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# USE OF ISOLATION STOPPLES® FOR VALVE REPLACEMENT ON TRANS ALASKA PIPELINE

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## ABSTRACT

In 1997 Alyeska Pipeline Service Company (Alyeska), operator of the Trans Alaska Pipeline System (TAPS), identified two mainline valves that required repair. The remote location, size and scale of these valves combined with the hydraulic profile of the pipeline presented significant challenges for the repair of the valves. Both valves were located such that the pipeline could not be simply drained to allow for repair or replacement. To drain the locations would have required facilities to drain, store, and re-inject or transport 108,000 bbls of oil. Isolation of these valves utilizing STOPPLES® reduced the volume of oil that needed to be handled but required repairs to be conducted by personnel working in a confined space behind the STOPPLES®.

The conceptual repair plan for each of these valves was evaluated through a Peer Review/Risk Assessment to validate or revise the isolation and repair concepts. This process provided the communication and evaluation methods that were necessary to gain acceptance of the use of STOPPLES® for isolation by the organizations performing the work, state and federal agencies monitoring the work, and TAPS stakeholders.

The work on Remote Gate Valve 80 (RGV 80) and Check Valve 122 (CKV 122) was completed during a single 28 hour pipeline shutdown in September of 1998. Both valves were isolated with STOPPLES® to minimize the crude handling requirements. This paper describes the repair of these valves from the conceptual design through the completion of the work.

## INTRODUCTION

Alyeska Pipeline Service Company (Alyeska), operates the Trans-Alaska Pipeline System (TAPS) which delivers crude oil from the North Slope of Alaska to the ice-free terminal at Port Valdez, Alaska. The mainline pipe is 48 inches in diameter and approximately half of the 800-mile length is installed below ground and the other half is supported above ground. *(Figure 1)*

In 1997, Alyeska implemented a program to test all of the mainline valves in TAPS to determine if the valves sealed adequately after 20 years of service. The first 3 years of this testing program identified two valves out of 148 tested that did not meet Alyeska's criteria for allowable internal leak through. One valve was a Remote Gate Valve (RGV 80) the other was a Check Valve (CKV 122). Both of these valves were scheduled for repair or replacement in 1998.

This paper describes the issues that defined the scope of these projects and the process that Alyeska utilized to determine the methods for isolation and repair of these valves.

## NOMENCLATURE

STOPPLE®: Is a registered trade name of T.D. Williamson Company, Inc. in the United States and foreign countries for equipment to isolate pipeline segments under line pressure.

## BACKGROUND

Included in the 800-mile pipeline between Prudhoe Bay and Port Valdez, Alaska are 177 mainline valves which provide capability for pump station isolation, pipeline over-pressure protection and oil spill volume mitigation. Of the 177 mainline valves, 95 are through-conduit gate valves, 81 are check valves, and one is a ball valve. The valves installed for oil spill mitigation are installed at major river crossings and approximately every 5 miles along the pipeline. The spacing of the valves is designed to limit the potential spill volume between the valves to nominally less than 50,000 barrels.

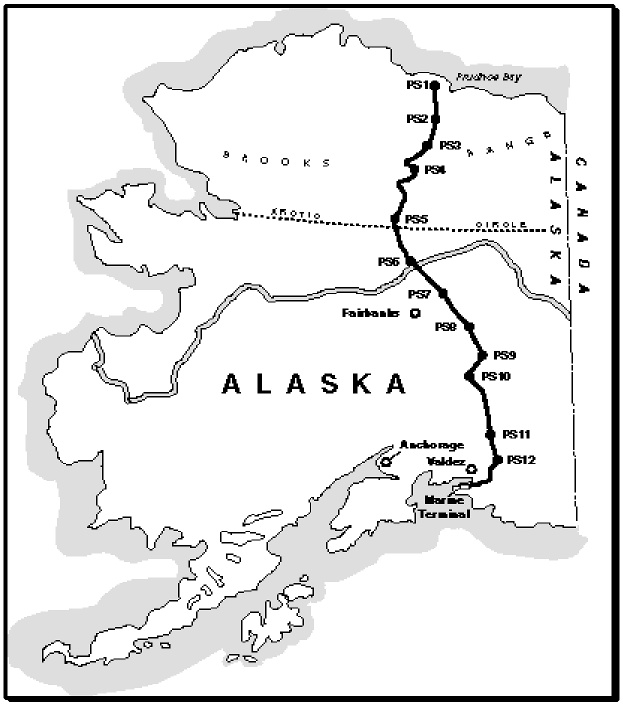


*Figure 1*: *Trans Alaska Pipeline System*

TAPS was commissioned in 1977 and has operated nearly continuously since startup. Since commissioning, none of the mainline valves had been replaced due to their performance prior to this project. Three check valves were replaced as part of the replacement of 8.5 miles of pipe and two additional check valves were repaired after having pipeline pigs stuck in them. As the majority of the mainline valves are installed as a contingency to limit the volume of a spill from a pipeline leak, they are seldom fully cycled. The mainline valves are function-tested semi-annually in accordance with Department of Transportation regulations. In addition, the mainline valves are winterized annually by draining any water from the body of the valve and injecting antifreeze and corrosion inhibitor to protect the valve.

The mainline gate valves are designed to establish a full seal on both the upstream and downstream seat. If the valve fully seals, the body of the valve can be fully de-pressured. During the winterization procedure, some valves were identified which could not be fully de-pressured. This condition indicated that one or both of the valves seats allowed some leakage into the valve body. *(Leak-by Figure 2)*. However, as this procedure was done with the valve in the fully open position and leakage could be coming from a single seat, no conclusions could have been made about the ability of the valve to seal in the closed position with differential pressure. *(Leak-through Figure 2)*.

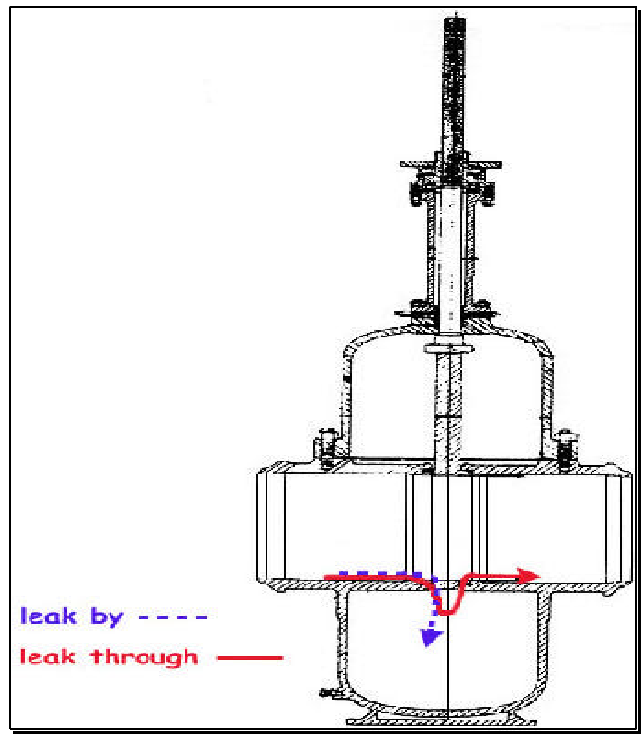


*Figure 2: Mainline Valve Potential Internal Leak Paths*

Concerns about the ability of mainline valves to seal grew during the early to mid 1990's as several repair projects were conducted at the pump stations. During these repairs and other maintenance activities, several facility isolation valves were found to not fully seal. The majority of these isolation valves are ball valves which cycle frequently during normal operations. These valves were repaired or replaced as required on an individual basis. However, in performing repair work at Pump Station 6 in 1996, it was determined that RGV 60 did not fully seal.

The concern about the condition of the TAPS mainline valves led to the development of the TAPS Valve Program. This is a comprehensive program of testing, maintenance, and repairs to provide assurance that the valves in TAPS continue to perform as required. As part of this program the sealing capabilities of all the TAPS mainline valves are to be tested by the end of 2000. To date, 148 of the 177 valves have been tested and two mainline valves did not meet Alyeska's criteria. These valves were RGV 80 and CKV 122.

RGV 80 is a gate valve manufactured by WKM and weighs 67,000 pounds. The valve is installed in an above ground configuration at TAPS milepost 519 between Pump Station 8 and Pump Station 9. The pipeline profile at this location is a valley with RGV 80 located at the low point. When the pipeline is shutdown the minimum static head at RGV 80 is approximately 550 feet. Draining the segment of pipeline containing RGV 80 would require the handling of approximately 90,000 barrels of oil. *(Figure 3)*.

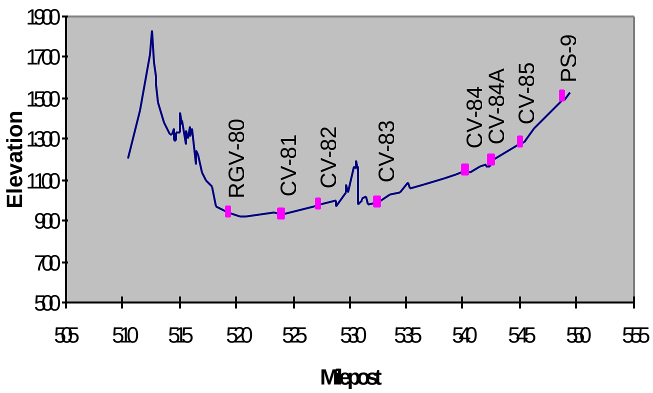


*Figure 3: Pipeline Profile: RGV 80*

CKV 122 is a check valve manufactured by WKM. It is installed below ground at TAPS milepost 780 on the south side of Thompson Pass on the bank of the Lowe River. (Figure 4). The pipeline profile at this location is similar to that of RGV 80 in that it is a valley with CKV 122 at the low point. The minimum static head at CKV 122 is approximately 1030 feet. Draining the pipeline segment containing CKV 122 would require handling approximately 18,000 barrels of oil. In addition, draining of this segment of pipe would require tapping into the pipeline in the Lowe River floodplain below the normal water level of the river.

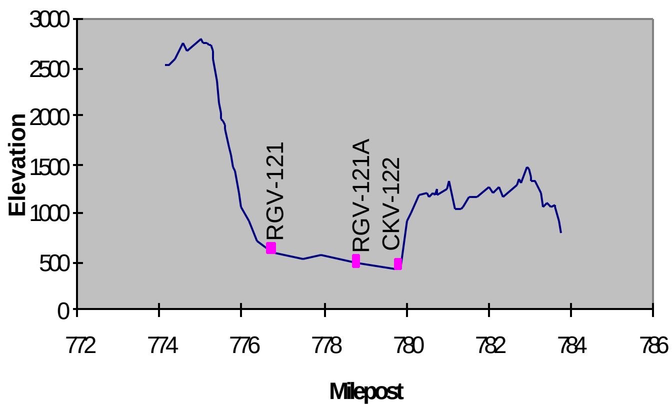


*Figure 4: Pipeline Profile CKV 122*

## CONCEPTUAL PROJECT PLANS

Conceptual repair plans were developed for each of the valves. The scope of each conceptual study was to evaluate the feasibility of alternative methods to isolate and repair or replace the valve. The primary valve repair options were to rebuild the existing valve in place or to cut the existing valve from the line and install a replacement valve.

The recommended repair method for CKV 122 was to repair the valve in place. The advantages to rebuilding the valve were:

- All the sealing and moving parts of the check valve could be replaced.
- Access to the valve's internal components and working space were relatively good.
- This type of work had been previously performed on TAPS mainline check valves.
- All of the sealing surfaces, wear surfaces, and moving parts could be fully examined.
- Mechanical repair would be far less complex than a valve replacement. Valve replacement would have required significant excavation, dewatering, and water discharge control due to the proximity of the Lowe River.
- Repair offered the contingency of removing the internal components and replacing the bonnet of the valve if it were determined that the valve was not repairable. This would allow for a replacement project to be planned and scheduled if necessary.
- The excavation and pipe stabilizing requirements would be significantly reduced for a repair of the valve vs. the replacement of the valve.

Risks associated with the repairing the valve in place were:

- Repair might not correct the sealing problem if the problem were in the valve body.
- Repair required personnel to work inside of the valve body for extended periods.

The recommended repair method for RGV 80 was to remove the existing valve and install a replacement valve. The advantages for replacement of the gate valve were:

- Installation of a new valve would provide assurance that the valve would seal when the work was completed.
- Removal and installation of an above ground valve would be less complex than attempting to rebuild the valve in place.
- Access to the sealing surfaces and working spaces would be limited in the gate valve.
- Costs for the repair and the replacement were nearly the same.
- Removal of the valve would provide the opportunity to fully examine the condition of a gate valve after 20 years of service in TAPS.

Risks associated with the replacement of RGV 80 were:

- Once the pipeline was cut there would be no simple way to return to operation if there were problems with the project implementation. Either a new valve would be installed or other contingencies implemented.
- The equipment lifts would be significant as the equipment weighs between 67,000 and 90,000 pounds.

## ISOLATION METHODS AND CONCERNS

Several scenarios for isolation were considered. However, the conceptual plans for both valves recommended utilizing single STOPPLES® for isolation of the valves (one STOPPLE® on each side of the valve). *(Figure 5)* Other alternatives considered were drain-down of the line segment and utilizing double STOPPLES® for isolation. The drain-down alternatives were not recommended due to the volumes of oil that needed to be handled. It became apparent that handling the drained oil alone would be a project more complex than the repair or replacement of the valves. Installation of double STOPPLES® was considered but represented a significant increase in the complexity of the work and previous study had shown no increase in personnel safety. A Double STOPPLE® configuration could provide more confidence in isolation from a leak past a STOPPLE®. Utilizing single STOPPLES® for the isolation of the valves combined with personnel working for extended periods of time behind the STOPPLES® in the body of CKV 122 represented a significant hurdle for acceptance of the recommendations from the conceptual studies.

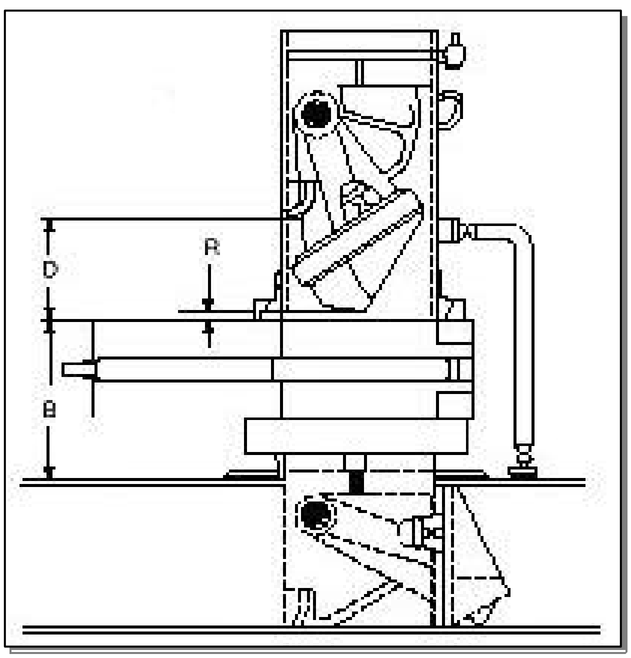


*Figure 5: STOPPLE® Machine*

STOPPLES® had been used on TAPS to isolate the mainline for maintenance and repairs similar to the proposed applications at RGV 80 and CKV 122. The management issues and risk assessments of STOPPLE® use on TAPS over time and the current procedural requirements were documented. However, STOPPLES® were last used for isolation on TAPS in 1991 and had not been used for isolation under Alyeska's current quality program which requires significantly greater documentation for materials, equipment and procedures.

Single STOPPLES® and a bypass were first used on TAPS in September 1979 to remove a stuck pig from CKV 29. T.D. Williamson (TDW) equipment was used to hot-tap the mainline to allow CKV 29 to be bypassed and then isolated with STOPPLES® The hot-tapping, STOPPLING®, work to remove the pig and the repair of CKV 29 were all performed with TAPS in operation under full line pressure.

Single STOPPLES® were next used on TAPS in January 1985 to bypass and allow the replacement of a damaged section of pipeline. There was high confidence of success based on the previous successful application of STOPPLE®/bypass techniques at CKV 29. The STOPPLING® equipment used was the same equipment previously utilized at CKV 29. However, failure of both STOPPLES® occurred during the depressurization of the isolated section after the STOPPLES® had been set. Failure occurred at a differential pressure of 680 psi. The south STOPPLE® failed, breaching the pressure barrier, buckling the control bar and dropping the STOPPLE® plugging head. The north STOPPLE® moved axially, bending the control bar. Failure analysis identified several contributing factors including equipment design, setting procedures and pipeline operating conditions.

The STOPPLING® equipment was modified and tested by TDW in 1985. Based on the tests, Alyeska restricted the use of the modified STOPPLES®. The STOPPPLES® could not be used for mainline repairs under flowing, high-pressure conditions, and no setting of STOPPLES® was allowed under flowing conditions. The functionality of the design was still dependent on the proper positioning of the STOPPLE® head on the bottom of the pipe, which could not be readily verified.

In 1990, Alyeska performed a series of tests in a STOPPLE® Qualification Program, developed a set of standards for use of STOPPLES® on TAPS, and established criteria for management to qualify STOPPLES® for use under flowing, high pressure conditions. The equipment was modified to include centering jigs on STOPPLE® cuts and ultrasonic probes were installed to ensure proper setting of the STOPPLE® heads. Tests were performed on a slanted jig to qualify techniques for conditions expected on the Atigun Reroute Project, where hot-taps were to be performed on pipe slopes up to 15 percent.

Based on the qualification program results, setting of STOPPLES® remained restricted to "no flow" conditions, but maintenance and repair activities could occur behind STOPPLES® under flowing, high pressure conditions. A double-block system using a second STOPPLE® behind the primary STOPPLE® was established as a operational standard for use of the TDW technology on TAPS, but single STOPPLES® were qualified for use based on a site-specific risk assessment.

Use of single STOPPLES® and a bypass in combination with station block valves to establish a double block system, was successfully utilized for the Pump Station 3 Repair Project in 1990.

In 1991 two sets of double STOPPLE®/bypasses were utilized to tie-in eight miles of replacement pipe for the Atigun Reroute Project. A quantitative risk assessment was made of repair strategies for the tie-in of the Atigun replacement pipe, including four different STOPPLE® scenarios.

In 1996, a risk assessment for the tie-in of additional facilities at Pump Station 1 approved the use of single STOPPLES® over double STOPPLING® scenarios. The project was subsequently canceled for other reasons and the STOPPLES® were not installed.

The use of STOPPLES® for isolation on TAPS is never considered a standard isolation method. Even with the multiple successful projects since 1985, there has always been a healthy concern for placing personnel at work behind STOPPLING® equipment. The repair of RGV 80 and CKV 122 added an additional dimension for those concerns with the requirement at CKV 122 for personnel to be working for long periods of time between the two isolation STOPPLES® inside the body of the check valve. This combination of concerns created a significant challenge in gaining acceptance of this approach to the work.

## RISK ASSESSMENT

A Peer Review/Risk Assessment was conducted in February of 1998 to evaluate the recommendations from the conceptual project plans, address the concerns with the isolation methods, and to fully communicate valve repair project issues with the concerned groups. The review and assessment group consisted of over forty people representing Alyeska engineering, operations and safety personnel, TDW Manufacturing, Owner Company safety and technical personnel, producer safety and technical personnel, WKM service personnel, implementation contractor personnel, and state and federal safety and oversight personnel.

The group reviewed the conceptual project plans as well as all of the documentation from the previous work and testing that had been performed utilizing STOPPLES® for isolation. After the review of the documentation, focus groups looked specifically at four separate areas of concern:

- STOPPLE® isolation and personnel safety (single vs. double STOPPLES®).
- Personnel safety working behind STOPPLES® in a confined space.
- Oil Spill Response contingencies.
- Project scheduling/logistics associated with performing both projects simultaneously.

The Peer Review/Risk Assessment validated the recommendations from the conceptual project plan. The assessment also identified over forty specific recommendations, which needed to be addressed or implemented to enhance the safety and efficiency of these projects. The recommendations covered a range from personnel training requirements to the construction of a contingency containment for the CKV 122 site. These recommendations were all addressed, implemented where appropriate, and documented. In addition to the Peer Review/Risk Assessment, other risk assessments were conducted later on specific project procedures as they were developed.

This Peer Review/Risk Assessment was the fundamental process for obtaining acceptance of the valve isolation plan. The risk assessment environment allowed regulatory and implementation concerns to be raised and addressed during the design phase of the project. Incorporating the recommendations to reduce risks into the design eliminated delays and redesign in the implementation phase of the work

## FINAL PROJECT SCOPE

The scope of the project integrated the project management for both of the valves to facilitate management, coordinate training, provide better logistical control and eliminate duplication in both efforts. The physical scope was to cut out and replace RGV 80 and to completely rebuild CKV 122 during a single 30-hour pipeline shutdown using single STOPPLES® for isolation. *(See Figure 6)*. The project was also responsible for training all necessary personnel in the procedures and practices that were required to perform the work. In addition to the valve work, a lined contingency containment pond was to be constructed at the CKV 122 site. This pond was sized to capture and contain all of the potential oil, which could leak in the event of an equipment failure and, thus, protect the Lowe River. The project also provided for pubic meetings and presentations covering the scope of the work.

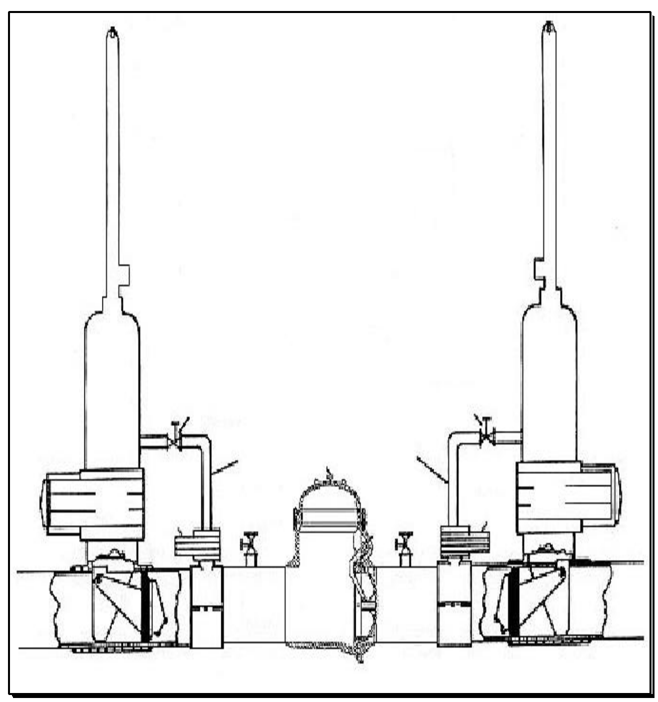

*Figure 6: Stopple Assembly Sketch*

## PROJECT EXECUTION

The Peer Review/Risk Assessment was conducted in February of 1998. Final scope was determined by March, installation of split-tee fittings started in July and the pipeline was shutdown for the physical valve work in September of 1998. *(See Figure 7)*. All of the project components were fit into this schedule after the February risk assessment: funding; final design; obtaining permits; material procurement; procedure development; training; testing; and implementation. The initial detailed project schedule developed in February showed only two weeks of potential slack time prior to the planned pipeline shutdown.

*Figure 7: Split-Tee Assembly*

A significant investment was made in the training of personnel performing the work for CKV 122, all of the procedures, tools, cleaning and methods for repairing the valve were developed and fully tested on a full size spare valve in Alyeska's Fairbanks Fabrication Facility. For the replacement of RGV 80, similar training was conducted on all of the equipment that would be utilized for the removal and replacement of the valve. The replacement valve was utilized to develop the required rigging and lifting equipment and procedures. Training was also conducted on the hot-tapping and STOPPLING® equipment.

Due to the limited space at the actual work sites, the training facilities were utilized to familiarize Alyeska personnel, agency personnel, and the public with the scope and scale of the work. This allowed agency personnel to concur or request modification of the practices and procedures that would be utilized during the actual repairs. This subsequently reduced the number of agency personnel that needed to be at the construction sites during the actual work.

In addition to developing the procedures, the training was utilized to prepare the detailed schedule for the actual work to be performed during the pipeline shutdown. The time required to perform the work at each site was estimated to take between 24 and 28 hours. The pipeline shutdown of 30 hours was planned and coordinated with TAPS Operations, North Slope Producers, Refiners, and the shippers.

While the shutdown was scheduled to take only 30 hours, the preparation for the work required coordination with TAPS Operations for several months prior to the shutdown as well as after the shutdown. In order to prepare for this work and shutdown, four 48 inch hot taps were made (two at each site) to allow for the installation of the STOPPLING® equipment. While this work was conducted on the operating pipeline, pigging operations had to be suspended from the start of the tapping operation to the installation of the completion plugs and pipe coupons. After the hot-taps were completed, the completion plugs were installed to allow pipeline pigging to be restored. Pigging operations were again suspended approximately two weeks prior to the pipeline shutdown to allow the completion plugs to be removed and the STOPPLING® equipment to be installed. Pigging operations were not resumed until after the repairs were made, the STOPPLING® equipment was removed, and the completion plugs were reinstalled.

During the pipeline shutdown, RGV 80 and CKV 122 were successfully repaired and tested. The pipeline was restarted 28 hours after being shutdown. CKV 122 was found to have debris in the seat area as well as mechanical damage to the seat and to the clapper. The debris had held the clapper away from the seat preventing the valve from sealing. The damage appeared to have been caused by a part of a washer being crushed into the seat by the hydraulic pressure against the clapper. RGV 80 also suffered mechanical damage to the down stream seat and to the gate. It appeared that some foreign material lodged between the seat and the gate. This subsequently led to gouging of both the seat and the gate as the valve was closed.

## CONCLUSION

The completion of this work re-established the performance capabilities required for the valves installed in TAPS at their respective locations. This project represented the first major mainline valve repairs completed under the TAPS Valve Program at a cost of nearly eight million dollars. The TAPS Valve Program is providing Alyeska assurance, that after 20 plus years of service, that the valves in TAPS function as required and will continue to function as long as TAPS is needed to operate.

In performing this work, the accomplishment in which Alyeska takes the greatest pride is that not a single operational incident, accident or personal injury occurred.


## ACKNOWLEDGMENTS

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