Hopkinton LNG Corp.
One NSTAR Way
Westwood, MA 02090-9230

Via Overnight Delivery

November 5, 2008

Mr. Byron Coy, PE
Director, Eastern Region
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
409 3rd Street, S.W. Suite 300
Washington, D.C. 20024

Re: CPF 1-2008-3001M

Dear Mr. Coy:

This correspondence is in response to your Notice of Amendment ("NOA") dated September 16, 2008 and the follow-up correspondence relative to Hopkinton LNG Corp.'s (the "Company") procedures for remediating external corrosion. Pursuant to your request, please find attached a copy of the Company's procedure for Cathodic Protection System Monitoring that has been revised in accordance with the guidance provided by your office. Note that this document has been extracted from the Company's comprehensive Maintenance Manual for the Hopkinton, MA LNG facility.

To the extent that it may be required, the Company respectfully requests waiver to file this information with your office on this date, rather than 30 days following the NOA. In our efforts to fully comply with the requirements listed in the NOA, the Company consulted further with your staff until just recently and then received appropriate internal reviews to implement the revised procedure. The Company requests that this response be accepted by your office.

If you have any further questions, comments or concerns, please feel free to contact me.

Sincerely,

/s/ Mark E. Gunsalus

Mark E. Gunsalus
Manager, Gas Supply and LNG Operations
NSTAR Electric & Gas Corporation

cc: Philip B. Andreas, Vice President, Gas Operations
Jon Pfister, Manager, Compliance
Hopkinton LNG Corp. file copy

3.0 Corrosion Control

3.1 General

A. The NSTAR Electric & Gas Corporation Corrosion Engineer shall be responsible for the design and execution of the plant's corrosion control program.

B. The Corrosion Engineer shall be responsible for the design, installation, operation, and maintenance of cathodic protection systems.

C. The corrosion control program must be in compliance with the Federal Rules and Regulations Part 192, "Transportation of Natural Gas and Other Gas by Pipeline: Subpart I, Requirements for Corrosion Control" and Federal Rules and Regulations Part 193, "LNG Facilities: Subpart G, Maintenance."

D. Corrosion Control personnel shall perform the corrosion control activities under the direction of the Corrosion Engineer and the plant manager. Corrosion control personnel include APCI plant operators as well as other personnel specified by the Hopkinton LNG Corporation.

The procedures that follow are typical methods for corrosion control. Field changes may be required when deemed necessary.

E. The Corrosion Engineer will review applicable design drawings and material specifications from a corrosion control viewpoint and make determinations that the materials involved in the following cases will not impair the safety or reliability of a component or any associated component:

1. New construction.

2. Repair, replacement, or significant alteration of a component.

F. The Corrosion Engineer will ensure that the form "Components Requiring Corrosion Control" as shown in Section 3.2 is instituted and completed as necessary.

G. The Corrosion Engineer shall prepare an annual report that summarizes the corrosion control activities at the plant. This report will include the status of the compliance with the Corrosion Control Procedures and also include the expansion of corrosion control activities and facilities, if any.

H. The Corrosion Engineer will submit the plant's Corrosion Control Report annually for the preceding year to the Plant Manager.

I. The Corrosion Engineer will use the Preventive Maintenance Scheduling and Reporting System (Appendix A) for scheduling and recording inspections and tests.

3.2 Determination of Components Requiring Corrosion Control

A. Any metallic component whose integrity or reliability could be adversely affected by corrosion during its intended service life must be provided with corrosion control, provided that the component is necessary to maintain safety in controlling, processing, or containing a hazardous fluid.

B. The types of corrosion that components may be subjected to are defined below:

1. External--Corrosion which occurs on the external surfaces of buried or submerged plant components.

2. Internal--Corrosion which occurs on the internal surfaces of plant components.

3. Atmospheric--Corrosion which occurs on the surfaces of plant components which are exposed to the atmosphere.

C. The two forms of acceptable corrosion controls are:

1. Application and utilization of cathodic protection systems, coatings, paints, inhibitors, or other generally accepted practices and procedures.

2. Inspection for corrosion and replacement under a program of scheduled maintenance.

D. Metallic components of corrosion-resistant material do not require internal corrosion protection or monitoring of internal corrosion if it can be demonstrated that the component will not be adversely affected by internal corrosion during its service life.

E. Use the Company's Preventive Maintenance Scheduling and Reporting System (Appendix A) for scheduling and recording inspections and tests.

3.3 External Corrosion Control

A. Each existing buried or submerged component that is subject to external corrosive attack must be protected from corrosion by either:

1. Material that has been designed and selected to resist the corrosive equipment involved, or

2. An external protective coating which meets the corrosion preventive requirements of 192.461, and a cathodic protection system designed to protect components in their entirety to meet the requirements of 192.463.

3. Any cathodic protection system designed for a structure must provide a level of cathodic protection that complies with one or more of the applicable criteria stipulated in Appendix D of Title 49 CFR Part 192.

B. All new buried or submerged components must be protected from corrosion as in paragraph A.1 or A.2 within one (1) year after the component is constructed or installed.

C. Each component that is subject to electrical current interference must be protected by a continuing program to minimize the detrimental effects of currents.

D. Cathodic protection systems must minimize adverse effects to adjacent metal components.

E. Each impressed current power source must be installed and maintained to prevent adverse interference with communications and control systems.

F. The corrosion control program must meet the requirements of Title 49, Part 192 of the Code of Federal Regulations, "Transportation of Natural Gas and Other Gas by Pipelines: Minimum Federal Safety Standards," Subpart I, "Requirements for Corrosion Control" particularly Section 192.461--External Corrosion Control: Protective Coatings and Section 192.463-- External Corrosion Control: Cathodic Protection.

G. Identify all buried pipelines and related components that shall be protected from external corrosion and record on the form "Components Requiring Corrosion Control" as shown in Section 4.2.

H. Each buried pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and other structures are electrically interconnected and cathodically protected as a single unit.

I. All cathodically protected systems must be electrically isolated. Isolation material must be installed in the following locations:

1. Between casings and carrier pipe.

2. At all metallic structures not requiring cathodic protection.

3. Between metals of different anodic potential where significant corrosion can occur as a result of this difference.

4. Where fault currents or lightning can affect the pipeline. This may occur close to electrical transmission tower footings or ground cables.

5. At control and telemetering piping, and electric conduit or wiring.

6. At the termination of gas service lines to engines, equipment, appliances, or plant buildings gas meters.

J. Apply an external protective coating and a cathodic protection system designed to protect all buried carbon steel pipelines within the plant that carry a flammable fluid.

K. New buried pipelines and related components must be coated and cathodically protected within one (1) year after completion of construction or installation.

L. When it is known or suspected that interference currents from other sources are affecting a pipeline or component, tests shall be conducted to determine the extent of the interference.

M. Whenever any portion of a buried pipeline or component is uncovered or exposed, an inspection shall be made by corrosion control personnel to determine the condition of the coating and evidence of corrosion.

N. Take prompt corrective or remedial action for any deficiency in external corrosion protection discovered as a result of any test survey or inspection. Such action may include a restoration or application of new or additional coatings and/or cathodic protection or replacement of the component.

O. Use the Preventive Maintenance Scheduling and Reporting System (Appendix A) to schedule and document piping and component inspections.

P. The date and description of each maintenance activity performed under these corrosion control procedures shall be documented and the record maintained for the life of the plant.

3.4 Cathodic Protection System Monitoring

A. Create file for each protected system.

Corrosion system files should sontain the following information as a minimum:

a. schematic of syste, indicating general test locations and mainline insulator locations

b. sketches showing location of each test station

c. past and present survey data

d. rectifier output summary, where applicable

B. Conduct survey once each calendar year at intervals not to exceed 15 months for galvanically protected structures.

C. Monitor and record interference bonds, whose failure would jeopardize structure protection, at intervals not to exceed 2-1/2 months.

D. Record systems will be updated at intervals not to exceed fifteenmonths.

3.4.1 Test Procedures

The procedures that follow are typical methods for cathodic protection system surveillance.
Specific application and adjustments of technique will be dictated by the particular Parameters of the individual systems. No system is identical to another. Many ares of deficiency analysis are not supported by definitive evidence. For example, a contact locator
survey relies on the interpretation of an audio signal by the operator. In many instances, this interpretation is based solely on the experience of the operator. Ther is no supportive electronic data such as ground voltage or current. A resistance contact, and poor coating condition can give exactly the same data and calculated results. They cannot be delineated by data analysis alone.

3.4.2 Monitoring Galvanic Anode Systems

A. Connect voltmeter negative to structure on the underground side of insulating fitting.

B. Place copper sulphate reference electrode directly over the structure (or as close to structure as possible), a minimum of 61' from an anode test station, or at the location of the previous survey.

C. Connect voltmeter positive to copper to copper sulphate reference electrode.

1) Read ground voltage (V) and record on data sheet.

2) If all ground voltage readings (V) are at or above 0.85 volts, test is completed.

D. If all ground voltage readings are not at or above 0.85 volts, turn to 3.4.4 for follow-up procedure.

3.4.3 Monitoring Impressed Current Systems

A. Rectifiers shall be inspected for proper operation at a minimum of six times each year, at intervals not to exceed 2-1/2 months.

B. Read and record the output DC current using the unit ammeter, portable instruments or both.

C. Be certain that the current is within established limits.

D. The output DC voltage may be read and recorded.

E. The AC output voltage may be read and recorded.

F. Any deficiencies in the operations of the rectifier should be corrected before the next scheduled inspection.

G. Each cathodic protetion system shall be surveyed at a minimum of once each calendar year, at intervals not to exceed 15 months.

1) Generally, surveillance tests for levels of cathodic protection will be conducted with the rectifier operating un-interrupted

2) If no anodes are present at a given test station, read the ground voltage (V) with a copper sulfate reference electrode placed over the pipeline, adjacent to the test station.

3) If system appears cathodically protected, and has an average coating resistance of 25,000 ohms/ft2, or higher, measure ground voltage approximately every 2500'.

4) If system appears cathodically protected, and has an average coating resistance less than 25,000 ohms/ft2, determine if ther are any areas of low ground voltage. Search for these areas through a combination of a more detailed ground voltage survey and average coating resistance determination by section, thrugh the use of current measuring test stations, bonded insulators having test stations, and or a current mapper.

5) Subsuquent ground voltage measurements should be taken at the areas determined to exhibit the lowest values.

6) Average coating resistance data should be obtained with the copper sulfate reference electrode first placed over the structure, and then placed approximately 30' remote.

7) If system is not cathodically protected, refer to Secton 3.4.4.

8) Conduct a "Pearson Survey" to locate coating damage and perpendicular contacts, or near perpendicular contact, when necessary.

3.4.4 Procedure for Analyzing Protection System Deficiency

A. If all ground voltage readings (V) are not at or above 0.85 volts, then proceed as follows:

1) Determine structure resistance to earth.

a. Connect current power source and circuitry.

b. Connect voltmeter to read ground voltage.

c. Adjust current (I) so as to obtain a measureable and meaningful voltage shift.

d. Read change in ground voltage (ΔV) and record. Δ V is the V with the current on minus V with the current off.

2) Calculate average coating resistance

a. Average coating resistance = $\Delta V/I$ x magnitude of total surface area of the structure in system (units will be ohms/ft^2).

b. If average coating resistance is over 5000 ohms/ft^2, protective current is lacking and test is complete.

c. If resistance is below 5000 ohms/ft^2, test effectiveness of insulating fittings utilizing an approved test method and/or device.

3) If insulating fitting is effective, then conduct a contact locator survey to locate foreign contact. Conduct contact locator test as follows:

a. Anodes should be disconnected from system before procedding with this test.

b. Connect transmitter between structure and isolated ground, such as anodes or driven or driven rod. A grounded structure can be used, but is second choice.

c. Follow the signal with the receiver upright and directly over the structure. Confirm pipeline location by nulling signal.

d. Signal drops off sharply over the contact, and remains low beyond the contact.

e. Survey in a circle around the point of contact, about 30' in radius. A contacting line or an uninsulated service will null the signal.

f. A contact with a parallel line will not easily result in confirmation of the point of contact.

g. A poorly coated, or bare structure, will cause the signal to slowly die, and may cause a significant signal change in an area of a large holiday.

B. Continued testing and troubleshooting (if needed) will be conducted during the test period to determine that the deficiency has been corrected.

C. If remedial action can not be performed prior to the next test period due to permitting, technical issues or other unforeseen problems, the situation will continue to be monitored on a more frequent basis to ensure the deficiency does not worsen.

1) Documentation for the reason why the deficiency could not be corrected will be available and kept with corrosion records.

2) A plan to correct the deficiency will be documented and kept with corrosion records.

3.5 Internal Corrosion Control

A. Inspection programs for internal corrosion shall be performed for all metallic components which carry contaminants that could be corrosive, and shall include all designated components on the form "Components Requiring Corrosion Control" as shown in Section 3.2. (none are known to exist).

B. Piping and components shall be monitored for internal corrosion control by:

1. insertion of probes or coupons at locations where internal corrosion is likely to occur, or

2. removal and inspection of component segments of downstream piping and/or spool pieces that are located where internal corrosion is likely to occur, or

3. sampling and chemical analysis.

C. Where internal corrosion control and monitoring is not utilized, it must be demonstrated that the component will not be adversely affected by internal corrosion during its service life.

D. Whenever a metallic component is protected from internal corrosion by any means, such as coatings or inhibitors, or has been designated as a component requiring internal corrosion monitoring, a monitoring device or scheduled inspection method designed to detect internal corrosion shall be used.

E. When any metallic component is removed from service or replaced, it shall be inspected for evidence of internal corrosion as well as the absence of corrosion. The results of the inspection shall be documented. If internal corrosion is found, the adjacent components shall be inspected to determine the extent of the corrosion.

F. Take prompt corrective or remedial action for any deficiency in internal corrosion protection discovered as a result of any test, survey, or inspection. Such action may include replacement of the component or other corrosion mitigation procedures.

G. Use the Preventive Maintenance Scheduling and Reporting System (Appendix A) for scheduling and recording inspections and tests.

3.6 Atmospheric Corrosion Control

A. Inspection programs for atmospheric corrosion shall be performed for all metallic components designated on the form "Components Requiring Corrosion Control" as shown in Section 3.2.

B. Inspections shall not be required for materials that have been designed and selected to resist the corrosive atmosphere involved.

C. Pipelines exposed to the atmosphere will be inspected at least once every three years, at intervals not to exceed thirty-nine months.

Pipelines will be inspected and information recorded regarding:

Coating quality, existing corrosion (localized or general; good, fair or poor), erosion, condition of fittings and support integrity.

Particular attention shall be given at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

Coating Evaluation

The following evaluation technique may be used:

A pipeline exhibiting a "GOOD" coating condition has an average of less than 3 square inches of coating damage per square foot of pipe area.

A pipeline exhibiting a "FAIR" coating condition has an average of from 3-5 square inches of coating damage per square foot of pipe area.

A pipeline exhibiting a "POOR" coating condition has an average of more than 5 square inches of coating damage per square foot of pipe area.

Corrosion Severity Evaluation

The following evaluation technique may be used:

Localized corrosion is that exhibiting scattered pitting to such an extent that the MAOP could not be jeopardized if corrosion were to progress to the point of wall penetration. When pitting is not encroaching upon one another the MAOP is not considered to be in jeopardy.

General corrosion is that exhibiting closely grouped pitting, that could jeopardize the MAOP if corrosion were to progress. Pitting is considered closely grouped when they are encroaching upon one another.

A pipeline exhibiting a "GOOD" corrosion condition has no corrosion or superficial corrosion, and no repair work is required.

A pipeline exhibiting a "FAIR" corroison condition has pitting but the structural integrity is intact, and no repair is required.

A pipeline exhibiting a "POOR" corrosion condition has pitting to the point where a repair or replacement ir required, or the structural integrity is suspect.

D. Maintain a continuing program of painting or insulation of other suitable protective coatings based upon the results of the inspection program so that atmospheric corrosion is controlled.

E. Inspect piping covered by thermal insulation whenever said insulation is removed. The Corrosion Engineer may require a program where systematic inspection of structures covered by thermal insulation is required.

F. Use the Preventive Maintenance Scheduling and Reporting System (Appendix A) to schedule and record tests, surveys, and inspections.