

PIPELINE SAFETY

HEARING

BEFORE THE

COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION UNITED STATES SENATE

ONE HUNDRED EIGHTH CONGRESS

SECOND SESSION

JUNE 15, 2004

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SENATE COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION

ONE HUNDRED EIGHTH CONGRESS

SECOND SESSION

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CONTENTS

Hearing held on June 15, 2004	Page 1
Statement of Senator Cantwell	50
Prepared statement	53
Statement of Senator Lautenberg	2
Statement of Senator McCain	1
Prepared statement	2

WITNESSES

Bonasso, Hon. Samuel G., Deputy Administrator, Research and Special Programs Administration, U.S. Department of Transportation; accompanied by Ms. Stacey Gerard, Associate Administrator for Pipeline Safety	4
Prepared statement	5
Connaughton, Hon. James L., Chairman, Council on Environmental Quality ..	11
Prepared statement	13
Mead, Hon. Kenneth M., Inspector General, U.S. Department of Transportation	14
Prepared statement	18
Siggerud, Katherine, Director, Physical Infrastructure Issues, U.S. General Accounting Office	28
Prepared statement	31
Spitzer, Hon. Marc, Chairman, Arizona Corporation Commission	40
Prepared statement	43
Epstein, P.E., Lois N., Senior Engineer, Oil and Gas Industry Specialist, Cook Inlet Keeper	55
Prepared statement	57
Murray, Hon. Patty, U.S. Senator from Washington	62
Prepared statement	64
Pearl, Barry, President and CEO, TEPPCO Partners, L.P., on behalf of the Association of Oil Pipelines and the American Petroleum Institute	65
Prepared statement	68
Report dated April 2004 entitled "The Liquid Pipeline Industry in the United States: Where It's Been Where It's Going" by Richard A. Rabinow	81
Letter dated May 20, 2004 to Hon. Don Young, Chairman, Committee on Transportation and Infrastructure, U.S. House of Representatives from Red Cavaney, President and CEO, American Petroleum Institute; Benjamin S. Cooper, Executive Director, Association Oil Pipe Lines; Bert Kalisch, President and CEO, American Public Gas Association; David Parker, President and CEO, American Gas Association and Donald F. Santa, Jr., President, Interstate Natural Gas Association of America ..	140
Fischer, Earl, Senior Vice President, Utility Operations, Atmos Energy Corporation, on behalf of the American Gas Association and the American Public Gas Association	141
Prepared statement	143
Howard, Robert T., Vice President and General Manager, Pipeline Operations, Gas Transmission Northwest Corporation, on behalf of the Interstate Natural Gas Association of America	149
Prepared statement	151

APPENDIX

Letter dated August 2, 2004 to Hon. John Breaux from Marc Spitzer, Chairman, Arizona Corporation Commission	159
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IV

	Page
Response to written questions submitted by Hon. John Breaux to:	
Samuel G. Bonasso	159
Hon. Kenneth M. Mead	161
Katherine Siggerud	162
Hon. Marc Spitzer	163
Lois N. Epstein	165
Response to written questions submitted to Barry Pearl by:	
Hon. John McCain	168
Hon. John Breaux	171
Response to written questions submitted to Earl Fischer by:	
Hon. John McCain	172
Hon. John Breaux	176
Response to written questions submitted to Robert T. Howard by:	
Hon. John McCain	179
Hon. John Breaux	180

PIPELINE SAFETY

TUESDAY, JUNE 15, 2004

U.S. SENATE,
COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION,
Washington, DC.

The Committee met, pursuant to notice, at 9:31 a.m. in room SR-253, Russell Senate Office Building, Hon. John McCain, Chairman of the Committee, presiding.

OPENING STATEMENT OF HON. JOHN MCCAIN, U.S. SENATOR FROM ARIZONA

The CHAIRMAN. Good morning. It has been 18 months since the Pipeline Safety Improvement Act of 2002 became law. That legislation, which was spearheaded by the Senate Commerce Committee, enacted a number of improvements to pipeline safety, including the establishment of an Integrity Management Program for gas pipelines, the establishment of qualifications standards for pipeline operators, the establishment of a three-digit/one-call number to reduce digging accidents, and the establishment of an interagency working group to streamline the issuance of Federal permits needed to perform pipeline repairs.

The purpose of today's hearing is to understand how the Act is working, whether the Office of Pipeline Safety is on schedule to meet the Act's implementation requirements, and to learn whether Congress needs to do more in this area. Pipelines carry most of the natural gas and oil transported in the United States and are one of the safest modes of transportation, representing less than two/one-hundredths of 1 percent of the total number of transportation fatalities on an annual basis, yet pipeline accidents, when they do occur, can result in significant fatalities, injuries, and damage to the environment, as was demonstrated by the accidents in Bellingham, Washington, in 1999, and Carlsbad, New Mexico, in the year 2000.

Pipeline ruptures can also affect energy supply. When a gasoline pipeline operated by Kinder-Morgan Energy Partners ruptured in Tucson last summer and remained out of service for approximately 2 weeks, fuel supplies dwindled, and there were reports of local price gouging. The Tucson action also highlighted the growing problem of encroachment on pipeline rights of way. The Tucson ruptured occurred in the vicinity of a new housing developing, and several new and, thankfully, unoccupied homes were sprayed with gasoline and had to be torn down.

More recently, another Kinder Morgan pipeline ruptured, this time in an environmentally sensitive area in California. Kinder

Morgan has been trying to perform needed repairs on the pipeline and relocate it away from the marsh for 3 years, but had been unable to obtain necessary environmental permits.

I hope our witnesses today will discuss the circumstances surrounding the accident and whether the work of the interagency task force formed under the 2002 Pipeline Act will be able to prevent such an accident from happening again.

By all accounts, the Office of Pipeline Safety has made great strides in the past several years in improving its performance overseeing pipeline safety. The agency has closed over 40 recommendations of the National Transportation Safety Board, and implemented most, although not all, of the congressional mandates enacted in 1992, 1996, and 2002. I commend OPS for the progress that has been made, and look forward to your comments about the agency's future challenges.

[The prepared statement of Senator McCain follows:]

PREPARED STATEMENT OF HON. JOHN MCCAIN, U.S. SENATOR FROM ARIZONA

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The CHAIRMAN. Senator Lautenberg?

**STATEMENT OF HON. FRANK R. LAUTENBERG,
U.S. SENATOR FROM NEW JERSEY**

Senator LAUTENBERG. Thanks, Mr. Chairman.

This is an important safety issue, and it seems to get little attention unless there's a major accident. Additionally, we now have a different consideration than that which we had when—in New Jersey, we had a terrible explosion in 1994. We've got to pay much more attention to the possibility of a terrorist attack on our extensive network of pipeline, which cover over two million miles.

In New Jersey, we experienced a major accident on March 23, 1994. It was when a 36-inch natural-gas pipeline exploded at a factory in Edison, New Jersey, sending gas hundreds of feet into the air. Now, fortunately, nobody was killed in that accident as a direct result, but almost a hundred people were hospitalized, and over 1,500 people had to be evacuated from their homes. The fire that ensued ignited roofs over nearby apartment buildings, and, once again, we were lucky that no one was killed. Now, I do mention the fact that firefighters found the soles of their shoes melting from the extreme heat and the possibility of this catastrophe were awesome to contemplate.

Now, following that accident, I introduced a bill called the Pipeline Safety Improvement Act of 1994. Mr. Chairman, you know that it—around here, it sometimes takes some time to get into active structure, but it wasn't until 2002 when Congress passed the Comprehensive Pipeline Safety Improvement legislation. It took a sustained effort by the Chairman and the Ranking Member of this Committee to see it through.

Now, because of the leadership of Senator McCain and Senator Hollings, Congress finally passed the Pipeline Safety Improvement Act of 2002. Pipelines play a critical role in the intra- and interstate movements of commodities, especially oil and gas. Pipelines transport 63 percent of the energy consumed in this country and 21 percent of the total annual freight tonnage. Now, if our highways and roads are the Nation's arteries, then pipelines could be called the capillaries. The operation of these privately owned pipelines must be safety-centered to protect both employees and the public, who may not even know when they're at risk. This is especially true when pipelines are transporting hazardous or flammable substances.

Now, states normally have the oversight responsibility. And they—as a matter of fact, it's 90 percent of the pipeline mileage in this country. But clearly there is an important Federal role in maintaining pipeline safety, especially now with the threat of terrorism.

So I look forward to hearing from our witnesses today on how the Federal Government can boost pipeline safety and security.

Thanks, Mr. Chairman.

The CHAIRMAN. Thank you very much, Senator Lautenberg.

Our first panel is the Honorable Samuel Bonasso, who is the Acting Administrator of Research and Special Programs at the United States Department of Transportation; the Honorable James L. Connaughton, who is the Chairman of the Council on Environmental Quality; the Honorable Kenneth Mead, Inspector General, Department of Transportation; Ms. Kate Siggerud, Director of Physical Infrastructure Issues at the General Accounting Office; and the Honorable Marc Spitzer, Chairman of the Arizona Corporation Commission.

Mr. Bonasso, we will begin with you, and thank you for coming today.

**STATEMENT OF HON. SAMUEL BONASSO, DEPUTY
ADMINISTRATOR, RESEARCH AND SPECIAL PROGRAMS
ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION;
ACCOMPANIED BY MS. STACEY GERARD,
ASSOCIATE ADMINISTRATOR FOR PIPELINE SAFETY**

Mr. BONASSO. Thank you, Mr. Chairman.

With me is Stacey Gerard, the Associate Administrator of Research and Special Programs, Office of Pipeline Safety.

Thank you for this opportunity to discuss our strategy and our long-term prospects for improving the safety and reliability of our Nation's pipeline infrastructure. My testimony addresses our responses to mandates in the Pipeline Safety Improvement Act of 2002, issues in its implementation, and the results of our actions. Our nation, our economy, and our way of life depend on the pipeline transportation system.

Pipelines are the safest, most-efficient way to transport the enormous quantities of natural gas and hazardous liquids we use each day. The Pipeline Safety Improvement Act of 2002 challenged RSPA to improve our pipeline safety—

The CHAIRMAN. Could I interrupt you a minute?

Mr. BONASSO. Yes, sir.

The CHAIRMAN. As opposed to what other methods? In other words, you say it's the safest, what are the other methods?

Mr. BONASSO. Transporting by barge and by rail for this—rail and truck for this type of commodity. So we have those other options.

The CHAIRMAN. Thank you. I wanted that for the record. Thank you.

Mr. BONASSO. All right.

As I said, we were challenged by the Safety Improvement Act to improve our safety program in pipelines. We have responded to this challenge with improved regulations, improved inspections, and improved enforcement. This is a comprehensive and informed plan to identify and manage the risks faced by operators in our communities. It has helped us implement new regulations, and addresses the majority of tasks required by the new law.

Last year, we completed the second step of our hazardous liquid and natural-gas integrity management regulations. These regulations are the most significant safety standards improvements for pipelines in the last 30 years. We are moving further to incorporate improved consensus standards that evaluate the adequacy of a pipeline operator's public education program and, by the end of the year, will finalize standards for operator qualifications. We are improving opportunities for communities to understand the importance of pipeline safety and to take local action for further pipeline protection. In addition, we are beginning a crisis communications initiative to improve the process of coordination and information-sharing following a pipeline accident.

With the Common Ground Alliance, we are spinning off regional alliances similar to the one in Arizona recently championed by the Arizona Corporation Commission. We have also petitioned the Fed-

eral Communications Commission for a national three-digit dialing code to provide a faster, simpler, and more efficient one-call system.

We have a five-year plan for pipeline research and development, and a memorandum of understanding with the Department of Energy and the National Institute of Standards and Technology for Research Planning. This has provided a clear vision for the advancement of technology focusing on improving pipeline safety.

As we continue with rigorous integrity management inspections of pipeline operators, we expect to discover more pipeline defects needing speedy repairs. This increased inspection, testing, and repair of pipelines could take more pipelines temporarily out of service and potentially impact the delivery of energy. Recognizing this potential problem, Congress required Federal agencies to participate in an interagency committee to facilitate the prompt repair of these pipelines so as to minimize safety, environment, and energy supply consequences. Under RSPA safety regulations, we have established timeframes for pipeline repairs depending on defect type and severity. Any serious time-sensitive repairs should qualify for expedited permitting. Once a serious pipeline condition is identified, it could potentially impact the safety of citizens and surrounding sensitive environments. Reviewing applications for such a pipeline repair should move to the front of the line and be dealt with in a new way. RSPA and its Office of Pipeline Safety are strongly committed to improving safety, reliability, and public confidence in our pipeline infrastructure.

We are also working hard to educate communities on how they can continue to live safely with pipelines. Following the leadership of your Committee and this Administration, the legislation passed in recent years takes a new, more comprehensive and informed approach to identifying and managing the risks pipeline operators face and the risks posed to our communities. Thanks to this knowledge and the cooperation of all the parties, today everyone involved with pipelines is safer, and so is the environment they pass through.

Thank you, sir. I'd be happy to take your questions.
[The prepared statement of Mr. Bonasso follows:]

PREPARED STATEMENT OF SAMUEL G. BONASSO, P.E., DEPUTY ADMINISTRATOR,
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION, U.S. DEPARTMENT OF
TRANSPORTATION

Mr. Chairman, my name is Samuel Bonasso. I am the Deputy Administrator of RSPA, the Research and Special Programs Administration of the U.S. Department of Transportation. With me is Stacey Gerard, Associate Administrator for the Office of Pipeline Safety (OPS).

Thank you for this opportunity to discuss our strategy and our long term prospects for improved safety and reliability of the Nation's pipeline infrastructure. We greatly appreciate this committee's attention and support for our work.

Under Secretary Mineta's leadership, RSPA and OPS have made great strides in meeting the mandates set forth in the Pipeline Safety Improvement Act (PSIA) of 2002. My testimony today will address our responses to these mandates, including specific implementation issues, and the results of our actions. Further, I want to make you aware of potential short and near term risks of reduced pipeline capacity and energy supply due to required pipeline testing and repairs.

The Nation's pipelines are essential to our way of life. The 2.3 million miles of natural gas and hazardous liquid pipelines carry nearly two-thirds of the energy consumed by our Nation. Pipelines are the safest and most efficient way to trans-

port the enormous quantities of natural gas and hazardous liquids across land used by our country.

Recent increased attention to the need for pipeline safety is rooted in demographic changes taking place in our country. Suburban development in previously rural areas has placed people closer to pipelines. This increases the risk that pipeline accidents, although infrequent, can have tragic consequences. Expansion and development also means more construction activity near pipelines—the leading cause of pipeline accidents.

Pipeline safety is more than inspecting pipelines. It involves (1) having better information to understand safety problems, (2) knowing where to set the bar in safety standards, (3) advancing technology to find and fix those problems, (4) partnering with state and local governments to oversee this critical infrastructure, and (5) building alliances to prevent damage and educate the public about how to live safely with pipelines.

Pipeline safety is a top priority for the Bush Administration and for Secretary Mineta, personally. With their support, RSPA and OPS have strengthened each of these five elements in just a few years.

Expanded enforcement has been an important approach in strengthening the pipeline safety program. In the past 10 years, 57 inspectors have been added to the OPS staff, from 28 inspectors in 1994 to 85 inspectors today. Our partnerships with the states, such as our agreement with the Arizona Corporation Commission, provide several hundred more inspectors.

I. We Are Implementing A Plan

With the enactment of the PSIA, we embarked on a new, more comprehensive and informed plan to identify and manage the risks that pipeline operators face and that pipelines pose to our communities. By collecting and using better information about pipelines, today we know more about pipelines, the world they traverse, and the consequences of a pipeline failure.

1. Higher Standards

We have raised the standards for pipeline safety, through integrity management requirements and 17 other regulations, and incorporated 30 new national consensus safety standards into our regulations.

2. Better Technology

To improve the technology available to assess and repair pipelines, we have awarded almost eight million dollars, for three dozen research projects since March 2002.

3. Stronger Enforcement

Our inspections are much more rigorous. Today, we spend 240 hours on a comprehensive integrity management inspection, in contrast to 32 hours in 1996 for a standard pipeline safety inspection.

We have adopted a tough-but-fair approach to improving enforcement, making heavier use of large fines, while guiding pipeline operators to meet higher standards. We have initiated steps to ensure that penalties are collected and acknowledged promptly.

4. Better States' Partnership

We have strengthened our partnerships with state pipeline safety agencies, such as the Arizona Corporation Commission, through increased training, shared inspection data bases, a distributed information network to facilitate communications, and policy collaboration.

5. Cleaning Up Our Record

Our new record as a regulator is important to us. In the past three years, the OPS has eliminated most of a 12-year backlog of outstanding mandates and recommendations from Congress, the National Transportation Safety Board, the DOT Inspector General, and the GAO. Over the past 4 years, we have responded positively to 41 NTSB safety recommendations and are working to close the remaining 10 recommendations.

6. Preparing Partners and Going Local

Helping communities to know how they can live safely with pipelines is a very important goal. We cannot succeed in improving pipeline safety without enlisting the help of local officials. We are moving on a number of fronts:

- Working with others, we have proposed to incorporate a new standard for public education in regulations to ensure community officials and citizens have essential safety information they need to make informed decisions;
- We have commissioned a study by the Transportation Research Board of the National Academy of Sciences on issues of encroachment and maintenance on pipeline rights-of-way which will report results in July.
- We have enlisted the help of the local fire marshals to bring information and guidance to communities to build understanding of pipeline safety and first responder needs, to help identify high consequence areas in communities, and to provide an understanding of LNG operations.
- Similarly, to foster safety and environmental protection on Tribal Lands, we are working toward a partnership with the Council of Energy Resource Tribes.

II. Responding to the Pipeline Safety Improvement Act of 2002 (PSIA)

Pipelines are the arteries of our Nation's energy infrastructure and critical to the Nation's viability and well being. The Congress recognized the critical importance of pipelines when it passed the Pipeline Safety Improvement Act of 2002.

The actions described above are consistent with the PSIA, which also has given us new mandates. Under Secretary Mineta's leadership, RSPA and OPS are aggressively responding to these new mandates.

1. Integrity Management

We have completed the most significant improvement in pipeline safety standards by finalizing regulation of integrity management programs for hazardous liquid and natural gas transmission operators. Going beyond the PSIA requirements, we are studying, in conjunction with the American Gas Association, the potential for an integrity management program that would be appropriate for gas distribution and municipal operators. We and our state partners have completed comprehensive inspections of large hazardous liquid operators. During these inspections, we observed that operators had completed over 20,000 repairs, 4,400 of which were time sensitive and important to find and fix expeditiously.

2. Operator Qualification

We have completed half of the reviews of interstate operators' qualification programs and expect to meet the 2006 statutory deadline. States have made similar progress. We plan to incorporate improved consensus standards for the qualification of pipeline operators for safety critical functions when the standards are completed later this year.

3. Public Education and Mapping

We believe that communication between Federal, State and local government, the operator and the public about how to live safely with pipelines is an important element in helping to assure the safety of our Nation's energy transportation pipeline infrastructure. Actions are underway to improve communications with state and local officials about actions they can take to protect their citizens and pipelines. We are improving opportunities for communities to understand pipeline safety and to take local action as required by the PSIA. We completed the National Pipeline Mapping system and we worked with pipeline operators to complete, by the December 2003 deadline, self assessments of their public education programs against new, higher standards.

To respond to the need for improved public awareness of pipelines, OPS, the National Association of Pipeline Safety Representatives (NAPSR), and the pipeline industry have cooperated to develop a national consensus standard—American Petroleum Institute's Recommended Practice 1162 (RP 1162) for public education. RP1162 is designed to help pipeline operators meet new standards established in the PSIA. It requires operators to identify audiences to be contacted, effective messages and communications methods, and information for evaluating and updating public awareness programs. We have proposed incorporation of RP 1162 into our regulations.

We are starting a Crisis Communications Initiative to improve communications following an accident. In July, we will host a workshop to develop the framework for this initiative, including a pilot program on crisis communications and inter-agency relationships. We expect this initiative to meet national objectives and to be complementary to the Homeland Security's National Response Plan, FERC's Liquefied Natural Gas efforts, and the National Association of Fire Marshal's education program.

4. Damage Prevention

Working with the Common Ground Alliance and the Federal Communications Commission, we have provided for a single, national three-digit number for one call systems, most likely 811. The Federal Communications Commission is expected to finalize this action later this year. This will allow all Americans to take one action to protect all pipelines from excavation damage—the major cause of pipeline damage and failure. By making it simpler to call one number to mark underground lines, we expect more people to use this important prevention service.

5. Research and Development

To provide a vision for the advancement of technology, we developed a memorandum of understanding with the Department of Energy and the National Institute of Standards and Technology for research planning, and have completed a five year plan. The plan includes a detailed management strategy for research solicitation and procurement; technology transfer and application of results; coordination and collaboration with other agencies, industry and stakeholders; approaches to communicate project findings; and methods of optimizing the use of resources.

6. Security

Since 9/11, the Department has devoted considerable attention to security across all modes of transportation, including national pipeline security. While the PSIA did not speak specifically to security, pipeline system integrity and security are inextricably linked. We maintain clear expectations for critical pipeline operators' security preparedness. With the Department of Homeland Security (DHS), we verify industry action by conducting audits of all major pipeline operators' security preparedness. OPS expanded its oil spill emergency response exercise program to include focus on security and law enforcement for maintaining the reliability of energy supply. The Department plans to continue working closely with DHS on pipeline security issues.

7. Interagency efforts to Implement Section 16 of the PSIA

Section 16 of the PSIA requires agencies with responsibilities relating to pipeline repair projects to develop and implement a coordinated process for environmental review and permitting. The interagency working group currently has five efforts underway to:

- refine early notification and Federal involvement procedures;
- identify electronic communication methods that would expedite and streamline review;
- establish practices that would reduce or minimize effects to the environment such that reviews would be expedited; and
- refine permitting and review procedures for time-sensitive pipeline repairs consistent with our regulatory and statutory obligations.

III. Keeping the Energy Infrastructure Viable

The Nation's economic viability and well-being depend on the enormous quantities of oil, fuel and natural gas transported safely, efficiently and at low cost by pipelines each and every day. The energy pipeline infrastructure in the United States represents a \$31 billion investment in over 2 million miles of pipeline technology that is essential to American economic interests—a myriad of goods and services as well as millions of jobs are made possible and supported by this transportation infrastructure.

Federal integrity regulations and PSIA have significantly increased the requirements on operators to test the integrity of this infrastructure, discover any defects and make repairs before ruptures or leaks can occur during the implementation of this important safety initiative. This initiative could take more pipelines temporarily out of service for inspection, assessment and repairs and could impact the delivery of energy.

There are two aspects of this safety initiative which are being given special attention by DOT and other Federal agencies.

First, we, from our safety purview, are the agency that sees the results of the testing of multiple pipelines by multiple operators across the regions of our Nation. Our experience suggests that many repairs will be required under our integrity management regulations—potentially tens of thousands of repairs annually, and perhaps clustering in a particular region of the country.

Second, while a pipeline operator awaits permits for repairs, the operating pressure of the pipeline usually needs to be reduced to maintain a safety margin. There is a risk that the amount of pressure reductions required pending permitting of re-

pairs could measurably reduce the energy capacity of pipeline systems in certain regions. Depending on where pipelines are located and how energy markets are impacted, pressure reductions during peak demand periods could result in fuel shortages and price increases.

The Congress recognized this potential problem and required Federal agencies to participate in an Interagency Committee to facilitate the prompt repair of our pipelines. Work is ongoing with the other relevant Federal agencies to develop guidance to ensure that any necessary Federal permits for repairs of pipelines in danger of rupture can be coordinated and expedited.

Some of the specific issues the Interagency Committee is addressing include:

- Feasibility of providing Federal permitting agencies with advance information about operator test schedule. Obtaining this information in advance could help agencies anticipate resources needed for permitting repairs and to exchange information about required actions as soon as possible. Pipeline operators, however, are concerned that by providing this information they might be expected to meet the schedule regardless of factors that are beyond their control (weather, availability of appropriate equipment and certified crews, etc.). Operators are also concerned that the testing schedules could become public information that can not be protected as proprietary information, releasing business-sensitive and possibly security-sensitive information.
- Methods to expedite environmental reviews. The Interagency Committee is examining the required consultative processes for permitting repairs in order to determine if actions can be taken that would enable operators to carry out repairs quickly while meeting safety standards.
- Potential energy supply impacts of multiple repairs in a regional area. As we have experienced recently in gasoline markets, a small change in pipeline supplies can have a dramatic impact on fuel price. In a situation with multiple pipelines in a regional area in need of repair, OPS would work with operators to prioritize the order of repairs and maintain safety. A time sensitive repair might qualify for expedited permitting because of the potential energy supply impact. Maintaining pipeline capacity and throughput is essential in supplying fuels to regional markets and vital to the Nation's industries.

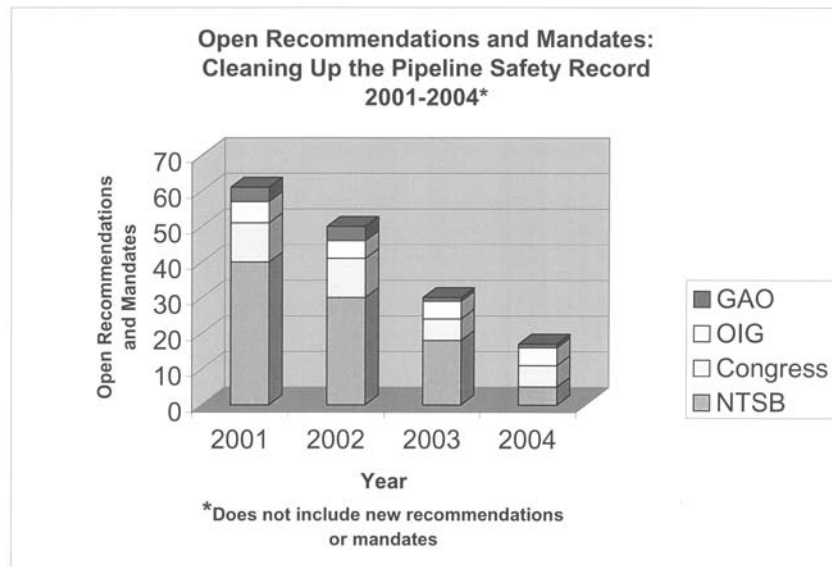
IV. We are achieving results.

Comparing years 1999 to 2003 to the previous five years, from 1994 to 1998, hazardous liquid incidents have decreased by 25 percent. By 2003, the volume of oil spilled had decreased by 15 percent from the previous 10-year average.

Excavation accidents have decreased over the past ten years by 59 percent. This is largely the result of work with our state partners and the more than 900 members of a damage prevention organization we initiated—the Common Ground Alliance (CGA). The CGA has formed 22 regional alliances to foster damage prevention activities and will soon announce two additional regional alliances, including a western regional common ground alliance, which is the result of a three-state effort led by the Arizona Corporation Commission.

In closing, I want to reassure you, Mr. Chairman, and all of the members of this committee, that Secretary Mineta, RSPA and the hardworking men and women in the Office of Pipeline Safety share your strong commitment to improving safety, reliability, and public confidence in our Nation's pipeline infrastructure.

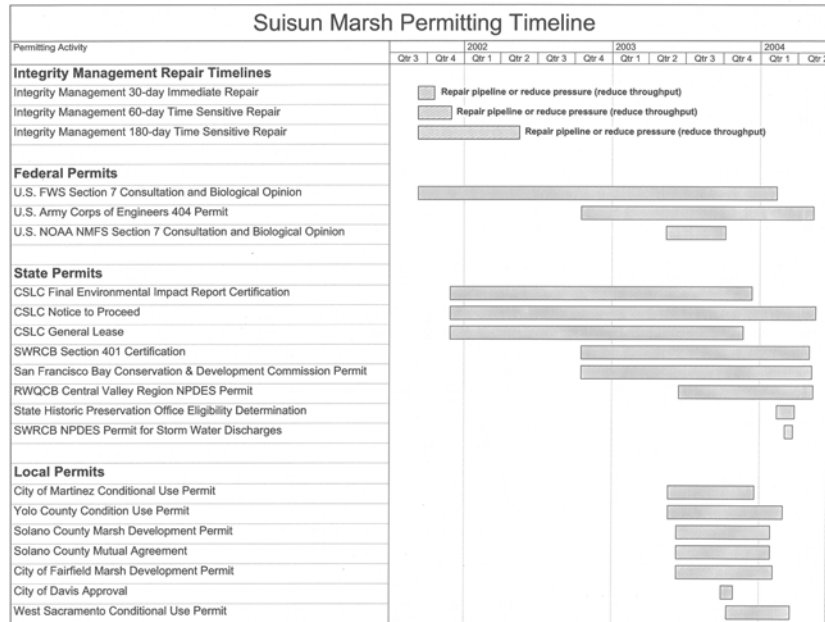
I will be happy to take your questions.



RSPA Enforcement Trends

Type of Action	Original Enforcement Policy (1990-1994)	Alternative Approach to Enforcement (1995-1999)	Current Policy (2000-2003)
Inspector Hours per Inspection	20	32	240
Average Number of Inspections Conducted per Year	534	924	821
Average Number of Civil Penalties Proposed per Year	63	19	42
Average Proposed Civil Penalty	\$16,500	\$19,000	\$45,000†
Number of Corrective Action Orders	11	9	34

† This average increases to \$91,000 if proposed penalties for the Olympic and El Paso cases are included



The CHAIRMAN. Thank you very much.
Mr. Connaughton?

**STATEMENT OF HON. JAMES L. CONNAUGHTON, CHAIRMAN,
COUNCIL ON ENVIRONMENTAL QUALITY**

Mr. CONNAUGHTON. Thank you, Mr. Chairman. Good morning, Senator Lautenberg.

First of all, I want to thank you, Mr. Chairman, for your leadership in getting this legislation and these authorities to us, and actually, Senator Lautenberg, for your foresight a decade ago.

I am the—the President was pleased to sign this legislation, and actually we moved very aggressively to put in place and get the processes moving to fulfill its mandates.

I am in charge of the—the Chair of the Interagency Task Force that oversees the energy projects streamlining to which this was assigned. Our goal has been to develop an efficient process for pipeline testing and more timely repair in a way that still ensures appropriate environmental stewardship and compliance.

We've already mentioned that our pipeline infrastructure is over 50 years old, and requires regular testing and inspection to ensure its reliability, protect human life, property, and natural resources, as well as to ensure sufficient supply of natural gas and liquid fuels, such as gasoline or diesel. At the same time, many of the pipelines that are subject to this new testing regime run through what are called high consequence areas. These are areas that are highly populated, they're sensitive to environmental damage, or they're located near waterways. Effecting timely repairs of these pipelines while enabling environmental protection is a critical challenge, as Congress recognized in the Pipeline Safety Act.

I'm pleased to report to you today that we have completed work on the memorandum of understanding that was called for by Section 16 of the Act, and the text of the MOU is attached to my written testimony. The process envisioned under the memorandum of understanding would expedite the ability of operators to obtain the necessary permits or authorizations prior to making repairs in a high consequence area when a time-sensitive repair is indicated by testing. And that is when the pipeline's physical condition is such that repair is mandated within a certain period of time by DOT's implementing regulations.

This process requires enhanced coordination among Federal agencies, and recognizes that early planning, notice, and consultation among pipeline operators and Federal agencies can result in timely decisions that enable these critical repair actions to go forward within the context of resource protection.

The MOU also supports the development of a comprehensive one-stop information system to improve information sharing between pipeline operators and the agencies to help identify potential issues and provide recommendations on best management practices that will avoid, reduce, or mitigate any impacts to resources of concern.

Even as the MOU was being developed by these participating agencies, we have been working to implement the process that is formalized in the MOU, and I'll outline just a few key points from that.

First, we are encouraging early notification by operators of their testing schedules, which would allow earlier consultations on issues that arise, as well as coordination of testing activities so that energy supply and price impacts can be minimized.

Second, we're working to consolidate the existing permitting process, which is sequential, into a more single, concurrent permitting process that is triggered by the operator upon finding that a time-sensitive repair is needed.

Third, we are considering the appropriate use of what are called categorical exclusions under the National Environmental Policy Act for instances where repairs can occur entirely within an existing right-of-way or where minimal additional access is required, so long as consensus best-management practices are used to avoid or minimize any impacts.

Now, this issuance of a categorical exclusion would be based on a determination that the specific category of actions—so these are repeated actions that you see again and again—described would not individually or cumulatively have a significant effect on the human environment, and, therefore, would not require further action-specific environmental assessment or an environmental impact statement. So that is, there's an environmental review as to the category of actions. Once that's done, those kinds of actions can proceed without having a one-by-one-by-one review.

Finally, we are working with operators to identify those instances where specific issues or additional authorizations, such as under the Endangered Species Act or the Clean Water Act, may have, in the past, prevented repairs in a timely manner. Specific procedures can then be developed to help avoid these issues in the future, and allow for more timely completion of repairs in each

case, while still allowing the Federal agencies to carry out their resource-protection responsibilities.

Given the state of our Nation's aging pipeline infrastructure, we're working hard to ensure that these timely repairs can be made, that accidents can be avoided, and human life, property, and natural resources are protected. At the same time, we're working to minimize any negative impacts on natural resources from this work, as well as any impacts on our Nation's energy supply.

And I'm happy to take your questions, as well.

[The prepared statement of Mr. Connaughton follows:]

PREPARED STATEMENT OF JAMES L. CONNAUGHTON, CHAIRMAN,
COUNCIL ON ENVIRONMENTAL QUALITY

Good morning Chairman McCain, Ranking Member Hollings, and Members of the Committee.

I am pleased to appear before you today to describe our efforts to implement the provisions of the Pipeline Safety Act of 2002 by developing an efficient process for expedited pipeline testing and repair while ensuring environmental stewardship.

The Nation's existing pipeline infrastructure, much of which is over 50 years old, requires regular safety and environmental reviews to ensure its reliability.

Timely testing and repair of both natural gas and hazardous liquid pipelines is essential to protect human life and property, and to facilitate the sufficient availability and use of natural gas and liquid fuels for our energy needs.

At the same time, many natural gas and hazardous liquid pipelines run through "High Consequence Areas": areas that are highly populated, are unusually sensitive to environmental damage, or are located along or near commercially navigable waterways.

Effecting timely repairs of these pipelines, while enabling effective environmental protection, is a critical challenge we are tackling as directed by Congress in Section 16 of the Pipeline Safety Act of 2002.

Our work is ongoing, and I am pleased to report to you today on our results thus far.

Implementation of the Pipeline Safety Act of 2002

Through Executive Order 13212, issued on May 18, 2001, President Bush directed Federal agencies to expedite reviews of authorizations for energy-related projects and to take other actions necessary to accelerate the completion of projects that will increase the production, transmission, or conservation of energy, while maintaining safety, public health and environmental protections.

The Executive Order also created a Task Force, chaired by CEQ, to monitor and assist Federal agencies in carrying out this directive.

Following pipeline ruptures in Bellingham, Washington in June 1999 and Carlsbad, New Mexico in August 2000 which caused loss of life and significant property damage, Congress enacted the Pipeline Safety Improvement Act of 2002 (PSIA), which was signed into law by President Bush on December 17, 2002.

Section 16 of the PSIA directed the President to establish an Interagency Committee to implement a coordinated environmental review and permitting process enabling pipeline repairs within the time periods specified by DOT regulations called for in other sections of the PSIA.

To implement Section 16 of the PSIA, the President issued Executive Order 13302 on May 15, 2003, adding these pipeline safety functions to the charge given the Task Force authorized under Executive Order 13212. Therefore, CEQ has coordination responsibility for efforts to implement Section 16 of the PSIA, and that is why I appear before you today.

MOU Development

During the summer and fall of 2003, a working group of the Task Force evaluated Federal permitting requirements, identified best management practices (BMPs), and developed a memorandum of understanding (MOU) to provide for a coordinated and expedited pipeline permit review process. The text of the MOU is attached to my written testimony.

The process envisioned under the MOU would expedite the ability of pipeline operators to obtain the necessary permits or authorizations prior to making repairs in a High Consequence Area when a "time-sensitive" repair is indicated by testing: that is, when the pipeline's physical condition is such that repair is mandated with-

in a certain period of time as directed by the PSIA and DOT's implementing regulations.

The MOU enhances coordination of the processes through which agencies with environmental and historic preservation review responsibilities under various statutes—such as the Clean Water Act, or the Endangered Species Act—meet those responsibilities in connection with the authorizations required to repair natural gas and hazardous liquid pipelines that have been identified by pipeline operators as in need of repair on a timely basis to protect life, health or physical property.

The MOU recognizes that early planning, notice, and consultation among pipeline operators and Federal agencies can result in a structured process that facilitates timely decisions and enables critical repair actions to go forward, within the context of resource conservation.

The MOU supports the development of a comprehensive, “one-stop” information system to allow pipeline operators and agencies alike access to the best available information on pipeline testing and repair schedules, agency official contact information, natural resource conservation needs, and recommendations on management practices for testing and repair.

Further, the MOU recognizes that the identification and use of best management practices (BMPs) to avoid, reduce, or mitigate impacts to resources of concern can be one means of implementing specific measures to protect affected resources and encourage increased environmental stewardship.

Further Actions

The Task Force working group continues to consult on specific steps and agency actions to implement the process envisioned in the MOU.

First, we are working with industry to encourage early notification by operators of their testing schedules, so as to enable early consultation on issues that arise, and coordinate pipeline testing so that energy supply and price impacts are minimized.

Second, interagency discussions are well along in attempting to consolidate existing sequential permitting processes into a single, concurrent permitting process for general repairs that is triggered by the operator upon finding of a time-sensitive repair need.

Third, we are considering the potential for proposing categorical exclusions under the National Environmental Policy Act for instances where repairs can occur entirely within an existing right-of-way, or where minimal additional access is required, so long as consensus Best Management Practices are used to minimize impacts. Issuance of a categorical exclusion would mean that the specific category of actions described in the categorical exclusion do not individually or cumulatively have a significant effect on the human environment, and therefore, neither an environmental assessment nor an environmental impact statement would be required.

Finally, we are working with pipeline operators to identify those instances where specific issues and additional authorizations may have in the past prevented repairs in a timely manner (*e.g.*, threatened or endangered species, navigable waterways, private lands, etc.). Once these instances are identified, we will work to develop specific procedures that will avoid these issues in the future and allow for timely completion of time-sensitive repairs in each case while allowing Federal agencies to carry out their resource protection responsibilities.

Conclusion

Given the state of our Nation's aging pipeline infrastructure, we are working to ensure that timely repairs can be made, accidents can be avoided, and human life and property is protected. At the same time, we are working to minimize negative impacts on the surrounding environment, and on our Nation's energy supply.

I will be glad to take any questions you may have. Thank you.

The CHAIRMAN. Thank you very much.
Mr. Mead, welcome back.

STATEMENT OF HON. KENNETH M. MEAD, INSPECTOR GENERAL, U.S. DEPARTMENT OF TRANSPORTATION

Mr. MEAD. Thank you, Mr. Chairman.

The CHAIRMAN. Mr. Mead, by your calculations, how many appearances have you made before this Committee, besides too many?
[Laughter.]

Mr. MEAD. It would probably be in the neighborhood of 50 or 60.

The CHAIRMAN. Thank you. Welcome back.

Mr. MEAD. Yes, sir.

We're issuing a report today. You'll be receiving it under a formal transmittal. I'll speak to the highlights of that.

You referred to the Bellingham, Washington, accident. That was, in fact, the impetus behind a 2000 audit that we did of this program. That was followed by a request from the U.S. Attorney there that we, along with the EPA, help to determine whether there were violations of Federal law associated with that accident.

Ultimately, in the largest criminal and civil settlement ever obtained in a pipeline case, two companies were ordered to pay \$36 million to resolve criminal and civil penalties, an additional \$77 million to ensure the safety of their pipelines.

Now, when we last testified before this Committee, in 2000, we reported that OPS was very slow. And I think that's probably a generous characterization. They are very slow to implement—I find—safety initiatives. It didn't matter whether they were congressionally mandated, came from NTSB, or some other place. Some mandates, some legislation remained outstanding, some more than 8 years past due. Also, overdue NTSB safety recommendations remained open, some for more than a decade. That lack of responsiveness prompted Congress to, again, mandate basic elements of a pipeline safety program. That culminated in the Pipeline Safety Improvement Act of 2002. That law actually incorporated recommendations from our audit report that had been initially requested by Senator Murray.

Well, I can report today that OPS has gotten the message, they've made considerable progress, cleared out most, but not all, the 1992, 1996 Congressional mandates, also closed out most of the NTSB recommendations. They were also removed from NTSB's most wanted safety list. Well, that said, much remains to be done.

OPS has issued—and I think they will tell you this—many important rules over the last couple of years. The most important ones, thought, you've alluded to in your opening remarks, what's called the Integrity Management Program for the hazardous liquid and natural gas transmission pipelines. That is the safety program the operators use to assess their pipelines for risk of a leak or a failure, take action to repair pipelines, and mitigate the risks.

So against that backdrop, I'd like to highlight four points. First, mapping where the pipelines are located. Two, the new IMP inspection process, and oversight of it. Third, closing a gap we see on natural gas distribution pipelines. And, four, pipeline security responsibilities.

Mapping where pipelines are located. When we testified before this Committee in 2000, we did not know where a substantial percentage of pipelines were located. I'm talking—by substantial, I mean over 50 percent of them. A voluntary mapping initiative that started in 1994 was not working, so Congress mandated that one—mandated it in 2002. OPS completed its mapping system this year. We now have 100 percent of the hazardous liquid pipeline and natural gas transmission pipelines mapped.

The new IMP inspection process. Operators are in the early stages of implementing their IMPs. Now, they are not required to have all these inspections completed for hazardous liquid pipelines

until 2009, and natural gas transmission pipelines until 2012, but about 25,000 miles of hazardous liquid pipelines have received inspections, and most of those have been in what they call high-consequence areas. They're areas of dense population——

The CHAIRMAN. Twenty-five thousand out of how many?

Mr. MEAD. Twenty-five thousand out of about 435,000. Well, that leaves about 135,000 of the hazardous liquid pipeline, and about, I think, 325,000 of natural gas transmission pipelines to go. Gas operators must begin inspections actually later this week. I believe it's on June 17.

Well, what are these inspections showing? There are early signs that the inspections are working well, and there was clearly a need for them. To date, more than 20,000 integrity threats have been identified and, according to OPS, remediated. That means fixed. A key point here is that these threats were identified in less than 16 percent of hazardous liquid pipeline. So we have a lot to go.

Once a threat's identified, OPS needs to follow up to ensure that the operators take corrective action. Of the 20,000 threats, here's how they broke down. About 1200 of them required immediate repairs, 760 required repairs within 60 days, and 2,400 required repairs within 180 days. The remainder weren't time-sensitive.

Now, the process here is not as simple as just identifying the problem and figuring out how to fix it. For some repairers, the environmental review and permitting process delayed preventive measures, as was demonstrated by a pipeline rupture in California as recently as April of this year. The deteriorating condition of this pipeline, Mr. Chairman, was well documented, it was well known. In fact, in 2001, the operator initiated the action to relocate the pipeline, but it took nearly 3 years and over 40 permits before approval to relocate was obtained. That was too late to prevent this spill. Fortunately, in this one, there was no loss at least of human life.

Congress recognized the need to expedite the environmental process when it passed the 2002 Pipeline Act, and an interagency task force was set up to do it. Well, a Memorandum of Understanding has been drafted. The Department of Transportation——

The CHAIRMAN. The 3 years and 40 permits, how much of that was Federal requirements versus state requirements?

Mr. MEAD. I don't have that breakdown. I can get it for you.

The CHAIRMAN. Do you know, Mr. Connaughton?

Mr. CONNAUGHTON. Yes, there are—of the main programs, of which there are about two dozen, three of them were Federal permitting programs—Fish and Wildlife Service, Army Corps of Engineers—and then three was the initial review done by the Integrity Management timeline issue. So it's largely Federal—it's largely state and local, but the Federal one, especially the endangered species one, is the one that took nearly the entire 3 years. So it's a smaller piece of the total number, but it has accounted for a larger——

The CHAIRMAN. It had a major impact on the 3-year delay. Thank you.

I'm sorry, Mr. Mead.

Mr. MEAD. That's OK.

Well, I want to say a word about this Memorandum of Understanding. The Department of Transportation signed it yesterday, and it's not clear to us what process changes this Memorandum of Understanding is actually going to require. I hope that it will become clear as it's implemented. I don't want to wait for a serious accident to occur. We don't need a repeat of that situation in California.

Now, the oversight of these IMPs. The IMP is actually—the inspections there are actually done by the operator, and the Office of Pipeline Safety oversees them. That means they have to monitor the implementation of more than 1100 pipeline operator IMPs, and they've done about 70 of those to date. Also, 10 years ago OPS had 28 inspectors to oversee pipeline safety. That has tripled, and it's augmented by about 400 state inspectors. Also, when we testified, in May 2000, OPS did not even train its inspectors on the use of "smart pig" technologies. That's an instrumented inspection device you stick in the pipelines. Well, they do so today.

I'm not going into detail on this, but I think that OPS is headed in the right direction on research and development, too. There, in 2000—or 1999, I think they had one research project. Today, they have 22. The funding for it has moved from \$2.7 million to almost \$9 million. And that's important, because these "smart pigs," they may be very smart, but they're not smart enough to detect all the problems that you find with pipelines.

Now, I think there's a safety gap on the actual gas distribution pipelines that I'd like to touch on. These pipelines, they deliver natural gas to the end users, and they make up, actually, over 85 percent—that's 1.8 million miles—of the 2.1 million miles of natural gas pipelines in this country. These natural gas distribution pipeline operators are not required to have an IMP, which is unlike the hazardous liquid operators and unlike the natural gas transmission pipeline operators. And according to industry officials, the reason for that, or the primary reason for it, is that their pipelines can't be inspected using "smart pigs." Well, in our opinion, that's not a sufficient reason for not requiring some form of an IMP. There are other IMP elements that can readily be applied to this segment of the industry, like developing timeframes on how often pipelines should be inspected, how—and when repairs should be made.

Our concern, Mr. Chairman, is that over the last 10 years, natural gas distribution pipelines experienced four times the numbers of fatalities and more than three times the number of injuries than the combined totals for hazardous liquid and natural gas transmission pipelines. I think that's a pretty good case for applying the IMPs.

Finally, security. The Office of Pipeline Safety took the lead to help reduce the risk of terrorist activity against the pipeline infrastructure following 9/11. But the guidance to the operators is currently voluntary, and OPS now states it plays a secondary or support role to the Transportation Security Administration, which is, of course, in DHS. The current Presidential directive addressing security is at too high a level of generality to provide clear guidance on each agency's responsibilities, the three agencies—DOT, DOE, and DHS. And the current guidance is basically, "Go collaborate and coordinate." And I think the delineation of the roles and re-

sponsibilities between those three agencies needs to be spelled out in a memorandum of understanding so that it's clearly understood who's going to be making rulemaking policy decisions, who will conduct the security inspections, and who's going to enforce the security requirements. Presently, that is unsettled. Thank you, Mr. Chairman.

[The prepared statement of Mr. Mead follows:]

PREPARED STATEMENT OF HON. KENNETH M. MEAD, INSPECTOR GENERAL,
U.S. DEPARTMENT OF TRANSPORTATION

Mr. Chairman, Mr. Vice Chairman, and Members of the Committee:

We appreciate the opportunity to testify today on the actions the Office of Pipeline Safety (OPS) has taken to improve pipeline safety and the actions that still need to be done.

OPS is responsible for overseeing the safety of the Nation's pipeline system, an elaborate network of more than 2 million miles of pipeline moving millions of gallons of hazardous liquids and more than 55 billion cubic feet of natural gas daily. The pipeline system is composed of predominantly three segments—natural gas transmission pipelines, natural gas distribution pipelines, and hazardous liquid pipelines—and has about 2,200¹ natural gas pipeline operators and 220 hazardous liquid pipeline operators. Pipelines are a relatively safe way to transport energy resources and other products, but they are subject to forces of nature, human action, and material defects that can cause potentially catastrophic accidents.

Following the deadly pipeline explosion and fire in Bellingham, Washington, in June 1999, Senator Patty Murray requested the Office of Inspector General to review the activities of OPS. Also, a few months following the Bellingham accident, the United States Attorney's Office, Western District of Washington, requested that we, in a joint effort with the Environmental Protection Agency's Criminal Investigation Division, assist in an investigation to determine whether violations of Federal law occurred in connection with the accident.

In the largest criminal and civil settlement ever obtained in a pipeline rupture case, two pipeline companies were ordered to pay \$21 million in criminal penalties and \$15 million in civil penalties. In addition, the companies were ordered to implement pipeline integrity/spill mitigation programs valued in the aggregate at \$77 million. The charges, the first ever brought under the Hazardous Liquid Pipeline Safety Act of 1979, as amended, included three criminal counts for violating this act, which sets minimum safety standards for training employees who operate interstate pipelines that carry hazardous liquids.

In response to Senator Murray's request, we reported in March 2000² that weaknesses existed in OPS's pipeline safety program and made recommendations designed to correct these weaknesses. These recommendations were later mandated in the Pipeline Safety Improvement Act of 2002 (2002 Act). This Act required us to review OPS's progress in implementing our recommendations. Our testimony today is based largely on the results of this second review.³

Historically, OPS was slow to implement critical pipeline safety initiatives, congressionally mandated or otherwise, and to improve its oversight of the pipeline industry. The lack of responsiveness prompted Congress to repeatedly mandate basic elements of a pipeline safety program, such as requirements to inspect pipelines periodically and to use smart pigs⁴ to inspect pipelines.

OPS is making considerable progress in implementing the recommendations in our March 2000 report by clearing out most, but not all, of the congressional mandates enacted in 1992 and 1996. It has also closed out nearly all the long-overdue National Transportation Safety Board (NTSB) safety recommendations we identified. In addition, OPS was removed from NTSB's most-wanted list of safety improvements in 2002. Even though OPS has issued many important rules for improving pipeline safety, the most important rules, relating to Integrity Management Pro-

¹ Of the 2,200 operators of natural gas pipelines, there are approximately 1,300 operators of natural gas distribution pipelines and 880 operators of natural gas transmission pipelines.

² OIG Report Number RT-2000-069, "Pipeline Safety Program," March 13, 2000.

³ OIG Report Number SC-2004-064, "Actions Taken and Needed for Improving Pipeline Safety," June 14, 2004.

⁴ A "smart pig" is an instrumented internal inspection device that traverses a pipeline to detect potentially dangerous defects, such as corrosion.

grams (IMP)⁵ will not be fully implemented for up to 8 years. This is a key issue as the IMP is the backbone of OPS's risk-based approach to overseeing pipeline safety.

It is against this backdrop that I would like to discuss five major points regarding pipeline safety: (1) mapping the pipeline system; (2) monitoring the evolving nature of IMP implementation; (3) monitoring operators' corrective actions for remediating pipeline integrity threats; (4) closing the safety gap on natural gas distribution pipelines; and (5) developing an approach to overseeing pipeline security.

- *Mapping the Pipeline System*—The first step to an effective oversight program is to identify where the assets to be overseen are located. In the past year, OPS completed the development of its national pipeline mapping system (NPMS), an initiative the pipeline industry was reluctant to support, so Congress mandated it in the 2002 Act. The NPMS is now fully operational and has mapped 100 percent of the hazardous liquid (approximately 160,000 miles of pipeline) and natural gas transmission (more than 326,000 miles) pipeline systems operating in the United States. Congress exempted natural gas distribution pipelines from the mapping mandate, so currently OPS does not have mapping data on the approximately 1.8 million miles of this type of pipeline.
- *Monitoring the Evolving Nature of IMP Implementation*—The next step is threefold: (1) operators assessing their pipelines for any potential integrity threat and correcting any threats that are identified, (2) OPS assessing whether the implementation of the operators' IMPs were adequate, and (3) OPS continuing to support research and development projects to improve pipeline inspection technology.
- As mandated by Congress, OPS issued regulations requiring pipeline operators of hazardous liquid and natural gas transmission pipelines to develop and implement IMPs. IMPs are in the early stages of implementation, and operators are not required to have all baseline integrity inspections completed of hazardous liquid pipelines until 2009 and of natural gas transmission pipelines until 2012. OPS required hazardous liquid pipeline operators—the first segment of the industry required to implement the IMP—to first complete baseline integrity inspections of pipeline miles in high-consequence areas, such as residential communities and business districts. These pipelines present the highest risk of fatalities, injuries, and property damage should an accident occur.
About 135,000 miles of hazardous liquid and more than 326,000 miles of natural gas transmission pipeline still need baseline integrity inspections. Nevertheless, there are early signs that the baseline integrity inspections are working well for operators of hazardous liquid pipelines, and *there was clearly a need for such inspections*. According to OPS, in the pipelines inspected so far, more than 20,000 integrity threats have been identified and remediated. A key point to remember, though, is these threats were identified in less than 16 percent (about 25,000 miles) of hazardous liquid pipeline miles requiring baseline integrity inspections.
- OPS will be monitoring the implementation of the IMP by more than 1,100 hazardous liquid and natural gas transmission pipeline operators. This is in addition to OPS's ongoing oversight activities, such as inspecting new pipeline construction and investigating pipeline accidents. As of April 30, 2004, the 63 largest operators of hazardous liquid pipelines have undergone initial IMP reviews by OPS inspection teams, leaving 157 hazardous liquid and 884 natural gas transmission pipeline operators still needing an initial IMP review by an OPS inspection team. Monitoring the implementation of pipeline operators' IMPs will be an ongoing process for years.
- In addition, OPS must continue to support research and development projects to improve pipeline assessment technology. The majority of operators are using smart pigs to assess pipelines under their IMPs, but smart pigs are not

⁵ The Integrity Management Program is a documented set of policies, processes, and procedures that includes, at a minimum, the following elements: (1) a process for determining which pipeline segments could affect a high-consequence area, (2) a baseline assessment plan, (3) a process for continual integrity assessment and evaluation, (4) an analytical process that integrates all available information about pipeline integrity and the consequences of a failure, (5) repair criteria to address issues identified by the integrity assessment and data analysis, (6) features identified through internal inspection, (7) a process to identify and evaluate preventive and mitigative measures to protect high-consequence areas, (8) methods to measure the integrity management program's effectiveness, and (9) a process for review of integrity assessment results and data analysis by a qualified individual.

a silver bullet that can identify all pipeline integrity threats. Smart pigs currently in use can successfully detect and measure corrosion, dents, and wrinkles but are less reliable in detecting other types of mechanical damage. As a result, certain integrity threats still go undetected after a baseline integrity inspection, and pipeline accidents may occur. Also, the smart pig technologies currently available cannot be used in natural gas distribution pipelines because the majority of distribution piping is too small in diameter (1 to 6 inches) and has multiple bends and material types intersecting over very short distances.

- *Monitoring Operators' Corrective Actions for Remediating Pipeline Integrity Threats*—Once a threat is identified, OPS will need to follow up to ensure that the operators take timely and appropriate corrective action. Of the more than 20,000 threats have been repaired to date, more than 1,200 required immediate repair, 760 threats required repairs within 60 days, and 2,400 threats required repairs within 180 days. More than 16,300 threats fall into the category of "other repairs," for which remediation activities are not considered time-sensitive.

In understanding the operators' actions to remediate many of these threats, IMP inspectors need a working knowledge of the operators' pigging operations and of the interpretation of inspections' results. At the time we issued our March 2000 report, OPS did not train its inspectors on the use of smart pig technologies and the interpretation of the result of the inspections. Since that time, OPS now provides a course to IMP inspectors where they gain the knowledge and skills required to conduct meaningful safety evaluations of operator pigging program inspections and of pigging data for hazardous liquid and natural gas transmission pipelines.

OPS's remediation criteria encompass a broad range of actions, which include mitigative measures (such as reducing the pipeline pressure flow), as well as repairs that an operator can take to resolve an integrity threat. But the process is not as simple as identifying the problem and determining how best to fix it. For some repairs, Federal and state environmental review and permitting processes have delayed preventive measures from occurring, as was demonstrated by the recent pipeline rupture in northern California. A hazardous liquid pipeline ruptured and released about 85,000 gallons of diesel fuel, affecting 20 to 30 acres of marshland.

The deteriorating condition of this pipeline was well documented by the operator, who initiated action to relocate the pipeline in 2001. However, it took nearly 3 years and more than 40 permits before the operator was given approval to relocate the pipeline. It was too late to prevent this spill, but fortunately in this case there was no loss of human life.

An Interagency Task Force was set up to monitor and assist agencies in their efforts to expedite their review of permits. However, the Task Force has yet to implement its Memorandum of Understanding (MOU) that would expedite the environmental review and permitting processes so that pipeline repairs can be made before a serious consequence occurs. If there are any further delays in implementing the MOU, then it may be necessary for Congress to take action.

- *Closing the Safety Gap on Natural Gas Distribution Pipelines*—The natural gas distribution system makes up over 85 percent (1.8 million miles) of the 2.1 million miles of natural gas pipelines in the United States. Distribution is the final step in delivering natural gas to end users such as homes and businesses. While hazardous liquid and natural gas transmission pipeline operators are moving forward with IMPs, natural gas *distribution* pipeline operators⁶ are not required to have an IMP. According to industry officials, the initial reason why natural gas distribution pipelines were not required to have an IMP is that the majority of distribution pipelines cannot be inspected using smart pigs.

The IMP is a risk-management tool designed to improve safety, environmental protection, and reliability of pipeline operations. That natural gas distribution pipelines cannot be internally inspected using smart pigs is not by itself a sufficient reason for not requiring operators of natural gas distribution pipelines to have IMPs. Other elements of the IMP can be readily applied to this segment of the industry, including but not limited to (1) a process for continual integrity assessment and evaluation, and (2) repair criteria to address issues identified by the integrity assessment and data analysis.

⁶There are some operators of natural gas transmission pipelines that are also operators of natural gas distribution pipelines. IMP requirements do not apply to their distribution pipelines.

Our concern is that the Department's strategic safety goal is to reduce the number of transportation-related fatalities and injuries, but natural gas distribution pipelines are not achieving this goal. Over the last 10 years, natural gas distribution pipelines have experienced over *4 times* the number of fatalities (174 fatalities) and more than *3.5 times* the number of injuries (662 injuries) than the combined totals of 43 fatalities and 178 injuries for hazardous liquid and natural gas transmission pipelines.

To address this issue, the American Gas Foundation, with OPS support, is sponsoring a study to assess the Nation's gas distribution infrastructure that will evaluate safety performance, current operating and regulatory practices, and emerging technologies.

- *Developing an Approach To Overseeing Pipeline Security*—It is not only important that we ensure the safety of the Nation's pipeline system, we must also ensure the security of the system. OPS took the lead to help reduce the risk of terrorist activity against the Nation's pipeline infrastructure following the events of September 11, 2001, but OPS now states it plays a secondary or support role to the Department of Homeland Security's (DHS) Transportation Security Administration (TSA).

The current Presidential Directive⁷ that addresses this issue is at too high a level of generality to provide clear guidance on each Agency's [DOT, DHS, and the Department of Energy (DOE)] responsibility in regards to pipeline security. The delineation of roles and responsibilities between DOT, DHS, and DOE needs to be spelled out in an MOU at the operational level so that we can better monitor the security of the Nation's pipelines without impeding the supply of energy.

Mapping the Pipeline System

To provide effective oversight of the Nation's pipeline system, OPS must first know where the pipelines are located, the size and material type of the pipe, and the types of products being delivered. The Nation's pipeline system is an elaborate network of over 2 million miles of pipe moving millions of gallons of hazardous liquids and more than 55 billion cubic feet of natural gas daily. The pipeline system is composed of predominantly three segments—natural gas transmission pipelines, natural gas distribution pipelines, and hazardous liquid transmission pipelines—run by about 2,200 natural gas distribution and transmission pipeline operators and 220 operators of hazardous liquid pipelines (as seen in Table 1). Of the 2,200 operators of natural gas pipelines, there are approximately 1,300 operators of natural gas distribution pipelines and 880 operators of natural gas transmission pipelines. There are approximately 90 Federal and 400 state inspectors responsible for overseeing the operators' compliance with pipeline safety regulations.

⁷Homeland Security Presidential Directive/HSPD-7, "Critical Infrastructure Identification, Prioritization, and Protection," issued December 2003.

Table 1.—Pipeline System Facts and Description

<i>System Segment</i>	<i>Facts</i>	<i>Segment Description</i>
Natural Gas Transmission Pipelines	326,595 Miles	Lines used to gather and transmit natural gas from wellhead to distribution systems
Natural Gas Distribution Pipelines	1.8 Million Miles	Mostly local distribution lines transporting natural gas from transmission lines to residential, commercial, and industrial customers
Hazardous Liquid Transmission Pipelines	160,000 Miles	Lines primarily transporting products such as crude oil, diesel fuel, gasoline, and jet fuel
<i>System Operators</i>	<i>Facts</i>	<i>Operators Description</i>
Natural Gas Transmission Operators	880	Large, medium, and small operators of natural gas transmission pipelines
Natural Gas Distribution Operators	1,300	Large, medium, and small operators of natural gas distribution pipelines
Hazardous Liquid Operators	220	Approximately 70 large operators and 150 small operators

Originally, industry was reluctant to map the Nation's pipeline system, so Congress responded by requiring, in the 2002 Act, the mapping of hazardous liquid and natural gas transmission pipelines. In the past year, OPS completed the development of the national pipeline mapping system (NPMS). The NPMS is now fully operational and has mapped 100 percent of the hazardous liquid (approximately 160,000 miles of pipeline) and natural gas transmission (more than 326,000 miles) pipeline systems operating in the United States. Congress excepted natural gas distribution pipelines from the mapping mandate, so OPS does not have mapping data on these pipelines.

As a result of OPS and industry's mapping efforts, Government agencies and industry have access to reasonably accurate pipeline data for hazardous liquid and natural gas transmission pipelines in the event of emergency or potentially hazardous situation. The public also has access to contact information about pipeline operators within specified geographic areas.

Monitoring the Evolving Nature of IMP Implementation

Hazardous liquid and natural gas transmission pipeline operators are in the early stages of implementing their IMPs. Safety baseline integrity inspections are just now being established systemwide—starting with hazardous liquid pipelines—so there are no comparable benchmarks. Nevertheless, as they begin implementing their IMPs, there is not yet enough evidence available to evaluate the IMP's effectiveness in strengthening pipeline safety. However, there are early signs that the baseline integrity inspections are working well for operators of hazardous liquid pipelines, and there was *clearly a need for such inspections*.

OPS is also in the early stages of overseeing the implementation of the operators' IMPs, starting with IMP assessments of operators of hazardous liquid pipelines. In doing so, OPS is challenged with monitoring the implementation of the IMPs of more than 1,100 hazardous liquid and natural gas transmission pipeline operators and assisting in the development of technologies to meet the requirements of the IMP for all sizes and shapes of pipelines and different threat detections.

Early Stages of Implementing Pipeline Operators' IMPs

The operators' implementation of their IMPs is a lengthy process. Even though the IMP rules have been issued in their final form, they will not be fully implemented for up to 8 years. For example, as part of the rules requiring IMPs for operators of natural gas transmission pipelines, operators are required to begin baseline integrity inspections no later than June 17, 2004, with inspections completed no later than December 17, 2012.

As operators begin implementing their IMPs, there are early signs that the baseline integrity inspections are working well for operators of hazardous liquid pipelines and that there was clearly a need for such inspections. So far, according to

OPS, results from the operators' baseline integrity inspections in predominantly high-consequence areas show that more than 20,000 integrity threats were identified and remediated. These threats may not have been discovered during the operators' routine inspections. One of the most serious threats discovered was a case of corrosion where greater than 80 percent of the pipeline wall thickness had been lost. It has since been repaired. A lesser threat discovered was minor corrosion along a longitudinal seam.

A key point to remember about the early baseline integrity inspection results for operators of hazardous liquid pipelines is that these 20,000 threats were discovered and remediated in less than 16 percent (about 25,000 miles) of pipeline miles needing inspection. About 135,000 miles of hazard liquid pipeline still needs baseline integrity inspections.

Although 20,000 threats were discovered in the first 25,000 miles, we cannot statistically project the number of threats that could be expected in the remaining 135,000 miles that still need baseline integrity inspections. We also cannot project the number of threats that could be expected in the more than 326,000 miles of natural gas transmission pipelines that have yet to receive baseline integrity inspections. Also, baseline integrity inspections will not be completed for several years and certain threats may be very time-sensitive, especially those to do with severe internal corrosion.

OPS required hazardous liquid pipeline operators—the first segment of the industry required to implement the IMP—to first complete baseline integrity inspections of pipeline miles in high-consequence areas, as these areas are populated, unusually sensitive to environmental damage, or commercially navigable waterways. These pipelines present the highest risk of fatalities, injuries, and property damage should an accident occur.

According to the American Petroleum Institute, nationwide there are approximately 160,000 miles of hazardous liquid pipelines, of which 51,400 miles are located in high-consequence areas. As required by the IMP rule, 25,700 of the 51,400 miles (50 percent) should receive baseline inspections by September 30, 2004. OPS estimates, of the nearly 327,000 miles of natural gas transmission pipelines, 24,970 miles are located in high consequence areas. But pipelines in high-consequence areas represent only about 16 percent of the total miles (76,370 of 487,000 total miles) for both hazardous liquid and natural gas transmission pipelines⁸ and accidents that occur in non-high-consequence areas can have catastrophic consequences, such as the deadly pipeline rupture, explosion, and fire near Carlsbad, New Mexico.

On August 19, 2000, a 30-inch-diameter natural gas transmission pipeline ruptured adjacent to the Pecos River near Carlsbad. The released gas ignited and burned for 55 minutes. Twelve members of a family who were camping under a concrete-decked steel bridge that supported the pipeline across the river were killed and their three vehicles destroyed. Two nearby steel suspension bridges for gas pipelines crossing the river were extensively damaged.

During the investigation, NTSB investigators found the rupture was a result of severe internal corrosion that caused a reduction in pipe wall thickness to the point that the remaining metal could no longer contain the pressure within the pipe. The significance of this finding cannot be overstated, as corrosion is the second leading cause of pipeline accidents, and pipeline operators will need to forge ahead on their baseline integrity inspections.

Monitoring the Implementation of Pipeline Operators' IMPs

OPS must now begin assessing whether the implementation of more than 1,100 hazardous liquid and natural gas transmission pipeline operators' IMPs were adequate. OPS must also perform ongoing oversight activities, such as inspecting new pipeline construction, monitoring research and development projects, and investigating pipeline accidents. To do so, OPS believes it will need to augment its own resources with those of the states to efficiently and effectively oversee the operators' IMPs.

OPS is actively overseeing IMP implementation through its assessments of hazardous liquid pipeline operators' IMP plans. As of April 30, 2004, the 63 largest operators of hazardous liquid pipelines have undergone the initial IMP assessments. That leaves 157 more operators of hazardous liquid pipelines and 884 operators of natural gas transmission pipelines who will need initial IMP assessments.

Monitoring the implementation of pipeline operators' IMPs will be an ongoing process. OPS IMP inspection teams, made up of Federal and state inspectors, spent

⁸The percentage of total miles in high consequence areas for hazardous liquid and natural gas transmission pipelines are early estimates and may change with the beginning of the pipeline operators' baseline integrity inspections.

approximately 2 weeks at each operator's headquarters reviewing results of integrity inspection and actions taken to address integrity threats, as well as overall IMP development and effectiveness. With about 1,041 pipeline operators who have not yet had an initial IMP assessment (at 2 weeks for each assessment), compounded by the fact that pipelines operators have up to 8 years to complete their baseline integrity inspections, the *overall* effectiveness of operators' IMPs in strengthening pipeline safety will not be known for years.

Advancing Threat Detection Technologies Is Fundamental to the Success of Integrity Inspections

As part of OPS's IMP rule, operators of hazardous liquid and natural gas transmission pipelines are required to inspect the integrity of their pipelines using smart pigs or an alternate equally effective method such as direct assessment. To date, OPS's integrity management assessments indicate that operators of hazardous liquids pipelines used smart pigs about 70 percent of the time to conduct their baseline integrity inspections and strongly favored the use of smart pigs over alternative inspection methods available under the IMP. Although there have been significant advances in smart pig technology, the current technology still cannot identify all pipeline integrity threats. Smart pigs currently in use can successfully detect and measure corrosion, dents, and wrinkles but are less reliable in detecting other types of mechanical damage. As a result, certain integrity threats go undetected and pipeline accidents may occur.

For example, on July 30, 2003, an 8-inch diameter hazardous liquid pipeline ruptured near a residential area under development in Tucson, Arizona, releasing more than 10,000 gallons of gasoline and shutting down the supply of gasoline to the greater metropolitan Phoenix area for 2 days. Whether this rupture could have been prevented is still not known because the cause of the rupture, stress crack corrosion,⁹ rarely causes failure in hazardous liquid pipelines. Also, currently there are no tools or mechanisms small enough to fit in 8-inch diameter piping in order to identify the threat of stress crack corrosion.

OPS's research and development (R&D) program is aimed at enhancing the safety and reducing the potential environmental effects of transporting natural gas and hazardous liquids through pipelines. Specifically, the program seeks to advance the most promising technological solutions to problems that imperil pipeline safety, such as damage to pipelines from excavation or corrosion. OPS sponsors R&D projects that focus on providing near-term solutions that will increase the safety, cleanliness, and reliability of the Nation's pipeline system.

OPS's R&D funding has more than tripled, from \$2.7 million in FY 2001 to \$8.7 million in FY 2003. Nearly \$4 million of the \$8.7 million is funding projects to improve the technologies used to inspect the integrity of pipeline systems in support of the IMP. OPS currently has 22 active projects that explore a variety of ways to improve smart pig technologies, develop alternative inspection and detection technologies for pipelines that cannot accommodate smart pigs, and improve pipeline material performance. For example, OPS has a project underway that will improve the capabilities of smart pigs to better detect and measure both corrosion and mechanical damage. The expected project outcome is a smart pig that is simpler to build and use.

The R&D challenge OPS now faces is seeing these projects through to completion, without undue delay and expense, to ensure that viable, reliable, cost-effective technologies become readily available to meet the demands of increased usage required under the IMP.

Monitoring Remediation of Pipeline Integrity Threats

Much of the Nation's existing pipeline infrastructure is over 50 years old. When pipeline integrity threats are identified, repairs may require Federal and state environmental reviews and permitting before the operator can proceed. However, OPS regulations identify repair criteria for the types of threats that must be repaired within specified time limits. At times, the environmental review and permitting processes become an obstacle that can delay the operators' remediation efforts.

When it passed the Pipeline Safety Improvement Act of 2002, Congress recognized that timely repair of pipeline integrity threats was essential to the well-being of human health, public safety, and the environment. Therefore, Congress directed the President to establish an interagency committee to develop and ensure the implementation of a coordinated environmental review and permitting process. This proc-

⁹Stress crack corrosion (SCC), also known as environmentally assisted cracking, is a relatively new phenomenon. Instead of pits, SCC manifests itself as cracks that are minute in length and depth. Over time, individual cracks coalesce with other cracks and become longer.

ess should allow pipeline operators to commence and complete all activities necessary to carry out pipeline repairs within any time periods specified under OPS's regulations.

Certain Pipeline Repairs Must Be Completed Within Specified Time Limits

OPS regulations identify remediation criteria for the types of threats that must be repaired within specified time limits, the length of which reflects the probability of failure. For hazardous liquid pipelines, the three categories of repair are defined as immediate repair, 60 days to repair, and 180 days to repair. For example, a top dent with any indication of metal loss requires *immediate* response and action, whereas a bottom dent with any indication of metal loss requires a response and action *within 60 days*. Other types of threats include remediation activities that are not considered time-sensitive. Using the criteria, pipeline operators must characterize the type of repair required, evaluate the risk of failure, and make the repair within the defined time limit.

Of the more than 20,000 threats that have been identified and remediated to date, more than 1,200 required immediate repair, 760 required repairs within 60 days, and 2,400 required repairs within 180 days. More than 16,300 threats fall into the category of other remediation activities that are not considered time-sensitive. OPS's remediation criteria encompass a broad range of actions, which include mitigative measures (such as reducing the pipeline pressure flow), as well as repairs that an operator can make to resolve an integrity threat. For immediate repairs, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of the threat.

The challenges inspectors face during a review of an operator's baseline integrity inspection results are to determine whether OPS's repair criteria were properly used to characterize the type of repair required for each threat identified and whether the operator's threat remediation plans are adequate to repair or mitigate the threat. More importantly, however, is that OPS will need to follow up to ensure that the operator has properly executed its remediation actions within the defined time limit.

Improvements Are Needed in Coordinating Federal and State Environmental Reviews and Permitting Processes

The transmission of energy through the Nation's pipeline system in a safe and environmentally sound manner is essential to the well-being of human health, public safety, and the environment. One way to do this is to develop and ensure implementation of a coordinated Federal and state environmental review and permitting process that will enable pipeline operators to complete pipeline repairs quickly. There will be mounting pressures to accelerate the environmental review and permitting processes, given the high number of threats found during the early stages of pipeline operators' baseline integrity inspections that must be repaired within specified time limits.

The recent pipeline rupture in northern California demonstrates the perils of not being able to promptly repair pipeline threats. In April 2004, a hazardous liquid pipeline ruptured in the Suisun Marsh south of Sacramento, California, releasing about 85,000 gallons of diesel fuel into 20 to 30 acres of marshland. Muskrats, beaver, and water fowl were affected by the spill. Fortunately, there were no human fatalities or injuries as a result of the rupture.

The deteriorating condition of the pipeline that ruptured was well documented by the pipeline operator, who had reduced pipeline operating pressure to lessen the risk of a rupture and keep the flow of energy to users in Sacramento and Chico, California, and Reno, Nevada. The pipeline operator wanted to relocate the pipeline away from the Suisun Marsh and initiated actions to do so in 2001. However, the environmental review and permitting processes took far too long: nearly 3 years and more than 40 permits in total. There is little doubt that the rupture would not have occurred had the permit process been quicker.

The importance of accelerating the permit process, when necessary, cannot be overstated. As we have noted, results from the hazardous liquid pipeline operators' baseline integrity inspections in high-consequence areas show that more than 20,000 integrity threats were identified for remediation. More than 1,200 threats required immediate repairs, 760 threats required repairs within 60 days, and 2,400 threats required repairs within 180 days. As operators continue with their baseline integrity inspections, the implications are that the number of integrity threats will continue to rise. According to OPS, repairs for other known pipeline threats are being delayed because of the environmental review and permitting processes, and they are best taken care of sooner rather than later, so as to prevent another incident like the Suisun Marsh rupture.

When it passed the 2002 Act, Congress recognized the need to expedite the environmental review and permitting process. Section 16 of the 2002 Act directed the President to establish an interagency committee that would implement a coordinated environmental review and permitting process so that pipeline repairs could be made within the time periods specified by IMP regulations.

Committee activities were to include:

- An evaluation of Federal permitting requirements.
- Identification of best management practices to be used by industry.
- The development of an MOU by December 17, 2003, (1 year after the enactment of the 2002 Act) to provide for a coordinated and expedited pipeline permit process that would result in no more than minimal adverse effects on the environment.

The 2002 Act also requires the committee to consult with state and local environmental, pipeline safety, and emergency response officials, and requires the Secretary of Transportation to designate an ombudsman to assist in expediting the pipeline process and resolving disagreements over pipeline repairs between Federal, state, and local permitting agencies and the pipeline operator.

To implement Section 16, the President issued an Executive Order in May 2003, establishing the Interagency Task Force and directed it to implement the committee activities. The Chairman of the Council on Environmental Quality chairs the Interagency Task Force, whose membership includes representatives from the Departments of Agriculture, Commerce, Defense, Energy, the Interior, and Transportation; the Environmental Protection Agency; the Federal Regulatory Commission; and the Advisory Council on Historic Preservation.

Although an MOU has been drafted, it has not been finalized as of June 11, 2004. According to OPS, not all members of the Interagency Task Force have agreed to the provisions of the MOU, while other members believe that there are provisions in the Clean Air Act, Clean Water Act, the Endangered Species Act that prohibit them from taking any action to expedite the permitting process. Until the MOU is finalized, an evaluation of Federal permitting requirements and identification of best management practices to be used by industry will be further delayed.

These issues need to be resolved by the Interagency Task Force. While the problem may not be easily resolved, Federal agencies must work together to accelerate the environmental review and permitting process to avoid failures like the Suisun Marsh rupture or even worse. If the Interagency Task Force set up to monitor and assist agencies in their efforts to expedite their review of permits cannot develop a method for expediting the environmental review and permit process so that pipeline repairs can be made before a serious consequence occurs, then it may be necessary for Congress to take action.

Closing the Safety Gap on Natural Gas Distribution Pipelines

The 2002 Act requires that the operators of natural gas pipeline facilities implement IMPs. However, the IMP requirement applies only to natural gas transmission pipelines and not to natural gas distribution pipelines.

As part of the IMP, operators of hazardous liquid and natural gas transmission pipelines are required to inspect the integrity of their pipelines using one or more of the following inspection methods: smart pigs, pressure testing, or direct assessment.¹⁰ According to officials of the American Gas Association, the initial reason why IMPs were not required for natural gas distribution pipelines is that distribution pipelines cannot be inspected using smart pigs. The smart pig technologies currently available cannot be used in natural gas distribution pipelines because the majority of distribution piping is too small in diameter (1 to 6 inches) and has multiple bends and material types intersecting over very short distances.

The IMP is a risk-management tool designed to improve safety, environmental protection, and reliability of pipeline operations. That natural gas distribution pipelines cannot be internally inspected using smart pigs is not by itself a sufficient reason for not requiring operators of natural gas distribution pipelines to have IMPs. Other elements of the IMP can be readily applied to this segment of the industry, including but not limited to (1) a process for continual integrity assessment and evaluation, (2) an analytical process that integrates all available information about pipeline integrity and the consequences of failure, and (3) repair criteria to address issues identified by the integrity assessment and data analysis.

¹⁰ Operators can choose another technology that demonstrates an equivalent understanding of the integrity of the pipeline but only after notifying OPS before the inspection begins.

Natural Gas Distribution Pipeline Safety Concerns

Our concern is that the Department's strategic safety goal is to reduce the number of transportation-related fatalities and injuries, but natural gas distribution pipelines are not achieving this goal. In the 10-year period from 1994 through 2003, OPS's data show accidents in natural gas distribution pipelines have caused more than *4 times* the number of fatalities (174 fatalities) and more than *3.5 times* the number of injuries (662 injuries) when compared to a combined total of 43 fatalities and 178 injuries associated with hazardous liquid and gas transmission pipeline accidents combined.

Accidents involving natural gas distribution pipelines can be as catastrophic as accidents involving hazardous liquids or natural gas transmission pipelines. For example, on December 11, 1998, in downtown St. Cloud, Minnesota, a communications crew ruptured an underground natural gas distribution pipeline, causing an explosion that killed 4 people, seriously injured 1, and injured 10 others. Six buildings were destroyed. In another example, in July 2002, a gas explosion in a multiple-family dwelling in Hopkinton, Massachusetts, killed 2 children and injured 14 others.

In the past 3 years, the number of fatalities and injuries from accidents involving natural gas distribution pipelines has increased while the number of fatalities and injuries from accidents involving hazardous liquid and natural gas transmission pipelines has held steady or declined. OPS's data show that fatalities and injuries from accidents involving natural gas distribution pipelines increased from 5 fatalities and 46 injuries in 2001 to 11 fatalities and 58 injuries in 2003. For the same period, fatalities and injuries from accidents involving hazardous liquid and natural gas transmission pipelines decreased from 2 fatalities and 15 injuries in 2001 to 1 fatality and 13 injuries in 2003.

Although OPS has moved forward with initiatives¹¹ to enhance the safety of natural gas distribution pipelines, OPS needs to ensure that the pace of its efforts moves quickly enough, given the upward trend in fatalities and injuries involving these pipelines and the projected increase in distribution pipelines to meet the increasing demand for natural gas.

OPS should require operators of natural gas distribution pipelines to implement some form of pipeline integrity management or enhanced safety program with the same or similar integrity management elements, except pigging, as the hazardous liquid and natural gas transmission pipelines. This would be consistent with OPS's risk-based approach to overseeing pipeline safety by using IMPs to reduce the risk of accidents that may cause injuries or fatalities to people living or working near natural gas distribution pipelines, as well as to reduce property damage.

Developing an Approach To Overseeing Pipeline Security

The focus of our recently completed review was pipeline safety. However, given the importance of protecting the Nation's infrastructure of pipeline systems, we also reviewed OPS's involvement in the security of the pipeline systems.

OPS's Security Efforts Following September 11, 2001

Following the events of September 11, 2001, OPS moved forward on several fronts to help reduce the risk of terrorist activity against the Nation's pipeline infrastructure, such as opening the lines of communication among Federal and state agencies responsible for protecting the Nation's critical infrastructure, including pipelines; conducting pipeline vulnerability assessments and identifying critical pipeline systems; developing security standards and guidance for security programs; and working with Government and industry to help ensure rapid response and recovery of the pipeline system in the event of a terrorist attack.

To protect the Nation's pipeline infrastructure, OPS issued new security guidance to pipeline operators nationwide in September 2002. In the guidance, OPS requested that all operators develop security plans to prevent unauthorized access to pipelines and identify critical facilities that are vulnerable to a terrorist attack. OPS also asked operators to submit a certification letter stating that the security plan had been implemented and that critical facilities had been identified. During 2003, OPS in conjunction with the DHS's TSA started reviewing operator security plans. The plans reviewed have been judged responsive to the OPS guidance.

Unlike its pipeline safety program, OPS's security guidance is not mandatory: industry's participation in a security program is strictly voluntary and cannot be enforced unless a regulation is issued to require industry compliance. In fact, it is still

¹¹ With OPS support, the American Gas Foundation is sponsoring a study to assess the Nation's gas distribution infrastructure that will evaluate safety performance, current operating and regulatory practices, and emerging technologies.

unclear what agency or agencies will have responsibility for pipeline security rule-making, oversight, and enforcement. Although OPS took the lead to help reduce the risk of terrorist activity against the Nation's pipeline infrastructure following the events of September 11, 2001, OPS has stated it now plays a secondary, or support, role to TSA, the agency with primary responsibility for ensuring the security of the Nation's transportation system, including pipelines.

Recent Initiatives Clarifying Security Responsibilities

Certain steps have been taken to establish what agency or agencies would be responsible for ensuring the security of the Nation's critical infrastructure, including pipelines. For example, in December 2003, Homeland Security Presidential Directive/HSPD-7 (HSPD-7):

- Assigned the DHS the responsibility for coordinating the overall national effort to enhance the protection of the Nation's critical infrastructure and key resources.
- Assigned DOE the responsibility for ensuring the security of the Nation's energy, including the production, refining, storage, and distribution of oil and gas.
- Directed DOT and DHS to collaborate on all matters relating to transportation security and transportation infrastructure protection and to regulating the transportation of hazardous materials by all modes, including pipelines.

Although HSPD-7 directs DOT and DHS to collaborate in regulating the transportation of hazardous materials by all modes, including pipelines, it is not clear from an operational perspective what "to collaborate" encompasses, and it is also not clear what OPS's relationship will be with DOE. The delineation of roles and responsibilities between DOT and DHS needs to be spelled out by executing an MOU or a Memorandum of Agreement. OPS also needs to seek clarification on the delineation of roles and responsibilities between itself and DOE.

Mr. Chairman, this concludes my statement. I will be pleased to answer any questions that you might have.

The CHAIRMAN. Thank you very much.
Ms. Siggerud, welcome.

**STATEMENT OF KATHERINE SIGGERUD, DIRECTOR,
PHYSICAL INFRASTRUCTURE ISSUES,
U.S. GENERAL ACCOUNTING OFFICE**

Ms. SIGGERUD. Thank you, Mr. Chairman and Members of the Committee, for the invitation to testify at this hearing on oversight of the Office of Pipeline Safety.

The information I will present today is based on our ongoing work looking at OPS's enforcement policy and practices. As you know, this work was required by the Pipeline Safety Improvement Act of 2002, and we will be issuing a full report on our work next month.

Pipeline transportation remains the safest form of freight transportation, and OPS has been taking a number of steps, including a more aggressive enforcement posture, to make pipelines safer. Enforcing pipeline safety standards and taking action against violators is an important part of OPS's efforts to prevent accidents. Therefore, my testimony today will cover two topics. First, the effectiveness of OPS's enforcement strategy, and, second, OPS's assessment of monetary sanctions, often called civil penalties, against interstate pipeline operators that violate Federal pipeline safety rules.

But before I address these two topics, let me put OPS's enforcement program in context. Over the past several years, OPS has been developing and implementing the risk-based approach that it believes will fundamentally improve pipeline safety. This approach, which my fellow witnesses have mentioned, is called integrity man-

agement. It requires interstate pipeline operators to identify and address safety-related threats to their pipelines in areas where an accident could have the greatest consequences. According to OPS, this approach has more potential to improve safety than its traditional approach, which focused on compliance, but not so much on threats. OPS emphasizes that integrity management coupled with other initiatives can change the safety culture of the industry and drive down the number of accidents.

Now that these initiatives are substantially underway, OPS is planning to improve the management of its enforcement program. Accordingly, my testimony today focuses on potential management improvements that should be useful to OPS as it decides how to proceed, and to this Committee as it continues to exercise oversight over this program.

Let me turn now to my first topic, the effectiveness of OPS's enforcement strategy. We've found that definitive information on the strategy's effectiveness is not available because OPS has not yet incorporated three key elements of effective program management. First, OPS has not established goals that specify the intended results of the new, more aggressive strategy it has had in place since 2000. Second, OPS has not developed a policy that describes the strategy and the strategy's contribution to pipeline safety. Finally, OPS has not put measures in place that would allow it to determine and demonstrate the effects of this new strategy on the industry's compliance. Without these three key elements, OPS cannot determine whether recent and planned changes in its enforcement strategy are having, or will have, the desired effects.

OPS is developing an enforcement policy that will help define the strategy. It has also begun to identify new measures of enforcement performance. OPS plans to finalize this policy sometime in 2005. However, it still needs to link its performance measures to program goals, a key element of effective program management.

One component of enforcement, OPS's assessment of civil penalties, is my second topic for today. Here, OPS is taking a more aggressive approach, imposing more and larger penalties than it did in the late 1990s. At that time, its policy was to partner with industry, and we and others expressed concern about a significant decrease in OPS's use of civil penalties. We found that, from 2000 through 2003, OPS increased its assessment of civil penalties to an average of 22 penalties a year, with an average of 14 penalties a year from 1995 through 1999. The average size of civil penalties also increased to about \$29,000 during the more recent years, compared with an average of around \$18,000 during the earlier years.

Pipeline safety stakeholders express differing views on whether OPS's increased use of civil penalties will help deter noncompliance with the pipeline safety regulations. Some of those we spoke with, such as pipeline industry officials, said that civil penalties of any size, or any other kind of enforcement action, act as a deterrent in part because they keep the companies in the public eye. Others, such as some of the pipeline safety advocacy groups, said that civil penalties may be too small to deter noncompliance.

Finally, we found that DOT had, in fact, collected most of the civil penalties that OPS assessed over the past 10 years. Data show that operators have paid 94 percent of the assessed civil penalties.

However, we found some gaps in communication between OPS and its collection agent about which penalties should be collected and which already had been collected. In light of the issues raised in my statement today, we are considering recommendations that could, first, enable OPS to demonstrate to the Congress that it has an effective enforcement strategy, and, second, remedy the problems we identified in OPS's collection of civil penalties.

Mr. Chairman, this concludes my statement, and I am happy to answer any questions.

[The prepared statement of Ms. Siggerud follows:]

GAO HIGHLIGHTS

Why GAO Did This Study

Interstate pipelines carrying natural gas and hazardous liquids (such as petroleum products) are safer to the public than other modes of freight transportation. The Office of Pipeline Safety (OPS), the Federal agency that administers the national regulatory program to ensure safe pipeline transportation, has been undertaking a broad range of activities to make pipeline transportation safer. However, the number of serious accidents—those involving deaths, injuries, and property damage of \$50,000 or more—has not fallen. Among other things, OPS takes enforcement action against pipeline operators when safety problems are found. OPS has several enforcement tools to require the correction of safety violations. It can also assess monetary sanctions (civil penalties).

This testimony is based on ongoing work for the Senate Committee on Commerce, Science and Transportation and for other committees, as required by the Pipeline Safety Improvement Act of 2002. The testimony provides preliminary results on (1) the effectiveness of OPS's enforcement strategy and (2) OPS's assessment of civil penalties.

What GAO Recommends

GAO expects to issue a report in July 2004 that will address these and other topics and anticipates making recommendations.




PIPELINE SAFETY




Preliminary Information on the Office of Pipeline Safety's Enforcement Activities

What GAO Found

The effectiveness of OPS's enforcement strategy cannot be determined because the agency has not incorporated three key elements of effective program management—clear program goals, a well-defined strategy for achieving goals, and performance measures that are linked to program goals. (See below.) Without these key elements, the agency cannot determine whether recent and planned changes in its strategy will have the desired effects on pipeline safety. Over the past several years, OPS has focused on other efforts—such as developing a new risk-based regulatory approach—that it believes will change the safety culture of the industry. While OPS has become more aggressive in enforcing its regulations, it now intends to further strengthen the management of its enforcement program. In particular, OPS is developing an enforcement policy that will help define its enforcement strategy and has taken initial steps toward identifying new performance measures. However, OPS does not plan to finalize the policy until 2005 and has not adopted key practices for achieving successful performance measurement systems, such as linking measures to goals.

Incorporation of Key Program Management Elements into OPS's Enforcement Strategy

Element	Extent
Clear program goals.	
Well-defined strategy for achieving goals.	
Performance measures linked to program goals.	

 Fully incorporated
  Partially incorporated
  Not incorporated

Source: GAO.

OPS increased both the number and the size of the civil penalties it assessed against pipeline operators over the last 4 years (2000–2003) following its decision to be “tough but fair” in assessing penalties. OPS assessed an average of 22 penalties per year during this period, compared with an average of 14 per year for the previous 5 years (1995–1999), a period of more lenient “partnering” with industry. In addition, the average penalty increased from \$18,000 to \$29,000 over the two periods. About 94 percent of the 216 penalties levied from 1994 through 2003 have been paid. The civil penalty is one of several actions OPS can take when it finds a violation, and these penalties represent about 14 percent of all enforcement actions over the past 10 years. While OPS has increased the number and size of civil penalties, stakeholders—including industry, state, and insurance company officials and public advocacy groups—expressed differing views on whether these penalties deter noncompliance with safety regulations. Some, such as pipeline operators, thought that any penalty was a deterrent if it kept the pipeline operator in the public eye, while others, such as safety advocates, told us that the penalties were too small to be effective sanctions.

PREPARED STATEMENT OF KATHERINE SIGGERUD, DIRECTOR, PHYSICAL INFRASTRUCTURE ISSUES, UNITED STATES GENERAL ACCOUNTING OFFICE

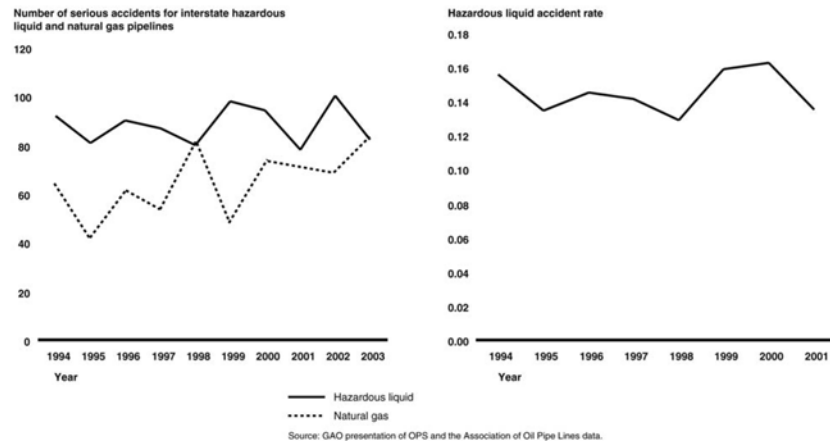
Mr. Chairman and Members of the Committee:

We appreciate the opportunity to participate in this hearing on the oversight of the Office of Pipeline Safety (OPS). As you know, pipeline transportation for hazardous liquids and natural gas is the safest form of freight transportation, and OPS has taken many steps to make it safer.¹ However, the number of serious hazardous liquid accidents has stayed about the same while the number of serious natural gas accidents has increased.² (See fig. 1.) Finally, the serious accident rate—which considers the amount of product and distance shipped—for hazardous liquids has decreased. None of these statistics show a constant pattern. In part, the lack of significant change over time and the fluctuation over time may be due to the relatively small number of serious accidents—an average of about 150 per year for both types combined.

¹Hazardous liquid pipelines carry products such as crude oil, diesel fuel, gasoline, jet fuel, anhydrous ammonia, and carbon dioxide.

²Serious accidents are those resulting in a death, injury, or \$50,000 or more in property damage.

Figure 1: Numbers of Serious Accidents and Accident Rate for Interstate Pipelines, 1994 through 2003



Notes: This figure does not include the injuries that occurred during one series of accidents caused by severe flooding near Houston, Texas, in October 1994.

The accident rate is the number of serious accidents per billion ton-miles shipped. (A ton-mile is 1 ton of a product shipped 1 mile.)

The accident rates are based on the volume of petroleum products shipped. Federal agencies and industry associations we contacted could not provide data on other hazardous liquids shipped. Aggregated industry data on the amounts of products shipped through hazardous liquid pipelines for 2002 and 2003 are not available so we do not present accident rate information for those years. We are inquiring into the availability of data on natural gas shipped through interstate pipelines; these data are needed to calculate the accident rates for this type of pipeline.

A cornerstone to OPS's efforts over the past several years has been the agency's development and implementation of a risk-based approach that it believes will fundamentally improve the safety of pipeline transportation. This approach, called integrity management, requires interstate pipeline operators to identify and fix safety-related threats to their pipelines in areas where an accident could have the greatest consequences. OPS believes that this approach has more potential to improve safety than its traditional approach, which focused on enforcing compliance with safety standards regardless of the threat to pipeline safety. Officials have emphasized that integrity management, coupled with other initiatives, such as oversight of operators' programs to qualify employees to operate their pipelines, represents a systematic approach to overseeing and improving pipeline safety that will change the safety culture of the industry and drive down the number of accidents.

Now that its integrity management approach and other initiatives are substantially under way, OPS recognizes that it needs to turn its attention to the management of its enforcement program. Accordingly, my testimony today focuses on opportunities for improving certain aspects of OPS's enforcement program that should be useful to OPS as it decides how to proceed and to this committee as it continues to exercise oversight.

My statement is based on the preliminary results of our ongoing work for this committee and others. As directed by the Pipeline Safety Improvement Act of 2002, we have been (1) evaluating the effectiveness of OPS's enforcement strategy and (2) examining OPS's assessment of monetary sanctions (called civil penalties) against interstate pipeline operators that violate Federal pipeline safety rules. We expect to report on the results of our work on these and other issues next month.

Our work is based on our review of laws, regulations, program guidance, and discussions with OPS officials and a broad range of stakeholders.³ To evaluate the effectiveness of OPS's enforcement strategy, we determined the extent to which the agency's strategy incorporates three key elements of effective program management:

³These stakeholders represent industry trade associations, pipeline companies, Federal enforcement agencies, state pipeline enforcement agencies and associations, pipeline safety advocacy groups, and pipeline insurers.

clear program goals, a well-defined strategy for achieving goals, and measures of performance that are linked to program goals. We also examined how OPS assessed civil penalties from 1994 through 2003 and the extent to which pipeline operators have paid them. Finally, we interviewed stakeholders on whether OPS's civil penalties help deter safety violations. As part of our work, we assessed internal controls and the reliability of the data elements needed for this engagement, and we determined that the data elements, with one exception, were sufficiently reliable for our purposes.⁴ We performed our work in accordance with generally accepted government auditing standards.

In summary:

- The effectiveness of OPS's enforcement strategy cannot be evaluated because the agency has not incorporated three key elements of effective program management—clear program goals, a well-defined strategy for achieving those goals, and measures of performance that are linked to the program goals. Without these three key elements, OPS cannot determine whether recent and planned changes in its enforcement strategy are having or will have the desired effects on pipeline safety. Under a more aggressive enforcement strategy (termed “tough but fair”) that OPS initiated in 2000, the agency is using the full range of its enforcement tools, rather than relying primarily as it did before on more lenient administrative actions, such as warning letters. However, OPS has not established goals that specify the intended results of this new strategy, developed a policy that describes the strategy and the strategy's contribution to pipeline safety, or put measures in place that would allow OPS to determine and demonstrate the effects of this strategy on pipeline safety. OPS is developing an enforcement policy that will help define its enforcement strategy and has taken some initial steps toward identifying new measures of enforcement performance. However, it does not anticipate finalizing this policy until sometime in 2005 and has not adopted key practices for achieving successful performance measurement systems, such as linking measures to program goals.
- OPS increased both the number and the size of the civil penalties it assessed in response to criticism that its enforcement activities were weak and ineffective. For example, from 2000 through 2003, following its decision to be tough but fair in assessing civil penalties, OPS assessed an average 22 penalties per year, compared with an average of 14 penalties per year from 1995 through 1999, when OPS's policy was to “partner” with industry, rather than primarily to enforce compliance. In addition, from 2000 through 2003, OPS assessed an average civil penalty of about \$29,000, compared with an average of \$18,000 from 1995 through 1999. Departmental data show that operators have paid 94 percent (202 of 216) of the civil penalties issued over the past 10 years. Civil penalties are one of several enforcement actions that OPS can take to increase compliance and represent about 14 percent of all enforcement actions taken over the past 10 years. Although OPS has increased both the number and the size of its civil penalties, it is not clear whether this action will help deter noncompliance with the agency's safety regulations. The pipeline safety stakeholders we spoke with expressed differing views on whether OPS's civil penalties deter noncompliance with the pipeline safety regulations. Some—such as pipeline industry officials—said that civil penalties of any size act as a deterrent, in part because they keep companies in the public eye. Others—such as pipeline safety advocacy groups—said that OPS's civil penalties are too small to deter noncompliance.

Background

OPS, within the Department of Transportation's Research and Special Programs Administration (RSPA), administers the national regulatory program to ensure the safe transportation of natural gas and hazardous liquids by pipeline.⁵ The office at-

⁴The data elements needed to determine when civil penalties were paid were, in our opinion, too unreliable to use to report on timeliness of payments. This limitation did not create a major impediment to our reporting on OPS's use of civil penalties overall.

⁵In general, OPS retains full responsibility for inspecting interstate pipelines and enforcing regulations applicable to them. OPS certifies states to perform these functions for intrastate pipelines. OPS has agreements with 11 state pipeline enforcement agencies, known as interstate agents, to help it inspect segments of interstate pipelines within these states' boundaries. However, OPS undertakes any enforcement actions identified through inspections conducted by interstate agents. ⁶Standards are technical specifications that pertain to products and processes, such as the size, strength, or technical performance of a product. National consensus standards

Continued

tempts to ensure the safe operation of pipelines through regulation, national consensus standards, research, education (*e.g.*, to prevent excavation-related damage), oversight of the industry through inspections, and enforcement when safety problems are found.⁶

In general, OPS retains full responsibility for inspecting interstate pipelines and enforcing regulations applicable to them. OPS certifies states to perform these functions for intrastate pipelines. OPS has agreements with 11 state pipeline enforcement agencies, known as interstate agents, to help it inspect segments of interstate pipelines within these states' boundaries. However, OPS undertakes any enforcement actions identified through inspections conducted by interstate agents.

The office uses a variety of enforcement tools, such as compliance orders and corrective action orders that require pipeline operators to correct safety violations, notices of amendment to remedy deficiencies in operators' procedures, administrative actions to address minor safety problems, and civil penalties. OPS is a small Federal agency. In Fiscal Year 2003, OPS employed about 150 people, about half of whom were pipeline inspectors.

Before imposing a civil penalty on a pipeline operator, OPS issues a notice of probable violation that documents the alleged violation and a notice of proposed penalty that identifies the proposed civil penalty amount. Failure by an operator to inspect the pipeline for leaks or unsafe conditions is an example of a violation that may lead to a civil penalty. OPS then allows the operator to present evidence either in writing or at an informal hearing. Attorneys from RSPA's Office of Chief Counsel preside over these hearings. Following the operator's presentation, the civil penalty may be reaffirmed, reduced, or withdrawn. If the hearing officer determines that a violation did occur, the Office of Chief Counsel issues a final order that requires the operator to correct the safety violation (if a correction is needed) and pay the penalty (called the "assessed penalty"). The operator has 20 days after the final order is issued to pay the penalty. The Federal Aviation Administration (FAA) collects civil penalties for OPS.⁷

From 1992 through 2002, Federal law allowed OPS to assess up to \$25,000 for each day a violation continued, not to exceed \$500,000 for any related series of violations. In December 2002, the Pipeline Safety Improvement Act increased these amounts to \$100,000 and \$1 million, respectively.

Key Management Elements Are Needed to Determine the Effectiveness of OPS's Enforcement Strategy

The effectiveness of OPS's enforcement strategy cannot be determined because OPS has not incorporated three key elements of effective program management—clear performance goals for the enforcement program, a fully defined strategy for achieving these goals, and performance measures linked to goals that would allow an assessment of the enforcement strategy's impact on pipeline safety.

OPS's Enforcement Strategy Has Been Evolving

OPS's enforcement strategy has undergone significant changes in the last 5 years. Before 2000, the agency emphasized partnering with the pipeline industry to improve pipeline safety rather than punishing noncompliance. In 2000, in response to concerns that its enforcement was weak and ineffective, the agency decided to institute a "tough but fair" enforcement approach and to make greater use of all its enforcement tools, including larger and more frequent civil penalties.⁸ In 2001, to further strengthen its enforcement, OPS began issuing more corrective action orders requiring operators to address safety problems that led or could lead to pipeline accidents. In 2002, OPS created a new Enforcement Office to focus more on enforcement and help ensure consistency in enforcement decisions. However, this new office is not yet fully staffed, and key positions remain vacant.

In 2002, OPS began to enforce its new integrity management and operator qualification standards in addition to its minimum safety standards. Initially, while oper-

are developed by standard-setting entities, such as the American Society for Testing and Materials, on the basis of an industry consensus.

⁶Standards are technical specifications that pertain to products and processes, such as the size, strength, or technical performance of a product. National consensus standards are developed by standard-setting entities, such as the American Society for Testing and Materials, on the basis of an industry consensus.

⁷To consolidate its accounting functions, in September 1993 RSPA began contracting with FAA to collect its accounts receivable, including civil penalties for OPS.

⁸For example, in May 2000, we reported that OPS had dramatically reduced its use of civil penalties and increased its use of administrative actions over the years without assessing the effects of these actions. See *Pipeline Safety: Office of Pipeline Safety Is Changing How It Oversees the Pipeline Industry*, GAO/RCED-00-128 (Washington, D.C.: May 15, 2000).

ators were gaining experience with the new, complex integrity management standards, OPS primarily used notices of amendment, which require improvements in procedures, rather than stronger enforcement actions. Now that operators have this experience, OPS has begun to make greater use of civil penalties in enforcing these standards.

OPS has also recently begun to reengineer its enforcement program. Efforts are under way to develop a new enforcement policy and guidelines, develop a streamlined process for handling enforcement cases, modernize and integrate the agency's inspection and enforcement databases, and hire additional enforcement staff. However, as I will now discuss, OPS has not put in place key elements of effective management that would allow it to determine the impact of its evolving enforcement program on pipeline safety.

OPS Needs Goals for its Enforcement Program

Although OPS has overall performance goals, it has not established specific goals for its enforcement program. According to OPS officials, the agency's enforcement program is designed to help achieve the agency's overall performance goals of (1) reducing the number of pipeline accidents by 5 percent annually and (2) reducing the amount of hazardous liquid spills by 6 percent annually.⁹ Other agency efforts—including the development of a risk-based approach to finding and addressing significant threats to pipeline safety and of education to prevent excavation-related damage to pipelines—are also designed to help achieve these goals.

OPS's overall performance goals are useful because they identify the *end outcomes*, or ultimate results, that OPS seeks to achieve through all its efforts. However, OPS has not established performance goals that identify the *intermediate outcomes*, or direct results, that OPS seeks to achieve through its enforcement program. Intermediate outcomes show progress toward achieving end outcomes. For example, enforcement actions can result in improvements in pipeline operators' safety performance—an intermediate outcome that can then result in the end outcome of fewer pipeline accidents and spills. OPS is considering establishing a goal to reduce the time it takes the agency to issue final enforcement actions. While such a goal could help OPS improve the management of the enforcement program, it does not reflect the various intermediate outcomes the agency hopes to achieve through enforcement. Without clear goals for the enforcement program that specify intended intermediate outcomes, agency staff and external stakeholders may not be aware of what direct results OPS is seeking to achieve or how enforcement efforts contribute to pipeline safety.

OPS Needs to Fully Define Its Enforcement Strategy

OPS has not fully defined its strategy for using enforcement to achieve its overall performance goals. According to OPS officials, the agency's increased use of civil penalties and corrective action orders reflects a major change in its enforcement strategy. However, although OPS began to implement these changes in 2000, it has not yet developed a policy that defines this new, more aggressive enforcement strategy or describes how it will contribute to the achievement of its performance goals. In addition, OPS does not have up-to-date, detailed internal guidelines on the use of its enforcement tools that reflect its current strategy. Furthermore, although OPS began enforcing its integrity management standards in 2002 and received greater enforcement authority under the 2002 pipeline safety act, it does not yet have guidelines in place for enforcing these standards or implementing the new authority provided by the act.¹⁰

According to agency officials, OPS management communicates enforcement priorities and ensures consistency in enforcement decisions through frequent internal meetings and detailed inspection protocols and guidance. Agency officials recognize the need to develop an enforcement policy and up-to-date detailed enforcement guidelines and have been working to do so. To date, the agency has completed an initial set of enforcement guidelines for its operator qualification standards and has developed other draft guidelines. However, because of the complexity of the task, agency officials do not expect that the new enforcement policy and remaining guidelines will be finalized until sometime in 2005.

⁹ OPS refers to the release of natural gas from a pipeline as an "incident" and a spill from a hazardous liquid pipeline as an "accident." For simplicity, this testimony refers to both as "accidents."

¹⁰ We have reported on challenges that OPS faces in enforcing its complex integrity management requirements consistently and effectively. See our August 2002 report, *Pipeline Safety and Security: Improved Workforce Planning and Communication Needed*, GAO-02-785 (Washington, D.C.: Aug. 26, 2002).

The development of an enforcement policy and guidelines should help define OPS's enforcement strategy; however, it is not clear whether this effort will link OPS's enforcement strategy with intermediate outcomes, since agency officials have not established performance goals specifically for their enforcement efforts. We have reported that such a link is important.¹¹

OPS Needs Adequate Measures of the Effectiveness of Its Enforcement Strategy

According to OPS officials, the agency currently uses three performance measures and is considering three additional measures to determine the effectiveness of its enforcement activities and other oversight efforts. (See table 1.) The three current measures provide useful information about the agency's overall efforts to improve pipeline safety, but do not clearly indicate the effectiveness of OPS's enforcement strategy because they do not measure the intermediate outcomes of enforcement actions that can contribute to pipeline safety, such as improved compliance. The three measures that OPS is considering could provide more information on the intermediate outcomes of the agency's enforcement strategy, such as the frequency of repeat violations and the number of repairs made in response to corrective action orders, as well as other aspects of program performance, such as the timeliness of enforcement actions.¹²

Table 1: Enforcement Program Performance Measures That OPS Currently Uses and Is Considering Developing

Measure	Examples
<i>Measures OPS currently uses</i>	
Achievement of agency performance goals	Annual numbers of natural gas and hazardous liquid pipeline accidents and tons of hazardous liquid materials spilled per million ton-miles shipped.
Inspection and enforcement activity	Number of inspections completed; hours per inspection; accident investigations; enforcement actions taken, by type; and average proposed civil penalty amounts.
Integrity management performance	Annual numbers of accidents in areas covered by integrity management standards and of actions by pipeline operators in response to these standards, such as repairs completed and miles of pipeline assessed. ^a
<i>Measures OPS is considering developing</i>	
Management of enforcement actions	The time taken to issue final enforcement actions, the extent to which penalty amounts are reduced, and the extent to which operators commit repeat violations.
Safety improvements ordered by OPS	Actions by pipeline operators in response to corrective action orders, including miles of pipeline assessed, defects discovered, repairs made, and selected costs incurred.
Results of integrity management and operator qualification inspections	The percentage of pipeline operators that did not meet certain requirements and the reduction in the number of operators with a particular deficiency.

Source: GAO analysis of OPS information.

^aOPS started collecting some of these data in 2002 but does not anticipate obtaining all of it on an annual basis until 2005.

We have found that agencies that are successful in measuring performance strive to establish measures that demonstrate results, address important aspects of program performance, and provide useful information for decision-making.¹³ While OPS's new measures may produce better information on the performance of its enforcement program than is currently available, OPS has not adopted key practices for achieving these characteristics of successful performance measurement systems:

- *Measures should demonstrate results (outcomes) that are directly linked to program goals.* Measures of program results can be used to hold agencies account-

¹¹ See U.S. General Accounting Office, *Managing for Results: Strengthening Regulatory Agencies' Performance Management Practices*, GAO/GGD-00-10 (Washington, D.C.: Oct. 28, 1999); *Agency Performance Plans: Examples of Practices That Can Improve Usefulness to Decision-makers*, GAO/GGD/AIMD-99-69 (Washington, D.C.: Feb. 26, 1999); and *The Results Act: An Evaluator's Guide to Assessing Agency Annual Performance Plans*, GAO/GGD-10.1.20 (Washington, D.C., Apr. 1998).

¹² In addition, measures of pipeline operator integrity management performance and of the results of integrity management and operator qualification inspections could provide information on the intermediate outcomes of these regulatory approaches.

¹³ See, for example, GAO/GGD/AIMD-99-69: *Executive Guide: Effectively Implementing the Government Performance and Results Act*, GAO/GGD-96-118 (Washington, D.C.: June 1996); and *Tax Administration: IRS Needs to Further Refine Its Tax Filing Season Performance Measures*, GAO-03-143 (Washington, D.C.: Nov. 22, 2002).

able for the performance of their programs and can facilitate congressional oversight. If OPS does not set clear goals that identify the desired results (intermediate outcomes) of enforcement, it may not choose the most appropriate performance measures. OPS officials acknowledge the importance of developing such goals and related measures but emphasize that the diversity of pipeline operations and the complexity of OPS's regulations make this a challenging task.¹⁴

- *Measures should address important aspects of program performance and take priorities into account.* An agency official told us that a key factor in choosing final measures would be the availability of supporting data. However, the most essential measures may require the development of new data. For example, OPS has developed databases that will track the status of safety issues identified in integrity management and operator qualification inspections, but it cannot centrally track the status of safety issues identified in enforcing its minimum safety standards. Agency officials told us that they are considering how to add this capability as part of an effort to modernize and integrate their inspection and enforcement databases.
- *Measures should provide useful information for decision-making, including adjusting policies and priorities.*¹⁵ OPS uses its current measures of enforcement performance in a number of ways, including monitoring pipeline operators' safety performance and planning inspections. While these uses are important, they are of limited help to OPS in making decisions about its enforcement strategy. OPS has acknowledged that it has not used performance measurement information in making decisions about its enforcement strategy. OPS has made progress in this area by identifying possible new measures of enforcement results (outcomes) and other aspects of program performance, such as indicators of the timeliness of enforcement actions, that may prove more useful for managing the enforcement program.

OPS Has Increased Its Use of Civil Penalties; the Effect on Deterrence is Unclear

In 2000, in response to criticism that its enforcement activities were weak and ineffective, OPS increased both the number and the size of the civil monetary penalties it assessed.¹⁶ Pipeline safety stakeholders expressed differing opinions about whether OPS's civil penalties are effective in deterring noncompliance with pipeline safety regulations.

OPS Now Assesses More and Larger Civil Penalties

OPS assessed more civil penalties during the past 4 years under its current "tough but fair" enforcement approach than it did in the previous 5 years, when it took a more lenient enforcement approach. (See fig. 2.) From 2000 through 2003, OPS assessed 88 civil penalties (22 per year on average) compared with 70 civil penalties from 1995 through 1999 (about 14 per year on average). For the first 5 months of 2004, OPS proposed 38 civil penalties. While the recent increase in the number and the size of civil penalties may reflect OPS's new "tough but fair" enforcement approach, other factors, such as more severe violations, may be contributing to the increase as well.

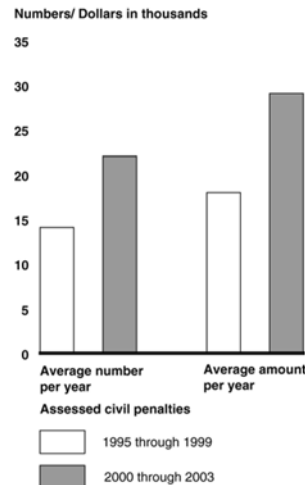
¹⁴ We have reported on the challenges faced by agencies in developing measures of program results and on their approaches for overcoming such challenges. See, in particular, GAO/GGD-00-10, *Managing for Results: Measuring Program Results That Are Under Limited Federal Control*, GAO/GGD-99-16 (Washington, D.C.: Dec. 11, 1998), and *Managing for Results: Regulatory Agencies Identified Significant Barriers to Focusing on Results*, GAO/GGD-97-83 (Washington, D.C.: June 24, 1997).

¹⁵ See, for example, GAO/GGD-96-118 and U.S. General Accounting Office, *Results-Oriented Government: GPRA Has Established a Solid Foundation for Achieving Greater Results*, GAO-04-38 (Washington, D.C.: Mar. 10, 2004).

¹⁶ The civil penalty results we present largely reflect OPS's enforcement of its minimum safety standards because integrity management enforcement did not begin until 2002.

Our results may differ from the results that OPS reports because our data are organized differently. OPS reports an action in the year in which it occurred. For example, OPS may propose a penalty in one year and assess it in another year. The data for this action would show up in different years. To better track the disposition of civil penalties, we associated assessed penalties and penalty amounts with the year in which they were proposed—even if the assessment occurred in a later year.

Figure 2: OPS's Use of Civil Penalties, 2000 through 2003, Compared with 1995 through 1999



Source: GAO analysis of OPS and FAA data.

Note: The amounts in this figure may not be comparable to the amounts that OPS reports. See footnote 16.

Overall, OPS does not use civil penalties extensively. Civil penalties represent about 14 percent (216 out of 1,530) of all enforcement actions taken over the past 10 years. OPS makes more extensive use of other types of enforcement actions that require pipeline operators to fix unsafe conditions and improve inadequate procedures, among other things. In contrast, civil penalties represent monetary sanctions for violating safety regulations but do not require safety improvements. OPS may increase its use of civil penalties as it begins to use them to a greater degree for violations of its integrity management standards.

The average size of the civil penalties has increased. For example, from 1995 through 1999, the average assessed civil penalty was about \$18,000.¹⁷ From 2000 through 2003, the average assessed civil penalty increased by 62 percent to about \$29,000.¹⁸ Assessed penalty amounts ranged from \$500 to \$400,000.

In some instances, OPS reduces proposed civil penalties when it issues its final order. We found that penalties were reduced 31 percent of the time during the 10-year period covered by our work (66 of 216 instances). These penalties were reduced by about 37 percent (from a total of \$2.8 million to \$1.7 million). The dollar difference between the proposed and the assessed penalties would be over three times as large had our analysis included the extraordinarily large penalty for the Bellingham, Washington, incident. For this case, OPS proposed a \$3.05 million penalty and had assessed \$250,000 as of May 2004.¹⁹ If we include this penalty, then over this period OPS reduced total proposed penalties by about two-thirds, from about \$5.8 million to about \$2 million.

OPS's database does not provide summary information on why penalties are reduced. According to an OPS official, the agency reduces penalties when an operator presents evidence that the OPS inspector's finding is weak or wrong or when the pipeline's ownership changes during the period between the proposed and assessed

¹⁷ All amounts are in current year dollars. Inflation was low during the 1995–2003 period. If the effects of inflation were considered, the average assessed penalty amount for 1995 through 1999 would be \$21,000 and the average amount for 2000 through 2003 would be \$30,000 (in 2003 dollars).

¹⁸ The median civil penalty size for the 1995–1999 period was about \$5,800 and the median size for the 2000–2003 period was \$12,700.

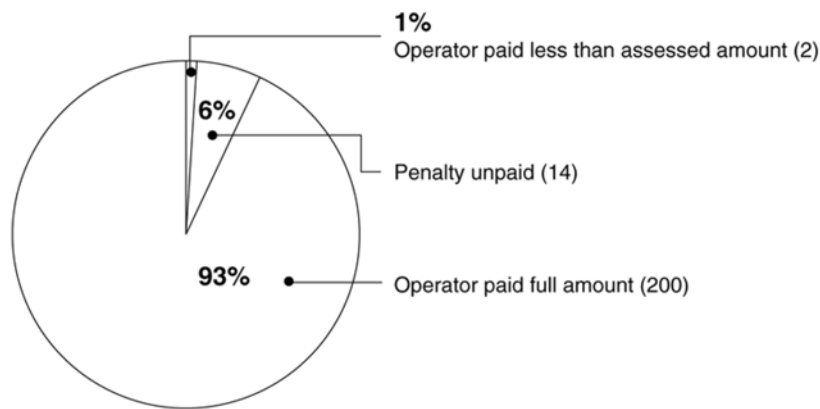
¹⁹ OPS proposed a \$3.05 million penalty against Equilon Pipeline Company, LLC (Olympic Pipeline Company) for the Bellingham incident and later assessed Shell Pipeline Company (formerly Equilon) \$250,000, which it collected. According to RSPA's Office of Chief Counsel, the penalty against Olympic Pipeline is still open, waiting for the company to come out of bankruptcy court.

penalty. It was not practical for us to gather information on a large number of penalties that were reduced, but we did review several to determine the reasons for the reductions. OPS reduced one of the civil penalties we reviewed because the operator provided evidence that OPS inspectors had miscounted the number of pipeline valves that OPS said the operator had not inspected. Since the violation was not as severe as OPS had stated, OPS reduced the proposed penalty from \$177,000 to \$67,000.

Operators Paid Full Amounts of Most Civil Penalties

Of the 216 penalties that OPS assessed from 1994 through 2003, pipeline operators paid the full amount 93 percent of the time (200 instances) and reduced amounts 1 percent of the time (2 instances). (See fig. 3.) Fourteen penalties (6 percent) remain unpaid, totaling about \$837,000 (or 18 percent of penalty amounts).

Figure 3: Number of Civil Penalties Paid, 1994 through 2003



Source: GAO analysis of OPS and FAA data.

In two instances, operators paid reduced amounts. We followed up on one of these assessed penalties. In this case, the operator requested that OPS reconsider the assessed civil penalty and OPS reduced it from \$5,000 to \$3,000 because the operator had a history of cooperation and OPS wanted to encourage future cooperation.

For the 14 unpaid penalties, neither FAA's nor OPS's data show why the penalties have not been collected. We expect to present a fuller discussion of the reasons for these unpaid penalties and OPS's and FAA's management controls over the collection of penalties when we report to this and other committees next month.

The Effect of OPS's Larger Civil Penalties on Deterring Noncompliance Is Unclear

Although OPS has increased both the number and the size of the civil penalties it has imposed, the effect of this change on deterring noncompliance with safety regulations, if any, is not clear. The stakeholders we spoke with expressed differing views on whether the civil penalties deter noncompliance. The pipeline industry officials we contacted believed that, to a certain extent, OPS's civil penalties encourage pipeline operators to comply with pipeline safety regulations because they view all of OPS's enforcement actions as deterrents to noncompliance. However, some industry officials said that OPS's enforcement actions are not their primary motivation for safety. Instead, they said that pipeline operators are motivated to operate safely because they need to avoid any type of accident, incident, or OPS enforcement action that impedes the flow of products through the pipeline and hinders their ability to provide good service to their customers. Pipeline industry officials also said that they want to operate safely and avoid pipeline accidents because accidents generate negative publicity and may result in costly private litigation against the operator.

Most of the interstate agents, representatives of their associations, and insurance company officials expressed views similar to those of the pipeline industry officials, saying that they believe civil penalties deter operators' noncompliance with regula-

tions to a certain extent. However, a few disagreed with this point of view. For example, the state agency representatives and a local government official said that OPS's civil penalties are too small to be deterrents. Pipeline safety advocacy groups that we talked to also said that the civil penalty amounts OPS imposes are too small to have any deterrent effect on pipeline operators. As discussed earlier, for 2000 through 2003, the average assessed penalty was about \$29,000.

According to economic literature on deterrence, pipeline operators may be deterred if they expect a sanction, such as a civil penalty, to exceed any benefits of noncompliance.²⁰ Such benefits could, in some cases, be lower operating costs. The literature also recognizes that the negative consequences of noncompliance—such as those stemming from lawsuits, bad publicity, and the value of the product lost from accidents—can deter noncompliance along with regulatory agency oversight. Thus, for example, the expected costs of a legal settlement could overshadow the lower operating costs expected from noncompliance, and noncompliance might be deterred.

Mr. Chairman, this concludes my prepared statement. We expect to report more fully on these and other issues when we complete our work next month. We also anticipate making recommendations to improve OPS's ability to demonstrate the effectiveness of its enforcement strategy and to improve OPS's and FAA's management controls over the collection of civil penalties. I would be pleased to respond to any questions that you or Members of the Committee might have.

The CHAIRMAN. Thank you very much.
Welcome, Commissioner Spitzer.

**STATEMENT OF HON. MARC SPITZER, CHAIRMAN,
ARIZONA CORPORATION COMMISSION**

Mr. SPITZER. Good morning, Mr. Chairman and Senator Lautenberg. My name is Marc Spitzer.

The CHAIRMAN. And Senator Cantwell.

Mr. SPITZER. Beg your pardon?

The CHAIRMAN. Go ahead.

Mr. SPITZER. Oh, I'm sorry. Senator, my apologies.

My name is Marc Spitzer, Chairman of the Arizona Corporation Commission, and I am honored to address the Committee this morning.

Today, I will update this Committee on the aftermath of the pipeline rupture in Arizona in July 2003 and the strides made by the United States Department of Transportation, Office of Pipeline Safety, OPS, and the Arizona Commission not only to strengthen the integrity of the pipelines in Arizona, but also the ongoing relationship between those two agencies. I will also propose solutions for your consideration, rather than cast blame, as many have already done, and with marginal benefit. These solutions address the need for some changes regarding the way agencies inspect and investigate the pipeline system. I will also discuss the relationship between our interstate pipeline system and an adequate supply of energy at reasonable prices.

On July 30, 2003, Kinder Morgan's eight-inch gasoline pipeline from Tucson to Phoenix burst, spewing gasoline on Tucson homes and disrupting the main supply line of gas to Phoenix. This resulting shortage, combined with the difficulty in obtaining other sources of the correct formula of fuel to be used in our region, created a situation that led to long gas lines, filling stations running out of gas, Arizonans unable to get to work, motorists stranded in 100-degree heat, and grave concern for the health, safety, and welfare of our community.

²⁰ Expected sanctions are the product of the sanction amount and the likelihood of being detected and sanctioned by that amount.

The pipeline rupture that occurred in Arizona in July 2003 is indicative of the aging infrastructure in the United States, and is the reason Federal and state governments need to conduct coordinated, aggressive inspections to reduce the risk of another pipeline rupture and the attendant environmental and economic damage.

In October 2003, Mr. Chairman, you held a hearing in Phoenix during which I made suggestions for improvement. Although more remains to be done, Mr. Chairman, your efforts, those of OPS, and my colleagues on the Arizona Commission have been successful.

Let me briefly highlight the cooperation the Arizona Commission has enjoyed with OPS since the Kinder Morgan rupture.

OPS timely released interstate pipeline safety records requested by the commission on behalf of other Arizona state and local officials. OPS personnel visited the commission and committed to develop rules governing the release of interstate pipeline records by state agents, consistent with the Patriot Act. OPS participated with our commission in numerous public forums, including a special task force to explain to the people of Arizona the Federal and state roles in pipeline safety regulation. We particularly appreciate OPS's support for a second metallurgical analysis of the Kinder Morgan pipe that failed last summer, enhanced inspection schedules for the 50-year-old segments of the pipeline, and efforts to expedite replacement of that line. This spirit of cooperation should continue.

While improving the communications between agencies is a step in the right direction, I believe more can be done. Current law allows a pipeline operator to contract with a lab for a postmortem on a piece of ruptured pipe. In Arizona, we have adopted rules requiring independent testing for intrastate pipeline access. Independent testing in serious cases should be Federal law, as well.

Arizona must be allowed to continue its participation with OPS in the oversight and inspection of pipelines, particularly in the integrity-management program. For obvious reasons, no homes should be built within 200 feet of a high-pressure eight- or twelve-inch gasoline pipeline. OPS should work with the states to develop clear guidance for counties and cities on the dangers and locations of pipelines to prevent residential zoning within 200 feet.

The gravest threat to pipeline safety is excavation. In an effort to prevent hazards arising from excavation, I would point out the participation of OPS and the Arizona Commission and the Common Ground Alliance. The CGA provides necessary information and education to the community about the dangers of unwary excavation.

At the Arizona Commission, we are making structural changes in our organization to increase the information flow from the Arizona Commission to OPS in order to better assist OPS and its sizable workload. Sharing is a two-way street. OPS should timely notify the states when requests for opinions concerning pipelines within their boundaries are received. States must be allowed to submit their comments on those requests before OPS renders its opinion.

Finally, OPS funding must be sufficient to achieve the safety Americans expect in the transportation of hazardous liquids.

Now, in the area of energy solutions, which I think are relevant to this issue of pipeline safety, better, more coordinated pipeline inspections are only part of the solutions. This Committee should also evaluate the positive impacts on pipeline safety associated with increasing the supply of energy available to the market. No gasoline refinery has been built in the Southwest United States since 1969. Limited refinery capacity imposes obvious stress on gasoline supply and relentless upward pressure on price. A new refinery in Arizona would reduce dependence on aging pipelines, the risks associated with high pressure on those lines, and allow more dependable petroleum distribution. The resulting reduction in required miles of pipeline transport will ease the burden on our commission's inspectors and OPS. The benefits of a refinery clearly serve the public health, safety, and welfare.

Government must address the connection between the myriad boutique fuels and stress on the pipeline system. As majority leader in the Arizona Senate, I negotiated Arizona's state implementation program with the EPA regional administrator. I understand the importance of clean air and the need for clean-burning gasoline to combat ozone, particulates, and carbon monoxide in the non-attainment areas in our state and throughout the country. However, the status quo hodgepodge of fuel blends with no Federal effort to standardize is highly inefficient for refineries, pipeline operators, and service stations, and needlessly expensive for motorists.

Natural gas supply is now critically low. Arizona has no production, zero storage, and constrained and costly pipeline transport. Federal and state agencies must unleash private operators willing to invest in natural gas production, new storage facilities, LNG terminals, and gas pipelines. A number of these projects are tied up in court. The Chair will be pleased to know that it is not just the telecom companies that endlessly litigate. But as with telecommunications, the public is ill-served by essential utilities mired in a perpetual legal morass.

Our Commission is committed to renewable energy to clean the environment and reduce dependence on volatile and expensive fossil fuels. Federal tax benefits for renewables recently passed by the Senate level the playing field, vis-à-vis heavily subsidized oil, gas, nuclear, and stability and tax treatment of clean energy technologies is an imperative.

In this extraordinary era of unstable crude oil supply, the Congress should reconsider CAFE standards. With premium gas at \$3 per gallon, Detroit may be happy to adapt.

The Arizona Commission has adopted demand-side management and energy-efficiency programs. We would welcome Federal teamwork with state agencies and the private sector to reduce demand.

Finally, Michael Gent and the North American Reliability Council have, for almost a year, been seeking legislation to make present electricity transmission rules legally enforceable. I am aware of a temptation to attach special-interest measures to a must-go bill, but it is a time for gamesmanship to end. It should not take another blackout to coerce the Congress to enact mandatory reliability standards proposed by the NERC.

I thank the Chairman and the Committee for your effort and the opportunity today. I ask you to continue your consideration of the

critical importance of our Nation's pipelines and its energy supply. And, Mr. Chairman, I might have been a little blunt in my remarks, but I had a very good mentor over the years, and I thank you.

[Laughter.]

[The prepared statement of Mr. Spitzer follows:]

PREPARED STATEMENT OF HON. MARC SPITZER, CHAIRMAN,
ARIZONA CORPORATION COMMISSION

I. Introduction

My name is Marc Spitzer, Chairman of the Arizona Corporation Commission (the "Arizona Corporation Commission" or "ACC"), and I am honored to address the Committee this morning.

Today, I will update this Committee on the pipeline rupture in Arizona in July 2003, and the strides made by United States Department of Transportation Office of Pipeline Safety ("OPS") and the ACC to not only strengthen the integrity of the pipelines in Arizona, but also the ongoing relationship between those two agencies. I will also propose for your consideration solutions addressing the need for some changes regarding the way agencies inspect and investigate the pipeline system. Finally, I suggest proposals to assure an adequate supply of energy.

II. Kinder Morgan Rupture, An Infrastructure Example

On July 30, 2003, Kinder Morgan's 8-inch gasoline pipeline from Tucson to Phoenix burst, spewing gasoline on Tucson homes and disrupting the main supply line of gas to Phoenix. The resulting shortage combined with the difficulty in obtaining other sources of the correct "formula" of fuel to be used in the region led to long gas lines, filling stations running out of gas, motorists stranded in 100-degree heat and grave concern for the health, safety and welfare of our community. The pipeline rupture that occurred in Arizona in July 2003 is indicative of the aging U.S. infrastructure and is the reason Federal and state governments need to conduct coordinated, aggressive inspections to reduce the risk of another pipeline rupture and the attendant environmental and economic damage.

In October 2003, the Chairman of this Committee held a hearing in Phoenix in which I made suggestions for improvement to the OPS. Mr. Chairman, although more remains to be done, your efforts and those of OPS and my colleagues on the Arizona Commission have been successful.

Let me briefly highlight the cooperation the Arizona Commission has enjoyed with OPS since the rupture. OPS timely released interstate pipeline safety records requested by the Commission on behalf of other Arizona state and local officials. OPS personnel visited the Commission and committed to develop rules governing the release of interstate pipeline records by state agents, consistent with the Patriot Act. OPS participated with our Commission in numerous public forums, including a special Task Force, to explain to the people of Arizona the Federal and state roles in pipeline safety regulation.

We particularly appreciate OPS' support for a second metallurgical analysis of the Kinder Morgan pipe that failed last summer, enhanced inspection schedules for the fifty year-old segments of the pipeline and efforts to expedite replacement of that line. This spirit of cooperation should continue.

III. Pipeline Inspection Solutions

In light of today's gasoline prices, Arizona cannot afford another situation like the one in July 2003, economically, environmentally or to protect public health. While improving the communications between agencies is a step in the right direction, I believe more can be done. I think the following areas need to be addressed:

- a. Arizona must be allowed to continue its participation with OPS in the oversight and inspection of pipelines, particularly in the Integrity Management Program ("IMP"). I should point out that in Arizona, OPS has graciously consented to state participation, which I understand is in accordance with the national model. This participation is important as each State has a cadre of trained experts at the ready, prepared to assist and support OPS in its task of ensuring interstate pipeline safety.
- b. Independent Exams should be required by law. The current system allows an entity that owns a pipeline to contract with a lab to do a "post mortem" on a piece of pipe that ruptured as the sole analysis as to why the problem occurred in the first place. This system of trust should be augmented with a sys-

tem to independently verify those results. In Arizona, we have adopted rules requiring independent testing for intrastate pipeline accidents. Independent testing in serious cases should be Federal law as well.

- c. Sharing is a two way street. At the ACC, we are currently making structural changes to our organization to increase the information flow *from* the ACC to OPS in order to better assist OPS and its sizable workload.
- d. Residential or commercial construction should not take place within 200 feet of a high pressure 8 or 12-inch gasoline pipeline. In Tucson, residential buildings were 37 feet from the pipeline. Within minutes over 6,000 gallons of gasoline had soaked several homes. We can only thank God they were unoccupied—but we must recognize the danger. Real estate development involves the use of heavy machinery and excavation—to continue to allow that to occur within 37 feet of a fifty-year old gasoline pipeline is insane. The Federal and state governments are obligated to impose restrictions where counties and cities fail to act. The OPS should work with states to develop clear guidance for counties and cities on the dangers and locations of pipelines to prevent residential zoning within 200 feet.
- e. The gravest threat to pipeline safety is excavation. In an effort to prevent hazards due to excavations, I would point out the participation of OPS and the ACC in the Common Ground Alliance (“CGA”). The CGA is a group of government and industry stake holders that try to work toward a “common ground” in the excavation community. It focuses on the areas of best practices, education and research and development, to name a few. The CGA provides necessary information and education to the community about the dangers of unwary excavation.
- f. OPS funding must be sufficient to achieve the safety Americans expect in the transportation of hazardous liquids.

IV. Energy Solutions

Better, more coordinated pipeline inspections are only a part of the solution. This Committee should also evaluate the positive impacts on pipeline safety associated with increasing the supply of energy available to the market.

No gasoline refinery has been built in the southwest United States since 1969. Limited refinery capacity imposes obvious stress on gasoline supply and relentless upward pressure on price. A new refinery in Arizona would reduce dependence on aging pipelines, the risks associated with high pressure in those lines, afford more dependable distribution and the ultimate reduction in required miles of pipeline will ease the burden on our Commission’s inspectors and OPS. The benefits of a refinery clearly serve the public health, safety and welfare.

Government must address the connection between myriad boutique fuels and stress on the pipeline system. There are at least thirteen and as many as thirty formulations of gasoline. Fewer fuel formulations would simplify gasoline distribution, and make refineries more efficient, thereby reducing the price volatility associated with a local supply disruption. As Majority Leader in the Arizona Senate I negotiated Arizona’s State Implementation Program with the EPA Regional Administrator. I understand the importance of clean air and the need for clean burning gasoline to combat ozone, particulates and carbon monoxide in non attainment areas in our State. However, the *status quo* hodgepodge of fuel blends, with no Federal effort to standardize, is highly inefficient for refineries, pipeline operators and service stations and needlessly expensive for motorists.

As I note below, natural gas supply is now critically low. Arizona has no production, zero storage and constrained and costly pipeline transport. The lack of storage capacity is a key determinate of natural gas price volatility. Storage capacity provides the system with a buffer to supply and demand shocks, allowing it to smooth the natural, cyclical swings in prices. Natural gas volatility and the means to flatten the cost curve are especially important when we are faced with declining domestic gas reserves. Ninety percent of new power plants under construction in the U.S. are gas fired and eighteen new natural gas fired plants are proposed in Arizona alone.

Federal and state agencies must unleash private operators willing to invest in natural gas production, new storage facilities, Liquefied Natural Gas (“LNG”) terminals and gas pipelines. A number of these projects are tied up in court. The Chair will be pleased to know it is not just the telecom companies that endlessly litigate, but as with telecommunications the public is ill-served by essential utilities mired in a perpetual legal morass. Congressional action may be necessary to sever this Gordian knot of parochial interests and Nimbyism.

Our Commission is committed to renewable energy to clean the environment and reduce dependence on volatile and expensive fossil fuels. Federal tax benefits for re-

newables, passed recently by the Senate, level the playing field *viz a vis* heavily subsidized oil, gas and nuclear, and stability in tax treatment of clean energy technologies is an imperative.

In this extraordinary era of unstable crude oil supply and increasing global demand, the Congress should reconsider the CAFE standards. With premium gas at \$3 per gallon, Detroit may be happy to adapt.

The Arizona Commission has adopted demand-side management and energy efficiency programs. The goal is to avoid construction of costly and polluting power plants. We would welcome Federal teamwork with state agencies and the private sector to reduce demand.

Finally, Michael Gent and the North American Reliability Council have for almost a year been seeking legislation to make the present electricity transmission rules legally enforceable. I am acutely aware of the temptation to attach special interest measures to a "must go" bill. But it is time for the gamesmanship to end. It should not take another blackout to coerce the Congress to enact the mandatory reliability standards proposed by NERC.

V. Difficulties in Assuring Adequate Supplies of Energy at Reasonable Prices

Since my tenure on the Arizona Commission our ratepayers have endured the consequences of disruptions to energy supply, price spikes and the attendant economic and personal damage and dislocation. This is of course true throughout the country. In the 21st Century economy, dependent upon increasing amounts of energy to sustain high American productivity, the Government has fallen short.

In January 2001, the California electricity market was unraveling, causing turmoil throughout the Western interconnection. There were many causes and culprits: lack of generation capacity, inadequate transmission, flawed regulation, absence of long-term contracts, misconduct of market participants culminating in old-fashioned panic. Enron's collapse and California aftershocks helped crater the merchant power sector. Huge market capitalization was wiped out. Wall Street spurns the energy sector depriving an industry of necessary capital investment for infrastructure. Moreover, human capital is growing scarce as college classes in electrical engineering are only one-third filled.

In natural gas, all evidence indicates the rosy scenario for North American gas production is a myth. The 2003 National Petroleum Council report indicates a structural deficit in natural gas production, something State utility regulators and customers already knew from the quintupling of commodity prices in 2001. Across the country, in the winter of 2003–2004 thousands of ratepayers could not afford to pay their gas heating bills and in then the shutoff notices came like the spring rains. Our Commission held a packed-house hearing at the Opera House in Prescott, Arizona to deal with customer complaints over high natural gas bills, and the villain was not even in the house. The gas LDC earned *nothing* on the high commodity costs passed through to our customers. Incantation of the term "market forces" was not accepted by those who knew the market was dysfunctional.

In the meantime, hundreds of thousands of American jobs in the fertilizer, ammonia and other industries have been lost to high natural gas prices. Brand new, clean-burning gas-fired electricity plants stand idle while filthy, polluting coal plants run flat out—all due to commodity fuel prices. And press reports suggest opposition to LNG terminals has cancelled all five pending LNG applications. While Americans bear a great burden from inadequate supplies of natural gas, gas pipeline and storage contracts remain inadequate to deal with bottlenecks and shortages.

The bottom line is America's energy consumption has grown and will continue to grow, however, supplies are dwindling or remain untapped, our infrastructure is collapsing and the economic growth *in* other countries has resulted *in* increased competition for energy supplies *in* the global market. These pressing issues need immediate attention.

I thank the Chairman and the Committee for the opportunity today, and I ask you to continue your consideration of the critical importance of our Nation's pipelines and its energy supply.

The CHAIRMAN. Thank you very much. Thank you very much, Commissioner Spitzer, and we're glad you're here.

Mr. Mead and Ms. Siggerud, from the tenor of your statements, you would give OPS and Department of Transportation fairly high marks for actions they've taken since the bill was passed in 2002.

Is that a correct assessment of your remarks, with some certain caveats?

Mr. MEAD. Yes.

Ms. SIGGERUD. Yes, I would say so. We are particularly pleased with the progress on the Integrity Management Program. GAO has always been a supporter of a risk-based approach to regulation.

The CHAIRMAN. Well, then I'd like to thank Mr. Bonasso and Mr. Connaughton and Ms. Gerard for the good work. A lot of times we don't have that kind of report from the GAO and the Inspector General, and we thank you for your good work. I hope you'll take seriously the additional recommendations that have been made.

Now, one of the problems that we've identified time after time in light of the Bellingham, Washington, situation, the California situation, Arizona pipeline ruptures, this whole issue of Federal/state coordination. So, Commissioner Spitzer, you would say, generally speaking, that coordination between the Arizona Corporation Commission and the Office of Pipeline Safety has been good? Or what kind of comments would you make about that?

Mr. SPITZER. Mr. Chairman, thank you. We've had some rocky times in the past, particularly prior to my tenure on the Commission. But I must say that since the Kinder Morgan episode in July 2003, and in the wake of the Committee hearing in Phoenix in October, OPS has worked very capably with us, and the information is coming downstream, and the IMP coordination has markedly improved, so we're extremely pleased with the relationship, and we'd hope it would not only continue in Arizona, but be applied nationally.

The CHAIRMAN. Mr. Mead, Ms. Siggerud, Mr. Connaughton and Mr. Bonasso, the one element of testimony here that's extremely disturbing, or should be a red flag, is the number of pipelines—and inspections have revealed a number of serious failings, or possible failings, of pipelines in the relatively small number that have been inspected. I guess we'll begin with you, Mr. Bonasso. Are you—does that concern you?

Mr. BONASSO. Well, yes, it does, but I'd like to put it just in a little bit more perspective. There were roughly 41,000 miles of high-consequence areas, and the integrity threats that were defined came in 25,000 of those miles. So we've done roughly half of the high-consequence areas. And what I think this shows is that the technology is showing that there are significant repairs needed in this.

The CHAIRMAN. More than had been originally estimated.

Mr. BONASSO. Perhaps. And that's the idea of integrity management—replace for cause, rather than failure. I—

The CHAIRMAN. Mr. Connaughton? Go ahead.

Ms. BONASSO.—I would ask to ask Ms. Gerard if she—

The CHAIRMAN. Ms. Gerard, would you like to add to that?

Ms. GERARD. I think that's a fair assessment. But the raising the standards is working for the intended effect, so I think that's a good thing. And I would say—

The CHAIRMAN. The good news is, it's working; the bad news is, we're finding out we've got more problems than we thought we had.

Ms. GERARD. But, fortunately, the technology is advancing to help us diagnose better.

Mr. MEAD. And I just—may I interject something here?

The CHAIRMAN. Sure.

Mr. MEAD. We've referred to this high—the 25,000 miles that have been inspected within these high-consequence areas, of which there are about 50,000 miles, I think, in the country for hazardous liquid. Well, that represents about 16 percent of the total. And you recall that Carlsbad, New Mexico, pipeline rupture some years ago. That was in a fairly rural area. It took out a couple of bridges and, I think, an entire family. And you can have some very serious consequences even though you may not be in a highly populated—in a densely populated area.

The CHAIRMAN. Mr. Connaughton?

Mr. CONNAUGHTON. Yes, the other point I would just add into this, it is important—and we've got this new information—it's important—the priority process that the legislation calls for, and that we put in place, is critical because there's a lot of work to be done. I would note, however, I think we have about 20,000 repairs that have been made, 4,400 of which have been time sensitive. And most of those have gone forward without significant delay. There has been a subset of those that are subject to some of these much more intensive permitting exercises, and that actually, from a resource perspective, gives me some cause for—

The CHAIRMAN. Yes, I was going to get to—

Mr. CONNAUGHTON.—optimism, which is, we can focus on a much smaller piece that requires the more intensive and integrated review. My bigger concern had been that this was going to be something even bigger than we thought we'd be able to tackle. And so I feel fairly good. But I do want to underscore, in that smaller set, we are just at the beginning of the integrated process, so we have a good process in place. And I appreciate Mr. Mead's remarks. But I do underscore, we have to implement it now in an effective way.

The CHAIRMAN. Ms. Siggerud?

Ms. SIGGERUD. Senator McCain, the issue that you raise was not a central focus of our review. However, I would note that the fact that we even have the information that you were able to provide is a great step forward, in my view, in terms of being able to, again, get at that issue about the effectiveness of the inspection and enforcement programs.

As you know, the Pipeline Safety Integrity Act of 2002 requires us to report quite extensively on the Integrity Management Program in 2006, and I hope to look at the issue you raised, along with other implementation issues, when we do so.

The CHAIRMAN. Mr. Spitzer, you talk about the fact that we don't have a refinery in Arizona. I think all of us are aware of that. Do you know of any community in Arizona that would welcome a refinery?

Mr. SPITZER. Well, actually, the Yuma County Board of Supervisors, I believe, has expressed some interest out—

The CHAIRMAN. My point is, at least from my experience, the reason why we don't have a refinery is because nobody wants one, and the process of starting one and getting in operation is viewed by many as an insurmountable task. We'll have witnesses here who will say exactly that. It's very alarming when—especially in a state like ours, where you have this tremendously high growth, and yet

apparently houses are being built right next to pipelines, which, as you say, no homes should be built within 200 feet, yet it continues as we speak. That's a bit disturbing.

Mr. SPITZER. Well, Senator, you allude to a very important global issue, and that's infrastructure, and it's complex. We are encouraging companies to build infrastructures in Arizona, and we've cited a number of power plants, high-voltage transmission lines. There is always the neighborhood outcry. But over time, we've managed to build the power plants that we need, and the transmission lines, through the corporation commission's process. Refineries are outside of our authority, as are the natural gas pipelines and gasoline pipelines.

I think, with the California fiasco in 2000–2001 that affected the entire western interconnection, and then the East Coast blackout of last year, I sense, Senator, a growing understanding that the electricity doesn't just come out of a socket, and the same with gasoline, and the same with natural gas, and we're able to overcome the NIMBYism. But we have a almost historic implosion within the energy industry, which means even if companies are willing to consider entering the hazards of the siting process at the FERC, Wall Street is not willing to finance a number of projects that need to be built. So it's a—it almost becomes a vicious circle.

The CHAIRMAN. And I don't take the side of Wall Street or Kinder Morgan, who I castigated severely after—in the past, who I think, according to most people, have improved their way of doing business rather dramatically. But Wall Street probably does not want to invest in something where compliance with the Endangered Species Act takes 2 or 3 years in order to move a pipeline, much less locate and build a major facility. So it's hard for me to blame an investor if the first time that a return on the investment is an unknown situation. I think it's very disturbing. I'd be glad to—I've run out of my time—Mr. Connaughton's assessment of the reason why the Kinder Morgan pipeline was not moved in California was because of bureaucratic delays which—everybody knew there was a problem there, but they couldn't relocate their pipeline because of compliance with a thicket of rules and regulations. And yet I doubt if I or anyone else would agree to significant modification of the Endangered Species Act.

Mr. Connaughton? This is a conundrum that is, I think, going to be with us for a long time.

Mr. CONNAUGHTON. Let me address two aspects of that. First, it is a given that a new refinery, on balance, will be safer and environmentally better than our old ones. And bringing on new capacity with new technology under the stringent laws we have that reduce air pollution, you know, how they manage waste, we're just in a new place today. So any new, major piece of capital infrastructure built in America is a net environmental benefit for America. Right now, it happens that we have increasing refining offshore that does not operate under those kinds of standards, and that doesn't help either because then we rely on our old infrastructure to get it to our consumers. So that's—from just a strict environmental perspective, we're not actually achieving our objectives.

And then I do share your concern, because I talk to the folks on Wall Street, and I talk to the people who would otherwise invest

in what are billion-dollar projects, when it takes 3 to 7 years to get a project built and you're looking at a return-on-investment, you want your return-on-investment coming fast, not long. And so it is a challenge that's with us.

I think some of these innovations on integrated permitting are going to help. I think the effort here, because we'll have a much better shared database on environmental conditions surrounding our mapped pipeline areas, is going to help, because if we have all that information up front, we can begin to collectively design projects better and get a higher level of assurance that they're not creating significant environmental impact. However, as long as we have eight to forty different review processes, those are eight to forty opportunities for the NIMBY effect to take place, and that is a architectural issue that we have to collectively resolve, I think, if we want brand-new, gleaming, safe, environmentally sound capital infrastructure in America.

The CHAIRMAN. I thank you for your good work, Commissioner Spitzer, and I hope that every zoning authority in America—I mean, in Arizona—is well aware of the zoning restrictions which should apply concerning construction of homes near an existing pipeline.

Senator Lautenberg?

Senator LAUTENBERG. Thanks, Mr. Chairman.

Based on the time remaining, I have time for only one question. I'll ask that the record be kept open. I submit others to writing.

I first commend the witnesses for their forthright statements. I think they were very good. What I hear is a fairly high grade, in response to the Chairman's question, for the effort—Mr. Mead and Ms. Siggerud. But I then am forced to ask this question. If it's working fairly well—and we all know that there's a lot of work to be done—more inspectors, more mapping, et cetera, et cetera, better technology—why move this, OPS, to the Federal Railroad Administration if it's fairly well covered under Transportation?

Hello?

[Laughter.]

Ms. SIGGERUD. Well, I'll take a crack at that, and then Mr. Mead.

From what I understand of the proposal, the goal of the proposal is to try to get RSPA to focus more specifically on its research mission. We have other work on RSPA that would certainly view that as a positive step. We believe that RSPA could, in fact, focus more specifically there, but there are issues with regard to moving OPS to FRA. I have not seen a lot of details of the proposal, but I would think that there are a couple of questions that one could ask about it. One is, in moving OPS elsewhere in DOT, are there similarities between the kinds of regulation, oversight, and inspections that OPS does in comparison with FRA or any—

Senator LAUTENBERG. And the activities.

Ms. SIGGERUD.—and the activities of the industry itself.

Senator LAUTENBERG. Sure.

Ms. SIGGERUD. So these, I think, are issues that DOT needs to be concerned about. Also, OPS is a relatively small organization in DOT. FRA, I believe, has in excess of about 800 employees. OPS is at about 150. So we need to think about the role of OPS in a

larger organization like that and whether it will get swallowed up or whether it could continue to pursue its mission effectively.

Senator LAUTENBERG. Ken Mead?

Mr. MEAD. Yes, sir. I think it's probably a good idea to combine the different research arms of DOT, including the Bureau of Transportation Statistics. They need to have a focus that's a critical mass.

I would be very careful, though, in what—in moving this organization, as well as to have this material function, which is another separate function inside of RSPA, that you make sure that they don't get too close to industry.

You'll recall, several years ago—and, Senator McCain, I think you'll recall this, too—with the Federal Motor Carrier Safety Administration, they were in the Federal Highway Administration, and we had a number of problems with their closeness. We have made a lot of progress in the last several years. I don't think you want to lose that. So if you move them, make sure that they're not going to go to a place where they'll end up being too close to industry.

Senator LAUTENBERG. Thank you.

The CHAIRMAN. Senator Cantwell?

**STATEMENT OF HON. MARIA CANTWELL,
U.S. SENATOR FROM WASHINGTON**

Senator CANTWELL. Thank you, Mr. Chairman. And if I could submit a longer statement for the record?

The CHAIRMAN. Without objection.

Senator CANTWELL. Thank you, Mr. Chairman. And thank you for your attention to this issue, starting with the hearing and focus on the Olympic pipeline explosion in 1999 and the passage of the Pipeline Safety Act in 2002 that you and Senator Murray and many others worked on. Very much appreciate your continued attention to this issue.

I have a question. We recently, in Seattle, just last week, we had a pipeline leak thousands of gallons in Renton, Washington, and caused a shutdown of jet-fuel crisis at Sea-Tac Airport. I'm wondering, is that in the half-percent or half of the congested area that you've already looked at? Would Puget Sound and the Puget Sound region qualify as that?

Ms. GERARD. Your question is whether or not that pipeline has been tested by the operator?

Senator CANTWELL. You, in your testimony, were saying, Here's where we are in testing, in general. And you were saying that you have half of what you would call high-consequence areas. I'm assuming those are population areas.

Ms. GERARD. Those are tests by the operators.

Senator CANTWELL. What's a high-consequence area?

Ms. GERARD. For a liquid pipeline, it's an area that we've defined as unusually environmentally sensitive, or it's a populated area defined by the census as a highly populated area or—not just a highly populated area, but a town or a township, and commercially navigable waterways. And in the definition of unusually environmentally sensitive, that includes drinking-water sources, for example.

Senator CANTWELL. So do you think the near suburbs of Seattle would qualify as such?

Ms. GERARD. Oh, it would definitely qualify. I thought your question was, Had the pipeline operator already completed their integrity baseline assessment?

Senator CANTWELL. That's my—yes, that's my question.

Ms. GERARD. I don't know. I'd have to get you that for the record.

Senator CANTWELL. OK. And when are you planning on completing the second half of those areas?

Ms. GERARD. The operator would be required—if they haven't already done it, and they may have, they would be required to complete that by 2009.

Senator CANTWELL. And what conclusions would we draw if they already have completed it?

Ms. GERARD. We can give you a report on what our inspection of their integrity plan is, for the record. We have completed our inspections as the Federal Government of all of the operators' integrity plans. We have inspected, as the Federal Government, to see whether or not they're complying with the requirements. I don't know whether the operator has completed their baseline testing. They have 7 years to do it, and for that particular operator, I don't know. I think that this particular failure was not a transmission line. It was a sampling line. And so I believe that they would include that as part of their integrity program to look at, if it failed, why did it fail, and then to make a correction in their integrity program.

Senator CANTWELL. What number of incidents have happened in this area of high consequence that you have tested already? Of the areas that you've tested so far, of the high-consequence areas, have you had any incidents of leakage or explosion since the testing has been completed?

Ms. GERARD. We'll have to get you that statistic for the record.

Senator CANTWELL. Don't you think that would be an interesting assessment of how well the testing—

Ms. GERARD. Right. We have—

Senator CANTWELL.—is going?

Ms. GERARD.—we have modified our inspection reports in the past few years to specifically zero in on that number so we can compare the results in high-consequence areas compared to the rest of the pipelines. So we'll have to—

Senator CANTWELL. Well, but in the areas that you've already tested, how many now have you found that you go back and you find that the testing didn't necessarily detect a potential problem. I think that's important data to track. One of the reasons I'm bringing this up is not just the situation that just happened recently in Puget Sound or the great number of issues that we have in the region, is that one of the debates in the 2002 bill was, How often should you do testing? The legislature—the Congress ended up settling on 10 years. I was more of an advocate of 5 years. Now, I'm assuming that, in some of these areas, you're using these hydro-statistic “smart pig” technology or something that is something that can be monitored on a more frequent basis. Is that correct?

Ms. GERARD. Yes, that's correct.

Senator CANTWELL. What percentage are you using technology versus—

Ms. GERARD. The vast majority of the pipelines for hazardous liquid are using internal inspection devices.

Senator CANTWELL. And so what kind of notification would you suggest Congress get if, on those incidents of areas that have already been tested, and then you still have leakage—what would be the notification process?

Ms. GERARD. We have a regulation in place that will require the operator to report on that question annually, the extent to which there have been failures in high-consequence areas.

Senator CANTWELL. And you would—

Ms. GERARD. That is a—

Senator CANTWELL.—that report would be—

Ms. GERARD.—new requirement. That is a new—

Senator CANTWELL.—and that report—

Ms. GERARD.—requirement.

Senator CANTWELL.—would be available to Congress once a year?

Ms. GERARD. Yes, for liquid pipelines. For gas pipelines, twice a year. Natural gas transmission, twice a year.

Senator CANTWELL. But you would get us this information now on this first half that you've already tested? I'm just curious about this incident in the Puget Sound area, or anything related to that, where we've already—this is our first assessment of testing. Right? The Act has been in place. Now we've gone out, we're patting ourselves on the back, we've got half the high-consequence areas done. The first and most important question I think we would ask is, since we've tested, have we had any incidences in those areas? The fact that we can't answer that question this morning may be good news because there have been no incidents, or it may be that—

Ms. GERARD. There may—

Senator CANTWELL.—or it may be that—

Ms. GERARD.—there may have been no incidents.

Senator CANTWELL.—we aren't doubling back on how good our testing is—you know, on how good our testing model is. So I'd appreciate that information.

And, Mr. Bonasso, if you could—part of the Olympic pipeline explosion outcome was a pipeline safety trust that the families coordinated to get a clearinghouse of information for pipeline safety nationwide. Do you work with that organization?

Mr. BONASSO. Yes. The Office of Pipeline Safety does work with that organization, and I'm not personally familiar with the specifics, and I'd like to ask Ms. Gerard to comment on it.

Ms. GERARD. We're working with the trust in at least two ways relatively formally. A representative of the trust is part of the peer-review process we use to do our research and development planning, and the trust participates in our program with the National Association of State Fire Marshals to advise us on community education efforts, to help us have public involvement in identifying the high-consequence areas, and to help us with developing an education program to acquaint communities with the science of protection of LNG facilities. So the trust is working with us on at least two projects, and then we invite them to participate when we have a public meeting on a topic that they would be interested in.

Senator CANTWELL. Thank you. I know my colleague is here, my time has run out—

The CHAIRMAN. Go ahead.

Senator CANTWELL. Well, thank you. I just wanted to thank Mr. Spitzer for mentioning the reliability standard legislation, very important legislation that I hope we get passed this year. If we don't get anything else done on energy, that would be very satisfactory.

I had a question as it relates—because we got into this discussion with the Chairman on investments in infrastructure, in energy infrastructure, and one of the issues is whether we have the proper focus on rate of return or on market-based rates. And I don't know if you, Mr. Spitzer, had any comments as to FERC's oversight on market-based rates and whether there is enough certainty in that market, given everything we've just seen in the West as it relates to electricity, or whether we need to make some adjustments.

Mr. SPITZER. The pendulum swings back and forth, Senator, and I've had these discussions with Ms. Showalter, the Chairman of your Commission in Washington State. In 1998, Wall Street loved Enron, at 90. They said buy. And the merchant model was the model. The pendulum swung all the way over. We've had two powerplants, in Arizona, who were in the merchant sector, go back to the bank. And so the merchant sector is now despised, and the vertically integrated monopoly is the prevailing model.

My personal opinion, since you asked it, is, the truth, I think, lies somewhere in between, and I believe that there's a role for both, depending upon the state. And being a state commissioner, we're certainly jealous of the state's rights and state's prerogatives, given that when retail prices go out of whack, when service stops, we're the ones who get the phone calls. Ms. Showalter gets the phone calls.

But I do think a balance is appropriate, and I'm hopeful that the pendulum will swing a little bit back to the merchant model, because it does yield price benefits for ratepayers as well as—it's difficult for me to justify, Mr. Chairman, Senator, the running a plant like the one in Laughlin, one of the dirtiest plants in the United States, coal, in a non-attainment area where the wind from the west blows over the Grand Canyon, when you have brand-new, clean-burning gas plants not being used only because they're in the merchant sector as opposed to part of the vertically integrated monopolies. So I'd like to see a balance between the two models.

Senator CANTWELL. And how important is transparency in these models, as it relates to the sector and their—

Mr. SPITZER. Obviously, we'd like to see the FERC at the wholesale—which we, at the state commissions, do not regulate—pursue liquid transparent pricing at the wholesale level.

Senator CANTWELL. Thank you.

Thank you, Mr. Chairman.

[The prepared statement of Senator Cantwell follows:]

PREPARED STATEMENT OF HON. MARIA CANTWELL, U.S. SENATOR FROM WASHINGTON

Thank you Mr. Chairman, I want to thank you for holding this hearing and for your personal leadership on the importance of pipeline safety.

Nearly half a million miles of oil and gas transmission pipelines crisscross the United States.

In my state alone, the Olympic pipeline system moves 12 million gallons of gasoline, diesel fuel and jet fuel through western Washington every day—from refineries at Cherry Point, north of Bellingham, and March Point, near Anacortes, to as far south as Portland, Ore.

Also, Washington depends on the Williams Northwest Pipeline, which supplies 80 percent of Washington's gas, primarily from Canada and the Rocky Mountains.

These pipelines and others like them comprise a crucial energy backbone of our country—providing the fuel and energy necessary for major production plants and factories, military installations and airports, and power generation facilities that keep our country moving.

When there is a disruption, there are serious consequences for our infrastructure.

Just last month, for example, the Olympic Pipeline leaked thousands of gallons of fuel and caused an intense fire in Renton Washington—shooting flames twenty feet in the air.

The Pipeline was shut for three days and created a jet-fuel crisis at Sea-Tac International Airport, which relies on the Olympic Pipeline as its sole supplier—in fact, the airport was just days away from having to close.

More important, however, these pipelines run through many of our state's urban areas—through, under and near parks, schools and major population centers—and accidents can be extremely hazardous and even deadly.

My state knows first-hand the tragedy of pipeline accidents.

Just last week, we recognized the tragic fifth anniversary of the Olympic Pipeline explosion near Bellingham.

This disastrous rupture spilled 237,000 gallons of gasoline and exploded into a fireball that killed two ten-year-olds, Stephen Tsiourvas [SEE-OR-VUS] and Wade King, and Liam Wood, an 18-year-old who was out fishing.

These kids were simply playing in a park and fishing in a river—when a threat that few people in the city even knew existed killed them.

I want to re-state that fact: few people in the city even knew that this pipeline ran through their city.

In fact, these pipelines run through our cities and neighborhoods and often they are buried underground without any knowledge of those living above them.

Ensuring the safety of these lines must be a principal priority, which is why I supported the Pipeline Safety Improvement Act of 2002 as a good step towards increased pipeline safety.

This legislation that was introduced under our chairman's leadership gives the Secretary of Transportation greater authority to take swift action in ensuring the safety of our pipeline system.

Specifically, the legislation included increased inspections, an expanded public right to know about pipeline hazards, environmental reviews intended to enable more timely pipeline repairs, and increased state oversight of safety activities.

I was particularly pleased that the legislation added a mandatory inspection requirement.

However, I must say that I remain disappointed that the final conference report did not include the Senate's requirement for testing every five years that was included as a Murray-Cantwell amendment in the Senate bill.

Instead, the law requires pipeline inspections over all lines once in the next ten years and every seven years thereafter. Physical testing is really the only way that we know the vulnerabilities of these systems and I think that testing only once in ten years is insufficient.

The final ten-year requirement must—I repeat must—be the absolute minimum standard.

We need to make sure that consistent physical testing of our pipelines is a principal priority, and I strongly encourage more testing beyond the statutory requirements.

It is important to recognize, that the OPS has made significant steps to increase safety—while last year there were 126 liquid pipeline accidents; this is almost a 50 percent decrease from a decade earlier.

Yet, 126 accidents are still too many. We need to do more.

I am pleased that the Administration's FY 2005 budget includes funding for 168 full-time inspectors—this is an increase from 111 when the Pipeline Safety bill was passed.

In addition to increased inspectors, I think we need to focus on providing states and communities the resources that they need to develop security, safety and response plans to ensure that we will not have another tragic pipeline anniversary to mourn.

I look forward to hearing from you today specifically about the ongoing testing of our Nation's pipelines and also the steps that are being taken to ensure trans-

parency in the pipeline system to ensure that our cities, municipalities and citizens are given the information that they need to make decisions regarding public safety around the pipeline routes.

The CHAIRMAN. Thank you.

I thank the witnesses, and I appreciate the opportunity to revisit this issue, and I thank you for the good work.

Next panel will be Ms. Lois Epstein, the Senior Engineer of Cook Inlet Keeper; Mr. Barry Pearl, President and CEO of TEPPCO Partners; Mr. Earl Fischer, Senior Vice President of Utility Operations at Atmos Energy Corporation, on behalf of the American Gas Association and the American Public Gas Association; and Mr. Robert Howard, Vice President and General Manager, Pipeline Operations, Gas Transmission Northwest Corporation, on behalf of the Interstate Natural Gas Association of America.

[Pause.]

The CHAIRMAN. Ms. Epstein, we'll begin with you. Welcome.

STATEMENT OF LOIS N. EPSTEIN, P.E., SENIOR ENGINEER, OIL AND GAS INDUSTRY SPECIALIST, COOK INLET KEEPER

Ms. EPSTEIN. Thank you very much, Mr. Chairman.

Good morning. My name is Lois Epstein, and I am a licensed engineer and an oil and gas industry specialist with Cook Inlet Keeper, in Anchorage, Alaska.

Cook Inlet Keeper is a member of the Waterkeeper Alliance, an alliance of approximately 100 organizations headed by Bobby Kennedy, Jr., and dedicated to water protection. Cook Inlet watershed is 47,000 square miles in size, and is where oil and gas first was developed commercially in Alaska, beginning in the late 1950s.

The Pipeline Safety Improvement Act of 2002 followed several tragic pipeline events, one of which, the Bellingham rupture that killed three youths, occurred 5 years ago last week.

The graph in my testimony shows that reported hazardous liquid pipeline incidents have been dropping yearly since 1994. It's also apparent from the graph that there has been a discernable upward—there has not been a discernable upward or downward trend in natural gas transmission or distribution incidents, by year. And I apologize for those of you who don't have a copy of the testimony. But I think it's important to put the trend in incidents in perspective and use that information in our discussion.

The natural gas transmission pipeline integrity management rule will not reduce incidents on those lines for several years, and it's unclear how much of a reduction we can expect, so it's very early right now to be evaluating that rule. This is true for several reasons. First, the long time-frame for implementation will delay the benefits. Second, because the rule only applies to an estimated 7 percent of transmission pipelines, by 2007, we may expect only a 3.5 percent reduction in incidents. Third, since the rule allows the use of not-fully proven methodologies—*i.e.*, direct assessment and confirmatory direct assessment—we need to wait several years to see whether OPS's approach will result in a meaningful reduction in incidents.

Public-interest organizations are particularly concerned about the large portions of pipelines that currently are not covered by pipeline integrity management rules. For example, it's unclear

whether the existing natural gas integrity rule covers the location near Carlsbad, New Mexico, where the August 2000 pipeline tragedy occurred.

The public also is very concerned that OPS has been unable, to date, to collect significant fines for violations of regulations from the tragedies in Bellingham and Carlsbad. OPS has touted the improvements it has required in those pipeline systems as a result of the accidents; however, that is like requiring brake upgrades in cars with brakes that failed and caused injuries and deaths. The public has no evidence that the increased penalties contained in Section 8 of the 2002 law are being used by OPS to send a message to pipeline operators that violations are both unacceptable and costly.

OPS has a particularly poor enforcement record, compared to EPA, which, as I understand it, GAO did not look at. And EPA also issues fines for oil pipeline spills, sometimes totaling tens of millions of dollars. So I think that kind of comparison is relevant. While the amount of fines has gone up, it's still starting from a very low baseline compared to EPA and potentially other agencies.

Additionally, without a preventive approach to enforcement, it's practically pointless to have preventive requirements in place, so it's important to do the enforcement before the accidents, as well as after.

Section 9 of the 2002 law states that the Secretary of Transportation may make grants for technical assistance to local communities and groups of individuals, not including for-profit entities, relating to the safety of pipeline facilities in local communities. OPS has not had any success obtaining appropriated funds for this purpose. Public-interest groups request that both Senator McCain and Senator Stevens, on the Appropriations Committee, as well as on this Committee, help ensure that this section of the law is carried out as intended.

As for regulatory gaps that OPS needs to address, these are discussed in my written testimony. One such gap that particularly affects Alaska and other oil-producing states is the lack of regulation of rural gathering and flow lines. These types of lines have serious environmental impacts, and this Committee needs to ensure that OPS collects spill data from these unregulated pipelines, and develops regulations to prevent releases from these lines.

Pipeline safety needs include modifications in Section 60104(c) of the law, which covers state preemption. There are numerous areas of oversight and regulation—for example, earthquake zone provisions, enforcement, the definition of high-consequence areas—where states might want to exceed Federal requirements to enhance pipeline safety and where their actions would not compromise a company's ability to operate its pipelines safely and smoothly, nor would those actions affect interstate commerce.

In summary, the Committee should pursue the following key items and others noted in my written testimony. Consider requiring OPS to make changes in the 2002 law if the natural gas transmission pipeline incident rate does not decline significantly over time. Ensure that OPS diligently enforces violations of its regulations, both prior to and following accidents. Ensure that OPS distributes pipeline safety information grants. Ensure that OPS con-

tinues to fill regulatory gaps and amend the pipeline safety law to collect spill data from currently unregulated gathering and flow lines. Amend the preemption provision of the pipeline safety law so it provides needed flexibility to states that wish to strengthen pipeline safety without impacting interstate commerce. And I haven't spoken about these last two items, but they are worth mentioning in the summary. Ensure that OPS, with its increased LNG responsibilities as new plants are being sited, has the resources it needs to ensure safety at LNG and pipeline facilities. And, finally, consider passage of a bill similar to H.R. 4277 to create a pipeline safety administration at DOT.

Due to my time limitations, I think I'm covering a lot of different topics, and I hope and encourage you to look at my written testimony for more details. But I thank you very much for your interest in this important topic. And thank you, Senator Murray, for joining us today and for your good work on this issue. I look forward to your questions.

[The prepared statement of Ms. Epstein follows:]

PREPARED STATEMENT OF LOIS N. EPSTEIN, P.E., SENIOR ENGINEER AND OIL AND GAS INDUSTRY SPECIALIST, COOK INLET KEEPER

Good morning. My name is Lois Epstein and I am a licensed engineer and an oil and gas industry specialist with Cook Inlet Keeper in Anchorage, Alaska. Thank you very much, Senator McCain, for holding this oversight hearing on pipeline safety and for your ongoing attention to this issue (even if some of that attention results from an unfortunate pipeline accident which took place in Tucson last July).

Cook Inlet Keeper is a nonprofit, membership organization dedicated to protecting Alaska's Cook Inlet watershed and the life it sustains. My background in pipeline safety includes membership since 1995 on the U.S. Department of Transportation's (DOT's) Technical Hazardous Liquid Pipeline Safety Standards Committee which oversees the Office of Pipeline Safety's (OPS') oil pipeline activities and rule development, testifying before Congress in 1999 and 2002 on pipeline law reauthorization, and researching and analyzing the performance of Cook Inlet's pipeline infrastructure by pipeline operator and type.¹ I have worked on safety and environmental issues for 20 years for two private consultants, the U.S. Environmental Protection Agency, Environmental Defense, and Cook Inlet Keeper.

My work in Alaska is entirely focused on the Cook Inlet watershed's oil and gas operations. From this vantage point, I can see how well the policies developed in DC work in the real-world. The Cook Inlet watershed, which includes Anchorage and drains an area approximately the size of Virginia, is where oil and gas first was developed commercially in Alaska, beginning in the late 1950s. Cook Inlet is an extraordinarily scenic and fisheries-and wildlife-rich, region.

In this testimony I will discuss:

- Implementation of the Pipeline Safety Improvement Act of 2002, including safety, regulatory, and policy progress, and enforcement concerns;
- Ongoing pipeline safety needs, namely increased public information and modifying the state preemption provision in the law;
- The role of OPS in Liquified Natural Gas facility oversight; and,
- The DOT reorganization and how that might impact OPS.

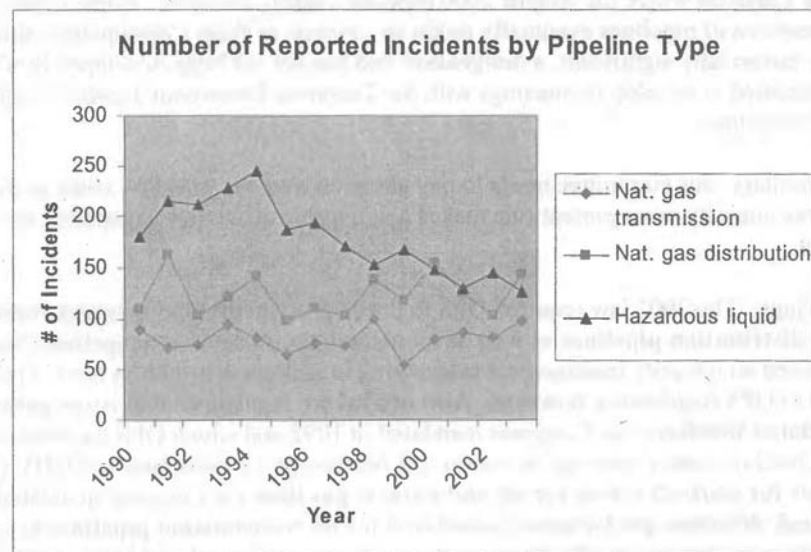
Implementation of the Pipeline Safety Improvement Act of 2002

The Pipeline Safety Improvement Act of 2002 (the 2002 law) was passed by Congress on November 15, 2002 following several tragic pipeline events, one of which the June 10, 1999 Bellingham rupture that killed three youths—occurred 5 years ago last week. Since this 1999 event and the August 19, 2000 natural gas pipeline rupture which killed 12 people including 5 children, there has been increased scrutiny of the pipeline industry, its performance, and of deficiencies in Federal and state oversight. The 2002 law contains some needed improvements but, like many

¹ See *Lurking Below: Oil and Gas Pipeline Problems in the Cook Inlet Watershed*, 28 pp. plus appendices, September 2002. www.inletkeeper.org/pipelines.htm

acts of Congress, it represents a compromise among competing interests. As a result, safety will be improved, but not necessarily by as much or as fast as the public would like.

To put my presentation in context, the graph below displays the performance of the industry over time based on reported incidents. As you can see from the top line, reported hazardous liquid pipeline incidents dropped after 1994, two years after Congress imposed mandatory requirements on OPS to prevent releases that impacted the environment (as opposed to releases which solely affected safety). It's also apparent that there has not been a discernable upward or downward trend in natural gas transmission or distribution incidents in recent years.



It is critical for this committee and its House counterparts to hold periodic oversight hearings to see if the law and its resulting regulations are, in fact, having an impact in reducing pipeline accidents. Keeping the time lag for pipeline performance improvements in mind, I n9W will discuss regulatory progress, regulatory gaps, important enforcement concerns, and Pipeline Safety Information Grants to Communities (Section 9 of the 2002 law).

Regulatory Progress: The most important rule issued as a result of the 2002 law, the natural gas transmission pipeline integrity management rule published on December 15, 2003 which went into effect this past January, will not reduce incidents on those lines for several years and it's unclear how much of a reduction we can expect. This is true for several reasons. First, the law requires baseline integrity assessments to occur within 10 years, with 50 percent of the assessments occurring within 5 years of the law's enactment; this long time-frame will delay the benefits. Second, because the rule only applies to an estimated 7 percent of transmission pipelines,² by 2007 (*i.e.*, five years after the law's enactment) we may expect only a 3.5 percent reduction in incidents, though the incidents that do occur should take place in areas of lesser consequences. Third, since the rule allows the use of not-fully-proven methodologies (*i.e.*, "direct assessment" and "confirmatory direct assessment"), we need to wait several years to see whether OPS' approach to this rule will result in a meaningful reduction in incidents.

Public interest organizations are particularly concerned about the large portions of pipelines that currently are not covered by the oil and natural gas pipeline integrity rules. For example, it's unclear whether the existing natural gas integrity management rule covers the location near Carlsbad where the August 2000 pipeline tragedy occurred. Some of the uncovered portions of pipelines eventually might be covered as High Consequence Areas that are culturally or historically significant,

²OPS states in the preamble to the rule "that about 22,000 miles of gas transmission pipelines are located in the [High Consequence Areas] in a network of 300,000 miles of gas transmission pipeline." (68 *Federal Register* 69815, December 15, 2003)

a designation that has not yet been developed by OPS but which it committed to develop in meetings with the Technical Hazardous Liquid Pipeline Safety Standards Committee.

In summary, this committee needs to pay attention over the next few years as to whether the natural gas integrity management rule makes a noticeable difference in pipeline incidents and their severity.

Regulatory Gaps: The 2002 law required OPS to develop *integrity management standards for natural gas distribution pipelines* as well as for natural gas transmission pipelines, but OPS has not yet proposed an integrity management rule-making to address distribution lines. This is not the only gap in OPS regulations, however. Also needed are regulations that cover *gathering lines and related flowlines*³ (as Congress mandated in 1992 and which OPS has made some progress on, holding public hearings in Austin and Anchorage 11 years later in 2003); specific *requirements for shut-off valves for oil and natural gas lines* (as Congress mandated in 1992 and 1996); *leak detection performance standards for oil transmission pipelines* to ensure that leaks of a particular size are rapidly discovered, as is the case for crude oil transmission lines in Alaska;⁴ *enhanced regulation of low-stress oil lines* given their potential for serious environmental impacts; requirements ensuring that *operators submit revised accident reports* which they are not required to do now (as the DOT Inspector General recommended⁵; and *failsafe requirements* to prevent over-pressurization.

Enforcement: It's clear the public is very concerned that OPS has been unable to date to collect significant fines for violations of OPS regulations from the tragedies in Bellingham and Carlsbad. OPS touts the improvements it has required in those pipeline systems as a result of the accidents,⁶ however that is like requiring brake upgrades in cars with brakes that failed and caused injuries and deaths. The public has no evidence that the increased penalties contained in Section 8 of the 2002 law are being used by OPS to send a message to pipeline operators that violations are both unacceptable and costly.

The U.S. General Accounting Office (GAO) soon will issue a report on OPS' enforcement record. I urge both GAO and this committee to compare OPS' enforcement program statistics with those of EPA, *i.e.*, examining the highest penalties issued for similar types of releases including pipeline-related oil pollution fines levied by EPA. To improve its enforcement program, OPS also needs to consider initiating a public comment period on significant pipeline penalties, as EPA does. I look forward to seeing GAO's updated statistics on the rate of OPS fines—in 1998, GAO found that OPS proposed a fine in only 1 of every 25 enforcement actions (a reduction from 1 in 2 in 1990),⁷ far too low a ratio if the government wants operators to follow regulations at least in part to avoid penalties.

Additionally, as I stated in my 2002 testimony,⁸ OPS needs to initiate several high profile, *preventive* enforcement actions to deter potential violators. Currently, OPS only pursues high-profile enforcement actions following pipeline accidents. Preventive enforcement, in contrast, would require OPS to penalize pipeline companies whose operations might result in serious releases prior to a release occurring. Major civil enforcement actions identifying violations of standards prior to accidents should be publicized and readily available on OPS' website. Without a preventive approach to enforcement, it's practically pointless to have preventive requirements in place.

Thus, the committee needs to ensure that OPS commits to enforce violations of its regulations, both prior to and following accidents.

Pipeline Safety Information Grants: Section 9 of the 2002 law states that:

The Secretary of Transportation may make grants for technical assistance to local communities and groups of individuals (not including for-profit entities) relating to the safety of pipeline facilities in local communities . . . The amount of any grant under this section may not exceed \$50,000 for a single grant recipient. The Secretary shall establish appropriate procedures to ensure the proper use of funds provided under this section. (§ 60130(a)(1))

To date, OPS has not established any such procedures, nor has it had any success obtaining appropriated funds for this purpose. As time goes on, there are missed op-

³These pipelines represented approximately 40 percent of reported releases from Cook Inlet watershed pipelines from 1997–2001. See *Lurking Below*, op. cit., p. 10.

⁴See 18 AAC 75.055.

⁵*Pipeline Safety Program, Research and Special Programs Administration, Report No. RT-2000-069*, Office of Inspector General, Audit Report, March 13, 2000, p. 22.

⁶Letter from DOT Secretary Norm Mineta to Congressman Rick Larsen, March 10, 2004.

⁷U.S. GAO, op. cit., p. 26.

⁸Before the U.S. House of Representatives Committee on Transportation and Infrastructure, the Subcommittee on Highways and Transit, February 13, 2002.

portunities for use of these funds, *e.g.*, such funds might have helped community organizations understand the technical and regulatory issues associated with the Tucson pipeline accident and/or assisted public interest groups in commenting on ongoing regulations and standards development. Public interest groups request that both Senator McCain and Senator Stevens on the Appropriations Committee help ensure that this section of the 2002 law is carried out as intended.

Pipeline Safety Needs

Increased Public Information: Pipelines do not require periodic renewals of operating permits so the public has almost no knowledge of the adequacy of pipeline operations following siting approvals. This means the public cannot help regulators identify High Consequence Areas, nor can it weigh in on the integrity measures utilized by particular pipeline operators. OPS and the industry have unreasonably resisted providing more information to the public on pipeline operations even though the types of additional information requested—such as the primary threats to pipelines, the integrity assessment tools utilized, the leak detection strategies used would have no security—related value. As stated in the preamble to the natural gas transmission pipeline integrity management rulemaking:

RSPA/OPS does not consider it appropriate to collect additional information relevant to integrity management for public dissemination. RSPA/OPS will implement an inspection program to evaluate operator implementation of this rule . . . Regulators will take enforcement action when appropriate, and records of such enforcement will be available to the public as they are now. (68 *Federal Register* 69800, December 15, 2003)

From this statement, it's clear that OPS does not appreciate the value of the public participating in integrity management rule implementation and enforcement. The statement implies that the public has nothing to add in terms of technical analyses of trends and patterns and/or on-the-ground knowledge, and that OPS has fool-proof inspection and enforcement mechanisms. Given that OPS has been frequently criticized for its poor enforcement record, the latter is a particularly implausible claim.

Because public participation and public dissemination of operational data are likely to strengthen pipeline safety (the latter through a powerful, non-regulatory means of demonstrating progress), the committee should encourage OPS to provide more information on pipeline operations to the public.

State Preemption: Current pipeline safety law prevents states from regulating and enforcing violations on interstate pipelines⁹ even if such regulation would improve safety and/or environmental protection and would not affect interstate commerce. This is an unnecessary intrusion on states' rights with serious adverse consequences since national regulations might not protect states sufficiently from pipeline hazards, *e.g.*, from earthquakes, difficult cleanup terrain, etc. There are numerous areas of oversight and regulation (*e.g.*, testing requirements, right-of-way management, landslide and earthquake zone provisions, enforcement, defining high consequence areas) where states might want to exceed Federal requirements to enhance pipeline safety, and where their actions would not compromise a company's ability to operate its pipelines smoothly and safely.

Interestingly, Sec. 3(a) of the 2002 law also finds the existing state preemption provision too broad. This provision contains a limitation on preemption for enforcement of state "one-call" notification programs. As this example shows, a well-designed provision that limits the preemption language currently in the law could strengthen pipeline safety.

OPS and Liquified Natural Gas Oversight

The 2002 law contains language dating from 1968 and 1979 that describes OPS' role in regulating liquified natural gas (LNG) facilities.¹⁰ While much recent attention has been focused on the Federal Energy Regulatory Commission's role in siting LNG import-regassification facilities, little attention has been paid to OPS' role in developing, implementing, and enforcing LNG siting, operating, and contingency plan rules.¹¹

The reason this issue is important to the committee is that the committee is aware of OPS' currently constrained inspection and enforcement resources. Given these resource constraints and the likelihood that OPS will need to initiate some new LNG-related rulemaking, policy, and enforcement work with the expected ex-

⁹ 49 U.S.C. § 60104(c).

¹⁰ 49 U.S.C. § 60103.

¹¹ These rules are contained in 49 CFR 193.

pansion of new LNG facilities in the U.S., OPS soon might face severe resource challenges. Without additional OPS resources, safety concerns for LNG and/or pipeline facilities nationwide might result.

Potential DOT Reorganization

On December 8, 2003, DOT Secretary Mineta proposed removing OPS from the Research and Special Programs Administration and combining it with the Federal Railroad Administration to form the Federal Railroad and Pipeline Administration. At least partly in response to this proposal, Congressman Young introduced H.R. 4277, a bill that would establish the Pipeline Safety Administration at DOT.

In general, public interest organizations believe that pipeline safety should be elevated within DOT, so we are supportive of Congressman Young's bill. Pipelines have enormous impacts both locally and nationwide and for too long have been relegated to a small, obscure office at DOT.

Summary

In conclusion, the committee should pursue the following items further in its oversight work:

- Periodically review the annual natural gas transmission line incident rate to see whether the integrity management rule is making a noticeable difference in the rate of incidents and incident severity;
- Ensure that OPS continues to fill regulatory gaps;
- Ensure that OPS diligently enforces violations of its regulations, both prior to and following accidents;
- Ensure that OPS distributes Pipeline Safety Information Grants;
- Strongly encourage OPS to provide information on pipeline operations with no security related value to the public;
- Research how best to amend the preemption provision of the pipeline safety law so it provides needed flexibility to states that wish to strengthen pipeline safety without impacting interstate commerce;
- Ensure that OPS' increased LNG responsibilities do not comprise safety at LNG or pipeline facilities; and,
- Consider passage of a bill similar to H.R. 4277 to create a Pipeline Safety Administration at DOT.

Thank you very much for your interest in this important topic. Feel free to contact me at any time with your questions or comments.

COOK INLET KEEPER
Anchorage, AK, July 2, 2004

Senator JOHN MCCAIN,
Chairman,
Committee on Commerce, Science, and Transportation,
U.S. Senate,
Washington, DC.

Dear Chairman McCain:

Thank you very much for holding the full committee oversight hearing on pipeline safety on June 15, 2004 where I appeared as a witness.

The statement on page 3 of my written testimony that there is a need for "requirements ensuring that operators submit revised accident reports which they are not required to do now (as the DOT Inspector General recommended)" requires clarification and revision. These requirements do exist in the pipeline safety code at:

- 49 CFR 191.9(b)—for distribution pipelines
- 49 CFR 191.15(b)—for gas gathering and transmission pipelines
- 49 CFR 195.54(b)—for hazardous liquid pipelines

According to the Inspector General, however, "even when OPS knows the information in the original accident report is inaccurate, under current regulations, it cannot correct the database without an operator's written revision."¹ The Inspector

¹*Pipeline Safety Program, Research and Special Programs Administration, Report No. RT-2000-069, Office of Inspector General, Audit Report, March 13, 2000, p. 5.*

General recommended that OPS “*establish an enforcement mechanism* to ensure [that] operators submit revised accident reports”² [emphasis added]. There still is a need for OPS to develop an enforcement mechanism, perhaps employing spot-checks of operator accident submittals, to ensure that all operators submit accurate, revised accident reports. My written testimony should have clearly stated such a recommendation.

Please include this letter in the hearing record.

Sincerely,

LOIS N. EPSTEIN, P.E.,
*Senior Engineer,
 Oil and Gas Industry Specialist.*

The CHAIRMAN. Thank you. Your written statement, along with the others, will be made part of the record.

Senator Murray, would you like to make a comment?

**STATEMENT OF HON. PATTY MURRAY,
 U.S. SENATOR FROM WASHINGTON**

Senator MURRAY. Thank you, Mr. Chairman. I appreciate the accommodation this morning, and I appreciate your holding this oversight hearing. Without your commitment and your hard work, along with Senator Hollings, we would never have enacted such a strong pipeline safety bill back in December 2002, and I appreciate all the work you’ve done on this.

Five days ago, I was in Bellingham, Washington, at a ceremony marking the fifth anniversary of the Bellingham pipeline explosion. That explosion killed three young boys and left a scar in my state that still has not healed. My sister is a public school teacher in Bellingham, and every year she asks her eighth-grade students to write about the most important even in their life, and she told me that this year an amazing number of them wrote about the Bellingham pipeline explosion. So I hope as we examine our progress today, we don’t lose sight of the real people whose lives have been torn apart by pipeline tragedies.

I am pleased to say that we have made progress in the past few years because of the law we passed, the funding we secured, and Congressional oversight. I want to commend RSPA and OPS for the dramatic improvements they’ve made, but we know our work is not done.

Before the Bellingham tragedy, like many people, I had never thought about the safety of our pipelines. I assumed someone was taking care of it. But after the accident, I discovered inadequate laws, insufficient oversight, too few inspections, and a lack of awareness about pipeline dangers. I learned that one of the most important public safety offices in our government was underfunded and neglected. So I asked Inspector General Ken Mead to investigate the Office of Pipeline Safety and give me recommendations for how to make the system work better.

Through my research and discussion, I learned that we needed to improve many areas. Safety standards, enforcement, penalties, technology, public education, state participation, and citizen involvement. So we began to work on legislation to address all those areas, and worked to get hearings on the subject. Chairman McCain and former Senator Gorton were real champions on that effort. In the Senate, we passed a pipeline bill three times—in Sep-

² *Ibid.*, p. 22.

tember 2000, in February 2001, and again in March 2002. Finally, the House passed a bill in July 2002, and our Act was signed into law in December 2002. A lot of Members worked together to pass that law, including Senators McCain, Hollings, Hutchinson, Inouye, Brownback, Breaux, Domenici, Bingaman, Wyden, Lautenberg, Corzine, Gorton, and Cantwell, and Representatives Metcalf and Larson, of Washington State.

Working together, we passed one of the strongest pipeline safety bills in American history. We then worked to fund it, and that has been a personal mission of mine, as the Ranking Member and past Chairman of the Transportation Appropriations Subcommittee.

So what has happened since we passed that law? Well, let me give you ten facts.

First, we are inspecting pipelines as never before, and our inspections are ten times more rigorous than before. Before this bill became law, a pipeline inspection was one person spending 20 hours. Today, it is a team of six people spending 240 hours. And today all large liquid pipeline operators have been inspected twice.

Second, we are finding and fixing pipeline problems at double the rate before the law.

Third, we've boosted the Office of Pipeline Safety by 20 percent, from 135 people up to 160 people now, and most of them are inspectors.

Fourth, we are making real gains in new technology. I have secured \$10 million in each of the past 2 years so we can develop the next generation of equipment for pipeline inspection, detection, repair, and monitoring.

Fifth, we have completed a national pipeline mapping system.

And, sixth, we've beefed up enforcement. In fact, in the past 3 years, the Office of Pipeline Safety has issued corrective action orders at three times the rate they did 5 years ago.

Seventh, we've more than doubled the size of the average civil penalty for violations.

Eighth, we've given local groups expertise and a real role in the process.

Ninth, we've increased our coordination with states and utilities so people are talking to each other before they dig.

And, finally, number ten, we boosted public education through a new standard that went into effect in December of last year.

And the statistics show pipeline safety has improved. Nationally, over the past 10 years, there was an average of 25.2 incidents per million miles of pipeline. Over the past 3 years, that average has declined to 21.7 incidents per million miles.

As I look at all these improvements, two things stand out. First, we turned a slow, reactive government agency into one that is active and aggressively enforcing those higher safety standards. Today, the Pipeline Office has closed 40 of 50 recommendations from the NTSB, and has made considerable progress on implementing IG recommendations. It has issued new rules in record time, and it has reached out to work with states and citizens groups as never before. And, second, we've empowered local citizen groups to be strong watchdogs for public safety. We've made progress, but our work is not yet done. The recent incidents in Auburn, Washington, in Arizona, and elsewhere show that we still

have a long way to go. The IG and GAO have come up with recommendations on how Congress and OPS can further improve pipeline safety. Those recommendations focus on maintaining and increasing OPS monitoring of the Integrity Management Program and ensuring that they follow up with corrective action orders and penalties. It is critical that OPS continue to push industry to live up to their obligations, and to punish them when they do not.

I want to highlight one set of recommendations the IG makes involving natural gas distribution lines. These distribution lines were not required to have integrity management plans. New, non-evasive technologies are being developed to test these pipelines for corrosion and defects, and I believe these lines should be required to have integrity management plans.

Five years after the Bellingham tragedy, we've made progress, but we cannot slip back and assume that someone else is protecting us. I'm committed to work with all of you to make sure that we keep our eye on the ball with strong enforcement, oversight, coordination, and funding. And I applaud you, Mr. Chairman and Members of the Committee, for this commitment. And I know that by staying vigilant and working together, we can keep our communities safe.

Thank you very much.

[The prepared statement of Senator Murray follows:]

PREPARED STATEMENT OF HON. PATTY MURRAY, U.S. SENATOR FROM WASHINGTON

Thank you, Mr. Chairman, for holding this oversight hearing. Without your commitment and hard work, along with Senator Hollings, we would have never enacted such a strong pipeline safety bill in December 2002.

Five days ago, I was in Bellingham, Washington at a ceremony marking the fifth anniversary of the Bellingham pipeline explosion. That explosion killed three young boys and left a scar in my state that still has not healed. My sister is a public school teacher in Bellingham. Every year, she asks her eighth grade students to write about the most important events in their lives. She told me that this year, an amazing number of them wrote about the Bellingham pipeline explosion. So as we examine our progress today we can't lose sight of the real people whose lives have been torn apart by pipeline tragedies.

I am pleased to say that we have made progress in the past few years because of the law we passed, the funding we secured, and Congressional oversight. I want to commend RSPA and OPS for the dramatic improvements they have made, but we know our work is not done.

Before the Bellingham tragedy, like many people, I'd never thought about the safety of our pipelines. I assumed that someone was taking care of it. But after the accident, I discovered inadequate laws, insufficient oversight, too few inspections, and a lack of awareness about pipeline dangers. I learned that one of the most important public safety offices in our government was under-funded and neglected. So, I asked Inspector General Ken Mead to investigate the Office of Pipeline Safety and give me recommendations for how to make the system work better.

Through my research and discussion, I learned that we needed to improve many areas like safety standards, enforcement, penalties, technology, public education, state participation and citizen involvement. So we began to work on legislation to address all of those areas and then worked to get hearings on the subject. Chairman McCain and former Senator Gorton were real champions in that effort.

In the Senate, we passed a pipeline bill three times—in September 2000, in February 2001, and again in March 2002. Finally, the House passed a bill in July 2002, and our Act was signed into law in December 2002.

A lot of Members worked together to pass that law, including Senators McCain, Hollings, Hutchison, Inouye, Brownback, Breaux, Domenici, Bingaman, Wyden, Lautenberg, Corzine, Gorton, and Cantwell, and Representatives Metcalf and Larsen, both of Washington state.

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as the Ranking Member and past Chairman of the Transportation Appropriations Subcommittee.

So what has happened since we passed the law? Let me give you 10 facts.

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As I look at all of those improvements, two things really stand out. First, we turned a slow, reactive government agency into one that is active and that's aggressively enforcing these higher safety standards. Today, the pipeline office has closed 40 out of 50 recommendations from the NTSB, and has made considerable progress on implementing IG recommendations. It has issued new rules in record time, and it's reached out to work with states and citizen groups as never before. And we've also empowered local citizen groups to be strong watchdogs for public safety.

We have made progress, but our work is not done. The recent incidents in Auburn, WA, Arizona, and elsewhere show that we still have a long way to go. The IG and GAO have come up with recommendations on how Congress and OPS can further improve pipeline safety. Those recommendations focus on maintaining and increasing OPS monitoring of the integrity management program, and ensuring that they follow up with corrective action orders and penalties. It is critical that OPS continue to push industry to live up to their obligations and to punish them when they do not.

I want to highlight one set of recommendations that the IG makes involving natural gas distribution lines. These distribution lines were not required to have integrity management plans. New, non-evasive technologies are being developed to test these pipelines for corrosion and defects. I believe these lines should be required to have integrity management plans.

Five years after the Bellingham tragedy, we have made progress, but we can't slip back and assume that someone else is protecting us. I am committed to making sure that we keep our eye on the ball with strong enforcement, oversight, coordination and funding. I applaud the Chairman and other members of this Committee for their commitment, and I know that by staying vigilant and working together, we can keep our communities safe.

The CHAIRMAN. Thank you very much.
Mr. Pearl?

STATEMENT OF BARRY PEARL, PRESIDENT AND CEO, TEPPCO PARTNERS, L.P., ON BEHALF OF THE ASSOCIATION OF OIL PIPE LINES AND THE AMERICAN PETROLEUM INSTITUTE

Mr. PEARL. Thank you, Mr. Chairman.

I'm Barry Pearl, President and CEO of TEPPCO Partners, L.P., and Chairman of the Association of Oil Pipe Lines. I appreciate this opportunity to appear before the Committee today on behalf of

AOPL and the pipeline members of the American Petroleum Institute. These organizations represent more than 50 pipeline companies that transport the vast majority of our Nation's liquid petroleum.

My company, TEPPCO Partners, LP, owns and operates more than 11,600 miles of pipelines in 16 states. Our operations include one of the largest common carrier pipelines in the U.S., transporting refined petroleum products and liquefied petroleum gases from the Gulf Coast to markets in the Midwest and the Northeast.

I've provided my full statement and several attachments. I ask that those be included in the record of this hearing. I'd now like to summarize that material for you.

It has been a year and a half since the enactment of the Pipeline Safety Improvement Act of 2002. On behalf of the members of AOPL and API, I wish to thank the Members of this Committee for passing this very important legislation.

As the Committee reviews the current state of pipeline safety, there are a few points that I'd like to emphasize.

First, there's a growing recognition that the oil pipeline infrastructure is critical to the American economy. We are committed to improving pipeline safety while ensuring the delivery of essential energy supplies.

Second, there has been tremendous progress in pipeline safety because of the PSIA, and also because of actions undertaken by the industry and by the Office of Pipeline Safety before the Act became law. My testimony includes two charts that show the improvement in the safety record of the oil pipeline industry. They are displayed on the easels behind me.

Third, many of the initiatives of the Pipeline Safety Act are being implemented in a more than satisfactory manner, and on or ahead of schedule. However, for one important initiative, pipeline-repair permit streamlining, progress has been disappointing. We think that with your help we can get this initiative back on track.

And, finally, we fear that much of the progress that has been made in pipeline safety could be diminished if not lost because of a reorganization plan that would transfer the pipeline safety program to the Federal Railroad Administration.

Let me briefly address each of these points in turn.

First, the role of oil pipelines. One half of total U.S. energy supply comes from petroleum, with 95 percent of the energy that powers transportation derived from petroleum products. Pipelines provide the only reasonable mode of transportation to supply large quantities of petroleum to most of the Nation's consuming regions. For example, two thirds of the ton miles of domestic petroleum transportation are provided by pipeline. There's no doubt that the oil pipeline infrastructure is crucial to American energy supply. The stewardship of this critical national asset is the joint responsibility of the industry I represent, the Department of Transportation, and Congress, through this Committee.

Now, turning to pipeline safety, oil pipeline operators have been subject to the Office of Pipeline Safety's integrity management regulations since March 2001, before enactment of the PSIA. Our members will complete the required baseline testing of the first 50 percent highest-risk segments of our systems prior to September 30

of this year. OPS has inspected each of these operators under these regulations at least twice.

The Oil Pipeline Integrity Management Program is generating safety benefits that significantly exceed anything anticipated when the program was designed. In the end, the oil pipeline mileage being tested under the OPS program will amount to four times the original estimate, and will exceed four fifths of the total system.

Operators are finding and repairing many conditions in need of repair and many less serious conditions that are found near defects. For every condition repaired under the rule, approximately six other conditions are excavated and evaluated. Operators are fixing what they find, often going beyond the requirements of the law.

While the benefits derived from the integrity management rule are much greater than originally estimated, so are the costs. Costs-per-operator are often running at a rate of tens of millions of dollars per year, far more than originally anticipated. Operators have, nevertheless, moved aggressively to provide the resources needed to implement their Integrity Management Programs.

We believe that our industry's substantial investment in pipeline integrity and leak prevention is a sound one, providing long-term benefits to both pipeline operators and the public.

Turning to pipeline-repair permit streamlining, an important initiative of the PSIA that needs the Committee's encouragement is the implementation of Section 16, which is concerned with expediting the repair of pipeline defects. Some limited progress has been made on implementing this section, but the largest portion of the work remains to be done, and the deadlines for energy action under the provision have passed.

Let me discuss my own company's recent experience in permitting. Last year, we discovered some anomalies in a key part of our pipeline system that transports propane to New York and Pennsylvania. One segment of pipe that needed replacement happened to be under a reservoir in Ohio. We were very concerned about this project, as it had to be completed prior to the high seasonal demand for propane, starting around October. Our permitting people estimated that it could take as long as 6 months to permit our work, which would have been a problem for us and the people in the Northeast, as we transport 40 percent of New York and Pennsylvania's propane demand and provide propane supply for several New England states.

Fortunately, we were able to quickly obtain an emergency permit from the Corps of Engineers in just a few weeks. We had great cooperation from the local authorities, and completed the repairs in time. However, had we not been so fortunate, we could have had a serious supply crisis on our hands impacting several important populous states.

Our point here is that we need an effective Federal permit-streamlining initiative to ensure that all pipelines have the experience that we had last fall and that critical petroleum supplies reach the markets that our customers and your constituents need.

Attached to my testimony are recent examples of operators who have not been as fortunate in obtaining permits required by Federal, state, and local agencies. These problems occur because these

agencies do not consistently accord the priority to pipeline safety that this Committee and OPS expects.

My prepared testimony includes several suggestions that we hope to discuss with the pipeline repair permit streamlining workgroup led by the Council on Environmental Quality. Our principal suggestion is that our industry experts be allowed to fully participate in the process, as we can provide valuable information and insight about what will work.

My last topic relates to the proposed transfer of OPS to the Federal Railroad Administration. We are concerned about the proposal to move the OPS to the Federal Railroad Administration. We fear that this proposal would inevitably disrupt the momentum for pipeline safety that OPS and the industry have worked so hard to create in the past several years. A loss of this momentum would be much more than a loss for OPS. It would be a loss for Congress, the public, and for pipeline safety.

We were very pleased to see the introduction of H.R. 4277, the Pipeline Safety Administration Establishment Act by Representative Don Young, Chairman of the House Transportation and Infrastructure Committee. This legislation would establish an independent pipeline safety administration within the Department of Transportation, with minimal disruption of OPS activities.

Our support for this legislation is based, first of all, on its merits, which are expressed in a joint Oil and Gas Association letter that I have provided for the Committee's record.

We urge the Committee to insist that any proposal for restructuring the Pipeline Safety Program not be merely neutral, but that it significantly enhances the program. The program deserves greater organizational recognition and authority within the Department.

In closing, we believe that the Pipeline Safety Improvement Act has been a significant success, but we have much work ahead of us if we are to fully achieve the purposes of this very important legislation. Our industry pledges to work with the OPS in this important task.

We need help from this Committee to ensure that a key section of the legislation, Section 16, related to pipeline repair permit streamlining, achieves the full intent of Congress and is effective in fostering a safer and more reliable pipeline infrastructure.

We also ask that the Committee carefully consider the issue of the proper organizational structure within the Department of Transportation for the Federal Pipeline Safety Program.

I thank you for providing me the opportunity to testify before the Committee on these important matters.

[The prepared statement of Mr. Pearl follows:]

PREPARED STATEMENT OF BARRY PEARL, PRESIDENT AND CEO, TEPPCO PARTNERS, L.P., ON BEHALF OF THE ASSOCIATION OF OIL PIPE LINES AND THE AMERICAN PETROLEUM INSTITUTE

Introduction

I am Barry Pearl, President and CEO of TEPPCO Partners, LP and Chairman of the Association of Oil Pipe Lines (AOPL). I am here to speak on behalf of AOPL and the pipeline members of the American Petroleum Institute (API). I appreciate this opportunity to appear before the Committee today on behalf of the AOPL and API.

AOPL is an unincorporated trade association representing 50 interstate common carrier oil pipeline companies. AOPL members carry nearly 85 percent of the crude oil and refined petroleum products moved by pipeline in the United States. API represents over 400 companies involved in all aspects of the oil and natural gas industry, including exploration, production, transportation, refining and marketing. Together, these two organizations represent the vast majority of the U.S. pipeline transporters of petroleum products.

TEPPCO Partners, L.P. is a publicly traded master limited partnership, listed on the New York Stock exchange under the symbol TPP. TEPPCO owns and operates more than 11,600 miles of pipeline in over 16 states. Our operations include one of the largest common carrier pipelines of refined petroleum products and liquefied petroleum gases in the United States; petrochemical and natural gas liquid pipelines; crude oil transportation, storage, gathering and marketing activities; and natural gas gathering systems. TEPPCO also owns 50 percent interests in Seaway Crude Pipeline Company, Centennial Pipeline LLC, and Mont Belvieu Storage Partners, L.P., and an undivided ownership interest in the Basin Pipeline. Texas Eastern Products Pipeline Company, LLC, an indirect wholly owned subsidiary of Duke Energy Field Services, LLC, is the general partner of TEPPCO Partners, L.P.

Summary

It has been a year and a half since the enactment of the Pipeline Safety Improvement Act of 2002 (Public Law 107-355, the "PSIA"). On behalf of the members of AOPL and API, I wish to thank the Members of this Committee for their leadership in passing that comprehensive and very important legislation.

As the Committee reviews the current state of pipeline safety and the progress that has been made since the PSIA became effective, there are a few points that we would like to emphasize.

- First, there is a growing recognition of the importance of the oil pipeline infrastructure to the American economy and the interrelations between pipeline safety, pipeline economic regulation and the essential energy supplies delivered through that infrastructure;
- Second, there has been tremendous progress in pipeline safety because of the PSIA, but there has also been much progress because of actions undertaken by the industry and by the Office of Pipeline Safety, even before the PSIA was signed into law;
- Third, while many of the initiatives of the PSIA are being implemented in a satisfactory manner and on schedule, this is not universally the case, and I will cite an important example at the intersection between pipeline safety and fuel supply where the Committee's help is needed; and
- Finally, a warning. We strongly believe that much of the progress that has been made in elevating the importance of pipeline safety and empowering the Federal role in ensuring the operation of an effective pipeline infrastructure is threatened by a reorganization plan that we understand is pending that would uproot the pipeline safety program and move it to the Federal Railroad Administration.

The Role of Pipelines in Petroleum Supply

About one-half of total U.S. energy supply comes from petroleum, with 95 percent of the energy that powers transportation derived from petroleum. Very few of the elements of the Nation's transportation system—the core of this Committee's jurisdiction—could operate without petroleum. Fully two-thirds of the ton-miles of domestic petroleum transportation is provided by pipeline. The total amount delivered by both crude oil and refined petroleum products pipelines is nearly twice the number of barrels of petroleum (14 billion) consumed annually in the United States.

The major alternatives to pipelines for delivery of petroleum are tank ship and barge, which require that the user be located adjacent to navigable water, and truck or rail, which are limited in very practical ways in the volume they can transport. In fact, pipelines are the only reasonable way to supply large quantities of petroleum to most of the Nation's consuming regions. Pipelines do so efficiently and cost-effectively—typically at 2–3 cents per gallon for the pipeline transportation cost charged to deliver petroleum to any part of the United States.

Oil pipelines are common carriers whose rates are controlled by the Federal Energy Regulatory Commission. Pipelines only provide transportation. Oil pipeline operators do not own or profit from the sale of the fuels they transport. Oil pipeline rates are not related to the price of the products oil pipeline operators transport. Oil pipelines move 17 percent of interstate ton-miles but only receive 2 percent of the total amount charged for interstate freight transportation, a bargain for the Na-

tion's economy that has been delivering needed fuel for American consumers quietly and effectively for decades.

The oil pipeline infrastructure is crucial to American energy supply. The care and stewardship of this critical national asset is an appropriate public policy concern and an important joint responsibility of the industry I represent, the Department of Transportation and Congress through this Committee.

I've included a report by Richard A. Rabinow entitled "The Liquid Pipeline Industry in the U.S.—Where It's Been and Where It's Going" prepared for AOPL that provides an overview of trends in the oil pipeline industry.

Progress Report on Pipeline Safety: Integrity Management

Companies represented by AOPL and API operate 85 percent of the Nation's oil pipeline infrastructure. Since March 2001, these operators have been subject to a mandatory Federal pipeline safety integrity management rule (Title 49, section 95.452) administered by the Department of Transportation's Office of Pipeline Safety. The oil pipeline industry's experience with pipeline integrity management preceded the enactment of the Pipeline Safety Improvement Act of 2002. Our operators will complete the required 50 percent of their baseline testing of the highest risk segments prior to the September 30, 2004 midpoint deadline set by the integrity management regulations. OPS has inspected the performance of each of these operators under these regulations at least twice—an initial "quick hit" inspection and a subsequent full inspection—and is proceeding with the second round of full integrity inspections. We have experience with the program that will be instructive to the Committee in its review.

The oil pipeline integrity management program is generating safety benefits that significantly exceed anything anticipated when the program was designed. To see how this is occurring, it is helpful to have a general understanding of how the integrity management program operates. The integrity management program requires integrity assessment, that is, regular safety testing with an internal inspection device (a "pig"), hydrostatic pressure or other equivalent means, and enhanced protections for those segments of pipe that "could affect" a "high consequence area". A "high consequence area (HCA)" is a defined term in the regulations that means a commercially navigable waterway, a high population area or an area unusually sensitive to environmental damage. Such unusually sensitive areas are also defined in the regulations. Each operator must have a process to determine whether a segment of pipe "could affect" an HCA. The process must consider a range of factors, such as the terrain, the volume and type of oil in the pipe and the physical ways oil released from the segment of pipe might impact the HCA.

In 2000, OPS estimated that under the proposed integrity management system approximately 22 percent of the pipeline segments in the national oil pipeline network would affect an HCA and therefore that operators in aggregate would be required to assess and provide enhanced protection for 22 percent of the national system. In fact, when oil pipeline operators carried out their analyses of how many of their segments could affect the high consequence areas that were actually identified under the regulations, it turned out that almost twice as many segments, 43 percent of the pipeline network nationally, could affect an HCA. So the benefits in theory are nearly twice as large as originally estimated.

But in fact, the benefits are even larger than that. The predominant method of testing oil pipelines utilizes internal inspection devices. The ports at which these devices are inserted into and removed from a pipeline are fixed in the system. These locations were established prior to the advent of integrity management regulations and without regard for the location of HCAs. The internal inspection devices therefore travel between ports, generating information about all the segments between those ports, whether they affect an HCA or not. As a result, as shown in OPS inspections of operators' plans, it is estimated that integrity testing will cover approximately 82 percent of the nations' oil pipeline infrastructure. Thus the actual mileage tested is almost four times the original OPS estimate.

Operators are finding and repairing many conditions in need of repair and many less serious conditions that are found near defects. For every condition repaired under the rule, approximately six other conditions are excavated and evaluated. Operators are fixing what they find, often going beyond the requirements of the law. The largest cost to the operator is in the scheduling and renting of the internal inspection device, obtaining the permits and carrying out the excavation, so once the pipeline is uncovered, operators fix many conditions that might never have failed in the lifetime of the pipeline. This result is a huge additional benefit to pipeline safety that will reduce the risk of pipelines to the public far into the future.

The benefit of the integrity management rule is much greater than originally estimated, so is the cost. Costs per operator that were estimated in the hundreds of

thousands of dollars are actually turning out to be in the tens of millions of dollars. Operators have nevertheless moved aggressively to provide the resources needed to implement integrity management.

Integrity Management Conclusions

What are the lessons of this experience?

OPS's integrity management program, which relies on the initiative, judgment and priorities of individual pipeline operators, is producing major benefits for the public and the environment without prescriptive regulation. The program is a mandatory one, so operators must participate, must carry out regular testing of their pipelines and must act promptly to address risks. But the operator has flexibility under the program in designing and administering the plan for testing and repair subject only to periodic inspection reviews by OPS. This partnership is proving enormously successful without resort to prescriptive, detailed regulations, intrusive second-guessing of operator decisions or aggressive enforcement with fines and penalties. Operators have been incurring the costs required to find the conditions that need repair, to make the repairs and to protect the lines for the future without specific assurance that these costs will be covered in the rates allowed by the Federal Energy Regulatory Commission. The integrity management program has been successful without resort to the threat of punishment or the need for financial incentives because the program aligns the interests of the operator and the regulator—to adopt the most effective and efficient preventative measures to keep the oil in the pipe. The recent spill and accident record of the pipeline industry (see charts) only underlines this success. It turns out to be true that the best investment for the operator and for the public is leak prevention.

Pipeline Safety: The Pipeline Safety Improvement Act of 2002 and More

In the Pipeline Safety Improvement Act of 2002 Congress endorsed the integrity management approach to pipeline safety that OPS had been administering with the oil pipeline industry at the time of enactment and extended the integrity management concept to natural gas transmission pipelines. In addition, the PSIA contains important provisions:

- Coordinating permitting by Federal agencies so that pipeline repairs can be carried out in a timely manner;
- Strengthening the qualifications of pipeline personnel and contractors;
- Ensuring that pipeline operators are active in promoting public awareness of pipelines along pipeline rights of way;
- Increasing OPS outreach to states and state regulators to assist with OPS activities;
- Authorizing a promising research and development program to develop better pipeline safety technology;
- Establishing a nationwide, toll-free three-digit telephone number to connect excavators to their local call-before-you-dig, one-call notification center;
- Supporting a study of pipeline right of way encroachment issues through the Transportation Research Board of the National Academies of Science and Engineering; and
- Authorizing adequate funding for the operation of the Office of Pipeline Safety;

In our view, the OPS has been very aggressive in seeking to implement these PSIA provisions and, with one exception that I will mention below, the progress achieved has been excellent. In addition, OPS has been responding to and satisfactorily addressing Congressional mandates from the time before the PSIA and outstanding National Transportation Safety Board, General Accounting Office and DOT Inspector General safety recommendations. Here the progress has been truly impressive. We anticipate that by the end of 2004 nearly all outstanding mandates and recommendations to the agency will have been appropriately addressed. Finally, OPS has been playing a very important role in assisting the pipeline industry and the Department of Homeland Security in developing a security program to protect critical pipeline infrastructure.

Pipeline Repair Permit Streamlining

An important initiative of the PSIA that needs the Committee's encouragement is the implementation of section 16, "Coordination of Environmental Reviews", which is concerned with expediting the repair of pipeline defects. Some limited progress has been made on implementing this section, but the largest portion of the

work remains to be done, and the deadlines for agency action under the provision have passed.

Under section 16 a Federal Interagency Committee on Coordination of Environmental Reviews for Pipeline Repair Projects has completed a Memorandum of Understanding that lays the foundation for a Federal pipeline repair permit streamlining process, but this MOU does not actually contain the provisions needed to effectuate the streamlining. Rather, it establishes a Working Group of Federal agency personnel to develop a joint regulatory approach to streamlining (which may rely on existing regulations of the participating agencies or may recommend changes to certain regulations). A successful Federal streamlining process will help with Federal permitting and also provide a model for state and local permitting agencies to follow. However, to our understanding the draft MOU of March 4, 2004 has not yet been signed by all the participating agencies and so is not effective. Nevertheless, the Working Group has held several meetings since the draft MOU became available, although to date the pipeline industry permitting experts have not been allowed to brief the Working Group or review its plans to see if any of the Working Group's proposals will actually facilitate pipeline repair permit streamlining.

A central theme of the PSIA is safety through prevention. The purpose of section 16 is to accelerate actions that prevent pipeline releases. OPS requires pipeline operators to investigate the condition of their pipelines on a regular basis and act within a time certain to repair any defects discovered that are judged to require repair. The more severe the defect, the shorter the time-frame required to make the repair. Pipeline repair will typically involve an excavation to uncover the buried pipe at the location of the defect on the pipeline right of way, and any such excavation in general requires a series of permits, some federal, some local, and most designed to protect the environment. The purpose of section 16 is to ensure that Federal agencies involved in permitting for such excavations coordinate so that pipeline operators are allowed to make the repairs that are needed in the timeframes required by the regulations. The coordination envisioned would not affect existing environmental law, but might require some adjustments to the existing regulations of some of the environmental permitting agencies.

The goal of section 16 is to see that the priority on pipeline safety set by this Committee and, through this Committee, by the Congress as a whole is implemented and is not frustrated because, although defects are discovered in a timely fashion to prevent releases, the permitting delays block carrying out the repairs needed to effectuate this prevention. The purpose of section 16 is to ensure timely actions required by one Federal agency—OPS—in the name of pipeline safety are not blocked by one or more other Federal agencies that do not have pipeline safety as a priority.

Pipeline repair permitting delays can also have an impact on energy supply. When a pipeline defect cannot be repaired within the time limits set by OPS, the pipeline operator must reduce pipeline pressure, and therefore throughput, by an amount that depends on the suspected seriousness of the defect—a greater reduction for defects that are more likely to be severe, but the reduction is typically at least 20 percent. Many operators reduce pressure on discovery of a potential defect. Once the repair is complete the operator is allowed to return to normal throughput.

The Number of Pipeline Excavations is Large Now and Will be Much Larger in the Future

Under OPS rules for oil pipeline operators, tens of thousands of potential defects are being discovered and repaired annually. As of December 31, 2003, the largest 47 oil pipeline operators have undergone inspection by OPS covering 97 percent of the mileage operated by these companies. These are the operators who eventually plan to include approximately 82 percent of their mileage in the mandatory testing program, even though strict requirements of the regulation would only require 43 percent of their mileage to be tested. According to OPS data as of the date of their respective first full inspections, these operators had carried out 4,344 time-sensitive repairs and 16,081 other repairs. Time sensitive repairs are those judged potentially serious enough that OPS regulations stipulate a repair deadline. These numbers underestimate the total volume of repairs prior to December 31, 2003 because they only include the repairs completed prior to each operator's particular inspection date, all of which occurred before December 31, 2003.

Completion of over 4,000 time-sensitive repairs is a success story of sorts, but it is not without some impact on the capacity of the Nation's petroleum delivery system. Many of those repairs involved pipeline pressure reductions. When a pipeline system operates at lowered pressure, its capacity is often reduced, increasing the likelihood of supply shortages, which generally puts upward pressure on petroleum

prices. We do not know the extent to which the Nation's current oil pipeline capacity has been reduced because of pressure reductions occasioned by repairs.

There is also no assurance that the required federal, state and local permits for pipeline repair activity can be obtained in a timely way even when Federal regulations set a clear deadline for completion of the repair. In the absence of full implementation of section 16 there is currently no organized process to streamline the pipeline repair permitting process to ensure that all involved are doing what they can to see that the Nation's fuel supply system is not limited by capacity restrictions. It seems to us that it would be prudent to put such a process in place, as the PSIA wisely requires.

We have been asked to forecast the magnitude of the permitting problems the pipeline industry will face in complying with OPS pipeline integrity management rules. We will try to respond. The oil pipeline integrity management regulations have been in effect since 2001, so our industry has some experience that can be used to try to answer this question.

One thing is clear: the "where" and "when" associated with complex permitting problems is inherently uncertain. It depends on where the apparent defects show up in testing, and that cannot be known in advance. While the industry has much experience with pipeline repairs that predates the pipeline integrity regulations, the sheer number of tests and repairs being executed and the existence of mandatory Federal time deadlines for completing particular repairs are unprecedented in the industry. We are learning as we go along.

An anecdote: a pipeline operator recently completed an internal inspection of a segment of pipe that produced approximately 100 potential repairs that under OPS rules appear to require completion in 180 days. The operator estimates that more than half of the required excavations for repair can be carried out routinely and another 40 can be carried out with the use of an Army Corps of Engineers Nationwide Permit. However, there are 3-5 excavations needed in locations that, at this time, the operator is not sure that permits can be obtained in time to complete the repair. So a large number of repairs will be made without special permitting concerns and a significant number of additional repairs can probably be made because of a pre-existing Federal permit-streamlining program. However, this pipe segment may nevertheless reduce pressure because of a few instances where there is no process in place to ensure the operator can obtain the necessary Federal permits that will allow them to meet the Federal repair deadline.

The burden on federal, state and local permitting agencies will increase as the OPS program of integrity management for natural gas transmission pipelines takes hold and as state integrity management programs for intrastate pipelines that mimic the Federal program are implemented.

Attached to my testimony are a number of recent examples that illustrate the very practical difficulties that arise for operators seeking in approval of the various repair site access permits required by federal, state and local agencies that have not been encouraged and are not organized to accord the same priority to pipeline safety that this Committee and OPS expects.

Recommendations on Pipeline Repair Permit Streamlining

The pipeline industry has several recommendations that we believe would foster progress towards effective pipeline repair permit streamlining:

- Agree to allow representatives of the pipeline industry who are experts in pipeline repair permitting to meet with the Working Group to serve as a resource in providing information about what is likely to be useful in expediting pipeline repairs.
- Work with industry to develop a set of pre-approved pipeline repair site access, use and restoration Best Management Practices such that a commitment by an operator to adhere in good faith to such BMPs would result in expedited permission to access repair sites to carry out the repair from any of the signatory agencies either through use of that agency's emergency procedures or another approach that allows the repair to be completed within the timeframes specified by DOT regulation.
- Commitment to use pre approved BMPs should result in a presumption of compliance by the operator with the requirements of the BMPs and a presumption that actions beyond restoration to pre-construction condition will not be required if BMPs are followed.
- BMPs should be habitat-specific rather than species-specific so that multiple species protection can be obtained within a single umbrella BMP.
- Coordinate multi-agency response to requests for permits such that involved agencies operate in parallel or in concert to issue all required permissions (not

just that of certain agencies) to the operator in a timely fashion to allow the repair to be completed within the timeframes specified by DOT regulation. To the extent possible the permitting process should be consolidated to limit to one the number of permits required (a consolidated permit). A process is needed to ensure that Federal agencies are aware of the relationships in permitting pipeline repairs among federal, state and local requirements and can act accordingly to achieve the goal of section 16.

- With respect to compliance with the Endangered Species Act, establish an agreement between the Department of Transportation and the Department of the Interior under which DOT will voluntarily assume the role of default coordinator, or a “nexus” by any other name, for pipeline repairs in those cases where no other Federal agency is available or able to act as the Federal nexus for ESA consultation. This agreement would stipulate that DOT’s voluntary participation in a coordination role for pipeline repairs does not mean that ordering or providing for pipeline repairs through regulation is a Federal action subject to the ESA or the National Environmental Policy Act.

The Federal government and the pipeline industry should be natural partners in seeing that the OPS integrity management program succeeds. The pipeline safety goals of the industry and the government are entirely aligned in this program. Done properly, pipeline repair permit streamlining will help significantly to ensure the success of this program, while reducing the burden on federal, state and local permitting agencies and allowing these agencies to focus resources on much more serious environmental problems. Done properly, pipeline repair permit streamlining will ensure the safety and reliability of the Nation’s pipeline infrastructure. Done properly, pipeline repair permit streamlining will reduce the risk of higher fuel prices to the Nation’s consumers.

The oil pipeline industry stands ready to work with the Interagency Committee and the Working Group to provide the information and any other assistance needed to carry out the intent of section 16 of the PSIA.

Proposed Transfer of OPS to the Federal Railroad Administration

Let me turn to a troublesome subject.

In December 2003 we were informed that Secretary of Transportation Norman Y. Mineta intended to propose a reorganization of the Department of Transportation as a part of the FY 2005 budget. As part of this proposal, the Research and Special Programs Administration, which houses the Office of Pipeline Safety, would be abolished and reinvented as the Research and Technology Innovation Administration, an entity built around the Department’s Volpe research center and devoted to transportation research and development. As a consequence, the Office of Pipeline Safety (and other “special programs” in the former RSPA) would be left without a home in the Department. The Secretary’s proposed solution for the OPS would be to transfer the pipeline safety program to the Federal Railroad Administration, an existing DOT administration governing a mode judged to be most similar to pipelines.

The oil pipeline industry and the members of AOPL and API have great appreciation for Secretary Mineta and all he has done to improve the programs of the Department of Transportation, including the pipeline safety program. However, our members’ reaction to the proposal to sever the pipeline safety program from its existing location and place it under the Federal Railroad Administration was uniformly negative.

There has been a sea change in pipeline safety in the last several years, and the Federal pipeline safety program has gained impressive and much-needed momentum. The quality and credibility of the program administered by the Office of Pipeline Safety has been immeasurably strengthened, and this strengthening is both recognized and augmented by Congress’ unanimous enactment of the PSIA. OPS’s successes have been accomplished through the hard work and creativity of its employees and particularly because of its very effective leadership during this period. We feel very strongly that this progress must continue. We have come a long way in pipeline safety, but we still have much further to go.

We believe the Secretary’s proposal, if implemented, would inevitably disrupt the momentum the agency has worked to hard to create in the past several years. The period required to re-establish this momentum can’t be known for sure, but we believe it would be measured in years, not months. This would be much more than a loss for OPS. It would be a loss for Congress, the public and for pipeline safety.

There are several reasons for our grave reservations about the Secretary’s proposal.

- As indicated above, the proposal is not likely to be neutral in terms of performance. Pipeline operator experience with mergers in the private sector teaches

that merged activities are very susceptible to a loss in momentum, particularly for the lesser of the merger partners, and often for both. The pipeline safety program has made very considerable progress in gathering strength and credibility in the last five years and is currently heavily engaged in the implementation of PSIA initiatives. Loss of this momentum through a transfer to a subordinate position in a substantially different program such as that of FRA would be a very serious concern for the pipeline industry.

- *The proposal is not likely to be neutral in terms of flexibility and responsiveness.* The Office of Pipeline Safety, operating within RSPA, has been very creative in finding solutions to problems. OPS has established a successful and very well-regarded pipeline safety research and development program that has attracted substantial private sector interest while requiring peer review and at least 50 percent private matching funds. OPS has been an active partner in creating the Common Ground Alliance, a non-profit organization focusing resources on preventing damage to pipelines and other underground facilities. OPS is leveraging the work of the National Association of State Fire Marshals to improve the understanding of pipeline issues in local fire departments and to provide more informed public participants in pipeline safety at the local level. OPS has been successfully addressing pipeline safety concerns of the National Transportation Safety Board, effectively closing almost every recommendation of the Board. OPS has continually worked to improve its relationship with the states that have active intrastate programs and states that don't. We believe it is critical to the credibility of OPS that these initiatives maintain or accelerate momentum under a reorganized DOT.
- *The proposal does not recognize competition between railroads and pipelines.* Liquid pipelines and railroads each transport petroleum. In certain markets there is therefore business competition between railroads and pipelines. All pipelines contest vigorously with railroads over the terms and conditions of railroad right of way crossings. The merged pipeline-railroad entity could influence this competition in favor of one side over the other, most likely to the detriment of the lesser merger partner.
- *The proposal is not likely to be neutral in terms of budget.* Most Federal umbrella organizations like RSPA provide generic services to the programs they house. OPS uses generic services provided by RSPA. These include information technology (OPS uses IT heavily); training; regional office support; advisory committees (two); budget development; procurement and contracting; legal and policy support; and state programs. Currently, FRA capabilities and expertise do not match RSPA's in the services used by OPS. Replicating these services within FRA would increase the cost of the merger by an estimated 5–10 percent, while likely failing, at least initially, to provide services fully replacing those that had been received from RSPA.
- *Separation of budgets would be required.* OPS is fully funded by the transmission pipeline industry through user fees and the Oil Spill Liability Trust Fund; FRA is taxpayer funded. Equity would require careful separation of budgets in the merged organization so that pipeline operators do not subsidize railroad operations.
- *The Federal Railroad Administration's budget is volatile.* FRA's budget includes Amtrak funding at several hundred million dollars (\$1,218 million in 2004 enacted, \$900 million in 2005 as proposed, with Amtrak recently estimating that \$1,800 million is actually required in 2005). Routine fluctuation in FRA's budget annually significantly exceeds the amount of the entire OPS budget. Within the merged railroad-pipeline entity, there may be significant uncertainty or actual fluctuation in the budget amounts available to the pipeline program relative to the experience in RSPA.

HR 4277

We were very pleased to see the introduction by the Chairman of the House Transportation and Infrastructure Committee, Rep. Don Young (R-AK), of H.R. 4277, the Pipeline Safety Administration Establishment Act. This legislation would establish an independent pipeline safety administration with the Department of Transportation with minimal disruption of OPS activities.

Our support for the legislation is based first of all on its merits. As I have testified, we believe the Federal pipeline safety program has become much stronger and more effective in recent years and the importance of the program and the infrastructure it oversees has received greater recognition than in the past. The Federal pipeline safety program deserves greater organizational recognition in the Department that befits its importance to the Nation.

We also welcome Chairman Young's initiative in introducing H.R. 4277 because it provides a significant alternative to the Secretary's proposal to place the pipeline safety under the Federal Railroad Administration and changes the nature of the conversation about the appropriate organizational structure for the program. The five associations that represent the Nations' oil and natural gas pipelines recently expressed our views on H.R. 4277 and the Secretary's proposal in a joint letter to Chairman Young. I have provided a copy of that letter for the Committee's records.

The tests for any new organizational structure for the Federal pipeline safety program are whether it strengthens the program, whether it helps make the program more effective and credible and whether it will further the hard work ahead to continue the progress the program has made. We plan to judge any proposal for structuring the pipeline safety program based on these tests.

The oil pipeline industry supports competent, effective, and credible Federal pipeline safety regulation. The nature of the commodities carried in oil pipelines and the level of public confidence pipeline operators are able to inspire mean some level of oversight is inevitable. Public confidence in the safety of pipelines, and our ability to continue to operate pipelines with the public's trust depends on the perception and the reality of competent oversight. The interstate character of the business and, indeed, the interstate character of the physical facilities themselves, require that the Federal government have the primary responsibility for this oversight. We therefore strongly believe that pipeline safety oversight should be housed in the U.S. Department of Transportation. If the structure governing the pipeline safety program within DOT has to change, we would urge the Committee to very carefully consider the impact of the change on stature of the program and the implications for the highly important service pipelines provide to the Nation.

The PSIA set an ambitious but highly appropriate course for the Federal pipeline safety program. H.R. 4277 opens the dialogue on the proper organizational structure to complement and facilitate the success of that program. The pipeline members of AOPL and API look forward to working with the Committee as this dialogue moves ahead.

Conclusion

Thank you for the opportunity to testify before the Committee on these important matters. The Committee's work product, the PSIA, is in our view a significant success, but all those interested in pipeline safety have much work ahead of us if we are to fully achieve the purposes of this very important legislation. Our industry pledges to seek alignment with the OPS to the maximum extent practicable in this important task.

We need help from this Committee to ensure that a key section of the legislation, section 16, relating to pipeline repair permit streamlining, achieves the full intent of Congress and is effective in fostering a safer and more reliable pipeline infrastructure. We also ask that the Committee carefully consider the issue of the proper organizational structure within the Department of Transportation for the Federal pipeline safety program, an issue that has been raised by the Secretary in his proposed reorganization of the Department and by the legislation introduced by Chairman Young.

Thank you very much.

PIPELINE INTEGRITY MANAGEMENT PROGRAM—CASE STUDY SUPPORTING A STREAMLINED PERMITTING PROCESS—CASE STUDY 1

Situation involves replacement of a line with dents. A series of dents are located on one piece of pipe in the middle of the pipeline crossing of the Delaware River. We ran in-line inspection tools and found the dents.

The situation prohibits repair in place so we will have to drill and pull into place a new pipeline segment across the Delaware River, from New Jersey to Pennsylvania shores, in the Philadelphia area.

This requires permits from the Core of Engineers, Fish and Game Commission, Commonwealth of Pennsylvania, State of New Jersey, local township(s), and the Philadelphia Airport. The permitting process (preparation, submittals, administration and technical reviews, revisions, final approval, etc.) takes more than one year to complete, of which 240 days alone are required for administrative and technical reviews.

In accordance with OPS Integrity Management regulations, we reduced the pipeline operating pressure once. Since further remedial action is required if we cannot complete repairs within 365 days, we have had to reduce the pressure again, while

in the process of obtaining all of the above mentioned permits and completing the pipeline replacement.

PIPELINE INTEGRITY MANAGEMENT PROGRAM—CASE STUDY SUPPORTING A
STREAMLINED PERMITTING PROCESS—CASE STUDY 2

Project Overview: In California, a pipeline company initiated a project in 2002 to conduct investigations of anomalies identified during a pipeline “smart pig” inspection survey run in 2001 that identified over 45 anomalies. The pipeline traverses environmentally sensitive habitat including freshwater wetlands, tidally influenced marshland, and habitat supporting several federally-and state-listed plant and animal species. The permitting process is complicated by various work windows that prevent or limit maintenance activities during specific times of the year along the pipeline right-of-way (e.g., seasonal flooding conditions, breeding and nesting seasons for listed species, etc.). These anomaly dig locations were similar to digs pursued in 2001 from a 1999 “smart pig” survey that took 14 months to process the permits.

Overview of Permitting Process: The project took 10 months to permit. Permitting involved four different Federal and state regulatory agencies. The U.S. Army Corps of Engineers (ACOE) was the lead agency for permitting. They were involved because the dig locations were located within “waters of the United States”. The U.S. Fish and Wildlife Service (USFWS) were also involved due to the potential presence of the federally protected species including endangered vernal pool tadpole shrimp, the threatened vernal pool fairy shrimp, the threatened giant garter snake, the endangered salt marsh harvest mouse, the endangered California clapper rail, the threatened Sacramento splittail, and the threatened Delta smelt. California agencies involved were the California Regional Water Quality Control Board (RWQCB) and the San Francisco Bay Conservation and Development Commission (BCDC).

Applications for digs indicated by the inspections were submitted in August 2002 for the following permits:

- ACOE Section 404 Pre-construction Notifications under Nationwide Permit 3;
- RWQCB 401 Water Quality Certifications triggered by the 404 process;
- Endangered Species Act (ESA), Section 7 biological consultation with the USFWS; and
- BCDC permit waiver pursuant to Section 29508 of the Suisan Marsh Preservation Act.

After the notification was submitted to the ACOE, the ACOE waited until May 2003 to send its letter to the USFWS to initiate the Section 7 consultation in May 2003. Fortunately, the applicant had been working with USFWS for months preceding the May 2003 letter from ACOE. Only because work was initiated and pursued by the operator on parallel tracks could final permits be issued in June 2003.

Approximately 70 permit conditions were included in the four permits. Permit conditions addressed the following general areas:

- Protecting soil and water from contamination during repair activities;
- Protection of the federally protected species during construction;
- Restoration of the areas to pre-construction conditions; and
- Mitigation for the impacts to species and habitat.

Lessons Learned from Case Study: There are a number of ways to improve the permitting process. Ten months is too long to permit relatively straightforward pipeline repair activity. It is not possible to meet the OPS rule repair time limit (e.g., immediate to 6 months) at locations where environmental permitting (with its extensive agency interactions) is required.

Ways to streamline the permitting process include:

- Streamlining the ACOE permitting process to expedite pipeline repairs while protecting the environment. Agency pre-review and approval of relatively routine activities prior to their commencement is not necessary. An alternative approach is to develop a set of Best Management Practices (BMPs) to protect the environment during repair activities, possibly similar to a Habitat Conservation plan or a nationwide Permit, that includes all jurisdictional agencies. Repair activities that use these BMPs would no longer require prior review and approval.
- ACOE permitting in states such as California is sequential, i.e., the ACOE reviews, then request consultation with the USFWS. Each agency approves a permit before they pass the ball to the next regulatory agency. Instead there

should be a parallel review process. For projects that do not qualify to use BMPs, OPS could act as a n ombudsman to resolve permitting issues among the various agencies and improve the safety of pipeline.

- Alternatively, for projects that require agency review, a site-specific plan for conducting the pipeline repair could be developed and submitted to the appropriate agencies for their review. If agencies did not respond after an appropriate interval consistent with time requirements in the 2001 OPS IMP rule the repair project could proceed under the 'safe harbor' of the conditions proposed in the applications.

PIPELINE INTEGRITY MANAGEMENT PROGRAM—CASE STUDY SUPPORTING A
STREAMLINED PERMITTING PROCESS—CASE STUDY 3

A 20" diameter products pipeline was scheduled to undergo an in-line inspection in accordance with DOT's Integrity Management Rule. The inspection on this system was scheduled such that the operator would expect to receive the tool data during June 2004.

A portion of the subject pipeline system traverses the Louisiana Coastal Management Zone which is under the jurisdiction of the Louisiana Department of Natural Resources, Coastal Management Division (CMD). Other agencies with jurisdiction over the pipeline's inspection include the U.S. Army Corps of Engineers (USACE) and the Parish Coastal Zone Management Committee.

In anticipation of the upcoming inspection, the operator filed an application with the CMD for an "Area Permit". The Area Permit is a relatively new permitting process utilized by the CMD (it was promulgated in October 2003) and is supposedly a streamlined process for allowing more timely pipeline repairs. The intent behind the Area Permit is to function as a general permit for the entire pipeline system within the Coastal Zone; however, the Area Permit does not authorize individual IMP repairs. Individual repairs are not authorized until the operator has provided the agency with site specific information about each repair location. The CMD suggests that once an operator has received Area Permit approval, individual IMP repairs can be authorized very quickly once the operator has provided the site specific information.

During early coordination with the CMD, the agency advised that they would be coordinating their review and approval of the Area Permit application in conjunction with the USACE. In fact, the operator was instructed to complete the USACE's standard permit application form (Form 4345) as part of the application package. However, during later discussions with the USACE, the operator learned that the USACE does not recognize the Area Permit as a valid permitting mechanism.

Despite the efforts in Louisiana to streamline the permitting process for IMP repairs, the Area Permit process seems to need further refinement in order to be truly valuable to pipeline operators. First, the CMD needs to understand that in the event of immediate conditions, there is often very little time to prepare the necessary site specific information including taking photos of the repair locations, generating maps of repair locations, etc. and get this information submitted to the CMD prior to initiating any repair activities. The impacts caused by IMP repairs, even in environmentally sensitive areas such as the Coastal Zone, are general minor and temporary in nature and should not warrant such extensive review.

Secondly, there appears to be a disconnect between the CMD and the USACE regarding the validity of the Area Permit process. Better coordination between these two agencies could result in the development of one permitting process that would address impacts caused by IMP repairs to "waters of the US" as well as impacts to the Coastal Zone.

Due to the uncertainty of being able to effect repairs, should the circumstance arise, the operator has temporarily postponed an In-line Inspection (but will still meet the regulatory deadline) of this system in order to get the permits in place. If the permits are not obtained by the regulatory deadline, and the operator is forced to shut down the system after conducting the In-line Inspection (and unable to effect repairs in a timely manner), there could be a potential loss of motor fuel supply to the Southeast/East Coast of up to 9,800,000 gallons per day. That could equate to (assuming 25 gallons of motor fuel are used to fill up an average vehicle) 392,000 vehicles per day that could be forced to look elsewhere for fuel, if it were available.

PIPELINE INTEGRITY MANAGEMENT PROGRAM—CASE STUDY SUPPORTING A
STREAMLINED PERMITTING PROCESS

Early 2002, a deformation with metal loss was identified on a pipe; under the IMP rule, this is an immediate condition. The geographical location of the pipe is within a large wetland complex and within the boundaries of a State Game Area which is managed by the Michigan Department of Natural Resources.

It was determined that this condition met the requirements of a Safety Related Condition as stated in 49 CFR 195.55 due to its location within an HCA. As such, operating pressure on the system was reduced by 20 percent and a SRC Report was filed with OPS five days after discovery.

Excavation and repair of this condition required a Land and Water Management (LWM) Permit which is a joint permitting process between the USACE and Michigan DEQ for Clean Water Act Section 404/401 impacts. A Special Use Permit was needed from Michigan DNR for working within the State Game Area. A Soil and Erosion Control Permit from the Muskegon County Department of Public Works was also required.

The unusual site conditions presented some challenges for accessing and dewatering the repair area since it was located in the middle of the expansion wetland and under approximately 4 ft. of water. It took several days to finalize the repair methodology which was needed prior to submitting the permit applications.

Once repair plans had been finalized, LWM permit applications were simultaneously submitted to the USACE and MDEQ 34 days after the initial find. Approximately one month (28 days) later, both agencies requested additional repair drawings. The drawings were provided to both agencies within 10 days of their request. The issuance of LWM permit approval was finally received 76 days after the initial discovery and 43 days after the application was submitted. 13 days after issuance of the LWM, authorization was received from the USACE under Nationwide Permit 12.

An attempt to investigate and repair the condition ensued 110 days after discovery, but because of the depth of the water and substrate, the work could not be executed in the manner authorized under the above reference permits.

A revised repair methodology was submitted to USACE and MDEQ 4 days later, requesting that the previously issued permits be modified to allow for the new construction techniques. MDEQ responded to this permit amendment request exactly one month later, via letter authorization. Similarly, the USACE responded 37 days after the revised request was submitted, by authorizing the work under Nationwide Permit 33. The repairs were finally completed 237 days after the discovery; more than six months after permitting efforts were initiated.

It should be noted that only the USACE and MDEQ permit authorizations were difficult to obtain. The Special Use Permit and the Soil Erosion Control Permit were both obtained within only days after applications for these permits were filed.

Reducing the pressure on this system has the net effect of removing 7,600 barrels/day of refined products from the market. Had this situation occurred in June, 2000, it would have further exacerbated the supply issue that was occurring in the State of Michigan at that time.

PIPELINE INTEGRITY MANAGEMENT PROGRAM—CASE STUDY SUPPORTING A
STREAMLINED PERMITTING PROCESS—CASE STUDY 5

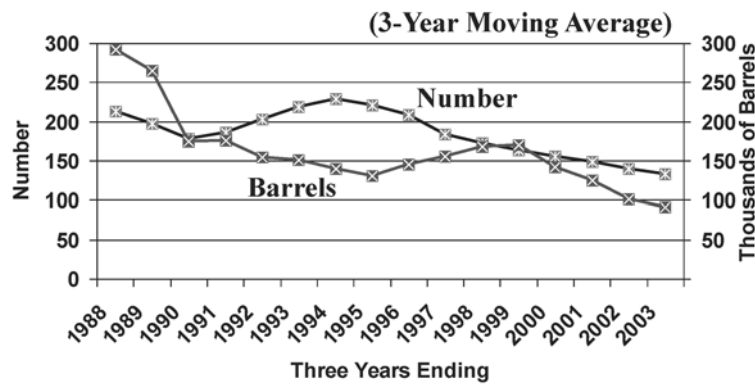
The Integrity Management Rule requires certain pipeline defects repaired within specific timelines. If these timelines cannot be met, a 20 percent operating pressure reduction must be taken until the defect is repaired or the system is otherwise modified to allow continued safe operation. In certain markets, this reduction in operating pressure can potentially reduce supply by more than 200,000 barrels per day (nearly one million gallons per day) having significant impacts on supply. In the fourth quarter of 2003 when distillate demand to the northeast is high, a pipeline repair could not be made within the 180-day time frame forcing a 20 percent pressure reduction on the pipeline. Within two weeks it became apparent that supplies to New York markets could be jeopardized. Numerous reasons attributed to the repair not being completed in the 180 days. One of which was permitting that eventually took 18 months and significant resources to obtain the proper permit for the appropriate repair method needed to complete the repair. Acquisition of the final permit that provided a practicable repair solution required a five month period and involved extensive lobbying of twelve Federal, State, and local environmental agencies, the Governor's office, and other resource stakeholders and interest groups.

In the meantime, other system changes were made to allow continued operation at normal operating pressures. In absence of these solutions, shortages in jet fuel

to key northeast airports as well as significant shortages of heating oil to northeast markets were probable. Furthermore, operation of refineries in the Gulf Coast and at least one additional pipeline in the northeast would have been impacted.

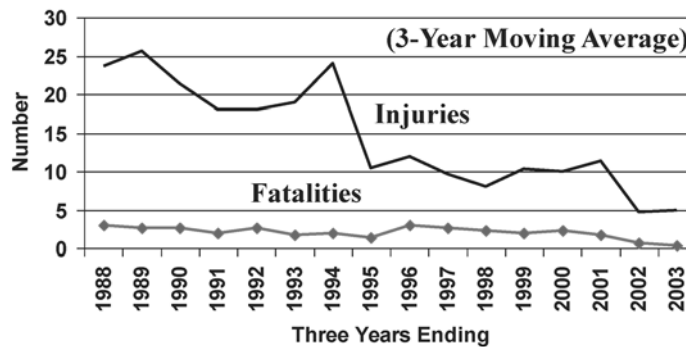
Near misses such as the one described above underline the need for permit streamlining. Coordination is necessary among pipeline operators, federal, state and local permitting agencies and the OPS. The Pipeline Safety Improvement Act was meant to protect public safety and the environment. Through permit streamlining, the intent of the Act and all stakeholders' objectives will be met along with timely repairs to pipelines, protection of the environment, and maintaining stability in fuel markets.

Oil Pipeline Releases and Safety Incidents



Source: Based on Office of Pipeline Safety, http://ops.dot.gov/stats/liq_sum.htm

Oil Pipeline Fatalities and Injuries (Public, Employee, Contractor)



Source: Based on Office of Pipeline Safety, http://ops.dot.gov/stats/liq_sum.htm

The Liquid Pipeline Industry
in the United States:

Where It's Been

Where It's Going

A Report prepared for the
Association of Oil Pipe Lines
by
Richard A Rabinow
April, 2004

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Table of Contents

Overview: The Liquid Pipeline Industry	1
Themes	5
The Liquid Pipeline Industry is Extremely Diverse	5
Decisions are Driven by Economic Analysis	6
The Liquid Pipeline Industry is Increasingly Proactive Regarding Environmental, Safety and other Matters of Public Interest	7
Right-of-Way Matters have become Major Challenges	8
Economic Regulation is Costly	9
Trends	11
The Need for Liquid Pipelines	11
Historical Overview	11
The Customers	14
The Commodities	15
Regional Considerations	21
Competition with Other Transportation Modes	27
Ownership Structure of the Liquid Pipeline Industry	28
Operational Factors	32
Operations Integrity	32
Security	34
Rights-of-Way	35
Capacity Management	36
Maintaining Product Quality	37
Field Operations	39
Work Force	41
Community Involvement	42
Costs	43
Legislative and Regulatory Impacts	45
Economic Oversight	46
Environmental Protection	48
Safety Oversight	49

Impact of Technology	49
Constructing, Operating and Maintaining Pipelines	49
Reducing Risk	51
Managing Costs	52
Summary --- The Outlook	53

List of Exhibits

1. Fact Sheet - US Liquid Pipeline Industry	4
2. Petroleum Overview 1950 to 2025	11
3. Selected Crude Oil Trunk line Systems	12
4. Major Refined Product Pipelines	13
5. Crude Oil Production and Oil Well Productivity 1950 to 2025	16
6. Petroleum Imports and Exports 1950 to 2025	16
7. Refineries: Input & Output and Number 1950 to 2025	18
8. Petroleum Products Supplied by Type 1950 to 2025	19
9. Petroleum Administration for Defense Districts	21
10. Daily Supply & Disposition of Crude Oil and Petroleum Products, 2001	22
11. Operational Parameters by PAD District, 2001	22
12. Oil Spill History: An Improving Record, 1968 to 2001	33
13. Typical Sequence of Petroleum Products Flow Through a Pipeline	39
14. Average Pipeline Cost Distribution 1990 to 1998	44

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About the Author

Richard A Rabinow retired from ExxonMobil Pipeline Company on April 1, 2002 after almost 34 years of service with ExxonMobil and its predecessors. Early in his career Mr. Rabinow held various assignments in the refining and supply functions, including the position of Manager of the Baytown Refinery during the mid-1980s. Thereafter he served as the Manager of the Office of Corporate Affairs and Manager of Environment and Safety for Exxon Company, USA.

Mr. Rabinow's association with pipelines began in 1993 when he served on the steering committee for an operational assessment of the Trans Alaska Pipeline System. A subsequent loan assignment as Senior Vice President of the Alyeska Pipeline Service Company was followed by his transfer to the Exxon Pipeline Company (EPC) and in early 1996 he was elected President. During his seven years as president of EPC and ExxonMobil Pipeline Company Mr. Rabinow also served on the TAPS Owners Committee, including a two-year term as Chairman, and on the Boards of Plantation Pipe Line Company and Yellowstone Pipeline Company. He also was active in AOPL and API activities and served a term as Chairman of AOPL.

Mr. Rabinow was educated at Lehigh University where he earned a Bachelor's Degree in Engineering Mechanics and at the Massachusetts Institute of Technology where he received Master's Degrees in Mechanical Engineering and in Management.

Overview: The Liquid Pipeline Industry

*Critical
Infrastructure:
Stability,
Diversity, and
Safety for
America's
Energy Supply*

The US liquid pipeline industry is large, diverse and vital to the economy. Comprised of approximately 200,000 miles of pipe in all of the fifty states, liquid pipelines carried more than 40 million barrels per day, or 4 trillion barrel-miles, of crude oil and refined products during 2001. That represents about 17% of all freight transported in the US, yet the cost of doing so was only 2% of the nation's freight bill. Approximately 66% of domestic petroleum moves by pipeline, with marine movements accounting for 28% and rail and truck the balance. An illustration of the low cost of pipeline transportation is the 3¢ per gallon cost to move a barrel of gasoline from Houston, Texas to New York Harbor, a small fraction of the cost of gasoline to the consumer.

Pipelines may be small or large, up to 48" in diameter, but with only minor exceptions all of the pipe is buried. Some lines are as short as a mile, while others may extend 1000 miles or more. Some are very simple, connecting a single source to a single destination, while others are very complex, having many sources, destinations and inter-connections. Most pipelines cross one or more state boundaries (interstate) while some are located within a single state (intrastate), and still others operate on the Outer Continental Shelf and may or may not extend into one or more states. US pipelines are located in coastal plains, deserts, arctic tundra, mountains and more than a mile beneath the surface of the Gulf of Mexico.

The materials carried in liquid pipelines embrace a wide range of liquids. Crude systems gather production from on-shore and off-shore fields, while transmission lines transport crude to terminals, inter-connection points and refineries. The crude oil may be of domestic origin or imported. Refined petroleum products, including motor gasoline, aviation fuels, kerosene, diesel fuel, heating oil and various fuel oils, whether produced in domestic refineries or imported to coastal terminals, are sizable portions of the pipelines business. Other materials include petrochemical feed stocks and products and natural gas liquids (NGLs), including propane, which are often referred to as highly volatile liquids (HVLs) because they are gases at atmospheric temperature and pressure, but liquids under the higher pressures in pipelines. Still other pipelined materials include carbon dioxide and anhydrous ammonia and some liquid pipeline companies operate lines carrying nitrogen, oxygen, and occasionally small amounts of natural gas. However, non-liquid pipelines handle almost all natural gas transmission and distribution.

Pipeline companies are structured and owned in many ways. Pipelines may be organized as stock corporations, partnerships, master limited

*Meeting the future:
increased safety and
security through
voluntary initiatives
and regulatory
oversight, with a
new focus on
community
involvement.*

partnerships (MLPs), limited liability companies (LLCs) and sometimes combinations of those forms. Many lines have a single owner who might be an independent company, an integrated energy company, a large company with interests in businesses other than energy, a non-affiliated liquids shipper or an individual investor. In addition, there are numerous pipelines that are jointly owned by some combination of the entities that own pipelines by themselves.

With few exceptions liquids pipelines are common carriers and the rates charged and the terms and conditions of the services are regulated by the Federal Energy Regulatory Commission (FERC) for interstate lines and similar state agencies for intrastate lines. The Office of Pipeline Safety (OPS) in the Department of Transportation provides most operational oversight, although other federal agencies, such as the EPA and the Minerals Management Service, play important roles. State agencies regulate intrastate lines and local jurisdictions become involved with a variety of matters, including siting and emergency response in the event of an incident.

The liquid pipeline industry has made significant progress over time in reducing the number of safety incidents and oil spills and the volume of oil spilled, although the long term objective of no incidents and no spillage remains elusive. The years 2000 and 2001 each represented record performance. The year 2002, while not another record, sustained the lower level of incidents and volume spilled. A number of voluntary initiatives and regulatory pressures are helping to meet ever increasing industry and public expectations.

The outlook during the first 25 years of the 21st Century is for US petroleum product demand to increase 9.5 million barrels per day (48%) with 2/3 of the growth being for transportation fuels. During that time inland crude production is expected to decline 900 thousand barrels per day, mostly in Texas, Louisiana, Oklahoma and the Rocky Mountain states, while Gulf of Mexico production likely will increase by 500 thousand barrels per day. And the forecast shows refining capacity growing 3.3 million barrels per day, mostly in Texas and Louisiana. That outlook would necessitate imports growing substantially, with crude up 4 million barrels per day and refined products up 6.3 million barrels per day. During the same period significant growth is expected in the petrochemical industry.

The implications of the outlook are significant for the liquid pipeline industry. With regard to crude transportation, it will be necessary to add large, expensive lines in the Gulf of Mexico, to add numerous large, short lines between marine terminals and coastal refineries and to add crude transmission infrastructure in the Midwest, to handle increased Canadian

Forecast: Market growth, infrastructure expansion, realignment, and more new technologies

imports, and along the Texas/Louisiana Gulf Coast. Disinvestment in inland crude gathering systems and associated crude transmission systems will occur, as will redeployment and re-investment in many areas of the country.

For refined product transportation the implications include expansions, some significant, to move imported product from coastal terminals to inland consumption points and major expansions of product transmission capacity from Texas/Louisiana Gulf Coast refining centers to the Southeast and the Midwest and to a lesser extent to Arizona, California and the Rocky Mountain region. The situation is likely to be complicated by a continuing proliferation in the number of grades of product. And the network of pipelines providing feedstock and carrying petrochemical products, especially along the Texas/Louisiana Gulf Coast will expand rapidly.

The growing reliance of our nation on petroleum products has other implications for the liquid pipeline industry. To accommodate substantial pipeline growth the availability of suitable rights-of-way, despite increasing urbanization, will be necessary. And, it is imperative that the existing infrastructure continue to be well maintained and the aging network of pipelines be selectively upgraded and replaced. Technology and effective management systems will be keys to accomplishing that, while assuring safe, environmentally sound and reliable operations.

There are several key points to keep in mind:

- The liquid pipeline industry will grow significantly during the next 25 years, although not so much as the natural gas pipeline system
- The industry is extremely diverse and is becoming more so, especially with the rapid growth of Master Limited Partnerships (MLPs) and the decreasing role of major integrated energy companies
- The pipeline industry is extremely competitive, and becoming more so, and there is a decreasing need for traditional economic regulation
- Technology will play an essential role in continuing to improve the safe, environmentally sound and reliable operation of liquid pipelines and to effectively deal with the challenges of an aging infrastructure
- Land use issues will be a major factor in acquiring rights-of-way that will be essential to expanding and reorienting the pipeline network to meet the nation's needs in the years ahead

Exhibit 1 Fact Sheet US Liquid Pipeline Industry		
Mileage	Crude oil trunk lines (usually 8" to 24"; up to 48")	55,000 miles
	Crude gathering (small lines; mostly TX/OK/LA/WY)	30 to 40,000 miles
	Petroleum products	95,000 miles
	Total liquid pipelines	Approx 200,000 miles
Jurisdictional measures	Federal Energy Regulatory Commission (FERC) - CY2000	195 interstate pipelines
		168,417 miles
		Revenue = \$6.26 Billion
	Office of Pipeline Safety, Dept of Transportation (OPSS)	150,000+ miles
Petroleum transported	Total oil transported in pipelines (2001)	40+ million barrels per day
		575+ billion ton-miles
		4 trillion barrel-miles
Cost of pipeline transportation	Example: Houston, Texas to New York Harbor	Approx \$1.25 per barrel
		Approx 3 ¢ per gallon
Proportion of US freight	Oil shipments as fraction of total freight	17%
	Cost as fraction of total national freight cost	2%
Mode of transportation (2001)	Pipelines	66%
	Water carriers (barges and tankers)	28%
	Trucks	4%
	Rail	2%
Substitution of truck or rail for pipelines	Basis: 150,000 barrel/day pipeline	
	Trucks: 200 barrels (~8400 gallons) each	750 trucks per day
		1 arrives/unloads every 2 min
	Unit train of 2000 barrel tank cars	75 car train every day
Decade of construction	Pre-1930s	2%
	1930s	7%
	1940s	13%
	1950s	22%
	1960s	23%
	1970s	17%
	1980s	9%
	1990s	7%
	2000+	less than 1%
Oil spillage	Main-line pipe	Approx 1 gal per million barrel-miles
		Less than 1 tsp per thousand barrel-miles

Themes

1. The Liquid Pipeline Industry is Extremely Diverse

Although the concept of a liquid pipeline is simple and straight forward, the reality is that the liquid pipeline industry in the United States is extremely diverse, in just about any way that one might attempt to measure the industry. For example:

- Size: Pipeline diameter can be as small as a few inches or as large as 4 feet, length can range from less than a mile to more than 1000 miles and the line can be a pipe of uniform dimension or comprised of sections of multiple diameters or even parallel, interconnected pipes
- Geography: Pipelines can be situated solely in one state, can cross many states, can operate entirely in federal waters outside any state or involve some combination of federal waters and one or more states. Pipelines operate in urban as well as remote areas, in arctic tundra, in deserts, in coastal plains, in mountains and deep under the surface of coastal waters.
- Commodities carried: Pipelines can be dedicated to transporting single commodities, such as crude oil, motor gasoline, jet fuel and propane, or can carry a range of different commodities or of distinct grades of a single commodity; a typical large product pipeline carries 30 to 50 products regularly
- Complexity: Some pipelines carry material from a single source to a single destination while others have many sources, destinations and connections to other pipelines
- Shippers: Some pipelines have a single shipper while others have dozens of shippers; some shippers have an affiliation with the pipeline while others have none
- Types of services: While the basic service provided by a pipeline is transportation from one point to another, other services can be provided such as treating, blending and storing materials and operating and maintaining pipeline facilities for others
- Corporate structure: Pipelines may be organized as stock corporations, partnerships, Master Limited Partnerships and Limited Liability Companies
- Ownership: Some pipelines are wholly owned by a single entity, sometimes by an integrated energy company and also by other entities in and out

of the energy business; other pipelines have multiple ownership where the owners might be other pipeline companies, other energy companies, various other corporate entities, investor groups or individual investors

Given the wide range of situations, from a small pipeline with a single owner, carrying a single material for a single customer, to large companies owning and operating thousands of miles of pipe in many states and in federal waters and carrying a long list of commodities for one hundred or more shippers, it is difficult to establish and administer policy in ways that are fair and equitable to the wide range of industry participants. Inasmuch as there exist subjects for which regulation is essentially non-discretionary, it is important that the industry's diversity be recognized and understood so that whatever regulation is imposed will be as effective as possible in meeting its objectives.

2. Decisions are Driven by Economic Analyses

Today, every pipeline entity, whether a small, independent operator or a part of a large, integrated oil company, makes decisions that are driven by similar business and economic analyses. Simply put, virtually every pipeline entity uses a similar process to make decisions, although the details of the analysis, the sophistication of the tools employed and the judgments and assumptions vary. The common elements of the analytical process are:

- The costs to construct operate and maintain the pipeline or segment in question
- The revenues, considering volumes, tariffs, seasonality and other variability over time that can be expected to be associated with the pipeline or segment being studied
- The competition as it exists and as it may change in response to the project under study and to other factors
- The business risks associated with the venture, which include the cost and schedule for executing a project, changes to the cost and revenue projections, legislative and regulatory changes, and the consequences of any operational incidents
- The inclusion of a profit component that provides a return to the investor, be it an individual or a large corporation, and is reflective of the cost of capital to the investor, the perceived risks involved and the alternative investments available

Every pipeline operator considers those factors when deciding whether to go forward with a project or whether to retain a particular business segment. Some may be more optimistic than others regarding cost, revenues and the longer term outlook, some may require a higher or lower return component and there may be

differences of opinion regarding the level of risk, but everyone considers the same factors. Contrary to what some may believe, even the pipeline companies that are a part of large, integrated oil companies must consider those factors and their decisions must be economically sound. The time is past; if in fact it ever existed, that the pipeline segment in an integrated company will make an unsound business decision because it is partly or wholly owned by a company that has other interests as a potential shipper.

3. The Liquid Pipeline Industry is Increasingly Proactive Regarding Environmental, Safety and other Matters of Public Interest

For a number of years the leadership of the liquid pipeline industry has been acutely aware of the importance of meeting or exceeding the public's expectations regarding environmental and safety performance. While the industry would argue that it always has striven for excellent operations, there were factors in the past, such as the state of technology, the level of performance standards, the then existing best practices and the priorities of the business, that did not provide the emphasis that operational excellence has achieved during recent years.

During the 1980s, there were a number of major incidents (including the chemical release in Bhopal, India and the propane explosion in Mexico City which together killed thousands of people and the Valdez, Alaska oil spill) that had a profound impact on the petroleum and petrochemical industries. There also have been widely reported incidents involving liquid and natural gas pipelines (including Brenham, Texas, Edison, NJ, Colonial Pipeline spills and the Bellingham, Washington explosion and fire) that brought home a recognition that pipelines, too, needed to respond and to improve operations. The overall response has been to alter priorities and to systematically re-examine operations with an eye to fundamentally improving the way pipelines are constructed, maintained and operated.

The general approach has been to develop and implement a set of management systems that cover all aspects of operations and virtually everything associated with them. Thus it starts with the leadership role of management, includes the selection, training and qualification of employees and contractors, the building, maintaining and operating of pipelines, risk assessment, the application of enhanced technology and incident prevention and response and ends with system evaluation and continuous improvement. As with most such broad initiatives, some companies became involved earlier than others, but with the passage of ten or more years virtually everyone is actively engaged. And the results show it, although everyone would be quick to acknowledge that the level of perfection expected by the public is not yet being met regularly.

During the mid-1990s alignment was built across the leadership of the liquid pipeline industry and a variety of initiatives were begun to further improve the industry's performance. Until then the pace of improvement had been slower

than desired; and there was a need for a step change improvement. Perhaps the most significant action that was taken was the establishment of a voluntary industry program, the Pipeline Performance Tracking System (PPTS), to record virtually every spill incident in keeping with a belief that something must be measured for it to be managed. That voluntary effort has been in place for several years, significant improvement is being seen and the federal safety regulatory agency recently adopted a reporting program similar to what the industry instituted. PPTS was not the only initiative. Others relate to better training for employees, better information for use by pipeline companies, regulators and emergency responders, research seeking to identify better tools and techniques and encouraging Congress and the regulators to adopt enhanced legislation to ensure uniform compliance.

4. Right-of-Way Matters have become Major Challenges

During most of the early history of the liquid pipeline industry the acquisition of rights of way for pipelines was relatively easy, reflecting routes that were mostly in sparsely populated, rural areas and the generally understood need to move crude oil from producing areas to refineries and products from refineries to consumers. In recent decades the situation has changed considerably, as the United States has become increasingly urbanized and the interests of the land owner and the oil industry have deviated. Today, the acquisition of rights of way can take extended periods, often much longer than the time required to construct a pipeline, involves difficult and time-consuming negotiations, is increasingly costly and often ends in litigation that can drag on for years and sometimes a decade or more. The outlook is for the situation to become even more difficult, time-consuming, costly and litigious. And this is true everywhere, even in areas such as Texas that are commonly thought to have close affinities to the petroleum industry.

There appear to be two basic factors that are driving the changes, one being financial interests and the other being safety concerns. Few land owners today have any vested interest in the petroleum industry; rather they desire to maximize the return from their land. So, if a pipeline crosses their property or if a new line is routed across it, their desire is to gain as large a payment as possible for granting access and most land owners are prepared to take whatever steps are available to bolster their case. Thus, dueling appraisals, the retention of specialized, sophisticated attorneys, protests before regulatory bodies and legal challenges are all part of the efforts to extract higher value for providing an easement to a pipeline. Others are concerned about the potential for safety incidents that could arise from a pipeline in close proximity to their homes, the schools their children attend, their places of business and so forth. They also express concern that the value of their property will be diminished by the presence of a pipeline easement. Despite the improving safety and environmental performance of pipelines, the relatively few significant incidents receive wide-

spread and graphic coverage and foster the NIMBY (Not in My Back Yard) philosophy that many industrial and public facilities face.

Another aspect of the right-of-way challenge is the effective management of existing easements. Despite the existence of safety concerns, land owners typically seek to limit the width of easements and to fight constraints on their use of the land immediately over the buried pipeline. A large body of historical data demonstrates that the single largest cause of pipeline safety incidents and spills is damage to pipelines by third-parties when they excavate, farm or conduct other activities in the rights of way. As a result there is a major effort underway by the pipeline industry and other interested parties (such as excavation contractors, regulatory bodies, telecommunications companies and utilities) to develop better ways to build and mark pipelines (and other underground utilities), to inform contractors and the public about the need for caution when working on or near easements, to enhance the nation-wide one-call system, to eliminate physical encroachments onto easements and to implement land use planning standards to reduce the risk of incidents from intrusions onto the rights-of-way.

5. Economic Regulation is Costly

The economic (i.e. rate) regulation of liquid pipelines is costly and it is questionable whether the regulatory structure that has evolved over a long period is still needed or justified. For the last decade pipeline rates have been set under four approved methodologies. The most common method has been to adjust rates according to a FERC-set index that uses an inflation factor to establish a ceiling for any rate. Alternatively, pipelines (1) may negotiate rates if all shippers using the service concur; (2) may use the market-clearing price provided that FERC has found the pipeline lacks market power in the effected origin and destination markets; or (3) may apply for traditional cost-of-service treatment. Shippers may also request a cost-of-service review of rates. Under the rules of common carriage applicable to all pipelines, the same rate must be charged to all similarly situated shippers. Of the various available methods, the least used, since the inception of indexation, has been cost-of-service. However, as pipeline assets change hands more rates are being challenged, which leads to more cost-of-service reviews being conducted and moves liquid pipelines closer to utility-type regulation than ever before.

Any analysis of the cost of regulation should start with the direct costs, which are significant, including employees of the pipeline companies, the regulatory staffs and the fees for lawyers retained by shippers and carriers. Such costs are measured in the tens of millions of dollars annually, but are not the most substantial costs associated with economic regulation. It is the indirect costs that are most significant. One is the opportunity cost of the management time that could be employed for higher economic value in many ways, such as improving operating performance and better serving the needs of shippers. And probably even more importantly, the economic regulation has a chilling effect on

investments in new infrastructure. The cost of any large pipeline project is measured in the millions, if not tens of millions, of dollars and uncertainty, which can result from economic regulation, is a major factor in delaying and even avoiding investment. The uncertainty arises because economic regulation is being used to delay projects and to drive down revenues to levels that may not provide adequate returns to the investors.

Once, there might have been an argument that despite the cost, economic regulation was needed for other reasons, such as protecting shippers. However, the pipeline industry has changed over time. Today it is a very diverse, competitive industry, with a large number of companies, an increasing number of large, independent entities (such as MLPs that can tolerate a lower return level because of tax advantages to their investors) and a much diminished participation by integrated majors. Furthermore, the situations of the pipeline companies owned by the majors have changed. Today, each must stand on its own and be judged by its financial and operating performance and virtually no credit is given for service to an affiliate. It is strictly business and an affiliated pipeline company must compete just like its unaffiliated brethren and show results. These changes, which have been underway for years, are accelerating.

A solution to changing economic times would be to limit economic regulation to cases of undue discrimination and otherwise let the marketplace set the appropriate level of pipeline rates. Maintaining some requirement for pipelines, such as to publish tariffs and to provide access under reasonable terms and conditions, should provide acceptable safeguards for all concerned.

Trends

The Need for Liquid Pipelines

Historical Overview

The history of liquid pipelines in the United States can be traced to the late 1800s in Ohio, Pennsylvania and New Jersey. The primary driver for the use of pipelines has always been economic. When oil was discovered and production commenced, crude oil volumes were small and a distributed transportation system, such as horse-drawn wagons, trucks, and railroads, was the most efficient means of transporting the oil to refineries where it would be converted into products desired by oil consumers. As the level of production increased it became economical to invest in pipelines, especially for the transmission lines that would carry the crude to the refineries. Depending upon the level of production in a particular field and the proximity of the wells one to another, producers might continue to use wagons and trucks or decide to invest in pipes to gather the crude.

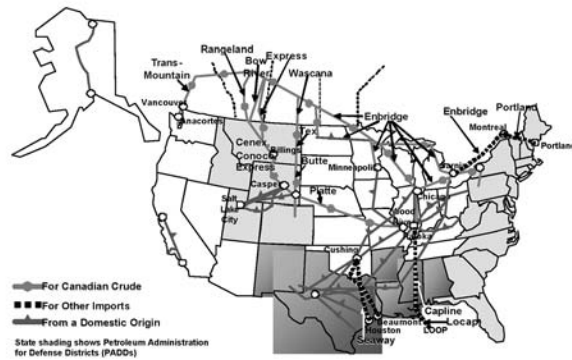
Exhibit 2. Petroleum Overview 1950 to 2025							
Thousand Barrels per Day							
	Crude Oil Production	Crude Oil Net Imports	Total Refinery Input	Refinery Dist. Capacity	Petro. Product Net Imports	Motor Gasoline Supplied	Total Petroleum Product Supplied
1950	5,407	392	6,020	6,220	153	2,616	6,458
1960	7,035	1,007	8,580	9,840	606	3,969	9,797
1970	9,637	1,310	11,750	12,020	1,850	5,785	14,697
1980	8,597	4,976	14,020	17,990	1,388	6,579	17,056
1990	7,355	5,785	14,590	15,570	1,375	7,235	16,988
2000	5,822	9,021	16,300	16,510	1,399	8,472	19,701
2010	5,630	11,510	NA	18,700	2,250	10,690	22,990
2025	5,330	13,060	NA	19,800	6,730	13,770	29,170

Energy Information Administration/Annual Energy Review 2001
Energy Information Administration/Annual Energy Outlook 2003

As the decades passed and exploration and production activities covered much of the US, the need to gather ever larger quantities of crude oil and then to transport that oil to refineries necessitated the construction of a large network of crude oil pipelines, both in-field gathering systems and large transmission lines. That trend continued through much of the twentieth century, peaking in 1970 at 9.4 million barrels of production per day in the Lower 48 states. Thereafter the trend reversed as the production in most inland domestic fields declined and by 2002 Lower 48 production had decreased to 4.8 million barrels per day. As a result, the throughputs in gathering systems and transmission lines declined, sometimes to the point where volumes would no longer support operations, and lines were shut down, abandoned or converted to other uses. Despite the decline in inland

production, the demand for crude oil to feed US refineries and ultimately for the consumption of refined petroleum products continued to grow. Those needs, along with improved technology, encouraged production in new areas. A primary growth area has been in ever-deeper waters in the Gulf of Mexico, with offshore production reaching 1.9 million barrels per day in 2001. In addition, the amount of foreign crude imported into the US has continued to grow, reaching 9.1 million barrels per day in 2002. In the decade ahead it can be expected that inland production, both in the lower-48 and in Alaska, will continue to decline, to approximately 1 million barrels per day in 2025, and that the deep-water Gulf of Mexico and foreign sources will provide increasing volumes of crude oil, 2.2 million barrels per day and 13.0 million barrels per day, respectively. Canadian crude imports are expected to grow modestly from 2000 to 2025 (i.e. 300 thousand barrels per day) while Persian Gulf and Mexican/Venezuelan imports are expected to increase 2 million barrels per day and 1.6 million barrels per day, respectively.

Exhibit 3. Selected Crude Oil Trunkline Systems



From "How Pipelines Make the Oil Market Work," Allegro Energy Group, December 2001

The consumption of petroleum products has always been widely disseminated and refineries tended to be widely distributed and sized to meet regional needs. For most of the first half of the twentieth century the vast majority of products were transported from refineries in discrete parcels, by trucks, rail cars, barges and tankers. During World War II the first large transmission pipelines for petroleum products were constructed, primarily from the Gulf Coast to the Mid-Atlantic States, driven by the vulnerability of coastal tankers to German U-boats. Since the war, the network of product pipelines has continued to grow. The outlook is for product demand, which was about 20 million barrels per day in 2002, to continue to increase, albeit at different rates in different parts of the country, reaching almost 30 million barrels per day in 2025. The trend for domestic refining capacity is to become more concentrated in regional centers and for imports of petroleum products to grow, reaching 6.7 million barrels per day in 2025 versus 1.4 million barrels per day in 2002. Those factors, including declines in inland crude production and the number of small inland refiners, will provide the impetus for expanding the network of product pipelines.

Exhibit 4. Major Refined Product Pipelines



From "How Pipelines Make the Oil Market Work," Allegro Energy Group, December 2001

The Customers

The circumstances of the petrochemical industry are similar to the refining industry. As plants increased in size it became more attractive to invest in pipelines to transport raw materials to the plants and in other pipelines to transport the products, especially intermediate products (i.e. those needing additional processing into consumer products), to other plants for further processing.

The customers and the commodities in the pipeline industry have changed over time.

Since the inception of the domestic petroleum industry in the late 19th century crude oil producers and refiners have been the primary customers of the liquid pipeline industry. Along the way the marketers of refined petroleum products also became a larger factor. Then, the rapid growth of the petrochemical industry during the second half of the twentieth century created a significant demand for pipelines to transport feed stocks to chemical plants and products from those plants to other plants for further processing. In recent decades other parties have become shippers on the pipelines, including the military, many of the airlines, crude and product importers and traders of crude and petroleum products.

The pipeline business adapts to the products and destinations that are in demand.

For much of the history of pipelines it was not unusual that some sort of affiliation existed between a pipeline and its shippers. The pipeline might have been organized as a separate entity, but its owner was often a parent that also had interests in the production, refining and marketing segments or by a railroad (Buckeye and Santa Fe Pacific). Under those circumstances it was common for a pipeline to work closely with its affiliated producer, refiner and marketer to develop pipeline infrastructure to move crude oil to a market, possibly an affiliated refinery; to transport crude, whether or not produced by an affiliate, to a refinery; and to move products to a market that might or might not be affiliated. A similar situation, but to a lesser extent, existed with petrochemicals inasmuch as the degree of integration of chemicals with petroleum has been considerably less than the integration of petroleum segments alone.

Commercial and military goals are accommodated in this diverse sector.

During the past few decades the extent of integration of pipelines with other segments of the petroleum industry has diminished considerably. Increasingly, and now to a large extent, the integrated companies demand that each segment, including pipeline transportation, stand on its own economically. That has caused the production, refining and marketing arms of integrated companies to look to non-affiliated transportation opportunities and for the affiliated pipeline companies to increasingly look to third party, non-affiliated business. An increasing number of joint ventures, with venture partners including a wide variety of participants, have diminished the situations where it is either practical or economical for a pipeline to deal solely with an affiliate. In addition, there are now many more independent participants in every segment of the petroleum industry and competition in all areas has forced every part of the industry, carrier and shipper alike, to seek the most economical transportation system. Still another factor in diminishing inter-affiliate business is the number of mergers in recent years, which resulted in restructurings that included the disposal of pipeline

assets to third-parties for regulatory and financial reasons. There is every indication that the trend of diminished affiliated business will continue and may well accelerate.

The Commodities

Materials carried via pipeline are numerous and varied. Operations have become more sophisticated due to the ever-increasing number of commodities transported everyday.

The list of materials transported by liquids pipelines is long. It starts with crude oil of many different grades and types, covers many refined petroleum products, including motor gasoline, aviation fuels, kerosene, diesel and heating oil and a variety of fuel oils, and a multiplicity of intermediate refinery streams. The list also includes natural gas liquids (NGLs), with propane being an example, and petrochemical feedstocks and products. The NGLs and petrochemical materials are typically referred to as highly volatile liquids (HVLs) since they are gases at atmospheric temperature and pressure, but liquids at the pressures in a pipeline. Other materials transported by liquids pipelines include carbon dioxide, coal slurry and anhydrous ammonia and some lines operated by liquid pipeline companies carry still other materials such as nitrogen, oxygen and hydrogen. In a few instances a liquids company may transport small quantities of natural gas, but natural gas pipeline companies handle virtually all transmission and distribution of natural gas. The number of discrete commodities is increased many-fold by gradations in the base commodity. For example, there are numerous grades of crude oil as a result of the differing properties such as sulfur and density and many grades of motor gasoline reflecting a wide variety of specifications. As an example, one Midwest pipeline operator reports carrying 34 grades of gasoline during a typical 10 day pipeline cycle. Large product pipelines have 30 to 50 products moving regularly and as many as 100 to 120 grades that move occasionally.

Crude oil may be produced domestically, either on-shore or in coastal waters, or may be imported from a foreign source. For the most part, until the second half of the twentieth century, the crude oil processed in US refineries was produced and gathered at inland fields in the US. The early production was predominantly in Pennsylvania and Ohio, but over time there were large finds in East Texas, West Texas, Oklahoma, Louisiana, California, Alaska and the Rocky Mountains and smaller discoveries elsewhere. It became economical to invest in pipeline infrastructure to gather the crude and then transport it to refineries as the production in any region increased.

As demand for petroleum products grew during World War II, and especially in the decades thereafter, tripling between 1950 and 2000, the consumption of crude grew from 6.0 million barrels per day in 1950 to 16.2 million barrels per day in 2002. During the decades of the 1940s, 1950s and 1960s domestic production increased to meet those needs, helped by controls on crude oil imports because economics favored foreign crude. By the early 1970s crude production was essentially at capacity at about 9 million barrels per day and controls were eliminated. During that post-war period, liquid pipelines rapidly increased their

capacity to transport crude to the growing refining centers, particularly on the Texas/Louisiana Gulf Coast.

Exhibit 5. Crude Oil Production and Oil Well Productivity 1950 to 2025							
Thousand Barrels per Day							
	GEOGRAPHIC LOCATION		SITE		TOTAL	Producing Wells (Thousands)	Average Production (Barrels per day)
	48 States	Alaska	Onshore	Offshore			
1950	5,407	0	NA	NA	5,407	NA	NA
1960	7,034	2	6,716	319	7,035	591	11.9
1970	9,408	229	8,060	1,577	9,637	531	18.1
1980	6,980	1,617	7,562	1,034	8,597	548	15.7
1990	5,582	1,773	6,273	1,082	7,355	602	12.2
2000	4,851	970	4,049	1,773	5,822	534	10.9
2010	4,980	640	3,150	2,470	5,630	NA	NA
2025	4,160	1,170	3,150	2,180	5,330	NA	NA

Energy Information Administration/Annual Energy Review 2001
Energy Information Administration/Annual Energy Outlook 2003

Exhibit 6. Petroleum Imports and Exports 1950 to 2025									
Thousand Barrels per Day									
	CRUDE			PETROLEUM PRODUCTS			TOTAL		
	Imports	Exports	Net	Imports	Exports	Net	Imports	Exports	Net
1950	487	95	392	363	210	153	850	305	545
1960	1,015	8	1,007	799	193	606	1,815	202	1,613
1970	1,324	14	1,310	2,095	245	1,850	3,419	259	3,161
1980	5,263	287	4,976	1,646	258	1,388	6,909	544	6,365
1990	5,894	109	5,785	2,123	748	1,375	8,018	857	7,161
2000	9,071	50	9,021	2,389	990	1,399	11,459	1,040	10,419
2010	11,580	60	11,510	3,250	1,000	2,250	14,830	1,060	13,760
2025	13,110	50	13,060	7,830	1,100	6,730	20,940	1,150	19,790

Energy Information Administration/Annual Energy Review 2001
Energy Information Administration/Annual Energy Outlook 2003

The logistics of crude supply began to change in the 1970s and the trends that emerged have continued until now. Inland production has been essentially maximized and most inland fields are in significant decline if not depleted. Domestic exploration efforts have moved to more remote locations, with notable success on the North Slope of Alaska in the late 1960s and early 1970s and into ever deeper water in the Gulf of Mexico, with recent activity in 5,000 feet to 10,000 feet of water. There were other successes, such as heavy crude oil expansion in California, along the California coast and in the Rockies, but none matched Alaska or the Gulf of Mexico. The result of an increasing total demand for crude and a decreasing ability to supply that need domestically has caused

crude imports to grow very significantly, reaching more than 9 million barrels per day, and accounting for some 60% of all crude oil refined in the US.

The impact on pipelines of the changes in crude supply has been significant. Gathering activities have diminished in virtually all inland areas, with systems being shut-down and abandoned, trucking replacing the use of pipelines, the remaining gathering systems being consolidated and ownership changing with the integrated and other larger companies being replaced with smaller, more specialized and often new companies. At the same time many of the crude transmission lines from the inland fields are no longer needed and are being taken out of service, to be converted to other uses or abandoned. Often, those that remain are operating at considerably less than capacity.

*Growth in
Canadian
crude imports*

While those changes were occurring in inland areas, other developments were taking place. Crude imports, largely to Gulf Coast, Atlantic Coast and upper Mid West refineries, grew rapidly. Marine terminals grew and relatively high-capacity but short pipelines were put in place to handle the coastal imports, while new and expanded transmission lines were built to move approximately 1.8 million barrels per day of Canadian crude to the US, especially to the upper Midwest. The pressure to move Canadian crude further south in the US triggered several of the largest pipeline expansions (i.e. Express, Enbridge, etc.) of the late 1990s and early 2000s.

*The Trans
Alaskan
Pipeline
System
(TAPS) is 800
miles long.*

During the 1970s a large transportation system, involving the 800 mile, 48" diameter Trans Alaska Pipeline System (TAPS) and a fleet of ocean-going tankers, was established to move North Slope crude to market, mostly on the West Coast, but for the 1980s and much of the 1990s to Gulf and Atlantic coast refineries as well. With the decline in Alaska production (TAPS throughput is currently at about 1 million barrels per day versus a peak in excess of 2 MB/D in 1988) the West Coast is once again seeing an increase in crude imports (750 thousand barrels per day).

The other major crude logistics development that is underway and is likely to continue throughout the next decade is the gathering and transportation of deep-water Gulf of Mexico production. For example, a 153-mile line of 18" and 20" pipe in the Western Gulf was completed in 2000 that transports crude gathered in 5000 feet of water. Even larger systems in the Central Gulf, such as Caesar and Proteus, are under development currently in even deeper water. The demands for capital and technology enhancements are significant and government policy is encouraging the growth in a safe and economic way.

Exhibit 7. Refineries: Input & Output and Number, 1950 to 2025								
Million Barrels per Day								
	INPUT		OUTPUT			REFINERIES		
	Crude Oil	Total	Motor Gasoline	Distillate Fuel Oil	Total	Number	Capacity	Utilization (%)
1950	5.74	6.02	2.74	1.09	6.02	320	6.22	92.50
1960	8.07	8.58	4.13	1.82	8.73	309	9.84	85.10
1970	10.87	11.75	5.70	2.45	12.11	276	12.02	92.60
1980	13.48	14.02	6.49	2.66	14.62	319	17.99	75.40
1990	13.41	14.59	6.96	2.92	15.27	205	15.57	87.10
2000	15.07	16.30	7.95	3.58	17.24	158	16.51	92.60
2010	17.14	NA	NA	NA	NA	NA	18.70	93.20
2025	18.39	NA	NA	NA	NA	NA	19.80	94.60

Energy Information Administration/Annual Energy Review 2001

Energy Information Administration/Annual Energy Outlook 2003

Throughout the early decades of the petroleum industry, refined products were manufactured at small to medium sized refineries located relatively close to the product markets. In that environment there was a heavy reliance on rail, barge, small coastal tankers and some limited scope pipeline systems to move the products from refineries to distribution terminals and then to use trucks to move the product the final step to service stations or to the customer directly. During World War II the combination of growing demand and submarine warfare led to the development of large pipelines to move products to the East Coast from the refining centers that were situated near the large supply of domestic crude along the Texas/Louisiana Gulf Coast. After the war, as the economy grew rapidly and the demand for products, especially motor gasoline, increased there were many expansions and additions to the network of product transmission pipelines. For example, the volume of oil moved by pipeline increased 42% between 1970 and 2002. However, the need remains for truck, and sometimes for rail, transportation to get products to the consumer. The seemingly ever-increasing demand for petroleum products continues to provide a need for more capacity in the transportation system and that is likely to be the case into the foreseeable future.

The transportation of petroleum products also has become more complex. The proliferation of product grades during recent decades, especially for gasoline, has been a complicating factor that required expanding the number of segregations in the material being shipped. There are capacity, cost and product quality implications of the multiplicity of grades. When there is sufficient volume, the simplest and least expensive pipeline operation would be a dedicated line, but rarely is the product volume large enough. Thus operators resort to batching --- shipping a sequence of discrete products (or batches). Care must be taken to maintain isolation between batches and any interface between successive batches must be down-graded (say premium gasoline into regular) or reprocessed. Sometimes the size of batches can be increased, lowering the transportation cost,

if more than one shipper is agreeable to meeting a common specification (i.e. a fungible product).

Exhibit 8. Petroleum Products Supplied by Type 1950 to 2025							
Thousand Barrels per Day							
	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Asphalt & Road Oil	Other Products	Total
1950	2,616	NA	1,082	1,517	180	1,063	6,458
1960	3,969	371	1,872	1,529	302	1,754	9,797
1970	5,785	967	2,540	2,204	447	3,721	14,697
1980	6,579	1,068	2,866	2,508	396	3,639	17,056
1990	7,235	1,522	3,021	1,229	483	5,020	16,988
2000	8,472	1,725	3,722	909	525	4,348	19,701
2010	10,690	1,900	4,610	600	NA	5,190	22,990
2025	13,770	2,740	5,870	640	NA	6,150	29,170
Energy Information Administration/Annual Energy Review 2001							
Energy Information Administration/Annual Energy Outlook 2003							

Motor gasoline

Motor gasoline accounts for about half of the volume of U.S. petroleum products consumption (8.8 million barrels per day out of 19.8 million barrels per day total in 2002). Once there were typically two or three grades of gasoline differentiated by their octane levels and in some parts of the country, particularly the northern areas, there were seasonal variations summer versus winter. Today there is a multiplicity of grades (as many as 30 to 40 according to a recent survey by the American Petroleum Institute), some specific to a particular region, state, county or even locality. Those changes have made pipeline operations more difficult, reduced the effective capacity of the existing transportation system, necessitated capital investment and generally raised costs. There seems to be no change in this trend and, if anything, the proliferation is likely to continue. For instance, a number of states are prohibiting gasoline containing MBTE and are requiring certain specific ethanol blends.

Transportation fuels

Other significant transportation fuels include jet and diesel fuels, accounting for more than 25% of total product demand in 2002. Whereas aviation gasoline was once the predominant aviation fuel and later naphtha-based jet fuel was the primary military aviation fuel, they have been superseded by kerosene based jet fuel, much of which is transported by pipeline for at least part of its journey to the consumer. As with gasoline, there are a growing number of grades of these fuels, with the advent of a very low sulfur diesel fuel in the near future posing many issues and concerns for the pipeline industry.

The remainder of the product barrel is comprised of other fuels, such as kerosene, heating oil, and a variety of heavier, higher-sulfur fuels. The lighter fuels (i.e. kerosene and heating oil) are often transported in batches with gasoline and other transportation fuels, whereas the heavier, dirty fuels, such as asphalt and heavy fuel oil, are much less compatible with the lighter fuels and are usually

Today's Marketplace demands safe transportation for "clean fuels," agricultural and industrial solvents, and many other liquids. Each commodity requires skillful handling and modern equipment.

transported in separate pipeline systems, which tend to be of limited scale in terms of size and distance covered. The higher viscosity materials also require special handling. Historically the lighter fuels were called "clean fuels", but in recent years the term "clean fuels" has been applied to fuels that have been further refined to remove impurities, such as sulfur, that will enable them to be "clean burning".

The natural gas liquids (NGLs) cover a range of materials, including ethane, propane, butane and mixtures of them, that are gases at atmospheric temperature and pressure, but liquids at the operating pressures in pipelines. Propane (or liquefied petroleum gas --- LPG) is a fuel widely used for agricultural purposes and for heating in rural areas and is pipelined when sufficient volumes make it economic. The other NGLs typically represent by-products from the production of crude and natural gas, petrochemical feedstocks and products and intermediate materials among gas plants associated with natural gas production, refineries and chemical plants. In low volumes NGLs are transported by truck and rail, but a pipeline network has developed in the larger production areas, such as East Texas and West Texas, along the Texas/Louisiana Gulf Coast with its concentration of gas plants, refineries and chemical plants and from Canada into Michigan. The demand for and availability of NGLs, associated with growth in Gulf of Mexico crude and natural gas production and growth in the petrochemical industry, provides an outlook for expanded NGL pipeline systems in the years ahead.

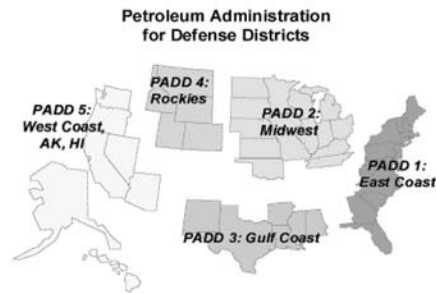
The situation with petrochemical feedstocks and products is similar to that of NGLs, although there are many materials moved by pipeline that do not fall under the umbrella of NGLs. For example, pipelines, particularly along the Texas/Louisiana Gulf Coast, transport ethylene, propylene (both in dilute and concentrated forms), butylenes, hexane, benzene, toluene, xylene, butadiene and many others, smaller streams. The petrochemical industry has grown rapidly during the last several decades and the outlook is for continued expansion as the overall economy grows. The need for liquid pipeline additions and expansions will grow concurrently.

There are other, miscellaneous materials carried by liquid pipeline companies, such as carbon dioxide (CO₂) and anhydrous ammonia, and non-liquid materials that are transported, such as nitrogen, oxygen, hydrogen and coal slurry. However, the circumstances that create the need for pipeline transportation are usually specific. Such situations will undoubtedly continue in the future and needs and opportunities will arise from time to time, but in the aggregate they represent a very small activity by the liquid pipeline industry.

Regional Considerations

Another dimension to an understanding of the needs for liquid pipelines is to take into account regional factors. Inasmuch as the government established a standard nomenclature for regional energy measurement and analysis during World War II that is still in use, it will be used here. Five Petroleum Administration for Defense Districts (or PADDs) were established, with PADD I covering the Atlantic Seaboard, PADD II encompassing the Mid-West, PADD III being along the Gulf Coast, PADD IV covering the Rocky Mountains and PADD V being along the West Coast, Alaska and Hawaii. Some PADDs are further subdivided, such as a north and south Atlantic, to better recognize regional differences.

Exhibit 9. Petroleum Administration for Defense Districts



Energy Information Administration "Oil Market Basics."

Exhibit 10. Daily Supply and Disposition of Crude Oil and Petroleum Products, 2001						
Thousand Barrels per Day						
	PADD I	PADD II	PADD III	PADD IV	PADD V	TOTAL
Crude production	20	458	3,271	288	1,764	5,801
Crude imports, net	1,476	888	5,925	275	746	9,310
Crude, net receipts	3	1,998	-1,907	-94	0	0
Refinery input - crude	1,499	3,303	7,278	500	2,547	15,127
- total	1,877	3,386	7,795	532	2,791	16,381
Finished petroleum products						
Refinery production	1,922	3,439	7,833	544	2,880	16,681
Imports, net	1,061	5	-297	6	-108	667
Receipts, net	2,762	895	-3,815	55	104	0
Products supplied	5,721	4,526	3,753	598	2,883	17,481
Energy Information Administration/Petroleum Supply Annual 2001, Volume 1						

Exhibit 11. Operational Parameters by PAD District, 2001											
Thousand Barrels per Day											
	PADD I		PADD II		PADD III		PADD IV		PADD V		TOTAL
Production	FL	12	OK	188	TX	1,162	WY	157	AK	963	
	PA	4	KS	93	LA	287	CO	45	CA	714	
	WV	3	ND	87	NM	186	MO	44	Fed offshore	85	
	Other	1	Other	90	Fed Offshore	1,536	UT	42	Other	2	
					Other	100					
Total	20		458		3,271		288		1,764		5,801
Refineries											
Number	16		27		56		16		38		153
Capacity	1,715		3,591		7,780		572		3,128		16,785
Refinery Crude Receipts											
Domestic	29		1,689		2,144		296		1,901		6,058
Foreign	1,472		1,613		5,104		205		744		9,139
Pipeline	68		3,287		3,016		468		1,022		7,860
Tanker	1,201		0		3,930		0		1,554		6,686
Barge	217		1		253		0		36		507
Tank cars	8		0		3		0		10		20
Trucks	7		14		47		33		23		124
Total	1,501		3,302		7,249		501		2,645		15,197
Energy Information Administration/Petroleum Supply Annual 2001, Volume 1											

*PADD I is
located
along the
Atlantic
seaboard.*

While PADD I was the home of the early American crude production industry, its fields are largely depleted. For many years there has been virtually no indigenous production (20 thousand barrels per day in 2001) and there is little likelihood of developing any meaningful amount. As a result, its refining industry (16 refineries with 10% of US capacity), which is concentrated along the coast in Virginia, Pennsylvania and New Jersey, relied on domestic crude transported by tanker largely from Texas and Louisiana ports until US crude production reached capacity in 1970. Since then the refineries have lived on an increasingly larger diet of foreign crude (98% in 2001), directly imported from the North Sea, South America, Africa and the Middle East.

With its large population, the demand for petroleum products in PADD I (5.7 million barrels per day) exceeds its indigenous refinery production so products must be imported (4.2 million barrels per day), both from PADD III (Texas and Louisiana) and increasingly from foreign sources. From time to time, the possibility of adding a major increment of refining capacity has been studied, but the economics were never favorable. Among the factors were higher East Coast construction costs, higher landed crude costs (because the lack of a deep water port led to the use of smaller, more expensive tankers) and the lack of downstream infrastructure to deliver product from a central refining location.

The situation in the South Atlantic sub-region differs slightly in that its demand is rising faster than in the North and it relies to a greater extent on pipeline imports of products from PADD III. The outlook, especially in the Southeast, is for increasing product imports from both domestic and foreign sources as the region's population grows. The major pipeline systems carrying product from PADD III into PADD I are Colonial and Plantation for motor gasoline, diesel, jet and heating oil and Dixie for propane. A number of older, smaller pipeline systems internal to PADD I are used to carry products from coastal refineries and terminals to interior areas. Systems originating in Providence, Rhode Island; Northern New Jersey; and the Philadelphia/Paulsboro, NJ area are examples.

*PADD II
encompasses
the Mid-West.*

PADD II is comprised of a populous, highly industrialized eastern section and a more rural, agricultural western section. For a long time indigenous crude production, supplemented with domestic crude from the northern Rockies and from Texas and Oklahoma was sufficient to supply local refineries. Refined product demand was met through a combination of output from the local refineries and product imports, primarily from the south, some by barges up the Mississippi River and other by pipeline. In recent decades local crude production has diminished considerably (dropping to 600 thousand barrels per day in 2001) and West Texas and Oklahoma crude production is preferentially sent to PADD II. Imported crude has increased to feed increased refining capacity and to offset declines from other sources. During 2001 1.3 million barrels per day of domestic

crude and 1.6 million barrels per day of foreign crude entered PADD II. A considerable portion of the imports originates in Western Canada, but lines such as Capline, which connects LOOP (Louisiana Offshore Oil Port) with the mid-west are an important source of crude. Depending upon short term supply and cost factors, the mix of imports swings between Canadian sources and crude that was tankered to the Gulf Coast. Inasmuch as refining capacity has remained relatively flat, with expansions off-setting shut-downs, the need to import domestic products has increased to meet growing demand, reaching 900 thousand barrels per day in 2001.

The liquid pipeline industry has responded to PADD II's needs by adding crude transmission capacity from Western Canada and from PADD III and product transmission capacity from PADD III. The overall crude carrying capacity exceeds PADD II's needs, and in recent years there have been periods when the systems from Canada and from the South have had significant spare capacity. The outlook is for a continuation of uncertainty in the mix of crude imports. As for products, a number of projects have been completed recently to move more products into PADD II from PADD III. The pace of those expansions and additions will depend upon the rate of product growth and whether there is any significant further curtailment of refining capacity within the region (27 refineries and 3.6 million barrels per day of capacity in 2001).

*PADD III
located along the
Gulf Coast, is the
US refining
center.*

During most of the twentieth century PADD III had sufficient crude production to meet the needs of the growing refining centers along the Texas/Louisiana Gulf Coast. After inland production reached maximum levels in the early 1970s, further growth in crude demand was supplied from foreign imports. With the decline of inland production and the shift to foreign crude it made sense to transport much of the remaining inland production to PADD II, mostly through Cushing, Oklahoma, and to increase foreign imports for the coastal refineries rather than to incur the cost of hauling that crude to the Mid-West. Another factor in the level of imports has been the amount of production in the Gulf of Mexico. Industry moved into coastal waters after World War II, but formerly sizable, near-shore volumes had declined significantly by the 1980s as fields were depleted. With advances in technology, exploration and production in deeper waters accelerated during the 1980s and 1990s and that substantial production (1.5 million barrels per day in 2001) has slowed the growth in crude imports. Because the product output of PADD III's refineries exceeds region demands there are essentially no product imports to the region and substantial product movements out of the region (3.8 million barrels per day in 2001), largely by pipeline, to the East Coast (PADD I) and the Mid-West (PADD II).

In view of the very large inland crude production in PADD III through much of the 20th century (3.3 million barrels per day in 2001), a crude pipeline system was established to transport that crude to the large coastal refining centers in Texas and Louisiana and to transport the excess to PADD II. As production declined and much of what remained went to the Mid-West, the need for the capacity

decreased, forcing the abandonment of lines and encouraging attempts to convert the remaining capacity to other uses. There was a short-lived blip in the 1980s when some of the under-utilized capacity was used to move excess Alaska and California crudes east from PADD V. For instance, All American Pipeline was built for that purpose. However, with the decline of production in Alaska that movement ceased during the 1990s. The process of reducing the crude pipeline infrastructure in PADD III is continuing and is the source of many issues and uncertainties. These include questions about asset rationalization through sales to small, independent operators, the age of the lines, the impacts (environmental and other) of using the pipe for other purposes and the growing urbanization of many parts of the region. The situation regarding product pipelines is different, in that the demand for product movements into PADDs I and II continues to increase and thus it is a matter of continuing to add capacity in logical, cost-effective increments. The outlook is for that trend to continue.

PADD IV is located at the Rocky Mountains.

PADD IV, the Rocky Mountains, is a sparsely populated and not highly industrialized region. As such the local crude production (288 thousand barrels per day in 2001) has tended to be sufficient to feed the typically small refineries (16 refineries with less than 600 thousand barrels per day capacity) that are located to satisfy the widely distributed population. In recent years the decline in Wyoming crude and the demand growth, particularly in Billings, Montana-area refineries serving the Northern area, has been met by modest increases in the availability of Canadian crude. Growth in Colorado has largely been met by small increases in local refining capacity and increased movement of refined products from the South (PADD III).

Given the scope of crude and product movements within PADD IV the pipelines are of modest size and the systems have been changing less than in the other PADDs, although there have been a number of recent ownership changes. An exception has been the addition and expansion of crude transmission pipelines passing through the northern part of PADD IV that carry crude from Western Canada to the Mid-West. While the changes taking place in PADD IV are modest in relation to those in other regions, the increasing availability of Canadian crude and the specter of product imports from the South is a major concern to local industry participants, especially in the Salt Lake City and Casper, Wyoming areas. One manifestation of the competitive situation is the relatively large number of cases brought to the FERC involving PADD IV pipeline transportation.

PADD V is located along the West Coast, Alaska and Hawaii.

The rapid and large population increases, the dependence on the automobile and the advent of stringent environmental regulations have had a major impact on PADD V, particularly in California. PADD V has long been home to crude production in and around Los Angeles, in State waters towards Santa Barbara and to production of heavy crude from large fields in the San Joaquin Valley between Los Angeles and San Francisco. In the late 1960s there were substantial finds of heavy, high sulfur crude in federal waters off Santa Barbara and of the giant Prudhoe Bay field on the North Slope of Alaska. Through the first half of the century local production had been sufficient to meet refining needs, but as demand for products outstripped domestic crude availability foreign crude imports increased to fill expanding refining capacity. With the advent of production in Alaska and the Outer Continental Shelf (OCS) imports were largely eliminated and refining capacity was added in the Pacific Northwest. That capacity was supplied with Alaska crude and the excess PADD V crude was transported to PADDs III and I via a logistics system combining marine and pipeline segments. By the year 2000 Alaska production had declined to one million barrels per day (versus a peak of 2.1 million barrels per day in 1988) and OCS production had declined substantially as well (85 thousand barrels per day in 2001). Thus, the movements to PADDs III and I ceased and foreign imports resumed. The high intensity refineries on the West Coast (38 refineries with 3.1 million barrels per day capacity in 2001) and some product imports have largely met the demands for refined products (2.9 million barrels per day in 2001), which are weighted much more heavily to motor gasoline than elsewhere in the US. From time to time there have also been marine movements of product to PADD V, usually from PADD III. Those movements, which transit the Panama Canal in purpose-built ships, are only economic during periods of price disruption.

Since early in the 20th century there has been a network of crude pipelines in place in California. For the most part, they have been private, proprietary lines, unlike the common carrier systems in the rest of the US. As refineries expanded and new ones were added and as production grew the pipeline network expanded to meet the growing transportation requirements. A relatively recent example was the construction of the common carrier intra-state Pacific Pipeline to move increased San Joaquin Valley (Bakersfield) production to Los Angeles area refineries.

The discovery of oil at Prudhoe Bay in 1969 necessitated creation of a large, expensive and rather unique transportation system comprised of the 800 mile, 48" diameter pipeline from Alaska's North Slope to a marine terminal at Valdez, Alaska. From there large tankers transport the crude to refineries, primarily in areas near Seattle, San Francisco and Los Angeles. During the years when the supply exceeded PADD V demand, the excess crude was transported to PADDs III and I. Initially the excess moved by tanker around South America, later a pipeline was constructed across Panama enabling tanker-pipeline-tanker

movements and still later a pipeline was built from the San Joaquin Valley to West Texas where it connected to the existing pipeline infrastructure enabling Alaska and OCS crude to reach the Houston area.

The refined products market in PADD V has historically operated independently of the markets elsewhere in the US. Distance and terrain were certainly factors, but generally adequate refining capacity, a proportionally greater demand for motor fuels and mandates for special grades of gasoline during recent decades have combined to discourage pipeline interconnections between PADDs III and IV and PADD V. Normally, the network of pipelines that has developed to move refined products to distribution terminals for dissemination to the ultimate consumer is adequate to meet West Coast needs. However, the supply/demand balance is fairly tight and the infrastructure provides only limited flexibility to accommodate short-term issues. Thus, if a few refineries encounter operating problems, if there is a problem in the distribution system (pipeline or other) or if prevailing prices jump, there is no quick mechanism for the energy industry to respond. The events in Phoenix during the summer of 2003 (i.e. price run-up and service station lines as a result of a pipeline outage) illustrate the impact of an infrastructure problem on supply and price. A few attempts have been made to add infrastructure, such as the Longhorn proposal (conversion/reversal of a former crude oil trunk line to refined products service) that could move Gulf Coast product to California in conjunction with Kinder Morgan's SFPP system, but economics, competitors and various local interests have stymied a solution.

Competition with other Transportation Modes

While liquids pipelines are the primary workhorse for transporting crude oil and refined petroleum products, tankers, barges, railroads and trucks are an important and, in some instances, an essential element of the transportation system. In almost all cases the selection of a transportation mode is an economic choice, but there are factors that swing the economics to favor one or another alternative.

The most obvious examples are that imports of crude and products, other than overland from Canada and Mexico, must move by tanker, whereas many locations cannot be reached by either tankers or barges. Probably the most significant factors in determining the optimum transportation mode relate to the number and location of the sources and destinations of the crude and products to be moved and the volumes (both average and extremes) among the sources and destinations. At one end of the range, pipelines, because they are capital intensive and not very flexible, are best suited for high volumes moving from a limited number of sources to a limited number of destinations. At the other end of the spectrum, trucks are extremely flexible and can extend the range of less flexible transportation modes. Trucks do not impose a large capital requirement, at least for low volume movements, but are expensive to operate. Railroads, barges and coastal tankers fall between the two extremes.

Until the rapid increase in crude imports in the 1970s, tanker transportation had been utilized to move PADD III crude to PADD I, to haul modest amounts of specialized foreign crude imports (such as Venezuelan asphalt crude) and for the coastal movement of petroleum products. Since then tankers have played a key role in the system for moving Alaska crude to lower-48 refineries and for importing foreign crude, while the previous uses have diminished or ceased.

There is a modest utilization of barges to move crude and a much larger utilization to move products in coastal service and on the major river systems. During recent years the role of barges, particularly on the river systems, although still significant, has been declining in response to environmental and safety concerns and to other operating issues, such as winter icing, low water limitations, flood situations and the expansion of other transportation alternatives. However, some areas, such as New England and southern Florida, remain dependent on coastal tankers and barges to transport products.

Short hauls and small-volume point-to-point movements clearly favor the use of trucks, especially when many sources or many destinations are involved. Thus, the movements of products to the consumers from distribution terminals are almost exclusively handled by trucks. It is a common sight to see trucks delivering motor gasoline to service stations, heating oil and propane to residential and commercial customers and aviation fuels to fixed base operators. Also, trucks are a strong competitor of pipelines for gathering crude, especially as fields are depleted and production declines, as well as for occasional, low-volume movements of miscellaneous crude and petroleum products.

Railroads tend to serve niche opportunities for moving crude and products. For example, there is a unit train operation in California moving heavy San Joaquin Valley crude to a refinery in the Los Angeles area and there is a unit train operating as part of the Yellowstone product system in Montana. In addition there are numerous movements among gas plants, refineries and petrochemical plants of feed stocks and intermediate products as a result of low and variable (sometimes seasonal) volumes.

Ownership Structure of the Pipeline Industry

The needs for liquid pipelines are diverse and so are the ways in which the industry is structured to meet those needs. Pipelines may be independent entities or may be owned, in whole or part, by integrated energy companies, by other companies in or out of the energy industry and by investors. In many instances they are owned jointly by a combination of entities. A particular pipeline may be organized as a stock corporation, a partnership, a particular form of partnership known as a Master Limited Partnership (MLP) or as a Limited Liability Company (LLC). Furthermore, the owner may not be the operator of a pipeline. While it is most common for an owner or one of the owners, in the case of a joint venture, to act as the operator, there are instances when an independent, third party operates

the line on behalf of the owner(s). The way in which a pipeline is owned and structured is a function of many factors, including the purpose of the pipeline, the complexity of the task, historical considerations, legislative and regulatory constraints, the ability to raise capital and a necessity to manage a wide variety of risks.

The way a pipeline company is structured must consider the purpose of the system. In its simplest form a pipeline may move a single material from one source to one destination over a distance as short as a mile or less, or as long as a thousand or more miles, and it might operate in a single state or cross numerous state boundaries, or it might be located in federal waters and not in any state. Examples include lines carrying crude oil from one production platform to another in the Gulf of Mexico, crude oil from one marine terminal to one refinery, jet fuel from one refinery or terminal to one airport, fuel oil from one terminal to one power plant or petrochemicals from one plant to another. Beyond those simplest forms the complexity can become considerable. There can be many sources and a single destination (such as crude gathering), a single source and many destination (such as a products line serving a single refinery and a number of end markets) and networks that include many sources and many destinations. And whatever the physical layout of the pipeline, it may carry a single product or many discrete products/grades and it may carry material for one or for many shippers.

*The role of
Integrated
Companies*

In the early years of the petroleum industry most pipelines were part of integrated companies, whether established by a crude producer needing to transport its crude to a market or by a refiner needing a reliable supply of feedstock for its refinery. But as the energy industry has grown and diversified, as new entrants have been established and as special situations have arisen the extent of integrated ownership has diminished to the point that only about one-third of liquid pipelines are part of integrated enterprises today. Along the way independent companies have been established whose sole business is pipeline transportation and related services. Also, other interests such as pension funds, private investors (individually or collectively in funds) and corporations in other businesses, such as electric utilities needing fuel for their power plants, have assumed ownership of pipelines. The effect of integrated ownership has also diminished greatly during the last ten to twenty years as financial and other pressures have caused the remaining integrated energy companies to demand that every segment of their company stand on its own. Thus, the pipelines owned by integrated companies look to third party business as essential to their well-being and the integrated owner ships on whatever pipeline will provide the best service at the best price.

Joint Ownership

Joint ownership of pipelines is increasingly common as a means to manage business risks, to achieve economies of scale, to obtain sufficient capital for large, risky projects and to enhance the ability to establish new pipelines in the face of increasing difficulties in obtaining permits and other approvals. The way in

which joint ownership is implemented takes many forms, both as to the structure of the venture and as to its management.

<i>Joint Venture</i>	A joint venture (JV) may look similar to a non-JV (i.e. a corporation, partnership, MLP or LLC), but have multiple owners and be managed as though it were a single entity. Alternatively, it could be organized as an Undivided Joint Interest (UJI) in which the owners act together to build, operate and maintain the pipeline, but each owner retains responsibility for its share of the common facility, performing activities such as posting separate tariffs, handling its own revenue accounting and so forth. A UJI has been described as multiple straws, each owned by a different party, within a single, larger straw. A well known example of a UJI is TAPS (the Trans Alaska Pipeline System). In that case five owners -- BP, ConocoPhillips, ExxonMobil, Unocal and Koch -- own varying shares, post their own tariffs and compete for shippers, but together have a contract with Alyeska Pipeline Service Company to operate the line for their mutual benefit. By agreement there is an Owners Committee to resolve any conflicts in operating instructions to the contract operator. JVs also can be managed directly by employees of the venture (as is case for Colonial and Explorer) or by one owner serving as the operator under contract to the JV (examples of which include Plantation, Yellowstone, West Shore and Wolverine). In the latter situation it is usual that the ownership agreement provide a mechanism for the operator to resign and for the owners to replace an operator.
<i>Undivided Joint Interests</i>	
<i>Stock Corporation</i>	During much of the twentieth century the most common form of structuring a pipeline venture, whether singly or multiply owned, was a stock corporation. Such entities are straight forward with the owner(s) holding the stock of the venture, but the entity raises capital itself to build facilities, receives revenues for its services, incurs costs to operate, pays taxes and provides dividends to its owners to the extent it is profitable.
<i>Partnerships, Limited Partnerships</i>	Along the way partnerships began to be utilized as a means to minimize tax liability, but they carried the risk that every partner assumed the business liabilities of the pipeline. As states allowed the creation of limited partnerships, that form came into use as a means of shielding the limited partners from the business liabilities and concentrating those risks with a managing general partner who typically owned only a small fraction (say 1%) of the venture. During the last ten years or so, states have allowed the creation of Limited Liability Companies (LLCs) to allow taxation benefits and liability protections in an entity that resembles a corporation. Although only recently available the LLC form is gaining wide usage.
<i>Limited Liability Companies</i>	
<i>Master Limited Partnerships</i>	Master Limited Partnerships (MLPs) are a variation of the partnership form that was created by the 1986 Tax Reform Act and are limited to the development, production and transportation of natural resources. In addition to the tax and liability benefits of limited partnerships, MLPs have great utility for raising capital because units (e.g. the analog of corporate shares) trade on stock

*Mergers,
Acquisitions,
and
divestments
are changing
the ownership
structure of the
pipeline
industry.*

exchanges and are generally available to public investors, large and small. The use of MLPs has increased rapidly during the past 15 years and can be expected to increase further. Even large, diversified energy companies such as Sun and Williams reorganized their pipelines into MLPs. Other examples of MLPs are Buckeye, Kaneb, TEPPCO, Kinder Morgan, Plains All American and Enterprise.

The owner and the operator of a pipeline need not be the same entity although it is most common for an owner to serve as the operator. That is especially true when there is a single owner, but less so for a joint venture. The operating entity has the day-to-day responsibility to control, monitor and maintain the pipeline. In addition there are many responsibilities of the operator relating to reporting, regulatory compliance, community interfaces and emergency response. There are several reasons for an owner to contract with a third party to operate its pipeline. The most common ones involve joint ventures where no owner wishes to accept total liability given their partial ownership or where the owners do not want one owner to serve as operator and thereby receive any perceived advantages. Other reasons for using a contract operator include insufficient operating capability within the owner organization and attempts to achieve economies of scale by utilizing an entity with other operations.

The structure of the US pipeline industry has been changing significantly in recent years as mergers, acquisitions, divestments and other transactions have occurred. The reasons for the changes go beyond evolving corporate forms and changes in the transportation needs of the industry's customers. Rather the drivers have been the need to manage costs, the desire to achieve economies of scale and to reduce a wide variety of business risks, the necessity of complying with regulatory requirements and the hope of realizing new business opportunities. Several examples are cited in the following paragraphs.

As throughputs have declined in inland crude gathering systems and in certain crude transmission pipelines, the owners of those systems and lines have attempted to find new customers to replace the declining business. When that has not been successful they have merged with competing systems to establish a viable successor, have sold to an existing player or to a new entrant, have sold or transferred the asset to a new entity to be used for some other purpose or, as a last resort, have shut down and abandoned the facilities.

The approval of many large corporate mergers has been conditioned by the FTC and the states on divestiture of ownership in one or more pipelines, such as Mobil's interests in Colonial and TAPS and Shell's interest in Plantation.

The advent of MLPs has provided the capital to acquire existing assets with a goal of improving profitability and providing an attractive return to a wide ownership population. As a result, MLPs' share of pipeline assets has grown significantly, through acquisition and by reorganizing pipelines into MLPs. Shifts in the transportation business, combined with needs to reallocate capital among

competing uses and changing assessments of the risks associated with pipeline transportation have led companies to divest assets that are no longer viewed as core to their business and where it is assessed that the asset may be worth more to someone else than to the existing owner.

The changes in the pipeline industry are increasing the level of competition and spurring efficiency improvements. Those changes are encouraging and likely to continue, but there are issues that flow from them. For the most part they relate to a diminishing role for the well established, well financed and larger organizations that have been the back bone of the industry for a century. In their place are new entrants that need to establish their positions and build the organizations and capabilities.

Operational Factors

Operational Integrity

Operational integrity: a focus on safety, environmental protection and reliable throughput.

Safe, environmentally sound and reliable operations, variously called Operations Integrity or Operational Excellence, is absolutely critical to the liquid pipeline industry. Throughout its history the industry has worked at making its operations safer for its employees and its neighbors and more environmentally friendly. And the long term trends show progress and demonstrate that pipelines are the safest means of moving petroleum. Despite that progress, there have been safety and environmental incidents and the industry's stakeholders have not been satisfied with the rate of improvement. In recognition that operations can and must be improved more rapidly the leadership of the pipeline industry has put in place voluntary initiatives to accelerate the pace. The objective is to strive to eliminate all incidents. That will be extremely challenging, and may never be fully realized, but industry-wide data covering the past few years demonstrate a step-change in the rate of progress.

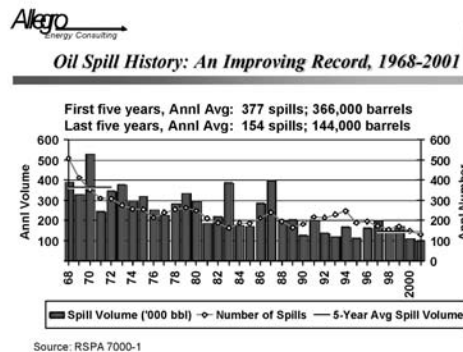
The key to achieving fundamental, long-term, sustainable improvements in operations integrity is to employ sound management systems that span the full spectrum of the design, construction, operation and maintenance of pipelines. It is essential that those systems be clear, understandable and practicable so that everyone having a role in their implementation knows the objectives of the system, what resources are available, who is responsible for performing the various activities, how performance will be measured to assure the objectives are being met and how the process can be improved as time passes, lessons are learned and technology improves. The coverage must be broad, including employees and contractors alike, extending from the most junior employee to the most senior manager and covering the processes that directly relate to operations and maintenance, the supporting ones, such as procurement, record keeping and human resources, as well as those associated with planning, risk assessment and risk mitigation. During the past dozen years or so, a number of management systems have been developed to achieve operations integrity. The systems go by

many names and have minor variations, but they contain the same fundamentals. Many companies voluntarily have adopted one or another system and even those that have not done so are employing many of the features of the approach since an increasing number of regulatory requirements mandate such systems, at least in some areas of operations and maintenance.

Measurement is an essential element of management systems. For a long time most pipeline companies have measured various operational parameters and the federal and state regulatory bodies with jurisdiction over the industry have mandated certain reporting requirements. Historically, there were gaps and inconsistencies in what was measured and reported and the thresholds for reporting were sometimes high relative to the performance that the industry and the public expected. For example, until the beginning of 2002 the Office of Pipeline Safety (OPS) had an incident reporting threshold of 50 barrels spilled unless damage exceeded \$50,000 or there was an injury, fatality, fire or explosion.

The liquid pipeline industry initiated a voluntary program effective January 1, 1999 to gather data on spills of any amount to water and other spills greater than 5 gallons. There were concerns as to what the data would show and how it might be misused to the disadvantage of the industry. Nonetheless, two-thirds of the industry participated. As with any new initiative it took a few data gathering cycles to clarify definitions, to standardize forms and to get the process working smoothly. Although the data are not publicly available, OPS has kept abreast of developments and used the industry experience to enhance its reporting systems effective in early 2002.

Exhibit 12



Since 1968, the year that data collection began, the spill record of the liquid pipeline industry has improved substantially, with the amount of oil spilled decreasing about 60%. During the five years 1968 to 1972 the industry averaged 377 incidents reportable to OPS per year and an annual spill volume of 366 thousand barrels. During the most recent five year period (1997 to 2001), the number of reportable average annual incidents dropped to 154 and the spill volume declined to 144 thousand barrels annually. The improvement continues as 2000 was a record low year and 2001 surpassed that (128 incidents, 97 thousand barrels). The available data show that pipelines have a better safety record than other modes of transportation and that outside force damage was the most important cause of large spills. Internal and external corrosion were a major cause of smaller spills, often on pipeline company property. All spill causes are being vigorously pursued to further improve performance.

Security

Post-September 11 security concerns are a top priority.

The tragic events of September 11, 2001 triggered a re-examination of the security of the oil pipeline network, which is the core of the US petroleum transportation system. As such, it is a valuable national asset that must be protected. Fortunately pipelines are physically robust with the vast majority of the system underground and less vulnerable than aboveground facilities. And pipeline operators have been managing the integrity, safety and security of their systems for many years. The historical efforts have been enhanced (1) by ready cooperation with the federal government to identify, for preparedness purposes, those pipeline facilities that are critical to the nation; (2) by cooperatively developing security guidance ("Guidelines for Developing and Implementing Security Plans for Petroleum Pipelines" --- API July 2002); and (3) by responding to the federal government's guidance for security contingency planning.

By April 1, 2003 operators of 95% of the oil pipeline infrastructure had certified to the US Department of Transportation their compliance with the contingency planning guidelines. Shortly thereafter the Office of Pipeline Safety began to conduct verification checks to validate the certifications. In addition, pipeline operators are conducting and will continue to conduct vulnerability assessments of critical pipeline facilities as the federal government and the industry develop a better understanding of the terrorist threats and capabilities. Operators have taken numerous steps, in many forms to enhance security and will continue to work closely with the Office of Pipeline Safety and the Department of Homeland Security to take prudent and practical actions, including monitoring threat information, analyzing pipeline vulnerabilities and implementing practical and reasonable protective measures.

Rights-of-Way

Rights-of-Way are a critical feature of planning, operating and maintaining the pipelines.

Pipelines physically reside in Rights of Way, which are sometimes owned by the pipeline owner, but more often are used under the terms of an agreement with a private landowner or a permit from a public landholder. During the early years of the industry, obtaining rights of way was relatively straightforward and the agreements tended to be simple documents. As the industry has matured the issues associated with rights of way have multiplied and there are many examples of contentious, emotional and protracted battles stemming from attempts to acquire new rights of way or to utilize existing ones. The outlook is for the situation to grow ever more difficult, given the increasing urbanization of the US, heightening concerns about environmental and safety matters, an increasing goal of extracting monetary value for use of the land and a growing unwillingness to site industrial type facilities in many areas.

Today, a well-written pipeline agreement or permit will address many terms, starting with a description of the physical easement, including its width. Other items include duration, renewal, fees, rights of the pipeline company to access the easement and rights of the landowner, restrictions on use of the easement by both parties, the number and size of lines, materials that may be transported, rights for expansion (number of lines, size of lines), communications among parties, abandonment (definition and responsibilities), and more. Older agreements often did not contemplate many of the issues and, as one or another situation has arisen, have resulted in expensive, time-consuming arguments and frequently in litigation. Modern agreements that deal with the range of terms and conditions and more clearly spell out the restrictions on the parties tend to raise the right of way cost.

Acquiring a Right of Way

A liquid pipeline desiring to invest in a new line has a number of options for acquiring a right of way. Whichever approach is pursued, an analysis of the alternative routes and the issues associated with each is the starting point. Once a lead route has been selected the pipeline has the option of buying the right of way in fee, in which case the company would become the landowner and maintain full control. That could be expensive and often impossible. Alternatively the pipeline can approach the landowners along the proposed right of way and negotiate voluntary agreements for easements. If that fails, and the proposed pipeline will be a common carrier, the pipeline company may be able to resort to using its right of eminent domain that is spelled out in the statutes of the particular state. Increasingly, using rights of eminent domain leads to time consuming and expensive litigation, but often the project may move forward before all of the cost issues are resolved. In view of the difficulty and expense of acquiring rights of way there are examples in highly developed areas, such as Houston, of pipeline corridors being established and set aside for future construction of lines. The initiative may originate with a pipeline company or it may be promoted by a local jurisdiction.

This discussion has focused on private landowners, but the permitting process for the use of public lands has many similar features. Under certain circumstances, both public and private, it may be necessary to conduct an environmental impact review, assessment or study as spelled out under NEPA (National Environmental Policy Act of 1969) which adds complexity, time and cost to the process.

Both for existing and new rights of way there are continuing responsibilities to maintain the rights of way and to comply with the provisions of the agreements. Operations and maintenance require keeping the easement clear (periodic mowing, side trimming of trees, etc.) inspecting it with some frequency (surveillance flights, traversing the route, etc.), inspecting and maintaining the line and any associated facilities, such as cathodic protection, valves and meters, and dealing with any encroachments that may occur. When restrictions in the agreements on use of the easement by the landowner have not been rigorously enforced it may become necessary to remove structures (i.e. buildings, sheds, fences, etc.). That can create considerable animosity between the pipeline and the landowner.

As the pipeline industry strives to reduce operational incidents, increasing attention has been focused on rights of way. Historical analyses show that the leading cause of the more severe incidents have been impacts sustained by the pipe, whether caused by the landowner or by someone, such as a utility company or contractor, operating on behalf of the landowner. Thus, ever more stringent processes, such as emphasis on a "call before you dig" process and increased surveillance, are being employed. Furthermore, in the event of an incident, no matter the cause, the safety of neighbors increases the further from the pipeline they are located. Thus, some initiatives associated with land use restrictions are beginning to establish minimum setbacks from pipelines. In a more urbanized environment these may be needed, but they raise issues of conflicting land use and can be contentious.

Capacity Management

Historically there has been sufficient pipeline capacity in the US to meet shippers' needs, whether for moving crude oil to market, providing feedstock to refineries and petrochemical plants or transporting products from those refineries and plants to consumers. However, from time to time, situations arise, such as the start-up of new facilities (e.g. a new production field or a new refinery), growth in aggregate demand, and short-term perturbations or emergencies (e.g. weather, pipeline outages, other supply disruptions) that call for steps to increase capacity. These are becoming more frequent, especially in some geographic areas such as the Mid-West and West Coast.

In many cases there are steps that can be taken to squeeze more capacity out of an existing system. Examples include raising the operating pressure on a line when it is safe to do so by adding or modifying the existing pumps, by adjusting the

schedule for moving multiple products on a particular line to take advantage of the specific configuration of the line and its related facilities, by reducing downtime through improvements in operations and maintenance practices and by employing relatively new technology, such as Drag Reducing Agent (DRA) that reduces friction in the pipe, thereby allowing a higher rate of flow. If such steps are insufficient, presumably there are business opportunities for one or another company to expand existing capacity or to add new capacity. It is always possible to build a new, large pipeline, but sometimes there are less costly opportunities, such as utilizing a line that had previously been in some other service and converting it to meet the new need, or swapping two lines to better match the physical capacity of the pipes with the needs of the respective shippers or removing local bottlenecks if most of the route would have sufficient capacity to meet the new situation.

*Prorationing and
capacity
enhancement*

During periods when there is insufficient capacity to meet the transportation needs of all shippers, established pipelines rely on provisions in their tariffs to prorate the available capacity among their shippers. Typically the existing capacity is shared in a way that reflects the historical pattern of shipments by the different shippers as well as their current needs and provides some consideration for new shippers not having an historical base. Usually a pipeline company will do everything possible to maximize the capacity available in the short term to avoid having to prorate capacity and to minimize the length of time prorationing is in effect. Available steps include deferring scheduled maintenance if the risks of doing so are reasonable, temporarily running spare equipment or running it harder, and increasing temporary staffing to expedite other short-term opportunities. Such steps apply in many situations, but depending upon the specifics there may be other opportunities that apply during supply disruptions. For example, if the problem is associated with a pipeline outage there are usually steps that can be taken to expedite the repair and the return of the facility to service. Needless to say, in any of these situations, good communications, coordination and cooperation among all of the interested parties and non-discriminatory solutions are essential.

Maintaining Product Quality

In the early years of the liquid pipeline industry the product quality emphasis was on avoiding any gross contamination of the material being transported. By the middle part of the twentieth century advances in the internal combustion engines for automobiles and the increasing use of airplanes raised the importance of maintaining product quality, especially in some of the grades being shipped. Higher-octane gasoline, aviation gasoline and later kerosene-type jet fuel required considerable care to avoid contamination. Then, in the years after World War II, the proliferation of special fuels, driven primarily by efforts to improve the environment, and the need to segregate some refinery and petrochemical plant feedstocks and intermediate products increased the challenge of maintaining product quality.

*Crude Oils and
quality banks*

In the early part of the 20th Century there was little distinction among the various crude oils. As the sources of crude diversified, so did the characteristics of the oil. Early on some crude oils were good sources of lubricants and others were light and sweet (i.e. low sulfur) and used to make a variety of fuel products. As production expanded westward, crude oils were produced that had large variations in sulfur, metals content and density (called gravity) and occasionally in some other characteristic. Since higher sulfur, heavier crude oils generally had a lower value, commingling different types of crude oils in a pipeline carried an economic penalty to some shippers. One solution to preserve the relative value of the crude oils being transported is to maintain segregations by crude oil type, but that takes more facilities and pipeline capacity, raises the transportation cost and is not always practical. Another approach is to impose a quality bank, whereby the shipper of the poorer quality crude pays some money into the quality bank and the shipper of the higher quality crude receives a payment to compensate for the degradation of its crude. Typically the pipeline establishes the quality bank in its tariff, handles the accounting and uses some simple measure, such as sulfur level or gravity level alone or in combination, as the basis for the payments and withdrawals. In these situations the pipeline operator is merely the banker or escrow agent for the shippers of the differing crude qualities.

*Feedstock to NGL
fractionators and
petrochemical
plants*

Although the quantities involved are considerably smaller, feedstock to NGL fractionators and petrochemical plants face analogous issues and solutions to those faced by crude oil. Because there will be further processing after transporting the raw materials there is a costly option of segregating the feeds or of commingling feeds whose quality varies and imposing a quality bank to compensate the shippers for the quality gained and lost during shipment.

*Products and
batching
segregation*

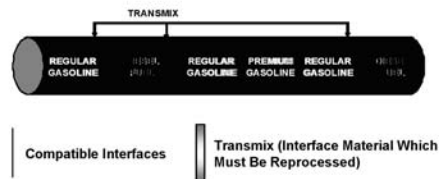
Products, whether from refineries or petrochemical plants, must have their characteristics maintained and cannot be commingled as is frequently done with crude oil. An exception is that a transmission pipeline may establish specifications for a fungible material, say regular gasoline, and batches from more than one shipper may be consolidated into a single fungible batch to be moved so long as the tendered material meets the minimum specifications. Commingling of fungible product thereby lowers the cost of transportation. In a few cases the volumes being transported are large enough, the distances are short enough or the specifications are so rigorous that dedicated lines can or must be used, usually at a significant cost. Fortunately, in most instances it is possible to batch the products, that is to say, carry multiple products in series in a single pipeline. Doing so requires additional facilities, which may include tanks, pumps, meters and analyzers, at the origin, destination and possibly at intermediate points. Close attention to scheduling the batches and good communications among the carrier and the shippers are essential. Good pipeline operations will minimize the mixing between successive batches. Depending upon the specifications of adjacent batches it may be possible to downgrade the interface between two batches into a succeeding lower quality material (such as premium gasoline into regular

gasoline), but in other cases it will be necessary to segregate the interface, called transmix, and to arrange for it to be reprocessed.

Maintaining the integrity of the quality of product being shipped, whether it moves in batches or in dedicated systems, can be influenced by many operational factors. Facilities must be maintained to avoid leaks across closed valves where different materials are in the lines on either side of the valve. Care must be taken in operations to establish the proper interconnections (i.e. lineups) within tank farms and terminals when moving products in and out of tankage, to be sure that other or off-spec materials, such as water and transmix, do not enter a batch of good material. Quality is maintained by proper sampling and analysis (in a product quality laboratory or via an in-line analyzer) at various points in the transportation system. In some cases the product quality requirements are so stringent that the only way to assure their integrity is to isolate the system from all other materials.

Exhibit 13

Typical Sequence of Petroleum Products Flow through a Pipeline



Field Operations

Good field operations, which are critical to the safe, environmentally sound and reliable operation of a pipeline system and which may have significant impacts on maintaining product quality and operating cost, cover a wide range of activities. For reasons of brevity the discussion will be limited to a few areas, including gauging and calibration, equipment and facility maintenance, inspection and surveillance and emergency preparation.

<i>Measurement</i>	Measurement of the material in the custody of a pipeline company, whether in the process of being transported or in a tank awaiting further action, is important to the carrier and to its shippers, both for commercial and operational reasons, such as remote and automatic leak detection. Installing, maintaining and calibrating appropriate flow meters and tank gauges are essential and require regular activities. Usually tanks can be gauged remotely, but it is customary for field personnel to manually gauge tanks at least once a month. In-line flow meters can often be read remotely, but it is common to require that meters be read manually as often as daily and sometimes for individual batches which may require multiple readings a day. Calibrating (or proving) meters can sometimes be done automatically for high volume situations, but more often there is a schedule based on throughput and the necessity to make temporary connections of a portable prover.
<i>Maintenance</i>	Equipment and facility maintenance involves routinely inspecting and checking equipment, conducting scheduled activities to prevent failures and unplanned shutdowns and making repairs after inspections and breakdowns. Activities include using scraper pigs to remove the buildup of paraffin on the inside of crude pipelines, lubricating pumps, valves and other equipment; periodically running equipment that would otherwise be idle; and using cathodic protection, paint systems and other coatings to protect facilities. Normally there is a large amount of electrical gear associated with pipeline operations that must be routinely inspected and maintained and an increasing utilization of electronics that requires routine maintenance, upgrading and trouble-shooting.
<i>Surveillance</i>	Field surveillance of a pipeline covers a range of activities, conducted with different frequencies, to assure the integrity of the operation and to identify steps to prevent future failures. A common type of surveillance, aerial patrols every few days or weeks, is designed to spot leaks, encroachments on the right of way or activities off the right of way that have potential to impact the pipeline. Normally the pilot has a means to communicate with ground personnel so prompt action may be taken if the situation requires a quick response. Other types of surveillance, typically conducted less frequently, include personnel walking or riding along the right of way to gain an up-close view of conditions on the ground and the equipment, close interval surveys to ascertain the effectiveness of the cathodic protection system and inspections of waterway crossings, whether the crossing is by a pipeline bridge or a pipe laying on the bottom of the waterway or buried beneath the bottom of the water.
<i>Preparations for emergencies</i>	Preparation for emergencies includes maintaining and testing equipment used to recognize and deal with unexpected and undesirable situations and conducting drills to familiarize field personnel with response plans and their roles in promptly and effectively dealing with emergency situations. Equipment for monitoring the pipeline and ancillary facilities include sensors to spot high temperatures and pressures, flames, releases of hydrocarbon vapors, high levels in tanks and imbalances between the volume of material entering a line and that leaving the

line. Other equipment is in place to shutdown and isolate sections of the pipeline, terminals or tank farms, under local or remote control or automatically. Drills are organized to rehearse steps that would be taken in response to oil spills or to other emergency situations. They frequently involve representatives from federal, state and local response organizations, and may be table-top exercises remote from the pipeline or field exercises that include the deployment of people and equipment.

Work Force

*Duties and
structure vary*

As with any business, pipeline companies are organized to provide specific services to their customers and to provide the range of activities needed to support their mission. Mission-specific tasks include designing and constructing facilities, handling right-of-way matters, operating and maintaining the pipelines and ancillary equipment, interfacing with the pertinent regulatory bodies and conducting commercial activities, such as establishing tariffs and interacting with shippers. The support activities cover a wide range of tasks, including technical, accounting and legal support, planning analysis and reporting, human resources and general management. Depending on the size, complexity and philosophy of the company, the ways in which the organization is structured and staffed vary widely. Some organizations are centralized and others distributed, some rely heavily on employees while others out-source many activities, using a high proportion of contractors, and some are leaner than others in the level of internal staffing.

*Pipelines have
moved from
manual to
remote
operations*

The way in which pipelines are operated and maintained has evolved considerably over time. In the early years of the industry operations were largely manual and there was a need for local oversight and control, so the operations work force was distributed throughout the pipeline network. Typical field organizations were structured along craft lines, such as with gaugers and operators in operations and with gangs, mechanics, electricians, instrument technicians and such in maintenance. With advances in technology, especially telecommunications, computing and remote sensing and control, it is possible to "operate" (i.e. "control") most pipeline networks, even those covering facilities across the United States, from a single control center that can be located virtually anywhere. Those controllers are usually located in rooms filled with sophisticated consoles containing computer screens, TV monitors, and the latest in communications technology and employing state of the art SCADA (Supervisory Control and Data Acquisition) systems that enable the computers and the controllers to monitor and remotely control facilities (i.e. start and stop pumps, open and close valves and check operating conditions) regardless of the location of those facilities.

Maintenance

In some ways the maintenance activities have not changed so much as operations, but increased mechanization has somewhat diminished the traditionally manual activities, while the equipment and instrumentation (i.e. pumps, motors, valves, analyzers, sensors and local controllers) have become much more sophisticated and hence require a higher skill set to maintain. Recognition of the technological

advances in operations and maintenance, together with the advent and emphasis on integrity management systems, caused many pipeline companies to take steps to enhance work force training and development, to raise performance standards and to periodically assess the qualifications of the relevant workers. Those initiatives recently became industry-wide and mandatory with the adoption by the Office of Pipeline Safety of the Operation Qualification (OQ) rule that is being implemented nation-wide.

*Contractor
use*

The utilization of contractors to design and build new pipelines typically involves a high level of contractor utilization, but the role of contractors in operations, maintenance and support activities varies widely among pipeline companies. Factors that often support the use of contractors include work that is seasonal or highly variable as to the level of effort, tasks that are relatively unskilled and with a high manual labor content and tasks that require an unusual skill set making it hard for a company to develop and maintain an in-house competency. Other factors influencing the mix of employees and contractors include the availability of suitable contractors locally, the cost of contract personnel, including overhead and benefits, whether or not the task is viewed as a core competency that should be maintained in-house and any over arching management view on out-sourcing. Regardless of the reason for using contractors, the expectations regarding competency must remain comparable to those for employees and the OQ rule holds the operator responsible for the competency qualifications whether the task is being handled by contractors or employees.

*Future work
force issues*

There are a number of work force issues facing the pipeline industry, many of which are being faced by other industries. As an example, the demographics of the employee population are such that a high proportion of the work force will retire during the next decade and replacing the attrition will be challenging with a smaller pool of candidates at the same time that employment standards are rising. A somewhat related issue is the shift from organizing the field work force along traditional craft lines to a more flexible, multi-skill approach. The former tends to be less efficient and more costly, whereas the latter can be more efficient and provide more opportunities for individual growth, but needs higher skilled individuals and more training. The role of unions, particularly international unions such as PACE (Paper, Allied-Industrial, Chemical and Energy Workers International Union), in the mix of represented and non-represented employees is another issue being faced by the industry. And various issues related to employee benefits, such as health care and pensions, are very much on the minds of employees and management.

Community Involvement

There may have been a short period in the early days of the pipeline industry when the interfaces with the public were limited, but for most of the history of the industry there has been an ever-increasing level of interaction. Today, separate from all the regulatory interactions, there are relations with the owners of the

property traversed by the pipelines, with neighbors, near and far, with the responders (police, fire and others) for drills or if an emergency were to occur and with the direct and indirect consumers of the transportation services provided by the pipelines. Pipelines increasingly recognize how important it is to expend the time and effort to establish and maintain sound, open communications with the various interested publics. With few exceptions there are only minor differences in the objectives of the industry and the public, but the increasing urbanization, growing awareness of pipelines and the influence of the media contribute to an ever heightening of society's expectations of all industry, not the least of which are pipelines.

Communications

The leadership of the liquid pipeline industry has recognized the trend and the need, not only to respond, but also to get out in front with communications. To that end the industry has initiated and supported various programs to more effectively communicate with the public, educating them with regard to pipelines, creating forums for dialogs on issues of mutual interest and responding to the interests and expectations of the public. The communications methods employed vary widely, including the preparation of written materials that are distributed proactively (to right of way owners and neighbors, for example) or in response to inquiries, the creation of web sites for any interested party to learn more about an individual company or the industry (e.g. www.pipeline101.com) and visits and presentations to many subsets of the public. Depending on the audience the efforts meet with varying degrees of success. In some cases, the public seems disinterested in the communications overtures. In other instances, there can be a lot of emotion associated with pipeline issues and it is not always possible to come to a readily satisfying resolution or compromise among the various views. Nonetheless, the communication and outreach effort is recognized to be essential and must be continued.

Costs

The financial performance of pipeline companies is driven by revenue, which is closely tied to the volumes being transported for their shippers, and the costs to operate, maintain and upgrade existing lines and to build new ones. And what is revenue to a pipeline is an additional cost to the producer to get its crude to market, to the refiner to get feedstock to its refinery and to the marketer to get its refined products to the consumer. Consequently, in today's competitive transportation market, shippers (even in integrated energy companies) apply considerable pressure on the pipeline companies to keep their tariffs low and the shippers back up their demands through commercial (i.e. by using other transportation options) and regulatory (i.e. by challenging tariffs) means. The result is that pipeline companies are driven to manage their costs in order to attract business and to improve their bottom line. Another factor increasingly impacting the industry's cost outlook is the need for investment and reinvestment to meet a variety of needs, some arising from shippers, some from legislative and regulatory requirements and some from public demands.

For many years the single largest cost to operate and maintain a pipeline was for the fuel and power needed to pump the crude and products. During the last decade or so, pipeline companies have

out-sourced many of the services previously handled in-house as a means to become more efficient and reduce their total costs. As a result, Outside Services was the single largest cost during the 1990s (22%), followed closely by Fuel and Power (21%). The cost of employees (Salaries and Wages at 14%) was next, followed by Supplies and Expenses at 9%. The FERC definition of "Supplies and Expenses" involves supplies consumed and expended in operations and includes expenses of aircraft and vehicle operations, travel and other employee expenses and related miscellaneous costs. The other 34% of operating and maintenance expenses are comprised of a wide range of miscellaneous costs.

Exhibit 14. Average Pipeline Cost Distribution 1990 to 1998			
OPERATING EXPENSES		CAPITAL EXPENSES	
	%		%
Outside services	22	Pipe construction	35
Fuel and power	21	Line pipe	20
Salaries and wages	14	Other station equipment	12
Supplies and expenses	9	Oil tanks	5
All other	34	Pumping equipment	4
		Line pipe fittings	3
		All other	21
	100		100

Source: Association of Oil Pipe Lines

The distribution of expenses associated with capital projects is largely influenced by the cost of the pipe and equipment and the cost of constructing the facilities. During the 1990s the single largest capital cost category was Pipe Construction (35%), followed by the cost of Line Pipe (20%), Other Station Equipment (12%), Oil Tanks (5%), Pumping Equipment (4%) and Line Pipe Fittings (3%). The category "All Other" accounted for the remaining 21% and was comprised of a large number of smaller categories.

Capital Investment

Unlike the post-war period of the 1950s through the 1970s during which some 62% of the presently existing pipeline infrastructure was put in place, the 1980s and 1990s saw relatively small additions, 9% and 7%, respectively. The reasons included the decline of inland crude production which made considerable pipeline mileage available for other purposes, the ability to debottleneck existing capacity and the limited growth of refining capacity. Today there are emerging factors that may alter the situation and increase the industry's need to invest. These include a shifting, growing population especially in some areas of the country, the limited remaining ability to achieve incremental capacity growth by redeploying existing infrastructure and the extremely capital intensive development of large crude reserves in very deep water (5000' to 10,000') in the Gulf of Mexico. Other reasons include the issues surrounding the maintenance of older pipelines and the

*Attracting
sufficient capital to
meet investment
and reinvestment
needs*

need to replace some portion of those systems, as well as the need to respond to the heightened public expectations of the industry that are reflected in legislative and regulatory requirements, including the development and implementation of expensive, cutting-edge technology.

The ability of the pipeline industry to attract sufficient capital to meet its investment and reinvestment needs will be strongly influenced by the balance of risk and reward perceived by potential investors. Whereas in the decades after World War II the large, often integrated, companies stepped up to meet obvious needs, such as investing \$8 Billion to build the Trans Alaska Pipeline System, today many things are different. The integrated companies are much less of a factor in the pipeline industry and even for those that remain, the ability of a pipeline affiliate to obtain capital is more challenging, as every project needs to stand on its own and compete with expensive, high return exploration and production investments. Concurrently, the sources of capital have become much more diverse. Examples include companies not in the energy industry, public and private funds and small, individual investors who buy units in Master Limited Partnerships. The ability to tap those sources requires a clear understanding of the rewards (i.e. the returns) and the risks.

The rewards include a steady, long term cash flow and an acceptable return, especially for those entities with a lower cost of capital. And, although there are segments of the industry that have been contracting and restructuring, the outlook is for substantial growth in order to meet the rising energy needs of the country.

On the other side of the balance the changing nature of the risks facing the industry will make it more difficult to attract capital. Some business risks have existed since the inception of the industry and will continue. Examples relate to the cost and schedule for executing projects, the impact of operational upsets and the effects of competition on volumes and revenues. Risks that may prove to be more important factors in the future involve the difficulties of obtaining permits and rights-of-way, operations in more difficult environments (such as deep water Gulf of Mexico), the extreme design and operating requirements that may be imposed on operators and the difficulty of specifying and applying new technologies. There are other risks that also influence the ability to raise capital. Perhaps the most important for a pipeline (including its owners, officers and employees) is the ever-increasing liability that flows from any sort of operating problem having a safety or environmental impact. In our litigious society the implications of an incident are enormous and will color investment decisions.

Legislative and Regulatory Impacts

Since 1906 when Congress passed the Hepburn Act, oil pipelines have been declared to be common carriers and have been subject to the provisions of the Interstate Commerce Act of 1887, which had applied previously only to railroads. Congress' action responded to the public outrage resulting from John D.

Rockefeller's Standard Oil gaining control of 90% of the refining industry and 80% of the oil transportation business and employing a variety of anti-competitive practices. The Interstate Commerce Commission (ICC) was responsible for regulating the oil pipelines, including rates and charges, terms of service, the form and content of tariffs, accounting, reporting and limits on the disclosure of shipper information, but not the construction and abandonment of pipelines, sales and leases of pipeline assets, non-transportation services and securities transactions. With the exception of some pipeline cases in 1914, the ICC was relatively inactive with regard to oil pipelines until the 1940s. Among the more significant regulatory actions thereafter were the Atlantic Refining Consent Decree in 1941 (which limited the dividends that a pipeline subsidiary could lawfully pay to its parent, thereby effectively limiting pipeline rates of return), the ICC Valuation Methodology during the 1940s (which determined asset values for recovery through rates) and the Williams Pipe Line and TAPS proceedings of the 1970s (both of which challenged existing rate methodologies).

Economic Oversight

In 1977, the Department of Energy Act created the Federal Energy Regulatory Commission (FERC) and transferred responsibility for oil pipelines to FERC from the ICC. The DOE Act specified that the interstate transportation of oil by common carrier pipeline was to be regulated by the FERC, thereby excluding anhydrous ammonia, CO₂, water and a variety of other materials which are regulated economically by other agencies or are not regulated as to rates. During the early years of FERC's oversight, its regulatory efforts were quite limited. Then in 1985 FERC issued Opinion No. 154-B, which set a new cost-based mechanism and in 1988, in a case involving Buckeye, FERC introduced the alternative of market based rates for situations in which a pipeline could demonstrate a lack of market power and thus be permitted to charge market-based rates. But the time and cost of proceedings under each of these methodologies was significant.

Congress, by enacting the Energy Policy Act of 1992, altered the regulatory landscape by mandating that the FERC create a simplified and generally applicable rate methodology. The Act deemed most existing and unchallenged rates just and reasonable, which is known as the "grandfathering" provision. Late in 1993 FERC responded by proposing an indexing approach that was adopted in 1994. It utilized an index that was the Producers Price Index for Finished Goods less one percent (i.e. PPI -1%). The chosen index methodology was effective initially for five years and was subsequently extended for a second five year period. That extension was challenged, largely because the cumulative index (3.5% from 1/1/95 to 7/1/02) lagged actual cost increases. The U.S. Court of Appeals for the DC Circuit vacated the extension and on February 20, 2003 FERC announced that rates would be indexed using the new PPI index (without the minus one percent) for the five year period 2001 to 2005. The index allows

Common carriage

pipelines to increase rates up to the index ceiling, largely without risk of challenge.

The notion of a common carrier flows from common law and subjects to regulation private property that is "affected with the public interest". A common carrier has certain obligations: to provide prompt and safe services, to be strictly liable for injuries, to avoid undue discrimination or preferences among shippers and to charge reasonable (i.e. not excessive) rates. The public also has obligations: to provide a fair return to the carrier and to arm the carrier with the right of eminent domain. And there are limits on the carrier's obligations, including: no requirement to continue in service and no requirement to expand, although a pipeline must treat shippers fairly if capacity is constrained.

While the indexing methodology has been the primary rate making mechanism since the mid-1990s, there are alternatives. The 154-B cost of service approach dating from 1985, market based rates and negotiated rates are all being utilized currently. The underlying requirement is that the rates must be just and reasonable, but there are many details and fine points that apply to each of the methodologies. These include the requirement that the service must strictly conform to provisions of the tariff (i.e. prorationing of capacity, demurrage, odorization, storage, handling, loading/unloading, blending, etc.). While undue discrimination is prohibited, some forms of discrimination, especially those aimed at responding to competitive pressures are allowed, so long as they are not "undue". These include proportional rate discounts, volume incentive discounts and favorable treatment for signatories of throughput and deficiency agreements. Through or joint rates also are allowed.

This discussion has centered on interstate rate making, which applies to about 80% of US oil pipeline mileage and volumes transported. The other, intrastate movements may be regulated by the respective states (often by a public utility commission, but sometimes with a different name, such as the Railroad Commission in Texas and the Regulatory Commission of Alaska) and most state statutes provide for generally similar approaches to economic regulation. An issue that sometimes arises involves decisions as to when a pipeline is in interstate versus intrastate service. Often the distinction is clear, but not always.

In addition to the more global interstate and intrastate issues, there can be some local economic regulatory issues, an example of which is franchise fees. In most cities utilities that have easements under the streets to distribute water, telecommunications, electricity and natural gas to consumers pay franchise fees to the city for the right to use those easements. Normally the fees are paid annually and can be substantial, perhaps a percentage of the value of the service being distributed. With few exceptions liquid pipelines do not use city streets as rights of way, although there may be numerous crossings of streets, especially as urban sprawl increases. In most places liquid pipelines pay a fee that bears some relationship to the costs incurred by the city to grant an initial permit and then to

administer it thereafter. However, in recent years, as the revenue needs of cities have increased, many have tried to impose franchise fees. Litigation has ensued and for the most part the liquid pipelines have prevailed. The situation in California is different in that a system of franchise fees imposed on oil pipelines has been in place for many years.

Environmental Protection

The pipeline industry must comply with a wide variety of environmental regulations, some of which directly affect new and existing facilities, while others represent an indirect impact because the regulations relate to the materials being transported. The Environmental Protection Agency (EPA) has the largest role in such regulation, but many other federal, state and local agencies are involved, some of which establish standards while others are charged with enforcement. The list of federal agencies includes, in addition to EPA, the Office of Pipeline Safety, the Bureau of Land Management, the Army Corps of Engineers, the Minerals Management Service, the US Fish and Wildlife, the US Coast Guard and the US Forestry Service. The number of state agencies is similarly wide-ranging. Aside from the challenges of dealing with a large number of agencies, there are conflicts and inconsistencies among the requirements imposed. An example of an area of conflicting jurisdiction is terminals, which may serve more than one function. Most pipeline terminals are under the purview of OPS, but most marketing terminals are under the jurisdiction of EPA. Another example is that offshore pipelines come under MMS rather than OPS jurisdiction. Furthermore, all too often state and local agencies are not consistent with their federal counterparts and there are state-to-state variations.

Most direct environmental regulation deals with releases to the environment, whether occurring during normal operations and maintenance activities, during construction or as the result of unplanned incidents. The regulations cover releases to air (tank emissions; fugitive emissions from pumps, valves and other equipment; releases occurring when equipment is opened for operations and maintenance; "spills" of highly volatile liquids, etc.) and to water (discharges from treating facilities, normal run-off from a site, run-off during construction and spills), handling of toxic substances and disposal of hazardous materials. The regulatory coverage includes specifying limits on discharges and mandating procedures for obtaining approvals for new and modified facilities and for establishing and testing plans for handling operational contingencies. With the passage of time the regulations are becoming more demanding, tightening emissions limits, imposing additional requirements for the contingency plans and raising the expectations and standards for the operation of pipelines, such as the training and qualification of operating and maintenance personnel.

The indirect environmental impacts relate to the increasingly stringent specifications for refined products, such as reducing the permissible level of sulfur or other compounds in some fuels (such as low sulfur diesel fuel) and

defining the composition of other fuels (e.g. banning MBTE, requiring ethanol addition, limiting RVP, etc.), particularly with respect to motor gasoline, in order to meet attainment standards in certain geographic areas. One impact of these new fuel requirements is simply the challenge of maintaining the integrity of a product, recognizing that only a slight amount of contamination will render the product useless and a candidate for reprocessing. Another outcome is the proliferation of grades of a fuel that require special care and handling which manifests itself in higher operational and maintenance costs and reduced capacity.

Safety Oversight

The growth in regulations related to the safety of pipeline operations and to the protection of employees, including contractors, and to the neighbors of pipelines is quite similar to the trend in the environmental area. Once again there are a multitude of federal, state and local agencies with an interest and a role and often some over-lap with the environmental regulations. With regard to worker safety the Occupational Safety and Health Administration plays the lead role, but others, particularly state OSHA organizations are involved. Safety of operations is primarily the responsibility of the Office of Pipeline Safety, but there are other agencies with an active interest, such as the Minerals Management Service for off-shore pipelines and state agencies such as the Railroad Commission in Texas that perform functions analogous to those of the OPS. Local entities, down to the level of cities and towns become deeply involved in contingency plans and drills for all sorts of emergency situations. As in the environmental area there are not always consistent standards and approaches among agencies and across state boundaries.

Impact of Technology

Throughout its 100-plus year history the pipeline industry has employed advances in technology, implementing new technology developed specifically for pipelines as well as taking advantage of developments in other areas and industries. Since the first pipeline was constructed, there has been a steady stream of advances relating to construction, operation and maintenance. Along the way there has been an increasing emphasis on new and improved techniques to reduce risk and there have been applications of technology aimed at managing costs.

Constructing and Maintaining Pipelines

Since the late 1800s, steel has been the material of choice for virtually all pipelines and tanks. The steel industry evolved rapidly in the late 19th century and as the steel making process improved, so did the quality of the steel, with stronger, tougher materials having fewer impurities and better welding properties becoming available. That progress continues with standards for the newest, strongest steel yet developed being adopted in 2002. The methods of converting

*Improved steel
and coatings*

steel plate into pipe have also changed a great deal. In the early days furnace butt welding and furnace lap welding were used to form the longitudinal weld on a section of pipe. There have been a number of improvements and today double submerged arc welded pipe is used and has a longitudinal weld as strong as the pipe itself. In parallel with improved materials and pipe fabrication there has been progress in coatings that protect the steel from the environment and enable an almost unlimited service life. Early coatings of mastic and tar have given way to fusion-bonded epoxies that provide a tough, corrosion resistant coating. Similar advances are employed in storage tanks to limit corrosion of the bottom and walls.

Construction

The methods of constructing pipelines have changed considerably from the early years when screwed joints, bolted flanges and other mechanical methods were used. In 1911 oxy-acetylene girth welds were first employed, but since the 1930s electric arc girth welding has been used. When pipelines are built the welds are checked by X-rays or ultrasonic probes to identify weld defects and corrections are made before completing the line. Then, before operation, the line is subjected to a hydrostatic test at pressures at least 25% higher than the maximum operating pressure to identify weak spots. Also, in-line electronic sensors may be used to identify construction defects. Analogous progress has been made in constructing storage tanks and other facilities associated with pipeline operations.

The evolution of the technology for constructing pipelines can be illustrated best by examples of pipelines that have been built in very difficult locations. A particular feat was construction of the Trans Alaska Pipeline System, the 800-mile, 48" pipeline from the North Slope of Alaska to the marine terminal at Valdez on Prince William Sound that was built during the 1970s. Half of the line had to be built above-ground as it traverses tundra that remains frozen all year, the right-of-way crosses three mountain ranges and numerous earthquake faults and the remote location of much of the line presented enormous and unprecedented construction challenges. Current examples are the lines being constructed to transport crude oil in the deep waters of the Gulf of Mexico, often in excess of 5,000 feet. Since it is impossible for humans to work at such depths the pipeline must be constructed on the surface, lowered to the bottom and then monitored and maintained remotely. Special materials, coatings, equipment and techniques have been developed and employed and the quest for new and better approaches continues.

During the past thirty years or so, the technology for inspecting liquid pipelines while in-service has advanced considerably. "Smart pigs," or internal inspection devices, have become more sophisticated with progress in electronics, miniaturization and sensor technology. Today there are a variety of devices available to identify imperfections in the steel forming the pipe wall, such as surface defects created during fabrication or by corrosion since installation, or the existence of cracks that if not repaired have a potential to lead to failure. Besides the internal devices, there are a large number of other tools, applying all sorts of

*Monitoring and
controlling
pipelines*

technology, to test and evaluate pipe, tanks, and equipment. Examples include ultrasonic and infra-red probes and vibration and gas detection sensors.

In recent years the technology for monitoring and controlling pipelines, tanks and ancillary equipment has evolved rapidly, taking advantage of developments in telecommunications and computer technology. Operating conditions, such as flow rate, temperature and pressure, as well as the condition of equipment, are determined by sensors that can be read locally and remotely. And control of equipment, such as valves, pumps and compressors, can be exercised manually, locally via programmable logic computers (PLCs) or remotely from sophisticated control centers. Most pipeline systems are now monitored and controlled from centralized control centers that employ state-of-the-art SCADA (System Control and Data Acquisition) systems. The operators sit at consoles with multiple computer screens and a variety of communications capabilities at their finger tips, controlling remote facilities and operations, conversing with employees in the field, viewing the status of operations and being assisted by computer programs that periodically check operating conditions and alarm when a significant deviation is noted.

Reducing Risk

The methods for repairing pipelines, tanks and other equipment have advanced, taking advantage of technological developments in materials, techniques and verification. The results are better quality, longer lasting repairs.

*Repairing
pipelines*

The on-going development and application of new technology is vital to reducing the risks associated with pipeline operations. The industry is dedicated to systematically eliminating risks and a major contributor is application of results from the industry's research and development programs. Virtually all of the advances associated with constructing, operating and maintaining pipelines also play a role in managing and reducing risk. It is obvious that better materials, fabrication, inspection, monitoring and control are essential.

There are other areas that also contribute to reducing risk. For example, research into enhanced surveillance techniques continues in hopes of being able to spot weak links so as to avoid leaks, as well as to detect spills quickly, before they grow and have a large impact on the environment. Some of the leads being pursued include better computer leak detection algorithms, improved sensors for airborne application and satellite imagery. Another area of emphasis involves a multi-industry cooperative effort to reduce incidents caused by excavators damaging or puncturing underground lines and other infrastructure such as fiber optic cables. Better mapping techniques, more precise methods for locating lines, enhanced ways of marking lines, better information systems, and even tougher pipe are all parts of the solution.

A number of research initiatives are underway to identify and develop new and better approaches. The liquid pipeline industry is leading and funding some of the efforts directly, some are jointly funded with the natural gas pipeline industry and the government is funding still others, particularly the Office of Pipeline Safety and the Department of Energy. Several major universities also conduct relevant research programs.

Managing Costs

Improvements in constructing, operating and maintaining pipelines have a positive impact on managing the costs of operating and maintaining pipelines. However, there are other initiatives that can also contribute, examples of which include cost-effectively increasing capacity, reducing energy consumption and finding more economical ways to maintain facilities.

DRA improves pipeline capacity

Seeking low-cost ways of squeezing more capacity out of existing lines has always been an objective. Systematically removing bottlenecks, raising operating pressure by modifying, adding and improving pumps and by looping some line sections are examples. However, a different approach represented a large breakthrough in the 1970s when the controlled addition of a small amount of a long-chained molecule was found to reduce the friction in a pipe, thus increasing the capacity in most cases. The additive, known as DRA (Drag Reducing Agent) has been employed in many crude and product pipelines and continuing research is aimed at finding even more effective DRA compounds, requiring less additive and more benefit.

Power management

Power, representing a large cost for pipeline operators, is a major area of emphasis. One thrust has been to employ equipment that uses less electricity, such as more efficient motors, variable speed motors and other equipment that requires less power. A second approach is aimed at managing the consumption of power by using sophisticated, computerized monitoring and management systems to reduce peak demands and to utilize interruptible supplies.

Maintenance management

Opportunities to lower costs by enhancing maintenance activities cover a wide range of examples, from simple to quite sophisticated. At one end of the spectrum there are complex, computer-based maintenance management systems that track equipment performance and maintenance history and enable the application of preventive maintenance, thereby largely eliminating the costly repairs necessitated by breakdowns. An example at the other end of the spectrum relates to the need to maintain pipeline rights-of-way through use of improved herbicides to manage the growth of vegetation and the use of helicopter mounted side-cutting tools to trim trees along rights-of-way. Between those examples is a long list of other approaches that employ new technology.

Summary --- The Outlook

During the first quarter of the 21st Century the demand for refined products will grow considerably, crude production will decline overall, although deep-water production will increase, and refining capacity will become more concentrated in major coastal refining centers and only grow modestly. And petrochemicals will continue to grow rapidly with the economy.

A short summary of the Energy Information Administration's Energy Outlook 2003, comparing 2025 with 2000 helps to put the outlook for liquid pipelines in perspective. During that period, refined product demand in the US is expected to increase 9.5 million barrels per day (48%), with more than 2/3 of the increase being for transportation fuels (motor gasoline, jet fuel and diesel). Domestic crude production is forecast to decline 0.5 million barrels per day (8%), with inland production forecast to decrease 900 thousand barrels per day (22%) and offshore production up 400 thousand barrels per day. However, during the period offshore production will be up as much as 1 million barrels per day. Refining capacity is expected to increase 3.3 million barrels per day (20%) despite the shutdown of additional smaller, inland refineries that EIA has not specified. The combined forecasts of product demand, crude production and refining capacity imply crude imports will increase 4.0 million barrels per day (45%) and refined product imports will increase 6.3 million barrels per day (380%).

The overall changes during the first 25 years of the 21st Century will impact the regions differently. Most of the decline in inland crude production will take place in PADD III, with some in PADDs II (Oklahoma) and IV, and the growth in offshore production will be in coastal waters off Texas and Louisiana (PADD III). Most refining capacity growth will be in the major coastal refining centers in PADD III, driven by the decline in inland crude production, the location of the demand growth and economies of scale favoring expansions. Thus there will be modest increases of Canadian crude imports into PADDs II and IV and of other crude into PADD V, but much of the increase in crude imports will be into PADD III. The increase in product imports will be predominantly into the East Coast, especially the mid-Atlantic and New England, and the West Coast.

The implications for crude transportation are the addition of large, expensive pipelines in the Gulf of Mexico, considerable additions of large, short lines between marine terminals and coastal refineries to handle crude imports and some additions of crude transmission infrastructure along the Texas/Louisiana Gulf Coast. Disinvestment in inland gathering and associated crude transmission systems and modest asset redeployment and re-investment associated with transporting domestic and foreign crude in PADDs II, III and IV can be anticipated. For refined product pipelines, the implications are expansions, in some cases significant, to move imported product from coastal terminals to inland consumption points and expansions of product transmission capacity from the

Texas/Louisiana Gulf Coast refining centers to the Southeast and the Mid-West, perhaps an interconnection to the southern portion of PADD V (Arizona and southern California) and some movements into the Rocky Mountain region. And the refined product situation is likely to be complicated by further changes to the number and quality of products being transported in response to health and environmental requirements. The network of pipelines providing feedstock and carrying petrochemical products, especially along the Texas/Louisiana Gulf Coast, will continue to expand rapidly. The investment in inland pipeline capacity, primarily for product service, will replace some existing capacity, but much of the existing pipeline network will remain in service. Thus, the existing infrastructure will continue to age, although enhanced inspection and repair techniques, selective upgrades and replacements and more sophisticated operational control systems will enable those pipelines to be operated safely.

The ability to expand the liquid pipeline network and to update the aging infrastructure will be ever more difficult. Increasing urbanization, ever higher environmental expectations, and a decreasing tolerance for siting industrial facilities will make the acquisition of pipeline rights-of-way even more challenging. Implications will include more expensive projects that take longer to develop and that involve a great deal of litigation.

In conclusion, the outlook for the liquid pipeline industry in the US is for ever improving environmental and safety performance, albeit at the same time that the public's expectations continue to rise rapidly, with little tolerance for operational incidents. An already diverse industry is likely to become even more so, especially as it relates to the number of product grades, the number of shippers, the entry of many new carriers, the growth of MLPs and the diminishing role of the major, integrated carriers who will continue to shift their emphasis toward major transmission lines and complex, capital intensive deep-water Gulf of Mexico projects, and away from inland crude gathering and older, smaller systems. Increased competition and a need for cost control will increase the importance for industry participants to rely on objective, impartial decision making and will diminish further the need for economic regulation, although the need for open access and the posting of tariffs will remain. Issues relating to rights of way will become even more contentious and expensive.

May 20, 2004

Hon. DON YOUNG,
Chairman,
Committee on Transportation and Infrastructure,
U.S. House of Representatives,
Washington, DC.

Dear Chairman Young:

On behalf of the natural gas and petroleum pipeline industries, we want to thank you for introducing H.R. 4277, the "Pipeline Safety Administration Establishment Act." We believe this legislation helps ensure the continued improvement and effectiveness of the Office of Pipeline Safety (OPS) within the Department of Transportation (DOT).

The members of our associations are united in our concern about the ramifications of DOT's draft reorganization plan announced by Secretary Mineta in December of 2003. While the announcement focused on the benefits of organizing DOT's research and development functions within a single administration, the secretary also proposed merging the Federal Railroad Administration (FRA) and OPS. We believe this merger would be detrimental to the mission and the performance of OPS. Therefore, we oppose such a merger.

The Office of Pipeline Safety has made great strides in improving its effectiveness over the last five years. It has successfully completed a number of critical rulemakings, including ones regarding hazardous liquid and natural gas pipeline integrity. OPS also has made outstanding progress both in fulfilling its Congressional mandates and in implementing DOT Inspector General and National Transportation Safety Board recommendations. OPS is not broken by any measure, and that is why we are concerned about the implications of DOT's proposed reorganization.

Your legislation gives OPS the autonomy and accountability it needs to fulfill its mandate to protect the public. If DOT attempts to proceed with a reorganization plan that includes merging OPS with FRA, we strongly encourage your committee to hold a hearing that will allow for a full and open discussion among all stakeholders.

We support your efforts to strengthen the Department of Transportation's pipeline safety program and look forward to working with you in that regard. Thank you once again for introducing H.R. 4277. If there is anything further we can do to assist you in your efforts, please do not hesitate to contact us.

Sincerely,

RED CAVANEY
President and CEO
American Petroleum Institute

BERT KALISCH
President and CEO
American Public Gas Association

DONALD F. SANTA, JR.
President Interstate
Natural Gas Association of America

BENJAMIN S. COOPER
Executive Director
Association Oil Pipe Lines

DAVID PARKER
President and CEO
American Gas Association

The CHAIRMAN. Thank you very much.
Mr. Fischer, welcome.

**STATEMENT OF EARL FISCHER, SENIOR VICE PRESIDENT,
UTILITY OPERATIONS, ATMOS ENERGY CORPORATION, ON
BEHALF OF THE AMERICAN GAS ASSOCIATION AND THE
AMERICAN PUBLIC GAS ASSOCIATION**

Mr. FISCHER. Thank you, sir.

Good morning, Mr. Chairman and Members of the Committee. I'm pleased to appear before you today.

My name is Earl Fischer, and I'm the Senior Vice President, Utility Operations of Atmos Energy Corporation. Atmos Energy is one of the largest pure natural gas distributors in the United States, delivering natural gas to about 1.7 million residential, commercial, industrial, and public authority customers. Our regulated utility services are provided to more than 1,000 small- and medium-size communities in 12 states.

I am here testifying today on behalf of the American Gas Association, AGA, and the American Public Gas Association, APGA. I hope that my testimony today will provide for a better understanding of how distribution systems work and how the implementation of the Pipeline Safety Improvement Act of 2002 affects us.

Let me begin by commending Congress for passing a fair and balanced pipeline safety bill in 2002. This Committee, and Chairman McCain in particular, had a very significant role in seeing that the bill went through, and I and both of our trade associations thank you for your commitment and your leadership. I join Senator Murray in her comments, as well.

Gas distribution utilities like Atmos are the last critical link in the natural gas delivery chain. To most customers, utilities are the face of the industry. We are the meter at the house. We interact daily with our customers and the public in the areas that we serve. Over the last 17 years, the amount of natural gas traveling through distribution pipelines has increased by almost a third, and more than 650,000 miles of pipeline have been added to the system during that period of time, yet the number of reportable incidents on distribution pipelines has decreased by 25 percent. This is a remarkable achievement, one that AGA and APGA attribute to the industry's overarching commitment to safety. At the same time, our commitment drives us to continually look for effective ways to improve our record.

Natural gas distribution pipelines are thoroughly regulated. As part of an agreement with the Federal Government in most states, state pipeline safety authorities have primary responsibility to regulate natural gas utilities and intrastate pipeline companies. In return, state governments have to adapt, as minimum standards, the Federal set of standards promulgated by the Department of Transportation. DOT, then, reimburses the state for up to 50 percent of their pipeline safety enforcement costs.

Distribution systems are constructed in configurations that look like a network or a web, use smaller-diameter pipe, and operate in high-density population areas at much lower volumes and at much lower pressures.

So what has occurred since implementation of the Pipeline Safety Improvement Act of 2002? The United States Department of Transportation Office of Pipeline Safety and Industry has diligently worked to address much of the scrutiny that arose during the debate of the 2002 bill. To their credit, OPS has dealt with the vast majority of this backlog, and is moving expeditiously to address the congressional mandates.

Given this tremendous progress, we are concerned over the proposed reorganization of DOT that would include moving OPS into the Federal Railroad Administration. Indeed, we cannot understand the rationale for wanting to make any move that could jeopardize this positive momentum that Mr. Pearl spoke about, as well.

In the most effective use of the span of time allowed us at this oversight hearing on pipeline safety, allow me to highlight six points that illustrate the progress made, with a more complete list being contained in my written testimony.

Point number one. The programs required by the Pipeline Safety Act are well underway. Many gas pipeline operators have already begun implementing the integrity rule, and many more will be ready to begin assessments by the deadline on June 17, 2004, only 2 days away. Approximately 30,000 miles of gas transmission lines operated by gas distribution utilities will have to be assessed under this rule, at a cost of \$3 billion in 20 years. At the same time, we must maintain an interruptible gas supply to our customers.

Point number two. We must expedite the environmental permitting process, as others have testified here today. Our members estimate that they must perform about 110,000 integrity inspections requiring excavation on intrastate pipelines over the next 7 years, and that is five or more per mile on the average. We need a more efficient process that will not allow one agency to prohibit a citizen from taking action required by another agency. There are good options under existing environmental laws for ensuring environmental protection in a way that is less process-intensive.

Point three. Injuries, fatalities, property loss, and the disruption of services could be reduced with the better use of the three-digit/one-call centers and systems. The Pipeline Safety Act also helped improve the systems by clarifying that State Departments of Transportation should participate; however, there is still nothing that will compel them to do so.

Point four. There has been significant progress on several other initiatives, including a right-of-way encroachment study, operator-qualification standard development, and public-awareness communications rulemaking.

Point five. I am pleased to report that the American Gas Foundation, with AGA, APGA, state and Federal regulator involvements, is proactively exploring existing regulations and practices addressing distribution system integrity in an effort to identify any needed enhancements. You should note that we have already identified a dozen currently mandated inspection requirements for distribution systems.

Point six is a plea for specific time to measure the results. In summary, we are underway with our implementation process. We think it would be premature to currently draw conclusions on the results of any of these programs, which have also resulted in a sub-

stantial number of regulatory mandates. We humbly request to be given sufficient time for effectiveness verification.

Public safety is the top priority of natural gas utilities. Historically, approximately one half of the current \$6.4 billion is spent by utilities in compliance with Federal and state regulators. At the same time, the other half is spent to ensure that our systems and communities are safe and that our gas is always reliably there.

Thank you for providing the opportunity to present our views on this very important matter of pipeline safety.

Thank you.

[The prepared statement of Mr. Fischer follows:]

PREPARED STATEMENT OF EARL FISCHER, SENIOR VICE PRESIDENT, UTILITY OPERATIONS, ATMOS ENERGY CORPORATION, ON BEHALF OF THE AMERICAN GAS ASSOCIATION AND THE AMERICAN PUBLIC GAS ASSOCIATION

Good morning, Mr. Chairman and members of the Committee. I am pleased to appear before you today and wish to thank the Committee for calling this hearing on the important topic of pipeline safety. My name is Earl Fischer. I am Senior Vice President, Utility Operations of Atmos Energy Corporation. Atmos Energy is one of the largest pure natural gas distributors in the United States, delivering natural gas to about 1.7 million residential, commercial, and industrial and public-authority customers. Our regulated utility services are provided to more than 1,000 small and medium-size communities in 12 states.

I am here testifying today on behalf of the American Gas Association (AGA) and the American Public Gas Association (APGA). The American Gas Association represents 192 local energy utility companies that deliver natural gas to more than 53 million homes, businesses and industries throughout the United States. AGA member companies account for roughly 83 percent of all natural gas delivered by the Nation's local natural gas distribution companies. AGA is an advocate for local natural gas utility companies and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international gas companies and industry associates.

The American Public Gas Association is the national, non-profit association of publicly owned natural gas distribution systems. APGA was formed in 1961, as a non-profit and non-partisan organization, and currently has 606 members in 36 states. Overall, there are 949 municipally owned systems in the U.S. serving nearly five million customers. Publicly owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

Natural gas meets one-fourth of the United States' energy needs. I am pleased to appear here today and hope that my testimony will provide you with a better understanding of how distribution systems work and how the implementation of the Pipeline Safety Improvement act of 2002 affects us.

AGA, APGA and its members commend Congress for ensuring that the safety bill passed in 2002. The legislation that was finally passed in the final days of the 104th Congress was a balanced, fair bill and will bring yet further safety improvements. This Committee and Chairman McCain in particular, had a very significant role seeing that the bill went through and I and the industry thank you for your commitment and leadership.

We would also like to commend the U.S. Department of Transportation Office of Pipeline Safety (OPS) for diligently working to address much of the disapproval that arose during the debate on the 2002 bill. OPS was criticized by Congress, the National Transportation Safety Board, DOT's Inspector General, and members of the public for not addressing numerous congressional mandates and safety recommendations. To their credit, OPS has dealt with the vast majority of this backlog and is moving expeditiously, and often in consultation with all affected stakeholders, to address the mandates in the Pipeline Safety Improvement Act of 2002. Given this tremendous progress, we are concerned over the proposed reorganization of DOT that would include moving OPS into the Federal Railroad Administration. Indeed, we cannot understand the rationale for wanting to make any move that could jeopardize this positive momentum.

Gas Distribution Utilities Serve The Customer

Gas distribution utilities or Local Distribution Companies (LDCs) are the last, critical link in the natural gas delivery chain. To most customers, utilities are the “face of the industry”. Our customers see our name on their bills, our trucks in the streets and our company sponsor ship of many civic initiatives. We live in the communities we serve and interact daily with our customers. Consequently, we take very seriously the responsibility of continuing to deliver natural gas to our communities safely, reliably and affordably.

Natural Gas Utilities Are Committed to Safety

Safety is a top priority, a source of pride and a matter of corporate policy for every company. These policies are carried out in specific and unique ways. Each company employs safety professionals, provides on-going employee evaluation and safety training, conducts rigorous system inspections, testing, and maintenance, repair and replacement programs, distributes public safety information, and complies with a wide range of Federal and state safety regulations and requirements. Individual company efforts are supplemented by collaborative activities in the safety committees of regional and national trade organizations.

Our industry’s commitment to safety is borne out each year through the National Transportation Safety Board’s annual statistics. Delivery of energy by pipeline is consistently the safest mode of energy transportation. Natural gas utilities are dedicated to seeing this continue. Over the last 17 years, the amount of natural gas traveling through distribution pipelines has increased by almost a third and more than 650,000 miles of pipeline have been added to the system—yet the number of reportable incidents on distribution pipelines has *decreased* by 25 percent. This is a remarkable achievement, one that AGA and APGA attribute to the industry’s overarching commitment to safety.

Natural gas distribution pipelines are thoroughly regulated. As part of an agreement with the Federal Government, in most states, State pipeline safety authorities have *primary* responsibility to regulate natural gas utilities as well as intrastate pipeline companies. However, state governments have to adopt as minimum standards the Federal safety standards promulgated by the DOT. In exchange, DOT reimburses the State for up to 50 percent of their pipeline safety enforcement costs. Therefore, what Congress does affects state regulations and our companies. The states may also choose to adopt standards that are more stringent than the Federal ones.

The Difference in “Pipelines”

While many may unintentionally link all “pipelines” together, there are indeed significant differences between the liquid transmission systems, natural gas transmission systems and natural gas distribution systems. Each industry faces different challenges, operating conditions and consequences of incidents.

Interstate transmission systems are generally made up of long runs of generally straight pipelines, having large diameter, and operated at high volumes and high pressures. Distribution systems, in contrast, are constructed in configurations that look like a network or web, use smaller diameter pipe, and operate at much lower volumes and pressures. However, many distribution companies also own and operate transmission pipeline segments within their systems.

Federal regulations recognize the differences between these three types of pipelines, and different sets of rules have been created for each. 49 CFR Part 192 sets out the regulations for natural gas transmission and distribution and the rules discriminate between the two, while 49 CFR Part 195 sets out the regulations for liquid transmission lines.

Status of Implementing the Pipeline Safety Improvement Act of 2002

Since the Pipeline Safety Improvement Act of 2002 was signed into law on December 17, 2002, many programs are under way to specifically address implementation of the law’s mandates and further safety enhancements of gas transmission and distribution systems. For gas transmission systems, most notable among many of the 2002 legislative mandates was integrity management for gas transmission pipelines. The law’s provisions have also resulted in a substantial number of regulatory mandates, initiatives and voluntary programs for distribution systems.

Federal Regulatory Mandates

The 2002 regulatory mandates affecting distribution systems include:

- Direct assessment standards development
- Environmental repair permit streamlining
- One-call 3-digit number rulemaking

- Right-of-way population encroachment study
- Operator qualification standard development
- Public awareness communication effectiveness rulemaking
- Infrastructure R&D grants program

Integrity Management Rule for Natural Gas Transmission

OPS issued the integrity management rule for natural gas transmission lines on December 12, 2003. The rule requires natural gas transmission pipeline operators to conduct periodic inspections in “high consequence areas”, which for natural gas pipelines are generally high-density population areas.

The nature of utility-owned transmission requires that over 50 percent of the lines under the integrity management rule be inspected using direct assessment methods. Direct assessment is an alternative to internal inspection (smart pigging) or pressure testing. It comprises a variety of screening and examination techniques to locate and identify potential problems in the pipeline. The anomalies located by direct assessment usually involve corrosion of the pipeline. Corrosion is the second leading cause of gas pipeline failures.

The direct assessment process entails performing two non-invasive complementary indirect exams of the section of the pipeline targeted by engineering analysis and predictions on that section. Typical indirect exams involve different approaches in measuring electrical values, so that any variations along the pipeline can give an indication of the locations where possible anomalies might be present. They may also involve checking for corrosion inside the pipe at preset sampling locations. The pipeline is then excavated at the previously identified locations, examined and repaired if necessary. The results are compared with predictions, becoming part of a learning curve about the condition of the pipeline and facilitating future direct assessments of similar sections of pipeline.

Direct assessment is estimated to cost between \$7,000 and \$15,000 per mile of pipeline examined, not including any necessary excavations. The latter can cost from \$2,500 to \$250,000 per excavation, depending on location.

Many gas pipeline operators have already begun implementing the integrity rule and many more will be ready to begin assessments by the deadline on June 17, 2004. Approximately 30,000 miles of gas transmission operated by gas distribution utilities will have to be assessed under this rule. In the aggregate, for gas distribution utilities, estimated costs of compliance with this rule will exceed \$3 billion in 20 years, not including integrity management pass-through costs from their gas transmission suppliers upstream, repairs, modifications, and changes in operations that may be necessary to maintain the reliability of gas supply in the face of large scale pipeline inspections and testing.

Direct Assessment Standards Development

The 2002 pipeline safety legislation also required that the DOT issue regulations prescribing standards for inspection of a pipeline facility by direct assessment. Such standards have been prescribed for external corrosion and are now being developed for internal corrosion and for stress corrosion cracking. The standards body leading this effort is the National Association of Corrosion Engineers (NACE). These standards will also be applicable to distribution pipelines.

Expedite Permit Streamlining: Timely Repairs vs. Permit Delays

Integrity management applied to distribution utility transmission lines will result in at least 100,000 excavation locations and possibly many more over the next 7 years. The vast majority of them will not result in repairs or replacement of pipe but ALL will require permits.

In the Pipeline Safety Improvement Act of 2002, Congress wisely recognized that it would be bad government and very inequitable to allow one agency to prohibit or prevent a citizen from taking an action required by another agency, and then penalize the citizen. This is what could happen if a Federal environmental agency fails to take timely action on a permit application for a pipeline safety repair, so that work cannot begin and end by the deadline set by the natural gas IMP rule. Under that rule, integrity repairs must be completed either (1) immediately, or (2) within one year after the discovery of an anomaly, depending on the type of defect involved. If a repair is not completed by the applicable deadline, the operator is required to reduce pressure and throughput on the affected pipeline by 20 percent until the repair can be completed. We are concerned that widespread, long-term pressure reductions would restrict supply and drive prices up.

Our members estimate they must perform about *110,000 integrity inspections requiring excavation on intra-state pipelines (5 inspections per mile on average) over the next 7 years*. That means there will be about 15,000 inspections per year requir-

ing a test hole. Although we have made our best estimates, we do not yet know what percentage of these will require further excavation to repair the line. The bottom line is that there are too many of these projects to use the traditional, time consuming process for obtaining individual permits for each and every site. Congress wisely recognized this should not be allowed to happen and therefore directed Federal agencies to develop a streamlined process to ensure that permits are given in time to allow timely repairs.

We need a more efficient process. Please note that we do *not* advocate changing underlying environmental standards or requirements. Our concerns are purely with the process. We only ask that the agencies work together in a seamless, efficient and coordinated way so that this important public safety work can start and finish on time.

Federal agencies have made some progress in streamlining their permit process. Interstate natural gas pipelines get their permits through an integrated FERC certification process and environmental review under the National Environmental Policy Act (NEPA). In December 2002, FERC and other Federal agencies entered into a Memorandum of Understanding (MOU) to coordinate and accelerate the way in which they process permits for the construction of new interstate natural gas pipelines. The 2002 MOU also covers permits for maintenance and repairs of interstate pipelines, so it has been interpreted to help streamline permits for repairs under the IMP Rule. Although AGA is pleased because some AGA members operate interstate pipelines, the 2002 FERC MOU does not cover integrity repairs on *intra-state* pipelines because they are not certificated by FERC.

The final Pipeline Repair Streamlining MOU specifically addresses the need to expedite integrity repairs that must be done “immediately” under the IMP Rule. We are pleased that the MOU sets out the general framework for authorizing other repairs to proceed without site-specific permits, provided certain conditions are met.

However, we are very concerned that there are no details in the MOU regarding how this will work. Instead, the MOU delegates this difficult and essential task to a new interagency working group. This group has little time remaining to develop a working process to streamline repair permits. Our members are on a tight schedule for beginning their integrity testing and first phase of repairs, and they will need timely authorization to begin this important public safety work.

AGA has been urging the agencies to seek broad input from experts in the field and to solicit creative “outside the box” solutions. There are good options for ensuring environmental protection in a way that is less process-intense. This can be done within the authority agencies have under existing environmental laws.

3 Digit Number for One-Call Systems

Congress has required the Federal Communications Commission to issue a rule that provides a toll-free 3-digit number that excavators and the public can use to easily connect to the appropriate one call center. One-call centers are designed to have personnel dispatched to the excavation site to have underground facilities—natural gas lines, petroleum and product lines, fiber optics, telephone, electricity, water and sewer lines—to avoid them being damaged. An easily remembered, easily advertised 3 digit number will increase the use of these vital services and therefore help avoid unnecessary accidents. The Federal Communications Commission just issued a proposed rule mandating the establishment of the 3-digit number.

The leading cause of accidents on distribution pipelines comes from excavators unintentionally striking our lines. It is known as excavation damage, also commonly called third-party damage. Year after year, these strikes cause over 60 percent of the total ruptures on utilities *and the vast majority of injuries and fatalities*.

We are continually urging states to require government agencies and their contractors to participate in One-Call programs. This would help eliminate some exemptions some state agencies currently have in several states from participation in One-Call. The Pipeline Safety Improvement Act of 2002 did help address this critical problem by clarifying that State departments of transportation should participate. However, there still is nothing to compel them to do so. Needless accidents continue to occur. Injuries, fatalities, property loss and disruption of services could be reduced with better use of One-Call centers and recommended practices for damage prevention.

Right-of-Way Encroachment Study

The 2002 pipeline safety legislation directed DOT to work with the Federal Energy Regulatory Commission and other Federal and state agencies to study the difficult problem of encroachment on pipeline rights-of-way and to make recommendations for improvements. We understand that this study is under way under the direction of a steering group. Encroachment is where buildings and structures are

placed on or very near the “no build zones” that a pipeline right-of-way represents. This is especially a problem where cities and towns expand to ultimately push up to a pipeline location that was rural when built.

We hope that the Committee will work with us to make progress on addressing this problem once the study’s recommendations are made public.

Operator Qualification Standards

In compliance with the 2002 legislative mandate, the OPS is leading development of a standard (ASME B31Q) for pipeline operations personnel qualification programs. This is another standard that has required significant member AGA and APGA member involvement in handling both training and operational aspects. The standard is still being developed and its completion is slated for the end of this year.

Public Awareness Communication Effectiveness

OPS is working with stakeholders from the liquids and gas industries to define what would be required to evaluate effectiveness of operator communication programs. With input from industry, OPS is separately working with the states to define regulatory requirements that will cover gas utilities. AGA and APGA members have been involved via a task group to highlight the fact that flexibility is needed to avoid duplication of communication efforts already being carried out by gas utilities in their respective service territories at the local levels.

Infrastructure Research and Development Grants

Congress significantly increased the authorization for OPS’ pipeline safety research and development program to \$10 million per year for four years. As OPS receives their funding primarily through user fees assessed on pipelines, these monies will likely be routinely provided. The pipeline safety act of 2002 also sought to coordinate the efforts of OPS with those of the Department of Energy. Generally OPS’ focus on those technologies that represent near-term development for field applications and provides matching dollars to the recipients.

With the increase in inspections and repairs and the expanding use of natural gas, better ways to do the job need to be found. Industry typically cannot provide directly all that is needed for R&D due to the nature of their rate framework. The natural gas surcharge that the Federal Energy Regulatory Commission (FERC) allowed for many years ends this year on August 1. FERC is considering an alternative proposal. AGA is also pursuing legislation that would establish a collaborative research program. AGA and APGA are hopeful that either the regulatory or legislative R&D funding proposal will become a reality. Either would solidify industry contributions to research. However, additional contributions for R&D are needed and AGA and APGA would welcome the opportunity to discuss with Committee members and staff the gas supply, transmission, distribution and utilization research that could be accomplished with increased public funding.

Additional Federal Regulatory Initiatives

Current Federal regulatory initiatives for distribution systems include:

- Operator qualification rule revision
- Public communications standard development
- Better crisis communication
- Excess flow valve installation
- Operator safety performance metrics

Operator qualification rule revision

To comply with NTSB recommendations, OPS expects to revise the operator qualification rule to include greater specificity. This has required significant AGA and APGA member involvement to ensure our members’ concerns are taken into account. AGA and APGA believe reasonable additional requirements are being developed to adequately address the NTSB concerns and will soon become part of the revised rule.

Public Communications Standard Development

A public communications standard (API Recommended Practice 1162) designed to address a variety of audiences has been completed under the American Petroleum Institute (API) banner, with input from industry and the regulatory community. It will be adopted by OPS via rulemaking on public education and communications.

Better Crisis Communication

OPS is working with stakeholders to define guidelines for operators to follow in issuing communications in the event of involvement in an accident involving pipe-

lines. The most recent one occurred on a gasoline pipeline in Tucson, AZ and sparked high-profile public hearings. Distribution utilities are engaged in deliberations with the other stakeholders to ensure concerns for gas utility communications are addressed.

Excess Flow Valve Installation

In response to an NTSB recommendation and more recently, public testimony, OPS is reconsidering whether to mandate the installation of excess flow valves on service lines. Mandated installation would pose a potential major added burden on AGA and APGA members that elect not to install such devices, but instead notify customers and install such devices upon request from the customer. Cost-benefit studies performed to date by OPS do not adequately justify the nationwide installation of these devices on a mandatory basis unless some shaky, easily refutable assumptions are made.

Operator safety performance metrics

OPS continues to look for ways to more clearly demonstrate the effectiveness of their safety programs. To this end, the agency is seeking to further improve and increase the gathering of safety performance data from operators. Federal regulators are contemplating further changes in operator reports to DOT that will also cover distribution systems. The distribution utilities remain committed to develop reasonable safety performance measurements with OPS and other stakeholders.

Voluntary Industry Programs

Voluntary industry programs involving distribution utilities include:

- A government-industry group examining existing regulations and practices addressing distribution system integrity in an effort to identify needed enhancements. Along with APGA, many AGA member companies are participating in this study, which is supported by the American Gas Foundation.
- In response to an NTSB recommendation, numerous gas distribution utilities have been collecting data on the performance of plastic pipe since January 2001. Government and industry stakeholders convene periodically to examine the data for areas of concern.
- Continued participation in the Common Ground Alliance to promote infrastructure damage prevention

LDCs comply with a regulatory program that devotes stringent attention to design, construction, testing, maintenance, operation, replacement, inspection and monitoring practices. We continually refine our safety practices. Natural gas utilities spend an estimated \$6.4 billion each year in safety-related activities and this figure will significantly increase once the legislative mandates adopted to date are implemented fully. Historically, approximately half of the current \$6.4 billion is spent in compliance with Federal and state regulations. The other half is spent, as part of our companies' voluntary commitment to ensure that our systems are safe and that the communities we serve are protected and products delivered.

Summary

In summary, many programs are under way to address implementation of the legislative mandates of 2002. They must be given sufficient time to allow verification of their effectiveness. We believe it would be premature to currently draw conclusions on the results or consequences of any of these programs. Furthermore, in view of the growing need for energy to support continued economic growth, legislative decisions on pipeline safety should support or be consistent with the needed growth in the energy delivery infrastructure.

The natural gas utility industry is proud of its safety record. Natural gas has become the recognized fuel of choice by citizens, businesses and the Federal Government.

Public safety is the top priority of natural gas utilities. We invite you to visit our facilities and observe for yourselves our employees' dedication to safety. We are committed to continue our efforts to operate safe and reliable systems and to strengthen One-Call laws and systems in every state.

Thank you for providing the opportunity to present our views on the important matter of pipeline safety. We look forward to working with federal, state and local authorities and representatives, as well as within our industry, to achieve the highest possible level of public and employee safety.

The CHAIRMAN. Thank you very much.
Mr. Howard?

**STATEMENT OF ROBERT T. HOWARD, VICE PRESIDENT
AND GENERAL MANAGER, PIPELINE OPERATIONS, GAS
TRANSMISSION NORTHWEST CORPORATION, ON BEHALF OF
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA**

Mr. HOWARD. Thank you, Mr. McCain. It's a pleasure to be here.

My name is Bob Howard, and I am testifying here on behalf of the Interstate Natural Gas Association of America. INGAA represents the interstate natural gas pipeline industry in North America—that's the U.S. and Canada—whose members transport over 90 percent of the natural gas consumed through 180,000-mile pipeline network. GTN is headquartered in Portland, Oregon, and has 1,350 miles of interstate natural gas pipelines operating in five states, including Arizona, and delivers about three billion cubic feet of natural gas per day, supplying almost a third of the West Coast's natural gas everyday needs.

As an aside, if I might, the proposed refinery would actually use natural gas off of a project that we're potentially developing that could be sourced from LNG development in Baja, Mexico.

Natural gas represents 25 percent of the primary energy consumed annually in the United States, proving the natural gas pipeline delivery network to be a critical part of the Nation's infrastructure.

Since this Committee debated the issue of pipeline safety, we're also saying that a great deal of progress has been made at the Office of Pipeline Safety. The backlog of unfinished Congressionally-mandated rulemakings are virtually gone, and certainly we've been involved in helping them clear those mandates and cooperate with them. And they've also made great strides in improving their public outreach.

Perhaps the most important accomplishment since 2002 is the completion of the natural gas pipeline industry integrity management rule that was completed this year, and they've worked very hard with our industry and the public in developing a final rule that remains true to the mandate from Congress that is technically based, practical, and effective.

I am personally involved, also, in their improved public education and communications effort, including work that I am associated with, the National Association of State Fire Marshals. Together, OPS and the National Association of State Fire Marshals are developing better training materials for our first-responders in strengthening the skills of first-responders nationwide, not just the career officers in big cities, but the volunteer fire departments throughout the country are going to have access to excellent training materials.

At GTN, communication with first-responders is a top priority, with over 300 face-to-face visits each year with the various first-responders and the agencies that support them. This should translate into increased faith in the safety and reliability of natural gas pipelines.

The Pipeline Safety Improvement Act requires each natural gas pipeline operator to conduct a risk analysis and develop an integrity management plan by December 17 of this year. The law also requires operators to begin integrity assessments by June 17, two days from now. You've heard it, and it's true in the natural gas pipeline industry, much of that work is well underway, and it

began before the rule was finalized, in order to make the necessary capital improvements to accommodate internal inspection tools.

At GTN, our total investment in integrity management will be between 40 million and 45 million, and we've spent already about 12 million of that.

I want to say, as part of that, there are, in the natural gas pipeline transmission industry, about 5,000 miles of HCA. We know, from surveys of our own members, that almost half of that has already been surveyed prior to the implementation of the rule. Not that it will be counted in the baseline assessments, but it has already been done. And so as we begin our baseline assessments, we have that data to compare with, with new and better technologies that we'll be using.

We've started our baseline programs at GTN through several sections of our system, and we have done most of our internal—our HCAs prior to the integrity management rule, as well, so we have that data ourselves. In addition, this year's work at GTN employed more than a hundred people over our existing work force. I hope you see that our industry is committed to fulfilling and surpassing the rule's requirements in providing that data.

The scope of the integrity assessment work to be done over the next 8 years, however, is enormous, and gives us some concern. Because all pipelines must comply simultaneously—we're all in the same boat—it will, most certainly, affect natural gas deliverability and delivered natural gas commodity prices.

In 2002, the INGAA foundation prepared an economic analysis of these pipeline capacity reductions and their effects on consumer prices. For a 10-year baseline period, the report estimated increased consumer natural gas prices of about one billion per year for the first 10 years.

One way to mitigate these unintentional price spikes can be by allowing for the coordination of inspection and repair activities among various competing pipelines which antitrust law currently restricts. We would urge Congress to consider an antitrust waiver for the coordination of those integrity assessments and repair activities.

Before concluding, we would also like to comment on the proposed merger of OPS and the Federal Railroad Administration. Our concern is that OPS would lose its focus and regulatory effectiveness—I heard them talk about it being a research agency, but it is also a regulatory agency—if it were to be subsumed into the much larger FRA. Much of OPS's recent success is due to the fact that it has actively improved public access to its agency and been able to act quickly and decisively in improving its programs and enforcement activities. We believe these activities could be diluted.

House Transportation and Infrastructure Chairman Don Young introduced legislation, H.R. 4277, last month to create a separate pipeline safety entity at DOT, and, given the concern of this country about pipeline safety, we strongly support his efforts.

Let me thank you, again, Mr. Chairman, for allowing me to testify today. Safety is of paramount importance to our industry, and we believe it is our obligation to work with Congress and the OPS to maintain and improve the safe, reliable operation of our pipelines in the years ahead. And I'd be happy to answer any questions.

[The prepared statement of Mr. Howard follows:]

PREPARED STATEMENT OF ROBERT T. HOWARD, VICE PRESIDENT AND GENERAL MANAGER, PIPELINE OPERATIONS GAS TRANSMISSION NORTHWEST CORPORATION, ON BEHALF OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Mr. Chairman and Members of the Committee:

Good morning. My name is Bob Howard and I am Vice President and General Manager of Pipeline Operations for Gas Transmission Northwest Corporation (GTN). I am testifying today on behalf of the Interstate Natural Gas Association of America (INGAA). INGAA represents the interstate and interprovincial natural gas pipeline industry in North America. INGAA's members transport over 90 percent of the natural gas consumed in the U.S., through an 180,000-mile pipeline network.

Gas Transmission Northwest is an interstate natural gas pipeline headquartered in Portland, Oregon. With 1,350 miles of transmission pipeline in three states, GTN delivers about 2.9 billion cubic feet of natural gas per day, supplying almost a third of the West Coast's total natural gas needs every day.

The North American pipeline network provides the indispensable link between natural gas supply and the local distribution companies that serve retail customers. Natural gas represents 25 percent of the primary energy consumed annually in the United States, a contribution second only to petroleum and exceeding that of coal. Consequently, the natural gas pipeline delivery network is a critical part of the Nation's infrastructure.

This is why the safe and reliable operation of these pipeline systems is so important. Because the natural gas pipeline network is essentially a "just-in-time" delivery system, with limited storage capability, customers large and small depend on reliable around-the-clock service. And of course, the public wants to know that these pipeline systems crisscrossing the Nation and serving their communities are safe. Mr. Chairman, these pipeline systems *are* safe—the safest mode of transportation in the country—and working together the pipeline industry and the Office of Pipeline Safety are making this valuable network even more safe and secure.

Progress at the Office of Pipeline Safety

Since this Committee last debated the issue of pipeline safety, several years ago, a great deal of progress has been made at the Department of Transportation's Office of Pipeline Safety (OPS). As recently as five years ago, many in Congress and in the public at large were saying that the OPS was an agency of sub-standard performance. The General Accounting Office cited the backlog of unfinished, congressionally mandated rulemakings, the numerous DOT Inspector General recommendations that had not been implemented, and the poor acceptance rate for National Transportation Safety Board (NTSB) recommendations. For years, the OPS had the lowest acceptance rate of any modal office at DOT for NTSB safety recommendations, at about 69 percent. Take a look at what has happened since that time. The OPS now has the second-highest acceptance rate for NTSB safety recommendations, right behind the Highway Safety Administration, at 86 percent. The backlog of unfinished, congressionally mandated rulemakings is virtually gone, and by any measure, OPS has made great strides in improving its effectiveness.

Perhaps the most important accomplishment by the OPS since the passage of the Pipeline Safety Improvement Act of 2002 is the completion of the natural gas pipeline integrity management rule. This rule, required by the 2002 Act, took the better part of 2003 to develop before its final issuance in December. When the Notice of Proposed Rulemaking was released to the public in early 2003, the INGAA membership had a great deal of concern about its focus, its effectiveness, and workability. However, the OPS took our concerns about the proposed rule seriously, and worked with our industry in developing a final rule that remains true to the mandate from Congress, and does so in a way that is technically-based, practical and effective.

INGAA believes that all of this work on the part of OPS has made the agency a more effective safety regulator. Enforcement has improved. Public education and communications efforts have improved. Audit and inspection activity is more focused and effective. All this should translate into Congress and the public having more faith in the safety and reliability of the natural gas pipeline infrastructure.

What the Pipeline Industry is Doing to Implement the New Integrity Rule

The pipeline industry has been working hard too. As the Nation increases its demand for natural gas, more pipeline capacity is needed to deliver additional supplies to growing markets. Whenever a new pipeline is proposed, or an existing pipeline proposes an expansion, communities and citizen groups raise the issue of safety.

These communities and groups often have significant influence in the approval process, and therefore their concerns need to be taken seriously. In order for our industry to meet its objectives for serving a growing natural gas market, we also need to reassure the public that pipelines are a safe mode for energy transportation.

Recent accident statistics are worth examination. For the years 2002 and 2003, there were no fatalities or injuries associated with accidents on interstate natural gas pipelines located in “high consequence areas,” or the areas with higher population near a pipeline. There were four accidents during this period that resulted in injuries to one pipeline employee and three pipeline contractors, but these occurred on natural gas pipeline segments located in rural areas; *i.e.*, not high consequence areas. Three accidents did occur on interstate natural gas pipelines in high consequence areas during 2002 and 2003, but these did not result in either a fatality or an injury, and were therefore only reported to OPS because the damage costs (including the cost of natural gas lost) exceeded \$50,000.

The new natural gas pipeline integrity rule has been a significant area of focus for the industry. Let me assure the Committee that we are not resting on our existing safety record. Over a dozen consensus standards have been completed, or are near completion, to support this rule, and have been supported by multimillion dollar collaborative research programs.

The Pipeline Safety Improvement Act requires each natural gas pipeline operator to conduct a risk analysis and develop an integrity management plan for pipeline in high consequence areas by December 17 of this year. However, the law also required operators to begin integrity assessments on their pipelines by June 17, two days from now. The “highest priority” fifty percent of an operator’s high consequence areas (based on the risk analysis) must complete a baseline integrity assessment within five years of enactment (December 17, 2007), with the remaining fifty percent to be completed within ten years of enactment (December 17, 2012).

This integrity assessment work is already well underway. INGAA has surveyed its membership to measure the amount of inspection activity taking place. One respondent’s answers are illustrative of the larger group. This pipeline has about 5900 miles of transmission pipeline of which about 200 miles is located in high consequence areas (HCAs). To date, about ten miles of these HCAs have completed a baseline assessment, but as a function of inspecting these ten miles of HCAs, the operator has had to also inspect 250 miles of non-HCA pipe.

The reason for these assessments going beyond the HCA requirement is simple. The vast majority of our pipelines are going to be inspected with internal inspection devices, commonly referred to as “smart pigs.” Special launcher and receiver facilities have to be constructed to both introduce a smart pig into a pipeline, and remove it at some point downstream. The most practical place (and often, the only place) to construct these launcher/receiver facilities are at compressor stations, which are typically located about 75 to 100 miles apart along a pipeline. The pipeline segment between compressor stations may have a few, discrete miles of HCAs, but in order to inspect the five or six miles of HCA pipe, the entire 75 to 100 mile segment between the stations will be inspected by the smart pig. INGAA estimates that about 6 percent of total natural gas transmission pipeline mileage is actually located in HCAs, but in order to assess the integrity of this 6 percent of pipeline mileage, about 60 to 70 percent of total interstate pipeline mileage will have to be inspected.

Mr. Chairman, I would like to provide the Committee with another example to illustrate my point. One INGAA member company is in the process of modifying a 58-mile section of pipeline so that internal inspection devices can be employed for integrity assessments. Since this pipeline was originally constructed in the mid-1950s, before the advent of smart pigs, it was not engineered to accommodate these devices. The pipeline operator has already identified 14 HCAs along this 58-mile segment, for a total HCA length of 8.74 miles. In order to assess the HCA portions of the pipe, pig launchers and receivers must be installed, and several valves will need to be replaced. The estimated modification costs for this one segment are \$5.1 million, and the estimated integrity assessment and repair costs are \$640,000. The work on this pipeline segment started last month, and is expected to last five months. During this five-month period, some part of the pipeline segment will either be completely shut down, or operating at reduced pressure.

At Gas Transmission Northwest, we are well underway with the installation of internal inspection infrastructure and our baseline assessments. We recently ran a “smart pig” through a section of our system and are in the process of examining the results. I am proud of the work we have done so far and we are committed to fulfilling and surpassing the rule requirements.

One Important Concern

The scope of the integrity assessment work to be done over the next eight years gives the INGAA membership some pause for concern. This is due to the fact that a significant number of pipeline segments will have to be removed from service in order to prepare for and perform assessments and any resulting repairs. This unprecedented integrity program will almost certainly affect natural gas deliverability and delivered natural gas commodity prices. The effect could be compounded because, coincidentally, the integrity assessments are happening during what will likely be a protracted period of tight natural gas supplies.

In past years, pipelines were able to perform most maintenance and repair activities during the warm months of the year, when natural gas demand was relatively low. During these periods of low seasonal demand, the natural gas pipeline network could more readily handle system downtime. Few, if any, customers were impacted in terms of service disruptions or higher natural gas commodity prices.

In today's natural gas market, however, demand not only peaks during the cold winter months, but also during hot summer months, due to the increased use of natural gas to generate electricity. This means that there are fewer weeks of the year when maintenance and repair can take place without impacting customers in some manner.

In 2002, the INGAA Foundation prepared an economic analysis of these pipeline capacity reductions, and their effects on consumer prices. The report¹ looked at anticipated pipeline inspection scenarios under an integrity management program, based in large part on how long the industry would be given to perform a baseline assessment. For a ten-year baseline period (*i.e.*, the one ultimately adopted by Congress), the report estimated increased consumer natural gas prices of about \$1 billion per year for the first ten years. Please note that these costs are not associated with the actual cost of inspections and repair activities, even though these costs will also be significant. Rather, the study looked only at the "costs to consumers due to deliverability constraints" and their effect on the natural gas commodity markets downstream.

One way these unintentional price spikes can be minimized is by allowing for the coordination of inspection and repair activities among various competing pipeline operators. Anti-trust law currently restricts such coordination. In the absence of such coordination, however, it is possible and even likely that multiple pipelines serving a given market could be down for inspection/repair at the same time, causing significant price increases and even service disruptions for that market. INGAA urges Congress to consider an anti-trust waiver for coordination of pipeline integrity assessment and repair activities.

We also want to join with others in urging the various Federal and state agencies involved in permitting pipeline inspection and repair activities to do so on a coordinated and expedited basis. We anticipate that our industry will be required to make significant modifications to our pipeline facilities over the next eight years, in order to accommodate internal inspection devices. The construction of smart pig launchers and receivers, for example, as well as replacing pipeline bends, segments and valves that cannot accept internal inspection devices may require permits from Federal and state authorities. The interstate natural gas pipeline members of INGAA are regulated economically by the Federal Energy Regulatory Commission (FERC). The FERC must approve the construction of any new interstate natural gas pipeline, or any major expansion or modification (in excess of a certain dollar amount) of an existing interstate natural gas pipeline. The FERC has also accepted the primary role for the enforcement of the National Environmental Policy Act (NEPA) as it relates to pipeline construction and the resulting effects on the environment. In 2002, the FERC lead an effort to create and sign a Memorandum of Understanding (MOU) between all of the *federal* agencies associated with any permitting activities for pipelines, such as the Corps of Engineers, the Environmental Protection Agency, and the U.S. Fish and Wildlife Service. This MOU commits the signatory agencies to concurrent review of a pipeline construction application, such that agencies can work together rather than at cross-purposes, thus saving time and effort. We are hopeful that this MOU can also be applied to integrity management-related activities. It should be noted, however, that this MOU does not include participation by state agencies. These state agencies are often the most intransigent in terms of approving permits on a timely basis. Once again, a signal from Congress as to the importance of approving these permits in a timely manner will be critical to the success of the Pipeline Safety Improvement Act of 2002.

¹ "Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas," prepared for the INGAA Foundation by Energy and Environmental Analysis, Inc., February, 2002.

The Proposed Merger of the OPS and the Federal Railroad Administration

Before concluding, INGAA would like to provide some comments to the Committee on the proposed merger of the Office of Pipeline Safety and the Federal Railroad Administration (FRA). The Secretary of Transportation announced his intent to move forward with this idea as part of an overall vision to gather the various research functions at DOT and place them under one authority. OPS is currently a part of the Research and Special Programs Administration (RSPA), which the Secretary envisions would be restructured in order to accept all transportation research-related activities from the various modal administrations. Since the OPS is a regulatory body, it would not fit within the new RSPA, and thus the proposal to move it to FRA.

INGAA does not have a quarrel with the Secretary regarding his vision for transportation research. Our concern is that the OPS would lose its focus and effectiveness if it were to be subsumed into the much larger FRA. As you have already heard, OPS has made great strides in improving its performance over the last five years. Much of that success is related to the fact that it has been able to act quickly and decisively in improving its programs and enforcement activities. It would indeed be a shame if, after having worked so hard to gain back its credibility, OPS were to lose it once again by getting lost in a large and unfamiliar bureaucracy.

Rather than merging with the FRA, INGAA supports the creation of a new Pipeline Safety Administration at DOT. House Transportation and Infrastructure Chairman Don Young introduced legislation (H.R. 4277) last month to create a separate pipeline safety entity at DOT, and we strongly support his efforts. We hope that a Senate companion bill will be introduced soon, and that it will have this Committee's support.

Conclusion

Let me thank you once again, Mr. Chairman, for allowing me to testify today. Safety is of paramount importance to our industry, and we believe that it is our obligation to work with Congress and the OPS to maintain and improve the safe, reliable operation of our pipelines in the years ahead. I would be happy to answer any questions you or the Committee members might have.

The CHAIRMAN. Thank you very much.

Ms. Epstein, do you share the other witnesses' opposition to shifting the RSPA over to the Office of—the Office of Pipeline Safety over to the Federal Railroad Administration?

Ms. EPSTEIN. Yes, I do.

The CHAIRMAN. I wonder who came up with that idea.

[Laughter.]

The CHAIRMAN. Ms. Epstein, what grade would you give the Office of Pipeline Safety today? And what grade would you have given it 5 years ago?

Ms. EPSTEIN. Five years ago, I would have given the Office of Pipeline Safety a very poor grade, probably a C-minus or a D. And today, I would give them an excellent grade on progress, but, in terms of where we want them to be, I would only give them about a B.

The CHAIRMAN. Everybody knows that there's going to be an increased demand for natural gas, as well as oil. Most witnesses agree we don't have the refining capacity or the pipeline capacity to meet these increased demands. What's your solution?

Ms. EPSTEIN. Well, as you know, Senator, it's a very complicated problem, and there are nuances, such as existing refineries have expanded at the same time that new refineries haven't been built. Certainly, I would hope we'd be moving more toward a decentralized renewable energy infrastructure, and I think there are ways that we can move faster than we have to date.

In terms of expanding pipelines, I agree with my fellow witnesses that we need to make the public more confident about pipeline safety, and that is going to help siting of new pipelines. I think we

are moving in that direction. But, in terms of what I said today, I know I've been somewhat more negative than others, but I feel that my role is to point out the deficiencies, and I knew others would point out the good things that have been done.

I think it's critical that we recognize that there have been some enforcement issues, and they're ongoing. And the public takes those very seriously. When you don't—when you issue high penalties and don't collect those, that is going to have an impact on whether people think you are doing all you can to ensure that those who aren't performing properly are going to improve.

And, at the same time, I would hope those in industry who have an excellent record and perform well and are investing to prevent problems recognize that a strong enforcement program will level the playing field, and those who are not doing as much as they are will be penalized for that.

The CHAIRMAN. Thank you. You strayed from my question, but it's very informative. Thank you.

[Laughter.]

The CHAIRMAN. Mr. Pearl and Mr. Fischer and Mr. Howard, were you surprised at the number of problems that have been—in the pipelines—that have been discovered under this new inspection regime? According to Mr. Mead, approximately 15 percent of the pipelines have been inspected, and the problem rate has been much higher than expected. And if you are surprised, what do you think needs to be done?

We'll begin with you, Mr. Pearl.

Mr. PEARL. Yes, I think, certainly from our company's vantage point, and most of my colleagues in the liquids pipeline industry, the current run of "smart pigs," inline inspection devices, has detected more anomalies than we certainly anticipated. Over the mid-to long-term, that's a good thing, because, as I mentioned in my testimony, we're not just looking in repairing those that are required by law. You know, most operators are taking a prudent view and anticipating. And if you see an anomaly now that perhaps doesn't meet the regulatory criteria, you'd still go ahead and repair it so you'd prevent a leak down the road.

I think, all in all, the experience, you know, has been good. I believe—there's a little difference in numbers here. From our numbers, 43 percent of the infrastructure will have been tested by the September 30 deadline. And, as I mentioned in my testimony, we've gone well beyond the mileage required under the Act. It's turned out that, because of the way you inspect pipelines, by large segments, we cover far more than the mileage required under the HCA regulations. I believe we're going to be around 85 percent.

So the bad news, I guess, from a cost standpoint is, we're seeing more. That's due to much better technology. These "smart pigs" are seeing a lot—things that we couldn't see just 2 or 3 or 4 years ago. And I think when we get through this first wave, we're hopeful, as an industry, that we'll have far fewer anomalies second time around.

The CHAIRMAN. Mr. Fischer?

Mr. FISCHER. I would certainly agree with Mr. Pearl. Yes, I do get surprised when I see statistics like that appear, but not surprised from the standpoint that we don't fully expect that to hap-

pen with today's technology. The technology out there today is tremendous, and 5 years from now will be even more so. So, yes, today's technology is uncovering a lot of things.

However, what should we do about it as we move forward? I really think there are a lot of things in this new Pipeline Safety Act that will keep us very much on track. We look at these pipelines over a period of 10 years, and 50 percent of them are to have been inspected and fully documented and repaired in 5 years. We begin the process every 7 years from the date of the first year that we completed that segment. So there's a constant revolving inspection process now put in place that we didn't have before you sponsored this legislation. So I do think things are—we must judge it as we go along. Is that enough? Is that—you know, what are we doing? However, there is a lot in place that is just really starting to read out right now, Senator.

The CHAIRMAN. Mr. Howard?

Mr. HOWARD. I'm, frankly, surprised. I just don't have enough information to know why—I mean, and what those results might be. It does raise in me a natural curiosity to try and dig into the numbers and understand them better so that we've got the benefit of having the information.

The CHAIRMAN. Well, I intend to write a letter today in opposition of this movement of the Office of Pipeline Safety, and we'll see if that works. If not, maybe we'll have to act legislatively. I'm not sure that when a system is working, with all the caveats that have been presented by the witnesses, including your important testimony, Ms. Epstein, why we would want to shift. And if there is a problem in America, it certainly is with our railroads. So maybe misery loves company. I'm not sure—

[Laughter.]

The CHAIRMAN.—if that's the rationale behind it, but that can be the only rationale that I can see.

I don't mean to branch out into other areas, because this issue is to—this hearing is to review the Act and see what needs to be done and how they're doing, and recognizing that we have to continue the vigorous oversight and vigorous pursuit of pipeline safety so we never have to have a series of hearings again that I know were as uncomfortable for you as were for me when we had the tragic loss of life. And despite the fact that one of the other witnesses mentioned that it's—they have less accidents and less fatalities when something happens like happened in Bellingham, Washington, it gets—it grips all of us.

But I would argue, particularly, these four witnesses, everyone agrees that we're going to have an energy crisis in this country, if we're not in one now. There's a huge backlash about the role of some companies. These recent tapes of Enron have disgusted and angered all of us. And then motivates many Americans to say, "These people need to be re-regulated." I'm, by nature, a deregulator.

So my request from you is, you start—your various organizations start looking at the challenges that we face ahead, as far as an adequate energy supply for the American people is concerned. I agree with you, Ms. Epstein, that alternate energy is a great—re-

newable energy sources are a great way to begin. I'm not sure that that solves the whole problem in the short term.

So I don't know if that crisis comes next year or 10 years from now. It's not a matter of—it's a matter of when, not whether. And so I hope you'll start focusing your attention, because these issues involve things such as a 3-year delay in moving a pipeline from one place to another. I'm particularly interested in that when—I'm in a high-growth state, and we have pipelines out in the desert now that are turning into communities, and it's a little disturbing to me that many of the local authorities who do the zoning don't know that these rules exist. Ranging from that to what's going to happen in the Middle East as we see continued unrest and disturbances in Saudi Arabia, a major source of oil. So we'd better start thinking about this from a global standpoint. Otherwise, we will be blamed for not being prepared for something that clearly lies ahead of us.

And that's the end of my sermon and tirade for today.

[Laughter.]

The CHAIRMAN. And I thank you all for being here, and I appreciate you participating in this hearing.

This hearing is adjourned.

[Whereupon, at 11:29 a.m., the hearing was adjourned.]

A P P E N D I X

ARIZONA CORPORATION COMMISSION
August 2, 2004

Hon. JOHN BREAUX,
Senate Committee on Commerce, Science, and Transportation,
Washington, DC.

RE: Post Hearing Questions for the Pipeline Safety Oversight Hearing on 6/15/04

Dear Senator Breaux:

This is in response to your questions posted.

I Independent Exams

We believe that where a major incident occurs, there should be an independent exam to ensure (1) Proper analysis of the cause of the rupture and (2) That appropriate remediation is undertaken for the integrity of the line. In 2003 Arizona broke new ground in that U.S. DOT/OPS agreed to a second independent test. OPS has authority to conduct the independent test, and OPS paid for the test. However, there is no statute or regulation compelling the operator to reimburse this taxpayer expense. Again, in compelling cases, such reimbursement by the operator for independent testing should be mandatory.

II Adequacy of Funding

The Arizona workplans for inspection of interstate pipelines in Arizona have been aggressive, but we believe appropriate, consistent with public safety and reasonable given the potential economic and human costs of inadequate inspection schedules. OPS responds to our workplans that funds are limited and that one state should not absorb disproportionate funding. This has the quixotic result of discouraging necessary inspections and "penalizing" states that zealously guard public safety, in Arizona pursuant to statutory mandate. If Arizona believes an inspection is necessary for a certain segment of pipeline, the adequacy of funding should not cause OPS to deny the request.

Please contact me if you have further questions.

Very truly yours,

MARC SPITZER,
Chairman.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN BREAUX TO
SAMUEL G. BONASSO

Question 1. Your testimony states that OPS has completed assessments of the integrity management plans of the 63 largest operators of hazardous liquid pipelines, with each assessment taking about 2 weeks to complete. Is OPS on track to complete the remaining 157 assessments for hazardous liquid pipelines and the 884 assessments of natural gas transmission pipelines in compliance with current deadlines?

Answer. OPS set a very aggressive 2-year schedule for completing its IMP assessments of the 63 largest operators of hazardous liquid pipelines. According to OPS, IMP assessments are on track for the remaining 157 hazardous liquid pipeline operators, who are mostly small operators. OPS anticipates completing its initial IMP assessments of the remaining hazardous liquid pipeline operators by the end of Fiscal Year 2005.

According to OPS, it needs to hire additional inspectors before it can begin its IMP assessments of operators of natural gas transmission pipelines. For Fiscal Year 2005, OPS has requested an additional 12 inspector positions. OPS also needs to provide the necessary IMP training to both Federal and state inspectors. According to OPS, there are many more inspectors at the state level to train for IMP assess-

ments of operators of natural gas transmission pipelines than were trained for IMP assessments of operators of hazardous liquid pipelines. Training will have to be completed before the assessments can begin.

OPS estimates beginning its initial IMP assessments of operators of natural gas transmission pipelines in the fall of 2005, with an estimated completion date in the spring of 2007. However, OPS will be in a better position to finalize its plans for completing IMP assessments of operators of natural gas transmission pipelines once the FY 2005 budget is passed.

Question 2. Do you believe OPS has sufficient resources to meet the mandates of the 2002 Pipeline Safety Improvement Act on schedule?

Answer. OIG has not assessed OPS's resource strengths to determine whether they are sufficient to meet the mandates and deadlines of the Pipeline Safety Improvement Act of 2002 (2002 Act).

Question 3. Your testimony notes that gas distribution lines are responsible for 4 times the number of fatalities and more than 3.5 times the number of injuries than hazardous liquid and gas transmission pipelines combined. Yet gas distribution pipelines are not included in the current integrity management initiatives. What specifically should Congress do to address this gap in the safety program?

Answer. In our final report,¹ we recommended that OPS require operators of natural gas distribution pipelines to either implement some form of pipeline integrity management or enhance safety programs with the same or similar integrity management elements as the hazardous liquid and natural gas transmission pipelines.

In its response to our recommendation, OPS stated that industry, state, and Federal regulators are now working to develop natural gas distribution IMPs and that a public workshop to discuss IMP concepts is planned for December 2004. However, other than stating that it is working with states and industry to develop an IMP for operators of natural gas distribution pipelines, OPS did not indicate when they expect to require an IMP for natural gas distribution pipelines. In our opinion, OPS should issue a rule no later than March 31, 2005, requiring operators of natural gas distribution pipelines to implement IMPs.

We would suggest that Congress get a commitment from OPS as to when it expects to require an IMP for operators of natural gas distribution pipelines, including realistic milestones and performance measures on the actions necessary to carry out its IMP initiative. OPS should also report to the committee on its progress periodically. If OPS and industry do not meet the milestones, Congress should proceed to close this safety gap by enacting legislation requiring an IMP for operators of natural gas distribution pipelines.

Question 4. What mandates from the 1992 and 1996 Acts has OPS still not implemented?

Answer. OPS has completed its action on all mandates from the 1996 Act. However, five mandates from legislation enacted in 1992 remain outstanding. All are over 10 years past due. The table below identifies those mandates OPS has yet to implement since our March 2000 report.

Status of Outstanding Mandates from 1992 Legislation

Pipeline Act & Section	Mandate	Status
1992 Sec. 108	Require periodic inspection of all offshore and navigable waterway natural gas pipeline facilities	NPRM published and awaiting public comment, final rule expected August 2004
1992 Sec. 207	Require periodic inspection of all offshore and navigable waterway hazardous liquid pipeline facilities	NPRM published and awaiting public comment, final rule expected August 2004
1992 Sec. 307(b)	Prepare a report to Congress on a study concerning how to abandon underwater pipelines	Report is in the clearance process, report expected July 2004
1992 Sec. 109(b)	Define and regulate natural gas gathering lines	NPRM comments under discussion, supplemental notice expected December 2004
1992 Sec. 208(b)	Define and regulate hazardous liquid gathering lines	OPS is coordinating with the states and industry to develop a definition, NPRM expected December 2004

NPRM: Notice of Proposed Rule Making

¹ OIG Report Number SC-2004-064, "Actions Taken and Needed for Improving Pipeline Safety," June 14, 2004.

Question 5. You note in your testimony that “Much of the Nation’s existing pipeline infrastructure is over 50 years old.” How much a correlation is there between the age of a pipeline and the likelihood of a leak or rupture?

Answer. The age of a pipeline can certainly be a contributing factor in pipeline failures, as was demonstrated in the pipelines that ruptured or leaked in Bellingham, Washington; Carlsbad, New Mexico; Tucson, Arizona; and • the Suisun Marsh in northern California. In each incident, the pipelines where the rupture or leak occurred were more than 35 years old. According to OPS, in the Bellingham and Carlsbad accidents, the ineffectiveness of the operators’ maintenance programs, compounded by the age of the pipeline, resulted in the pipeline failures.

OPS, through its research and development efforts, is looking into integrity threats (*i.e.*, external corrosion, internal corrosion, stress corrosion cracking, manufacturing defects, fabrication and construction defects, and third-party or mechanical damage) associated with aged pipelines. One current project underway will (1) evaluate the extent to which aging leads to loss of the pipelines capabilities, (2) identify material and construction anomalies common to vintage pipeline, and (3) develop a process to evaluate potential threats posed by such anomalies.

Question 6. In your opinion, should age be a factor in where pipelines are inspected, in addition to whether the pipeline is located in a “high-consequence area”?

Answer. Yes, as does OPS. In its guidance for implementation of an IMP, OPS lists 18 risk factors, including age of pipe, that pipeline operators should consider when establishing the frequency of IMP assessments in high-consequence areas. Generally, older pipe shows more corrosion and may be uncoated or have an ineffective coating for preventing corrosion. OPS rates pipe 25 or more years old as high risk and pipe less than 25 years old to be low risk, but factors such as the pipeline’s coating and corrosion conditions can affect the true risk level. Other risk factors that operators should consider when establishing an integrity assessment schedule include, among others, results from previous inspections, leak history, known corrosion or condition of the pipeline, type and quality of the protective coating, and operating stress levels in the pipeline.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN BREAUX TO
HON. KENNETH M. MEAD

Question 1. You point out that permitting for time sensitive pipeline repairs is a significant issue and mention the recent California accident. Do you know how many time-sensitive pipeline repairs have been delayed, past their required completion date, due to permitting problems?

Answer. According to OPS, information is not available on the actual number of time-sensitive pipeline repairs that have been delayed, past their required completion date, due to permitting problems. However, information obtained from OPS, California’s Office of the State Fire Marshal and pipeline operators, disclosed that not only have there been several time-sensitive pipeline repairs that were delayed due to permitting problems, pipeline relocations were also delayed due to the permitting process.

For example, in early 2002, a pipeline operator in Michigan discovered an integrity threat in pipe that was located within a large wetland complex managed by the Michigan Department of Natural Resources. Federal, state and local permits were required before the operator could take action to repair the pipe. The repairs were finally completed more than 6 months after permitting efforts were initiated.

According to officials in California’s Office of the State Fire Marshal, a 1,400-foot pipeline relocation in the San Francisco Bay area took 29 months to obtain permits and a 3-mile pipeline relocation in rural Contra Costa County, California took 3 years to obtain permits.

Question 2. In the California accident, I understand that the pipeline operator was trying to relocate the pipeline out of the marsh area. Does this require more permitting and a longer process than just a simple repair to an existing pipeline?

Answer. Yes, in this case, a significantly longer and larger environmental review and permitting process was required in order to relocate the pipeline away from the Suisun Marsh area. The pipeline operator was replacing approximately 70 miles of existing pipe with new pipe that would be re-routed away from the Suisun Marsh. Re-routing 70 miles of new pipe effected many more state and local environmental review and permitting jurisdictions that otherwise would not have been involved in the environmental review and permitting processes for a one-time repair to an existing pipeline. For example, only one city and county would have been involved in the permitting process had the operator chosen to repair the existing pipeline. By choosing to relocate the new pipe, the operator had to obtain environmental reviews and

permits from an additional six cities and two counties, not including local water, irrigation and sewage districts. As we testified, thirty-one separate Federal, state, and local agencies and railroads were involved in the environmental review and permitting processes for relocating the hazardous liquid pipeline away from the marsh area (see attachment).

Question 3. According to your testimony, there is still some clarification needed between DHS and DOT regarding pipeline security. What do you feel needs to be done to clearly define OPS's role for pipeline security?

Answer. Although Homeland Security Presidential Directive-7 directs DOT and DHS to collaborate in regulating the transportation of hazardous materials by all modes, including pipelines, it is not clear from an operational perspective what "to collaborate" encompasses. The delineation of roles and responsibilities between DOT and DHS needs to be spelled out by executing a Memorandum of Understanding or a Memorandum of Agreement. At a minimum, the Memorandum should state clearly what agency will have the primary responsibility for issuing pipeline security rules, orders and directives; and responsibility for overseeing and enforcing operators' compliance with security requirements.

Question 4. Are the approximately 90 Federal and 400 state inspectors responsible for pipeline safety adequate given the tasks ahead?

Answer. OPS is faced with a very aggressive and ambitious task in overseeing and enforcing the pipeline operators' execution of their integrity management programs (IMP) and, at the same time, performing other oversight activities such as inspecting new pipeline construction, monitoring research and development projects, and investigating pipeline accidents.

In our testimony, we stated that OPS had completed its IMP assessments of the 63 largest operators of hazardous liquid pipelines. Most of the heavy lifting lies ahead with 157 hazardous liquid and 884 natural gas transmission pipeline operators still needing an initial IMP review by an OPS inspection team.

Given the magnitude of this effort, with more than 1,000 pipeline operators who have not yet had an initial IMP assessment (at approximately 2 weeks for each assessment), OPS should be able to schedule out for the Committee a timetable for completing its initial IMP assessments in an effective and timely manner. In doing so, OPS should factor in its (1) staffing needs, both Federal and state inspectors, to conduct IMP assessments; and (2) training needs, both Federal and state, knowing that there are many more inspectors at the state level to train for IMP assessments of operators of natural gas transmission pipelines than were trained for IMP assessments of operators of hazardous liquid pipelines. As of June 30, 2004, 110 Federal and state inspectors have received the advanced IMP training, with an additional 58 Federal and state inspectors scheduled to take the advanced training in 2004.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN BREAUX TO
KATHERINE SIGGERUD

Question 1. If OPS does not have clear goals for its enforcement strategy, on what basis is the agency making decisions about whether to impose a civil penalty, versus issuing a compliance order or taking some other enforcement action?

Answer. When OPS finds a violation, it relies on regional directors to determine the most appropriate enforcement action for the situation. OPS has an enforcement manual that provides general guidance on the various types of enforcement actions and how they should be used. However, this guidance is out of date, because it reflects the agency's earlier more lenient enforcement approach of partnering approach with industry. Therefore, OPS management has communicated current enforcement priorities to staff and relies on frequent contact among regional directors to assure consistency. OPS intends to devote more attention to strengthening the management of the agency's enforcement program. OPS expects to finalize its new enforcement policy and guidelines sometime in 2005.

Question 2. If OPS does not have clear goals for its enforcement strategy, on what basis does the agency impose a civil penalties and how does it determine the amount of the penalty?

Answer. When imposing civil penalties, OPS must by law consider seven factors: (1) the nature, circumstances, and gravity of the violation; (2) the degree of the operator's culpability; (3) the operator's history of prior offenses; (4) the operator's ability to pay; (5) any good faith shown by the operator in attempting to achieve compliance; (6) the effect on the operator's ability to continue doing business; and (7) other matters as justice may require. OPS relies on frequent contact among regional direc-

tors to assure consistency. OPS is developing guidance that should help assure that it is making consistent decisions concerning civil penalties for all types of violations, but has told us that it does not anticipate finalizing this guidance until 2005.

Question 3. How well is OPS communicating with its state partners?

Answer. We believe that OPS has improved its communication with its state partners since we last reported on this issue 2000. Most of OPS's interstate agents we contacted (7 of 11) told us that their communications with OPS have improved since 2000, when we recommended that OPS do a better job of involving them in Federal pipeline safety efforts. However, most (7 of 11) also raised concerns that OPS was too slow in informing them of actions the agency took on their notices of operator noncompliance. OPS told us that effective November, 2003, it would provide states with written responses to their notices within 60 days of receiving them.

In addition, we recommended in 2002 that OPS develop a strategy for communicating with the states what role they will play in oversight activities. In response, OPS told us that it was pursuing various initiatives to improve communication with the states, such as additional meetings with state officials and providing states with access to agency information systems.

Question 4. How long does it take OPS to collect the civil penalties it assesses?

Answer. We could not determine whether operators paid penalties in a timely manner because we determined OPS's and FAA's data were not sufficiently reliable for this purpose.

Question 5. What effect does this delay have on the effectiveness of civil penalties in deterring safety violations?

Answer. According to economic literature, the longer it takes to collect a given dollar penalty—whose amount was set after considering the circumstances of the infraction and the damage caused by it—the lower its expected deterrent effect.

Question 6. How well has OPS fulfilled other GAO recommendations?

Answer. In response to two recommendations we made in 2000, OPS has worked more closely with state officials in overseeing pipeline safety and adopted a more aggressive enforcement posture. As a result, we believe that OPS has implemented these two recommendations. For the third recommendation, that OPS determine whether the reduced use of civil penalties has affected operators' compliance with pipeline regulations, OPS told us that it did not have sufficient data to do so. However, to better assure that it could address safety concerns, OPS changed its enforcement policy to make fuller use of its range of enforcement tools, including increasing the number and size of civil penalties. We believe that this action implemented the intent of this recommendation.

Five of our recommendations to OPS, made from 2001 to 2003, remain open. These include recommendations that OPS

- develop a workforce plan to ensure that it has the resources and expertise it needs to carry out all of its responsibilities,
- develop a strategy for communicating to the states what role they will play in pipeline safety oversight, and
- develop a systematic process for evaluating the outcomes of its R&D program.

We are aware that OPS is working on these open recommendations and will continue to monitor their progress.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN BREAUX TO
HON. MARC SPITZER

Question 1. What specific actions have been taken since the pipelines accident last summer in Tucson to improve your relationship between OPS and the ACC?

Answer. After a review of the situation, I concluded that a lack of communication was the primary culprit that damaged our relationship. In an effort to address this issue from our end, the ACC is in the process of hiring a supervisor in our pipeline division that will act as a liaison to FOPS. I believe that this action will result in obtaining the desired level of communication between the ACC and FOPS.

I would also highlight the following:

In January, 2004, the Arizona Corporation Commission held a series of forums on pipeline safety around the state. Federal pipeline safety personnel participated in the forums. I believe their participation in the forums has helped to improve communication between the agencies.

In May, 2004, Stacey Gerard, Jim Wiggins and Patricia Klinger of FOPS and the USDOT met individually with each Commissioner at the ACC. During our meeting,

those three individuals and I agreed that communication was the issue and implemented a plan to communicate more directly with each other.

Currently, Kinder Morgan has been keeping us informed on the activity taking place on the 6-inch Phoenix to Tucson line. This activity is part of a corrective action order FOPS issued to Kinder Morgan. Prior to that order Kinder Morgan did not appropriately communicate with the ACC. This communication has helped us to keep FOPS better informed.

Overall, I believe through the efforts of all parties involved, communication has and will continue to improve.

Question 2. Are you satisfied with this year's work plan for pipeline inspections, including the time authorized by OPS to inspect the Kinder Morgan pipeline?

Answer. Yes, Staff and I are satisfied with this year's work plan.

After consultation with the Staff, it is our understanding that FOPS granted our request to amend the current year work plan by adding an additional 15 days to inspect the remainder of Kinder Morgan pipeline facilities in Arizona. The only restriction is that we have to get all the other work noted in the work plan completed before we can pursue the additional inspection work we requested.

FOPS has expressed to me a willingness to grant such a request. The ACC expects to complete its required inspections in October of 2004. Therefore, there is no indication that the ACC will be restricted from conducting additional inspections outside the current work plan.

Question 3. The recent exchange of letters between Commissioner Mayes and OPS suggests that there may be a different interpretation of the work plan and how much flexibility it gives the state in performing inspections. What is your view?

Answer. As I stated above, Staff, FOPS and I are satisfied with the present form of the work plan. As to the comments of another Commissioner, in Arizona each Commissioner is an elected official. A majority of three Commissioners is required for a formal Commission position. I cannot comment on the reasons for a difference of opinion among the Commissioners on the relationship with FOPS.

Question 4. Your written testimony states that residential or commercial construction should not take place within 200 feet of a high pressure 8 or 12-inch gasoline pipeline. While you advocate for Federal and state standards, zoning is primarily a local issue, is it not? What progress is being made by cities in Arizona to prevent encroachment on pipeline rights-of-way?

Answer. I recognize that the law of land use has historically been promulgated and adjudicated by local governmental units. The 1911 Supreme Court decision of ***Town of Euclid*** ushered in a tradition of respect for the land use decisions (in that case zoning) of local government.

In the case of the Kinder Morgan rupture of 2003, an unfortunate pattern of urban development clearly emerged. Particularly in "growth" communities, real estate becomes dear. Residential, commercial and industrial real estate development places a premium on efficient use of raw land to maximize the rate of return to developer and land-owner (often these roles are combined).

My experience as an Arizona attorney is that local government generally accommodates real estate development. That is not necessarily a bad thing, but it is a fact. And in case where residential or commercial development draws opposition, it arises from the pre existing residents.

Where development is proposed in the vicinity of a natural gas or hazardous liquid interstate pipeline, there is no natural constituency as a check on the desire of the developer to maximize the value of the land, in fact the very nature of a remote development precludes neighborhood opposition. In the case of the Kinder Morgan rupture, development occurred only 37 feet from the pipeline.

Federal law limits developments near nuclear reactors, and to a lesser extent military installations and airports. That analogy should obtain in connection with proposed development adjacent to interstate pipelines.

I suggest a Federal rulemaking process be invoked by the U.S. DOT to fashion rules that adequately balance private property rights, local zoning authority and public health and safety. I believe expert testimony should be obtained to address an appropriate setback distance, recognizing that most pipeline ruptures are due to excavation.

Thank you once again for this opportunity to supplement my testimony on these very important issues.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN BREAUX TO
LOIS N. EPSTEIN

Question 1. In your testimony, you discuss the need for “preventive enforcement actions to deter potential violators”. Could you please provide us with a few examples of how this might work? What type of violations would be appropriate to address with preventive enforcement actions? Do other regulatory agencies regularly use preventive enforcement?

Answer. There are several sections of the pipeline safety regulations that Office of Pipeline Safety (OPS) enforcement personnel should pay particular attention to in order to prevent releases. Enforcement of these “preventive” regulations would supplement OPS’ non-preventive enforcement actions, which are enforcement actions that take place after releases have occurred.

In addition to OPS’ current enforcement emphasis on proper implementation of its integrity management programs for both hazardous liquid and natural gas transmission pipelines, OPS preventive enforcement actions should address the following specific regulatory violations:

- Inadequate external and internal corrosion prevention (49 CFR 192, Subpart I; 49 CFR 195, Subpart H). Corrosion caused 24.5 percent of the natural gas transmission pipeline releases and 24.4 percent of the hazardous liquid transmission pipeline releases in 2003.
- Inadequate internal inspection testing and/or analysis of test results.
- Improper performance of direct assessment. Because direct assessment allows great operator flexibility and is a lower-cost and less-proven alternative to smart-pigging, OPS must ensure that operators perform direct assessments properly for them to have value in preventing releases.
- Exposed pipelines (49 CFR 192.327 and 49 CFR 195.248).
- Poorly-done repairs.

My point is not that OPS never pursues enforcement actions related to these types of violations—it does on occasion, but practically no one except the violator knows that it has done so. OPS needs to pursue several enforcement actions in each of these regulatory categories, imposing relatively high penalties for non-compliance and with high media exposure. By doing so, all pipeline operators would realize they are at risk of receiving similar high penalties for similar violations.

As an example of another agency pursuing preventive enforcement for oil releases, I refer the reader to the U.S. Environmental Protection Agency’s (EPA’s) Underground Storage Tank 1998 Deadline Enforcement Strategy at <http://www.epa.gov/Compliance/resources/policies/civil/rcra/storagetank-mem.pdf> (Attachment A). Underground storage tank (UST) system releases derive from both tanks and their associated piping, so there is a strong correspondence with OPS’ pipeline regulations. The UST enforcement strategy states that “sub-standard UST systems should not operate after December 22, 1998. Those who delay [compliance] can be subject to monetary penalties of up to \$11,000 per day for each violation throughout their period of non-compliance” (p. 1). The strategy also states that “In pursuit of its goal, EPA will use all the enforcement tools available for dealing with UST violations, including administrative and judicial enforcement actions. Judicial enforcement actions are particularly appropriate in situations involving recalcitrant parties” (p. 3). A clearly articulated preventive enforcement strategy—available to both pipeline operators and the public on OPS’ website—like the UST enforcement strategy, would be very beneficial to prevent pipeline releases.

Question 2. Can you discuss the difference between OPS’s enforcement approach and the EPA’s, which I believe you are familiar with? Do you believe that OPS’s enforcement strategy is less effective than EPA’s in influencing industry’s behavior?

Answer. There are two major differences between EPA’s enforcement strategies and OPS’ enforcement strategies: (1) EPA pursues costly (to the operator), publicly-visible, and more-certain enforcement actions against the regulated community, which OPS does not do, and (2) EPA delegates enforcement to states if states are qualified to run their own enforcement programs, which OPS does not do for interstate pipelines because of an existing statutory prohibition.¹ For both these reasons, OPS’ enforcement strategy is less effective than EPA’s in improving industry’s performance. These items are discussed below.

1. *Costly, visible, and certain enforcement*—The U.S. Government Accountability Office (GAO) recently issued a report on OPS’ enforcement program that analyzed the size of the civil penalties levied by OPS. According to GAO, “the average civil

¹ 49 USC § 60104(c).

penalty that OPS assessed from 2000 through 2003 was about \$29,000”² Such penalties are far less than Congress envisioned when it raised the limits for OPS penalties in the Pipeline Safety Improvement Act of 2002 from \$25,000 per daily violation with a \$500,000 maximum to \$100,000 per daily violation with a \$1,000,000 maximum.

While I do not have data on the average civil penalty from EPA—and I encourage Congress or OPS to pursue that information—I can provide examples of pipeline releases that resulted in far higher (*more than 100 times higher*) penalties from EPA than from OPS for similar pipeline problems. These examples are shown in the following table, with more details provided in Attachment B:

Recent EPA Civil Penalties/Settlements for Pipeline Releases

Company	Date	Penalty	Summary of Violations
Mobil E & P	8/04	\$5.5 mill.	Oil and produced water releases, inadequate prevention and control, failure to notify EPA of releases
Olympic Pipeline/Shell	1/03	>\$5 mill.—Olympic/ >\$10 mill.—Shell	> 230,000 gal. of gasoline released, 3 human deaths, over 100,000 fish killed
Colonial Pipeline	4/03	\$34 mill.	1.45 mill. gal. of oil released in 5 states from 7 spills (from corrosion, mechanical damage, and operator error)
ExxonMobil	9/02	\$4.7 mill.	Approx. 75,000 gal. of crude oil released, fouling a river and nearby areas
Koch Industries, Inc.	1/00	>\$35 mill.	Approx. 3 mill. gal. of oil released in 6 states (from corrosion of pipelines in rural areas)

EPA penalties also are far more visible to the public, which make them more effective. First, EPA distributes press releases for its large penalties, which OPS has begun to do, and second, any EPA penalties greater than \$100,000 must be reported to the Securities and Exchange Commission under 17 CFR 229.103. The latter requirement means that company investors are aware of the violations and the penalty, which can provide a strong deterrent effect against additional violations.³

Last, EPA’s numerous civil penalty policies posted on the Internet at <http://cfpub.epa.gov/compliance/resources/policies/civil/penalty/> help ensure uniform and thus more certain enforcement against violators.

2. *Federal vs. state enforcement*—A simple description of EPA-based environmental enforcement is that qualified states are delegated primary enforcement responsibilities for environmental laws even as EPA retains the right to pursue enforcement actions. In contrast, OPS alone can pursue enforcement actions for interstate pipeline violations, although certain states assist in inspection and analysis of violations. While the EPA system is not perfect and is similar to OPS’ relationship with states with delegated responsibilities to oversee and enforce violations for intrastate pipelines, it is far superior to the current federal/state division of responsibilities for interstate pipelines.

According to the new GAO report, the states have approximately 400 pipeline safety inspectors and OPS has approximately 75 inspectors.⁴ Natural gas and hazardous liquid transmission pipelines (327,000 miles and 161,000 miles, respectively) primarily are interstate. As a result, the typical Federal inspector is responsible for oversight of approximately 6,500 miles of transmission pipeline. Additionally, Federal inspectors frequently are not as aware of certain technical, geographic, and even management issues associated with interstate pipelines as state pipeline safety officials are because of their proximity to the lines. As a result of limited Federal oversight resources and the Federal lack of familiarity with certain interstate pipeline concerns, it would be beneficial to change current law and allow qualified state pipeline safety officials to pursue enforcement actions against interstate pipeline operators.

A final problem with the current federal/state interstate pipeline enforcement relationship is that the states’ inability to pursue enforcement actions against interstate pipeline operators leads to frustrated state pipeline safety and elected officials. GAO spoke with one state pipeline safety official who stated that after his agency

²*Pipeline Safety: Management of the Office of Pipeline Safety’s Enforcement Program Needs Further Strengthening*, U.S. Government Accountability Office, GAO–04–801, July 2004, p. 4.

³Note that GAO did not consider this deterrent effect in its analysis of the effectiveness of OPS penalties.

⁴GAO, *op. cit.*, p. 12.

“alerted OPS to noncompliant activity at one company, it found the same violation 2 years later during the next scheduled inspection cycle.”⁵

Question 3. Can you discuss the need for oversight of flow and gathering lines? Do you think OPS and the states are doing enough to ensure the safety of these types of pipelines?

Answer. During my past three years of work in Alaska, I have become very familiar with the environmental and safety issues associated with oil and gas production fields from releases of crude oil, natural gas, and produced water.⁶ The rural nature of these lines has meant that, until recently, few have paid attention to their hazards. There currently is a pressing need for strengthened regulation of these lines.

Because Alaska has a very low threshold for reporting releases,⁷ I was able to ascertain what proportion of the oil pipeline releases in the Cook Inlet watershed came from flow and gathering lines. Of the 311 miles of oil pipelines in the watershed, 60 miles (19 percent) are flow and gathering lines. From 1997–2001, 41 percent of the reported oil pipeline releases in the watershed came from flow and gathering lines, including 7 of the 8 largest releases (ranging from 1,134 to 228,648 gallons). For the year following, 50 percent of the reported oil pipeline releases in the watershed came from these lines.

Given the clear environmental and safety problems flow and gathering lines pose in the Cook Inlet watershed and the apparent problem they cause in other areas in the country (see Cook Inlet Keeper’s comments to the OPS docket which are included as Attachment C and the August 3, 2004 Mobil example in Attachment B), I recommend that OPS:

1. Research the frequency and extent of releases from these pipelines on the North Slope of Alaska and in other oil and gas production states with appropriately low reporting thresholds; and,
2. Expeditiously begin a rulemaking on this issue.

Should OPS fail to address the environmental and safety issues associated with flow and gathering lines, Congress should ensure that it does so through appropriate oversight and/or legislation.

Question 4. You mention that the current Federal preemption policy that prevents states from regulating and enforcing violations on interstate pipelines is overly restrictive. How would you change this to allow a greater state role? What type of activities could states engage in that would increase pipeline safety, yet not unduly impact interstate commerce?

Answer. Given that states have particular pipeline safety concerns which OPS might not be sufficiently familiar with and thus might not address (*e.g.*, earthquakes, subsidence, uniquely aggressive corrosion), and the fact that many if not all state-specific issues can be addressed without adversely impacting interstate commerce, I recommend that OPS and/or Congress:

1. Query state pipeline safety officials on how states have exceeded Federal requirements for intrastate pipelines and on which of these requirements they think are needed for interstate pipelines; and,
2. Develop legislative language for the next pipeline safety law reauthorization that allows states to exceed Federal requirements to address state-specific conditions or needs in a manner which does not unduly impact interstate commerce.

As I stated in my testimony, 49 USC §60104(c) presents “an unnecessary intrusion on states’ rights with serious adverse consequences since national regulations might not protect states sufficiently from pipeline hazards, *e.g.*, from earthquakes, difficult cleanup terrain, etc.”⁸ Other areas where states might want to exceed Federal requirements include internal assessment requirements, right-of-way management, and definitions of high consequence areas. Simply put, requirements that are appropriate in one part of the country may not be adequate in another part of the

⁵ *Ibid.*, p.53.

⁶ “Produced water” is any water that comes to the surface during oil and gas production, including water containing oil from the geologic formation, injection water, and drilling additives. Produced water, which generally is briny, typically contains pollutants such as oil and grease, acids, ammonia, benzene, naphthalene, metals (*e.g.*, chromium, copper, lead, zinc), and sometimes radionuclides, following separation from crude oil and natural gas.

⁷ Releases from “unregulated” pipelines need not be reported to OPS.

⁸ Testimony of Lois N. Epstein, P.E., before the U.S. Senate Committee on Commerce, Science and Transportation, Oversight Hearing on Pipeline Safety, June 15, 2004.

country; if implementing such requirements would not unduly impact interstate commerce, states should be allowed to do so.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN MCCAIN TO
BARRY PEARL

Question 1. The Office of Pipeline Safety reports that the integrity management program for hazardous liquid pipelines has already resulted in 20,000 repairs. What kinds of problems have the inspections uncovered and how does the number of repairs under the integrity management program compare to the number completed annually before the program started?

Answer. The principal conditions being repaired are those that are required to be repaired by the OPS regulations at 49 CFR 195.452 (h) (5).

—Paragraph (h)(5)(i) describes immediate repair conditions, which include metal loss greater than 80 percent, predicted burst pressure less than the maximum operating pressure at the location of the anomaly, and dents at the top of the pipe (above the 4 and 8 o'clock position) with any metal loss, cracking, stress riser, or greater than six percent of nominal pipe diameter.

—Paragraph (h)(5)(ii) describes 60-day conditions, which include dents located on top of the pipeline with a depth greater than three percent of the pipeline diameter or dents on the bottom of the pipeline that have any indication of metal loss, cracking, or stress riser.

—Paragraph (h)(5)(iii) describes 180-day conditions, which includes dents with depth greater than two percent of the pipeline's diameter that affect pipe curvature at a girth weld or a longitudinal seam weld, dents located on the top of the pipeline with a depth greater than two percent of the pipeline's diameter, dents located on the bottom of the pipeline with a depth greater than six percent of the pipeline's diameter, anomalies with a calculated remaining strength of the pipe that shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly, an area of general corrosion with a predicted metal loss of greater than 50 percent, a potential crack indication that is determined to be a crack when excavated, corrosion of or along a longitudinal seam weld, or a gouge or groove greater than 12.5 percent of nominal wall thickness.

—Paragraph (h)(5)(iv) describes conditions for which an operator must schedule for evaluation and remediation, which include a change since a prior assessment, any mechanical damage to the top of the pipe, anomalies that are abrupt in nature, anomalies that are longitudinal in nature or extend over a large area, and anomalies located in or near cased crossings, crossings of another pipeline and areas with suspect cathodic protection.

In addition to required repairs, other repairs are being made as well. The 20,000 repairs to which you refer in your question is a number taken from a database assembled by OPS from its inspections/audits of thirty-six large and eleven small liquid pipeline operators conducted before December 31, 2003. OPS found these operators in total completed 1,191 immediate repairs, 756 60-day repairs and 2,397 180-day repairs. In addition, these operators undertook an additional 16,081 repairs that were not subject to regulatory time deadlines. Many repairs in this last category were paragraph (h)(5)(iv) repairs, but others were not required by the IMP, but were made anyway because the excavation has exposed a condition. Obtaining permits for excavation and excavation itself are significant expenses, so, once the pipe is exposed, operators have a strong incentive to take a conservative approach and repair anything they find that may possibly be a cause of concern, including many conditions that likely would never fail in the lifetime of the pipe. These discretionary actions enlarge the total number of reported repairs, but represent a significant benefit to pipeline safety that will reduce pipeline risk far into the future.

Although there is no comprehensive database to describe integrity inspections conducted by operators in the oil pipeline industry prior to the IMP, we know that such inspections were widespread. Based on my own experience, I would expect that the discovery of conditions and repair activity prior to the advent of the IMP for many of the stronger operators was similar to what they are experiencing now. For others the rate of assessment and the rate of repair have increased significantly as a result of IMP. The main differences under the IMP are the mandatory schedule for integrity assessments to which all operators must adhere and the mandatory time deadlines for completing the repairs for specific categories of conditions discovered. The IMP establishes a level expectation for the performance of all operators in the deployment of integrity assessment tools. The time deadlines for completion of repairs put pressure on operators to complete repairs sooner when conditions are discovered by these tools. There is no doubt that these deadlines accelerate the rate

of repair. These time deadlines for repairs lend urgency to achieving prompt and successful implementation by federal, state and local agencies of section 16 of the PSIA addressing the ability of operators to get permits needed to complete repairs within these time limits. In enacting the PSIA Congress was raising the expectation of performance for pipeline operators to enhance pipeline safety. In enacting section 16 of the PSIA, Congress was also raising the expectation of performance for government permitting agencies to do their part to achieve the safety goals of the PSIA.

By the way, there have actually been more than 20,000 repairs under the OPS integrity management program (IMP) for liquid pipelines since the program went into effect, and this is good news, not a concern. These repairs are reducing pipeline risks to the public by preventing leaks that will never have to be cleaned up and preventing environmental damage that will never need to be restored.

The 20,000 number in your question comes from a database assembled by OPS before December 31, 2003. OPS teams spent approximately one to two weeks at each operator's headquarters to review the results of the operator's integrity assessments and actions taken to address integrity issues. The schedule under the rule calls for fifty percent of the highest risk segments of each operator to be assessed by September 30, 2004, and operators are on track to meet that deadline. The data to which you refer provides a snapshot of the program in its early stages. Assessments and repairs are ongoing and will be ongoing for the foreseeable future. The data from your question covers conditions that an individual operator discovered through integrity assessment, evaluated and repaired in the period beginning with the effective date of the IMP and the date of OPS inspection for that operator. Since the OPS operator inspection visits did not all occur at the same time, and integrity assessments by operators continue after the OPS inspection, we can infer that the number of repairs is larger than the sum of the repairs reported at each operator's particular inspection date, all of which occurred before December 31, 2003. So the number of repairs completed by the industry as of December 31, 2003 is actually larger than 20,000.

Question 2. Given the number of repairs that have had to be performed, should the schedule for implementing integrity management be accelerated?

Answer. No. For hazardous liquid pipelines, the baseline inspections will reach the 50 percent point in 2004 and be completed in early 2008. Any further acceleration would be likely to disrupt those plans. Stability in the integrity management rules is very important at this point in their implementation. Operators are already undertaking the assessments required by the integrity management rules at a rapid pace, and most are ahead of the program's schedule. The expenditures for a company's integrity program are significant and budgets for future expenditures under the program are in place. Further acceleration of the program could lead to shortages of internal inspection devices (smart pigs) and personnel qualified to interpret the output of these devices. Correct interpretation is necessary to find the important conditions and limit unnecessary excavations. Moreover, immediate repairs are less than 6 percent of repairs in the data set you refer to in your first question, so the number of conditions requiring immediate action is relatively small.

The best way Congress can support the speedy repair of the nations' oil pipeline infrastructure is to push the Council on Environmental Quality and the Federal permitting agencies to promptly and fully implement section 16 of the PSIA to provide permit streamlining for repairs under the current schedule.

Question 3. How do these repairs correlate to the age of the pipelines involved?

Answer. Pipeline age as a risk factor is usually misunderstood. The issue isn't how long the pipeline has been in service, but how it was initially manufactured, how it was installed and how it has been maintained. Cathodic protection, for instance, keeps an underground pipeline from corroding. If a pipeline has been protected from third party damage and inspected and maintained over its life, you won't see any difference in the pipe's condition whether its age is 50 years, 30 years, or 10 years. The study by Kiefner and Trench, "Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction", which is available at <http://committees.api.org/pipeline/ppts/docs/decadefinal.pdf>, reviews the performance of oil pipelines as a function of age. The study found that prevention programs, monitoring, testing and renovation can effectively keep pipelines of any vintage fit for service. However, the era of construction matters, because manufacturing, construction and prevention techniques have evolved over time to produce better pipe and pipe that is better protected from the causes of leaks. Knowledge of a particular pipeline segment's history is taken into account in designing prevention programs. Pre-1930s pipelines (about 2 percent of the Nation's mileage) were constructed before modern manufacturing techniques were developed and accordingly require more careful evaluation and may require mitigation measures. By the late 1940s cathodic

protection began to be used to significantly reduce corrosion of steel pipe. By the late 1960s newer alloy and carbon steels greatly reduced manufacturing defects, and testing methods enabled addressing the defects that were present prior to placing the pipe in service. The 1980s and 1990s saw development of in-line inspection tools (smart pigs) that allow operators to evaluate pipelines without having to stop flow and take the pipeline out of service, permitting sophisticated assessment of pipe in the ground to determine where repairs are needed. Pipeline operators' integrity management programs integrate the full range of information available about the history of a pipeline segment to tailor assessment and maintenance practices to mitigate risk.

Question 4. The rate of incidents for hazardous liquid pipelines, while declining, is significantly higher than that of gas distribution and transmission pipelines. To what do you attribute this?

Answer. The incident reporting criteria are different for hazardous liquid and natural gas pipelines, which results in the appearance that there are more hazardous liquid pipeline incidents. Hazardous liquid pipeline operators must report releases from pipelines (historically at a threshold of 50 barrels and more recently at threshold of 5 gallons) even when there is no additional safety impact (fire, explosion, fatality or injury) or damage exceeding \$50,000.

The net effect is that essentially all hazardous liquid pipeline releases are reported to OPS as accidents. This reporting requirement reflects the potential for environmental harm from such releases. In contrast, releases from natural gas operators are not reportable unless there is additional impact such as a fatality, injury or damage exceeding \$50,000. In fact the vast majority of natural gas releases are not reported as accidents to OPS. Such releases are reported on a yearly basis through a natural gas annual report provided by each natural gas operator; such releases (without fatalities, injuries or substantial property damage) number in the thousands each year. The impacts from these, mostly small, releases are minimal. Because of the potential environmental impact of any hazardous liquid pipeline release, liquid pipeline releases are reportable even when there is no other safety impact, such as a fire, explosion, injury, fatality or substantial property damage. Please note that the testimony of the General Accounting Office, including the chart in the GAO testimony, does not accurately describe or compare the safety performance and accident rates of hazardous liquid and natural gas pipelines. We will be communicating with GAO about this issue and will provide the Committee with a copy of our letter.

Question 5. Why is it that the construction of new gas pipelines is regulated by the Federal Government (through PERC), but the construction of new oil pipelines is not?

Answer. Historically, government granted natural gas pipeline companies exclusive franchise territories, but oil pipeline operators have always served an unregulated end-use market. The Natural Gas Act (NGA) established a certificate of public convenience and necessity for natural gas pipeline construction that is granted to an approved natural gas pipeline operator by the Federal Energy Regulatory Commission. Such a certificate currently governs the construction of all new interstate natural gas pipelines. On the other hand, oil pipeline construction is not subject to prior Federal authorization, and no federal certificate authority is available to oil pipelines. The NGA certificate is issued to jurisdictional natural gas pipelines and provides that if FERC determines it in the public interest, it may order a natural gas pipeline company to extend or improve its facilities; in turn, abandonment of all or any part of its facilities by a natural gas pipeline company cannot be accomplished without the permission and approval of the Commission. In return for this obligation to serve, natural gas pipeline companies are granted a federal right of eminent domain through the certificate process. While the NGA was significantly amended (1942, 1958 and 1978), these aspects of the regulatory framework have not changed.

Federal pipeline construction certification has not been extended to oil pipeline companies, due in part to critical differences in regulatory history, marketplace and product characteristics and service functions between the two industries. For example, the Interstate Commerce Act, which provides the Federal authority for economic regulation of oil pipelines, is designed to encourage the growth of competing transportation modes and to allow commercial practices to govern most construction decisions. Federal eminent domain is not available to oil pipeline companies under the ICA. The ICA regulates oil pipelines as non-discriminatory common carriers. As common carriers, oil pipelines may benefit from a state's eminent domain law, depending on the statutes and precedents of that state. If an oil pipeline company seeks government assistance in constructing a pipeline, it applies to the state in

which the construction would occur, not the Federal Government, for authority to acquire the necessary right-of way.

Question 6. With demand for petroleum expected to increase 1.6 percent annually through 2025, according to the Department of Energy's Energy Information Administration, do you foresee a need for Federal help to get new pipelines permitted?

Answer. We do not seek Federal help in permitting new oil pipelines. The adequacy of oil pipeline capacity will become an issue in the future if rate treatment, now the province of the Federal Energy Regulatory Commission's implementation of the Interstate Commerce Act, fails to allow oil pipeline operators to attract the capital needed for expansion. With adequate ability to attract capital, oil pipeline operators have, with some important recent exceptions, been able to add capacity as needed. The industry has not found it appropriate to seek Federal intervention to ensure that permits for rights of way are provided in a timely fashion.

Question 7. The Interstate Natural Gas Association of America (INGAA) recommends that the natural gas industry be granted antitrust immunity to exchange information about pipeline testing to ensure that local gas supplies are not jeopardized by integrity management inspections. Has this been a problem for operators of hazardous liquid pipelines?

Answer. This has not been a problem for oil pipelines. Crude oil and petroleum product can reach most markets by many different modes and from many sources. Petroleum markets in general are highly competitive, and considerable flexibility is available to address supply issues. While pipelines are the safest and most efficient way to move these products, if pipeline transportation is not available, or if a particular pipeline is out of service, even in the short-term, alternative transportation or alternative supply is usually readily available, albeit sometimes at a higher cost. Unlike natural gas pipelines, hazardous liquid pipelines do not need to coordinate service among providers to avoid a market disruption.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN BREAUX TO
BARRY PEARL

Question 1. You mention in your testimony that while the extent of product shortages and market impacts caused by pipeline pressure reductions are largely unknown, that it is a very real potential problem. Do you have an estimate, or a sense, of how pipeline pressure reductions may be impacting gasoline pricing? Of the pipelines operating at reduced pressures, how many of these are because of permitting issues?

Answer. As you know, many factors affect gasoline prices, and it is very difficult to isolate the impact of any one of these factors. Experience tells us that a sudden loss in pipeline capacity has the potential to cause gasoline prices to spike, but the market generally reacts very quickly to increase supply. In any case, pipeline pressure reductions, which effectively reduce capacity, can't be helpful to the price situation faced by consumers. That is why we suggest that it would be prudent for government to expedite, to the extent possible, pipeline repair permitting, so pressure reductions are held to the absolute minimum necessary.

As you know, we filed with our testimony a number of case studies of the actual experience of liquid pipeline operators with permitting issues. However, we are not aware of any comprehensive industry-wide data to answer your question about the interaction of permit delays and pressure reductions. My own guess is that a significant portion, but by no means all, of the pipelines operating under reduced pressure do so out of an abundance of caution. A significant portion also operate at reduced pressure because operators have not gotten permits in a timely fashion. Our case studies indicate this. Some operators reduce pressure upon discovery of a time sensitive condition even though this is not a required action. Others reduce pressure only after the time deadline has passed and the reduction is required by OPS regulations. In these latter cases engineering analysis establishes that the original operating line pressure is below what the line can handle and the extra safety margin in place can absorb the risk presented by the condition.

Question 2. You point out that permitting for time sensitive pipeline repairs is a significant issue. How many time sensitive interstate liquid transmission pipeline repairs have been held up, past their required completion date, due to permitting problems?

Answer. As indicated above, we do not believe a database exists to permit answering this question in a quantitative way. Our case studies indicate that, as you put it, "sensitive interstate liquid transmission pipeline repairs have been held up, past their required completion date, due to permitting problems", but we do not know

the number or the percentage of completed repairs that experience this problem. We do know that delayed permitting is a problem, and one that would seem to be preventable.

Because of the risk posed by the anti-trust statutes, trade associations (or our members) must be careful not to provide data to one another or to the public that impacts competitive relationships or prices. Assembling information about what markets are likely to have tight supply because of pressure reductions could be considered problematic behavior on our part by some of our regulators or customers.

Question 3. Can you elaborate further on AOPL's idea for using Best Management Practices (BMP's) to expedite repairs to pipelines? Under your proposal, operators are assumed to be in compliance with permitting requirements if they employ BMP's in making repairs. Who would ensure that operators are following the BMP's in the field and that the work was completed without adversely impacting the environment?

Answer. We intend to identify or develop best management practices (BMPs) or activities that are acceptable to the relevant regulatory agencies, with the intent that operators could undertake these activities without prior agency approval, similar to the way in which activities are pre-approved under the Corps of Engineers' Nationwide Permit process. Any agency with oversight responsibility would always be free to review the performance of an operator to ensure that BMPs or activities are being properly carried out in practice. An operator who does not perform as required under pre-approved BMPs or activities would be subject to fines or enforcement. What we are recommending is a presumption of compliance so that the operator can promptly take the actions needed to complete the repair. We are not seeking permission to adversely affect the environment without sanctions.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN MCCAIN TO
EARL FISCHER

Question 1. According to statistics published by the Office of Pipeline Safety, gas distribution pipelines have experienced over 4 times the number of fatalities and more than 3.5 times the number of injuries that hazardous liquid and natural gas transmission pipelines combined. Shouldn't distribution pipelines, as suggested by Mr. Mead, be required to implement some form of integrity management program even if lines can't be pigged?

Answer. *Gas distribution systems have significantly fewer deaths and fatalities per mile than do the gas and liquid transmission lines put together.*

The safety record of natural gas distribution pipelines is truly extraordinarily positive. Unfortunately, the statistical data contained in the DOT Inspector General's report did not fairly or accurately represent this fact because of the way in which it was presented. In order to fully understand the safety record of the natural gas distribution sector, it is necessary to have a clear picture of the holistic nature of the natural gas system.

Over the last 10 years, the amount of natural gas traveling through natural gas distribution pipelines has increased by almost 6 percent, and 380,000 miles of pipeline have been added to the system. Based on 2003 data, there are now almost 1.9 million miles of natural gas distribution pipeline today serving over 60 million homes and businesses in the United States.* In contrast, there are only about 300,000 miles of gas transmission pipe and 160,000 miles of liquid transmission pipe. In order to compare statistics from one sector to another, the accident data must be put on a common basis. For example, calculations of vehicular transportation accidents use vehicle-miles or passenger-miles traveled to make valid comparisons. For gas pipelines, this should be done by using total miles of installed pipeline for a given category such as transmission or distribution.

When measured in this way, it is clear that gas distribution systems have significantly fewer deaths and fatalities per mile than do the gas and liquid transmission lines put together. (See table in Attachment 1.)

Nearly 50 percent of all incidents on natural gas distribution pipelines are caused by an excavator hitting a pipeline (third-party damage), often because the excavator failed to call ahead to have the location of the line marked. Preventing third-party damage is the single greatest safety goal of the natural gas distribution industry. For a single cause to be the source of almost 50 percent of all incidents is simply unacceptable. As we have done numerous times in the past, and continue to do so, we strongly urge Congress to focus attention on excavation damage prevention. A generation ago, gas, water and sewer lines were the primary underground facilities

* Based on DOT Office of Pipeline Safety website data extrapolated for 2003.

in our nation's communities. Today, with the addition of telecommunications, electric and other facilities located underground, our gas distribution pipelines are more at risk than before. As shown by the chart in Attachment 2, annual distribution incident statistics show a clear and distinct correlation between the level of construction activity and the number of incidents. If excavation damage (also called "third party damage") incidents are removed from the picture, a different trend appears, as shown by the green line with the short dashes in the chart. This more closely reflects the efforts of gas distribution operators in ensuring the safety of their systems.

Integrity programs like the one for natural gas transmission pipelines are not necessarily the best approach to preventing events such as excavation damage. Such events can be due to a number of causes, many of which cannot be mitigated by the actions of the gas operator alone no matter how diligent, resourceful, or technically well equipped.

We urge Congress to continue to enforce tough laws that focus on preventing and reducing excavation damage incidents, such as the one-call provision that was enacted in 1998 as part of TEA-21 and the excavation damage measures contained in the Pipeline Safety Improvement Act of 2002.

As discussed during the question and answer phase of the hearing, the inability of natural gas distribution lines to accommodate internal instrumented inspection devices called "smart pigs" was not why Congress excluded natural gas distribution pipelines from the integrity inspection requirement of the Pipeline Safety Act of 2002. But rather, *Congress acknowledged that there are already a variety of integrity management requirements for distribution systems.* Distribution systems were exempted from the rigorous gas integrity legislation of 2002 because these lines are located in high-density population areas and as such, already feature integrity safeguards that are incorporated in the current Code of Federal Regulation. Examples of these safeguards include extra-thick pipe walls, lower operating pressure and stress levels in the pipe, and a requirement that natural gas be odorized so people readily detect even small leaks by smelling the gas.

Maps of all pipelines are already available from the operator upon request by the jurisdictional state authority. Unlike interstate pipelines, most states regulate the utilities serving customers in the state. Thus, each state is in the best position to determine what makes sense as to maps and other utility records to be kept, as well as what is most effective in the oversight of distribution system integrity. A centralized database for distribution system maps kept by Federal Office of Pipeline Safety would do little to improve state oversight of an operator's system.

In addition, the current pipeline safety code contains 12 distinct requirements dictating the inspection of distribution pipeline facilities. The inspection frequencies depend on the location of the pipelines in relation to population and business activities.

Under individual authorizations by the state, most companies have been addressing the integrity of distribution systems on a risk-based prioritization schedule. This includes leak management programs and repair-replace decisions and processes that allow the operator to ensure distribution pipelines remain safe and reliable, while using ratepayer funds in the most efficient manner. This has been taking place for at least two decades and is expected to improve as technology and materials developments allow more sophisticated decision-making processes as well as longer life, stronger materials. In addition, some states chose to impose more stringent requirements than the Federal code, thus addressing specific concerns or conditions in their territory. The role of state commissions in setting pipeline safety requirements and verifying an enforcing compliance of distribution operators cannot be overemphasized.

Moreover, the gas utility members of the American Gas Association and the American Public Gas Association are conducting a study through the American Gas Foundation of enhancements to distribution system infrastructure integrity. Safety representatives from members of the National Association of Pipeline Safety Representatives and the National Association of Regulatory Utility Commissioners are also providing input to this study, to be completed by the end of 2004. In the meantime, critical experience is being accumulated with implementation of the transmission integrity rule.

To meet our Nation's present and future energy needs, any policy related to the assessment of almost 1.9 million miles of distribution piping must take into account the potential impact on safe, reliable and affordable delivery of natural gas, as well as minimize disruption to consumers, the public and the environment.

Question 2. What is the status of research efforts to develop smart pigs for smaller-diameter pipelines?

Answer. Several manufacturers and research organizations are working to develop new and improved internal inspection devices, also known as “smart pigs”.

A smart pig is a cylinder-shaped device outfitted with sensors and data acquisition electronics. It fits snugly inside a given diameter pipe. The pig is inserted into the pipe through a special fitting and the pipe upstream of the direction of the pig’s travel is pressurized with gas in order to propel it through the pipe at a steady speed. At the end of its pipe run, it must be retrieved through another special fitting. As the pig moves through the pipe, it imposes a magnetic field on the metal of the pipe and reads any localized distortions in the magnetic field that are typically caused by gouges, cracks, or metal loss in the pipe’s diameter. However, one pig does not necessarily read all of the possible defects. For example, a pig that uses ultrasound instead of magnetization has to be used to look for cracks aligned with the length of the pipe. This requires a liquid medium inside the pipe, thus making the pig unsuitable for gas pipe. To look for dents in the pipe, a “caliper” pig has to be used that measures slight changes in diameter of the pipe.

However, as the Inspector General testified, “smart pigs are not a silver bullet that can identify all pipeline integrity threats”. Even if smaller devices are developed, *the majority of the distribution system infrastructure will not be amenable to internal inspection using such devices, as distribution pipelines are vastly different from transmission lines.* Distribution pipeline systems are built in a network configuration; distribution pipes have numerous (many more than transmission) turns, valves, joints, branches and connections intersecting over very short distances that present obstacles to internal inspection devices. Normally, there is also insufficient pressure in the pipeline to drive the device through a line that has been rated for the low pressures typical of distribution systems. There must be sufficient space to insert and to remove the instrument from the pipe to be inspected; space is usually at a premium in urban streets and roadways where most of the distribution pipes are located.

The effectiveness of the smart pigging method is further reduced in view of the fact that 40 to 50 percent of the distribution piping in the U.S. today is made from plastic. Less than 5 percent of the distribution incidents are due to corrosion in metal pipe. As described above, smart pigs are designed to detect defects through magnetization. Plastic does not magnetize. Since plastic pipe typically does not dent on impact, caliper pigs are also useless.

In view of the above, other research and development initiatives are being implemented to ensure improved methods and equipment for distribution pipeline inspection. Examples of such are improved pipe locating tools that can pinpoint the depth of pipe, non-intrusive inspection methods and tools, and acoustic leak detection equipment.

Question 3. The Energy Information Administration (EIA) projects that demand for natural gas will rise an average of 1.4 percent annually from 2002 through 2025. What impact will this growth have on distribution pipelines?

Answer. Natural gas utility companies will continue improving the safety and reliability of their systems as demand for natural gas continues to grow. For example, utilities will implement methodical updates to systems, in some cases replacing thousands of miles of aging steel and cast iron pipe while installing new distribution pipe (most of which is durable plastic pipe) to meet the growing energy needs of homes, schools, businesses and other customers.

One of the biggest challenges that gas utilities will face in this endeavor is financial—not operational. Massive amounts of capital will be required to support utility expansion of natural gas distribution lines, as noted in the next response.

Question 4. Has the industry estimated how much additional pipeline capacity will be needed to accommodate the growth in demand?

Answer. Yes. Nearly \$70 billion (or a stunning \$5.3 billion per year) will be required for natural gas distribution facilities by 2025 (twice the rate for interstate pipelines and storage, which will cost \$35 billion), according to the September 2003 National Petroleum Council report, *Balancing Natural Gas Policy, Volume II*. Successful development of this distribution infrastructure will depend on key factors such as obtaining inter-agency coordination and regulatory certainty in all permitting processes, maintaining the historical levels of reliability and flexibility of natural gas services as gas demand grows and load patterns change, and developing mechanisms to foster research and development, the NPC said.

When it comes to gas distribution systems, the Federal environmental streamlining process is just the tip of the iceberg. Distribution operators must also contend with permits at the state and local levels, such as for state highways, railroad cross-

ings, local pavement breakup, street barricading, traffic control, and depending on location, with local environmental permits, as well as pavement breakup prohibitions and pavement restoration fees. The above-named National Petroleum Council report also states (and we agree) that obtaining permits and construction of new or replacement facilities is becoming more difficult and more expensive as a consequence of various growth management, building code and environmental policies. This area cannot be ignored when dealing with policies on distribution system integrity.

Hundreds of operators of gas transmission systems will soon be required to inspect their pipelines on a preset schedule. Many such pipelines will have to be shut down for inspections and the associated repairs. If gas outages occur, gas prices and reliability of delivery will come under intense pressure. Now, imagine the effects of a similar approach to distribution system integrity with over 6 times the mileage. This presents a potential for disrupting the everyday lives of gas customers and the public, if the approach to distribution integrity is not well thought out and adaptable to local circumstances and conditions. Obviously, even the Inspector General agrees that the approach to transmission integrity cannot be directly translated to distribution. If reliability of gas delivery is to be maintained, other approaches must be explored for distribution integrity. That is why the American Gas Foundation distribution study is so important.

Mechanisms to foster research and development when implemented could, for example, help speed development of technology enhancements that more effectively address excavation damage detection and prevention, and to better pinpoint and prevent gas leaks from escalating into a bigger hazard. As previously mentioned, advances in materials and equipment may further help enhance safety while maintaining operating efficiency.

The American Gas Association's three top priorities for research and development related to gas distribution are (1) improved gas system security; (2) enhanced reliability and integrity; and (3) improved efficiency for energy delivery. We fully concur with the Inspector General that the research projects the Office of Pipeline Safety is co-sponsoring with industry are key to safety improvements in the gas delivery infrastructure and must continue.

Attachments

Attachment 1
Mileage-Based Death and Injury
Statistics Comparisons

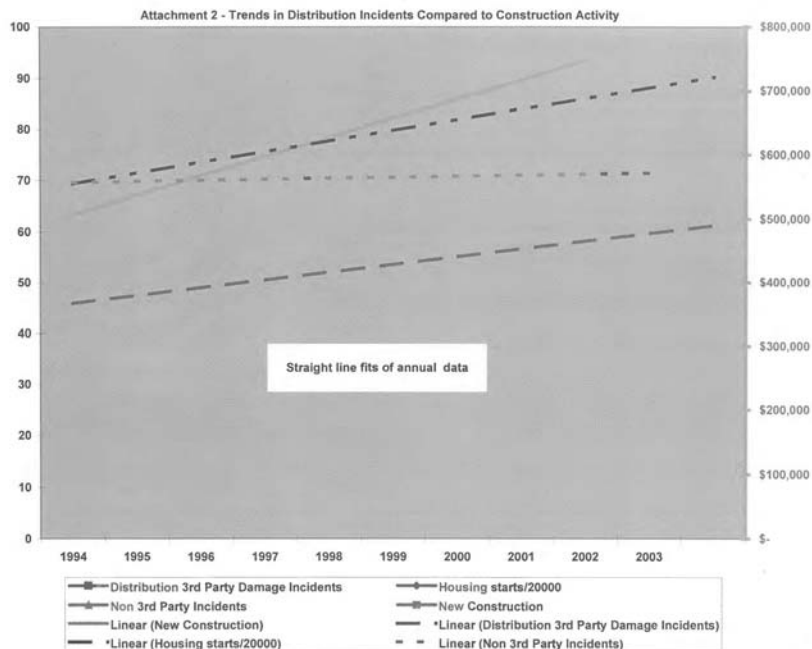
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6/29/2004

Year	Distrib. Injuries	Distrib. Deaths	Gas Trans. Injuries	Gas Trans. Deaths	Liq Injur	liq deaths	Gas Distr. Miles**	Gas Trans. Mileage	Liquids Mileage	Gas Distrib. per 100,000 miles	Liq + Transmiss. per 100,000 miles	Gas Distrib. per 100,000 miles	Liq + Transmiss. per 100,000 miles
1986	104	29	20	6	32	4	1,252,956	289,958	153,404	2.3	2.3	8.3	11.7
1987	115	11	15	0	20	3	1,314,695	291,857	152,859	0.8	0.7	8.7	7.9
1988	114	23	11	2	19	2	1,371,620	288,160	152,510	1.7	0.9	8.3	6.8
1989	91	20	28	22	38	3	1,382,687	287,926	152,376	1.4	5.7	6.6	15.0
1990	52	6	17	0	7	3	1,512,727	291,990	148,950	0.4	0.7	3.4	5.4
1991	77	14	12	0	9	0	1,480,221	293,862	150,341	0.9	0.0	5.2	4.7
1992	65	7	15	3	38	5	1,486,089	291,468	152,511	0.5	1.8	4.4	11.9
1993	84	16	17	1	10	0	1,542,667	293,263	165,781	1.0	0.2	5.4	5.9
1994	91	21	22	0	7	1	1,687,830	301,545	155,208	1.2	0.2	5.4	6.3
1995	43	16	10	2	11	3	1,673,651	296,947	153,549	1.0	1.1	2.6	4.7
1996	109	47	5	1	13	5	1,644,297	292,186	154,843	2.9	1.3	6.6	4.0
1997	67	9	5	1	5	0	1,643,720	294,370	155,038	0.5	0.2	4.1	2.2
1998	64	18	11	1	6	2	1,706,930	302,706	163,567	1.1	0.6	3.7	3.6
1999	80	16	8	2	20	4	1,733,548	296,100	156,876	0.9	1.3	4.6	6.2
2000	59	22	18	15	4	1	1,725,815	298,198	154,733	1.3	3.5	3.4	4.9
2001	46	5	5	2	10	0	1,821,250	290,468	158,489	0.3	0.4	2.5	3.3
2002	45	9	5	1	0	1	1,854,453	307,524	161,189	0.5	0.4	2.4	1.1
2003*	58	11	8	1	5	0	1,892,047	307,524	160,868	0.6	0.2	0.5	2.8
Total	1364	300	232	60	254	37				19	22	86	109
Total Deaths + Injuries										106	130		

* Extrapolated

** Distr. Miles = Miles of Mains + Number of Services x 65 feet/service



RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN BREAUX TO
EARL FISCHER

Question 1. Can you describe the ongoing AGA efforts with OPS to look at options for an integrity management program for distribution lines? How are the issues different than for those facing transmission lines?

Answer. AGA, OPS, NARUC and other stakeholders are constantly working in a collaborative effort to ensure the safe and reliable delivery of natural gas. Together, we are seeking to make improvements that will enhance our systems. Indeed, while the integrity management requirements contained in the Pipeline Safety Act of 2002 appropriately focused on transmission lines within high consequence areas, AGA and its members nevertheless immediately went to work to assess the effectiveness of the current distribution regulations to maintain system integrity. This assessment will be completed by the end of the year and should serve as the foundation for discussions on how to further improve distribution safety during the next reauthorization process.

Distribution pipelines are vastly different from transmission pipelines, and thus have a separate regulatory regime governing their safety. This regulatory regime is extensive, requiring no less than 24 separate types of safety activities to be conducted on each distribution system, and has contributed to superior distribution pipeline safety.

When compared with gas transmission and liquids incidents over the past 10 years, distribution systems show more incidents because there is 4 times more distribution pipe in service than transmission and liquids combined. Per 100,000 miles of pipe, however, the distribution incident count is less than transmission and liquids combined (46 versus 49 total over 10 years, respectively). Comparing statistics between different categories of pipelines is only meaningful if done in this way because the miles of pipeline and the yearly growth in mileage must be taken into account.

Interstate transmission systems are generally made up of long runs of generally straight pipelines occasionally crossing high-density population areas in our cities and towns. They feature large diameter pipe, and are operated at high volumes and high pressures. Distribution systems, in contrast, are constructed in configurations that look like a network or web, and run under practically every street in neighbor-

hoods and business districts where there are gas consumers. These systems use smaller diameter pipe. By being located in high-density population areas to begin with, they are required to operate at much lower volumes and pressures, often feature thicker-walled pipe and always carry odorized gas that can be readily smelled even if a small leak occurs.

Transmission pipelines are almost exclusively made of steel. To maximize the volume of natural gas transported, interstate pipelines operate at stress levels from 20 percent to 80 percent of the maximum stress allowed for the type of steel material being used. Distribution pipelines use steel, plastic, cast iron or other materials of construction. When steel is used, distribution regulations require that stress levels be below 20 percent of the maximum allowed stress. Currently plastic pipe makes up 52 percent of the Nation's distribution system, steel comes in second at 43 percent, with the other materials making up the remaining 5 percent. Use of these materials is not uniform throughout the country, with newer areas for example, using predominantly plastic pipe.

State pipeline safety authorities have *primary* responsibility to regulate natural gas utilities and intrastate pipeline companies, as part of an agreement with the Federal government. State governments then must adopt as their minimum standards the Federal safety standards promulgated by the DOT. In exchange, DOT reimburses the state for up to 50 percent of its pipeline safety enforcement costs. Clearly, Congress's actions make a strong impact on state regulations and our companies.

In addition, some states choose to impose more stringent requirements than the Federal code, thus addressing specific concerns or conditions in their territory. The role of state commissions in setting pipeline safety requirements and verifying an enforcing compliance of distribution operators cannot be overemphasized.

Finally, under individual authorizations by the state, many distribution operators have risk-based integrity management programs already in place as part of a "repair or replace" decision-making process. This allows these companies to actively manage system safety by prioritizing inspections, maintenance, repair or replacement of the various portions of their distribution system. In fact, 49 CFR Section 192.613 Continuing Surveillance, requires that operators consider a whole host of pipeline data to determine whether a segment should be reconditioned, phased out or undergo a reduction in operating pressure.

Section 192.613 states the following:

"(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions. (b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with § 192.619(a) and (b)."

In short, to ensure reliable gas delivery, various approaches must be explored for distribution integrity and these may not end up following the transmission integrity model.

To address such approaches, gas utility members of the American Gas Association and the American Public Gas Association are conducting a study through the American Gas Foundation of the distribution system infrastructure integrity in an effort to identify needed enhancements. State safety regulators of the National Association of Pipeline Safety Representatives and the National Association of Regulatory Utility Commissioners are also providing input to this study, to be completed by the first quarter of 2005. While OPS does not have direct jurisdiction over most distribution systems, the agency is also providing input.

State regulators are using their experience to help identify distribution pipeline issues that have contributed to incidents, impact safety and could be reasonably implemented without unnecessary increases to the consumers' gas utility bill. The American Gas Foundation study will present findings that may help the above government-industry group formulate recommendations for enhancing the pipeline infrastructure, ensuring pipeline integrity, and tracking progress in improving safety.

Question 2. What options exist to institute integrity management for distribution lines, given the limitations on using smart pigs?

Answer. The options are currently being studied and expected to be quite diverse, as distribution systems are designed and built to optimally fit the conditions found in the respective utility's specific service territory.

As briefly exemplified in our reply to the first question, the gas transmission, liquids, and distribution pipeline industries deal with differing challenges, operating

conditions and consequences of incidents. Federal regulations recognize the differences between these three types of pipelines, and different sets of rules have been created for each. 49 CFR Part 192 sets out the regulations for natural gas transmission and distribution and the rules discriminate between the two, while 49 CFR Part 195 sets out the regulations for liquid transmission lines. It should be noted also that many distribution companies also own and operate transmission pipeline segments within their systems.

The integrity management options for interstate transmission and liquid pipelines focused on methods to detect and repair points on the pipeline where anomalies are detected, to prevent stress at that point from causing a pipeline rupture. OPS issued the integrity management program or “IMP” rule for natural gas transmission lines on December 12, 2003. The rule requires natural gas transmission pipeline operators to conduct periodic inspections in “high consequence areas”, which for natural gas pipelines are generally high-density population areas.

For gas distribution systems, the repair of gas leaks is allowed to follow a gas industry standard¹ whereby the repair is prioritized according to how critical the leak is. The typically low pressures and volumes of gas in the pipe, in combination with the ever-present odor, provide an opportunity to react before the leak hazard escalates. Thus, for distribution systems and its widely different varieties, it is obvious that options for integrity management will have to be tailored to the conditions prevalent in the given service area.

Hundreds of operators of gas transmission systems will soon be required to inspect their pipelines on a preset schedule. Many such pipelines would have to be shut down for inspections and the associated repairs. If gas outages occur, gas prices and reliability of delivery will come under intense pressure. Now, imagine the effects on a distribution system with *over 6 times the mileage of gas transmission, if utilities are required to follow the integrity management script of a transmission IMP model*. This presents an unwarranted potential for greatly disrupting the everyday lives of gas customers and the public on a continuing basis, if the approach to distribution integrity is not well thought out and made adaptable to local circumstances and conditions.

Obviously, the approach to transmission integrity cannot be directly translated to distribution. Instead, it is critical that any process incorporate the regulations that are currently in-place, provide an approach that focuses only on where there may be areas of concern, and fully recognize the risk-based compliance approaches being utilized by state regulators with their operators.

Question 3. Can you discuss the excess flow valve installation? You suggest that there are problems with the cost benefits analysis used by OPS relating to the nationwide installation of these valves?

Answer. The existing regulation allows a natural gas utility to either notify customers of the availability and function of excess flow valves (EFVs), or to voluntarily install the valves on services which meet certain operating conditions. Therefore, under current rules, any customer that wants an EFV can get one when their service line is installed or replaced. As you may know, the valve is primarily intended to shut off gas flow when a service line rupture occurs resulting in escaping gas at a rate that is within 50 percent more than the normal flow to the customer's premises. This means that not all leaks in the gas line will trip the valve to shut-off.

There were three major concerns about the draft cost benefit analysis conducted by OPS in its study published on March 7, 2003:

1. OPS made several inaccurate or shaky assumptions in regard to incident prevention, EFV activation rate, and the ratio of reportable to non-reportable incidents. Specifically, OPS did not use its own incident data to estimate how many service line incidents could be prevented by EFVs. As a result the OPS draft analysis estimated that EFVs could prevent 10 times more service line incidents than have actually occurred over the past 20 years. In addition, OPS overestimated the number of minor, non-reportable incidents that EFVs might prevent². The assumptions led to overstating of the benefits and understating of the costs associated with mandatory EFV installation. These assumptions were necessary because there is a lack of EFV field operating performance data on the devices.
2. The estimate for the costs attributed to false activations for EFVs is not backed by adequate data. The study estimates the cost to rectify a false activation at

¹ See Gas Piping Technology Committee (GPTC) Guide. This is the work of an accredited consensus standards committee with members from industry, government and academia.

² Incidents are reportable to DOT if they result in death, injury requiring hospitalization and/or greater than \$50,000 property loss.

\$552. In some cases, this figure does not even cover the cost of pavement restoration and permit fees since the EFV is quite often located in the public road right-of-way.

3. The study lumped commercial services together with residential services in its analyses. The functionality and use of EFVs for residential services is far different than that for commercial services. This is largely due to the higher variation in gas consumption for commercial customers. An excess flow valve typically comes in different sizes to match different ranges of flows. A valve that is improperly matched to the flow can fail to close when needed or close unnecessarily.

On July 20, 2004, OPS placed a revised EFV cost/benefit analysis in the docket that corrects these discrepancies and now concludes that the *cost of EFV installation exceeds potential benefits by nearly 4 to 1*.

The natural gas utilities continue to support utility choice of either voluntary installation or customer notification for excess flow valves as provided in the current pipeline safety regulations. All of our members, even those that voluntarily install the valves believe mandated installation of the devices would take away the utilities' flexibility to install the valves when and where they do the most good.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN MCCAIN TO
ROBERT T. HOWARD

Question 1. You have suggested that there may be a need to provide an antitrust exemption to permit companies to coordinate their inspection and repair activities to avoid disruption of energy supply. Wouldn't such an exemption allow companies to be privy to information that could be used against their competitors?

Answer. Interstate natural gas pipelines are required by the Federal Energy Regulatory Commission (FERC) to be open-access, and place information about capacity availability, scheduling, planned and actual service outages or disruptions in service capacity, etc. on their respective websites on a real-time basis. See 18 C.P.R. 284.13(c)(5)(d). The maximum rate a pipeline can charge for service is set by the PERC under Section 4 of the Natural Gas Act, and set out in the pipeline's public tariff. Pipelines are required to post pricing information related to any discounts offered to shippers on their Internet websites (18 C.P.R. 358.5(d)), and make discounts equally available to all similarly situated shippers. This ensures that pipelines are transparent, and that all customers and competitors have equal access to important information about pipeline capacity availability and pricing. Our industry is therefore accustomed to providing operational and pricing data to the public in an open forum setting.

When a pipeline has *planned* maintenance or pigging that will disrupt service, the pipeline notifies its customers on the location of the maintenance or pigging, the anticipated duration of the maintenance or service disruption, and what services would be effected by the pipeline's activities. Pipelines want to give their customers as much advance notice as practical under the circumstances. This gives customers some time to adjust their natural gas supply needs and find alternative transportation if necessary. With *unplanned* service disruptions, the pipelines also post the relevant information but, because they must react immediately to circumstances beyond their control, they do not have the ability to provide their customers with as much advance notice.

The interstate pipeline transportation industry is a competitive market. Often, more than one pipeline serves a major market area. Pipelines could best serve their customers by coordinating their maintenance schedules to ensure that multiple pipelines serving a single market do not all choose to engage in maintenance at the same time. However, pipelines are concerned that if they coordinate with other pipelines on when to conduct safety inspections and related repairs, the pipelines could face antitrust lawsuits from customers and consumers that allege that the pipelines improperly have acted in concert to create shortages and increase either gas commodity or transportation prices.

If a pipeline must repair segments of pipeline as a result of inspecting its system, the pipeline may have to either reduce transportation throughput or perhaps take transportation lines out of service during the repair process. Customers may not be able to transport as much gas supply through these sections of the pipeline. The value of gas in certain areas may increase if the customer can get its gas to market; the value of gas that cannot leave the supply basin will fall.

INGAA is concerned that should pipelines coordinate repairs with other pipelines to minimize the likelihood that its disruptions do not occur at the same time as a

competitor or an interconnected pipeline, parties that may have been economically harmed by increased gas commodity or transportation prices could allege, albeit without merit, that the pipelines worked together to knowingly create these shortages and cause increased prices. While INGAA does not believe that these allegations would be supported in a court of law, it would still be time consuming and expensive to litigate each case. Accordingly, if the pipelines had explicit antitrust protection that permitted them to coordinate safety inspection and repair activities pursuant to the Pipeline Safety Improvement Act, pipelines would be able to work with other pipelines, including those that are part of the delivery chain from the production area to the market area, to ensure that as little service disruption occurs as possible.

Question 2. Shouldn't the Department of Energy and the Office of Pipeline Safety, which have access to the industry's inspection and repair schedules, be able to manage scheduling to avoid disruptions?

Answer. Natural gas pipelines are required under the new regulations to inform the Office of Pipeline Safety (OPS) as to the location of the High Consequence Areas (HCA) on their pipelines and as to whether a baseline inspection will be conducted in the first or last five years of the program. While there are performance reports required, there are no plans to notify OPS on the detailed scheduling of the baseline preparations, assessment and remediation. The complexity of scheduling these tasks in a centralized coordinated fashion is daunting at best. There are so many variables and competing priorities that successful centralized planning is a remote possibility. Not only are there many variables, but the rate of change of these variables is overwhelming. In planning maintenance, a pipeline needs to consider the particular demand curve of its customers, changes in weather, hydropower forecasts, nuclear plant outages in the pipeline's service area, and many other factors. For example, consider a pipeline that plans to perform maintenance during a month where the pipeline historically has seen low throughput due to mild temperatures. If a nuclear plant serving the same market must be taken down for repairs, or the weather changes dramatically, the pipeline must be ready to react and shift its maintenance schedule to ensure it can meet market needs. This need to react to market conditions makes a fixed central plan infeasible. It also highlights the need, as discussed in response to Question 1, for pipelines to be able to interact with each other on a real time basis without fear that their actions could trigger antitrust concerns.

Question 3. The Energy Information Administration (EIA) projects that demand for natural gas will rise an average of 1.4 percent annually from 2002 through 2025. What impact will this growth have on transmission pipelines?

Answer. This anticipated growth will translate into the need for additional pipeline capacity. Additional capacity will be needed in emerging production areas such as the Rocky Mountain region and Alaska, and in market areas such as the Northeast and Southwest where delivery capacity is becoming constrained.

Question 4. Has the industry estimated how much additional pipeline capacity will be needed to accommodate the growth in demand?

Answer. Yes. The INGAA Foundation will be releasing a report in July that outlines the natural gas pipeline and storage infrastructure expansions that will be required, out to 2020. In sum, if the U.S. market is to satisfy demand in an efficient manner by 2020, approximately \$61 billion (in constant 2003 dollars) in infrastructure investment must be made in both the U.S. and Canada. Approximately \$19 billion of investment will be needed for replacement of current pipe simply to maintain existing pipeline capacity. Nearly \$42 billion will be needed for new pipeline and storage projects. Of that, \$18 billion will be associated with the Alaska natural gas pipeline and a similar pipeline from the Canadian MacKenzie Delta.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. JOHN BREAUX TO
ROBERT T. HOWARD

Question 1. You point out that permitting for time-sensitive pipeline repairs is a significant issue. How many time-sensitive interstate natural gas transmission pipeline repairs have been delayed, past their required completion date, due to permitting problems, and what impact has this had on safety?

Answer. Natural gas pipelines have not yet been impacted by permitting for time sensitive-pipeline repairs. Based on the experience of hazardous liquid pipelines, we are concerned that this issue be addressed. First, let me differentiate between our segment of the industry, interstate natural gas transmission pipelines, and hazardous liquid pipelines.

The integrity regulation for hazardous liquid pipelines has been in effect for several years and the record of inspection and repair delays being discussed is primarily based on those experiences. The Association of Oil Pipe Lines has documented several cases and has reported the instances to the Office of Pipeline Safety. Based on the particular consequences of hazardous liquid pipeline incidents, the preponderance of the high consequence areas (HCA) where these repairs are occurring are at locations in environmentally sensitive areas which have more permitting requirements. As a comparison, the HCA areas on interstate natural gas pipelines are predominantly in high-density population areas that have less environmental issues due to previous human disturbances. Also, the design of the hazardous liquid regulations place a more rigorous timeline on repairing defects as compared to the natural gas integrity rule which used an improved technical basis to determine the repair response time.

The new integrity regulations for natural gas transmission pipelines just became effective on December 15, 2003, with individual integrity plans due in December of 2004; therefore, the amount of experience in our segment has not emerged. However, interstate natural gas pipelines have complied with the National Environment Policy Act (NEPA) for many years, since the Federal Energy Regulatory Commission (FERC) must approve the construction of any new interstate natural gas pipeline pursuant to the Natural Gas Act of 1938 (and therefore, a FERC construction certificate is a "major Federal action" under NEPA). While burdensome, this process does centralize the disparate permitting processes of various Federal agencies and we expect will be helpful if permitting for time-sensitive repairs becomes an issue on natural gas pipelines. In some respects NEPA provides an integrated review of environmental issues and provides programmatic approval of certain practices. However, *intrastate* natural gas pipelines and hazardous liquid pipelines do not employ this NEPA process. Only recently has the need for expedited inspection/repair activities brought this to the forefront for these pipeline sectors.

The amount of permits needed by the interstate natural gas pipeline sector due to integrity management activities remains difficult to predict at this stage. While it is true the U.S. has more natural gas transmission pipeline mileage than hazardous liquid pipeline mileage, hazardous liquid pipelines have a greater percentage of lines located in HCAs. This is because "environmentally sensitive areas" are included in the definition of HCAs for hazardous liquid pipelines, while HCAs for natural gas transmission lines are limited to areas near population. The natural gas sector will be seeking permits for activities such as the installation of smart pig launchers and receivers, and the replacement of pipeline segments/equipment that are not compatible with these inspection devices. And of course, we don't yet know how much repair activity will take place as a result of the integrity assessments.

We think it is important for Congress to remain aware of these permitting issues, and we support efforts to improve permitting processes for time-sensitive repairs in other pipeline segments as the integrity program moves forward. Congress created strict timeframes for baseline assessments when it enacted the Pipeline Safety Improvement Act and it is critical that Federal and state permitting agencies have the same concern about whether these requirements actually get completed within the prescribed time.

Question 2. OPS plays an important role in the regulation of liquefied natural gas (LNG) facilities. Given the growing usage of LNG and the many new LNG facilities being planned, do you think OPS has sufficient resources to focus the necessary attention on LNG facilities without compromising their ongoing pipeline safety efforts?

Answer. Yes, for the time being at least. OPS draws upon the expertise of a number of other organizations to fulfill its LNG regulatory responsibilities, including the Federal Energy Regulatory Commission (which must approve any new LNG terminal) and the National Fire Protection Association (NFPA). The NFPA, for example, develops (and periodically updates) fire-prevention standards (NFPA 59A) for the design, construction and operation of LNG facilities that have been subsequently adopted by OPS. FERC plays a major role in the approval of a design for a new terminal, and seeks input from the OPS as part of that process. The U.S. Coast Guard plays a significant role in the safety and security of both LNG terminals and the vessels delivering LNG to these terminals. So, while the OPS staff is relatively small, it can leverage the resources of these much larger organizations.

Question 3. You mention that the coordination of inspection and repair activities among various pipeline operators could help avoid market disruptions and price spikes, by ensuring that all of the pipelines serving a market are not off-line at one time due to repairs. INGAA has proposed authorizing an antitrust waiver for this

activity. Why couldn't OPS serve to coordinate this activity instead, since they already must be notified of the repairs?

Answer. Natural gas pipelines are required under the new regulations to inform the Office of Pipeline Safety (OPS) as to the location of the High Consequence Areas (HCA) on their pipelines and as to whether a baseline inspection will be conducted in the first or last five years of the program. While there are performance reports required, there are no plans to notify OPS on the detailed scheduling of the baseline preparations, assessment and remediation.

It's really not a question of notifying OPS of the repairs; the issue is coordination and sharing of outage schedules between pipelines so that the effort of one company's plans on upstream or downstream capacity can be understood. This sharing of capacity information may be viewed as anticompetitive, when the intended outcome instead is to avoid unnecessary outages. OPS does not currently perform this function and would require a significant expansion in staffing at OPS which is well beyond their current function. We believe that a waiver would be a much easier approach that would assure that sharing such information would not be deemed anticompetitive.

Question 4. What were INGAA's concerns with the initial proposed rulemaking of natural gas pipeline integrity management? How were these addressed in the final rule?

Answer. While there are a number of issues that concerned INGAA with the proposed rule, the central one dealt with the definition of a High Consequence Area (HCA). The proposed definition was imprecise and based on outdated modeling. Working with OPS last year, INGAA advocated a more precise definition, based upon "potential impact circles." Since natural gas is lighter than air, the release from a pipeline rupture goes straight up into the atmosphere (unlike hazardous liquid pipelines, where product can flow some distance away from the pipeline). These potential impact circles model the effects of a rupture and subsequent ignition, with the center of the circle being the rupture itself. Using mathematical formulas that take into consideration the maximum allowable operating pressure for the pipeline in question, the zone that would be affected by fire radiation can be accurately determined. Then an operator can survey the number of buildings within these circles to see if there are a sufficient number to classify a pipeline segment as being within an HCA. OPS decided to allow for the use of these potential impact circles in defining an operator's High Consequence Areas.

Question 5. In your testimony, you note that the law requires natural gas transmission pipeline operators to begin integrity assessments on their pipelines on June 17. Will all of your members be able to meet this deadline, without jeopardizing service to the public?

Answer. Our members are complying with the deadline to begin integrity assessments, and in fact a great deal of this work started months ago. The summer is generally a good time to perform maintenance activities, since there is less demand for natural gas during these months. The recent increase in gas-fired power generation has somewhat changed that dynamic, however, especially during abnormally hot days when the maximum amount of power is needed to meet demand.

Most of the work initiated to complete this deadline has been completed and was done without jeopardizing service. INGAA members will continue to do their utmost to prevent major service disruptions as a result of the integrity management activities. Some elements of the work, such as scheduling of inspection work and the extent to which repairs will be required, are difficult to predict right now. As we get further into the process, we hope to learn from experience and continue to minimize service impacts.

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