OCS Report
MMS 87-0114

Investigation of Shell Pipe Line Corporation Pipeline Leak South Pass Block 65 December 30, 1986

Gulf of Mexico
Off the Louisiana Coast

MMS
U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

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U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Regional Office

December 1987

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I. Investigation and Report

A. Authority

By memorandum dated February 18, 1987, pursuant to Section 208 (subsections 22d, e, and f) of the Outer Continental Shelf (OCS) Lands Act Amendments of 1978 and Minerals Management Service Manual, Part 640, Chapter 3, Accident Investigation, the following Minerals Management Service (MMS) personnel were named to serve as an investigative panel:

Chuck Schoennagel	Darice Breeding
Robert Lanza	Rufus Kirk
Eric Primeaux*	Robert Kelly

The panel was given the assignment to investigate and to prepare a public report of the pipeline leak that occurred approximately December 30, 1986, at South Pass Block 65, off the Louisiana coast.

B. Procedures

An informal meeting was conducted at the Minerals Management Service Gulf of Mexico Regional Office in Metairie, Louisiana, on February 27, 1987. Present at the meeting were Shell Offshore Inc. (SOI) and Shell Pipe Line Corporation (SPLC) personnel and MMS investigation panel members. During the meeting SOI and SPLC personnel presented the basic facts and assumptions relative to the South Pass Block 65 pipeline leak incident. Following this briefing, panel members independently investigated certain aspects of the incident. These specific aspects and the results are identified and discussed within the report findings. Subsequent to this initial

*Substitute for Robert Moore

meeting, SOI and SPLC personnel transmitted relevant data concerning system product metering, South Pass Area weather conditions, and observations during the leak period and also met with MMS personnel on May 7 and 21, 1987, to discuss pipeline measurement data.

II. Introduction

A. Background

The SPLC is the pipeline right-of-way (ROW) holder and/or operator of MMS Royalty Measurement Pipeline Systems 51.0 and 51.1, which gather liquid hydrocarbon production from Federal oil and gas leases in the Main Pass and South Pass Areas and also gather production from two State of Louisiana oil and gas leases. This production is injected into three separate pipelines identified as follows:

1. ARCO 10-inch line P/L ROW OCS-G 4351
2. Shell Cobia 12-inch line P/L ROW OCS-G 1701
3. Shell Pompano 12-inch line P/L ROW OCS-G 1686

The production is delivered to SOI's Main Pass Block 69 Platform A where the three streams are commingled and metered. Since offshore sales points for royalty purposes are established at the Federal oil and gas lease injection points, these Main Pass Block 69 meters serve the purpose of providing onshore delivery measurement data to the pipeline operator (SPLC) only.

The ROW for that portion of the Pompano Pipeline System involved in the leak incident, an 8-inch line from South Pass Block 65 Platform A to South Pass Block 62 Platform A, pipeline ROW OCS-G 1686-A, was granted to SPLC on April 7, 1969, under the 30 CFR 256 regulations. Operational regulation of the line is in accordance with Department of Transportation Regulation 49 CFR 195 — Transportation of Hazardous Liquids by Pipeline.

B. Description of Incident

An SOI-chartered helicopter on a routine flight between Mississippi Canyon Block 194 and South Pass Block 70 on the morning of December 30, 1986, observed an area of oil sheen and traced the source to the SOI South Pass Block 65 field. SPLC personnel were then notified, and upon investigation of the observed oil sheen, the pipeline was shut-in at 11:10 a.m. Telephone notification of Federal and State agencies by SPLC and SOI personnel occurred at approximately 12:40 p.m.

Subsequent to pipeline shut-in, a short pressure-test of the line was conducted by closing the downstream valve on South Pass Block 62 Platform A and briefly running the injection pump on Main Pass Block 153 Platform B in order to confirm that the leak was in the 8-inch line. Following this confirmation a survey vessel (*MV Hydrosurveyor*), a dive support ship (*CAL Diver I*), and an oil-spill recovery vessel (*MV BoTruck 22*) were mobilized and arrived on location in South Pass Block 65, December 31, 1986. Attempts to locate and uncover the leak point proceeded through January 3, 1987, at which time the vessels sought shelter in Mississippi River South Pass to await improved weather conditions. The dive support vessel returned to location on January 5, 1987. The leak point was found on January 6 at a distance approximately 2,400 feet from Platform A in South Pass Block 65. The pipeline was buried approximately 6 feet below the mudline at the point of damage in water depth of approximately 300 feet. A 35-foot section of damaged pipe was removed and replaced with an onsite-fabricated and onsite-tested spool piece utilizing Hydrocouple connectors. Following these repairs and operational pressure testing, the pipeline was put back in service on January 13, 1987.

C. Reported Oil Spill Observations

Observations of the silvery oil sheen by SPLC and SOI personnel on the afternoon of December 30, 1986, provided slick size information that was calculated into an estimated spill volume of 80 to 100 barrels.

D. Analysis of System Receipts and Deliveries

Subsequent to the pipeline leak detection, in the second week of January 1987 a routine review of the Main Pass gathering-system oil-measurement records by SPLC revealed a large imbalance for the month of December 1986. A detailed daily analysis was conducted, which showed that pipeline receipts (offshore input) began to exceed deliveries at Main Pass Block 69 on about December 27, 1986, and continued to substantially exceed daily deliveries through December 30, 1986, at which time the leak was detected and the pipeline shut-in.

E. Failure Analysis

Laboratory examination and analysis of the removed damaged pipe section at Shell Development Company's Westhollow Research Center in Houston, Texas, revealed the following:

1. The pipe had been flattened for several feet along the side of the crack location, forming a D-shaped cross section. This damage was assumed to have been caused by an earlier anchor-drag incident.

2. The leak crack, located on the south side of the pipe at the three o'clock position, was approximately 13 inches long; the crack width varied irregularly from 0 to 0.065 inch and had an estimated equivalent flow area of 0.5 square inch.

3. The failure mechanism was attributed to the initiation and propagation of surface fatigue or corrosion fatigue cracks in the damaged area due to the high local stresses induced by the deformation and the fluctuation of internal pipeline pressure.

4. The pipe material met the original design requirements, that of Grade X56 pipe.

F. Leak Rate Determination

The SPLC developed a theoretical crack model that was used to analytically predict the amount of oil that could have leaked under operating conditions.

Agreement was obtained between the above analytical model leak rates and actual leak-flow rates obtained from tests conducted on the damaged pipe section by capping the ends and pumping water into the pipe at various flow rates while measuring internal pipe pressures.

G. Possible Oil Spill Volume

The analysis of pipeline system receipts and deliveries, supported by the laboratory and analytical leak rates, indicated to SPLC that a spill of 23,000 to 29,000 bbls was possible during the period of time from December 27 through December 30, 1986.

III. Panel Investigation and Findings

MMS panel members independently investigated the following aspects of this incident:

- System measurement balance of sales measurement data. However, since certain data used by SPLC is not independently available to Minerals Management Service, SPLC was relied on for the onshore delivery measurements and State lease receipts into the system.
- Oil spill reports to the U.S. Coast Guard and MMS during the period December 1, 1986, through January 2, 1987, for the leak-affected area.
- The most likely surface spill path as developed by the National Oceanic and Atmospheric Administration (NOAA) Oil Spill Trajectory Model using local meteorological data of prevailing weather conditions during the time of the leak.
- Pressure-flow analytical model of the pipeline and leak.
- Sidescan-sonar survey of the leak site, which was performed on January 1,1987.

A. System Measurement Balance

A review of the total measurements was conducted by MMS for the 23 Federal offshore royalty injection points and the 2 State lease injection points, and a comparison was made with the 5 delivery meters at Main Pass Block 69 operated by SPLC and Chevron for the months of November and December 1986 and January 1987.

The review indicated there were no apparent discrepancies or problems with the operation and maintenance of the meters and the data collected from each meter. The findings establish comparative agreement between SPLC and MMS on the system volumes for these three months. The MMS tabulation of volumes (bbls) reported for offshore (receipts) and onshore (deliveries) are as follows:

			(Loss)/Gain	
Month	*Offshore*	*Onshore*	*Volume*	*% of Receipts*
November 1986	3,233,428	3,222,244	(11,184)	(0.34)
December 1986	3,115,773	3,087,193	(28,580)	(0.9)
January 1987	3,108,916	3,105,502	(3,414)	(0.11)

These tabulations show a large imbalance for each month ranging from 0.11% to 0.9% of the offshore injection volume. For the three months reviewed, the imbalance is recorded as a loss only. Without having a larger number of monthly statistics for comparison, it cannot be stated whether or not this system balance method is biased towards loss predictions. These findings do not indicate that a pipeline system leak volume can be determined to any degree of accuracy utilizing the pipeline receipts versus deliveries for this pipeline system.

Subsequent to the foregoing findings, SPLC was requested to provide historical delivery data for the system for the period January 1986 through June 1987. These unverified figures are as follows:

Month	Onshore	(Loss)/Gain Volume	(Loss)/Gain % of Receipts
January 1986	3,499,414	(11,164)	(0.319)
February	3,135,101	(6,204)	(0.198)
March	3,479,008	(8,507)	(0.245)
April	3,321,298	(3,946)	(0.119)
May	3,492,993	7,099	0.203
June	3,346,026	(9,517)	(0.284)
July	3,455,045	(6,065)	(0.176)
August	3,336,258	(6,150)	(0.184)
September	3,278,873	(1,216)	(0.037)
October	3,367,243	(1,826)	(0.054)
November	3,222,244	(14,309)	(0.444)
December	3,087,193	(29,197)	(0.946)

Month	Onshore	(Loss)/Gain Volume	(Loss)/Gain % of Receipts
January 1987	3,105,502	(3,552)	(0.114)
February	3,079,046	(769)	(0.025)
March	3,360,523	(3,154)	(0.094)
April	3,098,555	1,940	0.063
May	3,244,336	4,866	0.150
June	3,199,505	(2.713)	(0.085)

The total for the year 1986 indicates a loss of 91,002 bbls or an average loss of 7,583 bbls/month. These same figures for the six months of 1987 indicate a total loss of 3,382 bbls or an average loss of 564 bbls/month. Consideration of the resultant total tabulation for

1986 also supports a conclusion that the balance method was biased towards loss prediction and that any leak volume determination using this data would be highly suspect, especially since these measurement losses are not supported by actual spill sightings during the months they supposedly occurred.

B. Oil Spill Reports and Spill Trajectory

The results of the investigation into oil-spill reports to the U.S. Coast Guard and MMS during December 1986 identified the following oil slicks of unknown origin:

Date	*Reporting Location*	*Slick Description*	*Size*
12/27/86	Sohio MC 20-A	Silvery sheen	1-1/2 mile X undetermined
12/28/86	Chevron SP 49	Silvery sheen, patchy	1 mile X 5 miles
12/29/86	Exxon MC 280-A	Sheen	1 mile X out of sight
12/31/86	Chevron SP 49	Silvery sheen, patchy	1 mile X 5 miles

While these reports vary somewhat on size estimate, the slick description in all cases is reported as silvery sheen or sheen. The SPLC and SOI personnel described the slick observed on December 30, 1986, at the time the pipeline was shut-in as silvery sheen with color. The overlay, provided in attachment 1, identifies these report locations and also identifies other manned structure locations within the area.

Even though the NOAA Modeling and Simulation Studies Spill Trajectory Analysis is designed to model surface spills and not a subsurface release such as the pipeline leak that occurred in South Pass Block 65, NOAA was requested to run the model in order to determine the generalized path that a surface spill occurring in the area would follow.

A comparison of the Leak Area Oil Spill Report Overlay, attachment 1, with the NOAA Model spill trajectory results for December 30, 1986, shown in attachment 2, indicates that the probable path of the slick was adequately covered by the visual sightings and opportunities for observation. This finding also corroborates the results of the SOI report of opportunities for visual observation, which concluded that observations do not support the occurrence of a large spill volume. However, some surface slicks related to this pipeline leak may have gone undetected or, if detected, the slick thickness may have been underestimated due to the following factors, which affect the accuracy of visual observations:

1. Sea state.
2. Distance of observer above the water surface.
3. The direction of viewing compared with the location of the sun. (If viewed toward the light source, an oil slick will reflect light and could appear relatively silvery in color regardless of oil thickness).
4. The experience of the individual observer.
5. The oil may have evaporated, etc. (Oil that is thinly spread on the sea can usually be expected to disperse naturally and to biodegrade, evaporate, and photo-oxidize).

In addition, as the subject spill was a subsurface release of the oil under pressure beneath 6 feet of sediment, it is possible that some of the oil was transported subsurface away from the pipeline break, which may account for nondetection at the site of the spill. Regarding the fate of a subsurface spill, there is some evidence from the IXTOC I blowout (one of the few studied subsurface spills) that relatively high concentrations of gas, volatile liquid hydrocarbons, and high-molecular-weight compounds were transported subsurface away from the well site for distances up to 20-30 km (12-19 miles).

C. Analytical Pipeline Leak Model

A simulated pipeline model as shown in attachment 3 was used to develop an analytical model of the leak. The leak area of the pipe was assumed to be independent of internal pipe pressure for each of three computation routines where a constant equivalent flow area of 0.5, 0.72, and 1.43 square inches was used. The 0.5 square-inch area is the value of the residual leak area found in the damaged pipe section.

The results of the analytical model computations of flow rates into the pipeline and leak for various head pressure and back pressure combinations are shown in attachment 4. Since the actual operating pressures at the time of the leak are not known, an average of the Leak Rate (Q_c)/Input Rate (Q_a) ratio for these various, assumed pressure combinations and leak areas was calculated to be 0.41. These results indicate that, theoretically, an average maximum of 41 percent of the pipeline through-put at Platform A in South Pass Block 65 could have departed the pipeline through the leak. Using SPLC's assumption that the leak occurred on December 27, 1986, and continued through December 30, the total pipeline through-put for the period was 34,032 bbls; and the maximum possible *theoretical* leak volume could have been 13,840 bbls.

This volume has been identified analytically as the theoretical maximum-possible-leak volume. In considering this volume it must be remembered that many assumptions relative to system operating pressures and conditions, particularly the assumption of constant effective leak areas of 0.5, 0.72, and 1.43 square inches, could substantially influence this calculated leak volume. Even though many assumptions were made, this analytical leak model represents a relatively close approximation to actual pipeline/leak flow conditions, and the results can be used to show that the total pipeline through-put at Platform A in South Pass Block 65 could not have been forced through the leak area under operating conditions. This conclusion is counter to results of

SPLC's theoretical crack model and laboratory flow test of the damaged pipe section. However, the SPLC's model and test are basically orifice flow simulations and do not attempt to approximate actual pipeline operating conditions.

D. Leak Confirmation Pressure Test

Since little facts are known relative to the operating pipeline parameters before detection of the leak, certain assumptions are made after the fact in order to describe a possible leak scenario. As discussed in the preceding paragraph, the leak area was assumed to be 0.5, 0.72, and 1.43 square inches during pipeline operation. In reviewing the method used to confirm the leak existence — that of shutting in the pipeline at Platform A in South Pass Block 62 and using an injection pump on Platform B in Main Pass Block 153 to inject fluid and build up line pressure — it is possible to conclude that the leak area under operating conditions was minimal and that the area did not increase in size to the residual 0.5 square inch under operating conditions, but did so when subjected to the pressure test following pipeline shut-in.

E. Leak Site Sediment-Erosion

Under assumption that a large volume of oil had been released through the leak area, the velocity of the escaping oil would have been sufficient to scour the six feet of bottom sediments overlaying the pipe at the leak site. Since the leak area projected laterally from the pipe, the occurrence of this scouring action in this case should have removed sediment and created a depression. An examination of the sidescan sonar traces of the leak site recorded on January 1, 1987, shows no indication of a depression in the area of the leak.

F. Consideration of Factors Affecting the Surface Appearance and Observation of the Leaked Oil

On the assumption that a large volume of oil had actually been released through the pipeline leak, the question of whether it could go without detection remains to be examined. The findings indicate that actual sightings do not support the assumption of a large spill volume.

In an attempt to explain this lack of surface observation, it was suggested that the leaked oil could have been prevented from coming to the surface by becoming stratified between current layers — the fresh Mississippi River waters flowing over the salt waters of the Gulf of Mexico. For purposes of simplifying a discussion of this issue, assuming the respective specific gravities of the leaked oil, river water, and sea water to be 0.88, 1.00+, and 1.03, it would seem unlikely that even a significant velocity difference between the two water layers could overcome the positive buoyancy of the oil. Another point relative to this issue is that the river stage at the time of the leak was sufficiently low such that the separation of these water layers would be poorly defined.

The major factors controlling the physical, chemical, and biological processes that affect the fate of oil introduced into the marine environment are very complex and far beyond the scope of this report. However, it should be mentioned that one major feature of oil spills that has not received much attention and remains an enigma is the fate of nonstranded oil. Indeed, most of the subsurface-released oil from the IXTOC I blowout remained either at sea or in the atmosphere; and in spite of the extensive studies that were conducted, no estimate of a spill budget (mass balance) was determined. As there is so little information available regarding the fate of oil in subsurface spills, attempting to establish the fate of the oil released in the SPLC pipeline leak would be a guess at most.

IV. Conclusions

The SPLC report that a spill of 23,000 to 29,000 bbls was possible during the period of time from December 27-30, 1986, was based on an analysis of the pipeline system receipts and deliveries and supporting laboratory and analytical leak-rate results for the damaged pipe section.

However, the panel concludes that the SPLC analytical leak-rate determination did not simulate pipeline operating conditions sufficiently such that the results can be used to support the measurement imbalance as the possible leak volume. In spite of the difficulties of establishing a valid analytical pipeline leak model, particularly without actual system pressures, the approach by MMS — which indicates a possible maximum theoretical leak volume of 13,840 bbls during this period — is sufficiently valid to be useful for comparison purposes. This result also does not support the system measurement balance loss as the possible oil leak volume. Additionally, the MMS review of the system measurement balance for a 3-month period and the subsequently submitted 1-year-6-month measurement history indicate that such figures cannot be used to determine a leak volume.

In view of the problems associated with attempting to determine the thickness of an oil slick on water and in determining its size, as well as the various reasons a subsurface release of oil may go undetected, a leak volume cannot be determined from the reported visual sightings attributed to the pipeline leak. Additionally, as there is so little information regarding the fate of oil in subsurface spills, attempting to establish the fate of the oil released in the SPLC pipeline leak or to provide an estimate of a spill budget would be a guess at most.

The only bit of unblemished physical evidence that relates to this incident — the sidescan-sonar trace of the gulf bottom sediments at the leak site—shows no sign of agitated bottom sediments or a scoured depression. Even though this evidence does not lead to a determination of the actual leaked volume, it does support the conclusion that a large volume of oil did not exit through the pipeline leak.

It is the conclusion of the panel that there is insufficient evidence and analysis data to support any assumption that the maximum leak volume could have been the 29,000-bbl system loss as indicated by the SPLC measurement data.

The panel also concluded that there is insufficient information upon which to determine an actual leak volume. However, based on the visual observation reports of slicks the panel believes to be associated with this incident, the maximum observed leak volume is approximately 210 bbls.

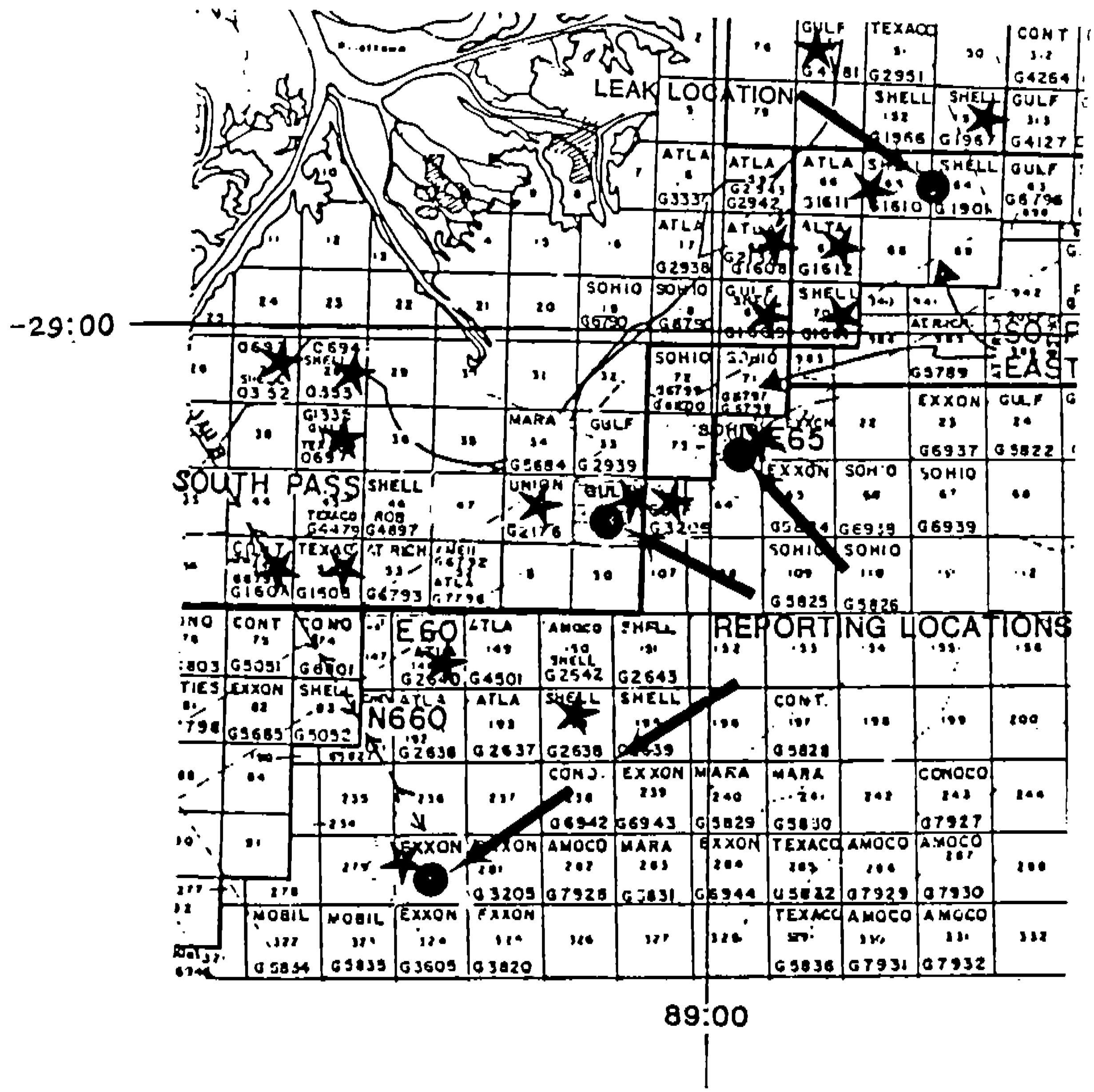
V. Recommendations

The SPLC should investigate the possibility of reducing the pressure fluctuation on this pipeline system such that leak detection methods can be utilized effectively.

The MMS Gulf of Mexico Region should investigate the applicability of pipeline leak detection systems, other than low-pressure sensors, for use on Gulf of Mexico pipelines.

MMS should sponsor a research project to identify the factors associated with the dispersion and adsorption of oil leaked from a buried subsea pipeline.

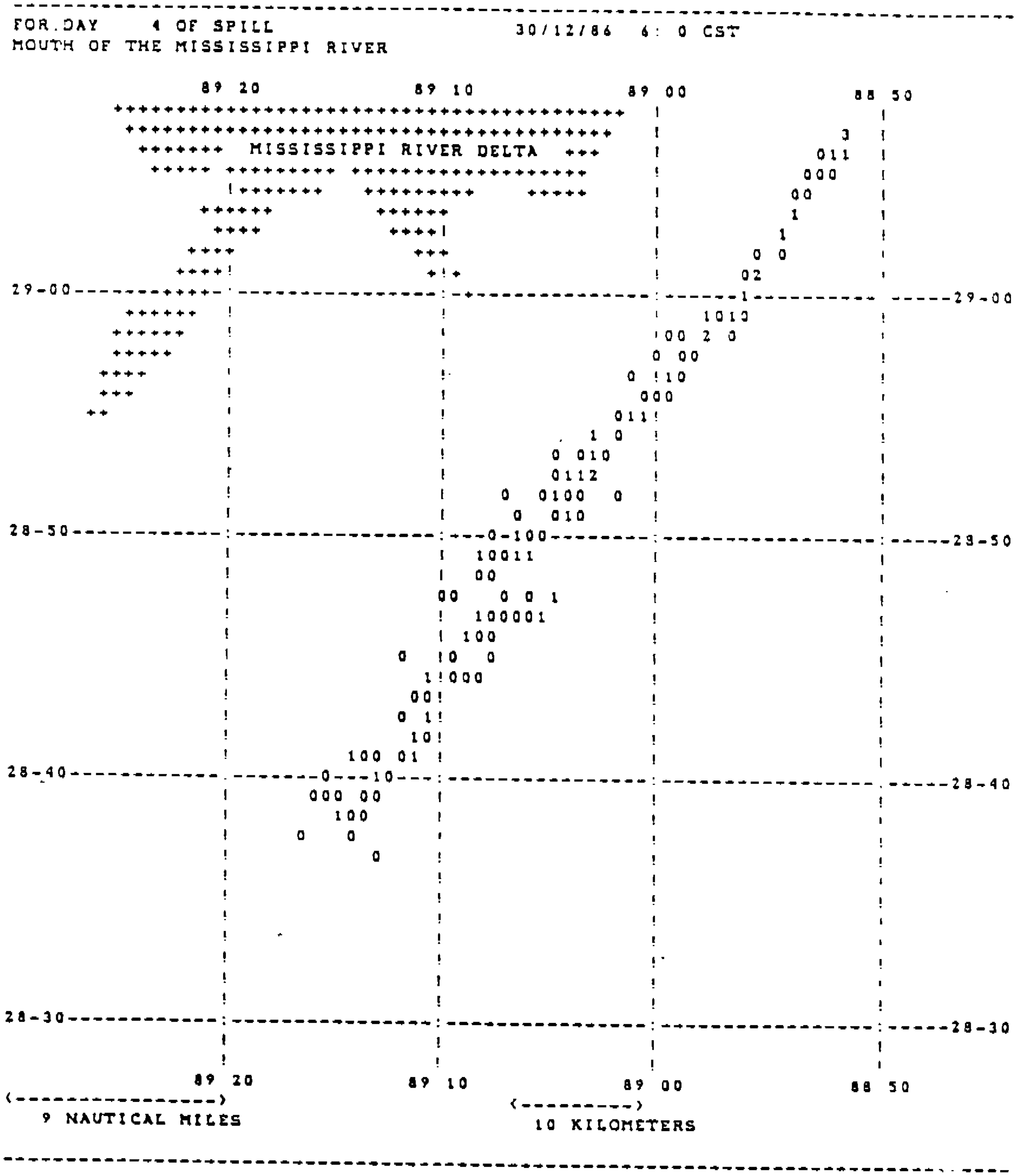
In support of the above project, pipeline operators should have divers, mobilized for repair operations, gather bottom sediment samples within the leak area.



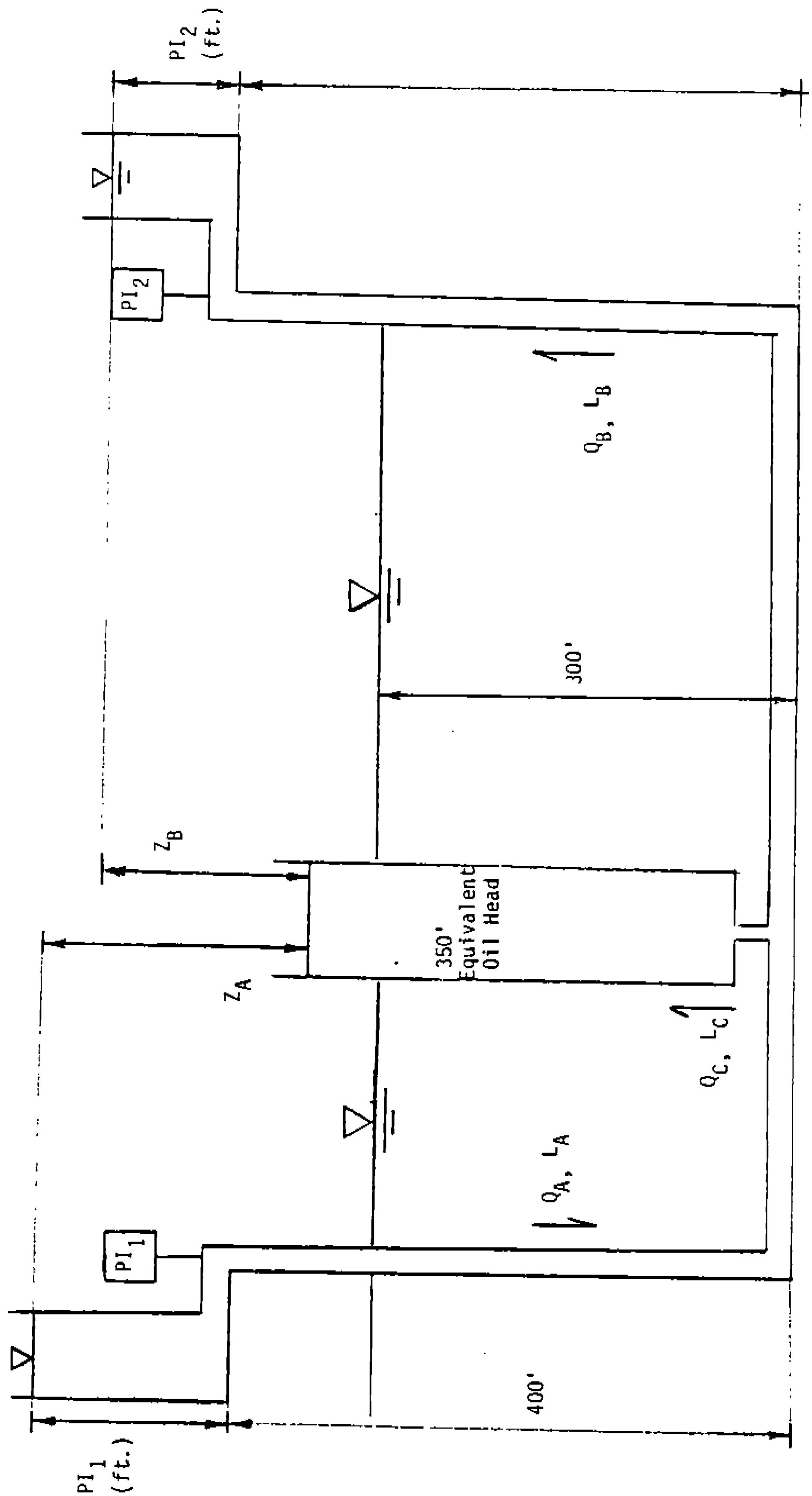
MANNED PLATFORM LOCATIONS

LEAK AREA MAP AND OIL-SPILL REPORT OVERLAY

ATTACHMENT 2



SURFACE SPILL MODEL TRAJECTORY PATH



ANALYTICAL PIPELINE LEAK MODEL

PI_1 / PI_2	Leak Area = 0.5 in² Q_a	Q_b	Q_c	Qc/Qa	Average Ratio	Leak Area 0.72 in² Q_a	Q_b	Q_c	Qc/Qa	Average Ratio	Leak Area 1.43 in² Q_a	Q_b	Q_c	Qc/Qa	Average Ratio
600 / 500	2.17	1.37	0.79	0.37		2.54	1.32	1.22	0.48		3.86	1.06	2.81	0.73	
600 / 400	2.76	1.98	0.79	0.29	0.28	3.14	1.93	1.21	0.38	0.37	4.48	1.72	2.76	0.62	0.60
600 / 300	3.22	2.44	0.78	0.24		3.59	2.40	1.20	0.33		4.94	2.21	2.72	0.55	
600 / 200	3.60	2.83	0.78	0.22		3.97	2.79	1.19	0.30		5.31	2.62	2.69	0.51	
500 / 400	2.10	1.38	0.72	0.34		2.45	1.34	1.11	0.45		3.66	1.11	2.55	0.70	
500 / 300	2.70	1.98	0.72	0.27	0.28	3.04	1.95	1.10	0.36	0.37	4.27	1.76	2.51	0.59	0.60
500 / 200	3.16	2.44	0.71	0.22		3.50	2.41	1.09	0.31		4.72	2.25	2.47	0.52	
400 / 300	2.04	1.39	0.65	0.32		2.34	1.35	.099	0.42		3.44	1.17	2.27	0.66	
400 / 200	2.63	1.99	0.64	0.24	0.25	2.94	1.96	.098	0.33	0.34	4.03	1.81	2.22	0.55	0.57
400 / 100	3.08	2.45	0.63	0.20		3.39	2.42	.096	0.28		4.47	2.29	2.18	0.49	

The Average Leak Ratio for the Three Assumed Leak Areas = <u>0.41</u>

PI_1 = Head Pressure (PSIG)

PI_2 = Back Pressure (PSIG)

Q_a = Flow Rate into Pipeline ft^3/sec.

Q_b = Flow Rate Downstream of Leak Point ft^3/sec.

Q_c = Flow Rate into Leak ft^3/sec.

TABULATION OF LEAK RATIOS