



VIA EMAIL ONLY
(bill.walker@alaska.gov)

April 7, 2017

Governor Bill Walker
State of Alaska
P.O. Box 110001
Juneau, AK 99811-0001

Dear Governor:

Thank you for the seriousness with which you and your staff have addressed the various industry compliance problems in Cook Inlet recently. I'm sure the distractions are unwelcome.

Today I learned of yet another incident in Cook Inlet – this time involving a gas line at Hilcorp's Steelhead platform. After what we've experienced the past few months—and what we know about the effects of Cook Inlet's unforgiving forces on pipelines and other facilities—it's clear we must address the issue of aging infrastructure in Cook Inlet if we hope to continue any semblance of responsible development.

Inletkeeper has been engaged in these issues for many years, and at this stage, we see several steps that need to happen to ensure we are doing development right in Cook Inlet.

First, we must understand the status of infrastructure in Cook Inlet. In 2002, Inletkeeper produced a report on Cook Inlet pipelines, and in 2005, we updated it (see attached). These reports highlight the extent of infrastructure installed in Cook Inlet in the 1960's, and provide a good starting point for conducting a comprehensive risk assessment or implementing an Inlet-wide integrity management plan. Regardless what we call it, we need a thorough audit of all pipelines and associated facilities in Cook Inlet to ensure they can protect our fisheries and support safe and reliable operations.

Second, we need to review and revise bonding and surety levels and requirements to ensure Alaskans are not stuck paying for decommissioning, removal and remediation (DR&R) costs for outdated infrastructure. A 2013 report commissioned by Inletkeeper found DR&R costs to address platforms and pipelines in Cook Inlet to be well over \$ 1 billion dollars, while the amounts help in bonds and other sureties were a small fraction of that amount (see attached).

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Because much of the infrastructure in Cook Inlet is pushing past the 50-year mark, it's only prudent for the state to make sure we have what it takes to address realistic DR&R scenarios.

Finally, on the west side of Cook Inlet lies the Drift River Oil Terminal (DROT). The facility was built in the mid-1960's, and it gathers and stores oil produced in Cook Inlet before loading it onto tankers for transit to processing facilities on the east side of Cook Inlet and elsewhere.

The facility is problematic for several reasons. For example, it is located at the base of an active volcano (Mt. Redoubt), and eruptions in 1989-90 and 2009 have created heightened risks to workers and local fisheries. The facility also necessitates oil tanker loadings, transits and unloadings in and around Beluga whale critical habitat, without the aid of escort tugs similar to Prince William Sound. Finally, the aging piping and other infrastructure at the facility are increasingly vulnerable to leaks and spills.

A state-of-the-art modern pipeline across Cook Inlet would address all these concerns, while creating Alaskan jobs and providing a much safer alternative for our fish and whale habitat than continuing to rely on the Drift River Oil Terminal.

I know with the Legislature still in session, your days are busier than usual. So, thank you for your attention to this letter, and I hope to meet with you or your staff in the coming weeks to explore possible paths forward.

Yours for Cook Inlet,

A handwritten signature in black ink, appearing to read "Bob Shavelson".

Bob Shavelson
Inletkeeper

Cc: (VIA EMAIL ONLY)
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John Hendricks, Governor's Office
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Lurking Below: Oil and Gas Pipeline Problems in the Cook Inlet Watershed



Lois N. Epstein, P.E.
Senior Engineer and Oil and Gas Industry Specialist

September 2002



COOK • INLET • KEEPER

Lurking Below:

**Oil and Gas Pipeline Problems in the
Cook Inlet Watershed**

Lois N. Epstein, P.E.
Senior Engineer and Oil and Gas Industry Specialist
Cook Inlet Keeper

September 2002

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Any errors in the study are the author's responsibility. Comments on the study are welcome and should be directed to:

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About the author: Lois N. Epstein, P.E. has worked for Cook Inlet Keeper as a Senior Engineer and an Oil and Gas Industry Specialist since May 2001 when she moved to Alaska from Washington, DC where she worked for Environmental Defense (formerly Environmental Defense Fund) for over thirteen years. Previous to these positions, Epstein worked for two private consulting firms and for the U.S. EPA Region 9 Office of Water. Currently, Epstein is seeking to improve the performance of the oil and natural gas infrastructure in the Cook Inlet watershed and to prevent new oil and gas development in sensitive areas through research, writing, and speaking, including invited testimony before the U.S. Congress. She is a licensed Professional Engineer in the State of Maryland and is a member of the federal Office of Pipeline Safety's advisory committee on hazardous liquid pipelines. Epstein has a masters degree from Stanford University in Civil Engineering with a specialization in environmental engineering and science, and undergraduate degrees from both Amherst College (in English) and MIT (in mechanical engineering), obtained as part of a 5-year liberal arts/engineering program of study. President Clinton nominated Epstein in October 2000 to the Chemical Safety and Hazard Investigation Board, however the U.S. Senate did not vote on her nomination before the end of the 106th Congress.

About Cook Inlet Keeper: Cook Inlet Keeper is a citizen-based, nonprofit, membership organization dedicated to protecting Alaska's Cook Inlet watershed and the life it sustains. Cook Inlet Keeper has its main office in Homer and a second office in Anchorage. www.inletkeeper.org

Lurking Below: Oil and Gas Pipeline Problems in the Cook Inlet Watershed

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Lurking Below: Oil and Gas Pipeline Problems in the Cook Inlet Watershed

Executive Summary

Oil and natural gas pipelines have operated in the Cook Inlet watershed since the mid 1960s, and there now are over 1000 miles of such pipelines. Because spills from these pipelines occur on an ongoing basis, Cook Inlet Keeper began a research project in 2001 to analyze the frequency, cause, and location of the watershed's pipeline releases during the most recent five year period, 1997-2001. Additionally, Keeper analyzed the strengths and deficiencies of the regulatory context under which the pipelines operate and pipeline companies' performance.

This study provides the results of the background research and the analyses, a list of potential priorities for Cook Inlet watershed pipeline improvements based on the spill record, and common-sense recommendations following from the analyses for state, federal, industry, and public interest organization actions to increase pipeline safety and environmental protection. In producing this study, Keeper's goals are to stimulate dialogue and to instigate changes that improve Cook Inlet watershed pipeline infrastructure and operations.

Principal Findings (1997-2001 data)

- Reported Cook Inlet watershed pipeline spills occur on average once each month (Sections I and III);
- Onshore oil pipelines have a disproportionately high spill rate compared to offshore pipelines (Section III);
- The total reported volume spilled from oil pipelines is over 50,000 gallons per year on average (Section III);
- The average oil pipeline spill size is 3,964 gallons, and the median spill size is 15 gallons (Section III);
- 30% of the oil pipeline spills exceed 50 gallons (Section III);
- The top 8 oil spills were from Unocal pipelines, with 7 of those 8 at the Swanson River Field in the Kenai National Wildlife Refuge (Section III);
- The federal government has issued only one penalty (\$5,000) to Cook Inlet watershed oil pipeline operators during this 5 year period, though it sent 17 letters on non-compliance and safety issues to watershed pipeline operators during this time (Section IV);
- It is highly likely that the exemptions in federal pipeline regulations for rural pipelines result in adverse environmental consequences through increased spill rates (Section V), and,
- A "report card" on Cook Inlet watershed pipeline company performance from 1997-2001 shows the following (Section V):

Performance = % of Cook Inlet Oil Pipeline Spills / % of Cook Inlet Oil Pipeline Mileage	Company
POOR	Unocal Forest Oil (formerly, Forcenergy. Note that, in contrast to Unocal, all spills were small)
FAIR	XTO Energy (formerly Cross Timbers, Shell)
GOOD	Tesoro
EXCELLENT	Cook Inlet Pipe Line Kenai Pipe Line Signature (newly installed pipeline, however)

Ten Key Recommendations

State:

1. The Alaska Department of Environmental Conservation (ADEC) should examine its data – and collect new data, as appropriate – on “gathering lines” (including a Best Available Technology study) and oil and natural gas production field wastewater pipelines to see if such lines should have strengthened regulations,
2. ADEC should evaluate whether there would be a net resource gain for oversight of Alaska’s pipelines by receiving federal approval of state pipeline safety inspection programs; if yes, the state should pursue this approach, and,
3. The Alaska legislature should modify its spill penalty requirements under AS 46.03.758 so that “oil” does not exclude “crude oil” for penalties unrelated to regulatory violations.

Federal:

4. The Office of Pipeline Safety (OPS) definition of “high consequence area” should be interpreted in a way that maximally protects the environment including the entire Cook Inlet watershed,
5. OPS should eliminate the exemptions currently in federal regulations for oil pipelines in rural areas,
6. OPS should ensure that offshore oil and natural gas pipelines with onshore separation or processing operations are not exempt from its regulations, while pipelines with offshore separation or processing operations are covered by these regulations, and,
7. OPS should levy and publicize significant penalties for Cook Inlet watershed pipeline regulatory violations and do likewise nationwide to send a strong message that regulatory violations are unacceptable.

State and Federal:

8. In order to assist in ongoing public and regulatory oversight over pipelines, ADEC and OPS should require pipeline companies to report operational data related to pipeline integrity on a regular basis, and the agencies should make this information available to the public via a user-friendly database (i.e., a pipeline “right-to-know” program) which does not compromise pipeline security.

Industry:

9. Pipeline operators and owners should act voluntarily and pro-actively to ensure best possible performance for their Cook Inlet watershed pipelines including: frequent, high-resolution smart-pigging; early replacement and upgrading of higher-risk pipelines; extensive corrosion control monitoring from day one of pipeline installation; and employing sophisticated leak detection and shut-off valve technologies.

Public Interest Organizations:

10. Public interest organizations should promote actions that can be taken immediately to improve pipeline safety and environmental protection rather than extensive, additional studies of the problems posed by the watershed’s pipelines.

I. Introduction

Over 1000 miles of oil and natural gas pipelines¹ pass through the Cook Inlet watershed's spectacular scenery, wildlife habitats, and waterways. Though pipelines can cause environmental damage during their construction phase, the most serious environmental and safety problems generally come from unanticipated releases during pipeline operations from pipeline failures or poor operating practices (e.g., maintenance-related spills). Pipeline operators can prevent the vast majority of oil and natural gas pipeline releases -- particularly in Alaska where third-party damage is relatively infrequent -- so releases should be a very rare occurrence. Nevertheless, according to Alaska Department of Environmental Conservation (ADEC) data from mid-1995 through mid-2001, Cook Inlet pipeline operators reported spills at a rate of approximately one per month.² Cook Inlet natural gas transmission pipeline operators, in contrast, reported only one release of natural gas during this time period to the federal government (there are no state reporting requirements); as a result, this study focuses primarily on oil pipelines.

The region's oil and natural gas pipeline infrastructure is aging – the oldest Cook Inlet pipelines date from the mid 1960s (see Appendix 1). Nevertheless, well-designed and operated pipelines should be usable for many decades. The unacceptably high rate of one spill per month cited above indicates, however, that a number of Cook Inlet oil (and oil-containing wastewater) pipelines likely have design and/or operating deficiencies. These deficiencies are made worse by:

- The lack of comprehensive and effective state and federal regulatory frameworks for pipelines, including the lack of permits for pipeline operation,
- The need for more federal and/or state fines both before and following pipeline releases, including penalties for releases that occur despite compliance with regulations,
- The limited number of regulators who oversee pipelines, and
- Inadequate investment in pipeline infrastructure and operations by some pipeline companies.

In addition to these problems with the current oversight structure for pipelines, there currently is a lack of data available to the public on pipeline operations, i.e., there is no public “right-to-know” about pipelines.

II. What's At Stake?

Oil and natural gas pipeline operations can pose a serious threat to safety, public lands, and private property. Oil pipeline ruptures and slow leaks can:

- Contaminate water and wildlife, as well as public, residential, and crop lands,
- Cause injuries and deaths from explosions and fires, and
- Release greenhouse gases.

¹ This figure includes the generally longer “transmission” pipelines and “gathering” lines (i.e., pipelines from oil and natural gas wells), as well as natural gas “distribution” pipelines which connect homes and businesses to gas transmission pipelines.

² See http://www.state.ak.us/dec/dspar/ciforum/ci_spilldata.htm, covering July 1, 1995 until June 30, 2001.

Additionally, because it is essentially impossible to restore contaminated groundwater to a pre-contamination condition, oil pipeline releases frequently diminish property values. Likewise, the impacts of oil and natural gas pipeline releases can reduce an area's attractiveness to tourists.

One of the most well-known oil pipeline tragedies occurred in June 1999 in Bellingham, Washington, when a gasoline pipeline rupture followed by an explosion killed three youths and destroyed a significant portion of a forested city park.

While oil pipeline releases primarily impact the environment, natural gas pipeline releases can pose significant safety hazards. Even in rural areas, natural gas pipeline releases can be deadly -- in New Mexico in the summer of 2000 for example, 12 campers, including seven children, died when an El Paso Natural Gas Company transmission pipeline release ignited.

The Cook Inlet watershed contains over 225 miles of active oil pipelines and over 690 miles of active natural gas pipelines (see Appendix 1), approximately 100 miles of active oil and natural gas "gathering lines"³ in several onshore production fields,⁴ and numerous miles of active natural gas distribution pipelines particularly in the Anchorage area. Oil and natural gas transmission pipelines in the watershed are located in national wildlife refuge and national forest lands, and they pass through state park and state recreation area lands and offshore waters owned by the state (see Figure 1). The Cook Inlet watershed's diverse and productive public and private lands and waters support a wide variety of wildlife including: black and brown bears, moose, migratory birds, whales, Dolly Varden and rainbow trout, halibut, and all five species of Pacific salmon.

Cook Inlet communities depend on the watershed's healthy waters and habitats for their livelihoods. Native villages pursue a subsistence lifestyle that is centuries old, with wild foods supplying a high percentage of villagers' diets. Additionally, each year over one million tourists from around the world travel to the Cook Inlet region, including Anchorage.

Oil operations are an important part of the Cook Inlet watershed's economic base. Nevertheless, there have been several, relatively recent oil pipeline spills in the watershed which illustrate the extent of the environmental impacts that can result from releases. The following examples, two onshore (Figures 2-3) and one offshore (Figure 4), show how large oil pipeline spills can be, and how they can damage environmentally-sensitive areas.


³ "Gathering lines" transport oil or gas relatively short distances from production wells to transmission pipelines or storage tanks.

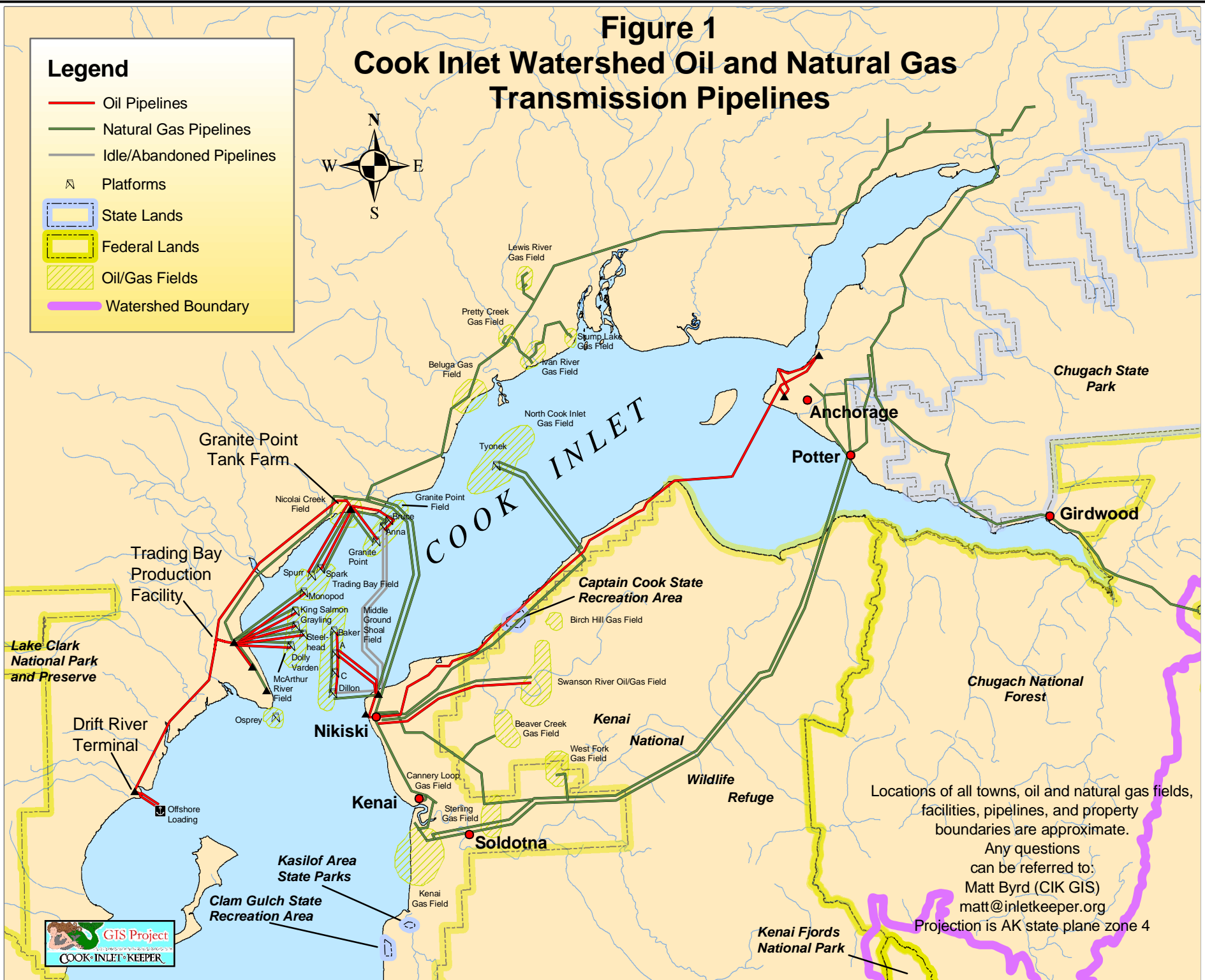
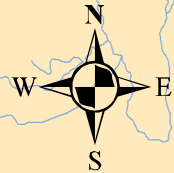
⁴ Unocal's Swanson River Field in the Kenai National Wildlife Refuge alone contains approximately 60 miles of oil pipelines, and there are at least eleven oil and natural gas onshore production fields in the Cook Inlet watershed.

Figure 1

Cook Inlet Watershed Oil and Natural Gas Transmission Pipelines

Legend

- Oil Pipelines
- Natural Gas Pipelines
- Idle/Abandoned Pipelines
-  Platforms
- State Lands
- Federal Lands
- Oil/Gas Fields
- Watershed Boundary



Locations of all towns, oil and natural gas fields, facilities, pipelines, and property boundaries are approximate.

Any questions
can be referred to:
Matt Byrd (CIK GIS)
matt@inletkeeper.org

Projection is AK state plane zone 4





Figure 2. January 7, 1999 photo of the Unocal 6" gathering pipeline spill in the Kenai National Wildlife Refuge. Black liquid is the released pipeline contents, which melted the three feet of snow present. Photo source: Alaska Department of Environmental Conservation website.

The Unocal 1/99 Gathering Line Spill in the Kenai National Wildlife Refuge

A recreational snowmachiner discovered a pipeline release of approximately 229,000 gallons of crude oil and produced water⁵ on January 6, 1999 in the Kenai National Wildlife Refuge. Cleanup of the approximately 9,000 square feet of contaminated land in a wooded area and the drainage area nearby, including open burning of oil-contaminated brush and construction of a new landfill cell, took 6 months; a low level of benzene contamination remains. The 3/8" hole in the 6" gathering line likely was from corrosion, however Unocal performed the failure analysis and ADEC does not confirm the release cause in its final "Situation Report" on its website.⁶

⁵ Produced water comes to the surface during oil and gas drilling operations and can include drilling additives. Produced water can contain pollutants such as oil and grease, acids, ammonia, benzene, naphthalene, and metals (e.g., chromium, copper, lead, zinc).

⁶ See http://www.state.ak.us/dec/dspar/perp/swanpipe2/status_13.htm.



Figure 3. August 1, 2001 photo of the Tesoro 10” transmission pipeline spill in Captain Cook State Recreation Area. The pinholes spraying petroleum products (i.e., jet fuel, diesel) likely are the result of corrosion, possibly related to metal interactions with the nearby Phillips Petroleum natural gas pipeline. Photo source: Alaska Department of Environmental Conservation website.

The Tesoro 7/01 Transmission Pipeline Spill in Captain Cook State Recreation Area

A Phillips Petroleum operator of a nearby natural gas pipeline discovered a sizable release of jet fuel, diesel, and/or gasoline into Captain Cook State Recreation Area on July 31, 2001, between the Swanson River and Bishop Creek near Nikiski. Cleanup of this release was still ongoing during the summer of 2002 (cleanup included tree removal and construction of a temporary road), with approximately 150,000 gallons of contaminated water and fuel collected to date. The total amount spilled is unknown. The release contaminated vegetation and a small stream, and contaminated “hot-spots” remain. The multiple pinholes in the oil transmission pipeline likely were caused by corrosion.⁷

⁷ See <http://www.state.ak.us/local/akpages/ENV.CONSERV/dspar/perp/tesoro5/index.htm>.



Figure 4. Photo of the Unocal 8” offshore oil pipeline which released 400-500 gallons of crude oil directly into Cook Inlet on October 23, 1999. The pencil shows the approximate length of the pipeline failure area. Photo source: Gary Folley, Alaska Department of Environmental Conservation (Soldotna office).

The Unocal 10/99 Dillon Platform Pipeline Spill into Cook Inlet

Unocal sensors detected a drop in pressure at 5 a.m. on October 23, 1999 in the 5.6 mile, low-pressure 8” pipeline between the offshore Dillon Platform and Unocal’s East Foreland Delivery Facility in Nikiski. By 11 a.m., the sheen on Cook Inlet was 10 miles long; by the next day, the sheen was 4 miles long and 500 yards wide. Skimmers and other equipment recovered some unknown portion of the oil. ADEC estimates that the total amount released was 400-500 gallons. Unocal conducted the analysis of failure cause, and the results are not readily available to the public via ADEC’s website.⁸ This pipeline is no longer in use.

⁸ See <http://www.state.ak.us/local/akpages/ENV.CONSERV/dspar/perp/dillon/index.htm>.

III. Recent Spill Statistics

Following a January 10, 2002 ADEC forum on “Offshore and Onshore Oil Pipelines in Cook Inlet” in Soldotna, Cook Inlet Keeper performed an extensive review of the self-reported spill data submitted to ADEC.⁹ Keeper identified those spills resulting from oil and natural gas¹⁰ pipelines, including gathering lines, in the Cook Inlet region during the most recent five-year period (see Appendix 2). The 66 reported oil pipeline spills from 1997-2001,¹¹ or over one per month, break down as shown in Table 1. The 4 reported spills from Marathon’s natural gas pipelines during this period, included in Appendix 2 for completeness, were not considered in Table 1 or the following analysis.

In addition to Table 1 findings, analysis of the reported oil pipeline release data shows:

- The total known volume spilled from oil pipelines over this five year period is 261,620 gallons (52,324 gallons per year) with 4 of the 66 oil spills of unknown size, including the substantial July 2001 spill in Captain Cook State Recreation Area,
- The average spill size is 3,964 gallons; the median spill size is 15 gallons,
- 30% of the pipeline spills with known volumes are greater than 50 gallons, and
- The top 8 spills with known volumes during this 5-year period were Unocal pipelines, with 7 of those 8 at the Swanson River Field.

Following the January forum, ADEC completed its own review of the spill reports submitted and identified those resulting from pipelines in the Cook Inlet region using criteria similar to Keeper’s (see Appendix 3 for the ADEC database). Although ADEC tabulated approximately the same number of spills as Keeper over a similar time period (see Figure 5), the ADEC database is missing the 9/1/00 and 2/5/01 pipeline spills.¹² Additionally, the ADEC database contains only early estimates of volume spilled rather than final numbers, whereas the Keeper database contains the final estimates (see, for example, the 1/6/99 pipeline spill in Appendices 2 and 3 where the ADEC database contains a released volume that is only 1% of the final amount, listed in Appendix 2).

⁹ At the time of the forum, Cook Inlet Keeper presented Interim Findings on the rate of Cook Inlet oil pipeline spills based on a preliminary analysis of ADEC’s spill database. As presented by Keeper’s Lois Epstein during the forum, these statistics were upper limits for the pipeline spill rate, since many of the pipeline spills in the database could not be broken out and definitively attributed to pipelines (note: ADEC now is working to upgrade its spill database).

¹⁰ Natural gas pipelines report releases to ADEC when the releases are liquid, e.g., natural gas “condensates” that accumulate in pipelines in low areas.

¹¹ Not including Anchorage-area oil and natural gas pipeline spills, some of which are of substantial size. For example, up to 80,000 gallons spilled from a pipeline connecting the Port of Anchorage to Anchorage International Airport over several years (“Fuel Spill is Traced to Pipeline,” Elizabeth Manning, *Anchorage Daily News*, August 5, 2000).

¹² See <http://www.state.ak.us/local/akpages/ENV.CONSERV/dspar/perp/swanson2/index.htm> and http://www.state.ak.us/local/akpages/ENV.CONSERV/dspar/perp/dolly/status_04.htm, respectively, for these spill reports.

Table 1
Cook Inlet Oil Pipeline Release Data, 1997-2001

Characteristic	Releases in Each Category¹³
Onshore/Offshore	<i>Onshore</i> – 88% (pipelines without substantial offshore mileage represent approximately 42% of the oil pipeline mileage in the Cook Inlet watershed ¹⁴) <i>Offshore</i> – 12% (pipelines with substantial offshore mileage represent approximately 58% of the oil pipeline mileage in the Cook Inlet watershed)
Release Cause	<i>Corrosion (external and internal)</i> – 27% <i>Unknown/unreported</i> – 26% <i>Human error/maintenance-related</i> – 20% <i>Pipeline infrastructure failure (e.g., pipe, valves, fittings, patches, etc.)</i> – 14% <i>Abandoned pipeline release</i> – 8% <i>Frozen pipeline</i> – 5% <i>Third-party damage</i> – 2%
Pipeline Type and Location(s)	<i>Onshore oil gathering</i> : Swanson River Field – 41% <i>Onshore oil processing</i> : XTO Energy facility (6%), East Foreland (3%), Trading Bay (14%), West McArthur River Unit (12%), Wik Road (2%) – 36% <i>Offshore pipelines</i> : Anna (3%), Dillon (3%), Dolly Varden (1.5%), Granite Point (1.5%), Grayling (1.5%), King Salmon (1.5%), Bruce (1.5%) – 14% <i>Tank farm</i> : Granite Point – 8% <i>Onshore oil transmission</i> : Captain Cook State Recreation Area – 2%
Pipeline Operator	<i>Unocal</i> – 76% <i>Forest Oil (formerly Forcenergy)</i> – 12% <i>XTO Energy (formerly Cross Timbers, Shell)</i> – 8% <i>Tesoro</i> – 2% <i>BP (formerly Amoco)</i> – 2% <i>Cook Inlet Pipe Line</i> – 0% <i>Kenai Pipe Line</i> – 0% <i>Signature</i> – 0%

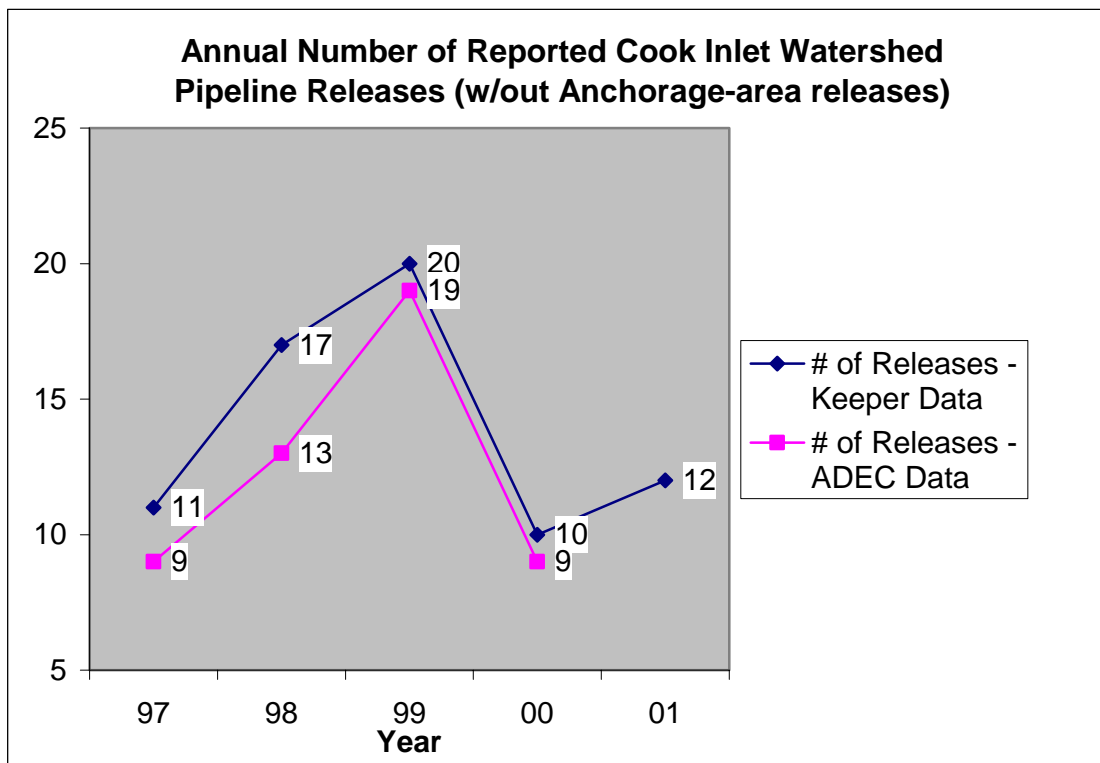
ADEC's pipeline spill database contains 68 spills over a 6-year period from mid-1995 until mid-2001, or approximately one per month. This database currently is undergoing revision, and its spill numbers and volumes released likely will be revised upward.¹⁵

¹³ Totals do not always equal 100% due to rounding.

¹⁴ Active and inactive Cook Inlet watershed oil pipeline mileage is approximately 311 miles, with 226 miles active, 25 miles inactive, and 60 miles in the Swanson River Field operated by Unocal (see Appendix 1).

¹⁵ Personal conversations with ADEC's Gary Folley, Environmental Specialist, in May 2002 and Leslie Pearson, Environmental Conservation Manager, in June 2002.

Figure 5



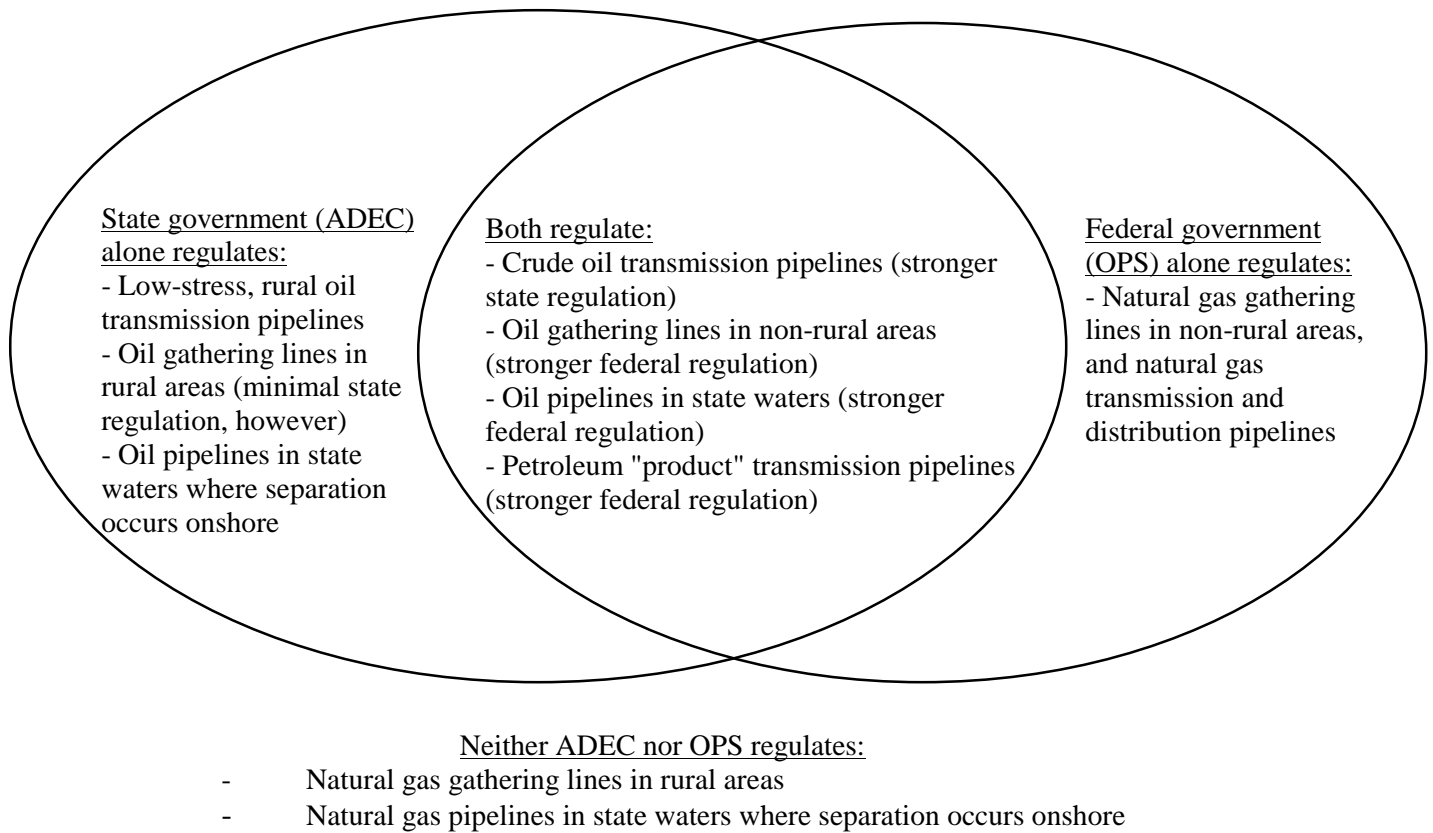
IV. The State and Federal Regulatory Context

Neither the state nor the federal government regulates all pipelines in Alaska. Figure 6 shows the jurisdiction of the state (ADEC) and federal (the Office of Pipeline Safety, or OPS, which is part of the U.S. Department of Transportation) governments over particular types of pipelines for release prevention. Table 2 summarizes the key state and federal regulations covering pipelines and their strengths and weaknesses.

State oversight: ADEC is the state agency with authority to prevent releases from oil pipelines.¹⁶ As of June 2002, there is less than one full-time employee equivalent working to prevent (as opposed to respond to) releases from oil pipelines in the Cook Inlet watershed.

¹⁶ ADEC-administered pipeline regulations covering “Oil and Hazardous Substances Pollution Control” are contained in Title 18 of the Alaska Administrative Code, Chapter 75. Other state agencies, principally the Regulatory Commission of Alaska (<http://www.state.ak.us/apuc/>) and the Alaska Department of Natural Resources’ Division of Oil and Gas (<http://www.dog.dnr.state.ak.us/oil/>), have roles related to pipelines that do not include release prevention. RCA sets the rates charged by pipelines and ADNRC approves siting of pipelines across state lands related to drilling operations. The Division of Governmental Coordination (<http://www.alaskacoast.state.ak.us>) reviews pipeline proposals for consistency with the Alaska Coastal Management Program. The Alaska Oil and Gas Conservation Commission (<http://www.state.ak.us/local/akpages/ADMIN/ogc/homeogc.htm>) focuses only on oil and gas drilling, not pipeline, issues.

Figure 6
Oversight Responsibilities for the Primary Regulators¹⁷ of Alaskan Pipelines for Prevention of Releases



¹⁷ The Alaska Department of Environmental Conservation and the federal Office of Pipeline Safety.

Table 2
Key Alaskan and Federal Regulations Covering Pipeline Release Prevention

Subject	State Cite	Strengths/Weaknesses	Federal Cite	Strengths/Weaknesses
General requirements	18 AAC 75.007 18 AAC 75.045 18 AAC 75.055 18 AAC 75.080	<u>Strengths</u> – Includes leak detection, weekly aerial surveillance (the federal reqt. is biweekly), and prompt leak shut-off for trans. pipelines <u>Weaknesses</u> – Limited, non-specific requirements for facility “piping” in 18 AAC 75.080; no coverage of natural gas pipelines	49 CFR 195 (oil) 49 CFR 192 (gas)	<u>Weakness</u> – Many requirements are difficult to enforce because they defer to operators’ judgments
Integrity management	None	Not applicable	49 CFR 195.452 (oil) None (gas)	<u>Strength</u> – Requires periodic pipeline integrity testing and repairs based on the tests <u>Weaknesses</u> – Applies only in federally-defined high consequence areas; doesn’t require use of shut-off valves or set a leak detection performance std.; OPS does not approve integrity plans
Leak detection performance standard	18 AAC 75.055 (for crude oil transmission pipelines)	<u>Strength</u> – Requires daily flow reconciliation to 1% of throughput	None which require a minimum leak detection capability for oil or gas pipelines	Not applicable
Reporting releases	18 AAC 75.300 18 AAC 75.380	<u>Strengths</u> – A very low reporting threshold (>1 gal.); requires submittal of a final report with revised data when a site undergoes cleanup under state rules <u>Weakness</u> – Monthly reports are not submitted in a uniform format so they are difficult for the public to review	49 CFR 195.50 (oil) 49 CFR 195.54 (oil) 49 CFR 191.3 (gas) 49 CFR 191.9 (gas) 49 CFR 191.15 (gas)	<u>Strength</u> – Recently lowered the threshold for reporting oil releases to 5 gallons <u>Weaknesses</u> – Pipelines exempt from regulations for preventing releases don’t report their releases; also, report revisions are not required when new data are available
Safety-related condition reports	None	Not applicable	49 CFR 195.55 (oil) 49 CFR 191.23 (gas)	<u>Strength</u> – Requires reporting of conditions that could result in pipeline failure later, e.g., overpressurization
Idle/abandoned pipelines	18 AAC 75.080(e)	<u>Strength</u> – Requires closure actions to be taken if crude oil transmission pipelines are out of service for more than one year <u>Weakness</u> – Only covers certain pipelines	49 CFR 195.59 (oil) 49 CFR 195.402(c)(10) (oil) 49 CFR 192.727 (gas)	<u>Weaknesses</u> – No definition of, or reqts. for, idle pipelines; abandonment reqts. for oil are non-specific
General discharge prevention and mitigation	18 AAC 75.400-495	<u>Strengths</u> – Requires description of actions taken to prevent/mitigate discharges, and a demonstration of the use of best available technology (def. in regulation); state approves plans	49 CFR 194 (oil) 49 CFR 195 (oil) 49 CFR 192 (gas)	<u>Weakness</u> – No best available technology reqt. nor any incentive to exceed minimum prevention reqts.
Penalties for oil releases	18 AAC 75.605-670	<u>Weakness</u> - Applies to petroleum, pet. product, and pet. byproduct releases, but not crude oil; penalties are low – max. penalty is \$10/gal.	13 USCA 1321(b)(7)	<u>Strength</u> – Up to \$1,000/42 gal. spilled (\$3,000/42 gal. for gross negligence); <u>Weakness</u> – Applies only to spills to water, not land

While ADEC does not issue permits for pipeline operations, at least every three years it reviews and approves “Oil Discharge Prevention and Contingency Plans” (c-plans) for pipelines,¹⁸ and these plans include some measures for release prevention. These plans cover oil of any kind, including crude oil, petroleum products, and any type of liquid hydrocarbon.

ADEC also has specific requirements for “crude oil transmission pipelines” including a leak detection performance requirement, weekly inspections, and leak shut-off requirements.¹⁹ Additionally, the state has minimal requirements for “piping” associated with oil terminals, crude oil transmission pipelines, and exploration and production facilities.²⁰ ADEC does not regulate natural gas gathering, transmission or distribution pipelines, except to the extent that their associated liquids are covered by c-plan and reporting requirements.

ADEC can levy civil penalties for releases of petroleum and petroleum products and byproducts into the environment, however these penalties do not apply to crude oil releases and the penalties are relatively low.²¹

Federal oversight: OPS, the relatively tiny federal agency regulating onshore and many offshore pipelines,²² oversees more than 2 million miles of oil (considered a “hazardous liquid”) and natural gas pipelines nationwide with approximately 100 staff. OPS does not issue permits and rarely penalizes companies for violations of its regulations.²³ The U.S. General Accounting Office and the U.S. Department of Transportation’s Office of Inspector General repeatedly have criticized OPS for not addressing regulatory weaknesses and gaps and not implementing National Transportation Safety Board pipeline safety recommendations in a timely manner.²⁴

¹⁸ As per the requirements of 18 AAC 75.400, et seq. ADEC currently is considering lengthening the time period between c-plan reviews from three to five years, however.

¹⁹ See 18 AAC 75.055.

²⁰ See 18 AAC 75.080.

²¹ See 18 AAC 75.605, et seq.

²² OPS-administered pipeline regulations are contained in Title 49, Parts 190-199, of the Code of Federal Regulations. Other federal agencies regulating offshore pipelines are the Minerals Management Service (MMS) and the U.S. Coast Guard (USCG). MMS regulates Outer Continental Shelf pipelines -- there are no such pipelines currently in Cook Inlet -- and its requirements are contained in 30 CFR 250. USCG regulates pipelines associated with deepwater ports -- there are three such pipelines in Cook Inlet, all connected with the Drift River facility on the west side of Cook Inlet. USCG requirements for pipelines are contained in 33 CFR 154 and 156. In contrast to OPS and MMS requirements, USCG regulations focus mostly on transfer “hoses” and have few technical requirements covering pipeline integrity such as corrosion prevention standards.

²³ OPS “decreased the proportion of enforcement actions in which it proposed fines from about 49 percent in 1990 to about 4 percent in 1998” (latest data available). *Pipeline Safety: The Office of Pipeline Safety Is Changing How It Oversees the Pipeline Industry* (GAO/RCED-00-128), U.S. General Accounting Office, Washington, DC, May 2000, p. 26.

²⁴ U.S. General Accounting Office: *Pipeline Safety: The Office of Pipeline Safety Is Changing How It Oversees the Pipeline Industry* (GAO/RCED-00-128), May 2000; *Pipeline Safety: Progress Made, but Significant Requirements and Recommendations Not Yet Complete* (GAO-01-1075), September 2001; *Pipeline Safety: Status of Improving Oversight of the Pipeline Industry* (GAO-02-517T), March 2002; U.S. Department of Transportation Office of Inspector General: *Pipeline Safety Program* (RT-2000-069), March 2000.

OPS did, however, recently issue “integrity management” regulations for hazardous liquid, including oil, pipelines.²⁵ These regulations require oil pipelines that can impact “high consequence areas”²⁶ to receive greater testing and operator and regulator scrutiny to ensure pipeline integrity. The regulations do not, however, specify the criteria for placement of shut-off valves, nor do they list the minimum sensitivity for leak detection systems (both items are left up to pipeline operators).

Key gaps in federal oil pipeline regulations that particularly apply to the Cook Inlet watershed and Alaska in general include exemptions for low-stress pipelines in rural areas and for gathering lines in rural areas.²⁷

Oil and natural gas gathering lines have unclear definitions in federal regulation,²⁸ and rural gas gathering lines also are exempt from federal regulation.²⁹ Significantly, the U.S. Congress in 1994 required OPS to define “gathering line” by 1994 and “regulated gathering line” by 1995 for both oil and natural gas pipelines,³⁰ however neither action has taken place.

Another exemption from OPS regulations allows offshore crude oil pipelines to be unregulated if separation or other processing occurs onshore.³¹ This is the case for Cook Inlet’s newest offshore platform – Forest Oil’s Osprey Project. Likewise, offshore natural gas pipelines are unregulated federally if separation or other processing occurs onshore.³²

During 1997-2001, OPS proposed and collected only one \$5,000 penalty from Cook Inlet pipeline operators while issuing 17 final orders, warning letters, and a letter of concern to these operators for violations of federal pipeline regulations. These 17 enforcement actions are listed in Table 3.

OPS rarely levies and publicizes significant penalties for regulatory violations *before* releases occur, which would send a strong message to pipeline operators on the risks of non-compliance. OPS has publicized, however, its proposed penalties *following* the June 1999 Bellingham, Washington and the August 2000 New Mexico pipeline tragedies.

State/federal interaction: The federal government grants states up to 50% of the funds needed for approved state pipeline safety inspection programs. These programs permit state regulators to

²⁵ See 49 CFR 195.452.

²⁶ See 49 CFR 195.450 and 195.6 which cover, respectively, populated and/or commercially-navigable areas, and areas that contain drinking water and/or ecological resources.

²⁷ See 49 CFR 195.1(b)(3)(i)(B) and 49 CFR 195.1(b)(4), respectively.

²⁸ See 49 CFR 195.2 and 49 CFR 192.3, respectively.

²⁹ See 49 CFR 192.1(b)(2).

³⁰ See 49 USCA 60101(b).

³¹ See 49 CFR 195.1(b)(5).

³² See 49 CFR 192.1(b)(1).

Table 3
Office of Pipeline Safety Enforcement Actions Against Cook Inlet Watershed Pipelines, 1997-2001

Pipeline Operator	Type of Enforcement	Date	Pipeline Involved	Violation Area(s)	Fine
Phillips	Final Order	12/31/01	Tyonek platform to Kenai	Corrosion prevention; pipeline classification	None
Tesoro	Final Order	12/4/01	Nikiski to Anchorage	Repair records; corrosion prevention	None
Unocal	Final Order	3/15/01	Records review in Kenai	Reporting of safety-related conditions	\$5,000
Shell	Final Order	2/9/01	Platforms A and C	Records and procedures; corrosion prevention; valve operation	None
Phillips	Warning Letter and Notice of Amendment	1/21/00	Records review in Kenai	Corrosion prevention; reporting of safety-related conditions	None
Cook Inlet Pipe Line	Warning Letter	7/7/99	Drift River to Granite Point	Documentation of procedures	None
Signature	Warning Letter	8/21/98	Port of Anchorage to airport (pipeline no longer in use)	Hydrotesting; valve operations	None
Enstar	Warning Letter	8/21/98	Records review in Anchorage; Girdwood, Indian, Bird distrib. lines	Pipeline classification; valve locations; leak survey requirements	None
Unocal	Letter of Concern	6/15/98	Bruce and Granite Pt. platforms to Granite Pt.; pipelines between Anna and Bruce	Corrosion prevention (rapid metal loss occurring from internal corrosion)	NA
Tesoro	Final Order	4/28/98	Nikiski to Anchorage	Inspection of Turnagain Arm crossing; corrosion prevention	None
Unocal	Warning Letter	11/17/97	Pipeline to Agrium; Swanson River Field to Kenai Pipe Line terminal	Valve testing	None
Enstar	Warning Letter and Notice of Amendment	10/21/97	Records review in Anchorage; Girdwood, Indian, Bird distrib. lines	Procedures; line markings; corrosion prevention	None
Tesoro	Final Order	10/20/97	Nikiski to Anchorage	Procedures; hydrotesting	None
Enstar	Warning Letter and Notice of Amendment	10/3/97	Records review in Anchorage and Soldotna; Kenai, Soldotna distribution lines	Corrosion prevention; line marking; procedures; patrolling	None
Enstar	Warning Letter and Notice of Amendment	10/3/97	Records review in Anchorage	Drug testing and related procedures	None
Enstar	Notice of Amendment	9/22/97	Records review in Anchorage; Kenai to Anchorage	Procedures; security	None
Unocal	Warning Letter and Notice of Amendment	9/4/97	Monopod, King Salmon, Grayling, Dolly Varden platforms to Trading Bay	Valve testing; procedures	None

inspect pipelines for compliance with federal requirements and to provide input into integrity management programs in their states. Alaska does not have an approved state program. As of April 2002, 16 states have this authority for oil pipelines and 48 states have it for natural gas pipelines.

The federal law covering OPS operations does not allow states to exceed federal safety standards for interstate pipelines³³ even if there are state-specific reasons why states might want to exceed federal requirements without impacting interstate commerce (e.g., requiring increased operator inspections or pipeline monitoring in earthquake-prone areas). This prohibition does not impact state-imposed requirements covering pipelines in the Cook Inlet watershed since all Cook Inlet pipelines are intrastate.

V. The Relationship Between the Spill Statistics and the Regulations

To assess whether state and federal pipeline oversight programs are working, it is important to understand the relationship between pipeline performance and the regulatory context. Cook Inlet Keeper chose to use a pipeline performance measure that compared the percent of Cook Inlet oil pipeline spills (i.e., the number of spills) to the percent of Cook Inlet oil pipeline mileage. Using this approach and assuming all pipeline reporting is accurate, disproportionately high or low ratios of these two measures indicate strong or weak regulator and/or operator performance, respectively. See Table 4 for the results of this analysis.

Table 4 shows that both Unocal and Forest Oil pipelines have disproportionately high spill numbers compared to their mileage. What's common among these companies is that both have a high percentage of their Cook Inlet watershed pipeline miles exempt from federal regulatory requirements because this mileage is rural. Thus, it is highly likely that the exemptions in federal pipeline regulations for rural pipelines result in adverse environmental consequences through increased spill rates. While Unocal has the top eight largest spills from 1997-2001 (ranging from 1,134 to 228,648 gallons in size, see Appendix 2), Forest Oil's reported spills each are less than 3 gallons.

In contrast, the excellent performance of Cook Inlet Pipe Line Company's pipelines likely demonstrates the effectiveness of the stringent state requirements that apply only to "crude oil transmission pipelines."³⁴ Kenai Pipe Line, which has an excellent spill record, also must meet these requirements but only has been required by ADEC to do so since 2000. State crude oil transmission pipeline requirements include a strong leak detection performance standard, more frequent aerial surveillance than required under federal regulations, and a prompt leak shut-off capability. Ironically, although federal oil pipeline requirements do not apply to Forest Oil's pipeline which Table 4 lists as having "poor performance," the relatively stringent state requirements for crude oil transmission pipelines do apply which could be the reason Forest Oil's spill volumes are small compared to Unocal's.

³³ See 49 USCA 60104(c).

³⁴ See 18 AAC 75.055.

Table 4
Performance Measurement of Cook Inlet Oil Pipeline Companies, 1997-2001

Operator	Approx. % of CI Oil Pipeline Miles³⁵	% of CI Oil Pipeline Spills³⁶	Analysis
Unocal	39	76	High spill rate; poor performance
Tesoro	23	2	Low spill rate; good performance
Cook Inlet Pipe Line	16	0	Very low spill rate; excellent performance
Kenai Pipe Line	7	0	Very low spill rate; excellent performance
XTO Energy (formerly Cross Timbers, Shell)	6	9	Middling spill rate; fair performance
BP (formerly Amoco)	6	2	Pipelines not in use; abandoned pipeline spill
Signature	2	0	Very low spill rate; relatively new pipeline
Forest Oil (formerly Forcenergy)	1	12	High spill rate; poor performance

Keeper believes that using the number of spills rather than the volume released results in a better measure of operator performance since a few large volume spills can distort the results. In fact, 99% of the known volume spilled during 1997-2001 was from Unocal operations (as opposed to 76% of the number of spills), with the January 6, 1999 spill alone representing 87% of the total volume released from pipelines in the Cook Inlet watershed during this period.

VI. Mis-regulation and Missing Regulations

This section covers two interrelated topics in Cook Inlet watershed pipeline oversight by the state and federal governments:

- 1) Mis-regulation of Cook Inlet watershed pipelines, i.e., when pipelines with similar characteristics are regulated differently; and,
- 2) Gaps in state and federal pipeline regulations and the resulting environmental impacts.

Mis-regulation: Appendices 4 (oil), 5 (natural gas), and 6 (“other”) show the inconsistencies and unknowns in Cook Inlet watershed pipeline regulation by the state and federal governments. The highlighted areas show pipelines that appear to be inconsistently regulated under current requirements. The “regulatory issues” section explains these inconsistencies and also identifies instances where unclear pipeline regulation has occurred to date. Despite repeated inquiries by Cook Inlet Keeper and because of the self-policing nature of state and federal pipeline

³⁵ As noted in footnote 12, the approximate mileage of active and inactive oil pipelines in the Cook Inlet watershed is 311 miles. See Appendix 1 for the mileage by company (not including oil production field pipelines).

³⁶ See Appendix 2 for the 70 pipeline spills during this period. Only the 66 oil pipeline spills were used in this analysis. Total does not equal 100% due to rounding.

regulations, there are some Cook Inlet watershed pipelines listed in these appendices where even the regulators do not know with certainty if they have oversight authority over those pipelines.

At the state level, the most critical distinction is whether pipelines are classified as crude oil transmission pipelines or as facility piping which means there are fewer safety and environmental protection requirements to meet. In recent years, ADEC has made an effort to review its classifications of Cook Inlet watershed pipelines and re-classified several pipelines as crude oil transmission pipelines. Nevertheless, as shown in Appendix 4, there are three additional Cook Inlet watershed pipeline segments owned by Cook Inlet Pipe Line that meet the crude oil transmission pipeline requirements³⁷ and should to be classified as such.

Federally, there are eight Unocal oil pipelines coming from offshore platforms where the operators dispute OPS' oversight authority for the *onshore* portions. In contrast, OPS has undisputed authority over the onshore portions of XTO Energy pipelines coming from its offshore platforms. Another inconsistency is that while the natural gas pipelines from Phillips' offshore Tyonek platform clearly are under OPS oversight,³⁸ the operators of 16 other natural gas pipelines (operated by Unocal, Marathon, and XTO Energy) from offshore platforms dispute OPS' oversight authority.

Missing regulations: At the federal level, the exemptions for low-stress oil pipelines in rural areas and for gathering lines in rural areas likely have resulted in soil and water contamination in the Cook Inlet watershed, and these exemptions need to be removed.³⁹ Many of these federally unregulated pipelines have had spills, as demonstrated by the 41% of reported releases in Table 1 occurring at the Swanson River Field. A U.S. Environmental Protection Agency spill responder provided further evidence of the problems posed by these unregulated pipelines at a 1997 public hearing held by OPS in New Orleans stating that:

[P]ipelines represent about 45 to 50 percent of the spill picture from our region. We receive about 3,000 to 5,000 spill reports per year within this region, and they range [in size from] just a few barrels to up to several hundred thousand gallons into the several thousand barrels criteria...Most of our spills unfortunately fall under [the] size of piping that's well below the six -- I think it's six inch and five-eighths of gathering line, such as a lot of the spills emanate from them, and it is kind of a concern to [On-Scene Coordinators] that there's not a voice from the regulatory community towards those areas that are unaddressed right now.⁴⁰

Other significant federal regulatory gaps are the two exemptions that allow offshore crude oil and natural gas pipelines to be unregulated, respectively, if separation or other processing occurs

³⁷ Though one of the offshore loading pipelines commonly is used for ballast water unloading, it can be put into service by Cook Inlet Pipe Line Company to carry crude oil.

³⁸ See <http://ops.dot.gov/regions/westerndocs/56301-M-56004o.pdf>.

³⁹ Note that these exemptions also apply to reporting of spills from these pipelines. This means that other than using state-level data (which are uneven in coverage) it is difficult to account for all the environmental damage exempt rural oil pipelines cause nationwide.

⁴⁰ Don Smith, U.S. Environmental Protection Agency, at the "Public Hearing on Response Plans for On-shore Oil Pipelines," New Orleans, Louisiana, January 29, 1997. Transcript available at <http://ops.dot.gov/trans97.htm>.

onshore. These pipeline exemptions have resulted in unnecessary, resource-intensive compliance disputes between OPS and Cook Inlet pipeline operators (see the 9-page Final Order issued to Phillips Alaska, Inc. on December 31, 2001⁴¹) and left several existing and proposed pipelines without any federal oversight though they likely pose significant safety and environmental hazards.

Likewise, because the U.S. Coast Guard (USCG) lacks specific pipeline integrity requirements, OPS or Minerals Management Service requirements should apply to pipelines currently regulated by the USCG, or USCG should expeditiously adopt detailed pipeline integrity standards.

There are no specific federal requirements for “idle” and/or abandoned oil pipelines except for reporting of abandonment to OPS for underwater pipelines located in commercially navigable waterways.⁴² As a result, oil pipelines that operators deem “idle” legally may be unmaintained for long periods of time and can pose environmental hazards if liquid residuals remain. Similarly, if abandoned pipelines do not have their contents emptied and the pipelines are not removed, they too can pose environmental hazards. On July 31, 2001, an abandoned underwater pipeline formerly operated by Amoco and now owned by BP leaked an unknown amount of crude oil into Cook Inlet; since then, more crude has been released into Cook Inlet during activities designed to remove the residual oil.⁴³

Additionally, the limitations in the federal government’s mapping and integrity management regulations are becoming increasingly apparent in the Cook Inlet region. Despite a long-standing, *voluntary* OPS program to collect geo-spatial data on transmission pipeline locations nationwide, as of April 2002 only one oil pipeline operator in the Cook Inlet watershed had submitted mapping data to OPS – Cook Inlet Pipe Line – representing only 16% of the region’s oil pipeline mileage. Moreover, it is difficult or impossible for the public to obtain information on the watershed’s “high consequence areas” (i.e., where the integrity management regulation applies), so the public cannot assess whether all high consequence areas have been properly considered by OPS and pipeline operators. Notably, pipeline operators in Cook Inlet have widely varying interpretations as to whether all the Inlet’s offshore pipelines are located in high consequence areas, or only those portions located in shipping lanes.⁴⁴

OPS’ integrity management regulation’s lack of protection for spills throughout a watershed and for cultural and historic sites is proving to be particularly problematic in the Cook Inlet region where spills from many of the pipelines on land can impact Cook Inlet and where so many long-

⁴¹ See <http://ops.dot.gov/regions/westerndocs/56301-M-56004o.pdf>, op. cit.

⁴² See 49 CFR 195.59.

⁴³ During the summer of 2002, BP has had difficulty removing residual oil from this pipeline, showing the importance of proper abandonment procedures. See http://www.state.ak.us/local/akpages/ENV.CONSERV/dspar/perp/010731201/status_06.htm, “Leaks abort effort to scour pipe” (Jon Little, *Anchorage Daily News*, August 21, 2002), and the recent U.S. General Accounting Office report on the topic of oil production infrastructure dismantlement, removal, and restoration: *Alaska’s North Slope: Requirements for Restoring Lands After Oil Production Ceases* (GAO-02-357), June 2002.

⁴⁴ Communication by the Office of Pipeline Safety’s Jerry Davis to the Cook Inlet Regional Citizens Advisory Council board, May 31, 2002.

standing native communities exist, respectively. The high consequence area regulation's lack of specific protection for public lands also is troubling, as a high percentage of this region's pipeline releases (see Appendix 2) occur on public lands, including all Swanson River Field spills, and waters (i.e., all offshore spills).

Last, OPS does not consider its review of integrity management plans to constitute issuance of a "permit," so there is no formal public involvement component in the plan review process either under OPS' National Environmental Policy Act responsibilities or required by OPS regulation. Without operating permit issuance (which the public could challenge if permit issuance was flawed) and/or public involvement in OPS' integrity management program, government and industry lack accountability. In fact, if OPS' budget is cut and it has insufficient staff to review integrity management plans, pipelines nevertheless could continue operating without governmental or public oversight.

VII. Changes Needed, Setting Priorities, and Measuring Pipeline Performance in the Future

There are several approaches that can and should be used to improve the performance of pipelines in Cook Inlet and throughout Alaska. These approaches fall into four general categories:

- 1) Improve regulations and their enforcement;
- 2) Provide additional operating data to the public so facilities with good or bad operations can be more easily identified (i.e., enhancing public right-to-know);
- 3) Strengthen liability to provide a financial incentive for improved performance; and,
- 4) Voluntary improvements by industry.

The relationship between these items and pipeline safety and environmental concerns is described below. The four sub-sections are followed by discussions on recommended public interest organization action, setting priorities for Cook Inlet watershed pipeline improvements, and improving measurement of performance.

Pipeline regulations and their enforcement. An effective regulatory program requires: 1) accurate knowledge of problems, 2) requirements that remedy the problems, and 3) adequate resources to oversee and enforce the requirements. Each of these components is deficient at present at the state and federal levels for oil and natural gas pipelines.

With respect to accurate knowledge of pipeline problems, currently there is inadequate information on Cook Inlet watershed pipeline locations (see Section VI's discussion on the voluntary federal collection of geo-spatial pipeline data), including the environmental and demographic characteristics of pipeline locations, and the operational characteristics of pipelines. Until Cook Inlet Keeper compiled its database for this study (see Appendix 1 and Appendices 4-6), there was no comprehensive regulator or industry database on Cook Inlet watershed oil and natural gas pipelines.

The lack of pipeline locational data and information on pipeline characteristics makes it very difficult for regulators and the public to assess which regulations apply to particular pipelines. In

particular, the federal integrity management program regulation⁴⁵ is mandatory only for those pipelines in high consequence areas.⁴⁶ To ensure enhanced pipeline safety, regulators and the public must know both where pipelines are located and if the integrity management program applies to any portion of those pipelines.

Because stricter state pipeline regulations apply only to crude oil transmission pipelines,⁴⁷ it is essential for state regulators and the public to have information which is relatively unavailable at present on processing facility locations, compositional information about water content (water can aggravate corrosion) in transported crude oil, use of pipelines for transport rather than shorter-distance gathering of crude, etc. The state needs to review these data to determine whether current regulations protect against the greatest risks of pipeline failure or if the crude oil transmission pipeline regulation needs to be expanded to cover, for example, gathering lines that perform similarly to transmission pipelines.

Another deficiency in ADEC's assessment of pipeline problems is that ADEC does not typically investigate the causes of significant pipeline releases. Usually there only are relatively poor-quality, industry-reported data on release causes and volumes spilled. As a result, regulatory priorities can be distorted without accurate – i.e., independently verified -- information on the causes and volumes of pipeline releases. Table 1 shows that industry self-reporting resulted in 26% of the oil pipeline releases having an unknown or unreported cause.

Summary of Recommended Changes to Assess Pipeline Problems

State:

- *ADEC should require pipeline operators to submit locational data on all their oil pipelines, i.e., transmission, gathering, and oil and natural gas production field wastewater pipelines,*
- *ADEC should examine its data – and collect new data, as appropriate – on gathering lines (including a Best Available Technology study) and oil field wastewater pipelines to see if such lines should have strengthened regulations, e.g., regulations similar to those that exist for “crude oil transmission pipelines,” and,*
- *ADEC should investigate the causes of significant pipeline releases rather than relying solely on industry investigations, and ensure that operators report the cause of all pipeline releases and revise volume estimates as new information becomes available.*

Federal:

- *OPS should require mandatory submittal of geo-spatial mapping data for all transmission pipeline operators, and*
- *The OPS definition of “high consequence area” should be interpreted in a way that maximally protects the environment including the entire Cook Inlet watershed, not in a narrow and inconsistent manner that benefits pipeline operators at the expense of the environment.*

⁴⁵ See 49 CFR 195.452, op cit.

⁴⁶ See 49 CFR 195.450 and 195.6, op cit.

⁴⁷ See 18 AAC 75.055, op cit.

It's clear from the information presented in this study that there are a number of regulatory weaknesses and gaps both in state and federal requirements. The key weaknesses and gaps are discussed in the portion of Section VI entitled "Missing Regulations" and in Table 2.

Summary of Recommended Changes to Pipeline Requirements

State:

- *ADEC should regulate petroleum product transmission pipelines in a manner similar to crude oil transmission pipelines with leak detection, weekly aerial surveillance and prompt leak shut-off requirements, as product pipelines can significantly impact the environment for the short- and long- term, and,*
- *ADEC should develop a form for reported pipeline releases to facilitate compilation in a database reviewable online.*

Federal:

- *To strengthen environmental protection, OPS should eliminate the exemptions currently in federal regulations for low-stress oil pipelines in rural areas and for gathering and oil field wastewater lines in rural areas,*
- *OPS should ensure that offshore oil and natural gas pipelines with onshore separation or processing operations are covered by its regulations, just as pipelines with offshore separation or processing operations are covered,*
- *OPS' integrity management regulation for oil pipelines needs to be supplemented with regulations that protect cultural and historic sites, specify use and placement of shut-off valves, and set a performance standard for leak detection,*
- *OPS should approve or disapprove of integrity management plans to ensure public accountability by both government and industry, and ensure that public participation is part of plan development and approval,*
- *OPS should develop a definition of "idle" pipelines, and develop and enforce requirements for abandoned pipelines,*
- *Congress should change the pipeline safety law to allow states to exceed federal safety standards for interstate pipelines as long as such requirements do not adversely impact interstate commerce, and,*
- *OPS or Minerals Management Service requirements should apply to pipelines currently regulated by the U.S. Coast Guard, or the Coast Guard should expeditiously adopt detailed pipeline integrity standards.*

On the issue of resources and enforcement, both ADEC and OPS currently need more staff to oversee pipelines in their respective jurisdictions, e.g., to ensure semi-annual office and field inspections of pipeline operations. As for enforcement, OPS' lack of a single, sizable penalty⁴⁸ for pipeline violations in the Cook Inlet watershed during the past five years – despite the number of violations documented in Table 3 – sends a message to pipeline operators that there is virtually no cost to them for non-compliance.

Additionally, as noted in the portion of Section IV Entitled "State/Federal Interaction," the state of Alaska could receive from the federal government up to 50% of the funds needed to run its state pipeline safety inspection programs if it received federal approval of its pipeline programs. The state should evaluate whether such a resource infusion would provide a net benefit in

⁴⁸ The single penalty levied (see Table 3) was only \$5,000, which is not sizable.

pipeline oversight within the state, particularly if federal oversight might diminish if this strategy is pursued.

ADEC and OPS staff limitations resulting from a lack of resources likely are a cause of the pipeline-specific “Misregulation” identified in Section VI.

Summary of Recommended Changes Regarding Oversight Resources

State:

- *The Alaska legislature should increase ADEC’s budget to allow two full-time employee equivalents to work on Cook Inlet watershed pipeline spill prevention and, if necessary to ensure competent staff, increase the salary-level for ADEC engineers,*
- *ADEC should evaluate whether there would be a net resource gain for oversight of Alaska’s pipelines by receiving federal approval of state pipeline safety inspection programs; if yes, the state should pursue this approach,*
- *ADEC should place its enforcement actions on the Internet as OPS does to ensure greater public accountability by both government and industry, and*
- *ADEC should reclassify the following pipelines (see Appendix 4):*
 - *Cook Inlet Pipe Line’s oil pipelines from the Drift River terminal to offshore loading need to be regulated as “crude oil transmission pipelines” under 18 AAC 75.055.*

Federal:

- *OPS should levy and publicize significant penalties for Cook Inlet watershed pipeline regulatory violations and do likewise nationwide to send a strong message that regulatory violations are unacceptable, and*
- *OPS should reclassify the following pipelines (see Appendices 4 and 5):*
 - *The onshore portions of Unocal’s oil pipelines from its offshore platforms need to be regulated under 49 CFR 195;*
 - *Kenai Pipe Line’s oil pipelines from XTO Energy to the Kenai Pipe Line terminal and from the Swanson River Field to Nikiski need to be regulated under 49 CFR 195 as these areas are not rural; and,*
 - *Unocal, Marathon, and XTO Energy’s natural gas pipelines from offshore platforms need to be regulated under 49 CFR 192.*

Pipeline right-to-know. As discussed in Section IV, pipelines do not require periodic renewals of operating permits, so the public has no ongoing reporting from pipeline operators on the adequacy of pipeline operations following siting approval or approval for conversion to a new use (e.g., from natural gas to oil transport). To ensure continuous improvement in pipeline safety as pipelines age, operators should submit to state and federal regulators a periodic report containing information on pipeline, or pipeline segment, operating characteristics, and this information should be transferred to a publicly available computer database. Regulators and the public then can use these data to analyze overall trends, and individual operator decisions on, pipeline operating practices (e.g., internal testing frequency).

Instituting a pipeline right-to-know program is a supplement to prescriptive regulations, and such a program should result in faster, non-prescriptive improvements in industry performance. No information reported by industry would pose a security risk or would be confidential business information. Examples of reported information that would help distinguish good and bad pipeline operations, include:

- The frequency of periodic internal testing, so those pipeline companies doing extensive testing -- and those doing little -- could be identified,
- The internal testing method used, to ascertain the quality of the testing (e.g., high or low resolution pipeline pigging), and
- The number of overpressurization incidents and the means used to detect overpressurization.

A pipeline right-to-know program would be similar to the U.S. Environmental Protection Agency's (EPA's) toxic chemical right-to-know program,⁴⁹ which has resulted in improved performance by those covered by the program. There has been a decrease in toxic chemical releases of nearly 50% in a decade as a result of EPA's right-to-know program; the "sunshine" provided by this EPA database clearly has promoted better performance. A multi-stakeholder, national "dialogue group" including energy-producing companies, the pipeline industry, state and federal agencies, and environmental organizations recently endorsed the pipeline right-to-know database concept.⁵⁰

Summary of Recommended Changes to Increase Public Accountability Through a Pipeline Right-to-Know Program

State and Federal:

- *ADEC and OPS should require pipeline companies to report operational data related to pipeline integrity on a regular basis, and the agencies should make this information available to the public via a user-friendly database which does not compromise pipeline security.*

Pipeline release liability. In addition to pipeline design and operational regulations and a right-to-know program, there's a need for a strong incentive to prevent pipeline releases through meaningful civil penalties for releases. At present, the cost of lost product generally is minimal compared to the costs of preventive upgrading of pipelines.

Penalties can be levied under current federal law for oil pipeline releases to navigable waters (thus excluding oil pipeline releases to land),⁵¹ and under state law for all non-crude petroleum releases,⁵² and for crude oil releases greater than 18,000 gallons.⁵³ These penalties, however, are discretionary, not imposed frequently, and limited in both scope and amount. The current penalty structure does not create a sufficient financial incentive for Cook Inlet watershed pipeline operators to take further action to avoid spills, particularly smaller crude oil spills (i.e., less than 18,000 gallons) to land. For many pipeline operators, it likely is cheaper to deal with the aftermath of a spill than to invest the resources needed avoid it.

⁴⁹ See <http://www.epa.gov/tri/>.

⁵⁰ "Expanding Natural Gas Pipeline Infrastructure to Meet the Growing Demand for Cleaner Power," Final Report of The Keystone Dialogue on Natural Gas Infrastructure, The Keystone Center, Washington, D.C., March 2002, p. 33.

⁵¹ See 33 USCA 1321(b)(7).

⁵² See AS 46.03.758.

⁵³ See AS 46.03.759.

Expanding state liability to smaller crude oil releases would represent a logical extension of existing state requirements, which currently have a maximum penalty of \$10 per gallon spilled. Likewise, establishing a liability standard for pipeline releases to land would be a logical extension of the federal Oil Pollution Act of 1990's liability standard, which allows the federal government to levy a fine up to \$1,000 per barrel (\$23.81 per gallon) for each release into navigable waters whether or not a regulation was violated, and \$3,000 per barrel (\$71.43 per gallon) for releases resulting from gross negligence or willful misconduct.

Summary of Recommended Changes to Increase Liability for Releases

State:

- *The Alaska legislature should modify its spill penalty requirements in AS 46.03.758(1)(6) so that "oil" does not exclude "crude oil" for penalties unrelated to regulatory violations.*

Federal:

- *In its reauthorization of the pipeline safety law, Congress should extend the Oil Pollution Act of 1990's liability standard for releases so it applies to pipeline releases to land.*

Industry action. Pipeline improvements can be achieved without changes in regulations and liability structures through voluntary actions by pipeline operators and owners. Unfortunately, given the differences in priorities among pipeline companies, it is impossible to achieve a uniform minimum level of performance through voluntary actions alone, so regulatory and liability structures must be in place. In a worldwide business environment with the rapid exchange of information, however, generally it is in the interest of industry to act pro-actively on safety and environmental concerns to avoid negative publicity should incidents occur regardless of governmental structures.

Summary of Recommended Industry Action

- *Pipeline operators and owners should act voluntarily and pro-actively to ensure best possible performance for their Cook Inlet watershed pipelines including: frequent, high-resolution smart-pigging; early replacement and upgrading of higher-risk pipelines; extensive corrosion control monitoring from day one of pipeline installation; employing sophisticated leak detection and shut-off valve technologies,*
- *The Alaska Oil and Gas Association should encourage Cook Inlet watershed pipeline operators to utilize best practices and technologies by surveying pipeline companies on their operations, providing forums for information transfer, and other appropriate strategies, and*
- *To ensure public accountability and encourage productive dialogue between Cook Inlet pipeline operators and their neighbors, operators should provide the public with a detailed annual report via the Internet on actual and planned measures for pipeline upgrades and actual and projected changes in pipeline performance (e.g., release volumes and frequency, etc.).*

Public interest organization action. While it's tempting to support more complete analyses of problems, when enough is known about an industry's deficiencies that effective actions can be taken to reduce hazards, those solutions should be pursued. In the Cook Inlet pipeline context,

some groups advocate for more studies on the watershed's pipelines such as a third party "risk assessment." Based on the data analyses presented in this study, however, pipeline operators and regulators currently have sufficient information to embark on actions that will reduce the risk of pipeline spills, leaks, and environmental damage in the near-to-mid term.

Additionally, because public interest organizations draw upon the diverse and dispersed expertise of the public, these organizations should support wide dissemination of information about Cook Inlet watershed pipelines, including posting such information on the Internet.

Summary of Recommended Public Interest Organization Action

- *Public interest organizations should promote actions that can be taken immediately to improve pipeline safety and environmental protection rather than extensive, additional studies of the problems posed by Cook Inlet watershed pipelines, and*
- *Public interest organizations should support Internet access to pipeline-specific operational and performance information and actual and planned measures for pipeline upgrades.*

Setting priorities for Cook Inlet watershed pipeline improvements. Based on the data in Tables 1 and 4, ADEC and OPS should consider setting the following priorities:

1. Reducing the number of onshore pipeline spills so they are not vastly disproportionate to the oil pipeline mileage. From 1997-2001, 88% of reported oil pipeline spills came from the approximately 42% of onshore oil pipeline mileage.
2. Reducing the number of pipeline releases from corrosion, pipeline parts, and other maintenance-related issues. These mechanisms, all under operator control, collectively are the most cited causes of releases among Cook Inlet watershed oil pipelines.
3. Reducing the number of oil pipeline releases occurring in the Swanson River Field in the Kenai National Wildlife Refuge. From 1997-2001, 41% of reported oil pipeline spills took place at this facility, including 7 of the 8 largest spills reported during this time period.
4. Ensuring improved performance from Unocal and Forest Oil pipelines, so their numbers of pipeline releases are not vastly disproportionate to their oil pipeline mileage. From 1997-2001, Unocal had approximately 39% of Cook Inlet watershed's oil pipeline mileage and 76% of the oil pipeline spills and Forest Oil had 1% of the mileage and 12% of the spills (though Forest Oil's spills were significantly smaller in size than Unocal's).

Measuring performance in the future. Table 4 provides one measure of oil pipeline operator performance, i.e., comparing the percentage of spills represented by each pipeline operator to their percentage of mileage over the most recent five-year time period. This measure, while valuable, can and should be supplemented over time by more sophisticated and specific measures of pipeline operator performance.

Based on discussions at the January 10, 2002 ADEC forum on "Offshore and Onshore Oil Pipelines in Cook Inlet"⁵⁴ and other research, Cook Inlet Keeper proposes that industry provide

⁵⁴ Transcripts are available at <http://www.state.ak.us/local/akpages/ENV.CONSERV/dspar/ciforum/>.

at least the following analytical and performance-related information to pipeline regulators and the public:

- Frequency of smart-pigging for each pipeline and type of smart-pig used (e.g., high or low resolution),
- Use of hydrotests on pipelines and test results,
- Pipeline or company-specific repair trigger for defects found by smart-pigging (e.g., 20% or 15% wall loss triggers a repair),
- Pipeline leak detection sensitivity and accuracy,
- Shut-off valve placement criteria, type(s) of valve(s) used, and the distances between the valves,
- Frequency of “close interval surveys,” distances between test locations, and other corrosion prevention practices,
- Frequency of exceedances of maximum operating pressure,
- Steps taken to address “vortex shedding”⁵⁵ problems with offshore pipelines (e.g., the length of an unsupported span that triggers remedial action),
- “Near miss” data, and,
- Other appropriate measures of operator and pipeline performance.

VIII. Conclusions

Cook Inlet Keeper performed this analysis of Cook Inlet watershed pipeline spills and their connection to state and federal regulatory strengths and weaknesses to spur improvements in pipeline performance. Keeper’s interest is in seeing that significant performance improvements occur without delay through regulatory and enforcement changes, voluntary actions by pipeline operators, or a combination of the two. We hope this documentation of pipeline problems and their potential solutions stimulates dialogue among all stakeholders on how best to proceed with pipeline infrastructure and operational improvements, both within the Cook Inlet watershed and nationally.

⁵⁵ “Vortex shedding” is a problem encountered by underwater pipelines where unsupported spans of pipeline shift and eventually fail due to tidal forces.

Appendix 1
Cook Inlet Oil and Natural Gas Pipeline Data

Pipeline	Liq./Gas	Liq. contents	Subsea?	Nom. Dia. (in.)	Length (miles)	Installed	Operator	Status
GPTF to Drift River	L	crude	N	20	41.50	1966	Cook Inlet PL	Operating
TBPF to Cook Inlet PL	L	crude	N	12	2.50	1967	Cook Inlet PL	Operating
Drift River tanks to shore	L	crude	N	42	0.75	1967	Cook Inlet PL	Operating
Drift River shore to offshore loading	L	crude	Y	30	1.80	1967	Cook Inlet PL	Operating
Drift River shore to offshore loading	L	crude/ballast	Y	30	1.80	1967	Cook Inlet PL	Operating
West McArthur to TBPF	L	crude	N	8	2.80	1994	Forest Oil	Operating
XTO Energy to KPL term.	L	crude	N	12	3.90	1965	Kenai PL/Tesoro	Operating
Swanson River O./G. F. to Nikiski	L	crude	N	8	19.20	1960	Kenai PL/Tesoro	Operating
Port of Anch. to airport (new)	L	product	Y	12	7.60	1998	Signature	Operating
KPL term. to Tesoro ref.	L	crude	N	24	<1	1983	Tesoro	Operating
Tesoro ref. to Port of Anchorage	L	products	Y	10	70.80	1976	Tesoro	Operating
Branch line to Anchorage airport	L	product	N	3	0.57	1996	Tesoro	Operating
Granite Pt. to GPTF	L	crude	Y	8	3.79	1966	Unocal	Operating
Anna to Bruce	L	crude	Y	8	1.59	1966	Unocal	Operating
Bruce to GPTF	L	crude	Y	6	5.30	1974	Unocal	Operating
Monopod to TBPF	L	emulsion	Y	8	9.00	1966	Unocal	Operating
King Salmon to TBPF	L	emulsion	Y	8	7.50	1967	Unocal	Operating
Grayling to TBPF	L	emulsion	Y	10	5.30	1967	Unocal	Operating
Steelhead to TBPF	L	emulsion	Y	8	7.95	1986	Unocal	Operating
Dolly Varden to TBPF	L	emulsion	Y	8	5.70	1967	Unocal	Operating
Dolly Varden to TBPF	L	emulsion	Y	4	5.70	1967	Unocal	Operating
Baker to A	L	crude	Y	8	2.50	1965	Unocal	Operating
Dillon to C	L	crude	Y	8	2.00	1966	XTO Energy	Operating
A to C	L	crude	Y	8	2.20	1967	XTO Energy	Operating
A to XTO Energy	L	crude	Y	8	7.00	1965	XTO Energy	Operating
A to XTO Energy	L	crude	Y	8	7.00	1965	XTO Energy	Operating

Appendix 1, continued
Cook Inlet Oil and Natural Gas Pipeline Data

Pipeline	Liq./Gas	Liq. contents	Subsea?	Nom. Dia. (in.)	Length (miles)	Installed	Operator	Status
E. Anchorage to Whittier	G	NA	N	8	50.00		Enstar	Operating
Beluga to Anchorage	G	NA	N	20	102.00		Enstar	Operating
Kenai to Anchorage	G	NA	Y	12	115.50		Enstar	Operating
Kenai to Anchorage	G	NA	Y	12/16	115.50		Enstar	Operating
Nikiski to Sterling (Royalty)	G	NA	N	8			Enstar	Operating
Sterling G.F. to Royalty	G	NA	N	4			Enstar	Operating
West McArthur to TBPf	G	NA	N	6	2.80		Forest Oil	Operating
W. Foreland #1 to W. McArth.	G	NA	N	6			Forest Oil	Operating
Spark to GPTF	G	NA	Y	6	7.20	1968	Marathon	Operating
Spurr to GPTF	G	NA	Y	6	8.40	1968	Marathon	Idle
Spurr to GPTF	G	NA	Y	6	8.40	1968	Marathon	Operating
GPTF to Beluga	G	NA	N	16	16.20		Marathon	Operating
TBPf to GPTF (CIGGS sys.)	G	NA	N	16	27.20		Marathon	Operating
GPTF to Nikiski shore (CIGGS sys.)	G	NA	Y	10	21.00		Marathon	Operating
GPTF to Nikiski shore (CIGGS sys.)	G	NA	Y	10	21.00		Marathon	Operating
Nikiski shore to Nikiski (CIGGS sys.)	G	NA	N	16	4.50		Marathon	Operating
Kenai G.F. to Nikiski	G	NA	N	20	17.55		Marathon	Operating
Cannery Loop G.F. to Kenai G.F. line	G	NA	N	8			Marathon	Operating
Wolf Lake to Beaver Creek	G	NA	N	8	5.50	2001	Marathon	Operating
Beaver Creek G.F. to Enstar	G	NA	N	12			Marathon	Operating
Tyonek to shore	G	NA	Y	10	13.00	1967	Phillips	Operating
Tyonek to shore	G	NA	Y	10	13.00	1967	Phillips	Operating
Tyonek shore to Nikiski	G	NA	N	16	34.00	1967	Phillips	Operating
Granite Pt. to GPTF	G	NA	Y	8	3.79	1966	Unocal	Operating
Anna to Bruce	G	NA	Y	8	1.59	1966	Unocal	Operating
Bruce to GPTF	G	NA	Y	6	5.30	1974	Unocal	Operating
Monopod to TBPf	G	NA	Y	8	9.00	1966	Unocal	Operating
King Salmon to TBPf	G	NA	Y	8	7.50	1967	Unocal	Operating
Grayling to TBPf	G	NA	Y	10	5.30	1967	Unocal	Operating
Steelhead to TBPf	G	NA	Y	10	7.95	1986	Unocal	Operating
Steelhead to TBPf	G	NA	Y	10	7.95	1986	Unocal	Operating
Dolly Varden to TBPf	G	NA	Y	8	5.70	1967	Unocal	Operating
Baker to A	G	NA	Y	8	2.50	1965	Unocal	Operating
Dillon to EFDF	G	NA	Y	8	5.61	1966	Unocal	Operating
Swanson River O./G. F. to KPL term.	G	NA	N	16	19.20		Unocal	Operating
KPL term. to Agrium facility	G	NA	N	16	0.60		Unocal	Operating

Appendix 1, continued
Cook Inlet Oil and Natural Gas Pipeline Data

Pipeline	Liq./Gas	Liq. contents	Subsea?	Nom. Dia. (in.)	Length (miles)	Installed	Operator	Status
Lewis C and Lewis D G.F.s to Enstar	G	NA	N	4	0.70		Unocal	Operating
Lewis C to Lewis D G.F.s	G	NA	N	2	0.50		Unocal	Operating
Pretty Creek G.F. to Enstar	G	NA	N	4	0.70		Unocal	Operating
Stump Lake G.F. to Ivan River G.F.	G	NA	N	6	6.00		Unocal	Operating
GPTF to CIGGS	G	NA	N	4	0.50		Unocal	Operating
CIGGS to Phillips LNG plant	G	NA	N	10	0.10		Unocal	Operating
Agrium facility to East Foreland	G	NA	N	10	4.70		Unocal	Operating
Ivan River Gas Field to Enstar	G	NA	N	8	8.00		Unocal	Operating
Dillon to C	G	NA	Y	8	2.00	1966	XTO Energy	Operating
A to C	G	NA	Y	8	2.20	1967	XTO Energy	Operating
Anna to East Foreland	Other (form. G)	NA	Y	10	19.00	1966	BP	Abandoned
Anna to East Foreland	Other (form. L)	NA	Y	10	19.00	1966	BP	Abandoned
Spark to GPTF	Other	?	Y	6	7.20	1968	Marathon	Used as an outfall line.
Dillon to EFDF	Other (form. L)	NA	Y	8	5.61	1966	Unocal	Abandoned

Note: This appendix does not include oil and natural gas production field pipelines.

Sources: Pipeline Risk Assessment, October 1999, Unocal Pipeline Integrity Program Schedule, Unocal; letter to Susan Harvey, ADEC, from Unocal, July 26, 2001; "Overview of Pipeline Regulatory Requirements, Cook Inlet, AK," CIRCAC, May 2000; Cook Inlet Area Pipeline Map, Enstar Natural Gas Co., Anchorage, AK, January 2001; "Final Project Description - Preferred Alternative, New Jet Fuel Pipeline to Supply Anchorage International Airport," Oasis Environmental, July 1998; "Central Cook Inlet Oil and Gas Gathering Lines," industry handout from the 1/10/02 Soldotna Pipeline Forum; 4/5/01 Unocal letter to Roger Little of OPS; Personal communications with Jerry Davis, OPS, Anchorage, AK, Ted Moore, ADEC, Anchorage, AK, and Jim Shew, Cook Inlet Pipe Line Co., Anchorage, AK.

Holes in the spreadsheet result from the unavailability of public information at the time of publication. Mileage is approximate and taken from the best available source. The author takes full responsibility for spreadsheet contents. Corrections, clarifications, and additions are welcome and should be sent to lois@inletkeeper.org.

Appendix 2
Cook Inlet Pipeline Releases Reported to ADEC, 1997-2001, Keeper Data

Date	Location	Operator	Material(s) Spilled	Gals.	Onshore/Off.	Reported cause
1/9/97	Granite Point Tank Farm	Unocal	Produced water	11,340	Onshore	Frozen pipeline ruptured
3/30/97	Swanson River Field	Unocal	Produced water & crude	1,134	Onshore	Corrosion
5/1/97	Swanson River Field	Unocal	Produced water	1,260	Onshore	Internal corrosion
5/2/97	Swanson River Field	Unocal	Produced water	10	Onshore	Corrosion
5/8/97	Swanson River Field	Unocal	Produced water	8	Onshore	Corrosion
8/3/97	Swanson River Field	Unocal	Produced water & crude	1,682	Onshore	Internal corrosion
9/29/97	Swanson River Field	Unocal	Crude & condensate	24	Onshore	Release from pipeline during maintenance
10/20/97	Swanson River Field	Unocal	Crude	84	Onshore	Pipeline failure
10/25/97	West McArthur River Unit	Forcenergy (now, Forest Oil)	Crude	<1	Onshore	Release from pipeline during maintenance
11/25/97	Trading Bay Production Facility	Unocal	Produced water	Unknown	Onshore	Pipeline failure
12/10/97	Granite Point Tank Farm	Unocal	Produced water	15	Onshore	Release from pipeline during maint. (valve left open)
1/10/98	Anna Platform pipeline	Unocal	Condensate	1	Offshore	Frozen pipeline; release during thawing
2/6/98	King Salmon Platform pipeline	Unocal	Waste oil	240	Offshore	"Abandoned" discharge pipeline used
2/10/98	Swanson River Field	Unocal	Crude	84	Onshore	Human error for not detecting valve failure
3/13/98	Kenai Gas Field	Marathon	Produced water & cond.	126	Onshore	Pipeline failure
4/6/98	Swanson River Field	Unocal	Produced water	42	Onshore	Thread erosion
4/26/98	Granite Point Tank Farm	Unocal	Crude	20	Onshore	Corrosion
4/29/98	Trading Bay Production Facility	Unocal	Crude	3	Onshore	External corrosion
5/4/98	Trading Bay Production Facility	Unocal	Produced water	10	Onshore	Pipeline failure
5/17/98	East Foreland pipeline	Shell (now, XTO)	Crude	840	Onshore	Aboveground pipeline failure
5/26/98	West McArthur River Unit	Forcenergy (now, Forest Oil)	Crude & condensate	<1	Onshore	Loose fitting
6/16/98	Cannery Loop Gas Field	Marathon	Condensate	Unknown	Onshore	Pipeline failure (pipeline installed in 1996)
7/7/98	Swanson River Field	Unocal	Condensate	10	Onshore	Pipeline failure
9/24/98	Trading Bay Production Facility	Unocal	Produced water	42	Onshore	External corrosion
10/7/98	Cross Timbers facility	Cross Timbers (now, XTO)	Crude	32	Onshore	Corrosion (6")
11/1/98	West McArthur River Unit	Forcenergy (now, Forest Oil)	Crude	2	Onshore	Pipeline valve failure
11/28/98	West McArthur River Unit	Forcenergy (now, Forest Oil)	Crude	<1	Onshore	Pipeline connection failure
12/17/98	Swanson River Field	Unocal	Crude	42	Onshore	Frozen pipeline; release from flare when thawed
1/6/99	Swanson River Field	Unocal	Produced water & crude	228,648	Onshore	3/8" hole (6")
1/18/99	Trading Bay Production Facility	Unocal	Crude	4	Onshore	Corrosion
2/11/99	Pipeline from Bruce Platform to shore	Unocal	Crude	8	Offshore	Pipeline failure
2/13/99	Swanson River Field	Unocal	Crude	<1	Onshore	Release from flare line
3/15/99	Swanson River Field	Unocal	Produced water	126	Onshore	Erosion-corrosion
4/16/99	West McArthur River Unit	Forcenergy (now, Forest Oil)	Crude	2	Onshore	Release from pipeline during maintenance
6/8/99	Wik Road, East Foreland	Unocal	Crude	2	Onshore	Abandoned outfall pipeline valve failure
6/18/99	Swanson River Field	Unocal	Crude	55	Onshore	External corrosion

Appendix 2, continued
Cook Inlet Pipeline Releases Reported to ADEC, 1997-2001 - Keeper Data

Date	Location	Operator	Material(s) Spilled	Gals.	Onshore/Off.	Reported cause
6/27/99	West McArthur River Unit	Forcenergy (now, Forest Oil)	Crude	2	Onshore	Abandoned water pipeline containing crude
7/9/99	Swanson River Field	Unocal	Crude	110	Onshore	Corrosion, wash-out
7/15/99	Trading Bay Production Facility	Unocal	Crude	1	Onshore	Abandoned pipeline containing crude cut
7/30/99	Swanson River Field	Unocal	Crude	1	Onshore	Release from pipeline during maintenance
8/11/99	Trading Bay Production Facility	Unocal	Crude	2	Onshore	Release from pipeline during maintenance
8/13/99	Grayling Platform pipeline	Unocal	Crude	1	Offshore	Release from pipeline during hydrotest
8/31/99	Granite Point Tank Farm	Unocal	Condensate	2	Onshore	Release from pipeline during maintenance
9/8/99	Swanson River Field	Unocal	Crude	15	Onshore	Pipeline failure
9/16/99	Trading Bay Production Facility	Unocal	Crude	1	Onshore	Internal corrosion
10/23/99	Dillon Platform pipeline	Unocal	Crude	450	Offshore	Pipeline failure
11/21/99	Swanson River Field	Unocal	Produced water	8,600	Onshore	Fiberglass wastewater pipe failure from abrasion (6")
11/23/99	Kenai Gas Field	Marathon	Condensate	1	Onshore	Pipeline failure
1/19/00	Swanson River Field	Unocal	Produced water	420	Onshore	Fiberglass wastewater pipe failure (4")
1/22/00	Swanson River Field	Unocal	Crude	3	Onshore	Failed check valve
3/14/00	Cross Timbers facility	Cross Timbers (now, XTO)	Crude	315	Onshore	Pipeline hole
3/31/00	Swanson River Field	Unocal	Crude	25	Onshore	Pipeline patch failure; "washed out"
6/21/00	Swanson River Field	Unocal	Produced water	2,100	Onshore	Internal corrosion, 1/8" hole (4")
7/29/00	Trading Bay Production Facility	Unocal	Produced water	5	Onshore	Corrosion (16")
8/12/00	Beaver Creek facility	Marathon	Produced water	88	Onshore	Valve failure, pipeline rupture
8/21/00	Pipeline from Dillon Platform to "C" Plat.	Unocal	Crude	<1	Offshore	Pipeline failure
9/1/00	Swanson River Field	Unocal	Produced water	2,540	Onshore	Fiberglass wastewater pipe failure during maint. (4")
11/28/00	Cross Timbers facility	Cross Timbers (now, XTO)	Crude	1,050	Onshore	1/4" hole in aboveground pipeline (8")
1/13/01	Swanson River Field	Unocal	Produced water & crude	42	Onshore	Fiberglass wastewater pipe failure
1/17/01	West McArthur River Unit	Forest Oil	Crude	3	Onshore	Broken line/fitting
2/5/01	Dolly Varden Platform pipeline	Unocal	Produced water & crude	124	Offshore	Corrosion, 1/4" hole
3/25/01	West McArthur River Unit	Forest Oil	Crude	2	Onshore	Open-ended pipe - human error
5/16/01	Cross Timbers facility outfall	Cross Timbers	Produced water	Unknown	Onshore	Wastewater outfall line failure
7/31/01	Anna Platform subsea pipeline	BP	Crude	Unknown	Offshore	Abandoned crude oil pipeline failure
7/31/01	Tesoro pipeline/Capt. Cook State R. A.	Tesoro	Diesel	Unknown	Onshore	Corrosion
8/27/01	Granite Point Tank Farm	Unocal	Condensate	<1	Onshore	Release from pipeline vent during maintenance
9/5/01	Granite Point Platform pipeline	Unocal	Crude	<1	Onshore	Pipeline failure
9/20/01	East Foreland pipeline	XTO Energy	Condensate	3	Onshore	Earthloader hit gas line
9/23/01	Swanson River Field	Unocal	Produced water & crude	25	Onshore	Release from open-ended pipeline during maintenance
11/14/01	Swanson River Field	Unocal	Condensate	8	Onshore	Release from flare line following maintenance

The pipeline accidents in this table do not include: Anchorage-area spills, oil and natural gas pipeline spills from non-production-related facilities, releases from facility piping, and diesel and hydraulic pipeline spills except for diesel spills from transmission pipelines. This database includes reported spills from Marathon's natural gas drilling operations.

Appendix 3
Cook Inlet Pipeline Releases Reported to ADEC, mid-1995 - mid-2001, ADEC Data

Date	Location	Material Spilled	Gallons	Onshore/Off.	Reported cause
7/24/1995	KENAI UNOCAL SWANSON RIVER FIELD WELL 12-A-10	Crude	126	Onshore	Valve Failure
7/28/1995	KENAI UNOCAL SWANSON RIVER FIELD I-33 WASTE WATER BUILDING	Crude	840	Onshore	Line Failure
8/3/1995	KENAI UNOCAL SWANSON RIVER FIELD 200' NORTH OF TIE IN TO 1-33	Crude	2	Onshore	Leak
9/28/1995	KENAI UNOCAL SWANSON RIVER FIELD	Crude	5	Onshore	Leak
11/14/1995	KENAI UNOCAL SWANSON RIVER FIELD 3" FLOW LINE	Produced Water	30	Onshore	Line Failure
11/25/1995	KENAI UNOCAL TRADING BAY PRODUCTION FACILITY ON LAND	Produced Water	10	Onshore	Line Failure
1/15/1996	KENAI UNOCAL SWANSON RIVER FIELD FLOW LINE #1	Produced Water	1890	Onshore	Corrosion
1/28/1996	KENAI UNOCAL SWANSON RIVER FIELD I-33 WW	Produced Water	420	Onshore	Valve Failure
3/10/1996	KENAI UNOCAL SWANSON RIVER FIELD IN PIPEWAY ON NORTH SIDE	Crude	30	Onshore	Leak
4/20/1996	KENAI UNOCAL SWANSON RIVER FIELD NEAR 22-23 PAD HOLE IN 21-33	Crude	84	Onshore	Line Failure
5/19/1996	KENAI UNOCAL SWANSON RIVER FIELD TANK SETTING 1-33	Produced Water	42	Onshore	Leak
6/17/1996	KENAI UNOCAL SWANSON RIVER FIELD 1-33 TANK SETTING	Crude	33	Onshore	Leak
9/2/1996	KENAI UNOCAL SWANSON RIVER FIELD TANK SETTING 1-33	Crude	25	Onshore	Corrosion
10/5/1996	KENAI UNOCAL TRADING BAY PRODUCTION FACILITY AT SCRAPER	Crude	500	Onshore	Line Failure
12/20/1996	KENAI UNOCAL SWANSON RIVER FIELD WEST OF 1-33 WASTE WATER	Produced Water	30	Onshore	Line Failure
3/30/1997	KENAI UNOCAL SWANSON RIVER FIELD	Crude	1134	Onshore	Corrosion
5/1/1997	KENAI UNOCAL SWANSON RIVER FIELD? WASTE DISPOSAL WELL	Produced Water	1260	Onshore	Corrosion
5/2/1997	KENAI UNOCAL SWANSON RIVER FIELD TANK SETTING I-33	Crude	10	Onshore	Leak
5/8/1997	KENAI UNOCAL SWANSON RIVER FIELD WELL 41-33 FLOW LINE BETWEEN	Produced Water	8	Onshore	Corrosion
7/22/1997	KENAI UNOCAL SWANSON RIVER FIELD I-33 WASTEWATER PUMP HOUSE	Produced Water	30	Onshore	Corrosion
8/3/1997	KENAI UNOCAL SWANSON RIVER FIELD	Produced Water	1680	Onshore	Corrosion
9/29/1997	KENAI UNOCAL SWANSON RIVER FIELD	Crude	24	Onshore	Human Error
12/10/1997	KENAI GRANITE POINT TANK FARM	Produced Water	15	Onshore	Human Error
12/21/1997	KENAI TRADING BAY WEST MCARTHUR RIVER UNIT	Crude	2	Onshore	Leak
1/24/1998	KENAI UNOCAL TRADING BAY PRODUCTION FACILITY UNDER BATTERY	Produced Water	5	Onshore	Line Failure
2/10/1998	KENAI UNOCAL SWANSON RIVER FIELD WELL PAD 213	Crude	84	Onshore	Cargo Not Secured
3/13/1998	KENAI GAS FIELD MARATHON FACILITY PAD 43-32	Produced Water	126	Onshore	Line Failure
4/26/1998	KENAI GRANITE POINT TANK FARM	Crude	20	Onshore	Unknown
4/29/1998	KENAI UNOCAL TRADING BAY PRODUCTION FACILITY RECYCLE LINE	Crude	3	Onshore	Corrosion
5/4/1998	KENAI UNOCAL TRADING BAY PRODUCTION FACILITY BLUFF ROAD	Produced Water	10	Onshore	Line Failure
5/17/1998	KENAI SHELL EAST FORELANDS FACILITY FROM 500 BBL PIPEWAY	Crude	840	Onshore	Corrosion
6/20/1998	KENAI SWANSON RIVER FIELD BATTERY ONE PIPEWAY BEHIND CHIEF	Crude	4	Onshore	Line Failure
6/20/1998	KENAI SWANSON RIVER FIELD BATTERY ONE PIPEWAY BEHIND CHIEF	Produced Water	36	Onshore	Line Failure
7/7/1998	KENAI SWANSON RIVER FIELD TANK SETTING 1-33	Natural Gas	10	Onshore	Line Failure
9/17/1998	KENAI UNOCAL SWANSON RIVER FIELD SOUTHEAST OF TANK SETTING	Crude	3	Onshore	Containment Overflow
9/24/1998	KENAI UNOCAL TRADING BAY PRODUCED WATER WOUFALL LINE AREA	Produced Water	42	Onshore	Corrosion

Appendix 3, continued
Cook Inlet Pipeline Releases Reported to ADEC, mid-1995 - mid-2001, ADEC Data

Date	Location	Material Spilled	Gallons	Onshore/Off.	Reported cause
10/7/1998	KENAI SHELL WESTERN ONSHORE FACILITY - CROSS TIMBERS OPE	Crude	55	Onshore	Leak
12/17/1998	KENAI SWANSON RIVER FIELD TANK 215	Crude	41	Onshore	External Factors
1/6/1999	KENAI SWANSON RIVER FIELD WEST OF TANK SETTING 1-27.	Crude	2520	Onshore	Corrosion
1/18/1999	KENAI UNOCAL TRADING BAY PRODUCTION FACILITY PIPE	Crude	4	Onshore	Corrosion
3/15/1999	KENAI SWANSON RIVER FIELD DISPOSAL WELL 31-33	Produced Water	126	Onshore	Corrosion
4/16/1999	KENAI FORCENERGY WEST MCARTHUR RIVER UNIT	Crude	2	Onshore	Cargo Not Secured
5/25/1999	KENAI TRADING BAY PRODUCTION FACILITY UNOCAL	Crude	7	Onshore	Valve Failure
6/8/1999	KENAI NIKISKI WIK ROAD MP 2 AT VALVE BOX EAST FORELANDS DE	Crude	2	Onshore	Valve Failure
6/18/1999	KENAI COOK INLET PLATFORM BRUCE ON PLATFORM	Crude	10	Offshore	Overfill
6/18/1999	KENAI SWANSON RIVER FIELD TANK SETTING 3-4 ON GROUND	Crude	55	Onshore	Corrosion
6/22/1999	KENAI SWANSON RIVER FIELD WEST OF MAIN FLARE	Crude	10	Onshore	Overfill
6/27/1999	KENAI FORCENERGY WEST MCARTHUR RIVER UNIT	Crude	2	Onshore	Line Failure
7/9/1999	KENAI SWANSON RIVER FIELD SRU 41-33 WELL UNDERGROUND PIF	Crude	110	Onshore	Corrosion
7/15/1999	KENAI TRADING BAY PRODUCTION FACILITY	Crude	1	Onshore	Other
7/30/1999	KENAI SWANSON RIVER FIELD 3-4	Crude	1	Onshore	Leak
8/11/1999	KENAI TRADING BAY PRODUCTION FACILITY ABOVE GROUND PROC	Crude	2	Onshore	Overfill
8/13/1999	KENAI COOK INLET GRAYLING PLATFORM ON WATER	Crude	1	Offshore	Line Failure
9/8/1999	KENAI SWANSON RIVER FIELD WELL PAD 4133 WO	Crude	15	Onshore	Leak
9/16/1999	KENAI TRADING BAY PRODUCTION FACILITY	Crude	1	Onshore	Corrosion
10/23/1999	KENAI COOK INLET DILLON PLATFORM ON WATER	Crude	504	Offshore	Line Failure
11/21/1999	KENAI SWANSON RIVER FIELD NEAR 1-4 WASTEWATER BUILDING	Produced Water	10500	Onshore	Leak
1/19/2000	KENAI SWANSON RIVER FIELD	Crude	1	Onshore	Leak
1/20/2000	KENAI TRADING BAY PRODUCTION FACILITY	Crude	20	Onshore	Leak
3/31/2000	SWANSON RIVER WELL PAD 42B - 05	Crude	25	Onshore	Leak
6/21/2000	SWANSON RIVER FIELD TS 1-4	Produced Water	200	Onshore	Leak
8/12/2000	BEAVER CREEK GAS FIELD PAD 1A	Produced Water	88	Onshore	Valve Failure
8/21/2000	NORTH COOK INLET PIPELINE BELOW DILLON PLATFORM 60 44.260	Crude	1	Offshore	Leak
11/28/2000	NIKISKI, CROSS TIMBERS ONSHORE FACILITY	Crude	504	Onshore	Valve Failure
12/14/2000	SWANSON RIVER FIELD TANK SETTING 127	Crude	40	Onshore	Leak
12/16/2000	TRADING BAY WEST END OF WEMCO TANKS BETWEEN #1	Crude	5	Onshore	Leak
1/13/2001	SWANSON RIVER FIELD 300 FT NORTH 1-4 TANK SETTING	Produced Water	1	Onshore	Leak
3/25/2001	WEST MCARTHUR RIVER UNIT	Crude	2	Onshore	Leak
5/16/2001	CROSS TIMBERS OUTFALL LINE	Produced Water	1	Onshore	Corrosion

See http://www.state.ak.us/local/akpages/ENV.CONSERV/dspar/ciforum/ci_spilldata.htm for a full description of location information.

Note: The 6/20/98 pipeline spill is listed twice in this database, once for spilling crude and once for spilling produced water. Other spills are not similarly listed.

Cook Inlet Keeper did not double-count the 6/20/98 spill in this study.

Appendix 4
Cook Inlet Oil Pipeline Regulatory Issues

Pipeline	Liq./Gas	Gath./Trans.	Operator	Regulator(s)	REGULATORY ISSUES
TBPF to Cook Inlet PL	L	T	Cook Inlet PL	OPS/DEC-T	
GPTF to Drift River	L	T	Cook Inlet PL	OPS/DEC-T	
Drift River tanks to shore	L	T	Cook Inlet PL	CG/DEC-F	Should be regulated by the state as a transmission line.
Drift River shore to offshore loading	L	T	Cook Inlet PL	CG/DEC-F	Should be regulated by the state as a transmission line.
Drift River shore to offshore loading	L	T	Cook Inlet PL	CG/DEC-F	Should be regulated by the state as a transmission line.
West McArthur to TBPF	L	T	Forest Oil	DEC-T	
XTO Energy to KPL term.	L	T	Kenai PL/Tesoro	DEC-T	Should be regulated by OPS; area is not rural.
Swanson River O./G. F. to Nikiski	L	T	Kenai PL/Tesoro	DEC-T	Should be regulated by OPS; area is not wholly rural.
Port of Anch. to airport (new)	L	T	Signature	OPS	
Tesoro ref. to Port of Anchorage	L	T	Tesoro	OPS/DEC-F	
KPL term. to Tesoro ref.	L	T	Tesoro	DEC-F	
Branch line to Anchorage airport	L	T	Tesoro	OPS	
Steelhead to TBPF	L	G	Unocal	OPS/DEC-F	Onshore portion should be regulated by OPS, as XTO's pipelines are.
Monopod to TBPF	L	G	Unocal	OPS/DEC-F	Onshore portion should be regulated by OPS, as XTO's pipelines are.
King Salmon to TBPF	L	G	Unocal	OPS/DEC-F	Onshore portion should be regulated by OPS, as XTO's pipelines are.
Grayling to TBPF	L	G	Unocal	OPS/DEC-F	Onshore portion should be regulated by OPS, as XTO's pipelines are.
Granite Pt. to GPTF	L	G	Unocal	OPS/DEC-F	Onshore portion should be regulated by OPS, as XTO's pipelines are.
Dolly Varden to TBPF	L	G	Unocal	OPS/DEC-F	Onshore portion should be regulated by OPS, as XTO's pipelines are.
Dolly Varden to TBPF	L	G	Unocal	OPS/DEC-F	Onshore portion should be regulated by OPS, as XTO's pipelines are.
Bruce to GPTF	L	G	Unocal	OPS/DEC-F	Onshore portion should be regulated by OPS, as XTO's pipelines are.
Baker to A	L	G	Unocal	OPS/DEC-F	
Anna to Bruce	L	G	Unocal	OPS/DEC-F	
Dillon to C	L	G	XTO Energy	OPS/DEC-F	
A to XTO Energy	L	G	XTO Energy	OPS/DEC-F	
A to XTO Energy	L	G	XTO Energy	OPS/DEC-F	
A to C	L	G	XTO Energy	OPS/DEC-F	

Sources: Pipeline Risk Assessment, October 1999, Unocal Pipeline Integrity Program Schedule, Unocal; letter to Susan Harvey, ADEC, from Unocal, July 26, 2001; "Overview of Pipeline Regulatory Requirements, Cook Inlet, AK," CIRCAC, May 2000; Cook Inlet Area Pipeline Map, Enstar Natural Gas Co., Anchorage, AK, January 2001; "Potential Construction and Operations Impact: Impact Analysis of Fuel Supply Alternatives for Anchorage International Airport," Oasis Environmental, April 1998; "Central Cook Inlet Oil and Gas Gathering Lines," industry handout from the 1/10/02 Soldotna Pipeline Forum; Personal communications with Jerry Davis, OPS, Anchorage, AK, Ted Moore, ADEC, Anchorage, AK, and Jim Shew, Cook Inlet Pipe Line Co., Anchorage, AK.

Gathering and transmission pipeline classifications are based on regulatory and physical conditions. Since these occasionally are in conflict, best professional judgement was used. Regulator(s) means the state or federal agency overseeing pipeline release prevention. Highlighted regulator(s) are those where there is a known inconsistency. The author takes full responsibility for spreadsheet contents. Corrections, clarifications, and additions are welcome and should be sent to lois@inletkeeper.org.

Appendix 5
Cook Inlet Natural Gas Pipeline Regulatory Issues

Pipeline	Liq./Gas	Gath./Trans.	Operator	Regulator(s)	REGULATORY ISSUES
Kenai to Anchorage	G	T	Enstar	OPS	
Kenai to Anchorage	G	T	Enstar	OPS	
E. Anchorage to Whittier	G	T	Enstar	OPS	
Beluga to Anchorage	G	T	Enstar	OPS	
West McArthur to TBPf	G	T	Forest Oil	None	Is this a gathering line under OPS' definition?
W. Foreland #1 to W. McArth.	G	T	Forest Oil	None	Is this a gathering line under OPS' definition?
Spurr to GPTF	G	G	Marathon	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Spurr to GPTF	G	G	Marathon	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Spark to GPTF	G	G	Marathon	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Wolf Lake to Beaver Creek	G	T	Marathon	None	Does this qualify as a transmission pipeline under OPS' definition?
TBPf to GPTF (CIGGS sys.)	G	T	Marathon	OPS	
Nikiski shore to Nikiski (CIGGS sys.)	G	T	Marathon	OPS	
Kenai G.F. to Nikiski	G	T	Marathon	OPS	
GPTF to Nikiski shore (CIGGS sys.)	G	T	Marathon	OPS	
GPTF to Nikiski shore (CIGGS sys.)	G	T	Marathon	OPS	
GPTF to Beluga	G	T	Marathon	OPS	
Cannery Loop G.F. to Kenai G.F. line	G	T	Marathon	OPS	
Beaver Creek G.F. to Enstar	G	T	Marathon	OPS	
Tyonek to shore	G	G	Phillips	OPS	
Tyonek to shore	G	G	Phillips	OPS	
Tyonek shore to Nikiski	G	T	Phillips	OPS	
Steelhead to TBPf	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Steelhead to TBPf	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Monopod to TBPf	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
King Salmon to TBPf	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Grayling to TBPf	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Granite Pt. to GPTF	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Dolly Varden to TBPf	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Dillon to EFDF	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Bruce to GPTF	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Baker to A	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Anna to Bruce	G	G	Unocal	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
Swanson River O./G. F. to KPL term.	G	T	Unocal	OPS	
Stump Lake G.F. to Ivan River G.F.	G	T	Unocal	None	Does this qualify as a transmission pipeline under OPS' definition?
Pretty Creek G.F. to Enstar	G	T	Unocal	OPS	
Lewis C to Lewis D G.F.s	G	T	Unocal	None	Does this qualify as a transmission pipeline under OPS' definition?

Appendix 5, continued
Cook Inlet Natural Gas Pipeline Regulatory Issues

Pipeline	Liq./Gas	Gath./Trans.	Operator	Regulator(s)	REGULATORY ISSUES
Lewis C and Lewis D G.F.s to Enstar	G	T	Unocal	OPS	
KPL term. to Agrium facility	G	T	Unocal	OPS	
Ivan River Gas Field to Enstar	G	T	Unocal	None	Does this qualify as a transmission pipeline under OPS' definition?
GPTF to CIGGS	G	T	Unocal	OPS	
CIGGS to Phillips LNG plant	G	T	Unocal	None	Does this qualify as a transmission pipeline under OPS' definition?
Agrium facility to E. Foreland	G	T	Unocal	OPS	
Dillon to C	G	G	XTO Energy	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.
A to C	G	G	XTO Energy	None?	Should be regulated by OPS, as Phillips' Tyonek pipelines are.

Sources: Pipeline Risk Assessment, October 1999, Unocal Pipeline Integrity Program Schedule, Unocal; letter to Susan Harvey, ADEC, from Unocal, July 26, 2001; "Overview of Pipeline Regulatory Requirements, Cook Inlet, AK," CIRCAC, May 2000; Cook Inlet Area Pipeline Map, Enstar Natural Gas Co., Anchorage, AK, January 2001; "Potential Construction and Operations Impact: Impact Analysis of Fuel Supply Alternatives for Anchorage International Airport," Oasis Environmental, April 1998; "Central Cook Inlet Oil and Gas Gathering Lines," industry handout from the 1/10/02 Soldotna Pipeline Forum; Personal communications with Jerry Davis, OPS, Anchorage, AK and Ted Moore, ADEC, Anchorage, AK.

Gathering and transmission pipeline classifications are based on regulatory and physical conditions. Since these occasionally are in conflict, best professional judgement was used.

Regulator(s) means the state or federal agency overseeing pipeline release prevention.

Highlighted regulator(s) are those where there is a known inconsistency.

The author takes full responsibility for spreadsheet contents. Corrections, clarifications, and additions are welcome and should be sent to lois@inletkeeper.org.

Appendix 6
Cook Inlet "Other" Pipeline Regulatory Issues

Pipeline	Liq./Gas	Gath./Trans.	Operator	Regulator(s)	REGULATORY ISSUES
Spark to GPTF	Other	G	Marathon	None?	Used as an outfall line, according to Marathon.
Dillon to EFDF	Other (formerly L)	G	Unocal	OPS/DEC-F	Abandoned
Anna to East Foreland	Other (formerly L)	T	BP	?	Abandoned
Anna to East Foreland	Other (formerly G)	T	BP	?	Abandoned

Sources: Pipeline Risk Assessment, October 1999, Unocal Pipeline Integrity Program Schedule, Unocal; letter to Susan Harvey, ADEC, from Unocal, July 26, 2001; "Overview of Pipeline Regulatory Requirements, Cook Inlet, AK," CIRCAC, May 2000; Cook Inlet Area Pipeline Map, Enstar Natural Gas Co., Anchorage, AK, January 2001; "Final Project Description - Preferred Alternative, New Jet Fuel Pipeline to Supply Anchorage International Airport," Oasis Environmental, July 1998; "Central Cook Inlet Oil and Gas Gathering Lines," industry handout from the 1/10/02 Soldotna Pipeline Forum; Personal communications with Jerry Davis, OPS, Anchorage, AK, Ted Moore, ADEC, Anchorage, AK, and Jim Shew, Cook Inlet Pipe Line Co., Anchorage, AK.

Gathering and transmission pipeline classifications are based on regulatory and physical conditions. Since these occasionally are in conflict, best professional judgement was used.

Regulator(s) means the state or federal agency overseeing pipeline release prevention.

The author takes full responsibility for spreadsheet contents. Corrections, clarifications, and additions are welcome and should be sent to lois@inletkeeper.org.

Comparison of Cook Inlet Keeper Pipeline Report¹ Accident Statistics for Oil with Accident Statistics for 9/15/02 - 9/15/03 and 9/15/03 - 9/15/05, Respectively

Statistic	“Lurking Below” Report	1 st Post-Report Analysis	2 nd Post-Report Analysis
Frequency	66/60 months <i>1.1 x/month</i>	9/12 months <i>0.75 x/month</i>	12/24 months <i>0.5 x/month</i>
Onshore/Offshore	88% / 12%	100% / 0%	83% / 17%
Cause:			
Corrosion	27%	0%	8%
Unknown/unreported	26%	33%	0%
Human error/maintenance-related	20%	22%	8%
Pipeline infrastructure failure	14%	22%	42%
Abandoned pipeline release	8%	11%	25%
Frozen pipeline	5%	22%	17%
Third-party damage	2%	0%	0%
Type/Location:			
Onshore oil field pipelines: Swanson River Field	41%	44%	67%
Onshore oil processing, including West McArthur River Unit and Trading Bay Production Facility	36%	56%	8%
Offshore pipelines	14%	0%	17%
Tank farm	8%	0%	0%
Onshore oil transmission	2%	0%	8%
Number of Reported Spills by Operator: ²			
Unocal	76%	78%	75%
Forest Oil	12%	22%	8%
XTO Energy	8%	0%	0%
Tesoro	2%	0%	0%
BP	2%	0%	8%
Cook Inlet Pipe Line	0%	0%	8%
Kenai Pipe Line	0%	0%	0%
Annual release volume	52,324 gal.	211 gal.	686 gal.
Average/median spill size (gal.)	3,964 / 15	23 / 8	114 / 4
Releases >50 gal.	30%	22%	33%
Largest spills	Top 8 - Unocal	Top 3 - Unocal	Top 2 - Unocal

¹ “Lurking Below: Oil and Gas Pipeline Problems in the Cook Inlet Watershed,” Lois N. Epstein, Cook Inlet Keeper, September 2002, see www.inletkeeper.org/pipelines.htm. The time period analyzed was 1997-2001.

² As discussed on p. 18 of “Lurking Below,” “Keeper believes that using the number of spills rather than the volume released results in a better measure of operator performance since a few large volume spills can distort the results. In fact, 99% of the known volume spilled during the 1997-2001 was from Unocal operations (as opposed to 76% of the number of spills), with the January 6, 1999 spill alone representing 87% of the total volume released from pipelines in the Cook Inlet watershed during this period.” Additionally, a large number of small volume spills indicates a systemic problem that should be remedied, and thus is noteworthy.

Oil Pipeline Analysis:

Unchanged:

- Offshore spills still occur at a rate of approximately 1 release/year
- Unocal has the highest release frequency with approximately 3/4 of all pipeline releases, and a disproportionately high spill rate since the company owns only 39% of the Cook Inlet oil industry's pipeline mileage
- Approximately 1/4 to 1/3 of the pipeline releases are >50 gallons; and,
- The largest spills are dominated by Unocal-owned pipelines

Favorable Trends:

- The overall pipeline spill rate decreased significantly to approximately 0.5 releases/month (from 1.1 releases/month in 1997-2001)
- XTO Energy, Tesoro, and Kenai Pipe Line have zero reported releases for the past three years
- Onshore oil processing releases decreased significantly (potentially because Forest Oil's operations are no longer new)
- Corrosion and unknown/unreported generally decreased as causes of releases; and,
- Median release volume decreased

Unfavorable Trends:

- Pipeline infrastructure failures, abandoned pipeline releases, and frozen pipelines together represent an increasingly large percentage of pipeline releases (probably because these pipeline release causes have not been a focus of preventive actions to date, unlike releases due to corrosion); and,
- Swanson River Field pipelines represent an increasingly large percentage of pipeline releases

Comparison of Cook Inlet Keeper Pipeline Report Accident Statistics for Gas with Accident Statistics for 9/15/02 - 9/15/03 and 9/15/03 - 9/15/05, Respectively

Statistic	“Lurking Below” Report	1 st Post-Report Analysis	2 nd Post-Report Analysis
Frequency	4 / 5 years <i>0.8 x/year</i>	1 / 1 year <i>1 x/year</i>	6 / 2 years <i>3 x/year</i>
Number of Reported Spills ³ by Operator: Marathon Aurora Gas	100% NA	100% NA	83% 17%
Annual release volume	43 gal.	55 gal.	5,412 gal.
Average/median spill size (gal.)	72 / 88	55 / 55	1,805 / 56
Releases >50 gal.	50%	100%	50%

Gas Pipeline Analysis:

Unchanged:

- Vast majority of the releases are from Marathon, the primary gas pipeline operator in the Cook Inlet watershed
- Median spill volume is relatively stable; and,
- Half or more of the releases are >50 gallons

Favorable Trends: None

Unfavorable Trends:

- Overall pipeline spill rate increased significantly (from 0.8 releases/year in 1997-2001 to 3 releases/year currently)
- Annual release volume increased significantly; and,
- Average release volume may be increasing

³ Natural gas pipelines must report spills of natural gas condensates and produced water to the state of Alaska (see 18 AAC 75.300).

Oil & Gas Infrastructure in Cook Inlet, Alaska

A Potential Public Liability?

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Oil & Gas Infrastructure in Cook Inlet, Alaska

A Potential Public Liability?

By John Talberth, Ph.D. and Evan Branosky



*Oil rigs and pipelines at Cook Inlet.
What will happen if this infrastructure is abandoned, how much
will it cost to clean it up and who will pay?*

In brief:

- In Alaska's Cook Inlet, oil and gas production has been on the decline for decades and, until recently, was presumed to be nearing the end of its economic life. However, in the past five years, there has been a "renaissance" in exploration and production, as technological advancements allow operators to extract resources from older fields. These advanced recovery methods require new infrastructure beyond the existing oil wells, platforms, pipelines, and onshore processing facilities now in place.
- The existing oil wells, platforms, pipelines, and onshore processing facilities are now nearly 50 years old and are starting to be shut in. As they shut in, oil and gas companies are required to initiate plans for dismantling and removal of key infrastructure on state-owned land and to restore affected marine and shoreline ecosystems (DR&R).
- However, as demonstrated in Alaska and other states, this obligation is often disputed, unclear or not met, leaving states and federal taxpayers with a potential financial liability for cleaning up the damage left behind. In Alaska, bond financing provides the State with funds for DR&R, which add to any private sector funds and covers costs should companies default on their obligations.
- Records provided by Alaska Department of Natural Resources (ADNR) staff and other public records cited by the General Accounting Office indicate that the value of DR&R funding committed through State bonding and included in ADNR databases to be roughly \$46 million. Additional bonding documented by Division of Oil and Gas staff but not included in ADNR databases indicates an additional \$140 million in performance bonds and guarantees.
- In contrast, the total costs of DR&R for 16 offshore platforms and 160 miles of oil pipelines in Cook Inlet will range between \$402 million and \$1.11 billion. Adding gas pipelines and other infrastructure with more ambiguous DR&R requirements would greatly increase this cost.

estimate and the associated funding gap. Thus, DR&R funding available to the State through bonds may represent no more than 25-50% of total anticipated costs.

As a result, this report makes the following preliminary observations and recommendations:

- Bonding and related surety obligations for oil and gas infrastructure need enhanced clarity and predictability to best serve the interests of industry, government and Alaskans alike;
- Currently, it is difficult and at times impossible to understand the amounts obligated by oil and gas companies for DRR operations; as a result, new DNR rules should promote transparency to allow members of the public, agency personnel and stockholders to better understand DRR liabilities;
- Regardless of a corporation's financial fitness, the recent financial crisis has shown that there is no such thing as "too big to fail." As a result, any new bonding or surety strategies must ensure all companies with DRR obligations, regardless of their financial wherewithal, set aside the resources needed to meet their DRR responsibilities.
- Bonding requirements should not be based on a schedule of nominal fees, but the actual expected costs of DR&R for each facility, pipeline, platform, or other infrastructure element.

Background

The oil and gas industry in Cook Inlet is in flux. Oil and gas infrastructure expanded rapidly after commercial production began in the late 1950s. Operators drilled a record 35 wells in 1966 and had installed 14 offshore production platforms by 1968 (Rothe 2005, Kenai Offshore Drilling 2013). Oil and gas production reached a record 300 million barrels of oil equivalent (MMBOE) in 1970. Since the late 1960s, however, just two platforms were installed respectively in 1986 and 2000. In 2006, operators drilled just five new wells and recovered 50 MMBOE. Regarding the outlook, one 2009 study noted that "new production is simply not outpacing natural field decline" even as two jack-up rigs prepared for deployment to aid with new exploration (DEAC 2009; Bradner 2013).

The two jack-up rigs – spurred by generous tax credits and other incentives—were an indication, however, that a new round of oil and gas development was on the horizon. Indeed, in the past five years, there has been a "renaissance" of exploration and development according to industry executives (Klouda 2013). For example, in late 2012 Cook Inlet Energy LLC announced plans to build the \$50 million, 29-mile Trans-Foreland Pipeline for transporting crude oil across Cook Inlet to the Tesoro Refinery to avoid the more risky tanker transports used today. The expectation is for greater production along the western shores to justify the investment (Loy 2012). Hilcorp's acquisition of Cook Inlet gas and oil assets will ensure additional supplies from older fields thought to be tapped out. Hilcorp specializes in technological innovations that help wring "oil and gas out of legacy fields abandoned by larger companies" (DeMarban 2013).

All this new activity is bolstered by new, more optimistic assessments of recoverable reserves by USGS and private companies. For the Cook Inlet region, the USGS now estimates that total undiscovered but technically recoverable oil resources range between 108 and 1,359 million barrels of oil (MBOE) and between 4,976 and 39,737 billion cubic feet (bcf) of gas – a significant increase over its 1995 projections

(USGS 2011). In 2013, Buccaneer Energy revised its estimates of proven oil reserves in the North Cook Inlet unit upward by 54 percent.¹

Regardless of these new discoveries or investments in exploration and development, there are ongoing concerns about the future of ageing industry infrastructure. Miles of pipeline, docking facilities, refineries, and offshore production platforms become irrelevant if production does not justify their continued operation or if they are deemed obsolete in the face of new, more efficient and effective technologies.

A complicated framework of state and federal policies establish the obligations and processes for dismantlement, removal, and restoration (DR&R), which could carry a high cost for companies and potentially Alaska residents. In particular, bonding requirements cover only a portion of the full cost of DR&R, and if companies go bankrupt or otherwise default on these obligations, the public could be left with the resulting liability.

In the past, a lack of specific requirements for cleanup and restoration led to the abandonment and inadequate cleanup of about 80 wells drilled on federal lands in what is now known as the National Petroleum Reserve in Alaska (Lazaroff 2002). As infrastructure in Cook Inlet continues to age and become obsolete, there are concerns that this scenario could be repeated.

To provide a preliminary estimate of the costs of DR&R for offshore platforms and pipelines in Cook Inlet and comparison to the likely value of DR&R funding available to the State, Cook Inletkeeper partnered with Center for Sustainable Economy (CSE) for a preliminary analysis of five relevant factors:

- 1) existing extent of industry infrastructure relevant to DR&R requirements in Cook Inlet;
- 2) age and life expectancy of the infrastructure;
- 3) state and federal laws and rules applicable to bonding and DR&R;
- 4) the value of bonds or other surety amounts committed for DR&R when operations cease; and
- 5) estimated actual DR&R costs needed to remove the infrastructure.

This preliminary report addresses each of these elements by relying on publicly available information. Greater precision in the figures and legal framework reported here would be possible with cooperative agreements from the companies that maintain fossil fuel infrastructure in Cook Inlet and the State of Alaska to share data and help frame a subsequent, more refined analysis.

Extent of Fossil Infrastructure in Cook Inlet

Fossil fuel infrastructure in Cook Inlet is well developed and documented (DEAC 2009; DOG 2009; Robertson and Parker Horn 2000). As of 2010, major components included:

- Sixteen offshore platforms producing oil and gas, including all process equipment, facility piping and associated pipelines. These platforms include 247 wells, of which 109 are shut-in. Four platforms are currently in lighthouse mode (e.g., wells shut in, production facilities cleaned, platforms decommissioned but navigational aids intact).
- Twenty-one onshore gas production facilities, including all process equipment, facility piping and associated pipelines. Six facility areas are not currently producing.

¹ Reported in Alaska Business Monthly, June 21st, 2013, available online at: <http://www.akbizmag.com/Alaska-Business-Monthly/June-2013/Buccaneer-Energy-Reserves-Resources-North-Cook-Inlet-Deep-Oil-Rights/>.

- Five onshore oil and gas processing facilities, including East Forelands Facility, Granite Point Tank Farm, Trading Bay Production Facility, West McArthur River Facility, and Kustatan Facility as well as associated process equipment, facility piping and pipelines.
- Drift River Marine Terminal and associated Christy Lee Platform, including all process equipment, storage tanks, facility piping and associated pipelines up to the berth loading arms.
- Oil and gas pipelines. Epstein (2002) identified over 1,000 miles of transmission pipelines, gathering lines, and natural gas distribution pipelines. Of these, a 2000 inventory of oil pipelines estimated 150 miles of pipeline length, of which 84 miles are offshore (Robertson and Parker Horn Company 2000). Since that time, the Osprey offshore platform and associated pipelines were put in place. This infrastructure includes one oil, one gas, and one water pipeline roughly two miles in length each and a set of onshore pipelines totaling 16.2 miles in length (Goff 2003).² Of these, roughly 10 are for oil, bringing the Cook Inlet total for oil to 160 miles.

This infrastructure is distributed throughout Cook Inlet but concentrated in the region bordered by the Kasilof to the southeast and Tyonek to the northwest (Appendix 1).

Age and Life Expectancy of the Infrastructure

Data describing the date of installation for both offshore platforms and oil pipelines is publicly available. These data are reproduced in Tables 1 and 2 below. Table 1 describes each of the 16 offshore platforms by name, 2009 operator, and year installed. The table also indicates the platform's status as of 2009 in terms of active and shut-in wells (DEAC 2009). Since that time, Hilcorp Energy LLC has taken control of Marathon Oil Company's Cook Inlet assets, mostly gas producing wells, as well as the Chevron Corporation Inlet properties that include the producing offshore oil platforms.

Table 2 describes the documented oil pipelines in Cook Inlet with respect to operator, pipeline type, pipeline length, and year of installation (Robertson and Parker Horn 2000; Goff 2003). Additional information on all pipelines – oil and gas – can be found in Epstein (2002). The Alaska Department of Environmental Conservation (ADEC) distinguishes two types of oil pipelines: crude oil transmission pipelines and facility pipelines. The difference is regulatory in nature, but does not affect CSE's estimates of DR&R costs since structurally there are few if any differences. As of 2005, Union (Unocal) merged and is a wholly owned subsidiary of the Chevron Corporation. As noted above, Hilcorp now controls most of Chevron's assets. Hilcorp presumably now operates Chevron pipelines in the Cook Inlet Basin, although legally Union is still listed as the owner. As such, Table 2 retains the original pipeline operator's name.

Given historical declines in Cook Inlet oil and gas production, there are questions as to how long this infrastructure will continue to be useful. Already, four offshore platforms are in lighthouse mode and seven oil and gas fields or units are not producing (DEAC 2009). While predicting the life expectancy of oil and gas infrastructure is a difficult and complex task, it is reasonable to assume that the useful life of this infrastructure is related to the reserves that remain and the annual depletion rate.

As late as 2009, experts presumed that oil and gas production in Cook Inlet was nearing the end of its useful life. These 2009 projections demonstrated that most existing fields would cease production in the 2015 to 2021 period if then-current production continued and no new reserves were located. According to the Alaska Division of Oil and Gas, just 109 MBOE oil and 1.5 trillion cubic feet of natural gas were left

² See also Conam construction descriptions available online at: http://conamco.rapidsys.com/index.php?option=com_content&task=view&id=17&Itemid=45.

to recover as of the 3rd quarter of 2007. The 2006 depletion rates were six MBOE oil and 196 bcf of gas. Applying these rates to the 2008 to 2013 period suggests that just 47 MBOE oil and 379 bcf gas remain. Current production rates would deplete oil reserves by 2021 and gas reserves by 2015 (DOG 2009).

However, since that time, and as noted previously, there has been a new wave (renaissance by some accounts) of oil and gas exploration and development in Cook Inlet, bolstered in part by new estimates of technically recoverable reserves by the USGS and private companies. The USGS estimates are at least two times greater for oil and thirteen times greater for gas than those reported in Table 3. Thus, attempts to forecast the life expectancy of Cook Inlet oil and gas infrastructure based on estimated reserves and depletion rates is fraught with uncertainty.

Regardless, one thing is clear: the first wave of oil and gas infrastructure installed in Cook Inlet in the 1960s has far exceeded its design life. As noted by Visser (1989), “[t]he initial development plans for the Cook Inlet fields anticipated an economical field life of about 20 years and the platform designs were based on this assumption.” This casts doubt on whether or not renovations and refurbishments are possible – as evidenced by plans to replace ageing and leaky pipelines with new ones and the current lighthouse status of four offshore platforms. Thus, issues over DR&R and whether or not adequate financial resources exist to restore Cook Inlet’s marine and coastal resources to their natural state remain a timely issue for consideration.

Table 1: Cook Inlet Offshore Platforms
(Alphabetical order by facility name)

Facility name	Operator (2009)	Active wells	Wells shut-in	Year Installed
Platform A	XTO Energy	15	2	1964
Platform Anna	Chevron*	12	3	1966
Platform Baker	Chevron*	1	13	1965
Platform Bruce	Chevron*	7	5	1966
Platform C	XTO Energy	12	4	1967
Platform Dillon	Chevron*	0	9	1966
Platform Dolly Varden	Chevron*	17	20	1967
Platform Granite Point	Mobil/ Chevron*	8	3	1966
Platform Grayling	Chevron/ Marathon*	20	15	1967
Platform King Salmon	Chevron/ Marathon*	12	13	1967
Platform Monopod	Chevron/ Marathon*	2	0	1966
Platform Osprey	Pacific Energy Resources	2	3	2000
Platform Spark	Marathon*	0	6	1968
Platform Spurr	Chevron/ Marathon*	8	8	1968
Platform Steelhead	Chevron/ Marathon*	24	4	1986
Platform Tyonek	Conoco-Phillips Alaska	7	0	1968

* By spring of 2013, Hilcorp had acquired most of Marathon’s and Chevron’s assets in Cook Inlet.

State and Federal Laws and Rules Applicable to Bonding and DR&R

This section discusses the regulatory requirements related to DR&R with an emphasis on the bonding requirements. While there are dozens of laws, rules and regulations relevant to the permitting and safe operation of pipelines and onshore processing facilities, DR&R obligations are not explicit (See, e.g. Robertson and Parker Horn Company 2000). In contrast, DR&R obligations with respect to offshore platforms and associated infrastructure are explicit. Both state and federal regulations apply.

Table 2: Cook Inlet Oil Pipelines

Original Operator	ADEC Class	Length (miles)	Installed
Kenai Pipeline	Facility pipeline	19.2	1960
Cross Timbers	Facility pipeline	7.0	1965
Kenai Pipeline	Facility pipeline	3.9	1965
Unocal	Facility pipeline	2.5	1965
Cook Inlet Pipeline	Crude oil pipeline	42.0	1966
Cook Inlet Pipeline	Facility pipeline	3.6	1966
Unocal	Facility pipeline	6.0	1966
Unocal	Facility pipeline	1.6	1966
Unocal	Facility pipeline	9.0	1966
Cross Timbers	Facility pipeline	2.2	1967
Unocal	Facility pipeline	6.0	1967
Unocal	Facility pipeline	7.0	1967
Unocal	Facility pipeline	5.7	1967
Marathon	Facility pipeline	7.2	1968
Unocal	Facility pipeline	8.4	1968
Unocal	Facility pipeline	1.6	1974
Tesoro	Facility pipeline	8.3	1974
Tesoro	Facility pipeline	1.0	1983
Unocal	Facility pipeline	6.5	1986
Forcenergy	Crude oil pipeline	1.3	1993
Forest Oil (est.)	Facility pipeline	2.0	2002
Forest Oil (est.)	Facility pipeline	8.0	2002
<i>Total:</i>		160.0	

State of Alaska laws and regulations

Of the two sets of laws and regulations that could apply to offshore production platforms in Cook Inlet, those for the State of Alaska are more relevant than those for the federal government. In the U.S. federal system, federal laws establish a baseline for compliance that states can exceed. In addition, all 16 offshore production platforms lie in state waters. Thus, there are no commercial, permanent platforms in the defined federal waters of Cook Inlet that would be subject only to the federal laws for production on the outer continental shelf. Federal laws remain relevant however, since a lease sale is scheduled for Cook Inlet in 2016 under the Five Year Outer Continental Shelf Oil and Gas Leasing Program for 2012 to 2017 (BOEM 2013).

The state laws and regulations are best explained according to the entities that implement and enforce them. The Alaska Oil and Gas Conservation Commission (AOGCC), administered within the Alaska Department of Administration, holds responsibility for protecting the subsurface integrity of oil and gas fields during well exploration and production phases. The AOGCC receives authority from the Alaska Oil and Gas Conservation Act, which also provides authority for many of the Commission's regulations. The regulations affecting DR&R span from 20 AAC 25.005 (drilling permit) to 20 AAC 25.172 (offshore location clearance) and cover bonding, abandonment, and plugging among other requirements.

Regarding bonding, an operator may be required to provide a third-party surety bond for more than \$100,000 for a single well or \$200,000 for all of its wells in the State. The bond “ensure[s] that each well is drilled, operated, maintained, repaired, and abandoned and each location is cleared...” according to requirements established further in the chapter. In addition, the operator must abandon wells within one year of the permanent cessation of recovery activity in the field or expiration date of the lease and sever wellhead equipment and casing at three feet below the original ground level. To date, most offshore production platforms have neither ceased activity nor faced expired leases. However, Chevron (now Hilcorp) provided the AOGCC a timetable for abandoning their Baker and Dillon platforms in May 2010. The company forecasts full removal in 2019.

The Alaska Department of Natural Resources (ADNR) has additional regulatory authority over DR&R operations. Established under the authority of the Alaska Land Act, 11 AAC 83.160 requires lessees to provide a bond for at least \$10,000 to ADNR before commencing operations. Alternatively, the lessee may provide a statewide bond for \$500,000. At his discretion, the ADNR Commissioner may require bonds for a greater amount. In 11 AAC 82, the State requires lease agreements to include the necessary bond amount and defines the conditions for lease transfers for companies that go out of business, sell their assets, or transfer the lease. For some leases, unit agreements establish DR&R requirements in excess of lease agreements. Thus, the lease and unit agreements provide the most accurate information on bond amounts to cover operations on the 16 offshore production platforms.

As documented by GAO, the ADNR can also require an unusual risk bond in addition to single well and statewide bonding requirements.³ State of Alaska regulations provide the ADNR Commissioner with the discretion to require additional financial assurances based on, among other factors, the degree of risk involved for the operations proposed or conducted on the lease including the financial background of the lessee (GAO 2002).

Lease agreements

CSE requested and obtained lease agreements for the 16 offshore production platforms from the State of Alaska (see reference section). All leases except one (i.e., lease number 381203 for the Osprey platform) are dated in 1962 and thus have similar bond requirements. Each lease includes the land tracts, their combined acres, and bonding requirements prior to the lease issuance and commencing drilling operations. Prior to lease issuance, the lessee must provide a bond of \$2.00 for each acre with the total amount exceeding \$1,000. In addition, prior to commencing drilling operations, the lessee must provide a bond of \$5,000 per well or \$100,000 for all of the lessee’s wells in the State. Requirements for the Osprey platforms are slightly higher, at \$5.00 per acre up to a \$10,000 minimum and statewide bond equal to the bond requirements in relevant regulations (i.e., 20 AAC 25.005 to 20 AAC 25.172 and 11 AAC 82). Table 4 lists the bond requirements in each lease that includes an offshore production platform.

Both the lease agreements from 1962 and the Osprey agreement from 1994 contain other bond conditions as well. If the State determines that greater bond amounts are necessary to cover the risk and operations of the lease activities, it may require the lessee to hold that additional bond. A statewide bond does not substitute for the additional amount. For example, if the per acre amount before leasing equals \$10,000 but the State requests \$20,000, the lessee is not covered by a \$100,000 statewide bond. Finally, for wells

³ The Alaska DNR recently issued a discussion paper laying out a proposed risk-based bonding strategy, and will hold a public workshop September 9, 2013 to take comments on the proposal. *See Possible Financial Strength Measures for Offshore Platforms South of the 68th Parallel* (August 23, 2013), available at: http://dog.dnr.alaska.gov/AboutUs/Documents/PublicNotices/Offshore_DRR_Briefing_Document_08_23_13PM.pdf

located in areas covered under unit agreements, the wells are covered by any statewide bond for those unit agreements. The bond amounts add to any private-sector financing reserved for DR&R. Since 1962, platforms transfers, company sales, negotiations among unit partners and other factors have influenced the amount of bonds that companies hold for DR&R.

Table 4: Bond Requirements in Leases that Include Offshore Platforms

Platform	Date installed	Lease number	Acre-based bond	Before-drill bond options	
				Per-well	Statewide
Anna	1966	18742	\$10,120	\$5,000	\$100,000
Baker	1965	17595	\$10,212	\$5,000	\$100,000
Bruce	1966	18742	\$10,120	\$5,000	\$100,000
Dillon	1966	18746	\$6,400	\$5,000	\$100,000
Dolly Varden	1967	18729	\$6,170	\$5,000	\$100,000
Granite Point	1966	18761	\$10,178	\$5,000	\$100,000
Grayling	1967	17594	\$10,232	\$5,000	\$100,000
King Salmon	1967	18772	\$7,680	\$5,000	\$100,000
Monopod	1966	18731	\$7,680	\$5,000	\$100,000
Osprey	2000	381203	\$19,200	N/A	N/A
Spark	1968	17597	\$10,240	\$5,000	\$100,000
Spurr	1968	17597	\$10,240	\$5,000	\$100,000
Steelhead	1986	18730	\$7,680	\$5,000	\$100,000
Tyonek	1968	17589	\$10,000	\$5,000	\$100,000
XTO A	1964	18754	\$7,492	\$5,000	\$100,000
XTO C	1967	18756	\$10,240	\$5,000	\$100,000

Finally, the lease agreements explain conditions related to other DR&R processes. The leases from 1962 include provisions for the State to cancel the lease. Within 60 days of a notice for failure to comply with lease requirements, the State may revoke a lease agreement if no working wells are on the land tracts. If the land tract includes working wells, only judicial proceedings may revoke the lease agreement. In addition, upon termination, the lessee has six months to remove its property from the land tract unless the State provides additional time. The 1994 lease agreement contains similar conditions with one exception. The lessee has one year to remove its property and must rehabilitate the site to the State's satisfaction. If the State prefers, the lessee may also abandon infrastructure such as roads, pads, and wells and become absolved of any further DR&R responsibility.

Unit agreements

The Alaska permitting process recognizes two types of access and recovery agreements. In addition to leases for tracts of land, the State also awards unit agreements for tracts that drain a common reservoir. The unit agreements allocate production shares. Lessees under well lease agreements may unite and form unit agreements when it serves the interest of companies, the State, and the general public.

In addition to the lease agreements, CSE requested and obtained unit agreements for the units that contain offshore production platforms (see references section). As follows, the North Middle Ground Shoals unit includes the Baker offshore production platform; South Middle Ground Shoals unit includes Dillon; North Trading Bay unit includes Dolly Varden, Grayling, King Salmon, and Steelhead; South Granite Point unit includes Granite Point; North Cook Inlet unit includes Tyonek; and the Redoubt unit includes the Osprey offshore production platform. Of the unit agreements, those for North Middle Ground Shoals, South Granite Point, and Redoubt have a similar format that includes DR&R provisions (Rothe 2005).

Those unit agreements provide lessees of their land tracts with one year to remove property upon termination of the agreement. They also provide the State with flexibility in requesting that some minimal infrastructure (e.g., roads, pads, wells) remain on site and absolves the lessees of further DR&R responsibility when those requests are made. Thus, those unit agreements extend some DR&R conditions of the lease agreement for the Osprey offshore production platform to the Baker and Granite Point platforms. Since its lease and unit agreements contain similar provisions, the unit DR&R requirements will have little effect on the Osprey platform.

Federal laws and regulations

While all current offshore production platforms are located in State waters, federal DR&R requirements remain relevant. The U.S. Department of the Interior Bureau of Ocean Energy Management (BOEM) develops and administers the Outer Continental Shelf Oil and Gas Leasing Five-Year Program (Program). Due to lack of industry interest, the Department of the Interior has not held a lease sale since 2004 when no companies submitted bids (BOEM 2011). However, the 2012 to 2017 Program plans a “special-interest” sale for planning area 244 in 2016 (BOEM 2013). In a special-interest sale, BOEM requests that companies nominate tracts within planning areas where they may have a bid interest. If no companies express interest, BOEM does not hold the sale.

After successfully bidding on a tract, receiving a lease, and implementing an offshore production platform, a company would need to comply with federal regulations for offshore development. Bonding requirements in the Code of Federal Regulations (CFR) span 30 CFR 556.52 to 30 CFR 556.59 and 30 CFR 250.1490 to 30 CFR 250.1491. Before BOEM awards a lease, the lessee must maintain a \$50,000 bond to ensure compliance with lease terms. The lessee may also hold an area wide bond of \$300,000 for all tracts within a planning area (e.g., planning area 244).

If the lessee conducted lease exploration before receiving the lease from BOEM, its exploratory bond is sufficient. At 30 CFR 556.52, exploratory lease bonds are valued at \$200,000 but the lessee is not required to provide such a bond if it provides an area wide bond for \$1,000,000. Finally, prior to commencing lease development and production, 30 CFR 556.53 requires the lessee to provide a \$500,000 lease development bond. Like the other bond requirements, the lease development bond is waived if the lessee maintains a \$3,000,000 area wide bond. Subsequent regulations explain the process for providing bonds, including performance and management requirements for insurance companies.

The regulations at 30 CFR 250.1700 to 30 CFR 250.1754 establish detailed requirements for decommissioning wells. In general, as noted at 30 CFR 250.1703, the requirements include receiving proper decommissioning approval, permanently plugging all wells, removing platforms, decommissioning pipelines, clearing the seafloor of all obstructions and right-of-way operations, and completing all activities in a safe manner. Similar to the Alaska State requirements, the U.S. Government may request that some infrastructure remain in place when in the public interest. Subsequent regulations under 30 CFR 250 explain the conditions for requesting different decommissioning activities.

Rationale for bond amounts

The different amounts for bonds included in this memorandum demonstrate evolving state regulations for basing bonds. The 1962 lease agreements set minimum bond amounts at \$1,000 per production platform or \$5,000 per well. In the 1994 lease agreement, however, the minimum bond amount increases to \$10,000, which is the amount required in 11 AAC 83.160 for lessees to provide before beginning development on a leased tract. Subsequent regulations appear to increase the bond amounts.

CSE asked ADNDR for the assumptions involved with establishing and changing bond amounts. Such information was not readily available and would require significant investigation into the legislative and regulatory history of the State bonding requirements. However, the U.S. Government explanation for establishing its bond amounts may provide insight on the Alaska process. For example, the Mineral Leasing Act of 1920 as amended requires federal regulations to require bonds or surety (e.g., cashier's checks, certified checks) set for an adequate amount to ensure complete and timely reclamation (GAO 2010).

In *Oil and Gas Bonds: Bonding Requirements and BLM Expenditures to Reclaim Orphaned Wells*, the U.S. Government Accountability Office notes that Bureau of Land Management (BLM) bond amounts for oil and gas activities have not been updated since being set in the 1950s and 1960s. Thus, its \$10,000 individual bond would increase to \$59,360 in 2009 dollars. Regulators must determine if it is necessary to increase bond amounts. If so, they must further determine whether it is sufficient to simply adjust the current amount for inflation or whether a full rebasing is necessary.

Other approaches by the U.S. Government to establishing bond amounts seem better able to accommodate increasing DR&R costs. For example, BLM bond amounts for locatable minerals (e.g., gold, silver, copper) base the bond amount on the estimated costs for BLM to contract with a third-party for site reclamation. For salable materials including sand and gravel, BLM sets bond amounts based on sales contracts. By establishing requirements to set bond amounts on values that accommodate inflation or adjust according to sales, government agencies ensure that their DR&R costs are covered equitably.

Bonds and Other Surety Amounts Committed for DR&R in Cook Inlet

The total funding committed for DR&R activities associated with Cook Inlet fossil fuel infrastructure is impossible to estimate based on publicly available information. An unknown amount is carried as a liability on corporate asset sheets, and often placed in an independent trust account (Fineberg 2004). Several factors affect private sector companies' decisions about the amount of funding to hold in reserve; including court cases, settled bankruptcies, asset transfers, and shareholder preferences. Much of the information is treated as confidential corporate data. Moreover, DR&R liabilities are typically lumped together under an "asset retirement obligations" line item contained in annual reports filed with the Securities and Exchange Commission. The ambiguity makes disaggregation to a particular infrastructure component impossible even for analysts with access to corporate records (Rothe 2005).

What can be estimated – and what is most relevant for CSE's analysis – is what companies have committed through bonds required by laws and regulations. Should companies default on their DR&R obligations, these bonds would be the only source of committed funds on hand for cleanup and restoration activities. Unfortunately, identifying the public-bond financing for any one well, platform, or unit is also extremely difficult. While there are clear bonding requirements for DR&R associated with platforms, these requirements have numerous discretionary provisions that allow for adjustments in bond requirements based on perceived risk and other factors. Moreover, bond requirements are often reconsidered and adjusted as ownership changes or the context of bankruptcies or other legal proceedings.

Nonetheless, in order to estimate a rough estimate of the bonds committed for removal of Cook Inlet platforms, CSE reviewed lease agreements, published information, regulatory requirements, and conducted phone and e-mail interviews with ADNDR staff.

Table 5 reports the results for three categories of bonds applicable to Cook Inlet platforms: (1) the acre-based bonds contained in lease agreements; (2) statewide bonds verified by ADNR staff⁴, and (3) additional risk bonds reported by GAO (2002). As indicated by Table 5, for the 16 Cook Inlet offshore platforms, the total amount committed through these regulatory processes for DR&R is roughly \$46 million. In addition to this amount, DOG staff identified additional bonding amounts secured in 2009 and 2013 as part of agreements with Hilcorp and Cook Inlet Energy. DOG staff indicated that these bonding amounts totaled an additional \$140 million at most.⁵

Again, to reiterate: this estimate does not represent the total on hand for DR&R. Companies operating offshore platforms typically have already budgeted for DR&R and maintain those liabilities on their books. Rather, the values reported in Table 5 estimate what the State of Alaska should have on hand should companies default on their DR&R obligations.

**Table 5: Estimated DR&R Funding for Cook Inlet Platforms
Committed Through Bonding and Included in ADNR Records**

Platform	Acre-based bond	Statewide bond	Risk bond*	DR&R Total**
Anna	\$10,120	\$500,000	-	\$510,120
Baker	\$10,212	\$500,000	-	\$510,212
Bruce	\$10,120	\$500,000	-	\$510,120
Dillon	\$6,400	\$500,000	-	\$506,400
Dolly Varden	\$6,170	\$500,000	-	\$506,170
Granite Point	\$10,178	\$500,000	-	\$510,178
Grayling	\$10,232	\$500,000	-	\$510,232
King Salmon	\$7,680	\$500,000	-	\$507,680
Monopod	\$7,680	\$500,000	-	\$507,680
Osprey	\$19,200	\$500,000	\$3,800,000	\$4,319,200
Spark	\$10,240	\$500,000	-	\$510,240
Spurr	\$10,240	\$500,000	-	\$510,240
Steelhead	\$7,680	\$500,000	-	\$507,680
Tyonek	\$10,000	\$500,000	-	\$510,000
XTO A	\$7,492	\$500,000	\$17,000,000	\$17,507,492
XTO C	\$10,240	\$500,000	\$17,000,000	\$17,510,240
<i>Totals:</i>	\$153,884	\$8,000,000	\$37,800,000	\$45,953,884

* As reported by GAO (2009).

** For the three bond categories included. According to Alaska officials, there may be other bonds that are in place, but they could not be verified.

Estimated actual DR&R costs needed to remove the infrastructure

Estimates for DR&R costs in Cook Inlet also carry uncertainty. Regulators and industry note three key sources of uncertainty including:

- Regulatory requirements. Although oil and gas companies clearly have obligations for DR&R and environmental remediation once fossil fuel infrastructure is not longer in use, the actual

⁴ Personal communication with Corazon C Manaois and Kim Kruse, Alaska Division of Oil and Gas, 8/6 and 8/7, 2013. ADNR noted that, in addition to the \$500,000 statewide bonds in place for each platform, all operators have additional bonds but the amounts were not included in ADNR records. CSE assumes that the per-acre bonds listed in Table 5 are included since they are specified in the lease agreements.

⁵ Personal communication with Kevin Banks, Alaska Division of Oil and Gas, 9/4/13.

activities required are far less clear. For example, a full range of DR&R activities may include plugging and abandonment of wells. However, as noted by the GAO (2002), the State of Alaska's DR&R requirements "offer no specifics on what infrastructure must be removed or to what condition lands used for oil industry activities must be restored." Thus, estimating actual DR&R costs is only possible if regulatory requirements are made explicit with respect to the wide range of DR&R activities that apply.

- Infrastructure configuration. Actual DR&R costs for any specific platform, pipeline, or other infrastructure elements depends upon a variety of factors specific to the infrastructure in question. For example, according to a study commissioned by the former Minerals Management Service, platform decommissioning costs can vary widely due to factors such as location and type (complexity) of the facility, number of structures to be removed, weight associated with the structure, the number of wells and conductors, removal method, and transportation and disposal options (Proserv Offshore 2010).
- Location. The location of a particular infrastructure element is another major factor that influences costs. For example, a recent analysis of DR&R costs in the North Sea found a 14-fold difference between decommissioning costs in the southern North Sea (less expensive) versus locations in the northern and central portions (UK Oil and Gas 2012). The difference was explained in part by geographic factors such as ocean depth and weather.

Despite these factors, there are a number of information sources on which to draw to develop general estimates for at least two fossil infrastructure elements in Cook Inlet: offshore platforms and oil pipelines. These are the infrastructure elements for which DR&R requirements are most explicit and most regulated. For platforms, we incorporate estimates from four sources.

The first is a study of North Sea DR&R costs sponsored by UK Oil and Gas, an industry association (UK Oil and Gas 2012). This study – which is regularly updated – provides estimates for 32 platforms, 202 pipelines, and 295 wells scheduled to be decommissioned over the next 15 years. The study partitions the analysis into two North Sea regions – southern and northern/central. The study also differentiates between platform decommissioning costs, costs associated with plugging and abandonment of wells and operating costs during decommissioning. In terms of comparability, the southern North Sea may be more appropriate for Cook Inlet considering its relatively shallow depths, proximity to shore, and weather. In the southern North Sea, decommissioning costs were estimated at \$28.51 million in 2013 dollars. Plugging and abandonment costs for platform wells were estimated at an additional \$2.37 million per well. The study also estimates that plugging and abandonment costs represent 80 percent of total decommissioning costs. Thus, by knowing the number of wells associated with a particular platform, CSE can derive an additional estimate of decommissioning costs for the entire platform installation.

Incorporating operations costs is more complex. Operations costs are included in the UK Oil and Gas (2012) estimates because "the initial disconnection from producing hydrocarbons does not significantly reduce the numbers of personnel and significant work is required to prepare the installations for decommissioning, such as cleaning, maintenance and activities carried out to ensure asset integrity is maintained before and during decommissioning." However, if DR&R activities commence relatively soon after production ceases, these costs are minimized. Also, it is unclear whether operations costs ought to be tallied under DR&R or just recorded as after-the-fact production costs. Because we have no basis for predicting the length of time between production cessation and DR&R commencement for Cook Inlet platforms or how companies are treating these costs, we exclude them for now.

The second is a study of decommissioning 23 offshore platforms in California, prepared by Proserv Offshore for the Minerals Management Service, now BOEM (Proserv Offshore 2010). The analysis

provides estimates ranging from \$12 million to \$149 million per platform – or an average of \$59.29 million per platform in 2013 dollars. Thirteen cost categories were considered (Appendix 2). Key factors driving the variance between platform costs were size, weight, and water depth.

The third source is an estimate for the Spurr platform in Cook Inlet. A dispute between Marathon Oil Company and Pacific Energy Resources (the former operator) led to litigation over DR&R liability.⁶ As part of that litigation, expected DR&R costs were made public. Estimates range from \$23 million to \$38 million in 2013 dollars. The fourth is a cost estimate for XTO Platforms A and C, the subject of a 1998 abandonment agreement with the State. The agreement estimated DR&R costs of \$15.5 million per platform for plugging and abandonment of all wells, removal of all structures, and buildings on the platform, and removal of the platform and associated pipelines (Rothe 2005). This is \$22.2 million in current dollars.

For oil pipelines, CSE incorporated two estimates referenced in Fineberg (2004) and based upon Alaska Public Utility Commission proceedings. The first is for the Cook Inlet Pipeline. DR&R costs were estimated to be \$17.9 million in 1982 or \$43.3 million in 2013 dollars. The second estimate is for the Kenai pipeline, estimated at \$5.66 million in 2013 dollars. Respectively, and based upon lengths reported in Table 2, these estimates translate into costs of \$1.03 million and \$0.29 million per mile.⁷

Table 6 summarizes these cost figures for both platforms and pipelines and what they imply for unit costs. Applying the minimum and maximum values from these data, CSE derived estimates of minimum (i.e., excluding operations costs) DR&R costs for all 16 Cook Inlet platforms and 160 miles of pipelines described in Tables 1 and 2. For platforms, CSE estimates range from \$355.20 million to \$948.64 million, a mean value of \$651.92 million. For pipelines, CSE estimates range from \$47.17 million to \$164.95 million, with a mean of \$106.06 million. Combined, the estimates imply a minimum DR&R liability for platforms and oil pipelines alone in Cook Inlet to range between \$402.37 million and \$1.11 billion. Comparing these cost figures to figures from Table 5 and additional bonding information supplied by DOG staff suggests that surety bonds committed to support Alaska DR&R activities represent no more than 25 to 50 percent of funds required for DR&R activities should companies default on their obligations.

Table 6: Estimates of DR&R Costs for Cook Inlet Platforms and Pipelines

Infrastructure element	Unit cost assumption (\$2013 millions)	Total costs (\$2013 millions)	Source
Platforms	\$22.20 per platform	\$355.20	Rothe (2005); GAO (2002)
Platforms	\$22.85 per platform	\$365.60	Law360 (2010)
Platforms	\$28.51 per platform	\$456.16	UK Oil and Gas (2012)
Platforms	\$38.09 per platform	\$609.44	Law360 (2010)
Platforms	\$45.33 per platform	\$725.28	UK Oil and Gas (2012) ⁸
Platforms	\$59.29 per platform	\$948.64	Proserv Offshore 2010
Pipelines	\$0.29 per mile	\$47.17	Kenai pipeline in Fineberg (2004)
Pipelines	\$1.03 per mile	\$164.95	Cook Inlet pipeline in Fineberg (2004)

⁶ See Law360 at: <http://www.law360.com/articles/210856/marathon-pacific-energy-pitch-ch-11-platform-deal>.

⁷ For both, we excluded shorter facility pipelines that bear the same project name.

⁸ Based on wells per platform reported in Table 1 and a plugging and abandonment cost of \$2.37 million per well inflated by 20 percent as per UK Oil and Gas (2012) assumptions.

Conclusions

Despite a resurgence of investment in oil and gas production in Cook Inlet and new, more optimistic reserve estimates, the disposition of ageing and obsolete fossil fuel infrastructure remains a major public concern. Much of this infrastructure was installed during the 1960s and is now far beyond its expected design life. Once operations cease at ageing oil platforms, pipelines, and onshore processing facilities, companies will need to commence DR&R activities which require removal of all infrastructure and restoration of marine and coastal environments.

While companies are presumed to have retained financial resources to complete DR&R tasks, the uncertainty inherent to profits, losses, and ownership changes affects their assets. If companies were to default on their responsibility, presumably the State of Alaska would bear the costs. But bonds required by the State represent only a fraction of the resources needed. This report suggests that likely bond values represent 25-50% of the likely \$402 million to \$1.11 billion needed to safely remove platforms and oil pipelines and complete ecological restoration activities. Gas pipelines and other infrastructure subject to DR&R requirements would put this cost far higher and the gap much greater. The magnitude of the gap suggests that bond requirements be reformed and related to actual DR&R costs rather than the nominal fees now set in place by Alaska statutes, rules, and regulations.

As a result, this report makes the following preliminary observations and recommendations:

- Bonding and related surety obligations for oil and gas infrastructure need enhanced clarity and predictability to best serve the interests of industry, government and Alaskans alike;
- Currently, it is difficult and at times impossible to understand the amounts obligated by oil and gas companies for DRR operations; as a result, new DNR rules should promote transparency to allow members of the public, agency personnel and stockholders to better understand DRR liabilities;
- Regardless of a corporation's financial fitness, the recent financial crisis has shown that there is no such thing as "too big to fail." As a result, any new bonding or surety strategies must ensure all companies with DRR obligations, regardless of their financial wherewithal, set aside the resources needed to meet their DRR responsibilities.
- Bonding requirements should not be based on a schedule of nominal fees, but the actual expected costs of DR&R for each facility, pipeline, platform, or other infrastructure element.

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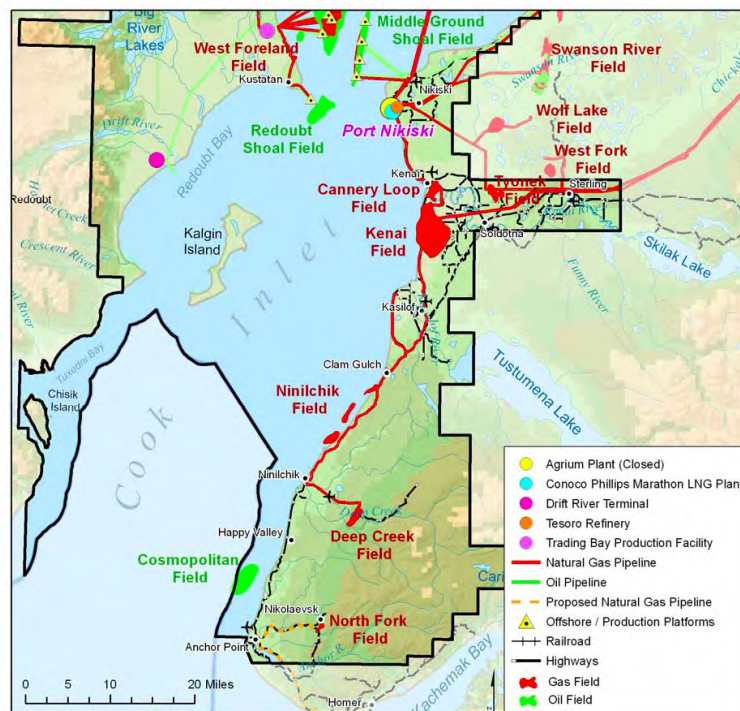
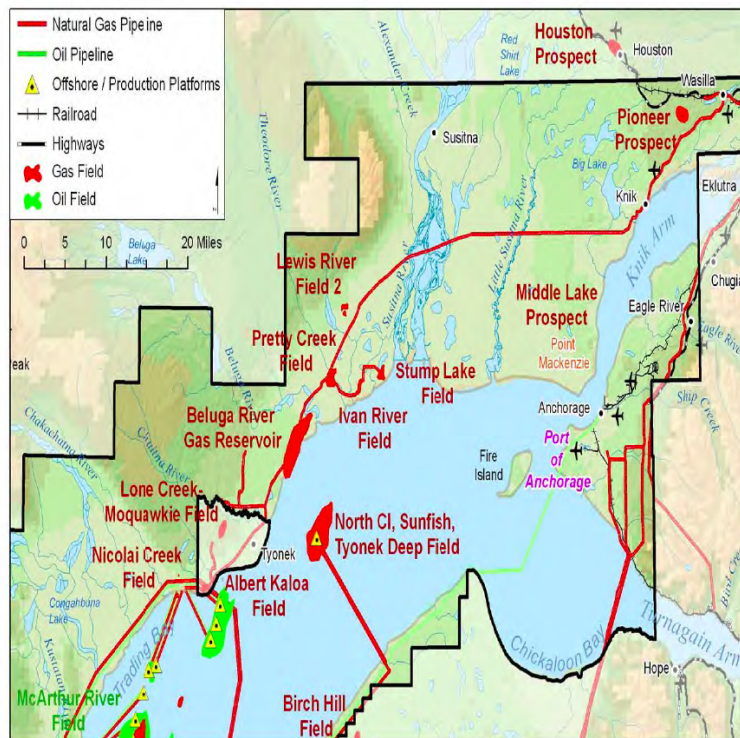
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Appendix 1: Cook Inlet Fossil Fuel Infrastructure (DOG 2009)



Appendix 2: Platform Decommissioning Costs (Proserv Offshore 2010)

Decommissioning Cost Percentages by Category

