FACTS

Trans Alaska Pipeline System ‘09

Alyeska pipeline
SERVICE COMPANY

Alyeska pipeline

FACTS

Collection of facts compiled over the duration of the operation of the Trans Alaska Pipeline System, by The Alyeska Pipeline Service Company.

pipeline fast facts

Air Temperature Range Along Route: -80°F to 95°F.

Area Covered by Pipeline System: 16.3 square miles.

Diameter of Pipe: 48 inches.

Elevations, Highest:

- Atigun Pass: 4,739 feet (crest, pipeline MP 166.6).
- Isabel Pass: 3,420 feet.
- Thompson Pass: 2,812 feet.

Grade, Maximum: 145% (55°) at Thompson Pass.

Length of Line: 800.302 miles (1,288 kilometers); includes 406.56 feet added in MP 200 reroute, April 22, 1985.

Linefill Volume: 9,059,057 bbl. This number differs with the "Linefill" (9,059,622 bbl).

Mountain Ranges Crossed, North to South (three): Brooks Range, Alaska Range, Chugach Range.

Number of Gallons in a Barrel: 42.

Right-of-Way Widths:

- Federal land: 54 feet (buried pipe); 64 feet (elevated pipe).
- State land: 100 feet.
- Private land: 54 feet to 300 feet.

River and Stream Crossings: 34 major, nearly 500 others.

Valves: 178.

Vertical Support Members (VSMs): 78,000.

Workpad, Length: 790 miles.

Years Built: 1974 to 1977.

acronyms and abbreviations

API: American Petroleum Institute.

APSC: Alyeska Pipeline Service Company.

ARCS: Alternate Route Communications System.

BWT: Ballast Water Treatment.

bbl: Barrel.

CV: Check Valve.

DRA: Drag Reducing Agent.

DSMA: Digital Strong Motion Accelerograph.

dwt: Deadweight Tons.

EMS: Earthquake Monitoring System.

ETT: Enhanced Tractor Tug.

GPS: Global Positioning System.

JPO: Joint Pipeline Office.

kV: Kilovolts.

MLU: Mainline Unit.

MP: Milepost.

MTU: Master Terminal Unit.

MW: Megawatts.

PRT: Prevention/Response Tug.

PS: Pump Station.

psi: Pounds Per Square Inch.

RCAC: Regional Citizens Advisory Council.

RGV: Remote Gate Valve.

SIPPS: Safety Integrity Pressure Protection System.

SERVS: Ship Escort Response Vessel System.

SR: Strategic Recongifuration.

TAPS: Trans Alaska Pipeline System.

TG: Turbine Generator

VFD: Variable Frequency Drive.

VMT: Valdez Marine Terminal.

UPS: Uninterruptible Power Supply.

A

ABOVEGROUND PIPE: See PIPE, Aboveground.

ACCESS ROADS: 225, linking state roads with pipeline, pump stations and airfields.

- Gravel Base: 3 feet minimum.
- Length: 120 feet to 7.5 miles.
- Number of Roads: 225.
- Width: 28 feet.

AIRFIELDS, Operations: Two of the 14 airfields built during TAPS construction are still in operation: Galbraith Lake (5,200 feet long) and Prospect (5,000 feet long). These two airfields are on federal land and are operated under state leases.

ALASKA, Facts:
Coastline: 33,900 miles.
Land Area: 586,000 square miles.
Population: 679,720 (2008, Alaska Dept. of Labor).

ALYESKA, Corporate Name: Alyeska Pipeline Service Company. "Alyeska" is an Aleut word meaning "mainland."

ALYESKA, Date of Incorporation: August 14, 1970.

ALYESKA, Early History: The Trans Alaska Pipeline System, or TAPS, was originally called the Trans Alaska Pipeline Project, and was a joint venture of Atlantic Pipe Line Company (now ConocoPhillips Transportation Alaska, Inc.), Humble Pipe Line Company (now ExxonMobil Pipeline Company) and BP Oil Corporation (now BP Pipelines (Alaska) Inc., formed to develop a plan for construction of a pipeline for Prudhoe Bay oil.

ALYESKA, Internet Address: http://www.alyeska-pipe.com

ALYESKA, Office Addresses:

Anchorage Office (Corporate Headquarters):
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Anchorage, AK 99508
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Toll free: (877) 257-5778
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Fairbanks Office:
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701 Bidwell Ave.
Fairbanks, AK 99701
Toll free: (877) 257-5778
Mailing Address:
Alyeska Pipeline Service Company
P.O. Box 60469
Fairbanks, AK 99706

SERVS Office:

Mailing Address:
Alyeska Pipeline Service Company
SERVS (Ship Escort Response Vessel System)
P.O. Box 109
Valdez, AK 99686
Toll free: (877) 257-5778

Valdez Marine Terminal Office:

Mailing Address:
Alyeska Pipeline Service Company
P.O. Box 300
Valdez, AK 99686
Toll free: (877) 257-5778

Washington, D.C. Office:

Alyeska Pipeline Service Company
1667 K St., NW, Suite 430
Washington, DC 20006
(202) 466-3866

ALYESKA, Owners: The consortium of companies that owns TAPS today. This includes:

BP Pipelines (Alaska) Inc.	46.93%
ConocoPhillips Transportation Alaska, Inc.	28.29%
ExxonMobil Pipeline Company	20.34%
Koch Alaska Pipeline Company, L.L.C.	3.08%
Unocal Pipeline Company	1.36%

ALYESKA, Personnel: Approximately 2,000 Alyeska employees and contractors operate and maintain the Trans Alaska Pipeline System. Total Alyeska employees and contractors as of January 2009 are: Total direct Alyeska employees: Approximately 810 (The number of personnel working at pump stations varies throughout the year and is captured in the statistics for Anchorage, Fairbanks or Valdez).

- Anchorage: 268
- Fairbanks: 267
- Valdez: 275
- Alaska residents: 97%, approximately.

Approximately 1,200 contractors work on TAPS.

ALYESKA, Responsibilities: Design, construct, operate and maintain the Trans Alaska Pipeline System.

ALYESKA TACTICAL OIL SPILL MODEL (ATOM): Software package specifically designed for oil spill trajectory modeling in Prince William Sound. ATOM is used to:

- Forecast path of oil, based on real weather input.
- Show wildlife impact potential and other sensitivities such as recreational sites, commercial fishing areas and shoreline types.
- Show locations of Prince William Sound communities and hatcheries.

ANIMAL CROSSINGS, Mainline: The purpose is to allow for free movement of big game animals (caribou, moose, etc.) across the pipeline right-of-way. Approximately 579 animal crossings are incorporated into TAPS, including:

ANIMAL CROSSINGS, Elevated: 554 (minimum height 10

feet).

ANIMAL CROSSINGS, Buried: 23.

ANIMAL CROSSINGS, Buried, Refrigerated: Two (MP 645 and MP 649).

ARCHAEOLOGICAL SURVEY, Preconstruction: The entire TAPS route was surveyed by the University of Alaska and Alaska Methodist University under contract to Alyeska. The survey, which cost approximately $2.2 million, resulted in the excavation of approximately 330 sites.

ARCS (Alternate Route Communications System): A private radio network used by TAPS technicians for voice communications in remote locations.

ATOM (Alyeska Tactical Oil Spill Model): See ALYESKA TACTICAL OIL SPILL MODEL.

B

BALLAST WATER TREATMENT (BWT):

The Valdez Terminal treats tanker ballast water to remove oil.

- Average ballast water treated: 55,000 bbl/day.
- Capacity of System: 14,000 bbl/hour.
- Crude oil recovered from ballast: 300 bbl/day average.
- Purity standards: 1.0 parts per million aromatic hydrocarbons (daily maximum).

BALLAST WATER TREATMENT (BWT) FACILITY: Major Components:

- Biological Treatment Tanks: One aboveground concrete tank with a capacity of 5.5 million gallons.
- Diffuser Line at Discharge into Port Valdez: The line discharges at a maximum depth of 300 feet at a distance of 700 to 1,050 feet offshore.
- Dissolved Air Flotation (DAF) Units: Three cells, each 144 feet long, 24 feet wide and 12 feet deep.
- Piping from Berths to Tanks: 42-inch diameter.
- Time Required for Treatment: 24 hours average.
- Settling Tanks: Two tanks with capacity of 430,000 bbl each, 53 feet 6 inches high and 250 feet in diameter.
- BETX Air Strippers: Four with a capacity of 1,100 gpm (gallons per minute) each.

- Regenerative Thermal Oxidizers: Two with a capacity of 10,000 cfm (cubic feet per minute) each.

BARREL, Crude Oil: The normal unit of measurement for crude oil: 1 bbl = 42 gallons; 310.9 pounds per bbl.

BELOWGROUND PIPE: See PIPE, Belowground.

BIRD SPECIES: More than 170 identified along the TAPS route.

BRIDGE, Yukon River: Located at MP 353.3.
- Construction Dates: 1974-1975.
- Cost: $30 million (Owners' share approximately $10 million).
- Dimenions: 2,295 feet long; road deck 30 feet wide; grade 5.99°.
- Name: Bridge officially named "E.L. Patton Yukon River Bridge" by Alaska Legislature in 1982, after E.L. Patton, President of Alyeska during pipeline construction. A monument to E.L. Patton was dedicated in October 1982.
- Opening Date: October 1979.
- River Width: 1,900 feet, typical.

BRIDGES, Pipeline: 13 total along TAPS.

BRIDGES, Road: 21 north of Yukon; 23 south of Yukon.

C

CARIBOU: TAPS crosses the ranges of the Central Arctic Herd on the North Slope and the Nelchina Herd in the Copper River Basin.

COLUMBIA GLACIER: Tidewater glacier in the northeast corner of Prince William Sound, at the head of Columbia Bay.
- Calving Rate: 13 million tons/day, approximately.
- Distance from Tanker Lanes: 8 to 9 miles.
- Height: Approximately 0 to 150 feet above sea level, at terminus.
- Impact on Tankers: When the captain of the port determines hazardous ice conditions exist in Valdez Arm, the Valdez Narrows ice routing measures are placed into effect in accordance with the Prince William Sound Vessel Escort Response Plan.
- Largest Icebergs Produced: 30 feet high, 300 feet in diameter, approximately.
- Length: 35 miles, approximately.
- Water Depth at Face: 0 to 1,000 feet, approximately.
- Width: 3 miles, approximately, at terminus.

COMMUNICATIONS, (ARCS): See ARCS.

COMMUNICATIONS SYSTEM: The primary communications system uses microwave, which is backed up by satellite.

COMMUNICATIONS SYSTEM, Central: Backbone communication system, remote gate valve, ARCS (Alternate Route Communication System). Control systems are provided for supervisory control and telemetering, seismic monitoring, and monitoring and control of remote gate valves.

COMMUNICATIONS SYSTEM, Enterprise Data Services: Voice, data, video, cable TV Enterprise data services are provided for business systems. The primary data system uses fiber optics, which is backed up by satellite.

CONCRETE WEIGHTS:
- Pipe coating: Used at river crossings; weight 75,000 pounds per 40-foot section.
- Saddles: Used in floodplains; weight 18,500 pounds each.

CONSTRUCTION, Airfields:
- Seven, 2,500 to 3,000 feet long.
- Seven, 5,000 feet long (Galbraith Lake and Prospect continue to be used for TAPS purposes).

CONSTRUCTION, Camps:
- Largest Camp: Valdez Marine Terminal, 3,480 beds.
- Largest Pipeline Camp: Isabel Pass, 1,652 beds
- Number, 1974 to 1977: 29 total.
- Smallest Pipeline Camp: Sourdough, 112 beds.

CONSTRUCTION, Contractors and Subcontractors: 2,000, approximately.

CONSTRUCTION, Cost: Approximately $8 billion for construction of entire system, including Valdez Terminal and pump stations, at conclusion of initial construction period in 1977. Does not include interest on capital investment or capital construction after 1977.

CONSTRUCTION, Ditch: See DITCH, Buried Pipeline.

CONSTRUCTION, Fatalities: See FATALITIES, Construction.

CONSTRUCTION, Hydrostatic Testing:
- Maximum, equivalent to 96% of specified minimum yield strength.
- Minimum, 125% of operating pressure or 750 psi, whichever was greater.

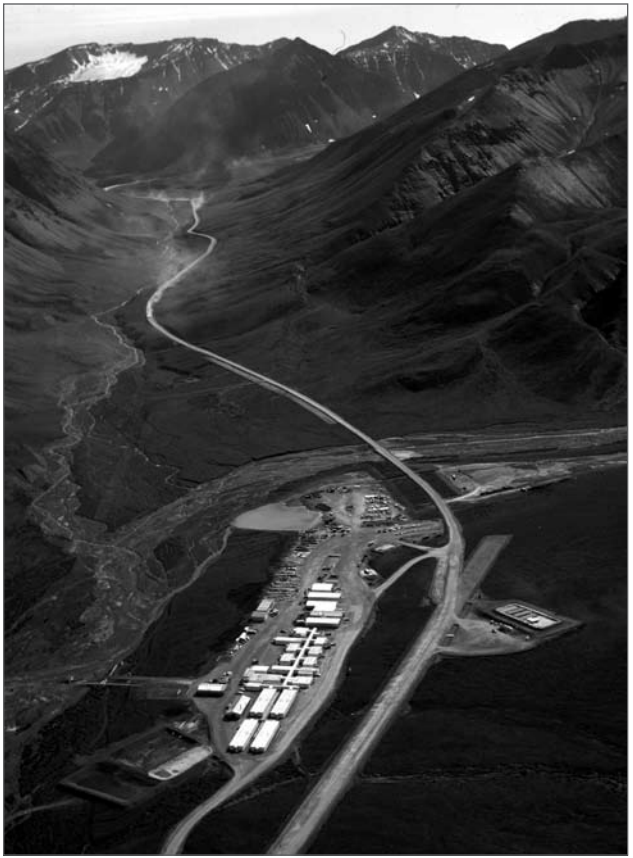
CONSTRUCTION, Materials:
- Gravel for Entire Project: 73 million cubic yards.
- Gravel for Workpad: 32 million cubic yards.
- Largest Piece Shipped: Floating tanker berth (3,250 tons).
- Shipped to Alaska: 3 million tons, approximately.

CONSTRUCTION, Notices to Proceed: See NOTICES TO PROCEED, Construction.

CONSTRUCTION, Permits: See PERMITS, Construction.

CONSTRUCTION, Time: 3 years, 2 months (April 29, 1974, to June 20, 1977) to complete pipeline, pump stations, roads and Terminal.

CONSTRUCTION, Time for Preconstruction Effort: Six years, approximately.



Atigun Construction Camp was one of 30 camps operating during pipeline construction. The buildings were removed and the site was revegetated in 1978.

CONSTRUCTION, Welding: See WELDS, Pipe.

CONSTRUCTION, Workforce:

- Minority Hire: Ranged from 14% to 19%.
- Peak, Contractors Only: 21,600.
- Peak, Total: 28,072 in October 1975 (Alyeska employees and contractors).
- Total for Project: 70,000 approximately (1969-1977).
- Women: Ranged from 5% to 10%.

CROSSINGS, Animal: See ANIMAL CROSSINGS.

CROSSINGS, Refrigerated, Road: The buried pipeline crossing of the Glenn Highway at Glennallen is refrigerated.

CRUDE OIL: A fluid made up of various hydrocarbon components, natural gas liquids and fixed gases.

CRUDE OIL, API Gravity: 33.4° API at 60°F for North Slope crude oil.

CRUDE OIL, TAPS:

- Temperature in 2008: 110°F at injection into pipeline at PS 1. Approximately 55.6°F at Valdez Terminal.
- Throughput (2008 average): 703,551 bbl/day = 29,315 bbl/hour = 20,520 gallons/minute.
- Travel Time in 2008: 12.9 days from PS 1 to Valdez Terminal.
- Velocity: 2.6 mph in pipeline.
- Weight: 300.5 pounds/bbl; 6.66 bbl/ton.

D

DALTON HIGHWAY (Formerly North Slope Haul Road): James B. Dalton Highway is the name applied by the state in 1981 to 415 miles of roadway, including the North Slope Haul Road and the 57-mile road from the Yukon River to Livengood, constructed by Alyeska in the winter of 1969-70 (this section of road was originally 56 miles, but one mile was added after realignment by the state at Livengood in 1981). James B. Dalton was a native-born Alaskan and graduate mining engineer who supervised construction of the Distant Early Warning (DEW) Line in Alaska. He was an expert in Arctic engineering and logistics and served as a consultant in early oil exploration in northern Alaska, pioneering winter trails for heavy equipment transport. The following information about the highway is current as of construction:

- Bridges, Permanent: 20.
- Grade: 12% maximum.
- Gravel Used: 32 million cubic yards.

DALTON HIGHWAY, Haul Road Portion: See HAUL ROAD.

DALTON HIGHWAY, Ownership: Originally Alyeska; control transferred to the state in October 1978.

DEADWEIGHT TONS (dwt): A unit of measure for the weight of tanker cargo; dwt x 7 = number of barrels, approximately.

DESIGN MODES, Selection: Soil sampling and other means were used to determine soil types along the route. Where thaw-stable soils were found, the pipeline was buried in the conventional manner. In areas of thaw-unstable soils, and where heat from the pipeline might cause thawing and consequent loss of soil foundation stability, the pipeline was insulated and elevated aboveground by means of a unique support system (see VERTICAL SUPPORT MEMBERS). To allow animals to cross, 23 sections were buried line-wide, each about 200 feet long.

DESIGN MODES, Types:

- Aboveground: 420 miles (see VERTICAL SUPPORT MEMBERS). Where thaw-unstable permafrost was encountered, problems associated with melting permafrost were avoided by placing the pipeline aboveground on an elevated support system. VSMs (pilings) were designed to resist frost-jacking forces and support the line.
- Belowground (Conventional): 376 miles. Where either unfrozen or thaw-stable permafrost was encountered, the pipeline was buried in the conventional manner with no special provisions for permafrost (see PIPE, Belowground (Conventional).
- Belowground (Special Burial): About four miles (see PIPE, Special Burial). Where thaw-unstable permafrost was found, but where the pipeline had to be buried for highway, animal crossing, or avoidance of rockslides and avalanches, the permafrost was protected from the heat of the pipeline by insulation around the pipeline.

Some special burials include ground refrigeration systems along with pipe insulations. Special burial locations:

- Atigun Pass: Two sections (about one mile) were buried in insulated boxes to provide protection from rockslides and avalanches.
- MP 645-649: Caribou crossing.
- MP 653: Caribou crossing.
- MP 681: Crossing of Glenn Highway.
- 23 Animal Crossings (All animal crossings are special burial).

DISCHARGE PRESSURE: Pressure of the oil leaving a pump station.

DITCH, Buried Pipeline: Eight feet wide, eight feet deep, approximately, but variable for overburden depth, which ranged from three to 35 feet.

DRAG REDUCING AGENT (DRA): A long-chain hydrocarbon polymer injected into the oil to reduce the friction due to turbulence in the oil.

DIGITAL STRONG MOTION ACCELEROGRAPH (DSMA): Field instrument to evaluate pipeline motion caused by earthquakes. (See EARTHQUAKE, DSMAs). Pipe is wrapped before being placed in the trench during construction.

E

EARTHQUAKE, Denali Fault, Nov. 3, 2002: The pipeline withstood a magnitude 7.9 earthquake that was centered along the Denali Fault in Interior Alaska, approximately 50 miles west of the pipeline. The ground along the fault moved an estimated 18 feet horizontally and nearly 2.5 feet vertically. The quake was the largest on the Denali Fault since at least 1912 and among the strongest earthquakes recorded in North America in the last 100 years.

EARTHQUAKE, Design Magnitude: The pipeline is designed to withstand a maximum 8.5 Richter Scale earthquake at the Denali Fault. The range is 5.5 to 8.5, depending on area. The seismic design of TAPS includes two levels of earthquake hazards: the design contingency earthquakes (DCE) and the design operating earthquakes (DOE). The DCE corresponds to the design earthquake magnitude and may interrupt operations but not compromise the pipe. The DOE is a lower-intensity earthquake that has ground motion amplitudes one-half those of a DCE. Operations should be able to continue following a DCE.

EARTHQUAKE, Design Movement: Maximum movement of pipe at pipeline crossing of major faults:

- Denali Fault: 20 feet lateral, five feet vertical.
- McGinnis Glacier Fault: Eight feet lateral, six feet vertical.

- Donnelly Dome Fault: Three feet lateral, 10 feet vertical.
- Minor Potential Faults: Two feet lateral, two feet vertical.

EARTHQUAKE, DSMAs: The instrumentation at field locations consists of accelerometers mounted on concrete pads which measure strong ground motions in three directions (tri-axial) and are connected to a digital strong motion accelerograph (DSMA). The DSMA, generally located in the pump station control room, processes the signals from the accelerometers in real time and reports alarms and selected data to the central processor at the Operations Control Center (OCC).

EARTHQUAKE, Faults Crossed by Pipeline: Denali, McGinnis Glacier and Donnelly Dome.

EARTHQUAKE, Monitoring System (EMS): Alyeska's EMS consists of sensing and processing instruments at Pump Station 1, at all pump stations south of Atigun Pass and at the Valdez Terminal. A central processing unit at the Operations Control Center is linked to the pipeline and terminal operator consoles. The EMS is specifically designed to process strong ground motions, to interpolate or extrapolate estimates of earthquake accelerations between the sensing instruments, and to prepare a mile-by-mile report comparing the estimated accelerations along the pipeline with the pipeline seismic design criteria. Field instrumentation consists of DSMAs (see EARTHQUAKE, DSMA).

EARTHQUAKE, Lateral Movement for Aboveground Pipeline: Two feet maximum (predicted).

ENHANCED TRACTOR TUGS (ETT): Nanuq and Tan'erliq (Alaska Native words for "polar bear" and "black bear"). Designed for tethered tanker escort and oil spill response operations. The 153-foot vessels enhance SERVS' ability to assist a disabled tanker. The state-of-the-art vessels have exceptional maneuverability and were deployed in 1999.

- Crew: Seven trained response personnel.
- Firefighting: ABS Class 1 firefighting rating that includes pumps, monitors, foam and vessel spray system.
- Propulsion: Voith Schneider system; 10,192 hp.
- Spill Response Equipment:
  - 3,300 feet of oil containment boom.
  - DESMI skimmers.
  - 70,000 gallons of recovered oil storage capacity.
  - Dispersant spray arm systems.

The *Tan'erliq* (far right), one of two enhanced tractor tugs at the Valdez Terminal.

F

FATALITIES, Construction: 32 incidents directly related to construction (includes employees of Alyeska, contractors and subcontractors; excludes common carriers) Note: there have been no fatalities associated with the SR project (see STRATEGIC RECONFIGURATION).

FATALITIES, Operations: Ten operations-related incidents (includes employees of Alyeska, contractors and subcontractors):

- 1977: PS 8 explosion.
- 1978: PS 8 snow-clearing accident.
- 1984: Valdez Terminal heavy equipment accident.
- 1985: Charter aircraft accident, Glennallen.
- 1987: Security helicopter accident, Keystone Canyon.
- 1997: Vehicle accident, Haul Road.
- 2000: Vehicle accident, Valdez Terminal.
- 2006: Tug operations accident, SERVS.

FAULT: See EARTHQUAKES, Faults.

FIRE SYSTEMS, Pump Stations: See PUMP STATIONS, Fire Systems.

FISH, Species: 34 identified in waters crossed by the pipeline.

FUEL GAS LINE: Carries natural gas from North Slope fields to fuel pump stations north of the Brooks Range. Generally parallels mainline crude oil pipeline, from Prudhoe Bay to PS 4. (Stations south of the Brooks Range are fueled by liquid turbine fuel.)

- Compressors: Two 1,200-hp gas turbine compressors at PS 1 boost gas pressure from approximately 600 psi to 1,100 psi.
- Diameter: 10 inches from PS 1 to MP 34 (34 miles); eight inches from MP 34 to PS 4 (115 miles).
- Gas temperature: 30°F, maximum (leaving PS 1).
- Length: 149 miles.
- Pig Launching/Receiving Facilities: PS 1, MP 34 and PS 4.
- Pressure: Design: 1,335 psi. Operating: 1,090 psi maximum currently.

FUEL, Required for All TAPS Operations 2008:

- Electricity at PS9: 83.7 mmmillion KWHRs.
- Fuel: 10.4 mmmillion gallons.
- Estimated Natural Gas Usage: 4.8 million MCF.

G

GABIONS AND CONCRETE MATS: Used in Atigun Floodplain Pipe Replacement Project as cover on pipe in shallow burial area for protection from natural erosion and scouring. A gabion is a metal cage filled with rock; gabions are used to stabilize banks.

- Gabions: 31,750 feet.
- Concrete Mats: 9,525 feet.

GLENNALLEN: Town near south junction of Glenn and Richardson Highways.

- Population: 514 (2007, Alaska Dept. of Labor).
- Precipitation, Annual Average: Nine inches.
- Snowfall, Annual Average: 39 inches.
- Temperature Range, Average: -10°F to 56°F.

GRADE, Maximum on TAPS Route: 145% (55°) at Thompson Pass.

H

HAUL ROAD: Portion of Dalton Highway from the Yukon River to Prudhoe Bay. Built by Alyeska.

- Cost: $125 million, approximately.
- Dates: Started April 29, 1974; completed and dedicated September 29, 1974.
- Labor: 3 million hours.
- Time: 154 days.
- Length: 358 miles (Yukon River to Prudhoe Bay)

HEAT PIPES: These self-contained passive refrigeration devices contain anhydrous ammonia or carbon dioxide gas under pressure which vaporize at temperatures just below freezing, rise and condense at radiators aboveground when the air temperature is well below freezing. This process transfers ground heat into the air during cold periods, thereby lowering the ground temperature to ensure thaw unstable soils remain frozen throughout the summer to steadily support the pipeline. There are 124,300 individual heat pipes along the pipeline (see VERTICAL SUPPORT MEMBERS).

INSULATION, Thickness:

- Elevated Pipeline: 3.75 inches thick.
- Refrigerated Belowground Pipeline: 3.2 inches thick.
- Under Gravel Workpad or Road: Two to four inches.

INTEGRITY MANAGEMENT PLAN (IMP): Integrity management comprises all activities that monitor and maintain the integrity of all hydrocarbon handling facilities on TAPS. The purpose of IMP is to protect the environment by preventing oil spills, comply with all laws and regulations, maintain facilities within industry standards, and monitor and mitigate integrity risks.

JOINT PIPELINE OFFICE (JPO): Joint federal and state office set up with representatives of various agencies with responsibility for monitoring TAPS.

LAND, Municipal Jurisdiction: Approximate pipeline length in each jurisdiction, north to south:

- North Slope Borough: 179.2 miles.
- Fairbanks North Slope Borough: 89.1 miles.
- City of Delta Junction: 5.5 miles.
- City of Valdez: 20.8 miles.

LAND OWNERSHIP, Area: Approximate area for all of TAPS (18.4 square miles total):

- State Government: 7.79 square miles.
- Federal Government: 6.27 square miles.
- Owner Companies: 2.9 square miles.
- Private: 1.41 square miles.

LAND OWNERSHIP, Owner: Approximate pipeline length for each ownership category (800 miles total):

- Federal Government: 376 miles.
- State Government: 344 miles.
- Private: 80 miles (including 51 miles on Alaska Native Corporation land).

LEAK DETECTION SYSTEM: Provides detection and location of oil spills. TAPS has three independent systems:

- Line Volume Balance (LVB), which compares the volume of oil entering the line with the volume leaving it.
- Transient Volume Balance (TVB), which compares reported flow with calculated flow and can identify the probable location of a leak by pipeline section.
- Alarms which signal deviations in pressure, flow or flow rate balance.

LINEFILL: The oil necessary to fill the pipeline to start the pumps in a mechanically sound manner. At a throughput of 0.935 million bbl per day, the linefill volume is 9,059,622 bbl.

LIVING QUARTERS: See PUMP STATIONS, Living Quarters.

M

MAXIMUM ALLOWABLE OPERATING PRESSURE: A rating indicating the maximum pressure at which a pipeline or segment of a pipeline may be operated under U.S. Department of Transportation regulations in normal conditions. Also called "pressure rating."

MOUNTAIN RANGES, Crossed by Pipeline: Brooks Range, Alaska Range and Chugach Range.

MUTUAL AID AGREEMENTS: See OIL SPILL RESPONSE, Mutual Aid Agreements.

N

NORTH SLOPE, Environment: A nearly flat, treeless plain, covering about 88,000 square miles extending from the foothills of the Brooks Mountain Range to the Arctic Ocean. For 56 days in winter, the sun never rises. Winter twilight provides sufficient light for driving without headlights during the day. Winter temperatures drop to -60°F. Wind chill factor may fall as low as -135°F. From mid-April to mid-August, there is daylight 24 hours a day. Summer temperatures climb to 70°F and higher.

NORTH SLOPE, Oil Discovery: Exploratory drilling on the North Slope continued for more than 20 years. Many unsuccessful exploratory wells were drilled and many companies gave up the search before the Prudhoe Bay Discovery Well was drilled by Atlantic Richfield Company and Humble Oil and Refining Company in 1967. A confirmation well the following year proved the discovery of the large oil and gas reservoir.

NORTH SLOPE, Oil Production Received at PS 1:

- 2006 Total: 277.06 million bbl.
- 2007 Total: 270.16 million bbl.
- 2008 Total: 257.50 million bbl.
- Cumulative Total, 1977 through 2008: 15.2 billion bbl.

NOTICES TO PROCEED, Construction: 465 federal and 403

state notices to proceed were required from the Federal Alaska Pipeline Office and the State Pipeline Coordinator's Office.

OIL SPILL CONTINGENCY PLAN, Pipeline: Trans Alaska Pipeline System Pipeline Oil Discharge Prevention and Contingency Plan:

- Containment Sites: 223 designated sites on or near drainages along TAPS. Criteria for selection: accessibility, river velocity, river channel configuration, environmental sensitivity. Equipment stored at containment sites varies per site and includes oil spill equipment, concrete anchors, and/or dam kits.
- Equipment: Varies by response facility. Total inventory available includes the following:
  - Vessels (jet boats, airboats, rafts, landing craft): 35
  - Boom, Containment: 48,500 feet.
  - Boom, Fire: 2,150 feet.
  - Vacuum Trucks: 11.
- Leak Detection: Four systems (see LEAK DETECTION SYSTEMS).
- Personnel:
  - Pipeline personnel trained in oil spill response. Each response facility has 24-hour oil spill response capabilities.
  - Drills: Field drills are conducted to evaluate preparedness to react to an oil spill. The drills permit evaluation of the training program,

particularly oil spill skills such as reconnaissance, assessment and response.
- Training: Training consists of a five-day academy for new employees and a two-day refresher for existing employees.

OIL SPILL CONTINGENCY PLAN, Tankers: Tankers transiting Prince William Sound are required by the state to have oil spill contingency plans. The Prince William Sound Tanker Oil Discharge Prevention and Contingency Plan is a required part of each tanker's individual contingency plan. Alyeska Pipeline/SERVS is the primary response action contractor responsible for the implementation aspects of the tanker plan. The prevention portion of this plan requires that each laden tanker transiting Prince William Sound must be escorted by two vessels, one of which must be a specially equipped prevention and response vessel or tug. Laden tankers are tethered to escort tugs from the Terminal through the Valdez Narrows and Valdez Arm. Also included in the plan are speed limits for tankers and weather restrictions. The response portion of the plan includes plans for open-water and nearshore shoreline response and support operations.

OIL SPILL CONTINGENCY PLAN, Terminal: The Valdez Marine Terminal Oil Discharge Prevention and Contingency Plan includes a comprehensive prevention plan outlining spill prevention measures taken at the Terminal, as well as a response section describing land and water response for spills originating from Terminal facilities. A spill from a tanker at berth or transiting Port Valdez is covered under the Prince William Sound Tanker Oil Discharge Prevention and Response Plan. Although a spill from a tanker is the responsibility of the tanker owner, Alyeska provides initial spill response.

- Personnel: Oil spill response crews trained to conduct land and water response operations are available 24 hours/day.
- Equipment: The following equipment is stored in Valdez:
  - Barges: Eight barges (900,000 bbl, approximately, for recovered oil) and one flat-deck barge with sensitive-area protection boom (serves as on-water staging location).
  - Boom: 49.7 miles of various types of containment and recovery boom.
  - Skimmers, Portable: Six barge-mounted; three vacuum skimmers; 24 weir/disc skimmers.
  - Skimmers, Self-Propelled: Four total: JBF 6001 (Valdez Star) with recovery rate of 2,000 bbl/ hour and storage of 1,310 bbl; JBF 3003 (two units) with recovery rate of 571 bbl/hour; and MARCO Class VII with recovery rate of 1,281 bbl/hour.
  - Tugs: Eleven.
  - Vacuum Trucks: Three.
  - Work Boats: 10.
- Prevention programs:
  - Corrosion control programs.
  - Inspection and records.
  - Medical monitoring.
  - Preventive maintenance.
  - Security.

– Substance abuse programs.
– Tank leak protection.
– Training programs.
– Transfer procedures.

OIL SPILL RESPONSE, Mutual Aid Agreements: An official agreement to provide equipment and resources for oil spill response to entities outside of Alyeska such as the United States Coast Guard.

OPERATIONAL INTEGRITY: An Alyeska program designed to assure the integrity of the pipeline system is maintained while attaining the highest standards of safety and environmental protection.

OPERATIONS CONTROL CENTER (OCC): The OCC continually monitors the status of all pump stations and valves using supervisory control and data acquisition (SCADA) systems with remote sensors. Data such as pressures, flow rates, temperatures, tank levels and valve positions are recorded and analyzed for abnormal operations or any indication of a pipeline leak. The pipeline controller at the OCC can rectify any abnormal operation by changing settings for pump speed or relief valves, or by issuing idle or stop commands to the mainline pumps. The OCC controller can also activate remote control valves. The monitoring and analysis systems include backup communications equipment and computers.

P

PACKLINE: Oil flow that completely fills a pipeline.

PERMAFROST: Any rock or soil material that has remained below 32°F continuously for two or more years. The two-year minimum stipulation is meant to exclude from the definition the overlying ground surface layer which freezes every winter and thaws every summer (called the "active layer" or "seasonal frost").

PERMAFROST, Affected Areas on TAPS: Approximately 75% of the line passes through permafrost terrain. The line traverses the continuous zone on the North Slope and through the Brooks Range. It then encounters the discontinuous and sporadic zones and passes through areas of no permafrost in the immediate vicinity of Valdez.

PERMAFROST, Depth Along Pipeline Route: A few inches to 2,230 feet, approximately.

PERMAFROST, Design Solutions: The pipeline design is based primarily on the soil conditions encountered along the right-of-way. There are three principal design modes: aboveground, conventional burial and special burial (see DESIGN MODES).

PERMAFROST, Problems:
- Frost-heaving: When the active layer freezes, ice forms

and pushes the ground surface upward.

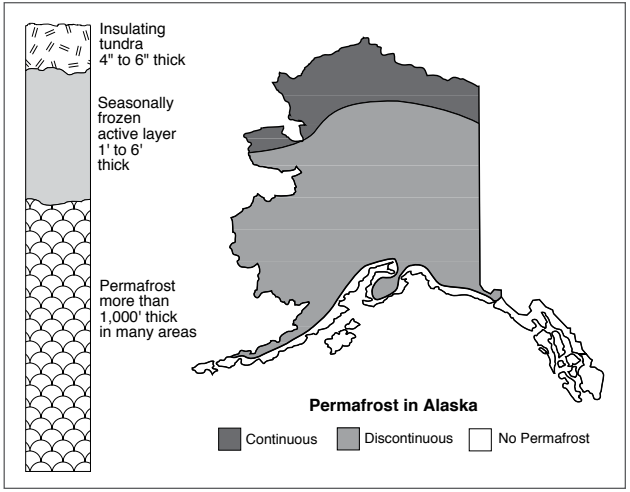
- Frost-jacking: When heaving occurs, if a structure embedded in the ground is not properly anchored to resist such movement, the structure will be forced upward along with the ground surface. In most cases, the structure does not return to its original position when the active layer thaws during the following summer. The net upward movement is called "jacking." This phenomenon can occur whenever there is seasonal freezing and thawing of the active layer and is not limited to permafrost areas. Thaw settlement: Structures founded on "thaw-unstable" permafrost may settle if large amounts of ice in the permafrost melt. Melting is typically caused by heat from the structure or changes to the natural thermal conditions.

PERMAFROST, Types:

- Cold Permafrost: Remains below 30°F (may be as low as 10°F as on the North Slope); tolerates introduction of considerable heat without thawing.
- Ice-Rich: 20% to 50% visible ice.
- Thaw-Stable: Permafrost in bedrock, in well-drained, coarse-grained sediments such as glacial outwash gravel and in many sand and gravel mixtures. Subsidence or settlement when thawed is minor, foundation remains essentially sound.
- Thaw-Unstable: Poorly drained, fine-grained soils, especially silts and clays. Such soils generally contain large amounts of ice. The result of thawing can be loss of strength, excessive settlement and so much moisture in the soil that it flows.
- Warm Permafrost: Remains just below 32°F. The addition of very little additional heat may induce thawing.

PERMAFROST, Zones:

- Continuous Zone: Permafrost is found almost everywhere in the zone, as the name implies; includes all of the North Slope.
- Discontinuous Zone: Permafrost is found intermittently; includes much of the interior of the state.
- Sporadic Zone: Permafrost is found in isolated small masses of permanently frozen ground.



PERMANENT LIVING QUARTERS: See PUMP STATIONS, Living Quarters.

PERMITS, Construction: 515 federal and 832 state permits were required to build TAPS.

PIG: A mechanical device which is pushed through the pipeline by the oil. Consists of cone-shaped polyurethane cups on a central body which matches the shape of the interior pipe wall. Bumper nose, urethane construction and light weight prevent damage to check valve clappers. Several types of pigs are used to improve flow characteristics, inspect for dents and wrinkles, inspect for pipeline corrosion and measure pipeline curvature.

- Batching: Used during initial linefill.
- Corrosion: A pig which detects corrosion or pitting in the pipe wall. These pigs may use different technologies to collect and record corrosion data. First run in 1978.
- Magnetic: Detects metal loss in pipe wall by measuring disturbances in a magnetic field. First run in 1978.
- Ultrasonic: Measures and records wall thickness of pipeline using ultrasonic transducers. First run in June 1989.
- Curvature: A pig using an inertial navigation system to determine pipeline location, curvature and pipe wall deformation. First run in 1992.
- Deformation: A pig which measures the diameter of the pipe. Defines changes in pipe diameter caused by dents, ovalities, or pipe bending. Changes are recorded and analyzed by engineers. First run in 1979.
- Scraper: A pig used for cleaning and flow enhancement. First run in 1977.

PIG, Launching/Receiving Facilities: PS 1 (launch only), PS 4 (launch and receive), PS 8 (contingency launch only for smart pigs), and Valdez Terminal (receive only).

PIG, Frequency: Smart pigs are run every three years. Scraper pigs are run every 7-14 days. Changes to this schedule are made based on operational needs.

PIPE: The pipe for TAPS was manufactured in Japan (Italy for Atigun floodplain pipe replacement project).

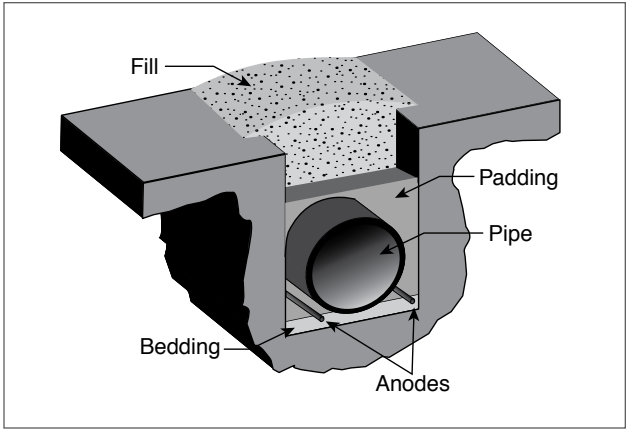
- Diameter, Outside: 48 inches (122 cm).
- Lengths, Standard: 40 feet and 60 feet.
- Pieces Required for Pipeline: Over 100,000.
- Tested To: Maximum axial force of 2.52 million pounds

TAPS employee cleans a scraper pig at the Valdez Marine Terminal. Scraper pigs, which clean the pipeline and enhance oil flow, are pushed by the oil.

and lateral deflection force of 459,000 pounds before wrinkling (typical test sample: 31 feet 5 inches).
- Thickness, Wall: 0.462 inches (466 miles) and 0.562 inches (334 miles).
- Total Shipped: 550,000 tons, approximately. 120 shiploads for original construction; Six for Atigun Floodplain Pipe Replacement Project.
- Volumetric Displacement: 11,366 bbl/mile (0.462-inch thickness); 11,270 bbl/mile (0.562-inch thickness).
- Weight: 235 pounds/linear foot (0.462-inch thickness); 285 pounds/linear foot (0.562-inch thickness).

PIPE, Aboveground: Specially designed vertical supports were placed in drilled holes or driven into the ground. In warm permafrost (see PERMAFROST) and other areas where heat might cause undesirable thawing, the supports contain two, two-inch diameter pipes called "heat pipes," containing anhydrous ammonia, which vaporizes belowground, and rises and condenses aboveground, removing ground heat whenever the air temperature is 5° to 10°F cooler than the ground temperature at the base of the heat pipe. Heat is transferred through the walls of the heat pipes to aluminum radiators atop the pipes (see VERTICAL SUPPORT MEMBERS).

PIPE, Belowground (Conventional): The pipe is underlain with a layer of fine bedding material and covered with prepared gravel padding and soil fill material, in a ditch from eight to 16 feet deep in most locations, but up to 49 feet deep at one location. Zinc ribbons, which serve as sacrificial anodes to inhibit corrosion of the pipe, are buried alongside the pipeline. (The Atigun pipe replacement section, 8.5 miles in length, has four magnesium ribbon sacrificial anodes installed.) Electrical currents in the earth's surface, called "telluric currents" and caused by the same phenomenon that generates the Northern Lights, can be picked up by the pipeline and zinc/magnesium anodes. The anodes act like grounding rods to safely return these currents to the earth, reducing the risk of damage to the pipeline.



PIPE, Special Burial, Non-Refrigerated: In areas of thaw-unstable soils calling for elevated pipeline construction, but where the pipeline had to be buried for highway crossings, animal crossings, or avoidance of rockslides and avalanches, the line was insulated to protect the permafrost from the heat of the pipeline and buried.

PIPE, Special Burial, Refrigerated: In some areas the line was insulated and buried in a refrigerated ditch. Refrigeration plants at each of these points circulate chilled brine through loops of six-inch diameter pipe to maintain the soil in a stable frozen condition.

PIPE SHOES: 39,000, approximately.

PORT OF VALDEZ: A natural fjord 12 miles long, 2.5 miles wide and up to 800 feet deep, with a tidal range of 12 to 14 feet.

POWER PLANTS, Pump Station: See PUMP STATIONS, Power.

PRESSURE, Maximum Operating: 1,180 psi.

PRESSURE RELIEF STATION: PS 5 re-injects oil drained down for pressure relief but does not have mainline pumps and does not boost total stream.

PRESSURE RELIEF VALVE: A valve designed to open automatically to relieve pressure and keep it below a designated level.

PRESSURE SPIKE: A sudden, brief rise in pressure.

PRESSURE SURGE: A pressure spike/excursion moving through the pipeline at sonic velocity. Produced by a sudden change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve or any other blockage of the moving stream.

PREVENTION/RESPONSE TUGS (PRTs): *Alert, Attentive* and *Aware.* Specifically designed for escorting and response service in Prince William Sound. Best technology for prevention and response missions by powerful ocean-class tugs. Deployed in 2000.

- Size: Approximately 140 feet long.
- Crew: Seven trained response personnel.
- Propulsion: Z drives; 10,200 horsepower.
- Firefighting: ABS Class 1 firefighting rating that includes pumps, monitors, foam and vessel spray systems.
- Spill Response Equipment:
  - 2,000 feet Kepner Sea Curtain oil containment boom.
  - Two DESMI skimmers.
  - Two 20-foot Kvichak workboats.

PRINCE WILLIAM SOUND REGIONAL CITIZENS ADVISORY COUNCIL (PWSRCAC): Independent citizens' council empowered by the federal Oil Pollution Act of 1990 to provide comment on Alyeska's PWS operations, promoting environmentally safe operation of the Valdez Marine Terminal and the TAPS tanker traffic in PWS.

- Budget: $2.8 million per year (provided by Alyeska under a signed contract that ensures PWSRCAC's absolute independence from Alyeska).
- Members:
  - Alaska State Chamber of Commerce
  - Alaska Wilderness Recreation & Tourism Association
  - Chugach Alaska Corporation
  - City of Cordova

– City of Homer
– City of Kodiak
– City of Seldovia
– City of Seward
– City of Valdez
– City of Whittier
– Community of Chenega Bay
– Community of Tatitlek
– Cordova District Fishermen United
– Kenai Peninsula Borough
– Kodiak Island Borough
– Kodiak Village Mayors Association
– Oil Spill Region Environmental Coalition
– Prince William Sound Aquaculture Corporation

PRUDHOE BAY: A coastal feature of the Beaufort Sea, approximately 250 miles north of the Arctic Circle and 1,300 miles south of the North Pole. Also used generally to describe a land area of petroleum development of Alaska's North Slope: 18th largest field in the world. Largest field in North America.

PUMPS, Booster: All pump stations have booster pumps to move oil from the storage tanks to the mainline. PS 1 has three mainline booster pumps to boost oil pressure. PS 5 also has injection pumps.

PUMPS, Definition:
- Full Head Pump: A two-stage pump with both impellers in series. It has one inlet and one outlet.
- Half Head Pump: A two-stage pump with both impellers in parallel. It has two inlets and two outlets. It can handle twice the flow of the full head but only produces half the (head) pressure rise.

PUMPS, Mainline Pumps:
- Half Head (60,000 gallons/minute each): PS 7.
- Full Head (20,000 gallons/minute each): All other pump stations.

PUMPS, Number Currently Operating: Pumps are currenting operating at PS 1, 3, 4 and 9. PS 5 is a relief station: (see PRESSURE RELIEF STATION), and one pumping unit is available for operation at PS 7 as an emergency standby.

PUMP STATION SR, Upgrades: Strategic Reconfiguration equipments slated for PS 1:
- Three mainline pump/motor modules or mainline units (MLUs).
- Electrical modules.
- Up to 20 megawatts (MW) power supply from Prudhoe Bay power grid including 69 kilovolts (kV) transmission line and substation.
- Approximately 13 MW and 5 MW gas fired power generation modules.
- Tie-ins and interconnecting crude oil piping and supports between existing facilities and new equipment.
- New motors, varible frequency drive (VFD) and switchgear to replace present direct turbine drives on booster pumps. Only two of the existing three units will be converted for the design throughput requirements.

- Essential facilities for cold restart shall be provided or maintained as appropriate.
- Modifications, removal and /or relocation of existing buildings as necessary.
- Upgraded relief control system actuators.
- Upgraded refrigeration facilities including cooling of fuel gas into pipeline leaving PS 1.
- Upgraded fire and gas systems in remaining process buildings to comply with fire code

PUMP STATION 3, Upgrades: Strategic Reconfiguration completed for PS 3:

- Three mainline pump/motor modules or MLUs.
- Electrical modules, including VFD.
- Two power generation modules, each approximately 13 MW, including gas turbine driver, generator and all associated auxiliary equipment, controls, instrumentation, protective devices. One gas turbine shall be capable of dual fuel operation (gas and liquid fuels) with gas being the main fuel option.
- Tie-ins and interconnecting crude oil and fuel gas piping and supports between existing facilities and new equipment.
- Essential facilities for cold restart.
- Liquid fuel loading skid and fuel tanks.
- Upgraded relief control system actuators.
- Liquid fuel backup generators distributing at 13.8 kV.
- Upgraded refrigeration facilities.
- Upgraded fire and gas systems in remaining process buildings to comply with fire code.

PUMP STATION 4, Upgrades: Strategic Reconfiguration completed for PS 4:

- Three mainline pump/motor modules or MLUs.
- Electrical modules, including VFD.
- Two power generation modules, each approximately 13 MW, including gas turbine driver, generator and all associated auxiliary equipment, controls, instrumentation, protective devices. One gas turbine shall be capable of dual fuel operation (gas and liquid fuels) with gas being the main fuel option.
- Tie-ins and interconnecting crude oil and fuel gas piping and supports between existing facilities and new equipment.
- Essential facilities for cold restart.
- Liquid fuel loading skid and fuel tanks.
- Associated facilities for waste water for maintenance facility.
- Upgraded relief control system actuators.
- Heating system utilizing electric makeup air heaters to facilitate future removal of existing therminol heating system.
- Liquid fuel backup generators distributing at 13.8 kV.
- Upgraded fire and gas systems in remaining process buildings to comply with fire code.

PUMP STATION 9, Upgrades: Strategic Reconfiguration completed for PS 9:

- Three mainline pump/motor modules or MLUs.
- Electrical modules, including VFD.
- Up to 23 MW power supply from Golden Valley Electric

Association including 138kV transmission lines and substation.
- Minimum 4.5 MW liquid fuel backup generator.
- Tie-ins and interconnecting crude oil piping and supports between existing facilities and new equipment.
- Essential features for cold restart.
- Upgraded relief control system actuators.
- Heating system utilizing electric makeup air heaters to facilitate future removal of existing therminol heating system.
- Upgraded fire and gas systems in remaining process buildings to comply with fire code.

PUMP STATIONS: Original design called for 12 pump stations with four pumps operating at each pump station. PS 11 was never built. PS 5 was built as a relief station. Eight stations were operating at startup (PS 1, 3, 4, 6, 8, 9, 10 and 12). PS 8 pump building was destroyed by an explosion and fire on July 8, 1977 that occurred during startup; the station was re-commissioned on March 7, 1978. PS 2 was commissioned October 2, 1979; PS 7 was commissioned December 1, 1980.

PUMP STATIONS, Crew: Crews vary per station; typically six to 25 employees. Shifts: one week on/one week off, or two weeks on/two weeks off, depending on station.

PUMP STATIONS, Crude Oil Tank Capacity: PS 1: 420,000 bbl; PS 5: 150,000 bbl; all others: 55,000 bbl.

PUMP STATIONS, Electrical Power: All stations generate electrical power. PS 9 purchases commercially generated power.

PUMP STATIONS, Fire Systems:
- Airfield rescue and fire training provided at stations with airports.
- Pump stations with airports have designated fire-fighting trucks for the airfields.
- Types: Halon, NOVAC, water and foam, dry chemical, wet chemical and carbon dioxide.

PUMP STATIONS, Fuel Requirements: 30,000 to 60,000 gallons per day, average, per station (fuel oil equivalent).

PUMP STATIONS, Permanent Living Quarters: Permanent living quarters at PS 3, 4, 5, 6, and 7. PS 9 personnel live in nearby communities.

PUMP STATIONS, Power: All stations generate electrical power, with power plants ranging from 1.3 megawatts at PS 1 to 4.7 megawatts at PS 6, depending on availability of commercial power, presence of topping unit, and/or vapor recovery system. PS 8 and 9 also purchase commercial power.

PUMP STATIONS, Refrigerated Foundations: PS 1, 3, 5 and 6.

PUMP STATIONS, Status as of June 2009:
- PS 1, 3, 4, and 9 operating.
- PS 5 operating as relief station only.
- PS 9, on line with new equipment December 8, 2006.
- PS 3, on line with new equipment February 12, 2008.
- PS 4, on line with new equipment May 21, 2009.

- PS 7, caretaker status March 9, 2008 in preparation for ramp down in late 2010.
- PS 2 ramped down July 1, 1997.
- PS 6 ramped down August 8, 1997.
- PS 8 ramped down June 30, 1996.
- PS 10 ramped down July 1, 1996.
- PS 11 was not built but has maintenance facilities.
- PS 12 placed in ramped down status April 1, 2005.

PUMP STATIONS, Topping Units: See TOPPING UNIT.

PUMP STATIONS, Turbines: Turbine engines drive the pumps. See TURBINES.

Pump Station 12, 65 miles north of Valdez, is in the southernmost station, pushing the oil up and over Thompson Pass.

PUMPS, Booster: All pump stations have booster pumps to move oil from the storage tanks to the mainline. (PS 1 has three mainline booster pumps to boost oil pressure.) PS 5 also has injection pumps.

PUMPS, Definition:
- Full Head Pump: A two-stage pump with both impellers in series. It has one inlet and one outlet.
- Half Head Pump: A two-stage pump with both impellers in parallel. It has two inlets and two outlets. It can handle twice the flow of the full head but only produces half the (head) pressure rise.

PUMPS, Mainline Pumps:
- Half Head (60,000 gallons/minute each): PS 2 and 7.
- Full Head (20,000 gallons/minute each): All other pump stations.

R

REGULATORY AGENCIES: The following agencies have jurisdiction over various aspects of TAPS. **The asterisk denotes a member of the Joint Pipeline Office (JPO):*

- Alaska Department of Environmental Conservation*
- Alaska Department of Fish and Game*
- Alaska Department of Labor & Workforce Development*
- Alaska Department of Natural Resources*
- Alaska Department of Public Safety
- Alaska Department of Transportation & Public Facilities
- Alaska State Fire Marshal*
- Regulatory Commission of Alaska
- Federal Aviation Administration
- Federal Energy Regulatory Commission
- Federal Maritime Commission
- Interstate Commerce Commission
- Local Boroughs and Municipal Governments
- U.S. Army Corps of Engineers
- U.S. Coast Guard
- U.S. Department of Commerce, National Oceanic and Atmospheric Administration
- U.S. Department of Interior, Bureau of Land Management*
- U.S. Department of Labor, Occupational Safety and Health Administration*
- U.S. Department of Transportation, Office of Pipeline Safety*
- U.S. Environmental Protection Agency*
- U.S. Fish and Wildlife Service*
- U.S. National Transportation Safety Board

RESTORATION, Area Revegetated: Nearly 7,750 acres (through 1997).

RESTORATION, Basic Data:

- Area: Approximately 550 acres.
- Camps, Pad Restoration: 14.
- Fertilizer Used: 5,500 tons.
- Grass Seed Used: More than 450 tons.
- Seedlings Planted: 83,500.
- Soil Samples, Random: 15,000 to test for regeneration.
- Trees Transplanted: 24,000.

RESTORATION, Visual Impact Stipulations: See VISUAL IMPACT STIPULATIONS.

RIGHT-OF-WAY WIDTH:

- Federal Lands: 54 feet (buried pipe); 64 feet (elevated pipe).
- State Lands: 100 feet.
- Private Lands: 54 feet to 300 feet.

ROAD CROSSINGS, Pipeline: 21 north of Yukon; 23 south. The crossing at the Glenn Highway in Glennallen is refrigerated.

S

SAFETY, Philosophy: The management and employees of Alyeska Pipeline Service Company believe that:

- All occupational injuries and illnesses are preventable.
- All Alyeska personnel have a personal responsibility for their own safety and the safety of their co-workers.
- If an employee or contractor observes or knows of an unsafe condition(s), he or she will appropriately and respectfully intervene to mitigate that condition(s). If the unsafe condition(s) cannot immediately be addressed or mitigated, it will be immediately reported up the chain of command.
- No business objective is so important that it will be pursued at the sacrifice of safety.
- Safe conduct is a condition of employment at Alyeska Pipeline Service Company.
- Safety is an integral part of every job performed on TAPS.
- Alyeska Pipeline Service Company will have the best safety performance in the industry.

These statements represent Alyeska's fundamental safety beliefs that are vital to Alyeska's business. Internalizing these beliefs will ensure that "nobody gets hurt."

SAFETY, Statistics: See FATALITIES.

SERVS (Ship Escort Response Vessel System): The mission of SERVS, which was established July 10, 1989, is to prevent oil spills by assisting tankers in safe navigation through Prince William Sound and to protect the environment by providing effective response services to the Valdez Marine Terminal and Alaska crude oil shippers in accordance with oil spill response agreements and plans.

SERVS, Boom: More than 49.7 miles of various types of oil containment and recovery boom are available at SERVS.

SERVS, Enhanced Tractor Tugs: See ENHANCED TRACTOR TUGS (ETTs).

SERVS, Fishing Vessels: 350+ vessels.

SERVS, Non-Mechanical Response Equipment:

- ADDS Pack: Two Airborne Dispersant Delivery Systems; treatment potential: 2,600 bbl/payload.
- Helitask Airborne Dispersant Systems(2): Treatment potential 4,200 gallons/payload.
- Heli-Torch: Two airborne ignition systems.
- Spill Spray: Three meter-controlled dispersant spray units; onboard tankage 3,000 gallons concentrate liquid.
- SERVS, Pre-staged Equipment: Hatcheries and sensitive areas: Lake Bay, Cannery Creek, Solomon Gulch, Main Bay, Sawmill Bay, Valdez Duck Flats and 10 sensitive areas in the Port of Valdez.
- Others: Naked Island, Port Etches, Whittier, Cordova, Chenega Bay and Tatitlek.

SERVS, Prevention/Response Tugs: See PREVENTION/RESPONSE TUGS (PRT).

SERVS, Response Barges: Nine.
- Open Water Barges: Five.
- Dedicated Nearshore Barge: One.
- Lightering Barges: Two.
- Deck Barge: One.
- Total Storage Capacity: More than 900,000 bbl.

SERVS, Response Centers: Chenega Bay, Cordova, Tatitlek, Valdez and Whittier.

SERVS, Skimmers: Approximately 108 skimming units:.
- Skimming Capacity: Ranges from greater than 3,000 bbl/hour to small systems for operating in shallow water.
- Total Recovery Capacity: More than 75,000 bbl/hour.
- *Valdez Star* Oil Spill Recovery Vessel: 123-foot vessel with dynamic-inclined-plane skimming system with a design skimming capacity of 2,000 bbl/hour.

SERVS, Vessels (Other): SERVS has five vessels besides the PRTs and ETTs. These five include docking tugs and the *Endurance*, an emergency response vessel.

SERVS, Wildlife Hazing: Capture and rehabilitation plans are in place for spill response support.

SHIP ESCORT RESPONSE VESSEL SYSTEM: See SERVS.

SLACKLINE: Oil flow that does not completely fill a pipeline.

SOIL SURVEYS, Pre-construction:
- Bore Holes: 3,500, approximately.
- Soil Samples: 15,000, approximately.

SPILLS, Reported: The table below lists the yearly totals for spills that are reported by regulation to agencies. These spills include Alyeska spills, shipper vessel spills and contractor spills that occurred on TAPS.

REPORTABLE SPILLS BY YEAR

Year	# of Spills	Amount (barrels)
1977	34	1,932
1978	24	16,013
1979	43	5,566
1980	55	3,531
1981	32	1,508
1982	30	39
1983	17	4
1984	32	78
1985	31	27
1986	40	38
1987	37	4
1988	35	14
1989	26	251,712
1990	31	6.06
1991	54	11
1992	55	19.5
1993	65	8.6
1994	44	324

1995	6	2
1996	12	814
1997	5	2
1998	5	.5
1999	8	.39
2000	6	4
2001	15	6,857
2002	9	.39
2003	3	.31
2004	0	0
2005	0	0
2006	1	.36
2007	4	22
2008	1	.09

STRATEGIC RECONFIGURATION: Strategic Reconfiguration (SR) is part of Alyeska's overall vision to renew assets and its organization. SR work began in 2001 and concentrated on reducing physical infrastructure and simplifying operations and maintenance. The project's goal is to position TAPS for more efficient operations while maintaining or enhancing safety, operational integrity and environmental performance. The new system is modular and scalable and will provide more flexibility for future increases or decreases in throughput. In addition, SR's more cost effective transportation system will better position the North Slope for future exploration, development, and production. In 2006, a decision was made to implement a phased-in approach and focus on installing SR equipment one pump station at a time. PS 9 near Delta Junction was selected as the first station to receive the SR upgrade, and PS 9 was brought online with SR equipment in February 2007. PS 3 was the next pump station to receive the SR equipment. Subsequently, PS 3 was brought online in December 2007. The knowledge and experience gathered at PS 3 and PS 9 was then applied to SR work at PS 4, which was brought online in May 2009. PS 1 will be the final pump station to receive the SR upgrade. Work at PS 1 is slated to begin in 2010.

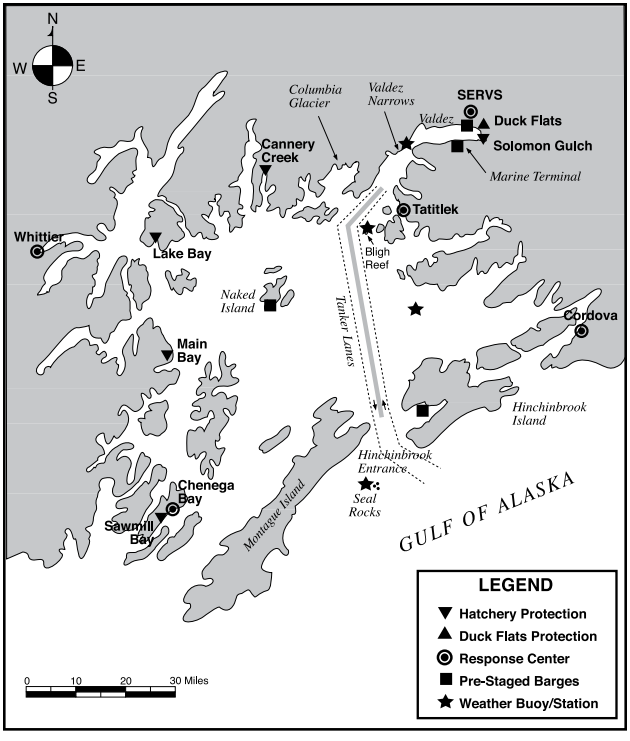
SUCTION PRESSURE: Pressure of the oil as it enters a pump station.

TANKER VAPOR CONTROL SYSTEM, VMT: Berths 4 and 5 are fitted with vapor recovery arms to collect vapors released during tanker loading. Operation of the system began on March 19, 1998.

TANKERS, Aids to Navigation and Safety:

- Major light house, light towers, differential GPS coverage, radar reflectors, racons, fog signals, buoys, day markers and strobe beacons.
- The U.S. Coast Guard maintains a vessel traffic service which includes radio/telephone communications with vessels, GPS-based transponder surveillance system in the Gulf of Alaska approaches and Prince William Sound, and two radar sites providing coverage in Port Valdez, the Valdez Narrows and Valdez Arm.
- Vessels are escorted through Prince William Sound.
- Ice navigation rules/restrictions and wind restrictions apply to tanker operations in the Sound.

TANKERS, Alyeska Role: The tankers that carry oil from the Valdez Marine Terminal are not owned by Alyeska. The role of Alyeska is to operate the Terminal and SERVS on behalf of the tanker owners. Alyeska, through SERVS, is contracted as a primary response action contractor to provide services in the event or threat of an oil spill from a



Map of Prince William Sound showing tanker lanes, hatcheries and duck flats, response centers, pre-staged barge locations that contain spill response equipment, and weather buoys and stations.

tank vessel carrying crude oil that has been transported by TAPS.

TANKERS, Approach Routes:
- Gulf of Alaska to Prince William Sound to Port Valdez, via Hinchinbrook Entrance following dedicated traffic lanes to Valdez Arm and Valdez Narrows.
- Hinchinbrook Entrance: 6.4 to 6.8 miles clearance.

TANKERS, Classification:
- General Purpose: Up to 25,000 dwt.
- Super Tanker: 25,000 to 150,000 dwt.
- Very Large Crude Carrier (VLCC): 150,000 to 300,000 dwt.
- Ultra Large Crude Carrier (ULCC): More than 300,000 dwt.

TANKERS, Draft of Largest Tankers: 85 feet.

TANKERS, Escorts: Outbound laden tankers are escorted by two tugs from the marine terminal to Cape Hinchinbrook, a distance of approximately 70 miles, with one tug remaining on station at Cape Hinchinbrook until the tanker proceeds 17 miles into the Gulf of Alaska. One of the tugs is attached (tethered) to the tanker for the first 20 miles to provide immediate assistance if required. Inbound tankers (in ballast) are provided a standby sentinel escort from the Gulf of Alaska to the Terminal. Alyeska invested more than $75 million in new escort tug technology and tug construction. The cornerstone of the 11-tug escort fleet includes two 10,000-hp Voith Schneider tractor tugs and three 10,000-hp Z-drive tugs. The tanker escort system

in Prince William Sound uses best available technology in accordance with State of Alaska and federal laws.

TANKERS, Largest Berthed and Loaded to Date: 270,000 dwt.

TANKERS, Natural Phenomena Affecting Movements:
- High Winds: The Valdez Narrows is closed to all tanker traffic if the Winds exceed 40 knots.
- Cape Hinchinbrook: When the winds exceed 45 knots or the seas exceed 15 feet, Hinchinbrook Entrance is closed to laden tankers.
- Glacier Ice: The U.S. Coast Guard Prince William Sound Vessel Traffic Center may impose ice routing measures as appropriate. These may include moveable one-way zones, daylight-only restrictions or closure to tankers (see also COLUMBIA GLACIER).

TANKERS, Number Loaded per Month: 25 average (2009).

TANKERS, Size that can be Berthed and Loaded: Berths 4 and 5: 270,000 dwt.

TANKERS, Traffic Lanes:
- Depths Along: 600 to 1,000 feet average; 350 feet minimum (in Valdez Narrows).
- Distance Separating: 1 mile.
- Width: 3/4 mile.
- Valdez Narrows: One-way traffic; clearance 1,000 yards from Middle Rock to southeast shore.

TANKERS, Turnaround Time at Terminal: 22 hours, 20 minutes, average, for berthing, offloading ballast, loading

crude and deberthing.

TELLURIC CURRENTS: Electrical currents in the earth's surface, caused by the same phenomenon that generates the Northern Lights.

THERMAL EXPANSION: Change in pipe length due to change in crude oil temperature.

- Tie-in Temperature: Actual pipe temperatures at the time when final welds were made which joined strings of pipe into a continuous line.
- Hot position: Pipe at maximum oil temperature (145°F).
- Cold position: Pipe at minimum steel temperature (-60°F, pre-startup).
- Each 40-foot length of pipe expands 0.031 inches with each 10°F rise in temperature and contracts the same distance with each 10°F drop in temperature.
- Longitudinal expansion of typical 720-foot straight aboveground segment from minimum tie-in temperature to maximum operating temperature: 9 inches. Note: Due to anchoring, the pipeline does not expand lengthwise but shifts laterally on the aboveground supports (see ZIGZAG CONFIGURATION).
- Maximum aboveground lateral movement:
  - Tie-in to hot position: 8 feet.
  - Tie-in to cold position: 4 feet.
- Thermal Stress: Maximum 25,000 psi where belowground pipeline is fully restrained by the soil (the maximum longitudinal stress due to change in temperature from pipe temperature at tie-in to maximum oil temperature).

THROUGHPUT: The amount of North Slope crude oil transported from Pump Station 1 to the Valdez Marine Terminal.

THROUGHPUT, Average (2008): 703,551 bbl/day, or 29,314.6 bbl/hour, or 20,520.2 gallons/minute.

THROUGHPUT, History: See table below.

Year	Daily Average	Yearly Total	Cumulative Total
1977	575,897	112,300,000	112,300,000
1978	1,087,695	397,008,750	509,308,750
1979	1,281,580	467,777,848	977,086,598
1980	1,516,213	554,934,043	1,532,020,641
1981	1,523,472	556,067,441	2,088,088,082
1982	1,619,566	591,141,545	2,679,229,267
1983	1,646,188	600,858,560	3,280,088,187
1984	1,663,487	608,836,116	3,888,924,303
1985	1,780,512	649,886,953	4,538,811,256
1986	1,823,110	665,434,992	5,204,246,248
1987	1,963,458	716,662,005	5,920,908,253
1988	2,033,082	744,107,885	6,665,016,108
1989	1,885,102	688,062,255	7,353,078,363
1990	1,793,292	654,551,673	8,007,630,036
1991	1,822,396	665,174,678	8,672,804,714
1992	1,746,893	639,363,127	9,312,167,841
1993	1,619,787	591,222,326	9,903,390,167
1994	1,587,177	579,319,503	10,482,709,670
1995	1,523,120	555,938,859	11,038,648,529

1996	1,435,810	525,506,504	11,564,155,033
1997	1,334,507	487,094,963	12,051,249,996
1998	1,206,839	440,496,271	12,491,746,267
1999	1,078,146	393,523,457	12,885,269,724
2000	999,202	365,707,875	13,250,977,599
2001	992,000	362,131,000	13,613,108,362
2002	1,000,916	365,334,233	13,980,609,456
2003	993,000	362,554,000	14,323,163,156
2004	935,134	342,249,701	14,685,413,157
2005	891,104	325,252,788	15,008,657,831
2006	759,081	277,064,405	15,377,064,405
2007	740,170	270,161,990	15,555,884,226
2008	703,551	257,499,836	15,813,384,062

THROUGHPUT, Maximum Daily: 1.14 million bbl average (with four pump stations operating). Rates exceeding 750,000 bbl require addition of drag reducing agent (DRA).

TOPPING UNIT: Mini-refinery that produces turbine fuel. Topping units are located at PS 6, 8 and 10, and all are ramped down. The unit at PS 10 was ramped down in 1995, the unit at PS 8 in 1996 and the PS 6 unit in 1997.

TURBINES, Fuel Requirements:

- Gas-Fired Units: 4.3 million cubic feet/unit/day average.
- Liquid-Fired Units: 30,000 gal/unit/day average (half head configuration); 24,000 gal/unit/day average (full head configuration).

TURBINES, Power Ratings: (Sea Level, 59°F):

- Avon Gas Generator: 24,600 exhaust gas horsepower.
- Reaction Turbine: 18,700 brake horsepower (half head configuration); 15,300 brake horsepower (full head configuration).

TURBINE GENERATORS, Electrical: PS 3 and PS 4 have two Siemens Cyclone 12.9 megawatt turbine generators. The units provide electricity to the station for essentials such as heat and lighting, as well as power for operations for the new SR electric pumps. Normally one generator is online with the second generator in standby. Both units run on natural gas from the fuel gas line that runs from the North Slope to PS 4, while one unit can be switched to run on diesel fuel.

U

ULTRA LARGE CRUDE CARRIER (ULCC): Tankers with more than 300,000 dwt.

ULTIMATE STRENGTH: The stress level at which the pipe will fail/rupture or "break." The ultimate strength of the steel is determined by testing during manufacture of the pipe.

V

VALDEZ MARINE TERMINAL (VMT): The VMT, the southern terminus of the trans-Alaska pipeline, is located on ice-free Port Valdez at the northeastern end of Prince William Sound. The VMT occupies approximately 1,000 acres on the southern shore of Port Valdez. The Terminal was designed to load tankers and to provide the storage capacity in TAPS to allow production on the North Slope to operate without impact-related delays from the marine transportation system. The Terminal, which operates with two tanker loading berths, has storage facilities with a working inventory capacity of 8.78 million barrels (bbl) of crude oil and a total volume of 9.18 million bbl.

VALDEZ MARINE TERMINAL, Berths: Four berths were built at the Terminal: Berth 1 (floating platform with 13 buoyancy chambers and weighing 6.5 million pounds) and Berths 3, 4 and 5 (fixed platform). Berth 1 is out of service and Berth 3 is used as a lay berth for tankers. Berths 4 and 5 are equipped with vapor-recovery arms, and as such, are the only active berths on the VMT.

VALDEZ MARINE TERMINAL, Cost to Build: $1.4 billion.

VALDEZ MARINE TERMINAL, Elevation: Sea level to 660 feet. All facilities except berths are 15 feet or higher.

VALDEZ MARINE TERMINAL, Emergency Shutoff Valves: Crude oil loading onto a tanker can be shut down in less than 10 seconds at loading rates up to 100,000 bbl/hour.

VALDEZ MARINE TERMINAL, Firefighting:

- Fire Boats: Six (tugs equipped with firefighting equipment).
- Fire Trucks: Four.
- Personnel Training: All Terminal technicians trained to incipient level; advanced training for exterior and interior level fire brigade members; annual refresher for all three levels.
- Systems: Portable extinguishers, water and foam systems, Halon, carbon dioxide.

VALDEZ MARINE TERMINAL, Fuel Requirements: All Terminal and SERVS operations (fuel oil equivalent) 500 bbl/day average.

VALDEZ MARINE TERMINAL, Power Generation:

- Primary Plant Facilities:
  - Three steam boilers each with an output of 175,000 pounds/hour at 600 psi at 750°F.
  - Three condensing steam turbine generators each with a capacity of 12.5 megawatts at 13.8 kilovolts.
- Standby systems:
  - Two 12-cylinder diesel generators: capacity 2.8 megawatts total.
  - Four uninterruptable power supply systems supplied by 125-volt battery bank for essential control equipment.

VALDEZ MARINE TERMINAL, Stack Heights: Boiler, 300 feet; incinerators (four) 108 feet.

VALDEZ MARINE TERMINAL, Holding Tanks (Crude):

- Capacity: 510,000 bbl each; 9.18 million bbl total volume.
- Dimensions: Height 63.3 feet, diameter 250 feet.
- Floor Thickness: 1/4-inch steel plate (on concrete ring wall).
- Number: 18.
- Roof: Fixed, conical.
- Roof Supports: 61 columns, diameter 24 inches.
- Slosh Zone: 3 feet, 9 inches.
- Space Enclosed: 1.2 acres each, approximately.
- Wall Thickness: Graduated from 1-1/8 inch steel bottom ring, to 1/2 inch top ring.

VALDEZ MARINE TERMINAL, Holding Tanks (Crude) Containment Dikes:

- Capacity: 110% capacity of both tanks, which accounts for water and snow accumulation.
- Number of Tanks in Each: Two.
- Reinforcing Steel: 52 miles in each, diameter 1/2 to 3/8 inch.

VALDEZ MARINE TERMINAL, Tanker Vapor Control System: See TANKER VAPOR CONTROL SYSTEM, VMT.

VALDEZ MARINE TERMINAL, Vapor Recovery: Five rotary compressors each rate at 13,500 standard cubic feet/minute. Two compressors are dedicated to recovering vapors from storage tanks, two compressors dedicated to recovering vapors from tanker berths and one swing

compressor that can provide either function.

VALDEZ MARINE TERMINAL (VMT), Workforce: Approximately 320 Alyeska employees and contractors work on the VMT.

VALDEZ NARROWS, Clearance: 1,000 yards: Middle Rock to southeast shore.

VALDEZ, Port: See PORT OF VALDEZ.

VALVE, Block: When closed, the valve can block oil flow in either direction. Block valves include manual gate valves, remote gate valves, and station block valves (suction valves and discharge valves).

- Manual Gate Valve: Block valve that is operated manually; placed in check valve segments periodically to provide more positive isolation than can be provided by check valves during pipeline maintenance.
- Remote Gate Valve (RGV): A remotely controlled block valve for the primary purpose of isolating segments of the line in the event of a catastrophic pipeline break. Valve operating times are either four or eight minutes to fully open or fully close.
- Station Block Valve: A gate valve installed at the inlet (suction) side and the outlet (discharge) side of the pump station or Terminal to isolate the facility from the pipeline in the event of an emergency.

VALVE, Check: A valve that operates one-way and prevents the reverse flow of oil. Check valves are designed to be held open by flowing oil and to drop closed automatically when oil flow stops or is reversed. To increase operating efficiency, some check valves are held fully open mechanically, thus lifting valve clappers entirely free of the oil stream, reducing turbulence. Actuators fitted to these valves receive signals from flow or pressure sensors to drop the valve clappers free. Once the clappers have been released, the actuated check valve functions as a normal check valve to stop flow reversal. Approximately one-half of the mainline check valves are fitted with hydraulic actuators. The remainder have manual actuators only.

VALVE, Pipeline:

- Check: 83.
- Gate: 71 (62 remotely operated, 9 manually operated).
- Block: 24.
- Total: 178.

VALVE, Pressure Relief: A valve designed to open automatically to relieve pressure and keep it below a designated level.

VALVES, Pump Stations and Terminal:

- Size: 2 to 48 inches.
- Design Pressure: Varies to meet process conditions. (Class 150# through Class 2500#).
- Type: Gate, ball, check, plug, etc.
- Number of Motor-Operated Valves: Approximately 1,000.

VALVE REPAIR PROGRAM: The program's goal is to evaluate the conditions of TAPS valves, actuators, and operators as appropriate and to implement a comprehensive maintenance program to ensure long-term

system integrity.

VAPOR RECOVERY: See VALDEZ MARINE TERMINAL, Vapor Recovery.

VERTICAL SUPPORT MEMBERS (VSM): Pipe embedded in the ground to support the aboveground pipe in areas of thaw-unstable permafrost. Some VSMs contain heat pipes to remove heat and keep the ground frozen.

- Number: 78,000.
- Depth Embedded: 15 to 70 feet.
- Distance Between: Anchor supports, 800 to 1,800 feet; standard supports, 60 feet, approximately.
- Number Fitted with Heat Pipes: 61,000 (122,000 individual heat pipes, 2 per VSM where fitted).

VISUAL IMPACT STIPULATIONS:

- Access Roads: 12° maximum allowable grade.
- Buffer strips (undisturbed land):
  - 300-foot width of undisturbed land along streams.
  - 500-foot width required between state highways and material sites.
  - 1/2 mile required between workpads and parks, refuges, etc.
- Right-of-Way Visibility: Maximum straight length permitted visible from highway: 600 feet.

VERY LARGE CRUDE CARRIER (VLCC): Tanker 150,000 to 300,000 dwt.

W

WATERFLOOD: An oil field term referring to a system of pumping water into the oil reservoir behind the produced oil to maintain reservoir pressure and ultimately recover more oil.

WELDS, Pipe:

- Double Joints: 42,000 (a "double joint" is two pipe sections welded into a single length before transport to the field for placement in the line).
- Field Girth Welds: 66,000.
- Passes for Field Girth Welds: Seven for 0.562-inch pipe; six for 0.462-inch pipe.

WORKFORCE, Construction: See CONSTRUCTION, Workforce.

Y

YIELD STRENGTH: The stress level above which the pipe will yield, bend and/or stretch.

Z

ZIGZAG CONFIGURATION: Aboveground sections of the pipeline are built in a zigzag configuration to allow for expansion or contraction of the pipe because of temperature changes. The design also allows for pipeline movement caused by an earthquake.

history, TAPS

Following is a chronology of the Trans Alaska Pipeline System since oil was discovered at Prudhoe Bay.

1968

Mar. 13 Atlantic Richfield Company (ARCO) and Humble Oil and Refining Company (now Exxon Company, U.S.A.) announce Prudhoe Bay discovery well.

June 25 Confirmation well announced by ARCO and Humble.

July 29 Pipeline field study team arrives in Alaska under authority of a transportation subcommittee of an ARCO-Humble North Slope Coordinating Committee.

Oct. 28 Atlantic Pipeline Company (a subsidiary of Atlantic Richfield), Humble Pipe Line Company (a subsidiary of Humble Oil and Refining Company), and BP Exploration U.S.A., Inc. (a subsidiary of British Petroleum Company, Ltd.) enter into an "agreement for a planning study and for engineering design and construction of the Trans-Alaska Pipeline Project."

1969

Feb. 7 Atlantic Pipeline, Humble Pipe Line and BP Oil Corporation (formerly BP Exploration U.S.A., Inc.) approve an amendment to their original agreement, electing to proceed with design and construction, and changing the name of the project to "Trans Alaska Pipeline System." The acronym "TAPS" is first used.

Feb. 10 Atlantic Pipeline, Humble Pipe Line and BP Pipeline Corporation (a subsidiary of BP Oil Corporation) announce plans to build an 800-mile trans-Alaska pipeline.

June 6 TAPS files for federal right-of-way permits over public lands.

Sept. 13 First 48-inch pipe arrives in Valdez from Japan.

Oct. 22 Humble Pipe Line, Atlantic Pipeline, and BP Pipeline are joined by Amerada Hess Corporation, Home Pipeline Company, Mobil Pipeline Company, Phillips Petroleum Company and Union Oil Company of California in joint venture.

December Alyeska builds road from Livengood to the Yukon River (winter of 1969-1970).

1970

April Law Suits are filed by environmental groups and others to block pipeline construction.

Aug. 27 Trans Alaska Pipeline System Agreement made and signed by Atlantic Pipeline Company, BP Pipeline Corporation, Humble Pipe Line Company, Amerada Hess Corporation, Home Pipeline Company, Mobil Pipeline Company, Phillips Petroleum Company and Union Oil Company of California all referred to as "TAPS Owners."

Aug. 27 TAPS Owners form Alyeska Pipeline Service Company, a separate corporation.

Aug. 27 Agreement made to design and construct the trans-Alaska pipeline. Alyeska Pipeline Service Company appointed as contractor and agent for the construction project.

1971

Jan. 1 Atlantic Pipeline Company (TAPS Owner) stock reissued to ARCO Pipeline Company.

1973

Nov. 16 Trans Alaska Pipeline Authorization Act (TAPAA) becomes law.

1974

January Home Pipeline Company (TAPS Owner) stock reissued to six other oil pipeline companies.

Jan. 3 Federal right-of-way grant issued.

Apr. 29 Construction of road from Prudhoe Bay to Yukon River begins.

May 3 State right-of-way lease issued.

Sept. 29 Road from Prudhoe Bay to Yukon River completed.

Dec. 19 Humble Pipe Line Company (TAPS Owner) stock reissued to Exxon Pipeline Company.

1975

Mar. 27 First pipe laid at Tonsina River.

Oct. 11 Yukon River Bridge completed.

Oct. 26 Pipeline project 50% complete.

1977

May 20 Operating agreement established between Alyeska Pipeline Service Company (as agent) to operate and maintain TAPS on behalf of TAPS Owners.

May 31 Final pipeline weld near PS 3.

June 20 First oil flows from PS 1 (10:26 a.m. AST, pig in trap; 10:27 a.m. AST, pig depart signal).

June 24 Oil front at PS 3 (12:56 p.m.).

June 25 Oil front at PS 4 (7:50 a.m.).

June 28 Oil front at PS 5 (6:23 a.m.).

July 1 Oil front at PS 6 (6:30 p.m.).

July 4 Nitrogen leak detected ahead of oil front, MP 489.12 (near PS 8 north block valve). Oil flow stopped.

July 7 Pipe repair, MP 489.12. Pipe and elbow cracked from injection of super cooled nitrogen. Pipe replaced.

July 7 Oil front at PS 8 (9:24 p.m.).

July 8 PS 8 pump building destroyed by explosion and fire; one fatality; oil loss, 300 bbl.

July 19 Oil leak (heavy equipment accident) at CV 7, 1,800 bbl.

July 20 Oil front at PS 9 (10:37 a.m.).

July 22 Oil front at PS 10 (4:46 a.m.).

July 26 Oil front at PS 12 (3:48 a.m.).

July 28 Oil reaches VMT (11:02 p.m.).

Aug. 1 ARCO *M/V Juneau* departs Valdez with first oil.

1978

Feb. 15 Oil spill caused by sabotage at Steele Creek, MP 457.53, 16,000 bbl.

Feb. 16 Pipe repair MP 457.53.

March 7 PS 8 recommissioned (11:05 a.m.).

1979

June 10 Oil leak caused by pipe settlement at MP 166.43, Atigun Pass, 1,500 bbl.

June 13 ARCO *M/V Heritage*, 1,000th tanker to load.

June 15 Oil leak caused by pipe settlement at MP 734.16, 4,000 bbl.

June 19 Pipe repair, MP 734.16.

July 1 First commercial injection of DRA into pipeline at PS 1.

Aug. 18 Curvature pig (super pig) stuck in line at CV 29.

Sept. 25 CV 29 opened; stopple and bypass installed; curvature pig removed.

Oct. 2 PS 2 commissioned.

October Yukon River Bridge opened.

1980

Jan. 22 1 billionth barrel arrives at VMT.

Feb. 11 Oil leak from leaking valve at VMT east tank farm, 3,200 bbl.

May 12 Oil leak from relief tank valve, 238 bbl.

Sept. 20 Monument to pipeline construction workers dedicated at VMT.

Dec. 1 PS 7 commissioned.

Dec. 29 *Thompson Pass*, 2,000th tanker to load.

1981

Jan. 1 Oil leak from drain connection failure at CV 23, 1,500 bbl.

Nov. 10 2 billionth barrel arrives at VMT.

Dec. 15 First Kuparuk field oil delivered to PS 1.

1982

June 7 RGV 121A, uncommanded closure.

June 19 *M/V Philadelphia*, 3,000th tanker to load.

June 20 5th anniversary of TAPS operations.

1983

July 21 3 billionth barrel arrives at VMT.

Nov. 8 *Tonsina*, 4,000th tanker to load.

1984

March 20 Removal of stuck scraper pig at CV 4 and relocation of pig trap from PS 5 to PS 4.

Nov. 1 Removal of stuck pig at PS 10.

1985

Jan. 11 *M/V Overseas Boston*, 5,000th tanker to load.

Mar. 11 4 billionth barrel arrives at VMT.

Apr. 22 MP 200 final tie-in of 48-inch permanent reroute (404.7 feet added to total pipeline length); reroute due to pipe settlement.

Nov. 2 Milne Point field start-up.

Nov. 9 Two primary generators damaged by fire in generator room at PS 1.

1986

Mar. 5 *ARCO Sag River*, 6,000th tanker to load.

Apr. 18 Union Oil Pipeline Company (TAPS Owner) becomes Unocal Pipeline Company.

Sept. 15 5 billionth barrel arrives at VMT.

Nov. 18 "Tee" damaged by scraper pig at PS 10, "tee" replaced.

Dec. 15 Lisburne field start-up.

Dec. 24 Sohio Pipeline Company (TAPS Owner) becomes Sohio Alaska Pipeline Company.

1987

Apr. 1 First high-definition corrosion pig run.

Apr. 19 *Atigun Pass*, 7,000th tanker to load.

June 20 10th anniversary of TAPS operations.

Sept. 29 Buckled pipe replaced, Atigun Pass, MP 166.4.

Oct. 3 Endicott field start-up.

1988

Jan. 1 BP Pipelines, Inc. (TAPS Owner) merged into Sohio Alaska Pipeline Company (TAPS Owner).

Jan. 14 Highest daily throughput of 2,145,297 bbl.

Feb. 16 6 billionth barrel arrives at VMT.

May 2 *M/V Chevron Mississippi*, 8,000th tanker to load.

September PS 2 pump manifold pipe replacement project complete.

October Atigun Pass releveling project, MP 167; pipe settled due to erosion of ground below.

1989

Jan. 3 Oil spill, Thompson Pass, 1,700 bbl; crack in vessel's hull.

Mar. 1 Sohio Alaska Pipeline Company (TAPS Owner) becomes BP Pipeline (Alaska), Inc.

Mar. 24 Oil spill, *Exxon Valdez*, 250,000 bbl; vessel ran aground at Bligh Reef.

May 27 *M/V Texaco Florida*, 9,000th tanker to load.

June 1 First ultrasonic corrosion pig run.

June 30 7 billionth barrel arrives at VMT.

July 10 Ship Escort Response Vessel System (SERVS) established for oil spill prevention and response in Prince William Sound.

August Feasibility study for Atigun floodplain pipe replacement project was done to replace 8.5 miles of mainline pipe between MP 157 and 165.5.

1990

Feb. 8 Alyeska and Regional Citizens' Advisory Council (RCAC) signed contract.

June Construction complete on VMT incinerator repair project.

June 12 Deadleg repair/replacement, PS 1.

July 31 M/V Exxon New Orleans, 10,000th tanker to load.

Aug. 25 1,000th SERVS escort.

September PS 3 corrosion repair; station temporarily bypassed.

September Construction begins on 8.5-mile Atigun Floodplain Pipe Replacement Project.

Sept. 15 Project to inspect, recoat, and reinsulate 1,600 feet of insulated buried mainline pipe between MP 167.3 and 167.5 completed.

December First shipment of pipe for Atigun Floodplain Pipe Replacement Project arrives in Valdez.

1991

Jan. 1 8 billionth barrel arrives at VMT.

Feb. 28 ARCO Pipeline Company (TAPS Owner) becomes ARCO Transportation Alaska, Inc.

March Concrete biological treatment tanks (BTT) placed in service at VMT.

September Atigun Floodplain Pipe Replacement Project completed (MP 157-165.5).

Oct. 2 *M/V Overseas Boston*, 11,000th tanker to load.

Oct. 14 2,000th SERVS escort.

1992

January Floor of crude oil storage Tank 5 at VMT replaced and cathodic protection installed.

April-May Corrosion repairs to 2.5-mile section of pipe in the Chandalar Shelf.

June First run of inertial pipeline pig.

June 20 15th anniversary of TAPS operations.

July 7 9 billionth barrel arrives at VMT.

July 30 Full-scale aerial dispersant test in Prince William Sound.

Aug. 7 RGV 73 uncommanded closure, overpressuring the pipeline.

September Tank 111 at PS 1 returned to service after bottom replacement project completed.

October Recoating of superstructure for Berths 3 and 4 at VMT completed.

December Completion of new roof for 40,000-square-foot dissolved air flotation (DAF) building at VMT.

Dec. 10 Fuel gas line (north of the Brooks Range) re-leveling project complete.

Dec. 28 *M/V ARCO California*, 12,000th tanker to load.

1993

Jan. 1 3,000th SERVS escort.

Jan. 20 Petro Star Refinery on-line in Valdez.

March Construction of new tug dock at VMT completed.

June PS 10, desalter for pretreating topping unit crude feed put in service.

June PS 9, Mainline Pump No. 3 converted to half-head operation.

September Recoating of VMT Berth 5 superstructure completed.

October Completion of inspection, repair and recoating of last of 10 storage tanks at VMT. This completes the initial inspection of all major storage tanks at VMT.

Dec. 10 Fuel gas line pig launcher installed at MP 34.

1994

March Tank 209 at PS 10 leaks 3,500 gallons of residual oil in tank farm.

Mar. 5 10 billionth barrel arrives at VMT.

May 13 *M/V ARCO Texas*, 13,000th tanker to load.

June 18 4,000th SERVS escort.

July 5 Alyeska selects method of tanker vapor control at VMT.

1995

Mar. 9 Valdez Emergency Operations Center/Escort Response Base opened

Mar. 30 Alyeska employees worked 1 million consecutive hours without a lost time accident.

April Alyeska completes major electrical improvement project (ANSC) line-wide.

May 24 PS 8 topping unit shut down.

Oct. 20 Alyeska and U.S. Department of Interior sign new Alaska Native Utilization Agreement.

Oct. 26 PS 7 idled for maintenance, three months.

December Alyeska completed construction on new otter rehabilitation facility.

Dec. 12 11 billionth barrel arrives at VMT.

Dec. 31 *M/V ARCO Juneau*, 14,000th tanker to load.

1996

January 5,000th SERVS escort.

Apr. 20 Oil leak at CV 92 discovered, 800 bbl released.

Apr. 25 CV 92 leak repair begins.

June 30 PS 8 placed in ramped down status.

July 1 PS 10 topping unit placed in ramped down status.

August Pressure pulsations felt in Thompson Pass created by slackline condition.

Sept. 17 Alyeska investigates pipe vibrations near pipeline MP 776.

Nov. 27 Alyeska responds to evidence of hydrocarbons detected by soil probes near MP 776; no spill found.

1997

January Exxon Pipeline Company (TAPS Owner) becomes ExxonMobil Pipeline Company.

January Temporary back-pressure system installed at VMT to stop pressure pulsations in Thompson Pass.

Jan. 1 Phillips Alaska Pipeline Corporation (TAPS Owner) stock reissued to Phillips Transportation Alaska, Inc.

June 20 20th anniversary of TAPS operations.

July 1 PS 2 placed in ramped down status.

Aug. 5 6,000th SERVS escort.

Aug. 8 PS 6 topping unit placed in ramped down status.

Aug. 12 M/V Overseas Juneau, 15,000th tanker to load.

Oct. 2 Permanent back-pressure control system operational.

Dec. 1 12 billionth barrel arrives at VMT.

1998

Mar. 19 Tanker vapor control system brought into full operation at VMT.

Sept. 25-26 Pipeline shut down for 28 hours, 40 minutes to repair CV 122 and replace RGV 80.

Oct. 15 Alyeska and U.S. Department of Interior renew Alaska Native Utilization Agreement.

1999

Jan. 27 *Nanuq*, enhanced tractor tug, arrives at Valdez to join SERVS fleet.

May 21 7,000th SERVS escort.

May 22 *Tan'erliq*, enhanced tractor tug, arrives at Valdez to join SERVS fleet.

June 26 *M/V ARCO Spirit*, 16,000th tanker to load.

July 10 10th anniversary of SERVS.

Sept. 11 Pipeline shut down for 25 hours, 49 minutes to replace RGV 60.

2000

February *M/V Alert*, prevention/response tug, arrives at Valdez to join SERVS fleet.

April Pipeline movement at MP 170.

Apr. 27 13 billionth barrel arrives at VMT.

May *M/V Attentive*, prevention/response tug, arrives at Valdez to join SERVS fleet.

June Scraper pig removed seat ring from CV 74.

June 30 Mobil Alaska Pipeline Company (TAPS Owner) stock reissued to Williams Alaska Pipeline Company, LLC.

July *M/V Aware*, prevention/response tug, arrives at Valdez to join SERVS fleet.

Aug. 1 ARCO Transportation Pipeline Company (TAPS Owner) stock reissued to Phillips Transportation Alaska, Inc.

Summer Extensive rebuilding of Berth 4 at VMT.

Sept. 16 Pipeline shutdown to replace CV 74 and the M-2 valve at PS 9.

Oct. 7 Shutdown to test remaining valves needed to complete the five-year test program for all mainline valves.

2001

July 11 *M/V Polar Endeavor*, first Millennium class double-hull tanker, arrives at VMT.

July 19 8,000th SERVS escort.

Summer Extensive renewal of Berth 5 at VMT.

Aug. 21 SERVS receives Distinguished Achievement award in recognition of outstanding third-party oil spill response to the grounding of the fishing vessel Windy Bay in Prince William Sound.

Sept. 22 *Marine Columbia*, 17,000th tanker to load.

Sept. 22 Pipeline shut down for mainline valve maintenance and integrity test and performance evaluation of two 48-inch mainline RGVs.

Oct. 4 Bullet hole at MP 400 leaks 258,000 gallons of oil. More than 178,000 gallons recovered and reinjected into the pipeline.

Oct. 25 Alyeska and U.S. Department of Interior renew Alaska Native Utilization Agreement.

November VMT Tank 94 raised two feet (ballast water tank, 250-foot diameter).

Nov. 2 First oil from Northstar field received at PS 1.

Nov. 9 *M/V Chevron Mississippi*, final tanker load after 30 years of service and 1,002 sailings, all ports (432 from VMT).

2002

June 20 25th anniversary of TAPS operations.

July 25 Pipeline shut down to replace RGV 39.

Aug. 1 Valdez Marine Terminal office building dedication.

Oct. 10 Laden tanker *Kenai* assisted by escort vessels when mechanical problems developed at Hinchinbrook Entrance.

Oct. 30 Main firewater distribution line at VMT relined.

November VMT Tank 93 raised two feet (ballast water tank, 250-foot diameter).

Nov. 3 7.9 earthquake at MP 588. Damaged shoes and VSM crossbeams repaired and replaced. No oil spilled.

Nov. 26 State of Alaska renews pipeline right-of-way for 30 years.

2003

Jan. 20 14 billionth barrel arrives at VMT.

April Alyeska Pipeline receives the American Petroleum Institute's 2002 Environmental Large Operator Award and recognition for improved safety performance (29% reduction in OSHA recordables over a three-year period).

July 23 9,000th SERVS escort.

Oct. 10 *M/V Marine Columbia*, 18,000th tanker to load.

2004

April Alyeska Pipeline receives the American Petroleum Institute's 2003 Environmental Large Operator Award and recognition for improved safety performance (47% reduction in OSHA recordables over a three-year period).

2005

April Alyeska Pipeline receives the American Petroleum Institute's 2004 Environmental Large Operator Award (no Pipeline Performance Tracking System (PPTS) releases).

Dec. 14 10,000th SERVS escort.

Dec. 21 15 billionth barrel arrives at VMT.

2006

April Alyeska wins the American Petroleum Institute's Distinguished Environmental and Safety Award, API's highest recognition for a pipeline operator. Alyeska also received the 2005 Environmental Large Operator Award (zero releases).

Apr. 11 *M/V Kodiak*, 19,000th tanker to load.

August Smart Pig run from PS 1 to PS 4, successful.

September Smart Pig run from PS 4 to VMT, not successful due to wax build up. Rerun scheduled for March 2007.

Dec. 22 Scraper Pig 67 came apart in line at PS 7.

2007

Jan. 9 Pipeline restarted after leak on bypass piping stopped. Feb. 9. Alyeska starts up new pumps at PS 9.

March Smart pig launches at Pump Station 4.

Mar. 22 Smart pig completes review of TAPS.

May 14 Project work at PS 3 stabilizes pipeline.

June 20 30th anniversary of TAPS operations.

Nov. 1 TAPS crews wrap up repairs to storm damage to Right-of-Way.

Dec. 17 New pumps started at PS 3: Second station to receive upgraded equipment.

2008

Jan. 23 Operations Control Center begins 24/7 operations in Anchorage

Feb. 7 BWT successfully connects to vapor recovery system, substantially reducing the risk of fire and explosion associated with flammable vapors in the tanks, and also eliminating a major source of emissions at VMT.

Apr. 3 Alyeska installs pressure containing sleeve to repair areas of external corrosion near PS 1.

June 28-29 Pipeline shut down to replace RGV 72.

Aug. 13 Alyeska wraps up cathodic protection project near Valdez.

Aug. 16-17 Pipeline shut down for routine maintenance, including pig trap replacement at VMT.

Aug. 19 SERVS assists *F/V Northern Mariner* that went aground on northeast side of Flemming Island.

Nov. 5 Federal Transportation Worker Identification Credential (TWIC) program implemented at VMT.

2009

Jan. 28 11,000th SERVS tanker escort.

April Alyeska receives 2008 American Petroleum Institute Distinguished Operator Award (Large Operator), among the oil industry's top honors and reserved for pipeline operators that demonstrate excellence in safety, environment and integrity.

May 21 New pumps started at PS 3: Second station to receive upgraded equipment.

repairs, major:

Following is a chronology of major TAPS repairs since 1977:

1977

July 7 MP 489.12: Approximately 20 feet south of north block valve at PS 8; damage to 30° elbow and pipe from injection of super cooled nitrogen ahead of oil front during oil-in. Replaced with new elbow and two six-foot pumps. Pipe reburied.

July 8 MP 489.24: Pump building at PS 8 destroyed in an explosion and fire; pipeline undamaged. Pump building was replaced and recommissioned on March 7, 1978.

September MP 388.00: North of Lost Creek; two bullet indentations. Covered with 48-inch diameter three-foot welded split-sleeve.

1978

February MP 457.53: Steele Creek; one-inch diameter hole (sabotage). Covered with 48-inch diameter, 22.5-inch bolted split-sleeve; subsequently covered with welded sleeve.

1979

June MP 166.43: North side Atigun Pass; hairline crack caused by buckle. Covered with 56-inch diameter, six-foot welded split-sleeve; 19 steel supports installed. Pipe reburied.

June MP 734.16: one mile north of PS 12; hairline crack caused by buckle in pipe. Covered with 56-inch diameter, 6.1-foot welded split-sleeve; seven steel supports installed. Pipe reburied.

September MP 157.62 to MP 157.65: Instrument pig ("super pig") lodged in line at CV 29. Stopple and bypass installed, valve bonnet lifted, pig removed. Pipe reburied.

October MP 166.41: North side Atigun Pass; buckled pipe. Covered with 56-inch diameter, six-foot welded split-sleeve. Pipe reburied.

1980

April MP 449.96: Indentation, possibly from bullet. Covered with 48-inch diameter, 18-inch welded split-sleeve.

May MP 159.70: Construction damage from backhoe during monitor rod installation. Covered with 48-inch diameter, 3.6-foot welded split-sleeve. Pipe reburied.

June MP 416.00: Approximately two miles south of PS 7; pipe settlement. Approximately 430-foot excavation; eight steel supports installed. Pipe not reburied.

August MP 752.00: Flash flood, 900 feet of overburden washed out; no damage. Pipe reburied.

November MP 720.00: Pipe settlement. Approximately 200-foot excavation; pipe lifted and concrete slurry added beneath pipe. Pipe reburied.

1981

No major repairs.

1982

April MP 168.40: South side Atigun Pass; pipe settlement. Approximately 300-foot excavation; concrete slurry added beneath pipe. Pipe reburied.

August MP 166.03: North side Atigun Pass; pipe buckle. Covered with 56-inch diameter, 6.5-foot welded split-sleeve. Pipe reburied.

1983

March MP 730.29: Pipe settlement. Approximately 102-foot excavation; nine concrete river weights removed, concrete slurry added beneath pipe. Pipe reburied.

April MP 200.24: Dietrich River channel; pipe buckle. River channel redirected temporarily; approximately 125-foot excavation; 56-inch diameter, six-foot welded split-sleeve installed; five specially designed steel supports installed. Pipe reburied.

October MP 45.97: Pipe settlement. Approximately 200-foot excavation; concrete slurry added beneath pipe. Pipe reburied.

1984

March Removal of scraper pig stuck at CV 4 and relocation of pig trap from PS 5 to PS 4.

November Removal of stuck pig at PS 10.

1985

January MP 200: Temporary bypass tie-in, pipe settlement.

April MP 200: Final tie-in of 48-inch permanent reroute (404.7 feet added to total pipeline length, April 22, 1985). Reroute due to pipe settlement.

1986

Oct. 10 Steele Creek: Permanent welded sleeve installed over bolted split sleeve.

Nov. 18 PS 10: Replaced "tee" damaged by stuck scraper pig.

1987

Sept. 29 MP 166.41 to 166.43: Atigun Pass. Replaced 234 feet of buckled pipe.

Aug. 25 Mechanical damage covered with three-foot welded sleeve.

1988

No major repairs.

1989

January 30 sleeves installed for corrosion repairs.

1990

January 86 sleeves installed for corrosion repairs.

Nov. 23 MP 172.62: Dent covered by six-foot welded sleeve.

Dec. 3 Mechanical damage covered with bolted clamp, later covered with a split "tee" (part of Atigun floodplain pipe replacement project).

1991

January 18 sleeves installed for corrosion repairs.

Mar. 8 MP 779.47: Mechanical damage covered by four-foot welded sleeve.

Apr. 6 MP 756.80: Mechanical damage covered by four-foot welded sleeve.

September MP 157-165.5: Atigun Floodplain Pipe Replacement Project (FPRP) completed. Permanent reroute of 8.5 miles of mainline pipe due to corrosion.

1992

No major repairs.

1993

June 6 MP 775: Mechanical damage covered by three-foot welded sleeve.

1994

July 22 CV 9: Bypass spool replacement and drain line repair.

July 30 CV 86: Bypass and drain line repair.

Sept. 30 CV 74: Drain line repair.

1995

Mar. 15 CV 55: Replace actuator.

June 8 CV 89: Replace actuator.

July 14 RGV stem leak repair.

Sept. 15 Extend Chena Hot Springs Road casing.

1996

Apr. 25 CV 92: Replace bypass line.

1997

Feb. 8 Wilbur Creek: Install "armadillo" sleeve; repair due to corrosion.

June 20 MP 775.75: Mechanical damage covered by 2.5-foot welded sleeve.

Oct. 9 MP 799.68: Corrosion repair covered by 4.8-foot welded sleeve.

1998

Mar. 19 Tanker vapor control system startup at VMT.

Sept. 25 Replaced RGV 80 and repaired CV 122.

1999

Apr. 26 MP 652: Two sleeves installed for corrosion repair.

Sept. 11 RGV 60: Replaced.

2000

May 26 MP 170: Completed reset and repair of tripped anchors, a result of the collapse of vapor pocket after pipeline restart.

June 1 MP 710.76: Mechanical damage covered by two, two-foot welded sleeves.

Sept. 16 PS 9: Replaced CV 74 and M-2 valve.

2001

Sept. 22 Pipeline shut down for mainline valve maintenance and integrity test, and performance evaluation of two 48-inch mainline RGVs.

Oct. 4 MP 400: Bullet hole repaired with hydraulic clamp. Clamp later replaced with a threaded O-ring fitting.

2002

July 27 RGV 39: Pipeline shut down to replace valve.

November MP 588: Repaired or replaced damaged shoes and VSM crossbeams from 7.9 earthquake on November 3, 2003.

July 10 Set full-close limit switches on valves along pipeline; changed out three valves in gas building at PS 3.

2003

July 18-19 Set full-close limit switches on RGVs; other pump station work.

Aug. 8-12 Set full-close limit switches on RGVs; other pump station work.

Aug. 15 Performed maintenance and tests on selected RGVs; OCC special commands.

Sept. 10-12 Set full-close limit switches on RGVs; other pump station work.

2004

July 10-11 Pig trap valve replacement at PS 4; set full-close limit switches on valves along pipeline.

Aug. 16-17 Tie-in work at PS 1 and PS 3 for Strategic Reconfiguration; perform maintenance and tests on selected RGVs; OCC special commands.

2005

June 19-20 Pig trap valve replacement at PS 4, due to factory defective valve installed in 2004. Install new mainline CV at PS 7.

July 23-24 Tie-in work at PS 9 for Strategic Reconfiguration. Ramp down and isolated PS 12 and replaced mainline through the station. Isolated all buildings at PS 12 for future demolition/salvage.

REPAIRS, MAJOR

2006

July 22-23 Isolated PS 10 from the mainline and installed a mainline 48-inch CV inside the manifold building. Replaced the 48-inch mainline check valve 109 located on the south bank of the Klutina River. Both these scopes were accomplished in the 36-hour shutdown.

2007

No major repairs.

2008

June 28-29 Replaced RGV 72 and removed the T's for SR configuration at PS 9.

Aug. 16-17 1,700 feet of bypass pipe installed at PS 2, permanently disconnecting PS 2 from TAPS.

shutdowns, pipeline:

Following is a chronology of TAPS pipeline shutdowns after oil first reached Valdez.

1977

Aug. 2	40 min	Equipment malfunction.
Aug. 15	110 hr, 11 min	PS 9 sump overflow.
Sept. 20	59 min	Equipment malfunction.
Oct. 9	4 hr, 14 min	Producer shutdown.

1978

Jan. 5	1 hr	Equipment malfunction.
Jan. 10	4 hr	Equipment malfunction.
Jan. 16	4 hr, 22 min	Equipment malfunction.
Jan. 17	3 hr, 41 min	Equipment malfunction.
Feb. 15	21 hr, 31 min	Sabotage, Steele Creek.
May 6	7 hr, 18 min	Equipment malfunction.
May 30	2 hr, 22 min	Equipment malfunction.
Sept. 4	3 hr	Equipment malfunction.
Dec. 17	2 hr, 8 min	Equipment malfunction.

1979

June 10	53 hr, 37 min	Atigun Pass leak.

1980

May 12	3 hr, 37 min	PS 10 crude tank valve leak.
Oct. 17	5 hr, 16 min	Scheduled maintenance.

1981

Jan. 1	15 hr, 38 min	CV 23 leak.
Feb. 8	3 hr, 54 min	Equipment malfunction.

1982

June 7	2 hr, 48 min	Equipment malfunction.
Dec. 22	12 hr	Equipment malfunction.

1983

No shutdowns.

1984

Mar. 20	57 hr, 40 min	Scraper pig stuck at CV 4. PS 4 trap relocation.
June 17	1 hr, 7 min	Equipment malfunction.
Oct. 5	5 hr	Producer maintenance.

1985

Jan. 21	66 hr	MP 200 bypass tie-in.
Apr. 22	20 hr, 40 min	MP 200 final reroute tie-in of 48-inch pipe (404.7 feet added to total pipeline length).
June 26	42 min	Equipment malfunction.
October		Removed stuck pig at PS 10.
Nov. 9	10 hr, 15 min	PS 1 explosion and fire.

1986

Sept. 26	31 hr, 50 min	Removed scraper pig at PS 10.
Nov. 18	16 hr, 54 min	Replaced "tee" at PS 10.

1987

Sept. 29	24 hr, 6 min	Atigun Pass pipe replacement.

1988

No shutdowns.

1989

Feb. 26	1 hr, 31 min	Power failure at PS 1.
	32 min	PS 1 block line.
Oct. 20	5 hr, 16 min	Repair corroded pipe at MP 144.2.

1990

Mar. 21	4 hr, 10 min	PS 3, broken valve 320.
June 12	12 hr, 39 min	PS 1, valve D2 pipe replacement.
June 12	1 hr, 34 min	PS 9 isolated station, valve M2 leak.
Nov. 20	3 hr, 17 min	Corrosion repair, welding at MP 157.87.
Dec. 15	1 hr, 42 min	High inventory and power failure at VMT.

1991

No shutdowns.

1992

Aug. 7	1 hr, 49 min	Uncommanded closure of RGV 73, electric short.
Oct. 7	35 min	Segment 11 RGV intransit indication.
Oct. 16	7 min	Segment 11 RGV intransit indication.

1993

May 20	9 min	PS 3 isolated gas building, broken fitting.
June 22	38 min	RGV 98; a false intransit indication, MLR2 project work.
Oct. 29	20 min	Loss of communication with segment 12 RGVs.

1994

Jan. 24	1 hr, 26 min	Isolate station at PS 10 caused by leaking nipple on 26-inch yard check valve.
Feb. 14	24 min	Isolate gas building at PS 1, faulty gas detector.
Apr. 15	24 hr, 28 min	Replace 002 valve at Valdez and troubleshoot segment 4 RGVs.
Apr. 18	7 hr, 57 min	Work on PS 4 systronics master panel.
June 8	1 hr	Communications failure with RGV 73, failed power converter.
June 12	36 min	Communications failure with RGV 69, battery failure.
Oct. 15	2 hr, 20 min	Communications failure with RGV 40.

1995

Feb. 22	19 min	PS 9 shut down by high-pressure shutdown switch.
June 16	2 hr, 25 min	Communications failure to segment 4 RGVs, RGVs 31-35 closed.
July 10	1 hr, 41 min	RGV 118 intransit indication.
July 10	29 min	Communications failure to segment 10, RGV 95.
July 11	1 hr, 30 min	Communications failure with RGV 95.
Sept. 11	15 hr, 45 min	Scheduled maintenance.

SHUTDOWNS, PIPELINE

Sept. 12	4 hr, 51 min	Completion of scheduled PS 2 maintenance.
Sept. 18	1 hr, 42 min	Communications failure with RGV 37.
Nov. 7	12 min	Fire alarm in PS 10 pump house building.

1996

Feb. 17	2 hr, 7 min	Communications failure with RGV 113.
May 6	21 hr, 45 min	Scheduled maintenance.
May 7	7 hr, 17 min	PS 8 valve seal repair; repair leaking PS 4 M2 valve body drain valve.
July 12	10 hr, 25 min	Scheduled maintenance, preparations for PS 8 and PS 10 rampdown.
Aug. 1	8 hr, 40 min	Scheduled maintenance as part of ramping down PS 8 and PS 10.
Aug. 6	11 hr, 2 min	Schedule maintenance as part of ramping down PS 8 and PS 10.

1997

Jan. 12	3 hr, 24 min	Communications failure with RGV 124.
Jan. 13	13 min	Communications failure at RGVs 62, 65, and 67.

June 1	2 hr, 9 min	False RGV indication at RGVs 32-44, segment 4.
June 26	5 hr, 44 min	Communications failure with RGVs in segment 12.
July 1	1 hr, 45 min	Communications failure with RGVs 31-33.
Aug. 1	17 hr, 49 min	Scheduled maintenance for PS 2 and PS 6 rampdown preparation.
Aug. 8	19 hr, 29 min	Placed PS 6 in ramped down status.
Aug. 12	25 min	False transit indication, PS 11, M-1 valve.
Sept. 19	14 min	False transit indication, RGV 103.
Nov. 8	1 hr, 17 min	Communications failure, RGV 45.

1998

May 18	5 hr, 9 min	PS 1 in-rush vapor test and vibration test of VMT incoming relief piping.
Aug. 5	24 min	Segment 10 RGVs in invalid status.
Aug. 14	5 hr, 4 min	Communications failure, segment 10.
Sept. 25	28 hr, 40 min	Valve maintenance, replaced RGV 80 and repaired CV 122.

Nov. 15	3 hr, 23 min	Communications failure to Segment 4 RGVs, relay failure.

1999

Feb. 15	15 min	Communications failure at RGV 60.
Feb. 17	1 hr, 25 min	Communications failure at RGV 105.
Feb. 23	2 hr, 12 min	Communications failure at RGV 32, battery failure.
Mar. 20	1 hr, 7 min	Communications failure at RGV 80.
Mar. 25	1 hr, 57 min	Communications failure at RGV 102.
Apr. 3	26 min	Communications failure at RGV 91.
Apr. 11	56 min	Communications failure at RGV 69.
June 8	1 hr, 13 min	Communications failure with all segment 4 RGVs.
June 17	34 min	Communications failure at RGV 91.
July 5	34 min	Communications failure at RGV 43.
July 5	1 hr, 52 min	Maintenance at Tea Lake, repeater loss of communication to segment 4 RGVs.

Sept. 11	25 hr, 49 min	Valve maintenance, replaced RGV 60, tested 46 mainline valves and completed 165 other maintenance tasks.
Oct. 16	1 hr, 10 min	Communications failure at RGV 67.
Nov. 9	26 min	Communications failure at RGV 53.
Nov. 13	8 hr, 6 min	Planned maintenance and autologic testing.
Dec. 8	2 hr, 34 min	False fire alarm in PS 1 booster pump building.
Dec. 23	36 min	Communications failure with RGVs 62 and 67.
Dec. 25	4 hr, 16 min	Communications failure at RGV 121.

2000

Feb. 10	1 hr, 24 min	Communication failure at RGV 42.
Apr. 17	1 hr, 26 min	PS 4 unintended stop flow/close RGV initiated due to invalid state transmitted from RGV 35A while troubleshooting power failure.
Apr. 22	43 min	Loss of visibility of PS 11 M-1.
Aug. 28	1 hr, 39 min	Communications failure at RGV 121A, battery failure.

Sept. 16	29 hr, 39 min	Planned line-wide maintenance shutdown.
Oct. 7	7 hr, 31 min	Planned line-wide shutdown for maintenance of mainline valve leak test.

2001

Feb. 26	1 hr, 24 min	PS 5 false fire alarm.
Apr. 3	2 hr, 59 min	Communications failure at RGV 32.
Apr. 18	6 hr, 38 min	Work on PS 4 Systronics Master Panel.
June 25	1 hr, 10 min	Automatic controls activated during planned failover of SCADA host computer.
Aug. 16	1 hr, 30 min	Communications failure at RGV 60.
Aug. 26	58 min	Communications failure at RGV 123.
Sept. 5	2 hr, 59 min	Communications failure at RGV 124.
Sept. 22	21 hr, 4 min	Planned maintenance shutdown.
Oct. 4	60 hr, 30 min	Bullet puncture at MP 400.
Oct. 18	1 hr, 57 min	PS 4 false fire indicator.
Oct. 28	4 hr, 5 min	Backbone communication system disruption.

Nov. 1	2 hr, 48 min	Communications failure at RGV 44.
Dec 20	2 hr, 30 min	Communications failure at RGV 44.

2002

Jan. 5	2 hr, 6 min	Segment 10 to 11 RGVs closed due to Copper Valley Electric Association power failure.
May 9	1 hr, 10 min	Communications failure at RGV 108.
June 11	2 hr	Communications failure at RGV 97.
July 27	29 hr, 57 min	Planned maintenance shutdown.
Sept. 16	35 min	Seismic system testing.
Oct. 12	3 hr, 20 min	Planned maintenance at PS 4.
Nov. 3	66 hr, 33 min	7.9 earthquake at MP 588.
Nov. 27	1 hr, 49 min	Communications failure, segment 4.

2003

Mar. 21	2 hr	PS 4 unintended stop flow/close RGVs 31-35.
July 18	5 hr, 56 min	Planned pipeline shutdown to set full closed limit switches on RGVs 118,119, 121, 121A.

July 19	4 hr, 48 min	Planned pipeline shutdown to set full closed limit switches on RGVs 115, 116, 117 and PS 11 BL2.
Aug. 8	4 hr, 1 min	Planned pipeline shutdown to set full closed limit switches on RGVs 26, 35, and PS 4 BL 1 and 2.
Aug. 12	3 hr, 52 min	Planned maintenance shutdown.
Sept. 10	4 hr, 5 min	Planned pipeline shutdown for full closed torque/limit switch verification/ calibration for RGVs 57, 72, 88 and 101.
Sept. 12	3 hr, 56 min	Scheduled pipeline shutdown for full closed torque/limit switch verification/calibration for RGV's 35, 35A, 69, 73 and 91.
Nov. 17	1 hr, 39 min	Pipeline shutdown due to communication failure at segment 6.

2004

Jan. 24	5 hr, 51 min	Communication failure at valve 972.
Apr. 28	3 hr	Planned maintenance shutdown.
May 22	41 min	Testing of Earthquake Monitoring System.
July 8	1 hr, 25 min	Communication failure at RGV in segment 9 and 10.

July 10-11	31 hr, 36 min	Planned maintenance shutdown.
Aug. 16	17 hr	Planned maintenance shutdown.
Aug. 30	3 hr, 9 min	Scheduled mini pipeline shutdown for planned maintenance.
Dec. 26	3 hr, 31 min	Communication failure at RGV 45.

2005

June 19	35 hr, 42 min	Planned maintenance shutdown.
July 8	1 hr, 17 min	Controlled pipeline shutdown to investigate CV 60B.
July 23	32 hr, 32 min	Planned maintenance shutdown.
Sept. 18	4 hr, 51 min	Scheduled mini pipeline shutdown for planned maintenance.
Nov. 3	3 hr, 20 min	Communication failure to all segment 12 RGVs.

2006

July 22-23	36 hr	Replace CV 109, Replace CV 109, and perform additional maintenance tasks.
Oct. 10	9 hr, 45 min	Communication failure at RGVs 117,118, 119, 121 and 121A, due to flooding between PS 12 & the VMT.

Oct. 21	3 hr, 30 min	Test SIPPS controls of RGVs, south of PS 3 to north of PS 9.
Oct. 26	3 hr, 30 min	Test SIPPS control of RGVs, south of PS 9 to PS 10.
Nov. 4	3 hr, 30 min	Test SIPPS control of RGVs, south of PS 11 to Valdez.
Nov. 7	3 hr, 38 min	Systronics power supply problem in MTU at PS 4.
Nov. 10	2 hr, 10 min	Systronics MTU power supply problem.
Nov. 15	16 hr, 25 min	Shut down due to high inventory in Valdez.
Nov. 17	6 hr, 8 min	Shut down due to high inventory in Valdez and problems at PS 4.
Nov. 18	22 hr, 30 min	Shut down to build inventory at PS 1.

2007

Oct. 29	7 hr, 16 min	Planned pipeline shutdown for scheduled maintenance at PS 4, RGVs 31 and 32 and MP 178.8 DRA test bed site.

2008

Feb. 23	6 hr, 29 min	Planned pipeline mini-shutdown for SIPPs cutover work.
Mar. 25	7 hr	Planned pipeline mini shutdown for scheduled work at PS 1, 3, 4, 5, 8 and 9.
Apr. 25	7 hr, 17 min	Planned pipeline mini shutdown for scheduled maintenance.
May 30	1 hr, 48 min	Unplanned shutdown, PS 9 MLUs shut down and utility breaker opened due to GVEA power upset.
June 28	28 hr, 49 min	Planned pipeline shutdown for scheduled maintenance.
Aug. 16	35 hr, 37 min	Planned pipeline shutdown for scheduled maintenance.
Oct. 24	6 hr, 10 min	Planned pipeline mini-shutdown for scheduled maintenance.
Dec. 9	43 min	Unplanned shutdown, PS 9 MLUs shut down and station power failure as a result of false fire detect indications in PS 9 VFD modules 1 and 2.
Dec 13	5 hr, 16 min	Planned pipeline mini-shutdown for scheduled maintenance.

SHUTDOWNS, PIPELINE

notes

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