An Assessment of Low Pressure Crude Oil Pipelines and Crude Oil Gathering Lines in California

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Notice

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Chapter 1

Introduction

The McGrath Lake oil spill in Ventura County stimulated public concern regarding crude oil gathering pipeline safety. The December 22, 1993 incident occurred from a crude oil shipping line. This spill released an estimated 2,200 barrels (42 gallons = 1 barrel) of crude oil. The oil surfaced and flowed through a culvert, traveled through 150 feet of woodland and brush, to McGrath Creek, then flowed another 1,200 feet into McGrath Lake. The lake is part of a tidal wetland within a large coastal dune system.

One of the results of this incident was the passage of California Assembly Bill 3261 (O'Connell) as codified in Section 51015.05 of the California Government Code. This statute requires that the California State Fire Marshal (CSFM):

- establish and maintain a centralized database containing specific information and data (pipeline locations, ownership, age, inspection history, etc.) regarding certain crude oil pipelines,
- conduct a study of the fitness and safety of these crude oil pipelines, and
- investigate incentive options that would encourage pipeline replacement or improvements, including, but not limited to, a review of existing regulatory, permit, and environmental impact report requirements and other existing public policies that could act as barriers to the replacement or improvement of these pipelines.

The following pipelines have been included in the data base and study:

- pipelines for the transportation of crude oil that operate at gravity or at a stress level of 20% or less of the specified minimum yield strength of the pipe; and,
- pipelines for the transportation of petroleum (crude oil) in onshore gathering lines located in rural areas.

Pipelines meeting this criteria have been included in the study and database whether they were operating or not during the study period; even abandoned, idle, or otherwise out of service pipelines have been included in the study and database. The following pipelines were *excluded* from the data base and study:

- interstate and intrastate pipelines which are currently regulated by the California State Fire Marshal or the United States Department of Transportation;
- gathering lines located entirely within the boundary of a California Division of Oil, Gas, and Geothermal Resources (DOGGR) oil field boundary, or which cross a boundary where two DOGGR oil fields are contiguous and are contained entirely within multiple DOGGR oil fields;
- flow lines located entirely within the boundary of a DOGGR designated oil field boundary, or which cross a boundary where two DOGGR oil fields are contiguous and are contained entirely within multiple DOGGR oil fields;
- natural gas pipelines;
- refined petroleum product pipelines; and
- abandoned pipelines which have been physically removed.

This report, combined with the completed database, are intended to meet the law's requirements of the CSFM. This report analyzes California's crude oil gathering pipeline risks utilizing leak incident data from January 1993 through December 1995. The database includes a complete inventory of the pipelines meeting the study criteria, their ownership and location, inspection and maintenance practices, the incidents which occurred from these lines during the study period, and various other data.

The study was funded by the U. S. Department of Energy, Bartlesville Project Office (USDOE), through its Management and Operations contract with BDM/Oklahoma, Inc. Jerry Simmons served as BDM/Oklahoma's project manager. EDM Services, Inc. conducted this study as a subcontractor to BDM/Oklahoma. Brian L. Payne served as the overall project manager and authored this report, except for Chapter 5. Chapter 5 and the conclusions/recommendations sections in the report concerning Incentives/Barriers was authored by Deborah Pratt and Jerry R. Simmons of BDM/Oklahoma.

1.1 Regulatory Authority

The California State Fire Marshal (CSFM) exercises safety regulatory jurisdiction over interstate and intrastate pipelines used for the transportation of hazardous or highly volatile liquid substances within California. In 1983, the Pipeline Safety and Enforcement Program was specifically created to administer this effort.

In 1987, CSFM acquired the regulatory responsibility for interstate lines when an agreement was executed with the United States Department of Transportation (USDOT). In doing so, CSFM became an agent of the USDOT responsible for ensuring that California interstate pipeline operators meet federal pipeline safety standards. Specifically, interstate pipelines under this agreement are subject to the federal Pipeline Safety Act (49 USC Chapter 601) and federal pipeline regulations.

CSFM's responsibility for intrastate lines is covered in the Elder California Pipeline Safety Act of 1981 (Chapter 5.5, California Government Code). The agency's responsibilities are twofold:

- To enforce federal minimum pipeline safety standards over all regulated interstate hazardous liquid pipelines within California; and

- To enforce federal minimum pipeline safety standards as well as the Elder California Pipeline Safety Act of 1981 on regulated hazardous liquid intrastate pipelines.

The California Division of Oil, Gas, and Geothermal Resources (DOGGR) has regulatory authority over all oil, gas, and geothermal exploration and production operations in the State. As a part of this authority, DOGGR has responsibility for regulating flowlines, gathering lines, and other in-field pipelines used to transport crude oil, natural gas, and other fluids. DOGGR's pipeline jurisdiction ends at the administrative boundary of a field, which is usually the point where ownership of oil or gas is transferred to a pipeline company or oil shipper.

As a result, there are crude oil pipelines which are not regulated by any State agency. These pipelines include those which leave DOGGR oil fields and do not meet the pipeline definition of Section 51010.5 of the California Government Code. These pipelines are the subject of this study.

1.2 Relative Safety Perspective

Before we analyze the risks associated with California's hazardous liquid pipelines, it is important to put the relative safety of pipelines versus other modes of transportation into perspective. The United States Department of Transportation, Research and Special Programs Administration's 1995 National Transportation Statistics - Annual Report provides some useful statistics in this regard.

During 1993, there were 43,179 transportation-related fatalities in the United States. This data is presented in Table 1-1 by mode of transportation. It should be noted that of the fourteen 1993 pipeline fatalities all occurred on gas pipelines. There were no fatalities which resulted from incidents on hazardous liquid pipelines.

Table 1-1
Fatalities by Mode of Transportation
1993 National Transportation Statistics

Mode	Fatalities	% of Total
Pipeline	14	0.03%
Air	782	1.81%
Marine	904	2.09%
Rail	1,349	3.13%
Highway	40,115	92.94%
Total	43,164	

In an attempt to compare the relative safety of each transportation mode, we have estimated the fatality rate per billion ton-miles transported. This was done by first determining the number of 1993 fatalities associated with revenue freight. This was performed for each mode of transportation as follows:

- Pipelines - All fatalities were included.

- Rail - All fatalities, including those occurring at grade crossings with vehicular traffic were included.

- Marine - Recreational boating fatalities were excluded.

- Air - All general aviation, air taxi, and commuter fatalities were excluded. Since the remaining air carrier data does not differentiate between incidents associated with passenger traffic versus those associated with freight, the resulting number of revenue freight fatalities is unrealistically high.

- Highway - Only truck fatalities were included. Since truck accidents often result in fatalities to those in automobiles, the resulting *truck only* fatality figure is unrealistically low.

The fatality rate was then determined by dividing the number of fatalities by the number of ton-miles transported. The number of fatalities and resulting fatality rates are presented in Tables 1-2 and 1-3. Despite the inherent data errors, the resulting rates provide a very useful method for determining the relative magnitudes of risk to human life. These results are summarized below, using an arbitrarily assigned risk of 1 for pipelines.

Pipelines	1
Marine	5
Rail	51
Highway	429

In other words, rail transportation results in roughly 51 times more fatalities than pipelines for a given number of ton-miles transported. Order of magnitude comparisons between the other modes could be determined similarly.

A general understanding of these relative risks is essential for those considering regulatory changes which could increase the cost of hazardous liquid pipeline construction, operation, and/or maintenance. Any increases in the shipping costs associated with such changes would likely result in a portion of the throughput being diverted from pipelines to other transportation modes. Since these other modes generally expose the public to a higher risk than pipelines, any such diversion may actually decrease overall transportation safety. For example, if a costly regulation decreased pipeline accidents by say 10%, but diverted some volume to an alternate, less safe mode of transportation, the new result may be a decrease in overall transportation safety.

There are already signs of this occurring, especially in Southern California. The crude from many of the older production fields which was historically transported by pipeline, has been diverted to truck transportation which has the worst safety record.

Table 1-2
Estimated Fatalities Associated with Revenue Freight
1993 National Transportation Statistics

Mode	Fatalities	% of Total
Pipeline	14	0.13%
Air	n/a	n/a
Marine	104	0.98%
Rail	1,349	12.77%
Highway	9,097	86.11%
Total	10,564	

Table 1-3
Estimated Fatalities Per Billion Ton-Miles Transported
1993 National Transportation Statistics

Mode	Fatalities	% of Total
Pipeline	0.02	0.17%
Air	n/a	n/a
Marine	0.11	0.93%
Rail	1.23	10.42%
Highway	10.44	88.47%
Total	11.80	

Chapter 2
Methodology

The methodology used to complete this study and compile the database in compliance with Section 51010.05 of the California Government Code has been outlined in the following subsections.

2.1 Funding and Contracting

The California State Fire Marshal, sought United States Department of Energy (DOE) funding. Funding was granted through the DOE's management and operating contractor for the National Oil Program, BDM/Oklahoma.

BDM/Oklahoma solicited proposals to conduct this study and prepare and compile the database. The proposals were evaluated using three specific assessment criteria: technical approach, management, and cost/price. EDM Services was selected as offering the best overall value for this project and was awarded a contract. The resulting contract was executed on May 15, 1995.

2.2 Steering Committee

The California State Fire Marshal designated Nancy Wolfe, Division Chief, Pipeline Safety and Enforcement, to coordinate the required study and work with BDM/Oklahoma and EDM Services to achieve the objectives of the law. At an organizational meeting, it was decided that a statewide Pipeline Assessment Steering Committee was need to provide guidance and assist with the study. Industry associations and State and local regulatory agencies nominated individuals to participate on the committee. The Pipeline Assessment Steering Committee members are listed on Table 2-1.

The first Committee meeting was held in Long Beach, California on November 17, 1994. During the meeting, a project schedule was established, the study parameters were discussed and agreed upon, and the process that BDM Oklahoma would use to select a subcontractor were discussed.

A second Steering Committee meeting was held on June 15, 1995, with EDM Services staff to kick-off the project. At this meeting, the following issues were resolved:

- The Committee established a definition of the leaks which should be included in this study. The criteria for reporting leaks to the California Office of Emergency Services (OES) (one barrel or more, or any spill onto water, or any spill which could threaten ground water) was selected for use.

- The Committee established a interval for collecting leak data. The Committee felt that leak data would not be uniformly available before November 1992 when the OES reporting requirements went into effect. As a result, the Steering Committee endorsed a two-year study period [January 1993, through December 1994] for this study.

- The Committee decided that all inactive and idle pipelines should be included in the study. Only abandoned lines which had been physically removed would be excluded from the study since they no longer exist.

- The Committee developed a definition for the pipelines to be included in this study. This definition was presented earlier in Chapter 1 of this report.

Additional Steering Committee meetings were held on July 19, 1995 and November 13, 1995. During these sessions, the project status was reviewed. The meetings proved to be very helpful as the representatives from government and industry all volunteered to help secure responses from the numerous operators who had not yet responded to the study.

In addition to the Steering Committee meetings, EDM Services staff attended and made presentations at the following meetings:

- November 9, 1995 Planning Meeting - Sacramento

- November 29, 1995 Legislative Update - Senator O=Connell=s Office, Sacramento

2.3 Identify Study Participants and Pipelines

Approximately 1,200 questionnaires were distributed by EDM Services to potential study participants on June 1, 1995. The mailing list for these notification and identification letters was compiled from the following:

- the owners and operators of CSFM-regulated interstate and intrastate pipelines,

- the owners and operators of refineries, chemical plants, and terminals located in California, and

- the owners and operators of all oil and/or gas wells located within the state.

The notification letter included the following:

- a brief description of the law requiring the study;

- a statement that the CSFM intends to use the study results to assess the fitness and safety of the pipelines and develop recommendations to improve, repair or replace proposed pipelines;

- notification that EDM Services= personnel would be contacting each operator by mail, telephone, and in some cases visiting selected operators to conduct field audits;

- a schematic drawing and description which defined the pipelines under study;

- a form to be used by each operator to identify a contact who would be responsible for coordinating study activities and to identify whether or not their company owned or operated any pipelines meeting the study criteria; and,

- notification that EDM Services would be forwarding questionnaires to each operator of pipelines meeting the study criteria, soliciting specific information regarding leak records, pipeline inventory, etc.

These initial questionnaires were due for return to EDM Services by June 12, 1995. However, through the end of July 1995, only 461 responses had been received, with 43 operators indicating that they owned or operated pipelines which should be included in the study. Having only received responses from about one-third of the operators who received the initial questionnaires, EDM Services initiated an extensive campaign.

2.4 Data Gathering

In June 1995, EDM Services developed pipeline inventory and leak data questionnaires. The questionnaires included the pipeline inventory and leak data forms and accompanying instructions. They were used to gather the necessary data. These forms and instructions were reviewed and endorsed by the Steering Committee, CSFM and BDM/Oklahoma prior to their distribution and use.

On June 30, 1995, EDM Services began distributing copies of the Pipeline Inventory and Leak Data Questionnaires to all operators who had been identified for participation in the study. These documents were then distributed to additional operators as they were identified for inclusion in the study.

2.5 Database Development

A database, containing the necessary data fields, was established using Microsoft Access database software. The database was structured using three tables.

! The first contained basic operator data (contact name, company name, address, telephone number, pipeline location, year of construction, preventive maintenance activities, leak detection system, etc.).

! The second contained the pipeline inventory data (segment diameter, pipe grade, pipe type, year installed, wall thickness, cathodic protection system, above/below grade, coating type, etc.).

! The third contained the leak data (location, date of leak, probable cause, injury/fatality data, total damage, volume spilled, volume recovered.

The pipeline operators forwarded completed Pipeline Inventory and Leak Data Questionnaires to EDM Services.

The pipeline inventory and leak data was input into the database as it was received from the pipeline operators. The last of the data for the pipelines identified for inclusion in the study were received on April 10, 1996.

2.6 Field Audits

EDM Services staff personally visited each operator who owned and/or operated pipelines which met the study criteria. This effort had a very positive impact on the accuracy of the study results. Specifically, a number of operators and pipelines were deleted from the study when it was found that their pipelines did not meet the study criteria. The largest percentage of these pipelines were located entirely within an proposed oil field boundary; as a result, they fell within the DOGGR=s jurisdiction and did not meet the study criteria. The second largest category of pipelines deleted from the study were CSFM-regulated interstate and intrastate pipelines, which were already under the CSFM jurisdiction.

The audits were also very useful in securing missing and incomplete data from the pipeline operators. Telephone interviews were also conducted to resolve inconsistencies and pursue questionable data.

2.7 Barriers and Incentive Options

A questionnaire was designed to gather information regarding the barriers and incentive options. On January 31, 1996, this questionnaire was distributed to the public agencies having pipeline jurisdiction, interested local agencies, Steering Committee members, interstate pipeline operators, intrastate pipeline operators, and the owners of pipelines meeting this study criteria. The questionnaires requested input on the following:

! What incentives could be provided to pipeline operators to encourage pipeline replacements or improvements?

! How could these incentives be implemented?

! What barriers had been encountered with pipeline replacement or improvement projects?

! Specifically, what regulatory barriers had been encountered?

! What specific permit barriers had been encountered?

- What environmental impact report requirements had been a barrier for pipeline replacement and/or improvement projects?

- What impact, if any, did these barriers have on the pipeline replacement and/or improvement project (e.g. project delay, deferral, elimination, etc.)?

- What were the actual consequences (financial, environmental, preventable leaks, public safety, employee safety, etc.) of these barriers? Did they impact pipeline safety?

- What were the potential consequences of these barriers?

- Case histories of pipeline replacement and/or improvement projects which have been delayed, deferred or canceled because of regulatory, permit or environmental impact barriers were requested.

- A description of the replacement/improvement project and the barriers encountered was requested.

- A description of the actual and potential consequences (financial, environmental, public safety, employee safety, etc.) of the project delay, deferral, or elimination was requested.

- If pipeline safety was sacrificed, specific details were requested regarding how and why it was impacted.

- Recommendations were requested for removing any of the barriers encountered.

The completed questionnaires were forwarded to BDM/Oklahoma for review and regulatory analysis. CSFM felt strongly that the identification of barriers/incentives should be done by an independent third party. This decision was based upon the fact that, as a pipeline regulator, CSFM itself could be the subject of comments from study participants. USDOE agreed to review the data and write the response concerning this subject.

2.8 Potential Data Inconsistencies

The importance of an accurate pipeline inventory on the study results can't be overemphasized; the inventory data directly affects the calculated incident rates since it is used in the denominator of the incident rate equation. For example, a ten percent error in the pipeline inventory alone would result in a corresponding ten percent error in the calculated incident rate.

Table 2-1
Pipeline Assessment Steering Committee

Member Name	Title	Organization
Tom Berg	Director	Resources Management County of Ventura
Jim Norris	Petroleum Coordinator	Building Department County of Santa Barbara
John Euphrat	Principal Planner	Planning Department County of San Luis Obispo
Mike Niblett	Petroleum Specialist	Petroleum Department County of Santa Barbara
Bill Guerard	State Oil & Gas Supervisor	DOGGR
John Donovan	Director Environmental & Regulatory Affairs	California Independent Petroleum Association (CIPA)
Les Clark	Vice President	Independent Oil Producers Agency (IOPA)
Frank Holmes	Coastal Coordinator	Western States Petroleum Association (WSPA)
Craig Jackson	Coordinator Environmental & Regulatory Compliance	Texaco USA
Nathan Manske	Lobbyist for Advocation & Research	Kahl Associates
Barry McMahan	Assistant Vice President	Seneca Resources
Dan Milhalik	Operations Coordinator	Texaco T&T
Cathy Reheis	Managing Coordinator	Western States Petroleum Association (WSPA)
Ralph Warrington	Senior Staff Engineer	Cal Resources LLC
Nancy Wolfe	Division Chief Pipeline Safety and Enforcement	California State Fire Marshal

Chapter 3
Background
Pipeline Risk Data

A number of sources are available for pipeline incident data. Unfortunately, few of them include the reliable pipeline inventory necessary to determine meaningful incident rates. In this Chapter, we have presented results from the following sources:

- CONCAWE Oil Pipelines Management Group's Special Task Force on Pipeline Spillages (OP/STF-1). Performance of Oil Industry Cross Country Pipelines in Western Europe, Statistical Summary of Reported Spillages. 1981 to 1994 annual reports.

- Line Pipe Research Supervisory Committee of the Pipeline Research Committee of the American Gas Association. An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines 1970 Through June 1984, NG-18 Report Number 158. 1989.

- Line Pipe Research Supervisory Committee of the Pipeline Research Committee of the American Gas Association. An Analysis of DOT Reportable Incidents for Gas Transmission and Gathering Pipelines for June 1984 Through 1992, NG-18 Report Number 213. 1995.

- United States Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety. Annual Report on Pipeline Safety. 1986 through 1992 annual reports.

Each of these reports provide pipeline incident data for *reportable* incidents. However, the criteria for *reporting* incidents differs for each study. This makes direct comparison of the individual results difficult. On the other hand, it provides a methodology for estimating incident rates for spills meeting various criteria.

The following subsections provide a summary of the data contained in each of these reports. The incident rates are shown in units of *incidents per 1,000 mile years*. This unit provides a means for predicting the number of incidents expected for a given length of line, over a given period of time. For example, if one considered an incident rate of 1.0 incidents per 1,000 mile years; one would

expect one incident per year on a 1,000 mile pipeline. If the pipeline was only one mile long, one would expect 1/1,000th of an incident per year, or an incident every 1,000 years. Using these units, frequencies of occurrence can be calculated for any pipeline length and/or time interval.

3.1 CONCAWE - 1981 Through 1994

We have summarized the pipeline results for western European pipelines, as presented in the CONCAWE Performance of Oil Industry Cross Country Pipelines In Western Europe, Statistical Summary of Reported Spillages, 1981 through 1994 annual reports in Table 3-1.
The criteria for including hazardous liquid pipeline incidents in these reports are as follows:

! all spills greater than one cubic meter (approximately 264 gallons or 6 barrels) and

! spills less than one cubic meter, if the spill had a noteworthy impact on the environment.

The reader should note that only onshore pipelines were included in these data. Also, beginning in 1994, non-commercially owned pipelines began to be included in the database.

It is interesting to note that this reporting criteria does not include any consideration for incidents which cause injuries and/or fatalities. As a result, the injury and fatality incident rates derived from this data may be low. Also, the overall incident rates for these relatively large spills are comparatively low, as shown below:

Incident Rate (per 1,000 mile/years)	.850
Injury Rate (per 1,000 mile/years)	.006
Fatality Rate (per 1,000 mile/years)	.018

Table 3-1
European Hazardous Liquid Pipeline Incidents
as Reported by CONCAWE
1981-1994

	1981	1982	1983	1984	1985
Total Pipeline Mileage	11,737	11,364	11,240	10,743	10,805
Number of Incidents	16	10	10	13	7
Incident Rate (Incidents/1000 Mile Years)	1.36	.88	.89	1.21	.65
Number of Injuries	0	0	0	0	0
Injury Rate (Injuries/1000 Mile Years)	.000	.000	.000	.000	.000
Number of Fatalities	0	0	0	0	0
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.000	.000	.000

	1986	1987	1988	1989	1990
Total Pipeline Mileage	10,805	10,805	10,992	11,737	12,024
Number of Incidents	12	8	11	13	4
Incident Rate (Incidents/1000 Mile Years)	1.11	.74	1.00	1.11	.33
Number of Injuries	0	0	0	1	0
Injury Rate (Injuries/1000 Mile Years)	.000	.000	.000	.085	.000
Number of Fatalities	0	0	0	3	0
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.000	.256	.000

	1991	1992	1993	1994	Total
Total Pipeline Mileage	13,049	13,359	13,422	19,138	171,220
Number of Incidents	14	7	10	11	146
Incident Rate (Incidents/1000 Mile Years)	1.07	.52	.75	.57	.85
Number of Injuries	0	0	0	0	1
Injury Rate (Injuries/1000 Mile Years)	.000	.000	.000	.000	.006
Number of Fatalities	0	0	0	0	3
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.000	.000	.018

Reportable incidents include:
1. All leaks greater than one cubic meter (264 gallons or approximately 6 barrels)
2. All leaks under one cubic meter which result in noteworthy environmental impact

3.2 U.S. Natural Gas Transmission and Gathering Lines - 1970 Through June 1984

Table 3-2 presents the reportable domestic natural gas transmission and gathering line incidents from 1970 through June 1984. Although this data is for natural gas lines, instead of crude oil lines which are the subject of this study, the data is worth noting for comparison. These natural gas transmission lines are of similar construction to the steel pipelines included in this study.

The criteria for leaks to be reported to the USDOT for inclusion in this data are as follows:

! resulted in a death or injury requiring hospitalization,

! required the removal from service of any segment of a transmission pipeline,

! resulted in gas ignition,

! caused an estimated damage to the property owner, or of others, or both, of $5,000 or more,

! involved a leak requiring immediate repair,

! involved a test failure that occurred while testing either with gas or another test medium, or

! in the judgement of the operator, was significant even though it did not meet any of the above criteria.

The incident rates for reported leaks meeting this criteria are summarized below:

Incident Rate (per 1,000 mile/years)	1.300
Injury Rate (per 1,000 mile/years)	.096
Fatality Rate (per 1,000 mile/years)	.016

Table 3-2
U. S. Natural Gas Transmission and Gathering Lines
1970 - June 1984

	1970	1971	1972	1973	1974	1975
Total Pipeline Mileage	284,196	285,482	285,575	285,241	293,885	267,079
Number of Incidents	343	409	409	471	458	366
Incident Rate (Incidents/1000 Mile Years)	1.21	1,43	1.43	1.65	1.56	1.37
Number of Injuries	24	24	37	19	21	21
Injury Rate (Injuries/1000 Mile Years)	.084	.084	.130	.067	.071	.079
Number of Fatalities	1	3	6	2	4	7
Fatality Rate (Fatalities/1000 Mile Years)	.004	.011	.021	.007	.014	.026

	1976	1977	1978	1979	1980
Total Pipeline Mileage	277,555	283,373	303,355	311,098	388,857
Number of Incidents	254	445	444	482	325
Incident Rate (Incidents/1000 Mile Years)	.92	1.57	1.46	1.55	.84
Number of Injuries	42	22	30	96	16
Injury Rate (Injuries/1000 Mile Years)	.151	.078	.099	.309	.041
Number of Fatalities	7	8	1	12	1
Fatality Rate (Fatalities/1000 Mile Years)	.025	.028	.003	.039	.003

	1981	1982	1983	1984;	Total
Total Pipeline Mileage	400,243	342,645	346,355	157,921	4,512,860
Number of Incidents	389	390	473	204	5,862
Incident Rate (Incidents/1000 Mile Years)	.97	1.14	1.37	1.29	1.30
Number of Injuries	6	41	25	11	435
Injury Rate (Injuries/1000 Mile Years)	.015	.120	.072	.070	.096
Number of Fatalities	6	10	2	2	72
Fatality Rate (Fatalities/1000 Mile Years)	.015	.029	.006	.013	.016

NOTES:
1. 36 of the total 72 fatalities were to employees of the operating company
2. 161 of the total 274 injuries were to employees of the operating company
3. 1984 mileage figure shown is **2** actual mileage to account for only **2** year of data

Reportable incidents includes:
1. Resulted in a death or injury requiring hospitalization
2. Required the service outage of any segment of a trans line
3. Resulted in gas ignition or leak requiring immediate repair
4. Caused an estimated damage to property of $5,000 or more
5. Involved test failure while testing with gas or other media
6. Was significant though it did not meet any of the above criteria

3.3 U.S. Natural Gas Transmission and Gathering Lines - June 1984 through 1992

Table 3-3 presents the reportable domestic natural gas transmission and gathering line incidents from June 1984 through 1992. It is important to note that in June 1984, the USDOT changed the criteria for reporting leaks. The most significant change was that in general, leaks causing less than $50,000 property damage, did not have to be reported. Since this value is significantly greater than the $5,000 criteria for the earlier study period, we see a significant decrease in the resulting *reportable* incident rate. Although impossible to verify using this data, we also believe that the actual frequency of incidents decreased during this period as a result of one-call system implementation, among other things.

The criteria for leaks to be reported to the USDOT from June 1984 through 1992 were as follows:

! Events which involved a release of gas from a pipeline, or of LNG or gas from an LNG facility, which caused: (a) a fatality, or personal injury necessitating inpatient hospitalization; or (b) estimated property damage, including costs of gas lost by the operator, or others, or both, of $50,000 or more.

! An event which resulted in an emergency shut-down of an LNG facility.

! An event that was significant, in the judgement of the operator, even though it did not meet the criteria above.

The incident rates for reported leaks meeting this criteria from June 1984 through 1992 are summarized below:

Incident Rate (per 1,000 mile/years)	.260
Injury Rate (per 1,000 mile/years)	.061
Fatality Rate (per 1,000 mile/years)	.018

As demonstrated by the approximately 80% reduction in the incident rate over the earlier period, we see that the change in reporting criteria, among other things, had a major influence on the results. However, it is interesting to note that the injury and fatality rates remained nearly unchanged from the earlier period.

Table 3-3
Onshore U. S. Natural Gas Transmission and Gathering Lines
June 1984 through 1992

	19840	1985	1986	1987	1988
Total Pipeline Mileage	157,921	324,426	340,202	290,176	310,079
Number of Incidents	82	115	77	59	80
Incident Rate (Incidents/1000 Mile Years)	.52	.35	.23	.20	.26
Number of Injuries	32	12	20	15	13
Injury Rate (Injuries/1000 Mile Years)	.203	.037	.059	.052	.042
Number of Fatalities	7	6	6	0	3
Fatality Rate (Fatalities/1000 Mile Years)	.044	.018	.018	.000	.010

	1989	1990	1991	1992	Total
Total Pipeline Mileage	313,751	294,504	315,290	327,484	2,673,833
Number of Incidents	83	72	65	52	685
Incident Rate (Incidents/1000 Mile Years)	.26	.24	.21	.16	.26
Number of Injuries	28	17	12	15	164
Injury Rate (Injuries/1000 Mile Years)	.089	.058	.038	.046	.061
Number of Fatalities	22	0	0	3	47
Fatality Rate (Fatalities/1000 Mile Years)	.070	.000	.000	.009	.018

NOTES: 1. 1984 mileage figure shown is **2** actual mileage to account for only **2** year data

Reportable incidents include:

1. Events which involve a release of gas from a pipeline, or of LNG or gas from a LNG facility which cause
   a. a fatality or personal injury requiring inpatient hospitalization
   b an estimated damage to property of $50,000 or more
2. Events which resulted in an emergency shutdown
3. Events which were significant though it did not meet any of the above criteria

3.4 U.S. Hazardous Liquid Pipeline Accidents - 1986 through 1992

As noted earlier, a reliable pipeline inventory is necessary to determine precise incident rates. The degree of accuracy of the domestic hazardous liquid pipeline inventory is questionable. For example, the total reported pipeline length remained constant for each year examined. However, we are aware of new line construction and line abandonments during this period. As a result, *we believe that the incident rates derived using the reported pipeline lengths are approximations only*; they should not be taken as absolute.

Table 3-4 presents the reportable domestic hazardous liquid pipeline incidents from 1986 through 1992. The criteria for incidents to be reported to the USDOT for inclusion in this data were as follows:

- explosion or fire not intentionally set by the operator,
- loss of more than 50 barrels of liquid or carbon dioxide,
- escape to the atmosphere of more than five barrels per day of highly volatile liquid,
- death of any person,
- bodily harm to any person resulting in loss of consciousness, necessity to carry the person from the scene, or disability which prevents the discharge of normal duties or normal activities beyond the day of the accident, and/or
- estimated property damage to the property of the operator, or others, or both, exceeding $5,000.

The approximate incident rates for reported leaks meeting this criteria are summarized below:

Incident Rate (per 1,000 mile/years)	1.31
Injury Rate (per 1,000 mile/years)	.149
Fatality Rate (per 1,000 mile/years)	.017

It's interesting to note that these results are essentially the same as those for reportable U.S. natural gas lines from 1970 through June 1984, which had a similar $5,000 property damage reporting requirement.

Table 3-4
U. S. Hazardous Liquid Pipeline Accidents
1986 - 1992

	1986	1987	1988	1989
Total Pipeline Mileage	150,000	155,000	155,000	155,000
Number of Incidents	203	237	196	161
Incident Rate (Incidents/1000 Mile Years)	1.35	1.53	1.26	1.04
Number of Injuries	32	20	19	38
Injury Rate (Injuries/1000 Mile Years)	.213	.129	.123	.245
Number of Fatalities	3	3	2	2
Fatality Rate (Fatalities/1000 Mile Years)	.020	.019	.013	.013

	1990	1991	1992	Total
Total Pipeline Mileage	151,000	152,300	152,300	1,070,600
Number of Incidents	177	210	223	1,407
Incident Rate (Incidents/1000 Mile Years)	1.17	1.38	1.46	1.31
Number of Injuries	7	5	38	159
Injury Rate (Injuries/1000 Mile Years)	.046	.033	.250	.149
Number of Fatalities	3	0	5	18
Fatality Rate (Fatalities/1000 Mile Years)	.020	.000	.033	.017

NOTES: Mileage figure are approximate as reported by US Department of Transportation, Annual Report on Pipeline Safety, as published for each year
After October 21, 1995, reportable incidents include:
1. Explosion or fire not intentionally set by the operator
2. Loss of more than 50 barrels of liquid or carbon dioxide
3. Escape to the atmosphere of more than 5 barrels per day of highly volatile liquid
4. Death of any person
5. Bodily harm to any person resulting in loss of consciousness, necessity to carry the person from the scene, or disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident
6. Estimated property damage (operator=s property or property of others, or both) exceeding $5,000

3.5 Summary of CSFM Regulated Hazardous Liquid Pipelines - 1981 through 1990

This study included all CSFM-regulated interstate and intrastate hazardous liquid pipelines. The systems included in this study had complete leak records. *All leaks, regardless of size, extent of property damage, or extent of injury were included in the study*. As a result, the incident rates were much higher than presented in earlier studies, which only included reported leaks fitting a relatively narrow criteria. A summary of these results is included in Table 3-5. The incident rates for *all* leaks, as well as those meeting the noted criteria, which occurred during the ten year study period are summarized below. (All financial data has been converted to $US 1994; the incident rates corresponding to various dollar amounts has been estimated using the available data.)

Incident Rate - all leaks (per 1,000 mile years)	7.08
Incident Rate - all crude oil leaks (per 1,000 mile years)	9.89
Incident Rate - > $1,000 (per 1,000 mile years)	5.80
Incident Rate - > $10,000 (per 1,000 mile years)	3.64
Incident Rate - > $100,000 (per 1,000 mile years)	1.36
Injury Rate - any severity (per 1,000 mile years)	.685
Fatality Rate (per 1,000 mile years)	.042

Table 3-5A

CSFM Regulated Hazardous Liquid Pipeline Data - All Leaks

1981 through 1990

	1981	1982	1983	1984	1985	1986
Total Pipeline Mileage	6,482	6,658	6,675	6,835	7,005	7,501
Number of Incidents	53	83	53	30	45	46
Incident Rate (Incidents/1000 Mile Years)	8.18	12.47	7.94	4.39	6.42	6.13
Number of Injuries	0	1	2	0	0	15
Injury Rate (Injuries/1000 Mile Years)	.000	.150	.300	.000	.000	2.000
Number of Fatalities	0	0	0	0	0	1
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.000	.000	.000	.133

	1987	1988	1989	1990	Total
Total Pipeline Mileage	7,587	7,600	7,609	7,610	71,563
Number of Incidents	60	52	42	43	507
Incident Rate (Incidents/1000 Mile Years)	7.91	6.84	5.52	5.65	7.08
Number of Injuries	0	0	31	0	49
Injury Rate (Injuries/1000 Mile Years)	.000	.000	4.074	.000	.685
Number of Fatalities	0	0	2	0	3
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.263	.000	.042

NOTE: The above table includes all leaks, regardless of size or severity

Table 3-5B

CSFM Regulated Hazardous Liquid Pipeline Data

Leaks Greater than $5,000 Damage

1981 through 1990

	1981	1982	1983	1984	1985	1986
Total Pipeline Mileage	6.482	6,658	6,675	6,835	7,005	7,501
Number of Incidents	52	73	44	30	41	40
Incident Rate (Incidents/1000 Mile Years)	8.05	10.96	6.59	4.39	5.85	5.33
Number of Injuries	0	1	2	0	0	15
Injury Rate (Injuries/1000 Mile Years)	.000	.150	.300	.000	.000	2.000
Number of Fatalities	0	0	0	0	0	1
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.000	.000	.000	.133

	1987	1988	1989	1990	Total
Total Pipeline Mileage	7,587	7,600	7,609	7,610	71,563
Number of Incidents	48	42	35	36	441
Incident Rate (Incidents/1000 Mile Years)	6.33	5.53	4.60	4.73	6.16
Number of Injuries	0	0	31	0	49
Injury Rate (Injuries/1000 Mile Years)	.000	.000	4.074	.000	.685
Number of Fatalities	0	0	2	0	3
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.263	.000	.042

NOTE: The above table includes all leaks which resulted in any injury, regardless of severity, and all leaks resulting in fatalities

Table 3-5C
CSFM Regulated Hazardous Liquid Pipeline Data
Leaks Greater than $50,000 Damage
1981 through 1990

	1981	1982	1983	1984	1985	1986
Total Pipeline Mileage	6,482	6,658	6,675	6,835	7,005	7,501
Number of Incidents	39	56	33	20	31	27
Incident Rate (Incidents/1000 Mile Years)	6.02	8.41	4.94	2.93	4.43	3.60
Number of Injuries	0	1	2	0	0	15
Injury Rate (Injuries/1000 Mile Years)	.000	.150	.300	.000	.000	2.000
Number of Fatalities	0	0	0	0	0	1
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.000	.000	.000	.133

	1987	1988	1989	1990	Total
Total Pipeline Mileage	7,587	7,600	7,609	7,610	71,563
Number of Incidents	34	30	21	26	317
Incident Rate (Incidents/1000 Mile Years)	4.48	3.95	2.76	3.42	4.43
Number of Injuries	0	0	31	0	49
Injury Rate (Injuries/1000 Mile Years)	.000	.000	4.074	.000	.685
Number of Fatalities	0	0	2	0	3
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.263	.000	.042

NOTE: The above table includes all leaks which resulted in any injury, regardless of severity, and all leaks resulting in fatalities

Table 3-5D

CSFM Regulated Hazardous Liquid Pipeline Data
Leaks Greater than $500,000 Damage

1981 through 1990

	1981	1982	1983	1984	1985	1986
Total Pipeline Mileage	6,482	6,658	6,675	6,835	7,005	7,501
Number of Incidents	36	50	30	19	28	21
Incident Rate (Incidents/1000 Mile Years)	5.55	7.51	4.49	2.78	4.00	2.80
Number of Injuries	0	1	2	0	0	15
Injury Rate (Injuries/1000 Mile Years)	.000	.150	.300	.000	.000	2.000
Number of Fatalities	0	0	0	0	0	1
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.000	.000	.000	.133

	1987	1988	1989	1990	Total
Total Pipeline Mileage	7,587	7,600	7,609	7,610	71,563
Number of Incidents	31	24	18	24	281
Incident Rate (Incidents/1000 Mile Years)	4.09	3.16	2.37	3.15	3.93
Number of Injuries	0	0	31	0	49
Injury Rate (Injuries/1000 Mile Years)	.000	.000	4.074	.000	.685
Number of Fatalities	0	0	2	0	3
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.263	.000	.042

NOTE: The above table includes all leaks which resulted in any injury, regardless of severity, and all leaks resulting in fatalities

3.6 Data Summary of California Crude Oil Pipelines Under Study - 1993 through 1995

This study included all California crude oil liquid pipelines not previously regulated by any State agency. The systems included in this study had complete leak records. Leak incidents of one barrel or more, or any spill onto water, or any spill which could threaten ground water were included in this study. The incident rates were very similar to the results for CSFM-regulated hazardous liquid pipelines. A summary of these results is included in Table 3-6. The incident rates for the leaks which occurred during the study period are summarized below.

Incident Rate - leaks > 1 bbl (per 1,000 mile years)	6.72
Incident Rate - > $1,000 (per 1,000 mile years)	6.72
Incident Rate - > $10,000 (per 1,000 mile years)	1.34
Incident Rate - > $100,000 (per 1,000 mile years)	1.14
Injury Rate - any severity (per 1,000 mile years)	0.00
Fatality Rate (per 1,000 mile years)	0.00

Note: Financial data is shown in constant $US 1994

Although the overall incident rates for this study were very similar to those recorded in the earlier CSFM-regulated hazardous liquid pipeline study (6.72 versus 7.08 incidents per 1,000 mile years), it's interesting to note that the incident rates for spills resulting in various amounts of damage were significantly lower, as indicated below.

Description	Crude Oil Pipelines Under Study	CSFM Regulated Pipelines
Incident Rate > $1,000 Damage (per 1,000 mile yrs)	6.72	5.80
Incident Rate > $10,000 Damage (per 1,000 mile yrs)	1.34	3.64
Incident Rate > $100,000 Damage (per 1,000 mile yrs)	**1.14**	1.36
Incident Rate > $1,000,000 Damage (per 1,000 mile yrs)	0.00	0.28

Note: Financial data converted to $US 1994

This parameter will be reviewed in more detail later in this report. However, this result is reasonable, since the crude oil pipelines under study are generally much smaller in diameter and length, are primarily located in rural areas, and do not transport refined petroleum products.

Table 3-6
California Crude Oil Pipelines Under Study
1993 through 1995

	1993	1994	1995	Total
Total Pipeline Mileage	494	496	496	1,486
Number of Incidents	1	4	5	10
Incident Rate (Incidents/1000 Mile Years)	2.02	8.06	10.08	6.72
Number of Injuries	0	0	0	0
Injury Rate (Injuries/1000 Mile Years)	.000	.000	.000	0
Number of Fatalities	0	0	0	0
Fatality Rate (Fatalities/1000 Mile Years)	.000	.000	.000	.000

NOTE: The above table includes all leaks >1 bbl

3.7 Comparison of Various Incident Data Sources

Table 3-7 demonstrates the differences that various reporting criteria have on the resulting incident rates. It should be noted that the California incident rates, which appear to be much higher, *are the only data which have been completely audited*. These data do *not* necessarily indicate that California's pipeline network presents a higher risk than those in other areas. Unfortunately however, we could not find audited data from other areas, with complete leak records, for comparison.

One of the benefits of having data available which met various reporting standards was that incident rates could be established for a variety of criteria. For example, the CSFM-regulated hazardous liquid data could be used to establish incident rates for *all* leaks and injuries. Data from the other studies could be used to establish incident rates for their specific reporting criteria. These differences are summarized in the following subsection.

Table 3-7
Comparison of Various Incident Data Sources

	Incident Rate	Injury Rate	Fatality Rate
CONCAWE (1981-1994)	.850	.010	.030
US Natural Gas (1970-1984)	1.300	.096	.016
US Natural Gas (1984-1992)	.260	.061	.018
US Hazardous Liquid (1986-1992)	1.310	.149	.017
CSFM Regulated Pipelines-all leaks (1981-1990)	7.080	.685	.042
Calif Crude Oil Pipelines Under Study (1993-1995)	6.720	.000	.000
Calif Leaks >5 bbl or >$5,000 (1981-1990)	3.360	.000	.000
Calif Leaks >$50,000 (1981-1990)	.670	.000	.000

NOTE: The California regulated hazardous liquid pipeline data includes all leaks and injuries, regardless of severity. Further, California data was completely audited. The resulting California incident rates do not necessarily indicate that California crude oil and/or regulated hazardous liquid pipelines pose a higher risk than those included in other studies. The reader should consult the report text for more complete discussion.

3.8 Uncorrected Pipeline Risks

Using the data developed in the prior subsections, one can estimate the incident rates for various pipeline events as follows:

Event	Incident Rate
Any size leak from CSFM regulated pipeline (per 1,000 mile years)	7.1
≥ 1bbl leak from crude oil pipeline under study (per 1,000 mile yrs)	6.72
Property damage >$1,000 (per 1,000 mile years)	6.7
Property damage >$10,000 (per 1,000 mile years)	1.3 to 3.6
Property damage >$100,000 (per 1,000 mile years)	1.1 to 1.4
Property damage >$1,000,000 (per 1,000 mile years)	0.0 to 0.28
Any injury (per 1,000 mile years)	0.0 to 0.70
Injury requiring hospitalization (per 1,000 mile years)	0.0 to 0.10
Fatality (per 1,000 mile years)	0.0 to 0.04

These values may be useful when evaluating the risks associated with proposed pipeline projects. However, as noted by the wide range of values presented, the user should use judgement in selecting the appropriate values for a particular project. Consideration should be given to the type of pipeline under investigation, the contents being transported, pipe age, type of coating, operating temperature, and other parameters. The data presented in Chapter 4 of this report, and the 1993 California Hazardous Liquid Pipeline Risk Assessment will aid the reader in making such assessments.

Chapter 4
General Risk Levels
Crude Oil Pipelines Under Study

Before reviewing the specific study results, it is helpful to review a profile of the crude oil pipelines included in this study. To reiterate the information presented earlier in Chapter 1, the following pipelines have been included in this study and database:

- pipelines for the transportation of crude oil that operate at gravity or at a stress level of 20% or less of the specified minimum yield strength of the pipe; and,

- pipelines for the transportation of petroleum (crude oil) in onshore gathering lines located in rural areas.

Pipelines meeting this criteria have been included in the study and database, whether they were operating or not during the study period; even abandoned, idle, or otherwise out of service pipelines have been included in the study and database. The following pipelines were *excluded* from the data base and study:

- interstate and intrastate pipelines which are currently regulated by the CSFM or USDOT;

- gathering lines located entirely within the boundary of DOGGR oil field boundary, or which cross a boundary where two DOGGR oil fields are contiguous and are contained entirely within multiple DOGGR oil fields;

- flow lines located entirely within the boundary of a DOGGR designated oil field boundary, or which cross a boundary where two DOGGR oil fields are contiguous and are contained entirely within multiple DOGGR oil fields;

- natural gas pipelines;

- refined petroleum product pipelines; and

- abandoned pipelines which have been physically removed.

It's also important to understand the leak incidents which have been included this study. As noted earlier, the criteria for defining these leaks was established by the Steering Committee. The criteria for reporting leaks to the California Office of Emergency Services (OES) (one barrel

or more, or any spill onto water, or any spill which could threaten ground water) was selected for use. Unfortunately, the OES spill database could not be used for this study, since it does not contain sufficient pipeline and leak details to facilitate any specific analysis.

The study period was established as a three year period from January 1993 through December 1995.

Although over 1,200 questionnaires were initially distributed to potential study participants, the actual number of leaks and the length of crude oil pipelines included in this study is relatively small; there are simply very few miles of pipeline which met the study criteria. This data set only included ten (10) leaks of one barrel or greater, which occurred during the three year study period, from only 496 miles of pipelines. This data sample is simply too small to draw many meaningful conclusions. Despite the instructions requesting that only leaks of one barrel or greater be reported (except for those meeting other criteria) we received ten leak reports for spills of less than one barrel. Since this data was not uniformly available or reported for all of the operators, these incidents of less than one barrel were not included in the study. It=s worth noting that the total damage from these leaks, which were excluded from the study, was nominal, averaging $3,460 per incident.

For comparison purposes, we have also presented data for CSFM-regulated hazardous liquid pipelines, as reported in the 1993 California Hazardous Liquid Pipeline Risk Assessment. Throughout this section, comparisons have been made between California=s crude oil pipelines under study and the CSFM-regulated pipelines, for reference. Profiles of these pipeline data sets are summarized below:

Description	**Crude Oil Pipelines Under Study**	**CSFM Regulated Pipelines**
Total Miles of Pipelines	496	7,800
Data Period	1993-1995 (3 yrs)	1981-1990 (10 yrs)
Total Miles of Piggable Pipeline/(% of total)	28 (5.6%)	4,495 (57.6%)
Total Number of Pipelines or Line Sections	113	552
Average Length of Each Pipeline (miles)	4.39	14.1
Mean Year of Original Construction	1953	1957
Mean Diameter of Pipe (inches OD)	7.5	12.3
Mean Diameter of Piggable Pipe (inches OD)	15.1	14.3
Largest Cause of Incidents / (% of all leak incidents)	Ext Corrosion (60%)	Ext Corrosion (59%)
Miles of Bare or Uncoated Pipe / (% of Total)	1.3-Bare/149-Unknown (0.3% bare; 30% unknown)	530 (6.8%)

Description	Crude Oil Pipelines Under Study	CSFM Regulated Pipelines
Miles of Cathodically Protected Pipe / (% of Total)	317 (64%)	6,976 (99.4%)
Mean Normal Operating Temperature	74.2°F	97.9°F
Number of Leaks During Study Period	10	514
Average Spill Size (bbl)	122.1	408
Median Spill Size (bbl)	3	5
Average Damage Per Incident (Uninflated - $US 1994)	$39,000	$211,000
Median Damage Per Incident ($US 1994)	$5,000	$10,710
Average Age Of Leak Pipe (years)	39.9	40.8
Average Diameter of Leak Pipe (inches)	7.5	10.2
Mean Normal Operating Temperature of Leak Pipe	64.5 °F	109.7°F
Injuries During Study Period	0	49
Fatalities During Study Period	0	3

In the table above, the terms *mean* and *average* were used to differentiate between the methods used to calculate the values. *Average* values were determined by simple division. For example, the average spill size was determined by dividing the sum of each individual spill volume by the total number of spills. *Mean* values, on the other hand, were determined by *weighting* the individual parameters by pipe length and the number of years of service during the study period. For instance, the mean normal operating temperature was determined as follows:

$$T_{mean} = \Sigma\ \{T_i L_i Y_i + T_{(I+1)} L_{(I+1)} Y_{(I+1)} + \ldots\} \div \Sigma\ \{L_i Y_i + L_{(I+1)} Y_{(I+1)} + \ldots\}$$

where: T_{mean} = mean normal operating temperature
T_i = normal operating temperature for line segment
L_i = length of line segment
Y_i = number of years of line segment operation during study period

We believe that this weighting method provides a much more meaningful representation of mean values for many parameters than simple division. It has been used where appropriate to determine the values shown in many of the tables presented in this report.

4.1 Overall Incident Causes

The overall incident rate for all pipelines included in this study was 6.72 incidents (one barrel or greater) per 1,000 mile years. Table 4-1A presents the detailed data.

As indicated, the leading cause of leak incidents of California=s crude oil pipelines under study from January 1993 through December 1995 was external corrosion, which caused 60 percent of all leaks. The second leading factor was internal corrosion, which caused 20% of all leaks.

The volumes spilled as a result of external corrosion were nominal in size, relative to the spill size resulting from other causes (three barrel average for external corrosion versus 300 barrel average for other causes).

The remaining 20% of the leaks were caused by third-party damage, distributed equally (10% each) between (a) third-party damage due to construction and (b) third-party damage due to farm equipment.

The incident cause distribution for California=s crude oil pipelines under study and CSFM-regulated hazardous liquid pipelines are compared numerically below.

Cause of Incident	Crude Oil Pipelines Under Study	CSFM Regulated Pipelines
External Corrosion	60%	59%
Internal Corrosion	20%	3%
Third Party	20%	20%
Equipment Malfunction	0%	5%
Weld Failure	0%	4%
Operating Error	0%	2%
Other	0%	10%

As shown, external corrosion caused the majority of the leak incidents in both data sets. (The issues regarding this cause of leaks will be explored in more detail in many of the following subsections of this report.)

Table 4-1
Overall Incident Causes - Crude Oil Pipelines Under Study
(Incidents per 1,000 mile years)

Cause of Incident	Number of Incidents	Incident Rate	Percentage
External Corrosion	6	4.03	60%
Internal Corrosion	2	1.34	20%
3rd Party/Construction	1	.67	10%
3rd Party/Farm Equipment	1	.67	10%
Total	106.72	6.72	100%
Number of Mile Years	1,487		
Mean Year of Pipe Construction	1953		
Mean Operating Temperature (1F)	74.2		
Mean Diameter (inches)	7.5		
Average Spill Size (barrels)	122.1		
Average Damage ($US 1994)	$39,020		

Internal corrosion caused a much larger percentage of the pipeline incidents under study (20% versus only 3% for the CSFM-regulated pipeline incidents.) This is not surprising, since many of these pipelines are crude oil gathering lines. As a result, one would expect that they carry a higher percentage of water and other impurities which would tend to increase the internal corrosion rate. In fact, many of these lines (330 miles, 67%) transport crude oil with water cuts between 1% and 3%; 19 miles (4%) transport crude oil with water cuts greater than 3%. This is in contrast to nearly all of the CSFM-regulated trunk lines, which typically transport crude oil with less than 1% water. The remaining 29% of the pipelines under study did not report this parameter.

Third party damage caused 20% of the pipeline incidents in this study. This is the same distribution as the CSFM-regulated hazardous liquid pipelines.

4.2 Incident Rates By Study Year

CSFM-Regulated Pipelines
For the CSFM-regulated hazardous liquid pipelines, varying leak incident rates were observed during the ten year study period. Table 4-2A shows the incident rate break-down for each year during the ten year survey period by cause.

The results demonstrate a slight decline over the ten year period: during the first five years the average incident rate was 8.5; during the latter half the average incident rate was 6.9 leaks per 1,000 mile years. An ordinary least squares line of best fit was determined to evaluate the statistical relevance of this overall leak data by year. It showed that the overall incident rate decreased 0.52 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* for this regression was 0.39. ***7****squared* values range from zero to one. They can be interpreted as the proportion of the variation in a given sample which can be explained by the resulting linear equation; they are a comparison of the estimated systematic model with the mean of the observed values. Very simply put, the closer the *R squared* value is to unity, the higher the relevance in the results.)

A similar regression was performed for external corrosion leaks only during the ten year study period. It indicated that the incident rate for external corrosion leaks was decreasing at the rate of 0.21 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* was 0.24.

The decreasing trend in incident rates is especially noteworthy considering the fact that all leak data was gathered at the end of the study period. With the increasing trend towards total leak reporting and recording, one would assume that the more recent data collected from a pipeline operator may be more complete than data regarding leaks which occurred several years ago. This would tend to result in relatively lower incident rates for early study years and a corresponding increasing incident rate trend. However, as discussed earlier, the data indicated a rather significant *decreasing* incident rate trend. This indicates two things: first, it indicates that the data gathered is relatively complete during the earlier years of the study; secondly, it indicates that if any incomplete record keeping did occur during the early years of the study period, the actual decreasing incident rate trend was higher than indicated by the regressions. To reiterate, the data indicated a rather significant decreasing incident rate trend, which may actually have been somewhat understated.

A third regression was performed for leaks caused by all causes except external corrosion during the ten year study period. It indicated that the incident rate for these leaks was decreasing at the rate of 0.19 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* was 0.26. The average spill volumes varied widely during the ten year study period. An ordinary least squares line of best fit was determined to analyze any trend in

this data. It indicated a 33.6 barrel per year reduction in average spill size, with an *R squared* of only 0.16.

Finally, ordinary least squares lines of best fit were determined for the average cost of damage per incident during the ten year study period. Prior to running the regressions, all cost data was normalized to constant 1983 US dollars. Using all incidents during the study period yielded a \$33,040 (\$US 1983), \$49,145 (\$US 1994) per year increase in average spill cost, with an *R squared* of 0.27. After deleting the 1989 San Bernardino train derailment, the regression indicated a \$23,366 (\$US 1983), \$34,755 (\$US 1994) per year increase in average spill cost, with an *R squared* of 0.33.

Table 4-2A
Incident Rates by Year of Study - CSFM Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	**1981**	**1982**	**1983**	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**
External Corrosion	4.78	7.21	4.19	3.36	3.14	3.73	5.67	3.95	2.89	3.55
Internal Corrosion	.00	.45	.30	.15	.14	.40	.53	.00	.00	.00
3rd Party/Construction	1.08	2.40	.60	.15	1.43	.67	.66	.79	.79	.53
3rd Party/Farm Equipment	1.08	.15	.90	.00	.00	.13	.13	.13	.13	.00
3rd Party/Train Derailment	.00	.00	.00	.00	.00	.00	.00	.13	.13	.00
3rd Party/Ext Corrosion	.00	.00	.00	.00	.14	.00	.13	.00	.00	.66
3rd Party/Other	.15	.30	.60	.00	.14	.40	.00	.13	.13	.13
Operating Error	.31	.30	.15	.00	.00	.00	.13	.00	.26	.00
Design Flaw	.00	.00	.00	.00	.00	.00	.00	.13	.00	.13
Equipment Malfunction	.15	.60	.45	.15	.43	.00	.40	.92	.26	.39
Maintenance	.00	.00	.00	.00	.29	.00	.00	.00	.39	.00
Weld Failure	.15	.60	.60	.29	.43	.13	.13	.26	.00	.13
Other	.46	.45	.15	.29	.29	.67	.13	.39	.53	.13
Total Number of Incidents	8.18	12.47	7.94	4.39	6.42	6.13	7.91	6.84	5.52	5.65
Number of Mile Years	6,482	6,658	6,675	6,835	7,005	7,501	7,587	7,600	7,609	7,610
Mean Year of Construction	1952	1953	1953	1954	1954	1956	1957	1957	1957	1957
Mean Operating Temp (1F)	97.0	97.4	97.4	96.8	98.4	97.9	98.0	97.9	98.0	98.0
Mean Diameter (inches)	10.8	10.9	10.9	10.9	11.1	12.3	12.3	12.4	12.4	12.4
Average Spill Size (bbl)	285.0	514.7	889.3	83.6	562.9	609.4	266.6	136.2	377.5	127.4
Avg Damage ($1,000 US 1994)	16.4	39.4	138.0	38.1	140.4	255.7	31.8	90.3	968.6	210.3

California Crude Oil Pipelines Under Study
Table 4-2B presents leak incident data for California's crude oil pipelines under study, by year, during the three year study period. The data sample indicates a sharp increase in the frequency of incidents per year. However, nearly all of the 1995 leaks occurred on one line, which the operator plans to replace. This situation points out the severe limitations of the very small three year data sample; this sample precludes the meaningful analysis of any trends which might exist.

We recommend that an analysis, similar to that conducted for the CSFM-regulated hazardous liquid pipelines, be conducted after several years of additional data has been collected.

Table 4-2B
Incident Rates by Year of Study - Crude Oil Pipelines Under Study
Incidents Per 1,000 Mile Years

Cause of Incident	1993	1994	1995
External Corrosion	.00	6.05	6.05
Internal Corrosion	2.02	.00	2.02
3rd Party/Construction	.00	2.02	.00
3rd Party/Farm Equipment	.00	.00	2.02
Total Number of Incidents	2.02	8.06	10.08
Number of Mile Years	494	496	496
Average Spill Size (bbl)	1.0	295.5	7.6
Average Damage ($US 1994)	$5,000	$92,750	$2,840

4.3 Decade of Construction Effects

CSFM-Regulated Hazardous Liquid Pipelines
The 1993 study regarding CSFM-regulated pipelines concluded that pipe age had a definite effect on the leak incident rates. Table 4-3A shows the variation in leak incident rates by decade of pipe construction for these regulated pipelines. As indicated, pipe construction before 1940 (1926 mean year of construction) had a leak incident rate nearly twenty times that of pipe constructed in the 1980's. An ordinary least squares line of best fit was determined to evaluate

the statistical relevance of the overall leak data by year of pipe construction. It indicated that the overall leak incident rate decreased 0.286 incidents per year per 1,000 mile years. The resulting *R squared* for this regression was 0.82. A second regression was performed which excluded all pipe installed prior to 1940. This regression indicated an overall leak incident rate reduction of 0.147 incidents per year per 1,000 mile years, with an *R squared* of 0.86. The study indicated that the vast majority of the difference in leak incident rates occurred because of variations in external corrosion rates. Some of the reasons for this variation may have included:

! The extent of external corrosion is generally considered a function of time. In general, the more time a given portion of pipe is allowed to corrode, the more likely it will be to develop a leak.

! Most believe that modern coatings are generally more effective than older coatings, especially those installed before the 1940's. The older pipe is likely to experience a higher external corrosion incident rate as a result.

! External corrosion rates are generally higher at elevated temperatures.

! Prior to the 1950's, it was common to install pipelines with little or no cathodic protection. For the most part, these older systems have either had new systems installed, or their older systems upgraded, to be consistent with present day practices. However, they often operated for several years with inadequate or no cathodic protection. The corrosion which occurred during these early years likely increased the resulting external corrosion leak incident rate.

An ordinary least squares line of best fit was determined for the external corrosion data only. Using all data, it indicated that the external corrosion rate declined by 0.217 incidents per year per 1,000 mile years, with an *R squared* of 0.79. A similar regression was performed excluding all pipe constructed prior to 1940. This regression indicated an external corrosion rate reduction of 0.097 incidents per year per 1,000 mile years, with an *R squared* of 0.95. However, it should be noted that both of these regressions resulted in a least squares line fit which would indicate a negative incident rate during the study period, which is impossible. However, the point should be made that there is a strong statistical relationship between pipe age and rate of external corrosion; the newer the pipe, the lower the external corrosion incident rate.

A third ordinary least squares line of best fit was prepared for leaks caused by all causes except external corrosion. It indicated that the incident rate for these leaks decreased at the rate of 0.069 incidents per year per 1,000 mile years. The resulting *R squared* was 0.80.

Table 4-3A

Incident Rate by Decade of Construction - CSFM Regulated Pipelines

Incidents Per 1,000 Mile Years

Cause of Incident	**Pre 1940**	**1940-49**	**1950-59**	**1960-69**	**1970-79**	**1980-89**
External Corrosion	14.12	4.24	2.47	1.47	1.24	.00
Internal Corrosion	.38	.27	.10	.16	.00	.28
3rd Party/Construction	1.96	1.06	.68	.66	.25	.28
3rd Party/Farm Equipment	.53	1.33	.05	.00	.00	.00
3rd Party/Train Derailment	.00	.00	.00	.05	.25	.00
3rd Party/Ext Corrosion	.45	.00	.10	.33	.00	.00
3rd Party/Other	.30	.13	.05	.05	.00	.00
Operating Error	.30	.13	.00	.11	.25	.00
Design Flaw	.08	.00	.00	.00	.00	.14
Equipment Malfunction	.38	.53	.10	.60	1.24	.00
Maintenance	.00	.00	.24	.00	.00	.00
Weld Failure	.38	.27	.15	.44	.25	.00
Other	.83	.13	.24	.27	.25	.28
Total Number of Incidents	19.70	8.08	4.17	4.15	3.72	.97
Number of Mile Years	13,247	7,546	20,612	18,311	4,030	7,252
Avg Year of Construction	1926	1944	1944	1965	1974	1985
Average Operating Temp (1F)	125.2	79.7	89.4	91.4	99.8	104.1
Average Diameter (inches)	8.58	11.11	11.82	11.27	13.79	19.55
Average Spill Size (bbl)	162	492	246	1,306	53	789
Average Damage ($US 1994)	46,517	177,902	252,479	738,001	127,589	244,407

California Crude Oil Pipelines Under Study

While the CSFM-regulated hazardous liquid pipeline data indicated a very strong correlation between pipe age and leak incident rates, we did not find the same correlation for the crude oil pipelines included in this study. Table 4-3B presents the leak incident rates by decade of pipeline construction. As shown, there is little correlation between pipe age and the incident rates for these pipelines.

The oldest group of pipe, which was that constructed before 1940, had a leak incident rate of 2.21 incidents per 1,000 mile years. The group with the highest leak incident rate was constructed in the 1960's; this group had a leak incident rate of 16.95 incidents per 1,000 mile years.

Similar to the analysis for the CSFM-regulated hazardous liquid pipelines, an ordinary least squares line of best fit was used to evaluate the statistical relevance of the overall leak data, by year of pipe construction, for the crude oil pipelines under study. It indicated that the overall leak incident rate was decreasing at the rate of 0.030 incidents per 1,000 mile years, for each year of decreasing pipe age. However, the resulting *R squared* for this regression was only 0.01, indicating little, if any, statistical relevance to this data. A similar regression was performed for external corrosion leaks only. This analysis indicated that the external corrosion leak incident rate was decreasing at the rate of 0.10 incidents per 1,000 mile years for each year of decreasing pipe age; the *R squared* for this regression was 0.14. As a result, the data for the crude oil pipelines under study does not indicate a statistical correlation between pipe age and the resulting leak incident rate. We suspect that this is largely due to the limited data sample available for this study. With a larger data sample, we would anticipate results similar to those for the CSFM-regulated pipelines for the same reasons discussed at the beginning of this section.

Table 4-3B

Incident Rate by Decade of Construction - Crude Oil Pipelines Under Study

Incidents Per 1,000 Mile Years

Cause of Incident	Pre 1940	1940-49	1950-59	1960-69	1970-79	1980-89	1990-95
External Corrosion	2.21	13.09	.00	11.30	.00	.00	.00
Internal Corrosion	.00	.00	4.97	5.65	.00	.00	.00
3rd Party/Construction	.00	.00	.00	.00	.00	5.38	.00
3rd Party/Farm Equipment	.00	.00	.00	.00	.00	.00	.00
Total Number of Incidents	2,21	13.09	4.97	16.95	.00	5.38	.00
Number of Mile Years	451.9	229.1	201.0	177.0	94.4	185.9	21.1
Mean Year of Construction	1930	1945	1954	1967	1974	1985	1992
Mean Operating Temp (1F)	54.3	76.5	70.4	78.2	92.2	102.2	137.1
Mean Diameter (inches)	7.8	6.6	6.1	10.6	6.5	7.4	9.6
Average Spill Size (bbl)	4.0	3.3	25.0	1.7	0.0	589.0	0.0
Average Damage ($US 1994)	$5,000	$6,067	$5,000	$3,333	$0	$176,000	$0

4.4 Operating Temperature Effects

CSFM-Regulated Hazardous Liquid Pipelines

The 1993 CSFM-regulated hazardous liquid pipeline study concluded that pipeline operating temperature had a definite effect on the leak incident rates. Table 4-4A shows the variation in leak incident rates by operating temperature for these CSFM-regulated pipelines.

With the exception of the relatively new pipelines operating at above 180°F (most were built around 1979), higher operating temperatures were directly related to higher leak incident rates. However, the data also indicated that the pipelines operated between 130 and 159°F were also the oldest. As a result, a logistic regression was performed to determine whether or not pipe age was masking the pipe operating temperature effects. The logistic regression results indicated that while holding various factors constant, including pipe age, operating temperature was positively related to the probability of a leak occurring from external corrosion. Operating temperature was not statistically related, however, to the probability of leaks occurring from other causes.

Ordinary least squares lines of best fit were also calculated to evaluate the statistical relevance of this CSFM-regulated pipeline data. For all leaks, the line indicated an increase of 0.11 incidents per 1,000 mile years, per °F increase in operating temperature, with an *R squared* of 0.89. For external corrosion leaks only, the regression resulted in an increase of 0.10 incidents per 1,000 mile years, per °F increase in operating temperature, with an *R squared* of 0.91. For all leaks, excluding external corrosion leaks, the regression resulted in an increase of 0.0077 incidents per 1,000 mile years, per °F, with an *R squared* of only 0.28. These data reaffirm the logistical regression results that the probability of leaks occurring from external corrosion was affected by operating temperature, while leaks from other causes were not affected by operating temperature.

The CSFM-regulated hazardous liquid pipeline data also indicated that spill sizes and monetary damage did not appear to be affected by operating temperature.

Table 4-4A
Incident Rate by Normal Operating Temperature - CSFM Regulated Pipelines
Incidents Per 1,000 Mile Years

Cause of Incident	**0-691F**	**70-991F**	**100-1291F**	**130-1591F**	**1601F+**
External Corrosion	.48	1.33	7.11	11.36	11.31
Internal Corrosion	.00	.21	.32	.57	.08
3rd Party/Construction	1.91	.94	.95	.57	.60
3rd Party/Farm Equipment	.00	.30	.47	.00	.08
3rd Party/Train Derailment	.00	.04	.00	.00	.00
3rd Party/Ext Corrosion	.00	.06	.16	.00	.15
3rd Party/Other	.00	.24	.16	.00	.15
Operating Error	.00	.11	.00	.00	.23
Design Flaw	.00	.04	.00	.00	.00
Equipment Malfunction	.00	.24	.16	.57	.98
Maintenance	.00	.09	.16	.00	.00
Weld Failure	.00	.19	.32	.00	.60
Other	.00	.21	1.11	1.14	.45
Total Number of Incidents	2.38	4.01	10.90	14.20	14.63
Number of Mile Years	2,097	46,641	6,332	1,760	13,260
Mean Year of Construction	1960	1959	1953	1947	1951
Mean Operating Temp (1F)	61.66	74.72	103.37	144.84	177.63
Mean Diameter (inches)	8.62	12.58	11.88	9.92	12.96
Average Spill Size (bbl)	12	480	72	7	601
Average Damage ($US 1994)	72,002	363,891	53,866	15,566	142,590

California Crude Oil Pipelines Under Study

The data for California's crude oil pipelines in this study did not indicate a similar operating temperature versus leak incident rate relationship. As shown in Table 4-4B, there was no correlation between operating temperature and the leak incident rate associated with California's crude oil pipelines.

An ordinary least squares line of best fit was used to evaluate the statistical relevance of the overall leak data, by operating temperature, for the crude oil pipelines under study. It indicated that the overall leak incident rate was increasing at the rate of 0.06 incidents per 1,000 mile years per 1°F increase in operating temperature. However, the resulting *R squared* for this regression was only 0.08, indicating little statistical relevance to this data.

A similar linear regression was also performed on the external corrosion caused incidents only. This analysis resulted in a *decreasing* external corrosion incident rate of 0.04 incidents per 1,000 mile years, per 1°F increase in operating temperature. The *R squared* for this regression was 0.48, again indicating little statistical relevance to this data. It's also worth noting that all six of the external corrosion caused incidents occurred on pipelines operating in the ambient temperature category. This group was the largest, comprising 70% of the pipe sample. It was also the oldest pipe, with a 1948 mean year of pipe construction. (See also Section 4.3 of this report for a discussion of pipe age effects.)

For the crude oil pipelines under study, these results do not indicate a statistical correlation between elevated pipe operating temperature and any increased risk of leak incidents. However, one must keep in mind the limited size of this data set. The small number of leaks (10) included in this limited three year study period, with only 496 miles of pipelines, is a very small sample. As noted earlier, this sample may not be large enough to show trends.

Table 4-4B

Incident Rate by Normal Operating Temperature - Crude Oil Pipelines Under Study

Incidents Per 1,000 Mile Years

Cause of Incident	**0-691F**	**70-991F**	**100-1291F**	**130-1591F**	**1601F+**
External Corrosion	6.86	.00	.00	.00	.00
Internal Corrosion	2.29	.00	.00	.00	.00
3rd Party/Construction	.00	.00	21.28	.00	.00
3rd Party/Farm Equipment	1.14	.00	.00	.00	.00
Total Number of Incidents	10.30	.00	21.28	.00	.00
Number of Mile Years	874.0	166.0	47.0	34.0	124.0
Mean Year of Construction	1948	1961	1977	1987	1962
Mean Operating Temp (1F)	53.1	83.9	109.1	147.0	177.2
Mean Diameter (inches)	8.0	5.8	5.8	10.3	7.7
Average Spill Size (bbl)	5.2	0	1,174	0	0
Average Damage ($US 1994)	$4,467	$0	$350,000	$0	$0

4.5 Pipe Diameter Effects

CSFM-Regulated Hazardous Liquid Pipelines

For the CSFM-regulated hazardous liquid pipelines, the leak incident rate for pipe 7" in diameter and less was over three times that for pipe larger than 20" in diameter (10.35 versus 3.17 incidents per 1,000 mile years). This is especially noteworthy since the mean operating temperature for the small diameter pipe was only 77.9°F, the lowest of any diameter range. However, the age of pipe in this category and in the 8-10 inch category was fairly old, which would tend to result in higher incident rates, as shown in earlier sections. This data is also presented in Table 4-5A.

The category of pipe in the 11-15 inch diameter range also had a relatively high incident rate (8.62 incidents per 1,000 mile years). Although these lines were a good deal newer, they operated at a higher mean operating temperature.

Surprisingly, the 16-20 inch pipe diameter range had a relatively low leak rate (3.49 incidents per 1,000 mile years), despite having the highest mean operating temperature range.

The largest pipe, over 20 inches in diameter, had the lowest leak incident rate, 3.17 incidents per 1,000 mile years. However, this pipe was the newest of any category, with a mean year of pipe construction of 1984. The mean operating temperature was moderate.

Three ordinary least squares lines of best fit were prepared using this data. The first, performed using all data, indicated an overall reduction in the leak incident rate of 0.29 incidents per 1,000 mile years, per diameter inch increase, with an *R squared* of 0.76. The second, included only external corrosion leaks; it indicated a reduction of 0.26 incidents per 1,000 mile years, per diameter inch increase, with an *R squared* of 0.82. The third was performed using all leaks except external corrosion caused leaks; it resulted in a reduction of only 0.03 incidents per 1,000 mile years, per diameter inch increase, with an *R squared* of 0.31. In short, for the CSFM-regulated pipelines, there was a correlation between pipe diameter and the incident rate for external corrosion leaks, but not for leaks caused by other factors. There are several possible explanations for this correlation:

- Larger diameter pipelines represent a larger capital investment for the pipeline operator. As a result, there may be a greater proportion of the operators' resources directed toward their construction, operation, and maintenance.

- The larger diameter lines are often more important to the operators' overall operation and/or revenue generation. As a result, they may receive more attention.

! The larger lines are likely to create a greater perceived risk in the event of their rupture. This could also cause an operator to direct more resources to their protection.

Table 4-5A

Incident Rate by Pipe Diameter - CSFM Regulated Pipelines

Incidents Per 1,000 Mile Years

Cause of Incident	**0-7"**	**8-10"**	**11-15"**	**16-20"**	**20"+**
External Corrosion	6.75	4.56	5.51	1.31	.40
Internal Corrosion	.33	.27	.13	.07	.00
3rd Party/Construction	1.96	.83	.97	.36	.79
3rd Party/Farm Equipment	.33	.27	.00	.51	.00
3rd Party/Train Derailment	.00	.00	.06	.00	.00
3rd Party/External Corrosion	.22	.13	.06	.00	.00
3rd Party/Other	.00	.20	.45	.07	.00
Operating Error	.11	.10	.26	.00	.00
Design Flaw	.00	.03	.00	.00	.40
Equipment Malfunction	.44	.17	.58	.36	1.19
Maintenance	.00	.03	.06	.15	.00
Weld Failure	.00	.30	.26	.36	.40
Other	.22	.57	.26	.22	.00
Total Number of Incidents	10.35	7.46	8.62	3.49	3.17
Number of Mile Years	9,183	30,021	15,435	13,760	2,525
Mean Year of Construction	1951	1948	1962	1964	1984
Mean Operating Temp (1F)	77.9	94.11	104.81	108.44	91.17
Mean Diameter (inches)	5.6	8.7	12.6	17.6	29.4
Average Spill Size (bbl)	55	190	489	1,980	88
Average Damage ($US 1994)	$26,981	$93,735	$643,141	$194,567	$526,788

California Crude Oil Pipelines Under Study
Slightly more than 90% of California=s crude oil pipelines under study are 10" or less in nominal diameter; roughly 50% of the lines are 7" or less in diameter. Table 4-5B presents the incident rates and distribution by pipe diameter range.

A statistical analysis was performed to examine any relationship between pipe diameter and the resulting leak incident rate for these pipelines. Somewhat surprisingly, a statistical relationship was not found for this limited sample.

Two ordinary least squares lines of best fit were prepared using this data. The first, performed using all data, indicated an overall reduction in the leak incident rate of 0.50 incidents per 1,000 mile years, per diameter inch increase; however, the resulting *R squared* was only 0.26, indicating little statistical relevance. The second, analysis included only external corrosion leaks; it indicated a reduction of 0.26 incidents per 1,000 mile years, per diameter inch increase, with an *R squared* of only 0.23. In short, for the California crude oil pipelines under study, there was not a correlation between pipe diameter and the resulting leak incident rate.

Table 4-5B
Incident Rate by Pipe Diameter - Crude Oil Pipelines Under Study
Incidents Per 1,000 Mile Years

Cause of Incident	0-7"	8-10"	11-15"	16-20"	20+@
External Corrosion	1.32	8.25	.00	.00	.00
Internal Corrosion	1.32	1.65	.00	.00	.00
3rd Party/Construction	.00	.00	13.33	.00	.00
3rd Party/Farm Equipment	.00	1.65	.00	.00	.00
Total Number of Incidents	2.65	11.55	13.33	.00	.00
Number of Mile Years	756	606	75	7	44
Mean Year of Construction	1955	1947	1968	1976	1970
Mean Operating Temp (1F)	76.0	72.8	83.9	60.2	67.1
Mean Diameter (inches)	5.5	8.3	11.4	16.0	22.1
Average Spill Size (bbl)	14.0	2.7	1,174.0	.0	.0
Average Damage ($US 1994)	$7,500	$3,600	$350,000	$0	$0

4.6 Leak Detection Systems

The California crude oil pipelines under study and the CSFM-regulated hazardous liquid pipeline data were sorted into pipelines having some type of supervisory control and data acquisition (SCADA) systems, and those without. These data are presented in Tables 4-6A and 4-6B, for the CSFM-regulated pipelines and the crude oil pipelines under study respectively.

In the 1993 study, 85% of CSFM-regulated hazardous liquid pipelines had SCADA systems. For California=s crude oil pipelines under study, however, only about 9% of the pipelines had some sort of SCADA system installed.

For the crude oil pipelines under study, the leak incident rate for pipelines without these types of systems was roughly the same as the incident rate for systems with SCADA, 6.80 versus 6.13 incidents per 1,000 mile years. For the CSFM-regulated pipelines, the pipelines with SCADA had a lower incident rate than those without, 6.29 versus 11.0 incidents per 1,000 mile years. However, *this does not indicate that SCADA systems reduce leak incident rates.*

The average spill size and property damage was much larger for the crude oil pipelines under study with SCADA, than those without (1174 versus 5.2 barrels and $350,000 versus $4,467 respectively). However, there was only one leak on the 54 miles of pipeline with SCADA and nine leaks on the 441 miles of pipeline without. As a result, the data set is too small to draw any meaningful conclusions.

Although the data set was too small to be meaningful, the results are somewhat surprising. SCADA systems generally provide a means of detecting leaks quickly, minimizing spill volumes; yet the leak on the pipeline system with SCADA resulted in the largest spill volume included in the study. This situation was also noted in the 1993 study regarding CSFM-regulated hazardous liquid pipelines.

Table 4-6A

Incident Rate by Leak Detection System - CSFM Regulated Pipelines

Incidents Per 1,000 Mile Years

Cause of Incident	With SCADA		Without SCADA	
	Number	Rate	Number	Rate
External Corrosion	214	3.49	87	7.98
Internal Corrosion	13	.21	1	.09
3rd Party/Construction	53	.86	11	1.01
3rd Party/Farm Equipment	15	.24	3	.28
3rd Party/Train Derailment	2	.03	0	.00
3rd Party/External Corrosion	5	.08	2	.18
3rd Party/Other	11	.18	3	.28
Operating Error	8	.13	0	.00
Design Flaw	2	.03	0	.00
Equipment Malfunction	21	.34	6	.55
Maintenance	5	.08	0	.00
Weld Failure	14	.23	5	.46
Other	23	.37	2	.18
Total Number of Incidents	386	6.29	120	11.00
Number of Mile Years	61,351		10,904	
Mean Year of Construction	1952		1945	
Mean Operating Temp (1F)	114.3		107.0	
Mean Diameter (inches)	12.4		9.5	
Average Spill Size (bbl)	476.7		157.6	
Average Damage ($US 1994)	$228,972		$82,129	

Table 4-6B

Incident Rate by Leak Detection System - Crude Oil Pipelines Under Study

Incident per 1,000 Mile Years

Cause of Incident	With SCADA		Without SCADA	
	Number	**Rate**	**Number**	**Rate**
External Corrosion	0	.00	6	4.53
Internal Corrosion	0	.00	2	1.51
3rd Party/Construction	1	6.13	0	.00
3rd Party/Farm Equipment	0	.00	1	.76
Total Number of Incidents	1	6.13	9	6.80
Number of Mile Years	163		1,324	
Mean Year of Construction	1965		1951	
Mean Operating Temp (1F)	89.0		61.1	
Mean Diameter (inches)	12.4		7.0	
Average Spill Size (bbl)	1,174.0		5.2	
Average Damage ($US 1994)	$350,000		$4,467	

4.7 Cathodic Protection System

As indicated in Table 4-1A, 60% of the leaks on California's crude oil pipeline systems under study were caused by external corrosion. Because of this fact, the effectiveness of cathodic protection systems and cathodic protection system inspections were evaluated.

CSFM-Regulated Hazardous Liquid Pipelines

Nearly 100% of the CSFM-regulated hazardous liquid pipelines were protected by either impressed current or sacrificial anode cathodic protection systems. We did not find a statistically relevant difference in the effect on leak incident rates between the two types of systems. However, we found a significant difference between protected and the few unprotected pipelines. As depicted in Table 4-7A, unprotected pipelines had an external corrosion leak incident rate over five times higher than protected lines.

Although a small sample, the unprotected lines were much newer than those covered by a cathodic protection system. Unprotected lines also operated at a higher mean operating temperature and were smaller in diameter. Cathodic protection systems appear to reduce the frequency of pipeline ruptures due to external corrosion.

Data was also collected regarding the frequency of cathodic protection surveys. Table 4-7B shows the overall and external corrosion only incident rates by the average frequency of cathodic protection surveys. Ordinary least squares lines of best fit were prepared to determine whether or not the frequency of cathodic protection surveys had any statistical relevance to leak incident rates. Surprisingly, the ordinary least squares lines of best fit showed a slightly decreasing incident rate with less frequent surveys. However, there was little if any statistical relevance to this data; the *R squared* values for all incidents and external corrosion only incidents were only 0.13 and 0.01 respectively. This situation may result from operators performing more frequent surveys on pipelines with higher leak incident rates.

A multinomial logistic regression analysis was performed to analyze this parameter. It indicated that the frequency of cathodic protection surveys was not statistically correlated with the external corrosion leak incident rate.

Table 4-7A
Cathodic Protection System - CSFM Regulated Pipelines
Incident Rate Comparison per 1,000 Mile Years

Cause of Incident	Cathodically Protected		Unprotected	
	Number of Incidents	Incident Rate	Number of Incidents	Incident Rate
External Corrosion	295	4.23	9	23.12
Internal Corrosion	14	.20	0	.00
3rd Party/Construction	64	.92	1	2.57
3rd Party/Farm Equipment	18	.26	0	.00
3rd Party/Train Derailment	2	.03	0	.00
3rd Party/External Corrosion	5	.07	1	2.57
3rd Party/Other	11	.16	3	7.71
Operating Error	8	.11	0	.00
Design Flaw	2	.03	0	.00
Equipment Malfunction	27	.39	0	.00
Maintenance	5	.07	0	.00
Weld Failure	19	.27	0	.00
Other	25	.36	1	2.57
Total Number of Incidents	495	7.10	15	38.53
Number of Mile Years	69,756		389	
Mean Year of Construction	1957		1970	
Mean Operating Temperature (1F)	97		138	
Mean Diameter (inches)	12.4		8.8	
Average Spill Size (bbl)	418		39	
Average Damage ($US 1994)	$215,814		$123,100	

Table 4-7B

Average Cathodic Protection Interval During Study Period
CSFM Regulated Pipelines

Incident Rate Comparison per 1,000 Mile Years

Cause of Incident	Up to 1.0 Years		1.1-2.0 Years		2.1-5.0 Years		5.1-10.0 Years	
	Total Number	Rate	Total Number	Rate	Total Number	Rate	Total Number	Rate
External Corrosion	146	3.43	100	6.68	48	4.10	4	3.33
Internal Corrosion	10	.24	4	.27	0	.00	0	.00
3rd Party/Construction	46	1.08	9	.60	6	.51	1	.83
3rd Party/Farm Equipment	10	.24	7	.47	1	.09	0	.00
3rd Party/Train Derailment	1	.02	0	.00	1	.09	0	.00
3rd Party/Ext Corrosion	3	.07	0	.00	3	.26	1	.83
3rd Party/Other	9	.21	4	.27	1	.09	0	.00
Operating Error	6	.14	2	.13	0	.00	0	.00
Design Flaw	1	.02	1	.07	0	.00	0	.00
Equipment Malfunction	21	.49	3	.20	3	.26	0	.00
Maintenance	5	.12	0	.00	0	.00	0	.00
Weld Failure	14	.33	4	.27	1	.09	0	.00
Other	13	.31	10	.67	1	.09	0	.00
Total Number of Incidents	285	6.70	144	9.62	65	5.55	6	4.99
Number of Mile Years	42,524		14,961		11,713		1,202	
Mean Year of Construction	1954		1958		1963		1953	
Mean Operating Temperature (1F)	93.3		98.5		98.1		73.8	
Mean Diameter (inches)	11.1		16.1		11.5		8.8	

California Crude Oil Pipelines Under Study

64% of the crude oil pipelines included in this study are protected by cathodic protection system. 19% are unprotected. The data for the remaining 17% was either missing or unknown. This data is shown in Table 4-7C. A graphic comparison is also presented which compares the distribution of cathodically protected pipelines for both the CSFM-regulated pipelines and crude oil lines included in this study.

The leak incident rate for the crude oil pipelines under study was roughly 30% lower for cathodically protected lines than it was for unprotected lines (7.36 versus 10.80 incidents per 1,000 mile years respectively). Although the data set was small, this trend is consistent with the data presented for the CSFM-regulated hazardous liquid pipeline system.

Table 4-7D presents the incident rates for the crude oil pipelines under study which have cathodic protection systems installed. It differentiates between the leak incident rates for those systems which are regularly inspected, and those that are not. The overall incident rate for the crude oil pipelines under study with cathodic protection systems that are regularly inspected was 9.24 incidents per 1,000 mile years, 32% lower than the protected lines which did not have regular cathodic protection system inspections. The data for external corrosion leaks only yielded a greater difference; the inspected systems had an external corrosion caused incident rate of 4.62 incidents per 1,000 mile years, less than one-half the external corrosion rate for un-inspected systems.

Table 4-7C
Average Cathodic Protection Interval During Study Period
Crude Oil Pipelines Under Study
Incident Rate Comparison per 1,000 Mile Years

Cause of Incident	Cathodically Protected		Unprotected		Unknown	
	Number of Incidents	Incident Rate	Number of Incidents	Incident Rate	Number of Incidents	Incident Rate
External Corrosion	4	4.20	2	7.20	0	.00
Internal Corrosion	1	1.05	1	3.60	0	.00
3rd Party/Construction	1	1.05	0	.00	0	.00
3rd Party/Farm Equipment	1	1.05	0	.00	0	.00
Total Number of Incidents	7	7.36	3	10.80	0	.00
Number of Mile Years	952		278		258	
Mean Year of Construction	1952		1958		1947	
Mean Operating Temp (1F)	71.7		89.5		69.8	
Mean Diameter (inches)	8.2		7.3		7.3	
Average Spill Size (bbl)	173.7		1.7		.0	
Average Damage ($US 1994)	$54,314		$3,333		$0	

Table 4-7D

Incidents by Cathodic Protection Inspections - Crude Oil Pipelines Under Study

Incident Rate Comparison per 1,000 Mile Years

Cause of Incident	Inspected		Not Inspected	
	Number of Incidents	Incident Rate	Number of Incidents	Incident Rate
External Corrosion	3	4.62	3	10.17
Internal Corrosion	0	.00	2	6.78
3rd Party/Construction	1	1.54	0	.00
3rd Party/Farm Equipment	1	1.54	0	.00
Total Number of Incidents	5	7.70	5	16.95
Number of Mile Years	649		295	
Mean Year of Construction	1959		1937	
Mean Operating Temp (1F)	79.7		54.1	
Mean Diameter (inches)	8.6		7.4	
Average Spill Size (bbl)	237.4		6.8	
Average Damage ($US 1994)	$74,040		$4,000	

NOTE: Only cathodically protected pipelines have been included in the above table.

4.8 Pipe Specification Effects

Another characteristic which could influence the propensity of leak incidents is the type of steel used in construction. Tables 4-8A and 4-8B present the incident rates for varying pipe specifications for the CSFM-regulated pipelines and crude oil pipelines under study, respectively. Although different pipe specifications had varying incident rates, it must be recognized that other factors also affected these rates.

<u>CSFM-Regulated Hazardous Liquid Pipelines</u>

78% of the hazardous liquid pipelines regulated by CSFM are constructed of ASTM/API X grade material. Normally, this pipe is manufactured from relatively high quality steel, with more strictly controlled chemistry. The mean year of construction and mean operating temperature for X-grade pipe used in CSFM-regulated pipelines were 1960 and 97.6°F respectively.

22% of the pipe was constructed of ASTM A53 material. The incident rate for this material was nearly 2.7 times higher than that for X-grade material. However, this pipe was on average 10 years older, which would tend to increase the incident rate.

However, the mean operating temperature was about 12°F lower, which would tend to reduce it.

An extremely small sample of pipe fell into the *miscellaneous or other* category (less than 1%). However, the leak incident rate for this sample was very high, nearly 14 times that of X-grade pipe. Although the pipe had a mean age nearly 10 years older, it operated at a mean operating temperature roughly 30°F cooler.

Table 4-8A
Incidents by Pipe Specification - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	X-Grade		A53 and Grade B		Other	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	87	1.80	103	7.64	8	41.72
Internal Corrosion	6	.12	5	.37	0	0
3rd Party/Construction	34	.79	13	.96	2	10.43
3rd Party/Farm Equipment	10	.21	5	.37	0	0
3rd Party/Train Derailment	2	.04	0	.00	0	0
3rd Party/External Corrosion	2	.04	3	.22	0	0
3rd Party/Other	11	.23	1	.07	0	0
Operating Error	3	.06	2	.15	0	0
Design Flaw	0	.00	1	.07	0	0
Equipment Malfunction	16	.33	9	.67	0	0
Maintenance	2	.04	1	.07	0	0
Weld Failure	14	.29	4	.30	0	0
Other	13	.27	2	.15	1	5.21
Total Number of Incidents	200	4.13	149	11.05	11	57.36
Number of Mile Years	48,412		13,489		192	
Mean Year of Construction	1960		1950		1950	
Mean Operating Temp (1F)	97.6		85.3		67.1	
Mean Diameter (inches)	13.1		8.8		8.9	
Average Spill Size (bbl)	757		63		24	
Average Damage ($US 1994)	$419,728		$162,473		$49,082	

California Crude Oil Pipelines Under Study

Although the CSFM-regulated hazardous liquid pipelines were largely constructed of ASTM/API X-Grade pipe, with a small percentage of *miscellaneous or other* pipe material, the crude oil pipelines included in this study were just the opposite. 60% of the crude oil pipelines under study were constructed of *unknown* pipe specification material. 18% of the pipe was X-Grade material. The remaining 22% was either ASTM A53 or API 5L grade B pipe.

It=s interesting to note that the leak incident rate for the *unknown* pipe was by far the lowest - 1.11 incidents per 1,000 mile years, versus 7.63 and 21.74 for the ASTM/API X-Grade and ASTM A53/API 5L Grade B pipe respectively. The *miscellaneous or other* pipe was by far the oldest, with 1944 as the mean year of construction. However, this pipe was operated at the lowest mean operating temperature.

Despite the large variation in the incident rates for these different pipe groups, the reader should note that the data sample was too small to support any meaningful conclusions. Further, although external corrosion caused the largest portion of the discrepancies, this disparity is likely caused by other factors; we do not believe that external corrosion is significantly affected by pipe specification.

Table 4-8B

Incidents by Pipe Specification - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

Cause of Incident	X-Grade	A53/Grade B	Other	Unknown
External Corrosion	.00	15.53	.00	1.11
Internal Corrosion	.00	6.21	.00	.00
3rd Party/Construction	3.82	.00	.00	.00
3rd Party/Farm Machinery	3.82	.00	.00	.00
Total Number of Incidents	7.63	21.74	.00	1.11
Number of Mile Years	262	322	3	900
Mean Year of Construction	1978	1952	1955	1944
Mean Operating Temp (1F)	108.7	67.9	97.7	66.2
Mean Operating Pressure	282.0	212.9	62.8	46.3
Mean Diameter (inches)	11.0	5.9	6.5	7.0
Average Spill Size (bbl)	588.5	5.7	.0	4.0
Average Damage ($US 1994)	$176,000	$4,743	$0	$5,000

4.9 Pipe Type Effects

<u>CSFM-Regulated Hazardous Liquid Pipelines</u>
Table 4-9A presents the CSFM-regulated pipeline data by the type of pipe installed. The data sample was broken down into five categories: *submerged arc welded* (SAW), *seamless* (SMLS), *electric resistance welded* (ERW), *lap welded* (LW) and *miscellaneous/other*. The pipe included in this database was distributed as follows:

Pipe Type	%
Electric Resistance Welded	76.3%
Seamless	16.8%
Lap Welded	4.0%
Submerged Arc Welded	0.9%
Miscellaneous/Other	2.0%

The data indicated that lap weld pipe had a very high leak incident rate; nearly 50 incidents per 1,000 mile years. However, it was also the oldest pipe, with a mean year of construction of 1933. The weld failure caused incident rate for lap welded pipe was also the highest in the group (1.83 incidents per 1,000 mile years).

Electric resistance welded (ERW) pipe had a comparatively low incidence of leaks, 2.7 incidents per 1,000 mile years. These leaks occurred on somewhat newer pipeline systems, with a mean year of construction of 1963. They also operated at a mean temperature near the mean for the entire pipe sample.

Seamless pipe experienced an incident rate of 6.1 incidents per 1,000 mile years. However, this pipe sample had a mean year of construction of 1951. The mean operating temperature was comparatively cool, 83.6°F.

Submerged arc welded pipe had a high incidence of leaks, 10.4 incidents per 1,000 mile years. This small pipe sample had a mean year of construction of 1978. The mean operating temperature was the highest of the group, 120.3°F.

Table 4-9A
Incidents by Pipe Type - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	SMAW	SMLS	ERW	LW	Other
External Corrosion	8.35	3.66	1.47	31.59	.00
Internal Corrosion	2.09	.22	.02	1.83	.00
3rd Party/Construction	.00	.86	.45	6.41	.00
3rd Party/Farm Equipment	.00	.22	.02	1.83	.00
3rd Party/Train Derailment	.00	.00	.02	.00	.00
3rd Party/Ext Corrosion	.00	.00	.09	.00	.00
3rd Party/Other	.00	.00	.12	.46	.00
Operating Error	.00	.11	.05	1.37	.00
Design Flaw	.00	.00	.00	.46	.00
Equipment Malfunction	.00	.54	.17	1.37	.00
Maintenance	.00	.11	.00	.46	.00
Weld Failure	.00	.00	.12	1.83	.00
Other	.00	.43	.14	2.29	.00
Total Number of Incidents	10.44	6.14	2.68	49.90	.00
Number of Mile Years	479	9,280	42,112	2,184	1,106
Mean Year of Construction	1978	1951	1963	1933	1952
Mean Operating Temp (1F)	120.28	83.59	98.02	86.87	85.58
Average Spill Size (bbl)	5	83	285	87	0
Average Damage ($US 1994)	$28,008	$290,684	$602,431	$102,121	$0

California Crude Oil Pipelines Under Study

Table 4-9B presents the data for the crude oil pipelines under study. The pipe within this database was distributed as follows:

Pipe Type	Miles	%
Electric Resistance Welded	110	22.2%
Seamless	59	11.9%
Lap Welded	71	14.4%
Submerged Arc Welded	14	2.9%
Unknown	223	46.9%

The data presented in Table 4-9B illustrates the limitations of this small data sample. Specifically, the *miscellaneous/other* pipe type, which includes drilling pipe, had the highest leak incident rate, 41.67 incidents per 1,000 mile years. However, this resulted from only one incident, caused by third party damage. Because of the very small inventory of pipe within this category, a very high incident rate resulted. As stated before, this data set is simply too small to provide meaningful analysis in many instances.

The seamless pipe also had a relatively high leak incident rate (33.9 incidents per 1,000 miles years). This rate was nearly four times higher than that for the next highest pipe type (ERW, with 9.06 incidents per 1,000 mile years). The biggest factor in this difference was external corrosion, which caused 28.2 incidents per 1,000 mile years for the seamless pipe, and 6.04 incidents per 1,000 mile years for ERW.

Although this difference is large, external corrosion is not generally considered a function of pipe type. External corrosion is generally affected by pipe age, operating temperature, and other parameters. As a result, we do not believe that there is a correlation between pipe type and the leaks caused by external corrosion. This difference is likely caused by other factors and the small data sample available.

The purpose of this evaluation was twofold: first, to determine the distribution of the crude oil pipe installed and second, to identify any explainable differences in the leak incident rate caused by pipe type. While we were able to accomplish the first objective, we were unable to identify any link between pipe type and the resulting leak incident rate.

Table 4-9B

Incident Rates by Pipe Type - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

Cause of Incident	SMAW	SMLS	ERW	LW	Other*	Unknown
External Corrosion	.0	28.23	6.04	4.67	.00	.00
Internal Corrosion	.00	.00	3.02	.00	.00	1.43
3rd Party/Construction	.00	.00	.00	.00	41.67	.00
3rd Party/Farm Equipment	.00	5.64	.00	.00	.00	.00
Total Number of Incidents	.00	33.87	9.06	4.67	41.67	1.43
Number of Mile Years	43	177	331	214	24	698
Mean Year of Construction	1969	1942	1972	1929	1985	1951
Mean Operating Temp (1F)	65.0	48.5	105.2	49.0	83.7	73.9
Mean Diameter (inches)	22.0	6.4	7.0	8.3	6.3	6.9
Average Spill Size (bbl)	.0	3.3	1.7	4.0	1,174.0	25.0
Average Damage ($US 1994)	$0	$5,050	$3,333	$5,000	$350,000	$5,000

*OTHER category includes drilling pipe

4.10 Operating Pressure Effects

CSFM-Regulated Hazardous Liquid Pipelines

The 1993 study concluded that the relationship between normal operating pressure and the probability of pipe rupture was not statistically significant. Table 4-10A shows that there was considerable variance in the incident rate by pressure range. These differences, however, disappeared once variables such as age of pipe and operating temperature were controlled in the logistic regressions.

A simple ordinary least squares line of best fit was also determined using the overall leak data for each pressure range. The data indicated a declining leak incident rate as operating pressure increased, with an *R squared* of 0.32. However, as indicated above, the logistical regressions, which take other factors into account, did not indicate a correlation between operating pressure and leak incident rates.

An ordinary least squares line of best fit was also prepared for spill size as a function of operating pressure. The slope of the ordinary least squares line of best fit indicated a roughly 90 barrel increase in mean spill size per 100 psi increase in operating pressure. This regression resulted in an *R squared* of 0.62. It should also be noted that mean pipe diameter was also slightly higher for pipelines operating within the higher operating pressure ranges; this would also skew the results in this direction.

A similar line of best fit was prepared for average damage as a function of operating pressure. The slope of the ordinary least squares line of best fit indicated a roughly $37,000 ($US 1983), $55,035 ($US 1994) increase in average damage per 100 psi increase in operating pressure. This regression resulted in an *R squared* of 0.58. However, as noted for spill volumes, pipe diameter variances would also generally affect spill damage.

Table 4-10A
Incidents by Normal Operating Pressure - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	PSIG								
	0-100	101-200	201-300	301-400	401-500	501-600	601-800	801-1000	1001+
External Corrosion	16.67	4.11	1.63	4.12	5.16	13.05	5.83	1.26	1.58
Internal Corrosion	.45	.69	1.23	.34	.23	.20	.00	.00	.00
3rd Party/Construction	1.80	2.29	1.02	.17	.70	1.19	1.09	.60	.75
3rd Party/Farm Equip	.00	.00	.61	.00	.47	.20	.40	.06	.48
3rd Party/Train Derail	.00	.00	.00	.00	.00	.00	.00	.00	.14
3rd Party/Ext Corrosion	.00	.46	.41	.00	.00	.20	.00	.06	.00
3rd Party/Other	.00	.69	.41	.00	.00	.00	.10	.36	.14
Operating Error	.45	.00	.20	.00	.47	.00	.30	.00	.07
Design Flaw	.00	.00	.20	.00	.00	.00	.00	.06	.00
Equip Malfunction	1.80	1.37	.00	.17	.00	.00	.69	.30	.21
Maintenance	.00	.00	.00	.00	.00	.00	.20	.18	.00
Weld Failure	1.35	.00	.20	.00	.23	.00	.30	.36	.27
Other	.90	.46	.20	.00	.70	1.19	.20	.42	.14
Total Incidents	23.43	10.06	6.13	4.81	7.97	16.01	9.10	3.65	3.77
Number of Mile Years	2,219	4,374	4,895	5,818	4,264	5,058	10,112	16,732	14,597
Mean Year of Const	1933	1954	1949	1940	1946	1934	1945	1958	1949
Mean Oper Temp (1F)	130.8	92.7	82.8	86.7	121.6	125.2	159.7	116.2	104.4
Average Diameter (inches)	9.9	11.0	8.6	12.7	8.7	9.3	11.1	16.4	11.7
Average Spill Size (bbl)	17	56	5	130	149	127	456	1,292	676
Avg Damage ($1000 US ›94)	88	106	57	74	39	19	104	248	872

California Crude Oil Pipelines Under Study

Not surprisingly, most of the crude oil pipelines under study were operated at relatively low pressures. In fact, 65% of these lines were operated at 100 psig or less. The operating pressure distribution for both the CSFM-regulated hazardous liquid pipelines and crude oil pipelines under study are presented below for comparison.

Operating Pressure (psig)	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines
1 - 100	64.7%	3.3%
101 - 200	8.2%	6.4%
201 - 300	10.1%	7.2%
301 - 400	9.7%	8.5%
401 - 500	2.2%	6.3%
501 - 600	3.3%	7.4%
601 - 800	1.8%	14.9%
800+	0.0%	46.0%

As indicated in Table 4-10B, there does appear to be a relationship between operating pressure and the resulting leak incident rate. Although we believe that leak incidents caused by third party damage are not related to operating pressure, it is reasonable to assume that operating pressure and leak incidents caused by internal and external corrosion could be related. Specifically, we found that the combined internal and external corrosion leak incident rates for crude oil pipelines under study were 26.00 and 18.21 incidents per 1,000 mile years for those operated between 201 - 300 psig and 301 - 400 psig respectively. The combined external and internal corrosion leak incident rate for pipelines operated at 100 psig or less was only 4.08 incidents per 1,000 incidents per 1,000 mile years.

However, the pipe operated at higher pressures also operated at a higher mean operating temperature. But the pipe was generally newer, with a more recent mean year of pipe construction. Additionally, the lower operating pressure group of pipelines had the highest average spill size and average property damage.

Although the data set was too small to draw any conclusions at this time, we believe that this parameter should receive additional consideration after several years of additional leak data has been gathered.

Table 4-10B

Incidents by Normal Operating Pressure - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

Cause of Incident	PSIG						
	0-100	101-200	201-300	301-400	401-500	501-600	601-800
External Corrosion	2.72	.00	17.33	18.21	.00	.00	.00
Internal Corrosion	1.36	.00	8.67	.00	.00	.00	.00
3rd Party/Construction	1.36	.00	.00	.00	.00	.00	.00
3rd Party/Farm Equipment	1.36	.00	.00	.00	.00	.00	.00
Total Incidents	6.79	.00	26.00	18.21	.00	.00	.00
Number of Mile Years	736	93	115	110	25	37	22
Mean Year of Construction	1945	1970	1958	1971	1979	1970	1971
Mean Operating Temp (1F)	54.5	79.7	102.2	93.1	136.2	60.0	60.0
Average Diameter (inches)	7.3	12.8	6.5	6.9	7.6	5.6	5.0
Average Spill Size (bbl)	242.0	.0	1.7	3.5	.0	.0	.0
Avg Damage ($1000 US ›94)	$74,000	$0	$3,333	$4,100	$0	$0	$0

4.11 External Pipe Coatings

This subsection examines the incident rates for various external pipe coatings. To accomplish this, the data sample was sorted into several categories, which represented nearly all of the coatings installed on the pipelines included in this study. These coating types, their common and trade names, and the percentage of each in operation during the study period are presented below. It should be noted that the coating type was reported as *unknown* on roughly 30% of the crude oil pipeline length included in this study. The figures below show the coating type distribution of the pipelines where the coating type was reported.

Coating Type	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines	Common/Trade Names
Extruded Polyethylene with Asphalt Mastic	15.6%	6.5%	X-Tru-Coat Plexco EEC 60XT (X-Tru-Coat)
Fusion Bonded Epoxy	2.7%	1.8%	FBE Mobilox Scotchcoat 206 or 202 Thin Film Epoxy
Extruded Polyethylene with Side Extruded Butyl	3.2%	7.6%	Pritec
Extruded Asphalt Mastic	16.3%	24.9%	Somastic Asphalt Mastic
Liquid Systems	0.0%	41.6%	Coal Tar Epoxy Carboline Epoxy
Mill or Field Applied Tape	5.1%	6.0%	Polyken Tape YG III Plicoflex Raychem Hotclad Synergy
Coal Tar	6.3%	4.7%	Coal Tar or Asphalt Enamel Wrapped
Bare Pipe	25.0%	6.8%	N/A
Other Coating Types	25.8%	0.0%	N/A

As indicated, there was a far greater percentage of bare pipe in the crude oil pipeline inventory under study than the CSFM-regulated hazardous liquid pipeline inventory (25% versus 6.8%).

CSFM-Regulated Hazardous Liquid Pipelines

Table 4-11A presents the leak incident rates by coating type for CSFM-regulated hazardous liquid pipelines. Although pipe age and operating temperatures had the greatest effect, there did appear to be differences in performance between the coating systems. The average external corrosion incident rate for the regulated pipelines was 4.18 incidents per 1,000 mile years. Generally, the more modern coatings had external corrosion incident rates lower than average, some significantly lower. The older asphalt mastic systems had slightly higher external corrosion incident rates. The coal tar and asphalt enamel wrapped pipe had an external corrosion incident rate nearly as high as the bare pipe.

Bare (uncoated) lines, which comprised roughly 7% of the total, suffered the highest external corrosion and overall incident rates. In fact, these values were almost three times the average values for all pipelines included in the study. However, these lines had the oldest mean year of pipe construction and a mean operating temperature higher than average.

The coal tar and asphalt enamel wrapped pipelines, about 5% of the total, had an external corrosion rate nearly as high as the bare pipelines. These lines were operated at an average of 8°F above the mean operating temperature. They were also on average five years newer than the mean.

Extruded asphalt mastic coated pipe, roughly one-quarter of the total, had the third highest external corrosion and overall incident rates. This pipe had the second oldest mean year of pipe construction and the lowest mean operating temperature.

The 2% of the total pipe coated with fusion bonded epoxy had the fourth highest external corrosion and overall incident rates. The external corrosion incident rate for this coating was slightly below the overall average. This pipe was the newest sample included in the study, with a 1984 mean year of pipe construction. However, the operating temperature was the highest of the group, 115.6°F.

Extruded polyethylene with asphalt mastic, liquid systems and mill applied tape had external corrosion incident rates roughly one-half to one-third the average. The overall incident rates for these coatings were also considerably lower than the average. The mean pipe age and mean operating temperatures varied considerably among these groups. However, the pipe was generally much newer than average, with higher than average operating temperatures.

The lowest incident rates were observed on pipe with extruded polyethylene with side extruded butyl, which comprised 8% of the total. The observed external corrosion and overall incident rates for these pipelines were both less than one-tenth the average values. This pipe sample was relatively new, with a 1973 mean year of pipe construction. The mean operating temperature was moderately high, 105.8°F.

Difficulties were encountered performing multiple logic regressions using the coating type as an independent leak indicator. This occurred because the leak data and pipe data were gathered separately. Subsequently, the data were compiled using two separate databases. The coating type data was gathered for each segment of each pipeline within the State, resulting in tens of thousands of individual pipe segments. However, the leak data contained only the pipeline identification on which the leak occurred, as well as other pertinent data. The leak data did not specifically identify which segment of pipe suffered the leak. As a result, some manipulation of the data was necessary to perform the multiple logic analysis. The resulting analysis did indicate a correlation between coating type and leak incident rates.

Table 4-11A
Incidents by Coating Type - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	Coating Type (see Legend below)							
	1	2	3	4	5	6	7	8
External Corrosion	2.49	3.71	.36	5.56	1.27	1.58	11.77	11.59
Internal Corrosion	.21	.00	.00	.27	.20	.00	.20	.29
3rd Party/Construction	1.04	.00	.18	1.31	.49	.45	1.60	1.45
3rd Party/Farm Equipment	.42	2.22	.00	.22	.00	.45	.00	.87
3rd Party/Train Derailment	.21	.00	.00	.00	.03	.00	.00	.00
3rd Party/External Corrosion	.00	.00	.00	.16	.13	.00	.00	.00
3rd Party/Other	.21	.00	.00	.16	.16	.23	.80	.00
Operating Error	.21	.00	.00	.11	.07	.00	.40	.29
Design Flaw	.00	.00	.00	.05	.00	.23	.00	.00
Equipment Malfunction	.21	.74	.00	.33	.33	.00	.40	.29
Maintenance	.00	.00	.00	.11	.03	.00	.00	.00
Weld Failure	.00	.00	.00	.05	.20	.68	.40	.29
Other	.42	.74	.00	.16	.20	.45	1.80	.58
Total Incidents	5.40	7.41	.53	8.51	3.09	4.06	17.35	15.65
Number of Mile Years	4,814	1,349	5,625	18,342	30,700	4,435	5,013	3,450
Mean Year of Construction	1974	1984	1973	1956	1959	1984	1948	1962
Mean Operating Temp (1F)	107.4	115.6	105.8	80.5	98.1	104.6	103.8	105.8

Legend: Coating Types
1. Extruded PE with Asphalt Mastic
2. Fusion Bonded Epoxy (FBE)
3. Extruded PE with Side Extruded Butyl
4. Extruded Asphalt Mastic (AM)
5. Liquid Systems
6. Mill Applied Tape
7. Bare Pipe
8. Coal Tar or Asphalt Enamel Wrapped

California Crude Oil Pipelines Under Study

As noted earlier, 30% of California=s crude oil pipelines under study were reported as *unknown*. 18% of the pipelines were bare. Another 18% was reported to be coated with *other* types of coatings. The next two largest groupings were extruded asphalt mastic /Somastic coated lines (11%) and extruded polyethylene with asphalt mastic coated pipelines (11%). The remaining 12% of the lines were coated by a variety of coating systems.

The highest leak incident rate was encountered on the coal tar or asphalt enamel wrapped pipelines. This result is consistent with the CSFM-regulated pipeline data. The crude oil lines in this study which were coated with coal tar or asphalt enamel had a leak incident rate of 45.8 incidents per 1,000 mile years. However, this data sample was very small. The incident rate resulted from only three leaks on 22 miles of pipeline. Two of the three leaks were caused by external corrosion, resulting in an external corrosion caused incident rate of 39.5 incidents per 1,000 mile years.

Two of the other external corrosion caused leaks occurred on pipe coated with somastic and other/unknown coatings. Only one external corrosion caused leak occurred on bare pipe. The external corrosion caused incident rates for the somastic, bare, and other/unknown coated lines were 5.85, 3.82, and 7.37 incidents per 1,000 mile years respectively. These rates are similar to the overall external corrosion caused incident rate for the entire California crude oil pipeline system included in the study - 4.02 incidents per 1,000 mile years.

Table 4-11B

Incidents by Coating Type - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

	Coating Type (see Legend below)				
	1	**2**	**3**	**4**	**5**
External Corrosion	.00	.00	30.53	5.85	.00
Internal Corrosion	.00	.00	15.27	.00	.00
3rd Party/Construction	.00	.00	.00	.00	.00
3rd Party/Farm Equipment	.00	.00	.00	.00	.00
Total Incidents	.00	.00	45.80	5.85	.00
Number of Mile Years	164	28	66	171	34
Mean Year of Construction	1979	1978	1952	1955	1986
Mean Oper Temp (1F)	85.1	181.1	65.9	81.6	98.6

	Coating Type (see Legend below)				
	6	**7**	**8**	**9**	**10**
External Corrosion	.00	.00	3.82	7.37	.00
Internal Corrosion	.00	.00	3.82	.00	.00
3rd Party/Construction	.00	.00	.00	3.69	.00
3rd Party/Farm Equipment	31.65	.00	.00	.00	.00
Total Incidents	32	.00	7.85	11.06	.00
Number of Mile Years	156	21	262	271	440
Mean Year of Construction	60.0	1953	1940	1959	1938
Mean Oper Temp (1F)		64.4	45.0	70.9	86.1

Legend: Coating Types
1. Extruded PE with Asphalt Mastic (AM)
2. Fusion Bonded Epoxy (FBE)
3. Coal Tar or Asphalt Enamel Wrapped (CT)
4. Somastic
5. Pritec
6. Mill Applied Tape (MAT)
7. Field Applied Tape (FAT)
8. Bare Pipe
9. Other
10. Unknown

4.12 Internal Inspections

During the last several years, there have been significant advances in the technologies available to internally inspect pipelines using instrumented devices commonly called *Asmart pigs@*. These tools use several technologies to identify wall thinning, buckling, erosion, corrosion and other anomalies. These technologies, available from various vendors, differ greatly in their ability to identify and quantify various forms of pipe damage and/or deterioration. Some are precise and sophisticated, while others are much more general.

Unfortunately, most of these inspection tools are rather long. As a result, they require smooth, long radius bends to facilitate their passage. Most will not traverse short radius elbows for example.

In this section, we will attempt to:

! quantify the total length of pipelines which could be inspected using smart pigs

! identify any differences in the leak incident rates for internally inspected pipelines.

<u>CSFM-Regulated Hazardous Liquid Pipelines</u>

Out of the roughly 7,800 miles of CSFM-regulated hazardous liquid pipelines, nearly 58% (4,495 miles) are capable of being inspected using these techniques with little or no modification. 70% (3,128 miles) of the pipelines which are capable of being inspected by smart pigs, have already been inspected in this manner.

Table 4-12A presents a comparison of the incident rates for pipelines meeting three criteria:

! pipelines which have been internally inspected,

! pipelines which could be inspected with little or no modification, but had not been inspected by the end of the study period, and

! those pipelines which are not capable of being inspected utilizing a smart pig without significant modification.

The data indicates that pipe which had been internally inspected had the lowest leak incident rate. However, this pipe was also the newest of any category, with a 1963 mean year of pipe construction, 6 years newer than average. This pipe was also operated at a mean operating temperature of 121°F, 23°F higher than average and had the highest mean pipe diameter, 15.3".

We also compared the two categories of pipe which had not been internally inspected. Although the pipe which was not capable of being inspected using a smart pig was newer and operated at a lower mean operating temperature, it had an overall incident rate almost double the rate for piggable pipe which had not been inspected. However, the mean diameter for non-piggable lines was much smaller, 8.7" versus 13.0".

Table 4-12A

Incidents by Internal Inspection - CSFM-Regulated Pipelines

Incidents per 1,000 Mile Years

Cause of Incident	Internally Inspected		Not Internally Inspected		Not Piggable	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	65	2.06	39	3.47	198	6.70
Internal Corrosion	2	.06	0	.00	12	.41
3rd Party/Construction	16	.51	6	.53	42	1.42
3rd Party/Farm Equipment	8	.25	0	.00	10	.34
3rd Party/Train Derailment	1	.03	1	.09	0	.00
3rd Party/Ext Corrosion	2	.06	0	.00	5	.17
3rd Party/Other	8	.25	1	.09	5	.17
Operating Error	2	.06	2	.18	4	.14
Design Flaw	1	.03	0	.00	1	.03
Equipment Malfunction	12	.38	4	.36	11	.37
Maintenance	3	.10	0	.00	2	.07
Weld Failure	11	.35	0	.00	8	.27
Other	8	.25	8	.71	9	.30
Total Number of Incidents	139		61	5.42	307	10.39
Number of Mile Years	31,500		11,253		29,550	
Percentage of Mile Years	43.6%		15.6%		40.9%	
Total Length (miles)	3,128		1,367		3,305	
Percentage Total Length	40.1%		17.5%		42.4%	
Mean Year of Construction	1963		1941		1944	
Mean Operating Temperature (1F)	121		148		97	
Mean Diameter (inches)	15.3		13.0		8.7	

California Crude Oil Pipelines Under Study

Only 2% (roughly 8 miles) of the California crude oil pipelines under study have ever been internally inspected using a smart pig. Another 4% (approximately 20 miles) could be internally inspected, but has not been inspected in this manner. The remaining 96% (468 miles) could not be internally inspected because of physical limitations (e.g. short radius elbows). Table 4-12B presents this data, as well as the leak incident rates.

All of the leaks occurred on pipe which was not capable of passing a smart pig. This pipe was the oldest, with a 1951 mean year of pipe construction. However, it operated at the lowest mean operating temperature (72°F). Although all of the leaks occurred on this pipe, the data for the pipe which has been internally inspected was too limited to yield any meaningful results.

Table 4-12B

Incidents by Internal Inspection - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

Cause of Incident	Internally Inspected		Not Internally Inspected		Not Piggable	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	0	.00	0	.00	6	4.27
Internal Corrosion	0	.00	0	.00	2	1.42
3rd Party/Construction	0	.00	0	.00	1	.71
3rd Party/Farm Equipment	0	.00	0	.00	1	.71
Total Number of Incidents	0	.00	0	.00	10	7.12
Number of Mile Years	24		59		1,404	
Percentage of Mile Years	2%		4%		94%	
Total Length (miles)	8		20		468	
Percentage of Total Length	2%		4%		94%	
Mean Year of Construction	1985		1972		1951	
Mean Operating Temp (1F)	80		81		72	
Mean Diameter (inches)	6.0		18.8		7.0	

4.13 Seasonal Effects

The possibility of incident rate variations throughout the year exist for many causes. For example, heavy winter rains could result in increased external corrosion leaks during the winter. Also, heavy summer construction activity could increase third party damage during this period. In an attempt to evaluate such seasonal variations, the leak data was sorted by month of occurrence.

CSFM-Regulated Hazardous Liquid Pipelines

This data is presented in Table 4-13A for CSFM-regulated hazardous liquid pipelines. Most of the leak causes appeared to have random variations throughout the year. Also, the limited data available for most causes made it difficult to identify any trends. However, the following points were noted:

! Third party damage from farm equipment did not occur from April through August during the entire ten-year study period.

! The overall leak incident rate was lowest from April through June.

Table 4-13A
Incidents by Month of Year - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
External Corrosion	3.65	3.49	4.98	3.15	3.15	3.82	5.64	3.15	3.65	3.49	5.97	6.31
Internal Corrosion	.33	.17	.17	.17	.00	.33	.33	.17	.00	.33	.33	.00
3rd Party/Construction	.50	.83	.50	1.00	.50	.50	1.66	.83	.83	1.66	1.16	.83
3rd Party/Farm Equip	.66	.33	.33	.00	.00	.00	.00	.00	.17	1.00	.33	.17
3rd Party/Train Derail	.00	.00	.00	.00	.17	.00	.00	.00	.00	.00	.00	.17
3rd Party/Ext Corrosion	.00	.00	.17	.17	.00	.17	.00	.17	.00	.17	.17	.17
3rd Party/Other	.17	.33	.83	.17	.00	.00	.17	.00	.00	.17	.00	.50
Operating Error	.00	.00	.17	.00	.00	.50	.00	.17	.00	.17	.33	.00
Design Flaw	.00	.00	.00	.00	.00	.00	.00	.17	.00	.00	.17	.00
Equipment Malfunction	.33	.83	.33	.00	.33	.17	.33	1.00	.17	.33	.17	.50
Maintenance	.00	.17	.00	.00	.00	.00	.00	.17	.17	.17	.17	.00
Weld Failure	.33	.66	.33	.33	.00	.17	.17	.33	.17	.33	.17	.17
Other	.33	.50	.17	.50	.17	.00	.50	.50	.33	.50	.50	.33
Total	6.31	7.30	7.97	5.48	4.32	5.64	8.80	6.64	5.48	8.30	9.46	9.13

California Crude Oil Pipelines Under Study

The incident rates by month of year for California=s crude oil pipelines under study are shown in Table 4-13B. Although this data set is far too limited to draw any meaningful conclusion, we noted that none of the external corrosion caused leaks occurred during the dry summer months (May through August).

Table 4-13B

Incidents by Month of Year - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

Cause of Incident	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
External Corrosion	1.62	.00	.00	.81	.00	.00	.00	.00	.81	.00	1.62	.00
Internal Corrosion	.00	.81	.00	.00	.00	.00	.00	.00	.00	.00	.00	.81
3rd Party/Construction	.00	.00	.81	.00	.00	.00	.00	.00	.00	.00	.00	.00
3rd Party/Farm Equip	.00	.00	.00	.00	.00	.81	.00	.00	.00	.00	.00	.00
Total	1.62	.81	.81	.81	.00	.81	.00	.00	.81	.00	1.62	.81

4.14 Pipeline Components

Table 4-14 presents a break-down of the pipeline material, sorted by cause, for each incident which occurred on CSFM-regulated hazardous liquid pipelines. As noted, nearly 87% of all incidents occurred in the pipe body itself. Valves were responsible for another 3.1% of the incidents. 2% were caused by longitudinal weld seam failures in the pipe body. 1.6% were caused by failure at welded fittings. The remaining 6.7% were from various other causes.

100% of the incidents from California=s crude oil pipelines included in this study spilled from the pipe body.

Table 4-14

Incidents by Item Which Leaked by Cause - CSFM-Regulated Pipelines

Incidents per 1,000 Mile Years

Cause of Incident	Pipe		Valve		Pump		Weld Fitting		Long Weld	
	#	%	#	%	#	%	#	%	#	%
External Corrosion	298	67.3	0	.0	0	.0	0	.0	0	.0
Internal Corrosion	14	3.2	0	.0	0	.0	0	.0	0	.0
3rd Party/Construction	62	14.0	2	12.5	0	.0	1	12.5	0	.0
3rd Party/Farm Equip	18	4.1	0	.0	0	.0	0	.0	0	.0
3rd Party/Train Derail	2	.5	0	.0	0	.0	0	.0	0	.0
3rd Party/Ext Corrosion	7	1.6	0	.0	0	.0	0	.0	0	.0
3rd Party/Other	13	2.9	0	.0	0	.0	1	12.5	0	.0
Operating Error	5	1.1	1	6.3	0	.0	1	12.5	0	.0
Design Flaw	0	0	1	6.3	0	.0	1	12.5	0	.0
Equipment Malfunction	6	1.4	5	31.3	2	40	0	.0	1	10
Maintenance	1	.2	3	18.8	0	0	0	.0	0	.0
Weld Failure	4	.9	0	.0	0	0	4	50	8	80
Other	13	2.9	4	.25	3	60	0	.0	1	10
Total	443	100	16	100	5	100	8	100	10	100

Table 4-14 (continued)

Incidents by Item Which Leaked by Cause - CSFM-Regulated Pipelines

Incidents per 1,000 Mile Years

Cause of Incident	Girth Weld		Thread Conn		Bolted Conn		Other	
	#	%	#	%	#	%	#	%
External Corrosion	2	100	0	0	0	0	4	17.4
Internal Corrosion	0	0	0	0	0	0	0	0
3rd Party/Construction	0	0	0	0	0	0	0	0
3rd Party/Farm Equipment	0	0	0	0	0	0	0	0
3rd Party/Train Derailment	0	0	0	0	0	0	0	0
3rd Party/External Corrosion	0	0	0	0	0	0	0	0
3rd Party/Other	0	0	0	0	0	0	0	0
Operating Error	0	0	0	0	0	0	0	0
Design Flaw	0	0	0	0	0	0	0	0
Equipment Malfunction	0	0	0	0	0	0	13	56.5
Maintenance	0	0	0	0	1	25	0	0
Weld Failure	0	0	0	0	0	0	3	13
Other	0	0	0	0	3	75	2	8.7
Total	2	100	0	0	4	100	23	100

4.15 Hydrostatic Testing Interval

This section presents the leak incident rates for pipelines grouped with various hydrostatic testing intervals.

CSFM-Regulated Hazardous Liquid Pipelines

The hydrostatic testing requirements for CSFM-regulated intrastate and interstate pipelines vary significantly. Basically, the regulations for intrastate lines require periodic hydrostatic testing while those for interstate lines require only initial hydrostatic testing. Specifically, Section 51013.5 of the California Government Code requires hydrostatic testing of intrastate pipelines as follows:

- Every newly constructed pipeline, existing pipeline, or part of a pipeline system that has been relocated or replaced, and every pipeline that transports a hazardous liquid substance or highly volatile liquid substance, must be tested in accordance with 49 CFR 195, Subpart E.

- Every pipeline not provided with properly sized automatic pressure relief devices or properly designed pressure limiting devices must be hydrostatically tested annually.

- Every pipeline over 10 years of age and not provided with effective cathodic protection must be hydrostatically tested every three years, except for those on the State Fire Marshal's list of higher risk pipelines which shall be hydrostatically tested annually.

- Every pipeline over 10 years of age and provided with effective cathodic protection shall be hydrostatically tested every five years, except for those on the State Fire Marshal's list of higher risk pipelines which shall be tested every two years.

- Piping within a refined products bulk loading facility shall be tested every five years for those pipelines with effective cathodic protection and every three years for those pipelines without effective cathodic protection.

For interstate pipelines, 49 CFR 195.300 requires hydrostatic testing of newly constructed pipelines; existing steel pipeline systems that are relocated, replaced, or otherwise changed; and onshore steel interstate pipelines constructed before January 8, 1971, that transport highly volatile liquids.

The data was reviewed to evaluate hydrostatic testing effectiveness. Two separate pieces of information were gathered. First, the total number of hydrostatic tests performed on each

pipeline during the ten year study period was gathered. Secondly, for each leak which occurred during the study period, the date of the preceding hydrostatic test was obtained.

To determine the average hydrostatic test interval for each pipeline during the study period, the ten year study period was divided by the total number of hydrostatic tests performed during the study period. Incident rates were then determined for each pipeline within given ranges of hydrostatic testing intervals. Table 4-15A presents the resulting data.

As indicated, the pipelines which were hydrostatically tested most frequently, up to two years average hydrostatic test interval, suffered the highest leak incident rate. However, these lines were the oldest, operated at the highest mean operating temperature, and had the smallest mean diameter. All of these factors would tend to increase the incident rate.

On the other end of the spectrum, the lines which had the longest average hydrostatic test interval suffered the lowest leak incident rates. But these lines were the newest and had the lowest mean operating temperature. Once again, these factors would tend to decrease their incident rates as we have already seen.

California's *higher risk* pipeline category would also tend to skew this data. As previously mentioned, these lines had a generally much higher leak incident rate. Those which were greater than 10 years old were required to be tested at either one or two year intervals, depending on whether or not they were cathodically protected.

Table 4-15B presents the second set of data - the time since hydrostatic testing for each leak, regardless of cause. Although not as drastic, this analysis resulted in similar results. As indicated, the pipelines which had the shortest interval between hydrostatic testing and the leak, suffered the highest leak incident rate. However, these lines were the oldest, operated at the highest mean operating temperature, and had the smallest mean diameter. All of these factors would tend to increase incident rates.

On the other hand, the lines which had the greatest length of time between hydrostatic testing and the subsequent leak, had the lowest leak incident rates. But these lines were the newest and had the lowest mean operating temperature. As has been previously noted, these factors would tend to decrease their incident rates.

With the data presented, it is difficult to readily determine the effectiveness of hydrostatic testing. The multiple regressions indicated that pipe age and operating temperatures had the greatest impact on leak incident rates. We believe that the data presented in this subsection reflected the pipe age and operating temperature effects. From these data alone, it is impossible to determine whether or not more frequent hydrostatic testing affected the frequency of leak incidents.

However, using these data, we do not conclude that more frequent hydrostatic testing reduced leak incident rates.

Table 4-15A
Average Hydrostatic Testing Interval During Study Period - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	Up to 2.0 Years		2.1 - 5.0 Years		5.1 - 10.0 Years	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	144	9.58	113	4.67	36	2.06
Internal Corrosion	6	.40	6	.25	0	.00
3rd Party/Construction	21	1.40	15	.62	16	.92
3rd Party/Farm Equipment	0	.00	6	.25	11	.63
3rd Party/Train Derailment	0	.00	0	.00	1	.06
3rd Party/Ext Corrosion	2	.13	4	.17	0	.00
3rd Party/Other	5	.33	2	.08	0	.00
Operating Error	5	.33	3	.12	0	.00
Design Flaw	0	.00	1	.04	0	.00
Equipment Malfunction	12	.80	9	.37	4	.23
Maintenance	0	.00	3	.12	0	.00
Weld Failure	3	.20	10	.41	2	.11
Other	3	.20	12	.50	4	.23
Total Number of Incidents	201	13.37	184	7.61	74	4.24
Number of Mile Years	15,032		24,173		17,449	
Mean Year of Construction	1949		1953		1959	
Mean Operating Temp (1F)	122.3		104.6		88.5	
Mean Diameter (inches)	11.4		12.7		12.3	

Table 4-15B

Time Since Last Hydrostatic Test at Time of Leak - CSFM-Regulated Pipelines

Incidents per 1,000 Mile Years

Cause of Incident	Up to 2.0 Years		2.1 - 5.0 Years		5.1 - 10.0 Years	
	Number	Rate	Number	Rate	Number	Rate
Total Number of Incidents	147	9.83	165	6.67	109	6.46
Number of Mile Years	14,953		24,745		16,876	
Mean Year of Construction	1949		1953		1959	
Mean Operating Temp (1F)	122.3		104.6		88.5	
Mean Diameter (inches)	11.4		12.7		12.3	

<u>California Crude Oil Pipelines Under Study</u>

In contrast to the CSFM-regulated hazardous liquid pipelines, there are no requirements for hydrostatic testing California=s crude oil pipelines under study. As a result, it was not surprising to find that 87% of these lines had never been hydrostatically tested; 2% had been tested within the last five to ten years; 1% had been tested within the last two to five years; and 10% had been tested within the last two years. The distribution and incident rates for these crude oil pipelines is presented in Table 4-15C.

Unfortunately, there was insufficient data to allow a meaningful analysis. However, the vast majority of the lines, which had never been tested, had a leak incident rate of 5.42 incidents per 1,000 mile years. This value is less than the 6.72 incidents per 1,000 mile year incident rate for all of the pipelines included in this study. Further, the leak incident rate for external corrosion caused leaks was 3.10 incidents per 1,000 mile years, versus 4.03 incidents per 1,000 mile years for all of the crude oil pipelines under study.

The highest incident rate occurred on the pipelines which had been tested within the last two to five years. This group suffered a leak incident fate of 167 incidents per 1,000 mile years. However, this resulted from only two leaks on about four miles of pipelines.

Based on this data, hydrostatic testing does not appear to categorically result in a reduction in the leak incident rate. The reader should note that these data may be misleading. Often, operators hydrostatically test lines with a relatively high history of leaks as a preventive maintenance measure. In this way, they attempt to identify the weak points in the pipeline. When a leak develops during the hydrostatic test, water is spilled instead of oil. This prevents significant environmental damage and allows the operator to repair or replace a damaged section of pipeline and prevent crude oil spills. As a result of this practice, the leak incident rates for frequently tested pipelines would be higher, since the lines selected for testing would have a higher incidence of leaks. The results would then indicate that frequently tested pipelines had a higher leak incident rate, while in reality, the hydrostatic tests may have been a very helpful tool for preventing and/or minimizing the number of future leaks.

Table 4-15C

Hydrostatic Testing Interval During Study Period - Crude Oil Pipelines Under Study

(Incidents per 1,000 Mile Years)

Cause of Incident	Up to 2.0 Years		2.1 - 5.0 Years		5.1 - 10.0 Years		None	
	Number	Rate	Number	Rate	Number	Rate	Number	Rate
External Corrosion	0	.00	2	166.67	0	.00	4	3.10
Internal Corrosion	0	.00	0	.00	0	.00	2	1.55
3rd Party/Construction	0	.00	0	.00	1	28.57	0	.00
3rd Party/Farm Equipment	0	.00	0	.00	0	.00	1	.77
Total Number of Incidents	0	.00	2	166.67	1	28.57	7	5.42
Number of Mile Years	149		12		35		1,291	
Mean Year of Const	1966		1951		1989		1950	
Mean Operating Temp (1F)	80		68		141		62	
Mean Diameter (inches)	11.0		8.0		11.0		6.9	

4.16 Spill Size Distribution

In many instances, the spill volume is often related to the amount of environmental and/or property damage involved with an incident. While the first barrel spilled usually causes the greatest damage per barrel spilled, additional spill volume most often tends to increase the environmental and property damage to some degree.

This section presents and compares the spill volume distribution data for both CSFM-regulated hazardous liquid pipelines and the crude oil pipelines under study. As is noted, the spill volumes from the crude oil pipelines in this study are much lower than those from the CSFM-regulated pipelines.

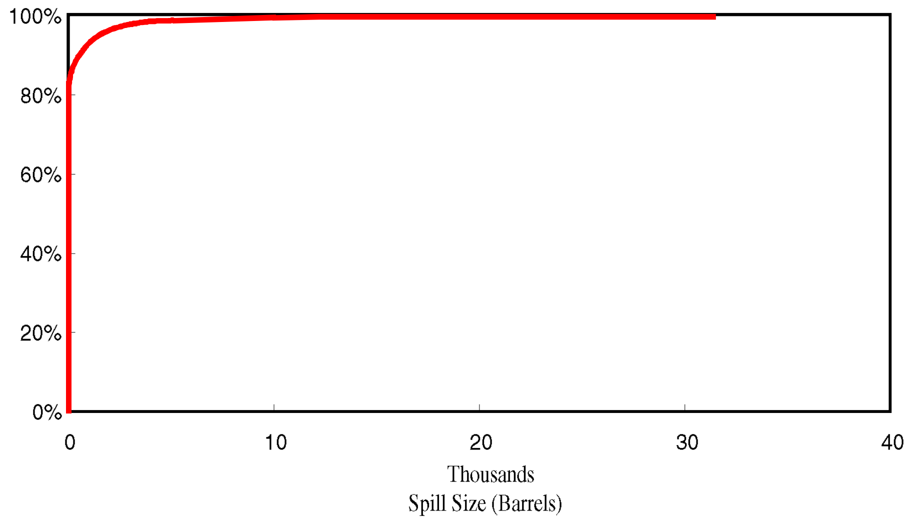
CSFM-Regulated Hazardous Liquid Pipelines

Selected data concerning spill size for the CSFM-regulated hazardous liquid pipeline leak sample are summarized below:

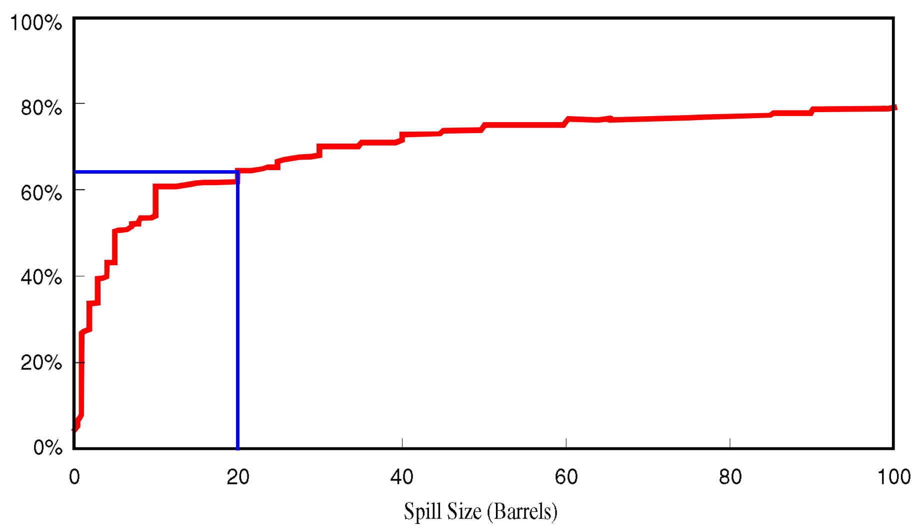
% of incidents resulted in spill volume of ≤1 bbl	27%
Median Spill Volume	5 bbl
% of incidents resulting in spill volume of ≤10 bbl	61%
% of incidents resulting in spill volume of ≤25 bbl	67%
% of incidents resulting in spill volume of ≤100 bbl	82%
% of incidents resulting in spill volume of ≤650 bbl	90%
% of incidents resulting in spill volume of ≤1750 bbl	95%
Largest spill volume	31,000

The large difference between the five barrel median spill size and the 408 barrel average spill size was caused by a relatively small number of incidents which resulted in large spill volumes. This increased the average value considerably.

Table 4-16A
Spill Size Distribution
CSFM Regulated Pipelines
Spill Size Versus Cumulative Percentage of Incidents



Spill Size Distribution
Spill Size versus Cumulative Percentage of Incidents
0 to 100 Barrels Only



NOTE: 64.48% of the incidents resulted in spills of 20 barrels or less.

Table 4-16B

Spill Size Distribution - CSFM-Regulated Pipelines

Spill Size (bbl)	Number of Incidents	%	Cumulative %
0 - .99	36	7.61	7.61
1 - 4	167	35.31	42.92
5 - 9	50	10.57	53.49
10 - 49	98	20.72	74.21
50 - 99	27	5.71	79.92
100 - 999	55	11.63	91.54
1,000 - 9,999	35	7.40	98.94
10,000 - 31,000	5	1.06	100
Total	473		

California Crude Oil Pipelines Under Study

Although the data sample is very small, the spill size distribution for California's crude oil pipelines under study are presented in Tables 4-16A and 4-16B. This spill size distribution data is useful in establishing the likelihood, or return interval, of a given size leak from a given pipeline. By combining the leak incident rate and the spill size distribution data, the probable return interval of various sized spills can be determined. The following leak incident rates for various sized spills were established using these data.

Spill Size per 1,000 mile years	**Crude Oil Pipelines Under Study**	**CSFM-Regulated Pipelines**
Number of Incidents-any size	n/a	7.08
Incidents ≥ 1 bbl	6.72	6.54
Incidents ≥ 10 bbl	2.02	3.29
Incidents ≥ 100 bbl	1.10	1.42
Incidents ≥ 1000 bbl	0.69	0.58
Incidents ≥ 10,000 bbl	0.00	0.075

As indicated, the incident rate for various sized spills from the crude oil pipelines under study are generally less than those from the CSFM-regulated hazardous liquid pipelines. As noted above, the probable return interval from a given length of pipeline can be determined using these data. Often, this data provides a more useful result. This data is presented below for a one-mile pipeline.

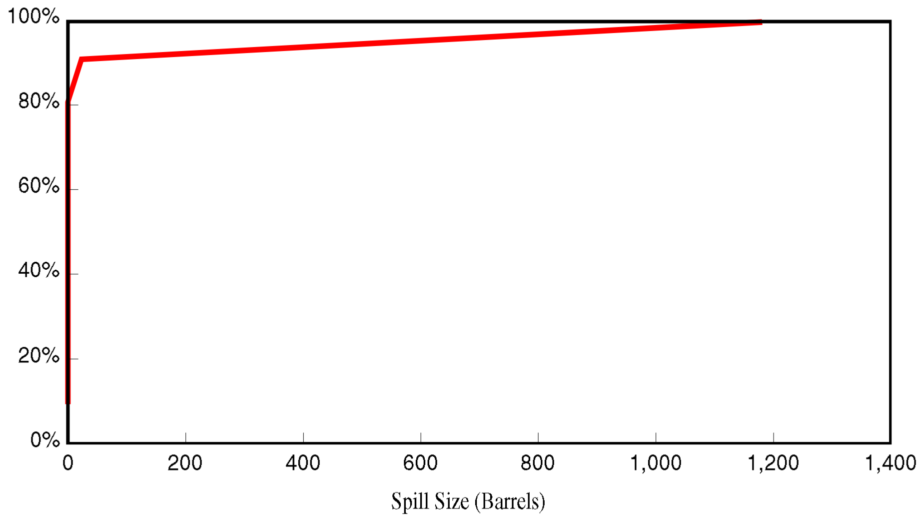
	Return Interval from any 1 mile of Pipeline (Years)	
Spill Size	**Crude Oil Pipelines Under Study**	**CSFM Regulated Pipelines**
Any size	n/a	141
≥ 1 bbl	149	153
≥ 10 bbl	495	304
≥ 100 bbl	909	704
≥ 1,000 bbl	1,450	1,720
≥ 10,000 bbl	infinite	13,300

This data can also be analyzed to determine the probable recurrence interval for various sized spills from all of the 7,800 miles of CSFM-regulated hazardous liquid pipelines and 496 miles of crude oil pipelines under study.

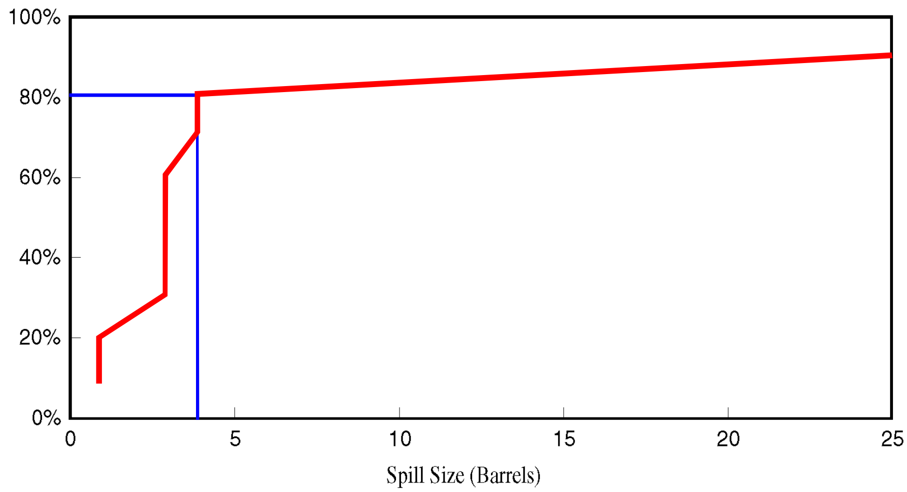
	Crude Oil Pipelines Under Study		CSFM Regulated Pipelines	
	Return Interval from 496 miles of pipeline		Return Interval from 7,800 miles of pipelines	
Spill Size	Time	Leaks per year	Time	Leaks per year
Any size	n/a		6.6 days	55
≥ 1 bbl	3.6 months	3.3	7.2 days	51
≥ 10 bbl	1.0 years		14 days	26
≥ 100 bbl	1.8 years		1.1 months	11
≥ 1,000 bbl	2.9 years		2.7 months	4.5
≥ 10,000 bbl	infinite		1.7 years	

As indicated, because of the relatively small length of crude oil pipelines under study and the lower frequency of a given size spill, the return interval for a given sized spill from these crude oil pipelines is far greater than for the CSFM-regulated hazardous liquid pipelines.

Table 4-16C
Spill Size Distribution
Crude Oil Pipelines Under Study
Spill Size Versus Cumulative Percentage of Incidents



Spill Size Distribution
Spill Size Versus Cumulative Percentage of Incidents
0 to 100 Barrels Only



NOTE: 80.00% of the incidents resulted in spills of four barrels or less.

4.17 Damage Distribution

The property damage distribution was very similar to the spill size distribution discussed in the preceding section. A few incidents resulted in relatively large property damage values which increased the mean values considerably. To the greatest extent possible, the damage figures used in this study included all costs associated with the incident (e.g. value of spilled fluid, clean-up, injury, judgements, fatalities, etc.).

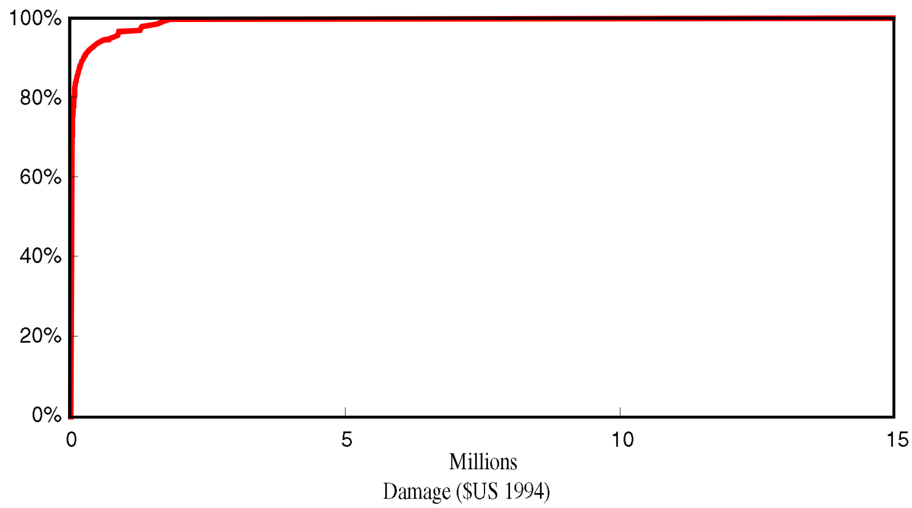
<u>CSFM-Regulated Hazardous Liquid Pipelines</u>

Table 4-17A depicts the property damage distribution data for CSFM-regulated hazardous liquid pipelines. All data has been shown in constant 1994 U.S. dollars. The values for each year were converted to 1994 constant dollars using the U.S. City Average Consumer Price Indices as published by the U.S. Bureau of Labor Statistics. A few points along the curve are presented below:

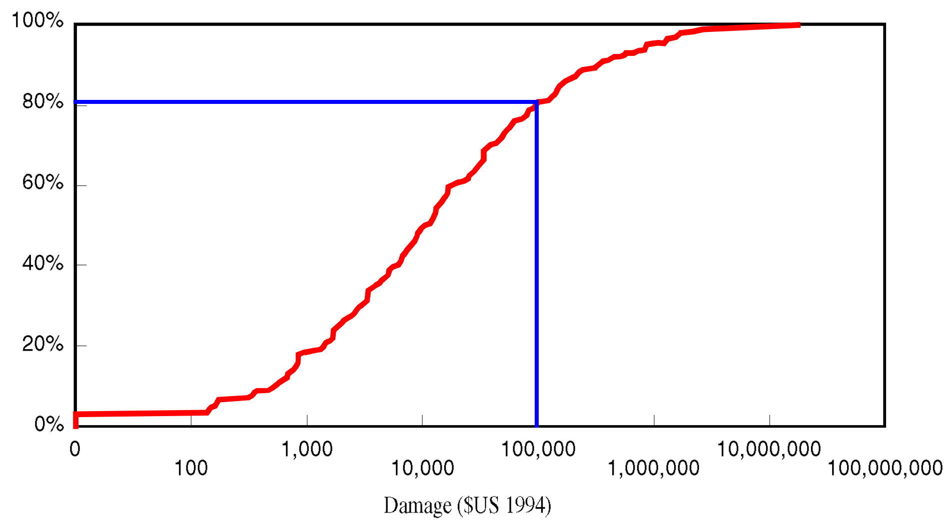
% of incidents resulting in damages of $2,000 of less	25%
Median damage	$11,000
% of incidents resulting in damage of $57,000 or less	75%
% of incidents resulting in damage of $270,000 or less	90%
% of incidents resulting in damage of $880,000 or less	95%
Largest reported damage for a single incident	$17,500,000*

*Figure may be increased as additional claims are settled.

Table 4-17
Property Damage Distribution
CSFM Regulated Pipelines



Damage Distribution
Logarithmic Scale



NOTE: 80.72% of the incidents resulted in damage of $100,000 or less.

California Crude Oil Pipelines Under Study

Although this data sample is very small, the damage distribution data for California's crude oil pipelines under study are presented in Tables 4-17B. In comparing Tables 4-17A and 4-17B, the shape of the curves are nearly identical for the CSFM-regulated hazardous liquid and crude oil pipelines in this study, except for the incidents which caused extensive property damage. Although the occurrence of spills which resulted in modest amounts of property damage were essentially the same for both groups of pipelines, the frequency of spills which caused $10,000 ($US 1994) in property damage or more was much greater for the CSFM-regulated pipelines.

These data are useful in establishing the likelihood, or return interval, of a leak resulting in a specific amount of damage from a given pipeline. By combining the leak incident rate and the damage distribution data, the probable return interval of various spills for a given pipeline can be determined. The following leak incident rates were established using these data.

Damage Resulting From Spill ($US 1994)	Incidents per 1,000 mile years	
	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines
$100	6.72	6.85
$1,000	6.72	5.80
$10,000	1.34	3.64
$100,000	1.14	1.36
$1,000,000	0.00	0.28
$10,000,000	0.00	0.028

As noted in the previous section, the probable return interval from a given length of pipeline can be determined using these data. Often, this provides a more useful result. These data are presented below for a one-mile pipeline.

Damage Resulting From Spill ($US 1994)	Return Interval from any 1 Mile of Pipeline (Years)	
	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines
$100	149	146
$1,000	149	172
$10,000	746	275
$100,000	1,090	735
$1,000,000	infinite	3,570
$10,000,000	infinite	35,700

These data can also be analyzed to determine the probable recurrence interval for various sized spills from all of the 7,800 miles of CSFM-regulated hazardous liquid pipelines and 496 miles of crude oil pipelines under study.

Spill Size ($US 1994)	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines
	Return Interval from 496 miles of these Pipelines	Return Interval from 7,800 miles of these Pipelines
$100	3.6 months, or 3.3 leaks per year	1 week, or 53 leaks per year
$1,000	3.6 months, or 3.3 leaks per year	7.8 days, or 45 leaks per year
$10,000	1.5 years	12 days, or 28 leaks per year
$100,000	2.2 years	1.1 months, or 11 leaks per year
$1,000,000	infinite	5.5 months, or 2.2 leaks per year
$10,000,000	infinite	4.6 years

As indicated, because of the relatively small length of crude oil pipelines in this study and the lower frequency of spills resulting in relatively large values of damage, the return interval for spills from these pipelines resulting in significant damage is greater than for the CSFM-regulated hazardous liquid pipelines.

4.18 Incident Rates by Internal Coating or Lining

The possibility for significant internal corrosion was envisioned on the crude oil pipelines evaluated in this study. As a result, data regarding the installation of internal liners or coatings was gathered. However, only about 1% of the pipelines had an internal liner or coating installed. Although not statistically relevant, all of the leaks occurred on unlined or uncoated pipe. The data sample was too small to facilitate an analysis of this parameter.

Table 4-18
Incident Rates by Above vs. Below Grade - Crude Oil Pipelines Under Study
(Incidents per 1,000 Mile Years)

Cause of Incident	Above	Below	Both
External Corrosion	.00	4.19	.00
Internal Corrosion	.00	1.40	.00
3rd Party/Construction	.00	.7	.00
3rd Party/Farm Equipment	.00	.7	.00
Total Number of Incidents	.00	6.98	.00
Total Number of Mile Years	45	1,432	10
Mean Year of Construction	1978	1952	1947
Mean Operating Temp (1F)	86.7	74.3	60
Mean Diameter (inches)	3.2	7.7	5.5
Average Spill (bbl)	0	122.1	0
Average Damage ($US 1994)	$0	$39,020	$0

4.19 Incident Rates by Above versus Below Grade Pipe

96.3% of the 496 miles of crude oil pipelines under study was buried below grade. Of the remaining pipe, 3% (15 miles) was installed above grade, and 0.7% (3 miles) was installed with a combination of both buried and above grade segments.

Table 4-19 presents the incident rates for the above and below grade pipelines. As indicated, all of the leaks occurred on the buried sections of line. However, this should not be considered statistically relevant because of the very limited data sample.

Cause of Incident	Above	Below	Both
External Corrosion	.00	4.19	.00
Internal Corrosion	.00	1.40	.00
3rd Party/Construction	.00	.70	.00
3rd Party/Farm Equipment	.00	.70	.00
Total number of Incidents	.00	6.98	.00
Number of Mile Years	45	1432	10
Mean Year of Construction	1978	1952	1947
Mean Operating Temperature (1F)	86.7	74.3	60
Mean Diameter (inches)	3.2	7.7	5.5
Average Spill (bbl)	0	122.1	0
Average Damage ($US 1994)	$0	$39,020	$0

4.20 Recovery of Spilled Volumes

Although only 10 leaks occurred during the three-year crude oil pipeline study period, the relationship between the volumes spilled and the volume recovered was reviewed. As indicated in Table 4-20, of the 1,221 barrels of crude oil spilled, roughly two-thirds (800 barrels) were recovered.

The lowest recovery percentage occurred from the external corrosion leaks. This relationship is not surprising, since these leaks are typically very slow, low leak rate incidents.

Table 4-20
Recovery of Spilled Volumes - Unregulated California Crude Oil Pipelines

Cause of Incident	Spilled (bbl)	Recovered (bbl)	Recovered (%)
External Corrosion	18	8	42%
Internal Corrosion	26	25	96%
3rd Party/Construction	1,174	764	65%
3rd Party/Farm Equipment	3	3	100%
Total	1,221	800	65%

4.21 Injuries and Fatalities

CSFM-Regulated Hazardous Liquid Pipelines
49 injuries and 3 fatalities resulted from incidents on CSFM-regulated hazardous liquid pipeline system during the ten year study period. Nearly 94% of the injuries and 100% of the fatalities resulted from only three incidents; it is remarkable that just over one-half percent of the total incidents resulted in all of the fatalities and nearly all of the injuries during the entire ten year study period. These incidents are briefly described below:

May 25, 1989, San Bernardino
On May 12, 1989, a freight train derailed in San Bernardino, California. On May 25, 1989, 13 days later, a CSFM-regulated interstate petroleum products pipeline ruptured. The National Transportation Safety Board determined that during the derailment, and later during the movement of heavy equipment to remove the wreckage, the high-pressure products pipeline adjacent to the tracks was damaged and weakened. Less than two weeks after the wreck, the pipeline ruptured and spilled more than 300,000 gallons of gasoline into a nearby neighborhood. Some of the gasoline ignited and caused significant fire damage. This incident resulted in two fatalities and thirty-one injuries.

February 22, 1986, Placer County
During the removal of an abandoned section of pipeline which had been relocated around a collapsed railroad trestle, approximately one barrel of gasoline was spilled. The fuel was ignited by a torch being used by the railroad's welding crew. As a result of the ignition, three welders jumped from the bridge into the creek below. This incident resulted in one fatality and one injury.

November 22, 1986, Tustin
A ten-inch API 5L X52, ERW pipe longitudinal weld seam ruptured. This resulted in the spill of about 11,000 barrels of unleaded gasoline. Fortunately, the spill did not result in fire or an explosion. Documents filed with the USDOT indicated that there were no injuries or fatalities meeting federal reporting criteria. (See also Chapter 3 of this study.) However, 14 emergency responders from the local fire department were treated for symptoms consistent with hydrocarbon exposure: eight were treated at a medical facility, four were treated and released at the scene, and one was hospitalized for observation. In addition, one civilian was also treated at the scene and released. These were treated as 14 injuries for the purposes of this study.

Each of these incidents had a different cause. Two were caused by some form of third party damage, while the third was caused by a material defect.

The number of incidents resulting in injuries and fatalities was too small to draw any meaningful conclusions. However, it should be noted that all injuries and fatalities occurred on pipelines carrying refined petroleum products. Crude oil pipeline incidents did not result in any injuries or fatalities during the study period.

The current requirements are basically the same for product and crude pipelines. However, although a limited sample, this data indicated that the risks to human life were likely greater for refined product pipelines. On the other hand, both crude and refined product pipeline incidents resulted in similar environmental concerns.

As mentioned previously, *all* injuries, regardless of severity, were included in these data. For instance, the 1986 Tustin incident resulted in 14 injuries which did not meet the USDOT injury reporting criteria. Deleting these injuries alone would have reduced the resulting injury rate for this study by more than one-third. The reader should keep this factor in mind while reading this section. Otherwise, the public injury risk could be over-exaggerated. Sufficient data was not available to sort the injuries incurred during the study period by severity.

California Crude Oil Pipelines Under Study

No injuries or fatalities occurred on the California crude oil pipelines during the three year study period. Further, the data sample was too small to be meaningful.

For example, if one simply applied the fatality rate or 0.042 fatalities per 1,000 mile years, which resulted from the CSFM-regulated hazardous liquid pipelines, one would anticipate a fatality every 16 years for the 496 miles of crude oil pipelines included in this study. This recurrence interval is greater than the three-year study period. As a result, one would not expect a fatality during this study. Further, as discussed above, the risk to human life from crude oil spills is likely less than for refined petroleum product pipelines, which would tend to increase the recurrence interval.

Chapter 5
Barriers and Incentive Options for Encouraging Pipeline Replacement or Improvements

5.0 Barriers and Incentive Options

As noted earlier in Chapter 1, Section 51015.05 of the California Government Code requires that CSFM investigate incentive options that would encourage pipeline replacement or improvements, including, but not limited to, a review of proposed regulatory, permit, and environmental impact report requirements and other proposed public policies that could act as barriers to the replacement or improvement of these pipelines.

To this end, on January 31, 1996, EDM Services distributed a questionnaire regarding incentive options and barriers to pipeline replacements and/or improvements. 231 questionnaires were distributed to:

- operators of CSFM-regulated hazardous liquid pipelines,
- all participants in this study,
- State regulatory and jurisdictional agencies,
- local communities with a high density of oil and gas activity (e.g. San Luis Obispo, Santa Barbara, and Ventura), and
- members of the Pipeline Assessment Steering Committee.

The questionnaire contained 14 questions designed to gather information on, measure attitudes toward, and obtain suggestions about proposed or potential incentives and barriers to pipeline replacement and/or improvement. Respondents were allowed one month to complete the written questionnaire, although considerable latitude was given to those who needed additional time. In all, 28 responses were received; a rate of response well within the bounds of acceptability for this method of study design and implementation. Nine completed questionnaires were obtained from regulatory or jurisdictional agencies and 19 were received from operators (both majors and independents). In addition, nine of the respondents stated in one form or another that their

company/agency could offer no comments to the CSFM on these particular issues. One respondent provided comments only on the initial permitting process due to a lack of experience in replacing or improving pipelines. Though not specified in the questionnaire, respondents were allowed to provide answers and case studies for pipeline projects that are not included in AB 3261 or otherwise a part of this study.

The responses were analyzed by BDM/Oklahoma and this chapter was authored by BDM/Oklahoma=s Deborah Pratt and Jerry Simmons using the responses received. Pratt and Simmons also developed the conclusions and recommendations sections concerning Incentives/Barriers in Chapters 6 and 7.

In the following analysis of the questionnaire results, some classifications and groupings of answers have been employed. First, a distinction was made between responses from regulatory agencies, on the one hand, and private companies on the other; due largely to observable differences in emphases and in the qualitative nature of the responses. Second, with regard to incentive options, a distinction was made between what can be termed "negative" and "positive" incentives. As used in this report, "negative" incentives refer to those actions (or suggested actions) taken by government agencies in response to pipeline leaks, non-compliance, etc. These incentives are often punitive in nature and seek to deter undesirable behavior or correct it after the fact. "Positive" incentives refer to those actions taken by regulatory agencies that seek to *reward* operators who have a history of sound regulatory compliance, thus engendering continued attention to issues of pipeline safety.

The first set of questions targeted potential and/or proposed incentive options available to regulating agencies. In each case, respondents were asked to identify incentives that would encourage pipeline replacements or improvements and indicate how these incentives should be implemented. The reader should note that respondents were not required to rigidly adhere to the format, but were afforded the opportunity to fully explain their responses and provide case studies where appropriate. The following is a summary of the responses to potential and/or proposed "incentives options".

5.1 Responses from Regulatory Agencies - Incentives

<u>Negative Incentives</u>

In one form or another, the most commonly cited potential and/or proposed negative incentives by regulatory agencies pertain to changing the nature and scope of the consequences of pipeline leaks and non-compliance. Possible consequences included:

- civil penalties,
- require replacement or re-conditioning of sections of pipeline that have "excessive" leak history,
- require reduced operating pressures for pipelines with "excessive" leak history,
- increase inspection of poorly maintained pipelines with identified integrity problems, and
- assess all annual fees based on the degree to which the pipeline is "leak prone".

<u>Positive Incentives</u>
The following "positive" incentives were most often suggested by the regulatory agencies:

- reduce inspection of new pipelines after a sound regulatory compliance history has been established,
- extend the time between required hydrostatic tests under State law for new or replaced pipelines,
- allow operators to use an alternative test method in lieu of the hydrostatic test,
- provide a "good service award" for the pipeline company with the most reconditioned or replaced sections of pipeline,
- provide assistance (financial and otherwise) to companies that are obtaining permits and authorizations to do replacements and/or improvements,
- adopt "regional guidelines and processes" for pipeline activities that promote environmental, safety, and health concerns,
- reward compliant operators with expedited government reviews,
- establish cooperative emergency response planning and resources, and
- categorically exclude pipeline replacements or improvements from the California Environmental Quality Act (CEQA).

5.2. Responses from Pipeline Operators - Incentives

Not surprisingly, suggested incentives by operators were skewed toward the positive side; that is, the number of *positive* incentives exceeded the number of *negative* incentives by almost nine to one. The following is a summary of the incentives suggested by the operators:

Negative Incentives

- issue fines to operators for every leak, incident, or other "negative" situation.

Positive Incentives

- reduce inspection frequencies/scope,
- streamline the permitting process (i.e. "one-stop-shopping"),
- reduce the frequency with which hydrostatic testing must be conducted,
- reduce/eliminate CSFM fees on pipelines that have been replaced or improved,
- provide for an automatic negative declaration of adverse environmental impact for pipeline replacement or repair projects being done to improve safety,
- formally recognize operators and individuals, (e.g. positive press releases, plaques, letters, notices of commendation, annual luncheon/dinner to recognize pipeline safety achievements, etc.),
- establish a fund to reimburse (or partially reimburse) corporate investments in technologies that reduce leaks and incidents, ensure compliance, etc., and
- establish an Operator Pipeline Safety Leadership Committee to provide ongoing recommendations to CSFM on pipeline safety issues.

5.3 Incentive Implementation

There were very few specific responses which provided input regarding how these incentives could be implemented. However, the idea of establishing some sort of a task force garnered support from both regulatory agencies and operators. The following implementation suggestions were offered by the participants.

- Create a joint industry/government task force in a partnering process to review promising ideas and determine feasible implementation,

- Implement all incentives at the regulatory "staff" level as opposed to hearings, appeals processes, etc.

- Leave the decision to replace or repair a pipeline "solely with the individual pipeline operator."

5.4 Summary of Questionnaire Results: Barriers

The second set of questions targeted perceived barriers to pipeline replacement projects. Respondents were asked to identify barriers, describe the actual and potential consequences of these barriers, and suggest ways in which the barriers could be mitigated. Although the questionnaire clearly distinguished between *barriers* and *incentives*, there was some overlap in the responses to each; that is, similar responses were received for both types of questions. In addition, seven of the nine regulatory agencies did not respond to questions on barriers citing, for the most part, a lack of relevant case histories of projects which have been delayed, deferred or canceled because of regulatory, permit or environmental impact barriers. A significant portion of the responses, therefore, came from the operators who responded to the questionnaire.

Regulatory Barriers, Permitting Barriers, and EIRs

By far the most commonly cited barriers to replacing or improving pipelines involve the permitting process. Across the board, operators indicated that these processes: (1) take far too long; (2) demand an unrealistic allocation of expenditures; and (3) may unnecessarily put the environment and the safety and health of the public at risk. Some of the difficulties expressed by respondents include:

- obtaining construction permits from various cities in a timely manner,

- obtaining Negative Declaration Status (often taking up to 18 months),

- acquiring an "Endangered Species Management Agreement" (2081 permit),

- complying with CEQA requirements due to implementation variances from county to county,

- erroneous application by the local fire department of city regulations to jet fuel pipelines (the "more is better" school of regulation),

- slow responses by local transportation and public works departments (One operator stated that it can take up to six months for a local department of transportation to decide on a relevant CEQA standard.),

- California Government Code Sections 51013 and 51014 regarding hydrostatic testing,

- franchise agreements requirements,

- local agency street opening excavation or building permit process,

- California Coastal Commission and BCDC permit processes, and

- Environmental Impact Reports.

5.5 Actual and Potential Consequences of Barriers

According to respondents, the actual and potential consequences of the identified barriers are predominately financial; although environmental, safety, and health consequences were also noted with some regularity. *There is a tremendous amount of concern among the operators that pipeline improvements/replacements have become so costly and cumbersome that they no longer have any incentive to be proactive in these matters*. In fact, one respondent stated that replacements and improvements are now considered "...only as a last resort to all other options."

Environment, public safety and health consequences were also noted by some respondents. For example, in one case, an operator proposed to install and operate internal corrosion inhibitor storage and injection facilities at its pump station facilities in a particular county. The initially proposed project took more than 18 months from application submittal to receipt of construction approvals and permits. Although other temporary measures were taken by the pipeline operator, these measures involved more risk that the actual proposed project and delayed the implementation of a more desirable corrosion inhibitor program; fortunately, pipeline integrity was not impacted by this delay. Other commonly cited consequences include:

- unnecessary and unrealistic expenditures of time and financial resources,

! project delays, deferrals, or elimination,

! actual amount of pipe replaced is decreased,

! hydrostatic testing requirements are accelerating leaks and leading to the generation of contaminated waste water, and

! marginal gathering lines are no longer being replaced by some operators.

5.6 Removing Barriers

The overwhelming consensus of the study=s participants is that the *permitting process* must be streamlined. One of the primary areas of concern involves jurisdictional issues. Many respondents (both regulators and operators) expressed a desire to eliminate overlapping agency and redundant requirements. As one operator stated,

> Although the respondents consensus was that the permitting process must be streamlined, it should be noted that some local agencies have made recent improvements to improve their processes. One county cited the issuance of minor use permits, instead of the more typical conditional use permits which require Planning Commission approval for pipeline upgrade projects. Emergency permit processes have also be developed to allow immediate pipeline work when circumstances warrant.

With respect to the CSFM in particular, respondents appear to want mechanisms to ensure that counties or other agencies (such as local fire, planning and health departments) do not impose requirements or regulate pipeline safety issues that fall under the exclusive authority of the CSFM. The most common suggestions for jurisdictional streamlining are as follows:

! develop Memoranda of Understanding which address problem areas and identify primary agency responsibilities,

! create or designate a single State agency with sole jurisdiction over pipeline issues, and

- establish the USDOT as lead permitting agency for pipeline maintenance projects for interstate pipelines

Respondents also provided the following suggestions about specific regulations, possible modifications, exemptions, and timing:

- consistently implement the Long Term Programmatic Permit for Threatened and Endangered Species among the different BLM Resource Area Offices for maintenance projects,
- develop a clear procedure (or flow chart) of required documents,
- set time limits for BLM to complete permit applications once received by the appropriate office,
- apply smart pigging requirement to new pipelines only,
- limit the requirement to upgrade all components within a line section when only a small replacement is required,
- eliminate periodic hydrostatic testing requirements on existing pipelines,
- provide categorical exemption under CEQA for pipeline replacement projects under the jurisdiction of the CSFM,
- eliminate the county billing method, and
- exempt pipeline safety replacement projects from EIRs.

5.7 Case Studies

Following are a few case studies and excerpts from the completed questionnaires. It should be noted that due to time constraints, many of the local agencies did not have an opportunity to develop specific case study responses. The reader should also note that the information presented in these case studies has not been independently verified, nor has a methodologically sophisticated analysis of the results been conducted. Hence, the excerpts below should not necessarily be taken as fact or considered to be representative of the entire sample of respondents. The intent of the questionnaire, and of this portion of the report, was to identify public policies that *could* act, or be perceived as barriers to the replacement or improvement of pipelines and, similarly, to identify possible incentive options that would encourage these

activities. The reader should note that the actual responses have been edited to remove the actual company and agency names.

A. We are attempting to replace and relocate a portion of an acetylene welded pipeline within the City A. A section of this pipeline runs through a school property. The only alternative to relocate this section would be to obtain new right-of-way through the City B. City B is not cooperating and is essentially telling us that they do not want to take on City A:s problem. This delay has caused the pipe not to be relocated to an area safer to the public.

B. CEQA is the most significant regulatory barrier. The implementation of CEQA varies significantly from county to county. Some counties have planning departments that take the CEQA issues to the Anth@ degree. As a illustration, a permit from County A for one pump station and one 10.5 mile pipeline has 109 permit conditions ... The permit costs are substantial; the 1995 permit fees from County A for this permit were about $192M. Probably one third of that was attributed to new construction in the pump station. The construction work required a Supplemental EIR that cost the operator in excess of $100M and took over 2 years to get approved. ..... Most of the pipeline replacement work that the operator undertakes is due to corroded pipe identified from internal inspections (smart pigging). We believe that permitting delays of 1-2 years is an excessive amount of time to wait when we know that the pipe is corroded. The actual consequences of the permitting barriers is that the operator does not replace pipe as quickly as it could without the barriers and the amount that could be replaced is less than it would be if the resource burdens of permitting were less. This tends to increase risk. Also we have stopped replacing marginal gathering lines. The economics of these pipelines can not justify the cost of preparing a development plan or a minor use permit and the expensive permitting process. We have begun the petition process with CPUC to begin shutting down these lines. The oil from the leases that these lines serve will have to be trucked.

C. This project was voluntarily proposed to reduce the risk of an environmental incident. The State Lands Commission strongly supported getting this work done but it was strictly up to us to take the initiative to get the permits. ..... Platform A lies about 2.5 miles off the California coast. It produces about 4,500 barrels of oil per day and 3 million cubic feet of gas per day. The oil and associated water are piped to a separation plant on the beach through a single 6-inch subsea pipeline. The sour gas is piped to the same plant for sweetening, dehydration and compression through a separate 6-inch subsea pipeline. The platform was installed along with the two pipelines in 1966. Mitered bends of 30° were used in the pipelines at the beach in the surf zone for a direction change. Miter bends are

not typically used for this purpose. Curved or manufactured bends are usually used for direction changes in pipelines. Today, electronic inspection tools known as Asmart pigs@ are pumped through pipelines to inspect the condition of the pipelines. These tools are usually about 10 to 12 feet long and are segmented to go around bends. The segments are too long to make it through a miter bend, so the miters must be replaced with curved bend pieces if an inspection is to be done on the lines. We would like to electronically inspect the condition of these 1966 vintage pipelines to insure that they are still in good condition. Annual pressure tests of these lines have not resulted in any problems or failures to date. A break or leak in the oil line would, of course, result in oil getting in the ocean. Replacement of these lines in their entirety would cost 3 to 5 million dollars and would take 2 to 3 years to permit, if permittable at all, under the current permit conditions.

This project involves simply cutting out the miter bends and welding in long radius bends. This is essentially four 6-inch pipeline cuts and eight 6-inch pipe welds. The previous 50% owner and operator of the operation started getting proposals to replace these miter bends in 1983. When we took over operating and 100% ownership in 1993, the previous operator still did not have permits to do this job. We started working on a design and permit application in the second quarter of 1994. This included many meetings with the county staff, the fire department and the county building department to insure compliance with all regulations and to negotiate the conditions imposed by these agencies. The application for county Planning and Development Plan Permit and Conditional Use Permit were officially submitted in December 1994. Additional permits required were:

- County Coastal Development Plan permit,
- California Coastal Commission Coastal Development Plan permit,
- U.S. Army Corps permit which require California Regional Water Quality Control Board (RWQCB) waiver or certification under the section 401 of the Clean Water Act, and
- California State Lands Commission approval.

The Coastal Commission=s Coastal Development Plan permit is essentially the same as the county CDP but it can=t be applied for until the county DP and CUP are approved. The Army Corps approval can=t be obtained until the California Coastal Commission CDP is received.

The whole process is burdened with redundancy. The county and Coastal Commission look at exactly the same issues and scrutinize these issues independently, wasting large amounts of time and money. The staff report by the county was over 100 pages. The State Lands Commission is the only agency that has the technical expertise to look at the mechanics of how this tidal zone job is being done. Yet the procedure was reviewed and scrutinized by the county planning department, the fire department, the county building department and the California Coastal Commission.

The county charges to for staff time for this project amount to somewhere in the neighborhood of $40,000 for review and staff report preparation. (Remember this is for a project requiring 4-6@ pipeline cuts and 8-6@ pipeline welds.)

Prior to ever getting to the planning commission=s Hearing Board, the county staff placed conditions in the staff report on the project; and, the applicant and county staff have a one-sided negotiation on these issues. We have very little leverage to get anything changed. The county took the opportunity to add operational conditions that had not been required or necessary in the past 30 years of operation and required acceptance in order to get the staff report finalized for the commissioners. For example, on very rare occasions the beach sections of the pipelines become completely uncovered by natural sand transport during the stormy season. Usually this occurs between January and March. We, as prudent operators, always watched the lines to insure they were not damaged or did not move around too much in the surf during time period. A new condition for the remaining life of the pipelines states that we must shut down the entire production operation when more than 20 feet of the 16,000 foot long pipeline is exposed in the surf zone and there are 12-foot high waves. This means we would be required by permit to shut down the production operation under the stated conditions event if there was no risk to pipelines. Another condition is that we must visually inspect the pipeline every day of the year and keep a written log for County inspection. This requirement disregards that over 300 days a year there is absolutely no sign of pipelines on the beach, so this requirement is an expensive waste of manpower. Another extreme condition requires draining the flush water, which is ocean water, from the pipe prior to cutting the pipe. This is following flushing the lines to a point where the flush water had less than 30 ppm Oil and Grease content. To drain the water we will have to hot tap a weld-o-let on the pipeline and drain the flush water out of the section of the pipe uphill of the cut point. This was proposed by us in an effort to get around having a Clean Seas vessel on location and avoid a job shutdown because of a sheen. In addition we are required to have over 400 foot of absorbent boom on site for spill protection. All this for .03 gallons (calculated at 30 ppm) of oil in the 1000 feet of 6-inch pipeline which was uphill of the cut.

To summarize, this is a project that we voluntarily proposed to protect the environment and insure we would not have an oil spill incident. It is what should be a simple job but will probably end up costing over $250M to do plus four days of lost production at $30,000 to $40,000 per day lost revenue. In a normal setting, this job would be much less costly and time consuming. It would have been done years ago and there would be many electronic inspection records by now that could be used to develop trends on pipe degradation. We would be able to accurately predict when and if a pipe problem would occur.

The economic considerations for this asset have changed recently. We no longer intend to perform this repair until we have determined the future of this operation. The subject of the miter bend replacement would not be at issue now if the permitting process would have been reasonable and timely. The miter bends would have been replaced by the prior operator years ago or by us in 1994.

This situation could easily be improved by making one agency responsible for reviewing this type of work. Then have policies that allow practical, common sense judgments on issues of how to do the job based on the end result being much better than the current condition. Eliminate the redundancy of multiple agencies looking at the same thing and rely on the agency that has the most technical expertise to review the project. Eliminate the county billing method that encourages 100 page documents for what would be a half day job in another location. There is no incentive for county staff to be efficient and effective.

Chapter 6
Conclusions

The conclusions which can be drawn from this study have been organized into two groups.

! The first includes those which can be drawn from the pipeline and leak database study conducted in accordance with California Government Code Section 51015.05.

! The second includes those conclusions which can be drawn from the incentive option investigation, also conducted in accordance with California Government Code Section 51015.05.

6.1 Database Findings

Although extensive efforts were taken to gather the most complete database possible, including the distribution of over 1,200 questionnaires aimed at identifying study participants, the resulting data set was relatively small. The data set can be summarized as follows:

Number of incidents (≥ 1 bbl)	10
Number of pipelines	113
Total length of pipelines (miles)	496
Mean diameter of pipe (inches)	7.5
Mean operating temperature	74.21F
Cathodically protected pipe (miles)	317 (64% of total)
Bare pipe (miles)	87 (18% of total)
Median spill size (bbl)	3
Average spill size (bbl)	122
Median damage ($US 1994)	$5,000
Average damage ($US 1994)	$39,020
Length of Underground Pipe (miles)	478 (96.3% of total)

Overall Incident Rates

The overall leak incident rate for leaks of one barrel or more from the crude oil pipelines under study was very similar to the hazardous liquid pipelines currently regulated by CSFM - 6.72 versus 6.54 incidents per 1,000 mile years respectively. However, the incident rate for larger spills was generally much less for the smaller, crude oil pipelines in this study. The results for these crude oil gathering lines are summarized as follows:

Spill Event per 1,000 mile years	**Incident Rate**
≥1 bbl	6.72
≥10 bbl	2.02
≥100 bbl	1.10
≥1,000 bbl	0.69
≥10,000 bbl (per 1,000 mile years)	0.00
≥$1,000 damage ($US 1994-per 1,000 mile years)	6.72
≥$10,000 damage ($US 1994-per 1,000 mile years)	1.34
≥$100,000 damage ($US 1994-per 1,000 mile years)	1.14
≥$1,000,000 damage ($US 1994-per 1,000 mile years)	0.00
Injury (per 1,000 mile years)	0.00
Fatality (per 1,000 mile years)	0.00

External Corrosion

External corrosion was by far the leading cause of incidents in this study, representing 60% of the total. However, with the limited data sample, we were unable to isolate the cause. The results of the 1993 study regarding CSFM-regulated pipelines indicated that pipe operating temperature and age were the two leading factors contributing to increased external corrosion. We suspect that this is also the case for the crude oil pipelines under study. However, the data set was too small to perform a conclusive analysis.

Recovery of Spilled Volumes
The operators reported that the ten leaks which occurred during the three-year study period resulted in an estimated 1,221 barrels of spilled crude oil. Roughly two-thirds (800 barrels) of this volume was recovered.

Injuries and Fatalities
No injuries or fatalities occurred on the California crude oil pipelines under study during the three year study period. However, the data sample was too small to be useful.

For example, if one simply applied the fatality rate or 0.042 fatalities per 1,000 mile years (which was established in the 1993 report on CSFM-regulated hazardous liquid pipelines) one would anticipate a fatality every 16 years for the 496 miles of crude oil pipelines under study. This recurrence interval is greater than the three year study period. As a result, one would not expect a fatality during this study period. Further, as discussed above, the risk to human life from crude oil spills is likely less than for refined petroleum product pipelines which would tend to increase the recurrence interval.

6.2 Incentive Option Investigation Findings

After compiling all of the study information on incentive options and barriers to pipeline replacement and/or improvement, a number of conclusions or findings can be drawn. This section summarizes these findings and provides recommendations to improve pipeline safety (public safety) and environmental protection, maintain adequate regulatory control, and allow pipeline operators to make sound business/economic decisions.

Most findings presented in this section were taken directly from responses to the questionnaire and from the case studies that were submitted. As noted above, the rate of response to the battery of questions on barriers was relatively low for the participating regulatory agencies. Therefore, it is important to remember that the findings and recommendations presented here do not necessarily reflect those that would have been obtained if a larger number of regulators had provided input. The major findings are summarized below:

! jurisdictional authority is not well defined,

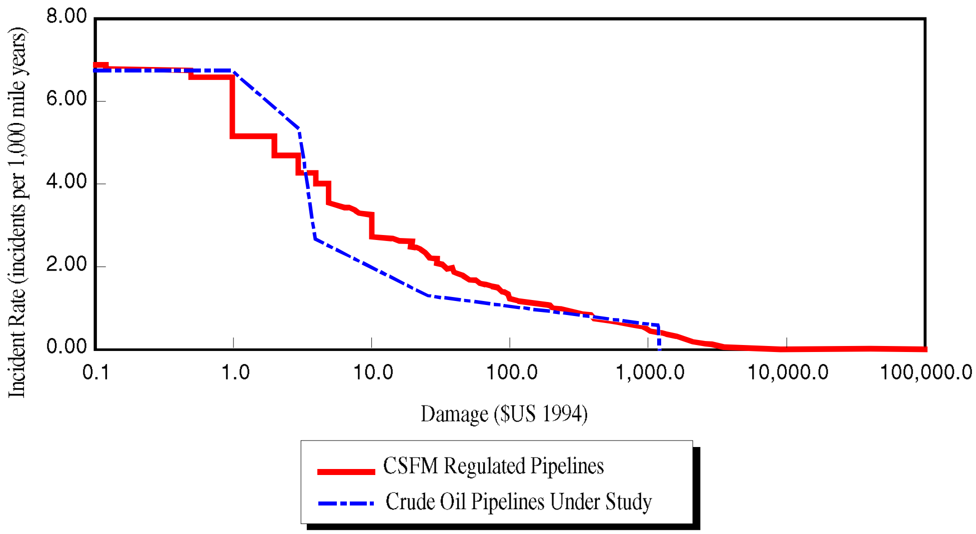
! permitting requirements overlap,

- there is no lead agency for permitting,
- compliance requirements vary from agency to agency and from location to location,
- permitting process is often too slow,
- some permits require overly burdensome testing,
- some pipeline repair and replacement projects, including routine maintenance, are not being done, and
- incentives to repair, replace and improve pipelines do not exist or have proven ineffective.

The following table lists some of the regulatory agencies involved in pipeline issues.

State	Federal	Local
Coastal Commission	Minerals Management Service	Resources Management Department
State Lands Commission	Department of Transportation	Public Works Department
Department of Parks and Recreation	Environmental Protection Agency	Fire Department
State Water Quality Control Board	Coast Guard	Environmental Health Department
State Fire Marshal	National Marine Fisheries Service	Board of Architectural Review
Department of Fish and Game	Fish and Wildlife Service	Air Pollution Control District
Air Resources Board	Bureau of Land Management	Systems Safety and Reliability Review Cmtee
Department of Transportation (Caltrans)		Zoning Department
		Planning Department
		Building Department

Table 6-1A
Spill Size Distribution
CSFM Regulated Pipelines versus Crude Oil Pipelines Under Study
Spill Size versus Incident Rate – Logarithmic Scale



Spill Size Distribution
Spill Size versus Cumulative Percentage of Incidents
0 to 100 Barrels Only

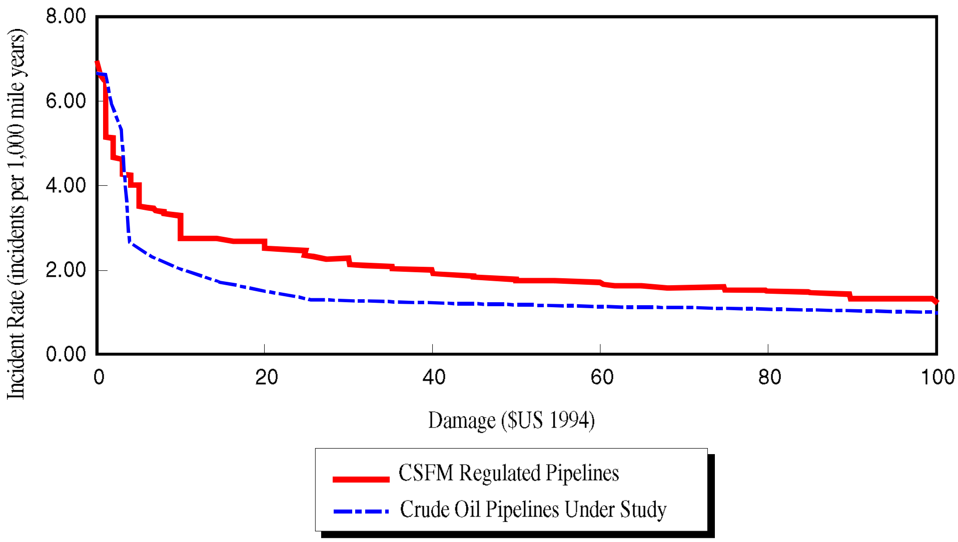
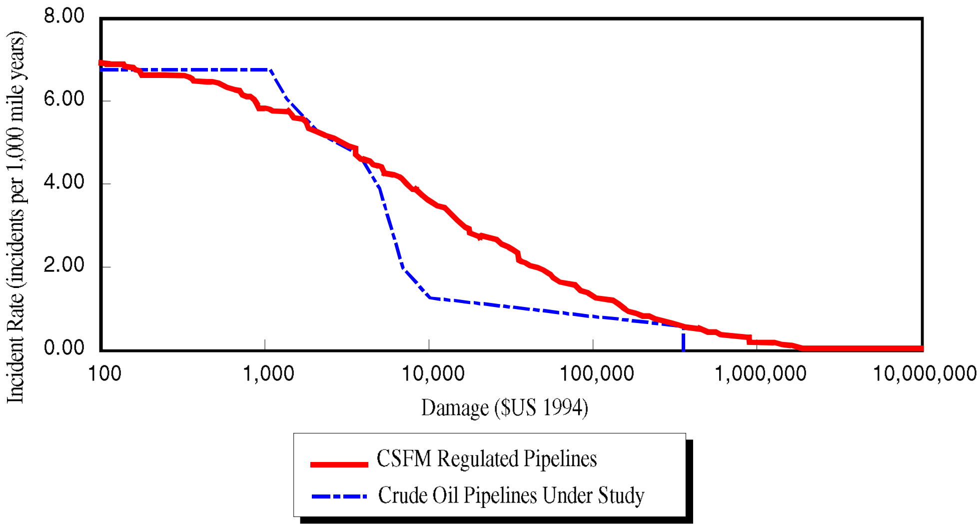


Table 6-1B

Property Damage Distribution

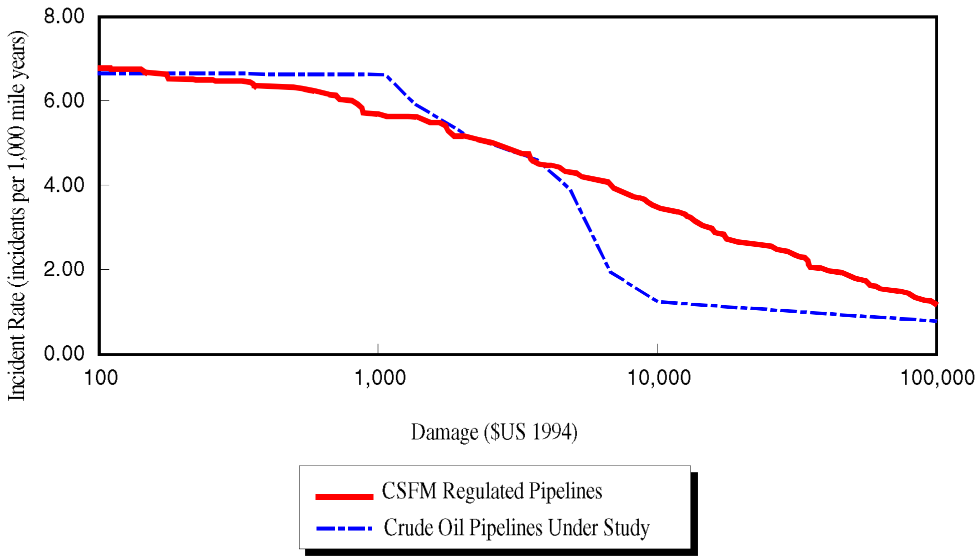
CSFM Regulated Pipelines

Versus Crude Oil Pipelines Under Study Incident Rate – Logarithmic Scale



Damage Distribution

Logarithmic Scale



Chapter 7
Recommendations

7.1 Database and Study

Although the data set for the California crude oil pipelines under study was relatively small, it was sufficient to determine an overall leak incident rate. This incident rate was essentially the same as the incident rate for hazardous liquid pipelines regulated by CSFM. Although the overall leak incident rates for these groups of pipelines were similar, the likelihood of large spills, and spills resulting in large values of damage, were much lower for the crude oil pipelines under study. And finally, although the data was limited, there was no evidence to suggest that crude oil spills pose a significant risk to human life. As a result, we recommend the following:

! Develop a set of criteria which can be used to identify pipelines which would likely impact unusually sensitive areas in the event of a leak. These criteria might include: likelihood of a spill from a given pipeline to reach a stream or waterway, etc. The CSFM Pipeline Safety Advisory Committee could be used to accomplish this recommendation.

! Distribute this criteria to the owners of the pipelines identified in this study. The operators could then identify those pipelines which would likely impact unusually sensitive areas in the event of a leak.

! Include the pipelines identified which would likely impact unusually sensitive areas in the scope/definition of those pipelines regulated by CSFM under Chapter 5.5 of the California Government Code.

! Modify the law to require continued leak and pipeline inventory reporting for all pipelines in this study. This will enable the CSFM to keep the database current.

In addition to these recommendations, we suggest the following actions:

! Further enhance efforts at partnering by continuing to invite the operators of these pipelines as well as representatives of other local and State agencies to the Pipeline Safety Conferences and other training programs sponsored by CSFM.

! The database effort conducted as part of this study should be expanded to include California's intrastate and interstate pipelines. Funding should be appropriated to support a comprehensive data base (e.g., all pipelines jurisdictional CSFM and pipelines included in this study) and establishment of comprehensive computerized pipeline mapping.

! The permitting process for pipeline replacement or upgrade projects (including local and State agencies) should be streamlined to the greatest extent possible.

7.2 Barriers and Incentive Options

The State of California has clearly made a number of strides toward clarifying its jurisdictional authority over oil and gas transportation facilities - most notably in Section 51015.05 of the California Government Code. This 1994 legislation, by defining operative terms such as Aproduction tanks and facilities@ and Atransportation facilities,@ resolved confusion and clearly distinguished between the jurisdictional authority of CSFM and that of DOGGR. In addition, this law is the driving force behind this study of incentive options and barriers to pipeline replacement and/or improvement in California. As possible evidence of the success of this statute, there was no indication by participants in this study that there is any lingering conflict between the jurisdictional responsibilities of DOGGR and CSFM.

Nevertheless, this study identified a number of levels of jurisdictional conflict and confusion. Although there was no evidence of perceived conflict among State-level agencies, it is clear that operators in particular perceive a tremendous amount of conflict between State-level agencies, on the one hand, and federal, county, and city agencies on the other.

One of the most striking conclusions, therefore, is that the *perception* of problems appears to be a serious problem for the State of California. Although the scope of this study (particularly the questionnaire) did not provide for independent verification or critical analysis of the information provided by the respondents, it is clear that there are any number of perceived barriers to pipeline replacement and improvements - these perceived barriers are particularly acute at the local government level.

Although detailed recommendations and specific implementation plans would be premature at this time, a number of general suggestions can be made. These suggestions should provide a useful backdrop and help guide the State of California as it further investigates its permitting process.

! The State should appoint a single lead agency with jurisdiction over every aspect of the permitting process in California. This lead agency should work in a *partnership* between State and local agencies, with consideration for local land use and other issues. One of the agency=s objectives should be to integrate federal, State and local policies for crude oil production and the transportation of crude oil and refined petroleum products.

! All permitting requirements should be standardized and redundancies and conflicts should be eliminated. A rigorous evaluation of the permitting process should be undertaken by the newly-appointed lead agency. Each requirement should be justified using sound scientific or other compelling reasoning.

! The newly-appointed lead agency should develop and implement a time line for permit application and approval. This time line should include Aconsequences@ for the agency or operator for not meeting scheduled milestones.

! The newly-appointed lead agency should consider the following incentives to repair, replace, or improve pipelines. The most obvious incentive for operators to improve, repair or replace pipelines will be the comprehensive streamlining of state and local regulations.

" reduction in the frequency of inspections for new pipelines;

" reduction of hydrostatic test frequency; etc.

! Pipeline repair/replacement which improves public and environmental safety should be removed from CEQA requirements

Chapter 8
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Executive Summary

The McGrath Lake oil spill in Ventura County stimulated public concern regarding the safe operation of crude oil gathering pipelines. This December 22, 1993 incident occurred from a crude oil shipping line. This spill released an estimated 2,200 barrels (42 gallons = 1 barrel) of crude oil. The oil surfaced and flowed through a culvert, traveled through 150 feet of woodland and brush, to McGrath Creek, then flowed another 1,200 feet into McGrath Lake. The lake is part of a tidal wetland within a large coastal dune system.

One of the results of this incident was the passage of California Assembly Bill 3261 (O'Connell) which clarified the jurisdictional authority within production fields for the Department's of Conservation's Division of Oil, Gas and Geothermal Resources (DOGGR). AB 3261 also added Section 51015.05 to the California Government Code mandating that the California State Fire Marshal (CSFM) complete three assignments:

- establish and maintain a data base of on-shore crude oil gathering lines and gravity or low pressure pipelines; and,
- conduct an assessment of the fitness and safety of on-shore crude oil gathering lines and gravity or low pressure pipelines; and,
- investigate barriers and incentives for replacement and improvement of all hazardous liquid pipelines.

CSFM has exclusive regulatory authority over most hazardous liquid transportation pipelines within California. However, all pipelines within production fields, and some gathering, gravity and low pressure lines are exempted from CSFM authority. ***It is important to note that the pipelines involved in the data base and in the fitness assessment as contained in this report are NOT currently jurisdictional to CSFM's pipeline safety program.*** Chapter 5 of this report contains information on the investigation of barriers and incentives for pipeline replacement. Because the issue of barriers/incentives involves many levels of hazardous liquid pipeline transportation, the review included all hazardous liquid pipelines outside production fields, refineries and terminal facilities.

Funding for this project was provided by the U.S. Department of Energy (USDOE). A Pipeline Assessment Steering Committee was established to supply input from local government, industry and the public. EDM Services of Simi Valley, California, was contracted to establish the data

base, analyze the information and develop the draft report. Prior to submission to the Legislature, the document was reviewed by CSFM, the Pipeline Assessment Steering Committee, the Pipeline Safety Advisory Committee, the California Department of Forestry and Fire Protection, the Resources Agency and the Governor's Office. During this entire review process, only minor editorial changes were made to the document for better word flow or to improve background information. No conclusion established as a result of the data analysis was altered during the review process.

In 1993, CSFM conducted an in-depth study of pipelines under its jurisdiction. Much of the analytical review of the information contained in the current report was evaluated and compared to the results of the 1993 study.

Comparing Modes of Transportation:
In analyzing the transportation of hazardous liquids, it is important to compare the safety risks of various modes of transportation. In doing so, US Department of Transportation fatality statistics were used. Risk of fatality by mode of transportation can be summarized as follows:

Pipeline	1
Marine	5
Rail	51
Highway	429

In other words, highway transportation results in 429 times more fatalities than pipelines. Order of magnitude comparisons between the other modes can be determined similarly.

A general understanding of these relative risks is essential for those considering regulatory changes which could increase the cost of hazardous liquid pipeline construction, operation and/or maintenance. Any increases in the shipping costs associated with such changes would likely result in a portion of the throughput being diverted from pipelines to other transportation modes. Since these other modes generally expose the public to a higher risk than pipelines, any such diversion may actually decrease overall transportation safety. There are already signs of this occurring, especially in Southern California. The crude oil from many of the older production fields which was historically transported by pipeline, has been diverted to truck and rail transportation which have the worst safety record.

The Data Base and Analysis:
EDM Services conducted an extensive campaign to gather information on crude oil gathering lines and gravity/low pressure pipelines. From a potential study pool of 1,200 participants, only 15 operators were identified as owning and/or operating pipelines which met the study criteria established in statute.[1] Because the resulting data set was so small, there were few meaningful conclusions that could be drawn from this limited data. The data set can be summarized as follows:

Number of pipeline operators	15
Number of pipelines	113
Total length of pipelines (miles)	496
Mean diameter of pipe (inches)	7.5
Mean operating temperature	74.21F
Cathodically protected pipe (miles)	317 (64% of total)
Bare pipe (miles)	87 (18% of total)
Median spill size (bbl)	3
Average spill size (bbl)	122
Median damage ($US 1994)	$5,000
Average damage ($US 1994)	$39,020
Length of Underground Pipe (miles)	478 (96.3% of total)
Number of incidents (≥ 1 bbl)	10

[1] The pipeline involved in the McGrath Lake oil spill was not one of the pipelines which met the study criteria established in Section 51015.05. However, because of the language in AB 3261 concerning DOGGR, this pipeline has been classified as a production line and is now jurisdictional to DOGGR's pipeline safety program.

Overall Incident Rate: The overall rate for incidents of one barrel or more from the crude oil pipelines under study is very similar to that of hazardous liquid pipelines regulated by CSFM --- 6.72 versus 6.54 incidents per 1,000 years respectively. However, the incident rate for larger spills is generally much less for the smaller crude oil pipelines in this study. The results for the California crude oil pipelines under study are summarized below:

Spill Event	Incident Rate
≥1 bbl (per 1,000 mile years)	6.72
≥10 bbl (per 1,000 mile years)	2.02
≥100 bbl (per 1,000 mile years)	1.10
≥1,000 bbl (per 1,000 mile years)	0.69
≥10,000 bbl (per 1,000 mile years)	0.00
≥$1,000damage ($US 1994-per 1,000 mile years)	6.72
≥$10,000 damage ($US 1994-per 1,000 mile years)	1.34
≥$100,000 damage ($US 1994-per 1,000 mile years)	1.14
≥$1,000,000 damage ($US 1994-per 1,000 mile years)	0.00
Injury (per 1,000 mile years)	0.00
Fatality (per 1,000 mile years)	0.00

Primary Cause of Incidents: External corrosion is by far the leading cause of incidents, representing 60% of the total. However, with the limited data sample, the cause could not be isolated. The results of the 1993 study regarding the CSFM-regulated hazardous liquid pipelines, indicated that pipe operating temperature and age were the two leading factors contributing to increased external corrosion. It can be presumed that this is also the case for the crude oil pipelines under study. However, the data set is too small to perform a conclusive analysis.

Recommendations Based on Data Analysis:
As previously stated, the overall incident rate for the crude oil pipelines under study is essentially the same as the incident rate for CSFM-regulated hazardous liquid pipelines. Although the overall leak incident rates for these groups of pipelines is similar, the likelihood of large spills and spills resulting in large values of damage were much lower for the crude oil pipelines in this study. And finally, although the data is limited, there was no evidence to suggest that crude oil spills pose a significant risk to human life. As a result of these findings, we recommend the following:

! Develop a set of criteria which can be used to identify pipelines which would likely impact unusually sensitive areas in the event of a leak. These criteria might include: likelihood of a spill from a given pipeline to reach a stream or waterway, etc. The CSFM Pipeline Safety Advisory Committee could be used to accomplish this recommendation.

! Distribute this criteria to the owners of the pipelines identified in this study. The operators could then identify those pipelines which would likely impact unusually sensitive areas in the event of a leak.

! Include the pipelines identified which would likely impact unusually sensitive areas in the scope/definition of those pipelines regulated by CSFM under Chapter 5.5 of the California Government Code.

! Modify the law to require continued leak and pipeline inventory reporting for all pipelines in this study. This will enable the CSFM to keep the database current.

In addition to these recommendations, we suggest the following actions:

! Continue to invite the operators of these pipelines as well as representatives of other local and State agencies to the Pipeline Safety Conferences and other training programs provided by the CSFM.

! The database effort conducted as part of this study should be expanded to include California's intrastate and interstate pipelines. Funding should be appropriated to support a comprehensive data base (e.g., all pipelines jurisdictional CSFM and pipelines included in this study) and establishment of comprehensive computerized pipeline mapping.

Barriers and Incentives to Pipeline Replacement or Improvement:
The third Legislative mandate provided in Section 51015.05 was to investigate the incentive options that would encourage pipeline replacement or improvement, including but not limited to, a review of proposed regulatory, permit, and environmental impact report requirements and other public policies that could act as barriers to the replacement or improvement of pipelines.

CSFM believed that the Legislature did not intend to limit the scope of our investigation to only those pipelines included in the data base and study. Therefore, more than 200 questionnaires regarding incentive options and barriers to pipeline replacement and/or improvement were distributed to:

- operators of CSFM-regulated hazardous liquid pipelines
- all participants in the study
- State regulatory and jurisdictional agencies
- local governments serving communities with a high density of oil and gas activity (e.g., San Luis Obispo, Santa Barbara and Ventura counties)
- members of the Pipeline Assessment Steering Committee

The questionnaire was designed to gather information on, measure attitudes toward, and obtain suggestions about proposed or potential incentives and barriers to pipeline replacement or improvement. As a State regulator, CSFM felt strongly that a neutral third party should be utilized to evaluated the results of this questionnaire. To that end, USDOE's representatives analyzed the questionnaire responses and authored the recommendations.

The study identified a number of levels of jurisdictional conflict and confusion. Although there was no evidence of perceived conflict among State-level agencies, it is clear that operators in particular perceive a tremendous amount of conflict between State-level agencies, on one hand, and federal, county, and city agencies on the other.

One of the most striking conclusions, therefore, is that the *perception* of problems appears to be a serious problem for the State of California. Although the scope of this study (particularly the questionnaire) did not provide for independent verification or critical analysis of the information provided by the respondents, it is clear that there are any number of perceived barriers to pipeline replacements and improvements. These perceived barriers are particularly acute at the local government level.

Although detailed recommendations and specific implementation plans would be premature at this time, a number of general suggestions can be made. These suggestions should provide a useful backdrop and help guide the State of California as it further investigates its permitting process.

- The State should appoint a single lead agency with jurisdiction over every aspect of the permitting process in California. This lead agency should work in a *partnership* relationship between State and local agencies, with consideration for local land use and other issues. One of the agency's objectives should be to integrate federal, State and local policies for crude oil production and the transportation of crude oil and refined petroleum products.

- All permitting requirements should be standardized and redundancies and conflicts should be eliminated. A rigorous evaluation of the permitting process should be undertaken by the newly-appointed lead agency. Each requirement should be justified using scientific or other compelling reasoning.

- The newly-appointed lead agency should develop and implement a time line for permit application and approval. This time line should include "consequences" for the agency or operator for not meeting scheduled milestones.

- The newly-appointed lead agency should consider the following incentives to repair, replace, or improve pipelines. The most obvious incentive for the operators to improve, repair or replace pipelines will be the comprehensive streamlining of State and local regulations.

    - reduction in the frequency of inspections for new pipelines

    - reduction in the frequency of hydrostatic testing

- Pipeline repair/replacement which improves public safety and environmental protection should receive relief from CEQA requirements, including an expanded time frame.