

Article

A DAS-Based Approach for Predicting Liquid Flow Velocity in Pipelines

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Abstract

Accurate measurement of liquid flow velocity is crucial for pipeline management in the petroleum industry. Traditional flowmeters, such as ultrasonic, electromagnetic, and pressure-based devices, provide only point measurements and often require intrusive installation. Distributed Acoustic Sensing (DAS) offers a non-intrusive alternative by converting optical fibers into continuous acoustic sensors with meter-scale resolution. In this study, a High-Definition DAS system was applied in a laboratory flow loop to monitor single-phase liquid flow. The recorded signals were analyzed in both time and frequency domains. Results showed that the pump operating frequency dominated the spectral energy, accompanied by dispersive features. Power spectral density (PSD) increased linearly with flow rate, while Doppler-induced frequency shifts in the dominant component enabled velocity prediction. A regression model achieved a high coefficient of determination ($R^2 = 0.9928$), confirming the strong predictive capability. These findings highlight DAS as a reliable and scalable solution for non-intrusive liquid flow monitoring in pipelines.

Keywords: distributed acoustic sensing; pipeline monitoring; single-phase liquid flow; flow velocity prediction; spectral analysis; Doppler effect

1. Introduction

Accurately monitoring liquid flow velocity in pipelines is critical for the petroleum industry, whether in water injection networks or oil transportation lines. A variety of traditional flow metering techniques have been employed to gauge flow velocity and rate in such pipelines. Chief among these are ultrasonic flowmeters, electromagnetic flow sensors, and pressure-based flow meters. Each of these conventional technologies has well-established principles and has seen widespread use in industrial practice. For example, ultrasonic transit-time flowmeters infer velocity by measuring the travel time difference in acoustic pulses upstream vs. downstream; they are non-intrusive and incur no pressure loss, making them suitable for large-diameter pipes [1–4]. Electromagnetic (mag) flowmeters, on the other hand, induce voltage in a conducting liquid moving through a magnetic field (Faraday's law) to determine flow speed, offering reliable and linear measurements for water and other conductive fluids [5]. Pressure-based devices (such as differential pressure flowmeters using orifice plates or Venturi tubes) create a pressure



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drop that can be correlated to flow rate, a century-old method known for its simplicity and robustness in single-phase flow. These instruments (along with others like turbine and vortex flowmeters) form the backbone of conventional pipeline flow monitoring in oil and gas operations.

Lots of scholars have introduced refinement strategies and novel measurement technologies. Shaban and Tavoularis demonstrated the utility of cross-correlation with dual wire-mesh sensors for multiphase flow measurement [6]. Zheng et al. examined the limitations of differential pressure meters for wet gas, highlighting challenges in precision [7]. Zheng et al. introduced a V-Cone meter with a two-phase mass flow coefficient for error correction in low gas volume fraction flows [8]. Wang et al. applied Coriolis meters with support vector machine models to enhance CO₂ flow measurement in CCS pipelines [9]. Wrasse et al. combined a Venturi tube with a capacitive sensor to simplify liquid flow rate estimation [10]. Barbariol et al. used machine learning for anomaly detection in multiphase flow meters, improving measurement reliability [11]. Pan et al. utilized gamma-ray attenuation for low-quality multiphase flows, proposing a linear correlation model for gas flow rate prediction [12]. Bismukhametov and Jäschke reviewed Virtual Flow Metering, emphasizing the integration of first principles and machine learning [13]. Guo et al. refined thermal diffusion measurement for vertical two-phase flow, offering a non-invasive approach with high accuracy [14]. Li and Bai introduced a physics-guided deep learning model for gas–liquid flow rate prediction [15]. Guo et al. developed a thermal diffusion method for slug flow measurement, correlating bubble and slug lengths with flow rates [16]. Ma et al. integrated a swirled with a Venturi tube to improve slug flow measurement, providing empirical correlations for flow rate determination [17].

Distributed Acoustic Sensing (DAS) has recently emerged as a novel approach that addresses many of the above limitations in pipeline flow monitoring. In a DAS system, a standard fiber-optic cable serves as a distributed sensor that captures acoustic vibrations along the length of the pipeline. An interrogator unit sends pulses of light down the fiber and detects minute strain disturbances via Rayleigh backscatter, effectively turning every meter of the fiber into a microphone listening to the pipeline's acoustics. Flowing liquids in a pipeline generate a variety of acoustic signatures—from turbulence noise to vibrations caused by eddies or interactions with pipe fittings—and DAS can detect these signals at high spatial resolution (on the order of 1 m) along the entire pipeline. This represents a fundamentally different paradigm from point sensors: instead of isolated measurements, DAS provides a continuous profile of acoustic activity associated with flow conditions. Notably, the technology is fully distributed and real-time, enabling operators to monitor flow dynamics at thousands of points simultaneously (typically one reading per meter of fiber) and to observe how flow characteristics evolve over long distances.

The key advantages of DAS for pipeline flow monitoring can be summarized as follows. First, it offers meter-level spatial resolution, allowing fine-grained detection of flow velocity variations or local anomalies that would be missed by sparse point sensors. Second, DAS provides continuous, distributed coverage: the fiber can span many kilometers, yielding 24/7 monitoring of the entire pipeline with no blind spots [5]. Third, it is essentially non-intrusive—fibers are typically strapped to the exterior of the pipe or buried alongside it, so installation requires no drilling into the pipe and causes no flow disturbance. This makes DAS deployable on existing pipelines without modification. Finally, DAS is well-suited for harsh environments common in the petroleum industry. Optical fibers are passive and immune to electromagnetic interference, and they can withstand extreme temperatures and pressures that would damage electronic instruments. These features have made DAS a promising technology for pipeline applications ranging from leak detection and pipeline security to flow assurance. Indeed, recent studies have demonstrated that DAS

can achieve high accuracy in flow measurements with spatial resolutions down to about 1 m, enabling precise quantification of flow behavior that was previously unattainable with conventional sensors [18].

Building on these developments, the present research explores the use of DAS for predicting liquid flow velocity in pipelines. In particular, we leverage DAS signals obtained in a controlled physical simulation experiment to develop a data-driven method for flow velocity prediction. In the experiment, a fiber-optic cable was deployed along a pipeline segment through which water flow was circulated, emulating real pipeline conditions. The DAS system continuously recorded the acoustic vibrations induced by the flowing liquid. By analyzing the characteristics of these distributed acoustic signals—for example, their energy levels and frequency content as a function of flow rate—we establish a relationship between the DAS measurements and the actual flow velocity. This approach demonstrates that non-intrusive DAS measurements can be used to quantitatively infer flow velocities in a pipeline.

2. Methodology

2.1. Principle of DAS

DAS is an optical fiber-based sensing technology that transforms a standard telecommunication fiber into a distributed array of acoustic sensors. The operating principle relies on the phenomenon of Rayleigh backscattering, which occurs naturally when coherent laser pulses are launched into the optical fiber. As the light propagates, microscopic inhomogeneities in the fiber core scatter a small fraction of the optical power back toward the source. The backscattered light contains a random interference pattern that is highly sensitive to changes in the optical path length of the scattering centers.

When the fiber is subjected to an external disturbance, such as strain induced by acoustic waves or mechanical vibrations, the optical path length within the corresponding fiber segment changes. This results in a phase modulation of the backscattered signal. By emitting coherent laser pulses at high repetition rates and applying phase-sensitive detection at the interrogator, the system can detect and quantify these minute changes. The phase difference between consecutive backscattered traces encodes the dynamic strain applied to each segment of the fiber.

To achieve spatial resolution, the fiber is conceptually divided into a series of gauge lengths. Each gauge length acts as an independent sensing unit, with its response derived from the cumulative Rayleigh backscatter within that segment. By adjusting the gauge length and pulse repetition frequency, DAS systems can provide meter-scale spatial resolution along tens of kilometers of fiber. Unlike discrete sensors, DAS enables truly distributed sensing, with thousands of virtual sensing points along a single optical fiber.

Mathematically, if the interrogator launches a laser pulse $E(t)$ into the fiber, the backscattered signal from a position z can be represented as:

$$E_b(z, t) = \sum_i A_i(z) \exp(j\phi_i(z, t)), \quad (1)$$

where $A_i(z)$ is the amplitude contribution from scattering center i , and $\phi_i(z, t)$ is the optical phase, which varies with external strain $\varepsilon(z, t)$. The strain-induced phase variation can be expressed as:

$$\Delta\phi(z, t) = \frac{2\pi n}{\lambda} L \varepsilon(z, t), \quad (2)$$

where n is the refractive index of the fiber, λ is the laser wavelength, nm, and L is the effective interaction length, m. By demodulating $\Delta\phi(z, t)$, the DAS system retrieves the dynamic strain response along the fiber.

This principle allows DAS to detect low-frequency structural deformations as well as high-frequency acoustic vibrations. In pipeline monitoring, the flow of liquids generates turbulent pressure fluctuations and vibrational energy that couple into the pipe wall and surrounding medium. The attached fiber detects these vibrations as distributed acoustic signatures, enabling DAS to serve as a non-intrusive, continuous monitoring tool for flow characterization.

2.2. Experimental Apparatus

2.2.1. HD-DAS

The Distributed Acoustic Sensing (DAS) system employed in this study utilizes a single optical fiber as the sensing element, enabling the real-time detection of acoustic and vibrational signals along the fiber length. This technology is particularly well-suited for downhole and multiphase flow monitoring in the petroleum industry, as it provides fully distributed measurements without the need for intrusive instrumentation. Relying on the principle of Rayleigh backscattering, DAS measures strain variations induced by external acoustic disturbances along the fiber cable, thereby delivering a high-resolution spatial profile of the entire wellbore or pipeline.

In this work, a High Definition Distributed Acoustic Sensing (HD-DAS) system was adopted to further enhance performance. HD-DAS incorporates heterodyne modulation and demodulation techniques, which utilize two optical modulators to generate a heterodyne pulse pair. These pulses propagate along the sensing fiber, and the backscattered light is processed to extract the phase changes caused by external acoustic waves. By exploiting the self-coherence of the pulse pair, the HD-DAS system eliminates the need for local light interference, thereby improving sensitivity and robustness.

The HD-DAS system, as shown in Figure 1, achieves a noise floor below -80 dB re $\text{rad}/\sqrt{\text{Hz}}$. It further provides a broad dynamic range exceeding 100 dB and a wide frequency response covering 0–2000 Hz. With a spatial resolution of 1 m and a strain resolution of $2.1 \text{ p}\epsilon/\sqrt{\text{Hz}}$, the system is capable of resolving subtle acoustic features along the fiber. Moreover, its passive nature obviates the need for an active sound source, making it well suited for continuous monitoring under laboratory and field conditions.

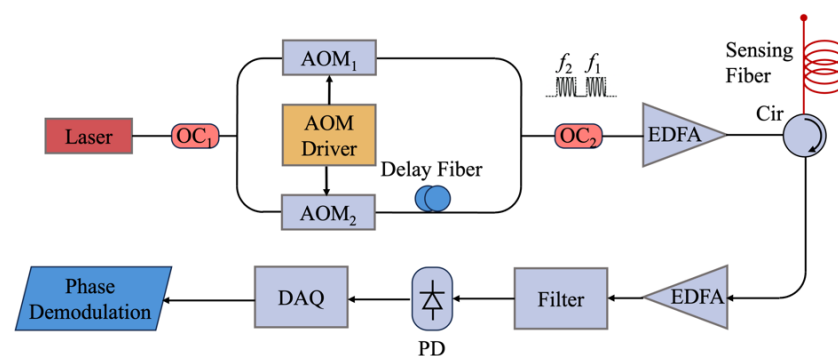


Figure 1. HD-DAS setup.

2.2.2. Experimental Circuit

The experimental circuit, illustrated in Figure 2, was specifically designed to investigate single-phase liquid flow. Water stored in a primary reservoir served as the working fluid. A centrifugal pump circulated the water through a closed-loop system, with a control valve employed to precisely regulate the flow rate within the prescribed range. As the liquid traversed the pipeline, hydrodynamic interactions between the fluid and the pipe wall induced vibrations, which were subsequently coupled into the structural boundaries. The pipe wall thickness is 12 mm, the inner diameter is 50 mm, and the material is stainless

steel. To capture these disturbances, an optical sensing fiber was positioned along the centerline of the test section. The HD-DAS system continuously interrogated the fiber and recorded vibration signals in real time, thereby ensuring accurate and high-fidelity data acquisition.

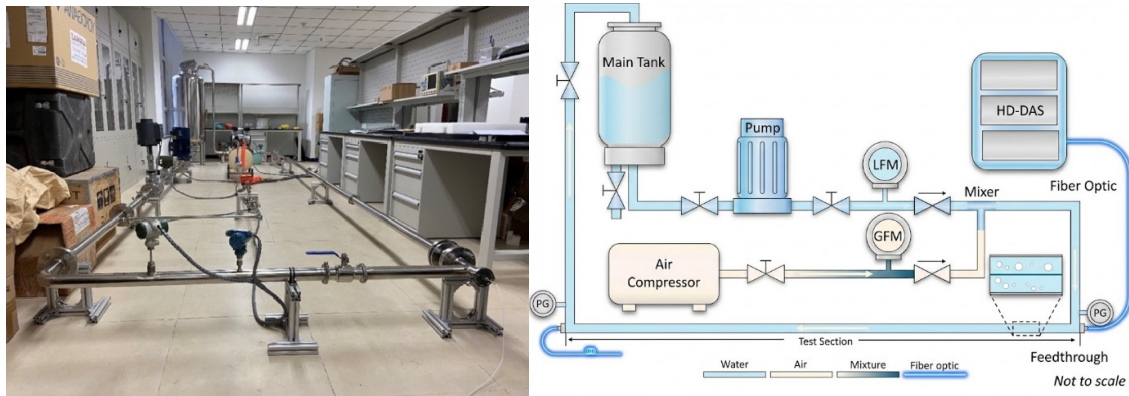


Figure 2. Experimental circuit.

The circulation loop directed water from the reservoir into the test section, where it passed through a liquid flowmeter and a check valve before entering the pipeline. After flowing through the test pipe, the water was returned to the reservoir, completing the closed-loop configuration. Feedthroughs were mounted at both ends of the test pipe, allowing the fiber to be tensioned and accurately aligned along the pipe axis. To mitigate Fresnel reflection artifacts, a reflective termination was introduced at the fiber end, while the leading end was connected to the HD-DAS interrogator, establishing a robust optical sensing pathway for detecting flow-induced vibrational signatures.

2.3. Experimental Scheme and Procedure

We conducted experiments focusing exclusively on single-phase liquid flow. The primary objective was to acquire vibration signals along the optical fiber to establish a predictive model for accurate flow rate estimation. Liquid flow rates were systematically varied from 0 to 20 m³/h in increments of 0.5 m³/h (i.e., 0, 0.5, 1.0, ..., 20 m³/h).

To ensure stability and repeatability, each test was performed over a 10-s interval. The measurement process was repeated 20 times for each flow rate condition, and the entire set of experiments was replicated six times, resulting in a cumulative testing duration of 1200 s across all conditions.

Prior to testing, the pipeline was fully filled with liquid and circulated for 20 min to eliminate residual air bubbles and to achieve steady-state flow conditions. The single-phase liquid flow experiments were then conducted according to the following procedure:

- The pump was activated and adjusted to the designated operating frequency (35 Hz in this study).
- The integrity of the optical fiber connection was verified to ensure reliable signal acquisition.
- The control valve was fine-tuned, and the liquid flowmeter was monitored to achieve the prescribed flow rate.
- Once the flow had stabilized, the DAS system was initiated to record vibration signals from the sensing fiber along the test pipe.
- Upon completion of each test interval and trial set, the liquid flow rate was adjusted to the subsequent target value, and the procedure was repeated until the entire flow range was covered.

3. Experimental Results

The time-domain responses obtained at a flow rate of $10 \text{ m}^3/\text{h}$ are presented in Figure 3. The section between 28 m and 35 m corresponds to the pipeline under study, where the optical fiber is tightly coupled to the pipe wall. Clear oscillatory patterns are observed in this region, exhibiting alternating positive and negative phase drifts. These drifts correspond to tensile and compressive strains in the optical fiber, induced by hydrodynamic pressure fluctuations and structural vibrations of the pipe wall. The signals confirm that the measured response is not solely attributable to direct acoustic excitation of the fiber but also represents the superposition of vibrational energy transmitted through the pipe structure. Compared to the upstream and downstream background signals, the pipeline section exhibits significantly higher amplitude and more coherent patterns, indicating that fluid-induced vibrations dominate the measured acoustic field. This confirms the feasibility of DAS for capturing liquid flow signatures in confined pipeline environments.

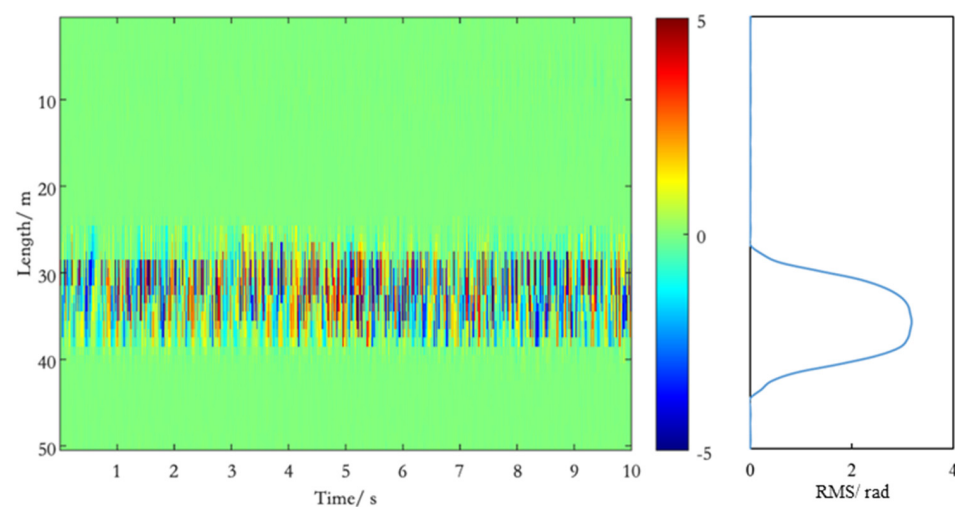


Figure 3. Time-domain DAS signals at $10 \text{ m}^3/\text{h}$.

The f–k spectrum of the same dataset is shown in Figure 4. Unlike applications in long-distance seismic or flow monitoring, no clear velocity-dependent features are discernible in this case. The absence of distinct energy ridges is primarily due to the short physical length of the test pipeline (7 m), which results in insufficient aperture for wavenumber resolution. In practical terms, the spatial resolution of the DAS system (1 m) implies that only a limited number of effective channels are available, thereby constraining the accuracy of dispersion imaging. Consequently, f–k analysis, although powerful in large-scale DAS applications such as seismic surveys, is not well suited for laboratory-scale flow monitoring experiments of this type. This observation underscores the importance of selecting signal processing techniques that are compatible with the scale and resolution of the experimental setup.

The wavelet synchro squeezed transform (WSST) of the signal at the 3 m location is shown in Figure 5. The results reveal that the dominant energy is concentrated near the pump operating frequency of approximately 35 Hz, consistent with the mechanical excitation introduced by the pump. In addition, a degree of frequency dispersion is evident, reflecting the interaction between the turbulent flow field and the structural modes of the pipe. The time–frequency representation highlights transient energy fluctuations superimposed on the pump frequency, which may be linked to flow instabilities at different velocities. These results demonstrate the capability of WSST to provide high-resolution insights into the non-stationary characteristics of flow-induced vibrations.

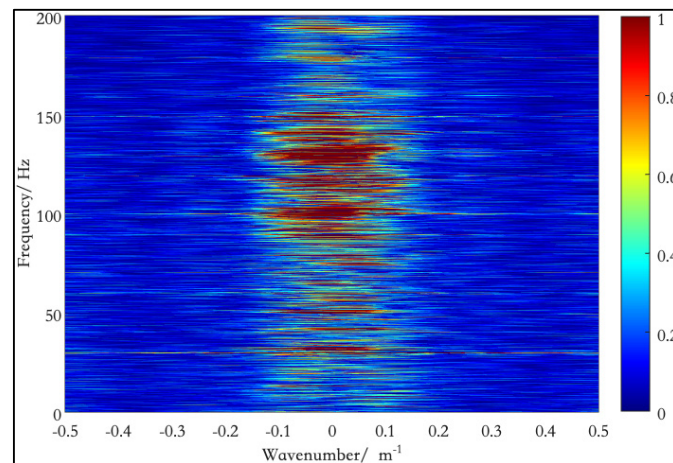


Figure 4. f–k spectrum of DAS signals at 10 m³/h.

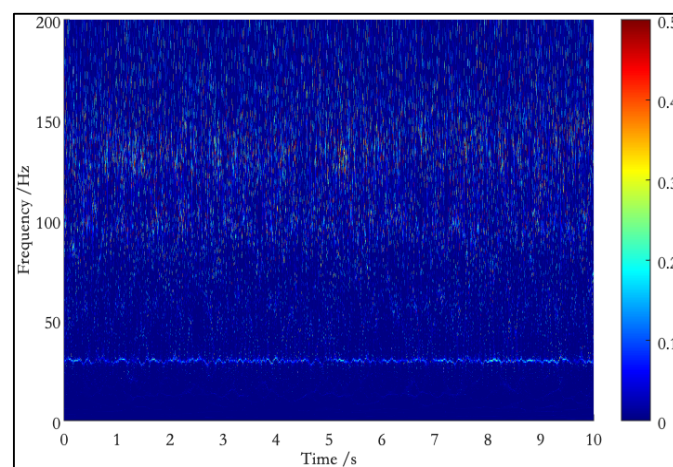


Figure 5. WSST analysis at 10 m³/h (3 m pipeline location).

PSD analysis of the 3 m signal (Figure 6) corroborates the WSST findings. The spectral distribution confirms that the dominant energy resides near 35 Hz, with secondary harmonics appearing at higher frequencies. The presence of harmonics suggests nonlinear coupling between the pump excitation and the turbulent structures within the pipe. Furthermore, the PSD amplitude increases systematically with flow rate, indicating a direct link between flow energy input and vibrational response. Compared to WSST, PSD provides a more concise summary of frequency content, making it particularly useful for developing quantitative flow metrics.

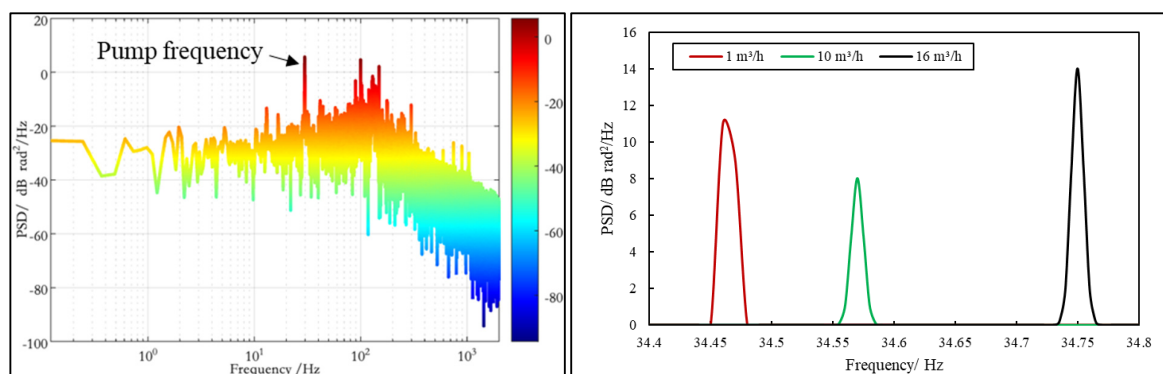


Figure 6. PSD at 10 m³/h (3 m pipeline location).

The cumulative PSD values across different flow rates, excluding the narrow region around the pump fundamental frequency (~ 3 Hz bandwidth), are plotted in Figure 7. The results clearly show that the integrated PSD rises monotonically with increasing flow rate. The trend is approximately linear, suggesting that total vibrational energy captured by the fiber is proportional to the kinetic energy of the fluid flow. This finding is consistent with theoretical expectations, as higher velocities generate greater turbulence and pressure fluctuations, which in turn induce stronger pipe-wall vibrations. The integrated PSD thus provides a reliable proxy for flow intensity and can be used as an input feature for predictive models.

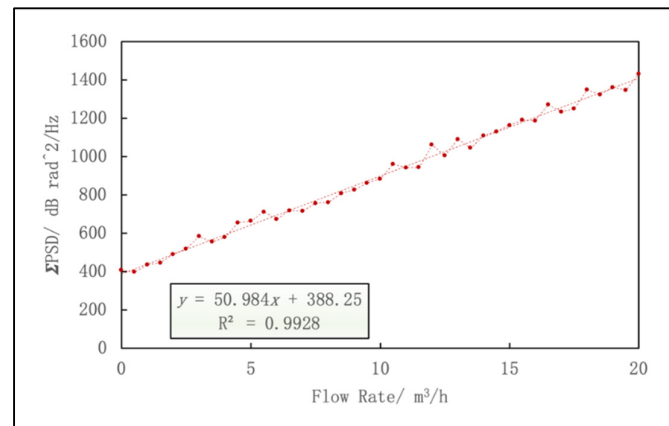


Figure 7. Integrated PSD at different flow rates (3 m pipeline location).

The dominant frequency evolution with flow rate was analyzed at 3 m, 4 m, and 5 m positions along the pipeline (Figure 8). A consistent negative shift in the dominant frequency was observed as the flow rate increased. This phenomenon can be attributed to the Doppler effect, whereby relative motion between the vibrating fluid structures and the sensing fiber induces a measurable frequency shift. While the nominal pump frequency is directly proportional to flow rate, the experimentally observed negative drift suggests that the flow field modulates the apparent frequency due to convective transport effects. This counterintuitive behavior strongly indicates that the dominant frequency shift can serve as a diagnostic feature for flow velocity estimation.

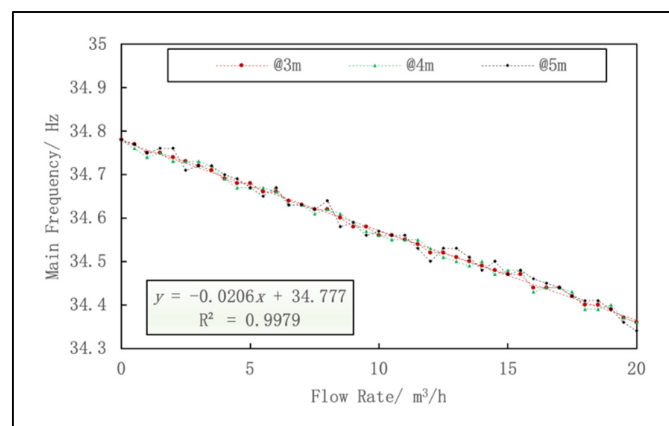


Figure 8. Dominant frequency versus flow rate.

Mathematically, the Doppler-induced frequency shift can be expressed as:

$$f' = f_0 \left(1 - \frac{v}{c} \right), \quad (3)$$

where f' is the observed frequency, f_0 is the pump excitation frequency, v is the flow velocity, and c is the effective propagation velocity of acoustic waves in the pipe–fluid system. Rearranging yields:

$$v = c\left(1 - \frac{f'}{f_0}\right). \quad (4)$$

By fitting the observed dominant frequency shift against the known flow rates, a regression model was developed to predict liquid flow velocity. The regression analysis yielded a coefficient of determination (R^2) of 0.9928, indicating excellent agreement between predicted and measured flow rates.

4. Discussion

The experimental data confirm that DAS technology effectively functions as a distributed vibration sensor array capable of detecting fluid–structure interactions along the pipeline. Time-domain analysis indicated that signal amplitude and coherence were significantly higher in the section where the optical fiber was tightly bonded to the pipe wall compared to loosen sections. This observation validates that the sensing mechanism relies primarily on the transfer of strain from the pipe wall to the fiber, driven by hydrodynamic pressure fluctuations and mechanical vibrations from the pump system. The spectral analysis revealed that the acoustic signature is dominated by the pump’s fundamental frequency and its harmonics, suggesting a strong coupling between the mechanical excitation source and the fluid column. Unlike point sensors that measure local fluid properties, DAS captures the structural response integrated over the gauge length, providing a continuous profile of the flow-induced vibration field.

A systematic analysis of the PSD demonstrates a clear linear dependency between the integrated spectral energy and the liquid flow rate. Physically, this relationship can be attributed to the increase in turbulent kinetic energy associated with higher flow velocities. As the Reynolds number increases, the intensity of wall-pressure fluctuations rises, transferring more energy to the pipe structure, which is subsequently detected by the fiber. Although the integrated PSD provides a straightforward metric for flow estimation, it is sensitive to the mechanical coupling quality between the fiber and the pipe. Variations in installation or environmental noise could potentially offset the energy baseline, suggesting that while PSD indicates flow intensity, it may require calibration for different installation conditions.

Beyond energy amplitude, the results identified a deterministic negative shift in the dominant vibration frequency as the flow rate increased. The study attributes this phenomenon to the Doppler effect, where the relative motion of the fluid medium modulates the frequency observed by the stationary sensing fiber. The regression model based on this frequency shift yielded a coefficient of determination of 0.9928. This indicates that frequency-domain features offer a robust parameter for velocity prediction. Unlike amplitude-based metrics, the frequency shift is less dependent on the intensity of the signal or the efficiency of the fiber-pipe coupling, making it a potentially more stable indicator for quantitative flow metering.

The limitations of the experimental scale were evident in the frequency-wavenumber f – k analysis. No distinct velocity dispersion ridges were observed in the f – k spectrum. This is attributed to the limited length of the test section (7 m) relative to the spatial resolution (1 m) of the system, which resulted in an insufficient aperture to resolve the wavenumber components of the propagating waves. While f – k processing is effective in long-distance seismic or pipeline monitoring applications for tracking convective eddies, this study suggests that for short-scale or localized metering sections, spectral analysis of dominant frequencies is a more applicable method.

From a theoretical standpoint, the Doppler effect formulation presented in Equation (3) predicts that the sign of the frequency shift is directly dependent on the flow direction. Specifically, when the fluid moves away from the sensing fiber, the observed frequency decreases ($f' < f_0$), producing the negative shift consistently observed in the present experiments. Conversely, if the flow direction were reversed such that the fluid moves toward the fiber, the formulation predicts a positive frequency shift ($f' > f_0$) of comparable magnitude. This directional dependence is an inherent property of the Doppler mechanism and would serve as strong additional evidence distinguishing the observed spectral displacement from other flow-dependent phenomena, such as changes in turbulence spectrum or structural resonance shifts. However, the current experimental apparatus incorporates a check valve that restricts flow to a single direction, precluding direct verification of this prediction within the present study. Future work will involve modifying the flow loop to enable bidirectional operation, thereby allowing experimental confirmation of the sign reversal in the Doppler shift. Such validation would further consolidate the physical basis of the proposed method and demonstrate its potential for identifying flow direction, which is of practical significance in pipeline operations such as detecting reverse flow or verifying flow routing in complex networks.

The findings support the feasibility of using DAS for non-intrusive flow measurement. By converting standard optical fibers into continuous acoustic sensors, the technology avoids the need for fluid contact or flow disruption, addressing the limitations of conventional intrusive flowmeters. The passive nature of the optical fiber also provides advantages in harsh environments where electronic sensors may fail. However, the current study focused on single-phase flow in a controlled laboratory environment. Future research is necessary to investigate the applicability of this spectral-shift method in multiphase flow regimes and to verify its stability under varying field conditions where background noise and temperature fluctuations are more significant.

5. Conclusions

This study demonstrates that DAS can effectively capture liquid flow-induced vibrations in pipelines. Time- and frequency-domain analyses revealed that the dominant energy was concentrated at the pump operating frequency, with additional dispersive features. The integrated PSD showed a strong linear dependence on flow rate, while Doppler-induced frequency shifts enabled the construction of a regression model with excellent predictive accuracy. These findings confirm that DAS, combined with advanced spectral analysis, provides a reliable and non-intrusive method for monitoring and predicting single-phase liquid flow rates.

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