Condition of the Trans-Alaska Pipeline System

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Executive Summary

The Trans-Alaska Pipeline System (TAPS) was constructed from 1974 through 1977 through the central portion of Alaska on a right-of-way granted by federal, state, and private landowners. The Federal Agreement and Grant of Right-of-Way for the Trans-Alaska Pipeline System (Federal Grant) was issued on January 23, 1974, and the State Right-of-Way Lease for the Trans-Alaska Pipeline (State Lease) was issued on May 3, 1974. Both the Federal Grant and State Lease were for a period of 30 years. On May 2, 2001, the current owners of TAPS applied for renewal of the Federal Grant and State Lease for a period of 30 years beyond the current expiration dates. The TAPS is operated by the Alyeska Pipeline Service Company (APSC) as an agent for the TAPS Owners. Regulation and oversight of TAPS is performed by six federal and seven state agencies working within the Joint Pipeline Office (JPO).

This report summarizing the current condition of TAPS has been prepared to support the evaluation of the request for renewal of the Federal Grant and State Lease. While TAPS is more than 25 years old, it still remains a very robust system. An illustration of the durability of the pipeline is its response to the large earthquake in central Alaska on November 3, 2002. Although there was extensive damage to public roads and other facilities in this area, the pipeline suffered only minimal damage. It was quickly and safely shutdown with no oil being released. Temporary repairs were made and oil began flowing through the pipeline within three days. The TAPS is being evaluated for any structural damage and repairs will be made as appropriate.

Since startup, the TAPS has delivered almost 14 billion barrels of crude oil from the North Slope of Alaska to the Valdez Marine Terminal (VMT) on Port Valdez, operating 99.6% of the time. The pipeline's high degree of reliability is a result of its engineering design, use of quality products and construction techniques, prudent operation of the system, vigilant oversight by federal and state regulatory agencies, and implementation of a thorough monitoring and maintenance program. A key element of this program is replacing components to ensure system integrity or to take advantage of technological improvements and efficiencies.

Since startup in June 1977, the TAPS facilities have been continually inspected, maintained, and upgraded to ensure safe operations. Many of these activities have been minor (such as routine maintenance of system components including pumps, motors and valves, or upgrading of computer and telecommunications system components), whereas others have been major construction projects (including the replacement of five pipeline valves and 8.5 miles of pipeline in the Atigun River valley, and the construction of the biological treatment tanks and tanker vapor control system at the VMT). These upgrades and maintenance activities resulted from the cooperative interaction between JPO and APSC to proactively address issues related to pipeline operations and are discussed in this report. The federal and state regulatory agencies responsible for monitoring TAPS operations have the authority to issue orders compelling corrective actions to ensure continued safe operations.

The TAPS was designed and constructed to function reliably in Alaska's harsh environment. Special features were incorporated into the pipeline design to address issues such as permafrost and corrosion control. The integrity of the pipeline and the components necessary for safe operation are inspected both visually and through the use of sophisticated instruments such as pigs that can monitor the wall thickness of the pipe. Portions of the pipe demonstrating significant metal loss (such that the estimated remaining wall thickness is less than that allowed in applicable engineering codes and standards) are repaired (sleeved) or replaced. The corrosion control management plan developed for TAPS by APSC in conjunction with JPO is considered a model for the pipeline industry.

The monitoring and maintenance program is a key to preserving safe operations of TAPS. The *Reliability Centered Maintenance* (RCM) strategy is currently being instituted for use on TAPS to support this need. The RCM process is a prescriptive approach that can be used to identify the maintenance needs of a physical asset to ensure operational safety, environmental responsibility, and functional reliability. The RCM analyses identify and document the relationship between equipment maintenance strategies and the preservation of associated system and subsystem functions. While the RCM process is a state-of-the-art method for identifying maintenance strategies, the effectiveness of such an approach is dependent on the current condition of the asset being maintained. As described in this report, the TAPS is in good condition and the RCM process can be effectively used to ensure continued safe operation for the foreseeable future.

Contents

The following is a list of acronyms and abbreviations (including units of measure) used in this document.

AAC	Alaska Administrative Code
ADNR	Alaska Department of Natural Resources
AFFF	aqueous film forming foam
AKOSH	Alaska Occupational Safety and Health
ANSC	AKOSH/NEC Safety Compliance
ARTS	Alyeska Radio Telephone System
ASME	American Society of Mechanical Engineers
API	American Petroleum Institute
APSC	Alyeska Pipeline Service Company
bbl	barrel(s)
BCS	Backbone Communication System
BLM	Bureau of Land Management
BTT	biological treatment tank
BVCS	Block Valve Communication System
BTEX	benzene, toluene, ethylbenzene, and xylene
BWTF	Ballast Water Treatment Facility
CB	citizen's band
CFR	Code of Federal Regulations
CKV	check valve
CIS	closed interval (over-the-line electrical potential) survey
CMP	Comprehensive Monitoring Program
DAF	dissolved-air flotation
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
DRA	drag reducing agent
DSMA	digital strong motion accelerator
EMS	earthquake monitoring system
ER	environmental report
ERB	Emergency Response Building
ºF	degrees Fahrenheit
FEIS	final environmental impact statement
FLIR	Forward Looking Infrared
GUI	graphical user interface
JPO	Joint Pipeline Office
kV	kilovolt
kW	kilowatt
LEFM	leading edge flow meter
LEL	lower explosive limit
LVB	line volume balance
MAOP	maximum allowable operating pressure
mg/l	milligrams per liter
MGV	manual gate valve
MLR	main line refrigeration
MP	Milepost
MTU	master terminal unit
MW	megawatt
NEC	National Electrical Code
NPDES	National Pollution Discharge Elimination System
OCC	Operations Control Center
OPS	Office of Pipeline Safety
OSHA	Occupational Safety and Health Administration
PC	personal computer
PE	professional engineer
PLC	programmable logic controller
PS	pump station
PSR	Pipeline Surveillance Report
psi	pounds per square inch
psig	pounds per square inch gauge
RCM	Reliability Centered Maintenance
RGV	remote gate valve
ROW	right-of-way
RTU	remote terminal unit
SCADA	supervisory control and data acquisition
SCFH	standard cubic feet per hour
TAPS	Trans-Alaska Pipeline System
TK	tank
TSI	Technical Service Instrument
TSS	total suspended solids
TVB	transient volume balance
TVMMP	TAPS Valve Maintenance Management Plan
UPS	uninterrupted power supply
VHF	very high frequency
VMT	Valdez Marine Terminal
VOC	volatile organic compound
VSM	vertical support member

Chapter 1

Background

The Trans-Alaska Pipeline System (TAPS) consists of an 800-mile, 48-inch-diameter crude oil pipeline that runs from Prudhoe Bay to Port Valdez; 11 pump stations; the Valdez Marine Terminal (VMT); and various support facilities. The pipeline is elevated aboveground for 420 miles and buried for the other 380 miles. The pump stations were built to move oil through the pipeline, and four of these are now on standby. The VMT on Prince William Sound has storage facilities for 9.18 million barrels (bbl) of oil and loading berths that can accommodate four tankers at a time, although normal scheduling is one tanker at a time. Except for occasional brief shutdowns for maintenance and repair, the pipeline has operated continuously since its startup in June 1977.

The TAPS is a complex system that moves crude oil from the North Slope of Alaska to the VMT. Since startup in 1977, the TAPS has delivered almost 14 billion bbl of crude oil. The TAPS was designed to move about 1.8 million bbl per day, and the peak daily throughput of 2.136 million bbl per day was reached in 1988. The current throughput is about 1 million bbl per day, which represents about 17% of the total domestic United States crude oil production. The crude oil travel time through the pipeline at the current flow rate is about 9 days.

The TAPS was constructed from 1974 to 1977 on a right-of-way (ROW) granted by federal, state, and private landowners; the TAPS facilities occupy about 16.3 square miles in Alaska. (While TAPS is authorized under a number of separate ROWs, common usage is to refer to these as a single ROW). The Federal Agreement and Grant of Right-of-Way for the Trans-Alaska Pipeline System (Federal Grant) was issued on January 23, 1974, and the State Right-of-Way Lease for the Trans-Alaska Pipeline (State Lease) was issued on May 3, 1974. Both the Federal Grant and State Lease are for a period of 30 years.

The current owners of TAPS applied for renewal of the Federal Grant and State Lease on May 2, 2001. The renewal application for the Federal Grant was provided to the Bureau of Land Management (BLM) of the U.S. Department of the Interior (DOI), and the renewal application for the State Lease was provided to the Alaska Department of Natural Resources (ADNR). The current TAPS owners are seeking renewal of the Federal Grant and State Lease for 30 years beyond the current expiration date. This report describing the current condition of TAPS has been prepared to assist in the renewal process for the Federal Grant and State Lease.

The TAPS is operated by the Alyeska Pipeline Service Company (APSC) as an agent for the TAPS Owners. The six owner companies are BP Pipelines (Alaska), Inc. (46.9263%); Phillips Transportation Alaska, Inc. (26.7953%); ExxonMobil Pipeline Company (20.3378%); Williams Alaska Pipeline Company, L.L.C. (3.0845%); Amerada Hess Pipeline Corporation (1.5000%); and Unocal Pipeline Company (1.3561%).

Regulation and oversight of TAPS is performed by a number of federal and state agencies working within the Joint Pipeline Office (JPO). The JPO is a consortium of six federal and seven state of Alaska agencies and is jointly managed by the BLM and the ADNR (Table 1). The JPO cooperative structure was formed in 1990. The individual agencies that make up the JPO receive their regulatory authority through federal and state laws and regulations. Each JPO agency retains its individual authority within this structure to accomplish oversight and regulatory goals.

The TAPS was designed and constructed to function reliably and safely in the harsh environment of Alaska. While the construction of TAPS was a major undertaking, it relied on proven engineering design and construction techniques. Special features were incorporated into the design of the pipeline to address environmental conditions such as permafrost. All but the very southern end of the pipeline traverses permafrost conditions. As the only oil transportation link to the North Slope, the pipeline had to have sufficient integrity to withstand arctic conditions. The pipeline was designed and constructed according to an approved quality assurance and control program.

Section 9 of the Federal Grant and Section 16 of the State

Table 1. Joint Pipeline Office

State Agencies:	Federal Agencies:
Department of Natural Resources: Administers state-owned land, as well as rights granted in land-use leases, permits, material sales, water rights, and water use.	**Bureau of Land Management:** Under the Department of the Interior, administers 88 million acres of public lands in Alaska. Issues and administers rights-of-way and permits for land use and cultural survey activities, and material sales related to pipeline use on federal land.
Department of Environmental Conservation: Regulates and issues permits to operate facilities that may affect air quality, generate waste, hazardous material treatment storage and disposal, or oil spill contingency plan approval.	**Department of Transportation/Office of Pipeline Safety**: Regulates the transportation by pipeline of hazardous liquids and gases, as well as drug testing related to pipeline safety, and conducts inspections of TAPS.
Department of Fish and Game: Regulates activities affecting fish passage, anadromous fish streams, and hazing of wildlife in connection with oil spills.	**Environmental Protection Agency:** Works in partnership with the Alaska Department of Environmental Conservation to administer regulatory programs such as the Clean Air Act, Clear Water Act, and Oil Pollution Act.
Department of Labor: Reviews practices and procedures pertaining to occupational safety and health; mechanical, electrical and pressure systems; and wage and hour codes to protect employees of the pipeline company.	**U.S. Coast Guard:** Issues permits for structures over navigable waters and oversees vessels and terminal safety.
Division of Governmental Coordination: Coordinates review of projects under the Alaska Coastal Management Program and consolidates state comments on National Environmental Policy Act issues.	**U.S. Army Corps of Engineers:** Issues approvals of structures or activities in navigable waters and approvals of placement of dredged or fill material in waters of the U.S. including wetlands.
Alaska State Fire Marshal's Office: Concentrates on fire and safety inspections, plan reviews, fire investigations, and public safety education.	**Minerals Management Service:** Manages the nation's natural gas, oil, and other mineral resources on the outer continental shelf.
Department of Transportation/Public Facilities: Provides design, construction and maintenance of primary and secondary land and marine highways and airports.	

Lease require APSC to establish and maintain a comprehensive quality control program. This program is described in the *Quality Control Manual* (QA-36). This manual and APSC implementing procedures are designed to ensure compliance with all applicable agreements, codes, standards, stipulations, and regulations during all phases of activities including design, modification, operation, maintenance, and ultimately termination of TAPS. The purpose of the quality control program is to assure APSC management, the public, and regulatory agencies that TAPS complies with the environmental and technical stipulations, operates reliably, and satisfies technical and other requirements intended to protect the health and safety of the public and TAPS workers as well as the environment.

Since startup in June 1977, the TAPS facilities have been continually inspected, maintained, and upgraded to ensure continued safe operations. In addition to routine maintenance activities, a number of major improvements (defined as projects costing in excess of $5 million) have been made to TAPS; those projects completed since 1987 are identified in Table 2. According to APSC, about $1.2 billion has been spent on upgrade projects since 1987; the total cost of all projects including major maintenance work during this period is approximately $2.5 billion (TAPS Owners 2001a). These upgrades have improved the overall quality and reliability of the pipeline and reduced the likelihood for leaks or other failures in the future.

This report has been prepared to summarize the current condition of selected TAPS systems necessary for safe and efficient operation of the pipeline. Since startup, the TAPS has operated 99.6% of the time, and much of the downtime (less than 1,000 hours over the 25-year period) was to perform scheduled maintenance activities. While TAPS has delivered almost 14 billion bbl of crude oil to the VMT, only about 31,600 bbl (or 0.002%) has been spilled, and more than half of this amount was due to sabotage events. The high degree of reli-

Table 2: Major Upgrades to the Trans-Alaska Pipeline System since 1987[a]

Description of Upgrade	Cost (Mil$)[b]	Time Frame (yrs)
Electrical system upgrades to safety codes	177.6	1993-1995
Oil spill response improvements	144.0	1989-2000
Tanker vapor control system at the VMT	101.7	1994-1997
Replacement of pipeline at Atigun Pass	91.4	1990-1991
Updates of engineering drawings	69.0	1993-2002
Improvements to pigging technology (approximately 50 pig runs since 1978)	50.0	1978-2001
Upgrades to controls and repair of Valves 74, 122, 80, and 60	43.8	1997-2000
Biological treatment tanks for Ballast Water Treatment Facility at the VMT	37.0	1990-1991
Corrosion protection program improvements for the pipeline (state cooperative program)	26.3	1996-2000
Corrosion protection for storage tanks at the VMT and pump stations	25.0	1997-2001
Computer system upgrades to address Y2K concerns	21.9	1998-2000
Refurbishment of berth loading systems at the VMT	15.6	1999-2001
Refurbishment of firewater piping at the VMT	11.7	1999-2001
Improvements to fire suppression system at the VMT tank farm	10.8	1999-2001
Installation of fiber optic communication system (oversight support)	9.3	1997-1999
Upgrades to vapor control flare at Pump Station 1	7.4	1993-1995
Installation of backpressure control/slackline at Thompson Pass	6.9	1997
Upgrades to workpad bridges	5.8	1998-1999
Improvements to leak detection capabilities (transient volume balance)	5.0	1997-1999
Construction of check valve vaults	5.0	1998-2000
Use of drag reducing agent (cost is offset by operational savings)	NA	Ongoing
Upgrades to system security (cost is confidential)	NA	Ongoing
Total	**865.2**	

[a] *The information in this table was provided by APSC and includes projects in excess of $5 million. According to APSC, the total cost of upgrades since 1987 is about $1.2 billion; the total of all projects over the lifetime of TAPS is approximately $3 billion (TAPS Owners 2001b). An upgrade includes either an improvement to TAPS or an extension of its useful life. This table does not include annual maintenance expenditures for corrosion protection and other routine activities. The annual cost to operate and maintain TAPS is about $400 million.*

[b] *The costs given here represent expenditures at the time the activities were undertaken and are not adjusted for inflation.*

ability of the pipeline is a result of its engineering design, use of quality products and construction techniques, prudent operation of the system, vigilant oversight by federal and state regulatory agencies, and implementation of a thorough monitoring and maintenance program. The importance of the monitoring and maintenance program increases as the system ages to identify facilities and equipment that need to be maintained. A key element of this program is replacing components to ensure system integrity or to take advantage of technological improvements and efficiencies.

The JPO uses the Comprehensive Monitoring Program (CMP) for oversight of TAPS. The JPO has issued 12 CMP reports since 1997 addressing a number of issues associated with TAPS operations. The recently issued CMP report, *TAPS Maintenance & Sustained Useful Life, January 2001 – May 2002,* provides a summary of activities conducted to date to evaluate and improve the monitoring and maintenance program for TAPS (JPO 2002). As noted in this report, the physical life of specific TAPS components is dependent upon (1) the original design criteria, (2) the materials used to construct the facilities, (3) the installation and construction techniques, (4) the procedures used to maintain and replace components as necessary, and (5) the ongoing maintenance program. An aggressive and thorough maintenance program is essential to ongoing safe operations of the pipeline system.

In reviews conducted by the JPO and other organizations including the General Accounting Office and the DOI Inspector General, it has been noted that maintaining functionality and operability of TAPS systems is equally important to strict compliance with the Federal Grant and State Lease, and applicable laws and regulations. The JPO has noted that adherence to engineering codes and standards and other regulations by itself does not guarantee operability of the various TAPS facilities. The current JPO maintenance oversight efforts have been designed to assess the maintenance requirements of particular TAPS systems and subsystems, the adequacy of systems and subsystems monitoring for potential functional failures, and the effectiveness of transitioning monitoring results into corrective maintenance work activities. A maintenance strategy formulation technique called *Reliability Centered Maintenance* (RCM) is currently being used to facilitate this effort.

Thread O-Ring plug repair to MP 400 section of aboveground pipe after bullet hole incident in October 2001 (photo courtesy of APSC).

The RCM process is a prescriptive approach used to identify the maintenance needs of a physical asset to ensure operational safety, environmental responsibility, and functional reliability. The TAPS RCM analyses identify and document the relationship between equipment maintenance strategies and the preservation of associated system and subsystem functions. The result of an RCM analysis is a list of actions to be performed to prevent the system from failing to perform its desired functions. The APSC committed in a Memorandum of Agreement dated June 27, 2002 (JPO and APSC 2002) to revise the *Maintenance System Manual* (MP-167) to be consistent with the RCM process identified in this recent CMP report.

While the RCM process is a state-of-the-art method for identifying maintenance strategies, the usefulness of such an approach is dependent on the current condition of the asset being maintained. The RCM process is most effective if used on an asset in reasonably good condition to prevent significant future deterioration with functional loss. As described in this report, the TAPS is in good condition and the RCM process can be effectively used to ensure its longevity.

This report summarizing the current condition of some key systems complements the maintenance and sustained useful life CMP report. Identifying the current condition and functions performed by a system and subsystem is the first step of the RCM analysis process. This report provides information on the status of these systems at a relatively high level and can support future RCM analyses for systems not yet evaluated. Knowledge of the current condition of the pipeline is necessary for renewal decisions.

This report was developed by compiling information from a number of sources including APSC manuals, JPO CMP reports, the Final Environmental Impact Statement (FEIS) on renewal of the Federal Grant (BLM 2002) and supporting documents, the Environmental Report (ER) prepared by the TAPS Owners to support preparation of the FEIS (TAPS Owners 2001a), published and unpublished information developed by APSC, and personal communication with JPO and APSC engineers. The bibliography (Chapter 4) identifies the citable sources used in this report. Many of these sources include similar information, which was corroborated and augmented by personal communications. It is not possible to cite individual sources for much of the descriptive information in this report. However, specific document citations are included in this report as appropriate.

While APSC manuals are identified as sources of information for this report, it should be noted that these manuals are proprietary information of APSC. These manuals are periodically updated and revised to reflect changes in pipeline operations and maintenance technologies. Reference is made to these manuals to identify the internal APSC procedures for conducting various activities; some of the manuals identified here may no longer be in effect and have been replaced by newer manuals. In addition, the FEIS and ER contain numerous pictures and diagrams that can be consulted for perspective on the information provided in this report. These figures and pictures illustrate environmental conditions (such as the extent of permafrost over the pipeline route) and engineering features (such as the support structures used for the aboveground portion of the pipeline).

Chapter 2

Major Systems

The TAPS consists of several major systems to ensure the safe and efficient movement of oil from the North Slope of Alaska to the VMT. The equipment and facilities for these systems are generally located at the 11 pump stations and the VMT. The pump stations are located at intervals of approximately 50 to 100 miles to boost crude oil pressure and provide relief storage in the event of an emergency shutdown. Pump Station (PS) 5 does not have mainline pumps and serves to relieve pressure on the downslope side of Atigun Pass. The TAPS was originally designed for 12 pump stations, but PS 11 was not built and mainline pumps were not added to PS 5 because the development and use of drag reducing agent (DRA) allowed the number of pump stations with mainline pumps to be reduced by two. The DRA is a long chain hydrocarbon polymer injected into the oil stream to reduce the energy lost during transit because of turbulence. The DRA-injection facilities are located at PS 1, 7, and 9 and at Milepost (MP) 238 south of the Brooks Range.

The 11 pump stations are similar in layout and function, although certain differences exist because of location and station tasks. The stations are housed within structures for protection against the environment and include pumps and turbine drivers, isolation valves, crude oil relief tanks with secondary containment, fuel-handling facilities, station and pipeline control facilities, living quarters (except for PS 1, 7, and 9), office buildings, shops and warehouses, and other facilities required for operating and maintaining the pipeline. The pump stations are fenced and have continuous security. PS 1 has a vapor recovery system for the crude oil storage tanks. PS 1, 3, 4, 5, 7, 9, and 12 are currently operating; PS 2, 6, 8, and 10 were placed on standby in 1996 and 1997 because of declining throughput and use of DRA. PS 7 and 12 may also be placed on standby over the next five to ten years.

The turbines at PS 1, 3, and 4 (north of the Brooks Range) are powered by natural gas that is carried from the North Slope through a gas pipeline that generally runs parallel to the oil

Pump Station 10 (photo© courtesy of David A. Predeger).

Pump Station 9 (photo© courtesy of David A. Predeger).

Pump Station 1 (photo© courtesy of David A. Predeger).

Valdez Marine Terminal on Sept. 16, 2002. (photo© courtesy of David A. Predeger).

pipeline. About the first 34 miles from PS 1 south is 10-inch diameter pipe and the remainder is 8-inch diameter pipe. Turbines at the other pump stations are powered with liquid turbine fuel purchased from commercial suppliers who deliver the fuel in tanker trucks. Crude oil topping units (which were small refineries) located at PS 6, 8, and 10 previously produced liquid turbine fuel for the pump stations. The topping units at PS 8 and 10 were placed on standby in 1996, and the topping unit at PS 6 was placed on standby in June 1997. Closure of these topping units significantly reduced operational risks. If the natural gas supply is interrupted, the turbines at PS 1, 3, and 4 can be converted to operate on liquid turbine fuel and fuel storage tanks are available at the stations.

The VMT is the southern end of TAPS and it is located on ice-free Port Valdez at the northeastern end of Prince William Sound. The VMT covers approximately 1,000 acres on the southern shore of Port Valdez. At the VMT, oil is loaded onto tankers for shipment to markets; most of the oil is shipped to the United States West Coast for refining and distribution. The VMT has storage facilities for 9.18 million bbl of crude oil and four loading berths. Berths 4 and 5 have vapor control systems and will be the primary loading berths in the future. Berths 1 and 3 do not have vapor control systems but can be used in special situations. Berth 2 was never built. Control of oil flow though the pipeline is directed by pipeline controllers at the Operations Control Center (OCC) located at the VMT.

The following systems which are considered significant for continued operations of TAPS are addressed in this document: mainline pipe, petroleum storage tanks, mainline valves, fuel gas pipeline, pressure relief systems, pipeline control systems, telecommunications, fire and gas protection systems, earthquake monitoring system, VMT ballast water treatment system, VMT vapor management systems, and electrical systems. Operators for these systems are generally located at the pump stations and the VMT. This report provides a description of these systems and the procedures being used to maintain system functionality.

While TAPS is more than 25 years old, many components have been replaced or upgraded over the years. In addition, a number of repairs and modifications have been made to various TAPS systems; these are highlighted in the following discussion.

2.1 Mainline Pipe

The mainline pipe is the backbone of TAPS and consists of an 800-mile long, 48-inch diameter steel pipeline. The pipeline extends from Prudhoe Bay about six miles from the Arctic

Coast of Alaska to the VMT on Port Valdez. The pipeline was built in three modes (aboveground, conventional burial, and special burial) depending on the environment, terrain, and soil conditions. The type of soil and the effects of heat transferred from the warm oil to the soil were the main factors in determining the construction mode.

The pipe was specially engineered and fabricated for TAPS. The pipeline is constructed of three grades of steel with minimum yield strengths of 60,000; 65,000; and 70,000 pounds per square inch (psi) in two wall thicknesses (0.462 and 0.562 inches). Maximum internal design pressures range from 832 to 1,180 psi. The higher grade of pipe with the heavier wall thickness was used where internal pressure is the highest, such as in pump station discharge line sections. Lower grade pipe is used near the inlet of the pump stations where the pressure is lower. The pipe is epoxy coated and taped for protection against corrosion caused by bacteriological, chemical, and electrolytic factors. The pipeline is designed to sustain all expected hydraulic pressures, thermal forces, and stresses induced by settlement, compaction, earthquakes, and weight between supports of the elevated line, including snow and wind loads.

The pipeline was originally planned to be buried for its entire length. However, prior to construction, a number of geologic, hydraulic, and seismic studies were performed to support the project, and engineering criteria were developed based on a combination of theoretical considerations, prior published engineering research, and engineering studies performed specifically for TAPS. All of these activities were intended to model or account for the extreme conditions and potential instabilities that could impact the integrity of the pipeline prior to its construction. The most important design issue that was resolved by these analyses and data was the distinction between thaw-stable and thaw-unstable permafrost.

As constructed, the pipeline is elevated aboveground for 420 miles and buried for 380 miles. The pipeline is elevated in locations where it traverses ice-rich soil that becomes unstable if thawed (thaw-unstable). The pipeline is buried in stable soils where thawing would not cause the pipe to settle (thaw-stable) and where there is no permafrost. Some exceptions exist, e.g., three sections of the pipeline (about four miles total) are buried in thaw-unstable soils for big game passage and a highway crossing. These sections are mechanically refrigerated to maintain soil stability. Several sections of pipeline at Atigun Pass (totaling close to a mile) are buried in insulated boxes to keep the permafrost from thawing and to protect the pipeline from avalanches. The remaining 375 miles of belowground pipeline was buried using conventional engineering practices.

The mainline pipe was constructed between 1975 and 1977, and the U.S. Department of Transportation (DOT) certified the pipeline on June 16, 1977. The Authorized Officer (representing DOI) gave APSC permission to operate TAPS on June 19, 1977. The design and construction of the pipeline was a systematic process, and the Authorized Officer reviewed and approved both the design criteria and mile-by-mile design details of the pipeline as the Federal Grant provisions for engineering review applied to the entire system. Construction oversight was provided by Bechtel Corporation, a large engineering firm with extensive experience in constructing com-

Pipeline construction complete above ground in Alaska Range area (photo courtesy of APSC).

plex engineering facilities including chemical processing facilities and nuclear power plants. Additional oversight was provided by APSC (acting as representatives of the TAPS Owners), field representatives of the Authorized Officer (including three private contractors), and to a lesser extent representatives of the DOT and other federal and state agencies. The State Pipeline Coordinator (representing the ADNR) was responsible for coordinating state oversight activities.

Since startup, only a small amount of mainline pipe has been replaced; the only significant sections requiring replacement were located in the Atigun River valley in the Brooks Range and near the Dietrich River. Both of these pipe replacement projects received the same level of scrutiny and oversight as original pipeline construction. The design, construction, and testing of both the original and replacement sections of mainline pipe are well documented. The original pipe design met DOT Office of Pipeline Safety (OPS) requirements for design (49 Code of Federal Regulations [CFR] 195.100), construction (49 CFR 195.200), and hydrostatic testing (49 CFR 195.300). In building the pipeline, the APSC followed internal quality assurance and construction procedures currently contained within the *Quality Program Manual* (QA 36), *Trans-Alaska Pipeline Welding Manual* (WL-51), *TAPS Engineering Manual* (PM 2001), and *Trans-Alaska Pipeline Maintenance and Repair Manual* (MR-48). The names of the manuals given here represent the most recent versions of these manuals.

Typical of very long pipelines, the primary risks to the TAPS mainline pipe are sabotage, hydraulic events, operator error, corrosion, settlement, washouts, seismic events, third party strikes, excavations, lack of proper maintenance, and latent construction defects such as pipeline dents. A number of operational incidents occurred during the first several years of operation, typical of many large complex projects. Most of the major leaks occurred during the first three years of operation as system components were brought online and operators became familiar with pipeline operations.

The most significant startup incident was an explosion and fire at PS 8 that destroyed a building, killed a worker, and resulted in the release of about 300 bbl of oil. A sabotage event occurred at Steele Creek near Fairbanks on February 15, 1978, in which a section of aboveground pipe was intentionally breached, resulting in the release of about 16,000 bbl. Another sabotage event occurred on October 4, 2001, when the pipeline was punctured by a shot from a high-powered rifle, resulting in the release of about 6,800 bbl of crude oil. Additional problems included buckling of the pipeline (Atigun Pass and MP 734), excavation damage, and third party damage. Pipeline vibration and fatigue have also been a concern (see Section 2.5.1 on the Thompson Pass slackline issue). Mitigation measures have been developed to address these and other issues to prevent their reoccurrence in the future.

2.1.1 Aboveground Pipe

2.1.1.1 Description

The 420 miles of aboveground pipe are located in areas that geotechnical investigations determined would become unstable if thawed. The pipeline was elevated to keep the warm oil pipe from heating these ice-rich soils. The aboveground assemblies were designed to allow for both axial and transverse movement of the pipe. The aboveground pipeline was built in a flexible trapezoidal (zigzag) configuration to allow for longitudinal expansion of the pipe to be converted to sideways movement; this configuration also accommodates pipe motion induced by an earthquake.

The aboveground sections of pipe are supported by approximately 39,000 *bents* located about every 60 feet. The bents consist of crossbeams installed between vertical support members (VSMs) placed in the ground; the TAPS includes about 78,000 VSMs. The aboveground pipe is insulated and mounted on a Teflon-coated shoe that can slide back and forth on the crossbeams. Movement of the pipe is generally back and forth across the crossbeams. Spacing between VSMs and crossbeam widths was set to provide maximum movement at expansion-loop bends with minimal movement near anchor structures.

Anchors were established every 800 to 1,800 feet in order to limit axial movement in the pipe, which could result in shoes falling off crossbeams. The anchor supports consist of four VSMs, a structural steel platform, and a friction slide plate assembly. The friction slide assembly is designed to resist an initial differential force in the longitudinal direction, i.e., along the pipe, before sliding and dissipating energy by crushing the honeycomb. Such axial movement does occur, primarily triggered by significant hydraulic events or earthquakes. There are some exceptions to the movement allowances, most notably just outside PS 7 where the pipe is fully restrained and behaves in a manner similar to belowground pipe. Between anchors, the pipe can move up to 170 inches side-to-side (laterally) for thermal expansion/contraction and seismic movement.

Leaning VSM north of Koyukuk River (photo© courtesy of David A. Predeger).

The VSMs are 18 inches in diameter and are typically embedded from 15 to 70 feet in the ground. About 62,000 VSMs contain passive heat transfer devices, referred to as heat pipes, in regions of warm permafrost. The cooling effect of passive heat transfer devices on the soils surrounding the piles increases the shear strength of the pile-soil bond. Heat pipes were not generally necessary in the VSMs located north of the Brooks Range because the permafrost is colder and stronger. The heat pipes are charged with anhydrous ammonia as the refrigerant. About 2 to 3% of the heat pipe's internal volume contains liquid ammonia and the remaining volume is filled with ammonia vapor.

Heat pipes work on the principal of evaporation and condensation of a working fluid. During winter, when the air is colder than the ground, heat from the ground causes the liquid ammonia in the lower portion of the heat pipe to vaporize. The vapor flows by differential pressures upward from the evaporator section (belowground) to the condenser section (aboveground) where the vapor condenses back to the liquid phase because of cooling by radiation and convection. The condensate flows downward by gravity on the internal wall surface of the heat pipe, where it absorbs heat from the ground and is re-evaporated to continue the process. The heat pipes work only in the winter when the air temperature is substantially lower than the ground temperature. At that time, the heat pipes drive a supercooling process, designed to extract much more heat than will be regained during the summer thaw. The system stops when the air temperature rises above the ground temperature, i.e., this is a one-way heat extraction system.

The VSMs have performed well over the past 25 years. Of the approximately 78,000 VSMs, no movement has been detected in about 55,000, and only an insignificant movement has been detected in most of the other VSMs. Because of movement trends, about 200 VSMs are currently on the engineering watch list for possible repair or replacement if required. About 250 VSMs have tilted greater than 3% from vertical with the maximum tilt being 18%. Twenty-four VSMs have been replaced to date, 18 at Squirrel Creek (MP-717) in 2000, and 6 south of PS 12 (MP-735) in Summer 2002 (discussed below).

Issues that are more significant for the aboveground portion of the pipeline include river migration, slope creep where soil forces VSMs down-slope, VSM/module contact, and other similar concerns. None of these issues present a current pipeline integrity or leak threat. These are discussed as follows.

• MP 197: In this area, a section of aboveground pipe near the east bank of the Dietrich River was threatened by erosion of the bank, which proceeded at a high rate for several years in the early to mid-1990s. The area was monitored and determined to require corrective action. A revetment was constructed at the eroding bank area to prevent further erosion in 1997.

• Treasure Creek (MP 442): At this location, the pipeline traverses an area that was disturbed in the early 1900s by mining activities. There is general down-slope movement (creep) that is likely related to permafrost destabilization on a hillside deforested by the original miners. This has manifested itself in tilting VSMs, out-of-level crossbeams, uneven shoe/beam contacts, excessive shoe overhang, and hanging shoes. The VSM displacement continues at a rate up to three inches per year in some bents. This movement has been accommodated by the design of the system that allows adjustment of pipe clamps, saddles, and crossbeams. The APSC continues to monitor and maintain this area as necessary to ensure the integrity of the pipeline.

• MP 680: Wet muskeg (organic matter) in a pond-crossing area appears to be causing the tripping of an anchor and movement of VSMs. The subsurface soils in the area freeze in the winter and thaw in the summer, causing soil and VSM movement. The anchor is checked annually, and maintenance adjustments to relevel the anchor frame are performed as needed.

•Klutina Hill (MP 698.1): This is an area of instability, as evidenced by a row of VSMs that is leaning to one side at angles of more than 10 degrees. The area was repaired in 1982 by adding wood chips to provide insulation, and installing heat pipes to stabilize the slope by refreezing it and cutting off groundwater migration. The area has been monitored annually since 1992, with inclinometers indicating that the VSMs are moving downhill at a rate of about 0.04 feet per year inside the repair zone and 0.07 feet per year outside the repair zone. Split-ring surveys, XYZ surveys, and thermistor monitoring are all conducted in addition to the inclinometer work. This movement has been accommodated by the design of the system that allows adjustment of the pipe clamps, saddles, and crossbeams. So far, the amount of movement does not justify an extensive repair effort. However, repairs will be performed prior to VSM movement that could compromise the integrity of the pipeline in this area.

•Squirrel Creek (MP 717): Considerable VSM movement has occurred in this area. The area has been monitored for movement since problems were first noted shortly after construction. Features that are found in this area include tilting VSMs, rotating bents, out-of-level crossbeams, uneven shoe/beam contacts, and significantly hanging shoes. Eighteen longer VSMs were installed in the summer of 2000. This area, as well as other locations having slope stability concerns, has been addressed in several JPO CMP reports. The area is closely monitored annually by APSC engineering, and maintenance adjustments are performed as needed.

•South of PS 12 (MP 735): Six VSMs were replaced in this area in August 2002 due to settling. The soil in the area is wet and unstable when thawed and heat pipes in the VSMs cannot keep the ground frozen. The replacement VSMs were placed deeper into the soil for stability. This area will continue to be closely monitored for VSM settlement. Adjustment of pipe clamps, shoes, and crossbeams are performed as needed.

In addition to the location-specific issues identified above, the APSC began to observe failure of some anhydrous ammonia charged heat pipes in the early to mid-1980s throughout the length of the pipeline. Upon investigation and research, it was concluded that the heat pipe radiator sections had become in some measure passive because of accumulated hydrogen gas. There are three possible causes of this hydrogen blockage: one being a chemical reaction inside the heat pipe vessel between ammonia and contaminants; a second being the breakdown of ammonia; and a third being a very slow galvanic process. A method of hydrogen extraction (called a *hydrogen getter pin*) was developed in the early 1980s. This method allows for hydrogen absorption by a core of zirconium dimanganese powder inside of a steel pin. About 1,300 heat pipes were repaired using this method from 1984 to 1986. Prototype testing of various maintenance methods proved that a better repair method was to vent the hydrogen gas and recharge the heat pipes with fresh refrigerant. Maintenance started in the summer of 2002 to vent hydrogen and recharge heat pipes with ammonia or carbon dioxide. Eight hundred fifty-five heat pipes were repaired by this method. The *Trans-Alaska Pipeline Maintenance and Repair Manual* (MR-48) provides a description of procedures for implementing this repair method.

An estimated 84% of all heat pipes along TAPS have some degree of blockage, potentially causing diminished heat transfer performance (JPO 2001b). Thus, APSC began an experimental program in the fall of 2000 to measure the heat transfer performance of blocked heat pipes (Sorensen, et al. 2002). This program was implemented to identify those heat pipes actually needing repair. A test program successfully identified heat pipe thermal degradation, and this method is now being used to identify heat pipes needing repair to meet design requirements. The test results indicate that the loss of heat transfer functionality as a result of hydrogen blockage is less serious than anticipated. For example, initial estimates were that as many as 6,500 heat pipes (out of 62,000) from Fairbanks south to Thompson Pass along the southern part of TAPS might need repair. Instead, it was found that only about 2,000 needed maintenance (Bradner 2002b).

2.1.1.2 Monitoring and Maintenance Activities

The APSC instituted a comprehensive monitoring program for the aboveground portion of the pipeline. This monitoring program has been in place since pipeline operations started in June 1977 to ensure that issues that could impact the integrity of the pipeline are identified to allow appropriate corrective actions to be taken. A number of the more significant repairs to date were discussed above. This program includes both structural and environmental issues and addresses items including erosion, oil spills, slopes, bridges, VSMs, faults, pipe shoes, glaciers, anchors, river and floodplain crossings, valves, fences, facilities, line markers, surface water on the ROW, pipe road-crossing casings, workpad conditions, pipe insulation, and cathodic protection systems. This program has been updated and modified over the years to incorporate new engineering technologies and lessons learned from pipeline operations.

Every year since startup, a ground-based surveillance and monitoring sweep known as the *line walk* has been conducted. The walkers make detailed notes on the condition of bents, module contacts, VSM tilts, insulation expansion joint damage, and any other structural problem that could compromise pipeline integrity. In some cases, the line walk crew leave physical marks on the shoes or pipes to note such things as shoe position, VSM tilt, and any other mark or identifier to help assess ongoing changes to the pipeline. These notes are an integral part of the monitoring program because they provide detailed information on the development of long-term anomalies or problems. In addition to this line walk, the monitoring program includes aerial surveillance. The DOT regulations in 49 CFR 195 and the *Trans-Alaska Pipeline System Oil Discharge Prevention and Contingency Plan* (APSC 2001a) require aerial surveillance biweekly, but often APSC performs weekly surveillance.

Two APSC documents govern practices with regard to surveillance and monitoring of the mainline pipe supports. These two documents are the *Surveillance Manual* (MS-31) and *Systems Integrity Monitoring Program Procedures* (MP-166). MS-31 is being revised to eliminate duplication with the monitoring information contained in MP-166. MS-31 describes the ground-based and fly-over surveillances in terms of observable conditions that warrant additional observations or alerting APSC engineering through the Pipeline Surveillance Report (PSR) system. The reportable conditions associated with aboveground pipe include:

·VSM/Module Contacts: This was a BLM audit item in 1994. At more than 400 locations along the pipeline system, the insulation module around the pipe was in contact with the VSM, and in some cases the shell was crushed. At some locations, the problem may stem from too small a span, i.e., the original design was based on computer modeling of the range of motion, and the width of the crossbeam was set to that range without regard to the width of the module. In some instances, the contact problem was known immediately at the time of construction, and workers created notches in the VSMs to provide extra room for the modules. Between 1994 and 1995, APSC engineering and consultants analyzed all the contacts. In all but 21 cases, the contacts were acceptable. In cases where the contacts were found to require action, bumpers were installed. Although not required for pipeline integrity, 78 additional bumpers were installed in the summer of 2002 to prevent further insulation module damage.

·Split Ring Surveys: The APSC surveys the elevations of split rings on VSMs to determine vertical movement over time. Split rings provide a convenient reference on each VSM, because it is fixed with respect to the VSM and can be easily surveyed. Split rings support the bracket component on which the crossbeam rests, and therefore provide a means of measuring differential movement resulting in out-of-level listing of the crossbeam. The split ring surveys are useful in directing load cell crews to areas where load measurements and saddle adjustments may be necessary.

·Uniform Load Tests: One of the key elements of the monitoring program is the load cell test program, which is focused on transition bents (aboveground to belowground transitions) and intermediate aboveground bents showing movement. Based on the split ring surveys, a crew uses load cell testing equipment to determine the load on each support assembly in a given segment. Results yield information on whether the movement of VSMs has caused unloading from some supports and consequently overloading of adjacent ones. The unloading/overloading is not readily discernible without this testing. The load cell testing indicates whether loads remain within acceptable loading criteria as provided in the *Design Basis Update* (DB-180). If excessive loads are found, the problem can be corrected by adjusting the shoe support height or by adjusting the split rings to realign loads within design criteria.

·Inclinometers: Used only in a few selected slope areas, inclinometers are installed when down-slope movement of surficial soils appears to be in progress. The inclinometers provide a reliable means of tracking changes from year to year. These are typically read as part of a biennial slope stability survey.

·Thermistors: Thermistors, like inclinometers, are installed and monitored only at selected locations (special study areas) where geotechnical instability induced by thawing is being monitored. The information does not provide a direct indication of impact on the mainline pipe, but rather indicates progression of thawing, which can be related qualitatively or quantitatively to soil movement, and therefore provides important information to assess and monitor long-term performance in areas of marginal stability. A primary weakness of thermistor monitoring is that the thermistor strings have limited long-term performance capability without periodic calibration testing or replacement. Besides being subject to mechanical damage, e.g., by ice expansion within the casing, the strings have also been found to drift out of calibration and after several years can yield unreliable or obviously incorrect results. In 2001 and 2002, APSC engineering assessed thermistors from Atigun Pass south to PS 12. This work included recalibration and reinstallation of 38 strings and the installation of 70 new strings. Thirty-six of the new strings were placed in newly drilled caissons and 34 were placed in the original casings.

·Shoe Position Surveys: The line walk crew measures the position of the shoe on the crossbeam in problem areas each year, physically marks the position at the site, and records the results in field notes. Additional notes may be taken by APSC maintenance coordinators, engineers, or consultants on annual or seasonal monitoring and surveillance visits. The positions triggering such survey notes are either excessive lateral migration causing crushing of the insulation module against the VSMs, or longitudinal migration of the VSM and crossbeam assembly such that shoes are partially overhanging (triggering corrective action to center the assembly by moving it along the pipe).

·XYZ Surveys: These are special study area surveys named after the standard Cartesian coordinate nomenclature. As the name would suggest, the surveys locate physical features (usually the VSMs) against the State Plan Coordinate System and the standard elevation datum applicable to the survey area. Such surveys are not routine; they are conducted solely in sections of the pipeline where slope creep movement of VSMs occur and to track migration usually down-slope of the VSMs over time.

·Tripped Anchors: After anchors are found in a tripped position, which can occur due to hydraulic events, temperature swings, or earthquakes, a crew is sent to re-center the pipe, if the anchor moved more than one inch from the center. A movement of one to three inches must be corrected within one year of discovery; a movement exceeding three inches must be corrected immediately. The procedures for repositioning and retorquing the anchor slide plates, and re-leveling the anchor platform are included in the *Trans-Alaska Pipeline Monitoring and Repair Manual* (MR-48).

·Shoe (Threaded Collar) Adjustments: If load cell data shows overloading or underloading in a particular bent (based on criteria listed in Section 3 of MR-48), or if shoes are out of level, the first approach to correct the problem is to adjust the threaded collar, which raises or lowers the pipe elevation $^1/_8$ inch per full turn.

·Split Ring Adjustments: If the position adjustment required to correct loading exceeds what can be accomplished with threaded collars, or if the crossbeam is out of level by more than 2%, the split rings require repositioning. This means that the support bracket is also adjusted, as is the crossbeam, the threaded collar, and ultimately the pipe.

·Infrared Surveys: The APSC performs a Forward Looking Infrared (FLIR) survey of the heat pipes every two to three years. These surveys may be conducted as often as every year, because logistics and weather considerations provide no guarantee of satisfactory completion of the entire line within a single survey year. The surveys can involve an early winter (usually October through December) fly-over of the aboveground pipe using a helicopter equipped with an infrared camera and recorder; ground-based assessment from trucks and snow cats can also be performed using hand-held infrared survey equipment. The camera is pointed at the mainline pipe and the heat pipes. If the heat pipes are fully functioning, the radiator section appears to *glow* (because of the heat being released). If the heat pipes are not functioning at all, the radiators appear dark. If the heat pipe is partially functioning (due to *blockage* in the form of light gases such as hydrogen stratified at the top radiator section), a dark section appears at the top of the radiator and a lighter section appears underneath. The recorded images are then graded in terms of a rough percentage of radiator surface shown as blocked. Since only the exceptions are of interest, the grading focuses only on the blocked or partially blocked heat pipes. This information is used to assess the need for corrective action on heat pipes to vent hydrogen, to perform recharge with anhydrous ammonia or carbon dioxide, or to replace the heat pipes with specially constructed heat tubes.

·Heat Pipe Restoration: The procedures for venting the hydrogen from the heat pipes and recharging the heat pipes for proper function are described in MR-48.

·VSM Replacement: Replacement of a VSM or installation of an additional VSM to replace or augment existing bents is an extremely rare event; it is generally considered a unique condition requiring site-specific engineering and project implementation. This process is therefore not described in MR-48. This action is necessary in cases of functional failure or anticipated functional failure of a VSM to support the pipeline adequately. Only 24 VSMs have been replaced over the lifetime of TAPS as discussed above.

·VSM Repair: The procedures for repairing physical damage to VSMs (dents, gouges, holes, and more severe damage) are provided in MR-48. Maximum dimensions for gouges and holes covered by the specified repair are given in this manual.

·Miscellaneous Repair: MR-48 also describes miscellaneous repair procedures including repair of shoes, Teflon pads, insulation, and repair of depressions around VSMs.

2.1.2 Belowground Pipe

2.1.2.1 Description

The belowground sections of the pipeline were primarily constructed in areas where permafrost was not present or where thaw-stable sands and gravels were present. In addition, three sections of pipe (about four miles total) were buried in thaw-unstable soil for big game passage and a highway crossing. These three sections are known as Main Line Refrigeration (MLR) sites 1, 2, and 7, and are mechanically refrigerated to maintain soil stability. Planned MLRs 3 through 6 were not built. Several sections of pipeline at Atigun Pass are buried in insulated boxes to keep the permafrost from thawing and to protect the pipeline from avalanches. In addition, there are many short sections of insulated pipe installed at big game crossings. Some of these sections require heat pipes to maintain the frozen soil in stable condition; the Authorized Officer required transitions between aboveground and belowground pipe to be insulated.

Belowground pipe is subject to numerous forces that could cause excessive stress by acting toward initiation of movement. Common phenomena affecting the stability of the underground pipe include erosion or scour, thermal degradation and settlement, down-slope movement, and pipe movement relative to ground embedment. Additional phenomena may be present on a rare, episodic basis and include liquefaction during earthquakes and glacial movement. These forces were known to the designers of TAPS and to the regulators. Accordingly, the design basis was formulated originally based on engineering analysis and supplemental engineering testing and research to assure maintenance of pipe integrity against such forces. Design features included allowances for thaw settlement for buried pipeline segments and pipe movement for aboveground sections to provide for crude oil temperature changes over time, and analysis of soil creep or frost jacking on the VSMs.

The APSC engineers also recognized that there was a possibility that in buried sections there could be ice in the ground that went undetected during construction and would later thaw, resulting in unwanted pipe movement. Monitoring procedures to address this possibility were required by the DOI. Over the past 12 years, the temperature of the crude oil in the pipeline at

VMT has decreased from about 100 °F to 60 °F as the oil throughput has decreased. This 40 °F drop in temperature means that the thaw bulb around the belowground pipe is no longer expanding and is likely contracting in some areas. Monitoring efforts are focused on known problem areas and the remainder of the pipeline is monitored less frequently. The entire pipe is monitored with a curvature pig to detect movement in the pipe that points to possible buckling. Currently, the entire pipeline is monitored by a pig on a three-year cycle.

There are two categories of design basis criteria relevant to the stability of the belowground pipe. The first category is comprised of prescriptive standards governing the relationship between the pipe and the surrounding soil. These include limitations on settlement and minimum cover depth requirements. The second category focuses on the behavior of the mainline pipe to external stresses such as load application or settlement as manifested in deformation and or strain.

<u>Pipe to Soil Criteria</u>: The major geotechnical influence affecting belowground stability is thaw settlement. This was recognized before construction and was addressed in the design criteria for TAPS. Section 2.2.2.1 (Thaw Settlement Criteria) of the *Design Basis Update* (DB-180) lists the following specified maximum allowable settlements for underground pipe:

•Maximum differential settlement of buried pipe is 0.5 feet in a 100-foot span, and

•Maximum total settlement of buried pipe is one foot.

Other applicable belowground stability criteria include the requirement that the minimum depth of cover over the pipe be three feet (Section 2.3.2.1 of DB-180), that at river crossings there be at least four feet of cover, measured from the top of the concrete coated pipe to the minimum existing riverbed elevation (Section 2.8.2.2 of DB-180), and that an allowance for a two-foot horizontal with two-foot vertical fault displacement exist in areas of active faults (Section 2.3.2.3 of DB-180).

In addition, there are geotechnical stability criteria that do not specify relative movement allowances between the soil and pipe. These include slope stability and thaw plug stability criteria. Exceeding these criteria could destabilize the zone around the pipe and cause excessive lateral and vertical movement of the pipe, thereby inducing unacceptably high strain and curvature.

<u>Pipe Response Criteria</u>: Another set of criteria relates directly to the effects that soil movement and instability (among other forces) may have on the pipe integrity. Pipe curvature, deformation, and strain are all controlled under specific criteria or risk-based analyses. By way of engineering analysis, it is assumed that exceeding or trending toward exceeding is a manifestation of soil destabilization; therefore, if no movement or high strains are observed, the soil regime is considered geotechnically stable. Relevant response criteria include:

·Limitations on primary stresses (hoop stresses, combinations of hoop and bending stresses, and effective stresses including thermal induced stresses) to set percentages of material specified minimum yield strength (Section 2.3.2.4 of DB-180), and

·Critical wrinkling curvature and allowable curvature changes (Section 2.3.2.5 of DB-180).

The design criteria for allowable curvature are based upon preconstruction testing of the mainline pipe at the University of California at Berkeley. Recently, several engineering studies and tests have lead APSC to evaluate the belowground pipe based on the demand on the pipe and the pipe's capacity to resist buckling. These studies have confirmed that the TAPS mainline pipe performs substantially better than anticipated in the original design.

<u>Corrosion Control</u>: The buried mainline pipe has an effective external surface coating material and is cathodically protected with zinc and magnesium sacrificial anodes, as well as impressed current systems. The coating is designed to prevent water and soil from making direct contact with the pipe and acts to eliminate the electrolytic path necessary for corrosion to occur. Where the coating is damaged, disbonded, or otherwise compromised, the pipe can experience external corrosion; cathodic protection is installed to mitigate this potential corrosion.

Two zinc ribbon anodes were placed in the mainline pipe ditch and connected to the pipe during construction. Corrosion will occur on the sacrificial anodes in lieu of the pipe. Approximately 250 miles of impressed current cathodic protection is also used for corrosion protection. Impressed current cathodic protection provides a low-level electrical current between remote anodes and the pipeline; the level of electrical current can be adjusted if necessary. However, impressed current requires a power source, which is not readily available at some locations along the pipeline.

Test stations and cathodic protection monitoring coupons are installed approximately every mile on the buried sections of the mainline pipe and are used to monitor the level of cathodic protection on the pipe. The monitoring coupons are small pieces of steel with the same metallurgical properties as the pipe. There are about 700 metal coupons along the pipeline, about one-half mile apart. These coupons are not subject to telluric (natural electrical current flow) interference and can be isolated from the permanently bonded passive zinc anodes to give IR (current times resistance) readings. Close interval (over-the-line electrical potential) survey (CIS) is also employed as part of the monitoring effort to collect pipe-to-soil potential measurements. A complete CIS of the mainline pipe is completed every three years.

Over 850 corrosion investigations had been undertaken by early 2002 along the pipeline. This is referred to as the *pig and dig* program. The principal tool guiding actual excavation and examination of the mainline pipe is called a corrosion pig. The APSC uses a corrosion pig that is an ultrasonic device that sends sound waves into the pipe wall. The return echo is measured to determine remaining wall thickness, which correlates to corrosion. The corrosion pigs are currently run on a three-year cycle. Continued development of the overall corrosion database (pig, dig, and monitoring data) is expected to lead to a five-year pigging cycle. The results of the excavation/investigation program have shown the pig data to be conservative. Although pipe corrosion was identified during the digs, repairs other than recoating (such as sleeving) were required in only a few cases in the last few years.

Whenever field analysis of the pipeline identifies an area having metal loss, but not to the extent that it violates the American Society of Mechanical Engineers (ASME) Standard B31.G requirements for maximum allowable operating pressure (MAOP), the affected piping is recoated and the pipeline segment continues in service. Whenever field analysis identifies an area of metal loss such that the pipe does not meet the ASME Standard B31.G requirements for MAOP, the affected segment is further tested using ultrasonic or mechanical procedures and the resulting data are submitted to APSC engineering for further evaluation. Further evaluation may result in repair (by sleeving) or acceptance of the affected segment. If it is determined that the area of metal loss will be subjected to a more detailed analysis, the detailed measurements of the metal loss area are made in accordance with APSC specifications B-510 and B-511. Corrosion analysis is performed in accordance with APSC specification B-512, *Pipeline Corrosion Evaluation Procedures*.

If any portion of pipe is found to be generally corroded so that the remaining strength of the pipe is at or below the MAOP, the APSC will do one or more of the following:

•Replace the pipe,

•Sleeve the pipe, or

•Reduce the MAOP commensurate with the limits specified in 49 CFR 195.400 through 195.440, based on the actual remaining wall thickness.

Localized pitting consists of clearly defined, relatively isolated regions of metal loss. After the minimum remaining wall thickness is determined, three methods are used to analyze the corrosion: mainline corrosion tables, ASME Standard B31.G techniques, or reduced wall methods using APSC specification B-512. If allowable stress levels are exceeded, the APSC immediately reduces operating pressure and determines if a Safety Related Condition Report needs to be filed with the DOT. Repair of the pipe is accomplished in accordance with the instructions in the *TAPS Engineering Manual* (PM-2001).

Whenever pipe is removed from the pipeline for any reason, the APSC inspects the internal surface for evidence of corrosion. If the pipe exterior is generally corroded such that the

Analysis of the pipe during corrosion dig at MP 363.4 south of PS 6 (photo courtesy of APSC).

Testing and documentation activities during corrosion dig at MP 363.4 south of PS 6 (photos courtesy of APSC).

remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the APSC investigates adjacent pipe to determine the extent of the corrosion. The corroded pipe must be replaced, sleeved, or based on the actual remaining wall thickness, the operating pressure must be reduced. The results of all inspection are documented in a Pipeline Investigation Report. If no corrosion is discovered on the pipe surface, the Pipeline Investigation Report is completed to document the condition of the pipe.

Problem detection for the buried pipe is conducted in a variety of ways. Smart pigs look for corrosion, curvature, and deformations. There are more than 400 test stations that give indications of the amount of cathodic protection on the pipe in addition to CIS surveys and visual inspections. The repair program on the belowground pipe started in the late 1980s. This program has entailed more than 850 digs, the installation of more than 150 pipeline sleeves, the replacement of 8.5 miles of pipe, and the addition of 250 miles of new impressed current corrosion protection to further mitigate damage to the pipeline. (Many of the installed sleeves were in the portion of the pipe that was eventually replaced, so that the number of sleeves currently on the pipe is significantly less than the number that were installed.) The corrosion control management plan developed by APSC in conjunction with JPO is considered a model for the pipeline industry. Its concepts have been incorporated into DOT pipeline integrity management regulations that went into effect nationwide March 31, 2002 (Bradner 2002a).

A number of anomalies have been uncovered by APSC through ongoing monitoring and surveillance activities. All significant anomalies that have been detected are documented in various engineering reports and studies including annual reports and JPO CMP reports. Although the majority of belowground piping has successfully maintained its stability, there are some areas where problems, or design anomalies, have been observed. The following is a list of anomalies that are being carefully scrutinized and evaluated by JPO and APSC to ensure the integrity of the pipeline.

·MP 200.2 and MP 200.4: Settlement in this area was detected initially by a second generation deformation pig (the Vetco pig) and confirmed by field surveillance personnel. The settlement at MP 200.2 was originally corrected by re-leveling the pipe. However in 1986, approximately one-half mile of buried pipe beneath the Dietrich River was subsequently rerouted and constructed in aboveground mode uphill and out of the floodplain. This reroute included both MP 200.2 and 200.4 areas. The original pipe in the floodplain was cleaned and abandoned in place.

·Atigun Pass: Areas of geotechnical instability were detected in 1979 when settlement caused a buckle that cracked and leaked in a section of mainline pipe uphill from an insulated box on the north side of Atigun Pass. This was repaired with a barrel sleeve and corrective action was taken to prevent further settlement. Similar incipient problems were found on the south side of the pass, caused by groundwater flowing through the melt zone around the pipe, carrying heat down the hill. A massive repair and stabilization effort was undertaken in 1980 which successfully arrested further settlement using a combination of grouting (to cut off or divert groundwater flow from the pipeline); mechanical ground freezing (to bring the thaw bulb back near the insulated box); replacement of insulation and the box and concrete support pad; installation of free standing heat pipes (to maintain the frozen ground); surface drainage interception; and installation of monitoring devices. Further analytical work was undertaken in 1996 and 1997 as a follow-up to an avalanche event, which damaged or destroyed a number of the heat pipes. Engineering analysis showed that the existing heat pipes were still functioning, and provided more than enough capacity for maintaining frozen ground.

·MLR 2: Settlement in the MLR 2 section of refrigerated belowground pipe was caused by several events including locally authorized shutdowns of the refrigeration skid during the wintertime (up to four months in duration) and by deferred maintenance related to the refrigeration skids. As a result, the MLR 2 area has been the focus of special study and monitoring, with significant maintenance and investment ongoing into the refrigeration units (including replacement with larger units). Localized thawing of the soil can lead to settlement and curvature of the pipeline, which increases the level of stress in the pipe and can lead to wrinkling. The APSC assessed the integrity implications of the pipeline curvature at MLR 2 in 1997, and the JPO concluded that the curvature of the pipeline did not require re-leveling in that area (JPO 1999a). Although the pipe movement has exceeded the original design settlement and yield criteria, engineering analysis has provided justification for continued operation of the pipeline as is, provided the maintenance and upgrades to the unit are completed. With the decrease in crude oil temperature and increased capacity of refrigeration, the settlement has appeared to diminish, and the areas of highest curvature are rebounding at a rate of about 0.8 inches per year (JPO 2001c).

·Salcha River Crossing: Another special study area was developed after the NOWSCO curvature pig data were analyzed for the Salcha River Crossing, indicating high curvature and resulting high strain in the pipe. The problem in this case was not soil instability; rather it was a result of the construction method and placement. In February and March 1976, the Salcha River was excavated (with an open-water excavation) to allow a buried pipe crossing (the largest such crossing at any river). The excavation method involved use of two high capacity draglines operating around the clock for several weeks with little or no effective way to check the bottom contours of the excavation in progress, or even at the end. Spot checking was minimal, tolerances were high, and intermediate slump or depression areas were inevitable.

The curvature and ovality of the pipeline at the Salcha River Crossing were addressed by analysis and smart pig investigations in the mid-1990s. As a result of investigations conducted in 1993 and 1994 with a smart pig at this crossing, the JPO recommended that APSC send the smart pig through this area again to inspect for stability, and perform a sensitivity analysis for inline inspection methods that identify wrinkling. The APSC sent the pig through the pipeline at the Salcha River Crossing in April 1997. The results of this investigation indicated that the curvature and ovality were stable at this crossing. These investigations confirmed that there was no progression of movement in the crossing area and there was no evidence of wrinkling (JPO 1999a). The pipe remains where it has been since it was installed 26 years ago. Analysis using demand/capacity ratio calculations have also shown the pipe to be in an acceptable condition.

·Pump Station Settlement Corrective Action Projects: Insulated boxes and relocating of piping from belowground to aboveground were undertaken in the early 1990s at PS 1, 2, 3, 5, 6, 10, and 12 to correct settlement of piping (detected using monitoring rods), as well as to correct corrosion found on the same piping.

Other significant belowground stability issues have included:

•MP 167 leak with repair using a barrel sleeve (approximately 200 feet of pipeline, including this sleeve, was subsequently replaced with new pipe),

•MP 734 leak with repair using a barrel sleeve (and subsequent resleeving in 2002),

•MP 46 re-leveling,

•MP 166.0 wrinkle with repair using a barrel sleeve, and

•MP 166.8 wrinkle with repair using a barrel sleeve.

There are many additional locations where dents and pipe deformation (to an oval shape) have occurred. These areas have been excavated, evaluated, and, if necessary, remediated. These investigations and remediations are documented in project files and the sleeves are recorded on the G-100 drawings.

2.1.2.2 Monitoring and Maintenance Activities

The APSC has instituted a comprehensive monitoring program for the belowground portion of the pipeline similar to that used for the aboveground portion. However, since this portion of the pipeline is not visible from the surface, special instruments are used to monitor the condition of the belowground pipe. This monitoring program has been in place since pipeline operations started in June 1977 to ensure that any issue that could impact the integrity of the pipeline is identified to allow appropriate corrective actions to be taken. This program includes elements necessary to ensure the structural stability of the pipeline and surrounding media applicable to the arctic and subarctic environment in which the pipeline resides.

To account for potential problems with the belowground pipe, a pipeline pig was built during the construction era to monitor for pipe movement. The *super pig* was used immediately after construction, and continued in use until it became stuck in Check Valve 29 and was destroyed. Unfortunately, the data from this pig never proved to be particularly useful, because the technology of that time was not advanced enough to yield the desired repeatability. In fact, the pipe did settle and leak at two locations in June 1979, and the settlement and distortion had not been detected by the super pig.

Two approaches were used to replace the super pig. One approach was to attach aluminum elevation monitoring rods to the pipe in suspect areas; approximately 2,000 such rods were installed and then monitored by surveyors for movement. Thermistor strings used to measure soil temperature were installed and used in conjunction with the monitoring rods. This increase in monitoring infrastructure occurred as a response to settlement problems detected in the mainline pipe in the late 1970s to mid-1980s. The second approach was to develop a deformation monitoring pig. This pig uses arms that contact the inside of the pipe and record the movement either in or out. A variation of this pig was used from 1981 until 1998. This pig successfully detected deformation caused by the settlement of the pipe at MP 200 in the Dietrich River.

During the MP 200 investigation, APSC surveyors began using the TSI tool (Technical Service Instrument's Ferro Phon) to electronically measure the depth of burial of the pipe by radio signals. The TSI tool was subsequently used over the entire pipeline to look for other areas of gross pipe movement. The TSI tool measures pipe burial depth within an accuracy of one foot and is not suitable for calculation of pipe curvature. The TSI data resides in the Engineering Data Management System and on the Expanded Plan and Profile drawings.

In the early 1990s, APSC engineers began working with another company to develop an inertial guidance pig. This pig is also called the curvature pig or Geopig (Hart, et al. 2002). It was first run in the pipeline in 1992 and is now run on a three-year cycle. This Geopig measures the position of the pipe in three dimensional space using gyros and accelerometers. This pig displays data in many different ways: plan, profile, horizontal strain, vertical strain, total curvature, and pitch. The strength of this pig is its software and the ability to display the data from two different runs at one time to show changes from run to run. This curvature pig has replaced the monitoring rods, thermistor strings, TSI tool, and deformation pig as the primary means of monitoring pipe curvature. The current pig, an inertial Geopig, compiles pipeline inertial and geometry data including shape, dents, buckles, curvature strain, and welds. At the same time, it records its position relative to welds and other control features.

As noted earlier, failure of the super pig lead to the installation of about 2,000 monitoring rods, which were generally read from the time of installation up to the early 1990s. In addition, thermistor strings were installed and read periodically to provide ground temperatures at certain sites, and soil borings were taken in areas indicating settlement. The importance of these tools declined after the completion and proving of the Geopig. While most monitoring rods remain in place, they are not replaced if destroyed. This technique of monitoring was always problematic, because it provided only spot-check data on pipe shape and behavior, and intermediate points were assumed (sometimes incorrectly) to be predictable from the rod data. The TSI readings were often taken to supplement these data, but the inaccuracies associated with the TSI tool discouraged reliance on this information. The TSI equipment is not used on a line-wide basis, but only at dig locations to verify depth of cover.

Experience has shown that thermistor strings should be limited to short term use, because they degrade and drift over time and provide unreliable data. Monitoring rods and thermistors are now only surveyed in areas of ongoing concern, such as MLR 2. The Geopig provides an excellent means of targeting the locations where the monitoring rods and thermistors could provide useful information. In addition, there are areas such as steep slopes where auxiliary study methods are essential. For slopes, a combination of aerial reconnaissance and photography, piezometers, and inclinometers may be used to supplement Geopig data.

The mainline belowground monitoring program for the pipeline currently consists of the periodic running of the curvature pig (Geopig) and analysis of the resultant data. The Geopig is the primary method of monitoring the belowground pipe for strain. The deformation pig is no longer used because upgrades to the Geopig now provide all the information previously obtained by the deformation pig. The results of these analyses are reported in the annual mainline belowground stability monitoring report. Monitoring rod, thermistor, TSI tool, and historic data are used to evaluate site-specific questionable areas where appropriate.

Monitoring criteria are established in Section 2.04, Mainline Belowground Monitoring, of the *System Integrity Monitoring Program Procedures* (MP-166). The criteria call for the screening of areas of high or increasing curvature (>85% of critical buckling curvature [K_{cr}] or where curvature is increasing at rates greater than 10% K_{cr} per year), and establishes requirements to analyze the curvature in accordance with software that establishes a demand/capacity ratio. All available evidence, including monitoring rod data and previous curvature data, are analyzed for trends indicating pipe movement. In addition, MP-166 requires a problem definition study for any high curvature area where the trend analysis indicates pipe movement. Also, information is to be reported for any areas where the curvature exceeds 70% K_{cr} in an originally straight pipe, or where there are waveforms, wrinkles, or buckles in the pipe but no evidence of movement. Extensive files of these results are maintained.

The *Trans-Alaska Pipeline Maintenance and Repair Manual* (MR-48) describes some specific actions and procedures. However, the criteria in the *Design Basis Update* (DB-180) and actions identified in MR-48 were developed based on dated monitoring technology. A number of advances have occurred in the monitoring technology for pipelines and associated engineering analysis techniques. Accordingly, the criteria in MR-48 are conservative. In some cases, special engineering studies on such sections as MLR 2 and the Salcha River have established the pipe to be within acceptable limits of the demand/capacity ratio even though the pipe is outside the curvature and strain limits specified in DB-180.

The identification of new areas of high strain or potential instabilities has declined greatly as a result of the detection capabilities of the curvature pig and the decline in throughput temperature. Nonetheless, any such discoveries require special engineering evaluation to determine the actions required to safeguard pipeline integrity.

<u>Surveillance</u>: In addition to the monitoring methods for belowground pipe discussed above, the APSC uses surveillance fly-overs and ground-based approaches to spot erosion areas, slope movements, leaks and spills, and signs of surficial settlement that could indicate deeper settlement affecting the pipe. In fact, in the case of a leak on the north side of Atigun Pass, surveillance by field personnel provided the original discovery. Field personnel performing inspections identify conditions that could compromise the integrity of the subsurface pipeline. The *Surveillance Manual* (MS-31) includes a list of *reportable conditions* associated with the belowground pipe. The list is not all-inclusive, but is a guide to the kinds of conditions that must be watched and evaluated by engineering. Reportable conditions include the following:

- Oil leakage or spillage,
- Inflow or outflow of water on the workpad (a possible indicator of *piping* in the pipe trench area, which could lead to loss of backfill and pipe support),
- Ground cracking (a possible indicator of pipe movement or failure in the ditch cover),
- River and floodplain changes that could affect pipeline stability or cover,
- Depressions (a possible indicator of pipe settlement),
- Ponding (a possible indicator of pipe settlement), and

•Exposed pipe (a definite indicator of erosion or failure of supporting soils).

These items are recorded on PSRs for follow-up action. Typically, these conditions require some engineering evaluation in consultation with field input. Although the PSR system fell into disuse in the mid-1990s, this system has been revived and APSC is planning to move it to the computerized work management system *Passport*. These reportable conditions may reveal the existence of an issue requiring resolution through corrective action, or they may simply be an observation with little consequence. Maintenance and repair actions are warranted if belowground stability is undermined to the point that the pipe integrity is threatened or if structures associated with belowground pipes are damaged as has happened several times in the past. In any event, the surveillance system is an integral part of maintaining the integrity of the system.

2.1.3 Pipeline Bridges

2.1.3.1 Description

The pipeline crosses streams in both buried and aboveground pipe spans, and at 13 locations, the crossing is made on bridges. One is a box girder bridge, nine are plate girder bridges, two are suspension bridges, and one is a tied arch bridge. A summary of pipeline bridge types, span lengths, and foundation types is given in Table 3.

Few modifications have occurred on pipeline bridges since their construction. The APSC monitors bridge performance through routine surveillance as well as third party inspections. Currently, there are no known conditions that represent a concern or threat to the integrity of pipeline bridges. All pipeline bridges are above the pipeline design flood level. There has been construction work to raise road and workpad bridges above the 50-year flood level, but this did not involve the pipeline bridges.

Box Girder Bridge: The Yukon River Bridge is an orthotropic box girder structure owned and maintained by the State of Alaska Department of Transportation/Public Facilities. This bridge also serves as a road bridge. In an orthotropic box girder bridge, the main supporting members are made up of steel plates welded together to form box beams with the tops of the box beams being an integral part of the driving deck.

Plate Girder Bridges: The main supporting members in plate girder bridges are made up of steel plates welded together to form deep wide flange beams. Each plate girder span is of a standard design, with the number of spans varying from one

Table 3 Pipeline Bridges

Bridge	MP	Type	Spans	Length (ft)	Foundation Type
Atigun River	140	Plate Girder	3	540	Thermal pipe pile
Un-named Creek	146	Plate Girder	1	180	Friction thermal pipe pile (Pier 1); thermal pipe pile (Pier 2)
Dietrich River	203	Plate Girder	2	360	Friction pipe pile (Pier 1); battered friction pipe pile (Pier 2)
Middle Fork Koyukuk River	219	Plate Girder	3	540	Friction pipe pile
Hammond River	220	Plate Girder	2	360	Thermal pipe pile (Pier 1); friction pipe pile (Piers 2 and 3)
South Fork Koyukuk River	254	Plate Girder	3	540	Battered friction pipe pile (Piers 1, 2, and 3); friction thermal pipe pile (Pier 4)
Yukon River	353	Box Girder	6	2295	Friction pipe pile
Hess Creek	376	Plate Girder	1	180	Friction pipe pile
Tatalina River	410	Plate Girder	1	180	Friction pipe pile
Shaw Creek	516	Plate Girder	1	180	Battered thermal pipe pile
Tanana River	528	Suspension	1	1200	Battered friction H-Piles
Gulkana River	650	Tied Arch	1	400	Thermal friction H-piles
Tazlina River	683	Suspension	1	650	Spread footings and anchors

to three. The spans are nominally 180 feet in length and are comprised of two plate girders bearing on concrete piers, which are supported on piles. The pipe pile configuration varies depending on site soil conditions. Standard shoes are used to support the pipe on crossbeams between the two plate girders so the pipeline is free to move as in other elevated sections. The Atigun River Bridge is unique because it also supports a small fuel gas pipeline on the downstream girder.

Koyukuk River Bridge (photo© courtesy of David A. Predeger).

Suspension Bridges: The Tanana River is crossed by a suspension bridge with a span of 1,200 feet. Suspension bridges suspend the pipe with large steel cables draped over towers and anchored to foundations on opposite banks. The suspension towers are over 150 feet high and are supported by steel H-piles driven into thawed sands and gravel. The main cable anchors are located 400 feet back from the suspension towers. The wind cables are anchored at a distance of about 111 feet upstream and downstream of each main tower. These anchors are supported on driven H-piles. Large river training structures have been provided at each bank of the river to prevent erosion at the anchors or tower foundations.

The Tazlina River is crossed by a suspension bridge with a span of 650 feet between the towers. The towers are about 70 feet high and are supported by concrete foundations bearing in thawed clay at a depth of about 30 feet. Main cable anchors are located 209 feet landward from each tower. Wind cable anchors are about 122 feet upstream and downstream of each tower and approximately 100 feet landward.

Tied Arch Bridge: The Gulkana River is crossed by a tied arch bridge with a span of 400 feet. The supporting element in a tied arch bridge is a steel arch with a horizontal steel member, tying the bases of the arch together to resist the tendency of the bases to move apart. The structure top chord consists of two steel box ribs, which form a compression arch. The structure bottom chord consists of two plate girders, which form tension ties and take longitudinal thrust forces from the compression arch. Steel box tension hangers suspended from the compression arch provide intermediate support points for the bottom chord. Standard shoes are used to support the pipe on crossbeams between the two bottom chord members so the pipeline is free to move as in other elevated sections. The two abutment piers are supported by H-piles driven into frozen gravelly clay.

The pipeline bridges were designed to accommodate static and dynamic load combinations, which included the weight of the pipe, fluid, insulation, snow and ice, wind, thermal expansion and contraction, and earthquakes. The pipeline bridges are located so that adequate clearance is provided between the bridge low chord and the pipeline design flood as well as to provide clearance for ice ride-up and navigational traffic. Final design of pipeline bridges was reviewed and approved by the Authorized Officer prior to issuance of a Notice to Proceed allowing construction. Inspection during the construction process provided assurance that the bridges were installed as designed, with allowance for approved deviations from the final design.

The performance history of pipeline bridges over the 25 years from commissioning to the present has been excellent. Annual and five-year professional engineer (PE) inspections have identified a number of minor structural and site discrepancies. Common findings include loose bolts (the normal result of thermal expansion and contraction as well as other operational loading conditions), minor surface corrosion, binding of elastomeric bearing pad material at expansion joints, and lateral erosion of stream banks. An example is spring hangers at the Tazlina River Bridge. The condition was first noted during a five-year PE inspection. A feasibility study was performed to determine repair alternatives and included a pipeline stress analysis for all loading and temperature conditions. The final design called for locking the spring hangers in place to function as constant elevation supports. The repair of the Tazlina River Bridge was performed in accordance with an approved engineering design prepared consistent with the TAPS quality assurance requirements. During the annual inspection in 2001, the primary items noted were the need to tighten bolts on most of the bridges, and a spalling concrete repair and loose cotter pin at the Tanana River Bridge.

2.1.3.2 Monitoring and Maintenance Activities

The JPO has monitored the APSC bridge maintenance program since the early 1990s. In 1993, the JPO identified that, while APSC did have bridge maintenance and repair manuals in place, the inspection of TAPS bridges was not consistently performed (JPO 2000). Subsequent to that finding, pipeline bridges are now inspected annually in accordance with Standard Inspection Procedure B1001 and APSC bridge inspection manuals. The inspection is conducted by APSC inspection, with inspection reports submitted to APSC system integrity for review. Pipeline bridges are inspected at intervals not exceeding five years by a PE registered in the State of Alaska to evaluate the integrity of the bridge. These inspections verify that each structure is performing as expected, note needed maintenance, notify appropriate personnel of improvement needs, and serve as an independent monitor to verify the effect of maintenance procedures. The APSC system integrity coordinates the five-year PE inspections. Future annual and five-year PE inspections of pipeline bridges are expected to continue at current levels.

Standard maintenance that may be performed by local maintenance coordinators without APSC system integrity involvement includes cleaning and removal of debris as well as touch-up painting, as outlined in the *Trans-Alaska Pipeline Maintenance and Repair Manual* (MR-48). Maintenance that is beyond the scope of standard maintenance requires the involvement of APSC system integrity and must be performed under a Work Order in accordance with a Work Site Procedure (PIP 5.2). An example of work that must be performed under a Work Order/Work Site Procedure is tightening of structural bolts.

Modification of pipeline bridges is conducted in accordance with the requirements of the *TAPS Engineering Manual* (PM-2001) and the *Quality Program Manual* (QA-36).

2.1.4 Summary Statement of Condition

The condition of the mainline pipe is well known and sound. Although the pipeline was constructed more than 25 years ago, the APSC has implemented an aggressive monitoring and maintenance program for the mainline pipe. The APSC has developed a number of new state-of-the-art techniques for monitoring the condition of the pipeline and detecting corrosion, dents, ovality, buckles, and curvature. Portions of the pipe have been replaced in the past and can be done so in the future if needed. Areas of concern potentially affecting the pipeline are known and properly addressed so that they are not a threat to the integrity of the aboveground pipe, belowground pipe, or pipeline bridges.

2.2 Petroleum Storage Tanks

2.2.1 Description

The TAPS has 82 petroleum storage tanks of 10,000 gallons (238 bbl) or larger capacity throughout the system. These tanks are used for the storage of crude oil, turbine fuel, and diesel fuel. Twenty-six of these 82 petroleum storage tanks are crude oil storage tanks (including crude oil breakout tanks) currently in service. The largest tanks on TAPS are located at the VMT, where eighteen 250-foot-diameter (approximately 510,000 bbl each) tanks are available for storage of crude oil. Two of these tanks are dual-purpose relief and storage tanks – the remaining 16 tanks are for storage.

All crude oil storage tanks for TAPS are cone-roof tanks, i.e., tanks with a flattened conical roof to allow a vapor reservoir at the top, and were constructed in accordance with the requirements from American Petroleum Institute (API) 650, *Tank Construction Code*, and bear API identification plates.

Tank (TK) 110 at PS 1 has a modified concrete ring-wall base that was added in 1979 to correct a settling problem. A concrete ring-wall was installed at TK 140 at PS 4 in 1998. The VMT tanks have concrete ring-wall foundations for seismic stability.

Vertical tanks at all locations were constructed from 1974 through 1976 and commissioned in 1977, except for those at PS 2 and 7. At these sites, the tanks were built from 1980 to 1983. The APSC inspects the crude oil tanks every 10 years or on the applicable schedule as given in API 653, *Tank Inspection, Repair, Alteration, and Reconstruction*. All aboveground crude oil storage tanks reside inside dikes to contain any oil spilled, should a tank fail. The dikes are designed to hold 110% of the aggregate volume of all tanks inside the dike plus an allowance for precipitation. In addition, a liner is buried under the top layer of gravel inside each dike to prevent crude oil from seeping into the soil outside the tank farm.

Crude Balancing Oil Tanks at PS 1: PS 1 uses two balancing tanks to control the flow to the booster pumps and into the pipeline. These tanks hold a total of 420,000 bbl of crude oil. The balancing tanks have dedicated cathodic protection systems to prevent external, soil-side floor corrosion. In addition, sacrificial anode systems in the tanks prevent internal floor corrosion. Both tank foundations settled shortly after startup of TAPS, creating a buckle in the walls of the tanks. A specialist was hired to relevel the tanks, perform a hydrotest, and assess their structural integrity; both tanks were determined to be acceptable. An ongoing surveying program monitors the buckles for changes.

East Tank Farm at the VMT (photo© courtesy of David A. Predeger).

Breakout Tanks: According to 49 CFR 195.2, a *breakout tank* is defined as “a tank used to (a) relieve surges in a hazardous liquid pipeline system or (b) receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline.” Breakout tanks are located at each pump station except PS 1. With the exception of PS 5, the breakout tanks hold 55,000 bbl and their primary function is pressure relief. PS 5 operates as a relief station and does not have mainline pumps; the purpose of this pump station is to relieve the pressure in the pipeline caused by the elevation of Atigun Pass. The breakout tank at PS 5 holds 150,000 bbl.

It is desirable to keep the level of crude oil in the breakout tanks low to make as much relief capacity as possible available. As soon as practical after a relief event of noticeable magnitude, the pipeline controller in the OCC at the VMT turns on the pump station’s booster pump, which reinjects crude oil into the suction side of the mainline pumps. In this way, oil is removed from the tanks and reintroduced into the pipeline oil stream.

All breakout tanks have dedicated cathodic protection systems for corrosion control. While TK 1 and 3 at the VMT do not meet the definition of breakout tanks given above (they are mainline crude oil relief tanks), these two tanks serve the same function as pump station breakout tanks. TK 1 and 3 also have dedicated cathodic protection systems to control corrosion.

VMT Crude Oil Storage Tanks: The VMT has 18 crude oil storage tanks, each having a capacity of 510,000 bbl; the total storage capacity of these 18 tanks is 9.18 million bbl. Four storage tanks are located at the West Tank Farm and 14 tanks are at the East Tank Farm. TK 2 and TK 4 through 18 store crude oil before it is loaded onto ships. As noted above, TK 1 and 3 are crude oil relief tanks. All storage tanks at the East Tank Farm have cathodic protection; the storage tanks at the West Tank Farm do not have cathodic protection. The inspection interval for the crude oil storage tanks at East and West Tank Farms is based on API 653, which has been adopted by the Alaska Department of Environmental Conservation as the regulatory standard.

2.2.2 Monitoring and Maintenance Activities

Since 1989, the APSC has conducted an ambitious tank inspection and repair program to ensure that the petroleum storage tanks throughout TAPS are safe, leak free, being operated to assure asset preservation, and in compliance with all federal and state regulations and API standards. The tank inspection and maintenance program is APSC's largest repetitive project activity since its inception in 1989. This project cost often exceeds $20 million per year. As regulations change, the APSC adopts technology to improve tank integrity, leak detection capabilities, and corrosion protection.

According to the stipulations given in Section 3.2.1.1 of the Federal Grant, all design, material, construction, operation, maintenance, and termination practices will be in accordance with safe and proven engineering practice, and shall meet or exceed the following:

•American National Standards Institute B31.4, *Liquid Petroleum Transportation Systems*; paragraph 434.21.3(a) refers to API Standard 650, and

•49 CFR 195, *Transportation of Hazardous Liquids by Pipeline*.

All TAPS tanks were designed and constructed to the above standards, and operation, maintenance, and repair of these tanks have all been conducted in accordance with the requirements identified in these standards. In addition to the subsections of 49 CFR 195 and 60 CFR 112, the tanks are in conformance or being modified to be in conformance with Occupational Safety and Health Administration (OSHA) requirements given in 29 CFR 1910.106.

The State of Alaska has jurisdiction over TAPS petroleum storage tanks. 18 Alaska Administrative Code (AAC) 75, *Oil and Hazardous Substance Pollution Control Regulations,* lists the requirements for these tanks and directs that the inspections and maintenance of these tanks conform to API Standard 653. The State of Alaska also requires that the petroleum facilities comply with the Uniform Fire Code. The storage tanks meet or exceed the requirements identified in these codes. In many cases, the Federal Grant and State Lease requirements and stipulations are more stringent than the codes.

The inspection methods and criteria used in APSC's internal tank inspections meet or exceed industry and regulatory standards. The APSC, working in conjunction with inspection companies, has developed inspection instrumentation and procedures that are now used worldwide in tank inspections. These instruments and procedures provide reliable and accurate assessment of the tank floors; they provide for inspection of approximately 95% of the tank floor. This exceeds the inspection criteria identified in API Standard 653 and allows APSC to have a very high confidence level in the inspection to identify and allow for the repair of any integrity threatening corrosion damage. This inspection program combined with the improved cathodic protection systems installed on the tanks provides assurance that the integrity of the tanks is maintained.

The operation, maintenance, inspection, and repair of these tanks are in accordance with applicable laws, codes, regulations, and standards. These requirements are identified in Section 3.20, Tank Monitoring, of the Sys*tems Integrity Monitoring Program Procedures* (MP-166). The APSC utilizes trained individuals responsible for all aspects of tank operation, maintenance, and inspection to help ensure compliance with applicable regulations and standards. Historically, the tanks have performed very well.

The APSC began internally inspecting tanks in 1982. Beginning in 1992, in conjunction with the adoption of API Standard 653, the APSC initiated an intensive inspection effort on aboveground storage tanks to ensure that all tanks were inspected to the new standard. All major tanks were inspected internally to API Standard 653 by 1997. Corrosion perforations were discovered in the floors of TK 111 at PS 1 and TK 10 at the VMT during these inspections. These perforations were filled with corrosion products and sludge and were essentially self-sealing. This prevented all but very minor leaks to the soil beneath the tanks.

The floors of five pump station tanks and 14 VMT tanks were replaced. The floor replacements were done to repair corroded tank floor plates and allow installation of sub-floor cathodic protection systems. The APSC has used both retrofitted and new cathodic protection systems to successfully protect tanks at the pump stations. All pump station relief tanks now have effective cathodic protection systems installed. Additionally, all TAPS tanks are equipped with Enraf sensitive gauging for leak detection and they also have or are being equipped with overfill alarm systems. These tanks have been in service since 1977 and there has never been a spill, overfill, or other significant problem with any of the tanks.

The tank inspection and maintenance program covers routine inspection, maintenance, and repair of the crude oil tanks.

The possibility of needing to replace all crude oil tanks is remote. The only plausible reasons would be a major design flaw or significant corrosion, and neither is likely. The tanks were designed and built by Chicago Bridge and Iron, which specializes in the design, engineering, fabrication, field erection, and repair of steel tanks, and have no known design flaws. Chicago Bridge and Iron is the leading provider of field-erected steel tanks in North America.

A rigorous corrosion management program is in place to prevent significant corrosion. The program includes both internal corrosion control and external corrosion control. Internal tank corrosion control consists of a combination of protective coatings and cathodic protection using sacrificial anodes. External corrosion control occurs through a variety of approaches, including external cathodic protection, internal nondestructive examination, or a combination of these two techniques.

Impressed current systems are the corrosion protection systems of choice and are being installed in various configurations depending on the method of tank construction. Systems include deep-well ground beds, distributed ground beds, undertank systems, and angle-drilled systems. The installation cost for each system is approximately $2 million. For tanks with liners under the tank bottom, only undertank cathodic protection systems have been successful. System design may vary between tanks and is affected by internal inspection results, associated repairs, and system economics.

Cathodic protection effectiveness and operation are monitored periodically by measuring structure-to-soil potentials and rectifier outputs. When possible, potential readings are taken at the tank perimeter on all tanks and on permanent reference cells installed under tanks. Rectifiers are checked bimonthly to verify that they are operating. Monitoring is conducted annually for structure-to-soil potentials; rectifier output (volts/amps), efficiency, and unit inspection; and anode outputs (amps) in junction boxes on ground beds.

The APSC conducts a rigorous inspection and maintenance program on all its in-service tanks. This inspection program meets or exceeds the requirements identified in 18 AAC 75; API Standard 653, Section 4; and 49 CFR 195.432. These inspections include daily, monthly, and five-year external inspections. The APSC performs internal inspections of every major operational tank based upon API standards. Operations personnel at the tank sites daily monitor all tanks for leaks. The personnel performing the inspections are knowledgeable about the tank, its operation, and the characteristics of the stored material. The results of the monthly inspections at pump stations and the VMT are entered into a database maintained on an APSC mainframe computer system. The results of these inspections will be kept for the life of the pipeline and are filed at the tank site and with the APSC tank steward. If a discrepancy is detected, the inspection is broadened and assessed. The APSC operations and engineering will then work together to address the irregularity.

Routine in-service inspections are conducted each calendar month, with no more than 45 days between inspections. The monthly inspections are conducted in accordance with APSC procedure SIP T-1001. Inspection personnel visually inspect all tanks as directed by preventive maintenance work order requirements. As in the daily inspections, the personnel performing these inspections are knowledgeable about the tank, its operation, and the characteristics of the stored material. The procedures detail specific points to check. The monthly inspection documentation is kept for the life of the pipeline and filed in accordance with APSC's company-wide filing plan CW-199, *Master List of Quality Records*, File Code 13.30. The pump station receives a copy of these inspection reports. When a deficiency or question is noted, APSC operations requests inspection and evaluation, and works with engineering to address the discrepancy.

A settlement survey is normally conducted annually, although these surveys can be more or less frequent, based on the tank foundation's past performance. The personnel performing these inspections are knowledgeable of the tank, the tank's operation, and the characteristics of the stored material. A survey of the cathodic protection system of each tank is done annually, as required by API Standard 653. The APSC's inspections are required to meet all facets of API Standard 653 requirements. The annual cathodic protection inspection documentation is kept for the life of the pipeline and filed in accordance with APSC's company wide filing plan CW-199, *Master List of Quality Records*, File Code 13.30. The pump station receives a copy of these inspection reports. If a discrepancy is noted, APSC operations expands the inspection and evaluation, and works with engineering to address the irregularity.

All of the tanks covered by 18 AAC 75 require a more thorough external inspection. The APSC's five-year inspections are required to meet API Standard 653 requirements for a five-year external inspection. The five-year inspections are conducted and signed by an authorized inspector as defined by API Standard 653. These inspections are conducted when all snow and ice are removed from the base of the tank, allowing full examination. The original inspection reports for five-year inspections are forwarded to the inspection team lead, with copies to pump station operations. If a discrepancy is noted, APSC operations expands the inspection and evaluation, and works with engineering to address the irregularity.

Tanks covered by 18 AAC 75 are allowed a maximum of 10 years between internal inspections, unless a shorter or longer inspection interval is prescribed by API Standard 653 or API RP 12R1. The tanks covered by DOT regulations in 49 CFR 195 are required not to exceed the 10-year interval for internal inspection, unless a longer period is allowed by API Standard 653, Section 4.4.2. The VMT ballast water and recovered crude oil tanks are covered by 18 AAC 75, as directed in the *Valdez Marine Terminal Oil Discharge Prevention and Contingency Plan*, (APSC 2001b). The internal inspections are conducted under the direction of an API Standard 653 authorized inspector. The inspections must satisfy the requirements of APSC inspection procedure SIP T-1001.

Preparatory work, inspection, and potential repair work is very involved for the internal inspections. The internal inspections are done through a funded maintenance program. Repairs and replacements are under a separately funded project. Inspections for the internal examination are performed to the specifications of APSC's inspection procedure SIP T-500 and API Standard 653. Internal inspection documentation, and any corrective actions taken are filed with the tank inspection project records, with copies to the inspection team lead. Copies of data and reports from the inspection are forwarded to the systems integrity team lead for updating of Table 7 in Section 3.20, Tank Monitoring, of the *Systems Integrity Monitoring Program Procedures,* (MP-166), and the corrosion data management system.

The record keeping requirements of inspection results are detailed in MP-166. During the recent renewal of the *Trans-Alaska Pipeline System Oil Discharge Prevention and Contingency Plan* (APSC 2001a), the inspection records of the pipeline tanks were requested by the State of Alaska. While TM-166 and the record keeping procedures included in it are new, all of the requested inspection data was retrieved, providing a good test of the new procedure and the completeness of the data.

Corrosion is the biggest operational integrity issue for any tank. Both external and internal corrosion can be problematic, with soil-side, bottom corrosion usually being the primary concern. Because of these concerns, the APSC addresses external, soil-side, bottom corrosion control through a variety of approaches. These include external cathodic protection, leak detection, internal nondestructive examination, and combinations of these methods. The nondestructive examination technique is used when warranted by the inspection program

For external, soil-side, bottom cathodic protection, several systems are used including deep-well ground beds, distributed ground beds, undertank anode grid systems, and angle-drilled systems. For tanks with liners under the tank bottom, only undertank anode grid cathodic protection systems have been successful. The design of the system is impacted by the internal inspection results, associated repairs, and system economics. The APSC specification B-485, *Impressed Current Cathodic Protection for Aboveground Storage Tanks – Grid System*, defines the application of these systems. The effectiveness of the installed cathodic protection system is monitored on a periodic basis, in accordance with the *System Integrity Monitoring Program Procedures* (MP-166) and API Standard 653. This effectiveness monitoring is conducted bimonthly for rectifier outputs, and annually for structure-to-soil potentials. External cathodic protection systems for tank protection are designed to be in conformance with the standards given in API Standard 651.

The cathodic protection systems are surveyed annually to ascertain the level of protection and ensure the protection of the tank bottoms. Internal corrosion control consists of utilizing a combination of several corrosion control methods, including protective coatings, internal cathodic protection, and chemical corrosion inhibitors. The internal surfaces of the tanks are primarily protected by a protective coating. The type of coating varies with the tank service, as well as the environment in which it will be applied. Coating selection, application, and internal cathodic protection is outlined in APSC Specification B-414, *Interior Coating of Steel Tanks*, and in conformance with API Standards 651 and 652. To supplement the internal coating on most crude oil storage tanks, internal cathodic protection is provided by sets of sacrificial anodes, as detailed in APSC Specification B484, *Sacrificial Cathodic Protection of Aboveground Storage Tanks, Internal*. In addition, corrosion inhibitor chemicals are added to the relief and balancing tanks, where they treat any separated water, and provide a protective chemical film on any exposed surface.

The requirements of 18 AAC 75 provide that inspection and repair guidelines for major petroleum tanks follow API Standard 653. This standard gives a recommended guideline for tank liners based on the metal thickness of the tank bottom. It also presents a formula for calculation of the minimum remaining tank wall, based on the corrosion rate that is to be used as a basis of repair. Repairs to TAPS tanks are in accordance with the requirements given in APSC Specification T-411, *Tank Repair*, and by requirements of API Standard 653. Work not covered by these documents must be specified by a qualified engineer utilizing API Standard 650.

The TAPS tank systems are under constant scrutiny. Whenever an enhancement is developed for a system, it is put into effect as soon as practical. Examples of these enhancements are the level sensing system improvements for the TAPS tanks, and the improved overfill alarm systems. Another enhancement implemented by APSC is the improvements made to the cathodic protection systems of several of the tanks. Another enhancement to the tank program is the publication and distribution of the *System Integrity Monitoring Program Procedures* (TM-166). All of the tanks at the VMT's East Tank Farm have the new undertank anode grid cathodic protection systems.

MP-166 was published as a controlled document and is routinely reviewed and updated. This manual is a summary of the requirements for management of TAPS tanks and covers all major and minor (as defined by 18 AAC 75) tanks on the pipeline and at the VMT. Section 3.20, Tank Monitoring, of MP-166 covers the inspection and maintenance of aboveground storage tanks, and delineates the record keeping requirements for both routine and non-routine maintenance inspections. This manual also establishes the record keeping responsibilities and requirements for tank inspections and maintenance.

The drawings for TAPS tanks reside in the Fairbanks Business Unit and the Valdez Business Unit document control centers. These include drawings from the original design and construction, APSC/Fluor appurtenance/orientation drawings, and as-built drawings. The drawings are accessible through the document control centers, and are maintained and updated. When the tanks are checked during internal inspections, the work is done as a program with repairs performed as a separately funded project. All tank inspection programs and repair projects include updating the drawings to reflect current as-built status, as well as changes initiated by the inspection and repair activities. If discrepancies are noted in the as-built drawings, they are corrected during the internal inspections. All major APSC storage tanks have been internally inspected, and their drawings updated.

Changes in the tank management program are documented through the processes established and required in *TAPS Engineering Manual* (PM-2001), *System Integrity Monitoring Program Procedures* (MP-166), *Quality Program Manual* (QA-36), and APSC inspection procedures. An integrity management engineer is assigned as the steward of Section 3.20, Tank Monitoring, of MP-166. The requirements of managing change are laid out from the planning phase through construction and completion. The record keeping requirements are specified for all changes, as well as the custody of the records and the term of retention of the records.

2.2.3 Summary Statement of Condition

The petroleum storage tanks are maintained through a rigorous inspection, monitoring, and repair program that meets applicable regulations and industry codes. As a result, the tanks are in good condition. The floors of five pump station tanks and 14 VMT tanks have been replaced and a sub-floor grid cathodic protection system installed. The good condition of the TAPS tanks after 25 years of service is not unusual. At other petroleum facilities, the original crude oil storage tanks have been in service since the 1930s.

2.3 Mainline Valves

Valves controlling the operational functions of TAPS are located on the mainline pipe, in pump stations, and at the VMT. The pipeline valves serve to minimize spills in the event of a leak in the mainline pipe, prevent overpressure of the pipeline, and isolate pump station and VMT facilities as necessary. This section covers the pipeline valves required for safe pipeline operations as listed in Appendix A of the *Procedural Manual for Operations, Maintenance and Emergencies* (OM-1).

During the design of TAPS, valve locations were selected based on a maximum static oil-spill volume set at 50,000 bbl, which was approved by the Secretaries of Transportation and Interior. The original approved plan had 142 mainline valves. Additional valves were added to isolate the pump stations and the VMT, and to further protect environmentally sensitive areas. The pipeline has a total of 177 48-inch-diameter valves. The longest segment of the pipeline without a remote gate valve (RGV) is 29.21 miles (between MP 519 and MP 548).

2.3.1 Description

The 48-inch-diameter pipeline valve system includes 62 RGVs, 81 check valves (CKVs), 9 manual gate valves (MGVs), 24 battery limit valves, and 1 ball valve which acts as a RGV. These valves are described as follows.

Remote Gate Valves: Gate valves are body double-block and bleed valves. When the valve closes, an internal pocket or *body* is created between two sealing vertical slabs of steel. If the valve is functioning optimally, the body can be drained of oil and its internal pressure reduced to zero gauge pressure, i.e., atmospheric pressure. Each valve has a bypass consisting of a 6-inch-diameter pipe and two 6-inch-diameter valves. This assembly is called a *bypass line*. Oil can flow through this line when the mainline 48-inch-diameter valve is closed and the bypass valves are open. This allows for pressure equalization across the pipeline valve and pipeline drain-down in the event of an emergency.

The RGVs are battery powered, motor-operated valves controlled via a redundant communications system or from a local control panel at the RGV site. In the event of motor, operator, or power failure, it is also possible to operate the valves by handwheel or by portable drive *operators* taken to the site. The RGVs in TAPS work with the CKVs to limit spills in the event of a pipeline break, leak, or rupture. In addition, the RGVs can isolate areas of pipe for maintenance and, in some circumstances, are used to prevent over-pressurization of the pipeline.

The RGV system design includes several fail-safe features to minimize the likelihood of a pipeline rupture due to an unexpected valve closure. If a single gate valve started to close, a negative pressure wave would surge down the line on the downstream side of the valve. On the upstream side, pressures could exceed the MAOP. Under such conditions, an RGV could cause a spill rather than prevent one. To minimize this risk, the RGV auto controls logic includes measures to reduce pressure upstream and to allow the positive pressure wave from upstream to pass the closing valve before it completely seals, thus keeping upstream pressure below the MAOP.

Check Valves: The 81 mainline CKVs prevent reverse oil flow in the line and can help prevent spills in the event of pipeline leaks or ruptures in ascending segments of pipe. All mainline CKVs can be locked open with the valve clapper raised out of the oil stream. In addition, 16 of the valves have active automatic systems which hold the valve clappers out of the oil stream and automatically release the clapper into the stream if pressure or flow in the line drops. Once pressure or flow returns to normal, the system raises the clapper back out of the stream. The CKVs must be locked out of the oil flow when an instrument pig is sent down the line. Collision between a pig and a valve clapper could damage the pig or the valve.

Manual Gate Valves: The nine MGVs are identical to the RGVs except they lack motorized operators, power, and automated controls. The MGVs are located near specific CKVs to provide more positive isolation of pipeline segments than would be provided by CKVs alone. A MGV can be closed to restrict oil flow to that segment of pipe. The MGVs are used primarily for maintenance purposes but could aid in secondary oil-spill containment if necessary.

Battery Limit Valves: The 24 battery limit valves provide facility and manifold isolation for pipeline, pump station, and VMT maintenance. These valves are identical to the mainline RGVs, but are powered and controlled differently. Except for one battery limit valve at PS 10 which acts as an RGV, these valves are not required for oil spill control. One battery limit valve is at the suction end of each pump station and one at the discharge end, except at PS 1, where there is only a discharge battery limit valve. There is also a battery limit valve at the inlet to the VMT. In addition, there is a 48-inch-diameter manifold ball valve between the two battery limit valves at PS 11 that functions as an RGV.

2.3.2 Monitoring and Maintenance Activities

New valves of two-inch nominal pipe diameter and larger in TAPS crude oil transportation service are under the jurisdiction of the DOT and must meet the pressure test requirements of API Standard 6D. The APSC specifications for most crude oil valves require that they be designed, constructed, and monogrammed in accordance with API Standard 6D. The DOT regulations given in 49 CFR 195 also require the pipeline operator to maintain those valves *required for safe operation* in good working order. The expression *good working order* is not defined in the regulation. The Federal Grant and State Lease specify that crude oil piping will adhere to what is now ASME B31.4.

The valves required for safe operation of the pipeline are well documented. Records of manufacturer, model, type, serial number, and location are available for each valve. The operating service history is also known. Each of the valves was successfully pressure tested prior to shipment and some were tested again as part of field hydrostatic pressure tests. The condition and acceptability of these valves at the time of installation is well documented. Since installation, the mainline valves have been exercised 10-20% of full stroke twice each year, which is standard pipeline industry practice. Starting in 1995, the remainder of the valves identified in Appendix A of the *Procedural Manual for Operations, Maintenance and Emergencies* (OM-1) were also stroked 20% of full travel two times each year to demonstrate that they will operate upon command.

Until the 1990s, the major effort was to assure mainline valves closed in case of a pipeline leak. After a near miss incident, it was realized that an unanticipated closure would isolate the pump station suction relief valves from the upstream pressure source, and the suction relief valves would be unable to protect the pipeline. The logic for the process control computers was modified to immediately idle the pumps at the upstream pump station and/or close selected RGVs if one of the RGVs signaled it was not fully open. Procedures were promulgated to manually idle the upstream pump station and/or close selected RGVs if communication was lost with a downstream valve for more than two minutes. The closing speed of 45 pipeline valves was slowed to further reduce the magnitude of pressure surges

During pipeline replacement at Atigun Pass in 1990 and 1991, 3 CKVs were removed from the pipeline and inspected after more than 13 years of service. These valves were found to be in good working order; two were refurbished and put into service, and the third used as a spare. In 1996, the APSC discovered a small weep at CKV 92 that was the result of the improper installation of a small steel operator vault. In addition to correcting the situation at CKV 92, the APSC took additional preventative action and installed new concrete vaults at four other belowground CKVs, which also had Ledeen actuators and vaults.

In the past, the performance data for mainline valves was mostly limited to operability information. The ability of valves to seal was limited to only a few incidents when sections of the pipeline or facilities were isolated for maintenance purposes. The ability of RGVs and pump station battery limit valves to seal was quite good. However, the process valves at the pump stations and the VMT exhibited more sealing problems and several have been replaced. The mainline gate valves have two seats that can independently seal the valve from leaking

Check Valve 82 (photo© courtesy of David A. Predeger).

through. If both seats seal, the body can be depressurized for stem packing repair and maintenance. Over half of the gate valves could not be completely depressurized so at least one seat was leaking.

In 1997, the APSC initiated the TAPS valve program. This program is an aggressive effort to determine the condition of critical pipeline and facility valves and improve maintenance procedures and documentation. The initial program goal was to ensure confidence in all critical valves, operators, and actuators, and to develop and implement a comprehensive maintenance program within three years. The JPO and DOT signed a Memorandum of Agreement with APSC dated January 23, 1997 (JPO and APSC 1997) that set interim goals to fulfill the program. A risk assessment was completed in 1997 to set priorities for the order of valve testing and to establish in-service sealing criteria with a response plan should a valve fail to meet the criteria. The program resulted in the TAPS valve maintenance management plan (TVMMP) that carries forward the best maintenance practices developed by the program.

All pipeline valves and actuators receive annual preventive maintenance and yearly function testing. In addition, preventive maintenance procedures are being enhanced to extend the longevity of all equipment. Engineers note changes in equipment and look for trends that indicate a need for additional maintenance or projects. Annual TVMMP evaluations and reports keep JPO and APSC engineers abreast of trends so that procedures are updated and preventive maintenance can be done.

Because of the TAPS valve program, all of the RGVs, CKVs, and pump station battery limit valves have been tested for leakage, and five valves have been repaired in-situ or replaced. The results of the tests conducted between 1997 and 2000 indicated that only three pipeline valves, RGV 80, RGV 39, and CKV 122, leaked more than the APSC's operational acceptance criteria. Regulatory agencies have endorsed APSC's TVMMP approach, and acknowledged that the operational acceptance criteria are only part of the overall program to maintain valves in good working order. In September 1998, RGV 80 was replaced and CKV 122 was repaired. RGV 39 was replaced in the summer of 2002. One additional valve (RGV 60) was tested to be within performance criteria but was replaced in 1999 due to its sensitive proximity to the Yukon River. Finally, CKV 74 was replaced in 2001 because the seat ring was pulled out of the valve by a pipeline pig.

Each valve that was replaced or repaired was thoroughly inspected to identify possible improvements which might prevent similar problems on the other pipeline valves. The valves failed to completely seal because of mechanical damage to the seats from foreign bodies being stuck between moving parts of the valve and from products injected into the valve seats causing a restriction in seat movement.

The pump station battery limit valves and pig trap valves (at PS 1 and 4, and the VMT) provide safe isolation and protect personnel, and thus are included in the focus of the TVMMP. The TVMMP looks at the complete function of these valves to ensure that the valve body, gear operators, and actuators are assessed so that they work together as desired. Separately the control logic, operating procedures, and equipment maintenance programs are evaluated to ensure compatibility and that the valves will function as required.

<u>Programs to Improve Valves</u>: The APSC has undertaken several other significant efforts to monitor the performance of mainline valves. Some continuing efforts include the following.

•The installation of soil gas probes at all belowground mainline valves. These probes are sampled at least annually to determine if there are any hydrocarbons present. In the event that hydrocarbons are detected, APSC then undertakes efforts to determine the source. This program makes it possible to detect small weeps or seeps, which would not be otherwise visible for a significant period.

•A program to excavate and inspect the belowground mainline CKVs was completed in 2002. All but 6 CKVs are now in underground vaults for ease of inspection and repair. The planned schedule for inspection and vaulting of these 6 valves is as follows:

o CKV 4 – scheduled for inspection and vaulting in 2003,

o CKV 5 – scheduled for inspection and vaulting in 2003,

o CKV 22 – scheduled for inspection and vaulting in 2003,

o CKV 86 – scheduled for inspection and vaulting in 2004,

o CKV 89 – scheduled for inspection and vaulting in 2004, and

o CKV 74 – repaired in 2000, scheduled for inspection and vaulting in 2010.

•In accordance with 49 CFR 195, function testing of the mainline valves is performed twice a year.

•During the execution of the annual winterization and electrical preventative maintenance tasks, the APSC collects and analyzes mechanical and electrical information about each pipeline valve. For example, all auxiliary piping, valve bonnet, and stem packing areas are inspected for seeps or weeps. Items that cannot be fixed immediately are tracked and corrected either through APSC's computerized work order system or through the nonconformance reporting process outlined in the *Quality Program Manual* (QA-36).

•The APSC has upgraded the buried control and power cables to RGVs (this effort was completed in 1999) and upgraded the CKV operators and lost motion devices. As part of the RGV control system upgrade, the APSC is now able to sense RGV positions.

•The APSC has added supplemental cathodic protection to RGVs to minimize external corrosion of valves and nearby piping.

2.3.3 Summary Statement of Condition

The APSC's valve maintenance program ensures the continued integrity of the valves. The 177 pipeline valves on TAPS receive regular maintenance and testing. The TVMMP closely monitors the status of valves, and maintenance activities are conducted as needed. Other than the five valves that have been repaired or replaced, all pipeline valves perform within APSC's operational acceptance criteria. Major repairs or replacement of individual valves are budgeted and planned in advance of the event.

Several components of pipeline valves wear out over time from normal use. Some examples are gate-valve stem seals, valve actuators, and operators. With the exception of cleaning and instrumented pigs, all materials hard enough to cause the most extensive damage to the valves were probably introduced into the pipeline during original construction, e.g., pieces of steel, wrenches, bolts, and other items accidentally left inside the pipe, and were long ago cleared from the pipeline. Even if damage were to occur, components of pipeline valves can be readily replaced or repaired.

2.4 Fuel Gas Pipeline

2.4.1 Description

The fuel gas pipeline transports natural gas from PS 1 through 4 (the pump stations north of the Brooks Range) to power the turbines that drive the crude oil pumps in the three operating pump stations (PS 2 has been placed on standby). Natural gas is the primary fuel for these stations, with liquid turbine fuel available as backup. Natural gas is produced with the crude oil pumped from the ground on the North Slope. Processing facilities separate the gas, and APSC receives a portion to use as fuel.

The gas pipeline is a thin walled (¼-inch thick) metal pipe that generally runs parallel to the oil pipeline and the Dalton Highway and is buried about 30 inches below ground. The fuel gas pipeline starts at the gas-metering enclosure at PS 1 where natural gas from North Slope producers is accepted,

Welding RGV 80 into place in September 1998.
An unidentified worker (right) installs a split-T for a drain down apparatus required before repairing CKV 122 (photos courtesy of © David A. Predeger).

odorized, metered, and filtered. A side stream supplies PS 1, and the remaining gas is compressed, cooled, metered, and routed to into the fuel gas line. The first 34 miles from PS 1 to the pig receiver and launcher at fuel-gas-line MP 34 is 10-inch-diameter pipe, and the remaining 115 miles is 8-inch-diameter pipe. The fuel gas line ends at PS 4.

The gas line consists of facilities for the isolation, filtering, metering, odorizing, compressing, cooling, and chilling of the natural gas and a pig launcher at PS 1; 34 miles of 10-inch pipeline from PS 1 to fuel-gas-line MP 34; the pig receiver and launcher at MP 34; 115 miles of 8-inch pipeline from MP 34 to PS 4; and ten manual gate valves along the line. The incoming-gas metering skid at PS 1 measures the quantity of fuel gas supplied to TAPS by North Slope producers. Flow measurement for the gas producers is performed with an orifice meter that includes pressure and temperature transmitters. A signal is sent to a flow computer, which is located in the PS 1 control room. The computer calculates the gas quantity passing through the meter and automatically adjusts for gas pressure and temperature variations and displays the calculated quantity. Signals for gas pressure, temperature, and flow rate are also sent to the producer.

After metering, the incoming gas is cleaned in the filter unit at PS 1 to remove foreign particles and liquids, which drain into the PS 1 crude oil storage tanks. Because Alaska North Slope natural gas is clean and dry, virtually no moisture enters the system. The filter unit is a low maintenance item requiring little or no attention except routine monitoring and periodic filter changes. After the gas is filtered, an APSC purchase gas meter measures the volume of incoming gas. This is used as a comparison and backup to the custody transfer meter described above. After leaving the APSC meter, the gas flow splits into two streams. The main stream continues into the fuel gas compressor module. The smaller stream is processed at the gas building for PS 1 use. Gas blowdown systems in the gas building and fuel gas compression module would remove pressurized gas in an emergency to effectively remove the possibility of explosion.

<u>PS 1 Gas Stream</u>: Before gas can be used for fuel at PS 1, its pressure must be reduced. This is done by a pressure letdown regulator. Since reducing the pressure of the gas has the effect of cooling it, the fuel gas heaters are used to heat the gas prior to this process. Without preheating, liquids could drop out into the gas stream, and condensation and ice might build up on the outside of the gas piping and other components. While ice and condensation are not hazardous to the piping, liquid buildup in the gas stream, ice buildup on gas fuel control devices, and water puddles on walking surfaces are significant hazards. After the pressure of the gas is reduced, the station-use gas meter measures the flow of gas for use at PS 1.

<u>Pipeline Gas Stream</u>: The main stream of fuel gas goes from the gas building to the fuel gas compression module. The gas is chilled in a refrigeration unit to prevent thawing of the permafrost around the buried fuel gas line. The gas is metered and returned to the gas building, where it flows into the pipeline that supplies gas to PS 3 and 4 (PS 2 is in standby). The fuel gas pipeline is equipped with a pig launcher at PS 1. Gas does not flow through this device unless a pig is needed. To launch a pig, the gas stream is rerouted into the launcher, where gas pressure pushes the pig out of the launcher and down the pipeline. Three types of pigs are used in the fuel gas pipeline: cleaning pigs (which remove liquids and solids and ensure the line is free of contaminants), geometry pigs (which determine the physical shape of the pipeline and measure pipe bends), and magnetic flux corrosion pigs (which look for defects in the pipe wall). Noncritical dents in the pipe prevented some types of pig runs in the 8-inch diameter pipe near PS 4 until recently when this segment of pipe was replaced with new pipe.

2.4.2 Monitoring and Maintenance Activities

Because the pump stations consuming natural gas can be converted to liquid fuel, the gas pipeline could be replaced on a planned basis without significantly impacting pipeline operations. However, failure of this pipeline is highly unlikely; the only foreseeable reason to replace the pipeline would be if large areas of corrosion developed. Cathodic protection mitigates corrosion, and pigs are used to inspect the line regularly so that engineers know when areas need maintenance. The fuel gas line is maintained to DOT standards given in 49 CFR 192 and is managed in accordance with the *Operating, Maintenance & Emergency Plans for the Fuel Gas Pipeline* (FG-78).

The APSC replaced several hundred feet of the fuel gas line near PS 4 in 2001 due to external corrosion caused by unique environmental conditions. In the warm summer months, groundwater flows over the pipe and warms it to just above freezing. The combination of warmth and liquid encourages corrosion. Because the gas pipeline transports a cool product, pipe replacement is generally simple and relatively economical. Minimal ground preparation is required (as opposed to the crude oil pipeline), no special backfill is necessary, and the pipe is buried only 30 inches below the surface.

Pipeline: The fuel gas pipeline appears to be generally in good condition. It may require occasional small repairs, but APSC does not anticipate complete replacement or other extensive work. There are two maintenance issues relating to the fuel gas line's depth of soil cover. First, the ground is settling around the pipe in some regions while the pipe stays in place. This exposes the gas line to the open air as the ground around it moves away. A well defined maintenance strategy is used at these locations. The pipe is surveyed in segments to determine where this phenomenon occurs. Where settling is occurring, remediation (reburial) is performed on a priority basis as determined by a risk assessment; an enhanced maintenance strategy has been proposed based on the same risk assessment.

The second condition that affects the fuel gas line's depth of cover is thermal expansion. In certain areas, the pipe has expanded because it is warmer than when it was installed. The pipe moves in the direction of least resistance and thus rises up from beneath the soil. The region where this occurs is monitored annually, and the pipe is reburied when it rises above a designated threshold. Furthermore, experimental projects for advance remediation have placed overfill in selected areas before the pipe emerges. This prevents the pipe from surfacing, helps insulate the ground, and may prevent the problem entirely.

The JPO has actively monitored the depth of cover over the fuel gas line. The issuance of findings by JPO in 1998 and a DOT/OPS Notice of Probable Violation on the fuel gas line led APSC to develop a five-year corrective action plan for depth of cover over the pipe, exposed pipe, and other compliance issues. The APSC is on schedule with this plan. The JPO is continuing to follow the progress of this corrective action plan through monitoring of the associated yearly projects (JPO 2001b).

In 2001, the APSC installed a new leak detection system on the fuel gas line that is similar to that used on the crude oil mainline pipe. This leak detection system for the gas line tracks gas flow, accounting for its compressibility. Information is updated several times every minute – a vast improvement over the previous system in which data was revised daily. The system will alert the pipeline controllers in the OCC if flow rate discrepancies are detected, which would be indicative of a leak.

Manual Gate Valves: The ten manual gate valves along the fuel gas line require annual maintenance consisting of lubricating the stem packing and flushing the valves with cleaners. A general visual check is done, and the valve actuators are checked to be sure they work properly. It is not expected that all of the valves will need to be replaced, but one or two may be changed on occasion if a valve no longer seals. The sealant injection lines on these buried valves were replaced in 2000 to bring the lines above ground. This makes the valves more accessible for regular maintenance.

Gas Compressor Module: The fuel gas compression module is continually maintained and will not need to be replaced if good maintenance continues and upgrades occur as required. The PS 1 fuel gas compression module controls were upgraded in 2001 and 2002. The project involved the replacement of the controls system for fire and safety, and for gas system isolation and blowdown. It also included upgrading the outdated pipeline anti-surge controls to better protect the gas compressors from surges, balance their load, and keep them close to their operating set points.

Fuel Gas Heaters: Fuel gas heater tube bundles may have to be replaced. An inspection program has been recommended because the tubes have been in service for many years.

Incoming Gas Metering Skid: The metering skid measures the natural gas supply from North Slope producers to PS 1. Past maintenance practices involved injecting sealant into system valves and leaving the valves with the sealant in place. The sealant settled into the metering piping and created local corrosion pits. The meter tube assembly was consequently replaced because the pits interfered with the meters' accuracy. Technicians currently use less sealant and flush the valves when sealant is no longer needed. In addition, a new, less corrosive type of sealant is now used.

Gas Filter/Separator: The gas filter/separator at PS 1 traps any sediment and liquid in the fuel gas supply from North Slope producers. The filter/separator is a very low maintenance component requiring only an occasional check of the unit's liquid level and filter cleaning. Filter/separators are also installed in the gas buildings at PS 3 and 4 to clean the fuel gas before it goes to pump station users.

Gas Blowdown Systems: In the gas buildings at PS 1, 3, and 4, and in the fuel gas compression module at PS 1, gas blowdown systems relieve excess pressure in piping when the system shuts down. The systems enhance safety by removing a potential fuel source for fires. The gas blowdown system in the fuel gas compression module was upgraded as part of the project to upgrade the fuel gas compressor module controls in PS 1. The gas building was not modified, because the control circuits are hard-wired and do not become obsolete.

Fuel Gas Chiller: This component of the fuel gas compression module chills the gas before it goes to the fuel gas pipeline. Chilling the gas minimizes the possibility of thawing the permafrost along the pipeline route. The chiller may require a new tube bundle in the heat exchanger because of normal wear.

2.4.3 Summary Statement of Condition

The fuel gas pipeline that provides fuel to power the pumps in PS 1, 3, and 4 is in good condition. The line is maintained and operated in accordance with federal regulations for gas pipelines. It is pigged regularly, and cathodic protection is installed to abate the effects of corrosion. The gas treatment and handling equipment at PS 1 (including the fuel gas compressor module that compresses and cools the gas routed to PS 3 and 4) is regularly maintained and upgraded as necessary. The fuel gas pipeline will continue to be sound as long as current maintenance efforts continue.

2.5 Pressure Relief Systems

2.5.1 Description

Pressure relief systems prevent pressure in the pipeline from exceeding 110% of the MAOP. Surge waves can be generated in the pipeline when flow stops quickly – for example, when a valve is closed or crude oil pumps are stopped. Opening pressure relief valves dissipates excess pipeline pressure. Oil flows out of the pipeline, through the valves and into breakout, or relief, tanks at the pump stations and the VMT. Pressure relief at each pump station is provided via suction and discharge relief valves and piping which all flow into a single crude oil relief tank. There are two or three relief valves on the suction and discharge sides of each pump station (except PS 4 which only has suction relief) and at the suction side of the VMT. These are not in use at PS 2, 6, 8, and 10, as these pump stations are currently on standby.

Relief valves are a critical component of pipeline integrity; they quickly dissipate excess pressures in the pipeline to avoid exceeding allowable operating pressures. The valves open very quickly – within 2 seconds – when certain operating parameters are exceeded. They stay open until pipeline pressure is reduced to an acceptable level.

Pipeline Pressure Relief: The pipeline's MAOP is the lower of the internal design pressure or 80% of the pipe's hydrostatic test pressure, as identified in 49 CFR 195.406(a). Due to the varying terrain along the pipeline, the MAOP at some points is lower than at others. These low points are *pinch points*, and they limit the movement of oil through the pipeline. To ensure that pressure violations do not occur during normal pipeline operation, the pipeline control system's host computer displays the pipeline's hydraulic gradient in the OCC to monitor pipeline pressures at all locations. This display is a dynamic hydraulic model of the pipeline that uses measured crude oil flows, pressures, and temperatures at pump stations and other locations as input. If the calculated pressure at any location exceeds the MAOP for that location, the gradient display will alarm and alert the pipeline controller at the OCC to take action.

Pump station pressure protection systems are local systems, which automatically protect the pipeline against over-pressurization caused by a pump station shutdown or a pressure controller failure. The mainline relief systems discharge crude oil to relief tanks when pressure set points are exceeded. The systems act locally, based on pressures measured at the pump station. Pressure relief activates automatically without the intervention of the pipeline controller at the OCC or pump station operator whenever the pressure exceeds the set point for relief. The pipeline controller does, however, establish and maintain the correct pressure controller set points.

Spare relief valves are installed to facilitate maintenance and improve safety. Because the relief valves cannot protect against over-pressurization caused by a spontaneous RGV closure, additional safeguards are provided through the RGV supervisory system master stations at the pump stations, and the RGV auto controls logic in the supervisory control and data acquisition (SCADA) host computer at the OCC. The RGV master stations prevent closure of RGVs against a flowing crude oil stream. In general, the upstream pump station must be shut down before a command from the pipeline operator at the OCC can close RGVs. The RGV auto controls logic automatically shuts down or idles upstream pump stations and/or closes selected upstream RGVs if any RGV or pump station suction battery limit valve is detected in a position other than fully open.

The TAPS has special control logic between PS 4 and 6 (called *hybrid logic*) to protect the pipeline against excessive pressures from the high static head at Atigun Pass. Events are initiated automatically and locally. This hybrid logic is discussed in Section 2.6.3. Relief valves at shutdown PS 6 and 10 remain in place, but have been closed off so that no oil can reach the valves. The relief valves have been removed from shutdown PS 2 and 8 for service elsewhere in the system.

<u>Pump Station Pressure Relief</u>: Pump station suction pressure is monitored by the TAPS control system. Each pump station has three levels of pressure relief control on the suction side:

•A suction pressure rate-of-rise controller opens the suction relief valves if the rate of suction pressure increase is more than 75 psi in 5 seconds. This rate-of-rise monitoring is designed to anticipate surges.

•A suction pressure relief controller opens the suction relief valves if pressure exceeds a set point. The relief valves modulate open and closed to control pressure.

•A suction pressure relief switch opens all the suction relief valves quickly and completely if pressure reaches the switch's set point.

Each pump station's discharge side has two levels of pressure relief control:

•A discharge pressure relief controller opens the discharge relief valves if pressure exceeds a set point. As on the suction side, the valves modulate open and closed to control pressure. Since PS 4 lacks discharge pressure relief valves, reaching the threshold there idles the mainline pumps.

•A discharge pressure relief switch shuts down the mainline pumps if pressure reaches the set point.

Both suction and discharge relief valves are quick-opening valves adjusted to open fully in 2 seconds, but close in 3.0 to 5.5 minutes (to minimize surge waves, vapor pockets, and the need for cyclical pipeline pressure relief). The valves can also modulate, opening and closing by degrees as needed. Regardless of the source, oil flows through open relief valves into the pump station's crude oil breakout tank. Valves remain open until pressure has dissipated below the valves' opening set point, after which the valves slowly close.

<u>VMT Pressure Relief</u>: The VMT pressure relief system consists of relief valves, which open and discharge crude oil to storage tanks when the inlet pressure exceeds the pressure set point. Relief valves from shutdown PS 2 and 8 were removed and permanently installed at the VMT to control the incoming pressure at a much higher threshold than was previously necessary. The pressure of the oil entering the VMT was raised from about 250 psi gauge (psig) to about 750 psig to move the slackline interface at Thompson Pass to a higher elevation, which reduces the vapor collapse pulsation pressure to a much lower pressure surge (from about 200 psi to less than 20 psi).

<u>Thompson Pass Slackline</u>: The TAPS is a very versatile system and has a number of mechanisms to control the oil pressure within the pipeline. The modifications made to pipeline operations in response to pipe vibrations at Thompson Pass are an example of this versatility. While this is not *pressure relief* issue per se, it is discussed here because it illustrates some of the pressure control mechanisms that can be used in pipeline operations.

Crude oil traveling through the pipeline traverses a variety of terrain, including the extremely steep Thompson Pass area. When the more rapidly moving incoming oil cascades down the steep angle of Thompson Pass, it catches up with the slower moving oil at the bottom of the slope. This is called a slackline condition. In a slackline, the pipeline pressure is at the vapor pressure of oil. The pipe is only partially full, with the oil containing gas bubbles of the lighter hydrocarbons. These bubbles will collapse where the pressure increases above the vapor pressure of oil. An hydraulic jump accompanies the return to packed line conditions, creating pressure fluctuations in the pipeline.

A slackline has always existed at Thompson Pass. However, the location of the interface point has been lowered on the hillside as pipeline throughput has declined from more than 2 million bbl per day in 1988 to less than 1 million bbl per day at present. During the summer of 1996, throughput reduced to less than 1.3 million bbl per day temporarily, and pipe vibrations were noticed. This was caused by the slackline interface getting close to a shelf on a Thompson Pass hillside where there are some bends in the pipe. The vibrations occurred every five to ten seconds and disturbed residents of a subdivision located near the TAPS ROW.

The vibrations were monitored at RGV 121 and pressure spikes reached 80 psi at this location. Engineers calculated that the spikes were about 44% stronger at a bench on Thompson Pass. Normal pressure in the pipeline at this location was about 100 psi; the pipeline is designed to be able to be operated up to 901 psi. An inspection with a smart pig showed that a short section of the pipe had taken on the slight shape of an oval, and that there were two small dents in the pipe. Soil gas probes, leak detection, and environmental monitoring equipment were installed in the area. No indication of a hydrocarbon release was detected.

The immediate solution, although temporary, was to maintain the throughput of oil in the pipeline as high as possible. As long as the throughput remained above 1.4 million bbl per day, the vibrations stopped. This solution was not practical in the long term due to the declining production of crude oil from the North Slope fields. The solution developed by APSC was to constrict the oil flow when it entered the Manifold Building at the VMT. By using a system of control valves, the pressure of the oil leading into the Manifold Building is increased, creating a *backpressure*. This is comparable to a garden hose that is squeezed to increase the water pressure within the hose.

The permanent backpressure control system at the VMT was completed in September 1997. The backpressure system is an arrangement of control valves and piping that increases pipeline pressures between the VMT and Thompson Pass. The increased pressures raised the slackline interface at Thompson Pass to an elevation that reduces pipeline pressure pulses and resulting vibrations.

Other potential slackline areas of the pipeline were identified and a testing program was designed for the areas that had some potential for a similar phenomenon to Thompson Pass. During the tests, the pipeline was operated through a range of flow rates. Of eight possible areas, Thompson Pass, Keystone Canyon, Atigun Pass, Finger Mountain, and MP 320 were tested. No pulsations comparable to those previously identified at the shelf on the Thompson Pass hillside were found. Based on these test results, the APSC concluded that it was not necessary to test other areas where potential slackline conditions presented a lower risk. These areas are Cascaden Ridge, Wilbur Ridge, and Isabel Pass.

2.5.2 Monitoring and Maintenance Activities

The pressure relief valves and piping are monitored and maintained to ensure continued safe operation of the pipeline. No components of the pressure relief system are expected to have an adverse effect on continued TAPS operations. Monitoring and maintenance activities for this system are discussed as follows.

Pressure Relief Valves: Most Fisher pressure relief valves at the pump stations were replaced with Introl valves in 1982. The Fisher valves experienced excessive cavitation and vibration, which compromised the integrity of the valves and associated piping. All Fisher valves were replaced except for those at PS 1, PS 12 discharge, and the VMT. The Fisher valves at the VMT were replaced with Introl valves during the VMT backpressure control project in 1997.

Introl valves tend to leak internally. This is not harmful to the pipeline because oil simply flows into the crude oil breakout tanks. It does require additional valve-seat repair and ongoing maintenance. The backpressure control valves at the VMT experienced mild erosion and have been placed on a maintenance schedule. One valve is being rebuilt every year. With five valves in service, every valve is rebuilt once in five years.

In 1997, some relief valves experienced another problem. The coupling bolts that connected a valve to its actuator came loose. When this happened, the actuator functioned as designed and failed open. However, because of the loose bolts, the actuator and valve were no longer connected, and the valve remained in its last position with no automated means to open or close it. A pipeline-wide study reviewed all valves and found others with the same problem. Since then, new bolts with longer threads and a locking connection that cannot work free have been installed.

Pressure Relief Piping: Major work to enhance or repair relief piping is not anticipated. Some work has been done recently as regular maintenance. At all pump stations and the VMT, anchors were installed to better restrain the pressure relief piping from excessive movement. During relief events, piping has been known to move a few inches with the surge of oil entering a line that is normally at atmospheric pressure. Although this does not harm the very flexible pipe, anchors were installed as a precaution to prevent damage to the tank walls. The high-pressure relief system piping at PS 5 was modified to eliminate underground piping because of concerns about corrosion. This was not a major project, and similar projects can readily be done in the future if there is a need.

2.5.3 Summary Statement of Condition

The condition of the pressure relief system is sound. Modifications have been made to the system to mitigate potential hazards such as those at Thompson Pass. The relief valves benefit from a rigorous inspection and maintenance program. The system does not pose any threats to TAPS operations that cannot be controlled or mitigated.

2.6 Pipeline Controls

This section addresses those control and communication systems that are line-wide and essential for the safety and control of the overall pipeline system. Because of the nature of many of these systems, they are continuously exercised in everyday operation of the pipeline. When malfunctions or failures occur, backup systems and procedures are in place to provide safety for continued operation or shutdown. For those systems that are not continuously exercised, maintenance programs to periodically test them are in place to assure their operability.

The pressure in the pipeline is controlled, monitored, and limited by three levels of pressure control. The first level is the suction and discharge pressure controller that maintains the speed of the mainline pumps to control pipeline pressure. This level of control maintains pipeline pressure at or below the MAOP. The second level of control is the suction and discharge pressure relief controllers that open the relief valves to prevent the pipeline pressure from exceeding 110% of MAOP during surges and other deviations from normal operation. The third level of control is the suction and discharge pressure switches that either open all of the suction relief valves or shut down the station to prevent the pipeline pressure from exceeding 125% of MAOP.

The pressure relief controllers and switches reside at the pump stations, and hence control the pressures at the stations. The pipeline controller at the OCC is responsible for maintaining the correct set points. The pipeline controller sets the set points at the pump stations to achieve the desired flow rate at a safe operating pressure. The pipeline controller must change the set points in response to changes in the flow rate or to account for changes in the line setup such as the shutting down of a mainline pump or the opening of a pressure relief valve. These changes can be gradual (such as associated with scheduled flow rate adjustments in response to crude oil availability) or rapid (such as related to mainline pumps tripping offline or pipeline shutdowns caused by external events such as loss of communications).

The pressure controllers and the pressure relief controllers are continuously monitored by the pipeline controller at the OCC. When the pipeline controller sends a change in set point to a pump station, a confirmation of the revised set point is returned to the OCC. The pipeline controller continuously monitors the pump station pressures to ensure that the pressure controllers are in fact maintaining the desired pressures.

The pressure relief controllers are exercised whenever the pipeline controller at the OCC purposely transfers oil into a relief tank by lowering the pressure relief controller set point to less than actual pipeline pressure. This test allows the pipeline controller to verify that the relief actions occur at the proper pressure. The calibration of the pressure controllers and the pressure switches is tested on a periodic maintenance schedule.

The control systems are designed to be fail safe. If the pressure relief controller fails or there is a failure in the hydraulic power system that operates the pressure relief valve actuator, the valve fails open and pressure in the pipeline is relieved as oil flows to the relief tanks. If the pressure controller fails, the mainline pumps slow down and cease pumping. In either situation, the pipeline controller at the OCC is alerted to the situation and can take appropriate actions to remedy the problem.

The pipeline controller at the OCC normally starts and stops the mainline pumps at the stations by issuing commands via the SCADA system. The pipeline controller can monitor the critical parameters on the mainline pumps such as gas generator speed, exhaust gas temperature, and pump speed. Mainline pumps are started and stopped to accommodate flow rate changes, pump maintenance requirements, and line upsets.

2.6.1 Supervisory Control and Data Acquisition System

2.6.1.1 Description

The supervisory control and data acquisition (SCADA) system is an integrated network that links two online host computers, intelligent remote terminal units (RTUs), and duplicate graphical user interface (GUI) operators' consoles. The pump station SCADA is interconnected and connected to the OCC via triple redundant communication channels. The OCC is the key to pipeline operation and control; the pipeline controllers at the OCC monitor and control all aspects of TAPS operations. Central to the OCC is the Data General MV20000 host computer and associated equipment for the SCADA system. The MV20000 interfaces between the OCC controllers and programmable logic controllers (PLCs) at the pump stations and other remote locations.

Process control devices report on variables such as temperature and pressure, and initiate alarms. The SCADA system transmits conditions and alarms from the pump stations, field instruments, and process control systems to the OCC. The SCADA system also allows the OCC computers to transmit process control set points and control commands to the local control systems at pump stations; all control systems run through the SCADA network. (A set point is a value used to control a process. When a set point is reached, the control system automatically performs some act such as increasing a pump's speed.)

Through the SCADA system, the OCC monitors all critical process conditions and controls process set points by remote control through the PLCs. The OCC computers monitor operating parameters and OCC personnel adjust pump station set points for suction pressure and discharge pressure. The SCADA system allows OCC staff to initiate most safety commands and to control the pipeline without local pump station interaction; however, devices at the pump stations actually implement the instructions. The OCC operational commands include *block line*, *isolate pump/idle pump house*, *close RGVs*, *open RGVs*, *close RGVs 31 through 35*, *isolate station*, *shutdown station*, and *shutdown system*. The OCC personnel communicate frequently with pump station operating personnel before initiating non-emergency pump station commands.

The heart of the SCADA system is a host computer network with an online, constantly running backup system. The primary host computer is online and communicating with the RTUs and GUIs. This unit initiates all requests for field information, responds to data requests from the GUIs, and initiates control actions either automatically or in response to GUI initiation. The second host computer receives the same RTU and GUI information and processes all data as if it were the primary computer. This ensures that the standby computer can become the primary unit within a few seconds of switch over.

The online host computer communicates with the OCC pipeline operator's consoles over an Ethernet communications system with a backup. At any time, communication between the GUI and the host can occur over any of the Ethernet channels. The pipeline operator's and VMT operator's consoles at the OCC have complete redundancy. Each console can operate either the pipeline or the VMT after a brief transition. The online host computer interfaces with field devices at the pump stations over triple redundant communications channels. All information requests or control commands can be executed over any of the three communication channels in near real time, approximately every three to four seconds under normal operation.

Each of the major control and communication systems are discussed below to show how each receives a combination of continuous monitoring and test data and how upgrades have improved the reliability, safety, and performance of the systems since the pipeline was originally constructed.

2.6.1.2 Monitoring and Maintenance Activities

No individual component of the SCADA system would significantly affect TAPS operations if it had to be replaced. The host computers have already been completely replaced and upgraded. Each component of the SCADA system is industrial grade, seismically qualified, and designed to be robust. While these devices are important to the overall system operation, they are low cost and alternatives exist.

MV20000 Host Computers: The pipeline is monitored and controlled by two Data General MV20000 mainframe computers located at the OCC. One computer is always online with a second computer on hot standby. There is a third MV20000 computer at the OCC, which is used for software development, testing, and evaluation. The computers are monitored by OCC personnel on a continuous basis. The programmers for this system work seven days a week and are on 24-hour call. All supervisory control, monitoring, and control of the pipeline and VMT are done by the control computer at the OCC. In addition to the continuous monitoring by OCC personnel, the computers undergo regular testing and planned *fail-overs* to the backup computer to ensure the functionality and performance of the entire system.

The Data General MV20000 host computers are not the original units installed during the construction of TAPS. The original host computer system consisted of redundant Xerox 530 computers. The Xerox 530 computer systems were replaced and the new system has been upgraded several times to take advantage of additional capabilities as technology has improved. The system replacement occurred in the early 1980s and the system was further enhanced and upgraded in phases to the current MV20000 system. Upgrades to the GUI and network interface devices continue. Data General is committed to supporting this system for the near future. At the same time, the APSC monitors and evaluates the viability of replacing these systems as part of the normal lifecycle replacement process.

Remote Terminal Units: The original RTUs were designed, constructed, and installed by Harris Corporation. These RTUs were non-intelligent, passive devices that were not expandable to meet growing operational needs. Eventually, Harris Corporation no longer supported them. In 1992, these systems were replaced with intelligent, industrial grade, seismically qualified PLCs manufactured by Square D Corporation. These devices provide high reliability and maintainability as the principal interfaces between field devices and the host computer. These systems were designed with extra interface slots and connection terminals to allow further expansion and operational changes to be performed using standard programming techniques.

Modems: The SCADA system connects the RTUs and host computer via digital modems supplied and supported by General Data Communications. These units are expected to be operational for the foreseeable future; however, they will be eliminated when APSC switches to a new digital communication system that does not require modems. Digital communication would have the direct data interface connections required for SCADA equipment.

Disk Drives: Numerous SCADA host computer support devices have been upgraded over time. The original paper-punch devices were replaced with tape storage units that were subsequently replaced with ClarIIon high-density disk storage systems. If the Data General ClarIIon disk drives were no longer supported, the APSC could select from several other disk storage devices to replace these units.

Firewalls: Network firewalls are designed to protect the system by preventing inadvertent or intentional access to computer systems and devices. The APSC has placed a network firewall between the SCADA system and the APSC network. A firewall also prevents access to the APSC network from the Internet. A third firewall was installed in 2000 next to the existing firewall between the SCADA and the APSC network. Firewalls operate on most standard, commercially available computer systems. The firewall system is continually managed for hardware and software upgrades.

2.6.1.3 Summary Statement of Condition

The TAPS SCADA system is reliable and robust. It provides complete system integration, data acquisition, and control actions in near real time. The various hardware and software components are designed for longevity. Either the equipment manufacturers support maintenance and upgrades for all critical components, or the systems are due for replacement in the near future. Based on current information, lifecycle evaluations, and plans for upgrades, this system has a virtually unlimited life and will continue to meet all operational requirements for the foreseeable future.

2.6.2 Remote Gate Valve Control System

2.6.2.1 Description

There are 62 RGVs along the pipeline to limit the volume of oil spilled in the unlikely event of a pipeline rupture. All are located at remote unmanned facilities. Most of them are located on downhill pipeline segments to stop oil flow in the event of a leak or other emergency. Special control systems are in place to control the RGVs. Commands to operate the valves can be initiated either from the upstream pump station or by the pipeline controller at the OCC. Special logic is built into the control systems to ensure that valves cannot be closed while an upstream pump station is operating, and to ensure that the sequence of opening valves will not create hydraulic problems in the pipeline. The operating status/position of the RGVs is continuously monitored by the Data General MV20000 computer and the pipeline controller at the OCC.

The RGVs are divided into ten segments, each consisting of the valves between adjacent pump stations. The segments start at PS 3 and extend to RGV 125 just outside the VMT. The master terminal unit (MTU) at the upstream pump station controls each segment's valves via the RTUs at the valves. Each MTU scans every RGV in its pipeline segment once a minute. Each valve's open/closed status and the status of its electrical and mechanical systems are sent to the MTUs.

Whenever RGVs are closed in the course of pipeline operation, the personnel at the OCC monitor their closure and opening performance. The RGVs are tested twice a year in accordance with DOT regulations. During planned shutdowns, some RGVs are closed and reopened from the OCC to test the entire control loop. The RGV control system is currently undergoing enhancement to better monitor and control the valves. The RGV control enclosure is equipped with intrusion alarms, which are transmitted to the OCC to alert the pipeline controller if entry is made into the RGV control enclosures and, if unauthorized, personnel at the OCC can call for immediate surveillance by security.

The SCADA host computer at the OCC receives status and alarm information. The OCC pipeline controller sends commands via the SCADA computer and MTUs to the appropriate RTU, which then transmits the command to the valves. The RTUs do not initiate any valve control actions. All actions are initiated by the OCC or pump station personnel, or from a local push-button command at the RGV. Communication between the MTU and the RTUs occurs over a communication system designed for high reliability and operability.

The RGV control system came under heavy scrutiny in the early 1990s because of an unexpected event in which an RGV closed without being commanded to do so by the TAPS control system. Such an event creates potential for pipeline overpressurization and possibly even rupture, depending on the location. Fortunately, pipeline controllers at the OCC were quickly alerted to the event and shut down the pipeline. The incident investigation revealed that a wiring short in the underground conduit caused the valve to close. Four things were done to prevent recurrence:

•Immediately after the event, a procedural change dictated that when communication with any RGV is lost and cannot be regained within two minutes, the pipeline would be shut down. This policy remains in effect.

•Engineers identified those valves that need to close more slowly than the standard design time of four minutes, so that in the event of an unplanned closure, there will be sufficient time to respond as needed to prevent pipeline overpressure. The gears to operate these valves were modified so they physically cannot close in less than seven to nine minutes.

•The APSC added a new software routine in the MV20000 host computer to immediately and automatically shut down the pipeline when a valve not fully open is detected.

•The control wiring at all RGV sites was modified to prevent a recurrence of this type of failure.

2.6.2.2 Monitoring and Maintenance Activities

The equipment and components comprising this system receive periodic maintenance to ensure continued safe operation of the pipeline. No individual component of the RGV control system would significantly affect TAPS operations if it needed significant repair or complete replacement. Each RGV segment uses identical equipment and processes as described below.

<u>Remote Terminal Units</u>: The RTUs monitor and control each

RGV and perform three primary functions:

•Monitor and report valve status and data. Each RTU continuously monitors several data points including valve position. When the MTU requests valve status and data, the unit transmits the most recent information.

•Monitor commanded valve movement. Each RTU monitors the local valve position and any MTU control commands. The RTUs control the starter for the motor and will not cause the valve to move unless it has received a valid command.

•Initiate and control valid control actions. When an RTU receives a valid command from the MTU, the RTU controls closing and opening of the valve.

The RTUs were upgraded in 1999 to triple modular redundant fault tolerant PLCs. This provides an extremely reliable system. Triple modular redundant fault tolerant technology allows up to two failures of the PLC operating system before operability is affected.

Master Terminal Units: The MTUs at the pump stations are original equipment that perform three functions:

•Obtain RGV PLC status and data. The MTU requests status information and other data from each valve sequentially, typically every 60 seconds.

•Transmit valve open and close commands. When either the pipeline controller at the OCC or local pump station operator initiates an RGV open or close command, these manually initiated actions are sent to the RTUs at the downstream valves.

•Transfer valve status information to the central SCADA system. When an MTU sends valve information to an RTU, that information is forwarded to the OCC via normal SCADA data transmissions.

The MTUs are scheduled for replacement by the middle of 2004 to take advantage of new technology.

2.6.2.3 Summary Statement of Condition

The RGV control system is in good condition and is undergoing further major enhancements. The RTUs were significantly upgraded in 1999 and the MTUs will be upgraded as part of a project to replace all remaining original RGV equipment with new technology. The RGV control system upgrade will improve dependability, lower risk, and provide long-term reliable control.

2.6.3 Hybrid Logic Between Pump Stations 4 and 6

2.6.3.1 Description

This section provides a discussion of the hybrid logic used to control pipeline operations. Also included in this section are brief discussions of the monitoring and maintenance activities for the backbone communication system and the block valve communication system. While these two communication systems are line-wide, monitoring and maintenance activities for these two communication systems are included here as these systems are very important to proper operation of the RGV auto controls logic.

Hybrid logic exists between PS 4 and 6 to protect the pipeline from becoming over-pressurized by the high static head of oil as it passes over the top of Atigun Pass. The hybrid logic system augments the normal RGV control system to account for high static pipeline pressures at Atigun Pass between PS 4 and 5 during an emergency pipeline shutdown. The MTU at PS 4 ensures that when the RGVs between PS 4 and 5 are commanded to close, they do so in a specific sequence. One of the first four valves at the top of Atigun Pass must fully close before the lower group of valves to the south begins to close. This eliminates the static head on the lower valves when they close. On reopening the RGVs, logic in the MTU sequences the valves to open starting from the southernmost valve, and opens the valve 50% before commanding the next upstream valve to open.

The following events will automatically trigger an *auto stop flow* command that results in idling the mainline pumps at PS 4. This signal is transmitted via redundant PS 4 to 5 point-to-point communication paths. When this occurs, the suction and discharge relief set points at PS 5 are lowered to 670 psig and the PS 5 injection pumps are stopped.

•The suction pressure at PS 6 exceeds a control set point,

•Loss of communication between PS 5 and 6 (via the pipeline controller at the OCC and the MV20000 host computer) after PS 5 has been in relief mode for more than 10 minutes,

•*Block line* command is issued at PS 5,

•*Close RGV command* is sent from the pipeline controller at the OCC to PS 5,

•Loss of communication between PS 4 and 5 on the two point-to-point communications paths, i.e., the pipeline controller at the OCC and MV20000 host computer, and the segment 4 RGV control system,

•Hybrid logic detects a loss of control power at PS 5, and

•Pipeline controller at the OCC closes RGVs south of PS 5.

The hybrid logic will issue a *stop flow/close RGVs 31 to 35* command to PS 4 via redundant PS 4 to 5 point-to-point communication paths in any one of the following three conditions: a local or remote PS 5 *isolate station* command has been issued, there are partially open RGVs or block valves in segment 4 of the RGV system, or a *close RGV* command is issued by the pipeline controller at the OCC. This command will shut down the mainline pumps at PS 4, block the line at PS 4, and close RGVs 31 to 35. In addition to the hybrid logic, PS 4 has local station logic that will initiate an idle of running pumps at PS 4 in the event of a total communications loss with PS 5 or the SCADA system at the OCC.

The pipeline control system's ability to communicate with the RGVs is critical. The hybrid logic quickly and reliably initiates mitigating action. The need for such a specialized system was recognized during TAPS design, and much study was done to determine which pipeline segments would require additional safety features. All emergency shutdown modes were considered in the original design and were accounted for in the hybrid logic. The only reasonable alternative to this control system would have been a series of relief tanks along the pipeline or very thick-walled pipe. Neither option was considered practical. The hybrid logic system normally resides in the SCADA control system's background and is not used on a regular basis.

The hybrid logic system is a combination of communication channels, pump station control panel logic, and commands issued by the pipeline controller at the OCC. The communication systems are seven independent communication channels, which use several different communication technologies: very high frequency (VHF) radios, microwave communications, fiber optic networks, and satellite communications. Each system provides dedicated communication channels as follows:

•RGV segment 4 prime: combination of VHF radio and microwave; this system is being replaced with the fiber optic system beginning in late 2002,

•RGV segment 4 backup: completely VHF radio,

•Super critical system 1: satellite system between PS 4 and 5,

•Super critical system 2: microwave channel between PS 4 and 5,

•SCADA prime: microwave channel between PS 4 and the OCC; this system is being replaced with the fiber optic system beginning in late 2002,

•SCADA backup: microwave channel between PS 4 and the OCC, and

•SCADA satellite: satellite channel between PS 4 and the OCC.

2.6.3.2 Monitoring and Maintenance Activities

Special PS 4 control panel logic monitors the status of the seven communication channels. If all seven PS 4 communication channels are lost simultaneously for longer than 100 seconds, PS 4 will shut down. Pump stations downstream continue pumping oil, removing it from the steep slope of Atigun Pass and eliminating the possibility of pipeline over-pressurization. If such an event were to occur, the PS 5 control panel contains logic that will issue a *block line* command to PS 5, independent of any other commands. The PS 5 control panel monitors communication status between the VMT and the pump station, the power supply levels of the station control panel, and the status of the PS 5 relief valves. Depending on the situation, the pump station control panel will initiate a *block line* command that shuts down PS 4. This command will be transferred to PS 4 to shut down that station and close valves in that segment.

The backbone communication and the PS 4 to 5 point-to-point communications paths are monitored continuously and alarms are displayed in the event of any loss of communications. The hybrid logic system is not regularly exercised, but is tested regularly by scheduled maintenance and during scheduled pipeline shutdowns. Any time the events on the pipeline initiate the hybrid logic, OCC personnel note that the logic functioned and initiate activities to check out and repair if any discrepancies are identified.

<u>Backbone Communication System</u>: The original backbone communications system (BCS) consists of two 2-way micro-

wave routes from the OCC to PS 1, and a satellite backup route with earth stations at PS 1, 4, 5, and the VMT. This system transmits data from the various field sites to the MV20000 host control computer and controls commands from the MV20000 back to the field sites. In addition to the above, there are two separate routes between PS 4 and 5 for the point-to-point hybrid logic circuits. The communication circuits are continuously monitored by automatic equipment used by AT&T in Fairbanks and by the OCC pipeline controller at the VMT. If the primary route fails, the equipment automatically and seamlessly switches to the backup route and generates a communication alarm. AT&T and/or APSC technicians are dispatched to troubleshoot and correct the problem. If both routes fail, the equipment automatically switches to the satellite backup system, a communications failure alarm is sounded, and AT&T and/or APSC technicians are immediately dispatched to troubleshoot and correct the problem. Written procedures are in place detailing how to respond to various communication alarm and communication failure situations. In the event of a total loss of communications (both routes and the satellite), written procedures are in place for PS 1 to initiate an orderly pipeline shut down.

The BCS scans the pump stations and other facilities approximately every 3 seconds. Because the pipeline controller at the OCC is constantly monitoring the SCADA data for purposes of pipeline control, failures are known almost instantaneously. When the transmission signal fails, it is immediately apparent. Thus, the condition of the BCS is known on a real time basis.

Block Valve Communication System: The block valve communication system (BVCS) consists of two 2-way routes between each pump station and the RGVs immediately downstream from that pump station, and a 1-way route (called the eavesdrop circuit) used by OCC personnel for monitoring purposes. The A route consists of a microwave channel between the pump station and the mountaintop repeaters, and a VHF radio from the mountaintop repeater to the RGV site. The B route is VHF all the way from the pump station to the valve. The communication links terminate at the MTU at each pump station and the RTU at each RGV. The RGV eavesdrop communication system listens in to the data being transmitted between the RTU at the valve and the MTU at the upstream pump station, and sends the data directly to the MV20000 computer at the OCC over a backbone microwave circuit. The MTU scans all the RTUs in that line segment once per minute on Channel A. The Channel B route is used when an RGV in that line segment is not responding on Channel A. On Channel B, the MTU scans the RTUs once every 4 minutes. The eavesdrop system listens in on both Channels A and B. The A route is being transitioned to a new fiber optic backbone system beginning in late 2002.

The BVCS microwave communication circuits are continuously monitored by automatic equipment at AT&T in Fairbanks, and in the OCC at the VMT. If the A route fails to any one or all RTUs in a segment, the equipment automatically and seamlessly switches to the B route and generates a communication alarm. AT&T and/or APSC technicians are dispatched on a scheduled basis to troubleshoot and correct the problem. If both routes fail to any one or all RTUs in a segment, the equipment generates a communication failure alarm. AT&T and/or APSC technicians are immediately dispatched to troubleshoot and correct the problem if this occurs. Existing written procedures detail response protocol for various communication failures on both routes. Written procedures also authorize the pipeline controller in the OCC to force a scan of the segment and to immediately idle the upstream running pump station and/or close selected RGVs if communications are not reestablished within two minutes. In this case, the pipeline controller manually initiates the same response that would be commanded by the RGV auto controls logic if an RGV were to close unplanned.

2.6.3.3 Summary Statement of Condition

The condition of the hybrid logic system is sound, and this system continues to evolve as operation requirements change and new technology becomes available. Many of the devices used in this system also support other pipeline functions. As these devices are upgraded, the hybrid logic will also be upgraded. For example, when the MTUs for the RGVs are replaced, the master and remote terminal units for the super critical systems 1 and 2 will be replaced.

2.6.4 Leak Detection Systems

2.6.4.1 Description

The TAPS leak detection systems, which provide early notification of potential pipeline leaks, consist of three independent networks: deviation alarms for pressure and flow rate, line volume balance (LVB), and transient volume balance (TVB). Each capitalizes on unique leak characteristics. The intent is to detect leaks as early and as small as possible to minimize environmental damage. These systems are software based and maintained at the OCC. The TVB is the primary leak detection system with the LVB and deviation alarms providing backup.

Deviation Alarms: The three types of deviation alarms used on TAPS are pressure, flow rate, and flow rate balance. The leak detection system looks for deviations from preset values or sudden changes in pressure, flow, or flow rate balance. This tool has been in service since startup to rapidly detect large leaks (700 bbl/hr or larger). The *pressure deviation alarm* is based on pump station suction and discharge pressure readings. Approximately every three to four seconds, the SCADA host computer retrieves pressure readings at each pump station. The current pressure reading is compared against a previously calculated base value. A drop in pressure greater than 1% of range generates a deviation alarm, as does a value outside the acceptable range of pressures. This method would detect large leaks between adjacent pump stations and between PS 12 and the VMT.

The *flow rate deviation alarms* are based on readings from each pump station's leading edge flow meter (LEFM) and the incoming meters at the VMT, all of which are scanned approximately every 10 seconds by the SCADA system. Each new reading is compared against a previously calculated base value. Any deviation greater than 1% of range causes an alarm to sound. Flow rates outside the present limits also generate an alarm. This method would detect large leaks between adjacent pump stations and between PS 12 and the VMT.

The *flow rate balance deviation alarms* are based on readings from each pump station's LEFM and the incoming meters at the VMT. The flow rate out of the pump station is compared with the flow rate into the next pump station. Any deviation greater than 1% on the calculated base will generate an alarm. This method would detect large leaks between adjacent stations and between PS 12 and the VMT.

Line Volume Balance: The LVB leak detection system is based on readings from the custody transfer meter at PS 1, the North Pole metering facility, the Petro Star Valdez metering facility, incoming meters at the VMT, and the pump station breakout tank levels. The SCADA computer gathers LEFM readings approximately every three to four seconds and calculates a weighted running average flow rate at each end of the pipeline. (A weighted running average flow rate is a continuously calculated, average flow rate.) With these data, the LVB system calculates every 30 minutes the average crude oil volume entering the pipeline at PS 1, and the average volume leaving it at the VMT, the three commercial refineries on the pipeline, and breakout tanks at the pump stations. The LVB leak detection compares the relative volumes of oil in and out of the pipeline to detect a leak. If more oil is entering the pipeline than exiting, a leak is declared. The LVB is a long-term, sensitive leak detection system good for finding small leaks. However, it may take 3.5 hours or more to detect a leak, and it does not locate the leak source. This system has been in operation since 1979.

Transient Volume Balance: The TVB system is a recent enhancement to TAPS leak detection capabilities and is a computerized method that uses mathematical models to detect leaks based on field measurements. Every 60 seconds, the TVB system calculates line-packing values derived from actual field pressures, temperatures, flow rates, and crude oil properties. (Line packing describes crude oil being compressed in the pipeline.) Based on this information, the TVB system can produce a reliable line pack and packing rate. This information is compared against the actual line flow rates measured by the LEFMs. Deviations between the modeled packing rate and measured flow rate indicate potential leaks. This method takes just nine minutes to detect a spill that the LVB system requires 3.5 hours to detect.

The TVB system is the primary leak detection system for TAPS. The TVB system was designed specifically for TAPS to detect leaks quickly and to calculate their location. This is possible because the TVB works between pipeline segments. A segment is typically defined as the pipeline between the discharge LEFM at one pump station and the suction LEFM at the next station. Development of this state-of-the-art system started in 1991 and went online in January 1998. It is designed to detect and locate all leaks capable of being detected by a model-based system.

Crude Oil Metering System: Oil from each North Slope producer enters PS 1 through individual meter sets, where oil volume is measured as accurately as possible before it is combined into one stream and pumped down the pipeline. Accurate measurement is required for custody transfer, tax purposes, and leak detection, and to schedule tankers out of the VMT. The oil is also very accurately measured where streams are diverted at the three commercial refineries (two at North Pole near Fairbanks and one at Valdez), and when entering the VMT.

Leading Edge Flow Meters: The LEFMs were replaced in 1997. These meters calculate the crude oil flow rate at each pump station based on ultrasonic waves transmitted across the pipe within the oil flow. Due to the Doppler effect, the ultrasonic waves will increase in speed when traveling with the oil flow and decrease in speed when moving against the flow. This time difference is mathematically converted to flow rate using standard time and distance formulas adjusted for the physical properties of the crude oil.

Software: The Scientific Software Intercomp TVB leak detection software gathers data such as crude oil flow rates, pressures, temperatures, and metering information. It calculates flow rates, line volume fill and packing rates, and other flow rate information. Based on these calculations, potential leaks and their locations can be identified. The TVB software was upgraded and enhanced as part of the Year 2000 (Y2K) software project. This upgrade and enhancement corrected Y2K issues and allowed the software to operate on a common IBM compatible Windows NT operating system.

In addition to the hardware based leak detection systems, there are a number of other monitoring and surveillance activities that provide early leak detection. These activities include routine aerial and ground inspections, security surveillance through various methods, and public information contacts. In fact, most crude oil spills on TAPS have been initially detected by human observation.

2.6.4.2 Monitoring and Surveillance

No components of the leak detection system are unique to that function. All data used to detect leaks come from equipment used in other processes. Furthermore, none of these components is so complex that having to replace it or do a major upgrade would significantly impact TAPS operations. All these components and systems have been upgraded since pipeline startup. No auxiliary components are dedicated to any of the leak detection systems. Field devices perform many tasks, such as continuously measuring suction and discharge pressure, flow rates, and temperatures, and supplying information to other devices. The LVB system employs the following components of other systems:

- Daniel crude oil metering systems at PS 1 and the VMT, and
- Data General MV20000 SCADA host computers.

The TVB employs the following components of other systems:

- Caldon LEFMs,
- Data General MV 20000 SCADA host computers, and
- Scientific Software Intercomp TVB leak detection software.

2.6.4.3 Summary Statement of Condition

The TAPS leak detection system has complete backup and is reliable and robust. It provides complete system integration, data acquisition, and control actions in near real time. The various hardware and software components are designed for longevity. Either the equipment manufacturers support maintenance and upgrades for all critical components, or the systems are due for replacement soon. Ground, air and other surveillance activities by trained personnel supplement the leak detection systems and provide additional assurance of detection for potential spills below the sensitivity thresholds of the leak detection systems. In addition, inline inspection tools (pigs) provide early detection of incipient pipe integrity threats.

2.7 Telecommunications

There are three primary communications systems used on TAPS. The microwave telecommunications system provides critical voice and control data communication for all facilities through a series of microwave towers on mountaintops across the pipeline's length. The Alyeska Radio Telephone System (ARTS) is a radio dispatch system that can be used anywhere along the pipeline and at any TAPS facility. A fiber optic communications system was recently installed along the pipeline and this system is currently used for non-operational data communications. The APSC plans on using the fiber optic system for pipeline control by the end of 2004.

2.7.1 Microwave Telecommunication System

2.7.1.1 Description

The microwave telecommunication system provides voice and data communication for all TAPS facilities between PS 1 and the VMT. Other facilities in Fairbanks and Anchorage are linked through commercial telecommunication providers. The current analog microwave system was installed during the construction of TAPS and has worked dependably for over 25 years, with slightly more than five hours of total communication outage during that time. Continuous monitoring, well-planned and executed maintenance, and strategic system upgrades have contributed to this system's success.

The existing analog microwave system is being upgraded to a digital microwave system between the North Slope and Fairbanks. This new system is expected to be in service in the very near future and will be fully capable of supplying communication capability for the foreseeable future. The new network will use the same sites as the original microwave system and will be covered by the same AT&T operation and support organization.

The microwave communication system has duplicate components throughout; there are backup transmitters, receivers, antennas, and power supplies at all locations. The communication system power supply is also redundant; dual diesel generators provide power to remote mountaintop sites, but there are also battery backups, which provide power for at least 48 hours in the unlikely event the dual generators completely fail. Should there be a microwave site or system outage, satellite channels are coupled to dedicated microwave channels to provide continuous communication from the VMT to any other site.

Forty microwave repeater stations form the backbone microwave network between PS 1 and the VMT. The 40 sites provide more than 300 communication channels. Each channel is duplicated at every location with redundant transmitters, receivers, and antennas.

For emergency alternate routing, the microwave system is linked to a satellite network consisting of earth stations tied to dedicated microwave channels. Earth stations are located at PS 1, 4, and 5, and at the VMT. If the control computer detects a microwave site or system failure, it will automatically switch communications to one of three dedicated satellite channels. A rerouted satellite message will go to the satellite earth link at either PS 1, 4, or 5. The message is then placed back on the microwave system to eventually reach its destination.

The BVCS transfers data between the RGVs and the upstream pump stations' MTUs to provide critical RGV monitoring and control information. The BVCS consists of two components: a VHF radio network that interfaces with the BVCS microwave system and a dedicated VHF network from each RGV to the next upstream pump station. The VHF radio transmitters and receivers connect each RGV to other radio systems in series until the final connection to the upstream MTU.

2.7.1.2 Monitoring and Maintenance Activities

The microwave system is owned and maintained by an international telecommunication company. The equipment is out of direct APSC control and responsibility; however, the APSC supports major system upgrades to ensure continuing long-term operations. For example, diesel powered generators at all mountaintop repeater sites were replaced with APSC's assistance. Any future large replacement projects would be done by the vendor, and APSC's costs would be amortized over a long period and would be about the same amount that the company pays today for this service.

Between August 1976, when the microwave system was commissioned, and August 2000, the microwave system achieved a reliability rate of 99.9976%. (The contract requires a minimum of 99.90% reliability.) Actual performance equates to a total communication outage of only 304 minutes in eight incidents over 24 years.

2.7.1.3 Summary Statement of Condition

The analog microwave system used on TAPS has performed with the highest reliability because of the system's design and extensive ongoing preventive maintenance. Although the system continues to perform reliably, aging components and new technology will dictate future repairs. AT&T is replacing the existing analog system with a new digital microwave communication system between the North Slope and Fairbanks. The transition of the microwave communication system is an interim step to assure continued communications reliability until pipeline controls migrate to the fiber optic system in 2004.

2.7.2 Alyeska Radio Telephone System

2.7.2.1 Description

The ARTS provides radio communications along the length of the pipeline extending two miles on either side of the ROW and to essentially all other TAPS sites, including RGVs, oil spill contingency equipment sites, pump stations, remote DRA injection sites, and airports. The two-way radio system provides communication among hand-held radios, mobile radios, and the telephone system. In addition, the two-way radio system provides communication to limited facilities outside the geographic area. This aids in nonessential communications that benefit overall company operations.

The current ARTS was designed and implemented during pipeline construction, and the equipment is reaching the end of its life. Individual sites have been converted to newer radio technology that will help extend the system's operational life. Current plans are to continue with this subsystem level replacement process, as need dictates. This approach to upgrading equipment provides the foundation to keep the system operating well into the future and gives the APSC additional time to plan and implement long-term system replacements.

Radios operate from PS 1 to the VMT. Twenty-three radio repeaters are located at pump stations and at the mountaintop microwave repeater sites. The 23 repeaters have been separated into four segments to better use radio frequencies and to connect to the telephone system. The radio network provides approximately 95% coverage of the entire pipeline route.

The ARTS is divided into four major segments: segment 1 covers the VMT (MP 800) to Delta Junction at approximately MP 530, segment 2 starts at MP 530 and continues north to approximately MP 405, segment 3 starts at MP 405 and ends at MP 215, and segment 4 starts at MP 215 and continues north to PS 1 at MP 0. Access to the telephone network from each ARTS segment is achieved by pressing a certain series of buttons on the radio keypad.

Repeater station near PS 5 (photo courtesy of © David A. Predeger).

A separate VHF radio system – commonly known as channel 4 – is a series of base stations that provide communication within a small geographic area such as a pump station. These units allow communication from the pump stations to local mobile and portable units supporting operations and projects.

2.7.2.2 Monitoring and Maintenance Activities

The ARTS radio system is considered a utility. While its loss would slow business and be an inconvenience, it would not affect the ability of TAPS to transport crude oil. Installing a replacement system would not be a significant impact on TAPS operations. The primary components of the radio system are the radio repeaters, base stations, and hand-held and mobile radios.

Repeaters: The repeaters provide the capability to "repeat" a voice transmission over long distances. These units pick up a radio transmission and broadcast it over a much wider area.

Communication Tower at PS 3 (photo courtesy of APSC).

Unlike a citizen's band (CB) radio, users can communicate with others far beyond the line-of-sight and around topographic features. The repeaters are located at AT&T mountaintop locations and the pump stations. AT&T is considering replacing its mountaintop repeater equipment with a new digital microwave system, which will still require access to the mountaintop locations. The APSC will negotiate an agreement with AT&T to keep ARTS radio repeaters at these sites.

Base Stations: A base station provides communications in a limited area. The base station does not repeat the user's message and only allows the user to connect to the base station. The system operates with high dependability, but over time, the APSC has selectively upgraded some sites when units have failed. Base stations are located in APSC facilities.

Hand-Held Radios: The APSC uses several models of Motorola hand-held radios. These units, which are portable, low power units similar to portable CB radios, allow communication beyond normal range through the repeaters and base stations.

Mobile Radios: Mobile radios are designed for use in vehicles. They transmit at higher power levels than hand-held radios and are permanently installed in a vehicle. These radios allow vehicle occupants to communicate from most locations where the vehicle will be.

2.7.2.3 Summary Statement of Conditions

Although most ARTS equipment consists of the original components which are now dated technology, the system continues to function reliably and is maintained as needed. The APSC and its telecommunications provider continue to replace aging devices with new technology. This system is acceptable for current and projected future needs.

2.7.3 Fiber Optic Communication System

2.7.3.1 Description

The Kanas Telecom, Inc., installed a complete fiber optic communication system along the TAPS route in 1998. There were problems identified with the initial installation of the fiber optic system and it has not been used by APSC for pipeline operations because of reliability concerns. GCI purchased the fiber optic system and plans to correct these problems. The system is currently used to communicate with RGV 123 and 124 and for noncritical voice and data communications. Other RGVs and TAPS components are being linked via the fiber optic system starting in late 2002. The APSC is planning to complete the migration of TAPS operational controls from the microwave radio system to the fiber optic system by the end of 2004. Earth stations will be installed at each pump station to provide backup for the fiber optic system.

The fiber optic communication system is designed to provide both voice and data telecommunication service. This system will interconnect all TAPS facilities from PS 1 to the VMT. A primary benefit of this new system would be the capability for expanding and enhancing telecommunications through the availability of a broader bandwidth.

2.7.3.2 Monitoring and Maintenance Activities

The fiber optic system is owned and maintained by a telecommunication company. The fiber cables are designed to last indefinitely and should not require maintenance or upgrade. However, additional fiber optic strands may be committed to meet increased demand. Fiber optic electronic manufacturers enhance their product lines to remain competitive. To date, enhancements have been compatible with systems already in use. While there are no guarantees that this backward compatibility will always exist, current industry practice supports this trend.

2.7.3.3 Summary Statement of Condition

The APSC continues to use the present microwave system in lieu of the new fiber optic system for pipeline operations. The existing system meets the needs of TAPS but is aging and does not support newer technology. As problems with the fiber optic system are resolved, the APSC plans to take advantage of the new technology, which will provide a long-term, higher speed telecommunication capability. With the new digital microwave communication system, the fiber optic system, and the satellite backup system, there will be multiple redundancies to ensure safe control of TAPS.

2.8 Fire and Gas Protection Systems

2.8.1 Pump Stations

2.8.1.1 Description

The fire and gas detection systems at the pump stations notify personnel of potential and actual fires through devices that detect fire, smoke, or hydrocarbon gas and alert people through facility-wide alarms. Fire suppression systems are automatically activated when a fire has been detected and are designed to extinguish the fire before it becomes unmanageable. Explosion inhibition systems are automatically activated when a potentially explosive concentration of hydrocarbon gas is detected.

The primary functions of the fire and gas detection and suppression systems are to detect smoke, flames, excessive temperatures, and hydrocarbon gas; alert personnel to a hazardous atmosphere or fire condition; isolate hydrocarbon sources by shutdown of equipment; start up emergency ventilation systems; blow down large volume gas systems; discharge Halon in a hazardous atmosphere or fire situation; and support the manual activation of Halon and/or foam in a hazardous atmosphere or fire situation. The APSC has completed a major upgrade to the pump station fire and gas detection and suppression systems to take advantage of new technology. The systems are regularly inspected and maintained.

The pump station fire and gas panels normally operate in automatic mode. This allows for automatic actions related to thermal or ultraviolet fire detection or hydrocarbon gas detection to occur expeditiously, including actions to isolate the pump house, isolate the pump station, and shut down the station if necessary. These automatic actions occur if a gas detector indicates a concentration that is 60% or greater of the lower explosive limit (LEL). In addition, if a gas detector reads 20% LEL, the ventilation rates are increased in certain gas fuel or gas handling facilities. The fire and gas system's automatic actions can be bypassed for maintenance or testing. Actions can also be initiated manually at the fire control panel or at the local fire alarm stations.

Fire Detection Systems: Automatic fire detection systems are installed throughout the pump station facilities. The main fire and gas alarm system at each pump station provides coverage in all buildings that are linked by the pump station hallway system. The permanent living quarters and most other detached buildings also have separate, local fire detection systems that report alarm conditions to the main fire and gas system. Local alarm systems are installed in most occupied temporary buildings including guard shacks, project offices, and break trailers. Fire detection devices include ionization, ultraviolet, and infrared flame detectors, and heat detectors. Hydrocarbon gas detection devices include catalytic element combustible gas detectors.

Except for certain local fire alarm systems that are separate from the pump station fire detection systems, an activated fire detection system sounds alarms in the station control room and at the OCC, and activates the station alarm system. The fire and gas detection systems provide ventilation unit automatic control, initiate equipment and process shutdown, and activate the fixed automatic fire suppression systems. Combustible gas detection systems are installed in buildings or areas where potentially explosive atmospheres can develop. With the exception of PS 7, all large volume process areas/zones are protected by gas detection voting logic. The gas detection systems automatically activate alarms in the State control room and at the OCC, start emergency ventilation units, control equipment and process shutdown, and activate the fixed, automatic total flooding and inerting systems.

Fire Suppression Systems: Fixed automatic (Halon) and manual (aqueous film forming foam [AFFF]) fire suppression systems are installed in selected buildings of the main pump station complexes. Fixed automatic dry chemical systems are provided in several of the detached buildings housing hazardous operations or contents. A wet standpipe system is installed in the permanent living quarters.

Halon flooding systems are the automatic, primary fire-fighting tool for buildings or modules that contain hydrocarbon handling or flammable gas handling equipment, and for rooms containing critical pump station equipment. A Halon total flooding system is also installed in the pump station hallways. Except in pump station hallways, the Halon total flooding systems are discharged automatically in response to activation of the detection systems. They may also be discharged manually by activating pull stations throughout the facility or from the fire control panel in the control room. The Halon concentration is calculated to extinguish fires and to inert explosive atmospheres in areas with crude oil or gas fuel. Since Halon is no longer manufactured, the APSC is stockpiling Halon from systems that are repaired or replaced. This stockpile will be used to resupply Halon systems in critical areas (areas with explosive potential that are occupied by personnel). Non-Halon systems are being placed in noncritical areas within new facilities.

Buildings or modules that contain hydrocarbon-handling equipment are also protected by a manually operated AFFF firewater deluge system that is activated by controls in the main control room. Firewater and foam solution is distributed through each pump station's firewater main by a fire pump and acts as manual, secondary fire suppression in the areas containing crude oil at the pump station. A foam tank is connected to the system and supplies the AFFF solution to the firewater in the facility to make foam.

A firewater main provides firewater to hose stations and fire hose connections installed in pump station hallway and shop/warehouse buildings, and to the sprinkler systems in the shop and fire pump room. The firewater main also supplies the standpipe in the permanent living quarters. There are no fixed automatic fire suppression systems in the pump station office buildings or any of the detached buildings located on the pump station pads, except for those buildings which house hazardous operations or contents.

2.8.1.2 Monitoring and Maintenance Activities

The APSC performs function tests of the fire protection systems at least annually. Systems are repaired or replaced as needed as a result of these inspections and other maintenance activities. The APSC has evaluated and revised maintenance of fire and gas detection and suppression systems to make the maintenance more specific and comprehensive. In response to a request from JPO, the APSC and JPO conducted an RCM analysis of four process areas that contained all components of the automatic fire and gas detection and suppression system. Most of the recommendations of this analysis were already included in APSC's maintenance program. The APSC is working to implement the remaining recommendations.

As a result of concerns regarding undocumented changes to fire protection systems, a task force of engineers, technicians, a representative of the State Fire Marshal, and an independent fire system expert recently completed an evaluation of fire code compliance of the pump station fire and gas detection systems (Woycheese 2002). The APSC is working through the issues identified in this evaluation. By agreement with the State Fire Marshal's Office, the APSC will correct all fire protection items that could impact human safety and TAPS functions by the end of December 2002. Fire protection items that arise from fire code concerns, but do not involve human safety or TAPS functions will be corrected by December 2005.

The APSC is also performing building integrity checks to determine if pump station structures can maintain Halon concentrations sufficient to provide an inert atmosphere in the event of an emergency. The integrity checks are completed at PS 9 and 12. All pump station process areas are to be checked by the end of December 2002. The remaining areas will be checked by June 2003.

2.8.2 Valdez Marine Terminal

2.8.2.1 Description

Fire detection systems are used at the VMT to give early notification of smoke, flame, or heat. Various devices detect anomalies and alert people through alarms. When a fire has been detected, fire suppression systems are activated to extinguish the fire before it becomes unmanageable. The VMT fire protection systems consist of onshore and offshore firewater systems, a foam system for tanks, a separate foam system for the East and West Metering Buildings, a Halon extinguishing system, carbon dioxide at some locations, and other auxiliary water systems involving fire trucks and other fire fighting equipment.

The onshore firewater system supplies seawater from Port Valdez to hydrants near critical buildings, tanks, and equipment. Water from the firewater system also supplies two fixed foam systems protecting tanks in the East and West Tank Farms, and a separate Metering Building foam system. Three pumping systems serve the three primary VMT areas: lower Terminal, upper Terminal east, and upper Terminal west. Jockey pumps maintain pressure in the main firewater lines. Booster pumps supply water to the East and West Tank Farms.

The three main firewater pumps are diesel driven deep well centrifugal pumps that draw seawater from a 45-foot deep vault. The main firewater pumps discharge into the lower Terminal firewater distribution system that provides firewater for the lower Terminal and suction side of the east and west fire pump buildings. Two main firewater pumps are required for the design of the protection systems; the third pump is an installed spare that can be used in the case of failure of one of the two main pumps. The east fire pump building boosts the pressure of the firewater from the main firewater pumps and provides water for the East Tank Farm area and the power/vapor complex. The west fire pump building boosts the pressure of the firewater from the main firewater pumps and provides water for the West Tank Farm area.

The firewater system is a closed-loop system. Any point on the main firewater lines can be supplied from two directions. Electric heat tracing is installed on sections of firewater line installed above the frost line (eight feet below grade). Cathodic protection protects the buried pipe from external corrosion.

Each of the four tanker berths has a separate fire control system. A firewater supply pump is located in the pump building on the offshore structure of each berth. The pump supplies firewater to the foam system on the berth. Seawater from the firewater pump is mixed with AFFF. The foam concentrate is stored on the berth and injected into the seawater via a pump and proportioner mounted on the foam-mixing skid. The skid control valve automatically mixes three parts of foam concentrate with 97 parts of water.

Each berth's system is tied into the onshore fire system by a redundant firewater line running along the berth causeway. The redundant firewater supply provides an alternate source of water to the berths. If the berth firewater pump fails, water may be supplied to the berth from the onshore firewater system. The redundant firewater supply lines to the berths may be placed in service simply by opening motor operated valves. The valves may be opened (or closed) from push-button stations located at each valve, at local stations, or from the appropriate power distribution centers. The offshore system and redundant firewater line are normally dry, i.e., water is not in the lines unless the system has been activated. These systems can be supplemented with fire trucks and other portable equipment and by fire protection equipment on tugboats.

These systems use ionization or photoelectric detectors for smoke, ultraviolet detectors for flame, and thermal detectors for heat. Except for certain local fire alarm systems that are separate from the VMT systems, an activated fire detection system sounds an alarm at the OCC and activates the alarm system. The fire detection systems may also provide ventilation unit automatic control, initiate equipment and process shutdown, and activate the fixed automatic fire suppression systems.

Combustible gas detection systems are installed in buildings or areas where potentially explosive atmospheres can develop in the presence of flammable vapors or gases. All large volume process areas/zones are protected by gas detection voting logic. The gas detection systems automatically start emergency ventilation units, control the equipment and process shutdown, and activate the fixed automatic systems.

Halon or carbon dioxide is automatically discharged when a fire condition is sensed and alarms sound. The chemicals are dispersed only in the area potentially exposed to the fire. Halon and carbon dioxide are colorless, odorless, electrically nonconductive gases. When discharged into an enclosed area, they are effective extinguishing agents for fires. Carbon dioxide total flooding suppression systems are installed in the fuel oil pump building, the fuel oil transfer shed, and the HU-3 hydraulic unit. Halon is installed in the Petrostar metering process area, Petrostar metering control room, Emergency Response Building (ERB) flammable storage room, ERB oil laboratory, ERB water laboratory, and Ballast Water Treatment Facility laboratory.

2.8.2.2 Monitoring and Maintenance Activities

The fire detection system is under continuous upgrade and the fire alarm panels and detection devices in VMT buildings were recently improved. Firewater piping was relined in 2000 for corrosion protection and a fire hydrant replacement program is in place, which will change out ten units every year until all are complete. All components of the firewater system have built-in redundancies to increase the likelihood that the system will work if needed. The primary components of the firewater system are discussed as follows.

Firewater Pumps: The firewater pumps get monthly maintenance, and their performance is thoroughly tested every year. No significant changes or repairs are anticipated for these pumps.

AFFF Distribution System: The VMT fire foam is being replaced with a more environmentally friendly product. The new product is much less corrosive, as well as more economical for waste handling.

Tank Farm Fixed Foam Systems: In 1999, an aggressive program was initiated to remove excess sediment from the crude oil storage tanks at the VMT. While doing routine tank cleaning, workers discovered that slowly accumulating crude oil sediments had covered the fire foam distribution piping inside the tanks. This hinders the foam from bubbling to the crude oil surface and suppressing fire in the tanks. The possibility of a fire inside the tanks is remote because of the very low oxygen atmosphere and lack of an ignition source. Nevertheless, the APSC decided the make the system as safe as possible by periodically using mixer motors to dislodge the sediment (which is mainly wax precipitated from cooling crude oil) and sending it to tankers when they take on crude oil. This process will likely become a standard operating procedure for tanker loading in the future.

2.8.3 Summary Statement of Condition

The APSC performs periodic maintenance and follows operating procedures to inspect and test the fire and gas detection and suppression systems regularly. Procedures are being upgraded to improve consistency and documentation, and to fill any identified gaps. These systems are in good condition and should continue to serve TAPS for the foreseeable future.

2.9 Earthquake Monitoring System

2.9.1 Description

The TAPS Earthquake Monitoring System (EMS) processes seismic data to evaluate the severity of an earthquake ground-shaking event along the pipeline route and to assess the potential for damage to the pipeline and supporting facilities. The most important objectives of the EMS are to determine whether the pipeline should be shut down in response to an earthquake and to delineate inspection requirements for the affected portion of the route. Based on preestablished criteria, the EMS will record seismic event data, monitor acceleration forces, annunciate alarms, generate event reports, initiate pipeline shutdown for large events, and generate a list of recommended system inspections and their locations. The EMS also maintains an historical database of event parameters and acceleration data for detailed analysis.

The EMS has been part of the pipeline monitoring and control system since startup of TAPS in June 1977. The EMS consists of 11 remote digital strong motion accelerator (DSMA) stations located at the VMT and at all pump stations except PS 2 and 3. The DSMAs sense ground motion using highly accurate force-balance accelerometers. Signals from these accelerometers are digitized and processed at each station to sense earthquakes, transmit alarms, initiate pipeline shutdown, record data, provide graphic displays, and generate reports for use in operations and damage assessments.

After more than 20 years of service, the APSC replaced the original EMS hardware in 1998 with a second-generation system composed of standard industrial grade personal computer (PC) components and associated software running on a Windows NT operating system. Implementing this enhanced system on PCs allows for easy replacement and enhancement as technology improves. The new EMS stations are installed in the same locations as the original system. Each station consists of ground motion sensing instrumentation and a rack-mounted computer that provides data acquisition, processing, recording, network communications, and output of alarms and analog signs to the OCC. The new DSMA stations use a network to share data between stations. Each DSMA has equal status, i.e., there is no central controlling station. All stations sense and process ground motion data and perform system-wide processing of data that are broadcast and shared with all other DSMAs. The Data General MV20000 central computer is also connected to the EMS network to retrieve information for creating displays and alarms at the pipeline controller's console in the OCC.

In addition to routine system functions, capabilities are included for dial-in access over telephone lines to retrieve data, test the system, and perform software maintenance as needed. Another feature of the system uses a digital-to-analog converter card to provide test signals to the accelerometers in the form of actual earthquake acceleration time histories. These tests, referred to as *self tests*, exercise all aspects of the system and provide a method for validating operational integrity. With the new 1998 DSMA stations, software for post-earthquake data processing and reporting of event parameters generally follows the performance specifications for the original system; however, improved analytical techniques with greater reliability were incorporated as appropriate. All software functions are now handled by the computers at each DSMA station rather than only by the pipeline control system computer (the Data General MV20000) at the OCC.

The EMS upgrade project offers a number of improvements relating to modern computers and improved technology resulting from advances in earthquake engineering research over the past two decades. The most notable improvements include the following:

- Each DSMA station generates post-earthquake reports from a single set of data, and personnel at each location can retrieve these reports.
- During an earthquake, acceleration time histories are stored in computer memory, and then automatically transferred to hard drives for semi-permanent storage after the event. Far more data can now be stored than previously.
- Each remote station is capable of processing acceleration time series to determine a much larger number of earthquake response coefficients over a broader frequency range. This results in better characterization of earthquake severity.
- Reports and inspection checklists are now available at each DSMA rather than only at the OCC. This will expedite post-event damage inspection.
- Authorized users are now able to log in remotely to any DSMA. If a DSMA station is disabled or otherwise unavailable, other DSMAs can be accessed to obtain the same data.
- Self-tests are automatically initiated and evaluated on a periodic basis, removing this responsibility from the OCC.
- Each site can initiate pipeline shutdown.

The DSMA units operate in three modes: pre-event, event, and post-event, with pre-event being the most common. In pre-event mode, each DSMA continuously measures ground accelerations along three axes and determines whether an event trigger has been received on any one of the three axes. The data are continuously scanned for a seismic event (real or test). If an earthquake is detected, the DSMA switches into the event mode and records acceleration time histories for each of the three axes of measurement. Visual and audible alarms are activated locally, and event alarms are passed to the pipeline control system for display at the OCC. Acceleration time histories are stored in a disk file for post-event processing and archiving. When the earthquake has ended, the DSMA switches to post-event mode and computes and stores event parameters that indicate earthquake severity.

Immediately after an earthquake, the EMS network distributes data from each triggered DSMA so that all DSMAs have data on the earthquake. Each DSMA processes the data to determine the severity of ground shaking along the pipeline route. The computer generates graphs and printed reports, which assist the pipeline controller in decision making and guide post-earthquake inspection efforts. A key report section compares computed earthquake parameters to design limits. If the shaken area requires an inspection, a checklist is generated to guide field response teams.

The pipeline controller determines the need for pipeline shutdown and field inspection through review of EMS-generated alarm displays and other control system information. The pipeline controller can intervene and override the automatic shutdown command. Shutdown actions are initiated manually by the pipeline controller, but a shutdown sequence will occur automatically if seismic alarms are not acknowledged at the OCC within 10 minutes. The pipeline controller at the OCC has written procedures for determining the location and extent of any damage and the appropriate actions to take depending on the location and magnitude of estimated damage. The computer generates a list of facilities and features along the pipeline ROW to check in the event of a large earthquake.

The DSMA stations are individually tested with a test signal on a regularly scheduled basis; each station is tested about twice a month. In addition to self tests, regular periodic testing of the instrumentation is also accomplished as part of APSC's preventive maintenance program.

2.9.2 Monitoring and Maintenance Activities

None of the EMS components are so substantial that the need to replace or upgrade them would significantly impact TAPS operations. This system relies on off-the-shelf computers and other components which, should they need to be replaced, are well within APSC's annual budget for such expenses. The EMS computers and tri-axial accelerometers are the key components of this system.

EMS Computer: The minimum computer hardware at each monitoring location consists of an industrial grade computer with a Pentium class processor, 32 megabytes of random access memory, two hard drives, and a floppy disk drive. In addition to the central processing unit, the computer chassis contains special cards to detect a seismic event, record peak horizontal and vertical accelerations, connect each DSMA to the network, and allow dial-in access by authorized users. The EMS hardware components are housed in a seismically qualified floor-mounted equipment rack.

Tri-Axial Accelerometer Assembly: Earthquake ground accelerations at each monitoring location (each DSMA) are measured on the three orthogonal axes (plant north-south, plant east-west, and vertical) by three force balance accelerometers mounted in a block. The accelerometers and associated interface electronics are enclosed in a hermetically sealed electrical junction box mounted on a five-foot-square by two-foot-thick concrete pad. The accelerometer signals are filtered and input to the analog-to-digital converter card for digital sampling. The EMS accelerometers have a long history of successful performance in the arctic environment. Typically, accelerometers work either correctly or not at all. Malfunction can be readily detected through system self tests. Accelerometer calibrations are periodically checked and adjusted as necessary.

2.9.3 Summary Statement of Condition

The EMS is in good condition. The system has recently been upgraded to take advantage of the latest technology. The system operated as designed in response to the large earthquake on November 3, 2002, by initiating automatic shutdown of the pipeline, calculating the severity of the event, and developing a checklist of approximately 160 items for inspection and evaluation. This system was instrumental in the shutdown of TAPS and provided good information to allow timely restart of the pipeline in a safe manner. As long as the EMS continues to receive regular maintenance and upgrades, it will serve TAPS for an essentially unlimited period of time.

2.10 Valdez Marine Terminal

The VMT is at the southern end of TAPS and includes equipment and facilities for managing the crude oil transported through the pipeline. Crude oil arriving at the VMT is measured at the East Metering Building and then goes to storage tanks or can be directly loaded onto tankers. The VMT has 18 crude oil storage tanks each with a capacity of 510,000 bbl; the total storage capacity of these 18 tanks is 9.18 million bbl. Four storage tanks are located at the West Tank Farm and 14 tanks are at the East Tank Farm. The VMT has four loading berths. Berths 4 and 5 have vapor control systems and will be the primary loading berths in the future. Berths 1 and 3 do not have vapor control systems but can be used in special situations. Berth 2 was never built.

Two major systems at the VMT that are instrumental for future TAPS operations are the Ballast Water Treatment Facility (BWTF) and the vapor management systems. The BWTF is used to treat ballast water from incoming tankers and other wastewater before discharge to Port Valdez in accordance with existing permits. The vapor recovery system manages the hydrocarbon vapors from the crude oil storage tanks at the VMT, and hydrocarbon vapor from tankers is managed by the vapor control system. The BWTF and vapor management systems are addressed in the following discussion.

2.10.1 Ballast Water Treatment Facility

2.10.1.1 Description

The BWTF processes ballast water offloaded from incoming tankers and wastewater from a variety of waste streams collected in the VMT industrial wastewater sewer system. Tankers use seawater for ballast to maintain stability and appropriate operating conditions on their return journeys to Port Valdez after delivering crude oil to various ports. Some tankers carry the ballast water in chambers segregated from the crude oil. This ballast water is discharged directly to Port Valdez after inspection for oily sheen in accordance with requirements of the U.S. Coast Guard and the U.S Environmental Protection Agency. Other tankers carry ballast water in the same tanks used for storing crude oil on the outbound journey. This ballast water contains residual hydrocarbons that cannot be discharged directly to Port Valdez. This contaminated ballast water is offloaded at the VMT and treated to remove hydrocarbons and other contaminants, and is then discharged to the marine waters of Port Valdez in accordance with the National Pollution Discharge Elimination System (NPDES) permit for the VMT.

Approximately 85 to 95% of the wastewater processed by the BWTF is tanker ballast and bilge water. Other influent sources include process wastewater, condensate from vapor recovery, potentially contaminated storm waters, oily washdown water, filter backwash, and minor spills from various containment systems in the BWTF. The NPDES permit requires extensive monitoring for the VMT to document the quantity of pollutants discharged from the outfalls, and the effects on the receiving water and marine sediments. Contaminants of concern in this water include total suspended solids (TSS) and total aromatic hydrocarbons (or BTEX – benzene, toluene, ethylbenzene, and xylene).

The BWTF discharges treated water at a typical rate of about 11 to 12 million gallons/day. Discharges peaked in the late 1980s and early 1990s. The effect of treatment improvements is most noticeable in the decrease in the amounts of TSS and BTEX released to Port Valdez. Biological treatment was demonstrated to provide improved treatment for trace organics at the end of the 1980s. The APSC moved to establish the current BWTF process beginning in 1989. By 1991, improvements to the plant enabled reduction of BTEX discharges by more than an order of magnitude, to an average value for the year of just over 0.1 milligrams per liter (mg/l) BTEX. Today, due to continuous process refinements, discharged BTEX is typically less than 0.02 mg/l, another order of magnitude reduction.

Effluent monitoring combined with well documented dilution and mixing process calculations demonstrate that water quality standards are maintained at the edge of the zone where effluent and seawater mix. Initial mixing and plume dispersion through the BWTF outfall achieve a reduction in the contaminant concentrations by a factor of 100 due to dilution. Continued dilution through the mixing zone results in contaminant concentrations well below the maximum levels allowed in State of Alaska Water Quality Standards given in 18 AAC 70.

The BWTF is designed to treat up to 30 million gallons/day of oily ballast water and industrial wastewater from activities at the VMT. Treatment occurs through three processes: gravity separation, dissolved-air flotation (DAF), and biological treatment.

<u>Gravity Separation</u>: Ballast water and other influent wastewaters are pumped to one of the three 18-million gallon ballast water storage tanks, known as the *90s Tanks*. In addition to influent storage, the 90s Tanks provide calm conditions to allow for separation of solids by gravity settling. The tanks are 250 feet in diameter and have a fill height of 49.5 feet. Pressure from the liquid level in the tanks provides energy to drive wastewater flow through the remainder of the treatment system.

Settling in the 90s Tanks typically occurs for a minimum of four hours, during which the tank is closed to further influent that may disturb the separation process. Oils and emulsions that migrate to the top of the liquid are skimmed and directed to the smaller 100-foot diameter oil recovery tanks (known as the *80s Tanks*) for further processing by gravity separation. Oil skimmed from the 80s Tanks is returned to the crude oil stream. About 1,000 bbl/day of oil are recovered by this system.

<u>Dissolved-Air Flotation</u>: Metering pumps are used to inject a polymer into the discharge line from the 90s Tanks to assist in accumulation of oil and other contaminant particles through an electrochemical process called *flocculation.* Groups of aggregated particles called *flocs* are more amenable to separation from the water in the DAF cells due to enhanced buoyancy and reduced surface tension.

The six DAF cells form the second level of treatment for oily wastewater in the BWTF. Each DAF cell is a concrete channel 24-feet wide, 112-feet long, and 12-feet deep. In this system, process water is exposed to high-pressure air in pressure-retention tanks packed with a plastic material. The plastic packing material results in a very large surface area to expose the flowing water to the air, maximizing the amount of high pressure air that is injected into the process water stream. Upon mixing with the main flow of wastewater, the air-filled water reverts to normal atmospheric pressure. Air comes out of solution in tiny bubbles which attach to oil and floc particles in the wastewater stream and rise to the surface, where they are skimmed and directed to the 80s Tanks for oil recovery. Water is pumped from the DAF outlet channel to the pressure-retention tanks for recycling through the DAF process.

<u>Biological Treatment</u>: When originally built in 1976, the BWTF employed only the gravity separation and DAF processes to remove oil from the wastewater before discharge to

Port Valdez. While this system achieved its original purpose, the discharge limits imposed on water treated in the BWTF under the NPDES permit were later revised to include a limit on BTEX. The APSC responded to this revision by adding biological oxidation as a third level of treatment in 1989. New concrete biological treatment tanks were put into service in 1990.

Wastewater discharged from the DAF cells is enriched with nutrients (phosphate and ammonia-nitrogen), which promote the growth of organisms that consume any remaining dissolved oils and aromatic hydrocarbons. The process is further enhanced by jet aeration and mixing in two parallel biological treatment tanks (BTTs). Water pumped through a header is aerated by a jet from a parallel air header at a pressure near atmospheric.

Microbial floc materials generated in the BTT are skimmed and redirected to the 80s Tanks. Underflow from the skimming systems is discharged through a baffle and weir system to a submarine outfall in Port Valdez. Temperature, BTEX, and oxygen are continuously monitored to ensure complete treatment. To provide supplemental removal of BTEX when biological upsets occur, a polishing air stripper was installed downstream of the BTTs to remove occasional elevated levels of BTEX prior to discharge.

Sludges: Sludges accumulate in the bottom of tanks and facilities comprising BWTF, mostly in the 90s Tanks, the DAF cells, and the BTTs. Sludges of similar composition also accumulate in sumps and portions of the industrial wastewater sewer system. Normal maintenance requires periodic cleaning of BWTF tanks and facilities, and a separate sludge tank is maintained at the BWTF for such residues. Recovered oil from the sludge tank is transferred directly to the 80s Tanks. Process solids from the sludge tank are managed in accordance with state and federal regulations for disposal off site.

Future Process Adjustments: As crude oil throughput declines in the future and double-hull tankers replace the existing tanker fleet, ballast water discharges to the BWTF are expected to decline. The effluent from the BWTF is likely to stabilize in the range of 3.5 to 6 million gallons/day by 2010, down from the present average level of 11 to 12 million gallons/day. This will likely mean a reduction in the concentration of hydrocarbons treated in the system.

New tankers will have segregated ballast chambers that never hold crude oil. Double-hull tankers can discharge this segregated ballast water directly to marine waters, following inspection to ensure that the ballast does not have an oily sheen. If it is decided to include segregated ballast water in the water directed to the BWTF, the volumes of ballast water treated would likely approach the high end of the range given above, although concentrations of hydrocarbons would be much lower than current levels. The ballast water treatment process would require further adjustments to optimize treatment.

The reduced volume of ballast water and reduced hydrocarbon levels will mean more flexibility in plant operation and influent wastewater storage. Processes will be monitored and adjusted to ensure that the hydrocarbon-consuming organisms function optimally in the biological treatment tanks and to maintain the highest quality effluent possible. As ballast water volumes decrease, the APSC may reduce or consolidate treatment processes.

2.10.1.2 Monitoring and Maintenance Activities

Ballast Water Storage Tanks (90s Tanks): Tanks 92, 93, and 94, which have been in operation since BWTF startup, have historically been taken out of service every five years for cleaning and inspection on a staggered rotation such that two tanks are always available for ballast water storage. Snow loads on the tanks are controlled by melting the snow with seawater. The melt water is contained in the secondary containment basin surrounding the tanks and is retrieved and processed through the BWTF. Over the past two years, Tanks 93 and 94 were each raised two feet in order to provide corrosion protection around the base of the tanks with a new cathodic protection system, minimize the potential for liner abrasion with additional cover over the liner in the diked area, and grade the diked area so that water drains away from the tanks. Due to the improved corrosion protection on Tanks 93 and 94, the inspection interval has been extended to 10 years. Tank 92 will not have a cathodic protection system installed and will remain on a five-year inspection interval due to uncertainties in the amount of ballast storage needed in the future.

Oil Recovery Tanks (80s Tanks): Tanks 80 and 81 are cleaned and inspected on a staggered five-year rotation. The tanks are much smaller than those used to store ballast water, and their foundations and liner systems are sufficient for the required performance.

DAF Cells: Like the BTTs, these concrete channels are taken out of service on a four-year staggered rotation for cleaning and inspection. Maintenance practices and inspection findings are documented in accordance with APSC's standard operating procedures.

Biological Treatment Tanks: The installation of these tanks was a major focus of the BWTF improvement project conducted from 1989 to 1991. The biological treatment and air strippers replaced the less effective aerated-lagoon treatment ponds. These tanks were constructed on unconsolidated fill material and have ongoing settlement issues but are closely being monitored on an annual basis. It is not likely that differential settlement will result in damage to the concrete sections or in damage to the expansion joints within the next six to eight years. The mode of differential settlement tends to open the expansion joints at the top, where hydraulic head due to tank content is low; any leakage at an expansion joint would occur slowly and could be repaired.

Outfall: The depth and position of the outfall pipe are critical in that a discharge pipe failure would limit the plant's capacity to process ballast water and could limit the ability to receive tankers at the VMT. The outfall pipe is constructed of high-density polyethylene that is immune to corrosion. Capacity is sufficient for maximum flows anticipated from the plant. The diffuser ports discharging the treated waste water into Port Valdez are inspected periodically by a robotic underwater camera to ensure operational integrity.

BWTF Piping: All piping in the BWTF was originally concrete-lined carbon steel. Corrosion of this piping began to be a significant problem in the 1980s. Much of the piping has been replaced with corrosion-resistant pipe; for example, the DAF cell piping is mostly stainless steel, and the piping from the DAF cells to the BTTs is now plastic. Piping from the tanker berths to the 90s Tanks underwent major rehabilitation beginning in 2001 after investigations revealed that the interior liner was failing and allowing the steel to be exposed to seawater, which caused serious corrosion problems.

General Maintenance: Ongoing maintenance includes regular inspection and operating procedures to maximize the longevity of the BWTF. Many mechanical system components including the BWTF control building, oil recovery building, polymer injection systems, nutrient additive system, DAF transfer pumps, exposed piping and ducting, fans and blowers, process instrumentation, skimmer systems, and valves may be replaced or upgraded in the course of regular maintenance. These components are covered individually and generally by the APSC's preventive maintenance program for the BWTF. Lubrication, inspection, and replacement of expendable parts are performed according to the documented procedures for each component. The preventive maintenance system is currently being converted to a computerized control system that provides an updated list every month of equipment service requirements. The preventive maintenance system also provides documentation that each activity is completed in accordance with specified procedures.

2.10.1.3 Summary Statement of Condition

The BWTF is currently in sound condition and will continue to be so provided that the current maintenance program continues. Successful operation of the BWTF is essential to TAPS operations. Ongoing monitoring and process controls ensure that the system meets treatment requirements specified in the NPDES permit. The BWTF utilizes proven wastewater treatment techniques and equipment, and existing facilities are monitored and maintained. Equipment is easily upgraded and replaced, as indicated by past improvements to this system.

2.10.2 Vapor Management Systems

2.10.2.1 Description

The VMT vapor management systems reduce atmospheric emissions of hydrocarbons from the storage tanks and tankers during crude oil loading operations. Crude oil vapor from storage tanks is managed by the vapor recovery system and vapor from tankers is managed by the vapor control system. While these two systems merge prior to the incinerators, they were constructed at different times and are discussed separately here. The vapor recovery system also provides inert (oxygen-deficient) vapor to the crude oil storage tanks, thus preventing the vapor within the tanks from entering a combustible range.

Because the storage tanks have fixed roofs, vapor must be collected from or supplied to the space above the oil whenever the tanks are being filled or emptied to prevent failure and the release of crude oil vapor to the atmosphere or air from being drawn into the tanks. When a storage tank is being filled with crude oil, vapor is collected from the tank and delivered to the powerhouse boilers for electricity generation or to the incinerators for burning. When a storage tank is being emptied, vapor is supplied to the tank. The vapor supplied to the tank may come from other tanks, from vapor collected from ships being loaded, or from the boiler flue gas (inert gas). When a ship is being loading, the vapor is piped and distributed to the storage tanks for vapor balancing, to the powerhouse boilers for electricity generation, or to the incinerators for burning.

Crude Oil Storage Tanks: The VMT has 18 crude oil storage tanks, each with a capacity of 510,000 bbl. The tanks are located in two areas, designated the East and West Tank Farms. The crude oil in the tanks is warm and releases hydrocarbon vapor into the tanks. To prevent atmospheric emissions of the hydrocarbon compounds, the vapor is collected and eventually burned in the incinerators or powerhouse boilers. The vapor recovery system serving the tank farms was part of the original construction of the VMT in the 1970s.

The vapor space in the tanks is controlled to maintain a slight positive pressure. If the pressure in a tank decreases beyond a preset value, a control valve at the tank opens to allow vapor or inert gas to flow into the tank from the vapor supply header. Conversely, if the pressure in a tank increases beyond a preset value, a control valve at the tank opens to allow vapor to flow out of the tank and into the vapor collection header.

Tank Farm Piping: There are two piping systems in the tank farms. The vapor supply system, also referred to as the *high pressure header*, normally operates at 10 to 15 psig and distributes vapor to the storage tanks as needed because of decreasing internal tank pressure. High pressure as used here to refer to the vapor supply system is somewhat a misnomer as it operates at 10 to 15 psig, but *high pressure* and *low pressure* are convenient ways of referring to the vapor supply and vapor collection streams, respectively. The high-pressure piping is insulated and located aboveground. The piping was originally carbon steel, but was subsequently replaced with stainless steel because of corrosion problems.

The vapor collection system, also referred to as the *low pressure header*, operates at a pressure of approximately -1.0 psig (or 1.0 psi vacuum) and collects vapor from any tank in which vapor must be removed because of increasing internal pressure. Most of the original insulated carbon steel piping in this system is still in service, although it has been replaced in a few isolated locations where repairs have been made.

Inert Flue Gas and Scrubbers: Hydrocarbon vapor from the storage tanks is combustible when mixed with sufficient oxygen. To prevent the potential for fire or explosion in the tanks or vapor systems, the oxygen is kept below the concentration needed for combustion by preventing air from entering the tanks. Whenever more vapor is needed in the system, inert gas is supplied. The inert gas for the system is created by taking a portion of the exhaust flue gas from the powerhouse boilers, cooling it, passing it through a scrubber, and delivering it to the vapor control system for distribution through the high pressure header to the storage tanks.

The scrubber system includes two scrubber vessels where the vapor encounters a counter-flow stream of caustic-and-water solution to reduce the sulfur dioxide in the flue gas. The inert gas system, as well as the rest of the vapor management system, is operated with low levels of oxygen so that the vapor is below the combustible range, thus providing safety from fire or explosion. Oxygen analyzers monitor the oxygen content of the vapor and alarm or shut down the system if 7 to 8% oxygen is detected.

Vapor Compressors: Five compressors are used to move vapor through the two vapor management systems. The compressors create vacuum conditions on the vapor collection portion of the systems and create positive pressure on the vapor distribution portion.

The vapor recovery system serving the storage tank farms and the vapor control system serving the tankers are each serviced by two compressors. A fifth compressor is in a swing configuration to serve either system as a backup. The two compressors serving the tank farm vapor recovery system and the swing compressor are rated for approximately 600,000 standard cubic feet per hour (SCFH). (Since the volume of gases is dependent on temperature and pressure, volumetric flow rates are given for *standard* conditions, which are 60 ^{o}F and 14.569 psi absolute). The compressors for the marine vapor control system are rated for approximately 785,000 SCFH. The compressors are helical-screw, positive-displacement type driven by 1,500-horsepower electric motors. The swing compressor serves as a backup for both the tank farm and marine portions of the system, thus allowing maintenance or replacement of a compressor without limiting operation of the complete system or the ability to either receive crude oil from the pipeline or discharge crude oil to tankers.

Vapor Incinerators: Three incinerators are installed to burn excess vapor, thus preventing atmospheric emission of hydrocarbon vapors containing volatile organic compounds (VOCs). The incinerators have a fuel-oil support burner that is fired to keep the incinerator above the minimum operating temperature when the vapor has a low hydrocarbon content or when there is no excess vapor to burn in the incinerator. The incinerators are each rated for 400 million British Thermal Units per hour firing capacity. The capacity of one or two incinerators is sufficient for all operating conditions of the vapor management systems. This allows the third incinerator to be out of service for maintenance or repair without limiting operation of the complete system. The incinerators have been tested, most recently in 1998, and have demonstrated VOC burning efficiency and emission levels that are within the requirements of federal and state regulations and permits.

Marine Vapor Collection System: The marine vapor control system was installed in 1997 to comply with federal regulations (Subpart Y of 40 CFR 63), which became effective March 19, 1998. The system collects vapor from tankers during crude oil loading operations. Marine vapor collection is provided at Berths 4 and 5, the two berths capable of handling all sizes of vessels loaded at the VMT. Berths 1 and 3 are not capable of loading the largest vessels that call at the VMT; Berth 2 was never constructed. The crude oil loading and vapor collection capacities of Berths 4 and 5 are sufficient to meet current and projected pipeline throughput volumes. The compressor configuration and incinerator capacity will accommodate the addition of vapor collection for a third berth, if needed in the future. The piping from the berths to the compressors is duplex stainless steel, a highly corrosion-resistant alloy.

During loading operations, vapor from a tanker is collected using a vapor compressor. The vapor is distributed to the storage tanks to balance the vapor space of tanks being emptied, routed to the powerhouse boilers for electricity generation, or sent to the incinerators for burning. The pressure within the marine vapor control system is maintained so that the vessel tanks are kept at a slight positive pressure, thus preventing ingress of air. Preventing air intrusion keeps the vapor oxygen deficient, and prevents a combustible mixture of hydrocarbon vapor in the vessel and the vapor control system.

The vapor collection systems at each berth include oxygen analyzers and detonation arrester systems, as required by U.S. Coast Guard regulations (Subpart E of 33 CFR 154). Oxygen analyzers monitor, alarm, and shut down the vapor control system based on the level of oxygen in the vapor. The detonation arrester system prevents a fire or detonation in the vapor piping from traveling from the shore facilities to the marine vessel, or vice versa. The detonation arrester system consists of a fast closing valve and chemical suppressants, which are released if a fire or detonation pressure wave is detected in the pipe. The detonation arrester system was developed for the VMT marine vapor control system by Fenwal Safety Systems and is certified by the U.S. Coast Guard. Before development of this system, no detonation arrester existed with adequate size and capacity for the vapor collection requirements at the VMT.

2.10.2.2 Monitoring and Maintenance Activities

Each portion of the VMT vapor management systems has received significant maintenance and upgrades over the past 10 years. This has resulted in an up-to-date system for management of hydrocarbon vapors at the VMT that is well suited for continued service and maintainability. With the benefit of operating experience and decisions based on long-term operating goals, many portions of the vapor management system are now in better condition for long-term operation and maintenance than when originally constructed. Various issues have arisen requiring analysis, maintenance, repair, or modification during the 25 years of operation of this system. The major issues and their solutions are discussed below.

Tank Farm Vapor Piping: The majority of the vapor recovery system was originally installed using carbon steel piping. During the first few years of operation, internal corrosion of the piping was identified as an issue requiring attention. The maintenance and repair progressed through several stages, eventually resulting in replacement of major portions of the piping in 1996 and 1997 with 316L stainless steel material. The stainless steel piping is highly resistant to corrosion under the conditions encountered in the vapor recovery system and is projected to have a life that can be maintained indefinitely.

Stainless steel piping is used for the vapor supply piping to each storage tank and for the piping between the compressors, flue gas scrubbers, and incinerators. The vapor collection piping from each storage tank is carbon steel, but is inspected annually and has not shown a need for replacement. Because the piping is aboveground, it is accessible if repair or replacement is needed.

When internal corrosion of the vapor recovery system piping was first identified, the area of greatest corrosion was in the piping that supplied inert gas to the storage tanks. The inert gas piping from the scrubbers to the compressors and the storage tanks suffered significantly higher rates of corrosion than the hydrocarbon vapor piping from the storage tanks to the compressors and incinerators. Inert gas for the system is created from exhaust flue gas, which carries residual amounts of sulfur compounds, carbon dioxide, and a low level (nominally 3%) of oxygen, all from the combustion process. The flue gas also has a high water vapor content from the combustion and scrubber processes. As the inert gas moves through the vapor piping towards the storage tanks, the water vapor condenses to liquid, which combines with the sulfur, carbon, and oxygen to form a corrosive, acidic liquid on the walls of the vapor piping.

The corrosion problem was addressed through several stages: conversion from a split system to a combined system, selective pipe replacement, dehydration, and replacement of carbon steel pipe with stainless steel pipe. These are discussed as follows.

The vapor recovery system for the tank farm was originally configured as a split system, with the inert gas going to the storage tanks being kept separate from the vapor collected from the tanks. The supply to the tank farm was all inert gas from the boiler flue gas exhaust, and all vapor collected from the tank farm was sent to the incinerators.

In the early 1980s, the system was reconfigured to a combined system. In the reconfigured system, inert gas is combined with vapor collected from the tank farm to supply vapor to tanks as needed, and only the excess vapor is sent to the incinerators. With this arrangement, the quantity of inert gas used is limited to what is needed to make up any net deficit vapor volume when some storage tanks are being filled and others are being emptied, rather than supplying the total quantity of vapor needed with inert gas.

The combined system is beneficial because less inert gas is introduced into the vapor system, thus reducing the amount of corrosive compounds in the piping system. The combined system also reduces the usage of the compressors, thereby reducing electricity consumed and the volume of vapor burned in the incinerators – thus reducing the total atmospheric emissions from the VMT. The change to a combined system brought about operational improvements and efficiencies, but did not fully solve the problem of corrosion in the vapor piping.

In the late 1980s, some portions of the vapor piping had corroded to the point that vapor leaks developed. Temporary patches were used to keep the system operational, and severely corroded sections of piping were replaced with new carbon steel material. Some sections of piping, particularly around the compressor building, were replaced with stainless steel piping. Engineering studies explored ways to reduce long-term corrosion of the vapor piping.

The vapor piping corrosion is accelerated by the water vapor carried in the flue gas and condensed on the pipe wall. To address this problem, a process was employed to dehydrate the vapor. Removal of the water vapor keeps the corrosive environment from developing in the piping, and corrosion rates of the carbon steel material are greatly reduced. A gas dehydrator installed in 1990 failed to operate satisfactorily and was abandoned after about a year. The process employed glycol-contactor dehydration and steam-heated regeneration. This process has been shown to be successful for dehydrating high-pressure natural gas streams; however, the relatively low pressure vapor system and the presence of aromatic hydrocarbons in the vapor resulted in low dehydration effectiveness and rapid fouling of the glycol.

Since vapor dehydration proved unsuccessful, the next step was to look at upgrading the piping material to increase corrosion resistance. The stainless steel pipe material used at a few replacement locations was showing good corrosion resistance. Corrosion monitoring showed that the carbon steel high-pressure piping was continuing to corrode and would need replacement. However, the carbon steel low-pressure piping had a low corrosion rate such that only isolated locations might need replacement in the following decade or two.

The piping from the scrubbers and all the high-pressure piping were replaced with stainless steel piping during 1996 and 1997. Major portions of the vapor management system are now in a better condition for long-term operation and maintenance than when originally installed. The stainless steel piping is performing well and is maintainable indefinitely. Corrosion monitoring continues for the vapor piping. The carbon steel piping is monitored to determine if or when any further replacement may be needed.

Vapor Compressors: All five vapor compressors have been overhauled and changed from carbon steel to stainless steel material to provide corrosion resistance and a maintainable unlimited life. One partial upgrade replacement occurred in 1992, three in 1997, one in 1999, and one in 2002. All the electric motor drivers were refurbished in 1996 and 1997.

During the first years of operation, corrosion products (rust) from the carbon steel pipe passed through the piping system and caused high rates of wear and high maintenance for the vapor compressors. The problem was addressed by installing filters on the suction side of the compressors. These filters captured corrosion products before they could reach the compressors. The demand on the filters has decreased since much of the flue gas and manifold piping has been replaced with stainless steel. Nevertheless, filters continue to serve a useful purpose of capturing corrosion products from the low-pressure piping.

During the 1990s, the five vapor compressors were upgraded in order to restore compressor performance, improve materials for increased longevity, and increase capacity to accommodate marine vapor control. The compressors' performance had deteriorated from regular use and especially from the severe duty imposed on them before the suction filters were installed. Internal compressor components had also suffered from corrosion. After a basic overhaul of two compressors in the late 1980s, a full upgrade program was initiated.

The first compressor upgrade was in 1992 and involved the installation of new stainless steel rotors and a stainless steel weld overlay of the compressor-case internal bore. The new rotors and re-bored case returned the compressor to full performance. The stainless steel materials were an upgrade over the original cast iron cases. This compressor later received a full stainless steel upgrade. With the stainless steel case and rotors, there should not be significant deterioration from corrosion. The compressors are expected to be serviceable for many years, with possibly an interim overhaul to restore the rotors.

In 1997, three compressors were upgraded with new stainless steel rotors and cases. One of the compressors was kept at original capacity, while the other two were increased in capacity to handle vapor collection from the marine vapor system. One additional compressor was upgraded in 1999 with the installation of new stainless steel rotors and cases; this compressor was kept at original capacity. The remaining compressor was upgraded with all stainless steel materials in 2002. The electric motor drivers for all compressors were refurbished in 1996 and 1997. The vibration and temperature monitoring instrumentation of the compressors and motors was also upgraded to current generation equipment.

Vapor Incinerators: In the late 1980s, the burners and refractory of the three vapor incinerators were deteriorating. In 1988 and 1989, the refractory, burners, and burner controls were replaced to keep the incinerators operating. The refractory initially selected for this application was inadequate and/or operating temperature was exceeded, and the refractory deteriorated rapidly. The high grade, high temperature refractory installed in 1990 has performed well.

The incinerators received a thorough inspection by the refractory vendor in 1996 and 1997 and showed good performance with no need for major repair or replacement. However, the incinerator burners and controls were modified when the marine vapor control system was added. This work expanded the rating of the incinerators and updated the control system to integrate it with the terminal-wide controls upgrade.

The incinerator equipment receives periodic preventive maintenance to keep it operating in compliance with the applicable air quality permit and to sustain long-term operation. The refractory shows no sign of failure or need for major repair in the near future. Nevertheless, the configuration of the three incinerators allows one to be out of service for repair or maintenance without affecting the operation of the vapor management systems.

Marine Vapor Control: The U.S. Environmental Protection Agency issued a regulation in 1995 under Subpart Y of 40 CFR 63 requiring collection of hydrocarbon vapors from marine vessels during loading activities. The marine vapor control system was installed at Berths 4 and 5 in 1997 in response to this requirement. During engineering of the system, attention was given to design and materials that would provide a long, low maintenance life for the system. The design benefited from lessons learned from operating the tank farm vapor recovery system for almost two decades.

An area of emphasis in designing the marine vapor control system was the selection of piping material. Corrosion studies were conducted, and a decision was made to use a duplex stainless steel material, which is highly resistant to corrosion from the acidic condensate that occurs in the vapor piping. The duplex stainless steel is also resistant to corrosion from chlorides, which are carried over from the saltwater flue-gas scrubbers used on the marine vessels. The duplex stainless steel provides essentially maintenance-free material for the piping system. After the first year of service, an examination showed no corrosion of the duplex stainless steel material. The piping is aboveground and accessible if repair or replacement is needed.

A detonation arrester system was developed by Fenwal Safety Systems for use in the vapor control system at Berths 4 and 5. This system was developed in 1995 and three areas of concern were identified in the first year of operation: corrosion of the aluminum valve gate, reliability of infrared detectors, and reliability of set point calibration of the detonation pressure detectors.

The aluminum gate of the Fenwal valve experienced corrosion and binding that prohibited proper operation of the valve. The condition was discovered during periodic testing and was attributed to sodium bicarbonate suppressant powder, which had been released a few months earlier because of a malfunctioning switch. The need to remove the powder and clean the pipe had not been recognized, and powder packed between the valve gate and body prevented the gate from moving freely. The sodium bicarbonate powder also accelerated corrosion of the aluminum gate.

The solution to the powder accumulation problem was to clean the valve and adjacent piping and to institute a requirement to perform this cleanup if the suppressant powder were released again. The cleanup of suppressant powder eliminates binding of the valve gate and prevents continued exposure of the aluminum to the sodium bicarbonate and associated accelerated corrosion. In addition to corrosion from sodium bicarbonate, the Teflon coating on the aluminum gate was deteriorating where condensed liquids from the vapor accumulated near the bottom bore of the gate. While this did not pose immediate problems to proper valve functioning, a long-term solution was needed. A spare valve and gate were procured and installed. Evaluation is underway to decide the best long-term course of action of either developing an improved gate/coating material or performing periodic gate replacement.

The infrared detectors were designed to fit the specific size and configuration required by the vapor piping. Initial reliability of the detectors was unsatisfactory for long-term operation because of ground-fault trouble conditions. Fenwal and APSC worked on improvements to bring the detectors to an acceptable level of reliability. Throughout the upgrade process, the system diagnostics would sense a malfunction and shut down the vapor control system to a safe condition. Thus, vapor collection was not performed without the protection offered by a functioning detonation arrester system.

In March 1999, the Fenwal system was actuated by a false alarm during a purging procedure, which involved pressurizing the piping with nitrogen. The suspected cause was a pressure detector whose set point had drifted lower than the normal calibration. Fenwal and APSC determined that the switch set point drift was not outside the level needed to detect a detonation. While it caused a few activations of the system, the vapor collection system was not operated without the protection of a functioning detonation arrester system.

Berths 4 and 5 are equipped for marine vapor control. If the pipeline throughput increases to the point that crude oil loading requirements exceed the capacity of the two berths, additional loading capacity could be obtained by adding vapor collection to another berth. The compressor configuration and incinerator capacity will accommodate such an addition. Routine and major berth maintenance will continue as long as the berths are in regular service. The vapor control regulation covering the berths includes a 40-day maintenance allowance each year

(40 CFR 63.562[d][2][ii][B]). Maintenance activities will be planned so that the work is accomplished within this time frame.

Storage Tank Vapor Valves: The vapor valves at each storage tank have been changed from carbon steel valves to stainless steel butterfly valves to provide corrosion resistance and a maintainable unlimited life. Most of the valves were replaced in the late 1980s. Individual inlet/outlet valves are in place on each of the 18 crude oil storage tanks. The tank valves are individually maintainable and replaceable, and maintenance on the valves can be performed without taking more than one tank out of service.

Inert Gas Scrubbers: The inert gas scrubbers contain stainless steel internals and have shown good performance with no need for replacement or major maintenance. Since there are two scrubbers, operations can continue with one out of service for maintenance.

Oxygen Analyzers: To enhance the safety of the vapor management systems, oxygen analyzers are provided at strategic locations throughout the system. In the early 1990s, the oxygen analyzers for the tank farm vapor recovery system were upgraded to provide current technology instrumentation and redundancy of analyzers. Oxygen analyzers provide a safety and monitoring method to support reliable operation. The analyzers are instrumentation components, which are directly maintainable and replaceable. The use of multiple and redundant oxygen analyzers allows for maintenance or replacement without impacting TAPS operations.

For the marine vapor control system, redundant oxygen analyzers are provided at the berths to monitor the vapor collected from the ships. Additional redundant oxygen analyzers are provided at the compressors. The oxygen analyzers at the berths are required by U.S. Coast Guard regulation (33 CFR 154.120[f] and 154.124[f-h]), and became a topic of attention in early 1999, the first year of operation of the marine vapor control system. The regulations for such systems require that changes to the system be reviewed by the Coast Guard. This level of regulatory interaction was new to APSC, and some changes were made to the oxygen analyzer flow sensing and diagnostic instrument without the proper review. The APSC reversed the changes and proceeded with proper submittal of changes to the Coast Guard.

The APSC also undertook an exhaustive analysis of the operability and maintainability of the oxygen analyzers using the RCM methodology. This analysis led to recommendations for improvements of the berth oxygen analyzers. Throughout the analysis and changes, the vapor control system was operated safely, and the requirement for shutting down the system upon high levels of oxygen was not violated.

Electronic Instrumentation and Control System: During 1996 and 1997, the instrumentation and control system for the vapor management systems, incinerators, compressors, tanks, berths, etc., was converted to the current state of the industry using a computer based distributed control system. This conversion replaced equipment approaching obsolescence. Components of the instrumentation and control system are individually maintainable and replaceable.

2.10.2.3 Summary Statement of Condition

The current condition of the vapor management systems is good and will remain so with continuation of the current maintenance program. The 1990s saw extensive engineering effort, maintenance, and equipment upgrades to all aspects of the vapor management systems. These improvements have placed these systems in a condition for reliable operation for the foreseeable future.

2.11 Electrical Systems

2.11.1 Description

The electrical systems include all generators, switches, transformers, motors and other equipment necessary for operation of TAPS. Most of these systems are located at the pump stations and the VMT. The electrical components are generally standard equipment that have been used in similar applications elsewhere. The design criteria for the use and installation of electrical system components are given in the *Design Basis Update* (DB-180).

The operations at the pump stations and the VMT are almost completely dependent on the electrical supply system at that facility. The control systems, communications, auxiliaries on all the mainline pumps and turbine drivers, starter motors, heating and ventilation systems, mainline valves, and many other components and systems necessary for safe pipeline operations are operated by electric power. Each facility has onsite generators with full backup capacity. The primary sources of electrical power at PS 1, 3, 4, 5, and 7 are Garrett dual fuel turbogenerators, since commercial electrical power is not available at these locations. Commercial utility electrical power is the primary power source for PS 9 and 12. (The other four pump stations are on standby.) PS 9 and 12 also have onsite generation capacity and can maintain full operation if the utility loses power.

The Garrett units provide 480-volt continuous power using natural gas as the primary fuel source for PS 1, 3 and 4. These units can be switched over to operate on liquid turbine fuel in the event that the source of natural gas is disrupted. The generators at pump stations south of the Brooks Range are powered with liquid turbine fuel purchased from commercial suppliers. The ratings of the prime generators at the pump stations (Garrett units) vary depending on elevation and maximum ambient temperature; the ratings range from 411 kilowatts (kW) at PS 12 to 485 kW at PS 1. The number of units at a pump station is determined by the power requirements of that station and ranges from one to a maximum of five at PS 1. In addition to these primary units, each station has at least one backup generator unit (the lifeline generator) for use in the event of total failure of the primary units. All of the pump stations are also equipped with an emergency backup generator which can be used if the lifeline generator fails; the emergency backup generator can also be used to support maintenance on the primary and lifeline units.

The electrical generation and distribution system at each pump station is segregated into two main buses, the primary power bus and the lifeline power bus; these two buses are in two different buildings at each pump station. There are three separate direct current power systems at the pump stations (120 volts, 48 volts, and 24 volts), each with a battery bank, a charger, and a circuit breaker panel. The systems provide power for communication systems, station supervisory control, station control panel, control circuits for certain motor control, and certain emergency standby equipment and lights.

Electrical power at the VMT is provided by three 12.5-megawatt (MW) steam turbine driven generators, a 1.05-MW diesel generator, and a 1.67-MW diesel generator. The three steam turbine driven generators are the primary power sources, with the two diesel generators serving as backup. Steam for the turbine driven generators is supplied by a boiler; a separate boiler is used for each of the three units. The boilers are fired with hydrocarbon vapors supplied by the VMT vapor management systems for controlling hydrocarbon emissions from the crude oil storage tanks and the tankers; purchased diesel fuel is used to supply the remainder of the fuel requirements for these boilers. Power distribution is at the 13.8-kilovolt (kV) generation voltage. The 15-kV switchgear is divided into two busses that are connected through a normally closed tiebreaker. This electrical power system provides power to all parts of the VMT and is used for motors, heating, lighting, control, and instrumentation.

The balance of the electrical systems includes distribution equipment such as switchgears, transformers, and motor control centers. Critical to the safe operation of TAPS are the uninterrupted power supply (UPS) and battery banks that supply continuous power to communications and pipeline control systems. The control systems at the pump stations that regulate the crude oil pressures in the pipeline and operate the safety shutdown circuits are on battery backed power sources; battery backed power sources are also used on the fire protection systems.

Commercial electric power is used to operate the refrigeration units at MLR 1, 2, and 7. These three sites and some pump stations have mechanical refrigeration equipment that is used on TAPS to keep subsurface soil frozen. Each of the 62 RGV sites has a large battery bank that is capable of stroking the valve several times and maintaining communications for several days without the need for recharge. Commercial electrical power is used to charge the batteries and is the primary power source for 16 RGV sites; backup power for these sites can be provided by a small Rankine cycle turbine driven generator rated at 600 watts to charge the batteries. The other 46 sites have two of the small Rankine cycle turbine driven generators to charge batteries, provide heat, and operate control systems. Hence, there are three sources of electric power for each of the 62 RGV sites.

2.11.2 Monitoring and Maintenance Activities

Routine maintenance of the electrical system components is performed as indicated in accordance with standard industry practices. Very few changes have been made to the power supply systems at the pump stations and the VMT. The installation of the marine vapor recovery system at the VMT has provided additional fuel for generation of steam for use in the turbine driven generators at the VMT. Information on the maintenance activities for the incinerators used to provide steam for the boilers at the VMT is given in Section 2.10.2.2. A second emergency generator was installed at PS 3; the connection of the emergency generator at this pump station was changed from the primary bus to the lifeline bus. Also, the batteries at the pump stations and the 62 RGV sites were replaced with new batteries from 1995 through 1999.

In the early 1990s, a number of concerns were raised regarding the electrical systems. The main issues were related to the maintenance of documentation (primarily drawings) used to operate and maintain the systems. In the past, electrical system additions and modifications were at times not well documented. Design information was difficult to locate, and drawings were often incomplete, inaccurate, and sometimes even unavailable. A number of documented OSHA and National Electrical Code (NEC) violations and alleged unsafe conditions led to a thorough inspection of OSHA requirements and resulting repair effort for the electrical systems. These included everything from inadequate conduit and cable tray supports to unlisted electrical equipment and improperly grounded devices.

All these items were corrected or otherwise acceptably addressed in 1994 to 1996 under the AKOSH (Alaska Occupational Safety and Health)/NEC Safety Compliance (ANSC) project. The JPO provided a significant amount of oversight on this project. The ANSC project involved an extensive inspection process to identify OSHA electrical code issues in all TAPS facilities. These issues were evaluated by APSC engineering and were repaired or a waiver was obtained. When the repair involved a modification, the drawings were updated. In addition, an extensive historical database was created to document the disposition of each issue.

The electrical inspections and other audits in the early and mid-1990s also identified a number of deficiencies in the methods used to design, install, and maintain the electrical (and other) systems and their documentation. As a result, a number of one-time efforts were undertaken to determine, correct, document, or improve the condition of the electrical systems. These efforts included:

·Completion of a review, analysis, and consolidation of electrical area classifications and area classification drawings in 1995,

·Completion of an RGV cable and conduit study resulting in modifications to these systems in 1996 and 1997,

·Completion of a review of drawings to ensure that the as-built drawings were accurate. This effort identified critical drawings for the I-1 and I-2 electrical systems which were then checked to ensure their accuracy,

·Replacement of all RGV batteries, and

·Completion of a random sampling audit of electrical drawings for accuracy.

The net result of these efforts was to ensure that the electrical systems were determinate safe and accurately documented.

The design of the electrical systems for TAPS is governed by the design basis, which is given in the *Design Basis Update* (DB-180). The design basis requires the electrical systems to be designed, installed, and maintained in accordance with the NEC and OSHA regulations in place at the time of installation. Some specific requirements such as area classifications, illumination levels, and lightning protection are addressed in other industry codes and standards. Due to the remote locations of some facilities, the power supply and distribution systems have been designed with considerable excess capacity and redundancy to assure reliability of electrical power for safety of personnel as well as pipeline and terminal operations.

Over the life of the TAPS, the original design and additions to it have proven to be safe, robust, and highly reliable. An initial high level of reliability has been further increased over the years through studies, the addition of generation capacity, and proactive maintenance. Deficiencies relative to the documentation and installation of modifications made over the years were addressed and resolved in the mid-1990s. Work processes and auditing methods have been put in place to assure that the electrical systems remain safe and well documented in the future. The JPO and APSC audit and surveillance personnel continue to focus attention on this area, and as a result, the APSC has continued to improve the work processes supporting installations and documentation.

Some of the major efforts initiated to increase reliability include the following:

·A risk assessment was performed following a generator fire at PS 1 in the mid-1980s. This risk assessment lead to extensive modifications to the generating system,

·A reserve power study was completed for PS 3 and 4,

·A complete VMT electrical system study was conducted in the early 1990s as a result of a power outage that occurred at the VMT, and

·A line-wide power load study was conducted in 1984.

In conjunction with the efforts noted above, systems and processes have been put in place to assure that the electrical systems remain determinate, safe, and properly documented in the future. These efforts include:

·Quality Program: The APSC has implemented a comprehensive quality program governed by the requirements identified in the *Quality Program Manual* (QA-36).

·Preventive Maintenance: Preventive maintenance programs for critical equipment such as generators, switchgear, breakers, batteries, UPS systems, and motors have been in place for years. The results from these programs undergo continuous review to determine trends from which the performance of electrical equipment can be continually improved.

·As-Built Maintenance Process: The APSC *As-Built Maintenance Process* (EP-004) contains procedures to assure accurate and timely incorporation of as-built conditions onto critical electrical drawings.

·Engineering Manual: The APSC *TAPS Engineering Manual* (PM-2001) governs the process for designing, installing, and documenting modifications to facilities, including a management change process for critical systems.

· Electrical Standards: The APSC has developed a series of standards and specifications for electrical components and systems. These standards are periodically reviewed and updated.

·Staffing: Electrical designers and engineers are now assigned to field locations, Alaska state certificates of fitness are required for personnel performing electrical work, and verification of these certificates is done annually.

2.11.3 Summary Statement of Condition

The TAPS electrical systems are in good operating condition and are monitored and maintained to ensure their reliability. Electrical equipment is replaced and upgraded as appropriate to maintain operability of the pipeline. Documentation has been updated to reflect as-built conditions. The equipment and systems are installed consistent with NEC and OSHA requirements and can continue to support operations of the pipeline for the foreseeable future.

Chapter 3

Conclusions

The TAPS is in overall good condition. This is a result of a combination of the procedures and materials used to design and construct the pipeline, and the ongoing monitoring and maintenance program. The JPO and APSC have worked in a cooperative manner to ensure the integrity of the pipeline. Various components have been upgraded and replaced to either take advantage of new technology or to replace worn or damaged components. Major activities include the replacement of 24 VSMs (18 at Squirrel Creek [MP 717] and 6 south of PS 12 [MP 735]), five pipeline valves (3 RGVs and 2 CKVs), two sections of belowground pipe (near Atigun Pass in the Brooks Range and near the Dietrich River), and the floors of five pump station tanks and 14 VMT crude oil storage tanks. Other activities include the upgrading of computers and communications systems, maintenance of the soil cover over the fuel gas pipeline, and correction of slope stability problems. There are numerous additional maintenance and upgrade activities that are addressed in this report. These are in addition to the routine maintenance activities that are common to all engineered facilities.

The pipeline has a high degree of operational flexibility and can accommodate a wide array of conditions. The changes made to pipeline operations to address pipe vibrations at Thompson Pass due to slackline conditions are indicative of the flexibility of this system. The APSC has been at the forefront of developing techniques for monitoring pipelines and developing procedures for corrosion control. Developing innovative approaches for addressing problems as they arise has been instrumental in the continued safe operation of the pipeline. The JPO and APSC have worked together to identify and develop procedures for implementing appropriate corrective actions.

While TAPS is more than 25 years old, it still remains a very robust system. An illustration of the durability of the pipeline is its response to the large earthquake that occurred on the Denali Fault 55 miles west of the pipeline on November 3, 2002. This

Displaced shoe from VSM near MP 588 after magnitude 7.9 earthquake on Nov. 3, 2002, approximately 45 miles north/north east of Cantwell, Alaska on the Denali Fault (photo courtesy of APSC).

earthquake measured 7.9 on the Richter scale and caused extensive damage to public roads and other facilities in the area. Although the pipeline moved an estimated seven to nine feet horizontally and two to three feet in the air during the earthquake, it was not breached and no oil was released. Automatic controls initiated shutdown activities when the earthquake struck, and APSC personnel at the OCC took manual control of the pipeline and brought TAPS to a safe shutdown condition within an hour. A number of VSMs were damaged in the area where the pipeline crosses the Denali Fault. The pipeline and valves in this area were checked and temporary repairs made to the bents; oil began flowing through the pipeline within three days. The TAPS is being evaluated for any additional structural damage and repairs will be made as appropriate.

Continued operation of TAPS is contingent on the continuation of an aggressive and thorough monitoring and maintenance program. This is especially important as the pipeline ages. The RCM strategy is currently being implemented for use on TAPS to ensure the functionality of critical systems and subsystems. There are a number of areas where the need for improvements have been identified, and enhancements and corrective measures are in progress; these include fire protection, telecommunications, and electrical systems. These areas are not independent, and problems in these systems can impact the overall functionality of other systems, e.g., electrical systems are integral to all other TAPS components. The RCM process is being used to support such evaluations and develop maintenance strategies.

In summary, the current condition of TAPS is sound. Procedures and processes are in place to identify and perform appropriate corrective actions to maintain this condition. The history of past operations has been good, and APSC has performed the necessary maintenance actions to ensure the long-term integrity of the pipeline.

Chapter 4

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