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MAINLINE VALVE TESTING ON THE TRANS ALASKA PIPELINE SYSTEM

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ABSTRACT

Alyeska Pipeline Service Company (Alyeska) operates the Trans Alaska Pipeline System (TAPS) that transports crude oil from Prudhoe Bay to the Valdez Marine Terminal. There are 177 mainline valves on the 800 mile 48" pipeline that minimize potential oil spill volume and isolate facilities on the system. In 1997, Alyeska conducted a risk assessment aimed at reducing the likelihood and severity of a mainline valve failing to fully seal. This risk assessment brought about the development of a Master Specification for in-service performance criteria and a test program aimed at measuring the valve performance to the specification. After three years of the test program, 147 valves have been tested and the remainder will be tested in 2000. Two valves have failed to meet the acceptance criteria and have been repaired/replaced. Lessons learned in the three-year test program are shared with the petroleum industry.

NOMENCLATURE

Body Double Block and Bleed Valves: Defined in API Specification 6D as a valve with the capability of obtaining a seal across the upstream and downstream seat rings of a double-seated valve when the body pressure is bled off to atmosphere through blow down valves or vent plugs. Useful in testing for integrity of seats (sealing ability) and in accomplishing minor stem or body repairs while the valve is in-service.

Equivalent Orifice Leak-through Area (A): The calculated equivalent orifice size (in. sq.) of leakage through the valve.

Maximum Acceptable Leak-through Area (A_m): The equivalent orifice size (in. sq.) of leakage that would not add to a spill from a 1" diameter hole at the lowest point in the pipeline segment.

Normalized Leak-through Rate: The flow rate calculated with the measured equivalent orifice leak-through area assuming zero pressure on one side of the valve and the head pressure of the highest point that could add to the spill.

Seat: The part of a valve against which the closure element (gate, ball, or clapper) makes contact contributing to a tight shut-off. In many ball and gate valves, the seat is a floating member containing a soft seating element (usually an O-ring).

Valve Leak-by: For double-seated valves, an internal valve leak. Condition in a gate or ball valve where crude oil can leak past either the upstream or downstream seat into the valve body, thereby pressurizing the valve body. (Note: For single-seated valves, see leak-through below.)

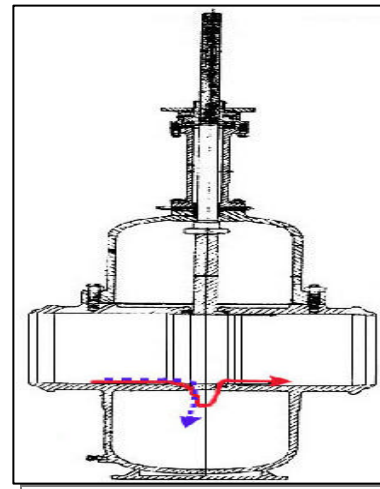


Figure 1. Leak-by vs. Leak-through

Valve Leak-through: Condition in a gate or ball valve where crude oil can leak past both valve seats causing the valve to leak from the high pressure side of the valve to the low pressure side when the valve is closed. (Fig. 1).

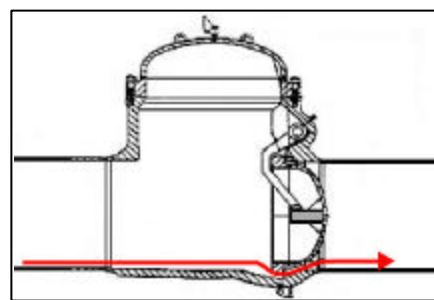


Figure 2. Leak-Through

For single-seated valves, such as check valves, a condition where crude oil can leak by the valve seat causing the valve to internally leak past the valve when the valve is in the closed position. (Fig. 2)

INTRODUCTION

After years of service, valves may perform differently than when originally supplied by the manufacturer and Alyeska was faced with developing maintenance programs to extend their service life after 20 years of continual operation. To achieve this goal and meet all regulatory requirements, Alyeska began a company wide TAPS Valve Program. (Aus et al, 2000) The program’s goals were to bring the valves up to a known service level, upgrade existing maintenance process, develop an in-service performance criteria, and complete a valve leak test program. The TAPS Valve Program decided to use a cost/risk based analysis approach in developing the performance criteria, maintenance risk model, and prioritizing valves for testing. The results of this risk assessment (Weber and Malvick, 2000) lead to prioritizing the valves for testing and to the development of the master specification defining the acceptable performance of the mainline valves.

The test program began in 1997 without any “Testing Textbooks”. ALYESKA was unaware of anyone performing such tests on mainline valves under operating conditions. Shutdowns had to be planned, procedures written and test teams put together to test the most critical valves. A method of calculating leak through rates was developed, using the compressibility factor for crude oil in a packed line. Measuring the rise in pressure over a period of time determined the leak-through rate. This leak through rate then brought about an effective equivalent orifice area, assuming the leak through the valve was a square edged orifice.

DEVELOPING THE SPECIFICATION FOR IN-SERVICE PERFORMANCE CRITERIA FOR PRIMARY CRUDE BLOCK VALVES

The Mainline Block Valve Risk Assessment studied the potential causes and hazards of valve leak through and developed a ranking system for identifying the most critical mainline valves on TAPS. This ranking was based on whether a valve leaking through could add to a 1” diameter leak in the pipeline, which was considered to be the most likely scenario for a pipeline leak. A review of this original risk assessment was performed a year later to clarify certain assumptions and further develop the in-service performance criteria to align with Alyeska Quality Program. This review also found the test data during

the first year supported the conclusions reached in the original risk assessment. It also provided a new appendix that recalculated the entire maximum acceptable leak through area for each mainline valve on the pipeline, using more accurate survey data. This appendix formed the basis for the Master Specification P504 In-Service Performance Criteria: Primary Crude Block Valves and the basis for determining conforming and non-conforming criteria under Alyeska’s Quality Program.

During the original risk assessment a model was developed to determine the impact of various parameters on the amount a valve could leak through. The model was subsequently simplified by focusing on the hydraulic forces acting on each individual valve. This was accomplished by reviewing survey data to determine the lowest and highest point between each valve and the highest point beyond the segment that the valve protects. The assumption was made that the head force acting on the leak would remain at the high point. The hole in the pipeline and the leak through the valve is assumed to be a round hole and the formula Eq. (1) for a square edge orifice is used. The leak rate was then simplified to gpm. Eq. (2)

$$Q = C_d \times A \times \sqrt{2 \times \rho \times \Delta P \times \frac{g_c}{144}} \quad (1)$$

- Where: Q = liquid discharge rate (lbs/sec)
- C_d = discharge coefficient, set to 0.61
- A = hole cross-sectional area (sq. in)
- ρ = density of liquid crude (54.57 lbs/ft³)
- ΔP = static head pressure (psi)
- g_c = conversion factor from lbf to lbm (32.2 ft/s²)
- The density of oil is based on a specific gravity of 0.876 for TAPS mixed crude.

Converting Q to GPM:

$$Q = 2.5 \times A \times \sqrt{\Delta P} \quad (2)$$

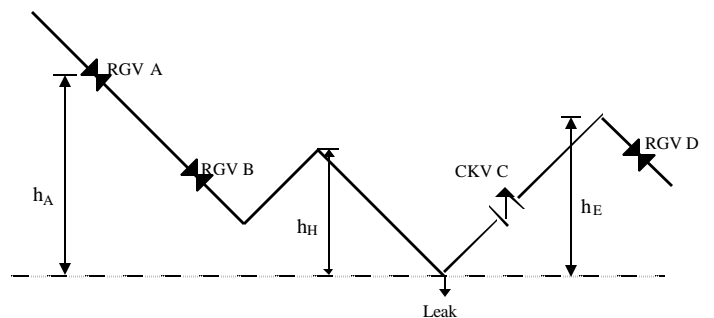


Figure 3: Diagram for Leak Through Calculation

Figure 3 illustrates how the equivalent leak through area is derived. In this situation the segment between Remote Gate Valve (RGV) B and Check Valve (CKV) C is being considered. The leak rate out of the pipe if both valves sealed is shown in Eq. (3).

$$Q_L = K \times A_L \times \sqrt{h_H} \quad (3)$$

If RGV B does not seal, the leak through RGV B is based on the difference in the high points h_A-h_H shown in Eq. (4).

$$Q_B = K \times A_B \times \sqrt{h_A - h_H} \quad (4)$$

The flow through RGV B calculated in Eq. (5) must be greater than the leak rate out of the pipe in order for RGV B to add to the spill. A similar set of equations is used to find the acceptable leak through rate of CKV C, using h_H and h_E .

$$Q_B > Q_L$$

$$K \times A_B \times \sqrt{h_A - h_H} > K \times A_L \times \sqrt{h_H}$$

for a 1" f hole, $A_L = 0.783$

$$A_B > 0.783 \times \sqrt{\frac{h_H}{h_A - h_H}} \quad (5)$$

Where:

- Q_L = Leak rate through hole in pipeline, GPM
- Q_B = Leak rate through RGV B, GPM
- A_L = Area of the leak, sq. in. = 0.783

h_H = Elevation of highest point between RGV B and

CKV C

A_B = Area of leak through RGV B, sq. in.

h_A = Elevation of highest point between RGV A and RGV B, ft.

h_E = Elevation of the highest point between CKV C and RGV D, ft.

The Master Specification P-504: In-Service Performance Criteria: Primary Crude Block Valves was written to outline valve function and operability criteria. The Maximum Acceptable Leak-Through Area (A_m) was calculated for each mainline valve on the pipeline using Eq. (5). A sample of the values calculated can be found in Table 1. The elevations h_H and h_A were determined from the pipeline survey database. Note that check valves seal in only one direction, so in some cases the high point might be in another segment.

Valve Name	In-Service Internal Leak Area, in ²
PS1 BL-1	1.00
CKV 1	0.96
CKV 2	0.98
CKV 3	1.37
CKV 4	0.68
CKV 5	0.68

MGV 5A	0.68
CKV 6	0.91
CKV 7	0.67
CKV 8	0.71

Table 1: Sample Table from Alyeska Master Specification P-504

VALVE TEST METHODS

A valve must have a differential pressure across it and a means of measuring the flow through the valve in order for it to be tested. Closing the valve to get a differential pressure across it requires a pipeline shutdown, which may only happen once a year. Obtaining differential pressure across the valve requires removal of crude from the pipeline, either by draining into a Pump Station or by use of a tanker. Measuring the relatively low flow rates through the valve is done by recording the change in pressure in a section of line isolated by the valve(s) being tested. The flow rate through the valve is calculated by the change in the volume of crude oil being compressed in the line over a period of time. The isolated section must be packed (no slack in the pipeline) and check valves can only be tested with a higher differential on the downstream side of the valve.

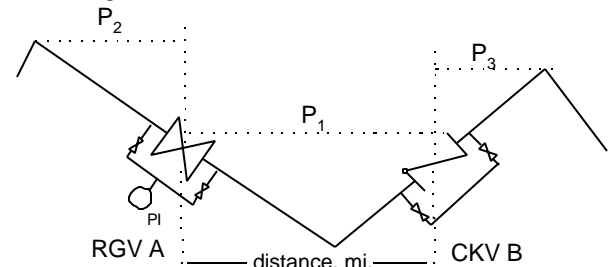


Figure 4: Pressure profile during valve testing

If crude is removed from the segment between RGV A and CKV B in Fig. 4 both valves can be tested simultaneously. A differential pressure across valve A is equal to $P_2 - P_1$. By closing the upstream bypass and opening the downstream bypass at RGV A, the pressure in the segment can be monitored over time. If both valves seal, there will be no increase in P_1 . If either valve leaks into the segment, the pressure will rise. The added volume can be calculated using the following Eq. (6):

$$\Delta V = \Delta P_1 \times \frac{V_1}{BulkMod} \quad (6)$$

Where:

ΔV = Change in volume of test section, BBL

ΔP_1 = Change in pressure during test period, psi

V_1 = Volume of test section, BBL

Bulk Modulus of oil = 180,000 psi.

The flow rate through the valve can then be determined by converting volume to the length of the test segment and dividing by test time Eq.(7).

$$Q = \frac{2.64 \times \Delta P_1 \times d}{t} \quad (7)$$

Where:

Q = leak through rate of valve, gpm

t = test time, min.

d = test segment distance, miles

This flow rate is the leak rate through either RGV A, CKV B or both. If we assume RGV A was leaking, we can calculate the equivalent orifice leak-through area in Eq. (8) by solving for A from Eq. (2), where ΔP is $P_2 - P_1$. If the pressures changed markedly during the test the average pressures are used in the calculation.

$$A = \frac{Q}{25 \times \sqrt{\Delta P}} = \frac{Q}{25 \times \sqrt{P_2 - P_1}} \quad (8)$$

The assumption that all flow is leaking through CKV B leads to the equivalent orifice leak-through area for CKV B in Eq. (9) using the differential pressure of $P_3 - P_1$.

$$A = \frac{Q}{25 \times \sqrt{\Delta P}} = \frac{Q}{25 \times \sqrt{P_3 - P_1}} \quad (9)$$

If either area is over the Maximum Acceptable Leak-Through Orifice Area that was established in Eq. (5), (and listed in the Master Specification P504) additional testing will be done to determine which of the valves is leaking through.

Temperature changes have been considered, and a drop in temperature would reduce the volume in the segment by the formula for thermal expansion Eq. (10):

$$\Delta V = 0.0004 \times \Delta T \quad (10)$$

Where:

ΔT = Temperature change, Deg F

Because of the insulation on the pipe and short test periods, experience has proven the temperature factor to be negligible and is not used.

TAPS crosses three mountain ranges, so the pipeline elevation varies from 22 to 4,737 feet. (Fig. 5)

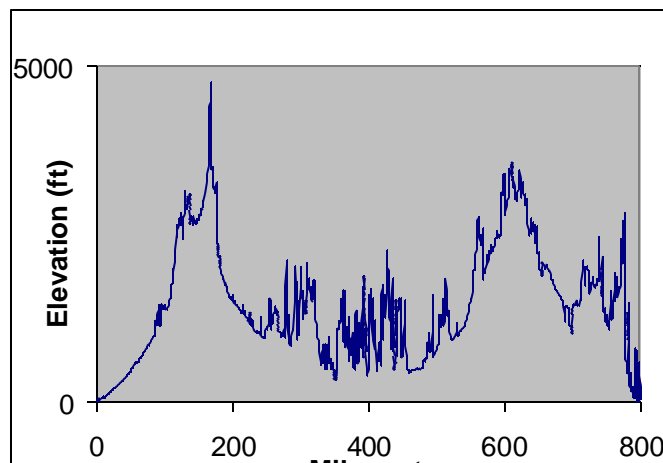


Figure 5: TAPS Elevation Profile

A combination of check valves and gate valves are installed to limit the amount of crude that could spill if a leak occurred, which makes valve testing a challenge. Several methods are used to accomplish this task. The initial method used was to drain crude from the pipeline between valves into tankers. This required welding a 2" Thread O Ring (TOR) on the valve bypass piping and draining the crude into tankers. This is the most expensive and least desirable method because of the added potential risk of crude spills during the operation and cleaning expenses for the tankers after the tests. Although this is the only option available for some situations, generally more desirable methods have been found.

Of the eleven Pump Stations once operated on the pipeline, only seven are operational today. Each of the operating Pump Stations and the Valdez Marine Terminal has relief facilities and storage tanks. These facilities provide a safe and efficient means of removing crude from the pipeline to create the necessary differential pressure. The Operational Control Center (OCC) for the pipeline develops a shutdown procedure that ensures the required head pressure and line pack are available for testing, then the valve(s) to be tested are closed and crude is drained into the facility through the relief valves into the storage tanks.

While testing the segment north of Pump Station 5 (PS 5) in September 1999, RGV 36 was closed after the pipeline was shutdown (Fig. 6). The pipeline was then drained down to 1560 feet of elevation using the relief and storage tanks at PS 5. The valves were then tested south to north from PS 5, by opening the bypass valves around CKV 50 and using the 2100 feet of head available from Gobblers Knob. This created a differential pressure of 203 psi on RGV 49 testing back to PS 5. After RGV 49 was tested, the bypasses around the valve were opened and CKV 48A was tested with the same 203-psi differential. This process continued all the way to CKV 41. A second team was using the head pressure from Atigun Pass to test the valves from north to south starting with RGV 31 and RGV 32, and continuing to RGV 40. CKV 38 had to be tested after the southern test section was completed so the same procedure could be used to create the reverse flow on the check valve.

OTHER TEST METHODS EMPLOYED

The VPAC 5131, an acoustical leak detection instrument, was used on several leaking valves and a calibration curve was developed using known leak rates. Leak rates as low as 2 gpm were detected and valve leakage can be measured with an approximate accuracy range of $\pm 25\%$. The instrument can be used on other types of valves both above ground and buried. To date, the data taken is considered information only, and is not felt to be accurate enough to preclude the use of more accurate techniques. The calibration and evaluation process will continue on this instrument because it has a great potential for identifying leaks not audible to the human ear.

Block and Bleed tests were performed on all gate valves in the open and closed position. This test is performed by bleeding down the body and monitoring the pressure rise in the body cavity. Three categories were assigned to depict sealing results:

- Category 1 – Both valve seats seal and no fluid enters the valve body.
- Category 2 – Valve seats do not seal but a “zero” body pressure can be maintained with the drain valve and vent open.
- Category 3 – Valve seats do not seal and “zero” body pressure cannot be maintained with the drain and vent open.

VALVE TEST PRIORITIES

The valves tested in 1997 were selected based on the results of a 1997 valve risk assessment that identified the most critical valves on the pipeline. Results were based on calculations that determined the effective leak through area of each mainline valve that would add to the spill volume of a 1” diameter pipeline leak based upon system hydraulics. The valves were then ranked according to their allowable effective leak through area (from smallest to largest) for testing. 14 valves with allowable effective areas less than 0.25 square inches were selected as priority test valves. 49 valves were secondary in consideration with 0.50 square inch leak through areas. Other valves that were added to the priority list included Pump Station battery limit valves and other valves that could be easily tested in conjunction with the priority test valves. The P/L shutdown dates were aligned with another project that required shutting down the pipeline for 12 hours.

After the results of the 1997 tests were studied, the plan was changed in 1998. The valves were still tested according to their ranking, but groups of adjacent valves were considered rather than single valves. This made the test program more efficient and allowed more valves to be tested during the short shutdowns. The 1999 tests were selected because the lengthy shutdown allowed the valves on the northern end of the pipeline to be taken out of service for the test. The valves remaining after 1999 are all in the southern end of the pipeline and can be done during shorter (less than 6 hour) shutdowns that will not require the Producers at Prudhoe Bay to shut in. The relief tanks at PS 5 and north can handle the production while the remaining valves can be done in multiple short duration shutdowns.

TEST RESULTS

In 1996, six valves were tested on the south side of Atigun Pass by closing the valves and monitoring the mainline (M/L) pressure recorders. All six valves were found to seal adequately.

In 1997, 40 valves were tested during two P/L shutdowns. A variety of test methods were used, ranging from monitoring

pressures at Operations Control Center (OCC) to draining crude from selected RGVs into tankers to get differential pressures across the valves. Of the 40 valves tested, all but three sealed for leak through. Of the three valves that did not seal, RGV 60 had a leak through area of 0.21 square inches, which is within the Risk Assessment Performance Criteria of a 0.64 square inch leak through area. RGV 80 had a leak through area of 0.61 square inches, which exceeded the P-504 acceptable area of 0.12 square inches. Check Valve 122 had a leak through area larger than 4.6 square inches, much greater than the Risk Assessment acceptable area of 0.20 square inches.

In 1998, 46 mainline valves were tested. The results found one gate valve and one check valve had measurable leak through, but both were within the acceptance criteria.

In September 1999, 39 mainline valves were tested. Four valves were found to have measurable leak through, but all within the acceptable criteria. Additional testing is scheduled for another 22 mainline valves in October 1999 to verify the September test results and test additional valves that could not be tested during the September tests. Mitigative measures will be taken on the valves that were found to leak through during the September tests to try and improve their performance.

The remaining 30 valves that have not been tested will be completed in 2000, along with any retests deemed necessary after the October 1999 tests.

As a result of the testing efforts over the past three years, two gate valves were replaced and one check valve was repaired in place. The first gate valve removed from service had obvious damage to the slab and was sent to the manufacturer for further analysis and refurbishment. The gate valve removed in September 1999 will be tested and then torn down by ALYESKA to determine the cause of leak through and validate the leak through area model.

LESSONS LEARNED DURING THE FIRST THREE YEARS

- Not all locations have suitable places to measure the pressure on the valve bypass piping. Some bypasses are buried and others do not have appropriate fittings for gauge installation. As a result, some sections between valves are fairly long, and require extended test times. Where pressures can't be measured, they must be determined by adjusting measured pressures at other valves by the hydraulic head.
- Test times vary based on the differential across the valve and the length of the test segment. 100 psi was selected as the minimum differential for a test, primarily to keep the test times from becoming excessively long. A rule of thumb developed requires a test time in minutes equal to 5 times the distance between valves in miles for a 100-psi differential. This equates to a 20-psi change over the test period for a small leak through. The test can be reduced to 4 times the distance with a 200-psi differential, and 2.5 times the distance with a 400 psi differential.

- In many cases, two valves can be tested together. If a differential is created across both valves and the pressure stays constant, then both are sealing. If the pressure rises, then one or both of the valves may be leaking, and further testing is required to determine which one is leaking. Our experience has shown the leaking valve can be detected with an acoustical instrument, stethoscope or the human ear on the valve body or exposed piping.
- If a valve has been found to pass the block and bleed test in the open position, the valve will seal with differential across it in the closed position. The fact that a valve does not pass the block and bleed test, is not a good indication that the valve will not seal when a differential is placed across it. By design the gate and check valves are forced against the sealing seat by the differential put on it.
- It is most efficient to test valves in groups which are adjacent to one another, starting at one position and working upstream or downstream, moving from valve to valve. When a valve is found to seal acceptably, it can be used as a block point for testing other valves.
- Care must be taken when draining back to avoid creating a slack line in the test section. Pressure must be greater than the bubble point vapor pressure in the section to avoid slack.
- The bypasses around check valves should be open prior to shutdown, in order to get a constant head pressure in the section of valves to be tested. Pressure waves in the line after shutdown can actually step the pressure up, because the check valves slam shut on reverse flow.
- The term “Normalized Leak-through Rate” was coined to better define valve leak-through. The highest elevation acting on a leaking valve, with the pipeline shut-in (all valves closed) is used in the flow formula Eq. (2). This flow rate in gpm is easier to understand than the area in square inches.
- A pump-around skid has been developed that will pump crude from the leaking side of the valve to the “high pressure” side of the valve, thus negating the affect of the leaking valve to the pipeline leak. This skid is self-contained and can be transported to any site on the TAPS.
- The pump around skid serves a dual purpose in mixing and injecting GELBLOK™, a viscous hydrocarbon based gel containing loss circulation material, that has been used to successfully seal a leaking mainline gate valve on the TAPS. GELBLOK™ was tested at RGV 60 (a gate valve that was known to leak) during a 1997 shutdown. It sealed off the 35 gpm leak within 10 minutes and retained its seal under an 800 psi differential. The product could be used to seal gate valves, ball valves or check valves with a leak through width up to ¼ inch.

CONCLUSION

Alyeska Pipeline Service Company realizes that valves that have been in service for 23 years cannot be expected to seal as they did when they left the factory, and has taken the lead in developing in-service performance criteria for valves. The TAPS Valve Program team has developed testing techniques and used it successfully on 147 valves.

After 3 years of testing the TAPS mainline valves, the results have been consistent with the predictions of the Risk Assessment conducted in 1997. Nine valves out of the 147 valves tested to date have shown some leak-through (6% compared to the prediction of 10%). Two valves have been above the maximum acceptable leak-through area and have been repaired/replaced. One of the other seven valves was replaced this year, and the valve is being tested and examined in the Fairbanks facility. It will be sent out for refurbishment, after the examination. Four of the valves are being retested to attempt mitigative sealing techniques and verify results obtained in earlier tests. The other two valves are less than the acceptable limits, so they will only be handled by contingency plans.

The testing program has succeeded in reaching its goals of developing the in-service performance criteria and testing the majority of the mainline valves. The program is now being turned over to the maintenance staff as part of the TAPS Valve Maintenance Management Plan.

ACKNOWLEDGMENTS

Bill Aus who formed and lead the TAPS Valve Program, and to Hank Wladkowski, Greg Shotts and Tim Geiger for their support in the development and implementation of the test program.

REFERENCES

Weber, B.J. and Malvick, M., 2000 “Trans Alaska Pipeline System Mainline Block Valve Risk Assessment”, ETCE/OMAE 2000.

MITIGATIVE MEASURES FOR LEAKING VALVES

The following measures have been established for the mitigation of the mainline valves that have been found to leak-through:

- Verification that a valve is fully closed using the handwheel. Limit switches normally stop the actuator at the end of valve travel. However, these limit switches were set 23 years ago before pipeline startup, and have not been recalibrated since. The handwheel is used to bring the valve down to the mechanical stop.
- Adding lubricant/sealant to the valve seats through the grease injection lines may improve sealing, but this has not been particularly effective because many of the sealant passageways are clogged from past maintenance practices when sealant was used when not fully required.

Aus W. T., Pomeroy G. W., Norton J.D., 2000 "Mainline Valve Operations and Maintenance Program On the Trans Alaska Pipeline", ETCE/OMAE 2000.

Alyeska Pipeline Service Company, Alyeska Master Specification, P-504, "Valve Performance Criteria, Rev. 1".

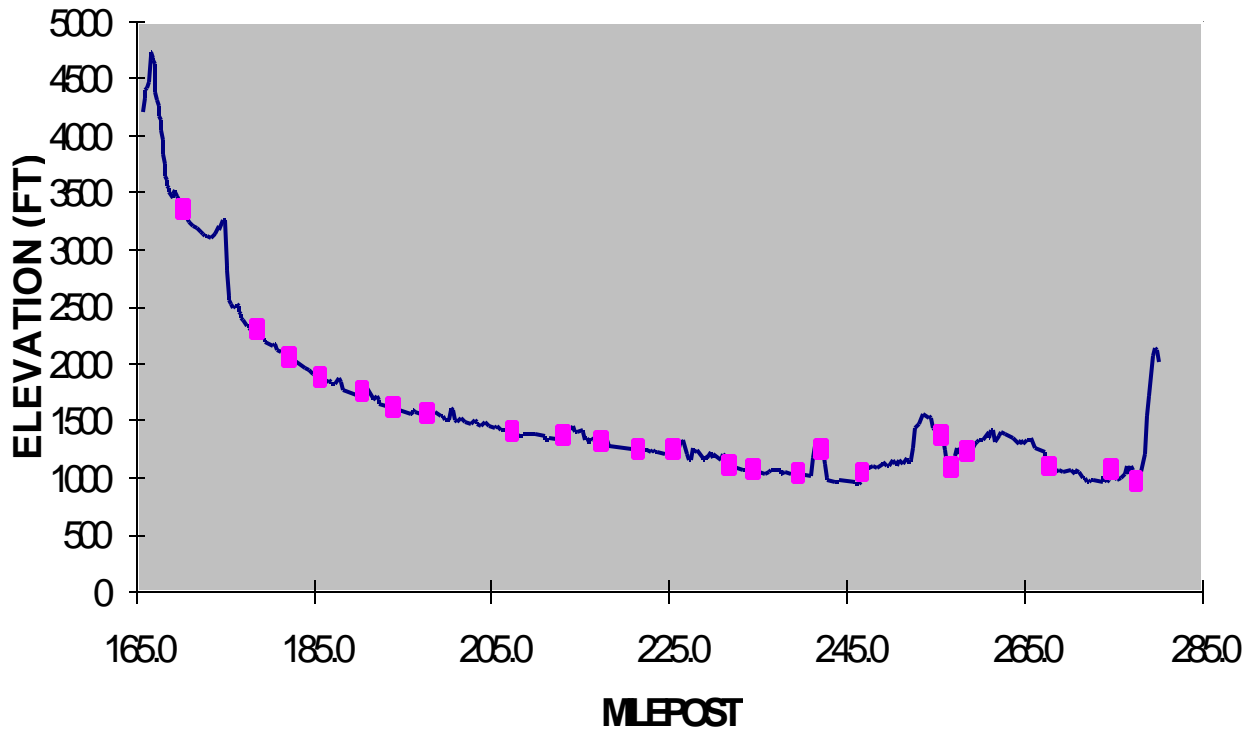


Figure 6: September 1999 Test Profile