Comments on Trans-Alaska Pipeline System Operations (Part II)

At Scoping Meeting for the TAPS Right of Way Renewal Application
Of the Owners of the Trans-Alaska Pipeline System (May 2001)

Prepared for
The Alaska Forum for Environmental Responsibility

By
Richard A. Fineberg
Research Associates
P.O. Box 416
Ester, AK 99725

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Twenty days ago I testified before you in Anchorage to introduce salient issues concerning the TAPS Owners’ recent application for renewal of the Grant and Lease under which they operate the Trans-Alaska Pipeline System (TAPS). In those prepared remarks, I challenged the sanguine assessment of the TAPS Owners that they operate the pipeline safely by reviewing a variety of operating problems or anomalies, which I summarized as follows:

- Closing pump stations despite communication system failures;
- continued restart problems; delayed valve replacements – I submit there is a pattern to what happens on TAPS, and the pattern is this: A major source of risk to the pipeline is the unexamined consequences of operational problems caused by chronic project delays, and that a major source of these delays is the constant budget pressure under which TAPS operates. There is little justification for this pressure, since TAPS earns a guaranteed profit . . . \(^1\)

Events of the past twenty days have confirmed the concerns I outlined September 20. Three oil spills associated with the planned shutdown and restart Sept. 22 and the 36-hour lag between the time Alyeska knew that a bullet hole had pierced the pipeline Oct. 4 and the application of a clamp to stop that leak appear to fit the assessment I offered Sept. 20. These events demonstrate the importance of time to the apprehension of – and

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reduction to – the adverse environmental impacts of TAPS. The time factor shows up in these events in two ways:

☞ (1) How long does it take Alyeska to identify a problem?

☞ (2) Once finally acknowledged, how long does it take Alyeska to remedy the problem?

The sum of these two periods is the length of time that Alaska’s environment is at needless or unjustified risk of chronic environmental degradation or, perhaps, severe environmental damage.

The oil spills associated with restarts September 22 provide a clear example of the first problem. As the attached documenting package makes clear, the Alaska Forum for Environmental Responsibility identified restarts as a problem for TAPS operators five years ago, but Alyeska and government monitors were both too slow to identify the problem and too quick to claim its resolution. By September 20, 2001, they both claimed – inexplicably to us, in view of the clear evidence to the contrary – that restarts were not a problem, despite a string of mishaps through seven years that indicated that there were significant problems associated with restarts.

The restart issue assumes increasing importance because pipeline shutdowns and restarts during the 1996 and 2000 period tripled in comparison to the average for the 17 years from 1979 through 1995 (see Figure 1, below). ² One can only hope that one result of the September 22 mishaps will be that the managers of TAPS will finally treat the shutdown and restart process with the special degree of care commensurate with a relatively high-risk activity (when compared, for example, to static operations).

Also during the past 20 days, TAPS was punctured by a bullet from a high-powered rifle, allegedly fired by a miscreant with a long record of criminal conduct. In this case, the time factor was painfully obvious to visitors to the oil spill site during that agonizing 36 hours that an unabated fire-hose stream of black crude oil spewed out of the pipeline and onto the tundra. Fortunately, the site was more than a mile from the Tolovana River, because the variety of clamps that the Alyeska contingency plan claims are readily available for emergency response were not readily available. While spill responders hustled – and performed commendably – to dig new containment pits as oil seeped through the saturated forest near the pipeline, Alyeska’s Incident Commander maintained, with a studied, philosophical calm, that everything was under control. “At this point,” he said, “there is nothing to do but wait,” he said, extolling the necessity for safety while a thick, black stream of oil was leaping from the pipeline at a rate of better than 120 gallons per minute. Safety, of course, is a legitimate concern; training and field

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3 This account is based on personal observation Friday, O dct. 5 and the TAPS Oil Spill Contingency Plan (Doc. CP-35-1, esp. Sec. 1.7.22), supplemented by Alaska Department of Environmental Conservation “Sitrep” reports press accounts.
drills should enable Alyeska to execute safe and rapid deployment of its response equipment.

For reasons that are not yet clear, a bullet hole clamp could not be used, while the hydraulic clamp could not be applied to stop the leak. Alyeska has given no reason why its contingency plan claims a bullet hole clamp in its arsenal of clamps if it can’t be used. Nor is it clear at this time whether Alyeska has more than one clamp that can handle bullet hole leak like the one October 4. The pipeline operators give two reasons for the delay in application of the hydraulic clamp to stop the leak: First, they wanted the pressure in the line to go down because they had only tested the clamp to 250 pounds per square inch. Then, the crane that Alyeska brought to the site was not big enough to handle the heavy clamp.

This may seem like an excellent response to the Governor and Commissioner of Environmental Conservation; it certainly doesn’t to the Alaska Forum. As the failures of the Exxon Valdez taught us in 1989, rapid response is crucial to spill mitigation. The spill site was on a level and well-maintained portion of the workpad, less than half an hour from a pump station and two hours from the major headquarters and storage facilities at Fairbanks. For most of the delay period, the weather was good; is 36 hours to mount a temporary clamp to close a bullet hole under these circumstances is cause for concern – not adulation. Hopefully, the black fruits of the delay responding to the MP 400 spill will not find their way to the Tolovana River next spring.

The significance of these events is that they are indicators that TAPS is not managed and operated in a manner that satisfactorily mitigates environmental risk. Also on September 20, I submitted a preliminary report identifying a documented design link between specific above-ground portions of the pipeline and the potential for soil liquefaction in the event of an earthquake. As discussed in that report, Alyeska employed its experimental, above-ground construction in these stretches to reduce the seismic hazard by keeping the substrate frozen. Since that design was experimental, it was anticipated that those sites would be closely monitored. Over time, Alyeska’s seismic experts appear to have forgotten the design logic. Instead, they conveniently assume the
design is working effectively to mitigate the seismic hazard. Global climate trends and the failure of the thermosyphon system are two of the significant factors that work against that assumption. Nevertheless, it appears that Alyeska’s engineers had not closely monitored – or even identified – the critical locations specified in TAPS design criteria prior to our inquiries on September 6.4

Delays in the replacement of RGV-39 on the Koyukuk River and in the execution of measures to assure that the TAPS can maintain sufficient heat to allow restart after an extended winter shutdown (the “cold restart” problem) are two other examples of chronic problems that place Alaska’s environment – and the major source of West Coast oil – to needless risk. I discussed RGV-39 in my Sept. 20 presentation, where I also suggested that the valve inspection program that Alyeska completed in the year 2000 – once again, in a belated response to a problem that should have been identified earlier – should be run on a continuous basis to detect poor valve performance before it becomes a threat to pipeline integrity, and to the environment.5

As for the cold restart question: If oil is allowed to congeal before restarting during winter, TAPS is liable to become the world’s longest chapstick. For this reason, JPO identified the lack of a cold restart plan as the most important operational compliance issue faced by the TAPS Owners today.6 Between supports, the above ground portion of the pipeline is sheathed by 3-3/4 inches of insulation and a galvanized sheet metal outer jacket. At the VSM’s, a plastic coated module contains insulation inside a fiberglass shell. According to Alyeska literature, the insulation was designed to be “totally wind and weather proof” in order to keep the oil warm enough during a winter shutdown to resume pumping for 21 days.7 However, for many years gaps in the top of

4 See: Richard A. Fineberg, “TAPS Seismic Liquefaction Stability Concerns” (Preliminary Report), Sept. 20, 2001. (In this case, the time question is not “what did they know and when did they know it?” Rather, the question is, “What did they forget and when did they forget it?”)
the modules and degradation of fabric expansion joints have allowed water to enter the insulation that protects the pipe. Water trapped in the protective jacket can reduce its insulating ability; during an extended winter shutdown, the insulating jacket that is supposed to be protecting the pipe instead is liable to encase the pipeline in an icy sheath that removes heat from the oil with great efficiency, reducing significantly the insulating capability of the protective shell and the time that TAPS can be shut down before the oil cools to the point that it gels.8

As discussed in the operations CMP report, one of the criteria TAPS was designed to meet was that the pipeline must be able to be restarted after a 21-day shutdown at temperatures of minus-40 degrees Fahrenheit. Alyeska’s cold restart capability was significantly reduced by the closure of four pump stations and the modification of Pump Station #5 during 1996 and 1997. Four years later -- while Alyeska is still trying to implement a replacement cold restart plan before the Nov. 1, 2001 deadline imposed by JPO – it appears that the pipeline operators have finally realized that water in the above ground insulation may jeopardize execution of a plan that will actually work.

Surprisingly, this long-standing problem does not appear to have been factored into the cold restart plan until very recently. During the summer of 2001, Alyeska maintenance personnel were fabricating new metal outer coverings to keep water from entering the insulation jacket in the future.9 However, it was not until the last week of August 2001 that Alyeska engineers apparently realized that in the event of a winter shutdown, water already in the insulation could result in a significant reduction in the period of time before oil congealed, making restart impossible. At that point, they quickly dispatched small maintenance teams to cut slits in the bottom of the insulating jacket at hundreds of above ground locations in the 50 miles of pipe between Fairbanks and Livengood.


9 Discussion Alyeska technicians from Pump Station #9 (August 28, 2001) and Pump Station #7 (September 6, 2001).
When asked about the reason work crews were sent out to drain water out of the insulation jacket in response to the annual August rain, Alyeska engineers first claimed that the project was conducted as part of an aggressive maintenance plan spelled out in an internal report detailing the results of a major, linewide assessment conducted during the previous year. But according to the Alyeska maintenance coordinator for that region, the effort to get the water out of the insulating jacket was not part of his planned maintenance for the season. Rather, the maintenance coordinator said, Alyeska engineers thought of the job one week and headquarters engineers working on the cold restart problem ordered it done the next.

A second concern in this regard is that wet insulation could exacerbate the potential for corrosion in the above ground mainline pipe. Alyeska has detected isolated instances of above ground mainline pipe corrosion. One of the sources of that corrosion is water in the insulating jacket at points where 2-x-4 shims were inserted between the pipe and the insulation module during construction. The wood, like the water, isn’t supposed to be inside the insulating jacket. While above ground corrosion has not posed a serious problem to pipeline integrity to date, 25 years ago Alyeska said that corrosion below ground would not be a problem, either.

As we have discussed in previous meeting with Argonne personnel, difficulties obtaining substantive information and limited resources prevent the creation of a complete list of problems on TAPS. Nevertheless, we hope the information we provided in Anchorage Sept. 20 and the information presented in Fairbanks today will be sufficient to encourage you to look carefully at the superficial assurances of the TAPS Owners that the pipeline is operated safely, and that the statutory and regulatory and contractual terms under which TAPS operates are sufficient to ensure that safety for the duration of an extended Grand and Lease renewal.

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10 Statement of Elden Johnson, Alyeska Systems Integrity Manager, at Sept. 6, 2001 briefing.
11 Interview with Pump Station #7 maintenance coordinator, Sept. 6, 2001.
12 In response to a reporter’s question in 1975, Alyeska provided this written response: “The pipe has a design life of 30 years. Actually, it probably has a life far beyond three decades. The pipe is essentially inert and the Alaska environment is not hostile to the pipe. We don’t have many corrosive contaminants” (memorandum from Larry [Carpenter] to Jill [Shepherd], Sept. 23, 1975).
In conclusion, we believe the events of the past 20 days serve to emphasize the importance of the five broad recommendations we tendered September 20. We further reiterate our observation that the financial constraints that are sometimes used to justify engineering decisions reducing or delaying environmental protection on TAPS are difficult to justify when the TAPS Owners receive at least $500 million a year in off-book, after-tax income on the accelerated collection of DR&R funds allowed by the TAPS Settlement Methodology (TSM) adopted in the 1985 TAPS tariff settlement agreement.¹³

Our more detailed report will come to you as soon as we are able to complete it.

Thank you once again for your kind attention.

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**List of Attachments (Re: Restarts)**

1995-1996 (*Pipeline in Peril*)


2000 (JPO)

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¹³ The imputed earnings from actual TAPS DR&R collections between 1977 and 2001 are entirely distinct from – that is, over and above – the following: (1) the guaranteed, tax-paid operating profit on TAPS that is provided through the pipeline tariff under TSM and (2) the estimated future cost of dismantling and removing TAPS facilities and restoring the right-of-way. For discussion and quantification of TAPS DR&R collections, see: Richard A. Fineberg, *Overcollection and Failure to Escrow TAPS DR&R Funds: Imputed Present and Future After-Tax Value to TAPS Owners of Excess DR&R Collections Under TSM*, June 24, 1999, and summary tables, (submitted as appendix to Part I of this testimony in Anchorage, Sept. 20, 2001).
1995-1996

(Pipeline in Peril)

Followed by key pages of footnotes 6-9 and 6-14.
PIPELINE IN PERIL

A STATUS REPORT ON THE TRANS-ALASKA PIPELINE

Prepared for the
Alaska Forum for Environmental Responsibility
by
Richard A. Fineberg, Ester, Alaska

September 1996
Figure 6.1

Typical Pump Station with Topping Plant

1- Incoming Pipeline
2- Outgoing Pipeline
3- Office Building
4- Manifold Building
5- Yard Check Valve
6- Main Pump Building
7- Control Room
8- Microwave Tower
9- Flare Stack
10- Shop / Warehouse
11- Living Quarters
12- Crude Oil Heater
13- Crude Oil Topping Unit
14- Booster Pump Building
15- Turbine Fuel Tanks
16- Residual Fuel Tank
17- Crude Oil Relief Tanks
replacement. Clearly, the problems were unanticipated: If the pipeline operators had spotted the control unit problem prior to the shutdown, they would have fixed it during the planned maintenance. Despite the difficulties that caused these two successive, unplanned extensions to the original shutdown, an Alyeska press release declared the maintenance operation "a success from several perspectives" because "there were no accidents or injuries."8

**September 1995 Shutdown.** After the planned, line-wide maintenance shutdown in September 1995, events associated with the startup at Pump Station #9 further illustrate the problems associated with operating an aging pipeline.9 After a day-long halt for pipeline repairs, stations to the north were pumping again but the oil still had not made its way through the line to the pumping facility just south of Delta Junction in the Alaska Range, three-quarters of the way to Valdez. It was just past midnight when the station operator told the "rover" — the assistant who checks the equipment at the facility — to expect an order from Valdez shortly to start up one of the big jet turbines that powers the pumps.

In a pipe segment between buildings at the pump station there is a 26-inch valve known as the yard check (see Figure 6.1, above). A check valve is a hinged, pressure-driven, one-way clapper. This one is normally closed to prevent back-flow. When the big valve opens, it can slam very hard. So hard, in fact, that it shakes the ground.

On that September night, a rapid pressure build-up before the oil flow arrived caused the yard-check to slam repeatedly. Over a 20-minute period, there were about five slams from the 26-inch valve. The rover went out to make sure nothing was leaking from the day's repairs and that things were "holding together." He reported finding nothing amiss. One of the incident reports would later note that the clapper was slamming and shaking the ground so violently that people thought they were hearing the explosion of artillery shells at a nearby military test site.

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8 Alyeska Pipeline Service Co., "Shutdown Leads to Pipeline Improvements" (press release #1071), April 19, 1994.

9 This description is based on several reports. See, for example:

- Alyeska Pipeline Service Co. — "Booster Pump Suction Line Damage Assessment" (memorandum from C.H. Roach [SBU Operations Engineer] to PS9 Area Team Leader), Sept. 13, 1995; "Subject: Start up of station after a pipeline shutdown" (statement of Pump Station #9 Controller), Sept. 14, 1995; "Statement of events that occurred during the evening of the 11th and the morning of Sept. 12th as noted by [rover]" (statement of Pump Station #9 rover), Sept. 13, 1995.
- "To whom it may concern" (memorandum from a concerned former pipeline employee [name withheld] to JPO), Sept. 19, 1995.
Back in the pump station control room, the rover and the controller went back to paperwork tasks. About an hour later, moving oil reached the station and they started the pumps. The pump station controller would recall later that despite the earlier hammering, the operation went so smoothly that he felt like a Maytag repairman.

But the slamming yard check valve was part of a start-up shaking that wrought havoc in the pump station's booster pump room. Sometime during the restart (nobody seems to know just when) the booster pump for the suction line — a 10-inch pipe that transfers oil from the pump station relief tank back into the mainline, upstream from the slamming yard check — was damaged. From dents in the building flashing where the ten-inch line enters the building and depressions in the ground where that pipe goes from above ground to below-ground, it appeared that the booster line was dancing around when the yard check slammed. The next day, the actuator that drives the booster suction valve — a unit so large that it takes two men to lift it — had ripped out of its four-bolt mounting and was lying on the floor. The actuator for the discharge valve was still atop the pipe, but it had moved at least one inch and was resting against the bolts of an adjacent flange, its housing cracked from the pounding it took when the yard check valve opened and closed to relieve pressure.

The incident at Pump Station #9 was discussed in E-mail chatter along the line; according to one report it would take two weeks to replace the booster pump. But the incident was not mentioned in the Alyeska press release that discussed the post-repair shutdown. In Alyeska’s public account, a leaking valve seal resulting from the repairs at Pump Station #2, far to the north, dictated the follow-up shutdown — not the actuator that was blown off-line at Pump Station #9.10 Workers at Pump Station #9 took advantage of the second hiatus to block off the booster line, restoring their section of the pipeline to temporary working order. Until the pump station relief system could be repaired, Pump Station #9 simply functioned without full use of its relief tank.

No problem — as long as nothing went wrong to the south of Pump Station #9 while the pump and the lines that carry oil in and out of the 55,000 barrel relief tank were out of commission. Of course that relief tank’s primary function is to divert oil from the mainline to allow rapid shutdown if something did go wrong.

What could go wrong?

Gate valve control problems like the one at Pump Station #4 in April 1994? In fact, similar valve control problems south of Pump Station #9 occur with disturbing regularity, as will be shown in Table 6.2 and discussed in Chapter 8, below. A small fire somewhere down the line? That’s not an infrequent occurrence, either (see Table 6.2).

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May 1996 Shutdown. What could go wrong was best exemplified during Alyeska's May 6, 1996 shutdown, which confirmed the trend of re-start problems established in 1994 and 1995. Repairs and maintenance were planned for that day at most pipeline locations. One of the problems Alyeska wanted to fix during the shutdown was the RGV that protects the Yukon River. That valve had been diagnosed as failing to seal properly nine months earlier. (The valve problem will be discussed in Chapter 8.)

A second task was to take the big relief tank at Pump Station #5 out of service for repairs. A detailed plan to handle all contingencies for the May 6, 1996 shutdown was supposed to have been completed for review and distribution two weeks before the shutdown. It didn't get done on time. The planning schedule "slipped drastically" and the work packages were still incomplete five days before the event, according to C.F. O'Donnell, Alyeska's System Wide Operations Team Leader. O'Donnell feared that the quality inspectors would make "significant findings" that the procedures of the new quality program were being violated.

O'Donnell was right to be worried about Alyeska's poor preparation for the shutdown, but he needn't have been concerned that the quality inspectors would find fault with the paperwork. He should have been worried about the pipeline itself. As it had at Pump Station #9 seven months earlier, the problem began when the oil flow from Prudhoe Bay reached a pump station. This time, it was Pump Station #8, just south of Fairbanks. Both seals on a mainline pump failed. With oil leaking at the pump house, the next move was to isolate the pump house from oil flow. The isolation valves inexplicably failed, too. Oil continued to flow into the pump station. The start-up turned into a near-disaster, with spilled crude oil and heavy smoke in the pump building.

What had happened, Alyeska investigators would later determine, was that the OCC turned on the mainline pump too soon; there wasn't enough pressure to start the pump, which overheated and suffered what investigators described as a "catastrophic failure" that resulted in "the release of crude oil and heavy smoke within the pump building." From the chronology, it appears that oil continued to flow into the overheated pump for fifteen agonizing minutes.

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12 "May 6, Shutdown Planning Delays" (memorandum from C.F. O'Donnell to NBUL's/SBUL's), May 1, 1996.


14 "PS 8 Seal Failure, MLU #2" (Alyeska causal factor analysis, May 20, 1996), 2, 3, 5.
Later in the day, to bring Pump Station #8 back on line and deal with another leaking valve at Pump Station #4, the northern portion of the line had to be shut down again. Due to faulty preparation, that proved somewhat difficult. The relief tank at Pump Station #5 is special. As the oil toboggans down the south slope of the Brooks Range from the Atigun Pass summit, pressure inside the 48-inch pipe can build to dangerous levels. To relieve that pressure, the tank at Pump Station #5 was built with three times more capacity than relief tanks at other pump stations.\(^\text{15}\) When Alyeska sidelined the large tank for repairs May 6, it planned to get by for a while by diverting mainline oil, as necessary, into the smaller relief tanks at Pump Stations #6, #7 and #8.

There was a flaw in this plan: At that time, Pump Station #7 had been out of service for almost a year for repairs. On May 7, when Pump Station #8 could not be used because it was still standing down from that morning's near disaster, only the spare capacity in the smaller relief tank at Pump Station #6 was available to take the place of the much larger pressure relief tank at Pump Station #5. To shut down the line, special teams had to be called in to draft new, make-shift operating procedures on the spot.\(^\text{16}\)

JPO personnel were in the field to monitor the shutdown. However, the agency seemed to be unaware of the inadequacy of Alyeska's planning for the shutdown or the seriousness of the near-catastrophe at Pump Station #8. Two weeks after the shutdown, the agency gave Alyeska its report on the shutdown. According to JPO:

May 4 thru May 7, the JPO deployed personnel to various pipeline locations to observe work activities and procedures associated with the May 6, 1996 shutdown. . . . A general evaluation of the shutdown work activities was performed, with emphasis on the implementation of the quality program.

It is generally felt that the shut-down activities were accomplished with a high degree of quality and professionalism. Alyeska Quality Assurance and Surveillance personnel were in the field to track implementation of the quality program. The JPO personnel were provided excellent support and assistance from all personnel contacted.\(^\text{17}\)

In that letter, JPO asked Alyeska to respond specifically to Alyeska's problems with remote gate valves (discussed in Chapter 8, below) and complained mildly about the lack of

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\(^{15}\) Alyeska Pipeline Service Co., *Operating the Trans-Alaska Pipeline* (June 1988), 6. In fact, although it is called Pump Station #5, no pumping units were ever installed. Managing flow on the south slope of the Brooks Range is Pump Station #5's principal operating task.


\(^{17}\) JPO, "Re: Oversight of May 6, 1996 TAPS Shutdown" (letter from Jerry Brossia [State Pipeline Coordinator] and Gary Reiner [Acting Authorized Officer, BLM] to Douglas Webb [Alyeska Sr. Vice President, Health, Safety, Environment and Corporate Affairs], May 21, 1996).
procedures governing software for support contractor document process control. JPO also shared with Alyeska two observations for which response was not requested, noting that

- there was no apparent final copy of the temporary operations procedures for the shutdown; and
- the shutdown immediately preceded a crew change, which caused coordinating problems.\(^{18}\)

In its review of the May 6 shutdown, JPO did not ask Alyeska about the near miss at Pump Station #8 or the need to improvise new line operating procedures later that day.

**Potentially Serious Incidents**

Shutdowns are not the only indicator of potentially serious problems associated with the operation of TAPS. Rather, shutdowns are merely the end result of problems that force Alyeska to stop pumping. To examine the pipeline's condition — and the potential risk that TAPS operations pose to workers, the general public and to the environment — it may be helpful to review a broader category of incidents: events with potentially serious consequences that occurred during pipeline operations. Table 6.2 presents information on events associated with TAPS operations during 1994 and 1995 from a variety of sources.\(^{19}\) An incident is listed here if it involves a crude oil spill or release of other hazardous materials, a fire, lost or malfunctioning communications systems essential to safe operation of the pipeline or any other incident that causes an unplanned pipeline shutdown or idling of mainline pumps.\(^{20}\) The range of mishaps that occurred during the operation of TAPS in 1994 and 1995 includes seven fires (two were large enough to trigger halon dumps), a 2,800 gallon propane leak at a remote gate valve, a 7,100 gallon spill of the corrosion inhibitor sodium hydroxide at the VMT and leaks of the refrigerant freon from the buried lines that keep the foundations at northern facilities frozen.


\(^{19}\) Due to the time required to assemble this list and because the task of this report is to examine the current condition of TAPS, only 1994 and 1995 were covered.

\(^{20}\) This total does not include problems at North Slope production facilities, planned shutdowns for repairs accomplished without incident or slowdowns to keep storage tanks at the Valdez terminal from overfilling when storms prevent tankers from safe transit.
• To reduce the possibility of accidental RGV closure, since early 1994 JPO has required Alyeska to shut down operations at upstream pump stations whenever Valdez loses communication with a gate valve for more than two minutes.

• To ensure that the Controller in Valdez knows what the field workers are doing while they are executing maintenance and repair work on the valves, Alyeska has placed greater emphasis on pre-maintenance training and communication procedures to be followed during maintenance activities.

• To ensure that field workers at an RGV do not accidentally trip a switch to close a valve manually, RGVs switches are being tagged more clearly and the switch that activates closing cannot be set to close and left unattended; to close the valve, someone must keep the switch depressed manually.\(^{15}\)

Without denigrating either the skill or the intentions of the individuals who are dealing with these problems, it should be noted that these measures can only partially mitigate the increased threat to the environment posed by TAPS aging equipment. Over both the leak detection and RGV problems looms a larger problem. The current SCADA system is antiquated. Worse yet, replacement parts are no longer available for portions of the system. The feasibility study for modernizing the communications system is not scheduled for completion until 1998.\(^{16}\)

The May 6, 1996 Shutdown Revisited

As discussed in Chapter 6, one of the tasks of the May 6, 1996 maintenance shutdown was to take the relief tank at Pump Station #5 out of service for repairs.\(^{17}\) This action exacerbates the environmental risk created by the perpetual problems that already diminish margins of operating safety on the Brooks Range south slope. These problems, described above and in the preceding two chapters, include:

• the unreliability of Alyeska's small leak detection system;
• the chronic failure of the special computer system that was supposed to provide automatic coordination of actions between Pump Station #4 and Pump Station #5;
• the frequent communication failures that plague the RGV system — many of them between Pump Station #4 and Pump Station #5; and
• the poor condition of the entire pipeline communications system, which is scheduled for replacement.

\(^{15}\) Interviews with JPO staff, Nov. 30, 1995 and Jan. 2, 1996.

\(^{16}\) See Chapter 7 and JPO, 1995 Annual Report, 24.

Against this backdrop, on May 6, 1996 Alyeska was taking the big Brooks Range relief tank at Pump Station #5 off-line while Pump Station #7 was still out of commission for extended repairs. It was therefore necessary to keep the line running at increased pressure levels in some stretches in order to push the oil in the line all the way from Atigun Pass to Pump Station #6, just south of the Yukon River. Unable to use the line's largest diversion tank, Alyeska's ability to shut down the line quickly to mitigate any problem developing between Atigun Pass and the Yukon River, 190 miles away, was further compromised. To avoid overpressuring, under many conditions the RGV closure sequence between the pass and the river would have to be slowed down.

During the shutdown, Alyeska also planned to deal with reported RGV problems. In view of the history of previous shutdowns, it was not surprising that the pipeline people experienced difficulties with RGVs up and down the line. For example, one of the RGVs in the Brooks Range just north of Pump Station #5 failed to work at all. Alyeska locked it open for the shutdown exercise and set about trying to find out why that valve kept blowing fuses instead of responding properly to commands.

During the September 1995 maintenance halt, RGV #60 had been tested and found to be leaking. The loss was later estimated at 90 gallons per minute. While the line was shut down May 6, 1996, Alyeska planned to pack the valve with grease in the hopes that the valve would seat properly and stop leaking. The attempted repair at RGV #60 did not work. It continued to leak. Additionally, during the May 6 shutdown a similar problem was discovered with at least one other RGV.

On restarting the line after these repair estimates, as described in Chapter 6, something went wrong during the re-start at Pump Station #8, 200 miles south of the Yukon River. When a problem developed in the pump room and the valves at that station were unable to effect isolation from the mainline, it was necessary to stop the flow that had just started from the north — as quickly as possible. But there were no procedures for rapid shutdown without the big relief tank at Pump Station #5 when both Pump Station #7 and Pump Station #8 were off-line. Temporary plans had been written for taking the Brooks Range relief tank off line, but the procedures necessary for handling the contingencies that developed apparently were not spelled out. In an emergency action, a line hydraulic engineer told the company newspaper, "we had to find the right set-point pressures [for operating the pipeline so] that if we did have to isolate a station, the line wouldn't be overpressured."
Alyeska managed to get out of its third problem-plagued planned shutdown in as many years without a catastrophe. When it was all over, the pipeline managers congratulated themselves on a job well done:

"It was a great example of the Quality Program at work," said [Southern Business Unit Leader Bill] Howitt. "I know some people were worried the Quality Program would slow us down. But it didn't. We worked the procedure in accordance with the PIPs and the Quality program, and it worked."  

In fact, several aspects of the May 6-7, 1996 shutdown and re-start demonstrate failures to apply the procedures of the quality program whose procedures had been instituted a year before and whose operation was formally approved by JPO one month before. In addition to the lack of basic planning discussed in Chapter 6, Alyeska violated its operating procedures by its failure to write up the RGV #60 in a nonconformance report (NCR).  

The NCR that should have been written immediately to document and ensure correction of the problem was only written after JPO formally advised Alyeska that "this was a known nonconformance" and asked Alyeska to "please provide a description of what action is to be taken to assure an acceptable seal is obtained at RGV #60."  

Conclusion

The TAPS operators are coping with equipment that is increasingly prone to breakdown as it ages. A valve system that is supposed to protect the environment and an antiquated communications system that is supposed to hold everything together both malfunction with disturbing frequency. In 1994 and 1995, RGV communication loss or malfunction occurred on the average of once a month. Eleven of those failures occurred in the south side of Atigun Pass, where special handling of oil flow is required to avoid the build-up of excess pressure that could rupture the line as the pipeline descends from the highest point on the line (see Table 8.1). These systems are undergoing major overhauls that will extend well beyond the Alyeska's announced plan to have the hardware fixed by the end of 1995. In some instances, the delayed "fix" represents an effort of questionable merit to ameliorate specific problems. For example, the new RGV gearing slows closure,

22 Ibid.

23 Ibid. A non-conformance report (NCR) is the document that identifies problems for tracking and resolution; past failure to write and follow-up on NCRs is one of the problems the new quality program is supposed to fix. (QA-36 Rev. 8.1, PIP 15)

24 JPO, "Re: Oversight of May 6, 1996 TAPS Shutdown" (letter from Jerry Brossia [State Pipeline Coordinator] and Gary Reimer [Acting Authorized Officer, BLM] to Douglas Webb [Alyeska Sr. Vice President, Health, Safety, Environment and Corporate Affairs], May 21, 1996); Alyeska Pipeline Service Co.: "NCR No. 6198 (05-0696 (VERIFIED))" (NCR prepared by S.P. Sorensen, P.E., June 5, 1996); Alyeska Pipeline Service Co., Nonconformance Report No. 6198, June 8, 1996.
allowing pipeline computers and staff more time to detect an unintended closure but increasing the size of potential spills.

On May 6, 1996, the pipeline people planned to take out a major component of this already weakened spill defense system at the same time that they were going to try to fix failing RGVs, including the one that protects the Yukon River. Having hatched this plan, Alyeska was already walking a tightrope of its own making when problems developed at Pump Station #8, several hundred miles to the south.

The notion that the public can rely on JPO to serve as a vigorous protector of public resources is dispelled by a review of the monitors' actions regarding the May 6, 1996 shutdown. By its own account, during the shutdown JPO deployed personnel to conduct a general evaluation of the implementation of the quality program that received final approval one month earlier. Despite the glaring problems noted here and in Chapter 6, JPO concluded "it is generally felt that the shut-down activities were accomplished with a high degree of quality and professionalism."

JPO's May 21, 1996 praise for the problem-studded shutdown and re-start is noteworthy for what it failed to discuss — in their laudatory evaluation of the operation, the monitors ignored the failures at Pump Station #8, the wisdom of taking the Brooks Range relief tank off line before bringing Pump Station #7 back on line and the lack of an adequate plan for operating contingencies. JPO did express concern about the RGVs and lack of paperwork to document the shutdown plan. But the JPO concern regarding the RGVs missed a major point: RGV #60's problem had been identified the previous September but the problem went unattended for nearly nine months — an even more egregious procedural violation.25

In view of the record of line-wide RGV problems and the fact that Pump Station #7 was already off-line, how could JPO have approved of a shutdown plan that did not spell out how to deal with the kind of problems that developed? If the quality plan installed one year earlier and formally approved five weeks before the May 6 shutdown was effective, why did it take JPO's instigation and another month after May 6 for Alyeska to execute the controlling paperwork required by the quality program? And why did Alyeska take eight months to get around to dealing with what is arguably one of the most important RGVs on the line?

The RGV #60 portion of the Alyeska's travails of May 6-7, 1996 has two major implications:

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25 See: "RGV60 Leak Test After Pipeline S/D" (electronic mail from Norman Ingram, Southern Business Unit Leader, to various persons, Sept. 21, 1995).
The purpose of this memorandum is to provide a summary of damage found in the booster pump P1 suction and discharge piping system during the 9/12/95 walk through.

The booster pump suction valves B20S & B20D were damaged after the 9/11/95 pipeline restart. This occurred following a series of suction relief events during the restart. History indicates this was not the first time that the booster pump suction line has been damaged from suction relief events. Damage found and observations made during the 9/12/95 walk through follows:

- Where the 10" suction line exits the ground there was settlement immediately adjacent to the pipe (approximately 1 ft of settlement within 2 ft of the pipe) and ground cracks aligned with the longitudinal direction of the 10" pipe.
- Where the 10" suction line enters the booster pump building the wall of the building is pulled out approximately 1 to 2 inches and the flashing is damaged. Because the wall is pulled out it is assumed that the initial movement was primarily in the longitudinal direction out of the building (to the north). Damage to the flashing indicates that the line moved laterally as well as longitudinally.
- The anchor bolts on the first pipe support south of valve B20S are bent and the pipe support is no longer plumb.
- The mating flange gasket on the suction side of B20S failed resulting in the release of a small amount of oil.
- The actuator on B20S was lying on the floor next to the valve. The actuator mounting bolts had been pulled out.
- Misalignment of the mating surfaces of the flange on the suction side of pump P1 was observed.
- Grout has spalled away from the base plate on the foundation for pump P1.
- The bolts between the four base plate and pump mounting plate on pump P1 were loose. It is likely that these bolts yielded during the relief event.
- Piping on the discharge of pump P1 shows signs of misalignment.
- The actuator for valve B20D appeared to be cracked and has moved approximately 1 inch. The actuator is now resting against the bolts of an adjacent flange.

Repair alternatives are being evaluated. Recommendations for repair will be forwarded when complete.
Sept. 14, 1995

Subject: Start up of station after a pipeline shutdown

These events are from 9/11 @ 1800 to 9/12 @ 0600.

After completing the pipeline shutdown work list for PS-9 and refilling the Pump Station, the day shift turned to station over to night shift (Dewar, Summers). OCC was not ready to start up at the scheduled 1900 hours and called for several delays i.e. 2130, 0100.

At 0026 hr's, the static pressure started to climb from 250# to 575#. This opened the suction relief valves. I called the rover to let him know that we might be called shortly to start up a unit. He arrived and after listening to the yard check valve slam each time the relief valves open, opted the check out the station. The slamming of the check valve is a normal occurrence when starting the line up with no flow established. The rover returned and noted "the ground sure shakes when the check valve closes". He was checking the yard check valve underground valves at the time.

After returning to the control room we checked the LEFM and noted there wasn't any flow in the line, just pressure buildup. At this point we worked on manually entering in the Datalogger Environmental readings that took approximately 1 1/2 hours to do, system difficulties.

At 0200 OCC called for a start on #2 MLU. By now there was enough flow through the unit that the low flow-rate alarm on the SCP did not come up with the load command. After loading the unit I noted to OCC, Dean, that that was the smoothest I had seen the line come up in a long time, referring to the 0200 time window. The flow rate through the #2 MLP was approximately 1.3 MM, which was exceeding our maximum flow through a single unit, so we started #3 MLU and brought it online.

This entire operation worked so smooth that I jokingly brought up being a Maytag repairman during the morning turnover. All systems appeared to be working as designed and at no time during the evening was there any reason for concern.

Steven J. Dewar
Sept. 13th 1995

Statement of events that occurred during the evening of the 11th and morning of Sept. 12th as noted by Henry R. Summers.

At around 2145 on the 11th OCC started bringing pressure up on the line. We hadn’t seen any flow yet just an increase of suction pressure. At about 0010 pressure in the line was above 500#’s and we were getting some flow through the station. Shortly thereafter the CRO and myself noticed that we were relieving on the suction side (pressure Approx. 575#’s). We then heard the yard check valve slam shut when the suction relief’s had bled suction pressure approx. 100#’s below discharge pressure. The suction relief’s then started shutting and suction pressure again exceeded the 575#’s relief point and the yard check again slammed shut. At this point I informed the CRO that I would go out and check the work sight and the relief’s. As I was checking around the different drain down points used during the previous days work, I was standing by the yard check when it slammed shut again. Then proceeded into the manifold building to see if the relief’s were holding together. Everything looked good in the manifold building and I proceeded back to the control room to report in. At this point it looked like OCC had finally adjusted pressure on the line to keep us under the suction relief set point of 575#. The suction relief’s had slammed open about five times during this period, which lasted about 20 minutes. It should be noted that the relief’s were not being controlled by thier dialed in set point on thiere controller but by a protective PSH-904 switch which causes the relief’s to go from full closed to full open in 2 seconds.

Pressure indication on the digital suction monitor showed that suction pressure reached 622# when I checked after everything was back to normal. I also talked to the night baseline personnel who thought that the Army base had been testing artillery again when they had heard the yard check valve slam shut. They also reported that they heard the valve slam shut about 5 times. The actual number of times should be able to be determined from the station DOT pressure chart recorder.

I, Henry R. Summers certify that the above information is the way things happened to the best of my recollection.

[Signature]

9/13/95
This is to keep you informed regarding our follow-up to the PS 8 mainline unit 2 seal failure on May 7, 1996. Attached is a copy of the Causal Factor Analysis, the SBU response to that analysis, and two requests for assistance to address the causal factors.

Please note that the cause of the seal failure was starting and idling the mainline pump with no suction pressure. Although we have requested that several recommendations be put in place to address the root cause of this, please make your teams aware that mainline units should not be started with less than 25 psig suction pressure. It is the responsibility of the Control Room Operator to advise and/or remind OCC if such a condition is present, and to protect the station equipment by interrupting the start sequence if necessary.

cc: Chuck O'Donnell, without attachments
    Ricardo Tapia/Rob Shoaf, with attachments
Executive Summary:

On May 6, 1996, TAPS was shut down for scheduled maintenance. At about 0515 hrs. on May 7, OCC began to restart the line. At about 0600 OCC changed shift. PS 8 was scheduled to change shift at 0630.

At approximately 0615 hrs. both the inboard and outboard seals on the Byron Jackson pump in the MLU #2 position at Pump Station 8 suffered a catastrophic failure due to overheating. The immediate result was the release of crude oil and heavy smoke within the pump building, and an isolate pump house command to PS 8. An indirect result was that a third shutdown of the pipeline was required, eventually resulting in the producers being reduced to 5% of nomination.

During shutdown and restart the line pressure at PS 8 is normally about 300 psig; however, during this restart the pressure was zero psig. During this shutdown the Mapco refinery was allowed to continue drawing crude from the pipeline, reducing the line pressure at PS 8 to zero.

The MLU pump seals are cooled by a system which depends upon the pressure rise across the pump. The M&M Rotating Equipment Engineer reports that for the pump to be safely operated at idle for a prolonged period of time (more than 2 or 3 mins.) a suction pressure in excess of 20 psig must be present. MLU 2 was started and brought to idle for about 13 minutes with zero suction pressure. The apparent cause of the seal failures was starting the pump with insufficient suction pressure.

The repairs and follow-up were handled effectively by the management and staff of PS 8.

Root Causes:

Less than adequate training and technical instructions provided to OCC controllers and PS 8 CROs.

Reduced pressure at PS 8 during restart.

Contributing Causes:

Less than adequate timing and execution of the restart; specifically, conducting the restart during shift change.

Recommended Corrective Actions:

The MLU control panels should be modified such that a start permissive is denied unless adequate suction pressure is present. This could also be done at OCC as a software modification.

Reexamine the unit bypass valve function line wide, in accordance with the lowered throughput and rampdown plan.

SWOT should issue a directive stating that no mainline pump should be started unless the station suction pressure is at least 25 psig and it is intended to load the pump within 15 minutes of reaching idle.
If at all possible, Alyeska should not schedule major activities such as pipeline restarts during the last hour of the shift, or during shift changes.

OCC should be provided with a training simulator, so that controller trainees can experience abnormal operating conditions on a no-risk basis. Training simulators are readily available and would have likely prevented this incident, and the subsequent machinery damage and loss of throughput. Currently OCC controllers are trained on the job, so only gain experience with abnormal operations on a random basis.

Root Cause Analysis:

At the verbal request of the Southern Business Unit Leader, Mr. W. D. Howitt, Quality Services performed a causal factor analysis to determine the root cause(s) of the seal failures of MLU # 2 at PS 8 on 5/7/96.

The first step in the analytical process was on-site fact finding. At approximately 1100 hrs. on 5/7/96, the PS 8 ATL requested on-site assistance from Safety, Engineering, Security, baseline maintenance, and Quality Services. This enabled Quality Services to observe the sequence of events first hand and to begin collecting documentation for the causal factor analysis.

The next step involved interviewing witnesses and technical experts. This was not done until two days after the event, to allow the parties involved to get back to a normal sleep cycle prior to the interviews. The following persons were interviewed:

<table>
<thead>
<tr>
<th>NAME</th>
<th>TITLE</th>
<th>DATE INTERVIEWED</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fred Chiu</td>
<td>PS 8 AATL</td>
<td>5-9-96</td>
</tr>
<tr>
<td>John Nunan</td>
<td>PS 8 Instrument Tech</td>
<td>5-9-96</td>
</tr>
<tr>
<td>Claude Robinson</td>
<td>SWOT Engineering Coord.</td>
<td>5-9-96</td>
</tr>
<tr>
<td>Mark Dahl</td>
<td>OCC Controller</td>
<td>5-9-96</td>
</tr>
<tr>
<td>John Hobson</td>
<td>M&amp;M Engineering Coord.</td>
<td>5-9-96</td>
</tr>
<tr>
<td>Valerie Butler</td>
<td>OCC Controller</td>
<td>5-10-96</td>
</tr>
<tr>
<td>Robin Schoenborn</td>
<td>PS 8 CRO</td>
<td>5-10-96</td>
</tr>
</tbody>
</table>

Next, a time line of events was established, and is presented in Appendix A.

Barrier analysis was conducted to determine what barriers could have prevented the seal failures, and whether they were in place.
Appendix A: Time Line for Seal Failures at PS-08 on 05-07-95

0501 PS-09  CSEL  Reset Station Permissive
0504 PS-09  CSEL  Reopen Station BL-1 and BL-2 opened Valve travel completed at 0509
0514 PS-01  CSEL  MLU # 1 Idled
0514 PS-03  CSEL  MLU # 2 Idled
0515 PS-04  CSEL  MLU # 1 Idled
0517 PS-08  CSEL  Reset Station Permissive
0525 PS-01  CSEL  MLU # 1 Loaded
0527 PS-06  CSEL  MLU # 2 Idled
0531 PS-06  CSEL  MLU # 2 Shutdown
0533 PS-03  CSEL  MLU # 2 Loaded
0536 PS-06  CSEL  MLU # 1 Idled
0538 PS-01  CSEL  MLU # 3 Idled
0541 PS-03  CSEL  MLU # 3 Idled
0544 PS-04  CSEL  MLU # 1 Loaded
0545 PS-04  CSEL  MLU # 2 Idled
0550 PS-01  CSEL  MLU # 3 Loaded
0551 PS-08  CSEL  MLU # 2 Idled  MLU #2 reached idle 0554
0558 PS-03  CSEL  MLU # 3 Loaded
0603 PS-04  CSEL  MLU # 2 Loaded
0605 PS-08  PS/ESC  MLU # 2 stopped, Unit smoking
0606 PS-08  CSEL  MLU # 4 Idled
0606 PS-08  MLU # 2 Seal Failure Alarm
0608 PS-08  PS/ESC  MLU # 4 Stopped, Rover reports leak in Pump house
1997,
1998,
1999
(U.S. DOT)
NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
AND
COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 15, 1999

Mr. Denis C. LeBlanc
Vice President, Corporate Services Division
Alyeska Pipeline Service Company
1835 Bragaw Street (MS 542)
Anchorage, Alaska 99512

Dear Mr. LeBlanc:

On May 11-15, May 26-29, June 8-12, August 12-14, and September 21-26, 1998, a representative of the Western Region, Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code conducted standard and follow-up inspections of Alyeska Pipeline Service Company (APSC) facilities and records from Pump Station 1 to the Valdez Marine Terminal on the Trans Alaska Pipeline System (TAPS).

As a result of the above inspections and review of recent operational events, it appears that you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations (CFR), Part 192 and 195. The items inspected and the probable violations are:

1. §195.406(b) requires that “No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section.”

Review of Alyeska’s operation records indicate two over-pressurization events have occurred on TAPS during the last two years. Both events occurred during scheduled start up of the TAPS following planned shutdowns. Root cause analyses of the over-pressure events indicate that human error and inadequate pipeline control systems contributed to the maximum allowable operating pressure (MAOP) being exceeded.
(a) On August 5, 1998, at approximately 11:54 PM, the pipeline pressure at Mile Post (MP) 568 on TAPS exceeded 130% of the MAOP. Records indicate the MAOP established at MP 568 is 901 psig. Surge analysis data, obtained from Alyeska records indicate the pressure at MP 568 peaked at 1171 psig. Further, the pressure at Pump Station 9 exceeded 110% of the MAOP at approximately 11:51 PM and lasted until 11:56 PM. Records indicate about 32 miles of pipe (MP 554 to MP 585) between Pump Station 9 and Pump Station 10 exceeded 110% of MAOP.

(b) On August 2, 1997, upon restart of Pump Station 7 on TAPS, a pressure gradient in the adjacent downstream section of the pipeline caused the MAOP to exceed 110%. Surge analysis data indicates the pressure was 119% of MAOP.

2. §195.416(i) requires that “each operator shall clean, coat with material suitable for the prevention of atmospheric corrosion, and, maintain this protection for, each component in its pipeline system that is exposed to the atmosphere.”

At the time of the inspections, the fiberglass insulation coating on the above-ground pipe at the MP 121.28 transition joint (animal crossing) contained a crack around its circumference immediately above the ground surface. Our OPS representative observed water migrating beneath the coating. Further, “smart pig” data indicates external corrosion is occurring at the adjacent below-ground pipe joint (Joint PYS-12807). The 1996 corrosion pig identified 63 corrosion calls with a maximum 139 mils of wall loss (.462” original wall thickness) had occurred on this pipe joint. The 1994 corrosion pig identified 45 corrosion calls with a maximum of 131 mils of wall loss at this same location. OPS believes that water penetrates the coating through the above-ground crack on the fiberglass insulation and may contribute to external corrosion behind the tape wrap on the below-ground pipe.

In addition to the cracked insulation at MP 121.28, our representative has identified similar conditions at the MP 562, 572, and 598 transition joints. These findings indicate that Alyeska is not maintaining their external fiberglass coating in order to adequately protect the pipeline from external corrosion.

3. §192.317(a) requires the operator to “take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.” and §192.703(b) requires each segment of pipeline that becomes unsafe to be replaced, repaired, or removed from service.
NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
COMPLIANCE ORDER
AND
NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 10, 2000

Mr. Lon R. Trotter
Vice President, Corporate Services Division
Alyeska Pipeline Service Company
1835 Bragaw Street (MS 542)
Anchorage, Alaska 99512

Dear Mr. Trotter:

On April 14-18, September 13-18, and September 29-30, 1999, a representative of the Western Region, Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code conducted standard inspections of Alyeska Pipeline Service Company (APSC) facilities and records from Pump Station (PS) 1 to Fairbanks on the Trans Alaska Pipeline System (TAPS).

As a result of the inspections, it appears you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations, Parts 192 and 195. The items inspected and the probable violations are:

1. §192.179 Transmission line valves.

   §192.179(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:
   (1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.
   (2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

   At the time of the inspection, Mainline Valve MGV-6 on the fuel gas line on TAPS was not protected from tampering and damage. The valve was located adjacent to the main highway and the valve was not enclosed with fencing or marked with signs to prevent vehicles from coming into contact with the valve. Further, the valve was leaning and not supported to prevent movement of the pipe.
5. §195.406 Maximum operating pressure.

§195.406(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:

(1) The internal design pressure of the pipe determined in accordance with §195.106.

(2) The design pressure of any other component of the pipeline.

§195.406(b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

Records indicate a pressure relief event occurred at PS 5 on October 16, 1999. The relief event caused an overpressure of Check Valve No. V203. The overpressure caused the valve bonnet to expand and leak approximately 5 gallons of crude on the floor of the booster pump building. Approximately 2000 gallons of crude was eventually recovered into a vacuum truck from secondary containment. Additionally, records indicate a similar pressure event of a pipeline component occurred at PS 9 on September 12, 1995. The relief event caused an overpressure of Booster Pump Valve B20S. The overpressure resulted in the valve actuator breaking off and the upstream valve gasket leaking crude oil.

Alyeska also recently experienced over pressure events on their pipeline system on August 5, 1998, and August 2, 1997. Subsequent to those events, Alyeska was issued a Notice of Probable Violation, Proposed Civil Penalty and Compliance Order, CPF No. 59502, dated March 15, 1999. As part of the proposed compliance order, Alyeska was required to “evaluate their pipeline control system for design deficiencies that could cause over pressure of the pipeline, and make appropriate corrections where warranted.” The over pressure event on October 16, 1999, indicates that this was not adequately completed.

6. §195.416 External corrosion control.

§195.416(a) Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, conduct tests on each buried, in contact with the ground, or submerged pipeline facility in its pipeline system that is under cathodic protection to determine whether the protection is adequate.

At the time of the inspection, Relief Tank 190 on the TAPS did not have adequate cathodic protection, as required by §195.416, due to the cathodic protection levels on Tank 190 not meeting the -850 mV or the 100 mV depolarization criteria, as required by NACE RPO 169. Additionally, the Cathodic Protection Test Stations RC-20, -21, and -38 at PS 1 did not meet the -850 mV or the 100 mV depolarization criteria as required by NACE RPO-169.
2000
(JPO)
JOINT PIPELINE OFFICE

Comprehensive Monitoring Program Report

A Look at Alyeska Pipeline Service Company’s Operation of the Trans-Alaska Pipeline System 1999/2000

Prepared by: Doug Lalla, Operations Program Lead
               Bob Krenzelok
               Jon Strawn
               Lee Sires
               Joe Hughes
               Joe Dygas
               Mike Wrabetz

February 2001

JOINT PIPELINE OFFICE
411 West 4th Avenue
Anchorage, Alaska 99501
(907) 271-5070
hydraulic significance (pinch points), corrosion derates and pig calls. The investigation found that at one location, milepost 247, the MAOP was exceeded by a slight margin (less than .5%) on several occasions during three of the four days sampled.

A maximum pressure of 905 psi at 2000 hours on 1/1/99 was recorded with a median pressure of 878 psi for the sample data at MP 247, as compared to a MAOP of 901 psi. A review of the data suggests the OCC Controller took prompt actions to bring pipeline pressure back to or below MAOP.  

4.1.4 Planned Shutdown and Re-starting of the Pipeline

• **1999 Status:** Alyeska's performance in re-starting the pipeline system improved during the last shutdown covered in the 1999 reporting period. However Alyeska needed to better plan restarts to 1) ensure attention to detail on procedure revision, 2) complete functional testing of new and repaired hardware, 3) document changes in operating status, and 4) develop contingencies for activities conducted during shutdowns to avoid reoccurrence of events from previous re-starts.

• **2000 Status:** Four planned pipeline shutdowns and restarts were observed during this reporting period. Other than 1 variance from the written procedure during the September 1999 shutdown, which did not affect pipeline integrity, all planned pipeline shutdown and restarts were conducted in accordance with procedure. Alyeska is found to be conducting planned pipeline shutdowns and restarts in a safe manner.

Details:

The JPO records of pipeline maintenance shutdowns from August 1, 1997, August 8, 1997, June 20 1998, and September 25 and 26, 1998 were reviewed and compared to the shutdown of September 11 and 12, 1999. Alyeska appeared to have initiated a high level of preplanning and oversight for the September 11 and 12, 1999 shutdown. The implementation of the Incident Command Center at the Fairbanks War Room provided a central point of coordination for the activities associated with the shutdown. JPO surveillance noted that Alyeska personnel at Operations Control Center (OCC) at Valdez allowed a variance from the OCC-2.05 procedure during the pipeline re-start. 10 This is similar to the situation reported by JPO during a start up in 1997, when Temporary Operating Procedure 1.05 was modified during the activity. 11 In 1997, the modification deleted requirements intended to prevent over pressuring the pipeline. In 1999, the variance from the established procedure did not affect pipeline integrity. This still reflected the continued practice of changing procedures without following the quality program. 12

A second planned pipeline shutdown and restart was observed by JPO on November 13, 1999. The pipeline was restarted in accordance with procedure. After the September 1999 startup, JPO

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9 JPO-00-E-003 engineering report dated 01/20/00
10 JPO-99-E-025 engineering report dated 09/12/99
11 JPO-97-A-005 assessment dated 08/27/97 and JPO-97-E-026 F/02 dated 08/18/97
12 JPO-00-A-002 assessment dated 02/01/2000
had recommended Alyeska look at their pipeline startup procedures to provide sufficient flexibility for pipeline controllers along with appropriate cautions. The result of Alyeska’s review was reflected in the Nov 13, 1999 startup procedure. The procedure used provided the essential guidance and necessary flexibility for potential variation in pipeline initial startup conditions.  

A third planned pipeline shutdown and restart was observed by JPO on September 16-17, 2000. The pipeline was shutdown and restarted in accordance with procedure.  

Prior to the shutdown, JPO noted that the relief set points were not included in the Trans-Alaska Pipeline Controller Operating Manual (DO-14), Department Operating Procedure (DOP), OCC-3.01, Table 3.10 for PS 12, for the condition with the relief system on and PS 12 bypassed (PS 2, PS6, PS8 and PS10 Bypassed). Alyeska indicated that there was another procedure to cover this situation, SUP 0.14, Rev 0. They, however, agreed to modify Table 3.10. 

A fourth planned pipeline shutdown and restart was observed by JPO on Oct 8, 2000. The pipeline was shutdown and restarted in accordance with procedure. JPO verified prior to the shutdown that Table 3.10 was modified with a Note (7), which specifies the criteria for determining the required relief controller setting.

4.1.5 TAPS Leak Detection System

• 1999 Status: The new transient volume balance system (TVB) improved TAPS leak detection capability, but still needed a performance reporting capability or, in other words, a measure of how well the leak detection system was working. This recommendation was made in the 1999 Operations CMP and the Trans-Alaska Pipeline System Pipeline Oil Discharge Prevention and Contingency Plan Finding Document and Response to Comments under Issue #14, Leak Detection for Crude Oil Pipelines. Small slow leaks were undetectable by the leak detection systems.

• 2000 Status: Alyeska implemented an automated system for measuring the performance of the TVB. The system complies with the recommendations made in the 1999 Operations CMP and the Trans-Alaska Pipeline System Pipeline Oil Discharge Prevention and Contingency Plan. In addition, the computer software and hardware were modified to meet the requirements of Y2K. Small slow leaks are still undetectable by the current leak detection systems.

Details: In response to the recommendations made in the 1999 Operations CMP and the Trans-Alaska Pipeline System Pipeline Oil Discharge Prevention and Contingency Plan, Alyeska has been providing monthly Transient Volume Balance Leak Detection System (TVB) performance data since January 1999 which include: analysis of false alarms per month categorized into causal groups; a performance summary characterizing the quality of the data input; a monthly

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13 JPO-99-S-129 surveillance report dated 12/08/99
14 JPO-00-S-055 surveillance report dated 09/18/00
15 JPO-00-S-057 surveillance report dated 10/08/00
assessments, 83% of the 1996 risk assessments and 67% of the 1997 risk assessments were closed out.

![Percentage of Risk Assessments Closed](image)

**Figure 5: Recommendation Closure Trends**

Alyeska Risk Program could be enhanced by addressing the following observations:

- As of May 5, 2000, there were 26 risk assessments, 2 dating back to 1995 with open risk recommendations. Of these 26 risk assessments, 16 had their due dates changed from the original proposed time lines.

- A thorough written justification is not provided for declining many recent risk recommendations. The lack of this written justification makes it difficult to judge from the database record the significance of not completing the recommended action. Alyeska has closed out the majority of the risk recommendations for recent scheduled risk assessments: Pipeline System HAZOP (85%), Pipeline Control System QRA (50%) and OCC Controller Human Factor Analysis (75%) with the single phrase “Not a system integrity issue.” In general the scheduled risk assessments have a broader scope and bring in outside expertise to facilitate the risk assessment process. Alyeska’s Risk Coordinator indicated that recommendations were carefully reviewed and the risk level 2 recommendations concerned financial loss and loss of production and not matters of safety, environment, or pipeline integrity.

### 4.3 Abnormal Operations
4.3.1 Pipeline Overpressure of August 5, 1998

1999 Status: The previous Operations CMP noted that an Alyeska engineering review concluded that pipeline damage was unlikely, however JPO was in the process of evaluating past overpressure pipeline pig data to verify Alyeska’s conclusion. It was also noted that it was an oversight priority to ensure Alyeska implements preventive measures in order to minimize future occurrences.

Regulatory Compliance

On March 15, 1999, the USDOT/OPS issued a Notice of Probable Violation (NOPV) relating to 49 CFR 195. 406(b). OPS alleged that on August 5, 1998, the pressure in the pipeline exceeded 130% of the maximum allowable operating pressure (MAOP). Further, on August 2, 1997 the pressure in the pipeline exceeded 119% of MAOP. Alyeska did not contest the finding, they paid the civil penalty and have completed the requirements of the Compliance Order. 35

2000 Status: JPO compared the deformation pig data prior to the August 5, 1998 incident to deformation data measured in October 1998 after the event and verified Alyeska’s conclusion that there was no observable damage. JPO also verified that additional logic changes had been implemented in the pipeline control system to reduce the likelihood of this type of event in the future.

Details:

Figure 6: July 1998 VETCO Pig Data Prior to Overpressure Event Showing 1 inch Dent at 6:00 Position

Figure 7: October 1998 VETCO Pig Data After Overpressure Event Showing no Change

35 REF:DOT-CPF 59502
On August 5, 1998, a significant overpressure of the Trans-Alaska Pipeline System occurred. Hydraulic pressure exceeded 110% maximum allowable operating pressure (MAOP) in the 32-mile segment between Pump Station 9 and 10. Alyeska completed a hydraulic analysis indicating that the pressure had peaked at 130% MAOP near Pipeline Milepost 568, south of Delta Junction, Alaska. Alyeska investigated the condition of the pipe after the event with the VETCO Deformation Pig. Alyeska found no change in the condition of the pipe after comparing the deformation data to previous Deformation Pig investigations. JPO verified the analysis by comparing deformation data before and after overpressure event. No change in pipe condition was found.

Alyeska implemented auto control logic changes to make it more difficult for a controller to make the same mistakes that occurred during the August 5, 1998 event. JPO monitored the testing of the new logic during the November 13, 1999 planned shutdown. The logic appeared to work as designed. Other enhancements proposed by Alyeska such as enhanced OCC visibility of the pipeline during MV20000 failure are dependent on the completion and implementation of the new RGV control system.

### 4.3.2 Backpressure System Damage/Pig#4 Incident

![Figure 8: Backpressure System Valve B, 18" Oil Entrance Filled with 48" Pig Cups](image)

![Figure 9: Steel Screen Destroyed by Pig](image)

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36 Alyeska report “Pig Data Review PS09 to PS10” dated 01/22/00  
37 JPO-00-S-053 surveillance report dated 10/02/00  
38 JPO-00-S-129 surveillance report dated 12/08/99
4.6 Conclusions:

4.6.1 Normal Operations:

This report finds that TAPS mainline pressure control devices are calibrated, maintained and operational. Four pipeline start and restarts were observed during this reporting period. Other than 1 variance from the written procedure during the September 1999 shutdown, which did not effect pipeline integrity, all planned pipeline shutdowns and restarts, observed from OCC, were conducted in accordance with procedure. In addition, it was verified that the Alyeska qualification and development program was fully implemented, thus a training program is in place.

4.6.2 Abnormal Operations:

Three major incidents that occurred since the 1999 Operations CMP and a follow up on a fourth incident were reviewed in this report. The incidents were the follow up on the Pipeline Overpressure of August 5, 1998, the Backpressure System Damage/Pig#4 Incident, the Milepost 170 Pipeline Movement and the Check Valve 74 Incident.

Pipeline Overpressure of August 5, 1998: USDOT/OPS issued a NOPV on March 15, 1999 relating to 49 CFR 195.406(b). Alyeska did not contest the finding; paid a civil penalty and completed the requirements of the Compliance Order. JPO has verified that the overpressure event caused no change in pipe shape by comparing deformation data before and after the overpressure event. JPO verified Alyeska has implemented auto control logic changes to make it more difficult for a controller to make the same mistakes that occurred during the August 5, 1998 event.

Backpressure System Damage/Pig#4 Incident: Alyeska completed its incident investigation and found a number of contributing causes including not following Alyeska’s procedures. JPO’s analysis of the event concurs with the causal factor findings. JPO is currently satisfied with Alyeska’s corrective actions and considers this instance of noncompliance as remedied.

Milepost 170 Pipeline Movement: USDOT/OPS is pursuing a NOPV because of probable violation of safety regulation 49 CFR 195.401(a), 195.402(c), 195.402(d) related to this incident. JPO concludes that Alyeska’s management of change process was inadequate for the logic changes at RGV-31 because it did not consider critical conditions which should be considered for an adequate design. Deficiencies in change management accounted for approximately 40% of the 1993 Quality Technology Company audit findings. JPO is currently satisfied with Alyeska’s corrective actions and considers this instance of noncompliance as remedied. However, the general issue of adequate management of change remains an open issue from last year’s Operations CMP.

Alyeska’s surveillance and monitoring were inadequate since they failed to find the damage until at least a month after its occurrence. JPO is still reviewing Alyeska pipeline surveillance program.
2000
(JPO)
JOINT PIPELINE OFFICE

Comprehensive Monitoring Program Report

A Look at Alyeska Pipeline Service Company’s Operation of the Trans-Alaska Pipeline System
1999/2000

Prepared by: Doug Lalla, Operations Program Lead
Bob Krenzelok
Jon Strawn
Lee Sires
Joe Hughes
Joe Dygas
Mike Wrabetz

February 2001

JOINT PIPELINE OFFICE
411 West 4th Avenue
Anchorage, Alaska 99501
(907) 271-5070
4.3.3 Milepost 170 Pipeline Movement

Figure 13: View of Pipeline near Milepost 170 from Road after Event

Figure 14: Pipeline Shoe Nearly Off Support

Figure 15: Anchor Platform Moved Against VSM
2000 Status: A design change of August 22, 1999 did not adequately take into account the hydraulic conditions resulting from timing of the opening of RGV-31, given a slack line condition below RGV-31. A pressure pulse was generated. The forces generated tripped seven pipeline anchors, sheared steel bolts on the anchor frames and moved the pipeline south up to 23 inches. Alyeska surveillance failed to find the damage until over a month after the incident is believed to have taken place. Subsequently, Alyeska has changed the timing at RGV-31, conducted soil gas monitoring and found no anomalous soil gas readings at the other below ground valves and modified their surveillance process by painting orange marker lines on the pipe anchor supports to make movement more evident.

Alyeska’s management of change process was inadequate for the change valve opening timing at RGV-31 because it did not identify critical conditions to be considered for an adequate design. In addition, availability of critical records did not appear to be adequate given that the reasons for the original 25% open condition were not readily apparent to the design team.

Alyeska’s surveillance and monitoring were inadequate since they failed to find the damage until at least a month after its occurrence. There were indications that prior pressure pulse events may have moved the pipe from its optimal position along the supports in this pipeline segment.

Regulatory Compliance

USDOT/OPS conducted an investigation into the tripped anchor incident at MP 170 on TAPS and has concluded that Alyeska is in probable violation of the following safety regulations:
1) 49 CFR 195.401(a): Alyeska failed to recognize all the hydraulic factors associated with the timing of opening RGV-31 and that elimination of the 15 minute hold time during start-up contributed to a significant pressure pulse being generated.
2) 49 CFR 195.402 (c) (3): Alyeska personnel did not follow normal operating procedures when they removed the RGV-35A control card for maintenance without first requesting OCC to inhibit the RGV Auto Control logic, which caused the pipeline to shutdown to prevent overpressure.
3) 49 CFR 195.402 (d) (1): Alyeska did not respond to, investigate, and correct the cause of the abnormal condition on TAPS which occurred on November 13, 1999 and February 10, 2000. OPS is pursuing a NOPV for above mentioned regulatory non-compliance.

Details: May 15, 2000 a pipeline pig launch crew discovered seven tripped pipeline anchors north of RGV-31. In addition to the tripped anchors, subsequent investigation found that the pipe had moved south up to 23 inches and some anchor frames’ steel bolts were sheared off. A JPO surveillance specialist was dispatched to the incident site. JPO directed Alyeska to provide a formal briefing on the incident, measures taken to prevent its reoccurrence, and surveillance procedures to assure quick detection of similar events in the future. In addition, JPO directed Alyeska to monitor all culverts, drainage pipes, galleries, pipeline surface-subsurface entry and exit points, and any other areas south along Atigun Pass where oil might appear if a release

48 REF: DOT-JOCS 87023
49 JPO Letter No. 00-086-LM dated 05/17/00
occurred in an adjacent buried section of pipeline. Alyeska was also directed to monitor all buried valves between RGV 31 and Pump Station 5 for possible oil vapors indicating a leak.\textsuperscript{50}

![Diagram of Pipeline immediately prior to opening RGV-31](image1)

Figure 16: Oil Position Prior to RGV 31 Opening (modified from Alyeska RCA)

![Diagram of Pipeline at the moment the vapor pocket collapsed after RGV-31 was opened](image2)

Figure 17: Collision of Oil Columns (modified from Alyeska RCA)

The Alyeska root cause analysis (Alyeska RCA) found that a pressure pulse was caused by the collapse of a vapor pocket just south of RGV-31 when RGV-31 was reopened after a pipeline shutdown on April 17, 2000.\textsuperscript{51} This pressure pulse caused the damage to the pipeline supports. Figure 16 (above) shows the position of the oil in the pipeline prior to the opening of RGV-31. Once RGV-31 was fully open, the oil column above RGV-31 traveled and collided with the column downstream shown in Figure 17. The impact caused a pressure pulse to move downstream and upstream. Most of the upstream section of pipe is aboveground. The above ground pipe is designed to move in a controlled manner and absorb energy using various sacrificial elements such as aluminum honeycomb absorbers at the pipeline anchors. The below ground pipe is restrained by the surrounding soil and does not experience lateral or transverse movement.

The root cause of the pressure pulse was a failure of the design which was implemented on August 22, 1999, by Project B023, to recognize all the hydraulic requirements associated with the timing of the opening of RGV-31.\textsuperscript{52} Prior to August 22, 1999, pipeline restart for RGV-31 was held at 25% open for 15 minutes before allowing full opening of the valve. The hold point was removed to speed up restart. Alyeska engineering reviewed and approved the change based on extensive prior analysis of valve closure analysis.\textsuperscript{53} Even though a management of change process was undertaken, it proved inadequate because the analysis was based on a faulty assumption. The opening sequence should have taken into account the slack line condition downstream of RGV-31.

\textsuperscript{50} JPO Letter No. 00-092-LM, dated 05/26/00
\textsuperscript{51} Alyeska report: “Milepost 170 Pipeline Movement Root Cause Analysis,” dated 06/23/00
\textsuperscript{52} Alyeska report: “Milepost 170 Pipeline Movement Root Cause Analysis,” dated 06/23/00
\textsuperscript{53} Alyeska Briefing: “TAPS Milepost 170 Pipe Movement”
The Alyeska root cause analysis subsequent to the event did a thorough job identifying the cause of the event. Significant findings included:

- Two other pipeline restarts generated pressure pulses prior to the April 17, 2000 event, one on November 13, 1999 and another on February 10, 2000. The cumulative effect of these events might have moved the pipe to its final position, although no movement was noted by Alyeska surveillance for the previous events.

- The pressure data acquisition rate does not allow an accurate measurement of the pressure pulse; thus OCC would not be aware of the magnitude of event. The pressure sensor only transmits the pressure every minute yet the pressure pulse is only 8 seconds wide. It is therefore unlikely that the true pulse height would be captured. Counter to the effect of under estimating the pulse height because of sampling rate, is the amplification of a rapid pressure change by nitrogen left in the pressure sensing line. The nitrogen is inserted to keep wax and drag reducing agent from plugging the line. The current pressure measurement sensors are designed to measure slow changes in pressure, not the rapid rise pulse produced by this event.

- Alyeska estimated the magnitude of the pressure pulses by modeling with their surge analysis program PAULA. The primary variables were the amount of oil trapped behind RGV-31 prior to opening, size of the slack line gap below RGV-31 and the timing of the opening. These variables determined the speed and momentum of the oil “train” flowing down hill.

- Modeling indicated that even the valve opening of 25% could create a significant pressure pulse. The causal factor analysis reviewed history of past events and found that anchors were tripped north of RGV-31 in 1995.

- Alyeska’s surge analysis indicates that pressure reached 109.8% of the Maximum Allowable Operating Pressure (MAOP) at milepost 169.27, which is just below the DOT 110% limit for abnormal events. This represents 63.6% of the Specified Minimum Yield (SMYS) of the pipe. The actual damage to the pipe supports is related to the rapid rate of change of the pressure wave, not the absolute value of the pressure.

**Conclusion:** JPO concluded that:

- Alyeska management of change process was inadequate for the logic change at RGV-31 because it did not identify critical conditions which should be considered for an adequate design. In addition, availability of critical records does not appear to be adequate given that the reasons for the original 25% open condition requirement were not readily available to the design team.

- Alyeska’s surveillance and monitoring were inadequate since the damage was not discovered until at least a month after its occurrence. There are indications that prior
pressure pulse events may have moved the pipe from its optimal position along the supports.

- **Follow up:**

  - Alyeska changed the opening sequence at RGV-31 to allow only 20% initial opening for ten minutes. Surge calculations indicate that this will prevent similar events in the future.\(^{54}\)

  - Alyeska conducted soil gas monitoring and found no anomalous soil gas readings\(^{55}\) and modified its surveillance process by painting orange marker lines on the pipe anchor supports to make movement more evident.\(^{56}\)

  - Alyeska has completed the repair of the pipe supports at MP 170.

  - JPO awaits the Curvature/Deformation Pig data to verify the condition of the below ground pipe downstream from RGV-31. The pig was run August 2000. The data is expected to be available by early in the year 2001.

### 4.3.4 Check Valve 74 Incident

![Figure 18: Check Valve 74 Seat Ring on BJ Curvature Pig](image)

**2000 Status**

\(^{54}\) Alyeska Change Management for OCC Personnel: “RGV-31 Triconex Ladder Logic Modifications”, dated 09/14/00.

\(^{55}\) Alyeska Letter No. 00-16069 dated 07/31/00

\(^{56}\) Alyeska Briefing: “TAPS Milepost 170 Pipe Movement”