CAAP Quarterly Report

12/30/2021

Project Name: Easy Deployed Distributed Acoustic Sensing System for Remotely Assessing Potential and Existing Risks to Pipeline Integrity

Contract Number: 693JK3215002CAAP

Prime University: Colorado School of Mines

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Reporting Period: [09/30/2021 – 12/30/2021]

Project Activities for Reporting Period:

The major activities completed during this period are summarized as below:

1. The project kick-off meeting was held on 10/26/2021.
2. Two Ph.D. students were interviewed and hired for this project. Ana Garcia-Ceballos (Ph.D. student in Geophysics at Mines, advisor Dr. Ge Jin) and Mouna Keltoum Benabid (Ph.D. student in Petroleum Engineering at Mines, advisor Dr. Yilin Fan) will both start in 2022 Spring.
3. Initial research has been done to address the questions raised during the kick-off meeting. That includes:
    a. The necessity of Task #2 (Detection of Dynamic Intermittent Flow). To address this problem, the PI consulted several experts in the midstream industry. In summary, undulating configurations commonly occur in gas gathering and transmission pipelines. These undulations can lead to intermittent flow that can accelerate corrosion/erosion due to the higher contact area between the liquid phase and pipe wall, high shear stresses, flow-induced pressure fluctuations and vibrations. Point pressure sensors at the compressor station may not be able to monitor the pressure fluctuations due to gas compressibility and the long distance between the slugging location and the compressor station. In another words, even though point sensors at the compressor station show stable pressures, it does not mean that there is no slugging in the pipeline system. DAS (Distributed Acoustic Sensing) has the potential to localize these hidden slugging regions that are missed by the point sensors, so that operators can pay more attention to these regions with higher risks. Details are explained in the Appendix, including what intermittent flow is, how it impacts corrosion/erosion, and why it cannot be monitored and controlled by the point sensors and control valves at the compressor stations for gas transmission pipelines.

b. The operating range of the tasks should be realistic to the actual field conditions. During this period, the PI has consulted several experts in the midstream industry regarding the actual operating conditions in the field. For example, in Colorado, low-pressure gas gathering pipelines (approximately 30 ~ 150 psi) commonly carry volumes ranging from a few MCFD to 30 MMSCFD approximately. High-pressure gas transmission pipelines (approximately 400 ~ 1600 psi) can carry high volumes in the neighborhood of 1 BSCFD. In our project, the gas velocity to be investigated as proposed is up to 18 m/s approximately. This velocity is equivalent to 2.5 BSCFD for a 36-in. pipe at 1000 psi, 1.1 BSCFD for a 24-in. pipe at 1000 psi, or 276 MMSCFD for a 12-in. pipe at 1000 psi. These pipe sizes are common for gas transmission pipelines. For gas gathering pipelines, this velocity is equivalent to 3.5 MMSCFD for a 4-in. pipe at 100 psi, or 1.35 MMSCFD for a 4-in. pipe at 30 psi. For the liquid velocity to be investigated in Task #2, it is equivalent to approximately 0.3 ~ 4.8 gal/MMCF for a 4-in. gas gathering pipeline at 30 psi, or 0.001 ~ 0.02 gal/MMCF for a 12-in. gas transmission pipeline at 1000 psi. Please note that the liquid volume in the actual field varies significantly from field to field. It also depends on the pigging frequency. In short, the gas and liquid velocities to be investigated in our project fall inside the actual operation range in the field.

c. Question: If the flow path in the larger sizes of pipelines would be affected by a shallower dents? Answer: All sensors have measuring upper and lower limits, and so does DAS. In Task#4, we will try different dent depths and see how DAS responds. We will not be able to test different pipeline sizes, but theoretically, we will know the dent depth/diameter ratio beyond which DAS can diagnose.

d. Question: It was proposed to test DAS sensors on damage detection using a test setup with pipe supports. Pipeline support is the design for aboveground pipelines, would confirm if Task 5 is only to test aboveground pipelines. For belowground pipelines, if the results could be applied and how to apply. Answer: Task#5 is only for aboveground pipelines. The results are not applicable for underground pipelines. We will look at the "underground" scenario in task#6 on leakage detection, which may induce some changes to the surroundings. We can see if DAS can monitor these changes, but cannot guarantee at this point.

4. Actions taken in this period to prepare for the experimental work:
   a. Preliminary training on facility operation and data acquisition performed for the PI and co-PI.
   b. The PI and co-PI met with the Edgar Mine's manager and crews, discussed potential concerns, and acquired agreements on running the experiments as proposed using the utilities at the Edgar Mine.
   c. We have contacted some companies on the required cables and delivery is expected soon.
   d. We discovered some connection problems for the air control valve and the data acquisition system (LabVIEW™), and are working to fix these problems.
5. Preliminary data processing training for the Distributed Acoustic Sensing signals was organized and completed.

In the original proposal, we planned for facility modification and preparation during this period. Overall, the activities completed during this period meet the current expectations and those in the original proposals.

Project Activities with Cost Share Partners:

The cost shares are the AY efforts of the PI and co-PIs. Activities are the same as above.

Project Activities with External Partners:

No external partners.

Potential Project Risks:

1. Since the project started immediately after the announcement, we did not have a chance to hire students in advance. The two Ph.D. students hired for this project will start their studies in 2022 Spring. Due to this timing, we anticipate a slight delay to the timeline proposed in the original proposal. However, it is still possible to complete everything before 09/29/2024 (the end date of the project). The adjusted timeline is provided in the next section.
2. There is a possibility of delay due to weather, especially during the snow season. Edgar Mine will be closed if there is heavy snow for safety concerns. In such a case, the students will not be able to work at the Mine during that period. Please note that the weather will not damage our facilities and equipment since they are inside the Mine.

Future Project Work:

We adjusted the timeline slightly according to the current situation, as given below:

Tasks	**Year 1**				**Year 2**				**Year 3**			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	2021	2022				2023				2024		
	O-D	J-M	A-J	J-S	O-D	J-M	A-J	J-S	O-D	J-M	A-J	J-S
Task#1. Detection of Liquid Accumulation at Pipeline Lower Spots												
1.1 Facility modification and preparation												
1.2 Flow loop test without liquid accumulation												
1.3 Flow loop tests with liquid accumulation												
Task#2. Detection of Dynamic Intermittent (Slug) Structure												
2.1 Flow loop tests with Interminttent Structure												
Task#3. Detection of Corroded Spots on Pipeline Interior												
3.1 Facility modification and preparation												
3.2 Lab tests of corrosion using speciman to determine acid type, concentration, and corrosion rate												
3.3 Flow loop test in buried pipe												
3.4 Flow loop test in unburied pipe												
3.5 Flow loop test in densely supported pipe												
3.6 Flow loop test in sparsely supported pipe												
Task#4. Detection of Dent/Deformation on Pipeline												
4.1 Flow loop test in buried pipe												
4.2 Flow loop test in sparsely supported pipe												
Task#5. Detection of Infrastructure Damage												
5.1 Flow loop test in densly supported pipe												
5.2 Flow loop test in sparsely supported pipe												
Task#6. Detection of Leakage												
6.1 Flow loop test in buried pipe												
6.2 Flow loop test in sparsely supported pipe												

In the next 30 days, we will:

1. Order the PVC pipe for Tasks #1&2.
2. Train the two new students on facility operation.
3. Fix the problems of the air control valve and connect it to the data acquisition system (LabVIEW^{TM}).
4. Modify the inlet section of the current facility for this project.

In the next 60-90 days, we will:

1. Start building the test section for Tasks #1&2.
2. Start the lab tests for Task #3, determining the acid type and concentration for the flow loop tests.
3. Train the two new students on DAS preparation and data acquisition.
4. Train the two new students on DAS and flow loop data processing.

Potential Impacts to Pipeline Safety:

During this period, we performed a literature review and consulted experts in the midstream on the corrosion/erosion induced by the intermittent flow. Please see the Appendix for detailed explanations.

Appendix A. Necessity of the detection of dynamic intermittent flow in gas gathering and transmission pipelines

What are the common dynamic intermittent flow in gas gathering and transmission pipelines?

Intermittent flow (INT) includes plug flow (PL), slug flow (SL), and pseudo-slug flow (PS), in which gas and liquid phases are transported in an intermittent manner. These are commonly observed in gas gathering and transmission pipelines when gas and liquid coexist in the system, especially in undulated pipelines when liquid accumulation occurs. Figure 1 shows typical flow pattern maps for two upward inclination angles, namely 0.03° and 0.1°, predicted by one of the widely used mechanistic model[1] in the oil and gas industry. Even a small increase of inclination angle from horizontal can change the flow pattern map dramatically, i.e., the range of intermittent flow expands significantly because of the gravity and liquid accumulation. In the field, no pipe is perfectly horizontal. And intermittent flow very commonly occurs in oil and gas pipelines due to the undulations.

Intermittent flow has been identified as the most disastrous flow pattern that can accelerate pipe corrosion and erosion by various researchers, which are discussed in detail in the next section. For small-inclined pipes, it mainly occurs due to the slow gas flow rate that is incapable of transporting liquid continuously in upward inclined pipes, as reflected in Figure 1. This mechanism is further explained in Figure 2, in which (a) and (b) show the schematic and picture of stratified flow that occurs at higher gas flow rates; while (c) and (d) show the schematic of intermittent flow formation and a picture of intermittent flow structure that occurs at a lower gas flow rate. The links to the corresponding video are provided in the title. Please note that the videos were recorded using a high-speed camera and played in slow motion. The experiments were conducted by the PI previously for another project. It is important to mention that the liquid flow rates in both videos are the same, at ~0.36 GPM. It can be noticed that liquid accumulation results in a dramatic increase of liquid volume in a pipeline. This can worsen corrosion and erosion and is explained in the next section.

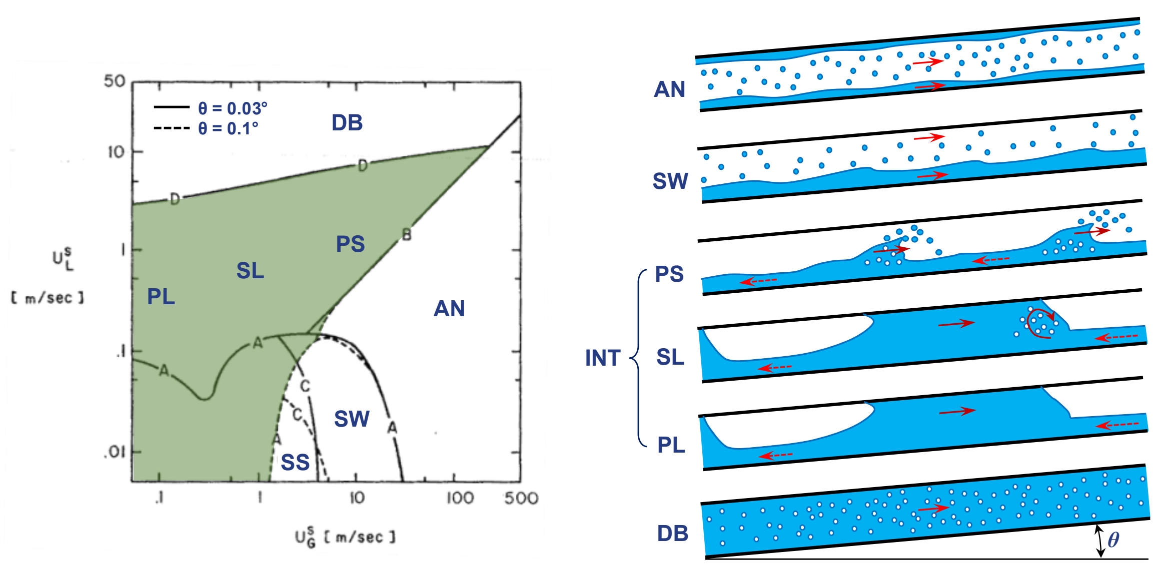

Figure 1. Flow pattern map predicted by Taitel and Dukler (1976) model for gas-liquid two-phase flow in 0.03° and 0.1° upward inclined pipes (The green region is where intermittent flow occurs in a 2-in. 0.1° upward inclined pipe) (AN: annular flow; SS: stratified smooth; SW: stratified wavy flow; INT: intermittent flow, which includes PS, SL, and PL; PS: pseudo-slug flow; SL: slug flow; PL: plug flow; DB: dispersed bubble flow) (the x-axis is gas superficial velocity, defined by the in-situ gas volumetric flow rate divided by the pipe cross-sectional area; the y-axis is the liquid superficial velocity, defined by the in-situ liquid volumetric flow rate divided by the pipe cross-sectional area)

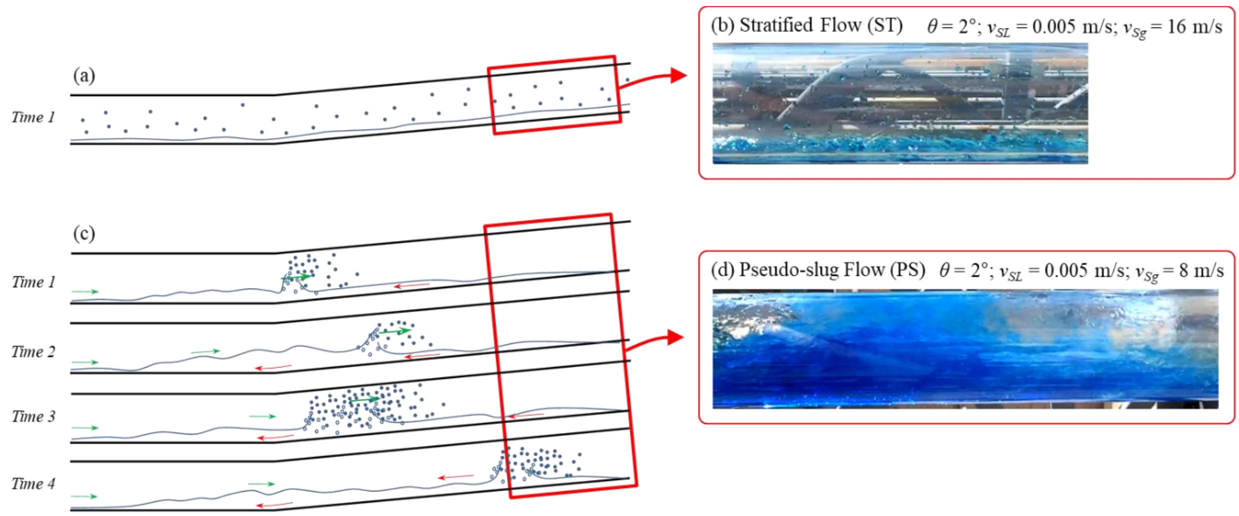

Figure 2. (a) Schematic of stratified flow; (b) a picture of stratified flow (slow-motion video link: https://drive.google.com/file/d/1EGcTXsM5r6C8UZqnrZKtaxUFp_ZtZ6SZ/view?usp=sharing); (c) schematic of intermittent flow formation in an inclined pipe[2]; (d) a picture of an intermittent flow structure (slow-motion video link: https://drive.google.com/file/d/1EI5T-qk3ENiWeF3RpJrDbSAoiANUg7YA/view?usp=sharing).

How does intermittent flow impact corrosion and erosion?

As shown in the video, gas and liquid flow intermittently when intermittent flow occurs, inducing oscillated/fluctuated shear stresses on the pipe wall, pressure fluctuations, and vibration. Figure 3 shows an example of pressure fluctuations at three locations in a facility with a valley configuration. The PI obtained the data for another project. It is worth mentioning that the flow patterns in the downhill (~10m long) and horizontal section (~19m long) are both stratified flow, and it is pseudo-slug flow in the uphill section (~10 m long). The corresponding flow behavior in the uphill section is shown in Figure 2(d), and the video link is in the title. The pressure fluctuations at P1 are because of the intermittent structures in the uphill section.

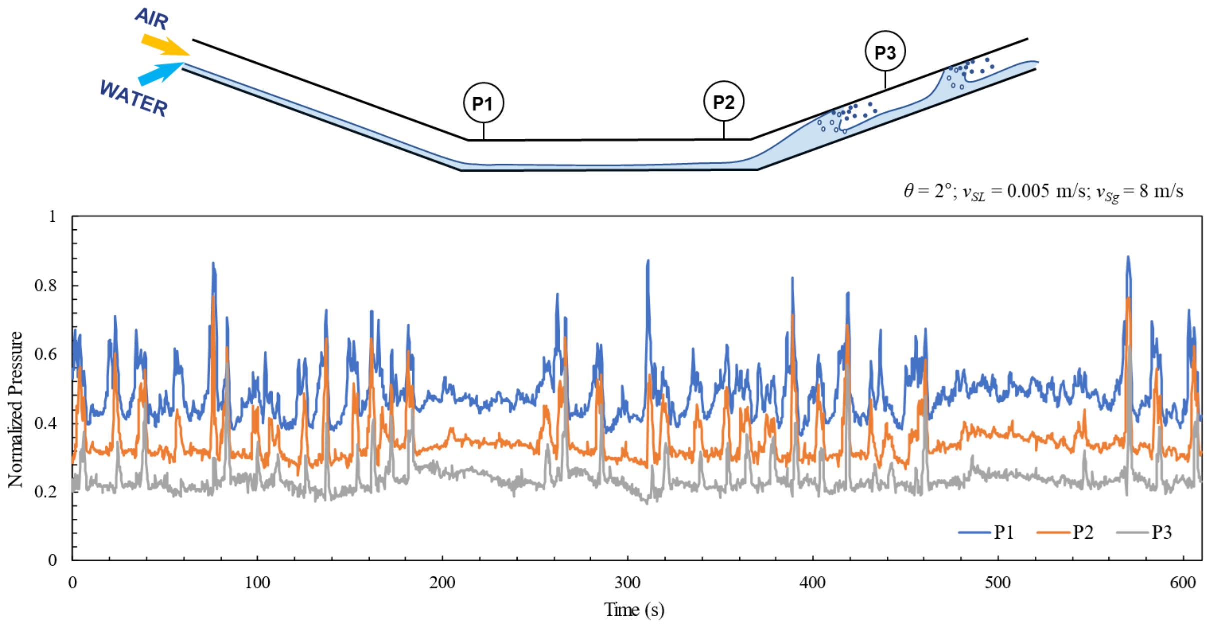

Figure 3. Normalized pressure fluctuations at three locations in a pipeline with a valley configuration when intermittent flow occurs in the uphill section

One of the factors that impact significantly pipeline corrosion and erosion is the contact area between the pipe wall and the liquid phase, which determines the mass transfer rate of ferrous ions. Previous studies have shown that the more area wetted by the liquid phase, the higher the corrosion rate[3,4]. This explains why corrosion/erosion is faster and more severe for oil pipelines than gas pipelines. However, when the gas pipeline is operated under intermittent flow conditions, the liquid phase is accumulated in the uphill section, moving upward and downward, as shown in Figure 2(d). The liquid volume can be very high. It can wet the entire pipe wall and therefore accelerate the corrosion/erosion rates.

Intermittent flow can also worsen corrosion/erosion because of its fast-moving structure, which accelerates and scoops up the slow-moving liquid film ahead of it into the mixing zone where an eddy is created (Figure 4). The structure velocity reaches the highest near the flow pattern transition from conventional slug (SL) to pseudo-slug flows (PS)[5], as indicated by the red box in Figure 4(c). According to [4], "the existence of slug flow and its propagation in multiphase oil and gas production pipelines can reduce the effectiveness of a corrosion inhibitor film due to the highly turbulent flow characteristics in the mixing zone." Some studies [6,7] have shown that "there are regions of high shearing forces which destroy the liquid boundary layer close to the wall, making the formation of a stable inhibitor film difficult. Further, it may be possible to strip off the film and corrosion material that is already present." Previous studies have also shown that corrosion/erosion rates increase with increasing shear stresses (i.e., velocities) [3,4,8].

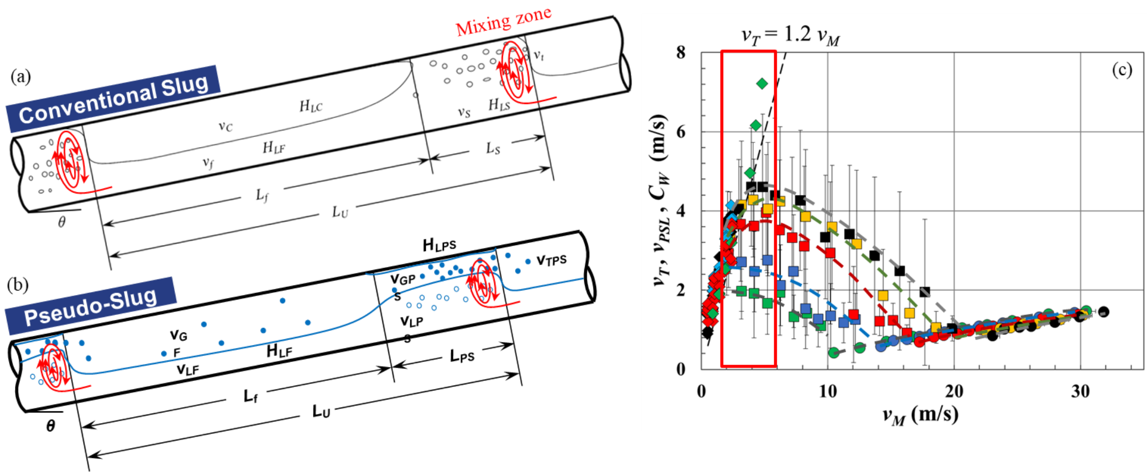

Figure 4. Pressure fluctuations at three locations in a pipeline with a valley configuration when intermittent flow occurs

Another factor that can further accelerate corrosion/erosion is the flow-induced oscillation/vibration, and pressure fluctuations (Figure 3). As mentioned in our original proposal, "pressure cycles may not lead to the initiation of cracking but can significantly contribute to its growth" [9]. One question raised during the kick-off meeting is: can the pressure fluctuation be eliminated by the controlling systems at the compressor station for gas transmission pipelines? The answer is given separately in the next section.

Can the pressure fluctuation induced by hydrodynamic intermittent flow in the gas transmission pipeline be controlled?

The gas transmission pipeline is long. It is common that the location where slugging (or intermittent structure) occurs far downstream from the compressor station (Figure 5). Since the gas is compressible, the pressure fluctuation at the slugging location may not be effectively monitored by the pressure sensors at the compressor station, i.e., the pressure may not be able to propagate such fast and far away because of the compressibility of the gas. In another words, although point pressure sensors at the compressor station show stable pressures, it does not mean that there is no pressure fluctuations/oscillations in the pipeline. If there is any choke between the slugging location and compressor station, it will further hinder the pressure propagation from downstream to upstream of the choke if the gas is flowing at the critical condition.

Despite the ineffectiveness of pressure propagation, it is known that the slug flow induced pressure fluctuation happens so fast. For example, it can be up to 0.2 s^{-1} for a 3-in. 2° upward inclined pipe, and it increases with liquid flow rate and inclination angles[5]. The PI's experience is that it is almost impossible to keep the pressure constant even in the laboratory using an industry-standard controller because of the fast pressure fluctuations induced by hydrostatic slugging. This means that, even the pressure sensors at the compressor station can monitor the pressure fluctuations in the pipeline, the control valve cannot respond fast enough to maintain a constant pressure.

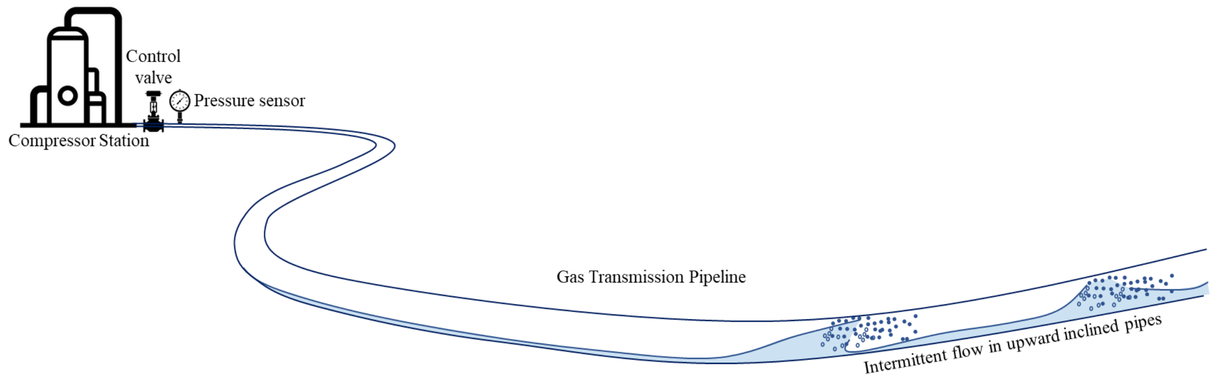

Figure 5. Location of intermittent structure can be far away from the compressor station

In summary, accurately identifying the intermittent flow/structures and their characteristics in gas gathering and transmission pipeline are essential to pipeline integrity management. The advantages of using DAS, in this case, are obvious compared to the point sensors, since it can provide continuous monitoring along the entire pipeline, and therefore potentially unveil the hidden risky region, such as the slugging region, which could be ignored by the point sensors.

Reference

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