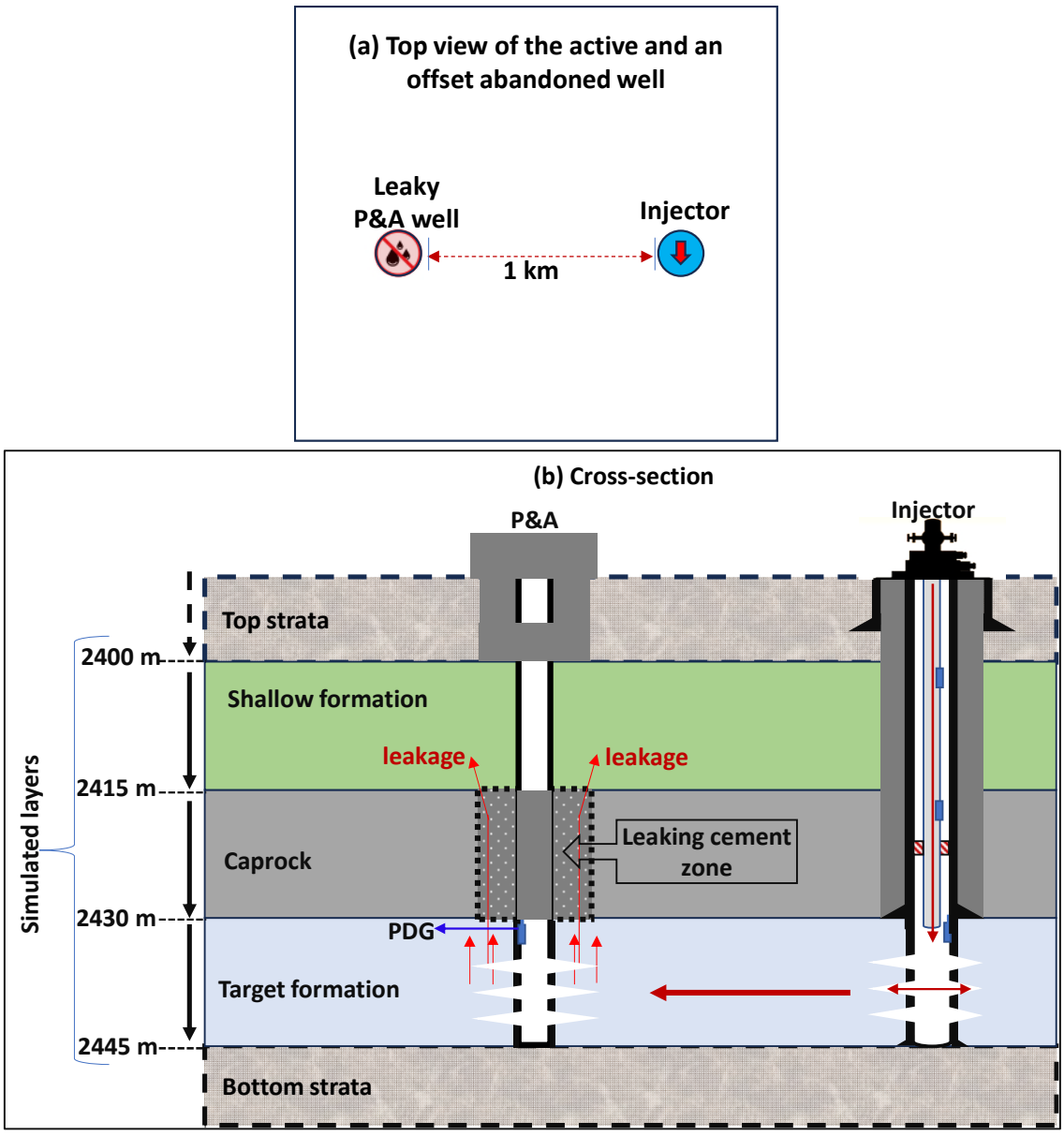


Figure 12. (a): Top view of Case 2 – P&A well and nearby injector (illustration, not to scale); (b): Reservoir system considering two formations separated by impermeable caprock assuming that leakage occurs only behind casing (casing-cement-rock interface) while installed cement barrier inside the wellbore remained competent.

3.3.2 PTA-based method to detect behind-casing leakage in abandoned wells

Figure 13 presents a simulated well monitoring sequence designed as a well test with small-rate injection in the beginning followed by long shut-in for the model configuration shown in Figure 12. Figure 13 displays rate and pressure responses under various scenarios of single formation and two-formation (or full) penetration in combination with two relative cement permeabilities k_c/k_m=1, and k_c/k_m=10. Figure 13a illustrates that, although the abandoned well remained shut-in (zero flow rate), a nearby injector operated at a constant 100 m³/d. Despite being closed, the downhole pressure in abandoned well reveals pressure buildup due to the injector's activity. Further, the simulated well monitoring sequences (only shut-in period) are interpreted using the PTA framework to ascertain understanding of leakage across the abandoned well.

In this study, the PTA-based leakage detection method from the previous section is adapted for abandoned well following similar steps. Leakage window is established using the flow capacity of the single target formation as the no-leakage limit and that of injection into two formations as the fully penetration limit, capturing the maximum injection rate if the adjacent formation fully contributes to flow (Rahman et al., 2015; Nooruddin & Rahman, 2021). Next, the influence of effective cement permeability (k_c) pressure behavior is examined by increasing k_c values to represent potential leakage scenarios. Figure 13b shows the resultant diagnostic log-log plot revealing impact of the cement permeability and nearby injector whereby derivatives exhibit a downward trend that becomes steeper as cement permeability increases. Additionally, the nearby injector imposes a pressure interference late-time boundary feature widely known in PTA (Gringarten, 2008).

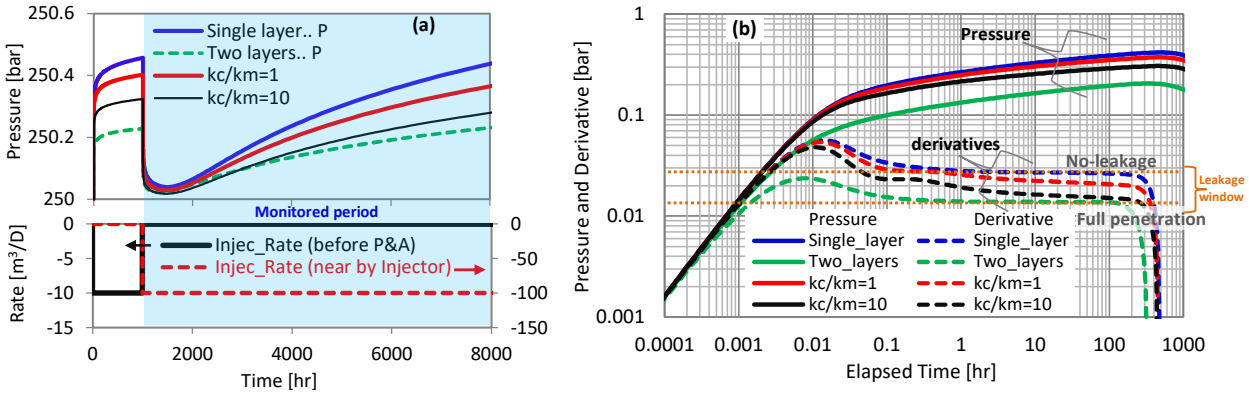


Figure 13. (a): History plot showing flow rate and simulated pressure for abandoned well for evaluating sensitivity to the ratio of the effective permeability of cement k_c to reservoir permeability k_m; (b): Standard diagnostic log-log plot with pressure and Bourdet derivatives: greater k_c values result in a more inclined derivative, late-time boundary feature reflects well interference

The simulated cumulative leakage into shallow formation relative to the cumulative injected volume is shown in Figure 14. Estimated leakage for both k_c/k_m=1 and k_c/k_m=10 is 1.2% and 2.5% corresponding to the injected volumes of 330 m³ and 730 m³ over the monitored period. These estimates are valid only within the context of the simulated case showing feasibility of leakage detection using PTA-based approach.

Thus, simulation study of an injector located 1 km from a leaking well demonstrates that the proposed PTA-based method detected behind-casing leakage for cement permeability equal or greater than the permeability of the target formation. The detection capacity of the method improves when the cement permeability becomes higher than the formation permeability, provided leakage volumes exceeding 1% of the injected volumes. The relative increase in effective cement-zone permeability (k_c) represents the hydraulic conductivity of annular gaps between casing-cement and cement-rock interfaces, and the detection results are applicable only to the simulated scenario.

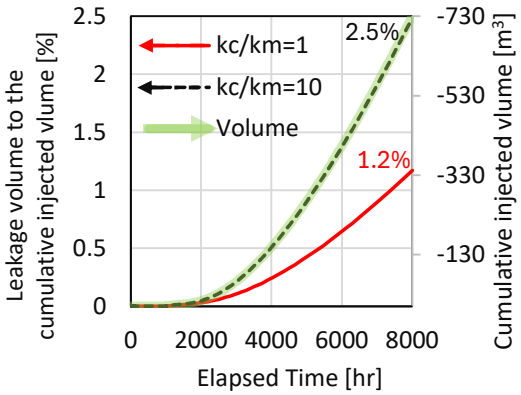


Figure 14. Leakage volumes as percentage of the cumulative injected volumes

4 Discussion

The application area and performance of the proposed PTA-based leakage detection methods are discussed, highlighting strengths and key limitations. The assessment covers induced-fracture leakage and behind-casing crossflow in both active and abandoned wells, considers the impact of data noise and gauge resolution, and outline avenues for future refinement and validation.

4.1 Application areas of the proposed approaches in real-time monitoring

The proposed approaches require only widely deployed PDGs providing real-time data, giving them potential for field application and practical integration in automated well monitoring and control workflows. Well operations are increasingly automated, drilling is mature (Cayeux et al., 2021), whereas injection monitoring and control is still developing (Shchipanov et al., 2024; Ambrus et al., 2024). Hence, new PDG data interpretation approaches such as ones proposed in this study are needed as opposed to traditional pressure falloff transient analysis (requiring additional shut-in cost) to facilitate early detection of leakage within well monitoring workflows. In such real-time monitoring applications, adjusting injection rate is the standard lever for injection optimization or leakage prevention (Ambrus et al., 2024).

4.2 Gauge capabilities and impact of noisy data

The effectiveness of the proposed PTA-based methods for real-time leakage detection could be challenged by measurement noise and capabilities of the pressure gauges. Fortunately, modern PDGs offer high-accuracy, low-drift, and high-resolution measurements, even under extreme pressures and temperatures, providing the flexibility to select gauges that match best the specific well and reservoir conditions. Table 3 summarizes the specifications of gauges currently available for long-term well monitoring.

Table 3. Specifications of Permanent Downhole Gauge (PDG) available on today's market (*Halliburton*, 2025; *Schlumberger*, 2025)

Guage parameters	Value
Calibrated working pressure range [bar]	Atmospheric to 2070
Calibrated working temperature range [°C]	25 to 225
Pressure accuracy [% full scale]	±0.015
Achievable pressure resolution [bar]	0.0002 to 0.0004
Pressure drift stability [% full scale/year]	Negligible at 1 bar and 25 °C Maximum drift is <0.02 at maximum pressure and temperature
Temperature accuracy [°C]	±0.15
Achievable temperature resolution [°C]	0.001

Temperature drift [°C/year]	<0.1

The resolution of the gauges, which is the smallest pressure change it can reliably measure, sets the limits on the interpretation of derived pressure-derivative. Current PDG technologies offer sufficient resolution (≈0.0002 bar) needed to distinguish leakage signatures from non-leakage baselines on a log–log plot. For instance, in the derivative plot (Figure 11a & Figure 13b), the no-leakage and full penetration limits span roughly 0.015–0.03 bar, falling within the gauge's resolution, ensuring these trends can be clearly identified.

Noise in downhole pressure measurements can complicate interpretation. For instance, the real SRT data, presented in (Mugisha, Shchipanov, et al., 2025) and reconstructed in Figure 15, revealed pressure derivatives with a noise which should be separated from the signal to capture fracture opening signatures. The authors employed the uncertainty envelope whereby the reference transient recorded below the fracturing pressure is tuned to match observed noise. In log-log plot (Figure 15b), noise amplitudes stay less than 1 bar, whereas genuine fracture-flow signals deviate by approximately 2 bar, enabling clear distinction between noise and the fracture opening signals.

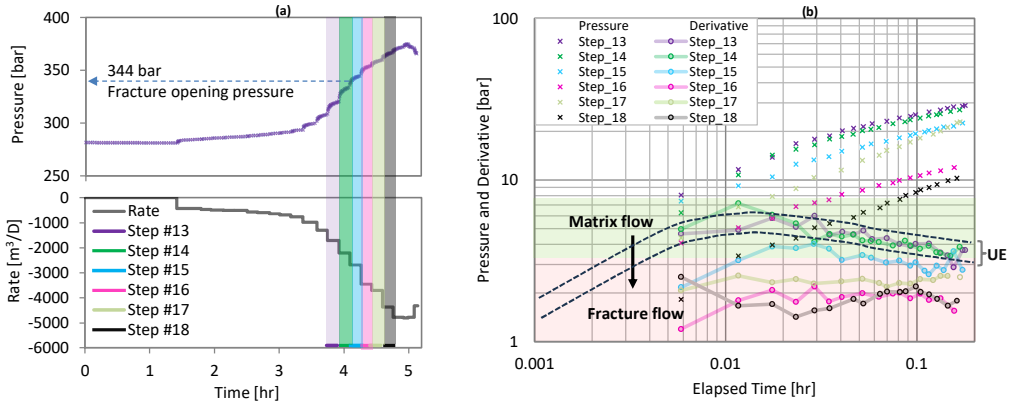


Figure 15. PTA-SRT interpretation results for a vertical water injector from (Mugisha, Shchipanov, et al., 2025): (a): History plot showing flow rate and pressure measurements; (b): Standard diagnostic log-log plot with pressure and Bourdet derivatives

Advances in downhole gauge technology, including high-pressure, high-temperature sensors for deep reservoirs and emerging wireless systems for plugged-and-abandoned wells (Champion, 2016), have greatly improved ability to collect reliable real-time measurements. However, the true benefit of these data streams depends on equally advanced interpretation techniques. By applying robust interpretation methods, raw measurements can be converted into actionable insights on well integrity and reservoir performance.

4.3 Comparing the proposed PDG/PTA-based methods to other standard methods

The current industry practice primarily relies on fiber-optic sensing and seismic surveys as the main tools for subsurface leakage monitoring as described in the introduction section. However, since Permanent Downhole Gauges (PDGs) are already widely installed in many wells, they present a promising opportunity for leakage detection as well. In such cases, the methods proposed in this study could be further explored for interpreting the acquired PDG data. It should be noted that additional testing and validation using field data is an essential next step toward the maturation and practical use of the proposed methodology.

Interpretation results of PDG/PTA-based methods are non-unique, since an inverse problem is solved, and confounded by other effects, with uncertainty reduced by using case-specific operational experiences, geology, production/injection history, and complementary monitoring (Cobanoglu & Shukri, 2020). Nevertheless, PDG/PTA does not suffer modality-specific constraints, described in the introduction section discussing different fiber-optics and micro-seismic options, and remains simpler and cheaper to operate, making it a practical complementary line (Benish et al., 2024) to fiber-optic or micro-seismic monitoring or may be considered as the main option, upon the limitations discussed above, if the last mentioned surveys are unavailable or infeasible.

Further, SCP monitoring is a widely used and useful indicator of wellbore-integrity loss, though its reliance on wellhead measurements limits depth resolution and may miss deeper leaks especially when partial isolation loss does not produce SCP (Lackey & Rajaram, 2019). Managing SCP may involve additional diagnostics, decompression, shut-ins, and environmental liabilities (Ibukun et al., 2024). To complement SCP monitoring, the proposed PTA-based methods could enhance prognostic well surveillance and enable depth-specific detection of behind-casing leakage, even in the absence of SCP signals.

4.4 Limitations and future studies

The proposed PTA-based leakage detection methods were tested on simulated cases under single-phase, isothermal flow, which limits its applicability to more complex injection scenarios. For instance, in CO_2 storage (Shchipanov et al., 2019; Baabbad et al., 2024) or geothermal energy production (Mugisha et al., 2024; Mugisha, Cui, et al., 2025), two-phase flow or thermal front movement introduce mobility-induced pressure derivative shifts that can mask leakage signals. Future work should test the proposed PTA-based methods under thermal-front propagation and phase-dependent mobility changes (Levitan, 2003), and further refine leakage-detection workflows. Validation and calibration of the proposed PTA-based methods on field datasets and cross-validation with complementary measurements, such as distributed temperature sensing (DTS), is essential to distinguish true leaks from phase-transition effects while preserving PTA monitoring option in the long term.

Further, induced fracturing was simulated using a pseudo-coupling method (Samier et al., 2008), where a pressure-dependent permeability function approximates fracture opening without explicit stress computations. The modeling approach gave a sufficient way to simulate initiated leakage and pressure responses. As follow up, future research may employ fully coupled geomechanical–reservoir simulations to enhance the precision of leakage initiation detection. Also, cement leakage simulations assumed a constant permeability, leading to approximate capture of crossflow behavior behind the casing. Studies focusing on the evolving mechanical failure of cement may better capture the mechanisms driving cement leakage initiation. High pressure and temperature changes during injection can induce radial casing expansion or contraction governed by thermo-mechanical properties (Boresi, 2003). The time-dependent effects may result in increase or decrease annular cement permeability, particularly in long-term operations. However, for short well tests and time-lapse pressure transient analyses, assuming constant effective permeability is reasonable, as variations over the test duration are likely negligible in practical applications.

In brief, the limitations of the current work include:

- Validation is limited to synthetic, numerically simulated cases with no direct field-data confirmation.
- Applicability restricted to vertical wells and homogeneous, infinite-acting reservoir assumptions.
- Testing on single-phase, isothermal flow models, excluding thermal and multiphase effects.
- Proxy-based fracture modeling without fully coupled geomechanical simulation.
- Static cement permeability assumptions for behind-casing leakage.
- Partial subjectivity in the definition of the Uncertainty Envelope.

Also, below are proposed future developments and research directions:

- Validation with field data, including retrospective analysis of injections or integrity-monitoring datasets.
- Extension of the framework to multiphase and non-isothermal flow for CCS and geothermal applications.
- Integration of fully coupled geomechanical-reservoir simulations to improve leakage modeling.
- Modeling of time-dependent cement degradation to better capture early-stage behind-casing leakage.
    - Automating Uncertainty Envelope using statistical or machine-learning-based methods to reduce subjectivity.
- Cross-validation with complementary monitoring technologies (e.g., DTS, DAS, SCP, microseismic data).
- Assessment of false-positive scenarios and development of diagnostic rules for operational deployment.

5 Conclusions

Building on top of the Pressure Transient Analysis method for Step Rate Test interpretation (PTA-SRT method) validated on field data (Mugisha, Shchipanov, et al., 2025), this paper has explored the feasibility of using PTA methods to detect out-of-zone injection in active and abandoned wells from widely available real-time pressure measurements provided by Permanent Downhole Gauges (PDG). PDGs are widely deployed worldwide and became a standard tool for well surveillance in some regions such as the Norwegian Continental Shelf. The feasibility has been studied by interpreting simulated well pressure responses obtained in 3D mechanistic reservoir model. The studied PDG/PTA-based detection methods may be considered as a part of a broader monitoring framework including well logging, allocated and distributed wellbore measurements, seismic surveys, and others.

In brief, this work provides a feasibility evaluation including:

- Applied PTA-based methods to interpret PDG pressure measurements to detect leakage in two cases: (i) fracture penetration of caprocks and (ii) behind-casing crossflow in a well. Multiple simulated leakage scenarios have confirmed the feasibility of early leakage detection for these cases.
- A concept of uncertainty envelope has been adopted within the PTA methods to improve diagnostic reliability under measurement noise.
- The PTA methods tested use only pressure and rate data and are potentially scalable to continuous or automated monitoring workflows.

Advantages and potential application areas for the tested PTA methods may include:

- The adopted PTA interpretation approaches include flowing transient interpretation, avoiding mandatory shut-in costs inherent to conventional well testing. At the same time, combining flowing and shut-in time-lapse interpretations may enhance repeatability and cross-validation, which may be a subject of future studies.
    - The PTA methods may be considered to complement the standard SCP monitoring at the wellhead for annular leakage detection and provide a pragmatic adjunct to time-consuming well logging.
- The interpretation framework is scalable for subsurface-injection integrity and environmental assurance in subsurface injection operations, particularly in fields with many repurposed or legacy wells where monitoring is critical.

This simulation study has demonstrated the feasibility of leakage detection using PTA methods under the scope of vertical well and single-phase slightly compressible isothermal flow. The results and conclusions are valid within these assumptions. Validation of the PDG/PTA-based methods developed using field data and comparison with other methods such as fiber-optics and microseismic monitoring is a necessary next step in maturation of this well monitoring technology for leakage detection.

Nomenclatures

i	index of pressure data point
k	step index
K	total steps
$p_{0,k}$	pressure at the beginning of step, bar
$p_{i,k}$	pressure data point, bar
$t_{0,k}$	time at the beginning of step, hr
$t_{i,k}$	time at data point, hr
$\Delta\bar{p}$	normalized pressure difference, bar
$\Delta p'$	pressure derivative, bar
$\Delta p'_{ref}$	reference derivative below fracturing pressure, bar
Ts	superposition time, dimensionless
Q	constant rate at a step (surface injection rate, used with a negative value), m^3/D

Q_{ref}	reference rate, m^3/D
b	multiplier
F_C	fracture conductivity, md.m
h	reservoir net pay thickness, m
k_m	matrix permeability, md
k_c	effective cement permeability, md
k_f	fracture permeability, md
$k_{f,max}$	maximum fracture permeability, md
m	mean, bar
α	numerical element in tuning UE
N	size of subset
p_f	fracture opening pressure, bar
σ	standard deviation, bar
w_f	fracture width, m
x_f	fracture half-length, m
S_S	Subset
L_l	Lower Limit (of Uncertainty Envelope), bar
U_l	Upper Limit (of Uncertainty Envelope), bar

Acronyms

CCS	Carbon Capture and Storage
DTS	Distributed Temperature Sensing
IARF	Infinite Acting Radial Flow
P&A	Plugged-and-Abandoned
PDG	Permanent Downhole Gauges
PTA	Pressure Transient Analysis
SCP	Surface Casing Pressure
SCVF	Surface Casing Vent Flow
SRT	Step-Rate Test
UE	Uncertainty Envelope

Credit Author Statement

Joshua Mugisha: Methodology, Investigation, Validation, Formal analysis, Visualization, Writing - original draft, review and editing. **Anton Shchipanov**: Conceptualization, Methodology, Investigation, Validation, Supervision, Writing – review and editing, Project administration. **Hans Joakim Skadsem**: Investigation, Validation, Writing – review and editing, Supervision. **Ingebret Fjelde**: Investigation, Validation, Writing – review and editing, Supervision.

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Data availability

Part of synthetic simulated data could be available by contacting the corresponding author (Joshua Mugisha) at jomu@norceresearch.no

Competing interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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