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**Review Article**

# Fundamentals of Hydrotest Requirements and Methodological Approach

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**ABSTRACT**

*Nowadays, existing pipelines are being hydrotested to demonstrate fitness for service due to difficulty in inspecting with conventional in-line tools resulting from flow condition, pipeline configuration and lack of pigging facility. Pipeline operators still view hydrotest as a difficult operation because of lack of robust methodological approach and difficulty in meeting hydrotest and dryness acceptance criteria. The present study considers detailed overview of hydrotest procedure, acceptance criteria and critical parameters such as entrapped air, water compressibility and temperature that influence hydrotest result. These parameters have formed the basis for measuring acceptance criteria of hydrotest result. Maximum allowable air volume in pipeline to meet hydrotest acceptance criteria is 0.2 percent while maximum allowable leftover water after dewatering is 4 percent volume of pipeline. But the dryness criteria for sales gas is a minimum of -20$^{o}$C dew point. Mobilization of adequately rated and calibrated test equipment and effective implementation of procedure would enhance hydrotest, dewatering and dryness results.*



## 1. INTRODUCTION

The first ever hydrotest of long-distance pipeline with water in 1950 by Texas Eastern Transmission Corporation marked the beginning of hydrotest in the oil and gas industry (Castaneda and Pratt, 1993). Hydrotest is a process that involves filling a pipeline system with water or gas and then pressuring it over its maximum allowable operating pressure (MAOP) within the range of 110 to 150 percent of MAOP (ASME, 2004). New pipelines are usually hydrotested during pre-commissioning phase to check for leak and integrity of welded joints and construction materials while existing pipelines are tested to demonstrate fitness for continued service (Guo et al., 2005; Anderson and Thorwald, 2016). The oil and gas industry, nowadays, accepts hydrotest as one of the assessment methods for verifying integrity and demonstrating fitness for continued service for pipelines that have been in operation for years. But in the past, it was not a standard practice (Rosenfeld and Gailing, 2013). Experience has shown that hydrotest mostly serves as an alternative method for pipelines that are difficult to pig with conventional in-line inspection tools due to various reasons ranging from lack of pigging facility, low flow rate and presence of bends lesser than 1.5D (NACE, 2000).

All difficult to pig pipelines can be technically inspected with in-line inspection tools either after some major or minor piping modifications, which are often not economically viable. Thus, it is difficult to make a business case to carryout modification. Pipelines hydrotest has been accepted as means of assessment method, nevertheless, there are still challenges of robust material requirement details, unavailability of clean water, entrapped air and lack of detail methodological approach (Keifner, 2001). Consequently, hydrotest acceptance criteria are difficult to achieve and hydrotest operators sometimes limit testing below 100 percent maximum allowable operating pressure (Shires and Harrison, 1988). In addition, the technical code and standard documents such as American Society of Mechanical Engineers (ASMEs B31.8, B31.4) and American Institutes of Petroleum (API 1110) only provide guidelines to hydrotest (Jacob, 2013). The aim of the present work is to provide a robust hydrotest methodological approach and in-depth knowledge to enhance hydrotest, dewatering and dryness results. The work would guide pipeline operators to draft comprehensive project execution plan and perform hydrotest that would meet acceptance criteria.

## 2. BENEFITS AND LIMITATIONS

One of the benefits of subjecting pipelines to hydrotest pressure is removal of most severe flaws that could fail at operating pressure and ensure that remaining flaws are well below the operating pressure to provide a margin of safety (Anderson and Thorwald, 2016). Additional benefits include modification of geometrical anomalies such as dents and relief of residual stresses if the test pressure is high enough to induce plastic strain, which may minimize likelihood of crack growth during operation. Apart from the benefit of strength and leak check, hydrotest water weight may compress soft soil on seabed and reduce short free span (Kirkwood and Cosham, 2000). On the other hand, hydrotest pressure could cause lateral buckling of pipelines that would ordinarily not happen under lower operating pressure and the hydrotest water weight could lead to unacceptable stresses at long free span that may be acceptable under gas fill service condition (Carr and Nash, 2014). The limitations also include potential pipeline rupture during excessive high-test pressure with huge consequences of economic impact (Anderson and Thorwald, 2016). Furthermore, hydrotest water require chemical treatment which are very expensive, and the pipelines need to be dewatered and possibly dried after hydrotest to prevent corrosion and hydrate formation. Report has shown that pipelines subjected to several hydrotest pressure had suffered pressure reversal phenomenon that cause growth of flaw, which then fail at second pressure test that is lower than the first test pressure (Keifner et al.,1980).

## 3. TEST METHOD

### 3.1. Test Material

Basic materials required on site to perform hydrotest ranging from pump spread and test instrument are provided in Table 1 and Table 2 respectively (DEP, 1994). A typical equipment set up for hydrotest is shown in Figure 1. The test instruments are usually calibrated to ensure measurement accuracy.

Table 1: Pump spread and fittings

| Equipment | Use |
|---|---|
| Lift pump | Lift water from sea or creek into break tank |
| Flood pump | Fill test section with water from break tank |
| Test pump | Pressurize test section to desired test pressure |
| Air Compressor | power pumps that are not diesel driven |
| Chemical injection pumps | Inject biocide, scavenger and corrosion inhibiter into test section |
| Filtration skid | Filter debris from water to a minimum of 50 microns |
| Break tank | Keep pumps constantly on load |

| | |
|---|---|
| Temporary manifold | Build with several sizes offtakes to allow instrument and pumps' connection |
| Discharge/suction hoses | Various sizes of hoses to connect pumps to break tanks, filter skid and test section |
| Set of crossover spool piece, 90- or 45-degree reducing elbows and adapter fittings | Connect test section to instruments, fill and test pumps |
| Check valves, ball valves and needle valves | Various sizes of valves to allow replacement of instrument or equipment during hydrotest and venting points |

Table 2: Test instrument

| Instrument | Use |
|---|---|
| Filling flowmeter | Measure and record fill volume of water into test section |
| Pressurizing flowmeter | Measure and record injected volume of water into test section |
| Pressure relieve valve set at 5% above test pressure | Prevent over pressurization of test section above test pressure or MAOP |
| Deadweight tester | Measure and record pressure with accuracy of $\pm 0.05\%$ |
| Pressure gauge | Measure and record pressure with accuracy of $\pm 0.6\%$ |
| Pressure chart recorder | Measure and record pressure with accuracy of $\pm 1\%$ |
| Ambient air temperature recorder | Measure and record ambient temperature with accuracy of $\pm 1\%$ |
| Pipeline temperature probes and recorders | Measure and record subsea and soil temperature with accuracy of $\pm 0.2\%$ |

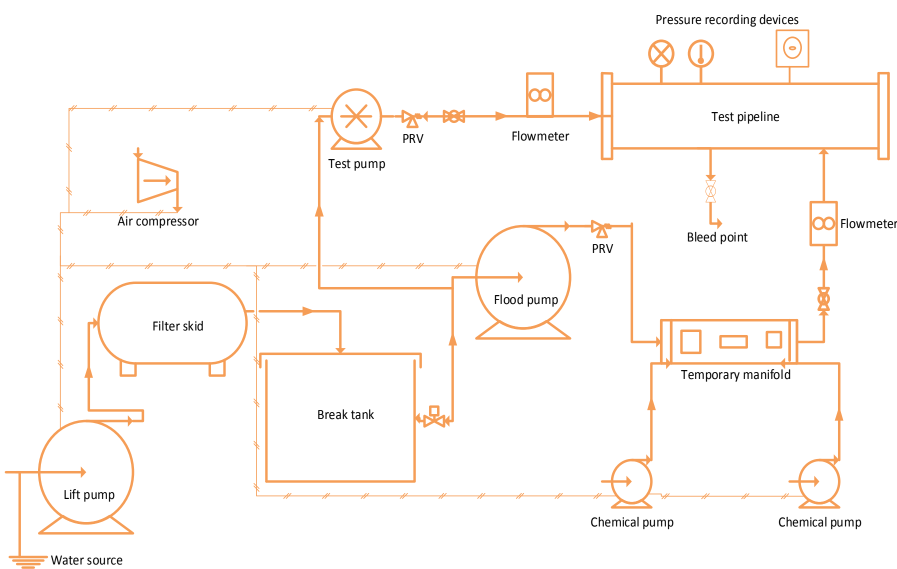


Figure 1: Equipment arrangement set up schematic

### 3.2. Water Treatment

All natural water contain oxygen and bacteria which vary in concentration from location to location (Dexter and Culberson, 1980; Darwin et al., 2010). The presence of bacteria colonies results in microbially induced corrosion while oxygen presence results in pitting corrosion due to oxygen differential concentration

(Frankel, 2003; Sogin et al., 2006). However, corrosion resulting from oxygen differential is no longer considered a major threat to carbon steel because oxygen is rapidly consumed within a closed system after two days (Penkala et al., 2010). Therefore, the philosophy of adding oxygen scavenging chemicals alongside biocide and corrosion inhibiting chemicals into hydrotest water is no longer considered because of cost and compatibility issues (Penkala et al., 2010). Thus, hydrotest water treatment may only require biocide and corrosion inhibitors except the hydrotest water will be left in the test section for more than 30 days or will not be completely dewatered (Moloney, 2011).

### 3.3. Pre-hydrotest Check

Prior to function testing of pumps, filling the test section and conducting hydrotest, basic checks are carried out after satisfactory completion of rigging up of pump spread and auxiliary equipment. The checks to be conducted include but not limited to the following (Palmer, 2004):

i. Examine all bolts connection points to ensure proper tightness.
ii. Verify that all required vent ports to vent air are opened during pipeline fill.
iii. Verify that pipeline volume is filled, vent and drain ports are plugged prior to pressurization.
iv. Verify that downstream and upstream valves that are used as isolation points are opened to the atmosphere.
v. Verify that temporary test manifold units are properly installed and tested.
vi. Verify that pumps and compressors are in good working condition.
vii. Verify that all calibrated instruments for measuring temperature, pressure, volume including pressure relieve valves are validated and ready for use.

### 3.4. Hydrotest Sequence

On completion of pipeline fill and removal of trapped air, the following procedural sequence is usually adopted in conducting hydrotest after satisfactory completion of the pre-hydrotest checks (API 2013; Palmer, 2004):

i. Conduct pressure test on connected temporary fittings up to 1.5% above test pressure and hold for about 10minutes.
ii. Apply incremental preliminary pressure at 15%, 30%, and 45% of the test pressure and hold the pressure for about 10 minutes to check for leaks and estimate volume of air presence.
iii. If leaks are detected during preliminary test pressure, locate the leaks, depressurize pipeline to zero pressure and address the leaks by tightening properly or repairing failed section.
iv. If leaks are not detected and volume of air is less 0.2%, continue application of pressure in increment of 25 psi every 2 minutes up to about 2% above test pressure.
v. Record readings of pressure, temperature, injected volume and test pump stroke counter at interval of 15 minutes throughout incremental pressurization period.
vi. Isolate the pipeline and stop the test pump after reaching maximum test pressure.
vii. Hold the maximum test pressure for either 8 hours or 24 hours as required by regulation and continue monitoring and recording pressure readings from deadweight tester and chart recorder until test is terminated.
viii. Pressure could drop few minutes after reaching the maximum test pressure and then hold subsequently due to trapped air absorption and drop in ground temperature. However, if the pressure drops significantly before holding, then resume application of pressure, recording of injected volume and pressure until maximum test pressure is reached.
ix. Upon satisfactory completion of test, gradually depressurize pipeline to zero pressure, rig down and demobilize equipment.

## 4. ACCEPTANCE CRITERIA

Fundamental factors such as entrapped air, compressibility of water and temperature effect have significant influence on hydrotest results. Thus, these factors have formed the basis for hydrotest acceptance criteria.

### 4.1. Entrapped Air

Unabsorbed air in pipelines has significant impact on hydrotest operation that may invalidate results due to compressibility of air. The unabsorbed air may be removed either by running pig under control speed, control flushing or venting at high points during pipeline fill (Russell, 2005). Acceptance criteria for remaining volume of air not absorbed into the hydrotest water shall be less than 0.2% of the pipeline volume (CSLC, 2003). The remaining volume of air may be computed with either Equation (1) or Equation (2).

$$A\% = 100\frac{(P_1 \, x \, P_2)}{14.7(P_2-P_1)} \, x \left[\frac{\Delta V}{V} - (P_2 - P_1)\left(0.0303 \, x \, 10^{-6}\frac{D}{t} + C\right)\right] \quad (1)$$

where, $A\% =$ percentage of remaining air volume in pipeline; $\Delta V =$ incremental volume of water injected or bled off from the test section between $P_1$ and $P_2$; $P_1$ and $P_2$ =absolute pressure before and after change in volume; $V =$ volume of fill test pipeline; $D$ =outside diameter of pipeline; $t =$ pipeline wall thickness and $C =$ compressibility of test fluid which is between $3 \, x \, 10^{-6} \, to \, 3.5 \, x \, 10^{-6}/psi$ and usually taken as the reciprocal of modulus of steel elasticity.

$$A\% = 100\frac{S_a - S_t}{V}V_P \quad (2)$$

Where, $S_a$ =actual number of pump stroke counter to 20 bar, $S_t =$ theoretical number of pump stroke counter to 20 bar and $V_P$ =volume per pump stroke counter.

### 4.2. Water Compressibility

Expansion and contraction of water which affect rate of volume change$(\Delta V)$ with rate of pressure changes $(\Delta P)$ may be used to estimate remaining volume of trapped air and volume of test fluid required to filled pipeline to attain desired hydrotest pressure (API, 2013). Two values of volume change with respect to pressure change $(\Delta V/\Delta P)$ , known as theoretical and field values are computed to allow comparison of values. The theoretical value of $\Delta V/\Delta P$ predicts changes in volume with respect to pressure change of pipeline undertest without entrapped air while the field value of $\Delta V/\Delta P$ provides actual volume change with respect to pressure changes, with little or no air presence (CSLC, 2003). A field value greater than theoretical is an indication of air presence whereas field value less than the theoretical may either be an indication of incorrect computation of pressure reading or volume measurement of test section (CSLC, 2003). The volume of water injected during test may be measured using a metering device like flowmeter or counting number of pump strokes of positive displacement pump calibrated to known volume per stroke counter. This rate of volume change with respect to pressure change, $(\Delta V/\Delta P)$ may be calculated in Equations (3) and (4) (Gray, 1986)

$$\frac{\Delta V}{\Delta P} = \left[\frac{D}{Et}(1 - v^2) + C\right] * V \quad \text{for restrained (buried pipeline)} \quad (3)$$

$$\frac{\Delta V}{\Delta P} = \left[\frac{D}{Et}(5/4 - v^2) + C\right] * V \quad \text{for unrestrained (above ground pipeline)} \quad (4)$$

Where $\Delta V =$ incremental change in volume, $\Delta P$ =incremental change in pressure, $v$ =poisson ratio $(= 0.3)$, $E$ =elastic modulus of steel elasticity $(2.07x10^8$ KPa) .

A plot of change in pressure and corresponding change in volume or number of pump strokes of positive displacement pump for every change in 25 psi incremental pressure should be plotted and extrapolated from elastic slope line to horizontal axis as shown in Figure 2. Any deviation of the plotted graph from elastic slope line marks an indication of either pipeline expansion or leakage (Keifner and Maxey, 2001). Extrapolation to the horizontal axis corresponds to air volume presence and can be estimated as:

$$A\% = \frac{Volume\ of\ air}{Volume\ of\ test\ section} \tag{5}$$

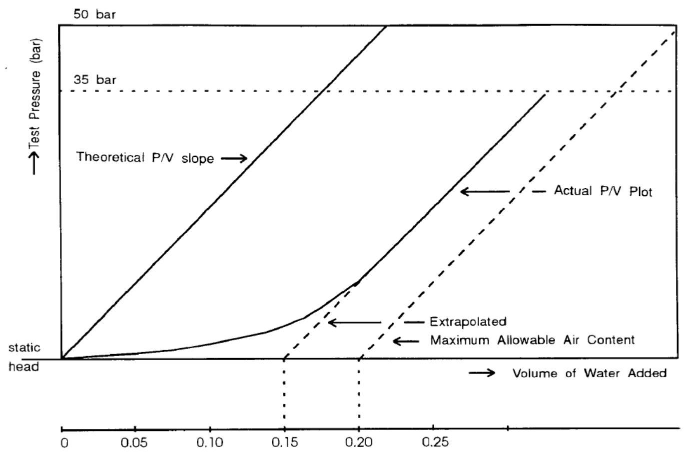

Figure 2: Typical plot of pressure versus volume (DEP, 1993)

### 4.3. Temperature Effect

Pipeline location, weather condition, ambient temperature and source of test fluid may cause an increment in test fluid temperature and consequently lead to circumferential expansion of pipeline wall and increment in test fluid volume (Gray, 1986; Bahadori and Vuthaluru, 2009). The combined variation of pipeline wall and test fluid volume may lead to pressure changes that are often misinterpreted as leaks for any pressure decrease, unless sufficient time is allowed for temperature stabilization (Jacob, 2013). The pressure versus temperature and volume versus temperature relationship due to temperature variation which may result in expansion or contraction of test fluid and pipeline wall are given in Equations (6) and (7) (Gray, 1986; DEP, 1993).

$$\frac{\Delta P}{\Delta T} = \frac{\gamma - 2\,(1+v)\propto}{\frac{D}{Et}(1 - v^2) + \frac{1}{C}} \quad \text{for restrained (buried pipeline)} \tag{6}$$

$$\frac{\Delta P}{\Delta T} = \frac{\gamma - 3\,(1+v)\propto}{\frac{D}{Et}(1 - v^2) + \frac{1}{C}} \quad \text{for unrestrained (above ground pipeline)} \tag{7}$$

$$\frac{\Delta V}{\Delta T} = V(\gamma - 2 \propto) \tag{8}$$

Where, $\propto$=linear expansion coefficient of steel ($= 1.17\ x\ 10^{-5}$ °C), $\gamma$ =volumetric expansion coefficient of test fluid and $\Delta T$ = change in temperature.

The pressure, ambient temperature and fluid test temperature should be plotted against time during leak tightness check or holding period to allow temperature and pressure variation analysis. An indication of leak

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or inaccurate temperature or pressure measurement may be established if the plot of pressure changes with temperature changes do not trend during pipeline pressurization (DEP, 1994).

### 4.4. Elevation Profile

Ground elevation profile of pipeline may vary because of unlevel terrain and this can lead to static head differential. But the hydrostatic head is critically dependent on the vertical height of water length from the ground level (Grupenhof, 2017). Therefore, an elevation change of pipeline should be evaluated prior to hydrotesting in order to ensure that the minimum pressure required to overcome the low and high points is below the rating of the pipeline. The maximum allowable change in elevation per test section is estimated using Equation (9) (Grupenhof, 2017).

$$\Delta Elevation = \frac{P_{test} - [1.25MAOP]}{0.433} \quad (9)$$

Where, $P_{test} = 100\%$ SMYS or ANSI class rating and $1.25MAOP$ =code minimum test pressure.

## 5. DEWATERING AND DRYNESS

On completion of hydrotest, the test water is removed by running bidi or foam pigs for piggable pipelines prior to transporting hydrocarbon product. For oil pipelines, the production may be used to propel pigs to remove test water from pipeline with a single pig run to prevent significant corrosion problem as shown in Figure 3 (Russell, 2005). Acceptance criteria by industry specification is that leftover water after dewatering exercise should not be more than 4 percent of the pipeline volume (O' Donoghue, 2004). For gas pipelines, leftover water may lead to serious corrosion and hydrate formation if water is not completely removed with several pigs runs. But where seawater is used as test fluid, slug of fresh water may be introduced between the first two pigs and propel by air compressor as shown in Figure 4 in order to remove residual salt from the pipeline (Russell, 2005).

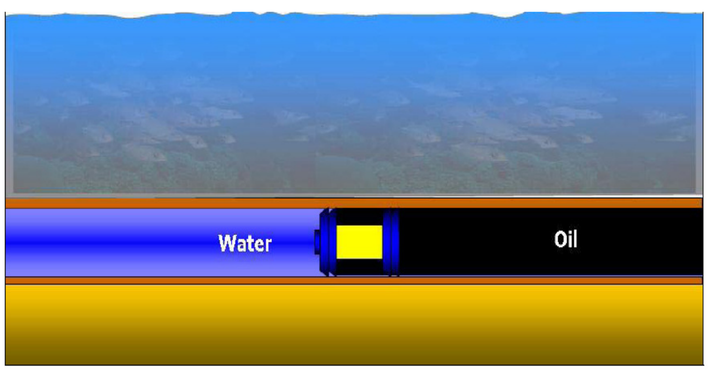

Figure 3: Oil pipeline dewatering (Russell, 2005)

One of the three basic methods of drying pipelines are methanol or glycol slug with pig run that is propelled by air compressor after bulk dewatering to prevent hydrate formation below temperature and pressure flash point (Ashburner, 1987; Gate, 2013). The glycol, though more toxic, is preferred to methanol because it is easier to handle in terms of safety compare to methanol which if allowed to mix with air is more explosive because of its low flash point (O' Donoghue, 2004). Volume of methanol or glycol slug required to prevent hydrate formation is estimated from Equation (10) (O' Donoghue, 2004):

$$V_g = 0.7DL \quad (10)$$

Where $V_g$ = volume of glycol and $L$ = pipeline length

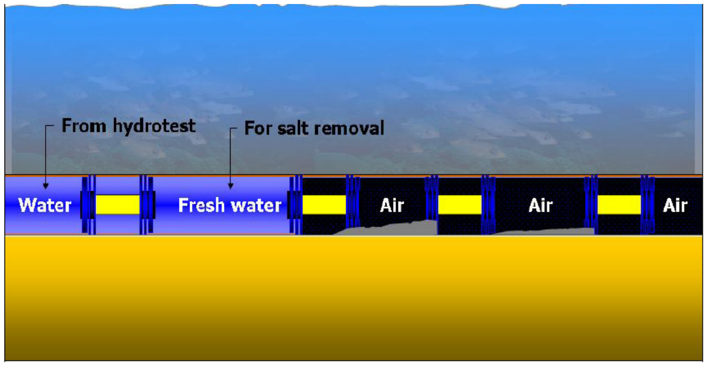

Figure 4: Gas pipeline dewatering (Russell, 2005)

The second dryness method is air drying (Figure 5). This involves running pigs with dry air as the propelling medium until the minimum dryness criteria of $-20$ ºC dew point is attained. This method is only recommended for sales gas and short pipelines (Gate, 2013). The third dryness method, (vacuum drying), removes leftover water from pipeline by allowing the leftover water to flow towards vacuum pumps and collected at exhaust point after vaporizing the leftover water by reducing and maintaining pipeline pressure below saturated vapor pressure and temperature (Ashburner, 1987). A pig train propelled by liquid nitrogen from tank or onsite generation nitrogen with membrane unit is usually run as shown in Figure 6 after completion of dewatering and dryness to remove residual air which may cause explosion after contacting with gas product (Gate, 2013).

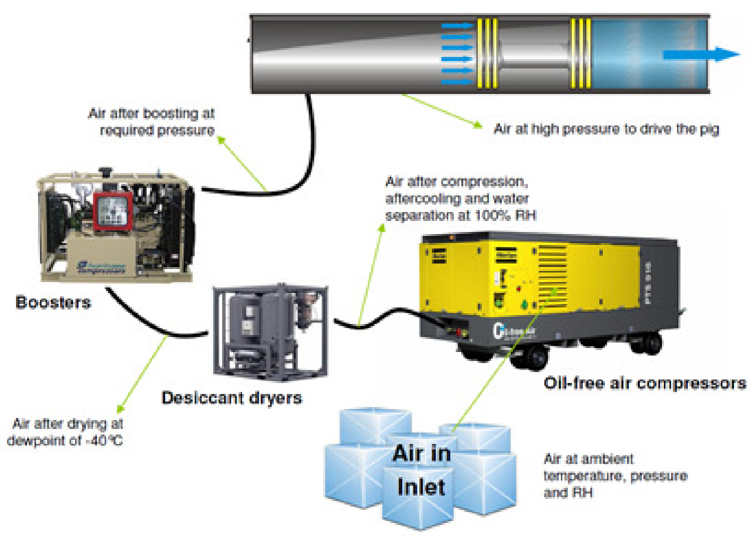

Figure 5: Typical air dryness spread set up (Atlas, 2016)

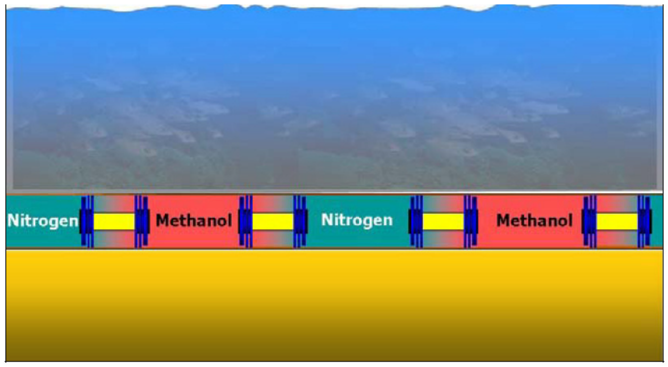

Figure 6: Pig train with nitrogen purge (Russell, 2005)

## 6. CONCLUSION

This paper provided an overview of hydrotest, dewatering and dryness acceptance criteria including required equipment and test method for performing hydrotest. Industry acceptance criteria for hydrotest is maximum of 0.2 percent air volume of pipeline and minimum of -20 $^{o}$C dew point for dryness. Acceptance criteria for remaining water after dewatering is a maximum of 4 percent of pipeline volume. Corrosion and hydrate formation may become a threat if dewatering and dryness acceptance criteria are not met. Furthermore, in-line plot of incremental pressure changes versus volume change and pressure change versus temperature after attaining preliminary pressure of 45 percent test pressure is necessary. The plot of these influential parameters during pressurization would help pipeline operators to monitor early potential deviation and make informed decision. Pressure reversal is strongly dependent on test pressure cycles and holding time of hydrotest pressure. Therefore, pipelines subjected to several pressure cycles and long holding time may suffer pressure reversal and eventual failures. Hydrotest may have gained wide acceptance for demonstrating pipelines fitness for continue in service but should not be recommended for high integrity criticality pipelines since it does not provide defect dimension information needed for pipeline integrity management plans.

## 7. CONFLICT OF INTEREST

There is no conflict of interest associated with this work.

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