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TRANS ALASKA PIPELINE SYSTEM MAINLINE BLOCK VALVE RISK ASSESSMENT

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ABSTRACT

Alyeska Pipeline Service Company (Alyeska) has 177 48-inch mainline remote operated gate and check block valves. Alyeska also has more than two hundred primary block valves ranging in size from 12 through 48 inches at twelve pump stations, two refinery connections, and the Valdez Marine Terminal. These valves are critical to personnel safety, facility isolation, and minimizing potential oil spill volumes. When some of these valves did not provide tight shut-off after nearly twenty years of service, Alyeska conducted a risk assessment to determine their in-service performance criteria. The in-service performance criteria for each valve established when a valve should undergo aggressive maintenance or be replaced if repairs are not possible.

The risk assessment combined the techniques of Failure Modes and Effects Analysis, What-If Analysis, and Qualitative Risk Analyses. It produced quantitative measures useful in identifying the criticality of each group of valves and prioritizing the valves for performance testing. The results of the risk assessment are the foundation of an aggressive five-year testing and maintenance program currently being implemented by the Trans Alaska Pipeline System (TAPS) Valve Program. This program is described in a paper by Pomeroy, Norton, and Aus (2000).

INTRODUCTION

All pipeline systems rely on the use of valves to modulate, divert, or even stop flow in the system. A particular class of valves, referred to as primary block valves, is especially important. These block valves stop the flow of crude oil under certain conditions that may threaten the personnel, facilities, or the environment.

The largest and most critical of the TAPS primary block valves are the 177 48” mainline remote operated gate and check block valves. After nearly twenty years of service, some of the valves no longer provided the tight shut-off originally specified. To address this and other issues for the mainline block valves and to meet regulatory requirements, Alyeska initiated the TAPS Valve Program. A risk based approach was used to establish in-service performance criteria and valve leak testing priority for the TAPS Valve Program so resources could be focused first on the most critical valves.

STUDY DESCRIPTION

The primary objective of the study was to establish the risks associated with the ongoing operation and maintenance of the pump station, terminal, and mainline primary block valves. A number of detailed objectives were met by gaining an understanding of the apparent risks associated with these valves:

- identify the criticality of valves or groups of valves
- prioritize the sequence and means of testing valves or groups of valves
- identify possible interim measures for valves that cannot be adequately tested
- report relative risk levels for each valve or group of valves

STUDY METHOD

The risk assessment was carried out in three phases as described below:

Phase 1 – Hazard Analysis: intended to identify the possible failure modes for the valves, along with the consequences of the failures

Phase 2 – Risk Assessment: a structured risk analysis, using a scoring system that reflects the general likelihood and consequences of valve seal failures

Phase 3 – Development of in-service performance and testing criteria

PHASE 1 - HAZARD ANALYSIS

The purpose of this phase was to identify and analyze all hazards of relevance to the risk assessment. Each hazard was described in terms of a possible scenario. A scenario is a chain of events, postulated for the purpose of review during a risk assessment.

A systematic review of technical as well as operational conditions that may influence the risk was conducted to identify each of the hazards that may arise. Historical records and experience from previous analysis provided a useful input to the hazard identification process. Checklists, hazard indices and reviews of historical occurrences were utilized. The hazard identification considered not only the initial events, but also the chain of events causing impairment, loss or damage.

For this study, the hazards of interest were defined as the following:

- valve leaks through – fluid is able to bypass the isolation function of the valve
- valve leaks by – fluid leaks past one of several barriers, fluid is still isolated, but maintenance is needed

A team of subject matter experts from Alyeska, along with staff from Alyeska's consultant, Det Norske Veritas (DNV), Inc., studied the potential causes and hazards of valve leak-through. The hazard identification phase answered four basic questions:

- what could cause crude oil leak-by into the valve's body cavity and what could cause crude oil leak-through from one side of the valve to the other?
- what leak rate could be expected from a particular failure mode?
- what is the likelihood of a particular failure mode?
- what are the general effects of the leak-by or leak-through on pipeline operations?

The first three questions were answered by conducting a Failure Modes and Effects Analysis (FMEA). The last question was answered by a "What-If" Analysis.

FMEA is used to examine the effects of potential failure modes on a larger system. The FMEA took a detailed look at the valve design, and was carried out for valves grouped by manufacturer and service.

The process used in the FMEA was to examine the valve internals, part-by-part, and to consider and then answer key questions about the part and its potential failures. For this study, the FMEA was limited to those parts and functions that affected the sealing function of the valve. The study examined failure modes and effects for three modes of operation: normal operation, line shutdowns, and emergency operation. Since the pipeline system is in normal operations over 99% of the time, most failure modes were derived for this mode of operation.

The FMEA was also used to estimate the likelihood of both leak-by and leak-through for the valves studied. After the failure modes were established for all valves, the review team assigned a likelihood for the failure mode to occur and a severity of leak, should the failure mode occur. The likelihood of a leak (either leak-through or leak-by) was estimated as belonging to one of four categories (Table 1).

Table 1: Assessment of Probabilities for FMEA

Qualitative Assessment of Probability	Quantitative Value Assigned for Probability
very low probability (VL)	once in one thousand valve years of operation (0.001/yr)
low probability (L)	once in one hundred valve years of operation (0.01/yr)
Medium probability (M)	once in ten valve years of operation (0.1/yr)
high probability (H)	once in four valve years of operation (0.25/yr)

The severity of a leak was estimated by categorizing the approximate leak rate for 100 psi of differential (psid) pressure on the seal. For each failure mode, the estimated leak rates were categorized into one of five categories based on the size of the leak (in^2) (Table 2).

Table 2: Assessment of Leak Rates

Qualitative Assessment of Leak Rate	Quantitative Value for Leak Rate
Very low leak rate (VL)	12 gpm at 100 psid, 0.05 in^2
Low leak rate (L)	25 gpm at 100 psid, 0.10 in^2
Medium leak rate (M)	60 gpm at 100 psid, 0.25 in^2
High leak rate (H)	125 gpm at 100 psid, 0.50 in^2
Very high leak rate (VH)	flow rate as if the valve did not fully close, >125 gpm at 100 psid, >0.50 in^2

Probability of Leak-By

The probability of leak-by was estimated by combining the probabilities for all failure modes that could lead to leak-by, regardless of size. Equation 1 was used to estimate the probability of leak-by:

$$\text{Probability of Leak-By} = 1 - \prod_{all\ LB} (1 - p_{LB}) \qquad (1)$$

where π = mathematical operation of taking the product of a set of values

p_{LB} = the probability associated with a leak-by failure mode

Probability of Leak-Through

Leak-through occurs if the failure mode leads directly to leak-through (for example, a foreign object stuck under the gate) or if leak-by occurs on both seals (for example, if both seats are badly corroded). In order for leak-through to occur, leak-by must occur at both the upstream and downstream seals on the valve. If the seals were operating completely independent of each other, the leak-through probability would simply be the leak-by probability for the upstream seal times the leak-by probability for the downstream seal. Since the two seals do not operate independently, the risk assessment must account for *common cause* failures increasing the likelihood that both seals leak by, producing a leak-through condition.

To account for common cause failures occurring on both seals, this study used a beta-factor approach to common cause analysis (WASH-1400, 1974).

The following expression was used for evaluating the probability of a leak-through due to a single failure mode or common cause failures of both seals.

$$\text{Probability of Leak-Through} = \{(\sum_{allLB} p_{LB})^2\} + \{b \times \sum_{allLB} p_{LB}\} + \{1 - \prod_{\text{all LT}} (1 - p_{LT})\} \qquad (2)$$

where β = the beta-factor for a given failure mode (set at 0.2)

p_{LB} = probability of a leak-by failure mode

p_{LT} = probability of a leak-through failure mode

In Equation 2, the first {} term represents the leak by failure modes that independently act to cause leak through, the second {} term represents the leak-through due to common cause failures of leak-by failure modes and the third {} term represents the combining of the leak through failure modes.

The FMEA uncovered 21 potential common failure modes for the valves. The failure modes range from corrosion on various sealing surfaces, to binding and foreign bodies blocking the gate or ball. The failure modes covered a broad spectrum of failures that could result in fairly small (12 gpm at 100 psid) up to very large (125 gpm at 100 psid) leak-through rates.

The probabilities of the failure modes are combined to produce the graph of leak-through versus leak-by probabilities (Figure 1, attached). The results of this analysis agree fairly closely with actual operating experience for the Alyeska's 48" mainline gate valves. Based on field data for 70 valves, 10% of the 48" gate valves leak-through compared to a predicted 16% probability, and 59% (50 out of 85) of the valves leak-by compared to a predicted 44% probability.

As expected, for valves that can have both leak-by and leak-through failure modes, the likelihood of leak-by is higher since failure of only one seat is required to produce leak-by. The only failure mode for 48" check valves and 6" single seated bypass valves is leak-through since they have only one seat that has to fail to produce leak-through.

Tables 3 and 4 show the listing of failure modes that lead to leak-by and leak-through, along with an estimate of likelihood. Refer to Tables 1 and 2 for a key to the abbreviations used in Tables 3 and 4.

In addition to the probabilities of leak-through and leak-by, the risk analysis also investigated the probabilities of different sizes of leaks occurring. In essence, Equation 2 was used for each of the postulated leak sizes, rather than for all leaks. In order to estimate probabilities for all leak sizes, qualitative estimates of the probabilities for all of the failure modes were input to a spreadsheet. These qualitative estimates were then translated into quantitative values using the information listed in Table 1. Finally, Equation 2 was applied to derive a total probability for each of the leak sizes.

Applying the above data to Equation 2 yields a set of probabilities for the various sets of hole sizes, as shown in Table 5 and Figure 2, attached. To gain an understanding of Table 5, consider a Manufacturer (Mfr.) B 48" gate valve. Based on the results of the FMEA, the calculated probabilities for that valve body style to have leak-through of a certain size are: 6.6% 0.1 in^2, 9.2% 0.25 in^2, 0.2% 0.5 in^2, and 0.1% large gap, for a total leak-through probability of 16.1%.

For a comparison of the statistical data in Table 5 and Figure 2 to the mainline valves, consider what is known about the 48" gate valves. As described previously, there are leak-through data on 70 gate valves. Of those valves, 63 seal, and only seven (10%) are known to leak-through in the closed position. Therefore, for 48" gate valves, field performance is 60% better than predicted by the FMEA calculated values in Table 5 and Figure 2.

The equivalent orifices for the leak-through at mainline gate valves, discovered to date, range from 0.01 to 0.61 in^2, all of which fall within the predicted ranges.

PHASE 2 - RISK ASSESSMENT

The risk assessment of the mainline valves was based on site specific location parameters. Risk was estimated as a function of resource value, spill size, and probability of a leak.

The expression used to determine the risk value of any section of the pipeline was as follows:

$$\textit{Risk Score} = \text{Spill Size} \times \text{Local Probability} \times \text{Resource Value} \times \{1 + \frac{\text{Penalty}}{20}\} \qquad (3)$$

where Spill Size = Maximum estimated spill volume, in thousand bbls

Local Probability = a measure of likelihood for location

Resource Value = the maximum value for resources in the segment

Penalty = penalty factor to account for potential difficulties of cleanup near water (0 or 20)

Each of the variables in the above expression is described in the following paragraphs.

Local Probability

The Local Probability was taken as the maximum value for the "Localized Risk" for a given segment between mainline valves. The Localized Risk values give consideration to many causes of pipeline leaks, including slope instability, vehicle traffic, sabotage, corrosion and settlement all of which were part of the original design valve location study.

Resource Value

The valve location study provides Resource Values for every mile segment along the pipeline. To be conservative, this risk assessment used the maximum value for each section between two valves.

Penalty

A review of the original basis for valve placement indicates that the impact of leaks in pipeline segments near water may have been underestimated due to additional spill clean-up difficulty. Spills near large bodies of water and swiftly-moving water have the potential to spread much greater distances, increasing the severity of consequences beyond the levels expressed by the Resource Values in the original valve risk assessment. To account for this, a 20-point penalty was assessed for all segments identified as being "near water." Segments not labeled as "near water" were given a zero penalty.

The impact of the Penalty is that a segment near water would have its risk score doubled; whereas, a segment away from water would not have its risk score adjusted.

Segments were identified as being near water if they met all of the following subjective criteria:

1. the segment ran parallel to a given body of water or stream for some distance (perpendicular crossings were not penalized because of the lower likelihood of a leak occurring in the relatively small segment in the immediate vicinity of the crossing)
2. the body of water or stream had "significant" value from an environmental or recreational standpoint
3. the body of water was large enough or stream flowed quickly enough such that cleanup would be significantly hampered.

Overall, 36 out of the 162 segments studied were assigned a penalty for proximity to water.

Estimate of Spill Size

The spill size is defined as the spill volume, given in thousands of barrels. The spill volume is estimated based on the amount of oil that could spill from a certain size hole in the pipeline:

$$SpillVolume(bbls) = \frac{Q_L \times K \times T}{r} \qquad (4)$$

where T = time to control the spill (hrs)
Q_L = liquid discharge rate (lbs/sec)
ρ = density of liquid crude (54.57 lbs/ft^3)
K = conversion from lbs/sec to bbls/hr (641.143)

For each segment, the spill volume calculation was performed at the location in the segment giving the highest leak rate. In general, this corresponds to the location with the greatest difference in elevation from valve-to-valve or from valve-to-peak.

The discharge rate (Q_L) of liquid through a sharp-edged orifice can be calculated as:

$$Q_L = C_d \times A \times \sqrt{2 \times r \times \Delta P \times \frac{g_c}{144}} \qquad (5)$$

where Q_L = 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/ft^3)
ΔP = static head pressure (psi)
g_c = conversion factor from lbf to lbm (32.2)

Note that the static head varies from location-to-location along the pipeline, depending on the elevation profile of the line. Calculation of static head pressure is described below.

The density of oil is based on a specific gravity of 0.876 for TAPS mixed crude.

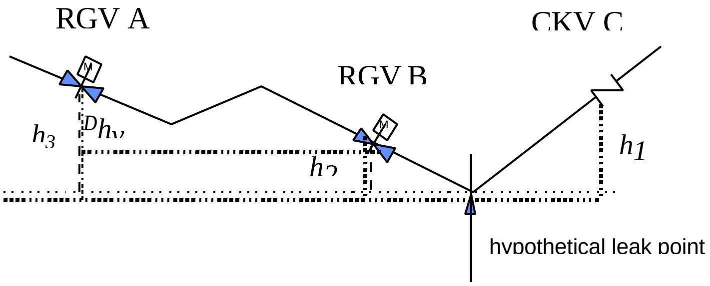
Approximation of Static Head Pressure

For each pipeline segment, two cases were studied: one in which the mainline valve seals perfectly, and one in which the mainline valve leaks-through.

Figure 3 depicts a simplified configuration of valves. The leak in a segment was assumed to occur at the lowest possible point in the line for that segment, in this case, between RGV B and CKV C. This adds to the conservative approach considering the likelihood of a leak occurring at exactly that point, but adequate for the purposes of ranking valves since it defines the case for the largest spill volume.

The first case (referred to as Case 1) represents the scenario where both valves RGV B and CKV C seal tightly in the event of a leak. The high point for Case 1 is the highest point in the segment between the two sealing valves (shown as h_1 in the above figure), in this case one of the valves, CKV C. The mainline leak rate is calculated using the static head (h_1) and 1" diameter mainline hole.

Figure 3: Example Mainline Valve Configuration



For the second case (referred to Case 2), each valve in the segment is considered to fail individually. The leak-through rate of each valve is calculated based on the static head (Δh_v) acting on the valve and the most statistically likely hole size derived from the probability calculations. If the valve leak-through rate exceeds the mainline leak rate, then the valve is determined to have the potential to increase the spill from a 1" diameter mainline leak. If the valve leak-through rate does not exceed the mainline leak rate, then it is determined not to have the potential to increase the spill from the mainline leak because it would not leak-through fast enough to keep the pipe above the mainline leak packed with crude oil.

Each segment of the pipeline was reviewed individually to determine the high points for Cases 1 and 2.

The height differential was then used to calculate the static head pressure (ΔP) as follows:

$$\Delta P = S.G. \times \Delta h \times K \tag{6}$$

where S.G. = specific gravity of crude (0.876 for crude)
Δh = differential height of crude, in feet
K = conversion factor (0.43352 psi per foot of head)

Estimation of Time to Control

The time to control is assumed to be the sum of times to complete three distinct phases of the spill control:

- time to detect and react (guillotine cut only)
- travel time or drain back or drain forward time
- time to excavate
- time to mitigate leak

These times to control the leak were estimated average times that could vary with weather and season. For the purposes of this study, specific worst case conditions for each segment were not considered because the goal was to achieve a relative ranking as opposed to an absolute ranking.

Travel Time or Drain Back Time - For travel times, each segment between valves was reviewed, and a qualitative assessment of travel time, in terms of low, normal, or high was made for the segment. These assessments were based on distance from spill responders, terrain, accessibility, potential weather caused delays, etc. The travel times associated with each qualitative category were estimated as follows:

Table 6: Response Time Estimates

Qualitative Response Time	**Estimated time (hours)**
low travel time	2
normal travel time	4
high travel time	8
time to excavate	12
time to plug the leak	6
time to drain back	see below

The time required to drain back was estimated as the time to configure the line for drain back (travel to and manually open check valves and check valve bypass valves) plus the time for the oil to drain past the point of the leak. The approximate time to drain back was estimated as the oil flow rate times the distance for drain back. The drain back distance was estimated as the milepost distance between two valves, and the drain back rate was presumed to be 3.5 mph based on the hydraulic gradient for the average segment. Therefore, the drain back time was assumed to be the drain back distance divided by drain back rate. Note that at most no more than four miles of mainline can be drained down into each pump station's relief tank. As a result, on the North Slope where drain back is most practical, only one segment between valves for each station north of the leak could be drained back.

In the areas where the line could be pumped down, the drain forward response time was set equal to zero because the RGV's would be left open while the downstream pump stations remained on line to pump down the oil.

If the time to drain back is less than the total time to control the leak, the time to drain back replaces the total time to control in Equation 4 because the mainline leak would be stopped by draining the oil in the pipe below the level of the leak.

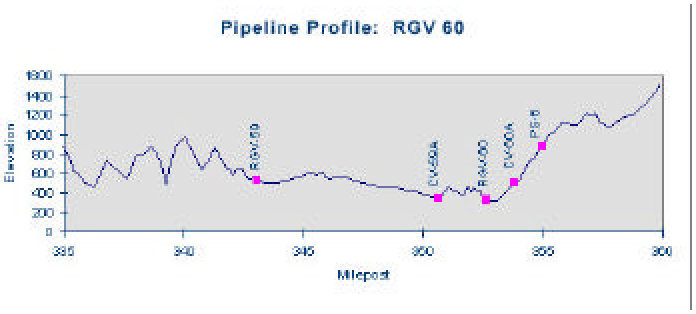
The *excavation time* was set to 0 for above ground segments, and to 12 hours for below ground segments.

The *time to plug* the leak was set to a constant of 6 hours.

Example Calculation of Risk Score

An example of the above calculation of risk is carried out below for RGV-60 for illustrative purposes. RGV-60 is located near the Yukon River at milepost 352.46, at an elevation of 335 feet. RGV-60 closes to isolate leaks north of the valve, between CV-59A and RGV-60, and to isolate leaks south of the valve, between RGV-60 and CV-60A. This example looks at estimating the risk due to RGV-60 failing to seal following a leak between RGV-60 and the Yukon River Bridge.

Figure 4: RGV 60 Profile



From the original design valve location study the following data is extracted:

- Highest local probability factor in the segment = 16.03.
- Resource Value for that location = 73.5
- Segment near water? = YES

The low point in this segment is just north of RGV-60 at an elevation of 325 feet. If RGV-60 (elevation 331 feet) does not seal, additional crude could spill from the segment between RGV-59 and RGV-60. If CV-60A (elevation 520 feet) does not seal, additional crude could spill from the segment between CV-60A and Pump Station 6. Following the line upstream, it is noted that CV-59A does not provide a seal for the hypothetical leak, so the line will drain from the highest point between RGV-59 and CV-59A, located at milepost 350.95 at an elevation of 610 feet.

For Case 1, assuming both RGV-60 and CV-60A seal tightly:

$$\Delta P = S.G. \times \Delta h \times K \quad = 0.876 \times (520-325)\,\mathrm{ft} \times 0.43352 = 74.05\,\mathrm{psi} \tag{7}$$

$$\begin{aligned} Q_L &= C_d \times A \times \sqrt{2 \times r \times \Delta P \times \frac{g_c}{144}} \\ &= 0.61 \times 0.785 \times \sqrt{2 \times 54.57 \times 74.05 \times \frac{32.2}{144}} \\ &= 20.4\ \mathrm{lbs/sec} \end{aligned} \tag{8}$$

Since drain back is not feasible at this location, the control time is governed by the time required to travel to the valve and control the leak. The location was rated as 'normal' for response time, giving a mobilization and travel time of 4 hours from Pump Station 5. The leak location is above ground, therefore no excavation is required to access the leak site. The time to control, or plug, the leak was set at 6 hours. This gives a total post-detection leak duration of about 10 hours. Substituting this information into Equation 4gives the following:

$$\mathit{Spill\ Volume}(\mathit{bbls}) = \frac{Q_L \times K \times T}{r} = \frac{20.36 \times 641.143 \times 10}{54.57} = 2393\ \mathrm{bbls} \tag{9}$$

$$\begin{aligned} \mathit{Risk\ Score}(\mathit{Case}1) &= \text{Spill Size} \times \text{Local Probability} \\ &\quad \times \text{ResourceValue} \times \{1 + \frac{\text{Penalty}}{20}\} \\ &= 2.39 \times 16.03 \times 73.5(1 + \frac{20}{20}) \\ &= 5639 \end{aligned} \tag{10}$$

Now, the leak-through rate for RGV-60 is calculated. Since the next valve upstream is a check valve (CV-59A) which cannot stop the southbound flow of oil, the high point between RGV-59 and CV-59A must be selected as high point to provide the driving force for the leak-through at RGV-60.

$$\Delta P = S.G. \times \Delta h \times K \quad = 0.876 \times (610-331)\,\mathrm{ft} \times 0.43352 = 106\,\mathrm{psi} \tag{11}$$

The risk assessment team determined that the worst case leak-through for a valve except for the valve failing to fully close would correspond with a 0.50 in^2 hole. Therefore, using the head north of RGV-60 and the 0.50 in^2 hole, the leak-through rate for RGV-60 would be:

$$\begin{aligned} Q_L &= C_d \times A \times \sqrt{2 \times r \times \Delta P \times \frac{g_c}{144}} \\ &= 0.61 \times 0.50 \times \sqrt{2 \times 54.57 \times 105.95 \times \frac{32.2}{144}} = 15.5\ \ \mathrm{lbs/sec} \end{aligned} \tag{12}$$

Since the leak-through rate for RGV-60 is lower than the leak rate calculated above for the 1" diameter mainline hole, RGV-60 would not significantly contribute to the total spill volume. As a result, the risk score for RGV-60 leaking is the same as for when the valve seals. This is due to the fact that the spill volume from the 1" diameter mainline hole when the valves seals was based on the pipe remaining packed for the duration of the leak. Since RGV-60 leaks-through at a rate less than the 1" diameter mainline leak, it would not provide enough oil to keep the mainline packed and the oil level would slowly drop away from the valve. (In this example, since CV-60A is so much higher than RGV-60, RGV-60 would have an even lower differential pressure across it, thus reducing the calculated leak-through to a lower value.)

When the process is repeated for RGV-60 sealing and CV-60A leaking-through, it is also determined that CV-60A would not significantly increase the spill from a 1" diameter mainline leak.

Stated in equation form, for a valve to significantly contribute to a mainline leak:

$$A_v \sqrt{\Delta h_v} \geq A_1 \sqrt{\Delta h_1} \tag{13}$$

where A_v = equivalent cross-sectional area of the hole in the leaking valve

Δh_v = uphill static head acting on the leaking valve
A_1 = equivalent cross-sectional area of the hole in the mainline pipe
Δh_1 = uphill static head acting on the hole in the mainline pipe

Phase 3 – DEVELOPMENT OF IN-SERVICE PERFORMANCE AND TESTING CRITERIA

The mainline valves were ranked based on whether they could increase the spill from a 1" diameter mainline leak and by utilizing the data and methods from the original 1976 TAPS valve location study. The 1" diameter mainline leak was chosen as the most likely leak scenario based on previous TAPS risk assessments and studying incident reports from other pipelines. The analysis generated a list of 14 valves that would increase a 1" diameter mainline leak if they had an equivalent leak-through area of 0.25 in^2. An additional 49 valves were identified that would increase the spill from a 1" diameter mainline leak if they leaked as if they had an equivalent leak-through area of 0.50 in^2. The remaining valves would not increase the spill from a 1" diameter mainline leak and are thus ranked using the scoring system described in this paper.

The TAPS Valve Program then used these results for two purposes:

- 1st to prioritize valves for testing over a four year period starting in 1997 and
- 2nd to develop a Quality Program "flag" that would earmark valves for further evaluation should they exceed the leak value that would add to the 1" pipeline leak scenario.

This "flag" became the basis for an Alyeska Master Specification which further defined the performance criteria sufficiently for use in Alyeska Quality Program Conformance/Non-conformance reporting. Once the acceptable leak-through "flag" (non-conformance) is exceeded, the risk assessment is then used as the base Acceptance Criteria for making decisions for repair, replace, or use as is.

Conclusion

The study team places a high level of confidence in the change in risk ranking prioritization because the valves at the top of the list are in close proximity to the major rivers that cross the Pipeline corridor. This fits with the intuitive ranking the study team had before adopting the semi-quantitative approach. Another positive aspect of the ranking is that utilizes much of the original criteria utilized in the original pipeline design.

From an overall Alyeska objective, the risk assessment became a solid base used by the TAPS Valve Program to meet its objectives and goals:

- define compliance regulatory stipulations;
- prioritize work to meet budget constraints;
- upgrade maintenance practices based on service criticality;
- increase operation confidence to operate within more defined margins;
- develop maintenance process's around Alyeska's current business objectives for safety, system integrity, protect the public and environment; and
- extend TAPS operations and useful economic life.

ACKNOWLEDGMENTS

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Figure 1. Probabilities of Leak-by and Leak-through

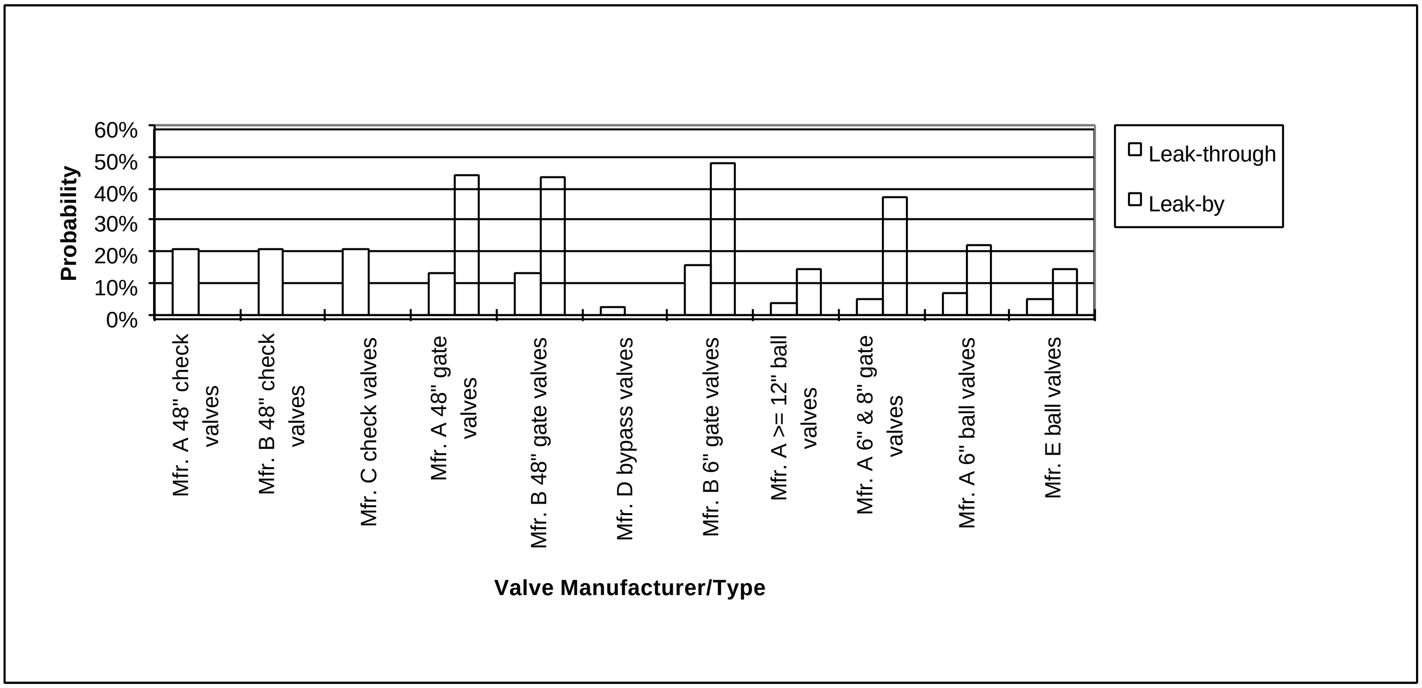


Table 3. Leak Probability, Type, and Equivalent Hole Size for Failure Modes for 48-inch Valves

		Mfr. B 48" gate valves			Mfr. A 48" gate valves			Mfr. A 48" check valves			Mfr. B 48" check valves			Mfr. C check valves		
Mode #	Description of Failure Mode	Probability	Type	Hole Size	Probability	Type	Hole Size	Probability	Type	Hole Size	Probability	Type	Hole Size	Probability	Type	Hole Size
1	scoring of the seat face	M	LB	L	M	LB	L	M	LT	L	M	LT	L	M	LT	L
2A	corrosion of seat face	M	LB	M	L	LB	M		LT						LT	
2B	corrosion of seat pocket	M	LB	M	M	LB	M	M	LT	M	M	LT	M	M	LT	M
2C	corrosion of gate when open, leak-by	M	LB	M	M	LB	M									
2D	corrosion of gate when closed	L	LB	M	L	LB	M									
3	binding of seat	M	LB	L	M	LB	L									
4	spring problems	L	LB	L	VL	LB	L				VL	LT	L			
5	O-ring deformation	L	LB	L	L	LB	L									
6	O-ring/U-cup hardening	L	LB	L	L	LB	L	L	LT	L	L	LT	L	L	LT	L
7	foreign object blocks full gate closure	VL	LT	VH	VL	LT	VH	VL	LT	VH	VL	LT	VH	VL	LT	VH
8	foreign object under gate	VL	LT	H	VL	LT	H			H						
9	gate misalignment	VL	LT	H	VL	LT	H									
10	Mfr. D valve roller pin breaks															
11	Mfr. D valve groove excessive wear															
12	Mfr. D valve stem fracture															
13	Mfr. D valve stem bushing fails															
14	Mfr. D valve trunnion bushing fails															
15	O-ring damage or partial disintegration				L	LB	L									
16	clapper distorted				M	LB	L	L	LT	H	L	LT	H	L	LT	H
17	clapper hinge assembly fails							VL	LT	H	VL	LT	H	VL	LT	H
18	erosion of seal ring							X			X			X		
19	seat set screw backs out							X			X			X		
20	seat ring detaches							VL	LT	H	VL	LT	H	VL	LT	H
21	clapper arm breaks							VL	LT	VH	VL	LT	H	VL	LT	H

0= no leak, LB=leak-by, LT=leak-through, Blank=not applicable, ND=no data, X=not considered credible, basis = single failure (1 seat or 1 o-ring)

Table 4. Leak Probability, Type, and Equivalent Hole Size for Failure Modes for 6-, 8- and 12-inch Valves

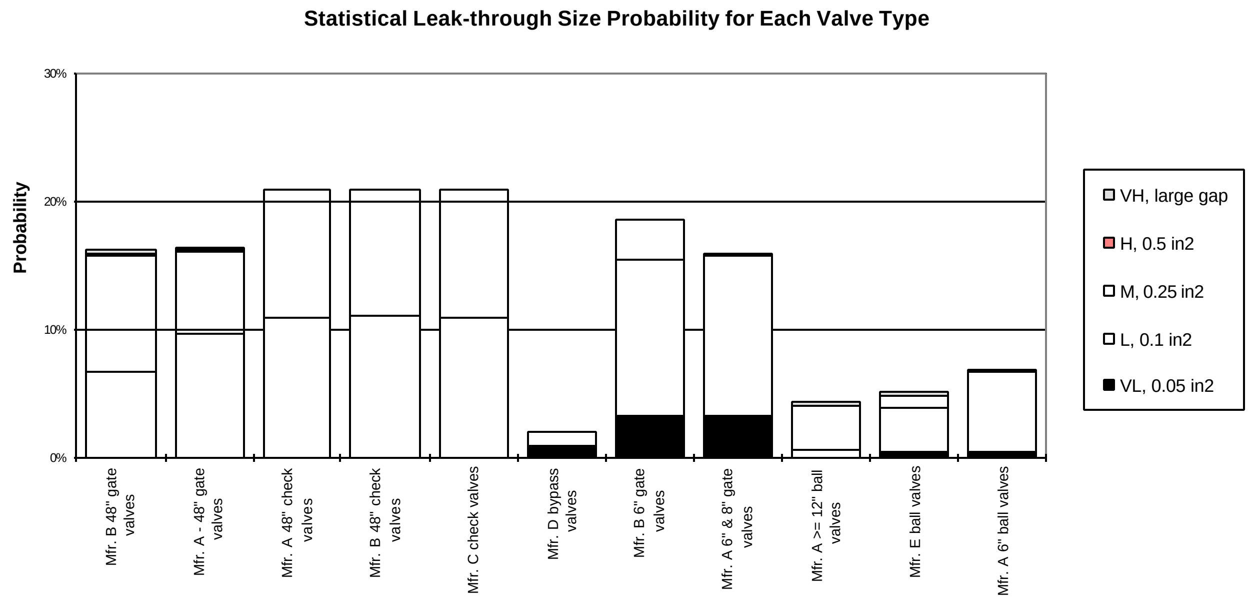
		Mfr. B 6" gate valves			Mfr. A >= 12" ball valves			Mfr. E ball valves			Mfr. A 6" & 8" gate valves			Mfr. A 6" ball valves			Mfr. D bypass valves		
Mode #	Description of Failure Mode	Probability	Type	Hole Size	Probability	Type	Hole Size	Probability	Type	Hole Size	Probability	Type	Hole Size	Probability	Type	Size	Probability	Type	Hole Size
1	scoring of the seat face	M	LB	VL	L	LB	L	L	LB	VL	M	LB	VL	L	LB	VL	L	LT	VL
2A	corrosion of seat face	M	LB	L	L	LB	M	L	LB	L	L	LB	L	M	LB	L	L	LT	L
2B	corrosion of seat pocket	M	LB	L	M	LB	M	M	LB	L	L	LB	L	M	LB	L			
2C	corrosion of gate when open, leak-by	M	LB	M							L	LB	L						
2D	corrosion of gate when closed	M	LB	L							L	LB	L						
3	binding of seat	M	LB	L	L	LB	L	L	LB	L	H	LB	L	L	LB	L			
4	spring problems				L	LB	L	L	LB	VL	VL	LB	VL	L	LB	VL			
5	O-ring deformation	L	LB	VL					LB		L	LB	VL						
6	O-ring/U-cup hardening	L	LB	L	L	LB	M	L	LT	M	L	LB	L	L	LB	M			
7	foreign object blocks full gate closure	VL	LT	H	VL	LT	VH	VL	LT	H	VL	LT	H	VL	LT	H	VL	LT	H
8	foreign object under gate	VL	LT	M							VL	LT	M						
9	gate misalignment	X	LT	M							VL	LT	M						
10	Mfr. D valve roller pin breaks																VL	LT	M
11	Mfr. D valve groove excessive wear																VL	LT	M
12	Mfr. D valve stem fracture																X	X	
13	Mfr. D valve stem bushing fails																X	X	
14	Mfr. D valve trunnion bushing fails																X	X	
15	O-ring damage or partial disintegration										L	LB	L						
15A	seal face O-ring damage																		
16	clapper distorted																		
17	clapper hinge assembly fails																		
18	erosion of seal ring																		
19	seat set screw backs out																		
20	seat ring detaches																		
21	clapper arm breaks																		
22	trunnion bearing seizes				VL	LT	VH	VL	LT	VH				VL	LT	H			
23	nylon inserts fail							L	LB	H									
24	Cameron pawl breaks on seal rotation							H	0	VL									

0= no leak, LB=leak-by, LT=leak-through, Blank=not applicable, ND=no data, X=not considered credible, basis = single failure (1 seat or 1 o-ring)

Table 5. Probabilities of Hole Sizes for Leaks from Valves

Valve Manufacturer/Type	VL, 0.05 in^2	L, 0.1 in^2	M, 0.25 in^2	H, 0.5 in^2	VH, large gap
Mfr. B 48" gate valves		0.066	0.092	0.002	0.001
Mfr. A - 48" gate valves		0.097	0.064	0.002	0.001
Mfr. A 48" check valves		0.109	0.100		
Mfr. B 48" check valves		0.110	0.100		
Mfr. C check valves		0.109	0.100		
Mfr. D bypass valves	0.010	0.010			
Mfr. B 6" gate valves	0.032	0.122	0.031	0.001	
Mfr. A 6" & 8" gate valves	0.032	0.125	0.002	0.001	
Mfr. A >= 12" ball valves		0.006	0.034		0.002
Mfr. E ball valves	0.004	0.034	0.010	0.001	0.001
Mfr. A 6" ball valves	0.004	0.062	0.002	0.001	

Figure 2. Probabilities of Hole Sizes for Leaks for Each Valve Type



At 100 psid, nominal leak rates are: H=125 gpm, M=60 gpm, L=25 gpm, VL=12 gpm