April 8, 1976

Mr. Richard B. Bender
Corrosion Associates
P.O. Box 11302
Fort Worth, Texas 76110

Dear Mr. Bender:

In your letter of March 31, 1976, you ask whether the exemptions contained in Section 192.455 apply to pipelines which are subject to the requirements of Section 192.457. We presume the question arises from the wording of Section 192.457 which provides that certain pipelines must be cathodically protected "in accordance with this subpart."

By its terms, Section 192.455 specifically applies to pipelines installed after July 31, 1971. Likewise, Section 192.457 specifically applies to pipelines installed before August 1, 1971. This distinction in the scope of the two sections indicates that the exemptions under Section 192.455 are intended to apply only to pipelines installed after July 31, 1971.

In Section 192.457, the phrase "in accordance with this subpart" is not intended to reference the exemptions from the cathodic protection requirement of Section 192.455. This is particularly true in light of the analogous usage of the phrase in Section 192.455 where exemptions are otherwise set forth. Rather, in both sections the phrase is grammatically used to describe the requirement for cathodic protection. The phrase indicates that other regulations in Subpart I, namely Section 192.463, govern the protection which must be provided.

Sincerely,

\signed\

Cesar DeLeon
Acting Director
Office of Pipeline
Safety Operations

dal\195\260\76-04-08

March 31, 1976

Mr. Cesar DeLeon
Acting Director
Office of Pipeline Safety
Department of Transportation
Washington, D.C. 20590

Dear Mr. DeLeon:

As an independent Corrosion Consultant, I need some assistance in interpreting a situation that has been presented to me by the regional Federal Housing Authority, Dallas, Texas.

The question concerns Section 192.455 and Section 192.457. They feel that they can interpret these two sections which will allow them exempt status from cathodic protection on an apartment project that is 20 years old. Can they apply the section dealing with systems installed after 1971 to a system that was installed prior to 1971? As we interpreted the law to them, they cannot do this.

In the past when we asked for help, it was inferred that only the owner or the operator can get answers. However, as a consultant working with your rules and regulations; and dealing with apartment project owners who can't even spell cathodic protection, we are working with you and need your help.

I do not like to be placed in a position where we would have to sign a document stating that cathodic protection is not needed on an apartment project when in fact we have interpreted your regulations that it be protected. Perhaps a letter or an answer in the monthly news OPSO Advisory Bulletin would benefit everyone in the industry, including H.U.D.

I am caught between two major Federal Bureaus (DOT and HUD.) I know the horror of a gas explosion, and I know what can be done with cathodic protection. I will not sign a document that is not true. Please assist me in this matter.

Sincerely yours,

RICHARD B. BENDER CORROSION ASSOCIATES

\signed\
R.B. (pipe) Bender
NACE Certification No. 14

dal\195\260\76-04-08

Mr. Richard B. Bender
Corrosion Associates
P.O. Box 11302
Fort Worth, Texas 76110

Dear Mr. Bender:

In your letter of March 31, 1976, you ask whether the exemptions contained in Section 192.455 apply to pipelines which were installed in an apartment project 20 years ago.

By its terms, Section 192.455 specifically applies to pipelines installed after July 31, 1971. Likewise, Section 192.457 specifically applies to pipelines installed before August 1, 1971. This distinction in the scope of the two sections indicates that the exemptions under Section 192.455 are intended to apply only to pipelines installed after July 31, 1971, and not to pipelines 20 years old.

We trust this satisfactorily responds to your inquiry.

Sincerely,

\signed\

Cesar DeLeon
Acting Director
Office of Pipeline
Safety Operations

dal\195\260\76-04-08

July 14, 1975

Mr. Joseph Caldwell, Director
Office of Pipeline Safety
Department of Transportation
2100 2nd Street, SW
Washington, D.C. 20590

Dear Mr. Caldwell:

Thank you for your letter of July 7, 1975 relative to the Control, Inc. Corrosion Control Program.

Based on the preamble to Subpart I and the broad meaning of the word "impractical", we have interpreted 192.457(b) to mean that an electrical survey is not mandatory and that operators could use leak surveys and/or records to determine areas of active corrosion. We have so advised the utilities in Tennessee as can be seen from my letter dated July 26, 1974.

Electrical survey procedures are not specific ad results can be indefinite and inconclusive, as is well stated in the enclosed paragraph 8-02 or Air Force Manual 88-9, Chapter 4; and other than in appendix D, Part 192 provides no specific criteria relative to soil resistivity or bacteria. I discussed this at length with Lance Heverly in 1972 and it is because of the above reasons we subsequently deleted 192.455(b) in Tennessee. It has been our opinion that leak surveys and/or records provide a more accurate and concrete indication of active corrosion.

With the 1976 deadline approaching we need to know whether to redirect our utilities or amend Part 192 in Tennessee to state specifically that leak surveys and/or records can be used as a method of determining areas of active corrosion, if such an amendment would not weaken the regulation. Your advice will be appreciated.

Sincerely,

\signed\

John Searcy, Engineer
Engineering Division

dal\195\260\76-04-08

July 26, 1974

TO: ALL GAS UTILITIES

FROM: John Searcy
Engineering Division

The Tennessee Public Service Commission, Engineering Division, is the authority enforcing the gas pipeline safety regulations for transmission and distribution in Tennessee. These regulations are susceptible to comments and interpretations by those other than authorized representatives of the Commission, and such comments and interpretations may be contrary to the intent of the regulations. Particularly susceptible are the regulations relating to leak surveys, corrosion control, and other operations which may involve the services of outside contractors, consultants, and/or suppliers.

Erroneous or misleading interpretations of, or statements concerning, regulations can cost you money unnecessarily in that services may be performed over and above that required by the regulations. Always contact me or the Gas Safety Inspector assigned to your area when you have questions concerning, or are in doubt about, the regulations. Do not abide by any statement concerning the regulations other than those made by representatives of the Commission unless you first verify with the Commission any statement you have heard concerning the regulations.

Outlining briefly the leak survey and corrosion control requirements, buried or submerged distribution pipelines installed prior to August 1, 1971, require cathodic protection by August 1, 1976, unless it can be shown that a corrosive environment does not exist. This may be shown, for example, by an analysis of corrosion related leak history. Pipelines unprotected because of such a showing must be re-evaluated every three (3) years to determine whether or not the environment has changed.

Pipelines installed after July 31, 1971, must be coated, and within one (1) year after construction, cathodically protected, regardless of whether or not a corrosive environment exists.

Probably the most well know cathodic protection criterion is the -.85 volt potential. However, there are other criteria in Appendix D of the Federal Minimum Safety Standards. Any of the criterion may be met.

There are also atmospheric corrosion control requirements for above ground pipelines.

Concerning leak surveys, business districts require a survey every year, and other areas require a survey every five (5) years.

8-02 FIELD TEST METHODS. It is important that corrosion field survey work be performed by experienced personnel. There is no other engineering field in which so many meaningless measurements or misinterpretations of results are likely to occur than when inexperienced personnel are called upon to do field survey work. Corrosion testing is widely diversified involving many different techniques, some of which are highly specialized. Tests may require durations of a few minutes to a year or more, and measurements may vary over wide limits. For example, potential measurements can vary from a few millivolts to hundreds of volts, and the currents involved may be a few milliamperes or hundreds of amperes. The size of a structure bears no relation to the type of test required. A small complex structure may involve many intricate measurements. Often the available data are fragmentary, and the conditions that cannot be measured are of greater significance than those that are obtainable. Consequently, judgment and experience in field-testing techniques are of great value. Due to the many factors involved, a corrosion investigation may include visual inspection, study of geographical areas, study of records, chemical analyses, electrical measurements, and sometimes biological studies. The proper combination of tests to use depends largely upon the data available and local conditions. Here again, the necessity for experienced personnel is evident. Corrosion survey reports should indicate not only the results of the tests, but also the reasons why particular tests were used or why they were excluded. Brief descriptions of some of the standard test practices are now presented.

a. Soil Resistivity Measurements. The voltage drop principle is used to determine the resistivity of soils and water. The electrolyte resistivity plays a big part in the rate of corrosion. However, it must be pointed out that no single test can be taken as an absolute determination of corrosivity. Variations in electrolyte resistivity are often the critical factor. For the design of cathodic protection systems, a knowledge of the soil resistivity values in a given area . . . **(The remainder of this page did not print and the typist has no idea what was in that area!)**

SUBPART I- REQUIREMENTS FOR CORROSION CONTROL

?192.457(C) Active Corrosion

1. What is a condition where you have continuing corrosion that is not detrimental to public safety?

2. Does this mean that if you have corrosion way out in the country in a place where no one lives, that no cathodic protection is required if the pipe was installed before 1971?

3. How about in a city if a pipe is 300 yards from a place where people would congregate or live.

?192.463(d)

1. Each operator shall take prompt remedial action to correct any deficiencies indicated by monitoring.

   a. What time period does the word prompt cover?

?192.455(f)

1. As far as enforcement of Part (f) of this regulation:

   a. If an operator wants to install an insulated fitting protected by alloyage, must this operator comply with each part of (f) (1, 2, &3)? If not, is the operator then in violation?

   b. An operator can use these fittings according to item (1) if he can show by tests, investigation, or <u>experience</u> that adequate corrosion control is provided by alloyage.

      1. Does this mean that an operator must be keeping some type of record to prove that from past experience the alloy used in the fitting has not had a corrosion problem. In other words, have records showing that brass or stainless steel after being in service for a period of years and experienced no corrosion problem.

      2. Would the operator have to prove this for all soil resistivities?

      3. Would it be adequate for an operator with no records of tests or investigations just to say they have experienced no corrosion problem with the

alloyage used in the fitting, therefore, it is meeting ?192.455(1)?

4. Who makes the final determination as to what types of alloyage are adequate; the operator, OPSR, OOE, the respective region?

c. Must an operator test the manufacturers's design to see if corrosion pitting would cause fitting to leak? Could he just review manufacturer's data?

d. Must an operator still keep track of the location of metal alloy fittings if the operator claims that he has adequately proven that there is no corrosion problem in all soil resistivity with respect to the alloy being used.

2. The small municipalities would have a hard time showing by tests and investigations that an alloy is adequate. Is it OK for these municipalities to depend on test results from other gas companies with respect to alloys used in these fittings as long as they keep track of where they are putting them?

October 16, 1979

Mr. R. E. Speckmann, Manager
Regulations and Maintenance Standards
Shell Pipe Line Corporation
P.O. Box 2648
Houston, TX 77001

Dear Mr. Speckmann:

Your letter of June 19, 1979, requesting a finding under 49 CFR 195.260(e) that valves are not justified at certain water crossings in your planned installation of the 48-inch diameter LOCAP crude oil pipeline between the Louisiana Offshore Oil Port (LOOP) terminal at Clovelly, Louisiana, and the existing input terminal to the Capline system at St. James, Louisiana.

In your letter, you stated that the LOCAP pipeline begins at LOOP's Clovelly, Louisiana, underground storage dome in Section 32, T18S, R22E, LaFourche Parish, and extends in a northerly direction across marshes, numerous bayous, swamps, the Intracoastal Waterway, and some farmland to the Capline Pipeline St. James Terminal located in Section 56, T12S, R16E, St. James Parish, Louisiana. Conditions along the LOCAP pipeline route are such that approximately 85 percent of the pipeline will be installed in marsh and swamp areas using weight coating for stability. The pipeline will be welded together and floated in a ditch excavated through these areas. The pipeline will be submerged, and the floatation ditch will be backfield to cover the pipeline. Brackish and fresh water will exist at various times of the year over most of the length of the new pipeline.

You indicated that precise compliance with?195.260(e) would result in the placement of what the Shell Pipe Line Corporation (SPLC) considers to be an impractical number of valves. Instead you proposed to place valves at initiating and delivery terminals, near Highway 3199 and near Highway 20, and on each side of the Intracoastal Waterway. The valves at the initiating and delivery terminals and on each side of the Intracoastal Waterway will be remotely operable from the Capline St. James Control Center. Further, you also proposed to install two means to detect leaks, as discussed hereafter.

In the evaluation of your request, this Office considered the following factors as relevant to whether justification exists for not installing valves as required:

1. <u>Effectiveness of Proposed Leak Detection and Shutdown System</u>

We found your plans for automated leak detection with alarms and remotely controlled block valves and shutdown pumps at Clovelly Station to be an effective, integrated set of alternative measures which will assure a level of safety far exceeding that attainable by literal adherence to ?195.260(e). Your first method, a dynamic computer model of the pipeline, will provide rapid response to suddenly occurring leaks. i believe this model will read telemetered pressures and flow rates from Clovelly and St. James. Utilizing hydraulic surge theory, the model will calculate and compare calculated and telemetered hydraulic variables. Computerized computations will ascertain the divergence between real and calculated values and send appropriate alarms to the oil movements controller if a leak is indicated.

The proposed second method of leak detection by comparison of input and delivery volumes will be read into a computer line balance program and compared at periodic intervals. If a discrepancy exists between the adjusted input and output volumes exceeding a preset limit, the proposed leak detection alarm will be signalled to the oil movements controller, who will be able to shut down the pumps at Clovelly Station and isolate the pipeline by means of remotely controlled block valves at initiating and delivery terminals and on each side of the Intracoastal Waterway. Your proposed leak detection and shutdown appear to be safe and surpass the safety provided if shutdown capabilities were limited to manually controlled valves placed as required by?195.260(e). Even if these remotely controlled valves failed to close in the event of a pipeline rupture, the response time required to manually close them should be no greater than the response time necessary to close any manually operated valves under?195.260(e).

2. Threat to the Integrity of the Pipeline at the Planned Water Crossings

The waterways to be crossed other than the Intracoastal Waterway are all less than 10 feet deep and most are less than 7 feet deep. Flow rates are so low that erosion of the pipeline cover is highly unlikely. Marine traffic consists of light, shallow draft boats and an occasional flat-bottomed barge, none of which can be expected to damage the pipeline within its 5-foot, filled trench by direct contact or dragging anchor. For these reasons, we conclude that the probability of pipeline rupture at these water crossings is not appreciably greater than that for the remainder of the pipeline.

3. Drainage from Line after Shutdown

Placement of valves on either side of the water crossing is to limit line drainage into the waterway after shutdown in the event of rupture at a crossing. In your proposed valving plan locations, Drawing No. SK-0146 showing pipeline water crossings, even though a valve is not near a crossing, very little oil is expected to escape from any line rupture that might occur at the crossing after shutdown occurs and all dynamic effects cease. The maximum grade elevation variation along the pipeline is limited to approximately 15 feet. The elevation at Clovelly Dome is 0 feet to -1 foot, and at the St. James Terminal, the elevation is approximately +14 feet at the delivery manifold. Eighty percent of the pipeline will be installed in marsh and swamp areas using weight coating for stability. It is reasonable to postulate for practical purposes that the line will lie mostly beneath the water level and that after shutdown, water pressure will confine most of the line fill to the pipeline except for small amounts displaced by the differential in density between oil and water.

Therefore, in consideration of the above information and conclusions, the Materials Transportation Bureau finds that valves and a leak detection system installed and operated as proposed in your letter of June 19, 1979, will provide an acceptable level of public safety and that placement of valves on each side of every water crossing, other than the Intracoastal Waterway, along the LOCAP pipeline is not justified.

Sincerely,

\signed\

Cesar DeLeon
Associate Director for
Pipeline Safety Regulation
Materials Transportation Bureau

dal\195\260\76-04-08

Shell Pipe Line Corporation

June 19, 1979

Mr. Cesar De Leon, Associate Director
for Pipeline Safety Regulation
Materials Transportation Bureau
Department of Transportation
Washington, D.C. 20590

Dear Mr. De Leon:

Shell Pipe Line will construct LOCAP Pipeline, a 48-inch diameter crude oil pipeline between the Louisiana Offshore Oil Port (LOOP) terminal at Clovelly, Louisiana, and the existing input terminal to the Capline system at St. James, Louisiana, Capline, in turn, delivers crude oil into the American mid-continent area.

The LOCAP pipeline segment was originally a part of the LOOP permit applications and approvals. Recently the owners of LOCAP Pipeline (Texaco, Inc., Marathon Pipe Line Company, Ashland Oil, Inc., and Shell Pipe Line Corporation) selected Shell Pipe Line Corporation to construct and operate it.

As shown on the attached sketch, the LOCAP line begins at LOOPS's Clovelly, Louisiana, underground storage dome in Section 32, T18S, R22E, LaFourche Parish, and extends in a northerly direction across marshes, numerous bayous, swamps, the Intracoastal Canal, and some farmland to the Capline Pipeline St. James Terminal located in Section 56, T12S, R16E, St. James Parish, Louisiana.

Conditions along the LOCAP pipeline route are such that approximately 85 percent of the pipeline will be installed in marsh and swamp areas using weight coating for stability. The pipeline will be welded together and floated in a ditch excavated through these areas. The pipeline will be submerged, and the floatation ditch will be backfilled to cover the pipeline. Brackish and fresh water will exist at various times of the year over most of the length of the new pipeline.

As in the case of LOOP Pipe Line System, extensive wetlands exist along most of the LOCAP pipeline route. Since approximately 18 bayous and submerged land areas will be crossed where the width of

dal\195\260\76-04-08

the crossing exceeds 100 feet (reference attached SK-046 (sic) for crossing locations), we believe, as in the case of LOOP pipeline, strict adherence to 49 CFR 195.206(c), "Transportation of Liquids by Pipeline", is neither practicable nor justifiable in this particular case. Due to the existence of a combination of water and marsh or swamp along the proposed 48-inch pipeline, block valves at all locations required by DOT regulations would not improve line safety nor appreciably reduce pollution should a failure occur.

Accordingly, we propose to install block valves at both sides of the Intracoastal Waterway, near Louisiana Highway 3199, near Highway 20, and at the initiating and delivery terminals. As shown on the attached sketch, valves located at terminals and the Intracoastal Waterway will be remotely operable from the Capline St. James Control Center. Maximum valve spacing will be approximately 16? miles. The recommended locations are accessible and serve a useful purpose should damage occur to the new pipeline.

Installation of valves in the above manner takes into consideration numerous related pipeline control factors including the following:

A. Leak Detection and Shutdown System

Line integrity features will be included in the supervisory control system to monitor the pipeline for leaks and provide rapid shutdown of the pipeline by the oil movements controller in the event a leak is detected. Two methods of monitoring for leaks will be included in the line integrity features. The first method, a dynamic computer model of the pipeline, will provide rapid response to suddenly occurring leaks. The model will read telemetered pressures and flow rates from Clovelly and St. James. Utilizing hydraulic surge theory, the model will calculate and compare calculated and telemetered hydraulic variables. Shell Pipe Line's computer program will ascertain the divergence between real and calculated values and send appropriate alarms to the oil movements controller if a leak is indicated.

The second method of leak detection functions by comparison of input and delivery volumes. Input and delivery volumes from custody transfer quality meters at Clovelly and St. James will be gathered each supervisory scan and will be read into a computer line balance program and compared at periodic intervals. At each comparison, line fill between the measurement points will be calculated by the computer and compared with the line fill calculation at the previous interval. Any change in line fill between the two intervals will be included in the line balance comparison. When a discrepancy exists between the adjusted input and output volumes exceeding a preset limit, a leak detection alarm will be presented to the oil movements controller.

Upon indication of a leak detection alarm, the oil movements controller will be able to shut down the pumps at Clovelly Station and isolate the pipeline by means of remotely controlled block valves at initiating and delivery terminals and on each side of the Intracoastal Canal - Clovelly Station to East Bank of Intracoastal Canal, East Bank to West Bank of Intracoastal Canal, and West Bank of Intracoastal Canal to St. James Terminal. Pressure transmitters will allow monitoring of the pressure in each of the three line sections for indications of leakage.

B. Pipeline Integrity at Planned Water Crossings (Excluding the Intracoastal Waterway)

The waterways to be crossed are all less than 10 feet deep. The waterway flow rates are such that erosion of the pipeline cover is highly unlikely. Marine traffic consists of light, shallow draft boats and an occasional flat-bottomed barge, none of which can be expected to damage the pipeline within its 5-foot backfilled trench by direct contact or dragging anchor. A significant degree of protection from exterior mechanical damage will be provided by the steel reinforced concrete weight coating approximately five inches thick and surrounding the pipe. It may, therefore, be concluded that the probability of pipeline rupture at these water crossings is not greater than that for the remainder of the pipeline.

C. Drainage from Line after Shutdown

Under the proposed valving plan, even though a valve may not be near a point of rupture, very little oil is expected to escape from any rupture after shutdown occurs and all dynamic effects cease. Because the maximum grade elevation variation along the pipeline is limited to approximately 15 feet (Clovelly Dome is 0 feet to -1 feet, St. James Terminal is approximately +14 feet at the delivery manifold) and because much of the line lies beneath the water level, the line fill should be confined to the pipeline by water pressure except for small amounts displaced by the differential in density between oil and water.

In consideration of the above, your concurrence with

LOCAP pipeline valve placement at water and road crossings as recommended is requested in lieu of requirements established under the provisions of 195.260(e) Part 195, Transportation of Liquids by Pipeline, DOT - Pipeline Safety Regulations.

Very truly yours,

\signed\

R. E. Speckmann, Manager
Regulations and Maintenance Standards

Attachments:

1. Sketch No. SD-13712 showing line location.
2. Drawing SK-0146 showing pipeline, water crossing, and proposed valve locations.

dal\195\260\76-04-08